4 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 of fast start pricing 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 the minimum, efficient level of uplift payments.

But PJM's practice does not result in efficient prices with the efficient level of 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 the daily uplift calculation for generators that receive regulation revenues, but are not currently included. The need for uplift should be calculated on a daily basis, as incorporated in the initial PJM market design, rather than on an hourly segment basis, and in some cases on a multiday basis, e.g. with multiday weekend commitments. 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 hourly segments and require uplift in other hourly segments. In the case where PJM makes multiday commitments, the uplift calculation should cover the entire multiday period rather than allowing a generator to be paid uplift on day one and earn significant profits on day three. 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 hourly segments. 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 length 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. The net revenues in those new segments are not counted as contributing to covering costs in the initial segment. The reverse is also true. Uplift is paid even when total net revenues cover or more than cover costs when the entire day is included. The same issue exists in the case of multiday commitments.

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.

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In PJM, all energy payments to demand response resources are uplift payments. The energy payments to these demand response 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 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]

Polar Vortex 2025 and Winter Storm Fern (2026) both resulted in a significant increase in uplift payments as a result of the fact that PJM chose a significantly different and better approach to the preparations for these winter weather events than PJM had taken for Winter Storm Elliott. Rather than rely on ineffective, inefficient, risky, and disruptive PAI incentives to provide assurance that generators would be ready for cold weather, PJM took direct steps to ensure a reliable outcome. The market results of PJM's actions during Polar Vortex 2025 and Winter Storm Fern vindicated PJM's strategy. PJM took conservative measures to ensure reliability, including voltage support, by scheduling resources in advance of the day-ahead energy market. These commitments were not made to meet reserve requirements. Higher reserve requirements would not have addressed the Polar Vortex 2025 issues, Winter Storm Fern issues, or cold weather reliability issues more generally. Units needed to buy gas in advance and actually be operating in order to meet the reliability issues.

The uplift associated with Polar Vortex 2025 and Winter Storm Fern was an expected outcome of conservative operations. This uplift is part of the way that PJM markets work and was the result of PJM's successful conservative operations approach to dealing with cold weather risks. PJM's commitment approach during Polar Vortex 2025 and Winter Storm Fern was significantly different than in 2024, for example. PJM committed only 1.4 percent of units on schedules less flexible than PLS during Polar Vortex 2025 and 1.3 percent during Winter Storm Fern, compared to 17.2 percent during weather alert days in 2024.

The market results of PJM's actions in preparation for and during Winter Storm Gerri, Polar Vortex 2025 and Winter Storm Fern were better than the market results of PJM's actions during Winter Storm Elliott. Uplift was the expected result and the preferred result to the massive and financially disruptive penalties that resulted from Winter Storm Elliott. Nonetheless, improvements are needed to make the advance commitment process more predictable, transparent and formalized. and made as market based as possible, in order to limit uplift to an efficient and effective level. These improvements should include implementing a multiday security constrained economic dispatch and commitment model that incorporates PJM's load forecast, energy cost forecasts, and units at risk, and provides commitment recommendations to PJM's dispatch prior to the Day-Ahead Energy Market. In addition, there should be rules about energy offers used for these commitments, and uplift rules should be revised to account for the multiday nature of these commitments.

Some market participants, primarily LSEs in restructured states, assert that the uplift resulting from advance commitment during recent winter events must be reduced because it is unhedgeable. What LSEs mean by unhedgeable is that they cannot include in their pricing for retail customers a guarantee that the payments by the retail customers to the LSEs will cover the uplift payments that the LSEs must pay. A typical contract between an LSE and retail customers in restructured states provides a fixed price for energy. LSEs buy energy in the PJM wholesale energy market and sell energy to retail customers at a fixed price. LSEs face the risk that the LMP for spot purchases of energy will exceed the price at which they sell energy. LSEs can hedge that exposure by buying power at forward prices and locking in a margin. There is no similar forward market for uplift. As a result, LSEs cannot hedge their exposure as effectively. Hedging means taking a position that offsets the risk associated with taking a position in a market. While it is correct that PJM markets and associated secondary markets do not provide the type of nearly perfect hedge for uplift as they do for energy price risk, the concept of hedging is broad. LSEs can attempt to hedge uplift risk in a variety of ways based on their view of the

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

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causes of uplift and potentially correlated phenomena like weather. Ultimately it is not PJM's responsibility or the responsibility of the PJM market design to provide a perfect hedge for any part of LSEs' risk, including the risk of uplift. It is not clear that uplift would be lower if PJM did not make advance commitments, and if PJM prices were significantly higher, and if some market participants incurred financial losses, as occurred in Winter Storm Elliott. Regardless, there is no supportable argument for such an approach. The result would simply shift costs and risks from LSEs to other market participants, including reliability costs and risks. There are real costs and risks that will not disappear. The MMU supports a more efficient advance commitment process. The goal of the PJM competitive market design is to provide power at the lowest possible cost. This includes efficient prices and an efficient level of uplift. The goal of PJM competitive markets is not to reduce costs and risks for any class of market participants by shifting costs and risks to others.

Overview

Energy Uplift Credits

- **Energy uplift credits.** Total energy uplift credits increased by $744.2 million, or 112.5 percent, during the first nine months of 2026 compared to the first nine months of 2025, from $661.6 million to $1,405.8 million.
- **Types of energy uplift credits.** During the first nine months of 2026, total energy uplift credits included $336.1 million in day-ahead generator credits, $850.9 million in balancing generator credits, $208.9 million in lost opportunity cost credits, $6.9 million in dispatch differential lost opportunity cost credits, and 2.4 million in reactive service credits.
- **Types of units.** During the first nine months of 2026, non-coal steam units received 95.2 percent of the day-ahead generator credits. Combined cycle units and combustion turbines received 82.3 percent of balancing generator credits. Combustion turbines received 69.5 percent of lost opportunity credits and 38.5 percent of dispatch differential lost opportunity cost credits. Hydro, wind, and solar received 49.3 percent of dispatch differential lost opportunity cost credits.
- **Concentration of energy uplift credits.** In the first nine months of 2026, the top 10 units receiving energy uplift credits received 38.7 percent of all credits and the top 10 organizations received 76.4 percent of all credits.
- **Lost opportunity cost credits.** Lost opportunity cost credits increased by $180.2 million, from $28.6 million to $208.9 million, or 629.3 percent, during the first nine months of 2026 compared to the first nine months of 2025.
- 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 68.3 percent of the $143.5 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.

Energy Uplift Charges

- **Energy Uplift Charges.** During the first nine months of 2026, total energy uplift charges increased by $744.2 million, or 112.5 percent, compared to the first nine months of 2025, from $661.6 million to $1,405.7 million.
- **Types of Energy Uplift Charges.** During the first nine months of 2026, total uplift charges included $336.0 million in day-ahead operating reserve charges, $1066.2 million in balancing generator charges, $2.4 million in reactive charges, $0.6 million in black start services, and $0.5 million in local congestion charges.

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.)

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- The MMU recommends that PJM not pay uplift to units for energy produced because of not following dispatch. (Priority: Medium. First reported 2018. Status: Not adopted.)[5]
- The MMU recommends that PJM pay uplift based on the offer at the lower of the actual unit output or the desired MW. (Priority: Medium. First reported 2018. Status: Not adopted.)[6]
- 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.)
- 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.)
- 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.)

5 PJM filed proposed changes to the uplift rules with the FERC on October 7, 2025 ("Reform to Energy Uplift Credit Rules," Docket No. ER26-59-000). The Commission Order on December 5, 2025, accepted the PJM Proposal as filed. PJM expects to implement the changes in 2027.

6 Id.

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- 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 and 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.)[7]
- The MMU recommends that PJM improve its advanced scheduling and commitment process in order to implement a transparent process in which units are scheduled and committed economically based on the known constraints prior to the day-ahead market. The multiday advance commitment process needs to address the communication process, the offers used for commitment evaluation, the operating parameters used for commitment evaluation, the financial consequences of commitment and the appropriate uplift rules. (Priority: High. First reported Q2 2026. Status: Not adopted.)

Conclusion

Competitive market outcomes result from energy offers equal to short run marginal costs that incorporate flexible operating parameters. When PJM permits a unit to include inflexible operating parameters in its offer and pays uplift based on those inflexible parameters, there is an incentive for the unit to remain inflexible. The rules regarding operating parameters should be implemented in a way that creates incentives for flexible operations rather than inflexible operations. The standard for paying uplift should be the maximum achievable flexibility, based on OEM standards for the benchmark new entrant unit (CONE unit) in the PJM Capacity Market 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 for inflexibility.

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. 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

7 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).

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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 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 fast start pricing.[8] 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 routinely 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.[9] 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 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. 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.

The MMU has recommended that PJM 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 has paid uplift to units even when they do not operate as requested by PJM, i.e. when units do not follow dispatch.

PJM and the MMU have defined and worked to implement systematic and verifiable rules for determining when units are following dispatch as a

8 Fast start pricing was approved by FERC and implemented on September 1, 2021. See 173 FERC ¶ 61,244 (2020).

9 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).

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primary screen for eligibility for uplift payments. On October 7, 2025, PJM submitted those rules as tariff revisions. The rules address the fact that, under the status quo, resources receive make whole payments for energy produced while not following PJM's dispatch instructions. The rules were approved by FERC on December 5, 2025. PJM expects to implement the rules in the first half of 2027.

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 efficient pricing at short run marginal cost. The goal should be to ensure that only the efficient and required level of energy uplift charges is paid and to ensure that all appropriate transactions pay a share of those charges 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 lost opportunity cost credits, local constraint 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. Black start credits and local constraint credits are not broken out individually and are included in the category of balancing generator credits, matching PJM's Market Settlements Reporting System.

Table 4-1 shows the uplift totals for each credit category during the first nine months of 2025 and 2026.[10] During the first nine months of 2026, energy uplift credits increased by $744.2 million or 112.5 percent compared to the first nine months of 2025. PJM commitment and dispatch decisions associated with the Winter Storm Fern 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, to an output level 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.

10 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 17, 2026.

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Table 4-1 Energy uplift credits by category: January through September, 2025 and 2026[11]

Category	Type	(Jan - Sep) 2025 Credits (Millions)	(Jan - Sep) 2026 Credits (Millions)	Change	Percent Change	2025 Share	2026 Share
Day-Ahead	Generators	$181.4	$336.1	$154.7	85.3%	27.4%	23.9%
Balancing	Generators	$448.6	$850.9	$402.4	89.7%	67.8%	60.5%
	Canceled Resources	$0.0	$0.0	($0.0)	(2.1%)	0.0%	0.0%
	Lost Opportunity Cost	$28.6	$208.9	$180.2	629.3%	4.3%	14.9%
	Dispatch Differential Lost Opportunity Cost	$2.0	$6.9	$4.9	251.9%	0.3%	0.5%
Synchronous Condensing	Synchronous Condensing	$0.0	$0.0	$0.0	0.0%	0.0%	0.0%
	Synchronous Condensing Lost Opportunity Cost	$0.0	$0.0	$0.0	0.0%	0.0%	0.0%
Reactive Services	Day-Ahead	$0.1	$0.2	$0.1	215.7%	0.0%	0.0%
	Generators	$0.5	$2.2	$1.7	312.4%	0.1%	0.2%
	Lost Opportunity Cost	$0.0	$0.0	$0.0	592.8%	0.0%	0.0%
	Condensing	$0.0	$0.0	$0.0	0.0%	0.0%	0.0%
	Condensing Lost Opportunity Cost	$0.0	$0.0	$0.0	0.0%	0.0%	0.0%
Black Start Services	Day-Ahead	$0.0	$0.0	$0.0	0.0%	0.0%	0.0%
	Balancing	$0.4	$0.6	$0.2	36.4%	0.1%	0.0%
	Testing	$0.0	$0.0	$0.0	181.5%	0.0%	0.0%
	Lost Opportunity Cost	$0.0	$0.0	$0.0	0.0%	0.0%	0.0%
Total		$661.6	$1,405.8	$744.2	112.5%	100.0%	100.0%

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. For this reason, operating reserve charges do not always have the same value as operating reserve credits, since not all categories of uplift credits are paid for by the same PJM participants. For example, in the case of local constraint credits, credits are paid to generators in the form of balancing operating reserve credits but charges are allocated as local constraint charges. The same applies in the case of units scheduled day ahead for reactive support, for which the credits are paid in the form of day-ahead operating reserve credits but charges are allocated as reactive services charges. 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

11 Year to year change is rounded to $0.01 million.

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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.

Starting with the *2024 Annual State of the Market Report for PJM*, local constraint credits are not broken out individually and are included in the category of balancing generator credits. Similarly, cancellation charges, lost opportunity charges, and dispatch differential lost opportunity cost charges are not broken out individually and are included in the category of balancing generator charges.

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

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

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

	Credits Category	Charges Category	Charge Responsibility
Reactive	Day-Ahead Operating Reserve	Reactive Services Charge	Zonal Real-Time Load
	Generator Reactive Services		
	LOC Reactive Services	Local Constraint Reactive Services	Transmission owner
	Condensing Reactive Services		
	Synchronous Condensing LOC Reactive Services		
Synchronous Condensing	Synchronous Condensing	Synchronous Condensing	Real-Time Load
	Synchronous Condensing LOC		Real-Time Export Transactions
Black Start	Day-Ahead Operating Reserve	Black Start Service Charge	Zone/Non-zone Peak Transmission Use and Point to Point Transmission Reservations
	Balancing Operating Reserve		
	Black Start Testing		
	Black Start LOC		

Types of Units

Table 4-4 shows the distribution of total energy uplift credits by unit type during the first nine months of 2026 and the first nine months of 2025. A combination of factors led to overall increased uplift payments, including unit specific issues and market issues including high fuel costs and PJM conservative operations during Winter Storm Fern (January 22 through 30, 2026).

Uplift credits paid to combustion turbines increased by $357.5 million or 137.1 percent during the first nine months of 2026 compared to the first nine months of 2025. During the first nine months of 2026, CTs received 69.5 percent of lost opportunity cost credits. Lost opportunity cost credits increased by $180.2 million or 629.3 percent during the first nine months of 2026 compared to the first nine months of 2025.

Uplift credits paid to steam coal units increased by $54.7 million or 114.8 percent during the first nine months of 2026 compared to the first nine months of 2025. During the first nine months of 2026, day-ahead uplift credits in the PEPCO Zone made up 95.4 percent of total day-ahead uplift credits and accounted for 110.6 percent of the increase in day-ahead uplift during the first nine months of 2026, primarily as a result of unit specific issues for the Chalk Point 3 and 4 units. Historically, steam coal units Brandon Shores 1 and 2 received a large share of day-ahead uplift credits, but during the first nine months of 2026 Brandon Shores 1 and 2 did not receive any day-ahead credits, a consequence of their RMR status implemented June 1, 2025, under which these units are only committed and dispatched in real time.

Uplift credits paid to non-coal (gas or oil fired) steam units increased by $215.6 million or 116.8 percent during the first nine months of 2026 compared to the first nine months of 2025. During the first nine months of 2026, gas or oil fired steam units received $400.2 million, 28.5 percent of total credits, compared to $184.5 million, 27.9 percent of total credits during the first nine months of 2025. During the first nine months of 2026, the day-ahead uplift paid to gas or oil fired steam units was 99.5 percent higher than during the first nine months of 2025 and accounted for 103.1 percent of the total increase in day-ahead operating reserves. The increase in day-ahead generator credits paid to gas or oil fired steam units in the PEPCO Zone accounted for 110.0 percent of the overall

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increase in day-ahead generator credits during the first nine months of 2026. In the PEPCO Zone, gas fired steam units Chalk Point 3 and 4 received $327.7 million in uplift during the first nine months of 2026.[12] During Winter Storm Fern, non-coal steam units received $120.7 million, or 30.2 percent of all credits received by non-coal steam units during the first nine months of 2026. Non-coal steam units received 15.7 percent of total uplift credits during the Winter Storm Fern.

Uplift credits paid to combined cycle plants increased by $111.4 million or 70.3 percent during the first nine months of 2026 compared to the first nine months of 2025. This increase occurred primarily in January 2026 as a result of the commitments made in advance of the day-ahead energy market during the Winter Storm Fern. Winter Storm Fern accounted for 84.0 percent of the uplift credits paid to combined cycle plants, and accounted for 54.7 percent of total uplift credits during the first nine months of 2026. During the first nine months of 2026, uplift credits to wind units were $4.5 million, down by 25.2 percent compared to the first nine months of 2025.

Table 4-4 Total energy uplift credits by unit type: January through September, 2025 and 2026[13] [14]

Unit Type	(Jan - Sep) 2025 Credits (Millions)	(Jan - Sep) 2026 Credits (Millions)	Change	Percent Change	(Jan - Sep) 2025 Share	(Jan - Sep) 2026 Share
Combined Cycle	$158.4	$269.9	$111.4	70.3%	23.9%	19.2%
Combustion Turbine	$260.5	$617.8	$357.2	137.1%	39.4%	43.9%
Diesel	$2.7	$5.5	$2.8	105.4%	0.4%	0.4%
Hydro	$0.9	$0.3	($0.7)	(71.9%)	0.1%	0.0%
Nuclear	$0.0	$0.0	$0.0	8,171.1%	0.0%	0.0%
Solar	$0.8	$5.4	$4.6	565.2%	0.1%	0.4%
Steam - Coal	$47.6	$102.3	$54.7	114.8%	7.2%	7.3%
Steam - Other	$184.5	$400.2	$215.6	116.8%	27.9%	28.5%
Wind	$6.0	$4.5	($1.5)	(25.2%)	0.9%	0.3%
Total	$661.6	$1,405.8	$744.2	112.5%	100.0%	100.0%

Table 4-5 shows the distribution of energy uplift credits by category and by unit type during the first nine months of 2026. The largest share of day-ahead credits, 95.2 percent, went to steam units (non-coal and coal). 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 54.2 percent of balancing credits and 69.5 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, 2026

Unit Type	Day-Ahead Generator	Balancing Generator	Canceled Resources	Lost Opportunity Cost	Reactive Services	Synchronous Condensing	Dispatch Differential Lost Opportunity Cost	Black Start Services
Combined Cycle	1.8%	28.1%	0.0%	11.6%	0.0%	0.0%	8.4%	6.7%
Combustion Turbine	1.8%	54.2%	100.0%	69.5%	88.4%	0.0%	38.5%	93.2%
Diesel	0.0%	0.2%	0.0%	1.8%	0.1%	0.0%	0.0%	0.0%
Hydro	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	3.6%	0.0%
Nuclear	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Solar	0.0%	0.0%	0.0%	1.8%	0.0%	0.0%	23.5%	0.0%
Steam - Coal	1.2%	9.0%	0.0%	10.2%	4.9%	0.0%	2.2%	0.0%
Steam - Other	95.2%	8.5%	0.0%	3.6%	6.6%	0.0%	1.6%	0.0%
Wind	0.0%	0.0%	0.0%	1.4%	0.0%	0.0%	22.2%	0.0%
Battery	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Total (Millions)	$336.1	$850.9	$0.0	$208.9	$2.4	$0.0	$6.9	$0.6

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

12 See Table 4-21 in this section.
13 Table 4-4 does not include balancing imports credits and load response credits in the total amounts.
14 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.

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service.[15] 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.[16]

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 27.8 percent during the first nine months of 2026 compared to the first nine months of 2025, increasing from 2,640 GWh in 2025 to 3,374 GWh in 2026. Day-ahead generation committed for reliability by PJM was 473.2 GWh during Winter Storm Fern.

Table 4-6 Day-ahead generation for reliability (GWh): January 2025 through September 2026

	2025			2026			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	82,985	1,158	1.4%	84,236	827	1.0%	(28.6%)
Feb	69,527	178	0.3%	72,667	128	0.2%	(28.4%)
Mar	66,147	200	0.3%	68,849	160	0.2%	(19.9%)
Apr	59,684	169	0.3%	61,846	418	0.7%	147.6%
May	63,112	109	0.2%	64,279	455	0.7%	316.4%
Jun	77,424	332	0.4%	76,152	468	0.6%	41.1%
Jul	89,665	265	0.3%	88,731	325	0.4%	22.3%
Aug	79,768	164	0.2%	84,968	260	0.3%	58.8%
Sep	69,243	65	0.1%	75,368	334	0.4%	413.8%
Oct	62,601	104	0.2%				NA
Nov	64,045	172	0.3%				NA
Dec	79,824	263	0.3%				NA
Total (Jan - Sep)	657,556	2,640	0.4%	677,095	3,374	0.5%	27.8%
Total	864,026	3,180	0.4%	677,095	3,374	0.5%	27.8%

15 See OA Schedule 1 § 3.2.3(b).
16 See OA Schedule 1 § 3.2.3(a).

Pool scheduled units are units that are committed in the day-ahead market based on economics. 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.

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 uplift category. During the first nine months of 2026, 62.9 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 37.1 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. A very small amount, 0.4 GWh or less than 0.1 percent, of day-ahead generation committed for reliability received uplift for reactive services.

Table 4-7 Day-ahead generation committed for reliability by uplift category (GWh): January through September, 2026

	Reactive Services (GWh)	Day-Ahead Operating Reserves (GWh)	Economic (GWh)	Total (GWh)
Jan	0.0	448.5	378.4	826.9
Feb	0.0	96.6	31.1	127.7
Mar	0.0	133.2	26.7	159.9
Apr	0.0	263.0	154.8	417.8
May	0.0	198.8	256.0	454.7
Jun	0.0	304.1	164.3	468.4
Jul	0.0	297.1	27.5	324.6
Aug	0.0	187.3	73.1	260.4
Sep	0.4	193.6	139.8	333.8
Total (Jan - Sep)	0.4	2,122.1	1,251.6	3,374.2
Share	0.0%	62.9%	37.1%	100.0%

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Balancing Uplift (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 lost opportunity 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 hourly segments 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 4-1 shows that balancing generator credits increased by 402.4 million or 89.7 percent during the first nine months of 2026 compared to the first nine months of 2025. Table 4-5 shows that combustion turbines (CTs) received 54.2 percent of balancing generator credits in during the first nine months of 2026, or $461.3 million. Combined cycle plants (CCs) received 28.1 percent of balancing generator credits during the first nine months of 2026, or $238.9 million. During Winter Storm Fern, CTs received $402.1 million in balancing generator credits while CCs received $226.9 million in balancing generator credits.

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. Units should be disqualified from receiving uplift when the units do not follow dispatch instructions, block load or self schedule.

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. 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.

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.[17] 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.

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

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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.

Table 4-8 shows monthly day-ahead and real-time LOC credits during 2025 and the first nine months of 2026. During the first nine months of 2026, LOC credits increased by $180.9 million or 622.3 percent compared to the first nine months of 2025. The overall increase included a $124.6 million increase in day-ahead LOC and a $56.3 million increase in real-time LOC.

During the first nine months of 2026, wind units received $3.0 million of lost opportunity cost credits, down $3.0 million compared to the first nine months of 2025. 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 capacity resources 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 use the lowest of the desired output, the estimated output based on actual wind conditions, and the capacity interconnection rights (CIRs) as the definition of the foregone opportunity.

Table 4-8 Monthly lost opportunity cost credits[18] [19][20] (Millions): January 2025 through September 2026

	2025			2026		
	Day-Ahead Lost Opportunity Cost	Real-Time Lost Opportunity Cost	Total	Day-Ahead Lost Opportunity Cost	Real-Time Lost Opportunity Cost	Total
Jan	$2.6	$4.5	$7.0	$74.2	$17.1	$91.3
Feb	$0.1	$0.4	$0.5	$9.4	$9.7	$19.1
Mar	$0.7	$1.5	$2.1	$6.1	$3.3	$9.4
Apr	$1.1	$1.0	$2.1	$6.6	$1.2	$7.8
May	$2.0	$0.1	$2.2	$6.2	$1.5	$7.7
Jun	$5.5	$1.4	$7.0	$7.4	$2.9	$10.4
Jul	$2.4	$0.6	$3.1	$18.7	$12.0	$30.8
Aug	$1.7	$0.4	$2.1	$4.7	$1.8	$6.5
Sep	$2.8	$0.2	$2.9	$10.1	$17.0	$27.1
Oct	$2.7	$0.2	$2.9			
Nov	$1.2	$0.7	$1.9			
Dec	$4.4	$5.2	$9.6			
Total (Jan - Sep)	$18.9	$10.2	$29.1	$143.5	$66.5	$210.0
Share (Jan - Sep)	65.1%	34.9%	100.0%	68.3%	31.7%	100.0%
Total	$27.2	$16.2	$43.4	$143.5	$66.5	$210.0
Share	62.7%	37.3%	100.0%	68.3%	31.7%	100.0%

18 Table 4-8 does not include pumped hydro lost opportunity cost credits in Real-Time Lost Opportunity Cost Credits.
19 Table 4-8 includes CT lost opportunity cost forfeiture in the Day-Ahead Lost Opportunity Cost. *See* "MSRS Report Format Documentation: CT Lost Opportunity Cost Forfeiture, version 5," for more details <https://www.pjm.com/markets-and-operations/billing-settlements-and-credit/msrs-reports-documentation.aspx>.
20 Table 4-1 and Table 4-8 are based on PJM Settlements reports that are updated by PJM with different resettlement bill cycles. As a result, the values in these tables may not match.

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Energy Uplift Charges

Energy Uplift Charges

Table 4-9 shows that energy uplift charges for the first nine months of 2026 were $1,405.7 million, or 1.6 percent of total PJM billing.[21]

Table 4-9 Total energy uplift charges: 2001 through September 2026

	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	$270.0	$111.3	70.1%	0.5%
2025	$766.4	$607.7	382.9%	1.0%
2026 (Jan - Sep)	$1,405.7	$639.4	83.4%	1.6%

Table 4-10 shows total energy uplift charges by category for the first nine months of 2025 and 2026. The increase of $744.2 million is comprised of a $154.6 million increase in day-ahead uplift (operating reserve) charges, a $587.2 million increase in balancing generator charges, a $1.8 million increase in reactive service charges, $0.2 million in black start service charges, and a $0.4 million increase in local congestion charges.

Table 4-10 Total energy uplift charges by category: January through September, 2025 and 2026[22]

Category	(Jan - Sep) 2025 Charges (Millions)	(Jan - Sep) 2026 Charges (Millions)	Change (Millions)	Percent Change
Day-Ahead Operating Reserves	$181.4	$336.0	$154.6	85.2%
Balancing Operating Reserves	$479.1	$1,066.2	$587.2	122.6%
Reactive Services	$0.6	$2.4	$1.8	306.2%
Black Start Services	$0.4	$0.6	$0.2	37.8%
Local Congestion Charges	$0.1	$0.5	$0.4	307.5%
Total	$661.6	$1,405.7	$744.2	112.5%
Energy Uplift as a Percent of Total PJM Billing	1.1%	1.6%	1.4%	118.3%

21 Charges and credits may not match exactly because while most credits are charged to market participants, some smaller categories are charged to the transmission owner and therefore not included in the charges.

22 The total PJM billing used in Table 4-10 is different from the total cost shown in Table 1-9. The total PJM billing in Table 4-10 represents the total dollars that pass through the PJM settlement process, while the total cost shown in Table 1-9 is the total cost to load and includes additional costs to load accounted for outside the PJM settlement process.

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Table 4-11 compares monthly energy uplift charges by category for 2025 through the first nine months of 2026.

Table 4-11 Monthly energy uplift charges: January 2025 through September 2026

	2025 Charges (Millions)						2026 Charges (Millions)					
	Day-Ahead	Balancing	Reactive Services	Local Congestion	Black Start Services	Total	Day-Ahead	Balancing	Reactive Services	Local Congestion	Black Start Services	Total
Jan	$153.9	$246.3	$0.0	$0.1	$0.0	$400.3	$177.3	$682.8	$0.0	$0.0	$0.0	$860.1
Feb	$2.5	$33.6	$0.0	$0.0	$0.1	$36.2	$31.1	$56.39	$0.1	$0.3	$0.2	$88.2
Mar	$6.1	$28.6	$0.5	$0.0	$0.1	$35.3	$2.3	$32.21	$0.0	$0.0	$0.1	$34.6
Apr	$3.9	$36.6	$0.0	$0.0	$0.1	$40.6	$6.0	$39.23	$0.0	$0.1	$0.1	$45.4
May	$2.9	$16.6	$0.0	$0.0	$0.0	$19.6	$6.8	$48.26	$1.9	$0.0	$0.1	$57.1
Jun	$5.8	$31.5	$0.0	$0.0	$0.0	$37.3	$15.5	$32.94	$0.1	$0.0	$0.1	$48.6
Jul	$2.3	$45.8	$0.0	$0.0	$0.0	$48.1	$67.3	$77.74	$0.0	$0.0	$0.0	$145.1
Aug	$3.1	$24.1	$0.0	$0.0	$0.0	$27.1	$6.0	$34.75	$0.0	$0.0	$0.0	$40.8
Sep	$0.9	$16.1	$0.0	$0.0	$0.0	$17.1	$23.7	$61.91	$0.2	$0.0	$0.0	$85.9
Oct	$0.6	$19.6	$0.0	$0.1	$0.0	$20.4						
Nov	$0.7	$32.2	$0.0	$0.0	$0.1	$33.0						
Dec	$18.2	$33.0	$0.0	$0.0	$0.0	$51.3						
Total (Jan - Sep)	$181.4	$479.1	$0.6	$0.1	$0.4	$661.6	$336.0	$1,066.2	$2.4	$0.5	$0.6	$1,405.7
Share (Jan - Sep)	27.4%	72.4%	0.1%	0.0%	0.1%	100.0%	23.9%	75.8%	0.2%	0.0%	0.0%	100.0%
Total	$200.9	$564.0	$0.7	$0.3	$0.5	$766.4	$336.0	$1,066.2	$2.4	$0.5	$0.6	$1,405.7
Share	26.2%	73.6%	0.1%	0.0%	0.1%	100.0%	23.9%	75.8%	0.2%	0.0%	0.0%	100.0%

Table 4-12 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 $339.4 million or 103.4 percent during the first nine months of 2026 compared to the first nine months of 2025. The balancing operating reserve charges for reliability and deviation do not include the balancing local constraint charges or the dispatch differential lost opportunity cost charges, which must be added separately to get the total balancing operating reserve charges. For example, during the first nine months of 2026 the balancing operating reserve charges and local congestion charges in Table 4-10 were $1,066.2 million and $0.5 million. The sum is equal to $1,066.8, which is the total of the balancing operating reserve reliability charges, the balancing operating reserve reliability charges, the balancing local constraint charges, and the dispatch different lost opportunity cost charges during the first nine months of 2026 in Table 4-12.

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Table 4-12 Balancing operating reserve charges: January through September, 2025 and 2026

Category	(Jan - Sep) 2025 Charges (Millions)	(Jan - Sep) 2026 Charges (Millions)	Change	Percent Change	2025 Share	2026 Share
Balancing Operating Reserve Reliability Charges	$328.1	$667.6	$339.4	103.4%	68.5%	62.6%
Balancing Operating Reserve Deviation Charges	$149.0	$391.8	$242.8	163.0%	31.1%	36.7%
Balancing Local Constraint Charges	$0.1	$0.5	$0.4	307.5%	0.0%	0.0%
Dispatch Differential Lost Opportunity Cost	$2.0	$6.9	$4.9	251.9%	0.4%	0.6%
Total	$479.2	$1,066.8	$587.6	122.6%	100.0%	100.0%

Table 4-13 shows the balancing operating reserve deviation charges by category for the first nine months of 2025 and the first nine months of 2026. Balancing operating reserve charges for deviations are allocated to virtual bids, UTCs, load, and interchange. The deviation charges attributed to generators during the first nine months of 2026 were $608.3 million, or 232.1 percent higher than during the first nine months of 2025. Deviation charges attributed to lost opportunity costs during the first nine months of 2026 were $209.6 million, or 549.9 percent higher than during the first nine months of 2025, and deviation charges attributed to dispatch differential lost opportunity costs during the first nine months of 2026 were $6.9 million, or 251.9 percent higher than during the first nine months of 2025.

Table 4-13 Balancing operating reserve deviation charges: January through September, 2025 and 2026

Source of Balancing Operating Reserve	(Jan - Sep) 2025 Charges (Millions)	(Jan - Sep) 2026 Charges (Millions)	Change (Millions)	Percent Change	(Jan - Sep) 2025 Share	(Jan - Sep) 2026 Share
Generators	$149.0	$391.8	$242.8	163.0%	81.3%	64.4%
Lost Opportunity Costs	$32.3	$209.6	$177.4	549.9%	17.6%	34.5%
Dispatch Differential Lost Opportunity Costs	$2.0	$6.9	$4.9	251.9%	1.1%	1.1%
Canceled Resources	$0.0	$0.0	($0.0)	-2.1%	0.0%	0.0%
Total	$183.2	$608.3	$425.1	232.1%	100.0%	100.0%

Table 4-14 shows additional energy uplift charges by category for the first nine months of 2025 and the first nine months of 2026. Reactive service charges during the first nine months of 2026 increased by 75.4 percent compared to the first nine months of 2025, and black start service charges increased by 27.4 percent compared to the first nine months of 2025. During the first nine months of 2026, reactive services made up 80.5 percent of additional charges and black start services charges made up 19.5 percent.

Table 4-14 Additional energy uplift charges: January through September, 2025 and 2026

Type	(Jan - Sep) 2025 Charges (Millions)	(Jan - Sep) 2026 Charges (Millions)	Change (Millions)	Percent Change	(Jan - Sep) 2025 Share	(Jan - Sep) 2026 Share
Reactive Services Charges	$0.6	$2.4	$1.8	75.4%	19.8%	80.5%
Black Start Services Charges	$0.4	$0.6	$0.2	27.4%	14.1%	19.5%
Total	$1.0	$3.0	$2.0	66.0%	34.0%	100.0%

Operating Reserve Rates

Under the operating reserves cost allocation rules, PJM calculates ten 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 4-15 shows a breakdown of operating reserve rates first nine months of 2025 and the first nine months of 2026. The operating reserve rates are calculated on a daily basis, and the table provides the minimum, maximum, and average value during the first nine months of both 2025 and 2026. Balancing operating reserve charges for reliability cover a part of the balancing generator credits, and therefore the reliability rates are elevated when balancing generator credits are high, as was the case with Winter Storm Fern. The RTO region, which includes the East and West regions plus exports that are at the interfaces or hubs not completely contained in either the East or West region, has an elevated reliability rate in the first nine months of 2026 due to high balancing operating reserve credits that were paid to units during Winter Storm Fern.

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Table 4-15 Operating reserve rates ($/MWh): January through September, 2025 and 2026

Rate	(Jan - Sep) 2025 Avg ($/MWh)	(Jan - Sep) 2025 Min ($/MWh)	(Jan - Sep) 2025 Max ($/MWh)	(Jan - Sep) 2026 Avg ($/MWh)	(Jan - Sep) 2026 Min ($/MWh)	(Jan - Sep) 2026 Max ($/MWh)	Difference of Avg ($/MWh)	Percent Difference of Avg
Day-Ahead	0.000	(0.000)	0.006	0.000	(0.000)	0.005	0.000	84.0%
RTO Reliability	0.491	0.000	22.978	0.978	0.000	55.837	0.487	99.2%
East Reliability	0.026	0.000	0.850	0.040	0.000	0.667	0.015	56.5%
West Reliability	0.002	0.000	0.144	0.009	0.000	0.313	0.007	394.7%
RTO Deviation	0.520	0.000	0.020	1.290	0.000	0.017	0.771	148.4%
East Deviation	0.259	0.000	2.604	0.971	0.000	10.493	0.712	274.7%
West Deviation	0.018	0.000	0.701	0.031	0.000	0.454	0.014	76.8%
Lost Opportunity Cost	0.105	0.000	2.227	0.831	0.000	31.756	0.726	687.9%
Canceled Resources	0.000	0.000	0.020	0.000	0.000	0.017	0.000	2.8%
Dispatch Differential Lost Opportunity Cost	0.003	0.000	0.022	0.010	0.000	0.851	0.007	243.6%

Table 4-16 shows 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. The INCs are responsible for paying the RTO deviation rate, the regional deviation rate, the LOC rate, and the canceled resources rate.

Table 4-16 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 Rate	X								
Black Start Services	Implicit Rate	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.

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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 4-17 provides a description of commitment and dispatch status, uplift eligibility and the ability to set price.[23] 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. [24]

Table 4-17 Dispatch status, commitment status and uplift eligibility[25]

		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

23 PJM has modified the basic rules of eligibility to set price using its CT price setting logic.

24 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.

25 PJM allows block loaded CTs to set LMP by relaxing the economic minimum by 10 to 20 percent using CT price setting logic.

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.[26] 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, and 0.9 percent are waiting for a PJM response. The remaining 77.1 percent occurred prior to October 2024 and are 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.[27] 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.

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 (uplift) when they are scheduled on their price-based offers during maximum generation conditions and their effective energy offer price exceeds $1,000 per MWh.[28] 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 the first nine months of 2026, PJM declared maximum generation conditions on January 27, May 18-20, July 1-3, July 15-16, September 1-3,

26 To date, the MMU has only requested resettlement of the most egregious cases.

27 OATT § 10.4.

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

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and September 17. On January 27, during Winter Storm Fern, uplift forfeiture was triggered for some units in the day-ahead market but not in the balancing market. On May 19, July 2, and September 1, uplift forfeiture was triggered for some units in the balancing market but not in the day-ahead market. On July 3 and July 16, uplift forfeiture was triggered for units in both the day-ahead and balancing market. The uplift forfeiture rule was triggered because these units received uplift that resulted in an effective energy payment that exceeded $1,000 per MWh. In 2025, PJM declared maximum generation conditions for January 22, June 23-25, July 15-16, July 24-25, and July 28-30. The uplift forfeiture rule was triggered on June 23-24, July 15-16, and July 24. As a result of the uplift forfeiture rule, some operating reserve uplift payments that would have been paid on the days uplift forfeiture was triggered were not paid.

Regulation Market Offsets

PJM does not include regulation market payments as an offset like other market revenues in the operating reserve calculations, although it should be included. Including regulation market revenues would result in lower uplift. Table 4-18 shows that the regulation market revenues in the first nine months of 2026 were $538.5 million and that the balancing generator credits for those units receiving regulation revenues were $47.4 million. The table shows that if the regulation market revenues had been incorporated in the operating reserve calculation as an offset, the balancing generator payment for those units would have been $42.7 million instead of $47.4 million, $4.8 million lower, or 10.0 percent. The impact of including the regulation market revenue as an offset in the uplift payment would result in a relatively small reduction in uplift payments because not all units receiving regulation market payments also received balancing operating reserve payments on the same days.

Table 4-18 Adjusted operating reserve credits: January through September, 2026

Month	Regulation Market Revenues (Millions)	Balancing Generator Credits (Millions)	Adjusted Balancing Generator Credits (Millions)	Difference
Jan	$61.8	$39.0	$37.6	($1.4)
Feb	$79.0	$2.6	$1.5	($1.1)
Mar	$47.2	$0.4	$0.3	($0.1)
Apr	$46.6	$1.0	$0.7	($0.2)
May	$46.5	$0.9	$0.5	($0.4)
Jun	$82.3	$0.5	$0.4	($0.2)
Jul	$89.9	$1.7	$1.0	($0.7)
Aug	$44.2	$0.2	$0.1	($0.1)
Sep	$41.0	$1.1	$0.4	($0.7)
Oct	$0.0	$0.0	$0.0	$0.0
Nov	$0.0	$0.0	$0.0	$0.0
Dec	$0.0	$0.0	$0.0	$0.0
Total	$538.5	$47.4	$42.7	($4.8)

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.[29]

Table 4-19 shows the concentration of energy uplift credits by unit. During the first nine months of 2026, the top 10 units received $544.6 million in energy uplift credits, 38.7 percent of total energy uplift credits. During the first nine months of 2025, the top 10 units received $247.5 million in energy uplift credits, 37.4 percent of total energy uplift credits.

29 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.

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Table 4-19 Top 10 units energy uplift credits: January through September, 2026

Category	Type	(Jan - Jun) 2025 Credits (Millions)	(Jan - Jun) 2026 Credits (Millions)	Change	Percent Change	2025 Share	2026 Share
Day-Ahead	Generators	$175.6	$326.7	$151.1	86.0%	96.8%	97.2%
Balancing	Canceled Resources	$0.0	$0.0	($0.0)	(2.1%)	100.0%	100.0%
	Generators	$88.0	$252.0	$164.0	186.4%	19.6%	29.6%
	Lost Opportunity Cost	$6.4	$41.3	$34.9	543.1%	22.4%	19.8%
	Dispatch Differential Lost Opportunity Cost	$1.0	$1.9	$0.9	89.3%	50.3%	27.1%
	Total Balancing	$95.4	$295.2	$199.7	209.4%	19.9%	27.7%
Reactive Services		$0.6	$2.2	$1.6	290.0%	94.7%	90.9%
Blackstart Services		$0.2	$0.3	$0.1	72.7%	37.8%	47.4%
Total		$247.5	$544.6	$297.1	120.0%	37.4%	38.7%

Table 4-20 shows the concentration of uplift credits by company. During the first nine months of 2026, the top 10 companies received $1,073.5 million in energy uplift credits, 76.4 percent of total energy uplift credits. During the first nine months of 2025, the top 10 companies received $466.1 million in energy uplift credits, 70.4 percent of total energy uplift credits.

Table 4-20 Top 10 orgs energy uplift credits: January through September, 2026

Category	Type	(Jan - Jun) 2025 Credits (Millions)	(Jan - Jun) 2026 Credits (Millions)	Change	Percent Change	2025 Share	2026 Share
Day-Ahead	Generators	$179.9	$333.8	$153.9	85.5%	99.2%	99.3%
Balancing	Canceled Resources	$0.0	$0.0	($0.0)	(2.1%)	100.0%	100.0%
	Generators	$285.7	$632.9	$347.2	121.5%	63.7%	74.4%
	Lost Opportunity Cost	$19.7	$138.6	$118.9	604.8%	68.7%	66.4%
	Dispatch Differential Lost Opportunity Cost	$1.6	$5.1	$3.5	225.9%	79.9%	74.0%
	Total Balancing	$306.9	$776.6	$469.7	153.0%	64.1%	72.8%
Reactive Services		$0.6	$2.4	$1.8	306.2%	100.0%	100.0%
Blackstart Services		$0.4	$0.6	$0.2	44.0%	92.1%	0.0%
Total		$466.1	$1,073.5	$607.5	130.3%	70.4%	76.4%

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Unit Specific Uplift Payments

FERC Order No. 844 allows PJM and the MMU to publish unit specific uplift payments by category by month. Table 4-21 through Table 4-25 show the top 10 recipients of total uplift, day-ahead operating reserve credits, lost opportunity cost credits, and dispatch differential lost opportunity credits.

Chalk Point 3 and 4 are non-coal steam units in the PEPCO Zone with an ICAP of 582 MW each. In the first nine months of 2026, Chalk Point 3 and 4 received a combined total of $327.7 million in uplift credits or 23.3 percent of total uplift credits, including $318.6 million in day-ahead operating reserve credits or 94.8 percent of total day-ahead operating reserve credits. In the first nine months of 2025, Chalk Point 3 and 4 received a combined total of $152.2 million in uplift credits or 23.0 percent of total uplift credits, including $148.3 million in day-ahead operating reserve credits or 81.8 percent of total day-ahead operating reserve credits.

Table 4-21 Top 10 recipients of total uplift: January through September, 2026

Rank	Unit Name	Zone	Total Uplift Credit	Share of Total Uplift Credits
1	PEP CHALKPOINT 4 F	PEPCO	$186,166,304	13.2%
2	PEP CHALKPOINT 3 F	PEPCO	$141,576,725	10.1%
3	BC BRANDON SHORES 2 F	BGE	$34,610,807	2.5%
4	BC BRANDON SHORES 1 F	BGE	$33,619,800	2.4%
5	JC REDOAK 1 CC	JCPL	$33,245,590	2.4%
6	ACE WEST DEPTFORD CROWN POINT 1 CC	AECO	$25,843,204	1.8%
7	PE PHILLIPS ISL LINWOOD 1 CC	PECO	$23,602,871	1.7%
8	BC WAGNER 3 F	BGE	$23,458,175	1.7%
9	COM 940 CORDOVA 3 CC	COMED	$21,861,056	1.6%
10	COM 900 ELWOOD 5 CT	COMED	$20,611,915	1.5%
Total of Top 10			$544,596,447	38.7%
Total Uplift Credits			$1,405,769,602	100.0%

Table 4-22 Top 10 recipients of day-ahead generation credits: January through September, 2026

Rank	Unit Name	Zone	Day-Ahead Operating Reserve Credit	Share of Day-Ahead Operating Reserve Credits
1	PEP CHALKPOINT 4 F	PEPCO	$179,408,546	53.4%
2	PEP CHALKPOINT 3 F	PEPCO	$139,154,061	41.4%
3	VP ROSEMARY IPP 1 F	DOM	$2,452,875	0.7%
4	VP CLOVER 1 F	DOM	$1,814,489	0.5%
5	PEP ST CHARLES-KELSON RIDGE 2 CC	PEPCO	$938,975	0.3%
6	PEP ST CHARLES-KELSON RIDGE 1 CC	PEPCO	$848,994	0.3%
7	PL MONTOUR 1 F	PPL	$626,466	0.2%
8	DPL VIENNA 8 F	DPL	$565,438	0.2%
9	ME BIRDSBORO 1 CC	METED	$432,756	0.1%
10	COM 951 AURORA 3 CT	COMED	$432,204	0.1%
Total of Top 10			$326,674,804	97.2%
Total day-ahead operating reserve credits			$336,086,590	100.0%

Table 4-23 Top 10 recipients of balancing generator credits: January through September, 2026

Rank	Unit Name	Zone	Balancing Generator Credits	Share of Balancing Generator Credits
1	BC BRANDON SHORES 2 F	BGE	$34,328,860	10.2%
2	BC BRANDON SHORES 1 F	BGE	$33,579,633	10.0%
3	JC REDOAK 1 CC	JCPL	$33,160,949	9.9%
4	ACE WEST DEPTFORD CROWN POINT 1 CC	AECO	$25,812,403	7.7%
5	BC WAGNER 3 F	BGE	$23,457,992	7.0%
6	PE PHILLIPS ISL LINWOOD 1 CC	PECO	$23,083,345	6.9%
7	COM 940 CORDOVA 3 CC	COMED	$21,858,738	6.5%
8	COM 900 ELWOOD 5 CT	COMED	$20,548,714	6.1%
9	BC WAGNER 4 F	BGE	$18,768,019	5.6%
10	COM 900 ELWOOD 7 CT	COMED	$17,389,264	5.2%
Total of Top 10			$251,987,917	29.6%
Total balancing operating reserve credits			$850,946,936	100.0%

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Table 4-24 Top 10 recipients of lost opportunity cost credits: January through September, 2026

Rank	Unit Name	Zone	Lost Opportunity Cost Credits	Share of Lost Opportunity Cost Credits
1	PEP DICKERSON H 1 CT	PEPCO	$5,315,443	2.5%
2	VP FOUR RIVERS 1 CT	DOM	$4,901,288	2.3%
3	VP LOUISA 5 CT	DOM	$4,773,346	2.3%
4	VP MARSHRUN 1 CT	DOM	$4,439,456	2.1%
5	VP DOSWELL 2 CT	DOM	$4,083,340	2.0%
6	PEP DICKERSON H 2 CT	PEPCO	$4,038,072	1.9%
7	VP MARSHRUN 3 CT	DOM	$4,000,326	1.9%
8	AEP AMOS 3 F	AEP	$3,614,687	1.7%
9	EKPC BLUEGRASS 2 CT	XIC	$3,153,680	1.5%
10	VP MARSHRUN 2 CT	DOM	$2,972,438	1.4%
Total of Top 10			$41,292,077	19.8%
Total lost opportunity cost credits			$208,859,963	100.0%

Table 4-25 Top 10 recipients of dispatch differential lost opportunity cost credits: January through September, 2026

Rank	Unit Name	Zone	Dispatch Differential Lost Opportunity Cost Credits	Share of Dispatch Differential Lost Opportunity Cost Credits
1	AEP CADENCE 1 SP	AEP	$844,059	12.3%
2	COM 942 NELSON 2 CC	COMED	$150,448	2.2%
3	AEP RIVERSTART 1 SP	AEP	$130,638	1.9%
4	VP DOSWELL 2 CT	DOM	$128,631	1.9%
5	AEP RIVERSTART 3 SP	AEP	$122,268	1.8%
6	COM 951 AURORA 1 CT	COMED	$104,807	1.5%
7	COM LONE TREE 3 WF	COMED	$100,844	1.5%
8	COM PILOT HILL 1 WF	COMED	$98,758	1.4%
9	COM MENDOTA HILLS 1 WF	COMED	$92,773	1.3%
10	VP DOSWELL 3 CT	DOM	$90,513	1.3%
Total of Top 10			$1,863,740	27.1%
Total dispatch differential lost opportunity cost credits			$6,885,761	100.0%

Reliability Must Run Units

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.

Brandon Shores 1 and Brandon Shores 2 and Wagner 3 and Wagner 4 submitted retirement notifications to PJM and the MMU in April and October of 2023. PJM determined that these resources were needed for reliability until transmission upgrades can be completed. Brandon Shores 1 and Brandon Shores 2 and Wagner 3 and Wagner 4 began providing Reliability Must Run (RMR) Service on June 1, 2025.[30] [31] When PJM requests the units to operate, they are paid LMP and receive uplift as balancing generator credits.

Table 4-26 shows Pre-RMR and RMR uplift credits for Brandon Shores 1 and Brandon Shores 2 and Wagner 3 and Wagner 4 in 2025 and during the first nine months of 2026. In the first five months of 2025, Brandon Shores 1 and Brandon Shores 2 and Wagner 3 and Wagner 4 were capacity resources in the PJM market and received a total of $19.9 million in day-ahead generator credits and $3.7 million in balancing generator credits. In the last seven months of 2025, Brandon Shores 1 and Brandon Shores 2 and Wagner 3 and Wagner 4 began providing RMR service and received $0.0 million in day-ahead generator credits and $41.4 million in balancing generator credits. During the first nine months of 2026, Brandon Shores 1 and Brandon Shores 2 and Wagner 3 and Wagner 4 received $0.0 million in day-ahead generator credits, $110.1 million in balancing generator credits and $0.3 million in lost opportunity cost credits.

The shift from day-ahead generator credits to balancing generator credits was a result of the RMR service. When providing RMR service the units are made unavailable in the day-ahead and real-time markets and are committed by PJM for reliability. Commitments are often made after the day-ahead market

30 See further discussion of RMR units in the *2026 Quarterly State of the Market Report for PJM: January through June*, Section 5: Capacity Market, at p 105.

31 *See* 191 FERC ¶ 61,098 (2025), *reh'g denied*, 191 FERC ¶ 62,189 (2025).

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has closed and with no day-ahead commitment the units are paid uplift in the balancing market. Units committed in advance of the day-ahead market should be made available and committed for reliability in the day-ahead by PJM.

Table 4-26 Uplift credits for Brandon Shores and Wagner by RMR status

RMR Status		Unit	Day-Ahead Generator Credits (Millions)	Balancing Generator Credits (Millions)	Lost Opportunity Cost Credits (Millions)	Dispatch Differential Lost Opportunity Cost Credits (Millions)	Total Credits (Millions)
2025	Pre-RMR (Jan - May)	BC WAGNER 3 F	$3.3	$0.2	$0.0	$0.0	$3.5
		BC WAGNER 4 F	$1.5	$0.5	$0.0	$0.0	$1.9
		BC BRANDON SHORES 1 F	$6.5	$1.2	$0.0	$0.0	$7.7
		BC BRANDON SHORES 2 F	$8.6	$1.9	$0.0	$0.0	$10.5
		Total	$19.9	$3.7	$0.0	$0.0	$23.6
	RMR (Jun - Dec)	BC WAGNER 3 F	$0.0	$9.4	$0.0	$0.0	$9.4
		BC WAGNER 4 F	$0.0	$1.7	$0.0	$0.0	$1.7
		BC BRANDON SHORES 1 F	$0.0	$20.8	$0.0	$0.0	$20.8
		BC BRANDON SHORES 2 F	$0.0	$9.5	$0.0	$0.0	$9.5
		Total	$0.0	$41.4	$0.0	$0.0	$41.4
2026	RMR (Jan - Sep)	BC WAGNER 3 F	$0.0	$23.5	$0.0	$0.0	$23.5
		BC WAGNER 4 F	$0.0	$18.8	$0.0	$0.0	$18.8
		BC BRANDON SHORES 1 F	$0.0	$33.6	$0.0	$0.0	$33.6
		BC BRANDON SHORES 2 F	$0.0	$34.3	$0.3	$0.0	$34.6
		Total	$0.0	$110.1	$0.3	$0.0	$110.5

Department of Energy (DOE) 202(c) Orders

Wagner 4 has an operating limitation on the maximum number of hours per year the unit can run while burning oil. On May 21, 2026, the Department of Energy ("DOE") authorized PJM to dispatch Wagner 4 beyond its operating limits for the calendar year when necessary for reliability. On August 19, 2026, the DOE extended the order through November 17, 2026.[32]

Eddystone 3 and 4 are dual fuel (natural gas and oil) steam units in PECO with an ICAP of 380 MW each. Eddystone 3 and Eddystone 4 planned to retire on May 31, 2025. On May 30, 2025, the DOE ordered that the operational availability and economic dispatch of Eddystone 3 and Eddystone 4 were necessary to meet resource adequacy and serve the public interest.[33] Eddystone 3 and Eddystone 4 remained in operation and are currently scheduled to continue operation until August 22, 2026.[34] Eddystone 3 and 4 are not offered into the day-ahead energy market. When PJM requests the units to operate, they are paid LMP and receive uplift as balancing generator credits.

Table 4-27 shows Pre-202(c) and 202(c) uplift credits for Eddystone 3 and Eddystone 4 in 2025 and during the first nine months of 2026. In the first five months of 2025, Eddystone 3 and Eddystone 4 were capacity resources in the PJM market and received a total of $3.8 million in balancing generator credits. In the last

32 Department of Energy, Order No. 202-25-6A (October 24, 2025), <https://www.energy.gov/sites/default/files/2025-10/202c%20Order%20No.%20202-25-6A_0.pdf>
33 16 U.S.C. § 824a(c).
34 Department of Energy, Order No. 202-26-24 (May 21, 2026), <https://www.energy.gov/documents/doe-emergency-order-202-26-24>.

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seven months of 2025, Eddystone 3 and Eddystone 4 remained in operation due to the 202(c) orders and received $0.9 million in balancing generator credits. During the first nine months of 2026, Eddystone 3 and Eddystone 4 remained in operation due to the 202(c) order and received $1.1 million in balancing generator credits.

Table 4-27 Uplift credits for Eddystone by 202c status

202c Status		Unit	Day-Ahead Generator Credits (Millions)	Balancing Generator Credits (Millions)	Lost Opportunity Cost Credits (Millions)	Dispatch Differential Lost Opportunity Cost Credits (Millions)	Total Credits (Millions)
2025	Pre-202(c) (Jan - May)	PE EDDYSTONE 3 F	$0.0	$2.0	$0.0	$0.0	$2.0
		PE EDDYSTONE 4 F	$0.0	$1.8	$0.0	$0.0	$1.8
		Total	$0.0	$3.8	$0.0	$0.0	$3.8
	202(c) (Jun - Dec)	PE EDDYSTONE 3 F	$0.0	$0.4	$0.1	$0.0	$0.5
		PE EDDYSTONE 4 F	$0.0	$0.5	$0.0	$0.0	$0.5
		Total	$0.0	$0.9	$0.1	$0.0	$1.0
2026	202(c) (Jan - Sep)	PE EDDYSTONE 3 F	$0.0	$0.6	$0.0	$0.0	$0.6
		PE EDDYSTONE 4 F	$0.0	$0.5	$0.0	$0.0	$0.5
		Total	$0.0	$1.1	$0.0	$0.0	$1.1

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.[35] 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 4-28 shows day-ahead operating reserve credits paid to committed and dispatched units called on the first nine months of 2026, classified by commitment schedule type. Units using price-based offers with parameter limited schedules received $1.9 million or 0.6 percent of day-ahead operating reserve credits. In the first nine months of 2026, units using price-based offers received $6.9 million or 2.0 percent, and units using cost-based offers received $327.3 or 97.4 percent.

Table 4-28 Day-ahead operating reserve credits by Offer Type: January through September, 2026

Offer Type	Day Ahead Operating Reserve Credits (Millions)	Share of DAOR
Cost	$327.3	97.4%
Price	$6.9	2.0%
PLS	$1.9	0.6%
Total	$336.1	100.0%

Table 4-29 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 require the use of parameter limited schedules (PLS) to prevent the exercise of market power through the use of inflexible parameters. Of all the day-ahead credits received during days with weather alerts, 97.6 percent went to units that were committed on cost schedules, which are parameter limited, 0.3 percent went to units that were committed on price PLS schedules, 1.3 percent went to units committed on price schedules less flexible than PLS, and 0.9 percent on price schedules as flexible as PLS. In the first nine months of 2026, including both cost and price schedules, 98.7 percent of day-ahead credits received during days with weather alerts went to units that were committed on a schedule that was as flexible as PLS. These results indicate a significant change in PJM's commitment approach during weather alerts. In 2024, PJM committed 17.2 percent of units on schedules less flexible than PLS during weather alert days. Starting in 2025, PJM began scheduling units in advance of the day-ahead market to ensure reliability. In 2025, PJM committed only 1.5 percent of units on schedules less flexible than PLS during weather alert days. During the first nine months of 2026, PJM committed 1.3 percent of units on schedules less flexible than PLS during weather alert days.

35 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>.

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Table 4-29 Day-ahead operating reserve credits during weather alerts by commitment schedule: January through September, 2026

Commitment Type During Hot and Cold Weather Alerts	Day Ahead Operating Reserve Credits	Share of DAOR during emergency alerts
Committed on cost (cost capped)	$194,378,344	97.6%
Committed on price schedule as flexible as PLS	$502,295	0.3%
Committed on price schedule less flexible than PLS	$2,587,797	1.3%
Committed on price PLS	$1,770,209	0.9%
Total	$199,238,646	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.[36] Temporary exceptions apply to cost based schedules and price based PLS schedules. In Table 4-29, units with temporary exceptions can be included in the committed on cost, committed on price PLS, and committed on price schedule as flexible as PLS categories. Table 4-30 shows the day-ahead operating reserve uplift credits received from 2018 through the first nine months of 2026 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 2026, 97 units requested an exception for a 24 hour minimum run time and 82 units received uplift payments amounting to $321.1 million of day ahead operating reserves and $270.9 million in balancing operating reserves, or 95.5 percent of total day-ahead operating reserves and 31.8 percent of total balancing operating reserves, corresponding to 22.8 percent and 19.3 percent of total uplift.

Table 4-30 Uplift credits for units with 24 hour minimum run times due to gas pipeline restrictions: 2018 through September 2026

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	$30.2	$2.4	79	41
2025	$149.4	$31.7	93	64
2026 (Jan - Sep)	$321.1	$270.9	97	82

Winter Storm Fern (January 22 through 30, 2026)

Winter Storm Fern is defined to include the meteorological definition of the storm plus related cold weather from January 22 through 30, 2026. Winter Storm Fern resulted in significant uplift payments. Table 4-31 summarizes the uplift payments by category during Winter Storm Fern. During the storm, generating units received $107.9 million in day-ahead operating reserve credits, 14.0 percent of total Winter Storm Fern uplift and 32.1 percent of total day-ahead operating reserves during the first nine months of 2026. During the storm, generating units received $577.0 million in balancing generator credits, 75.1 percent of total Winter Storm Fern uplift, and 67.8 percent of total balancing generator credits during the first nine months of 2026. Total uplift payments during the storm were $768.5 million, 54.7 percent of total uplift during the first nine months of 2026.

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

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Table 4-31 Energy uplift credits by category during Winter Storm Fern

Category	Type	2026 Winter Storm Fern Credits (Millions)	(Jan - Sep) 2026 Credits (Millions)	Share of Winter Storm Fern Uplift (Jan 22-30)	Winter Storm Fern Share of 2026 uplift (Jan -Sep)
Day-Ahead	Generators	$107.9	$336.1	14.0%	32.1%
Balancing	Generators	$577.0	$850.9	75.1%	67.8%
	Canceled Resources	$0.0	$0.0	0.0%	0.0%
	Lost Opportunity Cost	$83.6	$208.9	10.9%	40.0%
	Dispatch Differential Lost Opportunity Cost	$0.1	$6.9	0.0%	1.7%
Synchronous Condensing	Synchronous Condensing	$0.0	$0.0	0.0%	0.0%
	Synchronous Condensing Lost Opportunity Cost	$0.0	$0.0	0.0%	0.0%
Reactive Services	Day-Ahead	$0.0	$0.2	0.0%	0.0%
	Generators	$0.0	$2.2	0.0%	0.0%
	Lost Opportunity Cost	$0.0	$0.0	0.0%	0.0%
	Condensing	$0.0	$0.0	0.0%	0.0%
	Condensing Lost Opportunity Cost	$0.0	$0.0	0.0%	0.0%
Black Start Services	Day-Ahead	$0.0	$0.0	0.0%	0.0%
	Balancing	$0.0	$0.6	0.0%	0.0%
	Testing	$0.0	$0.0	0.0%	0.0%
	Lost Opportunity Cost	$0.0	$0.0	0.0%	0.0%
Total		$768.5	$1,405.8	100.0%	54.7%

Uplift during Winter Storm Fern was a result of advance commitments made by PJM in anticipation of the cold weather. PJM made advance commitments for the January 24 – February 2 operating days. These commitments were made before day-ahead energy market offers were due. Some of the units cleared the day-ahead energy market and did not require uplift payments because their offers were covered by the day-ahead LMP. The rest of the units committed in advance that did not clear the day-ahead energy market received balancing operating reserves credits because their offers were not fully covered by the real-time LMP. PJM made these commitments to mitigate generator performance risks based on available information about startup and operating uncertainty due to expected cold temperatures, natural gas supply illiquidity, and efforts to conserve oil fired generation in order to meet the forecasted peaks.[37] PJM also committed specific units in advance of the day-ahead market to ensure transmission system reliability, including voltage support.

As a result of the low temperatures expected on Saturday, January 24 and subsequent days, PJM committed units before temperatures reached the expected levels. On Friday, January 23, natural gas traded as a multiday package, referred to as the weekend package. The weekend package included gas days January 24, 25, and 26, covering the period from 10:00 AM on Saturday, January 24, to 10:00 AM on Tuesday, January 27. PJM committed units on Friday to ensure that the units could procure gas over the weekend. For the same reasons, PJM also committed gas units in advance of the January 27 to January 30 gas days, and in advance of the January 31 through February 2 weekend package.

37 See PJM "Winter Storm Gerri Review January 13–22, 2024," Operating Committee. (February 8, 2024). <https://www.pjm.com/-/media/DotCom/committees-groups/committees/oc/2024/20240208/20240208-item-11---cold-weather-update.pdf>.

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Table 4-32 shows the total energy uplift credits by unit type during Winter Storm Fern, as a share of total uplift in the first nine months of 2026, and as a share of total Fern uplift. Combined cycle plants received $226.8 million in uplift payments, non-coal steam units received $120.7 million and combustion turbines received $402.1 million. Winter Storm Fern accounted for 84.0 percent of the uplift received by combined cycle plants during the first nine months of 2026, and during the storm combined cycle plants received 29.4 percent of the uplift.

Table 4-32 Total energy uplift credits by unit type during the 2026 Winter Storm Fern

Unit Type	2026 Winter Storm Fern Credits (Millions)	(Jan - Sep) 2026 Credits (Millions)	Share of Winter Storm Fern Uplift (Jan. 22 - 30)	Winter Storm Fern Share of 2026 uplift (Jan - Sep)
Combined Cycle	$226.8	$269.9	29.5%	84.0%
Combustion Turbine	$402.1	$617.8	52.3%	65.1%
Diesel	$1.6	$5.5	0.2%	29.4%
Hydro	$0.0	$0.3	0.0%	4.8%
Nuclear	$0.0	$0.0	0.0%	0.0%
Solar	$0.0	$5.4	0.0%	0.1%
Steam - Coal	$16.5	$102.3	2.1%	16.1%
Steam - Other	$120.7	$400.2	15.7%	30.2%
Wind	$0.8	$4.5	0.1%	18.1%
Total	$768.5	$1,405.8	100.0%	54.7%

During Winter Storm Fern not all units scheduled in advance of the day-ahead market were paid uplift. Table 4-33 shows the distribution of energy uplift credits during Winter Storm Fern. Uplift was concentrated in ComEd, where 59 CT and CC units with a combined ICAP of 4,984.7 MW received $248.6 million in uplift, or 32.3 percent of Winter Storm Fern uplift. Excluding ComEd, the top ten unit recipients of uplift in total Winter Storm Fern had a combined ICAP of 5,080.8 MW and received $254.8 million, or 33.2 percent of Winter Storm Fern uplift. A total of 633 units received uplift during Winter Storm Fern.

Table 4-33 Total energy uplift credits concentration in ComED and other top 10 units during the 2026 Winter Storm Fern

Category	Units	Total ICAP	Uplift	Unit Share	ICAP Share	Uplift Share
ComED CT & CC	59	4,984.7	$248.6	9.3%	4.6%	32.3%
Top 10 non ComED units	10	5,080.8	$254.8	1.6%	4.6%	33.2%
All other units	564	99,308.1	$265.1	89.1%	90.8%	34.5%
Total	633	109,373.6	$768.5	100.0%	100.0%	100.0%

PJM's advanced commitment process during Winter Storm Fern was successful in mitigating risk and ensuring reliability. While the uplift associated with this strategy was expected, improvements are needed to make the advance commitment process more predictable, formalized, and as market based as possible in order to limit uplift to an efficient level.

The MMU recommends that PJM improve its advanced scheduling and commitment process in order to implement a transparent process in which units are scheduled and committed economically based on the known constraints prior to the day-ahead market. The multiday advance commitment process needs to address the communication process, the offers used for commitment evaluation, the operating parameters used for commitment evaluation, the financial consequences of commitment and the appropriate uplift rules.[38]

The majority of units committed in advance of the day-ahead market were not committed by PJM for reliability in the day-ahead market and either cleared in the day-ahead market economically or were committed and operated in real time and received balancing operating reserves. There were units committed in advance of the day-ahead market that were committed by PJM in the day-ahead market for reliability. Units committed for reliability by PJM are units that are committed to satisfy reliability needs, regardless of whether the offers are economic. Table 4-34 shows the total day-ahead generation and day-ahead generation committed for reliability during Winter Storm Fern. During the period of the storm, from January 22 through January 30, 2026, total PJM day-ahead generation was 27,006 GWh. PJM committed 473.2 GWh of day-ahead generation for reliability purposes, or 1.8 percent, during that period.

38 **See** Monitoring Analytics, LLC "Advanced Scheduling Proposal," Market Implementation Committee (August 5, 2026) <https://www.monitoringanalytics.com/reports/Presentations/2026/IMM_MIC_Advanced_Scheduling_Proposal_20260805.pdf>.

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Table 4-34 Day-ahead generation for reliability (GWh) during Winter Storm Fern: January 22 through January 30, 2026

Winter Storm Fern		
Total Day-Ahead Generation (GWh)	Day-Ahead PJM Must Run Generation (GWh)	Share
27,006	473.2	1.8%

Table Table 4-35 shows the total day-ahead generation committed for reliability by PJM by uplift category during Winter Storm Fern. During the storm, 42.7 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 57.3 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. During the storm, day-ahead generation committed for reliability by PJM did not receive any uplift for reactive services.

Table 4-35 Day-ahead generation committed for reliability by uplift category (GWh) during Winter Storm Fern: January 22 through January 30, 2026

	Winter Storm Fern			
	Reactive Services (GWh)	Day-Ahead Operating Reserves (GWh)	Economic (GWh)	Total (GWh)
Total	0.0	202.2	271.0	473.2
Share	0.0%	42.7%	57.3%	100.0%

Hot Weather Alert Days

Over the first nine months of 2026, PJM Issued a Hot Weather Alert for the entire PJM RTO over three periods: June 30, 2026, through July 4, 2026; July 14, 2026, through July 17, 2026; and August 31, 2026, through September 4, 2026. Table 4-36 summarizes the uplift payments by category during hot weather alert days. On hot weather alert days, generating units received $32.5 million in day-ahead operating reserve credits, $28.6 million in balancing operating credits, $29.0 million in lost opportunity credits, and $5.2 million in dispatch differential lost opportunity cost credits. Total uplift payments during hot weather alert days were $95.3 million, 6.8 percent of total uplift during the first nine months of 2026.

Dispatch differential lost opportunity cost credits accounted for 5.5 percent of total uplift paid during hot weather alerts, but hot weather alert days in 2026 accounted for 75.9 percent of total dispatch differential lost opportunity cost credits in the first nine months of 2026. 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 to an output level below the level that is economic at fast start prices in order to accommodate inflexible fast start resources. On July 3 and July 4, units were paid $5.1 million in dispatch differential lost opportunity credits, 96.8 percent of dispatch differential lost opportunity credits on hot weather days and 73.4 percent of total dispatch differential lost opportunity credits in the first nine months of 2026. During these days the fast start pricing run solved with constraint violations and reserve requirement shortages that did not occur in the actual market dispatch.

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Table 4-36 Total energy uplift credits by unit type during the 2026 RTO Wide Hot Weather Alert Days

Category	Type	2026 Hot Weather Alert Days Credits (Millions)	(Jan - Sep) 2026 Credits (Millions)	Share of Hot Weather Alert Days Uplift (Jan 22-30)	Hot Weather Alert Days Share of 2026 uplift (Jan -Sep)
Day-Ahead	Generators	$32.5	$336.1	34.1%	9.7%
Balancing	Generators	$28.6	$850.9	30.0%	3.4%
	Canceled Resources	$0.0	$0.0	0.0%	0.0%
	Lost Opportunity Cost	$29.0	$208.9	30.4%	13.9%
	Dispatch Differential Lost Opportunity Cost	$5.2	$6.9	5.5%	75.9%
Synchronous Condensing	Synchronous Condensing	$0.0	$0.0	0.0%	0.0%
	Synchronous Condensing Lost Opportunity Cost	$0.0	$0.0	0.0%	0.0%
	Day-Ahead	$0.0	$0.2	0.0%	0.0%
	Generators	$0.0	$2.2	0.0%	0.0%
	Lost Opportunity Cost	$0.0	$0.0	0.0%	0.0%
	Condensing	$0.0	$0.0	0.0%	0.0%
Reactive Services	Condensing Lost Opportunity Cost	$0.0	$0.0	0.0%	0.0%
	Day-Ahead	$0.0	$0.0	0.0%	0.0%
	Balancing	$0.0	$0.6	0.0%	0.5%
	Testing	$0.0	$0.0	0.0%	0.0%
Black Start Services	Lost Opportunity Cost	$0.0	$0.0	0.0%	0.0%
Total		$95.3	$1,405.8	100.0%	6.8%

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