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.

In PJM all energy payments to demand response resources are also uplift payments. The energy payments to these resources are not part of the supply and demand balance, they are not paid by LMP revenues and therefore the energy payments to demand response resources have to be paid as out of market uplift. The energy payments to economic DR are funded by real-time load and real-time exports. The energy payments to emergency DR are funded by participants with net energy purchases in the Real-Time Energy Market.

Overview

Energy Uplift Results

- **Energy Uplift Charges.** Total energy uplift charges decreased by $613.4 million or 68.2 percent in the first nine months of 2015 compared to the first nine months of 2014, from $899.1 million to $285.7 million.
- **Energy Uplift Charges Categories.** The decrease of $613.4 million in the first nine months of 2015 is comprised of a $0.6 million decrease in day-ahead operating reserve charges, a $573.7 million decrease in balancing operating reserve charges, a $17.5 million decrease in reactive services charges, a $0.1 million decrease in synchronous condensing charges and a $21.6 million decrease in black start services charges.

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.

- **Average Effective Operating Reserve Rates in the Eastern Region.** Day-ahead load paid $0.132 per MWh, real-time load paid $0.061 per MWh, a DEC paid $1.435 per MWh and an INC and any load, generation or interchange transaction deviation paid $1.303 per MWh.
- **Average Effective Operating Reserve Rates in the Western Region.** Day-ahead load paid $0.132 per MWh, real-time load paid $0.052 per MWh, a DEC paid $1.398 per MWh and an INC and any load, generation or interchange transaction deviation paid $1.266 per MWh.
- **Reactive Services Rates.** The DPL, ATSI and Dominion control zones had the three highest local voltage support rates: $0.124, $0.073 and $0.032 per MWh. The reactive transfer interface support rate averaged $0.002 per MWh.

Characteristics of Credits

- **Types of units.** Combined cycles received 26.8 percent of all day-ahead generator credits and 40.6 percent of all balancing generator credits. Combustion turbines and diesels received 87.0 percent of the lost opportunity cost credits. Coal units received 42.3 percent of all reactive services credits.
- **Concentration of Energy Uplift Credits.** The top 10 units receiving energy uplift credits received 33.9 percent of all credits. The top 10 organizations received 79.7 percent of all credits. Concentration indexes for energy uplift categories classify them as highly concentrated. Day-ahead operating reserves HHI was 5422, balancing operating reserves HHI was 3872, lost opportunity cost HHI was 3492 and reactive services HHI was 8928.
- **Economic and Noneconomic Generation.** In the first nine months of 2015, 87.2 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 2015, 2.2 percent of the total day-ahead generation MWh was scheduled as must run by PJM, of which 41.2 percent received energy uplift payments.

Geography of Charges and Credits

- In the first nine months of 2015, 88.2 percent of all uplift 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 generation, 3.1 percent by transactions at hubs and aggregates and 8.7 percent by interchange transactions at interfaces.
- Generators in the Eastern Region received 70.0 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.
- Generators in the Western Region received 29.8 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.
- External generators received 0.2 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.

Energy Uplift Issues

- **Lost Opportunity Cost Credits.** In the first nine months of 2015, lost opportunity cost credits decreased by $63.2 million compared to the first nine months of 2014. In the first nine months of 2015, resources in the top three control zones receiving lost opportunity cost credits, AEP, Dominion and AP accounted for 48.5 percent of all lost opportunity cost credits, 51.3 percent of all day-ahead generation from pool-scheduled combustion turbines and diesels, 52.3 percent of all day-ahead generation not committed in real time by PJM from those unit types and 58.0 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 were relied on for their black start capability on a regular basis during periods when the units were not economic. These black start units provided black start service under the ALR option, which means that the units had to run in order to provide black start services even if the units were not economic. PJM replaced all ALR units as black start resources as of April 2015. In the first nine months of 2015, the cost of the noneconomic operation of ALR units in the AEP Control Zone was $4.8 million, a decrease of $21.6 million compared to the first nine months of 2014.
- **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 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 2015, the average rate paid by a DEC in the Eastern Region would have been $0.186 per MWh, which is $1.249 per MWh, or 87.0 percent, lower than the actual average rate paid.

Recommendations

The MMU recognizes that many of the issues addressed in the recommendations are being discussed in PJM stakeholder processes. Until new rules are in place, the MMU's recommendations and the reported status of those recommendations are based on the existing market rules.

- 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. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that the implementation of closed loop interface constraints be studied carefully sufficiently in advance to identify issues and that, if they are to be used, 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.

(Priority: Medium. First reported 2013. Status: Not adopted. Stakeholder process.)

- The MMU recommends that PJM clearly identify and 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 to be made aware of the reasons for 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 2011. Status: Adopted partially.)
- 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 credits by unit in the PJM region. (Priority: High. First reported 2013. Status: Not adopted.)
- 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. Status: Not adopted. Stakeholder process.)
- 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. Status: Not adopted. Stakeholder process.)
- 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. Status: Not adopted. Stakeholder process.)
- The MMU recommends seven 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. Status: Partially adopted.)
  - 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. Status: Adopted.)
  - 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. Status: Adopted.)
  - The MMU recommends calculating LOC based on segments of hours not on an hourly basis in the calculation of credits paid to combustion turbines and diesels scheduled in the Day-Ahead Energy Market but not committed in real time. (Priority: Medium. First reported 2014. Status: Not adopted.)
  - The MMU recommends that units scheduled in the Day-Ahead Energy Market and not committed in real time should be compensated for LOC based on their real-time desired and achievable output, not their scheduled day-ahead output. (Priority: Medium. New recommendation. Status: Not adopted.)
  - The MMU recommends that units scheduled in the Day-Ahead Energy Market and not committed in real time be compensated for LOC incurred within an hour. (Priority: Medium. New recommendation. Status: Not adopted.)
  - The MMU recommends that only flexible fast start units (startup plus notification times of two hours or less) and short minimum run times (two hours or less) be eligible by default for the LOC compensation to units scheduled Day-Ahead Energy Market and not committed in real time. Other units should be eligible for LOC compensation only if PJM explicitly cancels their day-ahead commitment. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends that up to congestion transactions be required to pay energy uplift charges. (Priority: High. First reported 2013. Status: Not adopted. Stakeholder process.)

- 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. Status: Not adopted. Stakeholder process.)
- The MMU recommends allocating the energy uplift payments to units scheduled as must run in the Day-Ahead Energy Market for reasons other than voltage/reactive or black start services as a reliability charge to real-time load, real-time exports and real-time wheels. (Priority: Medium. First reported 2014. Status: Not adopted. Stakeholder process.)
- The MMU recommends reallocating the operating reserve credits paid to units supporting the Con Edison – PJM Transmission Service Agreements. (Priority: Medium. First reported 2013. Status: Not adopted.)
- 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. Status: Not adopted. Stakeholder process.)
- 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. Status: Not adopted.)
- The MMU recommends enhancing the current energy uplift allocation rules to reflect the elimination of day-ahead operating reserves, the timing of commitment decisions and the commitment reasons. (Priority: High. First reported Q1, 2014. Status: Not adopted. Stakeholder process.)

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.

In PJM all energy payments to demand response resources are also uplift payments. The energy payments to these resources are not part of the supply and demand balance, they are not paid by LMP revenues and therefore the energy payments to demand response resources have to be paid as out of market uplift. The energy payments to economic DR are funded by real-time load and real-time exports. The energy payments to emergency DR are funded by participants with net energy purchases in the Real-Time Energy Market.

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. Energy uplift payments also result from units' operational parameters that may require PJM to schedule or commit resources during noneconomic hours. 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'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. 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. 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.

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				
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 Reactive Services Local Constraint	Zonal Real-Time Load 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 decreased by 68.2 percent in the first nine months of 2015, compared to the first nine months of 2014, to a total of $285.7 million. Table 4-3 shows total energy uplift charges in the first nine months of 2001 through 2015.[2]

Table 4-3 Total energy uplift charges: January through September, 2001 through 2015

	Total Energy Uplift Charges (Millions)	Change (Millions)	Percent Change
Jan - Sep 2001	$240.3	NA	NA
Jan - Sep 2002	$204.6	($35.6)	(14.8%)
Jan - Sep 2003	$295.5	$90.9	44.4%
Jan - Sep 2004	$359.8	$64.3	21.8%
Jan - Sep 2005	$502.0	$142.2	39.5%
Jan - Sep 2006	$282.2	($219.9)	(43.8%)
Jan - Sep 2007	$384.1	$101.9	36.1%
Jan - Sep 2008	$392.8	$8.8	2.3%
Jan - Sep 2009	$245.6	($147.2)	(37.5%)
Jan - Sep 2010	$402.5	$156.8	63.9%
Jan - Sep 2011	$497.8	$95.3	23.7%
Jan - Sep 2012	$487.1	($10.6)	(2.1%)
Jan - Sep 2013	$620.7	$133.5	27.4%
Jan - Sep 2014	$899.1	$278.4	44.9%
Jan - Sep 2015	$285.7	($613.4)	(68.2%)

Total energy uplift charges decreased by $613.4 million or 68.2 percent in the first nine months of 2015 compared to the first nine months of 2014. Table 4-4 compares energy uplift charges by category for the first nine months of 2014 and 2015. The decrease of $613.4 million in 2015 is comprised of a decrease of $0.6 million in day-ahead operating reserve charges, a decrease of $573.7 million in balancing operating reserve charges, a decrease of $17.5 million in reactive services charges, a decrease of $0.1 million in synchronous condensing charges and a decrease of $21.6 million in black start services charges.

2 Table 4-3 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 October 14, 2015.

The decrease in total energy uplift charges was mainly a result of PJM not committing units for conservative operations in advance of the Day-Ahead Energy Market in the 2015 winter, compared to the 2014 winter. PJM still relied on some units committed for congestion in advance of the Day-Ahead Energy Market and during the reliability analysis after the Day-Ahead Energy Market closed, but the impact of these commitments on uplift in the first nine months of 2015 was significantly lower than in the first nine months of 2014.

Table 4-4 Energy uplift charges by category: January through September 2014 and 2015

Category	Jan - Sep 2014 Charges (Millions)	Jan - Sep 2015 Charges (Millions)	Change (Millions)	Percent Change
Day-Ahead Operating Reserves	$87.3	$86.7	($0.6)	(0.7%)
Balancing Operating Reserves	$757.7	$184.0	($573.7)	(75.7%)
Reactive Services	$27.4	$9.9	($17.5)	(63.8%)
Synchronous Condensing	$0.1	$0.0	($0.1)	(94.0%)
Black Start Services	$26.7	$5.1	($21.6)	(81.0%)
Total	$899.1	$285.7	($613.4)	(68.2%)

The decrease in energy uplift charges in the first nine months of 2015 was primarily a result of decreases from January 2014. Total energy uplift charges decreased by $561.3 million in January 2015, compared to January 2014, while energy uplift charges decreased by $52.2 million in February through September 2015, compared to February through September 2014. Table 4-5 compares monthly energy uplift charges by category for 2014 and 2015.

Table 4-5 Monthly energy uplift charges: 2014 and January through September 2015

	2014 Charges (Millions)						2015 Charges (Millions)					
	Day-Ahead	Balancing	Reactive Services	Synchronous Condensing	Black Start Services	Total	Day-Ahead	Balancing	Reactive Services	Synchronous Condensing	Black Start Services	Total
Jan	$35.8	$562.3	$3.8	$0.1	$4.0	$606.0	$16.8	$24.5	$1.79	$0.0	$1.7	$44.8
Feb	$9.5	$56.0	$1.0	$0.0	$0.9	$67.4	$31.4	$71.0	$2.4	$0.0	$1.1	$105.9
Mar	$5.7	$59.1	$2.7	$0.0	$2.6	$70.1	$7.0	$24.7	$2.1	$0.0	$1.9	$35.8
Apr	$4.2	$9.7	$5.3	$0.0	$2.8	$22.0	$3.1	$8.5	$1.7	$0.0	$0.1	$13.4
May	$6.4	$21.0	$5.3	$0.0	$1.8	$34.5	$5.7	$15.5	$0.7	$0.0	$0.2	$22.1
Jun	$5.3	$15.8	$4.2	$0.0	$2.1	$27.3	$9.1	$8.9	$0.5	$0.0	$0.0	$18.5
Jul	$6.7	$11.4	$2.9	$0.0	$4.4	$25.4	$5.0	$12.3	$0.1	$0.0	$0.0	$17.4
Aug	$5.8	$9.9	$1.0	$0.0	$4.1	$20.8	$4.5	$9.2	$0.0	$0.0	$0.0	$13.7
Sep	$8.0	$12.5	$1.3	$0.0	$3.9	$25.6	$4.1	$9.5	$0.6	$0.0	$0.0	$14.2
Oct	$9.5	$9.8	$0.8	$0.0	$2.6	$22.8						
Nov	$5.6	$10.1	$0.5	$0.0	$1.4	$17.6						
Dec	$9.0	$9.0	$0.7	$0.0	$2.2	$20.9						
Total (Jan - Sep)	$87.3	$757.7	$27.4	$0.1	$26.7	$899.1	$86.7	$184.0	$9.9	$0.0	$5.1	$285.7
Share (Jan - Sep)	9.7%	84.3%	3.0%	0.0%	3.0%	100.0%	30.3%	64.4%	3.5%	0.0%	1.8%	100.0%
Total	$111.3	$786.6	$29.5	$0.1	$32.9	$960.3	$86.7	$184.0	$9.9	$0.0	$5.1	$285.7
Share	11.6%	81.9%	3.1%	0.0%	3.4%	100.0%	30.3%	64.4%	3.5%	0.0%	1.8%	100.0%

Table 4-6 Day-ahead operating reserve charges: January through September 2014 and 2015

Type	Jan - Sep 2014 Charges (Millions)	Jan - Sep 2015 Charges (Millions)	Change (Millions)	Jan - Sep 2014 Share	Jan - Sep 2015 Share
Day-Ahead Operating Reserve Charges	$87.3	$86.5	($0.8)	100.0%	99.8%
Day-Ahead Operating Reserve Charges for Load Response	$0.0	$0.2	$0.2	0.0%	0.2%
Unallocated Congestion Charges	$0.0	$0.0	$0.0	0.0%	0.0%
Total	$87.3	$86.7	($0.6)	100.0%	100.0%

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 that pay 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.[3] [4] Day-ahead operating reserve charges decreased by $0.6 million or 0.7 percent in the first nine months of 2015 compared to the first nine months of 2014. Day-ahead operating reserve charges remain high primarily because of uplift payments to units scheduled as must run by PJM. Units are typically scheduled as must run by PJM in the Day-Ahead Energy Market when the day-ahead model does not reflect certain real-time conditions or requirements (for example, reactive or ALR black start) or when units have parameters that extend beyond the 24 hour day-ahead model.

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 decreased by $573.7 million in the first nine months of 2015 compared to the first nine months of 2014. This decrease was a result of lower balancing operating reserve charges in the 2015 winter compared to the 2014 winter. Balancing operating reserve charges decreased by $557.2 million in the months of January, February and March of 2015 compared to January, February and March of 2014.

3 See PJM. 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.

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

Table 4-7 Balancing operating reserve charges: January through September 2014 and 2015

Type	Jan - Sep 2014 Charges (Millions)	Jan - Sep 2015 Charges (Millions)	Change (Millions)	Jan - Sep 2014 Share	Jan - Sep 2015 Share
Balancing Operating Reserve Reliability Charges	$442.0	$38.4	($403.5)	58.3%	20.9%
Balancing Operating Reserve Deviation Charges	$314.2	$145.3	($168.9)	41.5%	79.0%
Balancing Operating Reserve Charges for Load Response	$0.0	$0.1	$0.0	0.0%	0.0%
Balancing Local Constraint Charges	$1.5	$0.2	($1.3)	0.2%	0.1%
Total	$757.7	$184.0	($573.7)	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 2015, 47.1 percent of balancing operating reserve deviation charges were for make whole credits paid to generators and import transactions, a decrease of 8.0 percentage points compared to the share in the first nine months of 2014.

Table 4-8 Balancing operating reserve deviation charges: January through September 2014 and 2015

Charge Attributable To	Jan - Sep 2014 Charges (Millions)	Jan - Sep 2015 Charges (Millions)	Change (Millions)	Jan - Sep 2014 Share	Jan - Sep 2015 Share
Make Whole Payments to Generators and Imports	$172.9	$68.4	($104.5)	55.0%	47.1%
Energy Lost Opportunity Cost	$139.9	$76.7	($63.2)	44.5%	52.8%
Canceled Resources	$1.4	$0.2	($1.2)	0.5%	0.1%
Total	$314.2	$145.3	($168.9)	100.0%	100.0%

Table 4-9 shows reactive services, synchronous condensing and black start services charges. Reactive services charges decreased by $17.5 million in the first nine months of 2015 compared to the first nine months of 2014. Black start services charges decreased by $21.6 million in the first nine months of 2015 compared to the first nine months of 2014 as a result of the replacement of black start units under the ALR (automatic load rejection) option in the second quarter of 2015.

Table 4-9 Additional energy uplift charges: January through September 2014 and 2015

Type	Jan - Sep 2014 Charges (Millions)	Jan - Sep 2015 Charges (Millions)	Change (Millions)	Jan - Sep 2014 Share	Jan - Sep 2015 Share
Reactive Services Charges	$27.4	$9.9	($17.5)	50.6%	66.2%
Synchronous Condensing Charges	$0.1	$0.0	($0.1)	0.2%	0.0%
Black Start Services Charges	$26.7	$5.1	($21.6)	49.2%	33.7%
Total	$54.2	$15.0	($39.2)	100.0%	100.0%

Table 4-10 and Table 4-11 show the amount and percentages of regional balancing charges in the first nine months of 2014 and 2015. 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 demand deviations. The regional balancing charges allocation table does not include charges attributed for resources controlling local constraints.

In the first nine months of 2015, regional balancing operating reserve charges decreased by $575.8 million compared to the first nine months of 2014. Balancing operating reserve reliability charges decreased by $403.5 million or 91.3 percent and balancing operating reserve deviation charges decreased by $172.3 million or 54.3 percent.

Table 4-10 Regional balancing charges allocation (Millions): January through September 2014

Charge	Allocation	RTO		East		West		Total	
Reliability Charges	Real-Time Load	$424.7	55.9%	$6.4	0.8%	$3.2	0.4%	$434.3	57.2%
	Real-Time Exports	$7.4	1.0%	$0.2	0.0%	$0.1	0.0%	$7.7	1.0%
	Total	$432.1	56.9%	$6.6	0.9%	$3.3	0.4%	$441.9	58.2%
Deviation Charges	Demand	$161.0	21.2%	$11.9	1.6%	$4.5	0.6%	$177.4	23.4%
	Supply	$43.3	5.7%	$3.5	0.5%	$0.9	0.1%	$47.7	6.3%
	Generator	$85.3	11.2%	$5.0	0.7%	$2.2	0.3%	$92.6	12.2%
	Total	$289.6	38.1%	$20.3	2.7%	$7.7	1.0%	$317.7	41.8%
Total Regional Balancing Charges		$721.7	95.0%	$26.9	3.5%	$11.0	1.4%	$759.6	100%

Table 4-11 Regional balancing charges allocation (Millions): January through September 2015

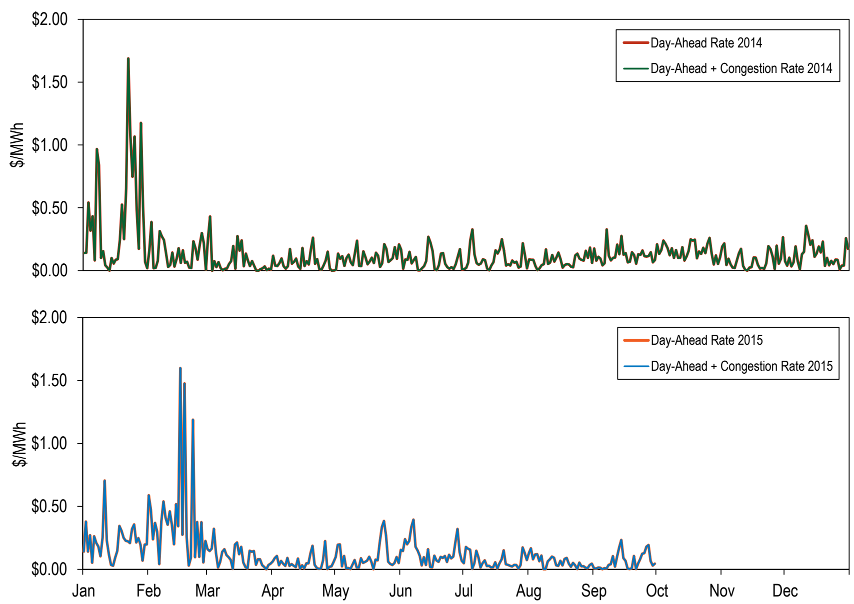
Charge	Allocation	RTO		East		West		Total	
Reliability Charges	Real-Time Load	$33.2	18.1%	$3.5	1.9%	$0.9	0.5%	$37.6	20.5%
	Real-Time Exports	$0.7	0.4%	$0.1	0.1%	$0.0	0.0%	$0.8	0.4%
	Total	$33.9	18.5%	$3.6	2.0%	$0.9	0.5%	$38.4	20.9%
Deviation Charges	Demand	$80.5	43.8%	$2.3	1.3%	$1.0	0.5%	$83.9	45.6%
	Supply	$23.4	12.7%	$0.7	0.4%	$0.3	0.2%	$24.4	13.3%
	Generator	$35.8	19.5%	$1.0	0.5%	$0.4	0.2%	$37.1	20.2%
	Total	$139.7	76.0%	$4.0	2.2%	$1.7	0.9%	$145.3	79.1%
Total Regional Balancing Charges		$173.6	94.5%	$7.6	4.1%	$2.6	1.4%	$183.8	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.[5]

Figure 4-1 shows the daily day-ahead operating reserve rate for 2014 and the first nine months of 2015. The average rate in the first nine months of 2015 was $0.136 per MWh, $0.002 per MWh lower than the average in the first nine months of 2014. The highest rate in the first nine months of 2015 occurred on February 16, when the rate reached $1.600 per MWh, $0.088 per MWh lower than the $1.689 per MWh reached in the first nine months of 2014, on January 22. 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 2014 and in the first nine months of 2015.

Figure 4-1 Daily day-ahead operating reserve rate ($/MWh): 2014 and 2015



5 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.

Figure 4-2 shows the RTO and the regional reliability rates for 2014 and the first nine months of 2015. The average daily RTO reliability rate was $0.055 per MWh. The highest RTO reliability rate in the first nine months of 2015 occurred on February 19, when the rate reached $0.772 per MWh, $23.821 per MWh lower than the $24.593 per MWh rate reached in the first nine months of 2014, on January 28.

Figure 4-2 Daily balancing operating reserve reliability rates ($/MWh): 2014 and 2015

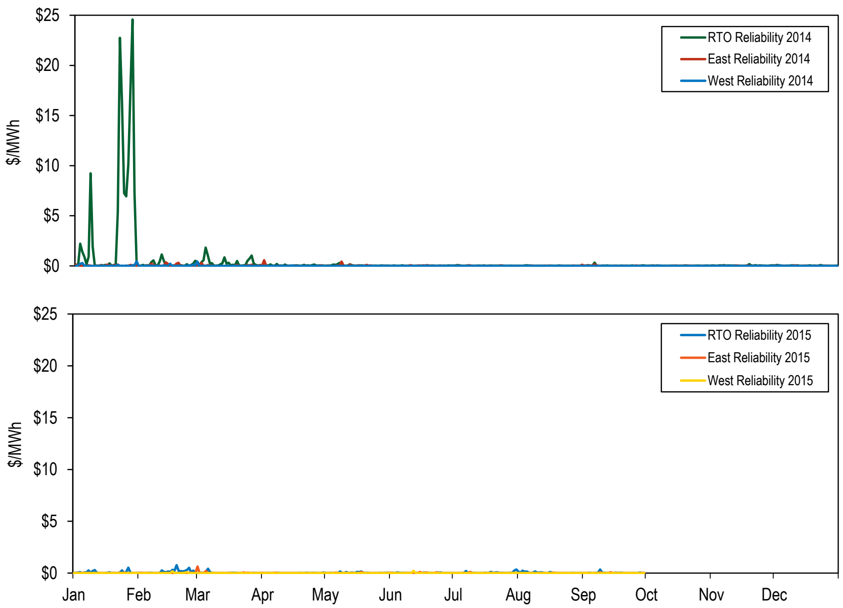


Figure 4-3 shows the RTO and regional deviation rates for 2014 and the first nine months of 2015. The average daily RTO deviation rate was $0.606 per MWh. The highest daily rate in the first nine months of 2015 occurred on February 17, when the RTO deviation rate reached $12.507 per MWh, $7.590 per MWh lower than the $20.097 per MWh rate reached in the first nine months of 2014, on January 25.

Figure 4-3 Daily balancing operating reserve deviation rates ($/MWh): 2014 and 2015

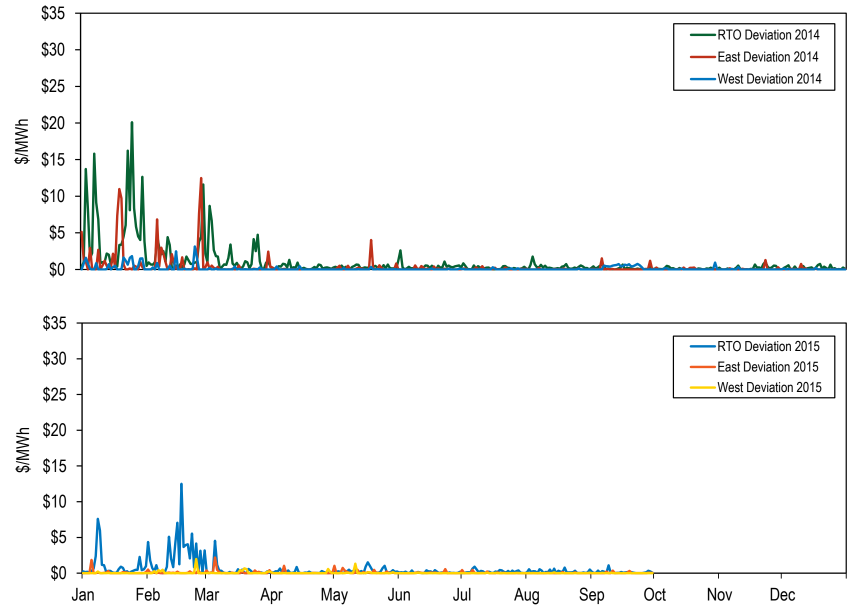


Figure 4-4 shows the daily lost opportunity cost rate and the daily canceled resources rate for 2014 and the first nine months of 2015. The lost opportunity cost rate averaged $0.741 per MWh. The highest lost opportunity cost rate occurred on February 19, when it reached $13.330 per MWh, $19.045 per MWh lower than the $32.375 per MWh rate reached in the first nine months of 2014, January 24.

Figure 4-4 Daily lost opportunity cost and canceled resources rates ($/MWh): 2014 and 2015

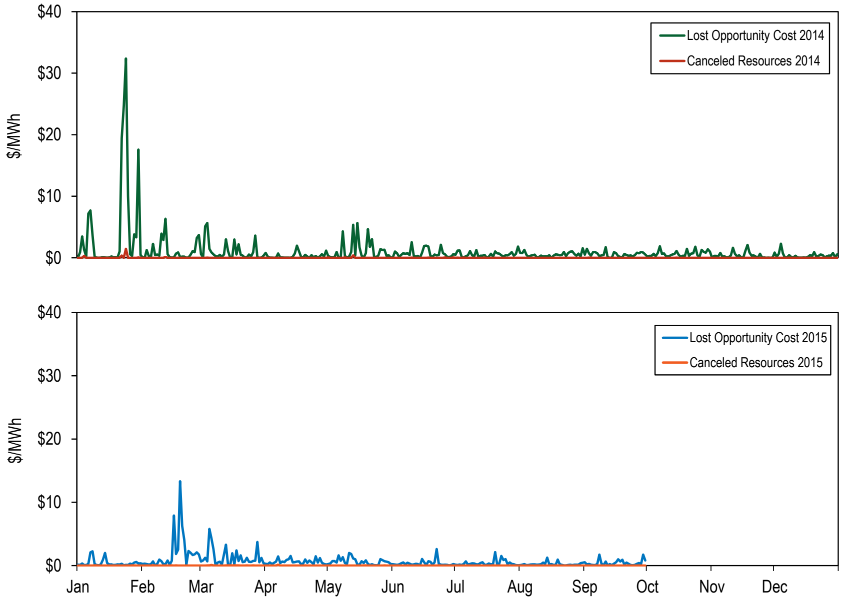


Table 4-12 shows the average rates for each region in each category in 2014 and 2015.

Table 4-12 Operating reserve rates ($/MWh): January through September 2014 and 2015

Rate	Jan - Sep 2014 ($/MWh)	Jan - Sep 2015 ($/MWh)	Difference ($/MWh)	Percent Difference
Day-Ahead	0.139	0.136	(0.002)	(1.8%)
Day-Ahead with Unallocated Congestion	0.139	0.136	(0.002)	(1.8%)
RTO Reliability	0.702	0.055	(0.647)	(92.1%)
East Reliability	0.023	0.012	(0.011)	(47.1%)
West Reliability	0.010	0.003	(0.007)	(71.6%)
RTO Deviation	1.491	0.606	(0.885)	(59.3%)
East Deviation	0.425	0.074	(0.351)	(82.6%)
West Deviation	0.159	0.034	(0.125)	(78.5%)
Lost Opportunity Cost	1.439	0.741	(0.698)	(48.5%)
Canceled Resources	0.015	0.002	(0.013)	(86.7%)

Table 4-13 shows the operating reserve cost of a one MW transaction in the first nine months of 2015. For example, a decrement bid in the Eastern Region (if not offset by other transactions) paid an average rate of $1.435 per MWh with a maximum rate of $17.552 per MWh, a minimum rate of $0.116 per MWh and a standard deviation of $2.181 per MWh. The rates in Table 4-13 include all operating reserve charges including RTO deviation 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 2015

		Rates Charged ($/MWh)			
Region	Transaction	Maximum	Average	Minimum	Standard Deviation
East	INC	17.264	1.303	0.019	2.114
	DEC	17.522	1.435	0.116	2.181
	DA Load	1.600	0.132	0.000	0.180
	RT Load	0.773	0.061	0.000	0.105
	Deviation	17.264	1.303	0.019	2.114
West	INC	17.264	1.266	0.019	2.086
	DEC	17.522	1.398	0.114	2.156
	DA Load	1.600	0.132	0.000	0.180
	RT Load	0.772	0.052	0.000	0.098
	Deviation	17.264	1.266	0.019	2.086

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. These charges result from uplift payments to units committed by PJM to support reactive/voltage requirements that do not recover their energy offer through LMP payments. These charges are separate from the reactive service revenue requirement charges which are a fixed annual charge based on approved FERC filings. 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.

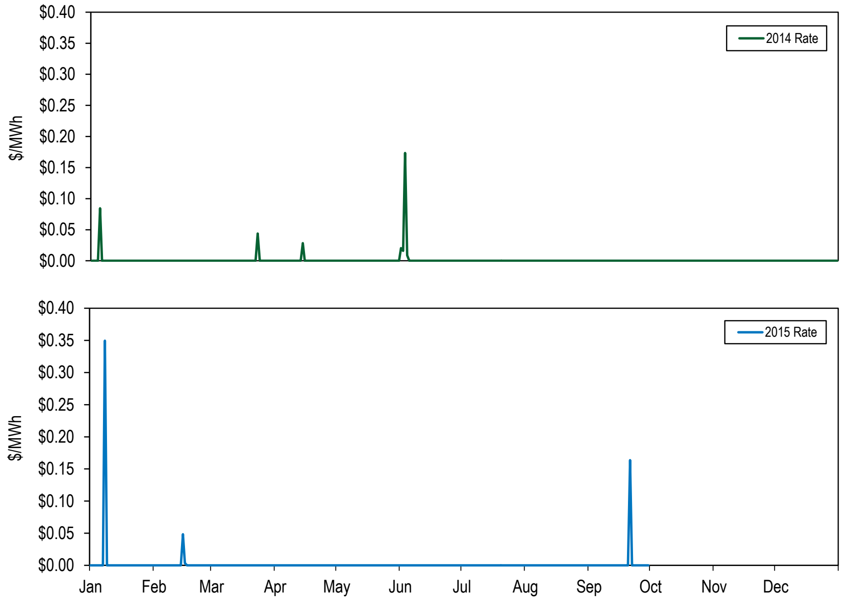
While reactive services rates are not posted by PJM, a local voltage support rate for each control zone can be calculated and a reactive transfer interface support rate can be calculated for the entire RTO. Table 4-14 shows the reactive services rates associated with local voltage support in the first nine months of 2014 and 2015. Table 4-14 shows that in the first nine months of 2015 the DPL Control Zone had the highest rate. Real-time load in the DPL Control Zone paid an average of $0.124 per MWh for reactive services associated with local voltage support, $0.369 or 74.9 percent lower than the average rate paid in the first nine months of 2014.

Table 4-14 Local voltage support rates: January through September 2014 and 2015

Control Zone	Jan - Sep 2014 ($/MWh)	Jan - Sep 2015 ($/MWh)	Difference ($/MWh)	Percentage Difference
AECO	0.012	0.000	(0.012)	(99.8%)
AEP	0.007	0.002	(0.005)	(71.2%)
AP	0.007	0.000	(0.007)	(100.0%)
ATSI	0.229	0.073	(0.156)	(68.2%)
BGE	0.001	0.000	(0.001)	(100.0%)
ComEd	0.001	0.000	(0.000)	(79.9%)
DAY	0.001	0.000	(0.001)	(94.6%)
DEOK	0.000	0.000	0.000	NA
DLCO	0.000	0.000	0.000	0.0%
Dominion	0.045	0.032	(0.013)	(28.6%)
DPL	0.493	0.124	(0.369)	(74.9%)
EKPC	0.000	0.000	0.000	0.0%
JCPL	0.000	0.000	0.000	0.0%
Met-Ed	0.003	0.003	0.000	10.7%
PECO	0.011	0.000	(0.011)	(100.0%)
PENELEC	0.216	0.020	(0.196)	(90.8%)
Pepco	0.001	0.000	(0.000)	(51.9%)
PPL	0.000	0.000	(0.000)	(23.6%)
PSEG	0.010	0.000	(0.010)	(100.0%)
RECO	0.000	0.000	0.000	0.0%

Figure 4-5 shows the daily RTO wide reactive transfer interface rate in 2014 and in the first nine months of 2015. The average rate in the first nine months of 2015 was $0.002 per MWh, 79.2 percent higher than the $0.001 per MWh average rate in the first nine months of 2014.

Figure 4-5 Daily reactive transfer interface support rates ($/MWh): 2014 and 2015



Balancing Operating Reserve Determinants

Table 4-15 shows the determinants used to allocate the regional balancing operating reserve charges in the first nine months of 2014 and 2015. Total real-time load and real-time exports were 1,711,640 MWh or 0.3 percent lower in the first nine months of 2015 compared to the first nine months of 2014. Total deviations summed across the demand, supply, and generator categories were 6,018,809 MWh or 6.2 percent higher in the first nine months of 2015 compared to the first nine months of 2014.

Table 4-15 Balancing operating reserve determinants (MWh): January through September 2014 and 2015

		Reliability Charge Determinants (MWh)			Deviation Charge Determinants (MWh)			
		Real-Time Load	Real-Time Exports	Reliability Total	Demand Deviations (MWh)	Supply Deviations (MWh)	Generator Deviations (MWh)	Deviations Total
Jan - Sep 2014	RTO	595,278,192	22,049,304	617,327,496	58,479,419	14,486,375	24,510,473	97,476,267
	East	280,726,751	8,437,636	289,164,387	28,618,489	8,052,694	11,263,168	47,934,351
	West	314,551,441	13,611,668	328,163,109	29,180,603	6,137,664	13,247,305	48,565,572
Jan - Sep 2015	RTO	601,744,740	13,871,116	615,615,856	62,504,715	16,525,041	24,465,321	103,495,076
	East	288,082,533	7,888,460	295,970,992	32,337,044	8,694,753	12,711,204	53,743,001
	West	313,662,208	5,982,656	319,644,864	29,554,921	7,571,944	11,754,117	48,880,982
Difference	RTO	6,466,548	(8,178,189)	(1,711,640)	4,025,295	2,038,666	(45,153)	6,018,809
	East	7,355,782	(549,177)	6,806,605	3,718,556	642,058	1,448,036	5,808,650
	West	(889,234)	(7,629,012)	(8,518,246)	374,318	1,434,280	(1,493,189)	315,410

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 2015, 22.8 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 77.2 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 2015

Deviation Category	Transaction	Deviation (MWh) RTO	East	West	Share RTO	East	West
Demand	Bilateral Sales Only	88,406	87,974	432	0.1%	0.2%	0.0%
	DECs Only	2,878,708	1,439,688	1,170,172	2.8%	2.7%	2.4%
	Exports Only	1,414,549	790,773	623,777	1.4%	1.5%	1.3%
	Load Only	43,579,535	21,371,030	22,208,505	42.1%	39.8%	45.4%
	Combination with DECs	10,246,628	6,398,379	3,504,348	9.9%	11.9%	7.2%
	Combination without DECs	4,296,889	2,249,200	2,047,689	4.2%	4.2%	4.2%
Supply	Bilateral Purchases Only	117,700	96,320	21,380	0.1%	0.2%	0.0%
	Imports Only	5,804,955	3,081,340	2,723,615	5.6%	5.7%	5.6%
	INCs Only	7,664,318	3,797,516	3,608,457	7.4%	7.1%	7.4%
	Combination with INCs	2,847,681	1,641,901	1,205,781	2.8%	3.1%	2.5%
	Combination without INCs	90,387	77,676	12,711	0.1%	0.1%	0.0%
Generators		24,465,321	12,711,204	11,754,117	23.6%	23.7%	24.0%
Total		103,495,076	53,743,001	48,880,982	100.0%	100.0%	100.0%

Energy Uplift Credits

Table 4-17 shows the totals for each credit category in the first nine months of 2014 and 2015. During the first nine months of 2015, 64.4 percent of total energy uplift credits were in the balancing operating reserve category, a decrease of 19.9 percentage points from 84.3 percent in the first nine months of 2014.

Table 4-17 Energy uplift credits by category: January through September 2014 and 2015

Category	Type	Jan - Sep 2014 Credits (Millions)	Jan - Sep 2015 Credits (Millions)	Change	Percent Change	Jan - Sep 2014 Share	Jan - Sep 2015 Share
Day-Ahead	Generators	$87.3	$86.5	($0.8)	(0.9%)	9.7%	30.3%
	Imports	$0.0	$0.0	$0.0	200.0%	0.0%	0.0%
	Load Response	$0.0	$0.2	$0.2	6,418.5%	0.0%	0.1%
Balancing	Canceled Resources	$1.4	$0.2	($1.2)	(85.8%)	0.2%	0.1%
	Generators	$614.7	$106.6	($508.1)	(82.7%)	68.4%	37.3%
	Imports	$0.1	$0.2	$0.0	39.9%	0.0%	0.1%
	Load Response	$0.0	$0.1	$0.0	119.5%	0.0%	0.0%
	Local Constraints Control	$1.5	$0.2	($1.3)	(88.1%)	0.2%	0.1%
	Lost Opportunity Cost	$139.9	$76.7	($63.2)	(45.1%)	15.6%	26.9%
Reactive Services	Day-Ahead	$23.3	$7.7	($15.6)	(67.0%)	2.6%	2.7%
	Local Constraints Control	$0.0	$0.0	($0.0)	(80.4%)	0.0%	0.0%
	Lost Opportunity Cost	$0.2	$0.1	($0.1)	(62.1%)	0.0%	0.0%
	Reactive Services	$3.0	$2.0	($1.1)	(34.5%)	0.3%	0.7%
	Synchronous Condensing	$0.8	$0.2	($0.7)	(80.9%)	0.1%	0.1%
Synchronous Condensing		$0.1	$0.0	($0.1)	(94.0%)	0.0%	0.0%
Black Start Services	Day-Ahead	$22.1	$4.3	($17.7)	(80.4%)	2.5%	1.5%
	Balancing	$4.3	$0.5	($3.8)	(89.2%)	0.5%	0.2%
	Testing	$0.3	$0.3	($0.0)	(3.0%)	0.0%	0.1%
Total		$899.1	$285.7	($613.4)	(68.2%)	100.0%	100.0%

Characteristics of Credits

Types of Units

Table 4-18 shows the distribution of total energy uplift credits by unit type in the first nine months 2014 and 2015. The decrease in energy uplift in the first nine months of 2015 compared to the first nine months of 2014 was due to lower credits paid to combined cycles, combustion turbines and steam turbines (not fired by coal) in the 2015 winter compared to the 2014 winter. Credits to these units decreased $533.9 million or 72.5 percent mainly because these units' offers were affected by high natural gas prices in January 2014. Credits paid to remaining unit types decreased by $79.8 million.

Table 4-18 Energy uplift credits by unit type: January through September 2014 and 2015

Unit Type	Jan - Sep 2014 Credits (Millions)	Jan - Sep 2015 Credits (Millions)	Change	Percentage Change	Jan - Sep 2014 Share	Jan - Sep 2015 Share
Combined Cycle	$391.4	$70.3	($321.1)	(82.0%)	43.5%	24.6%
Combustion Turbine	$232.2	$103.2	($129.0)	(55.5%)	25.8%	36.2%
Diesel	$2.7	$1.4	($1.3)	(48.4%)	0.3%	0.5%
Hydro	$1.6	$1.1	($0.5)	(29.1%)	0.2%	0.4%
Nuclear	$0.2	$0.3	$0.2	91.3%	0.0%	0.1%
Steam - Coal	$151.4	$77.4	($74.0)	(48.9%)	16.8%	27.1%
Steam - Other	$112.4	$28.7	($83.7)	(74.5%)	12.5%	10.1%
Wind	$7.0	$2.9	($4.2)	(59.0%)	0.8%	1.0%
Total	$899.0	$285.3	($613.6)	(68.3%)	100.0%	100.0%

Table 4-19 shows the distribution of energy uplift credits by category and by unit type in the first nine months of 2015. Combined cycle units received 26.8 percent of the day-ahead generator credits in the first nine months of 2015, 12.0 percentage points lower than the share received in the first nine months of 2014. Combined cycle units received 40.6 percent of the balancing generator credits in the first nine months of 2015, 16.1 percentage points higher than the share received in the first nine months of 2014. Combustion turbines and diesels received 87.0 percent of the lost opportunity cost credits in the first nine months of 2015, 19.9 percentage points higher than the share received in the first nine months of 2014.

Table 4-19 Energy uplift credits by unit type: January through September 2015

Unit Type	Day-Ahead Generator	Balancing Generator	Canceled Resources	Local Constraints Control	Lost Opportunity Cost	Reactive Services	Synchronous Condensing	Black Start Services
Combined Cycle	26.8%	40.6%	0.0%	7.6%	2.8%	15.9%	0.0%	1.5%
Combustion Turbine	3.1%	31.4%	23.8%	35.0%	86.2%	5.3%	100.0%	5.4%
Diesel	0.0%	0.7%	0.0%	30.6%	0.7%	0.2%	0.0%	0.0%
Hydro	1.0%	0.1%	76.2%	0.0%	0.0%	0.0%	0.0%	0.0%
Nuclear	0.0%	0.0%	0.0%	0.0%	0.4%	0.0%	0.0%	0.0%
Steam - Coal	60.0%	11.1%	0.0%	26.8%	6.1%	42.3%	0.0%	93.2%
Steam - Others	9.1%	16.0%	0.0%	0.0%	0.2%	36.3%	0.0%	0.0%
Wind	0.0%	0.1%	0.0%	0.0%	3.6%	0.0%	0.0%	0.0%
Total (Millions)	$86.5	$106.6	$0.2	$0.2	$76.7	$10.0	$0.0	$5.1

Table 4-19 also shows the distribution of reactive service credits and black start services credits by unit type. In the first nine months of 2015, coal units received 42.3 percent of all reactive services credits, 29.5 percentage points lower than the share received in the first nine months of 2014. Coal units received 93.2 percent of all black start services credits in the first nine months of 2015.

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, top 50 and top 100 units receiving energy uplift credits and units receiving 90 percent of all energy uplift credits. Figure 4-6 shows the concentration of energy uplift credits. The top 10 units received 33.9 percent of total energy uplift credits in the first nine months of 2015, compared to 35.7 percent in the first nine months of 2014. In the first nine months of 2015, 238 units received 90 percent of all energy uplift credits, compared to 218 units in the first nine months of 2014.

Figure 4-6 Cumulative share of energy uplift credits in January through September of 2014 and 2015 by unit

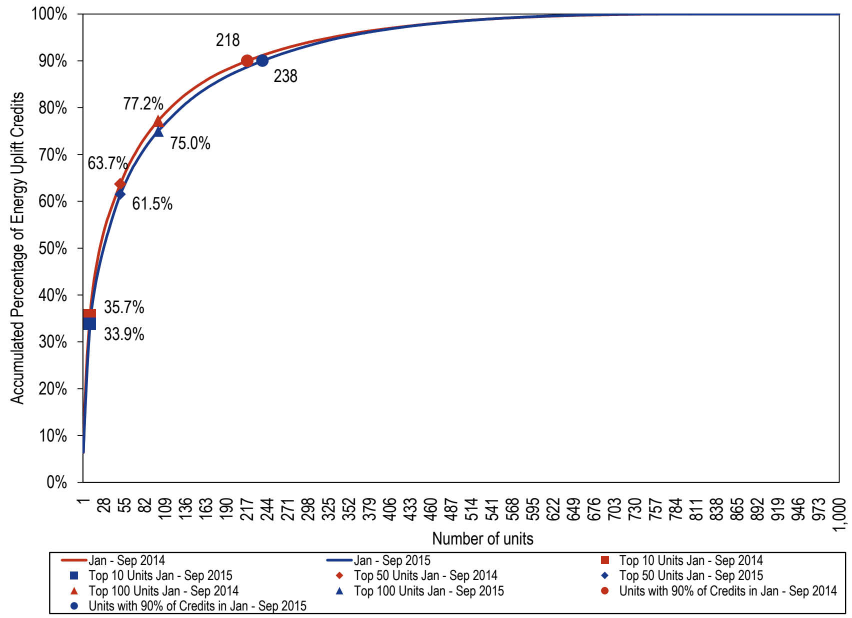


Table 4-20 shows the credits received by the top 10 units and top 10 organizations in each of the energy uplift categories paid to generators.

Table 4-20 Top 10 units and organizations energy uplift credits: January through September 2015

		Top 10 Units		Top 10 Organizations	
Category	Type	Credits (Millions)	Credits Share	Credits (Millions)	Credits Share
Day-Ahead	Generators	$49.3	57.0%	$82.7	95.6%
Balancing	Canceled Resources	$0.2	94.6%	$0.2	100.0%
	Generators	$49.7	46.6%	$87.2	81.8%
	Local Constraints Control	$0.1	72.4%	$0.2	100.0%
	Lost Opportunity Cost	$17.7	23.0%	$60.0	78.2%
Reactive Services		$8.6	86.9%	$9.9	99.8%
Synchronous Condensing		$0.0	91.3%	$0.0	100.0%
Black Start Services		$4.8	95.1%	$5.1	99.8%
Total		$96.6	33.9%	$227.4	79.7%

Table 4-21 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 2015, 71.9 percent of all credits paid to these units were allocated to deviations while the remaining 28.1percent were paid for reliability reasons.

Table 4-21 Identification of balancing operating reserve credits received by the top 10 units by category and region: January through September 2015

	Reliability			Deviations			
	RTO	East	West	RTO	East	West	Total
Credits (Millions)	$13.9	$0.0	$0.0	$35.3	$0.5	$0.0	$49.7
Share	28.0%	0.1%	0.0%	71.0%	0.9%	0.0%	100.0%

In the first nine months of 2015, concentration in all energy uplift credit categories was high.[6] [7] The HHI for energy uplift credits was calculated based on each organization's share of daily credits for each category. Table 4-22 shows the average HHI for each category. HHI for day-ahead operating reserve credits to generators was 5422, for balancing operating reserve credits

6 See *2014 State of the Market Report for PJM*, Volume II: Section 3: "Energy Market" at "Market Concentration" for a complete discussion of concentration ratios and the Herfindahl-Hirschman Index (HHI).
7 Table 4-23 excludes local constraints control categories.

to generators was 3786, for lost opportunity cost credits was 3474 and for reactive services credits was 8928.

Table 4-22 Daily energy uplift credits HHI: January through September 2015

Category	Type	Average	Minimum	Maximum	Highest Market Share (One day)	Highest Market Share (All days)
Day-Ahead	Generators	5422	1512	10000	100.0%	39.4%
	Imports	10000	10000	10000	100.0%	58.1%
	Load Response	10000	10000	10000	100.0%	99.3%
Balancing	Canceled Resources	9890	5650	10000	100.0%	64.1%
	Generators	3782	913	9906	99.5%	33.5%
	Imports	10000	10000	10000	100.0%	100.0%
	Load Response	9883	7043	10000	100.0%	68.4%
	Lost Opportunity Cost	3492	699	10000	100.0%	16.7%
Reactive Services		8928	2822	10000	100.0%	40.2%
Synchronous Condensing		10000	10000	10000	100.0%	100.0%
Black Start Services		9567	4140	10000	100.0%	94.4%
Total		2378	627	8383	91.4%	21.2%

Economic and Noneconomic Generation[8]

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 4-23 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 2015, 35.9 percent of the day-ahead generation was eligible for day-ahead operating reserve credits and 34.2 percent of the real-time generation was eligible for balancing operating reserve credits.[9]

Table 4-23 Day-ahead and real-time generation (GWh): January through September 2015

Energy Market	Total Generation	Generation Eligible for Operating Reserve Credits	Generation Eligible for Operating Reserve Credits Percent
Day-Ahead	623,183	223,819	35.9%
Real-Time	615,544	210,559	34.2%

Table 4-24 shows PJM's economic and noneconomic generation by hour eligible for operating reserve credits. In the first nine months of 2015, 87.2 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 4-24 shows the separate amounts of economic and noneconomic generation even if the daily generation was economic.

8 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.

9 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 4-24 Day-ahead and real-time economic and noneconomic generation from units eligible for operating reserve credits (GWh): January through September 2015

Energy Market	Economic Generation	Noneconomic Generation	Economic Generation Percentage	Noneconomic Generation Percent
Day-Ahead	195,260	28,559	87.2%	12.8%
Real-Time	153,142	57,417	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 4-25 shows the generation receiving day-ahead and balancing operating reserve credits. In the first nine months of 2015, 5.5 percent of the day-ahead generation eligible for operating reserve credits received credits and 3.9 percent of the real-time generation eligible for operating reserve credits was made whole.

Table 4-25 Day-ahead and real-time generation receiving operating reserve credits (GWh): January through September 2015

Energy Market	Generation Eligible for Operating Reserve Credits	Generation Receiving Operating Reserve Credits	Generation Receiving Operating Reserve Credits Percentage
Day-Ahead	223,819	12,314	5.5%
Real-Time	210,559	8,322	4.0%

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.[10] 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.[11] 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 4-26 shows the total day-ahead generation and the subset of that generation scheduled as must run by PJM. In the first nine months of 2015, 2.2 percent of the total day-ahead generation was scheduled as must run by PJM, 2.1 percentage points lower than in the first nine months of 2014.

Table 4-26 Day-ahead generation scheduled as must run by PJM (GWh): 2014 and January through September 2015

	2014			2015		
	Total Day-Ahead Generation	Day-Ahead PJM Must Run Generation	Share	Total Day-Ahead Generation	Day-Ahead PJM Must Run Generation	Share
Jan	81,479	2,627	3.2%	77,937	2,143	2.7%
Feb	70,942	3,404	4.8%	74,224	2,904	3.9%
Mar	72,681	2,894	4.0%	68,201	1,860	2.7%
Apr	60,688	2,825	4.7%	55,957	1,138	2.0%
May	61,919	2,808	4.5%	61,955	1,523	2.5%
Jun	70,230	3,421	4.9%	68,558	1,447	2.1%
Jul	75,606	3,733	4.9%	75,490	1,201	1.6%
Aug	73,003	2,778	3.8%	73,934	922	1.2%
Sep	65,066	2,792	4.3%	66,927	616	0.9%
Oct	61,223	2,444	4.0%			
Nov	64,991	1,857	2.9%			
Dec	70,853	2,023	2.9%			
Total (Jan - Sep)	631,615	27,284	4.3%	623,183	13,754	2.2%
Total	828,682	33,608	4.1%	623,183	13,754	2.2%

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.

10 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>.

11 See PJM. "PJM eMkt Users Guide," Section Managing Unit Data (version January 9, 2015) p. 48, <http://www.pjm.com/~/media/etools/emkt/ts-userguide.ashx>.

Table 4-27 shows the total day-ahead generation scheduled as must run by PJM by category. In the first nine months of 2015, 41.2 percent of the day-ahead generation scheduled as must run by PJM received operating reserve credits, of which, 3.6 percent was generation from units scheduled to provide black start services, 4.4 percent was generation from units scheduled to provide reactive services and 33.2 percent was generation paid normal day-ahead operating reserve credits. The remaining 58.8 percent of the day-ahead generation scheduled as must run by PJM did not need to be made whole.

Table 4-27 Day-ahead generation scheduled as must run by PJM by category (GWh): January through September 2015

	Black Start Services	Reactive Services	Day-Ahead Operating Reserves	Economic	Total
Jan	173	145	848	977	2,143
Feb	137	26	725	2,016	2,904
Mar	177	139	388	1,156	1,860
Apr	4	236	263	634	1,138
May	3	29	459	1,032	1,523
Jun	0	0	670	778	1,447
Jul	0	0	411	790	1,201
Aug	0	1	447	474	922
Sep	0	29	359	227	616
Total (Jan - Sep)	495	605	4,571	8,083	13,754
Share	3.6%	4.4%	33.2%	58.8%	100.0%

Total day-ahead operating reserve credits in the first nine months of 2015 were $86.5 million, of which $58.1 million or 57.1 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.[12] 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 4-28 shows the geography of charges and credits in the first nine months of 2015. Table 4-28 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 1.4 percent of all operating reserve charges allocated regionally, and resources in the AECO Control Zone were paid 1.1 percent of the corresponding credits. The AECO Control Zone received less operating reserve credits than operating reserve charges paid and had a 0.9 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 5.3 percent of all operating reserve charges allocated regionally, and resources in the PSEG Control Zone were paid 22.4 percent of the corresponding credits. The PSEG Control Zone received more operating reserve credits than operating reserve charges paid and had a 42.2 percent share of the surplus. The surplus is the sum of the positive entries in the balance column. Table 4-28 also shows that 88.2 percent of all charges were allocated in control zones, 3.1 percent in hubs and aggregates and 8.7 percent in interfaces.

12 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 4-28 Geography of regional charges and credits: January through September 2015[13]

Location		Charges (Millions)	Credits (Millions)	Balance	Shares: Total Charges	Shares: Total Credits	Shares: Deficit	Shares: Surplus
Zones	AECO	$3.9	$2.9	($1.0)	1.4%	1.1%	0.9%	0.0%
	AEP - EKPC	$39.9	$23.9	($16.0)	14.8%	8.8%	14.6%	0.0%
	AP - DLCO	$19.9	$14.9	($4.9)	7.3%	5.5%	4.5%	0.0%
	ATSI	$18.0	$6.6	($11.4)	6.7%	2.4%	10.3%	0.0%
	BGE - Pepco	$21.1	$68.3	$47.3	7.8%	25.3%	0.0%	43.0%
	ComEd - External	$25.6	$13.2	($12.4)	9.5%	4.9%	11.3%	0.0%
	DAY - DEOK	$14.8	$4.0	($10.8)	5.5%	1.5%	9.8%	0.0%
	Dominion	$27.2	$35.2	$8.0	10.1%	13.0%	0.0%	7.3%
	DPL	$7.2	$12.4	$5.1	2.7%	4.6%	0.0%	4.7%
	JCPL	$6.6	$2.2	($4.4)	2.4%	0.8%	4.0%	0.0%
	Met-Ed	$5.0	$1.7	($3.3)	1.8%	0.6%	3.0%	0.0%
	PECO	$12.6	$6.3	($6.4)	4.7%	2.3%	5.8%	0.0%
	PENELEC	$8.2	$11.4	$3.2	3.0%	4.2%	0.0%	2.9%
	PPL	$13.7	$6.6	($7.1)	5.1%	2.4%	6.5%	0.0%
	PSEG	$14.3	$60.7	$46.4	5.3%	22.4%	0.0%	42.2%
	RECO	$0.5	$0.0	($0.5)	0.2%	0.0%	0.4%	0.0%
	All Zones	$238.3	$270.1	$31.7	88.2%	99.9%	71.0%	100.0%
Hubs and Aggregates	AEP - Dayton	$0.6	$0.0	($0.6)	0.2%	0.0%	0.5%	0.0%
	Dominion	$0.9	$0.0	($0.9)	0.3%	0.0%	0.8%	0.0%
	Eastern	$0.4	$0.0	($0.4)	0.1%	0.0%	0.3%	0.0%
	New Jersey	$0.4	$0.0	($0.4)	0.2%	0.0%	0.4%	0.0%
	Ohio	$0.1	$0.0	($0.1)	0.0%	0.0%	0.0%	0.0%
	Western Interface	$0.3	$0.0	($0.3)	0.1%	0.0%	0.2%	0.0%
	Western	$5.8	$0.0	($5.8)	2.1%	0.0%	5.3%	0.0%
	RTEP B0328 Source	$0.0	$0.0	($0.0)	0.0%	0.0%	0.0%	0.0%
	All Hubs and Aggregates	$8.4	$0.0	($8.4)	3.1%	0.0%	7.6%	0.0%
Interfaces	CPLE Imp	$0.0	$0.0	$0.0	0.0%	0.0%	0.0%	0.0%
	Hudson	$0.4	$0.0	($0.4)	0.1%	0.0%	0.3%	0.0%
	IMO	$5.1	$0.0	($5.1)	1.9%	0.0%	4.6%	0.0%
	Linden	$0.5	$0.0	($0.5)	0.2%	0.0%	0.5%	0.0%
	MISO	$3.4	$0.0	($3.4)	1.3%	0.0%	3.1%	0.0%
	Neptune	$0.7	$0.0	($0.7)	0.2%	0.0%	0.6%	0.0%
	NIPSCO	$0.0	$0.0	($0.0)	0.0%	0.0%	0.0%	0.0%
	Northwest	$0.1	$0.0	($0.1)	0.0%	0.0%	0.1%	0.0%
	NYIS	$4.8	$0.0	($4.8)	1.8%	0.0%	4.3%	0.0%
	OVEC	$1.0	$0.0	($1.0)	0.4%	0.0%	0.9%	0.0%
	South Exp	$2.3	$0.0	($2.3)	0.8%	0.0%	2.0%	0.0%
	South Imp	$5.4	$0.0	($5.4)	2.0%	0.0%	4.9%	0.0%
	All Interfaces	$23.5	$0.2	($23.4)	8.7%	0.1%	21.4%	0.0%
	Total	$270.3	$270.3	$0.0	100.0%	100.0%	100.0%	100.0%

13 Zonal information in each zonal table has been aggregated to ensure that market sensitive data is not revealed. Table 4-28 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 4-29 shows the geography of reactive services charges. In the first nine months of 2015, 84.9 percent of all reactive service charges were paid by real-time load in the single zone where the service was provided, 14.9 percent were paid by real-time load in across the entire RTO and 0.2 percent were paid by real-time load in multiple zones. In the first nine months of 2015, the top three zones accounted for 80.0 percent of all the reactive services charges allocated to single zones.

Table 4-29 Geography of reactive services charges: January through September 2015[14]

Location	Charges (Millions)	Share of Charges
Single Zone	$8.5	84.9%
Multiple Zones	$0.0	0.2%
Entire RTO	$1.5	14.9%
Total	$10.0	100.0%

Black start services charges are allocated to zone and non-zone peak transmission use. Resources in one zone accounted for 94.5 percent of all the black start services costs in the first nine months of 2015. These costs resulted from noneconomic operation of units providing black start service under the automatic load rejection (ALR) option in the AEP Control Zone.

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

14 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).

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.[15] 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 to as real-time LOC.

In the first nine months of 2015, LOC credits decreased by $63.2 million or 45.1 percent compared to the first nine months of 2014. The decrease of $63.2 million is comprised of a decrease of $27.7 million in day-ahead LOC and a decrease of $35.4 million in real-time LOC. Table 4-30 shows the monthly composition of LOC credits in 2014 and the first nine months of 2015. In the first nine months of 2015, 20.2 percent of the day-ahead scheduled generation from combustion turbines and diesels was not committed in real time and paid LOC credits, 1.8 percentage points lower than in the first nine months of 2014.

Table 4-30 Monthly lost opportunity cost credits (Millions): 2014 and January through September 2015

	2014			2015		
	Day-Ahead Lost Opportunity Cost	Real-Time Lost Opportunity Cost	Total	Day-Ahead Lost Opportunity Cost	Real-Time Lost Opportunity Cost	Total
Jan	$44.2	$29.9	$74.1	$4.4	$0.9	$5.2
Feb	$5.9	$5.4	$11.3	$23.0	$3.0	$25.9
Mar	$8.3	$4.1	$12.4	$13.9	$1.5	$15.4
Apr	$1.6	$1.4	$3.0	$5.2	$0.5	$5.7
May	$10.4	$2.5	$12.9	$5.7	$1.8	$7.5
Jun	$7.2	$1.2	$8.4	$4.1	$0.4	$4.5
Jul	$6.2	$0.3	$6.5	$4.5	$0.4	$4.9
Aug	$5.2	$0.1	$5.3	$2.2	$0.4	$2.6
Sep	$5.3	$0.7	$6.0	$3.7	$1.3	$4.9
Oct	$5.5	$1.5	$7.0			
Nov	$3.9	$0.7	$4.7			
Dec	$4.0	$0.2	$4.2			
Total (Jan - Sep)	$94.3	$45.6	$139.9	$66.6	$10.1	$76.7
Share (Jan - Sep)	67.4%	32.6%	100.0%	86.8%	13.2%	100.0%
Total	$107.8	$48.0	$155.8	$66.6	$10.1	$76.7
Share	69.2%	30.8%	100.0%	86.8%	13.2%	100.0%

Table 4-31 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 4-31 shows that while day-ahead scheduled generation from CTs and diesels increased 3,167 GWh or 26.6 percent from 11,894 GWh in the first nine months of 2014 to 15,061 GWh in the first nine months of 2015, the generation that received LOC credits increased by 425 GWh or 16.2 percent.

15 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 4-31 Day-ahead generation from combustion turbines and diesels (GWh): 2014 and January through September 2015

	2014			2015		
	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	2,150	834	346	827	347	244
Feb	763	301	150	1,593	838	499
Mar	976	230	122	1,368	688	505
Apr	438	170	47	1,392	536	408
May	1,206	615	384	1,898	561	369
Jun	1,363	557	356	1,736	445	272
Jul	1,657	532	368	2,651	479	316
Aug	1,791	636	453	1,881	341	208
Sep	1,550	536	396	1,714	306	226
Oct	1,380	571	426			
Nov	683	284	133			
Dec	671	340	258			
Total (Jan - Sep)	11,894	4,411	2,622	15,061	4,540	3,047
Share (Jan - Sep)	100.0%	37.1%	22.0%	100.0%	30.1%	20.2%
Total	14,628	5,605	3,439	15,061	4,540	3,047
Share	100.0%	38.3%	23.5%	100.0%	30.1%	20.2%

Table 4-32 Lost opportunity cost credits paid to combustion turbines and diesels by scenario (Millions): 2014 and January through September 2015

	2014			2015		
	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	$19.6	$24.5	$44.2	$2.4	$2.0	$4.4
Feb	$3.6	$2.3	$5.9	$15.4	$7.5	$23.0
Mar	$3.6	$4.7	$8.3	$9.1	$4.8	$13.9
Apr	$0.8	$0.8	$1.6	$3.0	$2.2	$5.2
May	$8.2	$2.2	$10.4	$3.1	$2.7	$5.7
Jun	$5.4	$1.8	$7.2	$2.3	$1.8	$4.1
Jul	$3.8	$2.4	$6.2	$2.7	$1.8	$4.5
Aug	$3.7	$1.5	$5.2	$1.3	$0.8	$2.2
Sep	$3.0	$2.2	$5.3	$2.0	$1.7	$3.7
Oct	$3.3	$2.2	$5.5			
Nov	$2.9	$1.1	$3.9			
Dec	$2.6	$1.4	$4.0			
Total (Jan - Sep)	$51.8	$42.5	$94.3	$41.3	$25.3	$66.6
Share (Jan - Sep)	54.9%	45.1%	100.0%	62.1%	37.9%	100.0%
Total	$60.5	$47.3	$107.8	$41.3	$25.3	$66.6
Share	56.2%	43.8%	100.0%	62.1%	37.9%	100.0%

In the first nine months of 2015, the top three control zones in which generation received LOC credits, AEP, Dominion and AP, accounted for 48.5 percent of all LOC credits, 51.3 percent of all the day-ahead generation from combustion turbines and diesels, 52.3 percent of all day-ahead generation not committed in real time by PJM from those unit types and 58.0 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 4-32 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 4-32 shows that in the first nine months of 2015, $41.3 million or 62.1 percent of all LOC credits were paid to combustion turbines and diesels that did not run for any hour in real time, 7.1 percentage points higher than in the first nine months of 2014.

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 4-33 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 4-33 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 2015, 65.6 percent of the scheduled generation not committed by PJM from units receiving LOC credits was economic and the remaining 34.4 percent was noneconomic.

Table 4-33 Day-ahead generation (GWh) from combustion turbines and diesels receiving lost opportunity cost credits by value: 2014 and January through September 2015[16]

	2014			2015		
	Economic Scheduled Generation (GWh)	Noneconomic Scheduled Generation (GWh)	Total (GWh)	Economic Scheduled Generation (GWh)	Noneconomic Scheduled Generation (GWh)	Total (GWh)
Jan	344	356	701	246	102	348
Feb	117	170	288	497	335	832
Mar	116	112	228	543	140	682
Apr	49	130	179	366	168	534
May	333	238	571	281	261	542
Jun	269	234	502	257	144	401
Jul	245	232	477	287	138	425
Aug	268	346	614	165	128	293
Sep	298	225	524	219	82	300
Oct	332	231	563			
Nov	82	174	256			
Dec	214	116	330			
Total (Jan - Sep)	2,040	2,044	4,084	2,860	1,497	4,357
Share (Jan - Sep)	50.0%	50.0%	100.0%	65.6%	34.4%	100.0%
Total	2,667	2,565	5,232	2,860	1,497	4,357
Share	51.0%	49.0%	100.0%	65.6%	34.4%	100.0%

Black Start Service Units

Certain units located in the AEP Control Zone that had been relied on for their black start capability were replaced as black start resources on April 1, 2015. These black start units provided black start service under the automatic load rejection (ALR) option, which means that the units had to be running even if not economic. Units providing black start service under the ALR option could remain running at a minimum level, disconnected from the grid. The costs of the noneconomic operation of these units resulted in make whole payments in the form of operating reserve credits.

As a result of the replacement of these ALR units, the cost of the noneconomic operation of ALR units in the AEP Control Zone in the first nine months of 2015 decreased by $21.6 million compared to the first nine months of 2014. In the first nine months of 2015, the cost of the noneconomic operation of these units was $4.8 million, and 94.6 percent of this cost was paid by peak transmission use in the AEP Control Zone while the remaining 5.4 percent was paid by non-zone peak transmission use.[17] 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 $0.68 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 $0.01 per MW of reserved capacity for black start costs related to the noneconomic operation of ALR units.

Reactive / Voltage Support Units

Closed Loop Interfaces

PJM implemented closed loop interfaces with the stated purpose of improving the incorporation of reactive constraints into energy prices and to allow emergency DR to set price. PJM applies closed loop interfaces so that it can use units needed for reactive support to set the energy price when they would not otherwise set price under the LMP algorithm. PJM also applies closed loop interfaces so that it can use emergency DR resources to set the real-time LMP when DR resources would otherwise set price under the LMP algorithm. Nine of the 15 closed loop interface definitions were

16 The total generation in Table 4-34 is lower than the day-ahead generation not requested in real time in Table 4-33 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.

17 Non-zone peak transmission use is based on interchange transaction MW reservations.

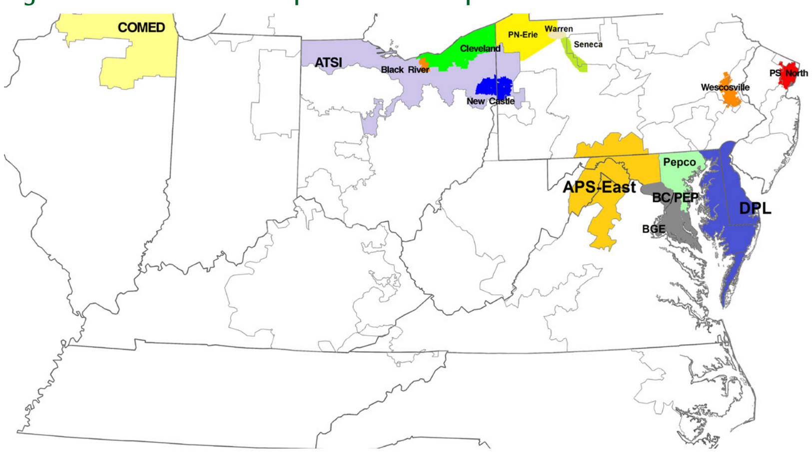
created for the purpose of allowing emergency DR to set price. These closed loop interfaces are used to model the transfer capability into a specific area. Areas or regions are defined in PJM by hubs, aggregates or control zones, all comprised of buses. Closed loop interfaces are not defined by buses, but defined by the transmission facilities that connect the buses inside of the loop with the rest of PJM. Table 4-34 shows the closed loop interfaces that PJM has defined.

Table 4-34 PJM Closed loop interfaces[18,19,20]

Interface	Control Zone(s)	Objective
ATSI	ATSI	Allow emergency DR resources set real-time LMP
APS-East	AP	Allow emergency DR resources / unit(s) needed for reactive to set real-time LMP
BGE	BGE	Allow emergency DR resources / unit(s) needed for reactive to set real-time LMP
BC/PEP	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)
DPL	DPL	Allow emergency DR resources / unit(s) needed for reactive to set real-time LMP
New Castle	ATSI	Allow emergency DR resources set real-time LMP
Pepco	Pepco	Allow emergency DR resources / unit(s) needed for reactive to set real-time LMP
PN-Erie	PENELEC	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

Figure 4-7 shows the approximate geographic location of PJM's closed loop interfaces.

Figure 4-7 PJM Closed loop interfaces map



18 See PJM. Manual 3: Transmission Operations, Revision 46 (December 1, 2014) at "Section 3.8: Transfer Limits (Reactive/Voltage Transfer Limits)," for a description of reactive interfaces.
19 See closed loop interfaces definitions at <http://www.pjm.com/markets-and-operations/etools/oasis/system-information.aspx>.
20 See the PS North interface definition at <http://www.pjm.com/pub/account/auction-user-info/model-annual/Annual-PJM-interface-definitions-limits.csv>.

In a DC power flow model, such as the one used by PJM for dispatch and pricing, units scheduled for reactive support are only marginal when they are needed to supply energy above their economic minimum. With the use of closed loop interface, these units are made marginal even when not needed for energy, by adjusting the limit of the closed loop interface. This artificially creates 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, raising energy prices and reducing uplift.[21]

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 distortion of the way in which the transmission network is modeled.

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. PJM has not explained why use of reactive interfaces rather than closed loop interfaces would not solve the issue. PJM has not explained why the other consequences of deviating from market fundamentals do not outweigh any benefits of artificially creating constraints in order to let reactive resources set price when they are not in fact marginal. PJM has not explained why the use of closed loop interfaces to permit emergency DR to set price is not simply a crude workaround to a viable solution, consistent with the LMP model, which would be to make DR nodal. The need for closed loop interfaces to let emergency DR set price is primarily a result of the fact that DR is zonal, or subzonal with one day's notice, and therefore cannot be dispatched nodally or set price nodally. The reduction of uplift is a reasonable goal in general, but the reduction of uplift is not a goal that justifies creating distortions in the price setting mechanism.

The MMU recommends that if PJM continues to create closed loop interfaces 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.

Confidentiality of Energy Uplift Information

All data posted publicly by PJM or the MMU must comply with confidentiality rules. Current confidentiality rules do not allow posting data for three or fewer PJM participants and cannot be aggregated in a geographic area smaller than a control zone.[22]

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.

21 See "PJM Price-Setting Changes" presented to the EMUSTF at <http://www.pjm.com/~/media/committees-groups/task-forces/emustf/20131220/20131220-item-02c-price-setting-option.ashx>

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

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. Units do not incur costs 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 day-ahead energy revenues, balancing energy revenues and a subset of net ancillary services revenues.[23]

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 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

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

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.[24] These recommendations are superseded by the MMU's recommendation to eliminate day-ahead operating reserve payments.[25] 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 2014 and the first nine months of 2015. In 2014 and the first nine months of 2015, energy uplift costs associated with units scheduled in the Day-Ahead Energy Market would have had been reduced by $68.3 million or 19.2 percent ($5.7 million paid to units providing reactive support, $6.4 million paid to units providing black start support and $56.2 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.

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.

24 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.

25 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>.

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 2014 and the first nine months of 2015, 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 $13.8 million, of which $10.0 million or 72.5 percent was due to generators that elected to self-schedule for regulation while being noneconomic and receiving balancing operating reserve credits.[26]

26 These estimates take into account the elimination of the day-ahead operating reserve category.

Self Scheduled Start

Participants may offer their units as pool-scheduled (economic) or self-scheduled (must run).[27] 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.

Lost Opportunity Cost Calculation

The current energy LOC calculations are inaccurate and create unreasonable compensation. The MMU recommends four modifications.[28]

- **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 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. This recommendation was partially adopted on September 1, 2015.
- **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 lost opportunity cost credits paid to combustion turbines and diesels scheduled in the Day-Ahead Energy Market but not committed in real time. This recommendation was adopted on September 1, 2015.
- **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. This recommendation was adopted on September 1, 2015.
- **Segmented Calculation:** Current rules calculate LOC on an hourly basis. This means that units receive an LOC payment during hours in which it is economic for them run and receive the benefit of not being called on during hours in which it is not economic for them to run. PJM dispatchers might make the right decision to not call a unit in real time because the operation of the unit during all the hours in which the unit cleared the

27 See "PJM eMkt Users Guide," Section Managing Unit Data (version January 9, 2015) p. 48. <http://www.pjm.com/~/media/etools/emkt/ts-userguide.ashx>.

28 See "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>.

Day-Ahead Energy Market would not be economic, but the unit could still receive an LOC payment. This is not the intent of LOC payments. LOC should be paid to resources to ensure that they operate following PJM's direction and not lose their profit. In the case of hourly calculations, units are not made indifferent, but are overcompensated compared to the compensation they would have received had they run. The MMU recommends calculating LOC based on segments of hours not on an hourly basis in the calculation of credits paid to combustion turbines and diesels scheduled in the Day-Ahead Energy Market but not committed in real time. This recommendation has not been adopted.

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 4-35 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 2015, for the two categories of lost opportunity cost credits. Energy LOC credits would have been reduced by a net of $21.3 million, or 27.8 percent, if all these changes had been implemented.[29]

Table 4-35 Impact on energy market lost opportunity cost credits of rule changes (Millions): January through September 2015

	LOC When Output Reduced in RT	LOC When Scheduled DA Not Called RT	Total
Current Credits	$10.1	$66.6	$76.8
Impact 1: Committed Schedule	$0.4	$5.6	$6.0
Impact 2: Using Offer Curve	($0.3)	$6.9	$6.6
Impact 3: Including No Load Cost	NA	($18.2)	($18.2)
Impact 4: Including Startup Cost	NA	($6.4)	($6.4)
Impact 5: Segmented Calculation	NA	($9.3)	($9.3)
Net Impact	$0.1	($21.4)	($21.3)
Credits After Changes	$10.2	$45.2	$55.5

29 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.

In addition to these four recommendations, the MMU recommends three additional steps to address other issues with the current LOC calculations:

- **Achievable Output:** CTs and diesels are compensated for LOC when scheduled in the Day-Ahead Energy Market and not committed in real time. This LOC calculation uses the day-ahead scheduled output as the achievable output for which units are entitled to receive LOC compensation. Units are paid LOC based on the difference between the real-time energy price (RT LMP) and the unit's offer times the day-ahead scheduled output. The MMU recommends that units scheduled in the Day-Ahead Energy Market and not committed in real time should be compensated for LOC based on their real-time desired and achievable output, not their scheduled day-ahead output. The actual LOC is a function of the real-time desired and achievable output rather than the day-ahead scheduled output. If a unit is capable of profitably producing more or fewer MWh in real time than the day-ahead scheduled MWh, it is the actual foregone MWh in real time that define actual LOC. Also, if a unit is not capable of producing at the day-ahead scheduled output level in real time it should not be compensated based on an output that cannot be achieved.
- **Intra-Hour Calculations:** CTs and diesels scheduled in the Day-Ahead Energy Market and not committed in real time are compensated for LOC based on their real-time hourly integrated output. In order to compensate a unit for LOC, PJM must determine if the unit was scheduled in the Day-Ahead Energy Market and if the unit was not committed in real time. Units clear the Day-Ahead Energy Market for full hours. That means that if a unit cleared the Day-Ahead Energy Market in an hour it is expected to produce energy in real time for the entire hour. The determination by PJM of whether a unit is committed or not committed in real time is based on the unit's hourly integrated output. If the hourly integrated output is greater than zero that means the unit was committed during that hour. But in real time a unit may be committed for part of an hour. The calculation of LOC does not reflect the exact time at which the unit was turned on. The MMU recommends that units scheduled in the Day-Ahead Energy Market and not committed in real time be compensated for LOC incurred within an hour.

- **LOC Unit Type Eligibility:** The current rules compensate only CTs and diesels for LOC when scheduled in the Day-Ahead Energy Market and not committed in real time. The reason for this difference is that other unit types have a commitment obligation when scheduled in the Day-Ahead Energy Market. For example, steam turbines and combined cycle units commitment instructions are their day-ahead schedule. Units of these types that clear the Day-Ahead Energy Market are automatically committed to be on or remain on in real time. CT and diesel commitment instructions occur in real time even if these units were committed in the Day-Ahead Energy Market. CTs and diesels are committed in real time, after PJM dispatch has a more complete knowledge of real-time conditions. The goal is to permit the dispatch of flexible units in real time based on real-time conditions as they evolve. The reason for this special treatment of CTs and diesels is that historically, such units were usually more flexible to commit than other unit types. But that is no longer correct and should not be assumed to be correct. The MMU recommends that only flexible fast start units (startup plus notification times of two hours or less) and short minimum run times (two hours or less) be eligible by default for the LOC compensation to units scheduled Day-Ahead Energy Market and not committed in real time. Other units should be eligible for LOC compensation only if PJM explicitly cancels their day-ahead commitment.

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 $0.362 and $0.419 per MWh in 2014 and between $0.366 and $0.372 per MWh in the first nine months of 2015 if the MMU's recommendations regarding energy uplift had been in place.[30,31]

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.[32] 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.[33] Demand transactions such as load, exports, internal bilateral

30 The range of operating reserve rates paid by up-to congestion transactions depends on the location of the transactions' source and sink.
31 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 prior September 8, 2014 and all cleared up-to congestion transactions would have cleared after September 8, 2014. 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.
32 See PJM. OATT 3.2.3 (o) for a complete description of how generators deviate.
33 Locations can be control zones, hubs, aggregates and interfaces. See "Determinants and Deviation Categories" in this section for a description of balancing operating reserve locations.

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 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.

Day-Ahead Reliability Energy Uplift Allocation

PJM may schedule units as must run in the Day-Ahead Energy Market when needed in real time to address 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.[34] The energy uplift paid to units scheduled for voltage is allocated to real-time load. The energy uplift associated with units scheduled for black start is allocated to real-time load and interchange reservations. The energy uplift paid to units scheduled because of local contingencies not modeled in the Day-Ahead Energy Market and scheduled because of their long lead times is allocated to day-ahead demand, day-ahead exports and decrement bids.

The MMU recommends allocating the energy uplift payments to units scheduled as must run in the Day-Ahead Energy Market for reasons other than voltage/reactive or black start services as a reliability charge to real-time load, real-time exports and real-time wheels.

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.[35] 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.[36] 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

34 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>.

35 See the *2014 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.

36 PJM. OATT Attachment K - Appendix § 3.2.3B (f).

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 2015, units providing reactive services were paid $0.6 million in balancing operating reserve credits in order to cover their total energy offer. In 2014, this misallocation was $2.3 million, for a total of $2.9 million in 2014 and the first nine months of 2015.

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.[37]

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 all day-ahead transactions and resources. All these transaction types have an impact on the outcome of the day-ahead 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. Energy uplift payments to units scheduled as must run in the Day-Ahead Energy Market (for reasons other than reactive or black start services) should be allocated to real-time load, real-time exports and real-time wheels.

The MMU recommends allocating energy uplift payments to units not scheduled in the Day-Ahead Energy Market and committed in real time, but before the operating day to the current deviation categories with the addition of up to congestion, wheels and units that clear the Day-Ahead Scheduling Reserve Market but do not perform.

The MMU recommends 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 allocating energy uplift payments to units committed during the operating day 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 affecting 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, real-time exports and real-time wheels independently of the timing of the commitment.

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

37 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>.

reliability in real time and payments to canceled resources should be allocated to real-time load, real-time exports and real-time wheels.

Table 4-36 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 4-36 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 in the Day-Ahead Energy Market 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 4-37 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 transactions and resources. 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 4-37 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	Scheduled by the day ahead model (not must run)	Day-Ahead Transactions and Day-Ahead Resources
		Scheduled as must run in the day ahead model	Real-Time Load, Real-Time Exports and Withdrawal Side of Real-Time Wheels
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	Real-Time Load, Real-Time Exports and Withdrawal Side of Real-Time Wheels
Units canceled before coming online	Cancellation Credit	NA	Real-Time Load, Real-Time Exports and Withdrawal Side of Real-Time Wheels

Quantifiable Recommendations Impact

Table 4-38 shows energy uplift charges based on the current allocation and energy uplift charges based on the MMU allocation proposal including the MMU recommendations regarding energy uplift credit calculations. Total charges (excluding black start and reactive services charges) would have been reduced by $130.9 million or 11.2 percent in 2014 and the first nine months of 2015 if three recommendations regarding energy uplift credit calculations proposed by the MMU had been implemented. The elimination of the day-ahead operating reserve credit would have resulted in a decrease of $56.2 million, the proposed changes to lost opportunity cost calculations would have resulted in a decrease of $56.9 million and the use of net regulation revenues offset would have resulted in a decrease of $13.8 million.[38] Table 4-38 shows that deviations charges would have been reduced by $316.0 million or 64.9 percent. The reason for this change is that, besides the reduction in the overall charges, under the MMU proposal, a subset of charges is reallocated to a new physical deviation category (based on the timing of the commitment of the resource being paid energy uplift) and another subset of charges is allocated to real-time load, real-time exports and real-time wheels (based on reliability actions).

38 The total impact of the elimination of the day-ahead operating reserve credit and the impact of net regulation revenues offset is greater because they also impact black start and reactive services charges.

Table 4-38 Current and proposed energy uplift charges by allocation (Millions): 2014 and January through September 2015[39]

Allocation	2014	Jan - Sep 2015	Total
Current			
Day-Ahead Demand, Day-Ahead Exports and Decrement Bids	$111.4	$86.5	$197.9
Real-Time Load and Real-Time Exports	$447.1	$38.4	$485.6
Deviations	$341.9	$145.3	$487.2
Total	$900.4	$270.3	$1,170.6
Proposal			
Day-Ahead Transactions and Day-Ahead Resources	$46.5	$25.8	$72.3
Real-Time Load and Real-Time Exports	$454.7	$87.4	$542.1
Deviations	$107.1	$64.0	$171.1
Physical Deviations	$207.6	$46.6	$254.2
Total	$815.9	$223.8	$1,039.7
Impact			
Impact ($)	($84.5)	($46.4)	($130.9)
Impact (%)	(9.4%)	(17.2%)	(11.2%)

The MMU calculated the rates that participants would have paid in 2014 and the first nine months of 2015 if all the MMU's recommendations on energy uplift had been in place. 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

39 These energy uplift charges do not include black start and reactive services charges.

calculations; reallocation of operating reserve credits paid to units scheduled as must run in the Day-Ahead Energy Market (for reasons other than reactive or black start services); 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 shows the energy uplift cost of a 1 MW transaction if these recommendations had been implemented in 2014 and the first nine months of 2015. Table 4-39 assumes two scenarios under the MMU proposal. The first scenario assumes that 50 percent of all up-to congestion transactions cleared volume would have remained prior to September 8, 2014 and all up-to congestion transactions cleared volume would have remained after September 8, 2104. The second scenario assumes zero volume of up-to congestion transactions in 2014 and the first nine months of 2015. Table 4-39 shows for example that a decrement bid in the Eastern Region (if not offset by other transactions) would have paid an average rate of $0.210 and $0.186 per MWh in the 2014 and the first nine months of 2015, under the first scenario, $2.195 and $1.249 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 $0.391 and $0.369 per MWh in 2014 and the first nine months of 2015 under the first scenario. Table 4-39 shows the current and proposed averages energy uplift rates for all transactions.

Table 4-39 Current and proposed average energy uplift rate by transaction: 2014 and January through September 2015[40]

		2014			Jan - Sep 2015		
	Transaction	Current Rates ($/MWh)	Proposed Rates - 50% UTC ($/MWh)	Proposed Rates - 0% UTC ($/MWh)	Current Rates ($/MWh)	Proposed Rates - 50% UTC ($/MWh)	Proposed Rates - 0% UTC ($/MWh)
East	INC	2.275	0.210	0.664	1.303	0.186	0.467
	DEC	2.404	0.210	0.664	1.435	0.186	0.467
	DA Load	0.129	0.019	0.024	0.132	0.016	0.018
	RT Load	0.450	0.460	0.460	0.061	0.135	0.135
	Deviation	2.275	1.328	1.778	1.303	0.595	0.873
West	INC	2.069	0.181	0.581	1.266	0.183	0.468
	DEC	2.199	0.181	0.581	1.398	0.183	0.468
	DA Load	0.129	0.019	0.024	0.132	0.016	0.018
	RT Load	0.439	0.460	0.460	0.052	0.135	0.135
	Deviation	2.069	1.226	1.622	1.266	0.523	0.805
UTC	East to East	NA	0.419	1.328	NA	0.372	0.934
	West to West	NA	0.362	1.162	NA	0.366	0.935
	East to/from West	NA	0.391	1.245	NA	0.369	0.934

July through September Energy Uplift Charges Analysis

Energy uplift charges decreased by $613.4 million (68.2 percent), from $899.1 million in the first nine months of 2014 to $285.7 million in the first nine months of 2015. This decrease was primarily the result of lower energy uplift charges associated with units committed for conservative operations in the first three months of 2015 compared to the first three months of 2014.

Energy uplift charges in the months of July through September decreased by $26.6 million or 37.0 percent), from $71.8 million in 2014 to $45.2 million in 2015. This change resulted from a decrease of $6.9 million in day-ahead operating reserve charges, a decrease of $2.9 million in balancing operating reserve charges, a decrease of $4.5 million in reactive services charges and a decrease of $12.3 in black start services charges.

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

Figure 4-8 shows the net impact of each category on the change in total energy uplift charges from the July through September 2014 level to the July through September 2015 level. The outside bars show the three month total of energy uplift charges in 2014 (left side) and the three month total of energy uplift charges in 2015 (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 2015 (an increase of $6.9 million).

Figure 4-8 Energy uplift charges change from July through September of 2014 to July through September of 2015 by category