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. 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 $16.0 million, or 15.7 percent, in the first nine months of 2017 compared to the first nine months of 2016, from $102.3 million to $86.3 million.
- **Energy Uplift Charges Categories.** The decrease of $16.0 million in the first nine months of 2017 is comprised of a $23.9 million decrease in day-ahead operating reserve charges, a $5.4 million decrease in balancing operating reserve charges and a $13.2 million increase in reactive services charges.
- **Average Effective Operating Reserve Rates in the Eastern Region.** Day-ahead load paid $0.027 per MWh, real-time load paid $0.029 per MWh, a DEC paid $0.338 per MWh and an INC and any load, generation or interchange transaction deviation paid $0.311 per MWh.
- **Average Effective Operating Reserve Rates in the Western Region.** Day-ahead load paid $0.027 per MWh, real-time load paid $0.025 per MWh, a DEC paid $0.330 per MWh and an INC and any load, generation or interchange transaction deviation paid $0.303 per MWh.
- **Reactive Services Rates.** The PENELEC, ComEd and BGE control zones had the three highest local voltage support rates: $0.130, $0.104 and $0.073 per MWh.

Characteristics of Credits

- **Types of units.** Coal units received 88.5 percent of all day-ahead generator credits. Combustion turbines received 74.4 percent of all balancing generator credits. Combustion turbines and diesels received 66.1 percent of the lost opportunity cost credits.
- **Concentration of Energy Uplift Credits.** The top 10 units receiving energy uplift credits received 35.0 percent of all credits. The top 10

organizations received 79.8 percent of all credits. Concentration indexes for energy uplift categories classify them as highly concentrated. Day-ahead operating reserves HHI was 7434, balancing operating reserves HHI was 3356 and lost opportunity cost HHI was 5366.

- **Economic and Noneconomic Generation.** In the first nine months of 2017, 85.1 percent of the day-ahead generation eligible for operating reserve credits was economic and 79.0 percent of the real-time generation eligible for operating reserve credits was economic.
- **Day-Ahead Unit Commitment for Reliability.** In the first nine months of 2017, 1.2 percent of the total day-ahead generation MWh was scheduled as must run by PJM, of which 54.5 percent received energy uplift payments.

Geography of Charges and Credits

- In the first nine months of 2017, 89.0 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 6.7 percent by interchange transactions at interfaces.
- Generators in the Eastern Region received 48.4 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.
- Generators in the Western Region received 49.0 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.
- External generators received 2.6 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 reallocating the operating reserve credits paid to units supporting the Con Edison – PJM Transmission Service Agreements. (Priority: Medium. First reported 2013. Status: Not adopted. Stakeholder process.)
- The MMU recommends that the total cost of providing reactive support be categorized and allocated as reactive services. Reactive services credits should be calculated consistent with the operating reserve credits calculation. (Priority: Medium. First reported 2012. Status: Not adopted. Stakeholder process.)
- The MMU recommends including real-time exports and real-time wheels in the allocation of the cost of providing reactive support to the 500 kV system or above, which is currently allocated solely to real-time RTO load. (Priority: Low. First reported 2013. Status: Not adopted. Stakeholder process.)
- The MMU recommends enhancing the current energy uplift allocation rules to reflect the elimination of day-ahead operating reserves, the timing of commitment decisions and the commitment reasons. (Priority: High. First reported 2012. Status: Not adopted. Stakeholder process.)
- 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 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.

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

Energy Uplift

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

Credits and Charges Categories

Energy uplift charges include day-ahead and balancing operating reserves, reactive services, synchronous condensing and black start services categories.

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.

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	in RTO, Eastern or Western Region
			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 $16.0 million or 15.7 percent in the first nine months of 2017 compared to the first nine months of 2016. Table 4-3 shows total energy uplift charges in the first nine months of 2016 and 2017.[5]

Table 4-3 Total energy uplift charges: January 1 through September 30, 2016 and 2017

	(Jan - Sep) 2016 Charges (Millions)	(Jan - Sep) 2017 Charges (Millions)	Change	Percent Change
Total Energy Uplift	$102.3	$86.3	($16.0)	(15.7%)
Energy Uplift as a Percent of Total PJM Billing	0.3%	0.3%	(0.1%)	(15.7%)

Table 4-4 compares energy uplift charges by category for the first nine months of 2016 and 2017. The decrease of $16.0 million in the first nine months of 2017 is comprised of a decrease of $23.9 million in day-ahead operating reserve charges, a decrease of $5.4 million in balancing operating reserve charges and an increase of $13.2 million in reactive service charges.

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 October 11, 2017.

Table 4-4 Energy uplift charges by category: January 1 through September 30, 2016 and 2017

Category	(Jan - Sep) 2016 Charges (Millions)	(Jan - Sep) 2017 Charges (Millions)	Change (Millions)	Percent Change
Day-Ahead Operating Reserves	$40.8	$16.9	($23.9)	(58.5%)
Balancing Operating Reserves	$60.5	$55.1	($5.4)	(8.9%)
Reactive Services	$0.8	$14.0	$13.2	1,596.4%
Synchronous Condensing	$0.0	$0.0	($0.0)	
Black Start Services	$0.2	$0.2	$0.0	3.6%
Total	$102.3	$86.3	($16.0)	(15.7%)

Table 4-5 compares monthly energy uplift charges by category for 2016 and the first nine months of 2017.

Table 4-5 Monthly energy uplift charges: January 1, 2016 through September 30, 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	$5.3	$1.5	$0.0	$0.0	$9.8
Sep	$2.9	$6.9	$0.1	$0.0	$0.0	$9.9	$3.0	$10.2	$2.3	$0.0	$0.0	$15.5
Oct	$3.6	$8.7	$0.3	$0.0	$0.0	$12.6						
Nov	$5.7	$2.8	$1.0	$0.0	$0.1	$9.5						
Dec	$7.3	$4.5	$0.4	$0.0	$0.0	$12.2						
Total (Jan - Sep)	$40.8	$60.5	$0.8	$0.0	$0.2	$102.3	$16.9	$55.1	$14.0	$0.0	$0.2	$86.3
Share (Jan - Sep)	39.9%	59.1%	0.8%	0.0%	0.2%	100.0%	19.6%	63.9%	16.3%	0.0%	0.2%	100.0%
Total	$57.3	$76.5	$2.5	$0.0	$0.3	$136.6	$16.9	$55.1	$14.0	$0.0	$0.2	$86.3
Share	42.0%	56.0%	1.8%	0.0%	0.2%	100.0%	19.6%	63.9%	16.3%	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 $23.9 million or 58.5 percent in the first nine months of 2017 compared to the first nine months of 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.

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 4-6 Day-ahead operating reserve charges: January 1 through September 30, 2016 and 2017

Type	(Jan - Sep) 2016 Charges (Millions)	(Jan - Sep) 2017 Charges (Millions)	Change (Millions)	(Jan - Sep) 2016 Share	(Jan - Sep) 2017 Share
Day-Ahead Operating Reserve Charges	$40.8	$16.9	($23.9)	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	$40.8	$16.9	($23.9)	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 decreased by $5.4 million in the first nine months of 2017 compared to the first nine months of 2016.

Table 4-7 Balancing operating reserve charges: January 1 through September 30, 2016 and 2017

Type	(Jan - Sep) 2016 Charges (Millions)	(Jan - Sep) 2017 Charges (Millions)	Change (Millions)	(Jan - Sep) 2016 Share	(Jan - Sep) 2017 Share
Balancing Operating Reserve Reliability Charges	$16.9	$17.3	$0.4	28.0%	31.5%
Balancing Operating Reserve Deviation Charges	$43.1	$37.1	($6.0)	71.3%	67.3%
Balancing Operating Reserve Charges for Load Response	$0.1	$0.2	$0.1	0.1%	0.4%
Balancing Local Constraint Charges	$0.4	$0.5	$0.1	0.6%	0.9%
Total	$60.5	$55.1	($5.4)	100.0%	100.0%

Table 4-8 shows the composition of the balancing operating reserve deviation charges. Balancing operating reserve deviation charges equal make whole credits paid to generators and import transactions, energy lost opportunity costs paid to generators and payments to resources canceled by PJM before coming online. In the first nine months of 2017, 73.0 percent of balancing operating reserve deviation charges were for make whole credits paid to generators and import transactions, an increase of 11.0 percentage points compared to the share in the first nine months of 2016. The increase in the share of make whole credits was not the result of an increase in make whole credits, but rather a decrease in energy lost opportunity cost credits, which decreased by $6.3 million or 38.7 percent.

Table 4-8 Balancing operating reserve deviation charges: January 1 through September 30, 2016 and 2017

Charge Attributable To	(Jan - Sep) 2016 Charges (Millions)	(Jan - Sep) 2017 Charges (Millions)	Change (Millions)	(Jan - Sep) 2016 Share	(Jan - Sep) 2017 Share
Make Whole Payments to Generators and Imports	$26.8	$27.1	$0.3	62.0%	73.0%
Energy Lost Opportunity Cost	$16.3	$10.0	($6.3)	37.8%	26.9%
Canceled Resources	$0.1	$0.0	($0.0)	0.1%	0.0%
Total	$43.1	$37.1	($6.0)	100.0%	100.0%

Table 4-9 shows reactive services, synchronous condensing and black start services charges. Reactive services charges increased by $13.2 million in the first nine months of 2017 compared to the first nine months of 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: January 1 through September 30, 2016 and 2017

Type	(Jan - Sep) 2016 Charges (Millions)	(Jan - Sep) 2017 Charges (Millions)	Change (Millions)	(Jan - Sep) 2016 Share	(Jan - Sep) 2017 Share
Reactive Services Charges	$0.8	$14.0	$13.2	82.1%	98.7%
Synchronous Condensing Charges	$0.0	$0.0	($0.0)	0.0%	0.0%
Black Start Services Charges	$0.2	$0.2	$0.0	17.9%	1.3%
Total	$1.0	$14.2	$13.2	100.0%	100.0%

Table 4-10 and Table 4-11 show the amount and percent shares of regional balancing charges in the first nine months of 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 the first nine months of 2017, regional balancing operating reserve charges decreased by $5.6 million compared to the first nine months of 2016. Balancing operating reserve reliability charges increased by $0.4 million or 2.3 percent and balancing operating reserve deviation charges decreased by $6.0 million or 14.0 percent.

Table 4-10 Regional balancing charges allocation (Millions): January 1 through September 30, 2016

Charge	Allocation	RTO		East		West		Total	
Reliability Charges	Real-Time Load	$13.1	21.9%	$2.9	4.8%	$0.4	0.7%	$16.4	27.3%
	Real-Time Exports	$0.4	0.7%	$0.1	0.1%	$0.0	0.0%	$0.5	0.9%
	Total	$13.6	22.6%	$3.0	5.0%	$0.4	0.7%	$16.9	28.2%
Deviation Charges	Demand	$22.5	37.5%	$2.8	4.6%	$0.4	0.6%	$25.7	42.7%
	Supply	$7.1	11.9%	$0.8	1.3%	$0.1	0.2%	$8.0	13.3%
	Generator	$8.2	13.7%	$1.1	1.8%	$0.1	0.2%	$9.5	15.7%
	Total	$37.9	63.1%	$4.6	7.7%	$0.6	1.0%	$43.1	71.8%
Total Regional Balancing Charges		$51.4	85.6%	$7.6	12.7%	$1.0	1.7%	$60.1	100%

Table 4-11 Regional balancing charges allocation (Millions): January 1 through September 30, 2017

Charge	Allocation	RTO		East		West		Total	
Reliability Charges	Real-Time Load	$15.0	27.5%	$1.4	2.6%	$0.3	0.6%	$16.7	30.7%
	Real-Time Exports	$0.6	1.0%	$0.0	0.1%	$0.0	0.0%	$0.6	1.1%
	Total	$15.5	28.5%	$1.5	2.7%	$0.3	0.6%	$17.3	31.9%
Deviation Charges	Demand	$21.7	39.8%	$0.8	1.4%	$0.4	0.8%	$22.9	42.0%
	Supply	$6.7	12.3%	$0.3	0.5%	$0.1	0.2%	$7.1	13.0%
	Generator	$6.8	12.5%	$0.2	0.4%	$0.1	0.2%	$7.1	13.1%
	Total	$35.2	64.6%	$1.3	2.3%	$0.6	1.2%	$37.1	68.1%
Total Regional Balancing Charges		$50.7	93.2%	$2.7	5.0%	$1.0	1.8%	$54.4	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 the first nine months of 2017. The average rate in the first nine months of 2017 was $0.027 per MWh, $0.037 per MWh lower than the average in the first nine months of 2016. The highest rate in the first nine months of 2017 occurred on February 12, when the rate reached $0.172 per MWh, $0.230 per MWh lower than the $0.402 per MWh reached in the first nine months of 2016, on

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.

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 in the first nine months of 2017.

Figure 4-1 Daily day-ahead operating reserve rate ($/MWh): January 1, 2016 through September 30, 2017

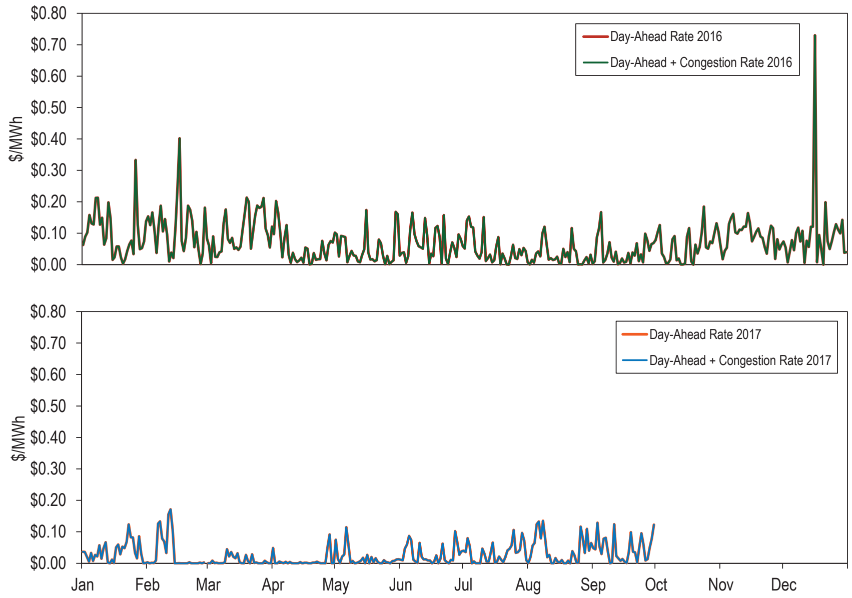


Figure 4-2 shows the RTO and the regional reliability rates for 2016 and the first nine months of 2017. The average daily RTO reliability rate was $0.026 per MWh. The highest RTO reliability rate in the first nine months of 2017 occurred on January 8, when the rate reached $0.390 per MWh, $0.155 per MWh higher than the $0.234 per MWh rate reached in the first nine months of 2016, on August 12.

Figure 4-2 Daily balancing operating reserve reliability rates ($/MWh): January 1, 2016 through June 30, 2017

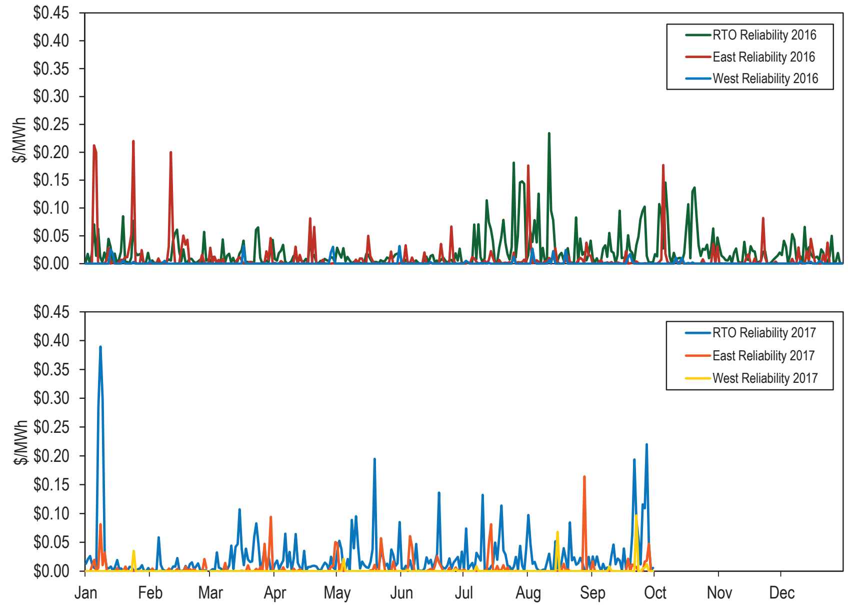


Figure 4-3 shows the RTO and regional deviation rates for 2016 and the first nine months of 2017. The average daily RTO deviation rate was $0.221 per MWh. The highest daily rate in the first nine months of 2017 occurred on January 9, when the RTO deviation rate reached $2.177 per MWh, $0.135 per MWh higher than the $2.042 per MWh rate reached in 2016, on October 19, 2016.

Figure 4-3 Daily balancing operating reserve deviation rates ($/MWh): January 1, 2016 through September 30, 2017

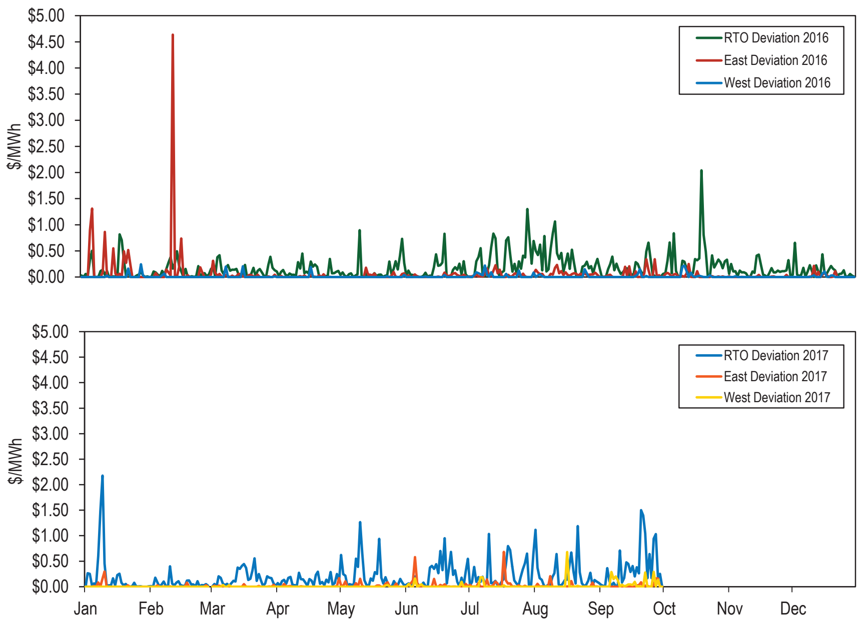


Figure 4-4 Daily lost opportunity cost and canceled resources rates ($/MWh): January 1, 2016 through September 30, 2017

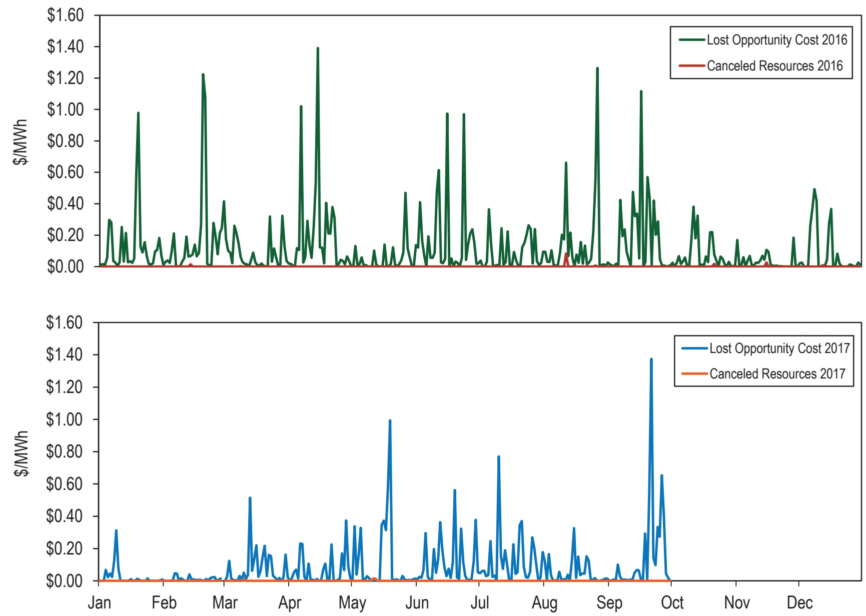


Figure 4-4 shows the daily lost opportunity cost rate and the daily canceled resources rate for 2016 and the first nine months of 2017. The lost opportunity cost rate averaged $0.088 per MWh. The highest lost opportunity cost rate occurred on September 20, when it reached $1.375 per MWh, $0.017 per MWh lower than the $1.391 per MWh rate reached in the first nine months of 2016, on April 14.

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

Table 4-12 Operating reserve rates ($/MWh): January 1 through September 30, 2016 and 2017

Rate	(Jan - Sep) 2016 ($/MWh)	(Jan - Sep) 2017 ($/MWh)	Difference ($/MWh)	Percent Difference
Day-Ahead	0.064	0.027	(0.037)	(57.3%)
Day-Ahead with Unallocated Congestion	0.064	0.027	(0.037)	(57.3%)
RTO Reliability	0.022	0.026	0.004	18.0%
East Reliability	0.010	0.005	(0.005)	(48.9%)
West Reliability	0.001	0.001	(0.000)	(11.6%)
RTO Deviation	0.182	0.221	0.039	21.7%
East Deviation	0.074	0.022	(0.052)	(70.8%)
West Deviation	0.011	0.012	0.000	4.1%
Lost Opportunity Cost	0.138	0.088	(0.050)	(36.3%)
Canceled Resources	0.000	0.000	(0.000)	(72.6%)

Table 4-13 shows the operating reserve cost of a one MW transaction in the first nine months of 2017. For example, a decrement bid in the Eastern Region (if not offset by other transactions) paid an average rate of $0.338 per MWh with a maximum rate of $2.805 per MWh, a minimum rate of $0.002 per MWh and a standard deviation of $0.415 per MWh. The rates in Table 4-13 include all operating reserve charges including RTO deviation charges. Table 4-13 illustrates both the average level of operating reserve charges by transaction types and the uncertainty reflected in the maximum, minimum and standard deviation levels.

Table 4-13 Operating reserve rates statistics ($/MWh): January 1 through September 30, 2017

		Rates Charged ($/MWh)			
Region	Transaction	Maximum	Average	Minimum	Standard Deviation
East	INC	2.770	0.311	0.000	0.417
	DEC	2.805	0.338	0.002	0.415
	DA Load	0.172	0.027	0.000	0.036
	RT Load	0.471	0.029	0.000	0.050
	Deviation	2.770	0.311	0.000	0.417
West	INC	2.770	0.303	0.000	0.407
	DEC	2.805	0.330	0.002	0.405
	DA Load	0.172	0.027	0.000	0.036
	RT Load	0.390	0.025	0.000	0.046
	Deviation	2.770	0.303	0.000	0.407

Reactive Services Rates

Reactive services charges associated with local voltage support are allocated to real-time load in the control zone or zones where the service is provided. These charges result from uplift payments to units committed by PJM to support reactive/voltage requirements that do not recover their energy offer through LMP payments. These charges are separate from the reactive service revenue requirement charges which are a fixed annual charge based on approved FERC filings. Reactive services charges associated with supporting reactive transfer interfaces above 345 kV are allocated daily to real-time load across the entire RTO based on the real-time load ratio share of each network customer.

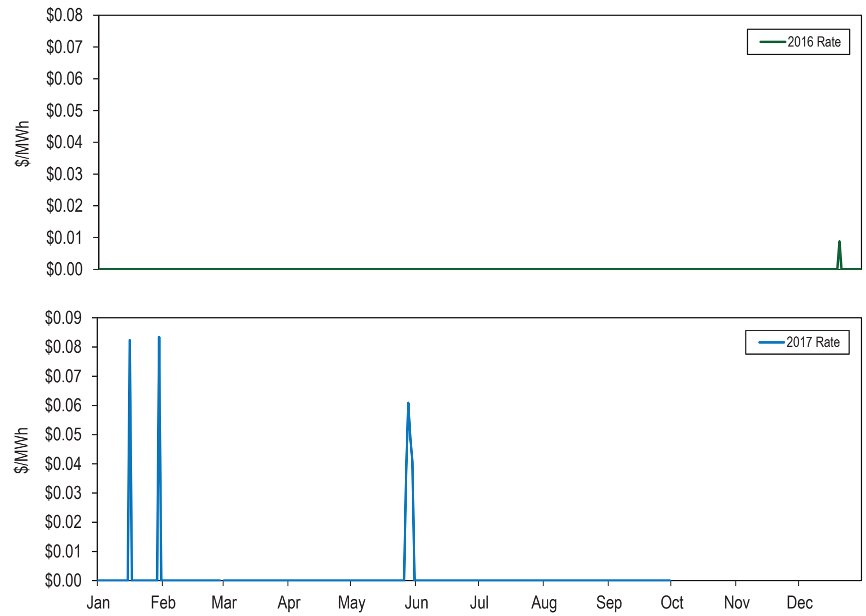
While reactive services rates are not posted by PJM, a local voltage support rate for each control zone can be calculated and a reactive transfer interface support rate can be calculated for the entire RTO. Table 4-14 shows the reactive services rates associated with local voltage support in the first nine months of 2016 and 2017. Table 4-14 shows that in the first nine months of 2017 the PENELEC Control Zone had the highest rate. Real-time load in the PENELEC Control Zone paid an average of $0.130 per MWh for reactive services associated with local voltage support, $0.128 or 5,051.4 percent higher than the average rate paid in the first nine months of 2016.

Table 4-14 Local voltage support rates: January 1 through September 30, 2016 and 2017

Control Zone	(Jan - Sep) 2016 ($/MWh)	(Jan - Sep) 2017 ($/MWh)	Difference ($/MWh)
AECO	0.000	0.000	0.000
AEP	0.000	0.001	0.000
APS	0.000	0.003	0.003
ATSI	0.000	0.000	0.000
BGE	0.000	0.073	0.073
ComEd	0.000	0.104	0.104
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	0.051	0.054	0.004
EKPC	0.000	0.000	0.000
JCPL	0.000	0.000	0.000
Met-Ed	0.001	0.005	0.004
PECO	0.000	0.002	0.002
PENELEC	0.003	0.130	0.128
Pepco	0.000	0.071	0.071
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 the first nine months of 2017. RTO wide reactive charges were incurred only once in 2016 (December) and three times in the first nine months of 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): January 1, 2016 through September 30, 2017



Balancing Operating Reserve Determinants

Table 4-15 shows the determinants used to allocate the regional balancing operating reserve charges in the first nine months of 2016 and 2017. Total real-time load and real-time exports were 20,266,491MWh, 3.3 percent lower in the first nine months of 2017 compared to the first nine months of 2016. Total deviations summed across the demand, supply, and generator categories were 4,884,276 MWh, 4.1 percent lower in the first nine months of 2017 compared to the first nine months of 2016.

Table 4-15 Balancing operating reserve determinants (MWh): January 1 through September 30, 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
(Jan - Sep) 2016	RTO	597,400,936	18,659,370	616,060,306	69,228,229	23,074,483	26,385,976	118,688,688
	East	282,979,481	8,416,523	291,396,004	34,935,836	13,261,882	14,623,858	62,821,576
	West	314,421,455	10,242,847	324,664,302	33,867,452	9,579,961	11,762,118	55,209,532
(Jan - Sep) 2017	RTO	571,775,428	24,018,387	595,793,815	68,670,597	23,785,666	21,348,149	113,804,412
	East	271,690,505	8,084,625	279,775,130	34,374,864	14,040,601	10,370,426	58,785,891
	West	300,084,922	15,933,762	316,018,684	33,912,951	9,504,084	10,977,723	54,394,758
Difference	RTO	(25,625,508)	5,359,017	(20,266,491)	(557,632)	711,183	(5,037,827)	(4,884,276)
	East	(11,288,976)	(331,898)	(11,620,874)	(560,973)	778,719	(4,253,432)	(4,035,685)
	West	(14,336,533)	5,690,915	(8,645,618)	45,499	(75,877)	(784,395)	(814,773)

Deviations fall into three categories, demand, supply and generator deviations. Table 4-16 shows the different categories by the type of transactions that incurred deviations. In the first nine months of 2017, 30.5 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 69.5 percent of all RTO deviations were incurred by participants that deviated due to other transaction types or due to combinations of other transaction types.

Table 4-16 Deviations by transaction type: January 1 through September 30, 2017

Deviation		Deviation (MWh)			Share		
Category	Transaction	RTO	East	West	RTO	East	West
Demand	Bilateral Sales Only	1,234,722	1,173,485	61,237	1.1%	2.0%	0.1%
	DECs Only	11,627,534	4,876,208	6,368,544	10.2%	8.3%	11.7%
	Exports Only	4,945,195	2,316,826	2,628,368	4.3%	3.9%	4.8%
	Load Only	46,810,999	23,743,246	23,067,754	41.1%	40.4%	42.4%
	Combination with DECs	2,957,308	1,610,005	1,347,303	2.6%	2.7%	2.5%
	Combination without DECs	1,094,838	655,094	439,744	1.0%	1.1%	0.8%
Supply	Bilateral Purchases Only	301,300	239,935	61,365	0.3%	0.4%	0.1%
	Imports Only	3,264,655	2,551,655	713,000	2.9%	4.3%	1.3%
	INCs Only	17,508,929	9,667,562	7,600,387	15.4%	16.4%	14.0%
	Combination with INCs	2,654,222	1,534,357	1,119,865	2.3%	2.6%	2.1%
	Combination without INCs	56,560	47,092	9,468	0.0%	0.1%	0.0%
Generators		21,348,149	10,370,426	10,977,723	18.8%	17.6%	20.2%
Total		113,804,412	58,785,891	54,394,758	100.0%	100.0%	100.0%

Energy Uplift Credits

Table 4-17 shows the totals for each credit category in the first nine months of 2016 and 2017. During the first nine months of 2017, 63.9 percent of total energy uplift credits were in the balancing operating reserve category, an increase of 4.8 percentage points from 59.1 in the first nine months of 2016.

Table 4-17 Energy uplift credits by category: January 1 through September 30, 2016 and 2017

Category	Type	(Jan - Sep) 2016 Credits (Millions)	(Jan - Sep) 2017 Credits (Millions)	Change	(Jan - Sep) 2016 Share	(Jan - Sep) 2017 Share
Day-Ahead Operating Reserve	Generators	$40.8	$16.9	($23.9)	39.9%	19.6%
	Imports	$0.0	$0.0	($0.0)	0.0%	0.0%
	Load Response	$0.0	$0.0	$0.0	0.0%	0.0%
Balancing Operating Reserve	Canceled Resources	$0.1	$0.0	($0.0)	0.1%	0.0%
	Generators	$43.7	$44.4	$0.7	42.7%	51.5%
	Imports	$0.0	$0.0	($0.0)	0.0%	0.0%
	Load Response	$0.1	$0.2	$0.1	0.1%	0.2%
	Local Constraints Control	$0.4	$0.5	$0.1	0.4%	0.6%
	Lost Opportunity Cost	$16.2	$10.0	($6.3)	15.9%	11.5%
Reactive Services	Day-Ahead	$0.0	$13.3	$13.3	0.0%	15.5%
	Local Constraints Control	$0.0	$0.0	$0.0	0.0%	0.0%
	Lost Opportunity Cost	$0.0	$0.1	$0.1	0.0%	0.1%
	Reactive Services	$0.8	$0.6	($0.2)	0.8%	0.7%
	Synchronous Condensing	$0.0	$0.0	$0.0	0.0%	0.0%
Synchronous Condensing		$0.0	$0.0	($0.0)	0.0%	0.0%
Black Start Services	Day-Ahead	$0.0	$0.0	$0.0	0.0%	0.0%
	Balancing	$0.0	$0.0	$0.0	0.0%	0.0%
	Testing	$0.2	$0.2	($0.0)	0.2%	0.2%
Total		$102.2	$86.2	($16.0)	100.0%	100.0%

Characteristics of Credits

Types of Units

Table 4-18 shows the distribution of total energy uplift credits by unit type in the first nine months of 2016 and 2017. The decrease in energy uplift in the first nine months of 2017 compared to the first nine months of 2016 was the result of lower credits paid to coal fired steam turbines, combustion turbines, and combined cycle units. Credits to these units decreased by $17.3 million or 21.8 percent.

Table 4-18 Energy uplift credits by unit type: January 1 through September 30, 2016 and 2017

Unit Type	(Jan - Sep) 2016 Credits (Millions)	(Jan - Sep) 2017 Credits (Millions)	Change	Percent Change	(Jan - Sep) 2016 Share	(Jan - Sep) 2017 Share
Combined Cycle	$10.1	$5.7	($4.4)	(43.6%)	9.9%	6.7%
Combustion Turbine	$45.9	$40.5	($5.5)	(11.9%)	44.9%	47.0%
Diesel	$0.5	$0.5	$0.1	12.7%	0.5%	0.6%
Hydro	$0.1	$0.0	($0.0)	(69.8%)	0.1%	0.0%
Nuclear	$1.1	$0.1	($1.1)	(93.1%)	1.1%	0.1%
Solar	$0.0	$0.0	$0.0	0.0%	0.0%	0.0%
Steam - Coal	$40.7	$33.3	($7.4)	(18.2%)	39.9%	38.7%
Steam - Other	$2.7	$3.9	$1.2	45.4%	2.6%	4.5%
Wind	$1.0	$2.0	$0.9	94.5%	1.0%	2.3%
Total	$102.1	$86.0	($16.1)	(15.8%)	100.0%	100.0%

Table 4-19 shows the distribution of energy uplift credits by category and by unit type in the first nine months of 2017. Coal fired steam turbines received 88.5 percent of the day-ahead generator credits in the first nine months of 2017, 3.7 percentage points higher than the share received in the first nine months of 2016. Combustion turbines received 74.4 percent of the balancing operating reserve generator credits in the first nine months of 2017, 2.3 percentage points higher than the share received in the first nine months of 2016. Combustion turbines received 63.5 percent of the lost opportunity cost credits in the first nine months of 2017, 15.1 percentage points lower than the share received in the first nine months of 2016.

Table 4-19 Energy uplift credits by unit type: January 1 through September 30, 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	5.5%	7.5%	0.0%	0.0%	9.5%	3.4%	0.0%	22.3%
Combustion Turbine	1.8%	74.4%	2.7%	72.4%	63.5%	2.1%	0.0%	77.7%
Diesel	0.0%	0.5%	0.0%	5.7%	2.5%	0.1%	0.0%	0.0%
Hydro	0.0%	0.0%	97.3%	0.0%	0.0%	0.0%	0.0%	0.0%
Nuclear	0.0%	0.0%	0.0%	0.0%	0.8%	0.0%	0.0%	0.0%
Solar	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Steam - Coal	88.5%	13.6%	0.0%	21.9%	5.9%	82.5%	0.0%	0.0%
Steam - Others	4.2%	3.4%	0.0%	0.0%	0.1%	11.9%	0.0%	0.0%
Wind	0.0%	0.5%	0.0%	0.0%	17.6%	0.0%	0.0%	0.0%
Total (Millions)	$16.9	$44.4	$0.0	$0.5	$10.0	$14.0	$0.0	$0.2

Table 4-19 also shows the distribution of reactive service credits and black start services credits by unit type. In the first nine months of 2017, coal units received 82.5 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 4-6 shows the concentration of energy uplift credits. The top 10 units received 35.0 percent of total energy uplift credits in the first nine months of 2017, compared to 35.6 percent in the first nine months of 2016. In the first nine months of 2017, 259 units received 90 percent of all energy uplift credits, compared to 267 units in the first nine months of 2016.

Figure 4-6 Cumulative share of energy uplift credits: January 1 through September 30, 2016 and 2017 by unit

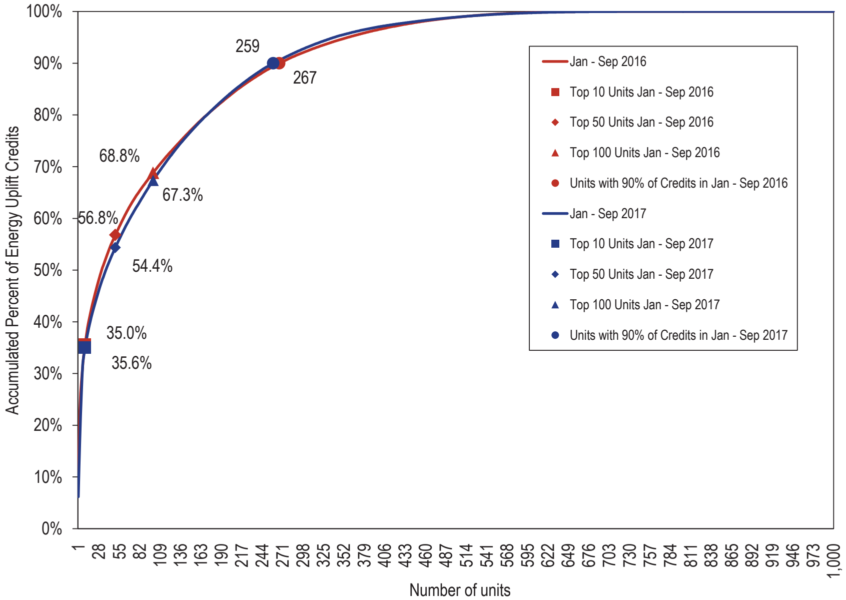


Table 4-20 shows the credits received by the top 10 units and top 10 organizations in each of the energy uplift categories paid to generators.

Table 4-20 Top 10 units and organizations energy uplift credits: January 1 through September 30, 2017

		Top 10 Units		Top 10 Organizations	
Category	Type	Credits (Millions)	Credits Share	Credits (Millions)	Credits Share
Day-Ahead Operating Reserve	Generators	$14.0	82.8%	$16.6	97.9%
Balancing Operating Reserve	Canceled Resources	$0.0	100.0%	$0.0	100.0%
	Generators	$6.1	13.8%	$32.9	74.0%
	Local Constraints Control	$0.4	79.5%	$0.5	100.0%
	Lost Opportunity Cost	$2.3	23.2%	$7.0	70.7%
Reactive Services		$13.0	92.5%	$14.0	100.0%
Synchronous Condensing		$0.0	0.0%	$0.0	0.0%
Black Start Services		$0.1	44.1%	$0.2	92.2%
Total		$30.1	35.0%	$68.6	79.8%

Table 4-21 shows balancing operating reserve credits received by the top 10 units identified for reliability or for deviations in each region. In the first nine months of 2017, 64.3 percent of all credits paid to these units were allocated to deviations while the remaining 35.7 percent were paid for reliability reasons.

Table 4-21 Identification of balancing operating reserve credits received by the top 10 units by category and region: January 1 through September 30, 2017

	Reliability			Deviations			
	RTO	East	West	RTO	East	West	Total
Credits (Millions)	$2.0	$0.2	$0.0	$3.7	$0.3	$0.0	$6.1
Share	32.7%	3.0%	0.0%	60.0%	4.3%	0.0%	100.0%

In the first nine months of 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 7434, for balancing operating reserve credits to generators was 3356, for lost opportunity cost credits was 5366 and for reactive services credits was 9021.

8 See *2016 State of the Market Report for PJM*, Volume 2: 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: January 1 through September 30, 2017

Category	Type	Average	Minimum	Maximum	Highest Market Share (One day)	Highest Market Share (All days)
Day-Ahead Operating Reserve	Generators	7434	2229	10000	100.0%	57.7%
	Imports	NA	NA	NA	NA	NA
	Load Response	10000	10000	10000	100.0%	100.0%
Balancing Operating Reserve	Canceled Resources	10000	10000	10000	100.0%	100.0%
	Generators	3356	965	10000	100.0%	14.0%
	Imports	10000	10000	10000	100.0%	100.0%
	Load Response	9749	5281	10000	100.0%	87.2%
	Lost Opportunity Cost	5366	1459	10000	100.0%	13.0%
Reactive Services		9021	3537	10000	100.0%	75.8%
Synchronous Condensing		NA	NA	NA	NA	NA
Black Start Services		9556	4997	10000	100.0%	31.3%
Total		3381	878	9824	99.1%	30.7%

Pool Scheduled and Self Scheduled Generation

In PJM, units can have either a pool scheduled or self scheduled commitment status. Pool scheduled units are committed by PJM while self scheduled units are committed by the generation owners. Self scheduled units specify an output level (MW) at which they must run. A self scheduled unit can specify to PJM that the economic minimum is must run or that the entire output of the unit is must run. Pool scheduled units can also specify to PJM that if committed, PJM must take the entire output of the unit. Table 4-23 shows the categories of PJM day-ahead and real-time generation commitment status:

- **Self Scheduled (Must Run):** MWh from self scheduled units that run regardless of dispatch signal.
- **Self Scheduled (Dispatchable):** MWh from self scheduled units that offer a dispatchable range to PJM.
- **Pool Scheduled (Block Loaded):** MWh from pool scheduled units that are offered to PJM as a single MWh block which is not dispatchable.
- **Pool Scheduled (Dispatchable):** MWh from pool scheduled units that are offered to PJM with a dispatchable range.
- **Not Defined Status:** MWh from units that did not specify their commitment status in their offer or did not have an offer.

Table 4-23 shows that in the first nine months of 2017, 64.4 percent of total generation in the day ahead market was self scheduled and 63.2 percent of total generation in the real time market was self scheduled. In the Day-Ahead Energy Market, 30.5 percent of the self scheduled generation was must run while 33.9 percent was dispatchable. In the Real-Time Energy Market 33.8 percent of self scheduled generation was must run while 29.4 percent was dispatchable. The results in Table 4-23 reflect the status of units that are committed while data for the same categories in the Energy Section is for unit offers.[10] The proportion of self scheduled units is significantly higher for committed units than for unit offers.

Table 4-23 Day-ahead and real-time generation commitment status percent: January through September 2017

Energy Market	Self Scheduled (Must Run)	Self Scheduled (Dispatchable)	Pool Scheduled (Block Loaded)	Pool Scheduled (Dispatchable)	No Defined Status
Day Ahead	30.5%	33.9%	3.3%	32.2%	0.0%
Real Time	33.8%	29.4%	4.3%	32.4%	0.2%

Economic and Noneconomic Generation[11]

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

10 See the *2017 State of the Market Report for PJM: January through September*, Section 3
11 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.

The MMU analyzed PJM's day-ahead and real-time generation eligible for operating reserve credits to determine the shares of economic and noneconomic generation. Each unit's hourly generation was determined to be economic or noneconomic based on the unit's hourly incremental offer, excluding the hourly no load cost and any applicable startup cost. A unit could be economic for every hour during a day or segment, but still receive operating reserve credits because the energy revenues did not cover the hourly no load costs and startup costs. A unit could be noneconomic for an hour or multiple hours and not receive operating reserve credits whenever the total energy revenues covered the total offer (including no load and startup costs) for the entire day or segment. In the first nine months of 2017, 35.5 percent of the day-ahead generation was eligible for day-ahead operating reserve credits and 33.5 percent of the real-time generation was eligible for balancing operating reserve credits.[12]

Table 4-24 Day-ahead and real-time generation (GWh): January 1 through September 30, 2017

Energy Market	Total Generation	Generation Eligible for Operating Reserve Credits	Generation Eligible for Operating Reserve Credits Percent
Day-Ahead	608,246	216,046	35.5%
Real-Time	610,802	204,624	33.5%

Table 4-25 shows PJM's economic and noneconomic generation by hour eligible for operating reserve credits. In the first nine months of 2017, 85.1 percent of the day-ahead generation eligible for operating reserve credits was economic and 79.0 percent of the real-time generation eligible for operating reserve credits was economic. A unit's generation may be noneconomic for a portion of their daily generation and economic for the rest. Table 4-25 shows the separate amounts of economic and noneconomic generation even if the daily generation was economic.

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

Table 4-25 Day-ahead and real-time economic and noneconomic generation from units eligible for operating reserve credits (GWh): January 1 through September 30, 2017

Energy Market	Economic Generation	Noneconomic Generation	Economic Generation Percent	Noneconomic Generation Percent
Day-Ahead	183,753	32,293	85.1%	14.9%
Real-Time	161,648	42,976	79.0%	21.0%

Noneconomic generation only leads to operating reserve credits when units' generation for the day or segment, scheduled or committed, is noneconomic, including no load and startup costs. Table 4-26 shows the generation receiving day-ahead and balancing operating reserve credits. In the first nine months of 2017, 2.6 percent of the day-ahead generation eligible for operating reserve credits received credits and 2.2 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): January 1 through September 30, 2017

Energy Market	Generation Eligible for Operating Reserve Credits	Generation Receiving Operating Reserve Credits	Generation Receiving Operating Reserve Credits Percent
Day-Ahead	216,046	5,650	2.6%
Real-Time	204,624	4,520	2.2%

Day-Ahead Unit Commitment for Reliability

PJM may schedule units as must run in the Day-Ahead Energy Market when needed in real time to address reliability issues of various types. PJM puts such reliability issues in four categories: voltage issues (high and low); black start requirements (from automatic load rejection (ALR) units); local contingencies not modeled in the Day-Ahead Energy Market; and long lead time units not able to be scheduled in the Day-Ahead Energy Market.[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-ahead operating reserve credits.[14] Units scheduled as must run by

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

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>.

PJM may set LMP if raised above economic minimum and following the dispatch signal and are eligible for day-ahead operating reserve credits. Table 4-27 shows the total day-ahead generation and the subset of that generation scheduled as must run by PJM. In the first nine months of 2017, 1.2 percent of the total day-ahead generation was scheduled as must run by PJM, 0.3 percentage points lower than the first nine months of 2016.

Table 4-27 Day-ahead generation scheduled as must run by PJM (GWh): January 1, 2016 through September 30, 2017

	2016			2017		
	Total Day-Ahead Generation	Day-Ahead PJM Must Run Generation	Share	Total Day-Ahead Generation	Day-Ahead PJM Must Run Generation	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%	61,170	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%			
Nov	59,983	819	1.4%			
Dec	72,478	1,112	1.5%			
Total (Jan - Sep)	621,392	9,034	1.5%	608,246	7,298	1.2%
Total	814,803	12,031	1.5%	608,246	7,298	1.2%

Pool-scheduled units are made whole in the Day-Ahead Energy Market if their total offer (including no load and startup costs) is greater than the revenues from the Day-Ahead Energy Market. Such units are paid day-ahead operating reserve credits. Pool-scheduled units scheduled as must run by PJM are only paid day-ahead operating reserve credits when their total offer is greater than the revenues from the Day-Ahead Energy Market.

It is illogical and unnecessary to pay units day-ahead operating reserves because units do not incur any costs to run and any revenue shortfalls are addressed by balancing operating reserve payments.

Table 4-28 shows the total day-ahead generation scheduled as must run by PJM by category. In the first nine months of 2017, 54.5 percent of the day-ahead generation scheduled as must run by PJM received operating reserve credits, 24.7 percent paid as day-ahead operating reserve credits and 29.8 percent paid as reactive services. The remaining 45.5 percent of the day-ahead generation scheduled as must run by PJM did not need to be made whole.

Table 4-28 Day-ahead generation scheduled as must run by PJM by category (GWh): January 1 through September 30, 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
Total (Jan - Sep)	2,175	1,799	3,324	7,298
Share	29.8%	24.7%	45.5%	100.0%

Total day-ahead operating reserve credits in the first nine months of 2017 were $16.9 million, of which $13.2 million or 78.2 percent was paid to units scheduled as must run by PJM, and not scheduled to provide black start or reactive services.

Geography of Charges and Credits

Table 4-29 shows the geography of charges and credits in the first nine months of 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 7.3 percent of all operating reserve charges allocated regionally, and resources in the ATSI Control Zone were paid 3.1 percent of the corresponding credits. The ATSI Control Zone received less operating reserve credits than operating reserve charges paid and had 11.5percent of the deficit. The deficit is the sum of the negative entries in the balance column. Transactions in the BGE Control Zone paid 4.0 percent of all operating reserve charges allocated regionally, and resources in the BGE Control Zone were paid 13.0 percent of the corresponding credits. The BGE Control Zone received more operating reserve credits than operating reserve charges paid and had 24.8 percent of the surplus. The surplus is the sum of the positive entries in the balance column. Table 4-29 also shows that 89.0 percent of all charges were allocated in control zones, 4.4 percent in hubs and aggregates and 6.7 percent in interfaces.

Table 4-29 Geography of regional charges and credits: January 1 through September 30, 2017

					Shares			
Location		Charges (Millions)	Credits (Millions)	Balance	Total Charges	Total Credits	Deficit	Surplus
Zones	AECO	$1.0	$0.5	($0.4)	1.3%	0.8%	1.6%	0.0%
	AEP	$9.4	$7.1	($2.2)	13.1%	10.0%	8.7%	0.0%
	APS	$4.0	$2.6	($1.4)	5.6%	3.7%	5.3%	0.0%
	ATSI	$5.2	$2.2	($2.9)	7.3%	3.1%	11.5%	0.0%
	BGE	$2.9	$9.2	$6.4	4.0%	13.0%	0.0%	24.8%
	ComEd	$8.1	$11.3	$3.3	11.3%	15.9%	0.0%	12.8%
	DAY	$1.3	$1.9	$0.6	1.8%	2.6%	0.0%	2.3%
	DEOK	$2.2	$1.0	($1.2)	3.1%	1.4%	4.8%	0.0%
	DLCO	$1.0	$0.3	($0.7)	1.4%	0.4%	2.9%	0.0%
	Dominion	$6.8	$9.1	$2.3	9.5%	12.7%	0.0%	9.1%
	DPL	$1.7	$4.7	$3.0	2.4%	6.6%	0.0%	11.7%
	EKPC	$1.1	$1.3	$0.2	1.5%	1.8%	0.0%	0.9%
	External	$0.0	$1.4	$1.4	0.0%	2.0%	0.0%	5.6%
	JCPL	$1.9	$0.6	($1.3)	2.7%	0.9%	5.2%	0.0%
	Met-Ed	$1.4	$0.7	($0.7)	2.0%	1.0%	2.7%	0.0%
	PECO	$3.4	$0.8	($2.7)	4.8%	1.1%	10.3%	0.0%
	PENELEC	$2.5	$1.6	($0.9)	3.5%	2.2%	3.5%	0.0%
	Pepco	$2.6	$11.1	$8.4	3.7%	15.5%	0.0%	32.9%
	PPL	$3.3	$1.0	($2.4)	4.7%	1.4%	9.2%	0.0%
	PSEG	$3.6	$2.8	($0.8)	5.1%	4.0%	3.1%	0.0%
	RECO	$0.2	$0.0	($0.2)	0.2%	0.0%	0.6%	0.0%
	All Zones	$63.4	$71.3	$7.9	89.0%	100.0%	69.3%	100.0%
Hubs and Aggregates	AEP - Dayton	$0.3	$0.0	($0.3)	0.4%	0.0%	1.2%	0.0%
	Dominion	$0.2	$0.0	($0.2)	0.2%	0.0%	0.6%	0.0%
	Eastern	$0.1	$0.0	($0.1)	0.2%	0.0%	0.5%	0.0%
	New Jersey	$0.1	$0.0	($0.1)	0.2%	0.0%	0.4%	0.0%
	Ohio	$0.0	$0.0	($0.0)	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	$2.3	$0.0	($2.3)	3.2%	0.0%	9.0%	0.0%
	RTEP B0328 Source	$0.0	$0.0	($0.0)	0.0%	0.0%	0.0%	0.0%
	All Hubs and Aggregates	$3.1	$0.0	($3.1)	4.4%	0.0%	12.2%	0.0%
Interfaces	CPLE Imp	$0.0	$0.0	$0.0	0.0%	0.0%	0.0%	0.0%
	Hudson	$0.0	$0.0	($0.0)	0.0%	0.0%	0.0%	0.0%
	IMO	$0.2	$0.0	($0.2)	0.3%	0.0%	0.8%	0.0%
	Linden	$0.2	$0.0	($0.2)	0.3%	0.0%	0.8%	0.0%
	MISO	$2.0	$0.0	($2.0)	2.8%	0.0%	7.7%	0.0%
	Neptune	$0.2	$0.0	($0.2)	0.3%	0.0%	0.9%	0.0%
	NIPSCO	$0.0	$0.0	($0.0)	0.1%	0.0%	0.1%	0.0%
	Northwest	$0.1	$0.0	($0.1)	0.1%	0.0%	0.3%	0.0%
	NYIS	$0.6	$0.0	($0.6)	0.8%	0.0%	2.3%	0.0%
	OVEC	$0.0	$0.0	($0.0)	0.0%	0.0%	0.1%	0.0%
	South Exp	$0.4	$0.0	($0.4)	0.6%	0.0%	1.7%	0.0%
	South Imp	$1.0	$0.0	($1.0)	1.4%	0.0%	3.8%	0.0%
	All Interfaces	$4.7	$0.0	($4.7)	6.7%	0.0%	18.5%	0.0%
	Total	$71.3	$71.3	$0.0	100.0%	100.0%	100.0%	100.0%