Energy Uplift (Operating Reserves)

Energy uplift is paid to market participants under specified conditions in order to ensure that resources are not required to operate for the PJM system at a loss.[1] Referred to in PJM as operating reserve credits, lost opportunity cost credits, reactive services credits, synchronous condensing credits or black start services credits, these payments are intended to be one of the incentives to generation owners to offer their energy to the PJM Energy Market for dispatch based on incremental offer curves and to operate their units at the direction of PJM dispatchers. These credits are paid by PJM market participants as operating reserve charges, reactive services charges, synchronous condensing charges or black start services charges.[2]

Overview

Energy Uplift Results

- **Energy Uplift Charges.** Total energy uplift charges increased by $258.8 million or 40.2 percent in the first nine months of 2014 compared to the first nine months of 2013, from $644.2 million to $902.9 million. The increase of $258.8 million in the first nine months of 2014 is comprised of an increase of $12.9 million in day-ahead operating reserve charges, an increase of $444.6 million in balancing operating reserve charges, a decrease of $156.1 million in reactive services charges, a decrease of $0.3 million in synchronous condensing charges and a decrease of $42.3 million in black start services charges.
- **Operating Reserve Rates.** The day-ahead operating reserve rate averaged $0.139 per MWh. The balancing operating reserve reliability rates averaged $0.702, $0.023 and $0.010 per MWh for the RTO, Eastern and Western regions. The balancing operating reserve deviation rates averaged $1.491, $0.425 and $0.159 per MWh for the RTO, Eastern and Western regions. The lost opportunity cost rate averaged $1.481 per MWh and the canceled resources rate averaged $0.013 per MWh.
- **Reactive Services Rates.** The DPL, ATSI and PENELEC control zones had the three highest reactive local voltage support rates: $0.499, $0.229 and $0.210 per MWh. The reactive transfer interface support rate averaged $0.001 per MWh.

Characteristics of Credits

- **Types of units.** Combined cycles received 38.8 percent of all day-ahead generator credits and 56.6 percent of all balancing generator credits. Combustion turbines and diesels received 68.2 percent of the lost opportunity cost credits. Coal units received 83.8 percent of all reactive services credits.
- **Concentration of Energy Uplift Credits:** The top 10 units receiving energy uplift credits received 35.5 percent of all credits. The top 10 organizations received 81.8 percent of all credits. Concentration indexes for energy uplift categories classify them as highly concentrated. Day-ahead operating reserves HHI was 4622, balancing operating reserves HHI was 2959, lost opportunity cost HHI was 3838 and reactive services HHI was 6964.
- **Economic and Noneconomic Generation.** In the first nine months of 2014, 87.5 percent of the day-ahead generation eligible for operating reserve credits was economic and 72.7 percent of the real-time generation eligible for operating reserve credits was economic.
- **Day-Ahead Unit Commitment for Reliability:** In the first nine months of 2014, 4.3 percent of the total day-ahead generation was scheduled as must run by PJM, of which 32.2 percent received energy uplift payments.

Geography of Charges and Credits

- In the first nine months of 2014, 90.7 percent of all charges allocated regionally (day-ahead operating reserves and balancing operating reserves) were paid by transactions at control zones or buses within a control zone, demand and generators, 2.1 percent by transactions at hubs and aggregates and 7.2 percent by transactions at interfaces.

1 Loss is defined as gross energy and ancillary services market revenues less than total energy offer, which are startup, no load and incremental offers.

2 Other types of energy uplift charges are make whole payments to emergency demand response resources and emergency transaction purchases. These categories are not covered in this section. See Section 6, "Demand Response" and Section 9 "Interchange Transactions" for an explanation on these payments.

Energy Uplift Issues

- **Lost Opportunity Cost Credits:** In the first nine months of 2014, lost opportunity cost credits increased by $62.9 million compared to the first nine months of 2013. In the first nine months of 2014, resources in the top three control zones receiving lost opportunity cost credits, AEP, Dominion and PENELEC accounted for 56.5 percent of all lost opportunity cost credits, 44.1 percent of all day-ahead generation from pool-scheduled combustion turbines and diesels, 51.7 percent of all day-ahead generation not committed in real time by PJM from those unit types and 61.2 percent of all day-ahead generation not committed in real time by PJM and receiving lost opportunity cost credits from those unit types.
- **Black Start Service Units:** Certain units located in the AEP Control Zone are relied on for their black start capability on a regular basis during periods when the units are not economic. These black start units provide black start service under the ALR option, which means that the units must be running in order to provide black start services even if the units are not economic. In the first nine months of 2014, the cost of the noneconomic operation of ALR units in the AEP Control Zone was $26.4 million.
- **Con Edison – PJM Transmission Service Agreements Support:** Certain units located near the boundary between New Jersey and New York City have been operated to support the transmission service agreements between Con Ed and PJM, formerly known as the Con Ed – PSEG Wheeling Contracts. These units are often run out of merit and received substantial balancing operating reserves credits.

Energy Uplift Recommendations

- **Impact of Quantifiable Recommendations:** The impact of implementing the recommendations related to energy uplift proposed by the MMU on the rates paid by participants would be significant. For example, in the first nine months of 2014, the average rate paid by a DEC in the Eastern Region would have been $0.324 per MWh, which is $2.632 per MWh less than the actual average rate paid.

Recommendations

- The MMU recommends that PJM clearly identify, classify all reasons for incurring operating reserves in the Day-Ahead and the Real-Time Energy Markets and the associated operating reserve charges in order for all market participants be aware of the reason of these costs and to help ensure a long term solution to the issue of how to allocate the costs of operating reserves. (Priority: Medium. First reported 2012.)
- The MMU recommends that PJM be transparent in the formulation of closed loop interfaces with adjustable limits and develop rules to reduce the levels of subjectivity around the creation and implementation of these interfaces. (Priority: Medium. First reported 2013.)
- The MMU recommends that PJM estimate the impact such interfaces could have on additional uplift payments inside closed loops, transmission planning, offer capping, FTR and ARR revenue, ancillary services markets and the capacity market to avoid unintended consequences. (Priority: Medium. First reported 2013.)
- The MMU recommends that PJM revise the current operating reserve confidentiality rules in order to allow the disclosure of complete information about the level of operating reserve charges by unit and the detailed reasons for the level of operating reserve payments by unit in the PJM region. (Priority: High. First reported 2013.)
- The MMU recommends the elimination of the day-ahead operating reserve category to ensure that units receive an energy uplift payment based on their real-time output and not their day-ahead scheduled output. (Priority: Medium. First reported 2013.)
- The MMU recommends reincorporating the use of net regulation revenues as an offset in the calculation of balancing operating reserve credits. (Priority: Medium. First reported 2013.)
- The MMU recommends not compensating self-scheduled units for their startup cost when the units are scheduled by PJM to start before the self-scheduled hours. (Priority: Low. First reported 2013.)

- The MMU recommends four modifications to the energy lost opportunity cost calculations:
  - The MMU recommends that the lost opportunity cost in the Energy and Ancillary Services Markets be calculated using the schedule on which the unit was scheduled to run in the Energy Market. (Priority: High. First reported 2012.)
  - The MMU recommends including no load and startup costs as part of the total avoided costs in the calculation of lost opportunity cost credits paid to combustion turbines and diesels scheduled in the Day-Ahead Energy Market but not committed in real time. (Priority: Medium. First reported 2012.)
  - The MMU recommends eliminating the use of the day-ahead LMP to calculate lost opportunity cost credits paid to combustion turbines and diesels scheduled in the Day-Ahead Energy Market, but not committed in real time. (Priority: Medium. First reported 2012.)
  - The MMU recommends using the entire offer curve and not a single point on the offer curve to calculate energy lost opportunity cost. (Priority: Medium. First reported 2012.)
- The MMU recommends that up-to congestion transactions be required to pay operating reserve charges. (Priority: High. First reported 2013.)
- The MMU recommends eliminating the use of internal bilateral transactions (IBTs) in the calculation of deviations used to allocate balancing operating reserve charges. (Priority: High. First reported 2013.)
- The MMU recommends reallocating the operating reserve credits paid to units supporting the Con Edison – PJM Transmission Service Agreements. (Priority: Medium. First reported 2013.)
- The MMU recommends that the total cost of providing reactive support be categorized and allocated as reactive services. Reactive services credits should be calculated consistent with the operating reserve credits calculation. (Priority: Medium. First reported 2012.)
- The MMU recommends including real-time exports and real-time wheels in the allocation of the cost of providing reactive support to the 500 kV system or above which is currently allocated to real-time RTO load. (Priority: Low. First reported Q2, 2014.)
- The MMU recommends enhancing the current energy uplift allocation rules to reflect the elimination of day-ahead operating reserves and the timing of commitment decisions. (Priority: High. First reported Q1, 2014.)

Conclusion

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

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

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

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

PJM has recognized the importance of addressing the issues that result in large amounts of energy uplift charges. In 2013, PJM stakeholders created the Energy Market Uplift Senior Task Force (EMUSTF).[3] The main goals of the EMUSTF are to evaluate the causes of energy uplift payments, develop ways to minimize energy uplift payments while maintaining prices that are consistent with operational reliability needs, and explore the allocation of such payments. In December 2013, PJM stakeholders created the Market Implementation Committee – Energy/Reserve Pricing and Interchange Volatility group to address issues such as improving the incorporation of operators' actions in LMP.[4]

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

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

Energy Uplift

The level of energy uplift credits paid to specific units depends on the level of the resource's energy offer, the LMP, the resource's operating parameters and the decisions of PJM operators. Energy uplift credits result in part from decisions by PJM operators, who follow reliability requirements and market rules, to start resources or to keep resources operating even when hourly LMP is less than the offer price including energy, no load and startup costs.

Credits and Charges Categories

Energy uplift charges include day-ahead and balancing operating reserves, reactive services, synchronous condensing and black start services categories. Total energy uplift credits paid to PJM participants equal the total energy uplift charges paid by PJM participants. Table 4-1 and Table 4-2 show the categories of credits and charges and their relationship. These tables show how the charges are allocated.

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

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

Table 4-1 Day-ahead and balancing operating reserve credits and charges

Credits Received For:	Credits Category:		Charges Category:	Charges Paid By:	
		Day-Ahead			
Day-Ahead Import Transactions and Generation Resources	Day-Ahead Operating Reserve Transaction Day-Ahead Operating Reserve Generator	→	Day-Ahead Operating Reserve	Day-Ahead Load Day-Ahead Export Transactions Decrement Bids	in RTO Region
Economic Load Response Resources	Day-Ahead Operating Reserves for Load Response	→	Day-Ahead Operating Reserve for Load Response	Day-Ahead Load Day-Ahead Export Transactions Decrement Bids	in RTO Region
	Unallocated Negative Load Congestion Charges Unallocated Positive Generation Congestion Credits	→	Unallocated Congestion	Day-Ahead Load Day-Ahead Export Transactions Decrement Bids	in RTO Region
		Balancing			
Generation Resources	Balancing Operating Reserve Generator	→	Balancing Operating Reserve for Reliability	Real-Time Load plus Real-Time Export Transactions	in RTO, Eastern or Western Region
			Balancing Operating Reserve for Deviations	Deviations	
			Balancing Local Constraint	Applicable Requesting Party	
Canceled Resources	Balancing Operating Reserve Startup Cancellation	→	Balancing Operating Reserve for Deviations	Deviations	in RTO Region
Lost Opportunity Cost (LOC)	Balancing Operating Reserve LOC				
Real-Time Import Transactions	Balancing Operating Reserve Transaction				
Resources Providing Quick Start Reserve	Balancing Operating Reserve Generator				
Economic Load Response Resources	Balancing Operating Reserves for Load Response	→	Balancing Operating Reserve for Load Response	Deviations	in RTO Region

Table 4-2 Reactive services, synchronous condensing and black start services credits and charges

Credits Received For:	Credits Category:		Charges Category:	Charges Paid By:
		Reactive		
Resources Providing Reactive Service	Day-Ahead Operating Reserve Reactive Services Generator Reactive Services LOC Reactive Services Condensing Reactive Services Synchronous Condensing LOC	→	Reactive Services Charge	Zonal Real-Time Load
			Reactive Services Local Constraint	Applicable Requesting Party
		Synchronous Condensing		
Resources Providing Synchronous Condensing	Synchronous Condensing Synchronous Condensing LOC	→	Synchronous Condensing	Real-Time Load Real-Time Export Transactions
		Black Start		
Resources Providing Black Start Service	Day-Ahead Operating Reserve Balancing Operating Reserve Black Start Testing	→	Black Start Service Charge	Zone/Non-zone Peak Transmission Use and Point to Point Transmission Reservations

Energy Uplift Results

Energy Uplift Charges

Total energy uplift charges increased by 40.2 percent in the first nine months of 2014, compared to the first nine months of 2013, to a total of $902.9 million. Table 4-3 shows total energy uplift charges in the first nine months of 2013 and 2014.[5]

Table 4-3 Total energy uplift charges: January through September 2013 and 2014

	Jan - Sep 2013	Jan - Sep 2014	Change	Percentage Change
Total Energy Uplift Charges	$644,177,048	$902,934,088	$258,757,040	40.2%
Energy Uplift as a Percent of Total PJM Billing	2.6%	2.2%	(0.3%)	(13.5%)

Total energy uplift charges increased by $258.8 million or 40.2 percent in the first nine months of 2014 compared to the first nine months of 2013. Table 4-4 compares energy uplift charges by category for the first nine months of 2013 and the first nine months of 2014. The increase of $258.8 million in the first nine months of 2014 is comprised of an increase of $12.9 million in day-ahead operating reserve charges, an increase of $444.6 million in balancing operating reserve charges, a decrease of $156.1 million in reactive services charges, a decrease of $0.3 million in synchronous condensing charges and a decrease of $42.3 million in black start services charges. The increase in total energy uplift charges was a result of high demand, high natural gas costs and high LMPs in the first quarter. High natural gas prices and higher energy offers for units scheduled in the Day-Ahead Energy Market and units committed in real time for conservative operations increased the day-ahead and balancing operating reserve charges. Higher energy prices reduced the energy uplift for coal units providing black start and reactive support in the first quarter. In contrast, low demand and low natural gas prices during the second and third quarters reduced energy uplift charges.

Table 4-4 Energy uplift charges by category: January through September 2013 and 2014

Category	Jan - Sep 2013	Jan - Sep 2014	Change	Percentage Change
Day-Ahead Operating Reserves	$74,426,144	$87,305,917	$12,879,773	17.3%
Balancing Operating Reserves	$316,936,238	$761,500,593	$444,564,355	140.3%
Reactive Services	$183,515,064	$27,411,829	($156,103,234)	(85.1%)
Synchronous Condensing	$396,245	$103,914	($292,331)	(73.8%)
Black Start Services	$68,903,357	$26,611,834	($42,291,523)	(61.4%)
Total	$644,177,048	$902,934,088	$258,757,040	40.2%

The increase in energy uplift charges in the first nine months of 2014 was a result of increases in January. Total energy uplift charges increased $487.0 million in January 2014, compared to January 2013, while energy uplift charges decreased by $228.2 million in February through September 2014 compared to February through September 2013. Table 4-5 compares monthly energy uplift charges by category for 2013 and 2014.

Table 4-6 shows the composition of the day-ahead operating reserve charges. Day-ahead operating reserve charges consist of day-ahead operating reserve charges for credits to generators and import transactions, day-ahead operating reserve charges for economic load response resources and day-ahead operating reserve charges from unallocated congestion charges.[6,7] Day-ahead operating reserve charges increased by $12.9 million or 17.3 percent in the first nine months of 2014 compared to the first nine months of 2013. Day-ahead operating reserve charges (excluding unallocated congestion charges) increased by $33.8 million or 63.1 percent in the first nine months of 2014 compared to the first nine months of 2013. This increase was primarily the result of higher natural gas prices and higher energy offers in January. There were zero unallocated congestion charges in the first nine months of 2014 compared to $20.9 million in the first nine months of 2013.

5 Table 4-4 includes all categories of charges as defined in Table 4-1 and Table 4-2 and includes all PJM Settlements billing adjustments. Billing data can be modified by PJM Settlements at any time to reflect changes in the evaluation of energy uplift. The billing data reflected in this report were current on July 11, 2014.

6 See OATT Attachment K-Appendix § 3.2.3 (c). Unallocated congestion charges are added to the total costs of day-ahead operating reserves. Congestion charges have been allocated to day-ahead operating reserves ten times, totaling $26.9 million.

7 See Section 13, "Financial Transmission Rights and Auction Revenue Rights" at "Unallocated Congestion Charges" for an explanation of the source of these charges.

Table 4-5 Monthly energy uplift charges: 2013 and 2014

	2013						2014					
	Day-Ahead	Balancing	Reactive Services	Synchronous Condensing	Black Start	Total	Day-Ahead	Balancing	Reactive Services	Synchronous Condensing	Black Start Services	Total
Jan	$11,122,613	$79,240,331	$23,604,234	$1,873	$8,453,397	$122,422,449	$35,827,200	$565,697,081	$3,773,749	$54,736	$4,037,517	$609,390,283
Feb	$5,126,444	$67,126,202	$17,624,984	$0	$6,988,632	$96,866,261	$9,492,509	$56,052,542	$1,043,326	$0	$883,414	$67,471,791
Mar	$6,688,755	$17,415,540	$14,350,138	$0	$6,768,618	$45,223,051	$5,672,791	$59,521,466	$2,682,504	$0	$2,638,249	$70,515,010
Apr	$5,712,618	$23,429,237	$13,670,581	$0	$9,242,815	$52,055,252	$4,185,010	$9,710,792	$5,272,525	$0	$2,812,795	$21,981,122
May	$11,823,204	$22,524,898	$17,214,142	$959	$8,667,665	$60,230,867	$6,385,787	$20,986,370	$5,278,711	$45,382	$1,844,100	$34,540,349
Jun	$9,805,163	$17,885,783	$22,055,239	$0	$7,954,457	$57,700,642	$5,255,216	$15,819,469	$4,156,517	$0	$2,113,151	$27,344,353
Jul	$8,310,384	$43,516,700	$19,633,771	$393,413	$5,858,221	$77,712,488	$6,732,413	$11,440,551	$2,879,977	$3,797	$4,370,704	$25,427,442
Aug	$4,159,471	$14,674,041	$27,827,070	$0	$7,584,998	$54,245,580	$5,793,886	$9,888,962	$1,043,798	$0	$4,067,771	$20,794,417
Sep	$11,677,492	$31,123,507	$27,534,905	$0	$7,384,554	$77,720,458	$7,961,105	$12,383,359	$1,280,723	$0	$3,844,132	$25,469,320
Oct	$2,473,704	$12,767,972	$41,721,299	$0	$6,708,931	$63,671,907						
Nov	$2,799,521	$17,709,922	$42,743,907	$132	$6,685,965	$69,939,448						
Dec	$5,253,661	$36,157,934	$43,464,829	$0	$4,403,308	$89,279,733						
Total (Jan - Sep)	$74,426,144	$316,936,238	$183,515,064	$396,245	$68,903,357	$644,177,048	$87,305,917	$761,500,593	$27,411,829	$103,914	$26,611,834	$902,934,088
Share (Jan - Sep)	11.6%	49.2%	28.5%	0.1%	10.7%	100.0%	9.7%	84.3%	3.0%	0.0%	2.9%	100.0%
Total	$84,953,031	$383,572,067	$311,445,099	$396,377	$86,701,561	$867,068,135	$87,305,917	$761,500,593	$27,411,829	$103,914	$26,611,834	$902,934,088
Share	9.8%	44.2%	35.9%	0.0%	10.0%	100.0%	9.7%	84.3%	3.0%	0.0%	2.9%	100.0%

Table 4-6 Day-ahead operating reserve charges: January through September 2013 and 2014

Type	Jan - Sep 2013	Jan - Sep 2014	Change	Jan - Sep 2013 Share	Jan - Sep 2014 Share
Day-Ahead Operating Reserve Charges	$53,528,214	$87,303,340	$33,775,126	71.9%	100.0%
Day-Ahead Operating Reserve Charges for Load Response	$4,376	$2,577	($1,799)	0.0%	0.0%
Unallocated Congestion Charges	$20,893,554	$0	($20,893,554)	28.1%	0.0%
Total	$74,426,144	$87,305,917	$12,879,773	100.0%	100.0%

Table 4-7 shows the composition of the balancing operating reserve charges. Balancing operating reserve charges consist of balancing operating reserve reliability charges (credits to generators), balancing operating reserve deviation charges (credits to generators and import transactions), balancing operating reserve charges for economic load response and balancing local constraint charges. Balancing operating reserve charges increased by $444.6 million in the first nine months of 2014 compared to the first nine months of 2013. This increase was primarily the result of higher natural gas prices and higher energy offers combined with significantly higher conservative operations commitment, lost opportunity cost compensation to generators scheduled in the Day-Ahead Energy Market and not committed in real time, and lost opportunity cost compensation to generators reduced in real time for reliability purposes.

Table 4-7 Balancing operating reserve charges: January through September 2013 and 2014

Type	Jan - Sep 2013	Jan - Sep 2014	Change	Jan - Sep 2013 Share	Jan - Sep 2014 Share
Balancing Operating Reserve Reliability Charges	$41,609,297	$441,956,178	$400,346,881	13.1%	58.0%
Balancing Operating Reserve Deviation Charges	$274,721,958	$318,027,927	$43,305,969	86.7%	41.8%
Balancing Operating Reserve Charges for Load Response	$468,085	$24,855	($443,230)	0.1%	0.0%
Balancing Local Constraint Charges	$136,898	$1,491,633	$1,354,735	0.0%	0.2%
Total	$316,936,238	$761,500,593	$444,564,355	100.0%	100.0%

Table 4-8 shows the composition of the balancing operating reserve deviation charges. Balancing operating reserve deviation charges equal make whole credits paid to generators and import transactions, energy lost opportunity costs paid to generators and payments to resources canceled by PJM before coming online. In the first nine months of 2014, 54.4 percent of balancing operating reserve deviation charges were for make whole credits paid to generators and import transactions, a decrease of 16.0 percentage points compared to the share in the first nine months of 2013.

Table 4-8 Balancing operating reserve deviation charges: January through September 2013 and 2014

Charge Attributable To	Jan - Sep 2013	Jan - Sep 2014	Change	Jan - Sep 2013 Share	Jan - Sep 2014 Share
Make Whole Payments to Generators and Imports	$193,391,245	$172,876,957	($20,514,288)	70.4%	54.4%
Energy Lost Opportunity Cost	$80,974,864	$143,861,955	$62,887,091	29.5%	45.2%
Canceled Resources	$355,849	$1,289,015	$933,166	0.1%	0.4%
Total	$274,721,958	$318,027,927	$43,305,969	100.0%	100.0%

Table 4-9 Additional energy uplift charges: January through September 2013 and 2014

Type	Jan - Sep 2013	Jan - Sep 2014	Change	Jan - Sep 2013 Share	Jan - Sep 2014 Share
Reactive Services Charges	$183,515,064	$27,411,829	($156,103,234)	72.6%	50.6%
Synchronous Condensing Charges	$396,245	$103,914	($292,331)	0.2%	0.2%
Black Start Services Charges	$68,903,357	$26,611,834	($42,291,523)	27.3%	49.2%
Total	$252,814,665	$54,127,577	($198,687,088)	100.0%	100.0%

Table 4-9 shows reactive services, synchronous condensing and black start services charges. Reactive services charges decreased by $156.1 million in the first nine months of 2014 compared to the first nine months of 2013. Black start services charges decreased by $42.3 million in the first nine months of 2014 compared to the first nine months of 2013. Both categories decreased primarily as a result of the fact that higher energy prices made the units more economic than in the first nine months of 2013. Reduced FMU adders decreased the amount of energy uplift paid to units providing reactive support. The removal of automatic load rejection black start units from must run black start status contributed to the reduction in the amount of energy uplift paid to units providing black start support in the first nine months of 2014.

Table 4-10 and Table 4-11 show the amount and percentages of regional balancing charges for the first nine months of 2013 and 2014. Regional balancing operating reserve charges consist of balancing operating reserve reliability and deviation charges. These charges are allocated regionally across PJM. The largest share of regional charges was paid by real-time load. The regional balancing charges allocation table does not include charges attributed for resources controlling local constraints.

In the first nine months of 2014, regional balancing operating reserve charges increased by $443.7 million compared to the first nine months of 2013. Balancing operating reserve reliability charges increased by $400.3 million or 962.2 percent and balancing operating reserve deviation charges increased by $43.3 million or 15.8 percent.

Table 4-10 Regional balancing charges allocation: January through September 2013

Charge	Allocation	RTO		East		West		Total	
Reliability Charges	Real-Time Load	$30,792,044	9.7%	$8,615,370	2.7%	$1,240,266	0.4%	$40,647,680	12.8%
	Real-Time Exports	$705,233	0.2%	$224,896	0.1%	$31,489	0.0%	$961,618	0.3%
	Total	$31,497,277	10.0%	$8,840,266	2.8%	$1,271,755	0.4%	$41,609,297	13.2%
Deviation Charges	Demand	$98,706,646	31.2%	$64,844,624	20.5%	$2,965,723	0.9%	$166,516,993	52.6%
	Supply	$26,844,532	8.5%	$17,444,856	5.5%	$839,735	0.3%	$45,129,123	14.3%
	Generator	$40,058,985	12.7%	$21,539,621	6.8%	$1,477,237	0.5%	$63,075,843	19.9%
	Total	$165,610,163	52.4%	$103,829,100	32.8%	$5,282,695	1.7%	$274,721,958	86.8%
Total Regional Balancing Charges		$197,107,439	62.3%	$112,669,366	35.6%	$6,554,450	2.1%	$316,331,256	100%

Table 4-11 Regional balancing charges allocation: January through September 2014

Charge	Allocation	RTO		East		West		Total	
Reliability Charges	Real-Time Load	$424,714,403	55.9%	$6,413,178	0.8%	$3,174,816	0.4%	$434,302,397	57.1%
	Real-Time Exports	$7,353,995	1.0%	$204,608	0.0%	$95,178	0.0%	$7,653,781	1.0%
	Total	$432,068,398	56.9%	$6,617,787	0.9%	$3,269,994	0.4%	$441,956,178	58.2%
Deviation Charges	Demand	$159,593,264	21.0%	$11,855,188	1.6%	$4,519,107	0.6%	$175,967,559	23.2%
	Supply	$43,734,785	5.8%	$3,496,081	0.5%	$938,642	0.1%	$48,169,509	6.3%
	Generator	$86,687,540	11.4%	$4,964,628	0.7%	$2,238,692	0.3%	$93,890,860	12.4%
	Total	$290,015,589	38.2%	$20,315,898	2.7%	$7,696,440	1.0%	$318,027,927	41.8%
Total Regional Balancing Charges		$722,083,986	95.0%	$26,933,685	3.5%	$10,966,434	1.4%	$759,984,105	100%

Operating Reserve Rates

Under the operating reserves cost allocation rules, PJM calculates nine separate rates, a day-ahead operating reserve rate, a reliability rate for each region, a deviation rate for each region, a lost opportunity cost rate and a canceled resources rate for the entire RTO region. See Table 4-1 for how these charges are allocated.[8]

Figure 4-1 shows the daily day-ahead operating reserve rate for 2013 and the first nine months of 2014. The average rate in the first nine months of 2014 was $0.139 per MWh, $0.053 per MWh higher than the average in the first nine months of 2013. The highest rate occurred on January 22, when the rate reached $1.689 per MWh, $1.043 per MWh higher than the $0.646 per MWh reached in the first nine months of 2013, on July 16. Figure 4-1 also shows the daily day-ahead operating reserve rate including the congestion charges allocated to day-ahead operating reserves. There were no congestion charges allocated to day-ahead operating reserves in the first nine months of 2014. The increase in the day-ahead operating reserve rate on January 22 was in large part the result of scheduling peaking resources which were noneconomic or economic for less than 50 percent of their scheduled run time. On January 22, 116 units received day-ahead operating reserve credits, 86 were economic for 50 percent or less of their scheduled run time. That was the highest number of units scheduled noneconomic in the Day-Ahead Energy Market in the first nine months of 2014. Also, on January 22, 60 units that were made whole though day-ahead operating reserves also provided day-ahead scheduling reserves for which they received additional revenue; eight of these units received enough net revenues from day-ahead scheduling reserves to cover their total energy offer (including no load and startup cost), which would have resulted in zero day-ahead operating reserve credits if the net revenues from day-ahead scheduling reserves could be used as an offset in the day-ahead operating reserve credit calculation.[9]

8 The lost opportunity cost and canceled resources rates are not posted separately by PJM. PJM adds the lost opportunity cost and the canceled resources rates to the deviation rate for the RTO region since these three charges are allocated following the same rules.

9 Net revenues from day-ahead scheduling reserves are used as offsets in the balancing operating reserve calculation.

Figure 4-1 Daily day-ahead operating reserve rate ($/MWh): 2013 and 2014

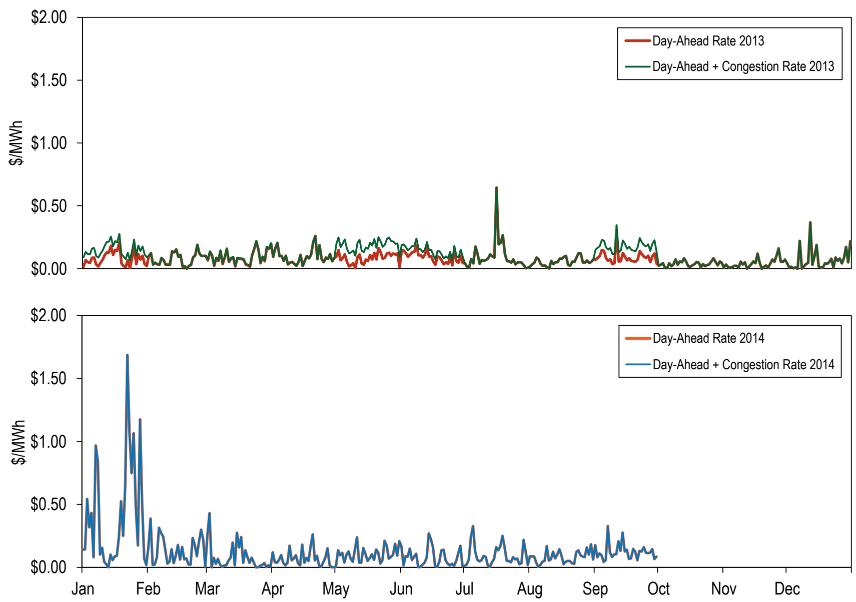


Figure 4-2 shows the RTO and the regional reliability rates for 2013 and the first nine months of 2014. The average daily RTO reliability rate was $0.702 per MWh. The highest RTO reliability rate in the first nine months of 2014 occurred on January 28, when the rate reached $24.593 per MWh, $23.791 per MWh higher than the $0.802 per MWh rate reached in the first nine months of 2013, on January 23. The increases in the RTO reliability rate on January 3, January 8 and between January 21 and 28 were the result of the commitment for conservative operations of natural gas fired generators with high offers.[10]

Figure 4-2 Daily balancing operating reserve reliability rates ($/MWh): 2013 and 2014

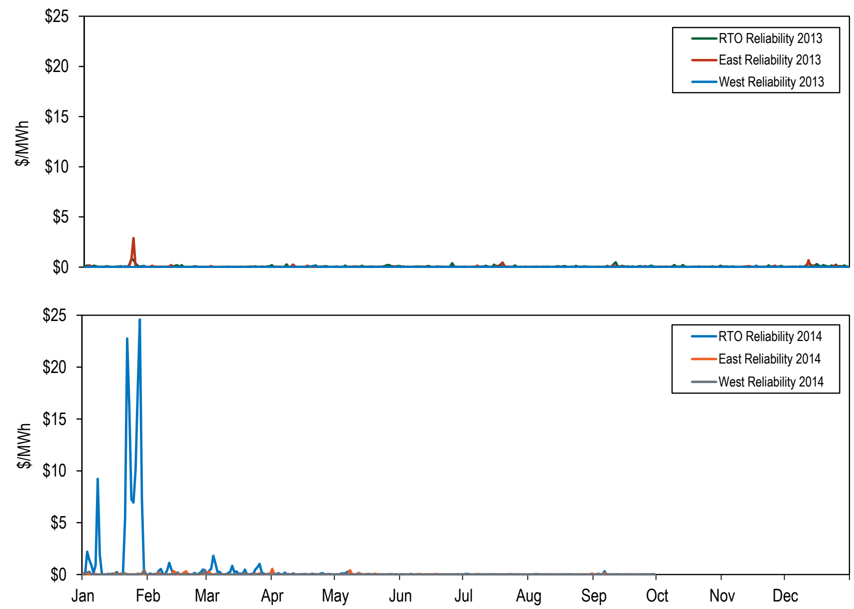


Figure 4-3 shows the RTO and regional deviation rates for 2013 and the first nine months of 2014. The average daily RTO deviation rate was $1.491 per MWh. The highest daily rate in the first nine months of 2014 occurred on January 25, when the RTO deviation rate reached $20.098 per MWh, $9.926 per MWh higher than the $10.172 per MWh rate reached in the first nine months of 2013, on January 23. In the first nine months of 2014 the RTO deviation rate increased while the Eastern Region deviation rate decreased, compared to the first nine months of 2013. In the first nine months of 2013, energy uplift was paid primarily to units committed to provide relief to local transmission constraints in the Eastern Region, while in the first nine months of 2014, energy uplift was paid primarily to units committed to meet overall load and provide reserves for peak hours.

10 See the *2014 Quarterly State of the Market Report for PJM: January through March*, Section 4, "Energy Uplift" at "Energy Uplift and Conservative Operations" for an explanation of the reasons and impact of units committed for conservative operations.

Figure 4-3 Daily balancing operating reserve deviation rates ($/MWh): 2013 and 2014

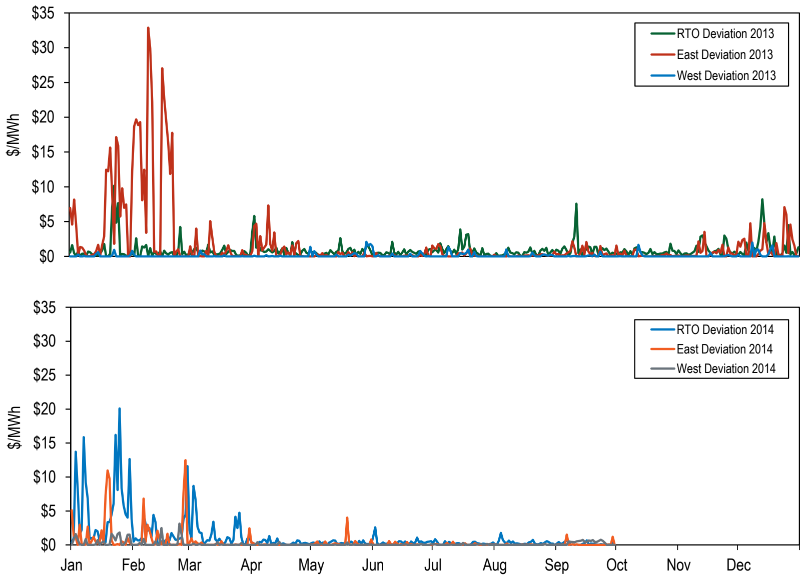


Figure 4-4 shows the daily lost opportunity cost rate and the daily canceled resources rate for 2013 and the first nine months of 2014. The lost opportunity cost rate averaged $1.481 per MWh. The highest lost opportunity cost rate occurred on January 24, when it reached $32.556 per MWh, $24.078 per MWh higher than the $8.478 per MWh rate reached in the first nine months of 2013, on September 11. On January 24, 2014, 63.5 percent of the lost opportunity cost rate was due to units reduced in real time for reliability purposes.

Figure 4-4 Daily lost opportunity cost and canceled resources rates ($/MWh): 2013 and 2014

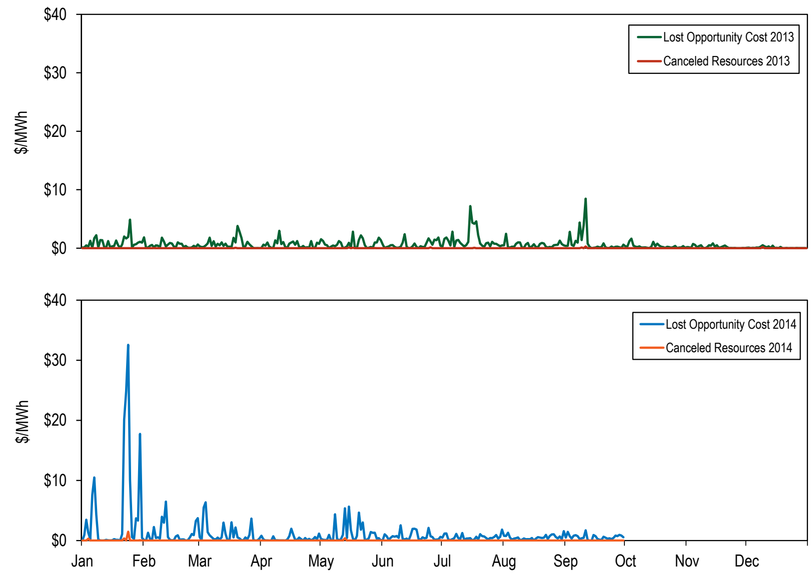


Table 4-12 shows the average rates for each region in each category for the first nine months of 2013 and the first nine months of 2014.

Table 4-12 Operating reserve rates ($/MWh): January through September 2013 and 2014

Rate	Jan - Sep 2013 ($/MWh)	Jan - Sep 2014 ($/MWh)	Difference ($/MWh)	Percentage Difference
Day-Ahead	0.086	0.139	0.053	62.1%
Day-Ahead with Unallocated Congestion	0.119	0.139	0.020	16.6%
RTO Reliability	0.053	0.702	0.650	1,235.7%
East Reliability	0.031	0.023	(0.008)	(25.9%)
West Reliability	0.004	0.010	0.006	146.6%
RTO Deviation	0.905	1.491	0.586	64.7%
East Deviation	2.208	0.425	(1.783)	(80.7%)
West Deviation	0.120	0.159	0.039	32.1%
Lost Opportunity Cost	0.870	1.481	0.611	70.2%
Canceled Resources	0.004	0.013	0.009	247.1%

Table 4-13 shows the operating reserve cost of a one MW transaction during the first nine months of 2014. For example, a decrement bid in the Eastern Region (if not offset by other transactions) paid an average rate of $2.956 per MWh with a maximum rate of $43.005 per MWh, a minimum rate of $0.109 per MWh and a standard deviation of $5.709 per MWh.

The rates in the table include all operating reserve charges including RTO deviation charges and unallocated congestion charges. Table 4-13 illustrates both the average level of operating reserve charges by transaction types and the uncertainty reflected in the maximum, minimum and standard deviation levels.

Table 4-13 Operating reserve rates statistics ($/MWh): January through September 2014

		Rates Charged ($/MWh)			
Region	Transaction	Maximum	Average	Minimum	Standard Deviation
East	INC	42.256	2.824	0.036	5.585
	DEC	43.005	2.956	0.109	5.709
	DA Load	1.689	0.132	0.000	0.189
	RT Load	24.630	0.592	0.000	2.711
	Deviation	42.256	2.824	0.036	5.585
West	INC	43.729	2.559	0.092	5.470
	DEC	44.478	2.691	0.109	5.596
	DA Load	1.689	0.132	0.000	0.189
	RT Load	24.652	0.579	0.000	2.712
	Deviation	43.729	2.559	0.092	5.470

Reactive Services Rates

Reactive services charges associated with local voltage support are allocated to real-time load in the control zone or zones where the service is provided. Reactive services charges associated with supporting reactive transfer interfaces above 345 kV are allocated to real-time load across the entire RTO. These charges are allocated daily based on the real-time load ratio share of each network customer.

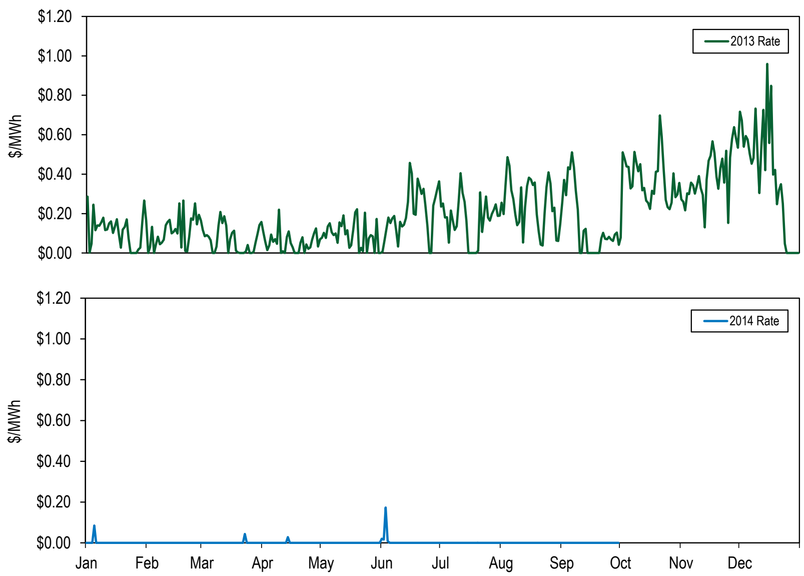
While reactive services rates are not posted by PJM, a local voltage support rate for each control zone can be calculated and a reactive transfer interface support rate can be calculated for the entire RTO. Table 4-14 shows the reactive services rates associated with local voltage support for the first nine months of 2013 and the first nine months of 2014. Table 4-14 shows that in the first nine months of 2014 the DPL Control Zone had the highest rate. Real-time load in the DPL Control Zone paid an average of $0.499 per MWh for reactive services associated with local voltage support, $1.366 or 73.3 percent lower than the average rate paid in the first nine months of 2013.

Table 4-14 Local voltage support rates: January through September 2013 and 2014

Control Zone	Jan - Sep 2013 ($/MWh)	Jan - Sep 2014 ($/MWh)	Difference ($/MWh)	Percentage Difference
AECO	0.269	0.012	(0.258)	(95.6%)
AEP	0.036	0.007	(0.029)	(80.3%)
AP	0.001	0.006	0.005	439.8%
ATSI	0.614	0.229	(0.386)	(62.8%)
BGE	0.187	0.001	(0.187)	(99.5%)
ComEd	0.002	0.001	(0.001)	(68.9%)
DAY	0.000	0.001	0.001	NA
DEOK	0.000	0.000	0.000	0.0%
DLCO	0.000	0.000	0.000	0.0%
Dominion	0.026	0.045	0.019	74.0%
DPL	1.865	0.499	(1.366)	(73.3%)
EKPC	0.010	0.000	(0.010)	(100.0%)
JCPL	0.010	0.000	(0.010)	(100.0%)
Met-Ed	0.426	0.003	(0.423)	(99.4%)
PECO	0.025	0.011	(0.014)	(56.9%)
PENELEC	0.021	0.210	0.189	906.9%
Pepco	1.521	0.001	(1.520)	(99.9%)
PPL	0.011	0.000	(0.011)	(99.4%)
PSEG	0.021	0.010	(0.011)	(50.7%)
RECO	0.236	0.000	(0.236)	(100.0%)

Figure 4-5 shows the daily RTO wide reactive transfer interface rate for 2013 and the first nine months of 2014. The average rate in the first nine months of 2014 was $0.001 per MWh, 99.0 percent lower than the $0.132 per MWh average rate in the first nine months of 2013. In the first nine months of 2014, energy uplift was paid to units providing support to the reactive transfer interfaces for only seven days. The significant decrease in reactive services charges allocated across the RTO was a result of the fact that units that were previously scheduled noneconomic to provide reactive services became economic based on higher energy prices and lower offers from the units providing reactive support due to reduced FMU adders, and therefore cleared the Day-Ahead Energy Market based on economics.

Figure 4-5 Daily reactive transfer interface support rates ($/MWh): 2013 and 2014



Balancing Operating Reserve Determinants

Table 4-15 shows the determinants used to allocate the regional balancing operating reserve charges for the first nine months of 2013 and the first nine months of 2014. Total real-time load and real-time exports were 16,185,475 MWh or 2.7 percent higher in the first nine months of 2014 compared to the first nine months of 2013. Total deviations summed across the demand, supply, and generator categories were 4,056,166 MWh or 4.4 percent higher in the first nine months of 2014 compared to the first nine months of 2013.

Table 4-15 Balancing operating reserve determinants (MWh): January through September 2013 and 2014

		Reliability Charge Determinants			Deviation Charge Determinants			
		Real-Time Load (MWh)	Real-Time Exports (MWh)	Reliability Total	Demand Deviations (MWh)	Supply Deviations (MWh)	Generator Deviations (MWh)	Deviations Total
Jan - Sep 2013	RTO	583,845,687	15,243,726	599,089,413	55,392,260	14,786,604	22,914,654	93,093,518
	East	278,332,308	7,065,335	285,397,643	29,616,581	7,440,457	9,968,095	47,025,134
	West	305,513,379	8,178,391	313,691,770	24,021,589	6,934,081	12,946,559	43,902,228
Jan - Sep 2014	RTO	593,301,895	21,972,993	615,274,888	58,266,134	14,455,372	24,428,178	97,149,684
	East	279,816,694	8,406,246	288,222,940	28,505,178	8,034,714	11,231,767	47,771,659
	West	313,485,201	13,566,747	327,051,948	29,083,018	6,125,709	13,196,411	48,405,138
Difference	RTO	9,456,208	6,729,267	16,185,475	2,873,874	(331,232)	1,513,524	4,056,166
	East	1,484,386	1,340,911	2,825,297	(1,111,403)	594,256	1,263,671	746,525
	West	7,971,822	5,388,356	13,360,178	5,061,429	(808,372)	249,853	4,502,910

Deviations fall into three categories, demand, supply and generator deviations. Table 4-16 shows the different categories by the type of transactions that incurred deviations. In the first nine months of 2014, 19.6 percent of all RTO deviations were incurred by participants that deviated due to INCs and DECs or due to combinations of INCs and DECs with other transactions, the remaining 80.4 percent of all RTO deviations were incurred by participants that deviated due to other transaction types or due to combinations of other transaction types.

Table 4-16 Deviations by transaction type: January through September 2014

Deviation		Deviation (MWh)			Share		
Category	Transaction	RTO	East	West	RTO	East	West
Demand	Bilateral Sales Only	229,399	151,937	77,463	0.2%	0.3%	0.2%
	DECs Only	7,572,821	2,351,850	4,545,138	7.8%	4.9%	9.4%
	Exports Only	4,331,267	2,577,482	1,753,785	4.5%	5.4%	3.6%
	Load Only	39,435,803	19,825,844	19,609,959	40.6%	41.5%	40.5%
	Combination with DECs	4,310,342	2,707,441	1,600,797	4.4%	5.7%	3.3%
	Combination without DECs	2,386,501	890,624	1,495,877	2.5%	1.9%	3.1%
Supply	Bilateral Purchases Only	339,297	229,285	110,012	0.3%	0.5%	0.2%
	Imports Only	6,879,867	4,698,779	2,181,088	7.1%	9.8%	4.5%
	INCs Only	5,121,191	1,984,573	2,841,669	5.3%	4.2%	5.9%
	Combination with INCs	2,035,677	1,052,732	982,944	2.1%	2.2%	2.0%
	Combination without INCs	79,340	69,343	9,996	0.1%	0.1%	0.0%
Generators		24,428,178	11,231,767	13,196,411	25.1%	23.5%	27.3%
Total		97,149,684	47,771,659	48,405,138	100.0%	100.0%	100.0%

Energy Uplift Credits

Table 4-17 shows the totals for each credit category for the first nine months of 2013 and the first nine months of 2014. During the first nine months of 2014, 84.3 percent of total energy uplift credits were in the balancing operating reserve category, an increase of 33.5 percentage points from 50.8 percent in the first nine months of 2013.

Table 4-17 Energy uplift credits by category: January through September 2013 and 2014

Category	Type	Jan - Sep 2013	Jan - Sep 2014	Change	Percentage Change	Jan - Sep 2013 Share	Jan - Sep 2014 Share
Day-Ahead	Generators	$53,563,623	$87,303,336	$33,739,713	63.0%	8.6%	9.7%
	Imports	$9	$2	($7)	(75.8%)	0.0%	0.0%
	Load Response	$4,376	$2,578	($1,798)	(41.1%)	0.0%	0.0%
Balancing	Canceled Resources	$355,849	$1,289,016	$933,167	262.2%	0.1%	0.1%
	Generators	$234,961,926	$614,703,238	$379,741,311	161.6%	37.7%	68.1%
	Imports	$38,615	$122,696	$84,082	217.7%	0.0%	0.0%
	Load Response	$467,943	$24,697	($443,247)	(94.7%)	0.1%	0.0%
	Local Constraints Control	$136,898	$1,491,741	$1,354,843	989.7%	0.0%	0.2%
	Lost Opportunity Cost	$80,974,864	$143,861,958	$62,887,094	77.7%	13.0%	15.9%
Reactive Services	Day-Ahead	$166,593,049	$23,286,206	($143,306,843)	(86.0%)	26.7%	2.6%
	Local Constraints Control	$106,287	$27,067	($79,220)	(74.5%)	0.0%	0.0%
	Lost Opportunity Cost	$337,468	$216,407	($121,061)	(35.9%)	0.1%	0.0%
	Reactive Services	$16,261,292	$3,048,779	($13,212,513)	(81.3%)	2.6%	0.3%
	Synchronous Condensing	$216,968	$833,372	$616,404	284.1%	0.0%	0.1%
Synchronous Condensing		$396,245	$103,915	($292,331)	(73.8%)	0.1%	0.0%
Black Start Services	Day-Ahead	$66,621,747	$22,074,455	($44,547,292)	(66.9%)	10.7%	2.4%
	Balancing	$1,950,779	$4,290,415	$2,339,636	119.9%	0.3%	0.5%
	Testing	$295,411	$246,964	($48,448)	(16.4%)	0.0%	0.0%
Total		$623,283,351	$902,926,841	$279,643,489	44.9%	100.0%	100.0%

Characteristics of Credits

Types of Units

Table 4-18 shows the distribution of total energy uplift credits by unit type for the first nine months of 2013 and the first nine months of 2014. The increase in energy uplift in the first nine months of 2014 compared to the first nine months of 2013 was due to credits paid to combined cycles, combustion turbines and steam turbines (not fired by coal). Credits to these units increased $413.4 million or 128.0 percent mainly because these units' offers were impacted by high natural gas prices in January 2014. Credits paid to remaining unit types decreased by $133.4 million.

Table 4-18 Energy uplift credits by unit type: January through September 2013 and 2014

Unit Type	Jan - Sep 2013	Jan - Sep 2014	Change	Percentage Change	Jan - Sep 2013 Share	Jan - Sep 2014 Share
Combined Cycle	$169,185,084	$391,297,533	$222,112,449	131.3%	27.2%	43.3%
Combustion Turbine	$125,151,118	$236,250,566	$111,099,448	88.8%	20.1%	26.2%
Diesel	$6,111,550	$2,820,497	($3,291,053)	(53.8%)	1.0%	0.3%
Hydro	$422,939	$1,478,402	$1,055,464	249.6%	0.1%	0.2%
Nuclear	$126,510	$166,104	$39,594	31.3%	0.0%	0.0%
Steam - Coal	$283,119,807	$154,841,133	($128,278,674)	(45.3%)	45.5%	17.2%
Steam - Other	$28,661,485	$108,876,086	$80,214,601	279.9%	4.6%	12.1%
Wind	$9,993,915	$7,046,546	($2,947,369)	(29.5%)	1.6%	0.8%
Total	$622,772,407	$902,776,866	$280,004,459	45.0%	100.0%	100.0%

Table 4-19 Energy uplift credits by unit type: January through September 2014

Unit Type	Day-Ahead Generator	Balancing Generator	Canceled Resources	Local Constraints Control	Lost Opportunity Cost	Reactive Services	Synchronous Condensing	Black Start Services
Combined Cycle	38.8%	56.6%	0.0%	0.0%	5.6%	4.7%	0.0%	0.0%
Combustion Turbine	14.0%	20.0%	0.5%	67.8%	67.4%	9.4%	99.9%	1.0%
Diesel	0.1%	0.2%	0.0%	0.0%	0.7%	0.7%	0.0%	0.0%
Hydro	0.2%	0.0%	98.5%	0.0%	0.0%	0.0%	0.1%	0.0%
Nuclear	0.0%	0.0%	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%
Steam - Coal	43.8%	5.9%	1.0%	29.1%	21.2%	83.8%	0.0%	99.0%
Steam - Others	3.0%	17.2%	0.0%	0.3%	0.2%	1.3%	0.0%	0.0%
Wind	0.0%	0.0%	0.0%	2.8%	4.8%	0.0%	0.0%	0.0%
Total	$87,303,336	$614,703,237	$1,289,016	$1,491,741	$143,861,957	$27,411,831	$103,915	$26,611,834

Table 4-19 shows the distribution of energy uplift credits by category and by unit type in the first nine months of 2014. Combined cycle units received 38.8 percent of the day-ahead generator credits in the first nine months of 2014, 7.8 percentage points lower than the share received in the first nine months of 2013. Combined cycle units received 56.6 percent of the balancing generator credits in the first nine months of 2014, 4.1 percentage points higher than the share received in the first nine months of 2013. Combustion turbines and diesels received 68.2 percent of the lost opportunity cost credits in the first nine months of 2014, 4.3 percentage points lower than the share received in the first nine months of 2013.

Table 4-19 also shows the distribution of reactive service credits, synchronous condensing and black start services credits by unit type. In the first nine months of 2014, coal units received 83.8 percent of all reactive services credits, 1.1 percentage points higher than the share received in the first nine months of 2013. Coal units received 99.0 percent of all black start services credits.

Concentration of Energy Uplift Credits

There continues to be a high level of concentration in the units and companies receiving energy uplift credits. This concentration results from a combination of unit operating characteristics, PJM's persistent need to commit specific units out of merit in particular locations and the fact that the lack of transparency makes it impossible for competition to affect these payments.

The concentration of energy uplift credits is first examined by analyzing the characteristics of the top 10 units receiving energy uplift credits. The focus on the top 10 units is illustrative.

The concentration of energy uplift credits in the top 10 units remains high in the first nine months of 2014. Table 4-20 shows that the top 10 units receiving total energy uplift credits, which make up less than one percent of all units in PJM's footprint, received 35.5 percent of total energy uplift credits in the first nine months of 2014, compared to 34.3 percent in the first nine months of 2013.

Table 4-20 Top 10 energy uplift credits units (By percent of total system): January through September 2013 and 2014

	Top 10 Units Credit Share	Percent of Total PJM Units
Jan - Sep 2013	34.3%	0.7%
Jan - Sep 2014	35.5%	0.7%

Table 4-21 shows the credits received by the top 10 units and top 10 organizations in each of the energy uplift categories paid to generators.

Table 4-21 Top 10 units and organizations energy uplift credits: January through September 2014

		Top 10 Units		Top 10 Organizations	
Category	Type	Credits	Credits Share	Credits	Credits Share
Day-Ahead	Generators	$47,948,901	54.9%	$76,967,889	88.2%
Balancing	Canceled Resources	$1,289,016	100.0%	$1,289,016	100.0%
	Generators	$301,191,968	49.0%	$540,976,934	88.0%
	Local Constraints Control	$1,204,020	80.7%	$1,482,485	99.4%
	Lost Opportunity Cost	$30,767,824	21.4%	$108,813,149	75.6%
Reactive Services		$20,912,810	76.3%	$27,117,745	98.9%
Synchronous Condensing		$94,367	90.8%	$103,915	100.0%
Black Start Services		$24,201,375	90.9%	$26,604,029	100.0%
Total		$320,622,492	35.5%	$738,339,111	81.8%

Table 4-22 shows balancing operating reserve credits received by the top 10 units identified for reliability or for deviations in each region. In the first nine months of 2014, 10.7 percent of all credits paid to these units were allocated to deviations while the remaining 89.3 percent were paid for reliability reasons.

Table 4-22 Identification of balancing operating reserve credits received by the top 10 units by category and region: January through September 2014

	Reliability			Deviations			
	RTO	East	West	RTO	East	West	Total
Credits	$268,824,454	$0	$0	$21,160,806	$11,206,709	$0	$301,191,968
Share	89.3%	0.0%	0.0%	7.0%	3.7%	0.0%	100.0%

In the first nine months of 2014, concentration in all energy uplift credit categories was high.[11] [12] The HHI for energy uplift credits was calculated based on each organization's share of daily credits for each category. Table 4-23 shows the average HHI for each category. HHI for day-ahead operating reserve credits to generators was 4622, for balancing operating reserve credits to generators was 2959, for lost opportunity cost credits was 3838 and for reactive services credits was 6964.

11 See Section 3, "Energy Market" at "Market Concentration" for a complete discussion of concentration ratios and the Herfindahl-Hirshman Index (HHI).
12 Table 4-23 excludes local constraints control categories.

Table 4-23 Daily energy uplift credits HHI: January through September 2014

Category	Type	Average	Minimum	Maximum	Highest Market Share (One day)	Highest Market Share (All days)
Day-Ahead	Generators	4622	1080	10000	100.0%	28.0%
	Imports	10000	10000	10000	100.0%	100.0%
	Load Response	10000	10000	10000	100.0%	89.7%
Balancing	Canceled Resources	9217	6054	10000	100.0%	98.5%
	Generators	2959	841	8994	94.8%	24.6%
	Imports	10000	10000	10000	100.0%	100.0%
	Load Response	10000	10000	10000	100.0%	70.6%
	Lost Opportunity Cost	3838	545	10000	100.0%	18.7%
Reactive Services		6964	2717	10000	100.0%	44.0%
Synchronous Condensing		10000	10000	10000	100.0%	51.2%
Black Start Services		6011	2906	10000	100.0%	99.0%
Total		1525	507	6725	81.7%	17.1%

Economic and Noneconomic Generation[13]

Economic generation includes units scheduled day ahead or producing energy in real time at an incremental offer less than or equal to the LMP at the unit's bus. Noneconomic generation includes units that are scheduled or producing energy at an incremental offer higher than the LMP at the unit's bus. Units are paid day-ahead operating reserve credits based on their scheduled operation for the entire day. Balancing generator operating reserve credits are paid on a segmented basis for each period defined by the greater of the day-ahead schedule and minimum run time. Table 4-24 shows PJM's day-ahead and real-time total generation and the amount of generation eligible for operating reserve credits. In the Day-Ahead Energy Market only pool-scheduled resources are eligible for day-ahead operating reserve credits. In the Real-Time Energy Market only pool-scheduled resources that follow PJM's dispatch instructions are eligible for balancing operating reserve credits.

The MMU analyzed PJM's day-ahead and real-time generation eligible for operating reserve credits to determine the shares of economic and noneconomic generation. Each unit's hourly generation was determined to be economic or noneconomic based on the unit's hourly incremental offer, excluding the hourly no load cost and any applicable startup cost. A unit could be economic for every hour during a day or segment, but still receive operating reserve credits because the energy revenues did not cover the hourly no load costs and startup costs. A unit could be noneconomic for an hour or multiple hours and not receive operating reserve credits whenever the total energy revenues covered the total offer (including no load and startup costs) for the entire day or segment. In the first nine months of 2014, 36.9 percent of the day-ahead generation was eligible for day-ahead operating reserve credits and 34.9 percent of the real-time generation was eligible for balancing operating reserve credits.[14]

Table 4-24 Day-ahead and real-time generation (GWh): January through September 2014

Energy Market	Total Generation	Generation Eligible for Operating Reserve Credits	Generation Eligible for Operating Reserve Credits Percentage
Day-Ahead	631,615	233,181	36.9%
Real-Time	614,864	214,845	34.9%

Table 4-25 shows PJM's economic and noneconomic generation by hour eligible for operating reserve credits. In the first nine months of 2014, 87.5 percent of the day-ahead generation eligible for operating reserve credits was economic and 72.7 percent of the real-time generation eligible for operating reserve credits was economic. A unit's generation may be noneconomic for a portion of their daily generation and economic for the rest. Table 4-25 shows the separate amounts of economic and noneconomic generation even if the daily generation was economic.

13 The analysis of economic and noneconomic generation is based on units' incremental offers, the value used by PJM to calculate LMP. The analysis does not include no load or startup costs.

14 In the Day-Ahead Energy Market only pool-scheduled resources are eligible for day-ahead operating reserve credits. In the Real-Time Energy Market only pool-scheduled resources that operate as requested by PJM are eligible for balancing operating reserve credits.

Table 4-25 Day-ahead and real-time economic and noneconomic generation from units eligible for operating reserve credits (GWh): January through September 2014

Energy Market	Economic Generation	Noneconomic Generation	Economic Generation Percentage	Noneconomic Generation Percentage
Day-Ahead	203,928	29,253	87.5%	12.5%
Real-Time	156,087	58,758	72.7%	27.3%

Noneconomic generation only leads to operating reserve credits when units' generation for the day or segment, scheduled or committed, is noneconomic, including no load and startup costs. Table 4-26 shows the generation receiving day-ahead and balancing operating reserve credits. In the first nine months of 2014, 6.4 percent of the day-ahead generation eligible for operating reserve credits received credits and 5.0 percent of the real-time generation eligible for operating reserve credits was made whole.

Table 4-26 Day-ahead and real-time generation receiving operating reserve credits (GWh): January through September 2014

Energy Market	Generation Eligible for Operating Reserve Credits	Generation Receiving Operating Reserve Credits	Generation Receiving Operating Reserve Credits Percentage
Day-Ahead	233,181	14,966	6.4%
Real-Time	214,845	10,807	5.0%

Day-Ahead Unit Commitment for Reliability

PJM may schedule units as must run in the Day-Ahead Energy Market when needed in real time to address reliability issues of various types. PJM puts such reliability issues in four categories: voltage issues (high and low); black start requirements (from automatic load rejection units); local contingencies not modeled in the Day-Ahead Energy Market; and long lead time units not able to be scheduled in the Day-Ahead Energy Market.[15] Participants can submit units as self-scheduled (must run), meaning that the unit must be committed, but a unit submitted as must run by a participant is not eligible for day-ahead operating reserve credits.[16] Units scheduled as must run by PJM may set LMP if raised above economic minimum and following the dispatch signal and are eligible for day-ahead operating reserve credits. Table 4-27 shows the total day-ahead generation and the subset of that generation scheduled as must run by PJM. In the first nine months of 2014, 4.3 percent of the total day-ahead generation was scheduled as must run by PJM, 0.4 percentage points lower than the first nine months of 2013.

Table 4-27 Day-ahead generation scheduled as must run by PJM (GWh): 2013 and 2014

	2013			2014		
	Total Day-Ahead Generation	Day-Ahead PJM Must Run Generation	Share	Total Day-Ahead Generation	Day-Ahead PJM Must Run Generation	Share
Jan	72,681	2,907	4.0%	81,479	2,627	3.2%
Feb	65,632	2,474	3.8%	70,942	3,404	4.8%
Mar	67,940	3,178	4.7%	72,681	2,894	4.0%
Apr	57,570	2,522	4.4%	60,688	2,825	4.7%
May	61,169	2,848	4.7%	61,919	2,808	4.5%
Jun	68,452	3,724	5.4%	70,230	3,421	4.9%
Jul	78,639	4,395	5.6%	75,606	3,733	4.9%
Aug	73,783	3,678	5.0%	73,003	2,778	3.8%
Sep	64,757	3,162	4.9%	65,066	2,792	4.3%
Oct	62,134	2,940	4.7%			
Nov	63,827	2,675	4.2%			
Dec	73,112	2,612	3.6%			
Total (Jan - Sep)	610,622	28,888	4.7%	631,615	27,284	4.3%
Total	809,695	37,115	4.6%	631,615	27,284	4.3%

Pool-scheduled units are made whole in the Day-Ahead Energy Market if their total offer (including no load and startup costs) is greater than the revenues from the Day-Ahead Energy Market. Such units are paid day-ahead operating reserve credits. Pool-scheduled units scheduled as must run by PJM are only paid day-ahead operating reserve credits when their total offer is greater than the revenues from the Day-Ahead Energy Market. It is illogical and unnecessary to pay units day-ahead operating reserves because units do not incur any costs to run and any revenue shortfalls are addressed by balancing operating reserve payments.

15 See PJM. "Item 12 - October 2012 MIC DAM Cost Allocation," PJM Presentation to the Market Implementation Committee (October 12, 2012) <http://www.pjm.com/~/media/committees-groups/committees/mic/20121010/20121010-item-12-october-2012-mic-dam-cost-allocation.ashx>.

16 See PJM. "PJM eMkt Users Guide," Section Managing Unit Data (version April 1, 2014) p. 48, <http://www.pjm.com/~/media/etools/emkt/ts-userguide.ashx>.

Table 4-28 shows the total day-ahead generation scheduled as must run by PJM by category. In the first nine months of 2014, 32.2 percent of the day-ahead generation scheduled as must run by PJM received operating reserve credits, of which, 9.3 percent was generation from units scheduled to provide black start services, 5.5 percent was generation from units scheduled to provide reactive services and 17.4 percent was generation paid normal day-ahead operating reserve credits. The remaining 67.8 percent of the day-ahead generation scheduled as must run by PJM did not need to be made whole.

Table 4-28 Day-ahead generation scheduled as must run by PJM by category (GWh): 2014

	Black Start Services	Reactive Services	Day-Ahead Operating Reserves	Economic	Total
Jan	216	157	232	2,022	2,627
Feb	84	30	428	2,862	3,404
Mar	242	162	325	2,166	2,894
Apr	333	243	442	1,807	2,825
May	235	238	564	1,772	2,808
Jun	251	328	506	2,336	3,421
Jul	374	241	685	2,434	3,733
Aug	395	54	760	1,569	2,778
Sep	404	54	805	1,530	2,792
Oct					
Nov					
Dec					
Total	2,533	1,508	4,747	18,497	27,284
Share	9.3%	5.5%	17.4%	67.8%	100.0%

Total day-ahead operating reserve credits in the first nine months of 2014 were $87.3 million, of which $42.4 million or 48.6 percent was paid to units scheduled as must run by PJM, and not scheduled to provide black start or reactive services.

The MMU recommends that PJM clearly identify and classify all reasons for paying operating reserve credits in the Day-Ahead and the Real-Time Energy Markets and the associated operating reserve charges in order to inform all market participants of the reason for these costs and to help ensure a long term solution to the issue of how to allocate the costs of operating reserves.[17] The overall goal should be to have dispatcher decisions reflected in transparent market outcomes to the maximum extent possible and to minimize the level and rate of operating reserve charges.

Geography of Charges and Credits

Table 4-29 shows the geography of charges and credits in the first nine months of 2014. Table 4-29 includes only day-ahead operating reserve charges and balancing operating reserve reliability and deviation charges since these categories are allocated regionally, while other charges, such as reactive services, synchronous condensing and black start services are allocated by control zone, and balancing local constraint charges are charged to the requesting party.

Charges are categorized by the location (control zone, hub, aggregate or interface) where they are allocated according to PJM's operating reserve rules. Credits are categorized by the location where the resources are located. The shares columns reflect the operating reserve credits and charges balance for each location. For example, transactions in the AECO Control Zone paid 1.2 percent of all operating reserve charges allocated regionally, and resources in the AECO Control Zone were paid 0.9 percent of the corresponding credits. The AECO Control Zone received less operating reserve credits than operating reserve charges paid and had a 0.8 percent share of the deficit. The deficit is the sum of the negative entries in the balance column. Transactions in the PSEG Control Zone paid 4.5 percent of all operating reserve charges allocated regionally, and resources in the PSEG Control Zone were paid 14.0 percent of the corresponding credits. The PSEG Control Zone received more operating reserve credits than operating reserve charges paid and had a 22.2 percent share of the surplus. The surplus is the sum of the positive entries in the balance column. Table 4-29 also shows that 90.7 percent of all charges were allocated in control zones, 2.1 percent in hubs and aggregates and 7.2 percent in interfaces.

17 The classification could occur via defined logging codes for dispatchers. That would create data that could be analyzed by the MMU and summarized for participants.

Table 4-29 Geography of regional charges and credits: January through September 2014[18]

					Shares			
Location		Charges	Credits	Balance	Total Charges	Total Credits	Deficit	Surplus
Zones	AECO	$10,311,572	$7,534,342	($2,777,230)	1.2%	0.9%	0.8%	0.0%
	AEP - EKPC	$145,268,987	$39,246,546	($106,022,441)	17.1%	4.6%	29.1%	0.0%
	AP - DLCO	$60,342,035	$20,859,821	($39,482,214)	7.1%	2.5%	10.8%	0.0%
	ATSI	$59,052,889	$20,058,868	($38,994,021)	7.0%	2.4%	10.7%	0.0%
	BGE - Pepco	$66,493,009	$67,792,777	$1,299,768	7.8%	8.0%	0.0%	0.4%
	ComEd - External	$86,713,125	$33,840,006	($52,873,119)	10.2%	4.0%	14.5%	0.0%
	DAY - DEOK	$46,789,616	$3,231,318	($43,558,298)	5.5%	0.4%	12.0%	0.0%
	Dominion	$88,623,349	$126,076,408	$37,453,058	10.5%	14.9%	0.0%	10.3%
	DPL	$21,476,433	$48,933,566	$27,457,132	2.5%	5.8%	0.0%	7.5%
	JCPL	$21,292,610	$66,357,541	$45,064,931	2.5%	7.8%	0.0%	12.4%
	Met-Ed	$16,944,325	$62,939,675	$45,995,350	2.0%	7.4%	0.0%	12.6%
	PECO	$39,153,897	$90,668,156	$51,514,259	4.6%	10.7%	0.0%	14.2%
	PENELEC	$22,013,555	$24,788,998	$2,775,444	2.6%	2.9%	0.0%	0.8%
	PPL	$44,206,812	$115,881,480	$71,674,667	5.2%	13.7%	0.0%	19.7%
	PSEG	$38,295,684	$118,948,044	$80,652,361	4.5%	14.0%	0.0%	22.2%
	RECO	$1,308,514	$0	($1,308,514)	0.2%	0.0%	0.4%	0.0%
	All Zones	$768,286,412	$847,157,546	$78,871,134	90.7%	100.0%	78.3%	100.0%
Hubs and	AEP - Dayton	$6,996,096	$0	($6,996,096)	0.8%	0.0%	1.9%	0.0%
Aggregates	Dominion	$1,427,216	$0	($1,427,216)	0.2%	0.0%	0.4%	0.0%
	Eastern	$248,226	$0	($248,226)	0.0%	0.0%	0.1%	0.0%
	New Jersey	$602,076	$0	($602,076)	0.1%	0.0%	0.2%	0.0%
	Ohio	$67,568	$0	($67,568)	0.0%	0.0%	0.0%	0.0%
	Western Interface	$472,299	$0	($472,299)	0.1%	0.0%	0.1%	0.0%
	Western	$8,106,659	$0	($8,106,659)	1.0%	0.0%	2.2%	0.0%
	RTEP B0328 Source	$39	$0	($39)	0.0%	0.0%	0.0%	0.0%
	All Hubs and Aggregates	$17,920,178	$0	($17,920,178)	2.1%	0.0%	4.9%	0.0%
Interfaces	CPLE Imp	$0	$0	($0)	0.0%	0.0%	0.0%	0.0%
	Hudson	$1,656,162	$0	($1,656,162)	0.2%	0.0%	0.5%	0.0%
	IMO	$6,131,342	$0	($6,131,342)	0.7%	0.0%	1.7%	0.0%
	Linden	$1,447,299	$0	($1,447,299)	0.2%	0.0%	0.4%	0.0%
	MISO	$13,248,994	$0	($13,248,994)	1.6%	0.0%	3.6%	0.0%
	Neptune	$2,921,252	$0	($2,921,252)	0.3%	0.0%	0.8%	0.0%
	NIPSCO	$8,080	$0	($8,080)	0.0%	0.0%	0.0%	0.0%
	Northwest	$90,601	$0	($90,601)	0.0%	0.0%	0.0%	0.0%
	NYIS	$10,496,917	$0	($10,496,917)	1.2%	0.0%	2.9%	0.0%
	OVEC	$3,562,980	$0	($3,562,980)	0.4%	0.0%	1.0%	0.0%
	South Exp	$4,323,469	$0	($4,323,469)	0.5%	0.0%	1.2%	0.0%
	South Imp	$17,193,758	$0	($17,193,758)	2.0%	0.0%	4.7%	0.0%
	All Interfaces	$61,080,854	$122,699	($60,958,156)	7.2%	0.0%	16.8%	0.0%
	Total	$847,287,445	$847,280,245	($7,200)	100.0%	100.0%	100.0%	100.0%

18 Zonal information in each zonal table has been aggregated to ensure that market sensitive data is not revealed. Table 4-29 does not include synchronous condensing, local constraint control, black start services and reactive services charges and credits since these are allocated zonally.

Reactive services charges are allocated by zone or zones where the service is provided, and charged to real-time load of the zone or zones. The costs of running units that provide reactive services to the entire RTO Region are allocated to the entire RTO real-time load. Table 4-30 shows the geography of reactive services charges. In the first nine months of 2014, 96.9 percent of all reactive service charges were paid by real-time load in the single zone where the service was provided, 0.1 percent were paid by real-time load in multiple zones and 3.0 percent were paid by real-time load across the entire RTO. In the first nine months of 2014, the top three zones accounted for 80.7 percent of all the reactive services charges allocated to single zones.

Table 4-30 Geography of reactive services charges: January through September 2014[19]

Location	Charges	Share of Charges
Single Zone	$26,525,033	96.9%
Multiple Zones	$41,118	0.2%
Entire RTO	$818,614	3.0%
Total	$27,384,764	100.0%

Black start services charges are allocated to zone and non-zone peak transmission use. Resources in one zone accounted for 99.1 percent of all the black start services costs in the first nine months of 2014. These costs resulted from noneconomic operation of units providing black start service under the automatic load rejection (ALR) option in the AEP Control Zone.

Synchronous condensing charges are allocated by zone. Resources in four control zones accounted for all synchronous condensing costs in the first nine months of 2014.

Energy Uplift Issues

Lost Opportunity Cost Credits

Balancing operating reserve lost opportunity cost (LOC) credits are paid to units under two scenarios. If a combustion turbine or a diesel is scheduled to operate in the Day-Ahead Energy Market, but is not requested by PJM in real time, the unit will receive a credit which covers the day-ahead financial position of the unit plus balancing spot energy market charges that the unit has to pay. For purposes of this report, this LOC will be referred to as day-ahead LOC.[20] If a unit generating in real time with an offer price lower than the real-time LMP at the unit's bus is reduced or suspended by PJM due to a transmission constraint or other reliability issue, the unit will receive a credit for LOC based on the desired output. For purposes of this report, this LOC will be referred as real-time LOC.

In the first nine months of 2014, LOC credits increased by $62.9 million or 77.7 percent compared to the first nine months of 2013. The increase of $62.9 million is comprised of an increase of $39.4 million in day-ahead LOC and an increase of $23.5 million in real-time LOC. Table 4-31 shows the monthly composition of LOC credits in 2013 and the first nine months of 2014. The increase in LOC credits was primarily a result of higher real-time energy prices during hours for which the units had been scheduled day ahead and should have been called in real time but were not and units that were manually dispatched down in order to maintain system reliability during periods of high energy prices. The impact of high real-time energy prices was partially offset by less generation receiving LOC credits in the first nine months of 2014 compared to the first nine months of 2013. In the first nine months of 2014, 22.3 percent of the day-ahead scheduled generation from combustion turbines and diesels was not committed in real time and paid LOC credits, 9.9 percentage points lower than in the first nine months of 2013.

Table 4-31 Monthly lost opportunity cost credits: 2013 and 2014

	2013			2014		
	Day-Ahead Lost Opportunity Cost	Real-Time Lost Opportunity Cost	Total	Day-Ahead Lost Opportunity Cost	Real-Time Lost Opportunity Cost	Total
Jan	$8,728,322	$2,753,013	$11,481,334	$47,556,189	$29,937,422	$77,493,611
Feb	$2,049,518	$2,681,099	$4,730,617	$6,049,668	$5,417,993	$11,467,661
Mar	$4,803,277	$2,324,036	$7,127,313	$8,763,427	$4,062,970	$12,826,397
Apr	$3,893,268	$1,888,605	$5,781,873	$1,624,650	$1,371,037	$2,995,687
May	$5,266,582	$3,251,673	$8,518,255	$10,480,844	$2,488,722	$12,969,566
Jun	$6,200,721	$826,758	$7,027,479	$7,231,886	$1,152,517	$8,384,403
Jul	$16,300,953	$3,191,321	$19,492,274	$6,273,056	$231,836	$6,504,892
Aug	$5,449,177	$234,782	$5,683,959	$5,232,739	$86,126	$5,318,866
Sep	$6,377,820	$4,753,940	$11,131,760	$5,278,095	$622,780	$5,900,875
Oct	$2,455,137	$630,186	$3,085,323			
Nov	$1,365,945	$778,925	$2,144,870			
Dec	$535,311	$573,134	$1,108,445			
Total (Jan - Sep)	$59,069,637	$21,905,226	$80,974,864	$98,490,554	$45,371,404	$143,861,958
Share (Jan - Sep)	72.9%	27.1%	100.0%	68.5%	31.5%	100.0%
Total	$63,426,030	$23,887,472	$87,313,502	$98,490,554	$45,371,404	$143,861,958
Share	72.6%	27.4%	100.0%	68.5%	31.5%	100.0%

19 PJM and the MMU cannot publish more detailed information about the location of the costs of reactive services, synchronous condensing or certain other ancillary services because of confidentiality requirements. See PJM. Manual 33: Administrative Services for the PJM Interconnection Agreement, Revision 11 (May 29, 2014).

20 A unit's day-ahead financial position equals the revenues from the Day-Ahead Energy Market minus the expected costs (valued at the unit's offer curve cleared in day ahead). A unit scheduled in the Day-Ahead Energy Market and not committed in real time incurs balancing spot energy charges since it has to cover its day-ahead scheduled energy position in real time.

Table 4-32 shows, for combustion turbines and diesels scheduled day ahead, the total day-ahead generation, the day-ahead generation from units that were not requested by PJM in real time and the subset of that generation that received lost opportunity costs credits. Table 4-32 shows that while day-ahead scheduled generation from CTs and diesels increased 826 GWh or 7.5 percent in the first nine months of 2014 compared to the first nine months of 2013, the generation that received LOC credits was reduced by 910 GWh or 25.6 percent.

Table 4-32 Day-ahead generation from combustion turbines and diesels (GWh): 2013 and 2014

	2013			2014		
	Day-Ahead Generation	Day-Ahead Generation Not Requested in Real Time	Day-Ahead Generation Not Requested in Real Time Receiving LOC Credits	Day-Ahead Generation	Day-Ahead Generation Not Requested in Real Time	Day-Ahead Generation Not Requested in Real Time Receiving LOC Credits
Jan	886	633	561	2,150	846	358
Feb	430	206	173	763	304	153
Mar	809	395	282	976	234	126
Apr	684	325	256	438	170	47
May	1,032	387	260	1,206	617	387
Jun	1,284	696	440	1,363	559	357
Jul	2,951	947	748	1,657	534	370
Aug	1,772	778	544	1,791	637	453
Sep	1,219	480	295	1,550	536	396
Oct	929	451	267			
Nov	578	213	120			
Dec	426	109	49			
Total (Jan - Sep)	11,068	4,846	3,558	11,894	4,437	2,648
Share (Jan - Sep)	100.0%	43.8%	32.2%	100.0%	37.3%	22.3%
Total	13,001	5,620	3,994	11,894	4,437	2,648
Share	100.0%	43.2%	30.7%	100.0%	37.3%	22.3%

In the first nine months of 2014, the top three control zones in which generation received LOC credits, AEP, Dominion and PENELEC, accounted for 56.5 percent of all LOC credits, 44.1 percent of all the day-ahead generation from combustion turbines and diesels, 51.7 percent of all day-ahead generation not committed in real time by PJM from those unit types and 61.2 percent of all day-ahead generation not committed in real time by PJM and receiving LOC credits from those unit types.

Combustion turbines and diesels receive LOC credits on an hourly basis. For example, if a combustion turbine is scheduled day ahead to run from hour 10 to hour 18 and the unit only runs from hour 12 to hour 16, the unit is eligible for LOC credits for hours 10, 11, 17 and 18. Table 4-33 shows the LOC credits paid to combustion turbines and diesels scheduled in the Day-Ahead Energy Market for units that did not run in real time and units that ran in real time for at least one hour of their day-ahead schedule. Table 4-33 shows that in the first nine months of 2014, $53.4 million or 54.2 percent of all LOC credits were paid to combustion turbines and diesels that did not run for any hour in real time, 11.5 percentage points lower than the first nine months of 2013.

Table 4-33 Lost opportunity cost credits paid to combustion turbines and diesels by scenario: 2013 and 2014

	2013			2014		
	Units that Did Not Run in Real Time	Units that Ran in Real Time for at Least One Hour of Their Day-Ahead Schedule	Total	Units that Did Not Run in Real Time	Units that Ran in Real Time for at Least One Hour of Their Day-Ahead Schedule	Total
Jan	$8,081,096	$647,226	$8,728,322	$21,107,023	$26,449,165	$47,556,189
Feb	$1,860,546	$188,972	$2,049,518	$3,653,270	$2,396,398	$6,049,668
Mar	$2,985,098	$1,818,180	$4,803,277	$3,603,333	$5,160,094	$8,763,427
Apr	$2,476,452	$1,416,816	$3,893,268	$838,032	$786,618	$1,624,650
May	$3,615,804	$1,650,778	$5,266,582	$8,291,781	$2,189,063	$10,480,844
Jun	$4,758,076	$1,442,645	$6,200,721	$5,401,100	$1,830,786	$7,231,886
Jul	$7,462,411	$8,838,541	$16,300,952	$3,819,486	$2,453,570	$6,273,056
Aug	$3,378,510	$2,070,667	$5,449,177	$3,677,848	$1,554,891	$5,232,739
Sep	$4,200,542	$2,177,278	$6,377,820	$3,029,813	$2,248,281	$5,278,095
Oct	$2,167,106	$288,031	$2,455,137			
Nov	$846,109	$519,836	$1,365,945			
Dec	$195,648	$339,663	$535,311			
Total (Jan - Sep)	$38,818,535	$20,251,102	$59,069,637	$53,421,686	$45,068,867	$98,490,553
Share (Jan - Sep)	65.7%	34.3%	100.0%	54.2%	45.8%	100.0%
Total	$42,027,399	$21,398,631	$63,426,030	$53,421,686	$45,068,867	$98,490,553
Share	66.3%	33.7%	100.0%	54.2%	45.8%	100.0%

Table 4-34 Day-ahead generation (GWh) from combustion turbines and diesels receiving lost opportunity cost credits by value: 2013 and 2014[21]

	2013			2014		
	Economic Scheduled Generation (GWh)	Noneconomic Scheduled Generation (GWh)	Total (GWh)	Economic Scheduled Generation (GWh)	Noneconomic Scheduled Generation (GWh)	Total (GWh)
Jan	544	121	664	365	359	725
Feb	171	53	224	134	159	293
Mar	269	144	413	128	105	233
Apr	225	93	318	66	114	180
May	228	129	357	374	198	572
Jun	364	272	635	336	168	504
Jul	713	202	915	334	145	480
Aug	436	275	711	336	281	617
Sep	293	166	459	332	192	524
Oct	256	175	431			
Nov	131	64	195			
Dec	35	59	94			
Total (Jan - Sep)	3,243	1,455	4,697	2,405	1,721	4,127
Share (Jan - Sep)	69.0%	31.0%	100.0%	58.3%	41.7%	100.0%
Total	3,665	1,753	5,418	2,405	1,721	4,127
Share	67.6%	32.4%	100.0%	58.3%	41.7%	100.0%

21 The total generation in Table 4-34 is lower than the day-ahead generation not requested in real time in Table 4-32 because the former only includes generation from units that received lost opportunity costs during at least one hour of the day. Table 4-34 includes all generation, including generation from units that were not committed in real time and did not receive LOC credits.

PJM may not run units in real time if the real-time value of the energy (generation multiplied by the real-time LMP) is lower than the units' total offer (including no load and startup costs). Table 4-34 shows the total day-ahead generation from combustion turbines and diesels that were not committed in real time by PJM and received LOC credits. Table 4-34 shows the scheduled generation that had a total offer (including no load and startup costs) lower than its real-time value (generation multiplied by the real-time LMP), defined here as economic scheduled generation, and the scheduled generation that had a total offer greater than its real-time value or noneconomic scheduled generation. In the first nine months of 2014, 58.3 percent of the scheduled generation not committed by PJM from units receiving LOC credits was economic and the remaining 41.7 percent was noneconomic.

Black Start Service Units

Certain units located in the AEP Control Zone are relied on for their black start capability on a regular basis even during periods when the units are not economic. The relevant black start units provide black start service under the automatic load rejection (ALR) option, which means that the units must be running even if not economic. Units providing black start service under the ALR option can remain running at a minimum level, disconnected from the grid. The costs of the noneconomic operation of these units results in make whole payments in the form of operating reserve credits. The MMU recommended that these costs be allocated as black start charges. This recommendation was made effective on December 1, 2012.[22]

In the first nine months of 2014, the cost of the noneconomic operation of ALR units in the AEP Control Zone was $26.4 million, and 94.3 percent of these costs was paid by peak transmission use in the AEP Control Zone while the remaining 5.7 percent was paid by non-zone peak transmission use. The calculation of peak transmission use is based on the peak load contribution in the AEP Control Zone. Load in the AEP Control Zone paid an average of $3.99 per MW-day for black start costs related to the noneconomic operation of ALR units. Non-zone peak transmission use is based on reserved capacity for firm and non-firm transmission service. Point-to-point customers paid an average of $0.02 per MW of reserved capacity for black start costs related to the noneconomic operation of ALR units.

PJM and AEP have issued two requests for proposals (RFP) seeking additional black start capability for the AEP Control Zone. PJM awarded all viable solutions from the last RFP.[23] PJM also approved new rules concerning black start service procurement. Resources selected through the new process are expected to provide black start service as of April 1, 2015.[24,25]

Reactive / Voltage Support Units

Closed Loop Interfaces

In 2013, PJM began to develop solutions to improve the incorporation of reactive constraints into energy prices. One of PJM's solutions was to create interfaces that could be used in such a way that units needed for reactive support could set the energy price. PJM also plans to use closed loop interfaces to set the real-time LMP with emergency DR resources and PJM has done so. These closed loop interfaces would be used to model the transfer capability into a specific area. Areas or regions are defined in PJM by hubs, aggregates or control zones, all comprised of buses. Closed loop interfaces are not defined by buses, but defined by the transmission facilities that connect the buses inside of the loop with the rest of PJM. Table 4-35 shows the closed loop interfaces that PJM has defined.

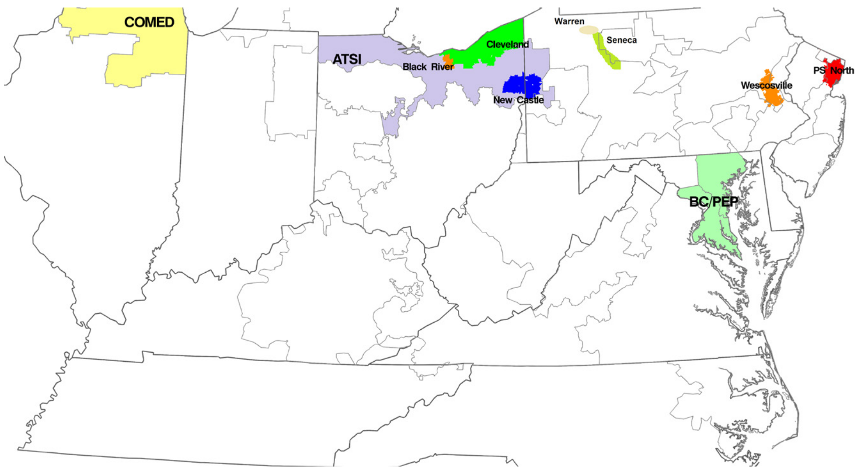
Table 4-35 PJM Closed Loop Interfaces[26,27,28]

Interface	Control Zone(s)	Objective
ATSI	ATSI	Allow emergency DR resources set real-time LMP
BC/PEPCO	BGE and Pepco	Reactive Interface (not an IROL). Used to model import capability into the BGE/PEPCO/Doubs/Northern Virginia area
Black River	ATSI	Allow emergency DR resources set real-time LMP
Cleveland	ATSI	Reactive Interface (IROL)
ComEd	ComEd	Reactive Interface (IROL)
New Castle	ATSI	Allow emergency DR resources set real-time LMP
PS North	PSEG	Objective not identified. Interface was modeled in 2014/2015 Annual FTR auction
Seneca	PENELEC	Allow unit(s) needed for reactive to set day-ahead and real-time LMP
Warren	PENELEC	Allow unit(s) needed for reactive to set day-ahead and real-time LMP
Wescosville	PPL	Allow emergency DR resources set real-time LMP

22 See PJM Interconnection, L.L.C., Docket No. ER13-481-000 (November 30, 2012).
23 See PJM. "Item 3: Black Start RFP Status," PJM Presentation to the System Restoration Strategy Task Force (June 14, 2013) <http://www.pjm.com/~/media/committees-groups/task-forces/srstf/20130614/20130614-item-03-srstf-bs-rfp-status.ashx>.
24 See the *2013 State of the Market Report for PJM, Volume II,* Section 10, "Ancillary Services" at "Black Start Service".
25 See PJM. Manual 14D: Generator Operational Requirement, Revision 28 (July 1, 2014) at "Section 10: Black Start Generation Procurement."
26 See PJM. Manual 3: Transmission Operations, Revision 45 (June 1, 2014) at "Section 3.8: Transfer Limits (Reactive/Voltage Transfer Limits)," for a description of reactive interfaces.
27 See the ATSI, Black River, New Castle, Seneca, Warren and Wescosville interfaces definitions at <http://www.pjm.com/markets-and-operations/etools/oasis/system-information.aspx>.
28 See the PS North interface definition at <http://www.pjm.com/pub/account/auction-user-info/model-annual/Annual-PJM-interface-definitions-limits.csv>.

Figure 4-6 shows the approximate geographic location of PJM's closed loop interfaces.

Figure 4-6 PJM Closed Loop Interfaces Map



Under the status quo, units scheduled for reactive support are only marginal when they are needed to supply energy above their economic minimum. Under the proposed solution these units could be made marginal even when not needed for energy, by adjusting the limit of the closed loop interface. This would create congestion in the area that can only be relieved by the units providing reactive support inside the loop. The goal is to reduce energy uplift from the noneconomic operation of units needed for reactive support by making these units marginal to the extent possible, hence reducing energy uplift costs.

The MMU has recommended and supports PJM's goal of having dispatcher decisions reflected in transparent market outcomes, preferably LMP, to the maximum extent possible and to minimize the level and rate of energy uplift charges. But part of that goal is to avoid disruption of the way in which the transmission network is modeled. The MMU recommends that PJM be transparent in the formulation of closed loop interfaces with adjustable limits and develop rules to reduce the levels of subjectivity around the creation and implementation of these interfaces. The MMU also recommends that PJM estimate the impact such interfaces could have on additional uplift payments inside closed loops, transmission planning, offer capping, FTR and ARR revenue, ancillary services markets and the capacity market before their implementation to avoid unintended consequences.

The MMU recommends that PJM not use closed loop interfaces to set zonal prices, rather than use nodal prices, to accommodate the inadequacies of the demand side resource capacity product or the inability of the LMP model to fully accommodate reactive issues. Market prices should be a function of market fundamentals and energy market prices should be a function of energy market fundamentals. The MMU recommends that the implementation of closed loop interface constraints be studied carefully sufficiently in advance to identify issues and that closed loop interfaces be implemented only after such analysis, only after significant advance notice to the markets and only if the result is consistent with energy market fundamentals.

AP South / Bedington – Black Oak Reactive Support

Beginning in 2012 and during almost all 2013, a set of units located in the BGE and Pepco control zones were scheduled and committed to provide reactive support to the AP South or the Bedington – Black Oak reactive transfer interfaces. These units were scheduled as must run in the Day-Ahead Energy Market whenever they would not clear the market based on economics and were selected by PJM to provide reactive support.

On December 24, 2013, PJM began to schedule less generation from units in the BGE and Pepco control zones in order to reduce energy uplift costs associated with the reactive support provided by these units to the 500 KV transmission lines that comprise the AP South and Bedington – Black Oak reactive transfer interfaces.[29] At the same time, PJM restarted modeling the BC/PEPCO reactive transfer interface in the Day-Ahead and Real-Time Energy

29 See PJM "Reactive Charges Update," PJM Presentation at the Market Implementation Committee (January 8, 2014) <http://www.pjm.com/committees-and-groups/committees/mic.aspx>.

Markets and reduced FMU adders to reactive units.[30] These actions eliminated energy uplift costs for the noneconomic operation of units providing reactive support to the AP South or the Bedington – Black Oak reactive transfer interfaces after December 24, 2013.

In the first nine months of 2014, the total scheduled generation from these units increased by 3,459 GWh or 31.2 percent when compared to the first nine months of 2013. Energy uplift credits in the Day-Ahead Energy Market paid to these units decreased 66.6 percent compared to the amount paid in the first nine months of 2013. These units were more economic in the first nine months of 2014 primarily as a result of higher LMPs in the first nine months of 2014.[31] The weighted average day-ahead LMP at these units' buses in the first nine months of 2014 was $87.69 per MWh, $38.98 per MWh higher than the average in the first nine months of 2013. Reduced FMU adders for these reactive units also significantly reduced the offers and energy uplift credits of these units.

Confidentiality of Energy Uplift Information

All data posted publicly by PJM or the MMU must comply with confidentiality rules. Current confidentiality rules do not appear to allow posting data for three or fewer PJM participants and cannot be aggregated in a geographic area smaller than a control zone.[32]

Energy uplift charges are out of market, non-transparent payments made to resources operating at PJM's direction. Energy uplift charges are highly concentrated in a small number of zones and paid to a small number of PJM participants. These costs are not reflected in PJM market prices. Current confidentiality rules prevent the publication of detailed data concerning the reasons and locations of these payments, making it difficult for other participants to compete with the resources receiving energy uplift payments. Uplift charges are not included in the transmission planning process meaning that transmission solutions are not considered. The confidentiality rules were implemented in order to protect competition. The application of confidentiality rules in the case of energy uplift information does exactly the opposite. Energy uplift is not a market and the absence of relevant information creates a barrier to entry. The MMU recommends that PJM revise the current energy uplift confidentiality rules in order to allow the disclosure of energy uplift credits by zone, by owner and by resource.

Energy Uplift Recommendations

Credits Recommendations

Day-Ahead Operating Reserve Elimination

The only reason to pay energy uplift in the Day-Ahead Energy Market is that a day-ahead schedule could cause a unit to incur losses as a result of differences between the Day-Ahead and Balancing Markets. Units cannot incur losses in the Day-Ahead Energy Market. There is no reason to pay energy uplift in the Day-Ahead Energy Market. All energy uplift should be paid in real time including energy uplift that results from differences between day-ahead and real-time schedules. Paying energy uplift in the Day-Ahead Energy Market results in overpayments.

Day-ahead operating reserve credits are paid to market participants under specific conditions in order to ensure that units are not scheduled in the Day-Ahead Energy Market by PJM to operate at a loss in real time. Balancing operating reserve credits are paid to market participants under specific conditions in order to ensure that units are not operated by PJM at a loss in real time. Units are paid day-ahead operating reserve credits whenever their total offer (including no load and startup costs and based on their day-ahead scheduled output) is not covered by the day-ahead energy revenues (day-ahead LMP times day-ahead scheduled output). Units are paid balancing operating reserve credits whenever their total offer (including no load and startup costs and based on their real-time output) are not covered by their

30 In 2012, the BC/PEPCO Interface was modeled in the Day-Ahead Energy Market starting on August 22, 2012. In 2013, the interface was stopped being modeled on September 25, 2013 and was resumed on December 27, 2013. In real time the interface was only modeled twice in 2012 and once in 2013 (before December 24). After December 24, 2013, the interface was modeled every day.

31 See Section 3, "Energy Market" at "Prices" for the components of the day-ahead and real-time LMP and their contribution in the first nine months of 2014 and the first nine months of 2013.

32 See "Manual 33 Administrative Services for the PJM Interconnection Operating Agreement," Revision 11 (May 29, 2014), Market Data Posting.

day-ahead energy revenues, balancing energy revenues and a subset of net ancillary services revenues.[33]

Units scheduled in the Day-Ahead Energy Market do not operate until committed or dispatched in real time. Therefore, it cannot be determined if a unit was operated at a loss or not until the unit actually operates. The current operating reserve rules governing the day-ahead operating reserve credits assume that units are going to operate exactly as scheduled because they are made whole based on their day-ahead scheduled output. A unit's real-time output may be greater or lower than their day-ahead scheduled output. Units dispatched in real time by PJM above their day-ahead scheduled output could be paid energy uplift in the form of balancing operating reserve credits if by increasing their output they operate at a loss because their offers are greater than the real-time LMP. Units dispatched in real time by PJM below their day-ahead scheduled output could be paid energy uplift in the form of balancing operating reserve credits if by decreasing their output the units operate at a loss or incur opportunity costs because real-time LMP is greater than the day-ahead LMP. The balancing operating reserve credits and lost opportunity costs credits ensure that units recover their total offers or keep their profits in real time.

Units scheduled in the Day-Ahead Energy Market that receive day-ahead operating reserve credits and for which real-time operation results in additional losses, are paid energy uplift in the form of balancing operating reserve or lost opportunity cost credits to ensure that they do not operate at a loss. This determination is not symmetrical because units scheduled in the Day-Ahead Energy Market that receive day-ahead operating reserve credits and for which real-time operation results in reduced losses or not loss do not have a reduction in energy uplift payments.

Units that follow PJM dispatch instructions are made whole through operating reserve credits to ensure that they do not operate at a loss. In order to determine if a unit operated at a loss, it needs to be committed or dispatched. The day-ahead scheduled output is one of PJM's dispatch instructions, but it does not determine if a unit actually operated at a loss. In order to determine if a unit operated at a loss it is necessary to take into account the unit's real-time output and both the day-ahead and balancing energy revenues and ancillary services net revenues.

In order to properly compensate units the MMU recommended enhancing the day-ahead operating reserve credits calculation in order to ensure that units receive an energy uplift payment based on their real-time output and not their day-ahead scheduled output whenever their real time operation results in a lower loss or no loss at all. The MMU also recommended including net DASR revenues as part of the offsets used in determining day-ahead operating reserve credits.[34] These recommendations are superseded by the MMU's recommendation to eliminate day-ahead operating reserve payments.[35] The elimination of the day-ahead operating reserve category also ensures that units are always made whole based on their actual operation and actual revenues. The MMU supports the PJM proposal of eliminating the day-ahead operating reserve category.

The MMU calculated the impact of this recommendation in 2013 and the first nine months of 2014. In 2013 and the first nine months of 2014, energy uplift costs associated with units scheduled in the Day-Ahead Energy Market would have had been reduced by $95.7 million or 14.0 percent ($10.3 million paid to units providing reactive support, $15.2 million paid to units providing black start support and $70.2 million paid to units as day-ahead and balancing operating reserves).

The elimination of the day-ahead operating reserve category would change the allocation of such charges under the current energy uplift rules. Under the current rules the charges categorized as day-ahead operating reserve charges would be allocated to deviations or real-time load plus real-time exports depending on the balancing operating reserve allocation rules.

33 The balancing operating reserve credit calculation includes net DASR revenues, net synchronized reserve revenues, net non-synchronized reserve revenues and reactive services revenues.

34 See *2013 State of the Market Report for PJM, Volume II* Section 4, "Energy Uplift," at "Day-Operating Reserve Credits," and at "Net DASR Revenues Offset" for an explanation of these recommendations.

35 PJM agrees with this recommendation. See "Explanation of PJM Proposals," from the Energy Market Uplift Senior Task Force (April 8, 2014). <http://www.pjm.com/~/media/committees-groups/task-forces/emustf/20140408/20140408-explanation-of-pjm-proposals.ashx>.

Net Regulation Revenues Offset

On October 1, 2008, PJM filed revisions to the Operating Agreement and Tariff with FERC related to the Regulation Market. The filing included four elements: implement the TPS test in the regulation market; increase the regulation offer adder from $7.50 per MW to $12.00 per MW; eliminate the use of net regulation revenues as an offset in the balancing operating reserve calculation; and calculate the lost opportunity cost on the lower of a unit's price-based or cost-based offer.

The elimination of the use of net regulation revenues as an offset in the balancing operating reserve calculation had a direct impact on the level of energy uplift paid to participants that regulate while operating noneconomic. The result of not using the net regulation revenues as an offset in the balancing operating reserve credit calculation is that PJM does not accurately calculate whether a unit is running at a loss. PJM procures energy, regulation, synchronized and non-synchronized reserves in a jointly optimized manner. PJM determines the mix of resources that could provide all of those services in a least-cost manner. Excluding the net regulation revenues from the balancing operating reserve credit calculation is inconsistent with the process used by PJM to procure these services.

Another issue related to this exclusion is the treatment of pool-scheduled units that elect to self-schedule a portion of their capacity for regulation. A unit can be pool-scheduled for energy, which means PJM may commit or dispatch the unit based on economics, but it can also self-schedule some of its capacity for regulation. When this happens the capacity self-scheduled for regulation is treated as a price-taker, but in the Energy Market any increase in MW to provide regulation are treated as additional costs, which can result in increased balancing operating reserve credits whenever the real-time LMP is lower than the unit's offer. For example, if a unit raises its economic minimum in order to provide regulation, the result is increased energy uplift.

The MMU recommends reincorporating the use of net regulation revenues as an offset in the calculation of balancing operating reserve credits. In 2013 and the first nine months of 2014, using net regulation revenues as an offset in the balancing operating reserve calculation would have resulted in a net decrease of balancing operating reserve charges of $22.7 million, of which $18.4 million or 81.2 percent was due to generators that elected to self-schedule for regulation while being noneconomic and receiving balancing operating reserve credits.[36]

Self Start

Participants may offer their units as pool-scheduled (economic) or self-scheduled (must run).[37] Units offered as pool-scheduled clear the Day-Ahead Energy Market based on their offers and operate in real time following PJM dispatch instructions. Units offered as self-scheduled are price takers in both the Day-Ahead and Real-Time Energy Markets unless self-scheduled units elect to submit a fixed energy amount per hour or a minimum must run amount from which the unit may be dispatched up but not down. Self-scheduled units are not eligible to receive day-ahead or balancing operating reserve credits. The current rules determine if a unit is pool-scheduled or self-scheduled for operating reserve credits purposes using the hourly commitment status flag. If the flag is set as economic the unit is assumed to be pool-scheduled, if the flag is set as must run the unit is assumed to be self-scheduled. When a unit submits different flags within a day, the day-ahead operating reserve credit calculation treats each group of hours separately. The day-ahead operating reserve credit calculation only uses the hours flagged as economic and excludes any hours flagged as must run.

In some cases, units offered as self-scheduled for some hours of the day and pool-scheduled for the remaining hours are made whole for startup cost. The MMU recommends that self-scheduled units not be paid energy uplift for their startup cost when the units are scheduled by PJM to start before the self-scheduled hours.

36 These estimates take into account the elimination of the day-ahead operating reserve category.
37 See "PJM eMkt Users Guide," Section Managing Unit Data (version April 1, 2014) p. 48. <http://www.pjm.com/~/media/etools/emkt/ts-userguide.ashx>.

Lost Opportunity Cost Calculation

The current energy LOC calculations are inaccurate and create unreasonable compensation. The MMU recommends four modifications.[38]

- **Unit Schedule Used:** Current rules require the use of the higher of a unit's price-based and cost-based schedules to calculate the LOC in the energy market. The MMU recommends that the LOC in the energy and ancillary services markets be calculated using the schedule on which the unit was scheduled to run in the energy market. This recommendation was proposed at the MIC.
- **No load and startup costs:** Current rules do not include in the calculation of LOC credits all of the costs not incurred by a scheduled unit not running in real time. Generating units do not incur no load or startup costs if they are not committed in real time. As a result, no load and startup costs should be subtracted from the real time LMP in the same way that the incremental energy offer is subtracted to calculate the actual value of the opportunity lost by the unit. The MMU recommends including no load and startup costs as part of the total avoided costs in the calculation of LOC credits paid to combustion turbines and diesels scheduled in the Day-Ahead Energy Market but not committed in real time. This recommendation was proposed at the MIC.
- **Day-Ahead LMP:** Current rules require the use of the day-ahead LMP as part of the LOC calculation logic when a unit is scheduled on a noneconomic basis day ahead, meaning that the unit's offer is greater than the day-ahead LMP. In the Day-Ahead Energy Market, such units receive operating reserve credits equal to the difference between the unit's offer (including no load and startup costs) and the day-ahead LMP. If such a unit is not dispatched in real time, under the current rules the unit receives LOC credits equal to the difference between the real-time LMP and the day-ahead LMP. This calculation results in double counting because the unit has already been made whole to its day-ahead offer in the Day-Ahead Energy Market through day-ahead operating reserve credits if necessary. If the unit is not committed in real time, it should receive only the difference between real-time LMP and the unit's offer, which is the actual LOC. The MMU recommends eliminating the use of the day-ahead LMP to calculate LOC credits paid to combustion turbines and diesels scheduled in the Day-Ahead Energy Market but not committed in real time.
- **Offer Curve:** Current rules require the use of the difference between the real-time LMP and the incremental offer at a single point on the offer curve (at the actual or scheduled output), instead of using the difference between the real-time LMP and the entire offer curve (area between the LMP and the offer curve) when calculating the LOC in the PJM Energy Markets for units scheduled in day ahead but which are reduced, suspended or not committed in real time. Units with an offer lower than the real-time LMP at the units' bus that are reduced in real time by PJM should be paid LOC based on the area between the real-time LMP and their offer curve between the actual and desired output points. Units scheduled in day ahead and not dispatched in real time should be paid LOC based on the area between the real-time LMP and their offer curve between zero output and scheduled output points. The MMU recommends using the entire offer curve and not a single point on the offer curve to calculate energy LOC.

These four modifications are consistent with the inputs used by PJM's software to commit combustion turbines in real time. PJM's commitment process is based on the forecasted LMPs, the reliability requirements, reserve requirement and the total cost of the units. The total cost of the units includes no load costs and startup costs and is based on the units' schedule on which it is committed.

Table 4-36 shows the impact that each of these changes would have had on the LOC credits in the Energy Market in the first nine months of 2014, for the two categories of lost opportunity cost credits. Energy LOC credits would have been reduced by a net of $20.4 million, or 14.2 percent, if all these changes had been implemented.[39]

38 See "LOC Session MA Energy LOC Proposal," MMU Presentation to the Market Implementation Committee (October 19, 2012) <http://www.pjm.com/~/media/committees-groups/committees/mic/20121019/20121019-loc-session-ma-energy-loc-proposal.ashx>.

39 The impacts on the lost opportunity cost credits were calculated following the order presented. Eliminating one of the changes has an effect on the remaining impacts.

Table 4-36 Impact on energy market lost opportunity cost credits of rule changes: January through September 2014

	LOC When Output Reduced in RT	LOC When Scheduled DA Not Called RT	Total
Current Credits	$45,371,404	$98,490,553	$143,861,957
Impact 1: Committed Schedule	$1,082,561	$10,978,109	$12,060,671
Impact 2: Eliminating DA LMP	NA	($2,838,266)	($2,838,266)
Impact 3: Using Offer Curve	($1,411,862)	$6,855,396	$5,443,534
Impact 4: Including No Load Cost	NA	($26,102,603)	($26,102,603)
Impact 5: Including Startup Cost	NA	($9,013,034)	($9,013,034)
Net Impact	($329,301)	($20,120,397)	($20,449,698)
Credits After Changes	$45,042,103	$78,370,157	$123,412,259

Allocation Recommendations

Up-to Congestion Transactions

Up-to congestion transactions do not pay energy uplift charges. An up-to congestion transaction affects unit commitment and dispatch in the same way that increment offers and decrement bids affect unit commitment and dispatch in the Day-Ahead Energy Market. All such virtual transactions affect the results of the Day-Ahead Energy Market and contribute to energy uplift costs. Up-to congestion transactions are currently receiving preferential treatment, relative to increment offers and decrement bids and other transactions because they are not charged energy uplift.

The MMU calculated the impact on energy uplift rates if up-to congestion transactions had paid energy uplift charges based on deviations in the same way that increment offers and decrement bids do along with other recommendations that impact the total costs of energy uplift and its allocation.

The MMU recommends that up-to congestion transactions be required to pay energy uplift charges. Up-to congestion transactions would have paid an average rate between $0.241 and $0.993 per MWh in 2013 and between $0.566 and $0.647 per MWh in the first nine months of 2014 if the MMU's recommendations regarding energy uplift had been in place.[40,41]

Internal Bilateral Transactions

Market participants are allocated a portion of the costs of balancing operating reserves based on their deviations. Deviations are calculated in three categories, demand, supply and generation. Generators deviate when their real-time output is different than the desired output or their day-ahead scheduled output.[42] Load, interchange transactions, internal bilateral transactions, demand resources, increment offers and decrement bids also incur deviations. These transactions are grouped in the demand and supply categories.

Generators are allowed to offset their deviations with other generators at the same bus if the generators have the same electrical impact on the transmission system. Load, interchange transactions, internal bilateral transactions, demand resources, increment offers and decrement bids are also allowed to offset their deviations. These transactions are grouped into two categories, demand and supply and aggregated by location. A negative deviation from one transaction can offset a positive deviation from another transaction in the same category, as long as both transactions are in the same location at the same hour.[43] Demand transactions such as load, exports, internal bilateral sales and decrement bids may offset each other's deviations. The same applies to supply transactions such as imports, internal bilateral purchases and increment offers. Unlike all other transaction types, internal bilateral sales and purchases do not impact dispatch or market prices. Internal bilateral transactions are used by participants to transfer the financial responsibility or right of the energy withdrawn or injected into the system in the Day-Ahead and Real-Time Energy Markets.

The MMU recommends eliminating the use of internal bilateral transactions (IBTs) in the calculation of deviations used to allocate balancing operating reserve charges. IBTs should not pay for balancing operating reserves and should not be used to offset other transactions that deviate. IBTs shift the responsibility for an injection or withdrawal in PJM from one participant to another but IBTs are not part of the day-ahead unit commitment process, do

40 The range of operating reserve rates paid by up-to congestion transactions depends on the location of the transactions' source and sink.

41 This analysis assumes that not all costs associated with units providing support to the Con Edison – PJM Transmission Service Agreements would be reallocated under the MMU's proposal. The *2013 State of the Market Report for PJM* analysis assumed that all such costs would be reallocated. This analysis also assumes that only 50 percent of all cleared up-to congestion transactions would have cleared had this recommendation been in place. The *2013 State of the Market Report for PJM* analysis showed that more than 66.7 percent of up-to congestion transactions would have remained under the MMU proposal.

42 See OATT 3.2.3 (o) for a complete description of how generators deviate.

43 Locations can be control zones, hubs, aggregates and interfaces. See the *2013 State of the Market Report for PJM, Volume II*, Section 4, "Energy Uplift" at "Energy Uplift" pp. 124-129 for a description of balancing operating reserve locations.

not set energy prices and do not impact the energy flows in either the Day-Ahead or the Real-Time Energy Market, and thus IBTs should not be considered in the allocation of balancing operating reserve charges. The use of IBTs has been extended to offset deviations from other transactions that do impact the energy market. The elimination of the use of IBTs in the deviation calculation would eliminate the balancing operating reserve charges to participants that use IBTs only in real time. Such elimination would increase the balancing operating reserve charges to participants that use IBTs to offset deviations from day-ahead transactions.

The impact of eliminating the use of internal bilateral transactions in the calculation of deviations use to allocated balancing operating reserve charges has been aggregated with the impacts of other recommendations.

Con Edison – PJM Transmission Service Agreements Support

It appears that certain units located near the boundary between New Jersey and New York City are frequently operated to support the transmission service agreements between Con Ed and PJM, formerly known as the Con Ed – PSEG Wheeling Contracts.[44] These units are often run out of merit and receive substantial day-ahead and balancing operating reserve credits. The MMU recommends that this issue be addressed by PJM in order to determine if the cost of running these units is being allocated properly.

Reactive Services Credits and Balancing Operating Reserve Credits

Energy uplift credits to resources providing reactive services are separate from balancing operating reserve credits.[45] Under the current rules regarding energy uplift credits for reactive services, units are not assured recovery of the entire offer including no load and startup costs as they are under the operating reserve credits rules. Units providing reactive services at the request of PJM are made whole through reactive service credits. But when the reactive services credits do not cover a unit's entire offer, the unit is made whole the balance through balancing operating reserves. The result is a misallocation of the costs of providing reactive services. Reactive services credits are paid by real-time load in the control zone or zones where the service is provided while balancing operating reserve charges are paid by deviations from day-ahead or real-time load plus exports in the RTO, Eastern or Western Region depending on the allocation process rather than by zone.

In the first nine months of 2014, units providing reactive services were paid $2.0 million in balancing operating reserve credits in order to cover their total energy offer. In 2013, this misallocation was $7.2 million, for a total of $9.2 million in the last year and six months.

The MMU recommends that reactive services credits be calculated consistent with the balancing operating reserve credit calculation. The MMU also recommends including real-time exports and real-time wheels in the allocation of the cost of providing reactive support to the 500 kV system or above. Currently only real-time RTO load pays.[46]

Allocation Proposal

The day-ahead operating reserve category elimination and other MMU recommendations require enhancements to the current energy uplift allocation methodology.

The current methodology allocates day-ahead operating reserve charges to day-ahead load, day-ahead exports and decrement bids. The elimination of the day-ahead operating reserve category shifts these costs to the balancing operating reserve category which could be paid by deviations or by real-time load plus real-time exports depending on the balancing operating reserve allocation rules. The MMU recommends creating a new category for energy uplift payments to units scheduled in the Day-Ahead Energy Market (for reasons other than reactive or black start services), which would be allocated to day-ahead load, day-ahead interchange transactions and virtual transactions. All these transaction types have an impact on the outcome of the day-ahead

44 See the *2013 State of the Market Report for PJM, Volume II*, Section 9, "Interchange Transactions" at "Con Edison and PSE&G Wheeling Contracts" for a description of the contracts.
45 OATT Attachment K - Appendix § 3.2.3B (f).
46 See the Day-Ahead Reliability and Reactive Cost Allocation Final Report (December 13, 2013) for a complete description of the issues discussed in that group. <http://www.pjm.com/~/media/committees-groups/task-forces/emustf/20131220/20131220-item-02b-darrca-final-report.ashx>.

scheduling process, so allocating these costs to all day-ahead transactions ensures that all transactions that affect the way the Day-Ahead Energy Market clears are responsible for any energy uplift credits paid to the units scheduled in the Day-Ahead Energy Market.

The MMU recommends allocating energy uplift payments to units not scheduled in the Day-Ahead Energy Market and committed in real time based on the current deviation categories with the addition of up-to congestion and wheeling transactions and the exclusion of offsets based on internal bilateral transactions. These costs should be allocated to the current deviation categories whenever the units receiving energy uplift payments are committed before the operating day.

The MMU recommends changing the allocation of lost opportunity cost and canceled resources. LOC paid to units scheduled in the Day-Ahead Energy Market and not committed in real-time should be allocated to deviations based on the proposed definition of deviations. LOC paid to units reduced for reliability in real time and payments to canceled resources should be allocated to physical deviations.

The MMU recommends allocating energy uplift payments to units committed during the operating day (CTs) to a new deviation category which would include physical transactions or resources (day-ahead minus real-time load, day-ahead minus real-time interchange transactions, generators and DR not following dispatch). This allocation would ensure that commitment changes that occur during the operating day and that result in energy uplift payments are paid by transactions or resources that result in the commitment of units during the operating day. For example, real-time load or interchange transactions that do not bid in the Day-Ahead Energy Market, generators and DR resources that do not follow dispatch would be allocated these costs. Any reliability commitment should be allocated to real-time load plus real-time exports independently of the timing of the commitment.

Table 4-37 shows the current allocation by energy uplift reason. For example, energy uplift payments to units scheduled in the Day-Ahead Energy Market are called day-ahead operating reserves, these costs are paid by day-ahead load, day-ahead exports and decrement bids. Any additional payment resulting from the real time operation of these units are called balancing operating reserves, these costs are paid by either deviations or real-time load and real-time exports depending on the amount of intervals the units are economic.

Table 4-37 Current energy uplift allocation

Reason	Energy Uplift Category	Allocation Logic	Allocation
Units scheduled in the Day-Ahead Energy Market	Day-Ahead Operating Reserve	NA	Day-Ahead Load, Day-Ahead Exports and Decrement Bids
Units scheduled in the Day-Ahead Energy Market	Balancing Operating Reserve	LMP < Offer for at least four intervals	Real-Time Load and Real-Time Exports
		LMP > Offer for at least four intervals	Deviations
Unit Not Scheduled Day Ahead and Committed in Real Time	Balancing Operating Reserve	Committed before the operating day for reliability	Real-Time Load and Real-Time Exports
		Committed before the operating day to meet forecasted load and reserves	Deviations
		Committed during the operating day and LMP < Offer for at least four intervals	Real-Time Load and Real-Time Exports
		Committed during the operating day and LMP > Offer for at least four intervals	Deviations
Units scheduled in the Day-Ahead Energy Market not committed in real time	LOC Credit	NA	Deviations
Units reduced for reliability in real time	LOC Credit	NA	Deviations
Units canceled before coming online	Cancellation Credit	NA	Deviations

Table 4-38 shows the MMU allocation proposal by energy uplift reason. The proposal eliminates the day-ahead operating reserve category and creates a new category for any energy uplift payments to units scheduled in the Day-Ahead Energy Market and committed in real time. This new category would be allocated to day-ahead load, day-ahead interchange transactions and virtual transactions. The proposal also eliminates the need to determine the number of intervals that units are economic to determine if the energy uplift charge should be allocated to deviations or to real-time load and real-time exports. In the proposal, any commitment instruction before the operating day would be allocated based on the proposed definition of deviations; any commitment instruction during the operating day would be allocated to physical deviations.

Table 4-39 shows the energy uplift cost of a 1 MW transaction if these recommendations had been implemented in 2013 and the first nine months of 2014. For example, a decrement bid in the Eastern Region (if not offset by other transactions) would have paid an average rate of $0.497 and $0.324 per MWh in the 2013 and the first nine months of 2014, $2.893 and $2.632 per MWh less than the actual average rate paid. Up-to congestion transactions sourced in the Eastern Region and sinking in the Western Region would have paid an average rate of $0.617 and $0.607 per MWh in 2013 and the first nine months of 2014. Table 4-39 shows the current and proposed averages energy uplift rates for all transactions.

Table 4-38 MMU energy uplift allocation proposal

Reason	Energy Uplift Category	Allocation Logic	Allocation
Units scheduled in the Day-Ahead Energy Market and committed in real time	Day-Ahead Segment Make Whole Credit	NA	Day-Ahead Load, Day-Ahead Interchange Transactions and Virtual Transactions
Units not scheduled in the Day-Ahead Energy Market and committed in real time	Real Time Segment Make Whole Credit	Committed before the operating day	Deviations
		Committed during the operating day	Physical Deviations
		Any commitment for reliability	Real-Time Load, Real-Time Exports and Withdrawal Side of Real-Time Wheels
Units scheduled in the Day-Ahead Energy Market not committed in real time	Day-Ahead LOC	NA	Deviations
Units reduced for reliability in real time	Real-Time LOC	NA	Physical Deviations
Units canceled before coming online	Cancellation Credit	NA	Physical Deviations

Quantifiable Recommendations Impact

The MMU calculated the rates that participants would have paid in 2013 and the first nine months of 2014 if all the MMU's recommendations on energy uplift had been in place. In order to avoid the release of confidential information, these impacts cannot be disaggregated by issue. These recommendations have been included in the analysis: day-ahead operating reserve elimination; net regulation revenues offset; implementation of the proposed changes to lost opportunity cost calculations; reallocation of operating reserve credits paid to units supporting the Con Edison – PJM Transmission Service Agreements; elimination of internal bilateral transactions from the deviations calculation; allocation of energy uplift charges to up-to congestion transactions and the MMU energy uplift allocation proposal.

Table 4-39 Current and proposed average energy uplift rate by transaction: 2013 and January through September 2014[47]

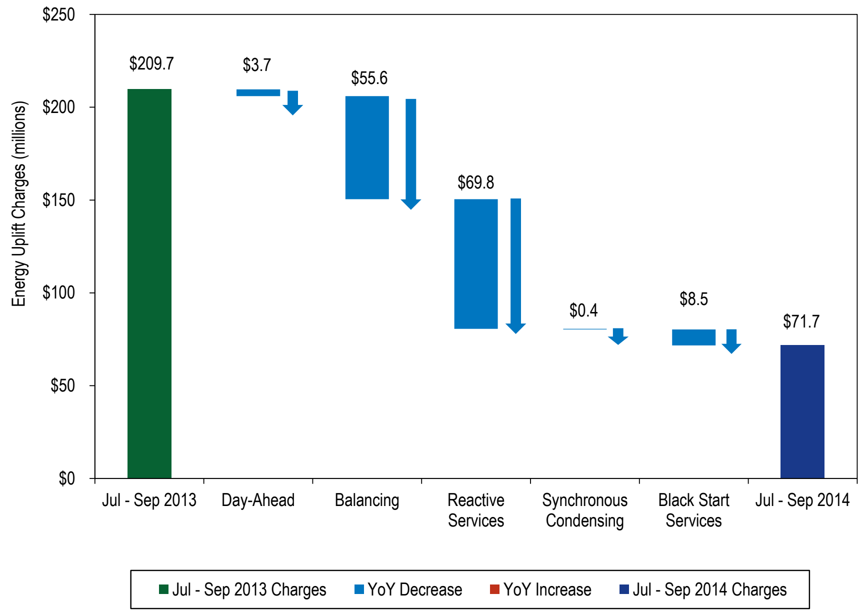
		2013		Jan - Sep 2014	
	Transaction	Current Rates ($/MWh)	Proposed Rates ($/MWh)	Current Rates ($/MWh)	Proposed Rates ($/MWh)
East	INC	3.286	0.497	2.824	0.324
	DEC	3.389	0.497	2.956	0.324
	DA Load	0.103	0.019	0.132	0.061
	RT Load	0.076	0.016	0.592	0.430
	Deviation	3.286	1.403	2.824	2.003
West	INC	1.653	0.120	2.559	0.283
	DEC	1.756	0.120	2.691	0.283
	DA Load	0.103	0.019	0.132	0.061
	RT Load	0.056	0.005	0.579	0.430
	Deviation	1.653	0.836	2.559	1.896
UTC	East to East	NA	0.993	NA	0.647
	West to West	NA	0.241	NA	0.566
	East to/from West	NA	0.617	NA	0.607

July through September 2014 Energy Uplift Charges Decrease

Energy uplift charges increased by $258.8 million (40.2 percent), from $644.2 million in the first nine months of 2013 to $902.9 million in the first nine months of 2014. This increase was highly concentrated in the first three months of 2014. Energy uplift charges increased by $482.9 million (182.5 percent), from $264.5 million in the first three months of 2013 to $747.4 million in the first three months of 2014. Energy uplift charges in the months of July through September decreased by $138.0 million (65.8 percent), from $209.7 million in 2013 to $71.7 million in 2014. This change resulted from a decrease of $69.8 million in reactive services charges, a decrease of $8.5 million in black start services charges, a decrease of $55.6 million in balancing operating reserve charges, a decrease of $3.7 million in day-ahead operating reserve charges and a decrease of $0.4 in synchronous condensing charges.

Figure 4-7 shows the net impact of each category on the change in total energy uplift charges from the July through September 2013 level to the July through September 2014 level. The outside bars show the July through September 2013 total energy uplift charges (left side) and the July through September 2014 total energy uplift charges (right side). The other bars show the change in each energy uplift category. For example, the second bar from the left shows the change in day-ahead operating reserve charges in July through September 2014 compared to July through September 2013 (a decrease of $3.7 million).

Figure 4-7 Energy uplift charges change from July through September 2013 to July through September 2014 by category



The decrease in day-ahead and balancing operating reserve charges was mainly a result of lower summer demand and lower offers from natural gas fired units in the Eastern region that had received substantial day-ahead and balancing operating reserve credits in July through September 2013. The change in the offers in 2014 was a result of lower natural gas prices in the period July through September 2014 when compared to the same period in 2013, which made these units more economic and therefore reduced the need to pay day-ahead and balancing operating reserve credits. Higher energy

47 The deviation transaction means load, interchange transactions, generators and DR deviations.

prices and reduced FMU adders reduced the energy uplift charges for reactive and black start services in July through September 2014 when compared to the same period in 2013. The removal of automatic load rejection black start units from must run black start status contributed to the reduction in the amount of energy uplift paid to units providing black start support.