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 dispatchers. 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 2018, energy uplift credits were $199.0 million, including $34.0 million in day-ahead generator credits, $90.2 million in balancing generator credits, $52.3 million in lost opportunity cost credits, $13.2 million in reactive credits, and $8.6 million in local constraint control credits.
- **Types of units.** Coal units received 61.3 percent of all day-ahead generator credits and 88.0 percent of all reactive service credits. Combustion turbines received 76.4 percent of all balancing generator credits and 71.9 percent of lost opportunity cost credits.
- **Economic and Noneconomic Generation.** In 2018, 84.6 percent of the day-ahead generation eligible for operating reserve credits was economic and 68.9 percent of the real-time generation eligible for operating reserve credits was economic.
- **Day-Ahead Unit Commitment for Reliability.** In 2018, 1.3 percent of the total day-ahead generation MWh was scheduled as must run by PJM, of which 47.3 percent received energy uplift payments.
- **Concentration of Energy Uplift Credits.** The top 10 units receiving energy uplift credits received 21.2 percent of all credits. The top 10 organizations received 74.6 percent of all credits. The HHI for day-ahead operating reserves was 8013, the HHI for balancing operating reserves was 2865 and the HHI for lost opportunity cost was 4860, all of which are classified as highly concentrated.

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

- **Lost Opportunity Cost Credits.** Lost opportunity cost credits increased by $37.7 million or 258.6 percent, in 2018 compared to 2017, from $14.6 million to $52.3 million. This increase was the result of combustion turbines and diesels scheduled day-ahead and not requested in real time. This increase was also a result of backing down steam and combined cycle units in order to control for the west to east transfer interfaces binding in January. Generation from combustion turbines and diesels scheduled day-ahead but not requested in real time receiving lost opportunity cost credits increased by 374 GWh or 58.6 percent in 2018, compared to 2017, from 639 GWh to 1,013 GWh.

Energy Uplift Charges

- **Energy Uplift Charges.** Total energy uplift charges increased by $72.0 million, or 56.5 percent, in 2018 compared to 2017, from $127.3 million to $199.3 million.
- **Energy Uplift Charges Categories.** The increase of $72.0 million in 2018 is comprised of a $9.2 million increase in day-ahead operating reserve charges, a $69.9 million increase in balancing operating reserve charges and a $7.3 million decrease in reactive services charges.
- **Average Effective Operating Reserve Rates in the Eastern Region.** Day-ahead load paid $0.041 per MWh, real-time load paid $0.029 per MWh, a DEC paid $0.722 per MWh and an INC and any load, generation or interchange transaction deviation paid $0.681 per MWh.
- **Average Effective Operating Reserve Rates in the Western Region.** Day-ahead load paid $0.041 per MWh, real-time load paid $0.027 per MWh, a DEC paid $0.735 per MWh and an INC and any load, generation or interchange transaction deviation paid $0.693 per MWh.
- **Reactive Services Rates.** The ComEd, Pepco, and EKPC control zones had the three highest local voltage support rates: $0.116, $0.023 and $0.015 per MWh.

Geography of Charges and Credits

- In 2018, 88.2 percent of all uplift charges allocated regionally (day-ahead operating reserves and balancing operating reserves) were paid by transactions at control zones, 2.9 percent by transactions at hubs and aggregates, and 8.9 percent by transactions at interchange interfaces.
- Generators in the Eastern Region received 47.7 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.
- Generators in the Western Region received 50.7 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.
- External generators received 1.6 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 Q1, 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 Q1, 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 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

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*, Section 3: "Energy Market" at "Internal Bilateral Transactions" for an analysis of the impact of this change on virtual bidding activity.

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 revise Manual 11 attachment C consistent with the tariff to limit uplift 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.[6])
- 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.[7])
- 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 Q1, 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 Q1, 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. New recommendation. 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 pricing without paying uplift to inflexible units would create incentives for market participants to provide flexible

6 Although this recommendation has not been adopted exactly as recommended by the MMU, the implementation of hourly offers by PJM has effectively adopted this recommendation.

7 On September 7, 2018 PJM made a compliance filing for FERC Order No. 844 to publish unit specific uplift credits. The compliance filing has not been accepted by FERC. Absent acceptance from the FERC, PJM will not begin publishing data on unit specific uplift credits.

solutions including replacing inefficient units with flexible, efficient units.

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 ten years. FERC Order No. 844 authorized the publication of unit specific uplift payments for credits incurred after January 1, 2019.[8]

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.[9]

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 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

8 Publication of unit specific uplift credits will begin after FERC accepts PJM's Order No. 844 compliance filing.

9 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.

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.

In 2018, energy uplift credits increased by $71.8 million compared to 2017, from $127.2 million to $199.0 million. Figure 4-1 shows the net impact of each credit category on the change in total energy uplift credits. The outside bars show the total energy uplift credits paid in 2017 (left side) and 2018 (right side). The interior bars show the change by credit type. The increase was a result of a $9.2 million increase in day-ahead credits, a $25.0 million increase in balancing credits, a $7.0 million increase in local constraint control credits, and a $37.7 million increase in lost opportunity cost credits.

Figure 4-1 Energy uplift credits change from 2017 to 2018 by category

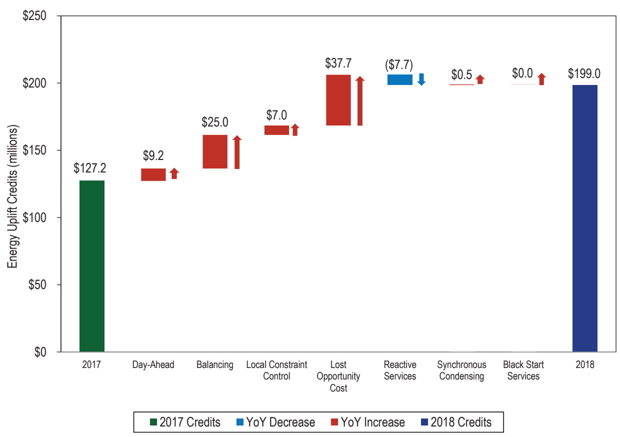


Figure 4-2 shows total uplift credits by month for 2017 and 2018. January 2018 was the highest uplift month in 2018 with $61.6 million or 31.0 percent of all credits in 2018. Out of the $61.6 million, 89.0 percent were balancing operating reserve and lost opportunity cost (LOC) credits ($33.1 million and $21.7 million).

The months of March through June also experienced an increase in uplift credits compared to 2017. This was the results of reliability and local constraint control issues that could only be addressed by specific large inflexible units. The increase in credits was also a result of an increase in LOC credits to CTs. This was result of modeling differences between the day-ahead and real-time markets causing combustion turbines committed in the day-ahead to not be requested in real time despite the units being economic.

Figure 4-2 Total uplift credits by month: 2017 and 2018

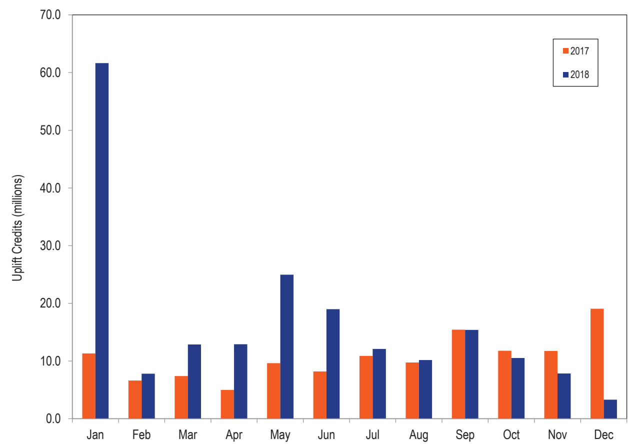


Figure 4-3 shows daily day-ahead, balancing, and lost opportunity cost credits by day for 2018. These three credit types make up 88.9 percent of all uplift credits. Figure 4-4 shows that uplift credits are highly concentrated in a few days. Out of the top ten uplift days in 2018, nine were in January. In those nine days there were $47.7 million in uplift credits. The high uplift on those days was the result of a combination of factors including the extreme cold weather, high natural gas prices, the commitment of large inflexible CTs, the failure of market power mitigation tools that allowed units needed for reliability to clear on price offers with significant mark ups, and differences between the day-ahead and real-time market models which caused commitment and dispatch differences between the day-ahead and real-time markets.[10]

10 See *2018 State of the Market Report for PJM*, Section 3: "Offer Capping for Local Market Power" at "Market Concentration" for a discussion of how generators with market power can evade mitigation.

Figure 4-3 Day-ahead, balancing, and lost opportunity cost uplift credits by day: 2018

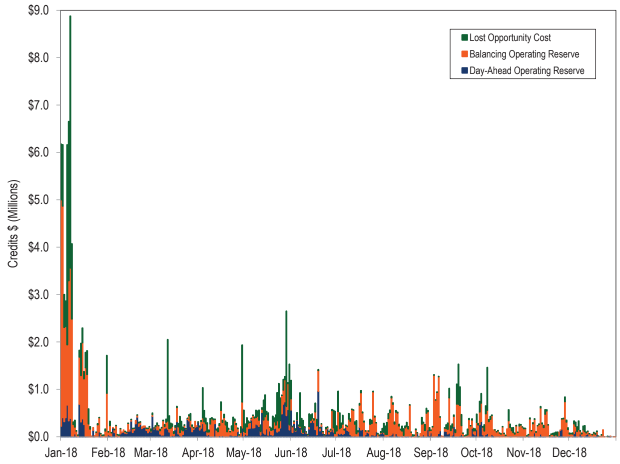


Table 4-1 shows the totals for each credit category in 2017 and 2018.[11] In 2018 energy uplift credits increased by $71.8 million or 56.4 percent compared to 2017.

Characteristics of Credits

Types of Units

Table 4-2 shows the distribution of total energy uplift credits by unit type for 2017 and 2018. The largest recipients of uplift credits were combustion turbines and coal fired steam units, receiving 55.0 percent and 22.9 percent of all uplift credits. In 2018, uplift credits to combined cycle units increased by $10.3 million or 102.2 percent compared to 2017. The majority of the increase occurred in January as a result of the extended cold weather. In 2018, uplift credits to gas and oil fired steam units increased by $13.7 million or 235.4 percent compared to 2017. The increase in uplift credits for these units was the result of reliability issues which required specific units to be committed.

Table 4-1 Energy uplift credits by category: 2017 and 2018

Category	Type	2017 Credits (Millions)	2018 Credits (Millions)	Change	Percent Change	2017 Share	2018 Share
Day-Ahead	Generators	$24.8	$34.0	$9.2	37.2%	19.5%	17.1%
	Imports	$0.0	$0.0	$0.0	194,450.3%	0.0%	0.0%
	Load Response	$0.0	$0.00	($0.0)	(65.5%)	0.0%	0.0%
Balancing	Canceled Resources	$0.0	$0.0	($0.0)	(100.0%)	0.0%	0.0%
	Generators	$65.3	$90.2	$24.9	38.1%	51.4%	45.3%
	Imports	$0.0	$0.5	$0.5	7,585.7%	0.0%	0.2%
	Load Response	$0.3	$0.0	($0.3)	(98.3%)	0.3%	0.0%
	Local Constraints Control	$1.5	$8.6	$7.0	463.6%	1.2%	4.3%
	Lost Opportunity Cost	$14.6	$52.3	$37.7	258.6%	11.5%	26.3%
Reactive Services	Day-Ahead	$19.3	$11.8	($7.5)	(38.8%)	15.1%	5.9%
	Local Constraints Control	$0.0	$0.0	$0.0	NA	0.0%	0.0%
	Lost Opportunity Cost	$0.2	$0.0	($0.2)	(94.6%)	0.2%	0.0%
	Reactive Services	$0.9	$0.9	($0.0)	(3.8%)	0.7%	0.4%
	Synchronous Condensing	$0.0	$0.5	$0.4	1,328.7%	0.0%	0.2%
Synchronous Condensing		$0.0	$0.0	$0.0	NA	0.0%	0.0%
Black Start Services	Day-Ahead	$0.0	$0.0	$0.0	NA	0.0%	0.0%
	Balancing	$0.0	$0.3	$0.3	1,159.7%	0.0%	0.1%
	Testing	$0.2	$0.0	($0.2)	(90.1%)	0.2%	0.0%
Total		$127.2	$199.0	$71.8	56.4%	100.0%	100.0%

11 Billing data can be modified by PJM Settlements at any time to reflect changes in the evaluation of energy uplift. The billing data reflected in this report were current on January 10, 2019.

Table 4-2 Energy uplift credits by unit type: 2017 and 2018

Unit Type	2017 Credits (Millions)	2018 Credits (Millions)	Change	Percent Change	2017 Share	2018 Share
Combined Cycle	$10.1	$20.3	$10.3	102.2%	7.9%	10.2%
Combustion Turbine	$62.1	$109.3	$47.2	76.0%	48.9%	55.0%
Diesel	$0.9	$1.7	$0.8	83.8%	0.7%	0.9%
Hydro	$0.1	$0.0	($0.1)	(100.0%)	0.1%	0.0%
Nuclear	$0.1	$0.4	$0.3	387.3%	0.1%	0.2%
Solar	$0.0	$0.0	($0.0)	(69.3%)	0.0%	0.0%
Steam - Coal	$45.7	$45.5	($0.1)	(0.3%)	36.0%	22.9%
Steam - Other	$5.8	$19.6	$13.7	235.4%	4.6%	9.9%
Wind	$2.2	$1.7	($0.4)	(20.3%)	1.7%	0.9%
Total	$126.9	$198.5	$71.6	56.4%	100.0%	100.0%

Table 4-3 shows the distribution of energy uplift credits by category and by unit type in 2018. 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, 87.8 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 88.0 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 76.4 percent of balancing credits and 71.9 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 pnode and the unit's balancing charges are greater than its day-ahead revenues.

Table 4-3 Energy uplift credits by unit type: 2018

Unit Type	Day-Ahead Generator	Balancing Generator	Canceled Resources	Local Constraints Control	Lost Opportunity Cost	Reactive Services	Synchronous Condensing	Black Start Services
Combined Cycle	8.6%	13.2%	0.0%	0.0%	10.4%	0.2%	0.0%	20.4%
Combustion Turbine	3.7%	76.4%	0.0%	0.8%	71.9%	8.5%	100.0%	79.6%
Diesel	0.0%	0.6%	0.0%	2.0%	1.7%	1.0%	0.0%	0.0%
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%	0.7%	0.0%	0.0%	0.0%
Solar	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Steam - Coal	61.3%	5.5%	0.0%	25.1%	11.6%	88.0%	0.0%	0.0%
Steam - Other	26.5%	4.3%	0.0%	72.2%	0.4%	2.4%	0.0%	0.0%
Wind	0.0%	0.0%	0.0%	0.0%	3.3%	0.0%	0.0%	0.0%
Total (Millions)	$34.0	$90.2	$0.0	$8.6	$52.3	$13.1	$0.0	$0.3

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

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 18, 2017) at 38, <http://www.pjm.com/-/media/etools/markets-gateway/markets-gateway-user-guide.ashx?la=en>.

subset of that generation committed for reliability by PJM. In 2018, 1.3 percent of the total day-ahead generation was committed for reliability by PJM, 0.1 percentage points higher than in 2017.

Table 4-4 Day-ahead generation committed for reliability (GWh): 2017 and 2018

	2017			2018		
	Total Day-Ahead Generation	Day-Ahead PJM Must Run Generation	Share	Total Day-Ahead Generation	Day-Ahead PJM Must Run Generation	Share
Jan	71,967	1,051	1.5%	78,368	1,209	1.5%
Feb	61,356	725	1.2%	63,095	780	1.2%
Mar	66,657	523	0.8%	67,699	1,712	2.5%
Apr	58,457	334	0.6%	59,019	967	1.6%
May	61,170	952	1.6%	65,017	1,799	2.8%
Jun	69,964	634	0.9%	71,001	1,188	1.7%
Jul	79,334	1,157	1.5%	79,653	846	1.1%
Aug	74,129	876	1.2%	80,864	476	0.6%
Sep	65,211	1,047	1.6%	69,596	659	0.9%
Oct	61,308	1,013	1.7%	64,003	533	0.8%
Nov	61,980	589	1.0%	64,183	744	1.2%
Dec	73,448	1,025	1.4%	70,864	215	0.3%
Total	804,982	9,926	1.2%	833,362	11,128	1.3%

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 2018 were $34.0 million. The top 10 units received $24.2 million or 71.2 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 2018, 47.3 percent of the day-ahead generation committed for reliability by PJM received operating reserve credits, 26.7 percent paid as day-ahead operating reserve credits and 20.6 percent paid as reactive services. The remaining 52.7 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): 2018

	Reactive Services (GWh)	Day-Ahead Operating Reserves (GWh)	Economic (GWh)	Total (GWh)
Jan	154	73	983	1,209
Feb	287	275	218	780
Mar	253	532	928	1,712
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	344	287	383	1,013
Nov	220	165	204	589
Dec	259	205	561	1,025
Total	2,531	3,272	6,461	12,264
Share	20.6%	26.7%	52.7%	100.0%

Total day-ahead operating reserve credits in 2018 were $34.0 million, of which $23.2 million or 68.1 percent was paid to units committed for reliability by PJM, and not scheduled to provide black start or reactive services. The remaining $10.8 million or 31.9 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 $68.9 million or 76.4 percent of all balancing operating reserve (BOR) credits in 2018. The majority of these credits, 99.3 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.

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 2018, generation by combustion turbines was 8.9 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 2.1 percent of generation from combustion turbines in the day-ahead market was uneconomic and only required $1.3 million in day-ahead generator credits. In the Real-Time Energy Market, 27.3 percent of generation from combustion turbines was uneconomic and required $68.9 million in BOR credits.

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 2018, 61.2 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, 17.6 percent was uneconomic in the real-time market and received $0.5 million in BOR credits. Of the 38.8 percent of real-time generation by CTs that operated outside of a day-ahead schedule, 42.5 percent was uneconomic in the real-time market and received $68.4 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 2018, although total CT generation committed in the day-ahead market was greater than CT generation in real time, only 48.8 percent of real-time generation by CTs operated on a day-ahead schedule.

Table 4-6 Characteristics of day-ahead and real-time generation by combustion turbines: 2018

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	1,388	4.9%	$1.0	1,257	33.4%	$22.8	(10.4%)
Feb	81	1.2%	$0.0	76	36.9%	$0.8	(6.6%)
Mar	718	1.9%	$0.0	503	22.9%	$1.6	(42.8%)
Apr	1,077	1.9%	$0.0	1,221	33.6%	$5.1	11.7%
May	1,748	1.1%	$0.0	1,670	27.2%	$4.4	(4.7%)
Jun	1,112	1.5%	$0.0	924	22.1%	$1.7	(20.4%)
Jul	1,960	1.9%	$0.0	2,206	23.5%	$6.3	11.2%
Aug	1,572	1.7%	$0.0	1,944	23.5%	$5.9	19.1%
Sep	1,564	1.3%	$0.0	2,078	25.2%	$8.1	24.7%
Oct	1,069	2.8%	$0.0	1,194	29.1%	$5.2	0.0%
Nov	328	2.4%	$0.0	659	39.5%	$5.9	0.0%
Dec	72	6.0%	$0.1	84	36.8%	$1.1	0.0%
Total	12,690	2.1%	$1.3	13,816	27.3%	$68.9	8.2%

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.

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: 2018

	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	613	48.8%	14.4%	$0.4	644	51.2%	51.4%	$22.4
Feb	21	27.9%	12.8%	$0.0	55	72.1%	46.3%	$0.8
Mar	339	67.5%	17.7%	$0.1	164	32.5%	33.5%	$1.5
Apr	698	57.2%	21.7%	$0.0	523	42.8%	49.5%	$5.0
May	1,145	68.6%	18.9%	$0.0	524	31.4%	45.3%	$4.4
Jun	650	70.4%	17.3%	$0.0	274	29.6%	33.4%	$1.7
Jul	1,484	67.2%	18.0%	$0.0	723	32.8%	34.8%	$6.3
Aug	1,241	63.9%	17.5%	$0.0	702	36.1%	34.0%	$5.9
Sep	1,218	58.6%	14.7%	$0.0	860	41.4%	40.0%	$8.1
Oct	781	65.4%	17.4%	$0.0	413	34.6%	51.4%	$5.2
Nov	240	36.5%	22.8%	$0.0	418	63.5%	49.1%	$5.9
Dec	24	28.4%	26.4%	$0.0	60	71.6%	40.9%	$1.1
Total	8,455	61.2%	17.6%	$0.5	5,360	38.8%	42.5%	$68.4

Lost Opportunity Cost Credits

Balancing operating reserve lost opportunity cost (LOC) credits are an incentive for units to follow PJM's dispatch instructions when PJM's dispatch instructions deviate from a unit's desired or scheduled output. 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 2017 and 2018. In 2018, LOC credits increased by $37.7 million or 258.6 percent compared to 2017. The increase of $37.7 million is comprised of a $27.6 million increase in day-ahead LOC and a $10.1 million increase in real-time LOC. 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 2018, 15.0 percent of day-ahead generation by combustion turbines and diesels was not requested in real time, 4.0 percentage points higher than in 2017.

Table 4-8 Monthly lost opportunity cost credits (Millions): 2017 and 2018

	2017			2018		
	Day-Ahead Lost Opportunity Cost	Real-Time Lost Opportunity Cost	Total	Day-Ahead Lost Opportunity Cost	Real-Time Lost Opportunity Cost	Total
Jan	$0.1	$0.3	$0.4	$13.7	$8.0	$21.7
Feb	$0.1	$0.1	$0.1	$0.1	$0.0	$0.2
Mar	$0.9	$0.2	$1.1	$3.2	$0.2	$3.4
Apr	$0.5	$0.3	$0.8	$2.0	$1.9	$3.9
May	$0.8	$1.0	$1.8	$6.0	$2.8	$8.8
Jun	$0.7	$0.8	$1.5	$3.5	$0.0	$3.5
Jul	$1.5	$0.2	$1.7	$2.1	$0.0	$2.1
Aug	$0.5	$0.1	$0.6	$1.7	$0.1	$1.9
Sep	$1.5	$0.5	$1.9	$2.2	$0.7	$2.9
Oct	$0.8	$0.2	$0.9	$1.9	$0.7	$2.5
Nov	$0.5	$0.3	$0.8	$0.5	$0.2	$0.7
Dec	$2.3	$0.6	$3.0	$0.7	$0.1	$0.8
Total	$10.1	$4.5	$14.6	$37.7	$14.6	$52.3
Share	69%	31%	100%	72%	28%	100%

Table 4-9 Day-ahead generation from combustion turbines and diesels (GWh): 2017 and 2018

	2017			2018		
	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	343	33	9	1,893	382	223
Feb	304	27	9	296	40	19
Mar	762	128	49	1,012	252	109
Apr	458	88	28	1,377	204	71
May	658	75	38	2,093	378	149
Jun	1,137	120	61	1,430	328	105
Jul	1,800	265	123	2,340	279	76
Aug	1,325	121	51	1,970	181	58
Sep	2,189	123	66	1,883	202	97
Oct	1,833	136	63	1,396	156	60
Nov	752	101	35	606	55	25
Dec	893	211	108	316	41	21
Total	12,455	1,428	639	16,612	2,496	1,013
Share	100%	11%	5%	100%	15%	6%

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

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

Table 4-11 shows day-ahead and real-time generation by commitment and dispatch status. Table 4-11 shows that in 2018, 39.4 percent of generation was pool-scheduled in the Day-Ahead Energy Market and 41.2 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 63.1 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): 2018

	Self Scheduled			Pool Scheduled						
	Dispatchable	Ecomin	Block Loaded	Dispatchable	Ecomin	Block Loaded	Total GWh	Total Pool Scheduled	Total Self Scheduled	Total Generation Eligible to Set Price
Day-Ahead Generation	96,161	187,874	220,917	140,405	163,094	24,910	833,362	328,410	504,952	236,567
Share of Day-Ahead	11.5%	22.5%	26.5%	16.8%	19.6%	3.0%	100.0%	39.4%	60.6%	28.4%
Real-Time Generation	81,262	153,766	256,317	131,935	179,522	32,734	835,536	344,191	491,345	213,197
Share of Real-Time	9.7%	18.4%	30.7%	15.8%	21.5%	3.9%	100.0%	41.2%	58.8%	25.5%

Economic and Noneconomic Generation[17]

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.

Table 4-12 shows the day-ahead and real-time economic and noneconomic generation from units eligible for operating reserve credits. In 2018, 84.6 percent of the day-ahead generation eligible for operating reserve credits was economic and 68.6 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): 2018

Energy Market	Economic Generation	Noneconomic Generation	Total Eligible Generation	Economic Generation Percent	Noneconomic Generation Percent
Day-Ahead	277,837	50,572	328,410	84.6%	15.4%
Real-Time	211,379	96,792	308,170	68.6%	31.4%

17 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.

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 2018, 2.2 percent of the day-ahead generation eligible for operating reserve credits received credits and 1.8 percent of the real-time generation eligible for operating reserve credits received credits.

Table 4-13 Generation receiving operating reserve credits (GWh): 2018

Energy Market	Generation Eligible for Operating Reserve Credits	Generation Receiving Operating Reserve Credits	Generation Receiving Operating Reserve Credits Percent
Day-Ahead	328,410	7,178	2.2%
Real-Time	308,170	5,682	1.8%

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.[18]

Figure 4-4 shows the concentration of energy uplift credits. The top 10 units received 21.2 percent of total energy uplift credits in 2018, compared to 33.6 percent in 2017. In 2018, 310 units received 90 percent of all energy uplift credits, compared to 267 units in 2017.

Figure 4-4 Cumulative share of energy uplift credits: 2017 and 2018 by unit

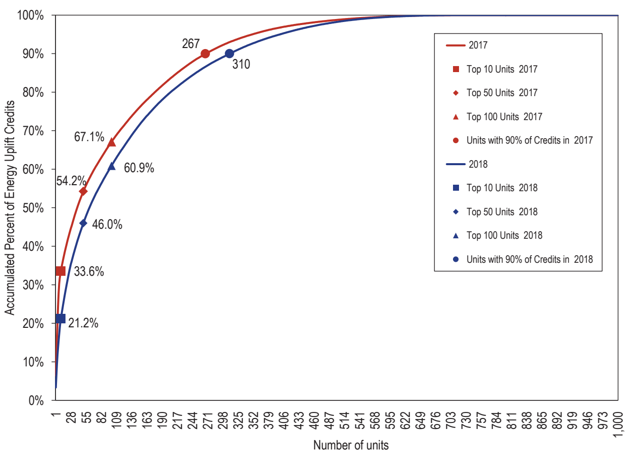


Table 4-14 shows the credits received by the top 10 units and top 10 organizations in each of the energy uplift categories paid to generators in 2018.

Table 4-14 Top 10 units and organizations energy uplift credits: 2018

		Top 10 Units		Top 10 Organizations	
Category	Type	Credits (Millions)	Credits Share	Credits (Millions)	Credits Share
Day-Ahead	Generators	$24.2	71.2%	$33.0	97.0%
Balancing	Canceled Resources	$0.0	0.0%	$0.0	0.0%
	Generators	$11.1	12.3%	$64.6	71.6%
	Local Constraints Control	$8.5	99.5%	$8.6	100.0%
	Lost Opportunity Cost	$9.3	17.7%	$37.5	71.8%
Reactive Services		$12.6	96.0%	$13.1	100.0%
Synchronous Condensing		$0.0	100.0%	$0.0	100.0%
Black Start Services		$0.1	48.0%	$0.3	90.8%
Total		$42.1	21.2%	$148.2	74.6%

18 As a result of FERC Order No. 844 PJM will begin publishing total uplift credits by unit by month for credits incurred after January 1, 2019. Data postings will begin pending FERC's approval of PJM's September 7, 2018 Order No. 844 compliance filing.

Table 4-15 shows balancing operating reserve credits received by the top 10 units identified for reliability or for deviations in each region. In 2018, 65.4 percent of all credits paid to these units were allocated to deviations while the remaining 34.6 percent were paid for reliability reasons.

Table 4-15 Balancing operating reserve credits to top 10 units by category and region: 2018

	Reliability			Deviations			
	RTO	East	West	RTO	East	West	Total
Credits (Millions)	$3.1	$0.1	$0.6	$5.3	$0.3	$1.7	$11.1
Share	27.8%	1.2%	5.6%	47.5%	2.5%	15.4%	100.0%

In 2018, concentration in all energy uplift credit categories was high.[19] [20] 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 8013, for balancing operating reserve credits to generators was 2865, for lost opportunity cost credits was 4860 and for reactive services credits was 9713. All of these HHI values are characterized as highly concentrated.

Table 4-16 Daily energy uplift credits HHI: 2018

Category	Type	Average	Minimum	Maximum	Highest Market Share (One day)	Highest Market Share (All days)
Day-Ahead	Generators	8013	2685	10000	100.0%	57.9%
	Imports	10000	10000	10000	100.0%	99.9%
	Load Response	10000	10000	10000	100.0%	81.5%
Balancing	Canceled Resources	NA	NA	NA	NA	NA
	Generators	2865	735	10000	100.0%	17.8%
	Imports	10000	10000	10000	100.0%	100.0%
	Load Response	9997	9944	10000	100.0%	47.4%
	Lost Opportunity Cost	4860	911	10000	100.0%	26.0%
Reactive Services		9713	4203	10000	100.0%	89.3%
Synchronous Condensing		10000	10000	10000	100.0%	100.0%
Black Start Services		9580	3968	10000	100.0%	52.5%
Total		3002	735	10000	100.0%	21.5%

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 4-17 and Table 4-18 show the categories of credits and charges and their relationship. These tables show how the charges are allocated.

19 See *2018 State of the Market Report for PJM*, Section 3: "Energy Market" at "Market Concentration" for a discussion of concentration ratios and the Herfindahl-Hirschman Index (HHI).
20 Table 4-16 excludes local constraint control categories.

Table 4-17 Day-ahead and balancing operating reserve credits and charges

Credits Received For:	Credits Category:		Charges Category:	Charges Paid By:	
		Day-Ahead			
Day-Ahead Import Transactions and Generation Resources	Day-Ahead Operating Reserve Transaction Day-Ahead Operating Reserve Generator	→	Day-Ahead Operating Reserve	Day-Ahead Load Day-Ahead Export Transactions Decrement Bids	in RTO Region
Economic Load Response Resources	Day-Ahead Operating Reserves for Load Response	→	Day-Ahead Operating Reserve for Load Response	Day-Ahead Load Day-Ahead Export Transactions Decrement Bids	in RTO Region
Unallocated Negative Load Congestion Charges Unallocated Positive Generation Congestion Credits		→	Unallocated Congestion	Day-Ahead Load Day-Ahead Export Transactions Decrement Bids	in RTO Region
		Balancing			
Generation Resources	Balancing Operating Reserve Generator	→	Balancing Operating Reserve for Reliability	Real-Time Load plus Real-Time Export Transactions	in RTO, Eastern or Western Region
			Balancing Operating Reserve for Deviations	Deviations	
			Balancing Local Constraint	Applicable Requesting Party	
Canceled Resources	Balancing Operating Reserve Startup Cancellation	→	Balancing Operating Reserve for Deviations	Deviations	in RTO Region
Lost Opportunity Cost (LOC)	Balancing Operating Reserve LOC				
Real-Time Import Transactions	Balancing Operating Reserve Transaction				
Economic Load Response Resources	Balancing Operating Reserves for Load Response	→	Balancing Operating Reserve for Load Response	Deviations	in RTO Region

Table 4-18 Reactive services, synchronous condensing and black start services credits and charges

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

Energy Uplift Results

Energy Uplift Charges Total energy uplift charges increased by $72.0 million or 56.5 percent in 2018 compared to 2017. Table 4-20 shows total energy uplift charges for 2001 through 2018.

Table 4-19 Total energy uplift charges: 2001 through 2018

	Total Energy Uplift Charges (Millions)	Change (Millions)	Percent Change	Energy Uplift as a Percent of Total PJM Billing
2001	$284.0	$67.0	30.9%	8.5%
2002	$273.7	($10.3)	(3.6%)	5.8%
2003	$376.5	$102.8	37.6%	5.4%
2004	$537.6	$161.1	42.8%	6.1%
2005	$712.6	$175.0	32.6%	3.1%
2006	$365.6	($347.0)	(48.7%)	1.7%
2007	$503.3	$137.7	37.7%	1.6%
2008	$474.3	($29.0)	(5.8%)	1.4%
2009	$322.7	($151.6)	(32.0%)	1.2%
2010	$623.2	$300.5	93.1%	1.8%
2011	$603.4	($19.8)	(3.2%)	1.7%
2012	$649.8	$46.4	7.7%	2.2%
2013	$843.0	$193.2	29.7%	2.5%
2014	$961.2	$118.2	14.0%	1.9%
2015	$312.0	($649.2)	(67.5%)	0.7%
2016	$136.7	($175.3)	(56.2%)	0.4%
2017	$127.3	($9.4)	(6.9%)	0.3%
2018	$199.3	$72.0	56.5%	0.4%

Table 4-20 shows total energy uplift charges by category in 2017 and 2018.[21] The increase of $72.0 million is comprised of an increase of $9.2 million in day-ahead operating reserve charges, an increase of $69.9 million in balancing operating reserve charges and a decrease of $7.3 million in reactive service charges.

Table 4-20 Total energy uplift charges by category: 2017 and 2018

Category	2017 Charges (Millions)	2018 Charges (Millions)	Change (Millions)	Percent Change
Day-Ahead Operating Reserves	$24.8	$34.0	$9.2	37.2%
Balancing Operating Reserves	$81.9	$151.8	$69.9	85.4%
Reactive Services	$20.4	$13.1	($7.3)	(35.6%)
Synchronous Condensing	$0.0	$0.0	$0.0	0.0%
Black Start Services	$0.3	$0.3	$0.0	17.9%
Total	$127.3	$199.3	$72.0	56.5%
Energy Uplift as a Percent of Total PJM Billing	0.3%	0.4%	0.1%	26.3%

Table 4-21 compares monthly energy uplift charges by category for 2017 and 2018.

21 Table 4-20 includes all categories of charges as defined in Table 4-17 and Table 4-18 and includes all PJM Settlements billing adjustments. Billing data can be modified by PJM Settlements at any time to reflect changes in the evaluation of energy uplift. The billing data reflected in this report were current on January 10, 2019.

Table 4-21 Monthly energy uplift charges: 2017 and 2018

	2017 Charges (Millions)						2018 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	$2.6	$7.5	$1.3	$0.0	$0.0	$11.4	$4.8	$55.4	$1.94	$0.0	$0.0	$62.1
Feb	$2.0	$1.3	$3.3	$0.0	$0.0	$6.6	$3.6	$1.9	$2.2	$0.0	$0.0	$7.8
Mar	$0.6	$5.4	$1.4	$0.0	$0.0	$7.4	$4.6	$6.4	$1.9	$0.0	$0.0	$12.9
Apr	$0.5	$3.2	$1.3	$0.0	$0.0	$5.0	$2.1	$9.6	$1.2	$0.0	$0.1	$12.9
May	$0.9	$7.4	$1.3	$0.0	$0.0	$9.7	$6.9	$16.1	$2.2	$0.0	$0.1	$25.2
Jun	$1.8	$5.5	$0.9	$0.0	$0.0	$8.3	$5.7	$12.0	$1.3	$0.0	$0.0	$19.0
Jul	$2.5	$7.5	$0.9	$0.0	$0.0	$10.9	$2.1	$9.5	$0.5	$0.0	$0.0	$12.1
Aug	$2.9	$5.4	$1.5	$0.0	$0.0	$9.8	$0.7	$9.2	$0.2	$0.0	$0.0	$10.2
Sep	$3.0	$10.3	$2.3	$0.0	$0.0	$15.5	$1.35	$13.0	$1.0	$0.0	$0.0	$15.4
Oct	$1.6	$7.9	$2.2	$0.0	$0.0	$11.8	$1.0	$8.9	$0.5	$0.0	$0.1	$10.5
Nov	$2.1	$7.7	$1.9	$0.0	$0.0	$11.8	$0.6	$7.0	$0.2	$0.0	$0.0	$7.8
Dec	$4.0	$12.8	$2.3	$0.0	$0.0	$19.1	$0.5	$2.7	$0.0	$0.0	$0.0	$3.3
Total	$24.8	$81.9	$20.4	$0.0	$0.3	$127.3	$34.0	$151.8	$13.1	$0.0	$0.3	$199.3
Share	19.5%	64.3%	16.0%	0.0%	0.2%	100.0%	17.1%	76.2%	6.6%	0.0%	0.2%	100.0%

Table 4-22 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.[22] Day-ahead operating reserve charges increased by $9.2 million or 37.2 percent in 2018 compared to 2017. Day-ahead operating reserve charges increased in 2018 due to reliability issues in the BGE and Pepco control zones as a result of new flow patterns, voltage issues in the ComEd and DPL zones, and the high load in early January which required additional commitments in the Day-Ahead Energy Market.

Table 4-22 Day-ahead operating reserve charges: 2017 and 2018

Type	2017 Charges (Millions)	2018 Charges (Millions)	Change (Millions)	2017 Share	2018 Share
Day-Ahead Operating Reserve Charges	$24.8	$34.0	$9.2	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	$24.8	$34.0	$9.2	100.0%	100.0%

Table 4-23 shows the composition of the balancing operating reserve charges. Balancing operating reserve charges consist of balancing operating reserve reliability charges (credits to generators), balancing operating reserve deviation charges (credits to generators and import transactions), balancing operating reserve charges for economic load response and balancing local constraint charges. Balancing operating reserve charges increased by $69.9 million in 2018 compared to 2017.

Table 4-23 Balancing operating reserve charges: 2017 and 2018

Type	2017 Charges (Millions)	2018 Charges (Millions)	Change (Millions)	2017 Share	2018 Share
Balancing Operating Reserve Reliability Charges	$26.7	$37.1	$10.3	32.7%	24.4%
Balancing Operating Reserve Deviation Charges	$53.3	$106.2	$52.9	65.1%	69.9%
Balancing Operating Reserve Charges for Load Response	$0.4	$0.0	($0.3)	0.4%	0.0%
Balancing Local Constraint Charges	$1.5	$8.6	$7.0	1.9%	5.6%
Total	$81.9	$151.8	$69.9	100.0%	100.0%

Table 4-24 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 2018, energy lost opportunity cost deviation charges increased by $37.9 million or 258.3 percent, and make whole

22 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, totaling $26.9 million.

deviation charges increased by $15.0 million or 38.9 percent compared to 2017. The increase in charges was the result of an increase in balancing and lost opportunity cost credits to generators.

Table 4-24 Balancing operating reserve deviation charges: 2017 and 2018

Charge Attributable To	2017 Charges (Millions)	2018 Charges (Millions)	Change (Millions)	2017 Share	2018 Share
Make Whole Payments to Generators and Imports	$38.6	$53.6	$15.0	72.4%	50.5%
Energy Lost Opportunity Cost	$14.7	$52.6	$37.9	27.5%	49.5%
Canceled Resources	$0.0	$0.0	($0.0)	0.0%	0.0%
Total	$53.3	$106.2	$52.9	100.0%	100.0%

Table 4-25 shows reactive services, synchronous condensing and black start services charges. Reactive services charges decreased by $7.2 million in 2018, compared to 2017. Reactive charges were incurred as a result of high voltage issues in the ComEd and DPL control zones, and low voltage issues in the PENELEC and AEP control zones. The decrease in reactive service charges resulted from a decrease in the need for reactive service in the BGE and Pepco zones.

Table 4-25 Additional energy uplift charges: 2017 and 2018

Type	2017 Charges (Millions)	2018 Charges (Millions)	Change (Millions)	2017 Share	2018 Share
Reactive Services Charges	$20.4	$13.1	($7.3)	98.8%	97.4%
Synchronous Condensing Charges	$0.0	$0.0	$0.0	0.0%	0.3%
Black Start Services Charges	$0.3	$0.3	$0.0	1.2%	2.3%
Total	$20.6	$13.5	($7.2)	100.0%	100.0%

Table 4-26 and Table 4-27 show the amount and shares of regional balancing charges in 2017 and 2018. Regional balancing operating reserve charges consist of balancing operating reserve reliability and deviation charges. These charges are allocated regionally across PJM. In 2018 the largest share of regional charges was paid by demand deviations which paid 42.8 percent of all regional balancing charges. The regional balancing charges allocation table does not include charges attributed for resources controlling local constraints.

In 2018, regional balancing operating reserve charges increased by $63.2 million compared to 2017. Balancing operating reserve reliability charges increased by $10.36 million, or 38.6 percent, and balancing operating reserve deviation charges increased by $52.8 million, or 99.1 percent.

Table 4-26 Regional balancing charges allocation (Millions): 2017

Charge	Allocation	RTO		East		West		Total	
Reliability Charges	Real-Time Load	$21.5	26.8%	$4.0	4.9%	$0.4	0.5%	$25.8	32.2%
	Real-Time Exports	$0.7	0.9%	$0.2	0.2%	$0.0	0.0%	$0.9	1.2%
	Total	$22.2	27.7%	$4.1	5.1%	$0.4	0.5%	$26.7	33.4%
Deviation Charges	Demand	$30.0	37.4%	$2.2	2.7%	$0.5	0.7%	$32.7	40.8%
	Supply	$9.1	11.4%	$0.7	0.8%	$0.1	0.1%	$9.9	12.3%
	Generator	$9.9	12.4%	$0.7	0.9%	$0.1	0.2%	$10.8	13.5%
	Total	$49.0	61.2%	$3.5	4.4%	$0.8	1.0%	$53.3	66.6%
Total Regional Balancing Charges		$71.2	88.9%	$7.6	9.5%	$1.2	1.5%	$80.1	100%

Table 4-27 Regional balancing charges allocation (Millions): 2018

Charge	Allocation	RTO		East		West		Total	
Reliability Charges	Real-Time Load	$31.4	21.9%	$2.9	2.0%	$1.6	1.1%	$35.9	25.1%
	Real-Time Exports	$1.0	0.7%	$0.1	0.1%	$0.0	0.0%	$1.2	0.8%
	Total	$32.4	22.6%	$3.0	2.1%	$1.6	1.1%	$37.1	25.9%
Deviation Charges	Demand	$56.9	39.7%	$1.9	1.3%	$2.4	1.7%	$61.3	42.8%
	Supply	$17.5	12.2%	$0.8	0.6%	$0.7	0.5%	$19.0	13.3%
	Generator	$24.0	16.8%	$0.9	0.6%	$1.1	0.7%	$25.9	18.1%
	Total	$98.5	68.7%	$3.6	2.5%	$4.1	2.9%	$106.2	74.1%
Total Regional Balancing Charges		$130.9	91.4%	$6.6	4.6%	$5.8	4.0%	$143.3	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 4-17 shows how these charges are allocated.[23]

Figure 4-5 shows the daily day-ahead operating reserve rate for 2017 and 2018. The average rate in was $0.041 per MWh, $0.011 per MWh higher than the average in 2017. The highest rate of 2018 occurred on June 19, when the rate reached $0.357 per MWh, $0.011 per MWh higher than the $0.346 per MWh reached in 2017, on November 30. Figure 4-5 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 2017 or 2018.

Figure 4-5 Daily day-ahead operating reserve rate ($/MWh): 2017 and 2018

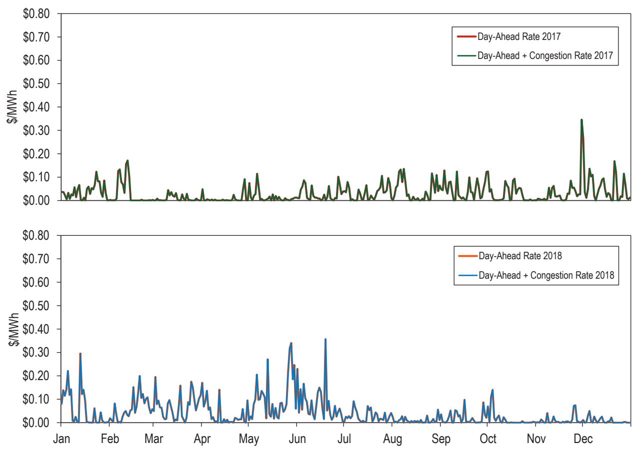


Figure 4-6 shows the RTO and the regional reliability rates for 2017 and 2018. The average RTO reliability rate 2018 was $0.040 per MWh. The highest RTO reliability rate in 2018 occurred on January 2, when the rate reached $0.731 per MWh, $0.341 per MWh higher than the $0.390 per MWh rate reached in 2017, on January 8.

Figure 4-6 Daily balancing operating reserve reliability rates ($/MWh): 2017 and 2018

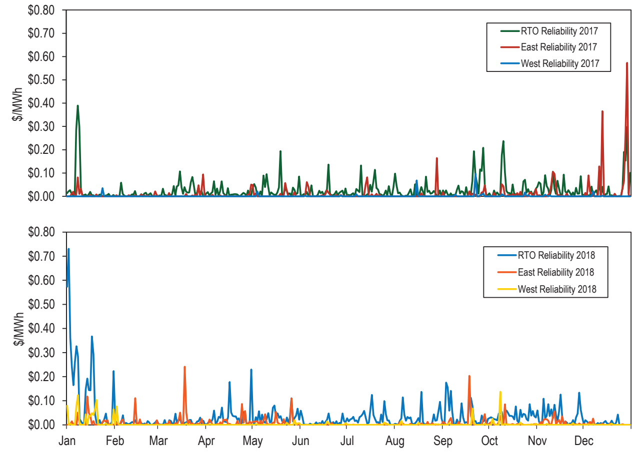


Figure 4-7 shows the RTO and regional deviation rates for 2017 and 2018. The average RTO deviation rate of 2018 was $0.297 per MWh. The highest daily rate of 2018 occurred on January 1, when the RTO deviation rate reached $4.48 per MWh, $2.311 per MWh higher than the $2.177 per MWh rate reached in 2017, on January 9.

Figure 4-7 Daily balancing operating reserve deviation rates ($/MWh): 2017 and 2018

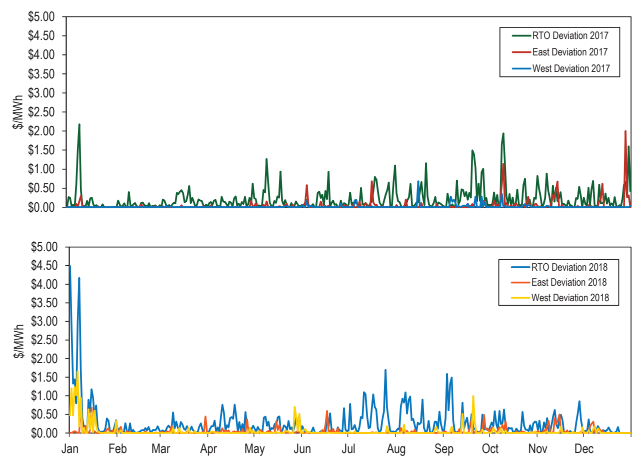


Figure 4-8 shows the daily lost opportunity cost rate and the daily canceled resources rate for 2017 and 2018. The average lost opportunity cost rate of 2018 was $0.341 per MWh. The highest lost opportunity cost rate occurred on January 7, when it reached $9.016 per

23 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.

MWh, $7.059 per MWh higher than the $1.957 per MWh rate reached in 2017, on December 27.[24]

Figure 4-8 Daily lost opportunity cost and canceled resources rates ($/MWh): 2017 and 2018

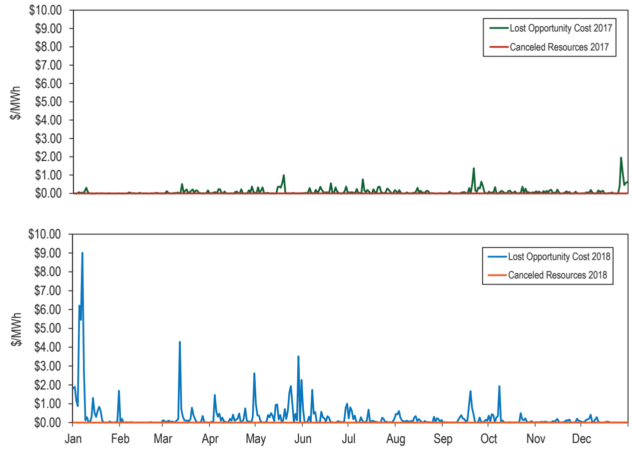


Table 4-28 shows the average rates for each region in each category for 2017 and 2018.

Table 4-28 Operating reserve rates ($/MWh): 2017 and 2018

Rate	2017 ($/MWh)	2018 ($/MWh)	Difference ($/MWh)	Percent Difference
Day-Ahead	0.030	0.041	0.011	35.0%
Day-Ahead with Unallocated Congestion	0.030	0.041	0.011	35.0%
RTO Reliability	0.028	0.040	0.012	40.9%
East Reliability	0.011	0.008	(0.003)	(31.3%)
West Reliability	0.001	0.004	0.003	272.8%
RTO Deviation	0.226	0.297	0.071	31.4%
East Deviation	0.045	0.044	(0.000)	(0.8%)
West Deviation	0.011	0.057	0.046	419.9%
Lost Opportunity Cost	0.097	0.340	0.243	251.6%
Canceled Resources	0.000	-	(0.000)	

Table 4-29 shows the operating reserve cost of a one MW transaction in 2018. For example, a decrement bid in the Eastern Region (if not offset by other transactions) paid an average rate of $0.681 per MWh with a maximum rate of $13.336 per MWh, a minimum rate of $0.000 per MWh and a standard deviation of $1.126 per MWh. The rates in Table 4-29 include all operating reserve charges including RTO deviation charges. Table 4-29 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 4-29 Operating reserve rates statistics ($/MWh): 2018

		Rates Charged ($/MWh)			
Region	Transaction	Maximum	Average	Minimum	Standard Deviation
East	INC	13.194	0.681	0.000	1.113
	DEC	13.336	0.722	0.000	1.126
	DA Load	0.357	0.041	0.000	0.059
	RT Load	0.733	0.029	0.000	0.076
	Deviation	13.194	0.681	0.000	1.113
West	INC	13.363	0.693	0.000	1.207
	DEC	13.505	0.735	0.000	1.222
	DA Load	0.357	0.041	0.000	0.059
	RT Load	0.731	0.027	0.000	0.077
	Deviation	13.363	0.693	0.000	1.207

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.[25] 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 4-30 shows the reactive services rates associated with local voltage support in 2017 and 2018. Table 4-30 shows that in 2018 the ComEd Control Zone had the highest rate. Real-time load in the ComEd Control Zone paid an average of $0.116 per MWh for reactive services associated with local voltage support, $0.023 or 16.6 percent lower than the average rate paid in 2017.

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

25 See *2018 State of the Market Report for PJM*, Section 10, "Ancillary Service Markets".

Table 4-30 Local voltage support rates: 2017 and 2018

Control Zone	2017 ($/MWh)	2018 ($/MWh)	Difference ($/MWh)	Percent Difference
AECO	0.000	0.000	(0.000)	(73.2%)
AEP	0.000	0.006	0.006	1,133.8%
APS	0.002	0.000	(0.002)	(100.0%)
ATSI	0.000	0.000	(0.000)	(100.0%)
BGE	0.055	0.001	(0.054)	(98.2%)
ComEd	0.139	0.116	(0.023)	(16.6%)
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	0.000	0.000	39.0%
DPL	0.073	0.014	(0.059)	(81.1%)
EKPC	0.001	0.015	0.014	2,053.7%
JCPL	0.000	0.000	(0.000)	(100.0%)
Met-Ed	0.004	0.000	(0.004)	(100.0%)
OVEC	NA	0.000	NA	NA
PECO	0.002	0.000	(0.002)	(100.0%)
PENELEC	0.099	0.023	(0.076)	(77.1%)
Pepco	0.054	0.000	(0.054)	(100.0%)
PPL	0.000	0.002	0.002	65,601.2%
PSEG	0.000	0.000	(0.000)	(100.0%)
RECO	0.000	0.000	(0.000)	(100.0%)

Balancing Operating Reserve Determinants

Table 4-31 shows the determinants used to allocate the regional balancing operating reserve charges in 2017 and 2018. Total real-time load and real-time exports were 789,165 GWh, 3.7 percent higher in 2018 compared to 2017. Total deviations summed across the demand, supply, and generator categories were 154,706 GWh, 1.9 percent higher in 2018 compared to 2017.

Table 4-31 Balancing operating reserve determinants (GWh): 2017 and 2018

		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
2017	RTO	759,025	30,140	789,165	91,907	30,537	29,372	151,816
	East	359,340	11,612	370,953	46,976	17,941	14,149	79,066
	West	399,685	18,528	418,213	44,433	12,292	15,222	71,947
2018	RTO	791,093	27,625	818,718	90,137	28,965	35,603	154,706
	East	374,599	15,791	390,390	44,758	17,047	19,565	81,370
	West	416,495	11,834	428,328	44,722	11,599	16,038	72,360
Difference	RTO	32,068	(2,515)	29,553	(1,770)	(1,572)	6,232	2,890
	East	15,258	4,179	19,437	(2,218)	(894)	5,416	2,304
	West	16,810	(6,694)	10,116	289	(692)	816	413

Deviations fall into three categories, demand, supply and generator deviations. Table 4-32 shows the different categories by the type of transactions that incurred deviations. In 2018, 27.4 percent of all RTO deviations were incurred by participants that deviated due to INCs and DECs or due to combinations of INCs and DECs with other transactions, the remaining 72.6 percent of all RTO deviations were incurred by participants that deviated due to other transaction types or due to combinations of other transaction types. As of November 1, 2018, internal bilateral transactions (IBTs) are no longer used for the calculation of deviations for purposes of allocating balancing operating reserve credits. Given that IBTs were only 0.2 percent of RTO deviations, this will have a negligible impact on balancing operating reserve rates.

Table 4-32 Deviations by transaction type: 2018

Deviation		Deviation (GWh)			Share		
Category	Transaction	RTO	East	West	RTO	East	West
Demand	Bilateral Sales Only	307	252	55	0.2%	0.3%	0.1%
	DECs Only	18,954	9,060	9,238	12.3%	11.1%	12.8%
	Exports Only	6,991	4,260	2,731	4.5%	5.2%	3.8%
	Load Only	60,057	29,896	30,161	38.8%	36.7%	41.7%
	Combination with DECs	1,999	790	1,209	1.3%	1.0%	1.7%
	Combination without DECs	1,829	501	1,328	1.2%	0.6%	1.8%
Supply	Bilateral Purchases Only	300	197	104	0.2%	0.2%	0.1%
	Imports Only	7,203	5,109	2,094	4.7%	6.3%	2.9%
	INCs Only	19,912	10,505	9,088	12.9%	12.9%	12.6%
	Combination with INCs	1,492	1,188	304	1.0%	1.5%	0.4%
	Combination without INCs	57	47	10	0.0%	0.1%	0.0%
Generators		35,603	19,565	16,038	23.0%	24.0%	22.2%
Total		154,706	81,370	72,360	100.0%	100.0%	100.0%

Geography of Charges and Credits

Table 4-33 shows the geography of charges and credits in 2018. Table 4-33 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 5.4 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 13.1 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 3.6 percent of all operating reserve charges allocated regionally, and resources in the BGE Control Zone were paid 6.1 percent of the corresponding credits. The BGE Control Zone received more operating reserve credits than operating reserve charges paid and had 9.3 percent of the surplus. The surplus is the net of the credits and charges paid at a location. Table 4-33 also shows that 88.2 percent of all charges were allocated in control zones, 2.9 percent in hubs and aggregates and 8.9 percent in interfaces.

Table 4-33 Geography of regional charges and credits: 2018

Location		Charges (Millions)	Credits (Millions)	Balance	Shares: Total Charges	Shares: Total Credits	Shares: Deficit	Shares: Surplus
Zones	AECO	$2.4	$2.7	$0.3	1.3%	1.5%	0.0%	0.7%
	AEP	$24.1	$24.3	$0.2	13.6%	13.7%	0.0%	0.4%
	APS	$9.8	$3.5	($6.3)	5.5%	2.0%	13.1%	0.0%
	ATSI	$12.8	$12.7	($0.2)	7.2%	7.2%	0.3%	0.0%
	BGE	$6.4	$10.8	$4.4	3.6%	6.1%	0.0%	9.3%
	ComEd	$18.2	$20.6	$2.3	10.3%	11.6%	0.0%	4.9%
	DAY	$3.1	$7.5	$4.4	1.8%	4.2%	0.0%	9.2%
	DEOK	$5.5	$2.7	($2.8)	3.1%	1.5%	5.8%	0.0%
	DLCO	$2.6	$0.9	($1.7)	1.5%	0.5%	3.6%	0.0%
	Dominion	$18.1	$27.1	$9.0	10.2%	15.3%	0.0%	19.0%
	DPL	$5.0	$11.6	$6.7	2.8%	6.6%	0.0%	14.0%
	EKPC	$2.3	$4.0	$1.7	1.3%	2.3%	0.0%	3.6%
	External	$0.0	$2.4	$2.4	0.0%	1.3%	0.0%	5.0%
	JCPL	$4.4	$1.7	($2.7)	2.5%	1.0%	5.5%	0.0%
	Met-Ed	$3.5	$1.3	($2.2)	2.0%	0.7%	4.6%	0.0%
	OVEC	$0.0	$0.0	($0.0)	0.0%	0.0%	0.0%	0.0%
	PECO	$7.9	$3.0	($4.9)	4.5%	1.7%	10.1%	0.0%
	PENELEC	$5.8	$6.4	$0.6	3.3%	3.6%	0.0%	1.3%
	Pepco	$6.1	$21.4	$15.3	3.4%	12.1%	0.0%	32.2%
	PPL	$9.6	$3.2	($6.3)	5.4%	1.8%	13.1%	0.0%
	PSEG	$8.4	$8.7	$0.3	4.8%	4.9%	0.0%	0.5%
	RECO	$0.3	$0.0	($0.3)	0.2%	0.0%	0.7%	0.0%
	All Zones	$156.4	$176.5	$20.1	88.2%	99.7%	56.9%	100.0%
Hubs and Aggregates	AEP - Dayton	$0.5	$0.0	($0.5)	0.3%	0.0%	1.1%	0.0%
	Dominion	$0.7	$0.0	($0.7)	0.4%	0.0%	1.5%	0.0%
	Eastern	$0.4	$0.0	($0.4)	0.2%	0.0%	0.9%	0.0%
	New Jersey	$0.4	$0.0	($0.4)	0.2%	0.0%	0.8%	0.0%
	Ohio	$0.2	$0.0	($0.2)	0.1%	0.0%	0.4%	0.0%
	Western Interface	$0.0	$0.0	($0.0)	0.0%	0.0%	0.1%	0.0%
	Western	$2.9	$0.0	($2.9)	1.6%	0.0%	6.0%	0.0%
	RTEP B0328 Source	$0.0	$0.0	($0.0)	0.0%	0.0%	0.0%	0.0%
	All Hubs and Aggregates	$5.1	$0.0	($5.1)	2.9%	0.0%	10.6%	0.0%
Interfaces	CPLE Exp	$0.0	$0.0	($0.0)	0.0%	0.0%	0.1%	0.0%
	CPLE Imp	$0.1	$0.0	($0.1)	0.1%	0.0%	0.2%	0.0%
	Duke Exp	$0.2	$0.0	($0.2)	0.1%	0.0%	0.4%	0.0%
	Duke Imp	$0.2	$0.0	($0.2)	0.1%	0.0%	0.4%	0.0%
	Hudson	$0.3	$0.0	($0.3)	0.2%	0.0%	0.6%	0.0%
	IMO	$1.5	$0.0	($1.5)	0.8%	0.0%	3.1%	0.0%
	Linden	$0.4	$0.0	($0.4)	0.2%	0.0%	0.9%	0.0%
	MISO	$3.4	$0.0	($3.4)	1.9%	0.0%	7.1%	0.0%
	NCMPA Imp	$0.2	$0.0	($0.2)	0.1%	0.0%	0.4%	0.0%
	Neptune	$0.5	$0.0	($0.5)	0.3%	0.0%	1.0%	0.0%
	NIPSCO	$0.1	$0.0	($0.1)	0.1%	0.0%	0.2%	0.0%
	Northwest	$0.2	$0.0	($0.2)	0.1%	0.0%	0.5%	0.0%
	NYIS	$1.5	$0.0	($1.5)	0.8%	0.0%	3.0%	0.0%
	South Exp	$2.7	$0.0	($2.7)	1.5%	0.0%	5.6%	0.0%
	South Imp	$4.3	$0.0	($4.3)	2.4%	0.0%	9.0%	0.0%
	All Interfaces	$15.7	$0.5	($15.2)	8.9%	0.3%	32.5%	0.0%
	Total	$177.2	$177.0	($0.2)	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).[26] 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 4-34 shows balancing operating reserve credits calculated using intraday segments and balancing operating reserve payments calculated on a daily basis. In 2017, balancing operating reserve credits would have been $8.3 million or 12.7 percent lower if they were calculated on a daily basis. In 2018, balancing operating reserve credits would have been $21.9 million or 24.3 percent lower if they were calculated on a daily basis.

Table 4-34 Intraday segments and daily balancing operating reserve credits: 2017 and 2018

	2017 BOR Credits (Millions)			2018 BOR Credits (Millions)		
	Intraday Segments Calculation	Daily Calculation	Difference	Intraday Segments Calculation	Daily Calculation	Difference
Jan	$7.0	$6.7	($0.3)	$33.1	$27.1	($6.1)
Feb	$1.2	$1.1	($0.1)	$1.8	$1.3	($0.4)
Mar	$4.3	$3.8	($0.5)	$3.0	$2.2	($0.8)
Apr	$2.3	$1.9	($0.4)	$5.6	$4.1	($1.5)
May	$5.4	$4.6	($0.8)	$5.8	$3.6	($2.2)
Jun	$3.8	$3.3	($0.5)	$2.7	$1.5	($1.2)
Jul	$5.6	$4.3	($1.3)	$7.4	$5.0	($2.4)
Aug	$4.7	$4.1	($0.6)	$7.2	$5.1	($2.1)
Sep	$8.2	$6.8	($1.4)	$9.5	$7.0	($2.5)
Oct	$7.0	$6.3	($0.7)	$6.2	$4.7	($1.4)
Nov	$6.1	$5.5	($0.5)	$6.3	$5.3	($1.0)
Dec	$9.7	$8.6	($1.0)	$1.6	$1.3	($0.3)
Total	$65.3	$57.0	($8.3)	$90.2	$68.3	($21.9)

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 4-35 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 $2.1 million or 11.3 percent lower had they been settled on an hourly basis compared to being settled on a five minute basis.

Table 4-35 Five minute settlement and hourly settlement of day-ahead lost opportunity cost credits: April through December, 2018

	2018 Day Ahead LOC Credits (Millions)		
	Five Minute Settlement	Hourly Settlement	Difference
Apr	$2.0	$1.9	($0.1)
May	$6.0	$5.5	($0.5)
Jun	$3.5	$3.0	($0.5)
Jul	$2.1	$1.8	($0.3)
Aug	$1.7	$1.6	($0.2)
Sep	$2.2	$2.1	($0.2)
Oct	$1.9	$1.7	($0.2)
Nov	$0.5	$0.5	($0.0)
Dec	$0.7	$0.6	($0.1)
Total	$20.7	$18.6	($2.1)

26 See PJM "Manual 28: Operating Reserve Accounting," Rev. 81 (October 25, 2018).

Table 4-36 shows day-ahead LOC credits calculated using intraday segments and LOC credits calculated on a daily basis. In 2017, LOC credits would have been $1.8 million or 18.2 percent lower if they were calculated on a daily basis. In 2018, LOC credits would have been $8.7 million or 23.2 percent lower if they were calculated on a daily basis.

Table 4-36 Five minute settlement and daily settlement of lost opportunity cost credits: 2017 and 2018

	2017 Day Ahead LOC Credits (Millions)			2018 Day Ahead LOC Credits (Millions)		
	Intraday Segments Calculation	Daily Calculation	Difference	Intraday Segments Calculation	Daily Calculation	Difference
Jan	$0.1	$0.1	($0.0)	$13.7	$11.0	($2.8)
Feb	$0.1	$0.0	($0.0)	$0.1	$0.1	($0.0)
Mar	$0.9	$0.7	($0.2)	$3.1	$2.6	($0.5)
Apr	$0.5	$0.3	($0.1)	$2.0	$1.3	($0.7)
May	$0.8	$0.7	($0.1)	$6.0	$4.7	($1.3)
Jun	$0.7	$0.6	($0.1)	$3.5	$2.3	($1.3)
Jul	$1.5	$1.3	($0.2)	$2.1	$1.5	($0.6)
Aug	$0.5	$0.4	($0.1)	$1.7	$1.4	($0.4)
Sep	$1.5	$1.3	($0.2)	$2.2	$1.7	($0.5)
Oct	$0.8	$0.6	($0.2)	$1.9	$1.4	($0.4)
Nov	$0.5	$0.3	($0.2)	$0.5	$0.4	($0.1)
Dec	$2.3	$1.9	($0.4)	$0.7	$0.5	($0.2)
Total	$10.1	$8.3	($1.8)	$37.7	$28.9	($8.7)

Closed Loop Interfaces

PJM implemented closed loop interfaces with the stated purpose of improving the incorporation of reactive constraints into energy prices and to allow emergency DR to set price.[27] PJM applies closed loop interfaces so that it can use units needed for reactive support to set the energy price when they would not otherwise set price under the LMP algorithm. PJM also applies closed loop interfaces so that it can use emergency DR resources to set the real-time LMP when DR resources would not otherwise set price under the fundamental LMP logic. Of the 20 closed loop interface definitions, 11 (55 percent) were created for the purpose of allowing emergency DR to set price.

Closed loop interfaces are used to model the transfer capability into a specific area. Areas or regions are defined in PJM by hubs, aggregates or control zones, all comprised of buses. Closed loop interfaces are not defined by buses, but defined by the transmission facilities that connect the buses inside the loop with the rest of PJM. When PJM wants a closed loop interface to bind, PJM reduces the capacity of the transmission facilities to a level that will artificially make marginal the resource selected by PJM. Table 4-37 shows the closed loop interfaces that PJM has defined and PJM's objective in defining each closed loop interface.

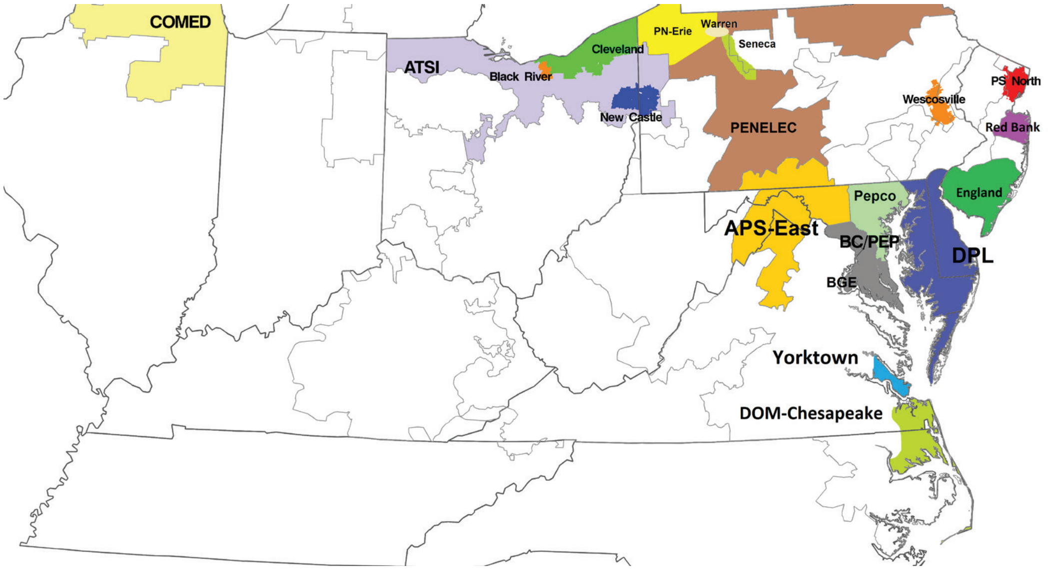
27 See PJM/Alstom. "Approaches to Reduce Energy Uplift and PJM Experiences," presented at the FERC Technical Conference: Increasing Real-Time and Day-Ahead Market Efficiency Through Improved Software in Docket No. AD10-12-006 <http://www.ferc.gov/june-tech-conf/2015/presentations/m2-3.pdf> (June 23,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

Table 4-37 PJM closed loop interfaces[28 29 30]

Interface	Control Zone(s)	Objective	Effective Date	Limit Calculation
APS-East	APS	Allow emergency DR resources / unit(s) needed for reactive to set real-time LMP	June 19, 2015	Limit equal to actual flow
ATSI	ATSI	Allow emergency DR resources / unit(s) needed for reactive to set real-time LMP	July 17, 2013	Limit equal to actual flow
BC	BGE	Allow emergency DR resources / unit(s) needed for reactive to set real-time LMP	June 19, 2015	Limit equal to actual flow
BC/PEP	BGE and Pepco	Reactive Interface (not an IROL). Used to model import capability into the BGE/PEPCO/Doubs/Northern Virginia area	NA	PJM Transfer Limit Calculator
Black River	ATSI	Allow emergency DR resources to set real-time LMP	September 1, 2014	Limit equal to actual flow
Cleveland	ATSI	Reactive Interface (IROL)	NA	PJM Transfer Limit Calculator
COMED	ComEd	Reactive Interface (IROL)	NA	PJM Transfer Limit Calculator
DOM-Chesapeake	Dominion	Allow emergency DR resources / unit(s) needed for reactive to set real-time LMP	August 14, 2015	Limit equal to actual flow
DPL	DPL	Allow emergency DR resources / unit(s) needed for reactive to set real-time LMP	June 19, 2015	Limit equal to actual flow
England	AECO	Allow emergency DR resources / unit(s) needed for reactive to set real-time LMP	June 1, 2017	Limit equal to actual flow
New Castle	ATSI	Allow emergency DR resources to set real-time LMP	July 1, 2014	Limit equal to actual flow
PENELEC	PENELEC	Allow emergency DR resources / unit(s) needed for reactive to set real-time LMP	April 22, 2015	Limit equal to actual flow
Pepco	Pepco	Allow emergency DR resources / unit(s) needed for reactive to set real-time LMP	June 19, 2015	Limit equal to actual flow
PL-Wescosville	PPL	Allow emergency DR resources / unit(s) needed for reactive to set real-time LMP	July 24, 2014	Limit equal to actual flow
PN-Erie	PENELEC	Allow emergency DR resources to set real-time LMP	April 22, 2015	Limit equal to actual flow
PS North	PSEG	Objective not identified. Interface was modeled in 2014/2015 Annual FTR auction	NA	NA
Red Bank	JCPL	Allow emergency DR resources / unit(s) needed for reactive to set real-time LMP	June 1, 2017	Limit equal to actual flow
Seneca	PENELEC	Allow unit(s) needed for reactive to set day-ahead and real-time LMP	February 1, 2014	Limit equal to actual flow
Warren	PENELEC	Allow unit(s) needed for reactive to set day-ahead and real-time LMP	September 26, 2014	Limit equal to actual flow
Yorktown	Dominion	Allow unit(s) needed for reactive to set day-ahead and real-time LMP	April 1, 2017	Limit equal to actual flow

Figure 4-9 shows the approximate geographic location of PJM's closed loop interfaces.

Figure 4-9 PJM Closed loop interfaces map



28 See PJM. "Manual 3: Transmission Operations," Rev. 48 (Dec. 1, 2015) for a description of reactive interfaces.
29 See closed loop interfaces definitions at <http://www.pjm.com/markets-and-operations/etools/oasis/system-information.aspx>.
30 See the PS North interface definition at <http://www.pjm.com/pub/account/auction-user-info/model-annual/Annual-PJM-interface-definitions-limits.csv>.

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

In a DC power flow model, such as the one used by PJM for dispatch and pricing, units scheduled for reactive support are only marginal when they are needed to supply energy above their economic minimum. With the use of closed loop interface, these units are forced to be marginal in the model even when not needed for energy, by adjusting the limit of the closed loop interface. This artificially creates congestion in the area that can only be relieved by the units providing reactive support inside the loop. The goal is to reduce energy uplift from the noneconomic operation of units needed for reactive support by forcing these units to be marginal when they are not, raising energy prices and thereby reducing uplift.[31]

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

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

Market prices should be a function of market fundamentals and energy market prices should be a function of energy market fundamentals. PJM has not explained why the other consequences of deviating from market fundamentals do not outweigh any benefits of artificially creating constraints in order to let reactive resources set price when they are not in fact marginal. PJM has not explained why the use of closed loop interfaces to permit emergency DR to set price is not simply a crude workaround to a viable solution, consistent with the LMP model, which would be to make DR nodal. The need for closed loop interfaces to let emergency DR set price is primarily a result of the fact that DR is zonal, or subzonal with one day's notice, and therefore cannot be dispatched nodally or set price nodally. With full implementation of the Capacity Performance market starting in the 2020/2021 Delivery Year, PJM will be able to dispatch DR within a PAI area, by only by guessing the DR connected to the each node. The reduction of uplift is a reasonable goal in general, but the reduction of uplift is not a goal that justifies creating distortions in the price setting mechanism.

CT Price Setting Logic

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

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

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

PJM and Alstom presented examples of this approach at the FERC Technical Conference, "Increasing Real-Time and Day-Ahead Market Efficiency Through Improved Software."[32] The presentation shows a two bus model connected by one transmission line, three generators (A, B and C) and load at one of the buses. Solution 1: In the solution based on the fundamental LMP logic that PJM has used since the inception of markets, two of the generators are committed (A at 50 MW and B at 50 MW) to serve load (100 MW). The LMP is set at $50 per MWh (the offer of generator A) at both buses. Generator B has to be made whole (paid energy uplift) because the LMP ($50 per MWh) does not cover the generator's offer ($100 per MWh). Generator B does not set the LMP because its economic minimum is higher than the relief needed to relieve the constraint. This solution is not acceptable for PJM because the most expensive generator would have to be made whole. In order to reduce energy uplift, PJM shows two alternatives. Solution 2: Artificially redefine the economic minimum of generator B to zero MW. Solution 3: Artificially redefine the limit of the transmission line to a level that would make the LMP higher at the bus where the most expensive generator is connected.

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

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

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

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

The MMU supports efforts to ensure that LMP reflects the appropriate marginal resource. The MMU recommends that if PJM believes it appropriate to use CT 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.

Energy Uplift Recommendations

Recommendations for Calculation of Credits

Day-Ahead Operating Reserve Elimination

The only reason to pay energy uplift in the Day-Ahead Energy Market is that a day-ahead schedule could cause a unit to incur losses as a result of differences between the Day-Ahead and Balancing Markets. Units cannot incur losses in the Day-Ahead Energy Market. Units do not incur costs in the Day-Ahead Energy Market. There is no reason to pay energy uplift in the Day-Ahead Energy Market. All energy uplift should be paid in real time including energy uplift that results from differences between day-ahead and real-time schedules. Paying energy uplift in the Day-Ahead Energy Market results in overpayments.

Day-ahead operating reserve credits are paid to market participants under specific conditions in order to ensure that units are not scheduled in the Day-Ahead Energy Market by PJM to operate at a loss in real time. Balancing operating reserve credits are paid to market participants under specific conditions in order to ensure that units are not operated by PJM at a loss in real time. Units

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

are paid day-ahead operating reserve credits whenever their total offer (including no load and startup costs and based on their day-ahead scheduled output) is not covered by the day-ahead energy revenues (day-ahead LMP times day-ahead scheduled output). Units are paid balancing operating reserve credits whenever their total offer (including no load and startup costs and based on their real-time output) are not covered by their day-ahead energy revenues, balancing energy revenues and a subset of net ancillary services revenues.[33]

Units scheduled in the Day-Ahead Energy Market do not operate until committed or dispatched in real time. Therefore, it cannot be determined if a unit was operated at a loss until the unit actually operates or does not operate. The current operating reserve rules governing the day-ahead operating reserve credits assume that units are going to operate exactly as scheduled because they are made whole based on their day-ahead scheduled output. A unit's real-time output may be greater or lower than their day-ahead scheduled output. Units dispatched in real time by PJM above their day-ahead scheduled output could be paid energy uplift in the form of balancing operating reserve credits if by increasing their output they operate at a loss because their offers are greater than the real-time LMP. Units dispatched in real time by PJM below their day-ahead scheduled output could be paid energy uplift in the form of balancing operating reserve credits if by decreasing their output the units operate at a loss or incur opportunity costs because real-time LMP is greater than the day-ahead LMP. The balancing operating reserve credits and lost opportunity costs credits ensure that units recover their total offers or keep their net revenues in real time.

Units scheduled in the Day-Ahead Energy Market that receive day-ahead operating reserve credits and for which real-time operation results in additional losses, are paid energy uplift in the form of balancing operating reserve or lost opportunity cost credits to ensure that they do not operate at a loss. This determination is not symmetrical because units scheduled in the Day-Ahead Energy Market that receive day-ahead operating reserve credits and for which real-time operation results in reduced losses or no loss do not have a reduction in energy uplift payments.

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

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

In order to properly compensate units, the MMU recommended enhancing the day-ahead operating reserve credits calculation to ensure that units receive an energy uplift payment based on their real-time output and not their day-ahead scheduled output whenever their real time operation results in a lower loss or no loss at all. The MMU also recommended including net DASR revenues as part of the offsets used in determining day-ahead operating reserve credits.[34] These recommendations are superseded by the MMU's recommendation to eliminate day-ahead operating reserve payments.[35] The elimination of day-ahead operating reserve payments also ensures that units are always made whole based on their actual operation and actual revenues.

The MMU calculated the impact of this recommendation for 2018. Energy uplift cost associated with units scheduled in the Day Ahead Energy Market would have been reduced by $12.1 million or 28.3 percent ($9.6 million paid as day ahead operating reserves and $2.5 million paid as reactive service credits).

The elimination of the day-ahead operating reserve category would change the allocation of such charges under the current energy uplift rules. If the day-ahead operating reserve category were eliminated but the MMU's uplift allocation recommendations were not implemented, units that clear the Day-Ahead Energy Market would be made whole through balancing operating reserve credits, which under the current rules are allocated to deviations or real-time load plus real-

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

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

time exports. Therefore, this recommendation should be implemented concurrently with the MMU's allocation recommendations.

Net Regulation Revenues Offset

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

The elimination of the use of net regulation revenues as an offset in the balancing operating reserve calculation had a direct impact on the level of energy uplift paid to participants that regulate while operating as noneconomic. The result of not using the net regulation revenues as an offset in the balancing operating reserve credit calculation is that PJM does not accurately calculate whether a unit is running at a loss. PJM procures energy, regulation, synchronized and nonsynchronized reserves in a jointly optimized manner. PJM determines the mix of resources that could provide all of those services in a least-cost manner. Excluding the net regulation revenues from the balancing operating reserve credit calculation is inconsistent with the process used by PJM to procure these services and inconsistent with the basic PJM uplift logic. Whether a unit is running for PJM at a loss defined by marginal costs cannot be determined if some of the revenues are arbitrarily excluded.

Another issue related to this exclusion is the treatment of pool-scheduled units that elect to self-schedule a portion of their capacity for regulation. A unit can be pool-scheduled for energy, which means PJM may commit or dispatch the unit based on economics, but it can also self-schedule some of its capacity for regulation. When this happens the capacity self-scheduled for regulation is treated as a price taker, but in the energy market any increase in MW to provide regulation are treated as additional costs, which can result in increased balancing operating reserve credits whenever the real-time LMP is lower than the unit's offer. For example, if a unit raises its economic minimum in order to provide regulation and the additional costs resulting from operating at a higher economic minimum are not covered by the real-time LMP, the unit will be made whole for the additional costs through balancing operating reserve credits.

The MMU recommends reincorporating the use of net regulation revenues as an offset in the calculation of balancing operating reserve credits. In 2018, using net regulation revenues as an offset in the balancing operating reserve calculation would have resulted in a net decrease of balancing operating reserve charges of $0.9 million.

Self Scheduled Start

Participants may offer their units as pool-scheduled (economic) or self-scheduled (must run).[36] Units offered as pool-scheduled clear the Day-Ahead Energy Market based on their offers and operate in real time following PJM dispatch instructions. Units offered as self-scheduled clear the Day-Ahead Energy Market regardless of their offers and may operate in real time following PJM dispatch instructions. Units offered as self-scheduled follow PJM dispatch instructions when they are offered with a minimum must run output from which the units may be dispatched up but not down. Self-scheduled units are not eligible to receive day-ahead or balancing operating reserve credits. The current rules determine if a unit is pool-scheduled or self-scheduled for operating reserve credits purposes separately for each hour using the hourly commitment status flag. If the flag is set as economic the unit is assumed to be pool-scheduled, if the flag is set as must run the unit is assumed to be self-scheduled. When a unit submits different flags within a day, the day-ahead operating reserve credit calculation treats each group of hours separately. The day-ahead operating reserve credit calculation only uses the hours flagged as economic and excludes any hours flagged as must run.

Units offered as self-scheduled for some hours of the day and pool-scheduled for the remaining hours are made whole for startup costs when they should not be. For example, if a unit is offered as self-scheduled for hours 10 through 24 and as pool-scheduled for the balance of the day and PJM selects the unit to start for

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

hour nine, the unit will be made whole for its startup cost if the hourly revenues do not cover the costs. The only hour used in the day-ahead or balancing operating reserve credit calculation is hour nine because the unit is not eligible for operating reserve credits for hours 10 through 24. The result is that any net revenue from hours 10 through 24 will not be used to offset the unit's startup cost despite the fact that the unit would have started and incurred those costs regardless of PJM dispatch instructions.

The MMU recommends that self-scheduled units not be paid energy uplift for their startup cost when the units are scheduled by PJM to start before the self-scheduled hours.

Lost Opportunity Cost Calculation

The current energy LOC calculations are inaccurate and create unreasonable compensation. The MMU recommended four modifications, of which three were adopted on September 1, 2015.[37] [38] The one outstanding modification not adopted by PJM is the calculation of LOC using segments of hours. Current rules calculate LOC on an interval basis; each interval is treated as a standalone calculation. This means that units receive an LOC payment during intervals in which it is economic for them to run and receive the benefit of not being called on during intervals in which it is not economic for them to run. PJM dispatchers might make the right decision to not call a unit in real time because the operation of the unit during all the hours in which the unit cleared the Day-Ahead Energy Market would not be economic, but the unit could still receive an LOC payment.

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

37 See *2015 State of the Market Report for PJM*, Volume 2 Section 4, "Energy Uplift," at "Lost Opportunity Cost Calculation" for an explanation of the adopted recommendations.
38 152 FERC ¶ 61,165 (2015)

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. This recommendation has not been adopted. The MMU calculated the impact of this recommendation for 2018. In 2018, lost opportunity cost payments would have had been reduced by $8.7 million or 23.2 percent.

In addition to the initial four recommendations, the MMU recommends two additional steps to address issues with the current LOC calculations:

- **Achievable Output:** CTs and diesels are compensated for LOC when scheduled in the Day-Ahead Energy Market and not committed in real time. This LOC calculation uses the day-ahead scheduled output as the achievable output for which units are entitled to receive LOC compensation. Units are paid LOC based on the difference between the real-time energy price (RT LMP) and the unit's offer times the day-ahead scheduled output.

  The actual LOC is a function of the real-time desired and achievable output rather than the day-ahead scheduled output. If a unit is capable of profitably producing more or fewer MWh in real time than the day-ahead scheduled MWh, it is the actual foregone MWh in real time that define actual LOC. Also, if a unit is not capable of producing at the day-ahead scheduled output level in real time it should not be compensated based on an output that cannot be achieved.

  The MMU recommends that units scheduled in the Day-Ahead Energy Market and not committed in real time should be compensated for LOC based on their real-time desired and achievable output, not their scheduled day-ahead output.

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

The MMU recommends that only flexible fast start units (startup plus notification times of 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.

Following Dispatch

PJM's method to determine whether a unit is following dispatch is fundamentally flawed. PJM does not currently have the ability to automatically monitor, identify, and measure whether generators are following dispatch. As a result, uplift eligibility is not determined correctly, generator deviations are calculated incorrectly and uplift credits are paid incorrectly.

PJM calculates the difference between units' output and units' ramp limited desired output for every five minute interval.[39] A unit is considered to be following dispatch if the difference is less than ten percent. Units that are considered to be following dispatch are not assessed any generator deviations.

PJM's following dispatch metric is incorrect for two reasons. The ramp limited desired output is based on the unit's generation during the prior five minute interval. The maximum deviation that unit can be assessed is limited to the unit's ramp rate over five minutes. For example, if the unit is operating at 500 MW and receives a dispatch down signal but remains at 500 MW for the first interval, the ramp limited desired output for the next interval will continue to be based on the 500 MW output level. This will continue without limit. For many units the ramp rate is low enough that the difference always remains below the ten percent threshold. The ramp rate for each unit used to calculate the ramp limited desired output is continuously adjusted by PJM based on the unit's performance, using a metric known as degree of generator performance (DGP). If a unit is either not responding to the dispatch signal or moving slower than its offered ramp rate, its desired output will be adjusted accordingly and the unit will be deemed to be following dispatch by definition. As a result, the following dispatch metric is not a meaningful basis for assessing whether units are following dispatch. For some units, it is impossible to fail the tests.

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.

Fast start resources, which include combustion turbines and diesels, are simply exempt from the following dispatch calculation.[40] As a result, these resources are considered to always be following dispatch, by definition. The MMU recommends that this exemption be eliminated and that all resources be evaluated with a meaningful following dispatch metric.

Quantifiable Impact of Recommendations

Table 4-38 shows the impact of the highest impact recommendations for the calculation of uplift credits. The recommendations include: the elimination of day-ahead credits; the inclusion of regulation offsets in the calculation of balancing operating reserve credits; and calculating the need for balancing operating reserve credits and LOC credits on a daily basis. The implementation of these recommendations combined would have reduced uplift credits by $47.4 million or 23.8 percent of all uplift credits in 2018.

39 For details see OATT § 3.2.3(o).

40 PJM defines fast start resources as resources with startup plus notification time of 2 hours or less and a minimum run time of 2 hours or less. See "PJM Manual 28: Operating Agreement Accounting," Rev. 81 (Oct. 25, 2018)

Table 4-38 Current and proposed energy uplift credits (millions)

Proposal	Credits Impacted	Current Credits (millions)	Proposal Credits (millions)	Difference (millions)
Eliminate day-ahead operating reserve credits	Day-ahead generator Day-ahead reactive	$45.8	$32.9	($12.9)
Include regulation offsets in the calculation of balancing operating reserves	Balancing operating reserve Local constraint Reactive	$100.1	$99.1	($0.9)
Calculate the need for balancing credits on a daily basis	Balancing operating reserve Local constraint Reactive	$100.1	$78.3	($21.8)
Calculate lost opportunity cost credits on a daily basis	Day-ahead LOC	$37.7	$28.9	($8.8)
Total combined impact of elimination of day-ahead credits, adding regulation offsets, and calculating balancing credits and day-ahead LOC credits on a daily basis	Day-ahead generator Day-ahead reactive Balancing operating reserve Day-ahead LOC	$183.6	$136.2	($47.4)

Recommendations for Allocation of Uplift Charges

Up to Congestion Transactions

Up to congestion transactions do not pay energy uplift charges. An up to congestion transaction affects unit commitment and dispatch in the same way that increment offers and decrement bids affect unit commitment and dispatch in the Day-Ahead Energy Market. All such virtual transactions affect the results of the Day-Ahead Energy Market and contribute to energy uplift costs. Up to congestion transactions are currently receiving preferential treatment, relative to increment offers and decrement bids and other transactions because they are not charged energy uplift.

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

The MMU calculated the impact on energy uplift rates if up to congestion transactions had paid energy uplift charges based on deviations in the same way that increment offers and decrement bids do. Table 4-39 shows the current average uplift rates for a 1 MW transaction and the average rates based on the proposed UTC uplift allocation. Two scenarios are presented, one assuming 100 percent of the 2018 UTC volume, and the other assuming 50 percent of the 2018 UTC volume. At 100 percent of the UTC volume a UTC would have paid on average between $0.489 and $0.500 per UTC MW. At 100 percent UTC volume UTC transactions would have paid $5.1 million in day-ahead uplift charges and $69.4 million in balancing deviation charges. At 50 percent UTC volume UTC transactions would have paid $2.8 million in day-ahead uplift charges and $52.0 million in balancing deviation charges.

Table 4-39 Current and proposed operating reserve rates ($/MWh): 2018

	Transaction	Current Average Rates	Average Rates with Proposed UTC Uplift Allocation (100% UTC Volume)	Average Rates with Proposed UTC Uplift Allocation (50% UTC Volume)
East	INC	0.681	0.233	0.347
	DEC	0.722	0.268	0.384
	DA Load	0.041	0.035	0.038
	RT Load	0.029	0.029	0.029
	Deviation	0.681	0.233	0.347
West	INC	0.693	0.227	0.342
	DEC	0.735	0.262	0.379
	DA Load	0.041	0.035	0.038
	RT Load	0.027	0.027	0.027
	Deviation	0.693	0.227	0.342
UTC	East to East	NA	0.500	0.731
	West to West	NA	0.489	0.721
	East to/from West	NA	0.495	0.726

Day-Ahead Reliability Energy Uplift Allocation

PJM may schedule units as must run in the Day-Ahead Energy Market when needed in real time to address reliability issues in four categories: voltage issues (high and low); black start requirements (from automatic load rejection units); local contingencies not modeled in the Day-Ahead Energy Market; and long lead time units not able to be scheduled in the Day-Ahead Energy Market.[41] The energy uplift paid to units scheduled for voltage is allocated to real-time load. The energy uplift associated with units scheduled for black start is allocated to real-time load and interchange reservations. The energy uplift paid to units scheduled because of local contingencies not modeled in the Day-Ahead Energy Market and scheduled because of their long lead times is allocated to day-ahead demand, day-ahead exports and decrement bids.

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

Reactive Services Credits and Balancing Operating Reserve Credits

Energy uplift credits to resources providing reactive services are separate from balancing operating reserve credits.[42] Under the current rules regarding energy uplift credits for reactive services, units are not assured recovery of the entire offer including no load and startup costs as they are under the operating reserve credits rules. Units providing reactive services at the request of PJM are made whole through reactive service credits. But when the reactive services credits do not cover a unit's entire offer, the unit is made whole for the balance through balancing operating reserves. The result is a misallocation of the costs of providing reactive services. Reactive services credits are paid by real-time load in the control zone or zones where the service is provided while balancing operating reserve charges are paid by deviations from day-ahead or real-time load plus exports in the RTO, Eastern or Western Region depending on the allocation process rather than by zone.

The MMU recommends that reactive services credits be calculated consistent with the balancing operating reserve credit calculation. The MMU also recommends including real-time exports and real-time wheels in the allocation of the cost of providing reactive support to the 500 kV system or above, in addition to real-time load.[43]

Allocation Proposal

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

The current method allocates day-ahead operating reserve charges to day-ahead load, day-ahead exports and decrement bids. The elimination of the day-ahead operating reserve category would shift these costs to the balancing operating reserve category which would be paid by deviations or by real-time load plus real-time exports depending on the balancing operating reserve allocation rules.

The MMU recommends creating a new category for energy uplift payments to units scheduled in the Day-Ahead Energy Market (for reasons other than reactive or black start services) that do not recover their operating cost after operating in the Real-Time Energy Market. These payments would be allocated to all day-ahead transactions and resources. All these transaction types have an impact on the outcome of the day-ahead scheduling process, so allocating these costs to all day-ahead transactions ensures that all transactions that affect the way the Day-Ahead Energy Market clears are responsible for any energy uplift credits paid to the units scheduled in the Day-Ahead Energy Market. Energy uplift payments to units scheduled as must run in the Day-Ahead Energy Market (for reasons related to expected conditions in the real-time market not including reactive or black start services) should be allocated to real-time load, real-time exports and real-time wheels.

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

42 OATT Attachment K–Appendix § 3.2.3B (f).

43 See the Day-Ahead Reliability and Reactive Cost Allocation Final Report (December 13, 2013) for a complete description of the issues discussed in that group. <http://www.pjm.com/~/media/committees-groups/task-forces/emustf/20131220/20131220-item-02b-darrca-final-report.ashx>.

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

The MMU recommends allocating energy uplift payments to units committed during the operating day to a new deviation category which would include physical transactions or resources (day-ahead minus real-time load, day-ahead minus real-time interchange transactions, generators and DR not following dispatch). This allocation would ensure that commitment changes that occur during the operating day and that result in energy uplift payments are paid by transactions or resources affecting the commitment of units during the operating day. For example, real-time load or interchange transactions that do not bid in the Day-Ahead Energy Market, generators and DR resources that do not follow dispatch would be allocated these costs. Any reliability commitment should be allocated to real-time load, real-time exports and real-time wheels independently of the timing of the commitment.

The MMU recommends changing the allocation of lost opportunity cost and canceled resources. LOC paid to units scheduled in the Day-Ahead Energy Market and not committed in real time should be allocated to deviations based on the proposed definition of deviations. LOC paid to units reduced for reliability in real time and payments to canceled resources should be allocated to real-time load, real-time exports and real-time wheels.

Table 4-40 shows the current allocation by energy uplift reason. For example, energy uplift payments to units scheduled in the Day-Ahead Energy Market are called day-ahead operating reserves, these costs are paid by day-ahead load, day-ahead exports and decrement bids. Any additional payment resulting from the real-time operation of these units are called balancing operating reserves, these costs are paid by either deviations or real-time load and real-time exports depending on the amount of intervals the units are economic.

Table 4-40 Current energy uplift allocation

Reason	Energy Uplift Category	Allocation Logic	Allocation
Units scheduled in the Day-Ahead Energy Market	Day-Ahead Operating Reserve	NA	Day-Ahead Load, Day-Ahead Exports and Decrement Bids
Units scheduled in the Day-Ahead Energy Market	Balancing Operating Reserve	LMP < Offer for at least four intervals	Real-Time Load and Real-Time Exports
		LMP > Offer for at least four intervals	Deviations
Units not scheduled in the Day-Ahead Energy Market and committed in real time	Balancing Operating Reserve	Committed before the operating day for reliability	Real-Time Load and Real-Time Exports
		Committed before the operating day to meet forecasted load and reserves	Deviations
		Committed during the operating day and LMP < Offer for at least four intervals	Real-Time Load and Real-Time Exports
		Committed during the operating day and LMP > Offer for at least four intervals	Deviations
Units scheduled in the Day-Ahead Energy Market not committed in real time	LOC Credit	NA	Deviations
Units reduced for reliability in real time	LOC Credit	NA	Deviations
Units canceled before coming online	Cancellation Credit	NA	Deviations

Table 4-41 shows the MMU allocation proposal by energy uplift reason. The proposal eliminates the day-ahead operating reserve category and creates a new category for any energy uplift payments to units scheduled in the Day-Ahead Energy Market and committed in real time. This new category would be allocated to day-ahead transactions and resources. The proposal also eliminates the need to determine the number of intervals that units are economic to determine if the energy uplift charge should be allocated to deviations or to real-time load and real-time exports. In the proposal, any commitment instruction before the operating day would be allocated based on the proposed definition of deviations; any commitment instruction during the operating day would be allocated to physical deviations.

Table 4-41 MMU energy uplift allocation proposal

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