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 short run marginal costs 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 $181.7 million, or 63.9 percent, in the first nine months of 2016 compared to the first nine months of 2015, from $284.5 million to $102.8 million.
- **Energy Uplift Charges Categories.** The decrease of $181.7 million in the first nine months of 2016 is comprised of a $46.0 million decrease in day-ahead operating reserve charges, a $121.6 million decrease in balancing operating reserve charges, a $9.2 million decrease in reactive services charges, and a $4.9 million decrease in black start services charges.
- **Average Effective Operating Reserve Rates in the Eastern Region.** Day-ahead load paid $0.067 per MWh, real-time load paid $0.030 per MWh, a DEC paid $0.445 per MWh and an INC and any load, generation or interchange transaction deviation paid $0.379 per MWh.
- **Average Effective Operating Reserve Rates in the Western Region.** Day-ahead load paid $0.067 per MWh, real-time load paid $0.022 per MWh, a DEC paid $0.386 per MWh and an INC and any load, generation or interchange transaction deviation paid $0.320 per MWh.
- **Reactive Services Rates.** The DPL, PENELEC and Met-Ed control zones had the three highest local voltage support rates: $0.051, $0.003 and $0.001 per MWh.

Characteristics of Credits

- **Types of units.** Combined cycles received 9.5 percent of all day-ahead generator credits and 11.2 percent of all balancing generator credits. Combustion turbines and diesels received 79.8 percent of the lost opportunity cost credits.
- **Concentration of Energy Uplift Credits.** The top 10 units receiving energy uplift credits received 35.4 percent of all credits. The top 10 organizations received 77.1 percent of all credits. Concentration indexes for energy uplift categories classify them as highly concentrated. Day-ahead operating reserves HHI was 6122, balancing operating reserves HHI was 3281, and lost opportunity cost HHI was 5176.
- **Economic and Noneconomic Generation.** In the first nine months of 2016, 86.2 percent of the day-ahead generation eligible for operating reserve credits was economic and 74.0 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 2016, 1.5 percent of the total day-ahead generation MWh was scheduled as must run by PJM, of which 44.4 percent received energy uplift payments.

1 Loss exists when gross energy and ancillary services market revenues are less than short run marginal costs, including all elements of the energy offer, which are startup, no load and incremental offers.

Geography of Charges and Credits

- In the first nine months of 2016, 89.9 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, 4.4 percent by transactions at hubs and aggregates and 5.7 percent by interchange transactions at interfaces.
- Generators in the Eastern Region received 52.0 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.
- Generators in the Western Region received 46.0 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.
- External generators received 2.0 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 2016, lost opportunity cost credits decreased by $59.3 million compared to the first nine months of 2015. In the first nine months of 2016, resources in three control zones, AECO, AEP and ComEd, accounted for 59.3 percent of all lost opportunity cost credits, 36.8 percent of all day-ahead generation from pool-scheduled combustion turbines and diesels, 52.0 percent of all day-ahead generation not committed in real time by PJM from those unit types and 51.8 percent of all day-ahead generation not committed in real time by PJM and receiving lost opportunity cost credits from those unit types.
- **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 2016, the average rate paid by a DEC in the Eastern Region would have been $0.032 per MWh under the MMU proposal, which is $0.414 per MWh, or 92.9 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 interface constraints to artificially override the nodal prices that are based on fundamental LMP logic in order to: accommodate rather than resolve the inadequacies of the demand side resource capacity product; address the inability of the power flow model to incorporate the need for reactive power; accommodate rather than resolve the flaws in PJM's approach to scarcity pricing; or for any other reason. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM not use price setting logic to artificially override the nodal prices that are based on fundamental LMP logic in order to reduce uplift. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that if PJM believes it appropriate to modify the price setting logic, PJM initiate a stakeholder process to create transparent and consistent modifications to the rules and incorporate the modifications in the PJM tariff. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends that PJM initiate an analysis of the reasons why some combustion turbines and diesels scheduled in the Day-Ahead Energy

Market are not called in real time when they are economic. (Priority: Medium. First Reported 2012. Status: Not adopted.)

- 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: Partially adopted 2014.)
- 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: Partially 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 2009. 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 market be calculated using the schedule on which the unit was scheduled to run in the energy market. (Priority: High. First reported 2012. Status: Adopted 2015.)
  - 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 2015.)
  - 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 2015.)
  - The MMU recommends calculating LOC based on 24 hour daily periods or multi-hour segments of hours for 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. First reported 2015. 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. First reported 2013. Status: Not adopted.)
  - The MMU recommends that only flexible fast start units (startup plus notification times of 30 minutes or less) and short minimum run times (one hour or less) be eligible by default for the LOC compensation to units scheduled in the 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. First reported 2015. Status: Not adopted.)
- The MMU recommends that up to congestion transactions be required to pay energy uplift charges for both the injection and the withdrawal sides of the UTC. (Priority: High. First reported 2011. 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. Stakeholder process.)
- 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 solely to real-time RTO load. (Priority: Low. First reported 2013. Status: Not adopted. Stakeholder process.)
- 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 2012. 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. Loss is defined to be receiving revenue less than the short run marginal costs incurred in order to generate energy. 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 short run 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 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 have persisted for more than ten years.

One part of addressing the level and allocation of uplift payments is to eliminate all day-ahead operating reserve credits. It is illogical and unnecessary to pay units day-ahead operating reserve credits because units do not incur any costs to run and any revenue shortfalls are addressed by balancing operating reserve credits.

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. Some uplift payments are the result of inflexible operating parameters included in offers by generating units. Operating parameters should reflect the flexibility of the benchmark new entrant unit in the PJM capacity market if the unit is to receive uplift payments from other market participants. 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.

But it is also important that the reduction of uplift payments not be a goal to be achieved at the expense of the fundamental logic of an LMP system. For example, the use of closed loop interfaces to reduce uplift should be eliminated because it is not consistent with LMP fundamentals and constitutes a form of subjective price setting. The same is true of what PJM terms its price setting logic.

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 incremental, 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	Zonal Real-Time Load
			Reactive Services Local Constraint	Applicable Requesting Party
		Synchronous Condensing		
Resources Providing Synchronous Condensing	Synchronous Condensing Synchronous Condensing LOC	→	Synchronous Condensing	Real-Time Load Real-Time Export Transactions
		Black Start		
Resources Providing Black Start Service	Day-Ahead Operating Reserve Balancing Operating Reserve Black Start Testing	→	Black Start Service Charge	Zone/Non-zone Peak Transmission Use and Point to Point Transmission Reservations

Energy Uplift Results

Energy Uplift Charges

Total energy uplift charges decreased by $181.7 million or 63.9 percent in the first nine months of 2016 compared to the first nine months of 2015. Table 4-3 shows total energy uplift charges in the first nine months of the years 2001 through 2016.[2]

Table 4-3 Total energy uplift charges: January through September, 2001 through 2016

	Total Energy Uplift Charges (Millions) (Jan - Sep)	Change (Millions)	Percent Change
2001	$240.3	$23.3	10.7%
2002	$204.6	($35.6)	(14.8%)
2003	$295.5	$90.9	44.4%
2004	$359.8	$64.3	21.8%
2005	$502.0	$142.2	39.5%
2006	$282.2	($219.9)	(43.8%)
2007	$384.1	$101.9	36.1%
2008	$392.8	$8.8	2.3%
2009	$245.6	($147.2)	(37.5%)
2010	$402.2	$156.5	63.7%
2011	$497.2	$95.1	23.6%
2012	$487.1	($10.1)	(2.0%)
2013	$620.7	$133.5	27.4%
2014	$899.9	$279.2	45.0%
2015	$284.5	($615.4)	(68.4%)
2016	$102.8	($181.7)	(63.9%)

Table 4-4 compares energy uplift charges by category for the first nine months of 2015 and 2016. The decrease of $181.7 million in the first nine months of 2016 is comprised of a decrease of $46.0 million in day-ahead operating reserve charges, a decrease of $121.6 million in balancing operating reserve charges, a decrease of $9.2 million in reactive services charges, a decrease of $0.01 million in synchronous condensing charges and a decrease of $4.9 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 July 18, 2016.

The decrease in total energy uplift charges was mainly a result of low natural gas prices in the first nine months of 2016 compared to the first nine months of 2016.

Table 4-4 Energy uplift charges by category: January through September, 2015 and 2016

Category	Jan - Sep 2015 Charges (Millions)	Jan - Sep 2016 Charges (Millions)	Change (Millions)	Percent Change
Day-Ahead Operating Reserves	$86.8	$40.8	($46.0)	(53.0%)
Balancing Operating Reserves	$182.6	$61.0	($121.6)	(66.6%)
Reactive Services	$10.0	$0.8	($9.2)	(91.7%)
Synchronous Condensing	$0.0	$0.0	($0.0)	(99.3%)
Black Start Services	$5.1	$0.2	($4.9)	(96.4%)
Total	$284.5	$102.8	($181.7)	(63.9%)

The decrease in energy uplift charges in the first nine months of 2016 was greatest for February. Total energy uplift charges decreased by $91.8 million from February 2015. Table 4-5 compares monthly energy uplift charges by category for 2015 and 2016.

Table 4-5 Monthly energy uplift charges: 2015 and 2016

	2015 Charges (Millions)						2016 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	$16.8	$24.7	$1.8	$0.0	$1.7	$45.0	$7.4	$7.5	$0.00	$0.0	$0.0	$14.9
Feb	$31.4	$71.1	$2.4	$0.0	$1.1	$106.0	$7.6	$6.5	$0.0	$0.0	$0.0	$14.2
Mar	$7.0	$24.8	$2.1	$0.0	$1.9	$35.8	$6.4	$3.9	$0.2	$0.0	$0.0	$10.5
Apr	$3.1	$8.5	$1.7	$0.0	$0.1	$13.4	$3.0	$4.7	$0.2	$0.0	$0.0	$8.0
May	$5.7	$15.4	$0.7	$0.0	$0.2	$22.0	$2.8	$3.3	$0.1	$0.0	$0.0	$6.3
Jun	$9.1	$8.6	$0.5	$0.0	$0.0	$18.2	$4.6	$5.3	$0.1	$0.0	$0.1	$10.1
Jul	$5.1	$11.9	$0.1	$0.0	$0.0	$17.1	$3.6	$11.4	$0.1	$0.0	$0.0	$15.1
Aug	$4.5	$9.1	$0.1	$0.0	$0.0	$13.6	$2.4	$11.4	$0.0	$0.0	$0.0	$13.8
Sep	$4.1	$8.7	$0.6	$0.0	$0.0	$13.5	$2.9	$6.9	$0.1	$0.0	$0.0	$9.9
Oct	$3.0	$5.3	$0.4	$0.0	$0.1	$8.8						
Nov	$4.3	$6.0	$0.1	$0.0	$0.0	$10.4						
Dec	$4.6	$4.2	$0.1	$0.0	$0.0	$8.8						
Total (Jan - Sep)	$86.8	$182.6	$10.0	$0.0	$5.1	$284.5	$40.8	$61.0	$0.8	$0.0	$0.2	$102.8
Share (Jan - Sep)	30.5%	64.2%	3.5%	0.0%	1.8%	100.0%	39.7%	59.3%	0.8%	0.0%	0.2%	100.0%
Total	$98.7	$198.1	$10.5	$0.0	$5.2	$312.5	$40.8	$61.0	$0.8	$0.0	$0.2	$102.8
Share	31.6%	63.4%	3.4%	0.0%	1.7%	100.0%	39.7%	59.3%	0.8%	0.0%	0.2%	100.0%

Table 4-6 Day-ahead operating reserve charges: January through September, 2015 and 2016

Type	Jan - Sep 2015 Charges (Millions)	Jan - Sep 2016 Charges (Millions)	Change (Millions)	Jan - Sep 2015 Share	Jan - Sep 2016 Share
Day-Ahead Operating Reserve Charges	$86.7	$40.8	($45.9)	99.8%	100.0%
Day-Ahead Operating Reserve Charges for Load Response	$0.2	$0.0	($0.2)	0.2%	0.0%
Unallocated Congestion Charges	$0.0	$0.0	$0.0	0.0%	0.0%
Total	$86.8	$40.8	($46.0)	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] Day-ahead operating reserve charges decreased by $46.0 million or 53.0 percent in the first nine months of 2016 compared to the first nine months of 2015. 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

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.

charges. Balancing operating reserve charges decreased by $121.6 million in the first nine months of 2016 compared to the first nine months of 2015.

Table 4-7 Balancing operating reserve charges: January through September, 2015 and 2016

Type	Jan - Sep 2015 Charges (Millions)	Jan - Sep 2016 Charges (Millions)	Change (Millions)	Jan - Sep 2015 Share	Jan - Sep 2016 Share
Balancing Operating Reserve Reliability Charges	$38.4	$17.5	($20.9)	21.0%	28.7%
Balancing Operating Reserve Deviation Charges	$143.9	$43.1	($100.8)	78.8%	70.7%
Balancing Operating Reserve Charges for Load Response	$0.1	$0.0	($0.1)	0.1%	0.0%
Balancing Local Constraint Charges	$0.2	$0.4	$0.2	0.1%	0.6%
Total	$182.6	$61.0	($121.6)	100.0%	100.0%

Table 4-8 Balancing operating reserve deviation charges: January through September, 2015 and 2016

Charge Attributable To	Jan - Sep 2015 Charges (Millions)	Jan - Sep 2016 Charges (Millions)	Change (Millions)	Jan - Sep 2015 Share	Jan - Sep 2016 Share
Make Whole Payments to Generators and Imports	$68.3	$26.7	($41.6)	47.5%	62.0%
Energy Lost Opportunity Cost	$75.4	$16.3	($59.1)	52.4%	37.9%
Canceled Resources	$0.2	$0.1	($0.1)	0.1%	0.1%
Total	$143.9	$43.1	($100.8)	100.0%	100.0%

Table 4-9 Additional energy uplift charges: January through September, 2015 and 2016

Type	Jan - Sep 2015 Charges (Millions)	Jan - Sep 2016 Charges (Millions)	Change (Millions)	Jan - Sep 2015 Share	Jan - Sep 2016 Share
Reactive Services Charges	$10.0	$0.8	($9.2)	66.3%	82.1%
Synchronous Condensing Charges	$0.0	$0.0	($0.0)	0.0%	0.0%
Black Start Services Charges	$5.1	$0.2	($4.9)	33.7%	17.9%
Total	$15.1	$1.0	($14.1)	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 2016, 62.0 percent of balancing operating reserve deviation charges were for make whole credits paid to generators and import transactions, an increase of 14.5 percentage points compared to the share in the first nine months of 2015.

Table 4-9 shows reactive services, synchronous condensing and black start services charges. Reactive services charges decreased by $9.2 million in the first nine months of 2016 compared to the first nine months of 2015. Black start services charges decreased by $4.9 million in the first nine months of 2016 compared to the first nine months of 2015 as a result of the replacement of black start units under the automatic load rejection (ALR) option in the second quarter of 2015.

Table 4-10 and Table 4-11 show the amount and percent shares of regional balancing charges in the first nine months of 2015 and 2016. 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 2016, regional balancing operating reserve charges decreased by $121.7 million compared to the first nine months of 2015. Balancing operating reserve reliability charges decreased by $20.9 million or 54.5 percent and balancing operating reserve deviation charges decreased by $100.8 million or 70.1 percent.

Table 4-10 Regional balancing charges allocation (Millions): January through September, 2015

Charge	Allocation	RTO		East		West		Total	
Reliability Charges	Real-Time Load	$33.2	18.2%	$3.5	1.9%	$0.9	0.5%	$37.6	20.6%
	Real-Time Exports	$0.7	0.4%	$0.1	0.1%	$0.0	0.0%	$0.8	0.4%
	Total	$33.9	18.6%	$3.6	2.0%	$0.9	0.5%	$38.4	21.1%
Deviation Charges	Demand	$79.6	43.7%	$2.3	1.3%	$1.0	0.5%	$83.0	45.5%
	Supply	$23.1	12.7%	$0.7	0.4%	$0.3	0.2%	$24.1	13.2%
	Generator	$35.5	19.5%	$1.0	0.5%	$0.4	0.2%	$36.8	20.2%
	Total	$138.3	75.8%	$4.0	2.2%	$1.7	0.9%	$143.9	78.9%
Total Regional Balancing Charges		$172.2	94.4%	$7.5	4.1%	$2.6	1.4%	$182.3	100%

Table 4-11 Regional balancing charges allocation (Millions): January through September, 2016

Charge	Allocation	RTO		East		West		Total	
Reliability Charges	Real-Time Load	$13.7	22.6%	$2.9	4.8%	$0.4	0.6%	$17.0	28.0%
	Real-Time Exports	$0.4	0.7%	$0.1	0.1%	$0.0	0.0%	$0.5	0.9%
	Total	$14.1	23.3%	$3.0	4.9%	$0.4	0.7%	$17.5	28.9%
Deviation Charges	Demand	$22.4	37.0%	$2.8	4.6%	$0.4	0.6%	$25.5	42.2%
	Supply	$7.2	11.8%	$0.8	1.3%	$0.1	0.2%	$8.0	13.3%
	Generator	$8.3	13.6%	$1.1	1.8%	$0.1	0.2%	$9.5	15.7%
	Total	$37.8	62.5%	$4.6	7.6%	$0.6	1.0%	$43.1	71.1%
Total Regional Balancing Charges		$52.0	85.8%	$7.6	12.5%	$1.0	1.7%	$60.6	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. Table 4-1 shows how these charges are allocated.[4]

Figure 4-1 shows the daily day-ahead operating reserve rate for 2015 and the first nine months of 2016. The average rate in the first nine months of 2016 was $0.064 per MWh, $0.072 per MWh lower than the average in the first nine months of 2015. The highest rate in the first nine months of 2016 occurred on February 16, when the rate reached $0.402 per MWh, $1.198 per MWh lower than the $1.600 per MWh reached in the first nine months of 2015, also on February 16. Figure 4-1 also shows the daily day-ahead operating reserve rate including the congestion charges allocated to day-ahead operating reserves. There were no congestion charges allocated to day-ahead operating reserves in 2015 or the first nine months of 2016.

4 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 4-1 Daily day-ahead operating reserve rate ($/MWh): 2015 and 2016

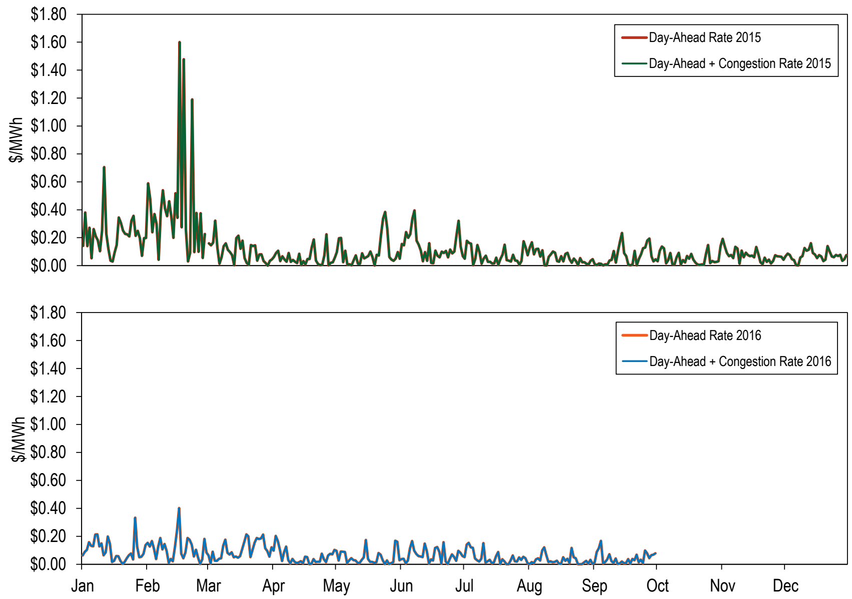


Figure 4-2 shows the RTO and the regional reliability rates for 2015 and first nine months of 2016. The average daily RTO reliability rate was $0.064 per MWh. The highest RTO reliability rate in the first nine months of 2016 occurred on August 11, when the rate reached $0.234 per MWh, $0.538 per MWh lower than the $0.772 per MWh rate reached in the first nine months of 2015, on February 19.

Figure 4-2 Daily balancing operating reserve reliability rates ($/MWh): 2015 and 2016

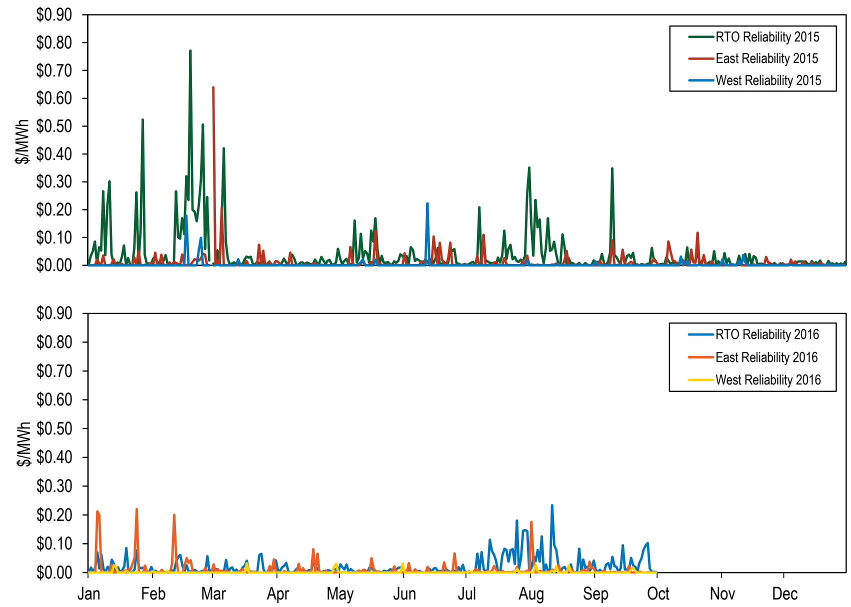


Figure 4-3 shows the RTO and regional deviation rates for 2015 and the first nine months of 2016. The average daily RTO deviation rate was $0.182 per MWh. The highest daily rate in the first nine months of 2016 occurred on July 29, when the RTO deviation rate reached $1.301 per MWh, $11.207 per MWh lower than the $12.507 per MWh rate reached in the first nine months of 2015, on February 17.

Figure 4-3 Daily balancing operating reserve deviation rates ($/MWh): 2015 and 2016

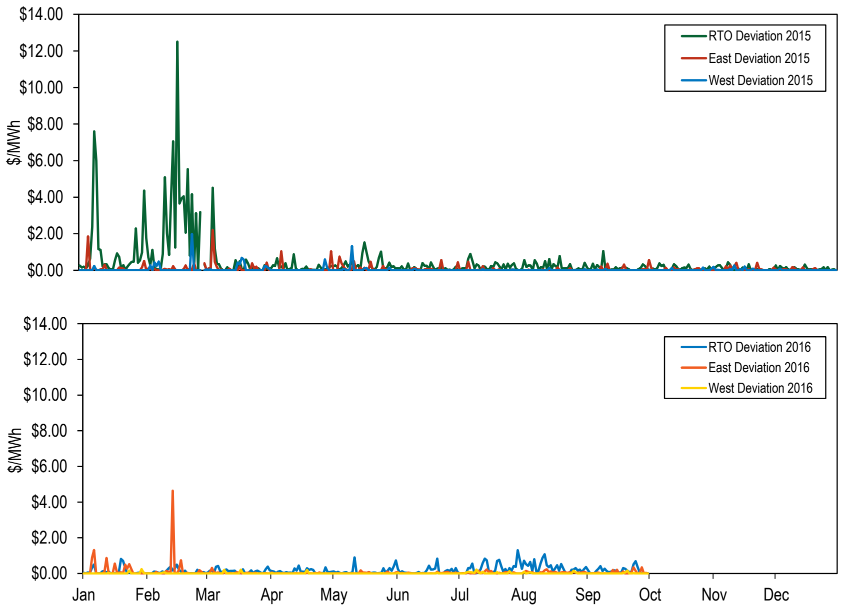


Figure 4-4 Daily lost opportunity cost and canceled resources rates ($/MWh): 2015 and 2016

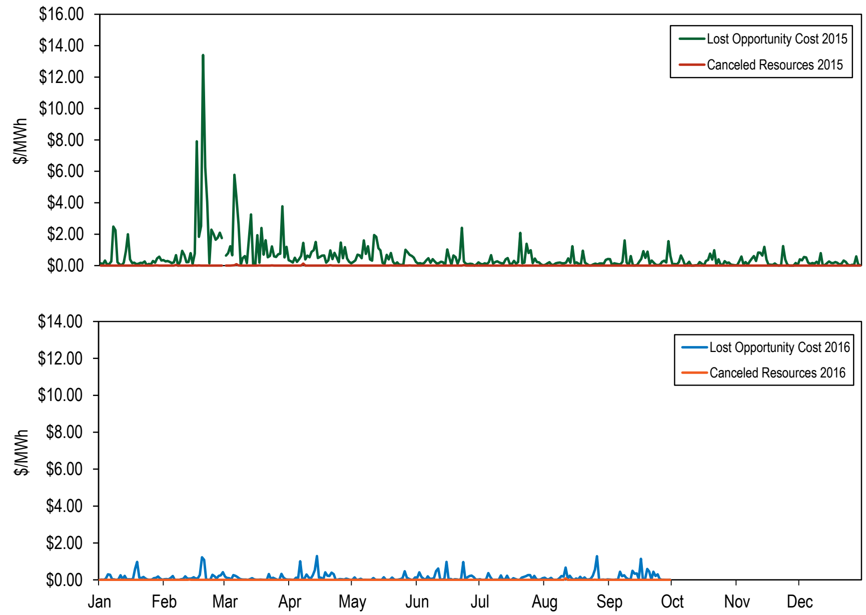


Figure 4-4 shows the daily lost opportunity cost rate and the daily canceled resources rate for 2015 and the first nine months of 2016. The lost opportunity cost rate averaged $0.139 per MWh. The highest lost opportunity cost rate occurred on April 14, when it reached $1.294 per MWh, $12.110 per MWh lower than the $13.404 per MWh rate reached in the first nine months of 2015, February 19.

Table 4-12 shows the average rates for each region in each category in the first nine months of 2015 and 2016.

Table 4-12 Operating reserve rates ($/MWh): January through September, 2015 and 2016

Rate	Jan - Sep 2015 ($/MWh)	Jan - Sep 2016 ($/MWh)	Difference ($/MWh)	Percent Difference
Day-Ahead	0.137	0.064	(0.072)	(52.9%)
Day-Ahead with Unallocated Congestion	0.137	0.064	(0.072)	(52.9%)
RTO Reliability	0.055	0.023	(0.032)	(58.3%)
East Reliability	0.012	0.010	(0.002)	(15.0%)
West Reliability	0.003	0.001	(0.002)	(56.2%)
RTO Deviation	0.602	0.182	(0.420)	(69.7%)
East Deviation	0.074	0.074	0.000	0.4%
West Deviation	0.034	0.011	(0.022)	(66.2%)
Lost Opportunity Cost	0.724	0.139	(0.585)	(80.8%)
Canceled Resources	0.002	0.001	(0.001)	(74.2%)

Table 4-13 shows the operating reserve cost of a one MW transaction in the first nine months of 2016. For example, a decrement bid in the Eastern Region (if not offset by other transactions) paid an average rate of $0.445 per MWh with a maximum rate of $4.904 per MWh, a minimum rate of $0.021 per MWh and a standard deviation of $0.449 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, 2016

		Rates Charged ($/MWh)			
Region	Transaction	Maximum	Average	Minimum	Standard Deviation
East	INC	4.883	0.379	0.001	0.460
	DEC	4.904	0.445	0.021	0.449
	DA Load	0.402	0.067	0.000	0.061
	RT Load	0.297	0.030	0.000	0.045
	Deviation	4.883	0.379	0.001	0.460
West	INC	1.828	0.320	0.000	0.337
	DEC	1.849	0.386	0.021	0.324
	DA Load	0.402	0.067	0.000	0.061
	RT Load	0.241	0.022	0.000	0.033
	Deviation	1.828	0.320	0.000	0.337

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 daily to real-time load across the entire RTO based on the real-time load ratio share of each network customer.

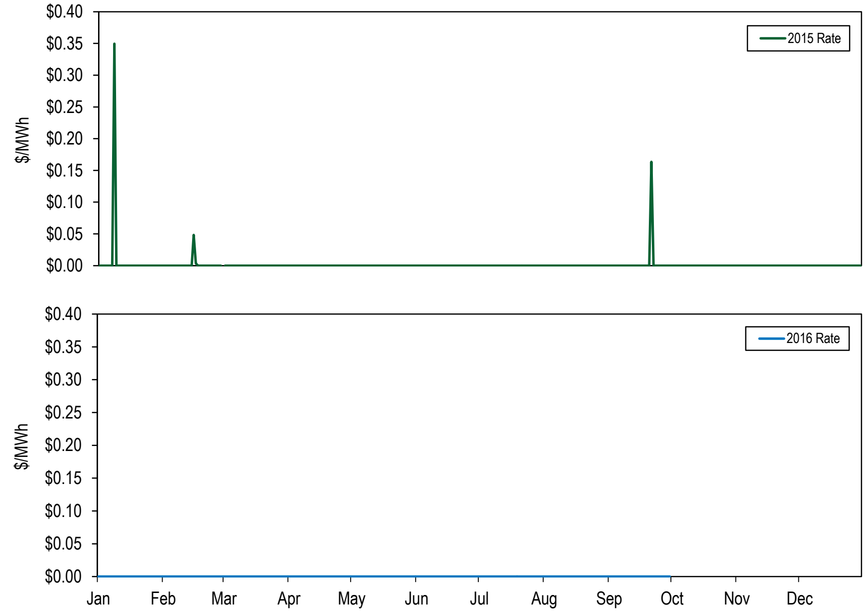
While reactive services rates are not posted by PJM, a local voltage support rate for each control zone can be calculated and a reactive transfer interface support rate can be calculated for the entire RTO. Table 4-14 shows the reactive services rates associated with local voltage support in the first nine months of 2015 and 2016. Table 4-14 shows that in the first nine months of 2016 the DPL Control Zone had the highest rate. Real-time load in the DPL Control Zone paid an average of $0.051 per MWh for reactive services associated with local voltage support, $0.074 or 59.3 percent lower than the average rate paid in the first nine months of 2015.

Table 4-14 Local voltage support rates: January through September, 2015 and 2016

Control Zone	Jan - Sep 2015 ($/MWh)	Jan - Sep 2016 ($/MWh)	Difference ($/MWh)	Percent Difference
AECO	0.000	0.000	(0.000)	
AEP	0.002	0.000	(0.002)	(81.7%)
AP	0.000	0.000	0.000	0.0%
ATSI	0.073	0.000	(0.073)	
BGE	0.000	0.000	0.000	0.0%
ComEd	0.000	0.000	(0.000)	(86.5%)
DAY	0.000	0.000	(0.000)	
DEOK	0.000	0.000	(0.000)	
DLCO	0.000	0.000	0.000	0.0%
Dominion	0.032	0.000	(0.032)	(99.3%)
DPL	0.125	0.051	(0.074)	(59.3%)
EKPC	0.000	0.000	0.000	0.0%
JCPL	0.000	0.000	0.000	0.0%
Met-Ed	0.003	0.001	(0.002)	(55.6%)
PECO	0.000	0.000	0.000	0.0%
PENELEC	0.020	0.003	(0.017)	(87.3%)
Pepco	0.000	0.000	(0.000)	
PPL	0.000	0.000	0.000	811.7%
PSEG	0.000	0.000	0.000	0.0%
RECO	0.000	0.000	0.000	0.0%

Figure 4-5 shows the daily RTO wide reactive transfer interface rate in the first nine months of 2015 and 2016. The average rate in the first nine months of 2016 was zero, compared to the $0.002 per MWh average rate in the first nine months of 2015 because PJM did not schedule any generation resource to provide voltage support to the 500 kV system.

Figure 4-5 Daily reactive transfer interface support rates ($/MWh): 2015 and 2016



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 2015 and 2016. Total real-time load and real-time exports were 3,256,396 MWh or 0.5 percent lower in the first nine months of 2016 compared to the first nine months of 2015. Total deviations summed across the demand, supply, and generator categories were 13,180,398 MWh or 12.6 percent higher in the first nine months of 2016 compared to the first nine months of 2015.

Table 4-15 Balancing operating reserve determinants (MWh): January through September, 2015 and 2016

		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 2015	RTO	603,587,854	13,908,345	617,496,199	63,166,479	16,575,236	24,746,411	104,488,125
	East	288,951,501	7,895,294	296,846,795	32,601,790	8,715,198	12,760,518	54,077,506
	West	314,636,354	6,013,051	320,649,405	29,950,539	7,601,347	11,985,893	49,537,779
Jan - Sep 2016	RTO	595,688,067	18,551,736	614,239,803	68,287,172	22,996,264	26,385,087	117,668,523
	East	282,160,616	8,393,058	290,553,674	34,616,935	13,223,676	14,599,773	62,440,384
	West	313,527,450	10,158,678	323,686,128	33,246,215	9,540,759	11,785,314	54,572,288
Difference	RTO	(7,899,788)	4,643,391	(3,256,396)	5,120,693	6,421,028	1,638,676	13,180,398
	East	(6,790,884)	497,764	(6,293,120)	2,015,145	4,508,478	1,839,255	8,362,878
	West	(1,108,903)	4,145,627	3,036,724	3,295,676	1,939,412	(200,578)	5,034,509

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 2016, 27.6 percent of all RTO deviations were incurred by participants that deviated due to INCs and DECs or due to combinations of INCs and DECs with other transactions, the remaining 72.4 percent of all RTO deviations were incurred by participants that deviated due to other transaction types or due to combinations of other transaction types.

Table 4-16 Deviations by transaction type: January through September, 2016

		Deviation (MWh)			Share		
Deviation Category	Transaction	RTO	East	West	RTO	East	West
Demand	Bilateral Sales Only	807,732	722,658	85,074	0.7%	1.2%	0.2%
	DECs Only	10,300,634	4,790,377	5,086,235	8.8%	7.7%	9.3%
	Exports Only	3,878,354	2,171,677	1,706,677	3.3%	3.5%	3.1%
	Load Only	47,286,050	23,069,400	24,216,650	40.2%	36.9%	44.4%
	Combination with DECs	4,515,338	3,096,096	1,419,242	3.8%	5.0%	2.6%
	Combination without DECs	1,499,064	766,727	732,337	1.3%	1.2%	1.3%
Supply	Bilateral Purchases Only	525,850	440,756	85,094	0.4%	0.7%	0.2%
	Imports Only	4,739,045	2,333,290	2,405,755	4.0%	3.7%	4.4%
	INCs Only	15,128,608	8,752,607	6,144,172	12.9%	14.0%	11.3%
	Combination with INCs	2,549,207	1,652,503	896,704	2.2%	2.6%	1.6%
	Combination without INCs	53,554	44,520	9,034	0.0%	0.1%	0.0%
Generators		26,385,087	14,599,773	11,785,314	22.4%	23.4%	21.6%
Total		117,668,523	62,440,384	54,572,288	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 2015 and 2016. During the first nine months of 2016, 59.3 percent of total energy uplift credits were in the balancing operating reserve category, a decrease of 4.9 percentage points from 64.2 in the first nine months of 2015.

Table 4-17 Energy uplift credits by category: January through September, 2015 and 2016

Category	Type	Jan - Sep 2015 Credits (Millions)	Jan - Sep 2016 Credits (Millions)	Change	Percent Change	Jan - Sep 2015 Share	Jan - Sep 2016 Share
Day-Ahead	Generators	$86.7	$40.8	($45.9)	(52.9%)	30.5%	39.7%
	Imports	$0.0	$0.0	($0.0)	(22.4%)	0.0%	0.0%
	Load Response	$0.2	$0.0	($0.2)	(100.0%)	0.1%	0.0%
Balancing	Canceled Resources	$0.2	$0.1	($0.1)	(70.8%)	0.1%	0.1%
	Generators	$106.6	$44.2	($62.4)	(58.5%)	37.5%	43.0%
	Imports	$0.2	$0.0	($0.2)	(92.2%)	0.1%	0.0%
	Load Response	$0.1	$0.0	($0.1)	(72.8%)	0.0%	0.0%
	Local Constraints Control	$0.2	$0.4	$0.2	101.8%	0.1%	0.4%
	Lost Opportunity Cost	$75.1	$16.3	($58.9)	(78.4%)	26.4%	15.8%
Reactive Services	Day-Ahead	$7.7	$0.0	($7.7)	(100.0%)	2.7%	0.0%
	Local Constraints Control	$0.0	$0.0	($0.0)		0.0%	0.0%
	Lost Opportunity Cost	$0.1	$0.0	($0.1)	(73.9%)	0.0%	0.0%
	Reactive Services	$2.1	$0.8	($1.3)	(61.8%)	0.7%	0.8%
	Synchronous Condensing	$0.2	$0.0	($0.1)	(86.3%)	0.1%	0.0%
Synchronous Condensing		$0.0	$0.0	($0.0)	(99.3%)	0.0%	0.0%
Black Start Services	Day-Ahead	$4.3	$0.0	($4.3)		1.5%	0.0%
	Balancing	$0.5	$0.0	($0.5)	(99.8%)	0.2%	0.0%
	Testing	$0.3	$0.2	($0.1)	(36.7%)	0.1%	0.2%
Total		$284.3	$102.7	($181.6)	(63.9%)	100.0%	100.0%

Characteristics of Credits

Types of Units

Table 4-18 shows the distribution of total energy uplift credits by unit type in the first nine months of 2015 and 2016. The decrease in energy uplift in the first nine months of 2016 compared to the first nine months of 2015 was primarily a result of lower credits paid to combined cycles, combustion turbines and steam turbines (not fired by coal) in the 2016 winter compared to the 2015 winter as a result of lower natural gas costs. Credits to these units decreased by $142.5 million or 71.0 percent.

Table 4-18 Energy uplift credits by unit type: January through September, 2015 and 2016

Unit Type	Jan - Sep 2015 Credits (Millions)	Jan - Sep 2016 Credits (Millions)	Change	Percent Change	Jan - Sep 2015 Share	Jan - Sep 2016 Share
Combined Cycle	$70.3	$10.1	($60.2)	(85.6%)	24.8%	9.8%
Combustion Turbine	$101.7	$45.9	($55.8)	(54.9%)	35.8%	44.7%
Diesel	$1.4	$0.5	($0.9)	(63.7%)	0.5%	0.5%
Hydro	$1.1	$0.1	($1.1)	(95.4%)	0.4%	0.1%
Nuclear	$0.3	$1.1	$0.8	260.1%	0.1%	1.1%
Steam - Coal	$77.4	$41.7	($35.6)	(46.1%)	27.3%	40.7%
Steam - Other	$28.8	$2.2	($26.5)	(92.3%)	10.1%	2.2%
Wind	$2.9	$1.0	($1.9)	(65.3%)	1.0%	1.0%
Total	$283.9	$102.7	($181.2)	(63.8%)	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 2016. Coal fired steam turbines received 85.6 percent of the day-ahead generator credits in the first nine months of 2016, 25.7 percentage points higher than the share received in the first nine months of 2015. Combustion turbines received 71.3 percent of the balancing generator credits in the first nine months of 2016, 39.9 percentage points higher than the share received in the first nine months of 2015. Combustion turbines and diesels received 79.8 percent of the lost opportunity cost credits in the first nine months of 2015, 7.0 percentage points lower than the share received in the first nine months of 2015.

Table 4-19 Energy uplift credits by unit type: January through September, 2016

Unit Type	Day-Ahead Generator	Balancing Generator	Canceled Resources	Local Constraints Control	Lost Opportunity Cost	Reactive Services	Synchronous Condensing	Black Start Services
Combined Cycle	9.5%	11.2%	0.0%	0.0%	3.4%	80.4%	0.0%	11.1%
Combustion Turbine	2.8%	71.3%	11.8%	65.7%	78.6%	12.0%	100.0%	88.9%
Diesel	0.0%	0.6%	0.0%	0.0%	1.1%	3.1%	0.0%	0.0%
Hydro	0.0%	0.0%	88.2%	0.0%	0.0%	0.0%	0.0%	0.0%
Nuclear	0.0%	0.0%	0.0%	0.0%	7.0%	0.0%	0.0%	0.0%
Steam - Coal	85.6%	13.8%	0.0%	32.0%	3.8%	0.0%	0.0%	0.0%
Steam - Others	2.1%	2.9%	0.0%	0.0%	0.2%	4.6%	0.0%	0.0%
Wind	0.0%	0.1%	0.0%	2.2%	5.9%	0.0%	0.0%	0.0%
Total (Millions)	$40.8	$44.2	$0.1	$0.4	$16.3	$0.8	$0.0	$0.2

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 2016, coal units received 0.0 percent of all reactive services credits, compared to 42.2 percent 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 parameters, PJM's persistent need to commit specific units out of merit in particular locations and the fact that the lack of transparency makes it almost impossible for competition to affect these payments.

Figure 4-6 shows the concentration of energy uplift credits. The top 10 units received 47.8 percent of total energy uplift credits in the first nine months of 2016, compared to 35.4 percent in the first nine months of 2015. In the first nine months of 2016, 268 units received 90 percent of all energy uplift credits, compared to 238 units in the first nine months of 2015.

Figure 4-6 Cumulative share of energy uplift credits in January through September, 2015 and 2016 by unit

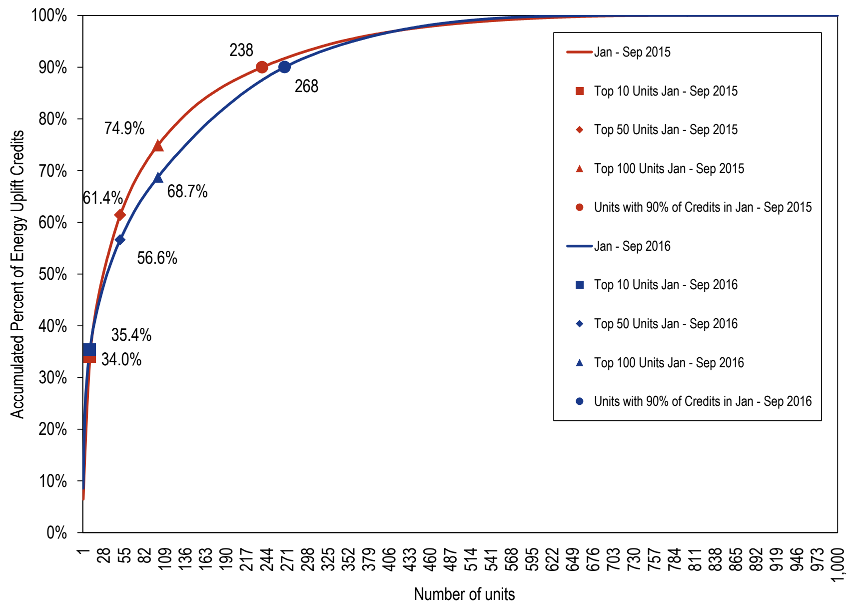


Table 4-20 shows the credits received by the top 10 units and top 10 organizations in each of the energy uplift categories paid to generators.

Table 4-20 Top 10 units and organizations energy uplift credits: January through September, 2016

		Top 10 Units		Top 10 Organizations	
Category	Type	Credits (Millions)	Credits Share	Credits (Millions)	Credits Share
Day-Ahead	Generators	$30.3	74.3%	$39.9	97.9%
Balancing	Canceled Resources	$0.1	100.0%	$0.1	100.0%
	Generators	$8.2	18.7%	$32.2	72.9%
	Local Constraints Control	$0.3	91.5%	$0.4	100.0%
	Lost Opportunity Cost	$4.5	27.9%	$11.9	73.4%
Reactive Services		$0.8	96.4%	$0.8	100.0%
Synchronous Condensing		$0.0	100.0%	$0.0	100.0%
Black Start Services		$0.1	49.5%	$0.2	96.0%
Total		$36.3	35.4%	$79.2	77.1%

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 2016, 83.4 percent of all credits paid to these units were allocated to deviations while the remaining 16.6 percent 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, 2016

	Reliability			Deviations			
	RTO	East	West	RTO	East	West	Total
Credits (Millions)	$1.2	$0.1	$0.0	$5.8	$1.1	$0.0	$8.2
Share	14.9%	1.8%	0.0%	69.9%	13.4%	0.0%	100.0%

In the first nine months of 2016, concentration in all energy uplift credit categories was high.[5] [6] 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 6122, for balancing operating reserve credits to generators was 3281, for lost opportunity cost credits was 5176 and for reactive services credits was 9951.

5 See *2015 State of the Market Report for PJM*, Volume II: Section 3: "Energy Market" at "Market Concentration" for a discussion of concentration ratios and the Herfindahl-Hirschman Index (HHI).

6 Table 4-22 excludes local constraints control categories.

Table 4-22 Daily energy uplift credits HHI: January through September, 2016

Category	Type	Average	Minimum	Maximum	Highest Market Share (One day)	Highest Market Share (All days)
Day-Ahead	Generators	6122	1589	10000	100.0%	41.7%
	Imports	10000	10000	10000	100.0%	63.2%
	Load Response	10000	10000	10000	100.0%	100.0%
	Canceled Resources	10000	10000	10000	100.0%	88.2%
Balancing	Generators	3281	864	9554	97.7%	14.3%
	Imports	10000	10000	10000	100.0%	100.0%
	Load Response	10000	10000	10000	100.0%	68.4%
	Lost Opportunity Cost	5176	1068	10000	100.0%	11.1%
Reactive Services		9951	6772	10000	100.0%	83.5%
Synchronous Condensing		10000	10000	10000	100.0%	100.0%
Black Start Services		9412	5110	10000	100.0%	41.4%
Total		2850	739	8954	94.6%	20.0%

Economic and Noneconomic Generation[7]

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 2016, 38.8 percent of the day-ahead generation was eligible for day-ahead operating reserve credits and 36.6 percent of the real-time generation was eligible for balancing operating reserve credits.[8]

Table 4-23 Day-ahead and real-time generation (GWh): January through September, 2016

Energy Market	Total Generation	Generation Eligible for Operating Reserve Credits	Generation Eligible for Operating Reserve Credits Percent
Day-Ahead	621,710	240,933	38.8%
Real-Time	622,146	227,867	36.6%

Table 4-24 shows PJM's economic and noneconomic generation by hour eligible for operating reserve credits. In the first nine months of 2016, 86.2 percent of the day-ahead generation eligible for operating reserve credits was economic and 74.0 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.

7 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.

8 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, 2016

Energy Market	Economic Generation	Noneconomic Generation	Economic Generation Percent	Noneconomic Generation Percent
Day-Ahead	207,802	33,131	86.2%	13.8%
Real-Time	168,555	59,312	74.0%	26.0%

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 2016, 3.3 percent of the day-ahead generation eligible for operating reserve credits received credits and 2.4 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, 2016

Energy Market	Generation Eligible for Operating Reserve Credits	Generation Receiving Operating Reserve Credits	Generation Receiving Operating Reserve Credits Percent
Day-Ahead	240,933	7,997	3.3%
Real-Time	227,867	5,359	2.4%

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 (ALR) 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.[9] 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.[10] 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 2016, 1.5 percent of the total day-ahead generation was scheduled as must run by PJM, 0.7 percentage points lower than the first nine months of 2015.

Table 4-26 Day-ahead generation scheduled as must run by PJM (GWh): 2015 and 2016

	2015			2016		
	Total Day-Ahead Generation	Day-Ahead PJM Must Run Generation	Share	Total Day-Ahead Generation	Day-Ahead PJM Must Run Generation	Share
Jan	78,023	2,143	2.7%	73,821	935	1.3%
Feb	74,373	2,904	3.9%	66,367	979	1.5%
Mar	68,294	1,857	2.7%	60,431	1,047	1.7%
Apr	56,110	1,138	2.0%	56,338	514	0.9%
May	62,067	1,523	2.5%	59,078	429	0.7%
Jun	68,643	1,447	2.1%	70,596	772	1.1%
Jul	75,631	1,201	1.6%	81,903	981	1.2%
Aug	74,065	922	1.2%	83,151	1,694	2.0%
Sep	67,075	616	0.9%	70,026	1,682	2.4%
Oct	58,897	763	1.3%			
Nov	58,570	486	0.8%			
Dec	62,976	551	0.9%			
Total (Jan - Sep)	624,281	13,752	2.2%	621,710	9,034	1.5%
Total	804,725	15,552	1.9%	621,710	9,034	1.5%

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.

9 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-minutes.ashx>

10 See PJM. "PJM eMkt Users Guide," Section Managing Unit Data (version July 9, 2015) p. 42, <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 2016, 44.4 percent of the day-ahead generation scheduled as must run by PJM received operating reserve credits, almost all paid day-ahead operating reserve credits, a small amount paid as reactive services, and none paid for black start services. The remaining 55.6 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, 2016

	Black Start Services	Reactive Services	Day-Ahead Operating Reserves	Economic	Total
Jan	0	0	375	560	935
Feb	0	0	584	395	979
Mar	0	0	712	335	1,047
Apr	0	0	263	251	514
May	0	0	289	140	429
Jun	0	0	534	238	772
Jul	0	0	419	562	981
Aug	0	0	410	1,284	1,694
Sep	0	2	422	1,258	1,682
Total (Jan - Sep)	0	2	4,008	5,024	9,034
Share	0.0%	0.0%	44.4%	55.6%	100.0%

Total day-ahead operating reserve credits in the first nine months of 2016 were $40.8 million, of which $31.8 million or 77.9 percent was paid to units scheduled as must run by PJM, and not scheduled to provide black start or reactive services.

Geography of Charges and Credits

Table 4-28 shows the geography of charges and credits in the first nine months of 2016. 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 AEP Control Zone paid 12.8 percent of all operating reserve charges allocated regionally, and resources in the AEP Control Zone were paid 8.5 percent of the corresponding credits. The AEP Control Zone received less operating reserve credits than operating reserve charges paid and had 11.2 percent of the deficit. The deficit is the sum of the negative entries in the balance column. Transactions in the BGE Control Zone paid 4.6 percent of all operating reserve charges allocated regionally, and resources in the BGE Control Zone were paid 48.1 percent of the corresponding credits. The BGE Control Zone received more operating reserve credits than operating reserve charges paid and had 48.1 percent of the surplus. The surplus is the sum of the positive entries in the balance column. Table 4-28 also shows that 89.9 percent of all charges were allocated in control zones, 4.4 percent in hubs and aggregates and 5.7 percent in interfaces.

Table 4-28 Geography of regional charges and credits: January through September, 2016

					Shares			
Location		Charges (Millions)	Credits (Millions)	Balance	Total Charges	Total Credits	Deficit	Surplus
Zones	AECO	$1.4	$2.6	$1.1	1.4%	2.5%	0.0%	2.9%
	AEP	$13.0	$8.6	($4.4)	12.8%	8.5%	11.2%	0.0%
	AP	$5.3	$1.8	($3.5)	5.3%	1.8%	9.0%	0.0%
	ATSI	$7.2	$2.3	($4.8)	7.1%	2.3%	12.4%	0.0%
	BGE	$4.7	$23.5	$18.8	4.6%	23.2%	0.0%	48.1%
	ComEd	$11.0	$11.8	$0.7	10.9%	11.6%	0.0%	1.8%
	DAY	$1.9	$2.2	$0.3	1.8%	2.1%	0.0%	0.8%
	DEOK	$2.8	$1.2	($1.6)	2.8%	1.2%	4.1%	0.0%
	DLCO	$1.4	$0.3	($1.1)	1.4%	0.3%	2.8%	0.0%
	Dominion	$10.3	$11.4	$1.1	10.2%	11.2%	0.0%	2.8%
	DPL	$2.6	$6.9	$4.3	2.6%	6.8%	0.0%	10.9%
	EKPC	$1.5	$2.5	$1.0	1.5%	2.5%	0.0%	2.5%
	External	($0.0)	$1.2	$1.2	-0.0%	1.2%	0.0%	3.1%
	JCPL	$2.8	$1.6	($1.2)	2.8%	1.6%	3.2%	0.0%
	Met-Ed	$2.0	$0.9	($1.1)	2.0%	0.9%	2.8%	0.0%
	PECO	$5.2	$0.7	($4.5)	5.1%	0.7%	11.4%	0.0%
	PENELEC	$2.9	$0.6	($2.3)	2.9%	0.6%	6.0%	0.0%
	Pepco	$4.0	$11.0	$6.9	4.0%	10.8%	0.0%	17.7%
	PPL	$5.0	$0.9	($4.2)	5.0%	0.9%	10.7%	0.0%
	PSEG	$5.8	$9.4	$3.7	5.7%	9.3%	0.0%	9.4%
	RECO	$0.2	$0.0	($0.2)	0.2%	0.0%	0.5%	0.0%
	All Zones	$91.1	$101.3	$10.2	89.9%	100.0%	74.0%	100.0%
Hubs and Aggregates	AEP - Dayton	$0.3	$0.0	($0.3)	0.3%	0.0%	0.7%	0.0%
	Dominion	$0.2	$0.0	($0.2)	0.2%	0.0%	0.5%	0.0%
	Eastern	$0.2	$0.0	($0.2)	0.2%	0.0%	0.4%	0.0%
	New Jersey	$0.1	$0.0	($0.1)	0.1%	0.0%	0.3%	0.0%
	Ohio	$0.0	$0.0	($0.0)	0.0%	0.0%	0.1%	0.0%
	Western Interface	$0.1	$0.0	($0.1)	0.1%	0.0%	0.2%	0.0%
	Western	$3.6	$0.0	($3.6)	3.6%	0.0%	9.3%	0.0%
	RTEP B0328 Source	$0.0	$0.0	($0.0)	0.0%	0.0%	0.0%	0.0%
	All Hubs and Aggregates	$4.5	$0.0	($4.5)	4.4%	0.0%	11.4%	0.0%
Interfaces	CPLE Imp	$0.0	$0.0	$0.0	0.0%	0.0%	0.0%	0.0%
	Hudson	$0.0	$0.0	($0.0)	0.0%	0.0%	0.0%	0.0%
	IMO	$0.4	$0.0	($0.4)	0.4%	0.0%	1.1%	0.0%
	Linden	$0.3	$0.0	($0.3)	0.3%	0.0%	0.7%	0.0%
	MISO	$2.0	$0.0	($2.0)	1.9%	0.0%	5.0%	0.0%
	Neptune	$0.4	$0.0	($0.4)	0.4%	0.0%	1.0%	0.0%
	NIPSCO	$0.0	$0.0	($0.0)	0.0%	0.0%	0.0%	0.0%
	Northwest	$0.1	$0.0	($0.1)	0.1%	0.0%	0.3%	0.0%
	NYIS	$0.8	$0.0	($0.8)	0.8%	0.0%	2.0%	0.0%
	OVEC	$0.1	$0.0	($0.1)	0.1%	0.0%	0.2%	0.0%
	South Exp	$0.5	$0.0	($0.5)	0.5%	0.0%	1.4%	0.0%
	South Imp	$1.2	$0.0	($1.2)	1.1%	0.0%	3.0%	0.0%
	All Interfaces	$5.7	$0.0	($5.7)	5.7%	0.0%	14.7%	0.0%
	Total	$101.3	$101.3	$0.0	100.0%	100.0%	100.0%	100.0%

Energy Uplift Issues

Lost Opportunity Cost Credits

Balancing operating reserve lost opportunity cost (LOC) credits are paid to units under two scenarios. If a combustion turbine or a diesel is scheduled to operate in the Day-Ahead Energy Market, but is not requested by PJM in real time, the unit will receive a credit which covers the day-ahead financial position of the unit plus balancing spot energy market charges that the unit has to pay. For purposes of this report, this LOC will be referred to as day-ahead LOC.[11] 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.

Table 4-29 Monthly lost opportunity cost credits (Millions): 2015 and 2016

	2015			2016		
	Day-Ahead Lost Opportunity Cost	Real-Time Lost Opportunity Cost	Total	Day-Ahead Lost Opportunity Cost	Real-Time Lost Opportunity Cost	Total
Jan	$4.4	$0.9	$5.2	$1.5	$0.2	$1.7
Feb	$23.0	$3.0	$25.9	$2.0	$0.1	$2.1
Mar	$13.9	$1.5	$15.4	$0.7	$0.3	$0.9
Apr	$5.2	$0.5	$5.7	$1.8	$0.6	$2.4
May	$5.6	$1.8	$7.4	$0.5	$0.1	$0.7
Jun	$3.8	$0.4	$4.2	$1.7	$0.9	$2.6
Jul	$4.1	$0.4	$4.5	$0.9	$0.5	$1.4
Aug	$2.1	$0.4	$2.5	$1.6	$0.4	$2.0
Sep	$3.0	$1.2	$4.2	$2.2	$0.2	$2.4
Oct	$1.5	$0.6	$2.1			
Nov	$1.8	$1.6	$3.3			
Dec	$2.4	$0.0	$2.4			
Total (Jan - Sep)	$65.0	$10.1	$75.1	$13.0	$3.3	$16.3
Share (Jan - Sep)	86.5%	13.5%	100.0%	79.7%	20.3%	100.0%
Total	$70.7	$12.3	$83.0	$13.0	$3.3	$16.3
Share	85.2%	14.8%	100.0%	79.7%	20.3%	100.0%

In the first nine months of 2016, LOC credits decreased by $58.9 million, 78.4 percent, compared to the first nine months of 2015. The decrease of $58.9 million is comprised of a decrease of $52.1 million in day-ahead LOC and a decrease of $6.8 million in real-time LOC. Table 4-29 shows the monthly composition of LOC credits in 2015 and 2016. In the first nine months of 2016, 5.3 percent of the day-ahead scheduled generation from combustion turbines and diesels was not committed in real time and paid LOC credits, 14.1 percentage points lower than in the first nine months of 2015.

Table 4-30 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 4-30 shows that day-ahead scheduled generation from CTs and diesels decreased by 1,333 GWh, 8.9 percent, from 15,061 GWh in the first nine months of 2015 to 13,728 GWh in the first nine months of 2016 and that the generation that received LOC credits decreased by 2,195 GWh or 75.1 percent.

11 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 4-30 Day-ahead generation from combustion turbines and diesels (GWh): 2015 and 2016

	2015			2016		
	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	827	347	244	705	211	115
Feb	1,593	838	499	746	192	92
Mar	1,368	688	505	1,090	162	66
Apr	1,392	536	408	1,531	276	95
May	1,898	556	365	1,349	115	48
Jun	1,736	406	242	1,433	231	80
Jul	2,651	432	273	2,697	229	77
Aug	1,881	331	202	2,402	144	58
Sep	1,714	291	183	1,774	240	97
Oct	1,375	204	108			
Nov	1,258	185	94			
Dec	1,041	314	180			
Total (Jan - Sep)	15,061	4,425	2,922	13,728	1,801	728
Share (Jan - Sep)	100.0%	29.4%	19.4%	100.0%	13.1%	5.3%
Total	18,734	5,128	3,304	13,728	1,801	728
Share	100.0%	27.4%	17.6%	100.0%	13.1%	5.3%

In the first nine months of 2016, the top three control zones in which generation received LOC credits, AECO, AEP and ComEd, accounted for 59.3 percent of all LOC credits, 36.8 percent of all the day-ahead generation from combustion turbines and diesels, 52.0 percent of all day-ahead generation not committed in real time by PJM from those unit types and 51.8 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 4-31 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 4-31 shows that in the first nine months of 2016, $7.1 million or 54.6 percent of all LOC credits were paid to combustion turbines and diesels that did not run for any hour in real time, 7.7 percentage points lower than the first nine months of 2015.

Table 4-31 Lost opportunity cost credits paid to combustion turbines and diesels by scenario (Millions): 2015 and 2016

	2015			2016		
	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	$2.4	$2.0	$4.4	$0.9	$0.7	$1.5
Feb	$15.4	$7.5	$23.0	$0.8	$1.2	$2.0
Mar	$9.1	$4.8	$13.9	$0.2	$0.5	$0.7
Apr	$3.0	$2.2	$5.2	$0.9	$0.9	$1.8
May	$3.0	$2.6	$5.6	$0.4	$0.2	$0.5
Jun	$2.2	$1.6	$3.8	$1.2	$0.4	$1.7
Jul	$2.5	$1.6	$4.1	$0.4	$0.5	$0.9
Aug	$1.3	$0.8	$2.1	$0.8	$0.8	$1.6
Sep	$1.6	$1.4	$3.0	$1.5	$0.7	$2.2
Oct	$0.9	$0.6	$1.5			
Nov	$1.0	$0.8	$1.8			
Dec	$1.8	$0.6	$2.4			
Total (Jan - Sep)	$40.5	$24.5	$65.0	$7.1	$5.9	$13.0
Share (Jan - Sep)	62.3%	37.7%	100.0%	54.6%	45.4%	100.0%
Total	$44.2	$26.5	$70.7	$7.1	$5.9	$13.0
Share	62.5%	37.5%	100.0%	54.6%	45.4%	100.0%

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 4-32 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 4-32 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 2016, 60.3 percent of the scheduled generation not committed by PJM from units receiving LOC credits was economic and the remaining 39.7 percent was noneconomic.

Table 4-32 Day-ahead generation (GWh) from combustion turbines and diesels receiving lost opportunity cost credits by value: 2015 and 2016[12]

	2015			2016		
	Economic Scheduled Generation (GWh)	Noneconomic Scheduled Generation (GWh)	Total (GWh)	Economic Scheduled Generation (GWh)	Noneconomic Scheduled Generation (GWh)	Total (GWh)
Jan	246	102	348	142	43	185
Feb	497	335	832	104	63	167
Mar	543	140	682	72	71	143
Apr	366	168	534	124	110	234
May	280	258	538	58	41	99
Jun	240	125	365	100	63	163
Jul	259	124	383	80	51	131
Aug	163	123	286	68	31	99
Sep	211	73	284	99	85	185
Oct	141	53	194			
Nov	113	51	164			
Dec	212	75	287			
Total (Jan - Sep)	2,804	1,448	4,251	848	559	1,407
Share (Jan - Sep)	65.9%	34.1%	100.0%	60.3%	39.7%	100.0%
Total	3,269	1,626	4,896	848	559	1,407
Share	66.8%	33.2%	100.0%	60.3%	39.7%	100.0%

The MMU recommends that PJM initiate an analysis of the reasons why some combustion turbines and diesels scheduled in the Day-Ahead Energy Market are not committed by PJM in real time when they are economic.

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.[13] 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 not otherwise set price under the fundamental LMP logic. Of the 17 closed loop interface definitions, 11(65 percent) were created for the purpose of allowing emergency DR to set price.

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 the loop with the rest of PJM. When PJM wants a closed loop interface to bind, PJM reduces the capacity of the transmission facilities to a level that will artificially make marginal the resource selected by PJM. Table 4-33 shows the closed loop interfaces that PJM has defined and PJM's objective in defining each closed loop interface.

12 The total generation in Table 4-32 is lower than the day-ahead generation not requested in real time in Table 4-30 because the former only includes generation from units that received lost opportunity costs during at least one hour of the day. Table 4-32 includes all generation, including generation from units that were not committed in real time and did not receive LOC credits.

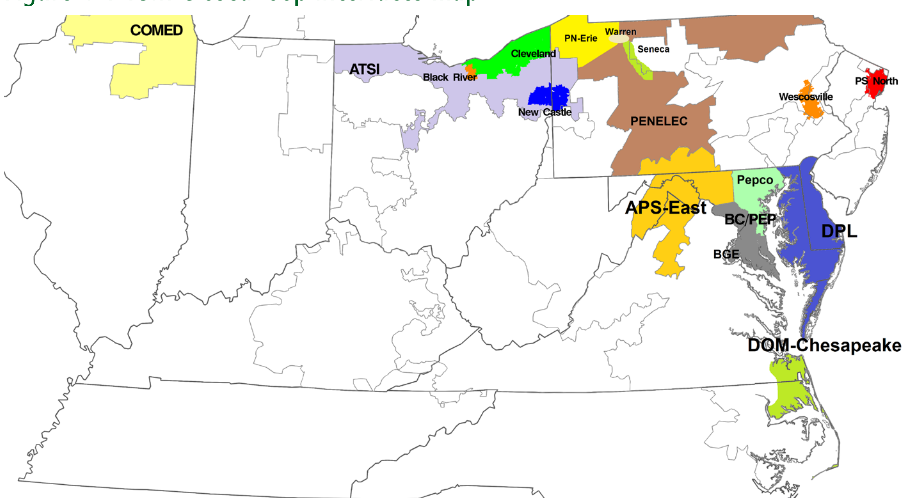
13 See PJM/Alstom. "Approaches to Reduce Energy Uplift and PJM Experiences," presented at the FERC Technical Conference: Increasing Real-Time and Day-Ahead Market Efficiency Through Improved Software in Docket No. AD10-12-006 <http://www.ferc.gov/june-tech-conf/2015/presentations/m2-3.pdf> (June 23, 2015).

Table 4-33 PJM closed loop interfaces[14] [15] [16]

Interface	Control Zone(s)	Objective	Effective Date	Limit Calculation
APS-East	AP	Allow emergency DR resources / unit(s) needed for reactive to set real-time LMP	June 19, 2015	Limit equal to actual flow
ATSI	ATSI	Allow emergency DR resources / unit(s) needed for reactive to set real-time LMP	July 17, 2013	Limit equal to actual flow
BC	BGE	Allow emergency DR resources / unit(s) needed for reactive to set real-time LMP	June 19, 2015	Limit equal to actual flow
BC/PEP	BGE and Pepco	Reactive Interface (not an IROL). Used to model import capability into the BGE/PEPCO/ Doubs/Northern Virginia area	NA	PJM Transfer Limit Calculator
Black River	ATSI	Allow emergency DR resources set real-time LMP	September 1, 2014	Limit equal to actual flow
Cleveland	ATSI	Reactive Interface (IROL)	NA	PJM Transfer Limit Calculator
COMED	ComEd	Reactive Interface (IROL)	NA	PJM Transfer Limit Calculator
DOM-Chesapeake	Dominion	Allow emergency DR resources / unit(s) needed for reactive to set real-time LMP	August 14, 2015	Limit equal to actual flow
DPL	DPL	Allow emergency DR resources / unit(s) needed for reactive to set real-time LMP	June 19, 2015	Limit equal to actual flow
New Castle	ATSI	Allow emergency DR resources set real-time LMP	July 1, 2014	Limit equal to actual flow
PENELEC	PENELEC	Allow emergency DR resources / unit(s) needed for reactive to set real-time LMP	April 22, 2015	Limit equal to actual flow
Pepco	Pepco	Allow emergency DR resources / unit(s) needed for reactive to set real-time LMP	June 19, 2015	Limit equal to actual flow
PL-Wescosville	PPL	Allow emergency DR resources / unit(s) needed for reactive to set real-time LMP	July 24, 2014	Limit equal to actual flow
PN-Erie	PENELEC	Allow emergency DR resources set real-time LMP	April 22, 2015	Limit equal to actual flow
PS North	PSEG	Objective not identified. Interface was modeled in 2014/2015 Annual FTR auction	NA	NA
Seneca	PENELEC	Allow unit(s) needed for reactive to set day-ahead and real-time LMP	February 1, 2014	Limit equal to actual flow
Warren	PENELEC	Allow unit(s) needed for reactive to set day-ahead and real-time LMP	September 26, 2014	Limit equal to actual flow

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

Figure 4-7 PJM Closed loop interfaces map



14 See PJM. "Manual 3: Transmission Operations," Revision 48 (December 1, 2015) at "Section 3.8: Transfer Limits (Reactive/Voltage Transfer Limits)," for a description of reactive interfaces.
15 See closed loop interfaces definitions at <http://www.pjm.com/markets-and-operations/etools/oasis/system-information.aspx>.
16 See the PS North interface definition at <http://www.pjm.com/pub/account/auction-user-info/model-annual/Annual-PJM-interface-definitions-limits.csv>.

PJM's uses closed loop interfaces to artificially allow the strike price of emergency DR to set LMP. This use of closed loop interfaces permits subjective price setting by PJM. PJM has not explained why the economic fundamentals require that DR strike prices set LMP when the resource is not marginal. Although DR should be nodal, DR is not nodal and cannot routinely set price in an LMP model. The MMU has recommended that DR be nodal so that it can set price when appropriate. The current PJM rules permit emergency DR to set a strike price as high as $1,849. There are no incentives for DR to set strike prices at an economically rational level because emergency DR is guaranteed the payment of its strike price whenever called. The MMU has recommended that emergency DR have an offer cap no higher than generation resources, that emergency DR be required to make offers in the Day-Ahead Energy Market like other capacity resources and the emergency DR be paid LMP rather than a guaranteed strike price when called on. PJM's use of closed loop interfaces is a result of significant deficiencies in the rules governing DR. PJM's use of closed loop interfaces is also result of significant issues with PJM's scarcity pricing model which is not adequately locational. PJM uses closed loop interfaces and emergency DR strike prices as a substitute for improved, more locational scarcity pricing.

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 forced to be marginal in the model 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 forcing these units to be marginal when they are not, raising energy prices and thereby reducing uplift.[17]

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 use of closed loop interfaces is a distortion of the model.

The MMU recommends that PJM not use closed loop interface constraints to artificially override the nodal prices that are based on fundamental LMP logic in order to: accommodate rather than resolve the inadequacies of the demand side resource capacity product; address the inability of the power flow model to incorporate the need for reactive power; accommodate rather than resolve the flaws in PJM's approach to scarcity pricing; or for any other reason.

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 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.

Price Setting Logic

In November 2014, PJM implemented a software change to its day ahead and real time market solution tools that would enable PJM to reduce energy uplift by artificially selecting the marginal unit for any constraint. The goal is to make marginal any unit committed by PJM to provide reactive services, black start or transmission constraint relief if such unit would otherwise run with an incremental offer greater than the correctly calculated LMP. PJM calls this approach price setting logic.

17 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>.

The application of the price setting logic reduces energy uplift payments by artificially increasing the LMP. The price setting logic is a form of subjective pricing because it varies from fundamental LMP logic based on an administrative decision to reduce energy uplift.

PJM and Alstom presented examples of this approach at the FERC Technical Conference, "Increasing Real-Time and Day-Ahead Market Efficiency Through Improved Software."[18] The presentation shows a two bus model connected by one transmission line, three generators (A, B and C) and load at one of the buses. Solution 1: In the solution based on the fundamental LMP logic that PJM has used since the inception of markets, two of the generators are committed (A at 50 MW and B at 50 MW) to serve load (100 MW). The LMP is set at $50 per MWh (the offer of generator A) at both buses. Generator B has to be made whole (paid energy uplift) because the LMP ($50 per MWh) does not cover the generator's offer ($100 per MWh). Generator B does not set the LMP because its economic minimum is higher than the relief needed to relieve the constraint. This solution is not acceptable for PJM because the most expensive generator would have to be made whole. In order to reduce energy uplift, PJM shows two alternatives. Solution 2: Artificially redefine the economic minimum of generator B to zero MW. Solution 3: Artificially redefine the limit of the transmission line to a level that would make the LMP higher at the bus where the most expensive generator is connected.

In solution 2, generator B is dispatched at 10 MW, despite the fact that this is physically impossible. This allows generator A to increase its output to 80 MW, which makes the transmission constraint binding and causes price separation between the two buses. This is an artificial result, not consistent with actual dispatch, designed to achieve an administrative goal.

In solution 3, the line limit is reduced from 80 MW to 40 MW, despite the fact that this is not the actual limit. As a result, generator A is dispatched to 40 MW (10 MW less than the original solution), the transmission line constraint is binding and congestion occurs. The goal is met and energy uplift is reduced to zero because the LMPs at both buses are increased so that they equal or exceed the generators' offers. Again, this is an artificial result, not consistent with actual dispatch, designed to achieve an administrative goal.

Attempting to reduce uplift at the expense of fundamental LMP logic is not consistent with the objective of clearing the market using a least cost approach. The result of PJM's price setting logic in this example is to increase total production costs.

The MMU recommends that PJM not use price setting logic to artificially override the nodal prices that are based on fundamental LMP logic in order to reduce uplift.

The MMU supports efforts to ensure that LMP reflects the appropriate marginal resource. The MMU recommends that if PJM believes it appropriate to modify the price setting logic, PJM initiate a stakeholder process to create transparent and consistent modifications to the rules and incorporate the modifications in the PJM tariff.

Confidentiality of Energy Uplift Information

All data posted publicly by PJM or the MMU must comply with confidentiality rules. Prior to March 31, 2016, confidentiality rules did not allow posting data for three or fewer PJM participants and did not permit aggregation for a geographic area smaller than a control zone.[19]

Energy uplift charges are out of market, nontransparent 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

18 See PJM/Alstom. "Approaches to Reduce Energy Uplift and PJM Experiences," presented at the FERC Technical Conference: "Increasing Real-Time and Day-Ahead Market Efficiency Through Improved Software," in Docket No. AD10-12-006 <http://www.ferc.gov/june-tech-conf/2015/presentations/m2-3.pdf> (June 23, 2015).

19 See PJM. Manual 33: Administrative Services for the PJM Interconnection Operating Agreement, Revision 12 (March 31, 2016) at "Market Data Postings."

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. PJM partially adopted the MMU recommendation at the March 31, 2016, Markets and Reliability Committee (MRC).[20] PJM adopted a rule permitting the posting of energy uplift information by control zone, regardless of the number of PJM participants receiving energy uplift payments in that control zone.

Energy Uplift Recommendations

Recommendations for Calculation of Credits

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.[21]

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 until the unit actually operates or does not operate. 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 net revenues 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.

20 See the Markets and Reliability Committee (March 31, 2016) minutes <http://www.pjm.com/~/media/committees-groups/committees/mrc/20160418-special/20160418-item-01-draft-minutes-mrc.ashx>.

21 The balancing operating reserve credit calculation includes net DASR revenues, net synchronized reserve revenues, net nonsynchronized reserve revenues and reactive services revenues.

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 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.[22] These recommendations are superseded by the MMU's recommendation to eliminate day-ahead operating reserve payments.[23] The elimination of day-ahead operating reserve payments also ensures that units are always made whole based on their actual operation and actual revenues.

The MMU calculated the impact of this recommendation for 2015 and the first nine months of 2016. In 2015 and the first nine months of 2016, energy uplift costs associated with units scheduled in the Day-Ahead Energy Market would have had been reduced by $35.3 million or 17.6 percent ($2.4 million paid to units providing reactive support, $0.9 million paid to units providing black start support and $32.0 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. If the day-ahead operating reserve category were eliminated but the MMU's uplift allocation recommendations were not implemented, units that clear the Day-Ahead Energy Market would be made whole through balancing operating reserve credits, which under the current rules are allocated to deviations or real-time load plus real-time exports. Therefore, this recommendation should be implemented concurrently with the MMU's allocation recommendations.

Net Regulation Revenues Offset

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

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 nonsynchronized 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 and inconsistent with the basic PJM uplift logic. Whether a unit is running for PJM at a loss defined by marginal costs cannot be determined if some of the revenues are arbitrarily excluded.

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

22 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.

23 PJM agrees with this recommendation. See "Explanation of PJM Proposals," from the Energy Market Uplift Senior Task Force (April 30, 2014). <http://www.pjm.com/~/media/committees-groups/task-forces/emustf/20140417/20140417-explanation-of-pjm-proposals.ashx>.

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 and the additional costs resulting from operating at a higher economic minimum are not covered by the real-time LMP, the unit will be made whole for the additional costs through balancing operating reserve credits.

The MMU recommends reincorporating the use of net regulation revenues as an offset in the calculation of balancing operating reserve credits. In 2015 and the first nine months of 2016, 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 $8.1 million, of which $6.1 million or 75.1 percent was a result of generators that elected to self-schedule for regulation while being noneconomic in the energy market and receiving balancing operating reserve credits.[24]

Self Scheduled Start

Participants may offer their units as pool-scheduled (economic) or self-scheduled (must run).[25] 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 clear the Day-Ahead Energy Market regardless of their offers and may operate in real time following PJM dispatch instructions. Units offered as self-scheduled follow PJM dispatch instructions when they are offered with a minimum must run output from which the units 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 separately for each hour 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.

Units offered as self-scheduled for some hours of the day and pool-scheduled for the remaining hours are made whole for startup costs when they should not be. For example, if a unit is offered as self-scheduled for hours 10 through 24 and as pool-scheduled for the balance of the day and PJM selects the unit to start for hour nine, the unit will be made whole for its startup cost if the hourly revenues do not cover the costs. The only hour used in the day-ahead or balancing operating reserve credit calculation is hour nine because the unit is not eligible for operating reserve credits for hours 10 through 24. The result is that any net revenue from hours 10 through 18 will not be used to offset the unit's startup cost despite the fact that the unit would have started and incurred those costs regardless of PJM dispatch instructions.

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 recommended four modifications, of which three were adopted on September 1, 2015.[26] [27] The one outstanding modification not adopted by PJM is the calculation of LOC using segments of hours. Current rules calculate LOC on an hourly basis; each hour is treated as a standalone calculation. This means that units receive an LOC payment during hours in which it is economic for them to 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 Day-Ahead Energy Market would not be economic, but the unit could still receive an LOC payment.

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

25 See "PJM eMkt Users Guide," Section Managing Unit Data (version July 9, 2015) p. 42. <http://www.pjm.com/~/media/etools/emkt/ts-userguide.ashx>.

26 See *2015 State of the Market Report for PJM*, Volume II Section 4, "Energy Uplift," at "Lost Opportunity Cost Calculation" for an explanation of the adopted recommendations.

27 152 FERC ¶ 61,165 (2015)

This is inconsistent with the basic PJM energy uplift logic. If a unit does not run in real time, it loses net revenues if the real-time LMP is greater than the unit's offer but it gains net revenues if the real-time LMP is lower than the unit's offer. The correct lost opportunity costs for units that clear the Day-Ahead Energy Market and are not committed in real time cannot be determined if profitable hours are arbitrarily excluded. In the case of separate hourly calculations, units are overcompensated compared to the net revenues they would have received had they run.

The MMU recommends calculating LOC based on 24 hour daily periods or multi-hour segments of hours for combustion turbines and diesels scheduled in the Day-Ahead Energy Market but not committed in real time. This recommendation has not been adopted. The MMU calculated the impact of this recommendation in the first nine months of 2016. In the first nine months of 2016, lost opportunity cost payments would have had been reduced by $2.3 million or 14.0 percent.

In addition to the initial four recommendations, the MMU recommends three additional steps to address 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 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.

  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.

- **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. These units are eligible for LOC compensation only if PJM explicitly cancels their day-ahead commitment for reliability purposes. 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 30 minutes or less) and short minimum run times (one hour or less) be eligible by default for the LOC compensation to units scheduled in the Day-Ahead Energy Market and not committed in real time.

Recommendations for Allocation of Charges

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 recommends that up to congestion transactions be required to pay energy uplift charges for both the injection and the withdrawal sides of the UTC.

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.

Up to congestion transactions would have paid an average rate between $0.290 and $0.295 per MWh in 2015 and between $0.050 and $0.063 per MWh in the first nine months of 2016 if the MMU's recommendations regarding energy uplift had been in place.[28] [29]

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.[30] Load, interchange transactions, internal bilateral transactions, demand resources, increment offers and decrement bids also incur deviations.

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 For example, a generator with a negative deviation (generation below the desired level) can offset such deviation if a generator at the same bus has a positive deviation (generation above the desired level) if this occurs in the same hour.

Load, interchange transactions, internal bilateral transactions, demand resources, increment offers and decrement bids are also allowed to offset their deviations. These transactions are grouped by demand and supply, and then 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 at the same location at the same hour.[31] Demand transactions such as load, exports, internal bilateral sales and decrement bids may offset. 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 (IBTs) 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.

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

28 The range of operating reserve rates paid by up to congestion transactions depends on the location of the transactions' source and sink.
29 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 to 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.
30 See PJM. OATT 3.2.3 (o) for a complete description of how generators deviate.
31 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.

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 MMU recommends eliminating the use of internal bilateral transactions (IBTs) in the calculation of deviations used to allocate balancing operating reserve charges.

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.[32] 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.

32 See PJM. "Item 12 - October 2012 MIC DAM Cost Allocation," PJM presentation to the Market Implementation Committee (October 12, 2012).

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.[33] 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.[34] 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 for the balance through balancing operating reserves. The result is a misallocation of the costs of providing reactive services. Reactive services credits are paid by real-time load in the control zone or zones where the service is provided while balancing operating reserve charges are paid by deviations from day-ahead or real-time load plus exports in the RTO, Eastern or Western Region depending on the allocation process rather than by zone.

In the first nine months of 2016, units providing reactive services were paid $0.3 million in balancing operating reserve credits in order to cover their total energy offer. In 2015, this misallocation was $1.0 million.

The MMU recommends that reactive services credits be calculated consistent with the balancing operating reserve credit calculation. The MMU also

33 See the *2015 State of the Market Report for PJM, Volume II*, Section 9, "Interchange Transactions" at " Consolidated Edison Company of New York, Inc. (Con Edison) Wheeling Contracts" for a description of the contracts.
34 PJM. OATT Attachment K - Appendix § 3.2.3B (f).

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, in addition to real-time load.[35]

Allocation Proposal

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

The current method 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 would shift these costs to the balancing operating reserve category which would 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 related to expected conditions in the real-time market not including 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 reliability in real time and payments to canceled resources should be allocated to real-time load, real-time exports and real-time wheels.

Table 4-34 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.

35 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>.

Table 4-34 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 4-35 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

Table 4-35 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.

Quantifiable Recommendations Impact

Table 4-36 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 $64.7 million or 16.3 percent in 2015 and the first nine months of 2016 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 $32.0 million, the proposed changes to lost opportunity cost calculations would have resulted in a decrease of $23.6 million and the use of net regulation revenues offset would have resulted in a decrease of $8.1 million.[36] Table 4-36 shows that deviations charges would have been reduced by $117.3 million or 58.7 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).

Table 4-36 Current and proposed energy uplift charges by allocation (Millions): 2015 and January through September 2016[37]

Allocation	2015	Jan - Sep 2016	Total
Current			
Day-Ahead Demand, Day-Ahead Exports and Decrement Bids	$98.5	$40.8	$139.3
Real-Time Load and Real-Time Exports	$41.1	$17.5	$58.6
Deviations	$156.5	$43.1	$199.7
Total	$296.2	$101.4	$397.6
Proposal			
Day-Ahead Transactions and Day-Ahead Resources	$27.5	$7.3	$34.9
Real-Time Load and Real-Time Exports	$99.7	$31.1	$130.7
Deviations	$68.1	$14.3	$82.4
Physical Deviations	$51.0	$33.9	$84.9
Total	$246.3	$86.5	$332.9
Impact			
Impact ($)	($49.8)	($14.9)	($64.7)
Impact (%)	(16.8%)	(14.7%)	(16.3%)

The MMU calculated the rates that participants would have paid in 2015 and the first nine months of 2016 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 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 4-37 shows the energy uplift cost of a 1 MW transaction if these recommendations had been implemented in 2015 and the first nine months of 2016. Table 4-37 assumes two scenarios under the MMU proposal. The first scenario assumes all the up to congestion transactions volume cleared. The second scenario assumes zero volume of up to congestion transactions in 2015 and the first nine months of 2016, in this scenario, the cost reflects the expected cost for the first 1 MW cleared up to congestion transaction. Table 4-37 shows for example that a decrement bid in the Eastern Region (if not offset by other transactions) would have paid an average rate of $0.147 and $0.032 per MWh in the 2015 and the first nine months of 2016, under the first scenario, $1.026 and $0.414 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 $0.292 and $0.057 per MWh in 2015 and in the first nine months of 2016 under the first scenario. Table 4-37 shows the current and proposed averages energy uplift rates for all transactions.

36 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.
37 These energy uplift charges do not include black start and reactive services charges.

Table 4-37 Current and proposed average energy uplift rate by transaction: 2015 and January through September 2016[38]

		2015			Jan - Sep 2016		
Transaction		Current Rates ($/MWh)	Proposed Rates - 100% UTC ($/MWh)	Proposed Rates - 0% UTC ($/MWh)	Current Rates ($/MWh)	Proposed Rates - 100% UTC ($/MWh)	Proposed Rates - 0% UTC ($/MWh)
East	INC	1.058	0.147	0.376	0.379	0.032	0.110
	DEC	1.173	0.147	0.376	0.445	0.032	0.110
	DA Load	0.115	0.013	0.015	0.067	0.004	0.006
	RT Load	0.050	0.118	0.118	0.030	0.053	0.053
	Deviation	1.058	0.497	0.723	0.379	0.385	0.462
West	INC	1.022	0.145	0.376	0.320	0.025	0.091
	DEC	1.137	0.145	0.376	0.386	0.025	0.091
	DA Load	0.115	0.013	0.015	0.067	0.004	0.006
	RT Load	0.042	0.118	0.118	0.022	0.053	0.053
	Deviation	1.022	0.429	0.658	0.320	0.300	0.364
UTC	East to East	NA	0.295	0.751	NA	0.063	0.221
	West to West	NA	0.290	0.752	NA	0.050	0.182
	East to/from West	NA	0.292	0.752	NA	0.057	0.202

July through September Energy Uplift Charges Analysis

Energy uplift charges decreased by $5.2 million (11.8 percent), from $44.1 million in July through September of 2015 to $38.9 million in July through September of 2016. This change resulted mainly from a decrease of $4.7 million in day-ahead operating reserve charges. Other categories had minor changes, balancing operating reserve charges increased by $0.1 million, reactive services charges decreased by $0.5 million. Synchronous condensing and black start services charges combined for a decrease of $0.03 million.

Figure 4-8 shows the net impact of each category on the change in total energy uplift charges from the July through September of 2015 level to the July through September of 2016 level. The outside bars show the total energy uplift charges in the months of 2015 (left side) and total energy uplift charges in the months of 2016 (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 of 2015 compared to July through September of 2016 (a decrease of $4.7 million).

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

Figure 4-8 Energy uplift charges change from July through September 2015 to July through September 2016 by category