Energy Uplift (Operating Reserves)

Energy uplift is paid to market participants under specified conditions in order to ensure that competitive energy and ancillary service market outcomes do not require efficient resources 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 uplift 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 as directed by PJM operators. These credits are paid by PJM market participants as operating reserve charges, reactive services charges, synchronous condensing charges or black start services charges.

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 cannot be eliminated, but uplift payments should 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 based on 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. The PJM market design incorporates efficient prices with minimal uplift payments. There are improvements to the market design and uplift rules that could further reduce uplift payments while maintaining efficient prices.

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.

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. The current payment structure for DR is an inefficient element of the PJM market design.[4]

Overview

Energy Uplift Credits

- **Types of credits.** In the first nine months of 2019, energy uplift credits were $70.6 million, including $13.9 million in day-ahead generator credits, $40.8 million in balancing generator credits, $12.6 million in lost opportunity cost credits, and $2.7 million in local constraint control credits.
- **Types of units.** Coal units received 90.9 percent of all day-ahead generator credits. Combustion turbines received 85.5 percent of all balancing generator credits and 94.8 percent of lost opportunity cost credits.
- **Economic and Noneconomic Generation.** In the first nine months of 2019, 82.7 percent of the day-ahead generation eligible for operating reserve credits was economic and 67.0 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 2019, 0.3 percent of the total day-ahead generation MWh was scheduled as must run by PJM, of which 47.8 percent received energy uplift payments.
- **Concentration of Energy Uplift Credits.** The top 10 units receiving energy uplift credits received 23.6 percent of all credits. The top 10 organizations received 73.5 percent of all credits. The HHI for day-ahead operating reserves was 8500, the HHI for balancing operating reserves was 3340

4 Demand response payments are addressed in Section 6: Demand Response.

and the HHI for lost opportunity cost was 5789, all of which are classified as highly concentrated.

- **Lost Opportunity Cost Credits.** Lost opportunity cost credits decreased by $36.0 million or 74.1 percent, in the first nine months of 2019 compared to the first nine months of 2018, from $48.3 million to $12.6 million. Generation from combustion turbines and diesels scheduled day-ahead but not requested in real time, receiving lost opportunity cost credits decreased by 428 GWh or 46.8 percent in the first nine months of 2019, compared to the first nine months of 2018, from 915.2 GWh to 487 GWh.

Energy Uplift Charges

- **Energy Uplift Charges.** Total energy uplift charges decreased by $106.3 million, or 60.1 percent, in the first nine months of 2019 compared to the first nine months of 2018, from $176.9 million to $70.6 million.
- **Energy Uplift Charges Categories.** The decrease of $106.3 million in the first nine months of 2019 is comprised of a $17.8 million decrease in day-ahead operating reserve charges, a $76.4 million decrease in balancing operating reserve charges, and an $11.9 million decrease in reactive services charges.
- **Average Effective Operating Reserve Rates in the Eastern Region.** Day-ahead load paid $0.022 per MWh, real-time load paid $0.029 per MWh, a DEC paid $0.340 per MWh and an INC and any load, generation or interchange transaction deviation paid $0.318 per MWh.
- **Average Effective Operating Reserve Rates in the Western Region.** Day-ahead load paid $0.022 per MWh, real-time load paid $0.027 per MWh, a DEC paid $0.324 per MWh and an INC and any load, generation or interchange transaction deviation paid $0.302 per MWh.
- **Reactive Services Rates.** The PENELEC, DPL, and Dominion control zones were the three zones with the highest local voltage support rate, excluding reactive capability payments: PENELEC had a rate of $0.011 per MWh, DPL had a rate of $0.007 per MWh, and Dominion had a rate of $0.002 per MWh.

Geography of Charges and Credits

- In the first nine months of 2019, 90.3 percent of all uplift charges allocated regionally (day-ahead operating reserves and balancing operating reserves) were paid by transactions at control zones, 3.0 percent by transactions at hubs and aggregates, and 6.8 percent by transactions at interchange interfaces.
- Generators in the Eastern Region received 41.9 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.
- Generators in the Western Region received 56.4 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.
- External generators received 2.1 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.

Recommendations

- The MMU recommends that uplift be paid only based on operating parameters that reflect the flexibility of the benchmark new entrant unit (CONE unit) in the PJM Capacity Market. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM not use closed loop interface constraints to artificially override nodal prices 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 CT price setting logic to modify transmission line limits 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 implement CT price setting logic, PJM first initiate a stakeholder process to determine whether such modification is appropriate. PJM should file any proposed changes with FERC to ensure review. Any such changes should be incorporated in the PJM tariff. (Priority: Medium. First Reported 2016. Status: Not adopted.)
- The MMU recommends that PJM initiate an analysis of the reasons why a significant number of 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 eliminating intraday segments from the calculation of uplift payments and returning to calculating the need for uplift based on the entire 24 hour operating day. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends the elimination of day-ahead operating reserves 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.)
- The MMU recommends enhancing the current energy uplift allocation rules to reflect the recommended elimination of day-ahead operating reserves, the timing of commitment decisions and the commitment reasons. (Priority: High. First reported 2012. Status: Not adopted.)
- 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 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. (Priority: Low. First reported 2013. Status: Not adopted. Stakeholder process.)
- The MMU recommends three modifications to the energy lost opportunity cost calculations:
  - The MMU recommends calculating LOC based on 24 hour daily periods 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 only flexible fast start units (startup plus notification times of 10 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.)
- 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: Adopted 2018.[5])
- 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 balancing operating reserve

5 As of November 1, 2018, internal bilateral transactions are no longer used for the calculation of deviations for purposes of allocating balancing operating reserve charges. See the 2018 State of the Market Report for PJM, Volume 2, Section 3: "Energy Market" at "Internal Bilateral Transactions" for an analysis of the impact of this change on virtual bidding activity.

credit 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, in addition to real-time load. (Priority: Low. First reported 2013. Status: Not adopted.)
- 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). The MMU recommends that PJM allow wind units to request 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 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: Partially adopted.)
- 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.[6])
- The MMU recommends that PJM pay uplift based on the offer at the lower of the actual unit output or the dispatch signal MW. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM develop and implement an accurate metric to define when a unit is following dispatch to determine eligibility to receive balancing operating reserve credits and for assessing generator deviations. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM eliminate the exemption for fast start resources (CTs and diesels) from the requirement to follow dispatch. The performance of these resources should be evaluated in a manner consistent with all other resources (Priority: Medium. First reported 2018. Status: Not adopted.)

Conclusion

Competitive market outcomes result from energy offers equal to short run marginal costs that incorporate flexible operating parameters. 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. The standard for paying uplift should be the maximum achievable flexibility, based on OEM standards for the benchmark new entrant unit (CONE unit) in the PJM Capacity Market. Applying a weaker standard 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.

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 the inflexible 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

6 On September 7, 2018, PJM made a compliance filing for FERC Order No. 844 to publish unit specific uplift credits. The compliance filing was accepted by FERC on March 21, 2019. PJM will begin posting unit-specific uplift reports on May 1, 2019.

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.

Implementing combined cycle modeling, to permit the energy market model optimization to take advantage of the versatility and flexibility of combined cycle technology in commitment and dispatch, would provide significant flexibility without requiring a distortion of the market rules.

The reduction of uplift payments should not be a goal to be achieved at the expense of the fundamental logic of the 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 CT price setting logic. The same is true of fast start pricing and of convex hull pricing. The same is true of PJM's proposal to modify the ORDC in order to increase energy prices and reduce uplift.

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

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 10 years. FERC Order No. 844 authorized the publication of unit specific uplift payments for credits incurred after July 1, 2019.[7]

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.

Up to congestion transactions continue to pay no energy uplift charges, which means that all others who pay these charges are paying too much.[8]

PJM needs to pay substantially more attention to the details of uplift payments including accurately tracking whether units are following dispatch, identifying the actual need for units to be dispatched out of merit and determining whether local reserve zones or better definitions of constraints would be a more market based approach.

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. 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

7 On March 21, 2019 FERC accepted PJM's Order No. 844 compliance filing. The filing stated that PJM would begin posting unit specific uplift reports on May 1, 2019. On April 8, 2019, PJM filed for an extension on the implementation date of the zonal uplift reports and unit specific uplift reports to July 1, 2019. On June 28, 2019, FERC accepted PJM's request for extension of effective dates.

8 On October 17, 2017, PJM filed with FERC a proposed tariff change to allocate uplift to UTC transactions in the same manner in which uplift is currently allocated to other virtual transactions, as a separate injection and withdrawal deviation. FERC rejected the proposed tariff change. The rejection was without prejudice and PJM has the option to submit a new proposal. See FERC Docket No. ER18-86-000. PJM has not filed a new proposal.

level of per MWh charges, to reduce the uncertainty associated with uplift charges and to reduce the impact of energy uplift charges on decisions about how and when to participate in PJM markets.

Energy Uplift Results

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 LMP is less than the offer price including incremental, no load and startup costs. Energy uplift payments also result from units' operational parameters that require PJM to schedule or commit resources when they are not economic. The resulting costs not covered by energy revenues are collected as energy uplift.

Table 4-1 shows the totals for each credit category for the first nine months of 2018 and 2019.[9] In the first nine months of 2019, energy uplift credits decreased by $106.2 million or 60.1 percent compared to the first nine months of 2018.

Table 4-1 Energy uplift credits by category: January through September, 2018 and 2019

Category	Type	(Jan - Sep) 2018 Credits (Millions)	(Jan - Sep) 2019 Credits (Millions)	Change	Percent Change	(Jan - Sep) 2018 Share	(Jan - Sep) 2019 Share
Day-Ahead	Generators	$31.8	$13.9	($17.8)	(56.1%)	18.0%	19.7%
	Imports	$0.0	$0.0	$0.0	259.1%	0.0%	0.0%
	Load Response	$0.0	$0.0	($0.0)	(74.8%)	0.0%	0.0%
Balancing	Canceled Resources	$0.0	$0.0	$0.0	NA	0.0%	0.0%
	Generators	$75.4	$40.8	($34.6)	(45.9%)	42.7%	57.8%
	Imports	$0.5	$0.0	($0.5)		0.3%	0.0%
	Load Response	$0.0	$0.0	($0.0)		0.0%	0.0%
	Local Constraints Control	$8.0	$2.7	($5.3)	(66.3%)	4.5%	3.8%
	Lost Opportunity Cost	$48.5	$12.6	($36.0)	(74.1%)	27.4%	17.8%
Reactive Services	Day-Ahead	$11.2	$0.2	($11.1)	(98.4%)	6.4%	0.3%
	Local Constraints Control	$0.0	$0.0	$0.0	NA	0.0%	0.0%
	Lost Opportunity Cost	$0.0	$0.0	$0.0	94.4%	0.0%	0.0%
	Reactive Services	$0.7	$0.3	($0.4)	(62.0%)	0.4%	0.4%
	Synchronous Condensing	$0.5	$0.0	($0.5)	(98.7%)	0.3%	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	NA	0.0%	0.0%
	Balancing	$0.2	$0.2	($0.0)	(4.5%)	0.1%	0.2%
	Testing	$0.0	$0.0	($0.0)		0.0%	0.0%
Total		$176.8	$70.6	($106.2)	(60.1%)	100.0%	100.0%

9 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, 2019.

Characteristics of Credits

Types of Units

Table 4-2 shows the distribution of total energy uplift credits by unit type for the first nine months of 2018 and 2019. Uplift credits decreased for all unit types. The reduction in uplift credits was largely the result of lower gas prices during the 2019 winter compared to 2018, replacement of coal units needed for reliability by combined cycles and transmission upgrades that reduced the need to commit units for reactive. Natural gas prices remained low, reducing the costs of gas units and reducing the need for, and level of, make whole payments. The mild weather reduced the need to commit combustion turbines which are the largest recipients of uplift credits. Combustion turbines had the largest reduction in uplift credits with a reduction of $44.1 million or 47.1 percent.

Table 4-2 Energy uplift credits by unit type: January through September, 2018 and 2019[10 11]

Unit Type	(Jan - Sep) 2018 Credits (Millions)	(Jan - Sep) 2019 Credits (Millions)	Change	Percent Change	(Jan - Sep) 2018 Share	(Jan - Sep) 2019 Share
Combined Cycle	$19.3	$2.7	($16.6)	(85.9%)	10.9%	3.8%
Combustion Turbine	$93.6	$49.6	($44.1)	(47.1%)	53.1%	70.2%
Diesel	$1.3	$0.6	($0.7)	(53.0%)	0.7%	0.9%
Hydro	$0.2	$0.0	($0.2)	(100.0%)	0.1%	0.0%
Nuclear	$0.4	$0.0	($0.4)	(100.0%)	0.2%	0.0%
Solar	$0.0	$0.1	$0.1	6,342.6%	0.0%	0.1%
Steam - Coal	$42.3	$15.5	($26.7)	(63.3%)	24.0%	22.0%
Steam - Other	$17.8	$2.0	($15.8)	(88.7%)	10.1%	2.8%
Wind	$1.5	$0.2	($1.3)	(88.5%)	0.8%	0.2%
Total	$176.3	$70.6	($105.7)	(60.0%)	100.0%	100.0%

Table 4-3 shows the distribution of energy uplift credits by category and by unit type in the first nine months of 2019. The characteristics of the different unit types explain why the shares of credit types are dominated by a particular unit type. For example, the majority of day-ahead credits, 96.7 percent, go to steam units. This is because steam units tend to be longer lead time units that need to be committed before the operating day. If a steam unit is needed for reliability and it is uneconomic it will be committed in the Day-Ahead Energy Market and receive day-ahead credits. Coal fired steam units received 48.3 percent of all reactive service credits as a result of the specific locations of the voltage issues and the location of the units. Combustion turbines, which, unlike other unit types, can be committed and decommitted in the real-time market, received 85.5 percent of balancing credits and 93.5 percent of lost opportunity credits. Combustion turbines committed in the real-time market require balancing credits as result of inflexible operating parameters, volatile real-time LMPs, and intraday segment settlements. Combustion turbines with a day-ahead schedule and not committed in real time will receive lost opportunity credits when they incur a loss as a result of not operating. A unit incurs a loss when the real time LMPs are greater than the day-ahead LMPs at the unit’s pricing node and the unit’s balancing charges are greater than its day-ahead revenues.

10 Table 4-2 does not include balancing imports credits and load response credits in the total amounts.
11 Solar units should be ineligible for all uplift payments because they do not follow PJM’s dispatch instructions. The MMU notified PJM of the discrepancy.

Table 4-3 Energy uplift credits by unit type: January through September, 2019

Unit Type	Day-Ahead Generator	Balancing Generator	Canceled Resources	Local Constraints Control	Lost Opportunity Cost	Reactive Services	Synchronous Condensing	Black Start Services
Combined Cycle	2.9%	4.5%	0.0%	8.3%	3.3%	0.0%	0.0%	26.8%
Combustion Turbine	0.3%	85.5%	0.0%	86.5%	93.5%	50.1%	0.0%	73.2%
Diesel	0.0%	0.7%	0.0%	4.9%	1.3%	1.7%	0.0%	0.1%
Hydro	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Nuclear	0.0%	0.0%	0.0%	0.0%	0.0%	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	90.9%	6.2%	0.0%	0.0%	0.5%	48.3%	0.0%	0.0%
Steam - Other	5.8%	2.8%	0.0%	0.0%	0.5%	0.0%	0.0%	0.0%
Wind	0.0%	0.1%	0.0%	0.4%	0.9%	0.0%	0.0%	0.0%
Total (Millions)	$13.9	$40.8	$0.0	$2.7	$12.8	$0.5	$0.0	$0.2

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 that would have otherwise not have 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.[12] 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.[13] Units committed for reliability by PJM are eligible for day-ahead operating reserve credits and may set LMP if raised above economic minimum and follow the dispatch signal. Table 4-4 shows the total day-ahead generation and the subset of that generation committed for reliability by PJM. In the first nine months of 2019, 0.3 percent of the total day-ahead generation was committed for reliability by PJM, 1.2 percentage points lower than in the first nine months of 2018. The decrease is the result of a decrease in the need to commit uneconomic steam coal units for reliability in the BGE and Pepco zones as they have been displaced by new combined cycle units in the Pepco Zone. For day ahead reactive service credits, transmission upgrades in MISO reduced commitments for reliability in ComEd, and account for the decrease of 98.4 percent in the first nine months of 2019 compared to the first nine months of 2018.

12 See PJM Operating Agreement Schedule 1 § 3.2.3(b).

13 See PJM. "PJM Markets Gateway User Guide," Section Managing Unit Data (version July 16, 2018) at 33, <http://www.pjm.com/-/media/etools/markets-gateway/markets-gateway-user-guide.ashx?la=en>.

Table 4-4 Day-ahead generation committed for reliability (GWh): January 2018 through September 2019

	2018			2019		
	Total Day-Ahead Generation	Day-Ahead PJM Must Run Generation	Share	Total Day-Ahead Generation	Day-Ahead PJM Must Run Generation	Share
Jan	78,368	1,209	1.5%	77,616	81	0.1%
Feb	63,095	780	1.2%	66,102	91	0.1%
Mar	67,699	1,712	2.5%	68,331	305	0.4%
Apr	59,019	967	1.6%	57,926	0	0.0%
May	65,017	1,799	2.8%	63,432	131	0.2%
Jun	71,001	1,188	1.7%	67,899	301	0.4%
Jul	79,653	846	1.1%	83,474	327	0.4%
Aug	80,864	476	0.6%	77,632	367	0.5%
Sep	69,596	659	0.9%	69,009	357	0.5%
Oct	64,003	533	0.8%			
Nov	64,183	744	1.2%			
Dec	70,864	215	0.3%			
Total (Jan - Sep)	634,312	9,636	1.5%	631,423	1,960	0.3%
Total	833,362	11,128	1.3%	631,423	1,960	0.3%

Pool scheduled units and units committed for reliability 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. Total day-ahead operating reserve credits in the first nine months of 2019 were $13.9 million. The top 10 units received $12.5 million or 89.7 percent of all day-ahead operating reserve credits. These units were large units with long commitment times and inflexible operating parameters.

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 4-5 shows the total day-ahead generation committed for reliability by PJM by category. In the first nine months of 2019, 47.8 percent of the day-ahead generation committed for reliability by PJM received operating reserve credits, of which 32.0 percent was paid as day-ahead operating reserve credits. The remaining 52.2 percent of the day-ahead generation committed for reliability by PJM was economic and did not need to be made whole.

Table 4-5 Day-ahead generation committed for reliability by category (GWh): January through September, 2019

	Reactive Services (GWh)	Day-Ahead Operating Reserves (GWh)	Economic (GWh)	Total (GWh)
Jan	0	35	46	81
Feb	0	58	33	91
Mar	0	222	83	305
Apr	170	163	634	967
May	273	632	893	1,799
Jun	256	532	400	1,188
Jul	79	224	543	846
Aug	95	82	300	476
Sep	142	103	414	659
Oct				
Nov				
Dec				
Total (Jan - Sep)	1,014	2,051	3,347	6,412
Share	15.8%	32.0%	52.2%	100.0%

Total day-ahead operating reserve credits in the first nine months of 2019 were $13.9 million, of which $11.4 million or 81.6 percent was paid to units committed for reliability by PJM, and not scheduled to provide black start or reactive services. An additional $0.2 million or 1.3 percent was paid to units scheduled to provide black start or reactive services or were pool scheduled in the Day-Ahead Energy Market

Balancing Operating Reserve Credits

Balancing operating reserve (BOR) credits are paid to resources operating at PJM's request that do not recover their operating costs from market revenues. BOR credits are calculated as the difference between a resource's revenues (day-ahead market, balancing market, ancillary markets, and day-ahead operating reserve credits) and its real-time costs (startup, no load, and energy offer). Combustion turbines (CTs) received $34.8 million or 85.5 percent of all balancing operating reserve (BOR) credits in the first nine months of 2019. The majority of these credits, 97.7 percent, are paid to CTs that are committed in real time either without or outside of a day-ahead schedule.[14] Such CTs generally are only economic for a short period compared to their minimum run time; operate on more expensive real-time offers compared to day-ahead offers; and are block loaded and provide more energy than is otherwise needed by the system. Uplift is higher than necessary because settlement rules do not include all revenues and costs for the entire day.

Balancing operating reserve credits for generators decreased by 45.9 percent from the first nine months of 2018 to the first nine months of 2019. The decrease was a result of lower natural gas prices in January 2018. Balancing operating reserve credits for generators during the winter months of January through March decreased by $26.5 million in 2019 compared with 2018. The decrease during winter months accounted for 76.5 percent of the total decrease of $34.6 million during the first nine months of 2019.

The credits paid to CTs committed in real time without a day-ahead commitment occurs despite the fact that combustion turbines are committed in the Day-Ahead Energy Market at levels comparable to the Real-Time Energy Market. Table 4-6 shows the monthly day-ahead and real-time generation by combustion turbines. In the first nine months of 2019, generation by combustion turbines was 25.8 percent greater in the Real-Time Energy Market compared to the Day-Ahead Energy Market. However, this varied month to month, with some months having greater day-ahead generation compared to real-time generation. Table 4-6 shows that only 5.3 percent of generation

14 Operating outside of a day-ahead schedule refers to units that operate for a period either before or after their day-ahead schedule, or are committed in the real-time market and do not have a day-ahead schedule for any part of the day.

from combustion turbines in the day-ahead market was uneconomic and did not need day-ahead generator credits. In the Real-Time Energy Market, 29.5 percent of generation from combustion turbines was uneconomic and required $34.8 million in BOR credits.

Table 4-6 Characteristics of day-ahead and real-time generation by combustion turbines: January through September, 2019

Month	Day-Ahead Generation (GWh)	Percent of Day-Ahead Generation that was Noneconomic	Day-Ahead Generator Credits (Millions)	Real-Time Generation (GWh)	Percent of Real-Time Generation that was Noneconomic	Balancing Generator Credits (Millions)	Generation Difference as a Percent of Real-Time Generation
Jan	261	9.5%	$0.0	227	46.6%	$4.0	(15.1%)
Feb	111	1.7%	$0.0	225	51.1%	$2.1	50.5%
Mar	230	0.9%	$0.0	372	43.2%	$3.1	38.0%
Apr	303	1.6%	$0.0	495	46.1%	$3.2	38.8%
May	514	6.3%	$0.0	595	27.2%	$1.6	13.6%
Jun	600	8.7%	$0.0	872	31.2%	$3.7	31.2%
Jul	2,080	5.1%	$0.0	2,866	26.2%	$8.0	27.4%
Aug	1,445	5.9%	$0.0	2,051	26.0%	$4.2	29.5%
Sep	1,450	4.0%	$0.0	1,723	26.5%	$5.0	15.8%
Total (Jan - Sep)	6,993	5.3%	$0.0	9,425	29.5%	$34.8	25.8%

An analysis of real-time generation by combustion turbines shows that BOR credits are incurred almost exclusively by combustion turbines that operate without or outside a day-ahead schedule. Table 4-7 shows that in the first nine months of 2019, 53.3 percent of real-time generation by CTs was from CTs that operated on a day-ahead schedule. Of the generation from CTs operating on a day-ahead schedule, 23.8 percent was uneconomic in the real-time market and did not received BOR credits. Of the 46.7 percent of real-time generation by CTs that operated outside of a day-ahead schedule, 36.0 percent was uneconomic in the real-time market and received $34.0 million in BOR credits. Thus while enough total generation from CTs is committed economically in the Day-Ahead Energy Market, uplift is incurred because the committed units operate at different times than originally scheduled and when CTs that were not committed day ahead operate in real time. For example, in January 2019, although total CT generation committed in the day-ahead market was greater than CT generation in real time, only 51.3 percent of real-time generation by CTs operated on a day-ahead schedule.

There are multiple reasons why the commitment of CTs is different in the day-ahead and real-time markets, including: differences in the hourly pattern of load; differences in interchange transactions; and behavior by other generators. Modeling differences between the day-ahead and real-time markets also affect CT commitment, including: the modeling of different transmission constraints in the day-ahead and real-time market models; the exclusion of soak time for generators in the day-ahead market model; and the different time scales used in the day-ahead and real-time markets.

Table 4-7 Real-time generation by combustion turbines by day-ahead commitment: January through September, 2019

	Real-Time Generation Operating on a Day-Ahead Schedule				Real-Time Generation Operating Outside of a Day-Ahead Schedule			
Month	Generation (GWh)	Share of Real-Time Generation	Percent of Generation that was Noneconomic	Balancing Generator Credits (Millions)	Generation (GWh)	Share of Real-Time Generation	Percent of Generation that was Noneconomic	Balancing Generator Credits (Millions)
Jan	110	48.7%	26.3%	$0.0	116	51.3%	65.9%	$4.0
Feb	48	21.5%	28.6%	$0.0	177	78.5%	57.3%	$2.1
Mar	134	36.0%	27.5%	$0.0	238	64.0%	52.1%	$3.1
Apr	184	37.2%	28.0%	$0.0	311	62.8%	56.8%	$3.2
May	303	51.0%	20.5%	$0.0	292	49.0%	34.1%	$1.6
Jun	414	47.5%	28.2%	$0.1	458	52.5%	33.8%	$3.6
Jul	1,678	58.6%	23.8%	$0.1	1,188	41.4%	29.6%	$7.9
Aug	1,138	55.5%	26.7%	$0.1	913	44.5%	25.1%	$4.1
Sep	1,013	58.8%	18.1%	$0.5	709	41.2%	38.6%	$4.5
Total (Jan - Sep)	5,023	53.3%	23.8%	$0.8	4,401	46.7%	36.0%	$34.0

Lost Opportunity Cost Credits

Balancing operating reserve lost opportunity cost (LOC) credits are intended to provide an incentive for units to follow PJM's dispatch instructions when PJM's dispatch instructions deviate from a unit's desired or scheduled output. LOC credits are paid under two different scenarios. The first scenario occurs if a unit of any type 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 its desired output. This LOC will be referred to as real-time LOC. The second scenario occurs if a combustion turbine or diesel engine is scheduled 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 any loss in the day-ahead financial position of the unit plus the balancing spot energy market position. This LOC will be referred to as day-ahead LOC.

Table 4-8 shows monthly day-ahead and real-time LOC credits in 2018 and the first nine months of 2019. In the first nine months of 2019, LOC credits decreased by $36.0 million or 74.1 percent compared to the first nine months of 2018. The decrease of $36.0 million is comprised of a $22.5 million decrease in day-ahead LOC and a $13.0 million decrease in real-time LOC. The significant reduction in LOC credits was the result of a milder winter in 2019 compared to 2018. Increased operator awareness of LOC and decreased uplift eligibility also contributed to the overall decrease. Table 4-9 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 the first nine months of 2019, 11.6 percent of day-ahead generation by combustion turbines and diesels was not requested in real time, 4.0 percentage points lower than in the first nine months of 2018.

Table 4-8 Monthly lost opportunity cost credits (Millions): January 2018 through September 2019

	2018			2019		
	Day-Ahead Lost Opportunity Cost	Real-Time Lost Opportunity Cost	Total	Day-Ahead Lost Opportunity Cost	Real-Time Lost Opportunity Cost	Total
Jan	$13.7	$8.0	$21.7	$0.4	$0.3	$0.7
Feb	$0.1	$0.0	$0.2	$0.1	$0.0	$0.2
Mar	$3.2	$0.2	$3.4	$0.4	$0.0	$0.5
Apr	$2.0	$1.9	$3.9	$0.5	$0.0	$0.5
May	$6.0	$2.8	$8.8	$1.6	$0.1	$1.6
Jun	$3.5	$0.0	$3.5	$0.7	$0.0	$0.7
Jul	$2.1	$0.0	$2.1	$1.9	$0.0	$2.0
Aug	$1.7	$0.1	$1.9	$1.7	$0.0	$1.7
Sep	$2.2	$0.7	$2.8	$4.7	$0.2	$4.9
Oct	$1.8	$0.7	$2.4			
Nov	$0.6	$0.2	$0.8			
Dec	$0.7	$0.1	$0.7			
Total (Jan - Sep)	$34.6	$13.7	$48.3	$12.1	$0.7	$12.8
Share (Jan - Sep)	71.6%	28.4%	100.0%	94.3%	5.7%	100.0%
Total	$37.6	$14.7	$52.3	$12.1	$0.7	$12.8

Table 4-9 Day-ahead generation from combustion turbines and diesels (GWh): January 2018 through September 2019

	2018			2019		
	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	1,899	382	223	692	38	13
Feb	301	40	19	370	19	4
Mar	1,018	250	109	524	48	12
Apr	1,379	204	71	619	71	21
May	2,095	378	149	848	171	49
Jun	1,432	328	105	938	130	46
Jul	2,343	279	101	2,555	198	69
Aug	1,972	181	71	1,901	198	110
Sep	1,885	200	68	1,808	321	163
Oct	1,398	149	71			
Nov	608	42	15			
Dec	318	37	11			
Total (Jan - Sep)	14,324	2,242	915	10,255	1,193	487
Share (Jan - Sep)	100.0%	15.6%	6.4%	100.0%	11.6%	4.7%
Total	16,648	2,470	1,012	10,255	1,193	487

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 4-10 provides a description of commitment and dispatch status, uplift eligibility and the ability to set price.[15] 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 unable to recover their operating cost for the day or segment.[16]

15 PJM has modified the basic rules of eligibility to set price using its CT price setting logic.
16 Resources do not recover their operating cost when market revenues for the day are less than the short run marginal cost defined by the startup, no load, and incremental offer curve.

Table 4-10 Dispatch status, commitment status and uplift eligibility[17]

Dispatch Status	Dispatch Description	Eligible to Set LMP	Commitment Status: Self Scheduled (units committed by the generation owner)	Commitment Status: 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 4-11 shows day-ahead and real-time generation by commitment and dispatch status. Table 4-11 shows that in the first nine months of 2019, 38.9 percent of generation was pool scheduled in the Day-Ahead Energy Market and 41.5 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 57.7 percent of real-time generation, are self scheduled.

Table 4-11 Day-ahead and real-time generation by status and eligibility to set LMP (GWh): January through September, 2019

	Self Scheduled			Pool Scheduled						
	Dispatchable	Economic Minimum	Block Loaded	Dispatchable	Economic Minimum	Block Loaded	Total GWh	Total Pool Scheduled	Total Self Scheduled	Total Generation Eligible to Set Price
Day-Ahead Generation	77,677	148,164	159,699	108,237	121,880	15,766	631,423	245,883	385,540	185,914
Share of Day-Ahead	12.3%	23.5%	25.3%	17.1%	19.3%	2.5%	100.0%	38.9%	61.1%	29.4%
Real-Time Generation	63,092	132,725	174,089	105,499	136,481	20,334	632,220	262,314	369,906	168,591
Share of Real-Time	10.0%	21.0%	27.5%	16.7%	21.6%	3.2%	100.0%	41.5%	58.5%	26.7%

Economic and Noneconomic Generation[18]

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 to or produce energy in real time at an incremental offer higher than the LMP at 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.

17 PJM allows block loaded CTs to set LMP by relaxing the economic minimum by 10 to 20 percent.
18 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.

Table 4-12 shows the day-ahead and real-time economic and noneconomic generation from units eligible for operating reserve credits. In the first nine months of 2019, 82.7 percent of the day-ahead generation eligible for operating reserve credits was economic and 67.0 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 4-12 shows the separate amounts of economic and noneconomic generation even if the daily or segment generation was economic.

Table 4-12 Economic and noneconomic generation from units eligible for operating reserve credits (GWh): January through September, 2019

Energy Market	Economic Generation	Noneconomic Generation	Total Eligible Generation	Economic Generation Percent	Noneconomic Generation Percent
Day-Ahead	203,259	42,624	245,883	82.7%	17.3%
Real-Time	148,678	73,068	221,746	67.0%	33.0%

Noneconomic generation only leads to operating reserve credits when a unit is unable to recover its operating costs for the day or segment. Table 4-13 shows the generation receiving day-ahead and balancing operating reserve credits. In the first nine months of 2019, 1.0 percent of the day-ahead generation eligible for operating reserve credits received credits and 1.5 percent of the real-time generation eligible for operating reserve credits received credits.

Table 4-13 Generation receiving operating reserve credits (GWh): January through September, 2019

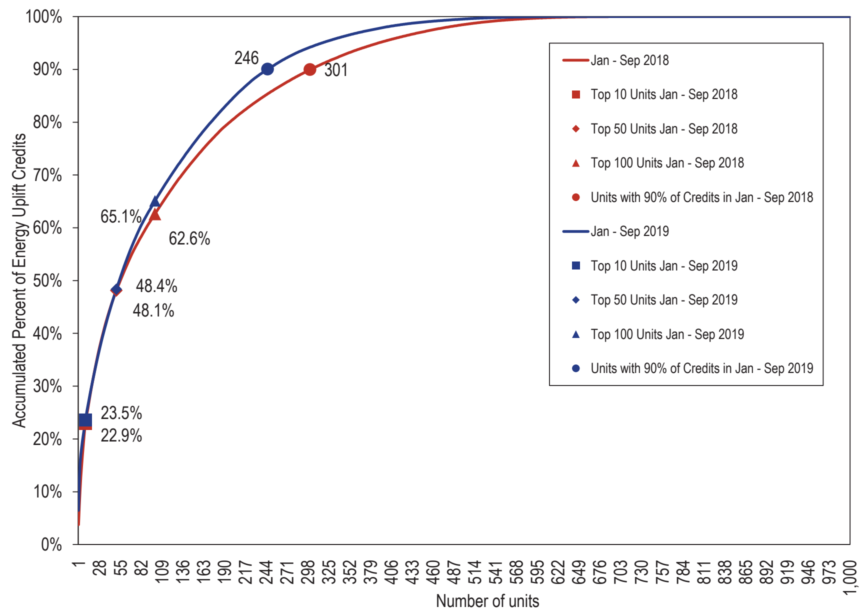
Energy Market	Generation Eligible for Operating Reserve Credits	Generation Receiving Operating Reserve Credits	Generation Receiving Operating Reserve Credits Percent
Day-Ahead	245,883	2,355	1.0%
Real-Time	221,746	3,394	1.5%

Concentration of Energy Uplift Credits

There is 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.[19]

Figure 4-1 shows the concentration of energy uplift credits. The top 10 units received 23.5 percent of total energy uplift credits in the first nine months of 2019, compared to 22.9 percent in the first nine months of 2018. In the first nine months of 2019, 246 units received 90 percent of all energy uplift credits, compared to 301 units in the first nine months of 2018.

Figure 4-1 Cumulative share of energy uplift credits: January through September, 2018 and 2019 by unit



19 As a result of FERC Order No. 844, PJM began publishing total uplift credits by unit by month for credits incurred on and after July 1, 2019 on September 10, 2019.

Table 4-14 shows the credits received by the top 10 units and top 10 organizations in each of the energy uplift categories paid to generators in the first nine months of 2019.

Table 4-14 Top 10 units and organizations energy uplift credits: January through September, 2019

		Top 10 Units		Top 10 Organizations	
Category	Type	Credits (Millions)	Credits Share	Credits (Millions)	Credits Share
Day-Ahead	Generators	$12.5	89.7%	$13.8	98.7%
Balancing	Canceled Resources	$0.0	0.0%	$0.0	0.0%
	Generators	$4.9	12.0%	$30.1	73.7%
	Local Constraints Control	$1.8	67.2%	$2.7	100.0%
	Lost Opportunity Cost	$3.3	26.4%	$9.4	74.4%
Reactive Services		$0.5	96.9%	$0.5	100.0%
Synchronous Condensing		$0.0	0.0%	$0.0	0.0%
Black Start Services		$0.1	48.9%	$0.1	89.1%
Total		$16.7	23.6%	$51.9	73.5%

Table 4-15 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 2019, 64.1 percent of all credits paid to these units were allocated to deviations while the remaining 35.9 percent were paid for reliability reasons.

Table 4-15 Balancing operating reserve credits to top 10 units by category and region: January through September, 2019

	Reliability			Deviations			
	RTO	East	West	RTO	East	West	Total
Credits (Millions)	$1.6	$0.1	$0.0	$3.0	$0.1	$0.0	$4.9
Share	32.2%	2.8%	0.9%	60.7%	3.0%	0.4%	100.0%

In the first nine months of 2019, concentration in all energy uplift credit categories was high.[20] [21] The HHI for energy uplift credits was calculated based on each organization's share of daily credits for each category. Table 4-16 shows the average HHI for each category. HHI for day-ahead operating reserve credits to generators was 8500, for balancing operating reserve credits to generators was 3340, for lost opportunity cost credits was 5789 and for reactive services credits was 9802. All of these HHI values are characterized as highly concentrated.

Table 4-16 Daily energy uplift credits HHI: January through September, 2019

Category	Type	Average	Minimum	Maximum	Highest Market Share (One day)	Highest Market Share (All days)
Day-Ahead	Generators	8500	2646	10000	100.0%	61.5%
	Imports	10000	10000	10000	100.0%	100.0%
	Load Response	9903	9708	10000	100.0%	99.1%
Balancing	Canceled Resources	NA	NA	NA	NA	NA
	Generators	3340	772	10000	100.0%	25.3%
	Imports	NA	NA	NA	NA	NA
	Load Response	NA	NA	NA	NA	NA
	Lost Opportunity Cost	5789	1083	10000	100.0%	24.4%
Reactive Services		9802	5518	10000	100.0%	39.2%
Synchronous Condensing		NA	NA	NA	NA	NA
Black Start Services		9374	5727	10000	100.0%	21.4%
Total		3220	725	10000	100.0%	17.6%

Unit Specific Uplift Payments

FERC Order No. 844 allows PJM and the MMU to publish unit specific uplift payments by category by month. Table 4-17 through Table 4-20 show the top 10 recipients of total uplift, day-ahead operating reserve credits and lost opportunity cost credits.

Table 4-17 Top 10 recipients of total uplift: July through September, 2019

Rank	Unit Name	Zone	Total Uplift Credit
1	BC BRANDON SHORES 1 F	BGE	$2,075,673
2	BC BRANDON SHORES 2 F	BGE	$1,998,368
3	DPL INDIAN RIVER 4 F	DPL	$637,876
4	PEP CHALKPOINT 4 F	Pepco	$475,644
5	COM 900 ELWOOD 9 CT	ComEd	$453,035
6	COM 900 ELWOOD 7 CT	ComEd	$425,105
7	COM 900 ELWOOD 8 CT	ComEd	$420,314
8	COM 900 ELWOOD 6 CT	ComEd	$416,278
9	COM 900 ELWOOD 3 CT	ComEd	$413,926
10	COM 900 ELWOOD 5 CT	ComEd	$389,076
Total (Jul-Sep)			$7,705,296
Share of total uplift credits			22.7%

20 See the *2019 Quarterly State of the Market Report for PJM: January through September*, Section 3: "Energy Market" at "Market Concentration" for a discussion of concentration ratios and the Herfindahl-Hirschman Index (HHI).
21 Table 4-16 excludes local constraint control categories.

Table 4-18 Top 10 recipients of day-ahead generation credits: July through September, 2019

Rank	Unit Name	Zone	Day-Ahead Operating Reserve Credit
1	BC BRANDON SHORES 1 F	BGE	$2,021,919.2
2	BC BRANDON SHORES 2 F	BGE	$1,965,831
3	DPL INDIAN RIVER 4 F	DPL	$562,508
4	PEP MORGANTOWN 1 F	Pepco	$176,306
5	PEP CHALKPOINT 2 F	Pepco	$160,435
6	DPL VIENNA 8 F	DPL	$117,513
7	PEP CHALKPOINT 1 F	Pepco	$113,532
8	PEP CHALKPOINT 3 F	Pepco	$88,817
9	COM 3 POWERTON 6	ComEd	$69,859
10	PEP CHALKPOINT 4 F	Pepco	$63,487
Total (Jul-Sep)			$5,340,207
Share of total day-ahead operating reserve credits			93.4%

Table 4-19 Top 10 recipients of balancing operating reserve credits: July through September, 2019

Rank	Unit Name	Zone	Balancing Operating Reserve Credit
1	PEP CHALKPOINT 4 F	Pepco	$412,158
2	BC WESTPORT 5 CT	BGE	$293,687
3	AEP FOOT HILLS 2 CT	AEP	$282,523
4	FE LEMOYNE 2 CT	ATSI	$272,152
5	AEP RIVERSIDE ZELDA 3 CT	AEP	$240,516
6	COM 952 ROCKFORD 11 CT	ComEd	$236,435
7	AEP RIVERSIDE ZELDA 1 CT	AEP	$235,660
8	COM 952 ROCKFORD 12 CT	ComEd	$234,139
9	DPL VIENNA 8 F	DPL	$230,753
10	AEP RIVERSIDE ZELDA 2 CT	AEP	$219,711
Total (Jul-Sep)			$2,657,733
Share of balancing operating reserve credits			13.6%

Table 4-20 Top 10 recipients of lost opportunity cost credits: July through September, 2019

Rank	Unit Name	Zone	Lost Opportunity Cost Credit
1	COM 900 ELWOOD 9 CT	ComEd	$386,219
2	COM 900 ELWOOD 3 CT	ComEd	$367,792
3	COM 900 ELWOOD 8 CT	ComEd	$366,269
4	COM 900 ELWOOD 7 CT	ComEd	$356,673
5	COM 900 ELWOOD 6 CT	ComEd	$321,856
6	COM 900 ELWOOD 1 CT	ComEd	$317,010
7	COM 900 ELWOOD 4 CT	ComEd	$312,184
8	COM 900 ELWOOD 2 CT	ComEd	$309,954
9	COM 900 ELWOOD 5 CT	ComEd	$280,878
10	DPL DEMEC - CLAYTON 2 CT	DPL	$251,464
Total (Jul-Sep)			$3,270,298
Share of total lost opportunity cost credits			37.8%

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 4-21 and Table 4-22 show the categories of credits and charges and their relationship. These tables show how the charges are allocated.

Table 4-21 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				
Lost Opportunity Cost (LOC)	Balancing Operating Reserve LOC	→	Balancing Operating Reserve for Deviations	Deviations	in RTO Region
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 4-22 Reactive services, synchronous condensing and black start services credits and charges

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

Energy Uplift Results

Energy Uplift Charges

Total energy uplift charges decreased by $106.3 million or 60.1 percent in the first nine months of 2019 compared to the first nine months of 2018.

Table 4-23 shows total energy uplift charges by category in the first nine months of 2018 and 2019.[22] The decrease of $106.3 million is comprised of a decrease of $17.8 million in day-ahead operating reserve charges, a decrease of $76.4 million in balancing operating reserve charges and a decrease of $11.9 million in reactive service charges.

Table 4-23 Total energy uplift charges by category: January through September, 2018 and 2019

Category	(Jan - Sep) 2018 Charges (Millions)	(Jan - Sep) 2019 Charges (Millions)	Change (Millions)	Percent Change
Day-Ahead Operating Reserves	$31.8	$14.0	($17.8)	(56.1%)
Balancing Operating Reserves	$132.5	$56.1	($76.4)	(57.7%)
Reactive Services	$12.4	$0.5	($11.9)	(96.2%)
Synchronous Condensing	$0.0	$0.0	($0.0)	(100.0%)
Black Start Services	$0.2	$0.2	($0.0)	(16.2%)
Total	$176.9	$70.6	($106.3)	(60.1%)
Energy Uplift as a Percent of Total PJM Billing	0.5%	0.2%	0.2%	37.6%

Table 4-24 compares monthly energy uplift charges by category for 2018 and the first nine months of 2019.

Table 4-24 Monthly energy uplift charges: January 2018 through September 2019

	2018 Charges (Millions)						2019 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	$4.8	$55.4	$1.9	$0.0	$0.0	$62.1	$1.0	$6.5	$0.1	$0.0	$0.0	$7.6
Feb	$3.6	$1.9	$2.2	$0.0	$0.0	$7.8	$0.8	$3.9	$0.0	$0.0	$0.0	$4.7
Mar	$4.6	$6.4	$1.9	$0.0	$0.0	$12.9	$2.3	$4.6	$0.0	$0.0	$0.0	$6.9
Apr	$2.1	$9.6	$1.2	$0.0	$0.1	$12.9	$0.1	$4.0	$0.0	$0.0	$0.0	$4.2
May	$6.9	$16.1	$2.2	$0.0	$0.1	$25.2	$1.4	$4.1	$0.1	$0.0	$0.1	$5.7
Jun	$5.7	$11.9	$1.3	$0.0	$0.0	$18.9	$2.6	$4.8	$0.2	$0.0	$0.0	$7.5
Jul	$2.1	$9.5	$0.5	$0.0	$0.0	$12.1	$1.4	$10.8	$0.0	$0.0	$0.0	$12.2
Aug	$0.7	$8.8	$0.2	$0.0	$0.0	$9.8	$2.7	$6.8	$0.0	$0.0	$0.0	$9.5
Sep	$1.3	$12.8	$1.0	$0.0	$0.0	$15.2	$1.66	$10.6	$0.0	$0.0	$0.0	$12.3
Oct	$1.0	$8.6	$0.6	$0.0	$0.1	$10.3						
Nov	$0.6	$7.0	$0.2	$0.0	$0.0	$7.9						
Dec	$0.5	$2.6	$0.0	$0.0	$0.0	$3.2						
Total (Jan - Sep)	$31.8	$132.5	$12.4	$0.0	$0.2	$176.9	$14.0	$56.1	$0.5	$0.0	$0.2	$70.6
Share (Jan - Sep)	18.0%	74.9%	7.0%	0.0%	0.1%	100.0%	19.8%	79.4%	0.7%	0.0%	0.2%	100.0%
Total	$34.0	$150.8	$13.2	$0.0	$0.3	$198.3	$14.0	$56.1	$0.5	$0.0	$0.2	$70.6
Share	17.1%	76.0%	6.6%	0.0%	0.2%	100.0%	19.8%	79.4%	0.7%	0.0%	0.2%	100.0%

22 Table 4-23 includes all categories of charges as defined in Table 4-21 and Table 4-22 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, 2019. The 2018 uplift charges differ from the 2018 uplift credits by $0.1 million in the PJM data although they should be equal. The MMU is investigating.

Table 4-25 shows the composition of 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.[23] Day-ahead operating reserve charges decreased by $17.8 million or 56.1 percent in the first nine months of 2019 compared to the first nine months of 2018. Day-ahead operating reserve charges decreased in the first nine months of 2019 as a result of a decrease in day-ahead unit commitments for reliability. The decrease in day-ahead operating reserve credits paid to units in Pepco and BGE combined accounted for 56.1 percent of the total decrease in day-ahead operating reserve charges in the first nine months of 2019 compared to the first nine months of 2018.

Table 4-25 Day-ahead operating reserve charges: January through September, 2018 and 2019

Type	(Jan - Sep) 2018 Charges (Millions)	(Jan - Sep) 2019 Charges (Millions)	Change (Millions)	(Jan - Sep) 2018 Share	(Jan - Sep) 2019 Share
Day-Ahead Operating Reserve Charges	$31.8	$14.0	($17.8)	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	$31.8	$14.0	($17.8)	100.0%	100.0%

Table 4-26 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 $76.4 million or 57.5 percent in the first nine months of 2019 compared to the first nine months of 2018.

Table 4-26 Balancing operating reserve charges: January through September, 2018 and 2019

Type	(Jan - Sep) 2018 Charges (Millions)	(Jan - Sep) 2019 Charges (Millions)	Change (Millions)	(Jan - Sep) 2018 Share	(Jan - Sep) 2019 Share
Balancing Operating Reserve Reliability Charges	$30.8	$17.1	($13.7)	23.3%	30.6%
Balancing Operating Reserve Deviation Charges	$93.7	$36.2	($57.5)	70.7%	64.6%
Balancing Operating Reserve Charges for Load Response	$0.0	$0.0	($0.0)	0.0%	0.0%
Balancing Local Constraint Charges	$8.0	$2.7	($5.3)	6.0%	4.8%
Total	$132.5	$56.1	($76.4)	100.0%	100.0%

Table 4-27 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 scheduled by PJM but canceled by PJM before coming online. In the first nine months of 2019, energy lost opportunity cost deviation charges decreased by $36.0 million or 74.1 percent, and make whole deviation charges decreased by $21.4 million or 47.5 percent compared to the first nine months of 2018.

23 See PJM Operating Agreement 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 only 10 times since 1999, totaling $26.9 million.

Table 4-27 Balancing operating reserve deviation charges: January through September, 2018 and 2019

Charge Attributable To	(Jan - Sep) 2018 Charges (Millions)	(Jan - Sep) 2019 Charges (Millions)	Change (Millions)	(Jan - Sep) 2018 Share	(Jan - Sep) 2019 Share
Make Whole Payments to Generators and Imports	$45.1	$23.7	($21.4)	48.1%	65.3%
Energy Lost Opportunity Cost	$48.6	$12.6	($36.0)	51.9%	34.7%
Canceled Resources	$0.0	$0.0	$0.0	0.0%	0.0%
Total	$93.7	$36.2	($57.5)	100.0%	100.0%

Table 4-28 shows reactive services, synchronous condensing and black start services charges. Reactive services charges decreased by $11.9 million or 96.2 percent in the first nine months of 2019, compared to the first nine months of 2018. The decrease in reactive service charges resulted from a decrease in the need for reactive service in ComEd.

Table 4-28 Additional energy uplift charges: January through September, 2018 and 2019

Type	(Jan - Sep) 2018 Charges (Millions)	(Jan - Sep) 2019 Charges (Millions)	Change (Millions)	(Jan - Sep) 2018 Share	(Jan - Sep) 2019 Share
Reactive Services Charges	$12.4	$0.5	($11.9)	98.2%	74.5%
Synchronous Condensing Charges	$0.0	$0.0	($0.0)	0.3%	0.0%
Black Start Services Charges	$0.2	$0.2	($0.0)	1.5%	25.5%
Total	$12.6	$0.6	($12.0)	100.0%	100.0%

Table 4-29 and Table 4-30 show the amount and shares of regional balancing charges in the first nine months of 2018 and 2019. Regional balancing operating reserve charges consist of balancing operating reserve reliability and deviation charges. These charges are allocated regionally across PJM. In the first nine months of 2019 the largest share of regional charges was paid by real-time load which paid 30.9 percent of all regional balancing charges. The regional balancing charges allocation table does not include charges attributed for resources controlling local constraints.

In the first nine months of 2019 regional balancing operating reserve charges decreased by $ 71.2 million compared to the first nine months of 2018. Balancing operating reserve reliability charges decreased by $13.7 million or 44.4 percent, and balancing operating reserve deviation charges decreased by $57.5 million, or 61.3 percent.

Table 4-29 Regional balancing charges allocation (Millions): January through September, 2018

Charge	Allocation	RTO		East		West		Total	
Reliability Charges	Real-Time Load	$26.2	21.1%	$2.3	1.8%	$1.4	1.1%	$29.9	24.0%
	Real-Time Exports	$0.8	0.6%	$0.1	0.1%	$0.0	0.0%	$0.9	0.7%
	Total	$27.0	21.7%	$2.4	1.9%	$1.4	1.1%	$30.8	24.7%
Deviation Charges	Demand	$50.8	40.8%	$1.3	1.0%	$2.2	1.8%	$54.3	43.6%
	Supply	$15.3	12.3%	$0.5	0.4%	$0.6	0.5%	$16.4	13.2%
	Generator	$21.5	17.2%	$0.6	0.5%	$1.0	0.8%	$23.1	18.5%
	Total	$87.5	70.3%	$2.4	1.9%	$3.8	3.1%	$93.8	75.3%
Total Regional Balancing Charges		$114.6	92.0%	$4.8	3.8%	$5.2	4.2%	$124.6	100%

Table 4-30 Regional balancing charges allocation (Millions): January through September, 2019

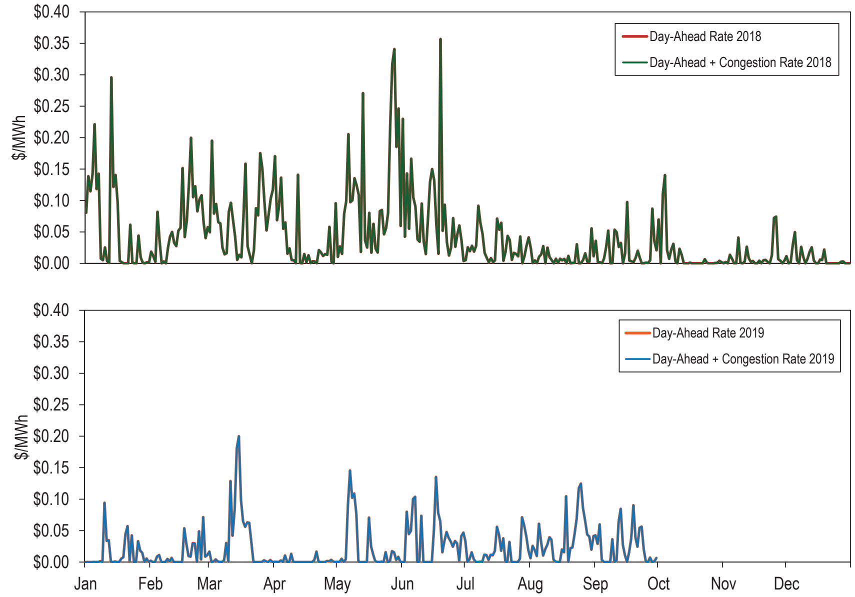
Charge	Allocation	RTO		East		West		Total	
Reliability Charges	Real-Time Load	$14.9	28.0%	$1.1	2.1%	$0.5	0.9%	$16.5	30.9%
	Real-Time Exports	$0.6	1.1%	$0.0	0.1%	$0.0	0.0%	$0.6	1.2%
	Total	$15.5	29.1%	$1.1	2.1%	$0.5	0.9%	$17.1	32.1%
Deviation Charges	Demand	$21.2	39.6%	$0.8	1.6%	$0.3	0.6%	$22.3	41.8%
	Supply	$5.6	10.5%	$0.3	0.5%	$0.1	0.2%	$6.0	11.2%
	Generator	$7.4	13.9%	$0.4	0.7%	$0.1	0.2%	$7.9	14.8%
	Total	$34.2	64.1%	$1.5	2.7%	$0.6	1.0%	$36.2	67.9%
Total Regional Balancing Charges		$49.7	93.2%	$2.6	4.9%	$1.0	2.0%	$53.4	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 4-21 shows how these charges are allocated.[24]

Figure 4-2 shows the daily day-ahead operating reserve rate for 2018 and the first nine months of 2019. The average rate in the first nine months of 2019 was $0.022 per MWh, $0.028 per MWh lower than the average in the first nine months of 2018. The highest rate in the first nine months of 2019 occurred on March 15, when the rate reached $0.200 per MWh, $0.157 per MWh lower than the $0.357 per MWh reached in the first nine months of 2018, on June 19. Figure 4-2 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 2018 or the first nine months of 2019.

Figure 4-2 Daily day-ahead operating reserve rate ($/MWh): January 2018 through June 2019



24 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 shows the RTO and the regional reliability rates for 2018 and the first nine months of 2019. The average RTO reliability rate in the first nine months of 2019 was $0.025 per MWh. The highest RTO reliability rate in the first nine months of 2019 occurred on January 22, when the rate reached $0.368 per MWh, $0.363 per MWh lower than the $0.731 per MWh rate reached in the first nine months of 2018, on January 2.

Figure 4-3 Daily balancing operating reserve reliability rates ($/MWh): January 2018 through June 2019

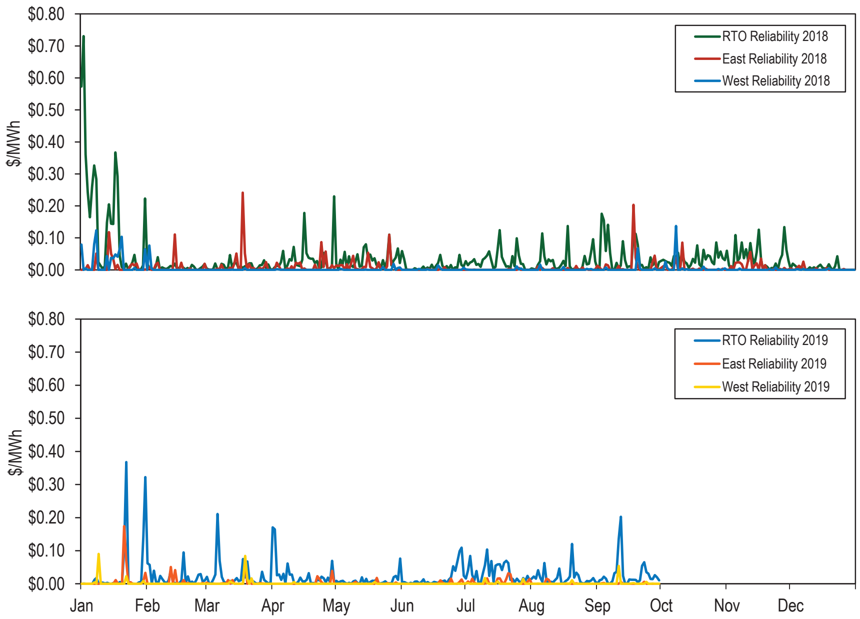


Figure 4-4 shows the RTO and regional deviation rates for 2018 and the first nine months of 2019. The average RTO deviation rate in the first nine months of 2019 was $0.185 per MWh. The highest daily rate in the first nine months of 2019 occurred on July 10, when the RTO deviation rate reached $1.227 per MWh, $3.261 per MWh lower than the $4.488 per MWh rate reached in the first nine months of 2018, on January 1.

Figure 4-4 Daily balancing operating reserve deviation rates ($/MWh): January 2018 through September 2019

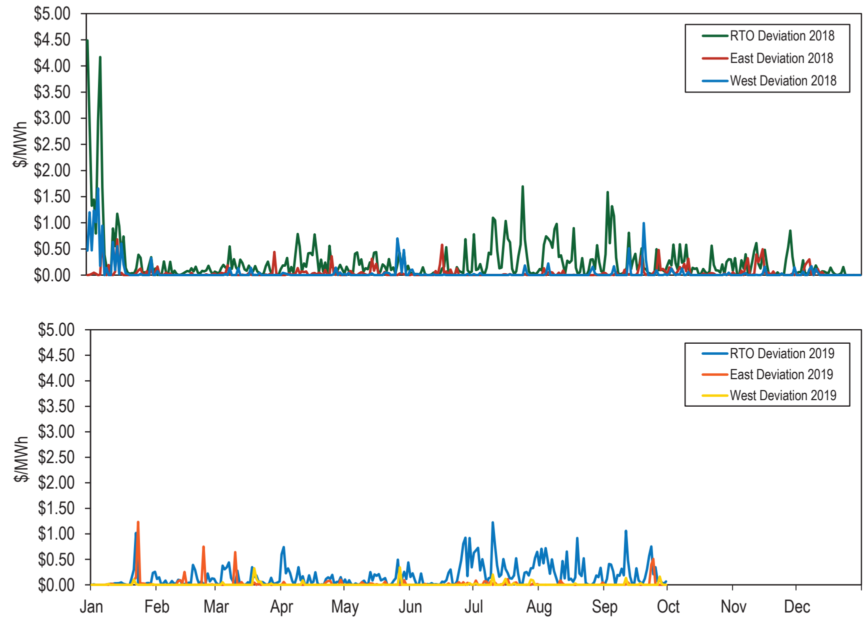


Figure 4-5 shows the daily lost opportunity cost rate and the daily canceled resources rate for 2018 and the first nine months of 2019. The average lost opportunity cost rate in the first nine months of 2019 was $0.107 per MWh. The highest lost opportunity cost rate in the first nine months occurred on May 23, when it reached $2.051 per MWh, $6.965 per MWh lower than the $9.016 per MWh rate reached in the first nine months of 2018, on January 7.[25]

25 For details about this event see **2018 Quarterly State of the Market Report for PJM: January through March**, Section 4: "Energy Uplift"

Figure 4-5 Daily lost opportunity cost and canceled resources rates ($/MWh): January 2018 through September 2019

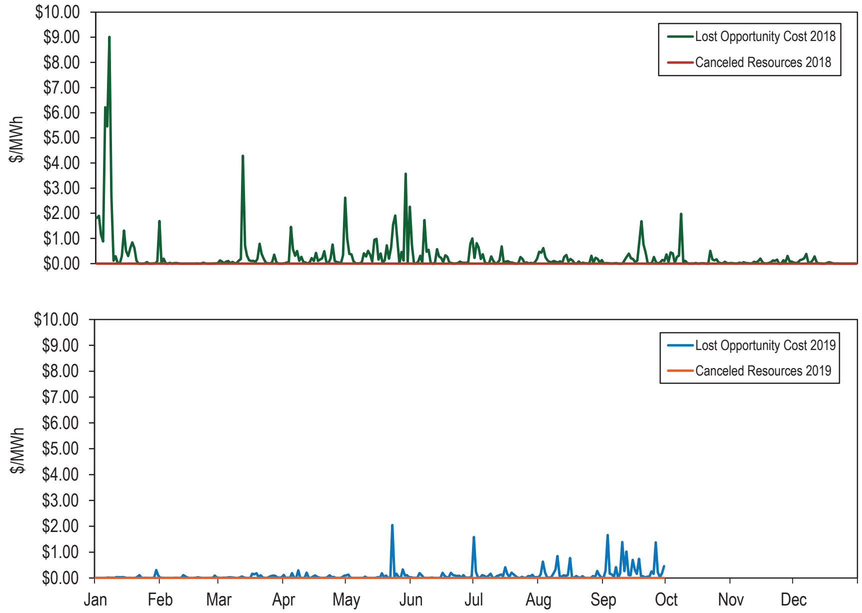


Table 4-31 shows the average rates for each region in each category for the first nine months of 2018 and 2019.

Table 4-31 Operating reserve rates ($/MWh): January through September, 2018 and 2019

Rate	(Jan - Sep) 2018 ($/MWh)	(Jan - Sep) 2019 ($/MWh)	Difference ($/MWh)	Percent Difference
Day-Ahead	0.051	0.022	(0.028)	(56.0%)
Day-Ahead with Unallocated Congestion	0.051	0.022	(0.028)	(56.0%)
RTO Reliability	0.043	0.025	(0.018)	(42.0%)
East Reliability	0.008	0.004	(0.004)	(51.7%)
West Reliability	0.004	0.002	(0.003)	(64.0%)
RTO Deviation	0.335	0.185	(0.150)	(44.8%)
East Deviation	0.039	0.025	(0.014)	(36.4%)
West Deviation	0.070	0.010	(0.061)	(86.3%)
Lost Opportunity Cost	0.419	0.107	(0.311)	(74.4%)
Canceled Resources	0.000	0.000	NA	NA

Table 4-32 shows the operating reserve cost of a one MW transaction in the first nine months of 2019. For example, a decrement bid in the Eastern Region (if not offset by other transactions) paid an average rate of $0.340 per MWh with a maximum rate of $2.252 per MWh, a minimum rate of $0.000 per MWh and a standard deviation of $0.364 per MWh. The rates in Table 4-32 include all operating reserve charges including RTO deviation charges. Table 4-32 illustrates both the average level of operating reserve charges by transaction types and the uncertainty reflected in the maximum, minimum and standard deviation levels. INCs and DECs have higher rates compared to real-time load because they are allocated a deviation charge while day-ahead and real-time load do not necessarily incur a deviation charge.

Table 4-32 Operating reserve rates statistics ($/MWh): January through September, 2019

		Rates Charged ($/MWh)			
Region	Transaction	Maximum	Average	Minimum	Standard Deviation
East	INC	2.219	0.318	0.000	0.364
	DEC	2.252	0.340	0.000	0.364
	DA Load	0.200	0.022	0.000	0.033
	RT Load	0.437	0.029	0.000	0.049
	Deviation	2.219	0.318	0.000	0.364
West	INC	2.230	0.302	0.000	0.357
	DEC	2.264	0.324	0.000	0.357
	DA Load	0.200	0.022	0.000	0.033
	RT Load	0.391	0.027	0.000	0.044
	Deviation	2.230	0.302	0.000	0.357

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 capability revenue requirement charges which are a fixed annual charge based on approved FERC filings.[26] Reactive services charges associated with supporting reactive transfer interfaces above 345 kV are allocated daily to

26 See 2018 State of the Market Report for PJM, Volume 2, Section 10: Ancillary Service Markets.

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 4-33 shows the reactive services rates associated with local voltage support in the first nine months of 2018 and 2019. Table 4-33 shows that in the first nine months of 2019 only two zones incurred reactive charges, in addition to reactive capability charges. Real-time load in the PENELEC Zone paid an average of $0.011 per MWh for reactive services, and real-time load in the DPL Control Zone paid an average of $0.007 per MWh for reactive services. The third highest rate for reactive services was in the Dominion Control Zone, where real-time load paid an average of $0.002 per MWh.

Table 4-33 Local voltage support rates: January through September, 2018 and 2019

Control Zone	(Jan - Sep) 2018 ($/MWh)	(Jan - Sep) 2019 ($/MWh)	Difference ($/MWh)	Percent Difference
AECO	0.000	0.000	(0.000)	(100.0%)
AEP	0.008	0.000	(0.008)	(98.1%)
APS	0.000	0.000	0.000	NA
ATSI	0.000	0.000	0.000	NA
BGE	0.001	0.000	(0.001)	(100.0%)
ComEd	0.144	0.000	(0.144)	(100.0%)
DAY	0.000	0.000	0.000	0.0%
DEOK	0.000	0.000	0.000	0.0%
DLCO	0.000	0.000	0.000	0.0%
Dominion	0.000	0.002	0.002	716.1%
DPL	0.018	0.007	(0.011)	(59.3%)
EKPC	0.018	0.000	(0.018)	(100.0%)
JCPL	0.000	0.000	0.000	0.0%
Met-Ed	0.000	0.000	0.000	0.0%
OVEC	0.000	0.000	0.000	0.0%
PECO	0.028	0.000	(0.028)	(100.0%)
PENELEC	0.000	0.011	0.011	NA
Pepco	0.000	0.000	0.000	0.0%
PPL	0.000	0.000	0.000	0.0%
PSEG	0.000	0.000	0.000	0.0%
RECO	0.000	0.000	0.000	0.0%

Balancing Operating Reserve Determinants

Table 4-34 shows the determinants used to allocate the regional balancing operating reserve charges in the first nine months of 2018 and 2019. Total real-time load and real-time exports were 614,673 GWh, 1.5 percent higher in 2019 compared to 2018. Total deviations summed across the demand, supply, and generator categories were 116,962 GWh, 0.4 percent higher in 2019 compared to 2018.

Table 4-34 Balancing operating reserve determinants (GWh): January through September, 2018 and 2019

		Reliability Charge Determinants (GWh)			Deviation Charge Determinants (GWh)			
		Real-Time Load	Real-Time Exports	Reliability Total	Demand Deviations (MWh)	Supply Deviations (MWh)	Generator Deviations (MWh)	Deviations Total
(Jan - Sep) 2018	RTO	604,102	19,848	623,950	68,645	21,129	26,711	116,485
	East	286,634	11,187	297,822	33,855	12,560	14,390	60,804
	West	317,468	8,660	326,128	34,231	8,447	12,321	55,000
(Jan - Sep) 2019	RTO	588,506	26,167	614,673	70,766	20,748	25,449	116,962
	East	281,297	11,382	292,679	34,450	11,259	12,961	58,670
	West	307,209	14,786	321,994	35,734	9,028	12,488	57,250
Difference	RTO	(15,596)	6,319	(9,277)	2,120	(381)	(1,262)	477
	East	(5,337)	194	(5,143)	595	(1,301)	(1,429)	(2,134)
	West	(10,259)	6,125	(4,134)	1,503	581	167	2,250

Deviations fall into three categories, demand, supply and generator deviations. Table 4-35 shows the different categories by the type of transactions that incurred deviations. In the first nine months of 2019, 31.8 percent of all RTO deviations were incurred by participants that deviated due to INCs and DECs or due to combinations of INCs and DECs with other transactions, the remaining 68.2 percent of all RTO deviations were incurred by participants that deviated due to other transaction types or due to combinations of other transaction types.

Table 4-35 Deviations by transaction type: January through September, 2019

Deviation Category	Transaction	Deviation (GWh) RTO	East	West	Share RTO	East	West
Demand	DECs Only	17,891	8,881	8,429	15.3%	15.1%	14.7%
	Exports Only	5,347	2,990	2,356	4.6%	5.1%	4.1%
	Load Only	45,601	22,329	23,272	39.0%	38.1%	40.6%
	Combination with DECs	1,922	246	1,677	1.6%	0.4%	2.9%
	Combination without DECs	5	5	0	0.0%	0.0%	0.0%
Supply	Imports Only	3,409	2,560	849	2.9%	4.4%	1.5%
	INCs Only	16,953	8,360	8,132	14.5%	14.2%	14.2%
	Combination with INCs	386	338	48	0.3%	0.6%	0.1%
	Combination without INCs	0	0	0	0.0%	0.0%	0.0%
Generators		25,449	12,961	12,488	21.8%	22.1%	21.8%
Total		116,962	58,670	57,250	100.0%	100.0%	100.0%

Geography of Charges and Credits

Table 4-36 shows the geography of charges and credits in the first nine months of 2019. Table 4-36 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 PPL Control Zone paid 5.6 percent of all operating reserve charges allocated regionally while resources in the PPL Control Zone were paid 1.8 percent of the corresponding credits. The PPL Control Zone received less operating reserve credits than operating reserve charges paid and had 9.7 percent of the deficit. The deficit is the net of the credits and charges paid at a location. Transactions in the BGE Control Zone paid 3.8 percent of all operating reserve charges allocated regionally, and resources in the BGE Control Zone were paid 16.0 percent of the corresponding credits. The BGE Control Zone received more operating reserve credits than operating reserve charges paid and had 31.9 percent of the surplus. The surplus is the net of the credits and charges paid at a location. Table 4-36 also shows that 90.3 percent of all charges were allocated in control zones, 3.0 percent in hubs and aggregates and 6.8 percent in interfaces.

Table 4-36 Geography of regional charges and credits: January through September, 2019

					Shares			
Location		Charges (Millions)	Credits (Millions)	Balance	Total Charges	Total Credits	Deficit	Surplus
Zones	AECO	$1.0	$0.9	($0.1)	1.4%	1.3%	0.3%	0.0%
	AEP	$9.6	$7.7	($1.8)	14.2%	11.5%	7.1%	0.0%
	APS	$3.5	$1.3	($2.2)	5.2%	1.9%	8.6%	0.0%
	ATSI	$4.8	$1.9	($2.9)	7.1%	2.8%	11.2%	0.0%
	BGE	$2.5	$10.7	$8.2	3.8%	16.0%	0.0%	31.9%
	ComEd	$7.9	$14.6	$6.7	11.7%	21.7%	0.0%	26.0%
	DAY	$1.1	$1.9	$0.8	1.7%	2.8%	0.0%	3.0%
	DEOK	$2.0	$1.3	($0.7)	3.0%	2.0%	2.8%	0.0%
	DLCO	$1.0	$0.2	($0.8)	1.4%	0.3%	3.0%	0.0%
	Dominion	$6.9	$10.6	$3.6	10.3%	15.7%	0.0%	14.1%
	DPL	$1.6	$3.6	$2.0	2.5%	5.4%	0.0%	7.8%
	EKPC	$0.8	$1.5	$0.7	1.2%	2.2%	0.0%	2.6%
	External	$0.0	$1.1	$1.1	0.0%	1.7%	0.0%	4.4%
	JCPL	$1.8	$0.1	($1.6)	2.6%	0.2%	6.4%	0.0%
	Met-Ed	$1.4	$0.2	($1.2)	2.1%	0.3%	4.6%	0.0%
	OVEC	$0.2	$0.0	($0.1)	0.2%	0.0%	0.5%	0.0%
	PECO	$3.0	$0.5	($2.5)	4.4%	0.8%	9.7%	0.0%
	PENELEC	$2.2	$1.3	($0.8)	3.2%	1.9%	3.3%	0.0%
	Pepco	$2.4	$5.1	$2.7	3.6%	7.6%	0.0%	10.4%
	PPL	$3.7	$1.2	($2.5)	5.6%	1.8%	9.7%	0.0%
	PSEG	$3.2	$1.5	($1.7)	4.8%	2.2%	6.6%	0.0%
	RECO	$0.2	$0.0	($0.2)	0.2%	0.0%	0.6%	0.0%
	All Zones	$60.7	$67.3	$6.6	90.3%	100.0%	74.5%	100.0%
Hubs and Aggregates	AEP - Dayton	$0.4	$0.0	($0.4)	0.6%	0.0%	1.6%	0.0%
	Dominion	$0.3	$0.0	($0.3)	0.4%	0.0%	1.1%	0.0%
	Eastern	$0.1	$0.0	($0.1)	0.2%	0.0%	0.5%	0.0%
	New Jersey	$0.2	$0.0	($0.2)	0.3%	0.0%	0.7%	0.0%
	Ohio	$0.1	$0.0	($0.1)	0.2%	0.0%	0.5%	0.0%
	Western Interface	$0.0	$0.0	$0.0	0.0%	0.0%	0.0%	0.0%
	Western	$0.9	$0.0	($0.9)	1.3%	0.0%	3.4%	0.0%
	RTEP B0328 Source	$0.0	$0.0	$0.0	0.0%	0.0%	0.0%	0.0%
	All Hubs and Aggregates	$2.0	$0.0	($2.0)	3.0%	0.0%	7.8%	0.0%
Interfaces	CPLE Exp	$0.0	$0.0	($0.0)	0.1%	0.0%	0.2%	0.0%
	CPLE Imp	$0.0	$0.0	($0.0)	0.0%	0.0%	0.1%	0.0%
	Duke Exp	$0.1	$0.0	($0.1)	0.1%	0.0%	0.2%	0.0%
	Duke Imp	$0.1	$0.0	($0.1)	0.1%	0.0%	0.3%	0.0%
	Hudson	$0.2	$0.0	($0.2)	0.2%	0.0%	0.6%	0.0%
	IMO	$0.1	$0.0	($0.1)	0.2%	0.0%	0.4%	0.0%
	Linden	$0.2	$0.0	($0.2)	0.3%	0.0%	0.9%	0.0%
	MISO	$1.9	$0.0	($1.9)	2.8%	0.0%	7.3%	0.0%
	NCMPA Imp	$0.1	$0.0	($0.1)	0.1%	0.0%	0.4%	0.0%
	Neptune	$0.2	$0.0	($0.2)	0.4%	0.0%	0.9%	0.0%
	NIPSCO	$0.1	$0.0	($0.1)	0.1%	0.0%	0.2%	0.0%
	Northwest	$0.1	$0.0	($0.1)	0.2%	0.0%	0.5%	0.0%
	NYIS	$0.5	$0.0	($0.5)	0.8%	0.0%	2.0%	0.0%
	South Exp	$0.5	$0.0	($0.5)	0.7%	0.0%	1.9%	0.0%
	South Imp	$0.5	$0.0	($0.5)	0.7%	0.0%	1.9%	0.0%
	All Interfaces	$4.5	$0.0	($4.5)	6.8%	0.0%	17.6%	0.0%
	Total	$67.3	$67.3	$0.0	100.0%	100.0%	100.0%	100.0%

Energy Uplift Issues

Intraday Segments Uplift Settlement

PJM pays uplift separately for multiple segmented blocks of time during the operating day (intraday).[27] The use of intraday segments to calculate the need for uplift payments results in higher uplift payments than necessary to make units whole, including uplift payments to units that are profitable on a daily basis. The MMU recommends eliminating intraday segments from the calculation of uplift payments and returning to calculating the need for uplift based on the entire 24 hour operating day.

Table 4-37 shows balancing operating reserve credits calculated using intraday segments and balancing operating reserve payments calculated on a daily basis. In 2018, balancing operating reserve credits would have been $19.5 million or 21.9 percent lower if they were calculated on a daily basis. In the first nine months of 2019, balancing operating reserve credits would have been $10.0 million or 24.6 percent lower if they were calculated on a daily basis.

27 See PJM "Manual 28: Operating Reserve Accounting," Rev. 82 (July 25, 2019).

Table 4-37 Intraday segments and daily balancing operating reserve credits: January 2018 through September 2019

	2018 BOR Credits (Millions)			2019 BOR Credits (Millions)		
	Intraday Segments Calculation	Daily Calculation	Difference	Intraday Segments Calculation	Daily Calculation	Difference
Jan	$33.2	$27.8	($5.3)	$5.4	$4.6	($0.8)
Feb	$1.7	$1.3	($0.4)	$2.5	$2.3	($0.3)
Mar	$3.0	$2.4	($0.6)	$3.6	$2.9	($0.7)
Apr	$5.6	$4.2	($1.4)	$3.5	$2.9	($0.6)
May	$5.8	$3.9	($1.9)	$2.3	$1.7	($0.5)
Jun	$2.6	$1.7	($0.9)	$4.1	$3.3	($0.8)
Jul	$7.4	$5.2	($2.1)	$8.8	$6.1	($2.7)
Aug	$6.8	$4.8	($2.0)	$5.1	$3.0	($2.0)
Sep	$9.3	$7.0	($2.3)	$5.7	$4.0	($1.7)
Oct	$5.9	$4.5	($1.3)			
Nov	$6.2	$5.3	($0.9)			
Dec	$1.6	$1.3	($0.3)			
Total (Jan - Sep)	$75.4	$58.4	($17.0)	$40.8	$30.8	($10.0)
Total	$89.1	$69.6	($19.5)	$40.8	$30.8	($10.0)

Prior to April 1, 2018, for purposes of calculating LOC credits, each hour was defined as a unique segment. Following the implementation of five minute settlements on April 1, 2018, LOC credits are calculated with each five minute interval defined as a unique segment. Thus a profit in one five minute segment, resulting from the real-time LMP being lower than the day-ahead LMP, is not used to offset a loss in any other five-minute segment. This change in settlements causes an increase in LOC credits compared to hourly settlement as generators are made whole for any losses incurred in a five minute interval while previously gains and losses were netted across the hour. Table 4-38 shows the impact of changing the settlements of day-ahead LOC credits from an hourly basis to a five minute basis. For the months of April through December 2018, day-ahead LOC credits would have been $5.4 million or 26.3 percent lower had they been settled on an hourly basis compared to being settled on a five minute basis. For the first nine months of 2019, LOC credits would have been $0.8 million or 6.2 percent lower had they been settled on an hourly basis compared to being settled on a five minute basis.

Table 4-38 Five minute settlement and hourly settlement of day-ahead lost opportunity cost credits: April, 2018 through September, 2019

	2018 Day Ahead LOC Credits (Millions)			2019 Day Ahead LOC Credits (Millions)		
	Five Minute Settlement	Hourly Settlement	Difference	Five Minute Settlement	Hourly Settlement	Difference
Jan	NA	NA	NA	$0.4	$0.4	($0.1)
Feb	NA	NA	NA	$0.1	$0.1	($0.0)
Mar	NA	NA	NA	$0.4	$0.4	($0.1)
Apr	$2.0	$1.3	($0.7)	$0.5	$0.5	($0.1)
May	$6.0	$4.7	($1.3)	$1.6	$1.4	($0.1)
Jun	$3.5	$2.3	($1.3)	$0.7	$0.6	($0.1)
Jul	$2.1	$1.5	($0.6)	$1.9	$1.9	($0.1)
Aug	$1.7	$1.4	($0.4)	$1.7	$1.6	($0.1)
Sep	$2.2	$1.7	($0.5)	$4.7	$4.5	($0.2)
Oct	$1.8	$1.4	($0.4)			
Nov	$0.6	$0.5	($0.1)			
Dec	$0.7	$0.4	($0.2)			
Total	$20.6	$15.2	($5.4)	$12.1	$11.3	($0.8)

Table 4-39 shows day-ahead LOC credits calculated using intraday segments and LOC credits calculated on a daily basis. In 2018, LOC credits would have been $ 5.4 million or 14.3 percent lower if they were calculated on a daily basis. In the first nine months of 2019, LOC credits would have been $1.8 million or 14.9 percent lower if they were calculated on a daily basis.

Table 4-39 Five minute settlement and daily settlement of lost opportunity cost credits: January 2018 through September 2019

	2018 Day Ahead LOC Credits (Millions)			2019 Day Ahead LOC Credits (Millions)		
	Intraday Segments Calculation	Daily Calculation	Difference	Intraday Segments Calculation	Daily Calculation	Difference
Jan	$13.7	$11.0	($2.8)	$0.4	$0.3	($0.1)
Feb	$0.1	$0.1	($0.0)	$0.1	$0.1	($0.0)
Mar	$3.1	$2.6	($0.5)	$0.4	$0.3	($0.1)
Apr	$2.0	$1.9	($0.1)	$0.5	$0.4	($0.2)
May	$6.0	$5.5	($0.5)	$1.6	$1.2	($0.3)
Jun	$3.5	$3.0	($0.5)	$0.7	$0.5	($0.2)
Jul	$2.1	$1.8	($0.3)	$1.9	$1.7	($0.2)
Aug	$1.7	$1.6	($0.2)	$1.7	$1.6	($0.1)
Sep	$2.2	$2.0	($0.2)	$4.7	$4.2	($0.5)
Oct	$1.8	$1.6	($0.2)			
Nov	$0.6	$0.5	($0.0)			
Dec	$0.7	$0.6	($0.1)			
Total (Jan - Sep)	$34.6	$29.5	($5.1)	$12.1	$10.3	($1.8)
Total	$37.6	$32.2	($5.4)	$12.1	$10.3	($1.8)