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.

Uplift is an inherent part of the PJM market design. Part of that uplift is the result of the nonconvexity of power production costs. Uplift payments should nonetheless be limited to the efficient level. In wholesale power market design, a choice must be made between efficient prices and prices that fully compensate costs. Economists recognize that no single price achieves both goals in markets with nonconvex production costs, like the costs of producing electric power.[2] [3] In wholesale power markets like PJM, efficient prices equal the short run marginal cost of production by location. The dispatch of generators in accordance with these efficient price signals minimizes the total market cost of production. For generators with nonconvex costs, marginal cost prices may not cover the total cost of starting the generator and running at the efficient output level. Uplift payments cover the difference.

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.

2 *See* Stoft, *Power System Economics: Designing Markets for Electricity*, New York: Wiley (2002) at 272; Mas-Colell, Whinston, and Green, Microeconomic Theory, New York: Oxford University Press (1995) at 570; and Quinzii, *Increasing Returns and Efficiency*, New York: Oxford University Press (1992).

3 The production of output is convex if the production function has constant or decreasing returns to scale, which result in constant or rising average costs with increases in output. Production is nonconvex with increasing returns to scale, which is the case when generating units have start or no load costs that are large relative to marginal costs. *See* Mas-Colell, Whinston, and Green at 132.

Overview

Energy Uplift Results

- **Energy Uplift Charges.** Total energy uplift charges decreased by $7.5 million, or 5.5 percent, in 2017 compared to 2016, from $136.7 million to $129.1 million.
- **Energy Uplift Charges Categories.** The decrease of $7.5 million in 2017 is comprised of a $32.6 million decrease in day-ahead operating reserve charges, a $7.2 million increase in balancing operating reserve charges and a $17.9 million increase in reactive services charges.
- **Average Effective Operating Reserve Rates in the Eastern Region.** Day-ahead load paid $0.030 per MWh, real-time load paid $0.037 per MWh, a DEC paid $0.386 per MWh and an INC and any load, generation or interchange transaction deviation paid $0.355 per MWh.
- **Average Effective Operating Reserve Rates in the Western Region.** Day-ahead load paid $0.030 per MWh, real-time load paid $0.028 per MWh, a DEC paid $0.357 per MWh and an INC and any load, generation or interchange transaction deviation paid $0.327 per MWh.
- **Reactive Services Rates.** The ComEd, PENELEC, and DPL control zones had the three highest local voltage support rates: $0.139, $0.099 and $0.073 per MWh.

Characteristics of Credits

- **Types of units.** Coal units received 78.7 percent of all day-ahead generator credits. Combustion turbines received 76.3 percent of all balancing generator credits. Combustion turbines and diesels received 70.3 percent of the lost opportunity cost credits.
- **Concentration of Energy Uplift Credits.** The top 10 units receiving energy uplift credits received 33.1 percent of all credits. The top 10 organizations received 77.9 percent of all credits. Concentration

indexes for energy uplift categories classify them as highly concentrated. Day-ahead operating reserves HHI was 7486, balancing operating reserves HHI was 3334 and lost opportunity cost HHI was 5538.

- **Economic and Noneconomic Generation.** In 2017, 85.1 percent of the day-ahead generation eligible for operating reserve credits was economic and 73.1 percent of the real-time generation eligible for operating reserve credits was economic.
- **Day-Ahead Unit Commitment for Reliability.** In 2017, 1.2 percent of the total day-ahead generation MWh was scheduled as must run by PJM, of which 54.9 percent received energy uplift payments.

Geography of Charges and Credits

- In 2017, 89.2 percent of all uplift charges allocated regionally (day-ahead operating reserves and balancing operating reserves) were paid by transactions (at control zones or buses within a control zone), demand and generation, 4.4 percent by transactions at hubs and aggregates and 6.4 percent by interchange transactions at interfaces.
- Generators in the Eastern Region received 50.7 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.
- Generators in the Western Region received 47.4 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.
- External generators received 1.9 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.

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 LMP 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. First Reported 2016. 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 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 four additional modifications to the energy lost opportunity cost calculations:
  - 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. Pending before FERC.)
- 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. Pending before FERC.)
- 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 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.)
- The MMU recommends modifications to the calculation of lost opportunity costs credits paid to wind units. The lost opportunity costs credits paid to wind units should be based on the lesser of the desired output, the estimated output based on actual wind conditions and the capacity interconnection rights (CIRs). In addition, the MMU recommends that PJM allow and wind units submit CIRs that reflect the maximum output wind units want to inject into the transmission system at any time. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM revise Manual 11 attachment C consistent with the tariff to limit compensation to offered costs. The Manual 11 attachment C procedure should describe the steps market participants must take to change the availability of cost-based energy offers that have been submitted day ahead. The MMU recommends that PJM eliminate the Manual 11 attachment C procedure with the implementation of hourly offers (ER16-372-000). (Priority: Medium. First reported 2016. 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 to make all market participants aware of the reasons for these costs and to help ensure a long term solution to the issue of how to allocate the costs of operating reserves. (Priority: Medium. First reported 2011. Status: Adopted 2015.)
- 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 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.)

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 incurred when LMP is greater than or equal to the incremental offer but does not cover start up and no load costs. 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.

Competitive market outcomes result from energy offers equal to short run marginal costs and that incorporate flexible operating parameters. But when PJM permits a unit to include inflexible operating parameters in its offer and pays uplift based on those inflexible parameters, there is an incentive for the unit to remain inflexible. The rules regarding operating parameters should be implemented in a way that creates incentives for flexible operations rather than inflexible operations. PJM has failed to hold coal, gas and oil steam turbines to the standard used for combined cycles, combustion turbines and diesels. The standard should be the maximum achievable flexibility, based on OEM standards. Applying a weaker standard to steam units effectively subsidizes inflexible units by paying them based on inflexible parameters that result from lack of investment and that could be made more flexible. The result both inflates uplift costs and suppresses energy prices.

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 consistent with pricing at short run marginal cost 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.[4] 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.

It is not appropriate to accept that inflexible units should be paid or set price based on short run marginal costs plus no load. The question of why units make inflexible offers should be addressed directly. Are units inflexible because they are old and inefficient, because owners have not invested in increased flexibility or because they serve as a mechanism for the exercise of market power. The question of why this unit was built, whether it was built under cost of service regulation and whether it is efficient to retain the unit should be answered directly. The question of how to provide market incentives for investment in flexible units and for investment in increased flexibility of existing units should be addressed directly. The question of whether inflexible units should be paid uplift at all should be addressed directly. Marginal cost pricing without paying uplift to inflexible units would create incentives for market participants to provide flexible solutions including replacing inefficient units with flexible, efficient units.

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. The same is true of fast start pricing and of convex hull pricing.

Accurate short run price signals, equal to the short run marginal cost of generating power, provide market incentives for cost minimizing production to all economically dispatched resources and provide market incentives to load based on the marginal cost of additional consumption. The objective of efficient short run price signals is to minimize system production costs, not to minimize uplift. Repricing the market to reflect commitment costs would create a tradeoff between minimizing production costs and reduction of uplift. The tradeoff would exist because when commitment costs are included in prices, the price signal no longer equals the short run marginal cost and therefore no longer provides the correct signal for efficient behavior for market participants making decisions on the margin, whether resources, load, interchange transactions, or virtual traders. This tradeoff would be created in more

4 On October 17, 2017, PJM filed with FERC to begin charging uplift to UTC transactions and eliminating the netting of deviations with internal bilateral transactions. See FERC Docket No. ER18-86-000.

limited form by PJM's fast start pricing proposal and in extensive form by PJM's modified convex hull pricing proposal.

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

Energy Uplift Results

Energy Uplift Charges

Total energy uplift charges decreased by $7.5 million or 5.5 percent in 2017 compared to 2016. Table 4-3 shows total energy uplift charges for 2001 through 2017.[5]

Table 4-3 Total energy uplift charges: 2001 through 2017

	Total Energy Uplift Charges (Millions)	Change (Millions)	Percent Change	Energy Uplift as a Percent of Total PJM Billing
2001	$284.0	$67.0	30.9%	8.5%
2002	$273.7	($10.3)	(3.6%)	5.8%
2003	$376.5	$102.8	37.6%	5.4%
2004	$537.6	$161.1	42.8%	6.1%
2005	$712.6	$175.0	32.6%	3.1%
2006	$365.6	($347.0)	(48.7%)	1.7%
2007	$503.3	$137.7	37.7%	1.6%
2008	$474.3	($29.0)	(5.8%)	1.4%
2009	$322.7	($151.6)	(32.0%)	1.2%
2010	$623.2	$300.5	93.1%	1.8%
2011	$603.4	($19.8)	(3.2%)	1.7%
2012	$649.8	$46.4	7.7%	2.2%
2013	$843.0	$193.2	29.7%	2.5%
2014	$961.2	$118.2	14.0%	1.9%
2015	$312.0	($649.2)	(67.5%)	0.7%
2016	$136.7	($824.5)	(85.8%)	0.3%
2017	$129.1	($7.5)	(5.5%)	0.3%

Table 4-4 compares energy uplift charges by category for 2016 and 2017. The decrease of $7.5 million in 2017 is comprised of a decrease of $32.6 million in day-ahead operating reserve charges, an increase of $7.2 million in balancing operating reserve charges and an increase of $17.9 million in reactive service charges.

Table 4-4 Energy uplift charges by category: 2016 and 2017

Category	2016 Charges (Millions)	2017 Charges (Millions)	Change (Millions)	Percent Change
Day-Ahead Operating Reserves	$57.3	$24.7	($32.6)	(56.9%)
Balancing Operating Reserves	$76.6	$83.8	$7.2	9.4%
Reactive Services	$2.5	$20.4	$17.9	719.1%
Synchronous Condensing	$0.0	$0.0	($0.0)	(100.0%)
Black Start Services	$0.3	$0.3	($0.0)	(7.8%)
Total	$136.7	$129.1	($7.5)	(5.5%)

Table 4-5 compares monthly energy uplift charges by category for 2016 and 2017.

5 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 January 9, 2018.

Table 4-5 Monthly energy uplift charges: 2016 and 2017

	2016 Charges (Millions)						2017 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	$7.4	$7.5	$0.0	$0.0	$0.0	$14.9	$2.6	$7.5	$1.25	$0.0	$0.0	$11.4
Feb	$7.6	$6.5	$0.0	$0.0	$0.0	$14.2	$2.0	$1.3	$3.3	$0.0	$0.0	$6.6
Mar	$6.4	$3.9	$0.2	$0.0	$0.0	$10.5	$0.6	$5.4	$1.4	$0.0	$0.0	$7.4
Apr	$3.0	$4.8	$0.2	$0.0	$0.0	$8.0	$0.5	$3.3	$1.3	$0.0	$0.0	$5.0
May	$2.8	$3.3	$0.1	$0.0	$0.0	$6.3	$0.9	$7.4	$1.3	$0.0	$0.0	$9.7
Jun	$4.6	$5.3	$0.1	$0.0	$0.1	$10.1	$1.8	$6.8	$0.9	$0.0	$0.0	$9.5
Jul	$3.6	$10.9	$0.1	$0.0	$0.0	$14.6	$2.5	$7.9	$0.9	$0.0	$0.0	$11.4
Aug	$2.4	$11.5	$0.0	$0.0	$0.0	$13.9	$2.9	$5.4	$1.5	$0.0	$0.0	$9.8
Sep	$2.9	$6.9	$0.1	$0.0	$0.0	$9.9	$3.0	$10.3	$2.3	$0.0	$0.0	$15.6
Oct	$3.6	$8.7	$0.3	$0.0	$0.0	$12.6	$1.6	$7.9	$2.2	$0.0	$0.0	$11.8
Nov	$5.7	$2.8	$1.0	$0.0	$0.1	$9.5	$2.1	$7.8	$1.9	$0.0	$0.0	$11.8
Dec	$7.3	$4.5	$0.4	$0.0	$0.0	$12.2	$4.0	$12.8	$2.3	$0.0	$0.0	$19.1
Total	$57.3	$76.6	$2.5	$0.0	$0.3	$136.7	$24.7	$83.8	$20.4	$0.0	$0.3	$129.1
Share	42.0%	56.0%	1.8%	0.0%	0.2%	100.0%	19.1%	64.9%	15.8%	0.0%	0.2%	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.[6] Day-ahead operating reserve charges decreased by $32.6 million or 56.9 percent in 2017 compared to 2016. Day-ahead operating reserve charges have decreased in 2017 due to transmission upgrades in the BGE and Pepco control zones that were completed in the first quarter of 2017. These upgrades have reduced the need to commit noneconomic coal fired generation in the BGE and Pepco control zones to meet local load. These upgrades have increased the transfer capability from other control zones into BGE and Pepco.

Table 4-6 Day-ahead operating reserve charges: 2016 and 2017

Type	2016 Charges (Millions)	2017 Charges (Millions)	Change (Millions)	2016 Share	2017 Share
Day-Ahead Operating Reserve Charges	$57.3	$24.7	($32.6)	100.0%	100.0%
Day-Ahead Operating Reserve Charges for Load Response	$0.0	$0.0	$0.0	0.0%	0.0%
Unallocated Congestion Charges	$0.0	$0.0	$0.0	0.0%	0.0%
Total	$57.3	$24.7	($32.6)	100.0%	100.0%

Table 4-7 shows the composition of the balancing operating reserve charges. Balancing operating reserve charges consist of balancing operating reserve reliability charges (credits to generators), balancing operating reserve deviation charges (credits to generators and import transactions), balancing operating reserve charges for economic load response and balancing local constraint charges. Balancing operating reserve charges increased by $7.2 million in 2017 compared to 2016.

Table 4-7 Balancing operating reserve charges: 2016 and 2017

Type	2016 Charges (Millions)	2017 Charges (Millions)	Change (Millions)	2016 Share	2017 Share
Balancing Operating Reserve Reliability Charges	$22.5	$27.1	$4.6	29.3%	32.3%
Balancing Operating Reserve Deviation Charges	$53.6	$55.0	$1.4	70.0%	65.6%
Balancing Operating Reserve Charges for Load Response	$0.1	$0.4	$0.3	0.1%	0.5%
Balancing Local Constraint Charges	$0.4	$1.4	$0.9	0.6%	1.6%
Total	$76.6	$83.8	$7.2	100.0%	100.0%

6 See OA Schedule 1 § 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 10 times, totaling $26.9 million.

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 2017, 73.3 percent of balancing operating reserve deviation charges were for make whole credits paid to generators and import transactions, an increase of 8.6 percentage points compared to 2016. The increase in the share of make whole credits was the result of an increase in make whole credits, and a decrease in energy lost opportunity cost credits, which decreased by $4.2 million or 22.3 percent.

Table 4-8 Balancing operating reserve deviation charges: 2016 and 2017

Charge Attributable To	2016 Charges (Millions)	2017 Charges (Millions)	Change (Millions)	2016 Share	2017 Share
Make Whole Payments to Generators and Imports	$34.7	$40.3	$5.6	64.8%	73.3%
Energy Lost Opportunity Cost	$18.8	$14.6	($4.2)	35.1%	26.6%
Canceled Resources	$0.1	$0.0	($0.1)	0.2%	0.0%
Total	$53.6	$55.0	$1.4	100.0%	100.0%

Table 4-9 shows reactive services, synchronous condensing and black start services charges. Reactive services charges increased by $17.9 million in 2017 compared to 2016. Reactive services charges increased in 2017 due to high voltage issues caused by light loads in the ComEd and DPL control zones, and low voltage issues caused by transmission outages in the BGE, Pepco and PENELEC control zones.

Table 4-9 Additional energy uplift charges: 2016 and 2017

Type	2016 Charges (Millions)	2017 Charges (Millions)	Change (Millions)	2016 Share	2017 Share
Reactive Services Charges	$2.5	$20.4	$17.9	89.9%	98.8%
Synchronous Condensing Charges	$0.0	$0.0	($0.0)	0.0%	0.0%
Black Start Services Charges	$0.3	$0.3	($0.0)	10.1%	1.2%
Total	$2.8	$20.6	$17.9	100.0%	100.0%

Table 4-10 and Table 4-11 show the amount and percent shares of regional balancing charges in 2016 and 2017. 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 2017, regional balancing operating reserve charges increased by $5.5 million compared to 2016. Balancing operating reserve reliability charges increased by $4.1 million or 17.6 percent, and balancing operating reserve deviation charges increased by $1.5 million or 2.8 percent.

Table 4-10 Regional balancing charges allocation (Millions): 2016

Charge	Allocation	RTO		East		West		Total	
Reliability Charges	Real-Time Load	$18.3	23.9%	$3.5	4.6%	$0.4	0.6%	$22.2	29.0%
	Real-Time Exports	$0.7	0.9%	$0.1	0.1%	$0.0	0.0%	$0.8	1.0%
	Total	$18.9	24.8%	$3.6	4.7%	$0.5	0.6%	$23.0	30.1%
Deviation Charges	Demand	$28.3	37.1%	$3.0	3.9%	$0.5	0.7%	$31.8	41.6%
	Supply	$9.2	12.0%	$0.8	1.1%	$0.1	0.2%	$10.1	13.3%
	Generator	$10.1	13.2%	$1.2	1.5%	$0.2	0.3%	$11.5	15.0%
	Total	$47.6	62.3%	$5.0	6.5%	$0.9	1.1%	$53.5	69.9%
Total Regional Balancing Charges		$66.6	87.0%	$8.6	11.3%	$1.3	1.7%	$76.5	100%

Table 4-11 Regional balancing charges allocation (Millions): 2017

Charge	Allocation	RTO		East		West		Total	
Reliability Charges	Real-Time Load	$21.8	26.5%	$4.0	4.8%	$0.4	0.5%	$26.1	31.9%
	Real-Time Exports	$0.8	0.9%	$0.2	0.2%	$0.0	0.0%	$0.9	1.1%
	Total	$22.5	27.5%	$4.1	5.0%	$0.4	0.5%	$27.1	33.0%
Deviation Charges	Demand	$31.0	37.8%	$2.2	2.6%	$0.5	0.6%	$33.7	41.1%
	Supply	$9.4	11.5%	$0.7	0.8%	$0.1	0.1%	$10.2	12.4%
	Generator	$10.3	12.5%	$0.7	0.9%	$0.1	0.2%	$11.1	13.5%
	Total	$50.6	61.7%	$3.5	4.3%	$0.8	1.0%	$55.0	67.0%
Total Regional Balancing Charges		$73.2	89.2%	$7.6	9.3%	$1.2	1.5%	$82.0	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.[7]

Figure 4-1 shows the daily day-ahead operating reserve rate for 2016 and 2017. The average rate in 2017 was $0.030 per MWh, $0.039 per MWh lower than the average in 2016. The highest rate of 2017 occurred on November 30, when the rate reached $0.346 per MWh, $0.056 per MWh lower than the $0.402 per MWh reached in 2016, 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 2016 or 2017.

Figure 4-1 Daily day-ahead operating reserve rate ($/MWh): 2016 and 2017

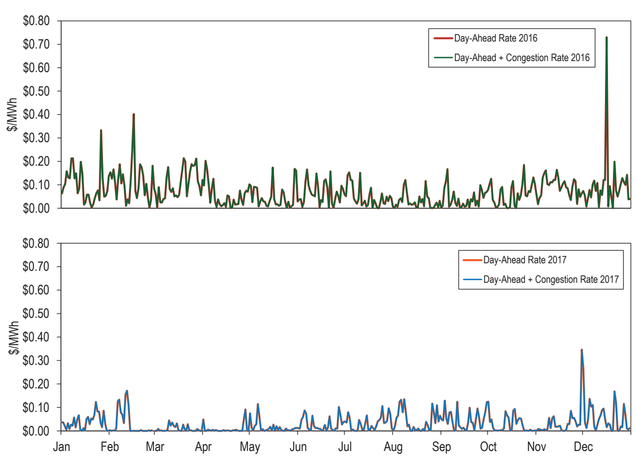


Figure 4-2 shows the RTO and the regional reliability rates for 2016 and 2017. The average daily RTO reliability rate was $0.029 per MWh. The highest RTO reliability rate in 2017 occurred on January 8, when the rate reached $0.390 per MWh, $0.155 per MWh higher than the $0.234 per MWh rate reached in 2016, on August 12.

Figure 4-2 Daily balancing operating reserve reliability rates ($/MWh): 2016 and 2017

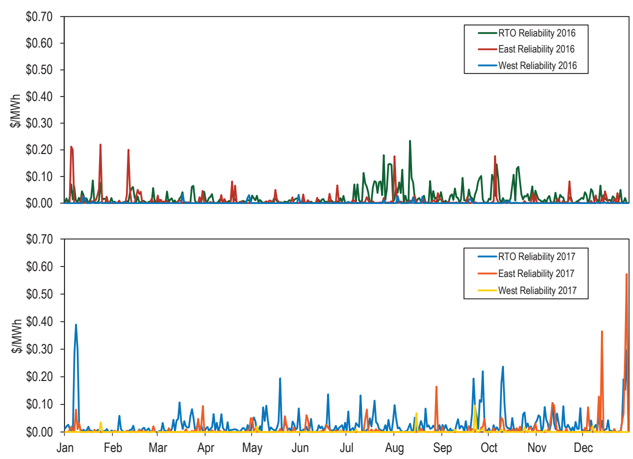


Figure 4-3 shows the RTO and regional deviation rates for 2016 and 2017. The average daily RTO deviation rate was $0.238 per MWh. The highest daily rate of 2017 occurred on January 9, when the RTO deviation rate reached $2.177 per MWh, $0.135 per MWh higher than the $2.042 per MWh rate reached in 2016, on October 19, 2016.

7 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 4-3 Daily balancing operating reserve deviation rates ($/MWh): 2016 and 2017

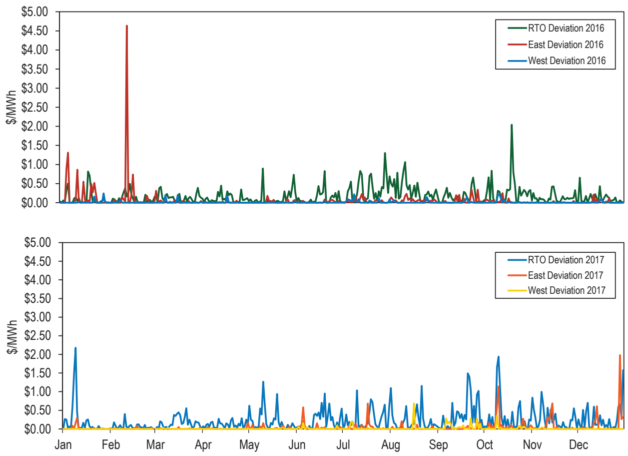


Figure 4-4 shows the daily lost opportunity cost rate and the daily canceled resources rate for 2016 and 2017. The lost opportunity cost rate averaged $0.097 per MWh. The highest lost opportunity cost rate occurred on December 26, when it reached $2.042 per MWh, $0.732 per MWh higher than the $1.294 per MWh rate reached in 2016, on April 14.

Figure 4-4 Daily lost opportunity cost and canceled resources rates ($/MWh): 2016 and 2017

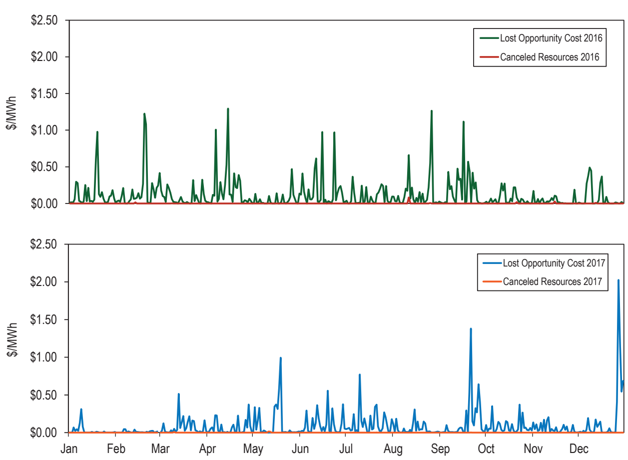


Table 4-12 shows the average rates for each region in each category in 2016 and 2017.

Table 4-12 Operating reserve rates ($/MWh): 2016 and 2017

Rate	2016 ($/MWh)	2017 ($/MWh)	Difference ($/MWh)	Percent Difference
Day-Ahead	0.069	0.030	(0.039)	(55.9%)
Day-Ahead with Unallocated Congestion	0.069	0.030	(0.039)	(55.9%)
RTO Reliability	0.024	0.029	0.005	21.4%
East Reliability	0.010	0.011	0.002	15.9%
West Reliability	0.001	0.001	(0.000)	(3.4%)
RTO Deviation	0.184	0.238	0.054	29.1%
East Deviation	0.061	0.045	(0.016)	(26.7%)
West Deviation	0.012	0.011	(0.001)	(4.3%)
Lost Opportunity Cost	0.119	0.097	(0.023)	(18.9%)
Canceled Resources	0.001	0.000	(0.000)	(80.1%)

Table 4-13 shows the operating reserve cost of a one MW transaction in 2017. For example, a decrement bid in the Eastern Region (if not offset by other transactions) paid an average rate of $0.386 per MWh with a maximum rate of $3.860 per MWh, a minimum rate of $0.002 per MWh and a standard deviation of $0.498 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): 2017

		Rates Charged ($/MWh)			
Region	Transaction	Maximum	Average	Minimum	Standard Deviation
East	INC	3.793	0.355	0.000	0.498
	DEC	3.860	0.386	0.002	0.498
	DA Load	0.346	0.030	0.000	0.042
	RT Load	0.869	0.037	0.000	0.073
	Deviation	3.793	0.355	0.000	0.498
West	INC	2.782	0.327	0.000	0.438
	DEC	2.816	0.357	0.002	0.437
	DA Load	0.346	0.030	0.000	0.042
	RT Load	0.390	0.028	0.000	0.048
	Deviation	2.782	0.327	0.000	0.438

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.

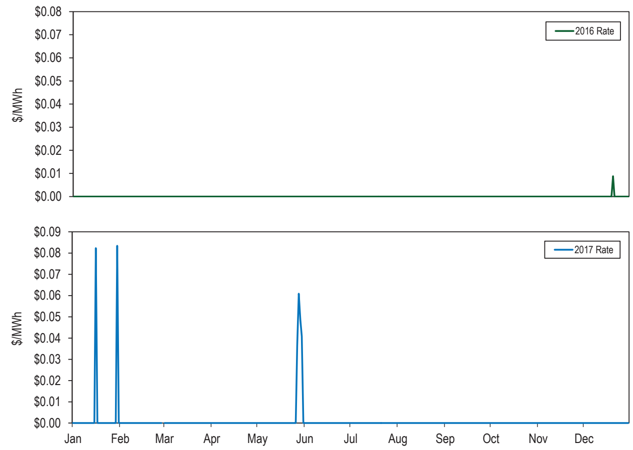
While reactive services rates are not posted by PJM, a local voltage support rate for each control zone can be calculated and a reactive transfer interface support rate can be calculated for the entire RTO. Table 4-14 shows the reactive services rates associated with local voltage support in 2016 and 2017. Table 4-14 shows that in 2017 the ComEd Control Zone had the highest rate. Real-time load in the ComEd Control Zone paid an average of $0.139 per MWh for reactive services associated with local voltage support, $0.129 or 1,236.1 percent higher than the average rate paid in 2016.

Table 4-14 Local voltage support rates: 2016 and 2017

Control Zone	2016 ($/MWh)	2017 ($/MWh)	Difference ($/MWh)
AECO	0.000	0.000	0.000
AEP	0.001	0.000	(0.000)
APS	0.000	0.002	0.002
ATSI	0.000	0.000	0.000
BGE	0.000	0.055	0.055
ComEd	0.010	0.139	0.129
DAY	0.000	0.000	0.000
DEOK	0.000	0.000	0.000
DLCO	0.000	0.000	0.000
Dominion	0.000	0.000	0.000
DPL	0.043	0.073	0.030
EKPC	0.013	0.001	(0.012)
JCPL	0.000	0.000	0.000
Met-Ed	0.001	0.004	0.003
PECO	0.000	0.002	0.002
PENELEC	0.015	0.099	0.084
Pepco	0.004	0.054	0.049
PPL	0.000	0.000	(0.000)
PSEG	0.000	0.000	0.000
RECO	0.000	0.000	0.000

Figure 4-5 shows the daily RTO wide reactive transfer interface rate in 2016 and 2017. RTO wide reactive charges were incurred only once in 2016 (December) and three times in 2017. Those are the only instances in which PJM scheduled resources to provide reactive support to reactive interfaces and the resources required make whole payments.

Figure 4-5 Daily reactive transfer interface support rates ($/MWh): 2016 and 2017



Balancing Operating Reserve Determinants

Table 4-15 shows the determinants used to allocate the regional balancing operating reserve charges in 2016 and 2017. Total real-time load and real-time exports were 16,016,057 MWh, 2.0 percent lower in 2017 compared to 2016. Total deviations summed across the demand, supply, and generator categories were 5,677,771 MWh, 3.6 percent lower in 2017 compared to 2016.

Table 4-15 Balancing operating reserve determinants (MWh): 2016 and 2017

		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
2016	RTO	778,268,661	26,912,664	805,181,325	92,336,602	31,071,990	33,717,607	157,126,199
2016	East	367,239,524	11,097,604	378,337,128	46,107,993	17,766,995	18,124,169	81,999,156
2016	West	411,029,137	15,815,060	426,844,197	45,694,031	12,971,113	15,593,438	74,258,582
2017	RTO	759,025,009	30,140,259	789,165,268	91,653,951	30,537,035	29,257,443	151,448,428
2017	East	359,340,463	11,612,111	370,952,574	46,903,090	17,940,636	14,141,817	78,985,543
2017	West	399,684,546	18,528,148	418,212,694	44,252,495	12,291,544	15,115,626	71,659,665
Difference	RTO	(19,243,652)	3,227,595	(16,016,057)	(682,651)	(534,955)	(4,460,164)	(5,677,771)
	East	(7,899,061)	514,507	(7,384,554)	795,097	173,641	(3,982,352)	(3,013,614)
	West	(11,344,591)	2,713,088	(8,631,503)	(1,441,536)	(679,569)	(477,812)	(2,598,918)

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 2017, 30.2 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 69.8 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: 2017

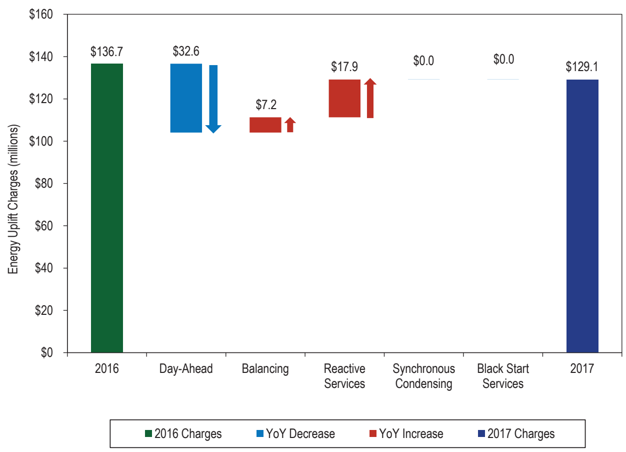
Deviation Category	Transaction	Deviation (MWh) RTO	East	West	Share RTO	East	West
Demand	Bilateral Sales Only	2,587,117	2,525,862	61,255	1.7%	3.2%	0.1%
	DECs Only	15,678,629	6,869,201	8,311,062	10.4%	8.7%	11.6%
	Exports Only	6,411,305	3,302,423	3,108,882	4.2%	4.2%	4.3%
	Load Only	61,298,318	30,926,070	30,372,247	40.5%	39.2%	42.4%
	Combination with DECs	4,172,095	2,429,675	1,742,420	2.8%	3.1%	2.4%
	Combination without DECs	1,506,486	849,859	656,627	1.0%	1.1%	0.9%
Supply	Bilateral Purchases Only	369,597	308,212	61,385	0.2%	0.4%	0.1%
	Imports Only	4,255,838	3,202,113	1,053,725	2.8%	4.1%	1.5%
	INCs Only	22,854,489	12,703,752	9,845,882	15.1%	16.1%	13.7%
	Combination with INCs	2,981,382	1,663,585	1,317,796	2.0%	2.1%	1.8%
	Combination without INCs	75,729	62,973	12,756	0.1%	0.1%	0.0%
Generators		29,257,443	14,141,817	15,115,626	19.3%	17.9%	21.1%
Total		151,448,428	78,985,543	71,659,665	100.0%	100.0%	100.0%

Year over Year Energy Uplift Charges Analysis

Energy uplift charges decreased by $7.5 million (5.5 percent), from $136.7 million in 2016 to $129.1 million in 2017. This change was the result of a decrease of $32.6 million in day-ahead operating reserve charges, an increase of $7.2 million in balancing operating reserve charges, and an increase of $17.9 million in reactive service charges. Other categories had smaller or no changes. There was a decrease of $0.02 million for black start service charges and there was no change in synchronous condensing charges.

Figure 4-6 shows the impact of each category on the change in total energy uplift charges from the 2016 level to the 2017 level. The outside bars show the total energy uplift charges in 2016 (left side) and total energy uplift charges in 2017 (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 2017 compared to 2016 (a decrease of $36.2 million).

Figure 4-6 Energy uplift charges change from 2016 to 2017 by category



Energy Uplift Credits

Table 4-17 shows the totals for each credit category in 2016 and 2017. During 2017, 64.8 percent of total energy uplift credits were in the balancing operating reserve category, an increase of 8.7 percentage points from 56.1 in 2016.

Table 4-17 Energy uplift credits by category: 2016 and 2017

Category	Type	2016 Credits (Millions)	2017 Credits (Millions)	Change	Percent Change	2016 Share	2017 Share
Day-Ahead Operating Reserve	Generators	$57.3	$24.7	($32.6)	(56.9%)	42.0%	19.2%
	Imports	$0.0	$0.0	($0.0)	(70.1%)	0.0%	0.0%
	Load Response	$0.0	$0.0	$0.0	1,882.0%	0.0%	0.0%
Balancing Operating Reserve	Canceled Resources	$0.1	$0.0	($0.1)	(80.8%)	0.1%	0.0%
	Generators	$57.1	$67.4	$10.2	17.9%	41.8%	52.2%
	Imports	$0.0	$0.0	($0.0)	(57.3%)	0.0%	0.0%
	Load Response	$0.1	$0.4	$0.3	317.5%	0.1%	0.3%
	Local Constraints Control	$0.4	$1.4	$0.9	219.6%	0.3%	1.1%
	Lost Opportunity Cost	$18.7	$14.6	($4.1)	(22.0%)	13.7%	11.3%
Reactive Services	Day-Ahead	$1.4	$19.3	$17.9	1,261.2%	1.0%	14.9%
	Local Constraints Control	$0.0	$0.0	($0.0)	(100.0%)	0.0%	0.0%
	Lost Opportunity Cost	$0.0	$0.2	$0.2	532.5%	0.0%	0.2%
	Reactive Services	$1.0	$0.9	($0.1)	(8.0%)	0.7%	0.7%
	Synchronous Condensing	$0.1	$0.0	($0.0)	(39.8%)	0.0%	0.0%
Synchronous Condensing		$0.0	$0.0	($0.0)	(100.0%)	0.0%	0.0%
Black Start Services	Day-Ahead	$0.0	$0.0	$0.0	NA	0.0%	0.0%
	Balancing	$0.0	$0.0	$0.0	698.7%	0.0%	0.0%
	Testing	$0.3	$0.2	($0.0)	(14.9%)	0.2%	0.2%
Total		$136.5	$129.1	($7.4)	(5.5%)	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 2016 and 2017. The decrease in energy uplift in 2017 compared to 2016 was the result of lower credits paid to coal fired steam turbines and combined cycle units. Credits to these units decreased by $15.1 million or 21.3 percent.

Table 4-18 Energy uplift credits by unit type: 2016 and 2017

Unit Type	2016 Credits (Millions)	2017 Credits (Millions)	Change	Percent Change	2016 Share	2017 Share
Combined Cycle	$14.7	$10.1	($4.6)	(31.5%)	10.8%	7.8%
Combustion Turbine	$58.8	$64.1	$5.3	9.1%	43.1%	49.8%
Diesel	$0.6	$1.0	$0.4	57.4%	0.4%	0.7%
Hydro	$0.1	$0.1	$0.0	38.0%	0.0%	0.1%
Nuclear	$1.2	$0.1	($1.1)	(93.3%)	0.9%	0.1%
Solar	$0.0	$0.0	$0.0	0.0%	0.0%	0.0%
Steam - Coal	$56.1	$45.6	($10.5)	(18.6%)	41.1%	35.4%
Steam - Other	$3.3	$5.8	$2.5	74.6%	2.4%	4.5%
Wind	$1.7	$2.0	$0.3	15.0%	1.3%	1.5%
Total	$136.4	$128.8	($7.7)	(5.6%)	100.0%	100.0%

Table 4-19 shows the distribution of energy uplift credits by category and by unit type in 2017. Coal fired steam turbines received 78.7 percent of the day-ahead generator credits in 2017, 2.3 percentage points lower than the share received in 2016. Combustion turbines received 76.3 percent of the balancing operating reserve generator credits in 2017, 3.0 percentage points higher than the share received in 2016. Combustion turbines received 67.3 percent of the lost opportunity cost credits in 2017, 7.8 percentage points lower than the share received in 2016.

Table 4-19 Energy uplift credits by unit type: 2017

Unit Type	Day-Ahead Operating Reserve	Balancing Operating Reserve	Canceled Resources	Local Constraints Control	Lost Opportunity Cost	Reactive Services	Synchronous Condensing	Black Start Services
Combined Cycle	9.2%	8.0%	0.0%	0.0%	10.7%	3.9%	0.0%	20.2%
Combustion Turbine	3.4%	76.3%	2.7%	90.3%	67.3%	2.9%	0.0%	79.8%
Diesel	0.1%	0.7%	0.0%	2.1%	3.0%	0.1%	0.0%	0.0%
Hydro	0.0%	0.0%	97.3%	0.0%	0.4%	0.0%	0.0%	0.0%
Nuclear	0.0%	0.0%	0.0%	0.0%	0.5%	0.0%	0.0%	0.0%
Solar	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Steam - Coal	78.7%	11.8%	0.0%	7.6%	5.7%	84.9%	0.0%	0.0%
Steam - Others	8.7%	3.0%	0.0%	0.0%	0.2%	8.2%	0.0%	0.0%
Wind	0.0%	0.3%	0.0%	0.0%	12.2%	0.0%	0.0%	0.0%
Total (Millions)	$24.7	$67.4	$0.0	$1.4	$14.6	$20.4	$0.0	$0.3

Table 4-19 also shows the distribution of reactive service credits and black start services credits by unit type. In 2017, coal units received 84.9 of all reactive services credits.

Concentration of Energy Uplift Credits

There continues to be a high level of concentration in the units and companies receiving energy uplift credits. This concentration results from a combination of unit operating 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 4-7 shows the concentration of energy uplift credits. The top 10 units received 33.1 percent of total energy uplift credits in 2017, compared to 36.0 percent in 2016. In 2017, 265 units received 90 percent of all energy uplift credits, compared to 274 units in 2016.

Figure 4-7 Cumulative share of energy uplift credits: 2016 and 2017 by unit

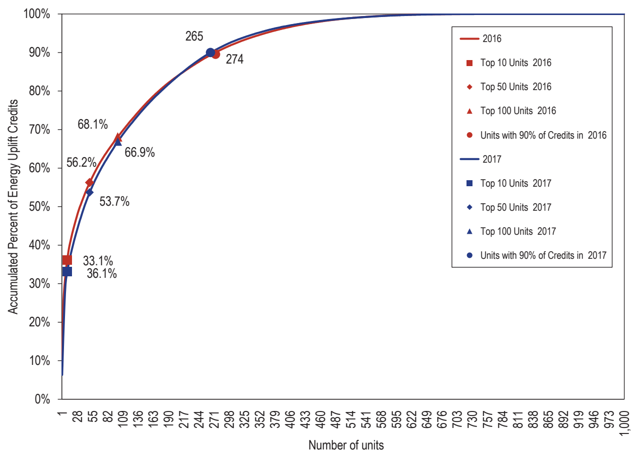


Table 4-20 shows the credits received by the top 10 units and top 10 organizations in each of the energy uplift categories paid to generators.

Table 4-20 Top 10 units and organizations energy uplift credits: 2017

		Top 10 Units		Top 10 Organizations	
Category	Type	Credits (Millions)	Credits Share	Credits (Millions)	Credits Share
Day-Ahead Operating Reserve	Generators	$19.0	77.0%	$24.0	97.0%
Balancing Operating Reserve	Canceled Resources	$0.0	100.0%	$0.0	100.0%
	Generators	$9.1	13.6%	$48.8	72.4%
	Local Constraints Control	$1.0	75.1%	$1.4	100.0%
	Lost Opportunity Cost	$3.0	20.3%	$10.3	70.7%
Reactive Services		$18.8	92.1%	$20.4	99.9%
Synchronous Condensing		$0.0	0.0%	$0.0	0.0%
Black Start Services		$0.1	40.8%	$0.2	93.6%
Total		$42.6	33.1%	$100.3	77.9%

Table 4-21 shows balancing operating reserve credits received by the top 10 units identified for reliability or for deviations in each region. In 2017, 57.8 percent of all credits paid to these units were allocated to deviations while the remaining 42.2 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: 2017

	Reliability			Deviations			
	RTO	East	West	RTO	East	West	Total
Credits (Millions)	$3.2	$0.7	$0.0	$4.4	$0.9	$0.0	$9.1
Share	34.6%	7.6%	0.0%	47.9%	9.9%	0.0%	100.0%

In 2017, concentration in all energy uplift credit categories was high.[8] [9] 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 7486, for balancing operating reserve credits to generators was 3334, for lost opportunity cost credits was 5538 and for reactive services credits was 9123.

8 See *2017 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).

9 Table 4-22 excludes local constraints control categories.

Table 4-22 Daily energy uplift credits HHI: 2017

Category	Type	Average	Minimum	Maximum	Highest Market Share (One day)	Highest Market Share (All days)
Day-Ahead Operating Reserve	Generators	7486	2229	10000	100.0%	53.5%
	Imports	10000	10000	10000	100.0%	100.0%
	Load Response	10000	10000	10000	100.0%	96.1%
Balancing Operating Reserve	Canceled Resources	10000	10000	10000	100.0%	100.0%
	Generators	3334	770	10000	100.0%	15.7%
	Imports	10000	10000	10000	100.0%	100.0%
	Load Response	9777	5281	10000	100.0%	88.4%
	Lost Opportunity Cost	5538	1481	10000	100.0%	17.7%
Reactive Services		9123	3537	10000	100.0%	80.3%
Synchronous Condensing		NA	NA	NA	NA	NA
Black Start Services		9630	4997	10000	100.0%	43.0%
Total		3325	747	9824	99.1%	29.5%

Uplift Eligibility

In PJM, units can have either a pool scheduled or self-scheduled commitment status. Pool scheduled units are committed by PJM as a result of the day-ahead market clearing auction while self-scheduled units are committed by generation owners. Table 4-23 provides a description of commitment and dispatch status, uplift eligibility and the ability to set price.[10] 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 are eligible for balancing operating reserve credits. Units are paid day-ahead operating reserve credits based on their scheduled operation for the entire day. Balancing 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. Resources receive day-ahead and balancing operating reserve credits only when they are eligible and are noneconomic for the day or segment. [11]

Table 4-23 Dispatch status, commitment status and uplift eligibility

			Commitment Status	
Dispatch Status	Dispatch Description	Eligible to Set LMP	Self Scheduled (units committed by the generation owner)	Pool Scheduled (units committed by PJM)
Block Loaded	MWh offered to PJM as a single MWh block which is not dispatchable	No	Not eligible to receive uplift	Eligible to receive uplift
Economic Minimum	MWh from the nondispatchable economic minimum component for units that offer a dispatchable range to PJM	No	Not eligible to receive uplift	Eligible to receive uplift
Dispatchable	MWh above the economic minimum level for units that offer a dispatchable range to PJM.	Yes	Only eligible to receive LOC credits if dispatched down by PJM	Eligible to receive uplift

Table 4-24 shows that in 2017, 34.9 percent of generation was pool-scheduled in the Day-Ahead Energy Market and 34.3 percent was pool-scheduled in the Real-Time Energy Market. Thus the majority of generation in both the day-ahead and real-time markets is not eligible to receive uplift credits. This occurs because the majority of nuclear and coal resources, which make up 67.5 percent of real-time generation, are self-scheduled.

10 PJM has modified the basic rules of eligibility to set price in its CT price setting logic. Under CT price setting logic, the economic minimum of a block loaded CT is assumed to be lower than the actual offer. The result is that the CT may set price at its incremental energy offer for a MWh output level that it cannot produce, and thus at a price that does not represent actual marginal cost. The reduction appears to be at the discretion of the operators and does not appear to be applied to all CTs. The rules are not clearly stated in the PJM tariff or manuals. Not all CTs with a reduced economic minimum are marginal.

11 Noneconomic resources are those whose market revenues for the day or segment are less than the short run marginal cost defined by the startup, no load, and incremental offer curve.

Table 4-24 Day-ahead and real-time generation by commitment status, dispatch status and eligibility to set LMP (GWh): 2017

	Self Scheduled			Pool Scheduled						
	Dispatchable	Ecomin	Block Loaded	Dispatchable	Ecomin	Block Loaded	Total GWh	Total Pool Scheduled	Total Self Scheduled	Total Generation Eligible to Set Price
Day Ahead Generation	100,329	175,247	248,652	110,251	144,342	26,154	804,975	280,747	524,228	210,580
Share of Day Ahead	12.5%	21.8%	30.9%	13.7%	17.9%	3.2%	100.0%	34.9%	65.1%	26.2%
Real Time Generation	94,620	167,846	269,722	102,165	146,932	28,677	809,962	277,774	532,188	196,785
Share of Real Time	11.7%	20.7%	33.3%	12.6%	18.1%	3.5%	100.0%	34.3%	65.7%	24.3%

Economic and Noneconomic Generation[12]

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 in real time at an incremental offer higher than the LMP and the unit's bus. 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 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 and startup cost. A unit could be noneconomic for multiple hours and not receive operating reserve credits whenever the total revenues covered the total offer (including no load and startup cost) for the entire day or segment.

Table 4-26 shows the day-ahead and real-time economic and noneconomic generation from units eligible for operating reserve credits. In 2017, 85.1 percent of the day-ahead generation eligible for operating reserve credits was economic and 73.4 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 4-26 shows the separate amounts of economic and noneconomic generation even if the daily or segment generation was economic.

Table 4-25 Day-ahead and real-time economic and noneconomic generation from units eligible for operating reserve credits (GWh): 2017

Energy Market	Economic Generation	Noneconomic Generation	Economic Generation Percent	Noneconomic Generation Percent
Day-Ahead	238,876	41,871	85.1%	14.9%
Real-Time	196,096	70,913	73.4%	26.6%

Noneconomic generation only leads to operating reserve credits when units' generation for the day or segment, scheduled or committed, is noneconomic, including no load and startup costs. Table 4-26 shows the generation receiving day-ahead and balancing operating reserve credits. In 2017, 2.8 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 received credits.

Table 4-26 Day-ahead and real-time generation receiving operating reserve credits (GWh): 2017

Energy Market	Generation Eligible for Operating Reserve Credits	Generation Receiving Operating Reserve Credits	Generation Receiving Operating Reserve Credits Percent
Day-Ahead	280,747	7,756	2.8%
Real-Time	267,009	6,357	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 that would have otherwise not been committed in the day-ahead. Such reliability issues include black start service and reactive service or reactive transfer interface control needed to maintain system reliability in a zone.[13] 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-

12 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.

13 See PJM. OATT 3.2.3 (b).

ahead operating reserve credits.[14] Units committed for reliability by PJM may set LMP if raised above economic minimum and following the dispatch signal and are eligible for day-ahead operating reserve credits. Table 4-27 shows the total day-ahead generation and the subset of that generation committed for reliability by PJM. In 2017, 1.2 percent of the total day-ahead generation was committed for reliability by PJM, 0.2 percentage points lower than in 2016.

Table 4-27 Day-ahead generation committed for reliability by PJM (GWh): 2016 and 2017

	2016			2017		
	Total Day-Ahead Generation	Generation Committed for Reliability by PJM	Share	Total Day-Ahead Generation	Generation Committed for Reliability by PJM	Share
Jan	73,821	935	1.3%	71,967	1,051	1.5%
Feb	66,367	979	1.5%	61,356	725	1.2%
Mar	60,431	1,047	1.7%	66,657	523	0.8%
Apr	56,338	514	0.9%	58,457	334	0.6%
May	59,078	429	0.7%	61,164	952	1.6%
Jun	70,573	772	1.1%	69,964	634	0.9%
Jul	81,801	981	1.2%	79,334	1,157	1.5%
Aug	83,021	1,694	2.0%	74,129	876	1.2%
Sep	69,962	1,682	2.4%	65,211	1,047	1.6%
Oct	60,950	1,066	1.7%	61,308	1,013	1.7%
Nov	59,983	819	1.4%	61,980	589	1.0%
Dec	72,478	1,112	1.5%	73,448	1,025	1.4%
Total	814,803	12,031	1.5%	804,975	9,926	1.2%

Table 4-28 Day-ahead generation committed for reliability by PJM by category (GWh): 2017

	Reactive Services	Day-Ahead Operating Reserves	Economic	Total
Jan	318	256	477	1,051
Feb	411	172	141	725
Mar	215	2	306	523
Apr	106	31	197	334
May	213	166	573	952
Jun	162	157	315	634
Jul	226	300	630	1,157
Aug	266	385	224	876
Sep	257	330	459	1,047
Oct	344	287	383	1,013
Nov	220	165	204	589
Dec	259	205	561	1,025
Total	2,998	2,456	4,473	9,926
Share	30.2%	24.7%	45.1%	100.0%

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 committed for reliability 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.

Table 4-28 shows the total day-ahead generation committed for reliability by PJM by category. In 2017, 54.9 percent of the day-ahead generation committed for reliability by PJM received operating reserve credits, 24.7 percent paid as day-ahead operating reserve credits and 30.2 percent paid as reactive services. The remaining 45.1 percent of the day-ahead generation committed for reliability by PJM did not need to be made whole.

Total day-ahead operating reserve credits in 2017 were $24.7 million, of which $19.1 million or 77.4 percent was paid to units committed for reliability by PJM, and not scheduled to provide black start or reactive services.

Geography of Charges and Credits

Table 4-29 shows the geography of charges and credits in 2017. Table 4-29 includes only day-ahead operating reserve charges and balancing operating reserve reliability and deviation charges since these categories are allocated regionally, while other charges, such as reactive services, synchronous condensing and black start services are allocated by control zone, and balancing local constraint charges are charged to the requesting party.

Charges are categorized by the location (control zone, hub, aggregate or interface) where they are allocated according to PJM's operating reserve rules. Credits are categorized by the location where the resources are located. The shares columns reflect the operating reserve credits and charges balance for each location. For example, transactions in the ATSI Control Zone paid 7.0 percent of all operating reserve charges allocated regionally while resources in the ATSI Control Zone

14 See PJM. "PJM Markets Gateway User Guide," Section Managing Unit Data (version July 18, 2017) p. 32, <http://www.pjm.com/-/media/etools/markets-gateway/markets-gateway-user-guide.ashx?la=en>.

were paid 3.2 percent of the corresponding credits. The ATSI Control Zone received less operating reserve credits than operating reserve charges paid and had 11.3 percent of the deficit. The deficit is the sum of the negative entries in the balance column. Transactions in the BGE Control Zone paid 4.1 percent of all operating reserve charges allocated regionally, and resources in the BGE Control Zone were paid 11.7 percent of the corresponding credits. The BGE Control Zone received more operating reserve credits than operating reserve charges paid and had 22.9 percent of the surplus. The surplus is the sum of the positive entries in the balance column. Table 4-29 also shows that 89.2 percent of all charges were allocated in control zones, 4.4 percent in hubs and aggregates and 6.4 percent in interfaces.

Table 4-29 Geography of regional charges and credits: 2017

					Shares			
Location		Charges (Millions)	Credits (Millions)	Balance	Total Charges	Total Credits	Deficit	Surplus
Zones	AECO	$1.4	$1.2	($0.2)	1.3%	1.1%	0.6%	0.0%
	AEP	$13.7	$11.6	($2.1)	12.9%	10.9%	5.9%	0.0%
	APS	$5.9	$3.2	($2.7)	5.5%	3.0%	7.6%	0.0%
	ATSI	$7.5	$3.4	($4.0)	7.0%	3.2%	11.3%	0.0%
	BGE	$4.3	$12.5	$8.1	4.1%	11.7%	0.0%	22.9%
	ComEd	$11.3	$15.4	$4.1	10.6%	14.4%	0.0%	11.4%
	DAY	$1.9	$3.3	$1.4	1.8%	3.1%	0.0%	4.0%
	DEOK	$3.1	$1.2	($2.0)	2.9%	1.1%	5.5%	0.0%
	DLCO	$1.4	$0.3	($1.2)	1.3%	0.3%	3.3%	0.0%
	Dominion	$11.0	$15.4	$4.4	10.3%	14.4%	0.0%	12.4%
	DPL	$2.9	$7.4	$4.5	2.7%	6.9%	0.0%	12.7%
	EKPC	$1.5	$1.8	$0.3	1.4%	1.7%	0.0%	0.8%
	External	$0.0	$1.6	$1.6	0.0%	1.5%	0.0%	4.5%
	JCPL	$2.9	$0.8	($2.1)	2.7%	0.8%	5.8%	0.0%
	Met-Ed	$2.2	$0.9	($1.4)	2.1%	0.8%	3.9%	0.0%
	PECO	$5.3	$1.3	($4.0)	4.9%	1.2%	11.2%	0.0%
	PENELEC	$3.9	$2.8	($1.2)	3.7%	2.6%	3.3%	0.0%
	Pepco	$4.0	$15.1	$11.1	3.7%	14.2%	0.0%	31.3%
	PPL	$5.3	$2.4	($2.9)	4.9%	2.3%	8.0%	0.0%
	PSEG	$5.4	$5.2	($0.2)	5.1%	4.9%	0.7%	0.0%
	RECO	$0.2	$0.0	($0.2)	0.2%	0.0%	0.6%	0.0%
	All Zones	$95.2	$106.7	$11.5	89.2%	100.0%	67.7%	100.0%
Hubs and Aggregates	AEP - Dayton	$0.4	$0.0	($0.4)	0.4%	0.0%	1.2%	0.0%
	Dominion	$0.2	$0.0	($0.2)	0.2%	0.0%	0.6%	0.0%
	Eastern	$0.2	$0.0	($0.2)	0.2%	0.0%	0.5%	0.0%
	New Jersey	$0.2	$0.0	($0.2)	0.2%	0.0%	0.5%	0.0%
	Ohio	$0.1	$0.0	($0.1)	0.1%	0.0%	0.2%	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)	3.4%	0.0%	10.1%	0.0%
	RTEP B0328 Source	$0.0	$0.0	($0.0)	0.0%	0.0%	0.0%	0.0%
	All Hubs and Aggregates	$4.7	$0.0	($4.7)	4.4%	0.0%	13.3%	0.0%
Interfaces	CPLE Imp	$0.0	$0.0	$0.0	0.0%	0.0%	0.0%	0.0%
	Hudson	$0.1	$0.0	($0.1)	0.1%	0.0%	0.2%	0.0%
	IMO	$0.3	$0.0	($0.3)	0.3%	0.0%	0.9%	0.0%
	Linden	$0.4	$0.0	($0.4)	0.3%	0.0%	1.0%	0.0%
	MISO	$2.5	$0.0	($2.5)	2.3%	0.0%	7.0%	0.0%
	Neptune	$0.4	$0.0	($0.4)	0.4%	0.0%	1.1%	0.0%
	NIPSCO	$0.0	$0.0	($0.0)	0.0%	0.0%	0.1%	0.0%
	Northwest	$0.1	$0.0	($0.1)	0.1%	0.0%	0.4%	0.0%
	NYIS	$1.0	$0.0	($1.0)	0.9%	0.0%	2.7%	0.0%
	OVEC	$0.0	$0.0	($0.0)	0.0%	0.0%	0.1%	0.0%
	South Exp	$0.7	$0.0	($0.7)	0.7%	0.0%	2.0%	0.0%
	South Imp	$1.3	$0.0	($1.3)	1.2%	0.0%	3.7%	0.0%
	All Interfaces	$6.8	$0.0	($6.8)	6.4%	0.0%	19.1%	0.0%
Total		$106.7	$106.7	$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 an incentive for units to follow PJM's dispatch instructions when PJM's dispatch instructions deviate from a unit's desired or scheduled output. They are paid under two different scenarios. The first scenario occurs 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. In this scenario 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. The second scenario occurs if a combustion turbine or diesel engine is schedule to operate in the Day-Ahead Energy Market, but it is not requested by PJM in real time. In this scenario 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.[15]

Table 4-30 shows monthly day-ahead and real-time LOC credits in 2016 and 2017. In 2017, LOC credits decreased by $4.1 million or 22.0 percent compared to 2016. The decrease of $4.1 million is comprised of a $4.0 million decrease in day-ahead LOC and a decrease of $0.1 million in real-time LOC. Table 4-31 shows for combustion turbines and diesels scheduled day-ahead generation, scheduled day-ahead generation not requested in real time, and the subset of day-ahead generation receiving LOC credits. In 2017 11.4 percent of day-ahead generation by combustion turbines and diesels was not requested in real time, 1.5 percentage points lower than in 2016.

Table 4-30 Monthly lost opportunity cost credits (Millions): 2016 and 2017

	2016			2017		
	Day-Ahead Lost Opportunity Cost	Real-Time Lost Opportunity Cost	Total	Day-Ahead Lost Opportunity Cost	Real-Time Lost Opportunity Cost	Total
Jan	$1.5	$0.2	$1.7	$0.1	$0.3	$0.4
Feb	$2.0	$0.1	$2.1	$0.1	$0.1	$0.1
Mar	$0.7	$0.3	$0.9	$0.9	$0.2	$1.1
Apr	$1.9	$0.6	$2.4	$0.5	$0.3	$0.8
May	$0.5	$0.1	$0.7	$0.8	$1.0	$1.8
Jun	$1.7	$0.9	$2.6	$0.7	$0.8	$1.5
Jul	$0.8	$0.5	$1.4	$1.5	$0.2	$1.7
Aug	$1.6	$0.4	$2.0	$0.5	$0.1	$0.6
Sep	$2.2	$0.2	$2.4	$1.5	$0.5	$1.9
Oct	$0.8	$0.2	$0.9	$0.8	$0.2	$0.9
Nov	$0.3	$0.1	$0.4	$0.5	$0.2	$0.7
Dec	$0.3	$0.8	$1.1	$2.5	$0.6	$3.0
Total	$14.3	$4.4	$18.7	$10.3	$4.3	$14.6
Share	76.2%	23.8%	100.0%	70.4%	29.6%	100.0%

Table 4-31 Day-ahead generation from combustion turbines and diesels (GWh): 2016 and 2017

	2016			2017		
	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	705	211	115	359	33	9
Feb	746	192	92	318	27	9
Mar	1,090	162	66	778	128	49
Apr	1,531	276	95	473	88	28
May	1,349	115	48	669	75	38
Jun	1,433	231	80	1,153	120	61
Jul	2,697	227	76	1,815	265	123
Aug	2,402	143	58	1,341	121	51
Sep	1,774	239	97	2,205	123	66
Oct	1,360	155	60	1,850	138	65
Nov	512	68	25	757	106	38
Dec	462	48	21	898	213	110
Total	16,062	2,068	831	12,616	1,438	646
Share	100.0%	12.9%	5.2%	100.0%	11.4%	5.1%

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

Table 4-32 shows for combustion turbines and diesels the historical scheduled day-ahead generation, scheduled day-ahead generation not requested in real time, and total day-ahead LOC credits. The decrease in day-ahead LOC credits is attributable to several factors. As shown in Table 4-32 since 2014 there has been a continuous decrease in the share of day-ahead generation not requested in real time. In September 2015, PJM adopted three recommendations proposed by the MMU to improve the calculation of LOC payments.

Table 4-32 Historical day-ahead generation from combustion turbines and diesels and day-ahead lost opportunity cost credits (GWh): 2013 through 2017

	Day-Ahead Generation	Day-Ahead Generation Not Requested in Real Time	Share of Day-Ahead Generation Not Requested in Real Time	Day-Ahead LOC Credits (Millions)
2013	13,001	5,620	43.2%	$63.4
2014	14,628	5,636	38.5%	$112.1
2015	18,734	5,128	27.4%	$83.0
2016	16,062	2,068	12.9%	$18.6
2017	12,616	1,438	11.4%	$14.6

PJM may not run units in real time if the real-time value of the energy (generation multiplied by the real-time LMP) is lower than the units' total offer (including no load and startup costs). Table 4-33 shows the total day-ahead generation from combustion turbines and diesels that were not committed in real time by PJM and received LOC credits. Table 4-33 shows the scheduled generation that had a total offer (including no load and startup costs) lower than its real-time value (generation multiplied by the real-time LMP), defined here as economic scheduled generation, and the scheduled generation that had a total offer greater than its real-time value or noneconomic scheduled generation. In 2017, 60.0 percent of the scheduled generation not committed by PJM from units receiving LOC credits was economic and the remaining 40.0 percent was noneconomic.

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.

Table 4-33 Day-ahead generation (GWh) from combustion turbines and diesels receiving lost opportunity cost credits by value: 2016 and 2017[16]

	2016			2017		
	Economic Scheduled Generation (GWh)	Noneconomic Scheduled Generation (GWh)	Total (GWh)	Economic Scheduled Generation (GWh)	Noneconomic Scheduled Generation (GWh)	Total (GWh)
Jan	142	43	185	11	11	22
Feb	104	63	167	8	11	19
Mar	72	71	143	58	42	99
Apr	124	110	234	38	28	67
May	58	41	99	45	16	61
Jun	100	63	163	67	29	96
Jul	79	50	129	130	74	204
Aug	67	31	97	54	37	91
Sep	99	85	184	73	29	102
Oct	69	52	121	71	49	121
Nov	20	35	55	42	39	81
Dec	21	24	44	103	102	205
Total	954	667	1,621	700	467	1,167
Share	58.9%	41.1%	100.0%	60.0%	40.0%	100.0%

16 The total generation in Table 4-33 is lower than the day-ahead generation not requested in real time in Table 4-31 because the former only includes generation from units that received lost opportunity costs during at least one hour of the day. Table 4-31 includes all generation, including generation from units that were not committed in real time and did not receive LOC credits.

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.[17] 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 4-34 shows the closed loop interfaces that PJM has defined and PJM's objective in defining each closed loop interface.

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

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

17 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).

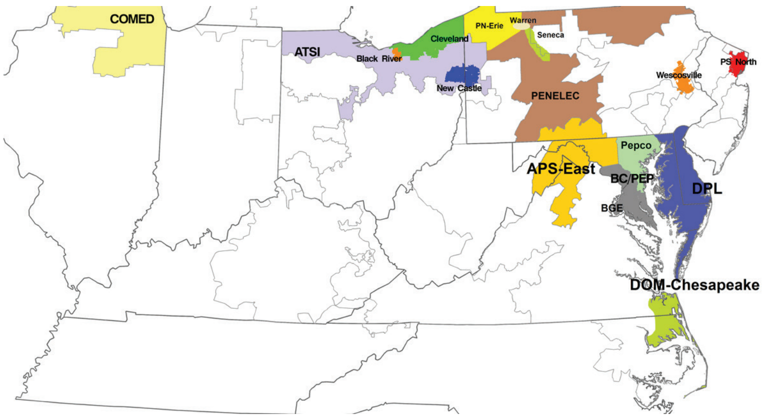
18 See PJM. "Manual 3: Transmission Operations," Rev. 48 (Dec. 1, 2015) at "Section 3.8: Transfer Limits (Reactive/Voltage Transfer Limits)," for a description of reactive interfaces.

19 See closed loop interfaces definitions at <http://www.pjm.com/markets-and-operations/etools/oasis/system-information.aspx>.

20 See the PS North interface definition at <http://www.pjm.com/pub/account/auction-user-info/model-annual/Annual-PJM-interface-definitions-limits.csv>.

Figure 4-8 shows the approximate geographic location of PJM's closed loop interfaces.

Figure 4-8 PJM Closed loop interfaces map



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.[21]

The MMU has recommended and supports PJM's goal of having dispatcher decisions reflected in transparent market outcomes, preferably LMP, to the maximum extent possible and to minimize the level and rate of energy uplift charges. But part of that goal is to avoid distortion of the way in which the transmission network is modeled. The 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

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

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.

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."[22] 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

22 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).

aggregation for a geographic area smaller than a control zone.[23]

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 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).[24] 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.[25]

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.

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

24 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>.

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

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

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

In order to properly compensate units, the MMU recommended enhancing the day-ahead operating reserve credits calculation to ensure that units receive an energy uplift payment based on their real-time output and not their day-ahead scheduled output whenever their real time operation results in a lower loss or 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.[26] These recommendations are superseded by the MMU's recommendation to eliminate day-ahead operating reserve payments.[27] 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 2016 and 2017. In 2016 and 2017, energy uplift costs associated with units scheduled in the Day-Ahead Energy Market would have had been reduced by $23.8 million or 20.2 percent ($2.9 million paid to units providing reactive support $20.8 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.

26 See *2013 State of the Market Report for PJM*, Volume 2 Section 4: "Energy Uplift," at "Day-Operating Reserve Credits," and at "Net DASR Revenues Offset" for an explanation of these recommendations.

27 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>.

Another issue related to this exclusion is the treatment of pool-scheduled units that elect to self-schedule a portion of their capacity for regulation. A unit can be pool-scheduled for energy, which means PJM may commit or dispatch the unit based on economics, but it can also self-schedule some of its capacity for regulation. When this happens the capacity self-scheduled for regulation is treated as a price taker, but in the energy market any increase in MW to provide regulation are treated as additional costs, which can result in increased balancing operating reserve credits whenever the real-time LMP is lower than the unit's offer. For example, if a unit raises its economic minimum in order to provide regulation 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 2016 and 2017, 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 $2.3 million, of which $1.3 million or 54.5 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.[28]

Self Scheduled Start

Participants may offer their units as pool-scheduled (economic) or self-scheduled (must run).[29] 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 24 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.[30] [31] 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

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

29 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>.

30 See *2015 State of the Market Report for PJM*, Volume 2 Section 4, "Energy Uplift," at "Lost Opportunity Cost Calculation" for an explanation of the adopted recommendations.

31 152 FERC ¶ 61,165 (2015)

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.

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 for 2017. In 2017, lost opportunity cost payments would have had been reduced by $7.6 million or 52.2 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.

Actual Cost Reimbursement

PJM Manual 11 (Energy and Ancillary Services Market Operations) Attachment C describes an after the fact cost recovery procedure that is not consistent with the PJM tariff. The MMU recommends that PJM revise Manual 11 Attachment C Procedure for Cost Reimbursement to be consistent with the PJM tariff. Manual 11 incorrectly states that the purpose of this procedure is to address "differences between cost-based offers and actually incurred costs for resettlement." The PJM tariff rules for compensation greater than LMP payments are covered by the OA Schedule 1 Section 3.2.3, which specifies that compensation shall be made based on the "applicable offer" or "offered price" and not based actually incurred costs which can be known only after the fact.

The MMU recommends that PJM revise Manual 11 consistent with the tariff to limit compensation to offered costs. The Manual 11 procedure should describe the steps market participants can take to change the availability of cost-based energy offers that have been submitted day ahead. This procedure only applies for units that have not been committed by PJM in the Day-Ahead Energy Market or in real time. This enables PJM dispatchers to select the most appropriate cost-based energy offer to set the LMP and possible uplift payments. The MMU recommends that PJM eliminate this procedure when hourly offers (ER16-372-000) are implemented as this rule was a short term solution for the absence of hourly offers.

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 $0.044 and $0.055 per MWh in 2016 and between $0.021 and $0.024 per MWh in 2017 if the MMU's recommendations regarding energy uplift had been in place.[32] [33]

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.[34] Load, interchange transactions, internal bilateral transactions, demand

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

33 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.

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

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.[35] 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 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.[36] 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.

Reactive Services Credits and Balancing Operating Reserve Credits

Energy uplift credits to resources providing reactive services are separate from balancing operating reserve credits.[37] 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

35 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.

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

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

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 2017, units providing reactive services were paid $0.6 million in balancing operating reserve credits in order to cover their total energy offer. In 2016, this misallocation was $0.3 million.

The MMU recommends that reactive services credits be calculated consistent with the balancing operating reserve credit calculation. The MMU also recommends including real-time exports and real-time wheels in the allocation of the cost of providing reactive support to the 500 kV system or above, in addition to real-time load.[38]

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

38 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>.

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 4-35 shows the current allocation by energy uplift reason. For example, energy uplift payments to units scheduled in the Day-Ahead Energy Market are called day-ahead operating reserves, these costs are paid by day-ahead load, day-ahead exports and decrement bids. Any additional payment resulting from the real-time operation of these units are called balancing operating reserves, these costs are paid by either deviations or real-time load and real-time exports depending on the amount of intervals the units are economic.

Table 4-35 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 4-36 shows the MMU allocation proposal by energy uplift reason. The proposal eliminates the day-ahead operating reserve category and creates a new category for any energy uplift payments to units scheduled in the Day-Ahead Energy Market and committed in real time. This new category would be allocated to day-ahead transactions and resources. The proposal also eliminates the need to determine the number of intervals that units are economic to determine if the energy uplift charge should be allocated to deviations or to real-time load and real-time exports. In the proposal, any commitment instruction before the operating day would be allocated based on the proposed definition of deviations; any commitment instruction during the operating day would be allocated to physical deviations.

Table 4-36 MMU energy uplift allocation proposal

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

Quantifiable Recommendations Impact

Table 4-37 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 $33.9 million or 14.1 percent in 2016 and 2017 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 $20.8 million, the proposed changes to lost opportunity cost calculations would have resulted in a decrease of $10.3 million and the use of net regulation revenues offset would have resulted in a decrease of $2.3 million.[39] Table 4-37 shows that deviations charges would have been reduced by $87.1 million or 79.9 percent. The reason for this change is that, besides the reduction in the overall charges, under the MMU proposal, a subset of charges is reallocated to a new physical deviation category (based on the timing of the commitment of the resource being paid energy uplift) and another subset of charges is allocated to real-time load, real-time exports and real-time wheels (based on reliability actions).

Table 4-37 Current and proposed energy uplift charges by allocation (Millions): 2016 and 2017[40]

Allocation	2016	2017	Total
Current			
Day-Ahead Demand, Day-Ahead Exports and Decrement Bids	$57.3	$24.7	$82.1
Real-Time Load and Real-Time Exports	$22.5	$27.1	$49.5
Deviations	$53.7	$55.3	$109.0
Total	$133.5	$107.1	$240.6
Proposal			
Day-Ahead Transactions and Day-Ahead Resources	$10.7	$7.4	$18.1
Real-Time Load and Real-Time Exports	$44.5	$21.1	$65.6
Deviations	$16.0	$6.0	$21.9
Physical Deviations	$44.7	$56.5	$101.2
Total	$115.8	$90.9	$206.7
Impact			
Impact ($)	($17.7)	($16.2)	($33.9)
Impact (%)	(13.2%)	(15.1%)	(14.1%)

The MMU calculated the rates that participants would have paid in 2016 and 2017 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 4-38 shows the energy uplift cost of a 1 MW transaction if these recommendations had been implemented in 2016 and 2017. Table 4-38 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 2016 and 2017, in this scenario, the cost reflects the expected cost for the first 1 MWh cleared up to congestion transaction. Table 4-38 shows for example that a decrement bid in the Eastern Region (if not offset by other transactions) would have paid an average rate of $0.027 and $0.012 per MWh in the 2016 and 2017, under the first scenario, $0.391 and $0.374 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 $0.049 and $0.023 per MWh in 2016 and 2017 under the first scenario. Table 4-38 shows the current and proposed averages energy uplift rates for all transactions.

39 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.

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

Table 4-38 Current and proposed average energy uplift rate by transaction: 2016 and 2017[41]

		2016			2017		
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	0.347	0.027	0.093	0.355	0.012	0.040
	DEC	0.418	0.027	0.093	0.386	0.012	0.040
	DA Load	0.071	0.004	0.006	0.030	0.003	0.004
	RT Load	0.031	0.058	0.058	0.037	0.027	0.027
	Deviation	0.347	0.387	0.451	0.355	0.504	0.531
West	INC	0.302	0.022	0.078	0.327	0.011	0.037
	DEC	0.372	0.022	0.078	0.357	0.011	0.037
	DA Load	0.071	0.004	0.006	0.030	0.003	0.004
	RT Load	0.023	0.058	0.058	0.028	0.027	0.027
	Deviation	0.302	0.312	0.366	0.327	0.415	0.440
UTC	East to East	NA	0.055	0.186	NA	0.024	0.081
	West to West	NA	0.044	0.156	NA	0.021	0.074
	East to/from West	NA	0.049	0.171	NA	0.023	0.077

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