Energy Uplift (Operating Reserves)

In a well designed wholesale power market, energy uplift is paid as credits to market participants under specified conditions in order to ensure that competitive energy and ancillary service market outcomes do not require efficient resources operating at the direction of PJM, to operate at a loss.[1] Referred to in PJM as operating reserve credits, lost opportunity cost credits, dispatch differential lost opportunity 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. These uplift credits are paid by PJM market participants as operating reserve charges, reactive services charges, synchronous condensing charges or black start services charges. Fast start pricing, implemented on September 1, 2021, required a new uplift credit to pay the lost opportunity costs of units that are backed down in real time to accommodate the less flexible fast start units for which fast start pricing assumes flexibility. The result is to create a greater reliance on uplift rather than price signals as an incentive to follow PJM's instructions.

Uplift is an inherent part of the PJM market design. Part of 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 concept incorporates efficient prices with minimal uplift payments.

But PJM's practice does not minimize uplift payments. In some cases, PJM pays uplift that is not consistent with the rules. In some cases, the rules permit the payment of uplift that is not consistent with the goal of PJM market design. Regulation revenues should be included as an offset to uplift, but are not currently included. The need for uplift should be calculated on a daily rather than a segment basis, as incorporated in the initial PJM market design. The goal of uplift should be to ensure that units are not required to run at a loss on a daily basis. The goal should not be to lock in profits in some segments and require uplift in other segments. There are identified improvements to PJM's application of the rules, and to the market design and uplift rules that could reduce uplift payments to the efficient level.

PJM's day-ahead generator credits and balancing generator credits are calculated by operating day and by operating segment. Segments for day-ahead generator credits equal the hours in which the unit cleared in the day-ahead market. Segments for balancing generator credits are defined as the greater of the day-ahead schedule and the unit's minimum run time. Intervals in excess of the minimum run time or in excess of the hours cleared in the day-ahead market become new segments.

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]

1 Losses occur 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, and the unit is following PJM instructions including both commitment and dispatch instructions. There is no corresponding assurance required when units are self scheduled or not following PJM dispatch instructions.

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.

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

Overview

Energy Uplift Credits

- **Energy uplift credits.** Total energy uplift credits increased by $101.2 million, or 86.2 percent, in the first nine months of 2024 compared to the first nine months of 2023, from $117.3 million to $218.5 million.
- **Types of energy uplift credits.** In the first nine months of 2024, total energy uplift credits included $93.7 million in day-ahead generator credits, $95.0 million in balancing generator credits, $25.5 million in lost opportunity cost credits, and $1.3 million in local constraint control credits. Dispatch differential lost opportunity credits, which are a subset of balancing operating reserves, were implemented as part of fast start pricing on September 1, 2021, and were $1.6 million in the first nine months of 2024.
- **Types of units.** In the first nine months of 2024, steam coal units received 39.2 percent of day-ahead generator credits, and combustion turbines received 75.1 percent of balancing generator credits and 86.8 percent of lost opportunity cost credits. Combined cycle units and combustion turbines received 38.2 percent of dispatch differential lost opportunity credits.
- **Day-ahead unit commitment for reliability.** In the first nine months of 2024, 0.5 percent of the total day-ahead generation MWh was scheduled as must run for reliability by PJM, of which 59.8 percent received energy uplift payments.
- **Concentration of energy uplift credits.** In the first nine months of 2024, the top 10 units receiving energy uplift credits received 43.0 percent of all credits and the top 10 organizations received 75.7 percent of all credits. The average HHI for day-ahead operating reserves was 7738, the HHI for balancing generator credits was 2522 and the HHI for lost opportunity cost was 4782, all of which are classified as highly concentrated.
- **Lost opportunity cost credits.** Lost opportunity cost credits increased by $7.6 million, or 42.6 percent, in the first nine months of 2024, compared to the first nine months of 2023, from $17.9 million to $25.5 million. Some combustion turbines and diesels are scheduled day-ahead but not requested in real time, and receive day-ahead lost opportunity cost credits as a result. This was the source of 88.0 percent of the $25.5 million of lost opportunity costs.
- **Following dispatch.** Some units are incorrectly paid uplift despite not meeting uplift eligibility requirements, including not following dispatch, not having the correct commitment status, or not operating with PLS offer parameters. Since 2018, the MMU has made cumulative resettlement requests for the most extreme overpaid units of $17.9 million, of which PJM has resettled only $3.9 million, or 22.0 percent.
- **Daily uplift.** In the first nine months of 2024, balancing generator charges would have been $15.4 million, 16.2 percent, lower if they had been calculated on a daily basis rather than a segmented basis. Uplift was designed to be charged on a daily basis and not on an intraday segmented basis.
- **CT uplift exemption:** The rule that allowed CTs to be paid uplift regardless of how well they followed dispatch was terminated on November 1, 2022. Starting November 1, 2022, CTs are paid uplift if necessary to cover costs based on the lower of actual or desired output (calculated by PJM based on the dispatch signal) like all other unit types. During the first nine months of 2024, terminating the CT uplift exemption is estimated to have reduced balancing generator credits by $4.3 million or 5.9 percent.

Energy Uplift Charges

- **Energy Uplift Charges.** In the first nine months of 2024, total energy uplift charges (equal to total energy uplift credits) increased by $101.2 million, or 86.2 percent, compared to the first nine months of 2023, from $117.3 million to $218.5 million.
- **Types of Energy Uplift Charges.** In the first nine months of 2024, total uplift charges included $93.7 million in day-ahead operating reserve charges, $123.5 million in balancing generator charges, $1.0 million in reactive charges, and $0.3 million in black start services.

- **Average Effective Operating Reserve Rates in the Eastern Region.** Day-ahead load, exports, DECs and UTCs paid $0.130 per MWh in the Eastern Region. Real-time load and exports paid an average of $0.086 per MWh. Deviations paid $0.341 per MWh in the Eastern Region.
- **Average Effective Operating Reserve Rates in the Western Region.** Day-ahead load, exports, DECs and UTCs paid $0.130 per MWh in the Western Region. Real-time load and exports paid $0.075 per MWh. Deviations paid $0.301 per MWh in the Western Region.

Geography of Charges and Credits

- In the first nine months of 2024, 90.2 percent of all uplift charges allocated regionally (day-ahead operating reserves and balancing generator credits) were paid by MW at control zones, 3.1 percent by MW at hubs and aggregates, and 6.6 percent by MW at interchange interfaces.
- In the first nine months of 2024, generators in the Eastern Region received 44.3 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.
- In the first nine months of 2024, generators in the Western Region received 53.3 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.
- In the first nine months of 2024, external pseudo tied generators received 1.2 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.

Recommendations

- The MMU recommends that uplift be paid only based on operating parameters that reflect the flexibility of the benchmark new entrant unit (CONE unit) in the PJM Capacity Market. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM not pay uplift to units not following dispatch, including uplift related to fast start pricing, and require refunds where it has made such payments. This includes units whose offers are flagged for fixed generation in Markets Gateway because such units are not dispatchable. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM pay uplift based on the offer at the lower of the actual unit output or the dispatch signal MW. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends eliminating intraday segments from the calculation of uplift payments and returning to calculating the need for uplift based on the entire 24 hour operating day. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends the elimination of day-ahead uplift 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 that units not be paid lost opportunity cost uplift credits when PJM directs a unit to reduce output based on a transmission constraint or other reliability issue. There is no lost opportunity because the unit is required to reduce for the reliability of the unit and the system. (Priority: High. First reported 2021. Status: Not adopted.)
- The MMU recommends reincorporating the use of net regulation revenues as an offset in the calculation of balancing generator credits. (Priority: Medium. First reported 2009. Status: Not adopted.)
- The MMU recommends that self scheduled units not be paid energy uplift credits 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.)
- 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 units with 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 (UTC) 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: Partially adopted.)
- The MMU recommends allocating the energy uplift credits paid to units scheduled by PJM 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 generator credit calculation. (Priority: Medium. First reported 2012. Status: Not adopted. Stakeholder process.)
- The MMU recommends including real-time exports and real-time wheels in the allocation of the cost of providing reactive support to the 500 kV system or above, in addition to real-time load. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends modifications to the calculation of lost opportunity costs credits paid to wind units. The lost opportunity costs credits paid to wind units should be based on the lesser of the desired output, the estimated output based on actual wind conditions and the capacity interconnection rights (CIRs). The MMU recommends that PJM require wind units to request CIRs based on the maximum output used in the ELCC calculation for wind units. (Priority: Low. First reported 2012. Status: Partially adopted.)
- The MMU recommends that PJM clearly identify and classify all reasons for incurring uplift in the day-ahead and the real-time energy markets and the associated uplift 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 uplift. (Priority: Medium. First reported 2011. Status: Partially adopted.)
- The MMU recommends that PJM revise the current uplift confidentiality rules in order to allow the disclosure of complete information about the level of uplift by unit and the detailed reasons for the level of uplift credits by unit in the PJM region. (Priority: High. First reported 2013. Status: Partially adopted.)[5]

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 demand (VRR) curve. 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 inflates uplift costs, suppresses energy prices, and is an incentive to inflexibility.

5 On September 7, 2018, PJM made a compliance filing for FERC Order No. 844 to publish unit specific uplift credits. The compliance filing was accepted by FERC on June 21, 2019. 166 FERC ¶ 61,210 (2019). PJM began posting unit specific uplift reports on May 1, 2019. 167 FERC ¶ 61,280 (2019).

It is not appropriate to accept that inflexible units should be paid uplift based on inflexible offers. 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 solutions including replacing inefficient units with flexible, efficient units.

Implementing combined cycle modeling, to permit the energy market model optimization to take advantage of the versatility and flexibility of combined cycle technology in commitment and dispatch, would provide significant flexibility without requiring a distortion of the market rules. But such modeling should not be used as an excuse to eliminate market power mitigation or an excuse to permit inflexible offers to be paid uplift. There are defined steps that could and should be taken immediately to improve the modeling of combined cycle plants that do not require investment in combined cycle modeling software, including modeling soak time, and accurately accounting for transition times to power augmentation offer segments.

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 fast start pricing. The same is true of PJM's proposals 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 creates a tradeoff between minimizing production costs and reduction of uplift. The tradeoff exists 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 now exists based on PJM's recently implemented fast start pricing approach.[6] Fast start pricing affects uplift calculations by introducing a new category of uplift in the balancing market, and changing the calculation of uplift in the day-ahead market.

When units receive substantial revenues through energy uplift payments, these payments are not fully transparent to the market, in part 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. FERC Order No. 844 authorized the publication of unit specific uplift payments for credits incurred after July 1, 2019.[7] However, Order No. 844 failed to require the publication of unit specific uplift credits for the largest units receiving significant uplift payments, inflexible steam units committed for reliability by PJM in the day-ahead market.

Uplift payments could be significantly reduced by reversing many of the changes that have been made to the original basic uplift rules. The goal of uplift is to ensure that competitive energy and ancillary service market outcomes do not require efficient resources operating for the PJM system, at the direction of PJM, to operate at a loss. In the original PJM design, uplift was calculated on a daily basis, including all costs and net revenues. But that

6 Fast start pricing was approved by FERC and implemented on September 1, 2021. See 173 FERC ¶ 61,244 (2020).
7 On June 21, 2019, FERC accepted PJM's Order No. 844 compliance filing. 166 FERC ¶ 61,210 (2019). The filing stated that PJM would begin posting unit specific uplift reports on May 1, 2019. On April 8, 2019, PJM filed for an extension on the implementation date of the zonal uplift reports and unit specific uplift reports to July 1, 2019. On June 28, 2019, FERC accepted PJM's request for extension of effective dates. 167 FERC ¶ 61,280 (2019).

rule was changed to use only segments of the day. The result is to overstate uplift payments because units may be paid uplift for a day in which their net revenues exceed their costs. In the original PJM design, all net revenues from energy and ancillary services were an offset to uplift payments. But that rule was changed to eliminate net revenue from the regulation market. The result is to overstate uplift payments, for no logical reason.

Uplift payments could also be significantly reduced to a more efficient level by eliminating 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 generator credits.

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 better definitions of constraints would be a more market based approach. PJM pays uplift to units even when they do not operate as requested by PJM, i.e. when units do not follow dispatch. PJM uses dispatcher logs as a primary screen to determine if units are eligible for uplift regardless of how they actually operate or if they followed the PJM dispatch signal. The reliance on dispatcher logs for this purpose is impractical, inefficient, and incorrect. PJM needs to define and implement systematic and verifiable rules for determining when units are following dispatch as a primary screen for eligibility for uplift payments. PJM should not pay uplift to units that do not follow dispatch. PJM continues to pay uplift to units that do not follow dispatch.

The MMU notifies PJM and generators of instances in which, based on the PJM dispatch signal and the real-time output of the unit, it is clear that the unit did not operate as requested by PJM. The MMU sends requests for resettlements to PJM to make the units with the most extreme overpayments ineligible for uplift credits. Since 2018, the MMU has requested that PJM require the return of $17.9 million of incorrect uplift credits of which PJM has agreed and resettled only $3.9 million over the last two years, or 22.0 percent. In addition, PJM has refused to accept the return of incorrectly paid uplift credits by generators when the MMU has identified such cases and generators offer to repay the credits.

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. The result would also be to increase incentives for flexible operation and to decrease incentives for the continued operation of inflexible and uneconomic resources. PJM does not need a new flexibility product. PJM needs to provide incentives to existing and new entrant resources to unlock the significant flexibility potential that already exists, to end incentives for inflexibility and to stop creating new incentives for inflexibility.

Energy Uplift Credits

The level of energy uplift credits paid to specific units depends on the level of the resource's energy offer, the LMP, the resource's operating parameters and the decisions of PJM operators. Energy uplift credits result in part from decisions by PJM operators, who follow reliability requirements and market rules, to start resources or to keep resources operating even when LMP is less than the offer price including incremental, no load and startup costs. Energy uplift payments also result from units' operational parameters that require PJM to schedule or commit resources when they are not economic. Energy uplift payments currently also result, incorrectly, from decisions by units to maintain an output level not consistent with PJM dispatch instructions. The resulting costs not covered by energy revenues are collected as energy uplift credits.

The day-ahead operating reserves category includes multiple credit types that are paid to resources cleared uneconomically in the day-ahead market. These resources include generators, imports, and load response.

The balancing operating reserves category includes multiple credit types based on the service provided by the resources. These credit types, paid to compensate for uneconomic generation in the balancing market, include generator credits, lost opportunity cost credits, dispatch differential cost credits, local constraints control credits, load response credits, import credits, and canceled resource credits. The largest credit type in the balancing operating reserves category is balancing generator credits. The reactive services category includes multiple credit types. Black start services credits exist to compensate resources for black start services in the day-ahead and balancing markets, as well as testing.

Table 4-1 shows the uplift totals for each credit category during the first nine months of 2023 and 2024.[8] In the first nine months of 2024, energy uplift credits increased by $101.1 million or 86.2 percent compared to the first nine months of 2023. Winter Storm Gerri caused significant increases in day-ahead generator credits, balancing generator credits, and lost opportunity cost credits.

The dispatch differential lost opportunity cost is a credit that exists only as a result of fast start pricing. This credit is paid to flexible resources that are artificially dispatched down below the level that is economic at fast start prices, in order to accommodate inflexible fast start resources. Fast start pricing was introduced on September 1, 2021.

Table 4-1 Energy uplift credits by category: January through September, 2023 and 2024[9]

Category	Type	(Jan - Sep) 2023 Credits (Millions)	(Jan - Sep) 2024 Credits (Millions)	Change	Percent Change	2023 Share	2024 Share
Day-Ahead	Generators	$42.8	$93.7	$50.9	119.1%	36.4%	42.9%
	Imports	$0.0	$0.0	($0.0)	NA	0.0%	0.0%
	Load Response	$0.0	$0.0	$0.0	NA	0.0%	0.0%
Balancing	Canceled Resources	$0.1	$0.1	$0.0	NA	0.0%	0.0%
	Generators	$54.8	$95.0	$40.2	73.4%	46.7%	43.5%
	Imports	$0.0	$0.0	$0.0	NA	0.0%	0.0%
	Load Response	$0.0	$0.0	$0.0	NA	0.0%	0.0%
	Local Constraints Control	$0.6	$1.3	$0.7	121.4%	0.5%	0.6%
	Lost Opportunity Cost	$17.9	$25.5	$7.6	42.6%	15.2%	11.7%
	Dispatch Differential Lost Opportunity Cost	$0.5	$1.6	$1.1	207.9%	0.4%	0.7%
Reactive Services	Day-Ahead	$0.5	$0.1	($0.4)	(86.2%)	0.4%	0.0%
	Local Constraints Control	$0.0	$0.0	$0.0	NA	0.0%	0.0%
	Lost Opportunity Cost	$0.0	$0.0	$0.0	NA	0.0%	0.0%
	Reactive Services	$0.0	$0.9	$0.9	9,724.4%	0.0%	0.4%
	Synchronous Condensing	$0.0	$0.0	$0.0	NA	0.0%	0.0%
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	NA	0.0%	0.1%
	Testing	$0.3	$0.0	($0.3)	(100.0%)	0.2%	0.0%
Total		$117.4	$218.5	$101.1	86.2%	100.0%	100.0%

8 Billing data can be modified by PJM Settlements at any time to reflect changes in the evaluation of energy uplift. The billing data reflected in this report were current on October 11, 2024.
9 Year to year change is rounded to one tenth of a million, and includes values less than $0.05 million.

Categories of Credits and Charges

Energy uplift charges include day-ahead and balancing operating reserves, reactive services, synchronous condensing and black start services categories. Uplift credits paid to individual participants are paid for by charges to the groups of PJM market participants. The groups of participants charged varies depending on the type of uplift credit. Table 4-2 and Table 4-3 show the categories of credits and charges and their relationships.

For example, in Table 4-2, day-ahead operating reserve credits for generators are paid for by day-ahead operating reserve charges. Those charges are paid for by market participants in proportion to their day-ahead load, day-ahead exports, and virtual transactions (DECs and UTCs). The charges are aggregated over the entire RTO region. Balancing generator reserve credits are paid for by two different types of charges: balancing operating reserve charges for reliability and balancing operating reserve charges for deviations. Charges for reliability are paid for by PJM members in proportion to their real-time load and real-time export transactions. Reliability charges are aggregated regionally over the entire RTO region, within the Western region, or within the Eastern region. Balancing operating reserve charges for deviations are paid for by PJM members in proportion to their deviations, which includes virtuals (INCs and DECs), UTCs, load, and interchange. The deviation charges are aggregated regionally over the entire RTO region, within the Western region, and within the Eastern region. Lost opportunity cost credits are paid for by balancing operating reserve charges for deviations. The charges for deviations are paid for by PJM members in proportion to their deviations, which includes virtuals (INCs and DECs), UTCs, load, and interchange. The deviation charges are aggregated regionally over the entire RTO region.

Table 4-3 shows the relationship between credits and charges for resources providing reactive, synchronous condensing, and black start services. For example, the five sub-categories of reactive services credits (day-ahead operating reserves, generator, LOC, condensing, and synchronous condensing LOC) are paid by two different charge categories: reactive service charges and local constraint reactive services. The reactive service charges are paid by PJM members in proportion to their zonal real-time load, while the local constraint reactive service charges are paid for by transmission owners.

Table 4-2 Day-ahead and balancing operating reserve credits and charges

<table>
<tr><th></th><th>Credit Category</th><th>Charges Category</th><th>Charge Responsibility</th><th>Geographic Charge Aggregation</th></tr>
<tr><td rowspan="4">DAY-AHEAD</td><td>Day-Ahead Operating Reserve Transaction</td><td>Day-Ahead Operating Reserves for Transactions</td><td rowspan="4">Day-Ahead Load, Day-Ahead Exports, DECs & UTCs</td><td rowspan="4">RTO Region</td></tr>
<tr><td>Day-Ahead Operating Reserve Generator</td><td>Day-Ahead Operating Reserve for Generators</td></tr>
<tr><td>Day-Ahead Operating Reserves for Load Response</td><td>Day-Ahead Operating Reserve for Load Response</td></tr>
<tr><td>Unallocated Negative Load Congestion Charges
Unallocated Positive Generation Congestion Credits</td><td>Unallocated Congestion</td></tr>
<tr><td rowspan="8">BALANCING</td><td rowspan="2">Balancing Generator Reserves</td><td>Balancing Operating Reserve for Reliability</td><td>Real-Time Load plus Real-Time Export Transactions</td><td rowspan="2">RTO, Eastern, and Western Region</td></tr>
<tr><td>Balancing Operating Reserve for Deviations</td><td>Deviations (includes virtual bids, UTCs, load, and interchange)</td></tr>
<tr><td>Dispatch Differential Lost Opportunity Cost (DDLOC)</td><td>Balancing Operating Reserve for Deviations</td><td>Real-Time Load plus Real-Time Export Transactions</td><td rowspan="5">RTO Region</td></tr>
<tr><td>Canceled Resources</td><td rowspan="3">Balancing Operating Reserve for Deviations</td><td rowspan="3">Deviations (includes virtual bids, UTCs, load, and interchange)</td></tr>
<tr><td>Lost Opportunity Cost (LOC)</td></tr>
<tr><td>Real-Time Import Transactions</td></tr>
<tr><td>Balancing Operating Reserves for Load Response</td><td>Balancing Operating Reserve for Load Response</td><td>Deviations (includes virtual bids, UTCs, load, and interchange)</td></tr>
<tr><td>Local Constraints Control</td><td>NA</td><td>Transmission Owner</td><td>NA</td></tr>
</table>

Table 4-3 Reactive services, synchronous condensing and black start services credits and charges

<table>
<tr><th></th><th>Credits Category</th><th>Charges Category</th><th>Charge Responsibility</th></tr>
<tr><td rowspan="5">Reactive</td><td>Day-Ahead Operating Reserve</td><td rowspan="3">Reactive Services Charge</td><td rowspan="3">Zonal Real-Time Load</td></tr>
<tr><td>Generator Reactive Services</td></tr>
<tr><td>LOC Reactive Services</td></tr>
<tr><td>Condensing Reactive Services</td><td rowspan="2">Local Constraint Reactive Services</td><td rowspan="2">Transmission owner</td></tr>
<tr><td>Synchronous Condensing LOC Reactive Services</td></tr>
<tr><td rowspan="2">Synchronous Condensing</td><td>Synchronous Condensing</td><td rowspan="2">Synchronous Condensing</td><td>Real-Time Load</td></tr>
<tr><td>Synchronous Condensing LOC</td><td>Real-Time Export Transactions</td></tr>
<tr><td rowspan="4">Black Start</td><td>Day-Ahead Operating Reserve</td><td rowspan="4">Black Start Service Charge</td><td rowspan="4">Zone/Non-zone Peak Transmission Use and Point to Point Transmission Reservations</td></tr>
<tr><td>Balancing Operating Reserve</td></tr>
<tr><td>Black Start Testing</td></tr>
<tr><td>Black Start LOC</td></tr>
</table>

Types of Units

Table 4-4 shows the distribution of total energy uplift credits by unit type during the first nine months of 2024 and the first nine months of 2023. A combination of factors led to overall increased uplift payments.

The longstanding rule which inexplicably exempted CTs from the otherwise generally applicable rules governing the payment of uplift credits, was terminated effective November 1, 2022. Prior to November 1, CTs were paid uplift regardless of their output and regardless of whether they followed dispatch and as a result, CTs had no incentive to follow PJM dispatch signals.

Uplift credits paid to combustion turbines increased by $36.4 million or 59.9 percent during the first nine months of 2024 compared to the first nine months of 2023. In the first nine months of 2024, CTs received 86.8 percent of lost opportunity cost credits. Lost opportunity cost credits increased by $7.6 million or 42.6 percent compared to the first nine months of 2023.

Uplift credits paid to steam coal units increased by $10.8 million or 32.6 percent in the first nine months of 2024 compared to the first nine months of 2023. In the first nine months of 2024, day-ahead uplift credits for reliability were $85.8 million, compared to $39.5 million in the first nine months of 2023. In the first nine months of 2024, day-ahead credits for reliability in the PEPCO and BGE Zones made up 89.2 percent of total day-ahead credits for reliability. Increased day-ahead generation committed by PJM as must run for reliability in the first nine months of 2024 resulted in increased day-ahead operating reserve credits. Similarly, increased uneconomic real-time generation by steam units also resulted in higher balancing operating generator credits.

Uplift credits paid to non-coal (gas or oil fired) steam units increased by $47.7 million or 301.8 percent in the first nine months of 2024 compared to the first nine months of 2023. In the first nine months of 2024, gas or oil fired steam units received $63.5 million, 29.1 percent of total credits, compared to $15.8 million and 13.5 percent during the first nine months of 2023. In the first nine months of 2024, the day-ahead operating reserves paid to gas or oil fired steam units was 339.4 percent higher than in the first nine months of 2023, and accounts for 80.8 percent of the total increase in day-ahead operating reserves. The increase in balancing generator credits to gas or oil fired steam units was a result of an increase in credits to a small number of units in the BGE and PPL Zones.

Uplift credits paid to combined cycle units increased by $6.5 million or 187.4 percent in the first nine months of 2024 compared to the first nine months of 2023. This increase occurred primarily in January 2024 because Winter Storm Gerri led PJM to increase day-ahead commitments.

In the first nine months of 2024, uplift credits to wind units were $1.4 million, down by 10.8 percent compared the first nine months of 2023.

Table 4-4 Total energy uplift credits by unit type: January through September, 2023 and 2024[10 11]

Unit Type	(Jan - Sep) 2023 Credits (Millions)	(Jan - Sep) 2024 Credits (Millions)	Change	Percent Change	(Jan - Sep) 2023 Share	(Jan - Sep) 2024 Share
Combined Cycle	$3.5	$10.0	$6.5	187.4%	3.0%	4.6%
Combustion Turbine	$60.8	$97.2	$36.4	59.9%	51.8%	44.5%
Diesel	$2.5	$1.5	($1.0)	(41.3%)	2.2%	0.7%
Hydro	$0.0	$0.8	$0.8	174,815.6%	0.0%	0.4%
Nuclear	$0.0	$0.0	$0.0	19,364.7%	0.0%	0.0%
Solar	$0.2	$0.2	$0.1	46.8%	0.1%	0.1%
Steam - Coal	$33.1	$43.9	$10.8	32.6%	28.2%	20.1%
Steam - Other	$15.8	$63.5	$47.7	301.8%	13.5%	29.1%
Wind	$1.5	$1.4	($0.2)	(10.8%)	1.3%	0.6%
Total	$117.4	$218.5	$101.1	86.2%	100.0%	100.0%

Table 4-5 shows the distribution of energy uplift credits by category and by unit type in the first nine months of 2024. The largest share of day-ahead credits, 39.2 percent, went to steam units. Steam units tend to be longer lead time units that are 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 uplift credits. The PJM market rules permit combustion turbines (CT), unlike other unit types, to be committed and decommitted in the real-time market. As a result of the rules and the characteristics of CT offers, CTs received 75.4 percent of balancing credits and 86.8 percent of lost opportunity cost credits. Combustion turbines committed in the real-time market may be paid balancing credits due to inflexible operating parameters, volatile real-time LMPs, and intraday segment settlements. Combustion turbines committed in the day-ahead market but not committed in real time receive lost opportunity credits to cover the profits they would have made had they operated in real time.

Table 4-5 Energy uplift credits by unit type: January through September, 2024

Unit Type	Day-Ahead Generator	Balancing Generator	Canceled Resources	Local Constraints Control	Lost Opportunity Cost	Reactive Services	Synchronous Condensing	Black Start Services	Dispatch Differential Lost Opportunity Cost
Combined Cycle	2.8%	6.2%	0.0%	0.0%	4.4%	0.4%	0.0%	4.9%	22.4%
Combustion Turbine	1.1%	75.1%	0.0%	90.8%	86.8%	92.2%	0.0%	95.0%	15.8%
Diesel	0.0%	0.9%	0.0%	3.9%	2.1%	2.9%	0.0%	0.1%	0.8%
Hydro	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	52.9%
Nuclear	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Solar	0.0%	0.0%	0.0%	0.0%	0.9%	0.0%	0.0%	0.0%	0.9%
Steam - Coal	39.2%	7.1%	100.0%	4.8%	0.3%	4.6%	0.0%	0.0%	5.2%
Steam - Other	56.8%	10.7%	0.0%	0.0%	0.5%	0.0%	0.0%	0.0%	0.4%
Wind	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Total (Millions)	$93.7	$95.0	$0.1	$1.3	$25.5	$1.0	$0.0	$0.3	$1.6

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

Day-Ahead Unit Commitment for Reliability

PJM can schedule units as must run in the day-ahead energy market that would otherwise not have been committed in the day-ahead market, when needed in real time to address reliability issues. Such reliability issues include thermal constraints, reactive transfer interface constraints, and reactive service.[12] 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. Participants can submit units as self scheduled (must run), meaning that the unit must be committed, but a unit submitted as self scheduled by a participant is not eligible for day-ahead operating reserve credits.[13]

Table 4-6 shows total day-ahead generation and day-ahead generation committed for reliability by PJM. Day-ahead generation committed for reliability by PJM increased by 45.4 percent in the first nine months of 2024 compared to the first nine months of 2023, from 2,253.3 GWh in 2023 to 3,277.3 GWh in 2024.

Table 4-6 Day-ahead generation committed for reliability (GWh): January 2023 through September 2024

	2023			2024			Percent Change of PJM Day-Ahead Must Run Generation
	Total Day-Ahead Generation (GWh)	Day-Ahead PJM Must Run Generation (GWh)	Share	Total Day-Ahead Generation (GWh)	Day-Ahead PJM Must Run Generation (GWh)	Share	
Jan	71,124	30	0.0%	78,045	748	1.0%	2,403.6%
Feb	63,475	34	0.1%	66,466	14	0.0%	(57.3%)
Mar	67,239	28	0.0%	64,645	22	0.0%	(20.2%)
Apr	57,403	43	0.1%	58,620	254	0.4%	483.8%
May	60,290	41	0.1%	63,626	449	0.7%	1,004.2%
Jun	67,940	101	0.1%	76,318	418	0.5%	315.2%
Jul	82,998	751	0.9%	84,648	746	0.9%	(0.6%)
Aug	80,191	564	0.7%	81,327	523	0.6%	(7.3%)
Sep	68,163	662	1.0%	67,393	104	0.2%	(84.3%)
Oct	59,646	45	0.1%				NA
Nov	62,747	342	0.5%				NA
Dec	70,753	59	0.1%				NA
Total (Jan - Sep)	618,823	2,253	0.4%	641,087	3,277	0.5%	45.4%
Total	811,969	2,699	0.3%	641,087	3,277	0.5%	45.4%

Pool scheduled units are units that submit offers to sell energy in the day-ahead market. Units committed for reliability by PJM are units that are committed to satisfy reliability needs, regardless of whether the offers are economic. Self scheduled units are self committed by the generation owner and are not eligible for uplift. Pool scheduled units and units committed for reliability are made whole in the day-ahead energy market if their total cost-based offer (including no load and startup costs) is greater than the revenues from the day-ahead energy market. Such units are paid day-ahead uplift (operating reserve credits). Total day-ahead operating reserve credits in the first nine months of 2024 were $93.7 million, of which $85.8 million or 91.6 percent was paid to units committed for reliability by PJM, and not scheduled to provide reactive services. An additional $0.1 million in day-ahead operating reserves paid to units scheduled to provide reactive services. The top 10 units running for reliability received $80.9 million or 86.4 percent of all day-ahead operating reserve credits. These units were large units with operating parameters less flexible than PLS parameters, including long minimum run times.

12 See OA Schedule 1 § 3.2.3(b).
13 See OA Schedule 1 § 3.2.3(a).

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

Table 4-7 shows the total day-ahead generation committed for reliability by PJM by category. In the first nine months of 2024, 59.8 percent of the day-ahead generation committed for reliability by PJM was paid day-ahead operating reserve credits (including day-ahead reactive services). The remaining 40.2 percent of the day-ahead generation committed for reliability was economic, meaning that the generation was not paid operating reserve credits because prices covered the generators' offers.

Table 4-7 Day-ahead generation committed for reliability by category (GWh): January through September, 2024

	Reactive Services (GWh)	Day-Ahead Operating Reserves (GWh)	Economic (GWh)	Total (GWh)
Jan	0.3	221.9	525.4	747.6
Feb	0.0	14.4	0.0	14.4
Mar	0.0	22.5	0.0	22.5
Apr	0.0	231.5	22.2	253.7
May	0.0	393.9	54.7	448.5
Jun	0.0	379.9	37.8	417.7
Jul	0.0	363.7	382.7	746.4
Aug	0.0	227.3	295.5	522.8
Sep	0.0	103.7	0.0	103.7
Total (Jan - Sep)	0.3	1,958.7	1,318.3	3,277.3
Share	0.0%	59.8%	40.2%	100.0%

Balancing Operating Reserve Credits/Balancing Generator Credits

Balancing operating reserve (BOR) credits are paid to resources that operate as requested by PJM that do not recover all of their operating costs from market revenues. Balancing operating reserves include multiple credit types that are paid to units in the balancing market, such as generator credits, lost opportunity cost credits, dispatch differential cost credits, local constraints control credits, load response credits, import credits, and canceled resource credits. Balancing generator credits are the largest category of balancing operating reserves. Balancing generator credits are calculated by segment as the difference between a resource's revenues (day-ahead market, balancing market, reserve markets, reactive service credits, and day-ahead operating reserve credits but excluding regulation revenues) and its real-time offer (startup, no load, and incremental energy offer). Segments for balancing generator credits are defined as the greater of the day-ahead schedule and the unit's minimum run time. Intervals in excess of the minimum run time are treated as new segments. Table 4-5 shows that combustion turbines (CTs) received 75.1 percent of all balancing generator credits in the first nine months of 2024, or $71.0 million. Table 4-9 illustrates that the majority of these credits, 98.6 percent, were paid to CTs committed in real time either with or without a day-ahead schedule.[14]

Uplift is higher than necessary because settlement rules do not include all revenues and costs for the entire day. Uplift is also higher than necessary because settlement rules do not disqualify units from receiving uplift when they do not follow PJM's dispatch instructions. PJM apparently considers units that start when requested and turn off when requested to be operating as requested by PJM regardless of how well the units follow the dispatch signal.[15] Units should be disqualified from receiving uplift when the units do not follow dispatch instructions, block load or self schedule.

PJM's position on the payment of uplift is illogical and PJM's definition of units not operating as requested is illogical. The logical definition of operating as requested includes both start and shutdown when requested and that units follow their dispatch signal. Both should be required in order to receive uplift. Paying uplift to units not following dispatch does not provide an incentive for flexibility. The MMU recommends that PJM develop and implement an accurate metric to define when a unit is following dispatch, instead of relying on PJM dispatchers' manual determinations, to evaluate eligibility for receiving balancing generator credits and for assessing generator deviations. As part of the metric, the MMU recommends that PJM designate units whose offers are flagged for fixed generation in Markets Gateway as not eligible

14 Operating without 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.

15 *See* "Operating Reserve Make Whole Credit Education," slide 13, PJM presentation to the Resource Adequacy Senior Task Force. (April 13, 2022) <https://pjm.com/-/media/committees-groups/committees/mic/2022/20220413/item-11a---operating-reserve-make-whole-credits-education.ashx>.

for uplift. Units that are flagged for fixed generation are not dispatchable. Following dispatch is an eligibility requirement for uplift compensation.

Table 4-1 shows that balancing generator credits increased by 73.4 percent in the first nine months of 2024 compared to the first nine months of 2023.

Table 4-8 shows monthly day-ahead and real-time generation by combustion turbines. In the first nine months of 2024, generation by combustion turbines was 3.8 percent lower in the real-time energy market than in the day-ahead energy market. Table 4-8 shows that only 1.3 percent of generation from combustion turbines in the day-ahead market was uneconomic, while 28.3 percent of generation from combustion turbines in the real-time market was uneconomic and was paid $71.0 million in balancing generator credits. The increased level of uneconomic real-time generation resulted in increased balancing generator credits in the first nine months of 2024.

Table 4-8 Characteristics of day-ahead and real-time generation by combustion turbines eligible for operating reserve credits: January through September, 2024

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)	Ratio of Day-Ahead to Real-Time Generation
Jan	1,240	1.3%	$0.1	966	36.3%	$11.8	1.3
Feb	515	0.9%	$0.0	561	28.1%	$4.1	0.9
Mar	805	1.7%	$0.0	906	40.8%	$8.3	0.9
Apr	1,670	1.4%	$0.1	1,958	34.5%	$14.4	0.9
May	1,716	0.7%	$0.1	2,212	32.3%	$16.0	0.8
Jun	1,756	1.3%	$0.1	1,598	29.6%	$6.1	1.1
Jul	3,453	2.0%	$0.5	2,941	22.0%	$3.2	1.2
Aug	2,629	1.4%	$0.2	2,192	23.3%	$2.9	1.2
Sep	1,911	0.5%	$0.0	1,790	21.1%	$4.3	1.1
Total (Jan - Sep)	15,693	1.3%	$1.1	15,124	28.3%	$71.0	1.0

In the first nine months of 2024, balancing operating reserve credits paid to combustion turbines were $71.3 million. Of that amount, $70.1 million, or 73.7 percent of the $95.0 million in total balancing generator credits, was paid to combustion turbines operating without or outside a day-ahead schedule (Table 4-9).

Table 4-9 shows real-time generation by combustion turbines by day-ahead commitment status in January 2023 through September 2024. In the first nine months of 2024, real-time CT generation operating consistent with their day-ahead schedule increased compared to the first nine months of 2023. In the first nine months of 2024, 76.9 percent of real-time generation by CTs was consistent with a day-ahead schedule, compared to 75.3 percent in the first nine months of 2023. CTs that operate on a day-ahead schedule tend to receive lower balancing generator credits because it is more likely that the day-ahead LMPs will support (prices above offer) committing the units. Day-ahead LMPs support committing the units because the day-ahead model optimizes the system for all 24 hours, unlike in real time when PJM uses ITSCED to optimize CT commitments with an approximately two hour look ahead. In addition, uplift rules continue to define all day-ahead scheduled hours as one segment for the uplift calculation (in which profits and losses during all hours offset each other). The shorter segments in real-time are defined by the minimum run time and allow for fewer offsets, resulting in greater amounts of uplift. Losses during the minimum run time segment are not offset by profits made in other segments on that 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, and differences in interchange transactions. 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 optimization time periods used in the day-ahead and real-time markets.

Table 4-9 Real-time generation by combustion turbines by day-ahead commitment: January 2023 through September 2024

		Real-Time CT Generation Operating on a Day-Ahead Schedule				Real-Time CT Generation Operating Outside of a Day-Ahead Schedule			
Month-Year		Generation (GWh)	Share of Real-Time Generation	Percent of Real-Time Generation that is Noneconomic	Balancing Generator Credits (Millions)	Generation (GWh)	Share of Real Time Generation	Percent of Real-Time Generation that is Noneconomic	Balancing Generator Credits (Millions)
2023	Jan	370	70.9%	17.8%	$0.0	151	29.1%	51.2%	$3.2
	Feb	284	78.1%	30.0%	$0.0	80	21.9%	51.7%	$1.3
	Mar	379	71.0%	26.0%	$0.1	155	29.0%	60.2%	$3.6
	Apr	839	61.0%	23.6%	$0.1	538	39.0%	63.4%	$9.5
	May	1,141	68.9%	18.1%	$0.0	516	31.1%	65.9%	$8.5
	Jun	1,349	71.9%	12.7%	$0.0	526	28.1%	43.7%	$4.1
	Jul	2,328	80.8%	17.8%	$0.1	555	19.2%	35.1%	$5.6
	Aug	1,851	83.9%	18.5%	$0.2	355	16.1%	38.5%	$3.4
	Sep	1,211	78.5%	26.8%	$0.2	332	21.5%	59.7%	$4.7
	Oct	1,797	74.4%	25.0%	$0.2	620	25.6%	66.2%	$11.3
	Nov	891	64.8%	22.4%	$0.1	484	35.2%	63.1%	$10.3
	Dec	594	72.3%	19.3%	$0.1	228	27.7%	62.6%	$4.9
	Total 2023 (Jan - Sep)	9,753	75.3%	19.5%	$0.7	3,207	24.7%	51.5%	$43.8
2024	Jan	739	76.5%	25.5%	$0.1	227	23.5%	71.7%	$11.7
	Feb	383	68.2%	13.5%	$0.1	178	31.8%	59.4%	$4.0
	Mar	547	60.4%	22.3%	$0.1	359	39.6%	68.9%	$8.2
	Apr	1,268	64.7%	19.4%	$0.3	690	35.3%	62.2%	$14.1
	May	1,400	63.3%	14.9%	$0.1	812	36.7%	62.4%	$15.9
	Jun	1,228	76.8%	23.5%	$0.1	370	23.2%	49.8%	$6.1
	Jul	2,640	89.8%	20.3%	$0.1	301	10.2%	37.4%	$3.1
	Aug	1,961	89.5%	20.7%	$0.2	230	10.5%	46.0%	$2.8
	Sep	1,468	82.0%	17.3%	$0.0	322	18.0%	38.5%	$4.3
	Total 2024 (Jan - Sep)	11,633	76.9%	19.8%	$1.0	3,490	23.1%	56.7%	$70.1

Lost Opportunity Cost Credits

Balancing operating reserve lost opportunity cost (LOC) credits are intended to provide an incentive for units to follow PJM's dispatch instructions when PJM's dispatch instructions deviate from a unit's desired or scheduled output. LOC credits are paid under two scenarios.[16] 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 manually 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. Such units are not actually forgoing an option to increase output because the reliability of the system and in some cases the generator depend on reducing output. This LOC is referred to as real-time LOC. The second scenario occurs if a combustion turbine or diesel engine clears the day-ahead energy market, but is not committed in real time. In this scenario the unit will receive a credit which covers any lost profit in the day-ahead financial position of the unit plus the balancing energy market position. This LOC is referred to as day-ahead LOC.

16 Desired output is defined as the MW on the generator's offer curve consistent with the LMP at the generator's bus.

Table 4-10 shows monthly day-ahead and real-time LOC credits in 2023 and the first nine months of 2024. In the first nine months of 2024, LOC credits increased by $7.6 million or 42.6 percent compared to the first nine months of 2023. The increase comprised of a $7.0 million increase in day-ahead LOC and $0.6 million increase in real-time LOC.

In the first nine months of 2024, wind units received $1.4 million of uplift, down by $0.2 million compared to the first nine months of 2023. Wind units that are capacity resources are now required to procure Capacity Interconnection Rights (CIRs) equal to the maximum facility output included in the calculation of their ELCC value. Wind units that are not capacity resources are not required to procure CIRs equal to the maximum facility output, but are paid uplift when PJM requests that the units reduce output below the maximum facility output but above the CIR level. Units do not have a right to inject power at levels greater than the CIR level that they pay for and therefore should not be paid uplift when system conditions do not permit output at a level greater than the CIR. The real-time lost opportunity costs credits paid to wind units should be based on the lowest of the desired output, the estimated output based on actual wind conditions, or the capacity interconnection rights (CIRs).

Table 4-10 Monthly lost opportunity cost credits[17] (Millions): January 2023 through September 2024

	2023			2024		
	Day-Ahead Lost Opportunity Cost	Real-Time Lost Opportunity Cost	Total	Day-Ahead Lost Opportunity Cost	Real-Time Lost Opportunity Cost	Total
Jan	$1.9	$0.0	$1.9	$0.8	$0.2	$1.0
Feb	$0.6	$0.3	$0.9	$0.8	$0.1	$0.9
Mar	$0.7	$0.0	$0.7	$1.6	$0.1	$1.8
Apr	$1.3	$1.1	$2.4	$1.4	$0.7	$2.1
May	$1.5	$0.0	$1.5	$1.4	$0.5	$2.0
Jun	$1.1	$0.3	$1.4	$3.4	$0.5	$3.9
Jul	$4.2	$0.2	$4.4	$6.4	$0.2	$6.6
Aug	$2.2	$0.0	$2.3	$4.7	$0.5	$5.2
Sep	$2.0	$0.5	$2.5	$1.8	$0.2	$2.0
Oct	$1.3	$0.2	$1.5			
Nov	$1.0	$0.1	$1.1			
Dec	$1.9	$0.0	$2.0			
Total (Jan - Sep)	$15.4	$2.5	$17.9	$22.4	$3.1	$25.5
Share (Jan - Sep)	86.1%	13.9%	100.0%	88.0%	12.0%	100.0%
Total	$19.6	$2.8	$22.4	$22.4	$3.1	$25.5
Share	87.5%	12.5%	100.0%	88.0%	12.0%	100.0%

Table 4-11 shows day-ahead generation for combustion turbines and diesels, including scheduled day-ahead generation, scheduled day-ahead generation not requested in real time, and day-ahead generation receiving LOC credits. In the first nine months of 2024, 9.4 percent of day-ahead generation by combustion turbines and diesels was not requested in real time, 0.1 percentage points higher than during the first nine months of 2023. In the first nine months of 2024, day-ahead generation by combustion turbines increased by 13.8 percent, day-ahead generation not requested in real time increased by 15.3 percent, and day-ahead generation not requested in real time receiving lost opportunity costs increased by 31.3 percent, compared to the first nine months of 2023. Unlike steam units, combustion turbines that clear the day-ahead energy market have to be instructed by PJM to come online in real time.

17 Table 4-10 does not include pumped hydro lost opportunity cost credits in Real-Time Lost Opportunity Cost Credits.

Table 4-11 Day-ahead generation from combustion turbines and diesels (GWh): January 2023 through September 2024

	2023			2024		
	Day-Ahead Generation (GWh)	Day-Ahead Generation Not Requested in Real Time (GWh)	Day-Ahead Generation Not Requested in Real Time Receiving LOC Credits (GWh)	Day-Ahead Generation (GWh)	Day-Ahead Generation Not Requested in Real Time (GWh)	Day-Ahead Generation Not Requested in Real Time Receiving LOC Credits (GWh)
Jan	830	158	58	1,552	58	13
Feb	809	148	30	685	45	22
Mar	740	73	21	937	128	42
Apr	1,448	162	68	1,812	199	81
May	1,823	162	73	1,884	111	45
Jun	2,009	143	55	1,936	217	85
Jul	3,407	292	84	3,693	401	155
Aug	2,580	199	76	2,875	313	129
Sep	1,701	91	27	2,097	175	73
Oct	2,340	111	35			
Nov	1,322	86	25			
Dec	960	98	52			
Total (Jan - Sep)	15,346	1,428	492	17,470	1,647	646
Share (Jan - Sep)	100.0%	9.3%	3.2%	100.0%	9.4%	3.7%

Energy Uplift Charges

Energy Uplift Charges

Table 4-12 shows that energy uplift charges for the first nine months of 2024 were $218.5 million, or 0.6 percent of total PJM billing. Table 4-12 shows annual total energy uplift charges increased.

Table 4-12 Total energy uplift charges: January 2001 through September 2024

	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	$198.2	$70.9	55.7%	0.4%
2019	$88.5	($109.7)	(55.3%)	0.2%
2020	$90.9	$2.4	2.7%	0.3%
2021	$178.4	$87.5	96.3%	0.3%
2022	$284.5	$106.1	59.5%	0.3%
2023	$158.7	($125.8)	(44.2%)	0.3%
2024 (Jan - Sep)	$218.5	$59.8	37.7%	0.6%

Table 4-13 shows total energy uplift charges by category for the first nine months of 2023 and 2024. The increase of $101.2 million is comprised of a $50.9 million increase in day-ahead operating reserve charges, a $49.7 million increase in balancing generator charges, a $0.5 million increase in reactive service charges, and less than $0.1 million increase in black start services charges.

Table 4-13 Total energy uplift charges by category: January through September, 2023 and 2024[18]

Category	(Jan - Sep) 2023 Charges (Millions)	(Jan - Sep) 2024 Charges (Millions)	Change (Millions)	Percent Change
Day-Ahead Operating Reserves	$42.8	$93.7	$50.9	119.1%
Balancing Operating Reserves	$73.8	$123.5	$49.7	67.3%
Reactive Services	$0.5	$1.0	$0.5	101.1%
Synchronous Condensing	$0.0	$0.0	$0.0	0.0%
Black Start Services	$0.3	$0.3	$0.0	16.5%
Total	$117.3	$218.5	$101.2	86.2%
Energy Uplift as a Percent of Total PJM Billing	0.3%	0.6%	0.2%	73.4%

Table 4-14 compares monthly energy uplift charges by category for 2023 and the first nine months of 2024.

Table 4-14 Monthly energy uplift charges: January 2023 through September 2024

	2023 Charges (Millions)						2024 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	$1.7	$5.7	$0.0	$0.0	$0.0	$7.4	$32.7	$23.95	$0.9	$0.0	$0.0	$57.5
Feb	$1.0	$4.5	$0.0	$0.0	$0.1	$5.6	$1.2	$5.39	$0.0	$0.0	$0.1	$6.7
Mar	$1.3	$4.9	$0.0	$0.0	$0.1	$6.3	$1.1	$10.78	$0.0	$0.0	$0.0	$12.0
Apr	$2.0	$13.0	$0.4	$0.0	$0.1	$15.5	$12.1	$19.43	$0.0	$0.0	$0.0	$31.6
May	$0.4	$10.8	$0.0	$0.0	$0.0	$11.3	$12.5	$21.06	$0.0	$0.0	$0.0	$33.6
Jun	$1.8	$7.0	$0.0	$0.0	$0.0	$8.7	$14.4	$13.73	$0.0	$0.0	$0.0	$28.2
Jul	$10.6	$12.5	$0.0	$0.0	$0.0	$23.1	$8.4	$11.59	$0.0	$0.0	$0.0	$20.0
Aug	$12.0	$6.4	$0.0	$0.0	$0.0	$18.5	$6.9	$10.67	$0.1	$0.0	$0.0	$17.6
Sep	$11.9	$8.9	$0.1	$0.0	$0.0	$21.0	$4.4	$6.88	$0.0	$0.0	$0.0	$11.3
Oct	$2.8	$13.7	$0.1	$0.0	$0.0	$16.7						
Nov	$3.7	$12.4	$0.0	$0.0	$0.0	$16.1						
Dec	$0.4	$7.4	$0.0	$0.0	$0.0	$7.9						
Total (Jan - Sep)	$42.8	$73.784	$0.5	$0.0	$0.3	$117.3	$93.7	$123.5	$1.0	$0.0	$0.3	$218.5
Share (Jan - Sep)	36.5%	62.9%	0.4%	0.0%	0.2%	100.0%	42.9%	56.5%	0.5%	0.0%	0.1%	100.0%
Total	$49.7	$107.4	$0.6	$0.0	$0.3	$158.0	$93.7	$123.5	$1.0	$0.0	$0.3	$218.5
Share	31.5%	67.9%	0.4%	0.0%	0.2%	100.0%	42.9%	56.5%	0.5%	0.0%	0.1%	100.0%

18 The MMU uses Total PJM Billing values provided by PJM. For 2019 and after, the Total PJM Billing calculation was modified to better reflect PJM total billing through the PJM settlement process.

Table 4-15 shows the composition of day-ahead operating reserve charges. Day-ahead operating reserve charges include payments 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.[19] [20] Day-ahead operating reserve charges increased by $50.9 million or 119.1 percent in the first nine months of 2024 compared to the first nine months of 2023.

Table 4-15 Day-ahead operating reserve charges: January through September, 2023 and 2024

Type	(Jan - Sep) 2023 Charges (Millions)	(Jan - Sep) 2024 Charges (Millions)	Change (Millions)	(Jan - Sep) 2023 Share	(Jan - Sep) 2024 Share
Day-Ahead Operating Reserve Charges	$42.8	$93.7	$50.9	100.0%	100.0%
Day-Ahead Operating Reserve Charges for Load Response	$0.0	$0.0	$0.0	0.0%	0.0%
Unallocated Congestion Charges	$0.0	$0.0	$0.0	0.0%	0.0%
Total	$42.8	$93.7	$50.9	100.0%	100.0%

Table 4-16 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 $49.7 million or 67.3 percent in the first nine months of 2024 compared to the first nine months of 2023.

Table 4-16 Balancing operating reserve charges: January through September, 2023 and 2024

Type	(Jan - Sep) 2023 Charges (Millions)	(Jan - Sep) 2024 Charges (Millions)	Change (Millions)	(Jan - Sep) 2023 Share	(Jan - Sep) 2024 Share
Balancing Operating Reserve Reliability Charges	$27.4	$50.9	$23.5	37.2%	41.3%
Balancing Operating Reserve Deviation Charges	$45.8	$71.2	$25.4	62.0%	57.7%
Balancing Operating Reserve Charges for Load Response	$0.0	$0.0	($0.0)	0.0%	0.0%
Balancing Local Constraint Charges	$0.6	$1.3	$0.7	0.8%	1.1%
Total	$73.8	$123.5	$49.7	100.0%	100.0%

Table 4-17 shows the composition of the balancing operating reserve deviation charges. Balancing operating reserve deviation charges are the sum of: make whole credits paid to generators and import transactions, energy lost opportunity costs paid to generators, and payments to resources scheduled by PJM but canceled by PJM before coming online. In the first nine months of 2024, energy lost opportunity cost deviation charges increased by $7.6 million or 42.6 percent, and make whole deviation charges increased by $17.8 million or 63.8 percent compared to the first nine months of 2023.

Table 4-17 Balancing operating reserve deviation charges: January through September, 2023 and 2024

Charge Attributable To	(Jan - Sep) 2023 Charges (Millions)	(Jan - Sep) 2024 Charges (Millions)	Change (Millions)	(Jan - Sep) 2023 Share	(Jan - Sep) 2024 Share
Make Whole Payments to Generators and Imports	$27.9	$45.7	$17.8	61.0%	64.2%
Energy Lost Opportunity Cost	$17.9	$25.5	$7.6	39.0%	35.8%
Canceled Resources	$0.0	$0.0	$0.0	0.0%	0.0%
Total	$45.8	$71.2	$25.4	100.0%	100.0%

19 See PJM Operating Agreement Schedule 1 § 3.2.3(c). Unallocated congestion charges are added to the total costs of day-ahead operating reserves. Congestion charges have been allocated to day-ahead operating reserves only 10 times since 1999, totaling $26.9 million.
20 See the *2022 Annual State of the Market Report for PJM*, Volume II: Section 13, Financial Transmission Rights and Auction Revenue Rights.

Table 4-18 shows reactive services, synchronous condensing and black start services charges. Reactive services charges increased by $0.5 million in the first nine months of 2024, compared to the first nine months of 2023.

Table 4-18 Additional energy uplift charges: January through September, 2023 and 2024

Type	(Jan - Sep) 2023 Charges (Millions)	(Jan - Sep) 2024 Charges (Millions)	Change (Millions)	(Jan - Sep) 2023 Share	(Jan - Sep) 2024 Share
Reactive Services Charges	$0.5	$1.0	$0.5	65.7%	76.8%
Synchronous Condensing Charges	$0.0	$0.0	$0.0	0.0%	0.0%
Black Start Services Charges	$0.3	$0.3	$0.0	34.3%	23.2%
Total	$0.8	$1.3	$0.5	100.0%	100.0%

Operating Reserve Rates

Under the operating reserves cost allocation rules, PJM calculates 10 separate rates: a day-ahead operating reserve rate, a reliability rate for each region (RTO, East, or West), a deviation rate for each region, a lost opportunity cost rate, a canceled resources rate, and a dispatch differential lost opportunity cost rate.

Table 4-19 illustrates the composition of charges and the transactions included in the charge calculation. For example, balancing operating reserve charges for deviations are calculated by adding the RTO deviation rate, the regional deviation rates, the LOC rate, and the canceled resources rate. For example, the INCs are responsible for paying the RTO deviation rate, the regional deviation rate, the LOC rate, and the canceled resources rate.[21]

Table 4-19 Composition of charges

		Transaction / Resource Type								
Charge	Rate	Load	Generation	Imports[1]	Exports[1]	Wheels	Economic DR	INCs	DECs	UTCs
Day-Ahead Operating Reserve	Day-Ahead Operating Reserve Rate	X			X				X	X
Balancing Operating Reserves for Reliability	RTO Reliability Rate	X			X					
	Regional (East or West) Reliability Rate	X			X					
Balancing Operating Reserves for Deviations[2]	RTO Deviation Rate	X	X	X	X		X	X	X	X
	Regional (East or West) Deviation Rate	X	X	X	X		X	X	X	X
	LOC Rate	X	X	X	X		X	X	X	
	Canceled Resources Rate	X	X	X	X		X	X	X	
Reactive Services	Implicit Rates	X								
Black Start Services	Implicit Rates	X[3]		X[4]	X[4]	X[4]				
Synchronous Condensing	Implicit Rate	X			X					

[1] Dynamic scheduled transactions are exempt from operating reserve charges.
[2] Participants only pay deviation charges if they incur deviations based on the rules specified in Manual 28.
[3] Load is charged black start services based on their zonal peak load contribution.
[4] Interchange transactions are charged black start services based on their point to point firm and non-firm reservations.

21 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.

Table 4-20 shows the average rates for each region in each charge category in the first nine months of 2023 and 2024. The average day-ahead rate during the first nine months of 2024 was $0.130 per MWh, with a minimum rate of $0.000 per MWh and a maximum rate of $4.255 per MWh. The average during the first nine months of 2024 is $0.074 per MWh higher than the average day-ahead rate during the first nine months of 2023.

The average RTO reliability rate during the first nine months of 2024 was $0.073 per MWh, with a minimum rate of $0.000 per MWh and a maximum rate of $0.662 per MWh. The average RTO reliability rate during the first nine months of 2024 is $0.036 per MWh higher than the average rate during the first nine months of 2023.

The average RTO deviation during the first nine months of 2024 was $0.178 per MWh, with a minimum rate of $0.000 per MWh and a maximum rate of $4.445 per MWh. The average RTO deviation rate during the first nine months of 2024 is $0.104 per MWh higher than the average rate during the first nine months of 2023.

Table 4-20 Operating reserve rates ($/MWh): January through September, 2023 and 2024

Rate	Avg 2023 (Jan - Sep) ($/MWh)	Min 2023 (Jan - Sep) ($/MWh)	Max 2023 (Jan - Sep) ($/MWh)	Avg 2024 (Jan - Sep) ($/MWh)	Min 2024 (Jan - Sep) ($/MWh)	Max 2024 (Jan - Sep) ($/MWh)	Difference of Avg ($/MWh)	Percent Difference of Avg
Day-Ahead	0.056	(0.000)	0.428	0.130	(0.000)	4.255	0.074	132.9%
Day-Ahead with Unallocated Congestion	0.056	(0.000)	0.428	0.130	(0.000)	4.255	0.074	132.9%
RTO Reliability	0.037	0.000	0.228	0.073	0.000	0.662	0.036	97.3%
East Reliability	0.015	0.000	0.330	0.014	0.000	0.348	(0.002)	(11.2%)
West Reliability	0.001	0.000	0.106	0.002	0.000	0.048	0.001	48.0%
RTO Deviation	0.074	(0.000)	0.621	0.178	(0.000)	4.445	0.104	140.4%
East Deviation	0.046	0.000	0.680	0.049	0.000	1.877	0.003	7.5%
West Deviation	0.006	0.000	0.161	0.009	0.000	0.343	0.003	44.0%
Lost Opportunity Cost	0.064	0.000	1.092	0.114	0.000	0.929	0.051	80.0%
Canceled Resources	0.000	0.000	0.000	0.000	0.000	0.000	0.000	NA
Dispatch Differential Lost Opportunity Cost	0.001	0.000	0.005	0.003	0.000	0.013	0.002	196.2%

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 if they are committed out of merit to provide reactive, or incur opportunity costs associated with reduced energy output. These charges are currently separate from the reactive service capability charges.[22] Charges for reactive capability payments will be eliminated based on Order No. 904.[23] 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.

22 See *2023 Annual State of the Market Report for PJM*, Volume 2; Section 10: Ancillary Service Markets.
23 *Compensation for Reactive Power within the Standard Power Factor Range*, Order No. 904, 189 FERC ¶ 61,034 (2024).

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 4-21 shows the reactive services rates associated with local voltage support in the first nine months of 2023 and 2024. Table 4-21 shows that in the first nine months of 2024, ACEC and DPL incurred reactive service rates of 0.1046 $/MWh and 0.0090 $/MWh.

Table 4-21 Local voltage support rates: January through September, 2023 and 2024

Control Zone	(Jan - Sep) 2023 ($/MWh)	(Jan - Sep) 2023 Charge (Millions)	(Jan - Sep) 2024 ($/MWh)	(Jan - Sep) 2024 Charge (Millions)	Rate Difference ($/MWh)	Rate Percent Difference
ACEC	0.000	$0.00	0.105	$0.79	0.105	NA
AEP	0.001	$0.12	0.000	$0.00	(0.001)	(100.0%)
APS	0.000	$0.00	0.000	$0.00	0.000	NA
ATSI	0.000	$0.00	0.000	$0.00	0.000	0.0%
BGE	0.017	$0.38	0.002	$0.04	(0.016)	(89.6%)
COMED	0.000	$0.00	0.000	$0.00	0.000	0.0%
DAY	0.000	$0.00	0.000	$0.00	0.000	0.0%
DUKE	0.000	$0.00	0.000	$0.00	0.000	0.0%
DUQ	0.000	$0.00	0.000	$0.00	0.000	0.0%
DOM	0.000	$0.00	0.000	$0.00	0.000	0.0%
DPL	0.000	$0.00	0.009	$0.12	0.009	NA
EKPC	0.000	$0.00	0.000	$0.00	0.000	0.0%
JCPLC	0.000	$0.00	0.000	$0.00	0.000	0.0%
MEC	0.000	$0.00	0.002	$0.02	0.002	NA
OVEC	0.000	$0.00	0.000	$0.00	0.000	0.0%
PECO	0.000	$0.00	0.000	$0.00	0.000	0.0%
PE	0.000	$0.00	0.000	$0.00	0.000	0.0%
PEPCO	0.000	$0.00	0.000	$0.00	0.000	0.0%
PPL	0.000	$0.00	0.000	$0.00	0.000	0.0%
PSEG	0.000	$0.00	0.000	$0.00	0.000	0.0%
REC	0.000	$0.00	0.000	$0.00	0.000	0.0%
Total (Jan - Sep)	NA	$0.50	NA	$0.98	NA	NA

Uplift Eligibility

In PJM, units have either a pool scheduled or self scheduled commitment status. Pool scheduled units are committed by PJM while self scheduled units are committed by generation owners. Table 4-22 provides a description of commitment and dispatch status, uplift eligibility and the ability to set price.[24] In the day-ahead energy market only pool scheduled resources are eligible for day-ahead operating reserve credits. A unit may be self scheduled in the day-ahead market and then be pool scheduled and dispatched in subsequent days to remain online, in which case they would be eligible for uplift for the subsequent days. In the real-time energy market only pool scheduled resources that follow PJM's dispatch are defined in the tariff as eligible for balancing operating reserve credits. However, in practice, units receive uplift credits when not following PJM's dispatch signal. 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. [25]

Table 4-22 Dispatch status, commitment status and uplift eligibility[26]

		Commitment Status	
Dispatch Status	Dispatch Description	Self Scheduled (units committed by the generation owner)	Pool Scheduled and following PJM's dispatch signal (units committed by PJM)
Block Loaded	MWh offered to PJM as a single MWh block which is not dispatchable	Not eligible to receive uplift Not eligible to set LMP	Eligible to receive uplift Not eligible to set LMP unless fast start eligible
Economic Minimum	MWh from the nondispatchable economic minimum component for units that offer a dispatchable range to PJM	Not eligible to receive uplift Not eligible to set LMP	Eligible to receive uplift Not eligible to set LMP unless fast start eligible
Dispatchable	MWh above the economic minimum level for units that offer a dispatchable range to PJM.	Only eligible to receive LOC credits if dispatched down by PJM Eligible to set LMP	Eligible to receive uplift Eligible to set LMP

Energy Uplift Issues

Uplift Resettlement

Some units have been incorrectly paid uplift despite not meeting uplift eligibility requirements, including not following dispatch, not having the correct commitment status, or not operating with PLS offer parameters. The MMU has requested that PJM correctly resettle the uplift payments in these cases.[27] Since 2018, the cumulative resettlement requests total $17.9 million, of which PJM has agreed and resettled only $3.9 million over the last two years, 22.0 percent, over the last two years, and 1.4 percent are waiting for a PJM response. The remaining 75.6 percent occurred prior to July 2022 and is subject to the OATT's limitation on claims. That limit does not apply and would not have applied if PJM informed the market participant within two years of the occurrence of the issue.[28] PJM should inform market participants of a potential issue when the MMU raises the issue with PJM and the market participant in order to ensure that the issues can be addressed. PJM has refused to accept the voluntary return of incorrectly paid uplift credits by generators when the MMU has identified such cases. The MMU continues to bring new cases to the attention of PJM.

24 PJM has modified the basic rules of eligibility to set price using its CT price setting logic.
25 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.
26 PJM allows block loaded CTs to set LMP by relaxing the economic minimum by 10 to 20 percent using CT price setting logic.
27 To date, the MMU has only requested resettlement of the most egregious cases.
28 OATT § 10.4.

The MMU identifies units that are not following dispatch and that are therefore not eligible to receive uplift payments. These findings are communicated to unit owners and to PJM. The units are identified by comparing their actual generation to the dispatch level that they should have achieved based on the real-time LMP, unit operating parameters (e.g. economic minimum, maximum and ramp rate) and energy offer.

Uplift Forfeiture Rule

The uplift forfeiture rule was introduced in 2000 after PJM observed that in the summer of 1999 units could circumvent the $1,000/MWh offer cap by submitting high offers associated with a long minimum run time (e.g. 24 hours). The rule states that units will not be paid operating reserve credits when they are scheduled on their price-based offers during maximum generation conditions and their effective energy offer price exceeds $1,000 per MWh.[29] Maximum generation conditions include maximum generation emergencies, maximum generation emergency alerts, and when PJM schedules units based on the anticipation of a maximum generation emergency or maximum generation emergency alert.

In 2022 and 2023, PJM declared maximum generation conditions on five separate days. During these days, some units received uplift payments in violation of the uplift forfeiture rule. The five days in question are December 23 through 25 of 2022 (Winter Storm Elliott) and July 27 and 28 of 2023. The MMU has determined that balancing operating reserves paid on December 23 and 24 of 2022 should be forfeited. PJM resettled the operating reserve credits paid to units that exceeded an effective offer price of $1,000 per MWh on December 23 and 24, 2022. The total balancing operating reserve credits returned totaled $1.7 million. In 2024, PJM declared maximum generation conditions on August 27, however the uplift forfeiture rule was not triggered because no unit was paid uplift with an effective energy price-based offer that exceeded $1,000 per MWh.

Regulation Market Offsets

PJM does not include regulation market payments as an offset like other market revenues in the operating reserve calculations. Including regulation market revenues would result in lower uplift calculations. Table 4-23 shows that the regulation market revenues in the first nine months of 2024 were $80.4 million and that the balancing generator credits for those units receiving regulation revenues was $9.1 million. The table shows that if the regulation market revenues had been incorporated into the operating reserve calculation as an offset, the adjusted balancing generator payment for those units would have been $8.0 million instead of $9.1 million, 12.1 percent lower.

Table 4-23 Adjusted operating reserve credits: January through September, 2024

Month	Regulation Market Revenues (Millions)	Balancing Generator Credits (Millions)	Adjusted Balancing Generator Credits (Millions)	Difference
Jan	$12.1	$3.3	$3.1	($0.2)
Feb	$5.7	$0.5	$0.5	($0.0)
Mar	$6.9	$0.9	$0.9	($0.1)
Apr	$6.5	$1.9	$1.7	($0.2)
May	$10.3	$0.9	$0.8	($0.2)
Jun	$8.6	$0.5	$0.4	($0.1)
Jul	$9.3	$0.4	$0.2	($0.1)
Aug	$13.0	$0.4	$0.2	($0.1)
Sep	$8.0	$0.4	$0.3	($0.1)
Total	$80.4	$9.1	$8.0	($1.1)

Intraday Segments Uplift Settlement

PJM pays uplift separately for multiple blocks of time (segments) during the operating day (intraday).[30] 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.

29 See OA Schedule 1 Section 3.2.3 (m) Operating Reserves

30 See PJM "Manual 28: Operating Reserve Accounting," Rev. 96 (Sep. 1, 2024).

Table 4-24 shows balancing operating reserve credits calculated using intraday segments and balancing operating reserve payments calculated on a daily basis. In the first nine months of 2024, balancing operating reserve credits would have been $15.4 million or 16.2 percent lower if they were calculated on a daily basis. In the first nine months of 2023, balancing operating reserve credits would have been $12.3 million or 22.5 percent lower if they were calculated on a daily basis.

Table 4-24 Intraday segments and daily balancing operating reserve credits: January 2023 through September 2024

	2023 Balancing Generator Credits (Millions)			2024 Balancing Generator Credits (Millions)		
	Intraday Segments Calculation	Daily Calculation	Difference	Intraday Segments Calculation	Daily Calculation	Difference
Jan	$3.8	$3.0	($0.7)	$22.6	$19.4	($3.2)
Feb	$3.4	$3.0	($0.4)	$4.4	$3.8	($0.6)
Mar	$4.2	$3.4	($0.7)	$8.7	$7.4	($1.3)
Apr	$10.5	$8.7	($1.8)	$16.9	$15.1	($1.8)
May	$9.3	$7.3	($1.9)	$18.8	$16.2	($2.6)
Jun	$5.1	$3.8	($1.3)	$8.7	$7.4	($1.3)
Jul	$8.0	$5.8	($2.2)	$4.8	$3.2	($1.6)
Aug	$4.1	$2.6	($1.5)	$5.3	$4.1	($1.2)
Sep	$6.4	$4.7	($1.6)	$4.8	$3.0	($1.8)
Oct	$12.1	$8.9	($3.1)			
Nov	$11.2	$8.7	($2.5)			
Dec	$5.3	$4.4	($0.9)			
Total (Jan - Sep)	$54.8	$42.5	($12.3)	$95.0	$79.6	($15.4)
Total	$83.4	$64.5	($18.9)	$95.0	$79.6	($15.4)

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 within the hour. Table 4-25 shows the impact on day-ahead LOC credits to CTs that are committed DA but not RT. The table shows the LOC credits calculated in three ways: with the five minute settlement calculations implemented in April 2018; with hourly settlements prior to the change in April 2018; and with daily settlements. In the first nine months of 2024, LOC credits would have been $1.9 million or 8.4 percent lower if they had been settled on an hourly basis rather than on a five minute basis. In the first nine months of 2024, LOC credits would have been $5.1 million or 22.7 percent lower if they had been settled on the recommended daily basis rather than being settled on a five minute basis.

Table 4-25 Comparison of five minute, hourly, and daily settlement of day-ahead lost opportunity cost credits: January through September, 2024

	2024 Day-Ahead LOC Credits (Millions)				
	Five Minute Settlement (Status Quo)	Hourly Settlement (Pre-April 2018)	Difference	Daily Settlement (Recommendation)	Difference
Jan	$0.8	$0.7	($0.1)	$0.5	($0.3)
Feb	$0.8	$0.8	($0.1)	$0.7	($0.2)
Mar	$1.6	$1.6	($0.0)	$1.4	($0.2)
Apr	$1.4	$1.3	($0.1)	$0.9	($0.5)
May	$1.4	$1.5	$0.1	$1.3	($0.2)
Jun	$3.4	$2.9	($0.5)	$2.4	($1.0)
Jul	$6.4	$5.6	($0.8)	$4.8	($1.7)
Aug	$4.7	$4.4	($0.3)	$3.8	($0.9)
Sep	$1.8	$1.8	$0.0	$1.6	($0.2)
Total (Jan - Sep)	$22.4	$20.5	($1.9)	$17.3	($5.1)

Concentration of Energy Uplift Credits

The recipients of uplift payments are highly concentrated by unit and by company. 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 a lack of full transparency has made it more difficult for competition to affect these payments.[31]

Table 4-26 shows the concentration of energy uplift credits. The top 10 units received 43.0 percent of total energy uplift credits in the first nine months of 2024. The top 10 companies received 75.7 percent of total energy uplift credits in the first nine months of 2024.

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

Table 4-26 Top 10 units and organizations energy uplift credits: January through September, 2024

		Top 10 Units		Top 10 Organizations	
Category	Type	Credits (Millions)	Credits Share	Credits (Millions)	Credits Share
Day-Ahead	Generators	$83.8	89.4%	$92.7	99.0%
Balancing	Canceled Resources	$0.1	100.0%	$0.1	100.0%
	Generators	$14.1	14.8%	$68.0	71.5%
	Local Constraints Control	$1.2	88.4%	$1.3	100.0%
	Lost Opportunity Cost	$5.0	19.4%	$17.9	70.0%
	Dispatch Differential Lost Opportunity Cost	$0.9	57.8%	$1.3	84.6%
	Total Balancing	$21.1	17.1%	$88.6	71.7%
Reactive Services		$1.0	97.1%	$1.0	100.0%
Synchronous Condensing		$0.0	NA	$0.0	NA
Black Start Services		$0.2	53.5%	$0.3	96.2%
Total		$94.0	43.0%	$165.4	75.7%

Unit Specific Uplift Payments

FERC Order No. 844 allows PJM and the MMU to publish unit specific uplift payments by category by month. Table 4-27 through Table 4-31 show the top 10 recipients of total uplift, day-ahead operating reserve credits and lost opportunity cost credits.

Brandon Shores 1 and Brandon Shores 2 and Wagner 3 and Wagner 4 submitted retirement notifications to PJM and the MMU in April[32] and October[33] of 2023. Brandon Shores 1 and 2 are coal units in BGE with an ICAP of 635 MW and 638 MW. Wagner 3 and 4 are oil units in BGE with an ICAP of 305 MW and 397 MW. PJM determined that these resources were needed for reliability until transmission upgrades can be completed. In the first nine months of 2024, the Brandon Shores units received $37.4 million in uplift, 17.1 percent of all uplift payments and the Wagner units received $13.8 million in uplift, 6.3 percent of all uplift payments. In the first nine months of 2023, the Brandon Shores units received $30.7 million in uplift, 26.1 percent of all uplift payments and the Wagner units received $4.3 in uplift, 3.7 percent of all uplift payments.

32 Lebsack, Dale, President Brandon Shores LLC, Talen Energy, November 11, 2024, <https://www.pjm.com/-/media/planning/gen-retire/deactivation-notices/brandon-shores-deactiviation.ashx>

33 Lebsack, Dale, President H.A. Wagner LLC, Talen Energy, November 11, 2024, <https://www.pjm.com/-/media/planning/gen-retire/deactivation-notices/wagner-deactiviation-notice.ashx>

Table 4-27 Top 10 recipients of total uplift: January through September, 2024

Rank	Unit Name	Zone	Total Uplift Credit	Share of Total Uplift Credits
1	BC BRANDON SHORES 2 F	BGE	$22,102,491	10.1%
2	PEP CHALKPOINT 3 F	PEPCO	$19,555,291	8.9%
3	BC BRANDON SHORES 1 F	BGE	$15,291,752	7.0%
4	PEP CHALKPOINT 4 F	PEPCO	$12,869,527	5.9%
5	BC WAGNER 3 F	BGE	$6,993,652	3.2%
6	BC WAGNER 4 F	BGE	$6,778,822	3.1%
7	PL BRUNNER ISLAND 3 F	PPL	$3,885,063	1.8%
8	PL MARTINS CREEK 4 F	PPL	$2,286,707	1.0%
9	DPL INDIAN RIVER 4 F	DPL	$2,151,960	1.0%
10	PL MARTINS CREEK 3 F	PPL	$2,107,958	1.0%
Total of Top 10			$94,023,223	43.0%
Total Uplift Credits			$218,505,623	100.0%

Table 4-28 Top 10 recipients of day-ahead generation credits: January through September, 2024

Rank	Unit Name	Zone	Day-Ahead Operating Reserve Credit	Share of Day-Ahead Operating Reserve Credits
1	BC BRANDON SHORES 2 F	BGE	$20,799,116	22.2%
2	PEP CHALKPOINT 3 F	PEPCO	$18,153,919	19.4%
3	BC BRANDON SHORES 1 F	BGE	$14,311,106	15.3%
4	PEP CHALKPOINT 4 F	PEPCO	$12,439,535	13.3%
5	BC WAGNER 3 F	BGE	$5,910,561	6.3%
6	BC WAGNER 4 F	BGE	$5,240,043	5.6%
7	PL BRUNNER ISLAND 3 F	PPL	$3,110,654	3.3%
8	PL MARTINS CREEK 4 F	PPL	$1,418,333	1.5%
9	PL MARTINS CREEK 3 F	PPL	$1,411,870	1.5%
10	PE EDDYSTONE 4 F	PECO	$981,702	1.0%
Total of Top 10			$83,776,839	89.4%
Total day-ahead operating reserve credits			$93,702,591	100.0%

Table 4-29 Top 10 recipients of balancing generator credits: January through September, 2024

Rank	Unit Name	Zone	Balancing Generator Credits	Share of Balancing Generator Credits
1	DPL INDIAN RIVER 4 F	DPL	$2,105,787	2.2%
2	BC WAGNER 4 F	BGE	$1,538,778	1.6%
3	AEP ROBERT P MONE 1 CT	AEP	$1,487,321	1.6%
4	PEP CHALKPOINT 3 F	PEPCO	$1,401,372	1.5%
5	BC BRANDON SHORES 2 F	BGE	$1,302,345	1.4%
6	AEP ROBERT P MONE 3 CT	AEP	$1,280,196	1.3%
7	EKPC JK SMITH 1 CT	EKPC	$1,264,209	1.3%
8	EKPC JK SMITH 2 CT	EKPC	$1,264,130	1.3%
9	AEP ROBERT P MONE 2 CT	AEP	$1,221,994	1.3%
10	EKPC JK SMITH 3 CT	EKPC	$1,186,360	1.2%
Total of Top 10			$14,052,493	14.8%
Total balancing operating reserve credits			$95,041,057	100.0%

Table 4-30 Top 10 recipients of lost opportunity cost credits: January through September, 2024

Rank	Unit Name	Zone	Lost Opportunity Cost Credits	Share of Lost Opportunity Cost Credits
1	FE RICHLAND 4 CT	ATSI	$772,257	3.0%
2	FE RICHLAND 5 CT	ATSI	$704,668	2.8%
3	VP LADYSMYTH 1 CT	DOM	$649,964	2.5%
4	VP LOUISA 5 CT	DOM	$435,387	1.7%
5	VP LADYSMYTH 4 CT	DOM	$433,273	1.7%
6	VP REMINGTON 4 CT	DOM	$401,079	1.6%
7	DPL ROCK SPRINGS 1 CT	DPL	$400,790	1.6%
8	DPL ROCK SPRINGS CT3	DPL	$396,120	1.6%
9	PEP DICKERSON H 1 CT	PEPCO	$388,726	1.5%
10	DPL ROCK SPRINGS 2 CT	DPL	$370,384	1.5%
Total of Top 10			$4,952,648	19.4%
Total lost opportunity cost credits			$25,496,225	100.0%

Table 4-31 Top 10 recipients of dispatch differential lost opportunity cost credits: January through September, 2024

Rank	Unit Name	Zone	Dispatch Differential Lost Opportunity Cost Credits	Share of Dispatch Differential Lost Opportunity Cost Credits
1	AEP SMITH MOUNT 1-5 H	AEP	$221,081	14.0%
2	VP GASTON 1-4 H	DOM	$156,167	9.9%
3	AP BATH COUNTY 1-6 H	DOM	$139,439	8.8%
4	VP KERR DAM 1-7 H	DOM	$123,852	7.8%
5	VP BATH COUNTY 1-6 H	DOM	$120,136	7.6%
6	JC YARDS CREEK 1-3 H	JCPLC	$37,819	2.4%
7	VP FOUR RIVERS 1 CT	DOM	$30,942	2.0%
8	PL HUMMEL STATION 1 CC	PPL	$29,222	1.9%
9	VP PANDA STONEWALL 1 CC	DOM	$28,616	1.8%
10	PS NEWARK ENERGY CENTER 10 CC	PSEG	$24,341	1.5%
Total of Top 10			$911,613	57.8%
Total dispatch differential lost opportunity cost credits			$1,577,745	6.2%

Uplift Credits and Market Power Mitigation

Absent effectively implemented market power mitigation, unit owners that submit noncompetitive offers or offers with inflexible operating parameters, can exercise market power, resulting in noncompetitive and excessive uplift payments.

The three pivotal supplier (TPS) test is the test for local structural market power in the energy market.[34] If the TPS test is failed, market power mitigation is applied by offer capping the resources of the owners identified as having local market power to their cost-based offer. Offer capping is designed to set offers at competitive levels.

Table 4-32 shows the uplift credits paid to committed and dispatched units in the first nine months of 2024 by offer type. Units received $58.0 million or 61.0 percent of balancing generator credits and $29.2 million or 31.2 percent of day-ahead operating reserve credits in the first nine months of 2024 using price-based offers. Units received $27.6 million or 29.0 percent of balancing generator credits and $63.9 million or 68.2 percent of day-ahead operating reserves in the first nine months of 2024 using cost-based offers.

34 See the MMU Technical Reference for PJM Markets, at "Three Pivotal Supplier Test" for a more detailed explanation of the three pivotal supplier test. <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

Table 4-32 Operating Reserve Credits by Offer Type: January through September, 2024

Offer Type	Day Ahead Operating Reserve Credits (Millions)	Balancing Generator Credits (Millions)	Day Ahead Reactive Credits (Millions)	Real Time Reactive Credits (Millions)	Total	Share of Total Uplift
Cost	$63.9	$27.6	$0.0	$0.9	$92.4	42.3%
Price	$29.2	$58.0	$0.0	$0.0	$87.3	39.9%
Price PLS	$0.6	$7.6	$0.0	$0.0	$8.1	3.7%
Cost & Price	$0.0	$1.6	$0.0	$0.0	$1.6	0.7%
Cost & PLS	$0.0	$0.2	$0.0	$0.0	$0.2	0.1%
Price & PLS	$0.0	$0.1	$0.0	$0.0	$0.1	0.0%
Total	$93.7	$95.0	$0.1	$0.9	$189.7	86.8%
Share	49.4%	50.1%	0.0%	0.5%	100.0%	NA

Table 4-33 shows day-ahead operating reserve credits paid to units called on days with hot and cold weather alerts, classified by commitment schedule type. On weather alert days, PJM can use parameter limited schedules (PLS) to prevent exercises of market power through the use of inflexible parameters. Of all the day-ahead credits received during days with weather alerts, 78.6 percent went to units that were committed on cost schedules, which are parameter limited, 4.2 percent went to units that were committed on price PLS schedules and 17.2 percent went to units committed on price schedules less flexible than PLS. The 17.2 percent that went to units committed on a price schedule less flexible than PLS indicates an issue with the process that PJM uses to apply parameter mitigation on weather alert days. Resources should not receive uplift based on inflexible parameters during emergencies and alerts.

Table 4-33 Day-ahead operating reserve credits during weather alerts by commitment schedule: January through September, 2024

Commitment Type During Hot and Cold Weather Alerts	Day Ahead Operating Reserve Credits	Share of DAOR during emergency alerts
Committed on cost (cost capped)	$10,602,139	78.6%
Committed on price schedule as flexible as PLS	$2,097	0.0%
Committed on price schedule less flexible than PLS	$2,313,023	17.2%
Committed on price PLS	$567,451	4.2%
Total	$13,484,710	100.0%

Gas fired generators may request temporary exceptions to parameter limits such as minimum run time based on restrictions imposed by natural gas pipelines, including ratable takes.[35] Table 4-34 shows the uplift credits received from 2018 through September of 2024 by units that submitted parameter exception requests for a 24 hour minimum run time based on gas pipeline restrictions. In the first nine months of 2024, 79 units requested an exception for 24 hour minimum run time and 36 units received uplift payments amounting to $28.7 million of day ahead operating reserves, or 30.6 percent of total day-ahead operating reserves and 13.1 percent of total uplift. During the same time period, units that requested an exception for 24 hour minimum run time received $2.3 million in balancing generator credits, or 2.4 percent of total balancing generator credits and 1.0 percent of total uplift credits.

Table 4-34 Uplift credits for units with 24 hour minimum run times due to gas pipeline restrictions: 2018 through September 2024

Year	Day-Ahead Operating Reserve Credits (Millions)	Balancing Generator Credits (Millions)	Number of Units with 24 Hour Min Run Time Exceptions	Number of Units with 24 Hour Min Run Time Exceptions that Received Uplift
2018	$4.9	$0.7	25	2
2019	$0.2	$0.6	37	12
2020	$0.2	$0.2	13	2
2021	$0.7	$0.6	61	42
2022	$14.4	$9.8	81	38
2023	$10.7	$1.5	75	23
2024 (Jan - Sep)	$28.7	$2.3	79	36

Fast Start Pricing

Fast start pricing was implemented on September 1, 2021. With fast start pricing, cleared and dispatched MW are determined in the dispatch run, identical to the single dispatch and pricing process prior to fast start, while LMPs are determined in the pricing run, which calculates prices based on the counterfactual assumption that the fast start resources are flexible and can back down to a low economic minimum MW. Fast start pricing creates a divergence between the pricing run LMP that signals a higher MW for some

35 See OA Schedule 1 Section 6.6 (C) Minimum Generator Operating Parameters – Parameter Limited Schedules.

resources and the lower dispatch run MW to which PJM dispatches the resource based on its offer curve. The resources dispatched down would produce more MWh if they responded to the actual market LMP from the pricing run.

As a result, the implementation of fast start pricing required a new uplift credit. The dispatch differential lost opportunity cost is a credit that exists only as a result of fast start pricing. This credit is paid to flexible resources that are artificially dispatched down below the level that is economic at fast start prices, in order to accommodate inflexible fast start resources. The resulting dispatch differential lost opportunity cost credit is the revenue lost by the resource as a result of operating at the lower dispatch MW rather than the MW on its offer curve corresponding to the actual market LMP from the pricing run. Table 4-1 shows that the dispatch differential lost opportunity cost during the first nine months of 2024 was $1.6 million. Table 4-5 shows that 22.4 percent of the dispatch differential lost opportunity cost credit was paid to combined cycle units and 15.8 percent to combustion turbines.

In some cases, PJM paid dispatch differential payments to resources that did not follow PJM dispatch instructions. PJM should not make these payments as they are directly counter to the logic of fast start pricing as well as to tariff rules. The MMU recommends that PJM not make such payments and require refunds where it has not already done so. This is part of the broader recommendation that PJM stop paying uplift to resources that do not follow dispatch.

Proponents of fast start pricing assert that it reduces uplift to fast start units by raising LMP, and thus revenue, when they are operating. This reduction in uplift would be most likely to occur in balancing operating reserves payments. To the extent that fast start pricing increases day-ahead prices, it may also reduce Day-Ahead Operating Reserve payments. But fast start pricing also increases other uplift payments, especially the new dispatch differential lost opportunity cost payment. Day-ahead lost opportunity cost payments to fast start resources may also increase because real-time LMPs are higher than they would be without fast start pricing.

Table 4-35 shows the amount of uplift paid to fast start units by major uplift category. Fast start units received $23.8 million in balancing generator credits, or 25.1 percent of total balancing operating reserves. Fast start units received $4.1 million in day-ahead lost opportunity costs, or 18.1 percent of all lost opportunity costs. Fast start units received less than $0.1 million in day-ahead operating credits, or less than 0.1 percent of total day-ahead operating reserve credits.

Table 4-35 Monthly day-ahead operating reserves, balancing generator credits, and day-ahead lost opportunity cost credits for fast start units: January through September, 2024

Month	Day-Ahead Operating Reserves (Millions)	Share of Monthly Day-Ahead Operating Reserves	Balancing Generator Credits (Millions)	Share of Monthly Balancing Generator Credits	Day Ahead Lost Opportunity Cost Credits (Millions)	Share of Monthly Day Ahead Lost Opportunity Cost Credits
Jan	$0.0	0.0%	$2.6	11.5%	$0.2	24.4%
Feb	$0.0	0.1%	$2.0	45.1%	$0.0	5.1%
Mar	$0.0	0.2%	$3.6	41.1%	$0.1	7.1%
Apr	$0.0	0.0%	$4.9	29.2%	$0.1	5.3%
May	$0.0	0.0%	$4.8	25.6%	$0.1	3.7%
Jun	$0.0	0.0%	$1.7	19.0%	$0.4	12.6%
Jul	$0.0	0.2%	$1.5	30.2%	$1.7	26.8%
Aug	$0.0	0.1%	$1.0	18.8%	$1.1	22.7%
Sep	$0.0	0.1%	$1.8	38.4%	$0.4	20.3%
Total (Jan - Sep)	$0.0	0.0%	$23.8	25.1%	$4.1	18.1%

Table 4-36 shows the day-ahead, balancing generator credits, and day-ahead lost opportunity cost credits for combustion turbines by month, also included in Table 4-35.

Table 4-36 Day-ahead operating reserves, balancing operating reserves, day-ahead lost opportunity cost credits for fast start combustion turbines: January through September, 2024

Month	Day-Ahead Operating Reserves	Share of Monthly Day-Ahead Operating Reserves	Balancing Generator Credits	Share of Monthly Day-Ahead Operating Reserves	Day-Ahead Lost Opportunity Cost Credits	Share of Monthly Day-Ahead Lost Opportunity Cost Credits
Jan	$0.0	0.0%	$2.5	65.9%	$0.2	8.6%
Feb	$0.0	0.0%	$1.9	56.3%	$0.0	7.4%
Mar	$0.0	0.1%	$3.5	84.2%	$0.1	16.4%
Apr	$0.0	0.3%	$4.8	45.9%	$0.1	5.4%
May	$0.0	0.5%	$4.7	50.9%	$0.0	3.0%
Jun	$0.0	0.1%	$1.6	31.4%	$0.4	34.9%
Jul	$0.0	0.1%	$1.3	16.3%	$1.6	39.2%
Aug	$0.0	0.0%	$1.0	23.3%	$1.0	46.1%
Sep	$0.0	0.0%	$1.8	28.1%	$0.3	17.2%
Total (Jan - Sep)	$0.0	0.0%	$23.3	24.6%	$3.9	25.1%

Winter Storm Gerri (January 13 – 22, 2024)

Winter Storm Gerri, which lasted from January 13 through 21, 2024, had a significant impact on uplift, especially day-ahead operating reserves. Table 4-37 summarizes the uplift payments by category during Winter Storm Gerri. During the period of the storm, units received $32.6 million in day-ahead operating reserve credits, equivalent to 34.8 percent of total day-ahead operating reserves during the first nine months of 2024. Units received $19.5 million in balancing generator credits during the storm, equivalent to 20.5 percent of total balancing generator credits during the first nine months of 2024. Overall, total uplift payments during the storm totaled $53.9 million, or 24.7 percent of total uplift during the first nine months of 2024.

Uplift during Winter Storm Gerri increased as a result of out of market commitments made by PJM in anticipation of the cold weather. The out of market commitments resulted primarily from conservative operations but also included unit commitments for transmission constraints. Conservative operations are triggered by weather, environmental, physical or cyber security events, among other types of events.[36]

PJM provided multiple reasons for the out of market commitments. PJM stated that units with extended start times were committed early, before the cold weather started. Units that did not operate in the previous eight weeks, prior to the storm, were considered for additional start time. Units with extensive minimum down time were kept online if they were expected to be needed for the peak load. Weekend gas package purchases were also considered when making out of market commitments to gas units to address generators' risk related to gas purchases for the expected peak days.[37]

36 See PJM "Manual 13: Emergency Operations," Section 3.2 Conservative Operations Rev.92 (Dec. 20, 2023).
37 *See* "Winter Storm Gerri Review January 13–22, 2024," PJM presentation to the Operating Committee. (February 8, 2024) <https://www.pjm.com/-/media/committees-groups/committees/oc/2024/20240208/20240208-item-11---cold-weather-update.ashx>.

Table 4-37 Energy uplift credits by category during Winter Storm Gerri

Category	Type	Winter Storm Gerri Credits (Millions)	(Jan - Sep) 2024 Credits (Millions)	Share (Jan - Sep)
Day-Ahead	Generators	$32.6	$93.7	34.8%
	Imports	$0.0	$0.0	0.0%
	Load Response	$0.0	$0.0	0.0%
Balancing	Canceled Resources	$0.0	$0.1	0.0%
	Generators	$19.5	$95.0	20.5%
	Imports	$0.0	$0.0	NA
	Load Response	$0.0	$0.0	NA
	Local Constraints Control	$0.0	$1.3	0.0%
	Lost Opportunity Cost	$0.9	$25.5	3.4%
	Dispatch Differential Lost Opportunity Cost	$0.1	$1.6	5.6%
Reactive Services	Day-Ahead	$0.0	$0.1	69.8%
	Local Constraints Control	$0.0	$0.0	NA
	Lost Opportunity Cost	$0.0	$0.0	84.6%
	Reactive Services	$0.8	$0.9	87.7%
	Synchronous Condensing	$0.0	$0.0	NA
Synchronous Condensing		$0.0	$0.0	NA
Black Start Services	Day-Ahead	$0.0	$0.0	NA
	Balancing	$0.0	$0.0	NA
	Testing	$0.0	$0.3	0.0%
Total		$53.9	$218.5	24.7%

Table 4-38 summarizes the total energy uplift credits by unit type during Winter Storm Gerri. In the first nine months of 2024, non-coal steam units were particularly affected by the storm, and received 35.7 million in uplift payments during the period of the storm, accounting for 56.1 percent of the total $63.5 million in uplift during the first nine months of 2024. Similarly, during the first nine months of 2024, combined cycle units were also strongly impacted by the storm, and received $6.2 million and accounted for 62.2 percent of the $10.0 million in uplift that was received during the first nine months of 2024. Combustion turbines were less impacted by the storm, and uplift payments to those units only account for 10.8 percent of uplift payments during the first nine months of 2024.

Table 4-38 Total energy uplift credits by unit type during Winter Storm Gerri

Unit Type	Winter Storm Gerri Credits (Millions)	(Jan - Sep) 2024 Credits (Millions)	Share (Jan - Sep)
Combined Cycle	$6.2	$10.0	62.2%
Combustion Turbine	$10.5	$97.2	10.8%
Diesel	$0.2	$1.5	10.2%
Hydro	$0.1	$0.8	6.4%
Nuclear	$0.0	$0.0	0.0%
Solar	$0.0	$0.2	0.9%
Steam - Coal	$1.4	$43.9	3.1%
Steam - Other	$35.7	$63.5	56.1%
Wind	$0.1	$1.4	3.8%
Total	$53.9	$218.5	24.7%

Table 4-39 summarizes the energy uplift credits by unit type during the period of Winter Storm Gerri

Table 4-39 Energy uplift credits by unit type during Winter Storm Gerri

Unit Type	Day-Ahead Generator	Balancing Generator	Canceled Resources	Local Constraints Control	Lost Opportunity Cost	Reactive Services	Synchronous Condensing	Black Start Services	Dispatch Differential Lost Opportunity Cost
Combined Cycle	7.1%	19.9%	0.0%	0.0%	0.2%	0.0%	0.0%	0.0%	14.0%
Combustion Turbine	0.3%	45.3%	0.0%	0.0%	83.5%	93.8%	0.0%	0.0%	9.0%
Diesel	0.0%	0.5%	0.0%	0.0%	4.7%	0.9%	0.0%	0.0%	0.9%
Hydro	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	60.5%
Nuclear	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Solar	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	2.0%
Steam - Coal	1.4%	3.7%	0.0%	100.0%	5.8%	5.3%	0.0%	0.0%	10.3%
Steam - Other	91.1%	30.6%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.0%
Wind	0.0%	0.0%	0.0%	0.0%	5.7%	0.0%	0.0%	0.0%	2.3%
Total (Millions)	$32.6	$19.5	$0.0	$0.1	$0.9	$0.9	$0.0	$0.0	$0.1