Energy Uplift (Operating Reserves)

Energy uplift is paid to market participants under specified conditions in order to ensure that competitive energy and ancillary service market outcomes do not require efficient resources operating for the PJM system, at the direction of PJM, at a loss.[1] Referred to in PJM as operating reserve credits, lost opportunity cost credits, reactive services credits, synchronous condensing credits or black start services credits, these uplift payments are intended to be one of the incentives to generation owners to offer their energy to the PJM energy market for dispatch based on short run marginal costs and to operate their units as directed by PJM. These uplift credits are paid by PJM market participants as operating reserve charges, reactive services charges, synchronous condensing charges or black start services charges. Effective November 1, 2020, UTC transactions are allocated day-ahead and real-time uplift charges, and are treated for uplift purposes as equivalent to a decrement bid (DEC) at the sink point of the UTC.[2]

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.[3] [4] In wholesale power markets like PJM, efficient prices equal the short run marginal cost of production by location. The dispatch of generators based on these efficient price signals minimizes the total market cost of production. For generators with nonconvex costs, marginal cost prices may not cover the total cost of starting the generator and running at the efficient output level. Uplift payments cover the difference. The PJM market design incorporates efficient prices with minimal uplift payments. Actual results in PJM do not minimize actual uplift payments. There are improvements to the market design and uplift rules that could further reduce uplift payments while maintaining efficient prices.

In PJM, all energy payments to demand response resources are uplift payments. The energy payments to these resources are not part of the supply and demand balance, they are not paid by LMP revenues and therefore the energy payments to demand response resources have to be paid as out of market uplift. The energy payments to economic DR are funded by real-time load and real-time exports. The energy payments to emergency DR are funded by participants with net energy purchases in the real-time energy market. The current payment structure for DR is an inefficient element of the PJM market design.[5]

Overview

Energy Uplift Charges

- **Energy Uplift Charges.** Total energy uplift charges increased by $2.8 million, or 3.6 percent, in the first six months of 2022 compared to the first six months of 2021, from $79.3 million to $82.1million.
- **Energy Uplift Charges Categories.** The increase of $2.8 million in 2022 was comprised of a $1.6 million increase in day-ahead operating reserve charges, a $0.9 million decrease in balancing operating reserve charges, a $0.3 million increase in reactive services charges and a $0.2 million decrease in black start services.
- **Average Effective Operating Reserve Rates in the Eastern Region.** Day-ahead load, exports, DECs and UTCs paid $0.019 per MWh in the Eastern Region. Real-time load and exports paid an average of $0.077 per MWh. Deviations paid $0.390 per MWh in the Eastern Region.
- **Average Effective Operating Reserve Rates in the Western Region** Day-ahead load, exports, DECs and UTCs paid $ 0.019 per MWh in the Western

1 Loss exists when gross energy and ancillary services market revenues are less than short run marginal costs, including all elements of the energy offer, which are startup, no load and incremental offers, 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 172 FERC ¶ 61,046 (2020).

3 *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).

4 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.

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

Region. Real-time load and exports paid $0.058 per MWh. Deviations paid $0.271 per MWh in the Western Region.

Energy Uplift Credits

- **Types of credits.** In the first six months of 2022, energy uplift credits were $82.1 million, including $8.8 million in day-ahead generator credits, $55.0 million in balancing generator credits, $14.0 million in lost opportunity cost credits, and $1.2 million in local constraint control credits. Dispatch differential lost opportunity credits, implemented as part of fast start pricing on September 1, 2021, were $0.6 million during the first six months of 2022
- **Types of units.** In the first six months of 2022, coal units received 49.0 percent of day-ahead generator credits, and combustion turbines received 86.1 percent of balancing generator credits and 87.2 percent of lost opportunity cost credits. Combined cycle units and combustion turbines received 69.7 percent of dispatch differential lost opportunity credits.
- **Economic and Noneconomic Generation.** In the first six months of 2022, 89.4 percent of the day-ahead generation eligible for operating reserve credits was economic and 64.0 percent of the real-time generation eligible for operating reserve credits was economic.
- **Day-Ahead Unit Commitment for Reliability.** In the first six months of 2022, 0.2 percent of the total day-ahead generation MWh was scheduled as must run for reliability by PJM, of which 32.9 percent received energy uplift payments.
- **Concentration of Energy Uplift Credits.** In the first six months of 2022, the top 10 units receiving energy uplift credits received 16.8 percent of all credits and the top 10 organizations received 74.4 percent of all credits. The HHI for day-ahead operating reserves was 8404, the HHI for balancing operating reserves was 2647 and the HHI for lost opportunity cost was 5096, all of which are classified as highly concentrated.
- **Lost Opportunity Cost Credits.** Lost opportunity cost credits increased by $2.9 million, or 25.8 percent, in the first six months of 2022, compared to the first six months of 2021, from $11.1 million to $14.0 million. Some combustion turbines and diesels are scheduled day-ahead but not requested in real time, and receive day-ahead lost opportunity cost credits as a result. This was the source of 86.1 percent of the $14.0 million. The day-ahead generation paid LOC credits for this reason increased by 45.6 GWh or 23.8 percent during the first six months of 2022, compared to the first six months of 2021 from 191.3 GWh to 236.9 GWh.
- **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 $14.9 million, of which PJM has resettled $1.5 million, or 9.8 percent.
- **Daily Uplift.** In the first six months of 2022, balancing operating reserve charges would have been $12.1 million or 21.9 percent lower if they had been calculated on a daily basis rather than a segmented basis. In the first six months of 2021, balancing operating reserve credits would have been $8.4 million or 15.2 percent lower if they had been calculated on a daily basis rather than a segmented basis. Uplift was designed to be charged on a daily basis and not on an intraday segmented basis.

Geography of Charges and Credits

- In the first six months of 2022, 86.2 percent of all uplift charges allocated regionally (day-ahead operating reserves and balancing operating reserves) were paid by transactions at control zones, 6.2 percent by transactions at hubs and aggregates, and 8.5 percent by transactions at interchange interfaces.
- In the first six months of 2022, generators in the Eastern Region received 52.1 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.
- In the first six months of 2022, generators in the Western Region received 45.4 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.

- In the first six months of 2022, external generators received 2.4 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.

Recommendations

- The MMU recommends that uplift be paid only based on operating parameters that reflect the flexibility of the benchmark new entrant unit (CONE unit) in the PJM Capacity Market. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM not pay uplift to units not following dispatch, including uplift related to fast start pricing, and require refunds where it has made such payments. This includes units whose offers are flagged for fixed generation in Markets Gateway because such units are not dispatchable. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM pay uplift based on the offer at the lower of the actual unit output or the dispatch signal MW. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends eliminating intraday segments from the calculation of uplift payments and returning to calculating the need for uplift based on the entire 24 hour operating day. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends the elimination of day-ahead uplift to ensure that units receive an energy uplift payment based on their real-time output and not their day-ahead scheduled output. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends enhancing the current energy uplift allocation rules to reflect the recommended elimination of day-ahead uplift, the timing of commitment decisions and the commitment reasons. (Priority: High. First reported 2012. Status: Not adopted.)
- The MMU recommends that units not be paid lost opportunity cost uplift 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 Q2, 2021. Status: Not adopted.)
- The MMU recommends reincorporating the use of net regulation revenues as an offset in the calculation of balancing operating reserve credits. (Priority: Medium. First reported 2009. Status: Not adopted.)
- The MMU recommends that self scheduled units not be paid energy uplift for their startup cost when the units are scheduled by PJM to start before the self scheduled hours. (Priority: Low. First reported 2013. Status: Not adopted.)
- 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 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 payments to units scheduled as must run in the day-ahead energy market for reasons other than voltage/reactive or black start services as a reliability charge to real-time load, real-time exports and real-time wheels. (Priority: Medium. First reported 2014. Status: Not adopted. Stakeholder process.)
- The MMU recommends that the total cost of providing reactive support be categorized and allocated as reactive services. Reactive services credits should be calculated consistent with the balancing operating reserve credit calculation. (Priority: Medium. First reported 2012. Status: Not adopted. Stakeholder process.)
- The MMU recommends including real-time exports and real-time wheels in the allocation of the cost of providing reactive support to the 500 kV system or above, in addition to real-time load. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends modifications to the calculation of lost opportunity costs credits paid to wind units. The lost opportunity costs credits paid to wind units should be based on the lesser of the desired output, the estimated output based on actual wind conditions and the capacity interconnection rights (CIRs). The MMU recommends that PJM allow wind units to request CIRs that reflect the maximum output wind units want to inject into the transmission system at any time. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM clearly identify and classify all reasons for incurring 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 (operating reserve) confidentiality rules in order to allow the disclosure of complete information about the level of uplift (operating reserve charges) by unit and the detailed reasons for the level of operating reserve credits by unit in the PJM region. (Priority: High. First reported 2013. Status: Partially adopted.)[6]
- The MMU recommends that PJM eliminate the exemption for CTs and diesels from the requirement to follow dispatch. The performance of these resources should be evaluated in a manner consistent with all other resources (Priority: Medium. First reported 2018. Status: Not adopted.)

Conclusion

Competitive market outcomes result from energy offers equal to short run marginal costs that incorporate flexible operating parameters. When PJM permits a unit to include inflexible operating parameters in its offer and pays uplift based on those inflexible parameters, there is an incentive for the unit to remain inflexible. The rules regarding operating parameters should be implemented in a way that creates incentives for flexible operations rather than inflexible operations. The standard for paying uplift should be the maximum achievable flexibility, based on OEM standards for the benchmark new entrant unit (CONE unit) in the PJM Capacity Market. Applying a weaker standard effectively subsidizes inflexible units by paying them based on inflexible parameters that result from lack of investment and that could be made more flexible. The result both inflates uplift costs and suppresses energy prices.

It is not appropriate to accept that inflexible units should be paid 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

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

provide flexible solutions including replacing inefficient units with flexible, efficient units.

Implementing combined cycle modeling, to permit the energy market model optimization to take advantage of the versatility and flexibility of combined cycle technology in commitment and dispatch, would provide significant flexibility without requiring a distortion of the market rules. But such modeling should not be used as an excuse to eliminate market power mitigation or an excuse to permit inflexible offers to be paid uplift.

The reduction of uplift payments should not be a goal to be achieved at the expense of the fundamental logic of the LMP system. For example, the use of closed loop interfaces to reduce uplift should be eliminated because it is not consistent with LMP fundamentals and constitutes a form of subjective price setting. The same is true of what PJM terms its CT price setting logic. The same is true of fast start pricing. The same is true of PJM's proposal to modify the ORDC in order to increase energy prices and reduce uplift.

Accurate short run price signals, equal to the short run marginal cost of generating power, provide market incentives for cost minimizing production to all economically dispatched resources and provide market incentives to load based on the marginal cost of additional consumption. The objective of efficient short run price signals is to minimize system production costs, not to minimize uplift. Repricing the market to reflect commitment costs will create a tradeoff between minimizing production costs and reduction of uplift. The tradeoff will exist because when commitment costs are included in prices, the price signal no longer equals the short run marginal cost and therefore no longer provides the correct signal for efficient behavior for market participants making decisions on the margin, whether resources, load, interchange transactions, or virtual traders. This tradeoff now exists based on PJM's recently implemented fast start pricing proposal (limited convex hull pricing). Fast start pricing was approved by FERC and implemented on September 1, 2021.[7] 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.

7 See 173 FERC ¶ 61,244 (2020).

When units receive substantial revenues through energy uplift payments, these payments are not fully transparent to the market, in part because of the current confidentiality rules. As a result, other market participants, including generation and transmission developers, do not have the opportunity to compete to displace them. As a result, substantial energy uplift payments to a concentrated group of units and organizations have persisted. FERC Order No. 844 authorized the publication of unit specific uplift payments for credits incurred after July 1, 2019.[8] 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 in the day-ahead market.

One part of addressing the level and allocation of uplift payments is to eliminate all day-ahead operating reserve credits. It is illogical and unnecessary to pay units day-ahead operating reserve credits because units do not incur any costs to run and any revenue shortfalls are addressed by balancing operating reserve credits.

On July 16, 2020, following its investigation of the issue, the Commission ordered PJM to revise its rules so that UTCs are required to pay uplift on the withdrawal side (DEC) only.[9] The uplift payments for UTCs began on November 1, 2020.[10] This had been a longstanding recommendation of the MMU.

PJM needs to pay substantially more attention to the details of uplift payments including accurately tracking whether units are following dispatch, identifying the actual need for units to be dispatched out of merit and determining whether local reserve zones or better definitions of constraints would be a more market based approach. PJM pays uplift to units even when they do not operate as requested by PJM, i.e. they do not follow dispatch. PJM uses dispatcher logs as a primary screen to determine if units are eligible for uplift regardless of how they actually operate or if they followed the PJM dispatch signal. The

8 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).

9 See 172 FERC ¶ 61,046 (2020).

10 On October 17, 2017, PJM filed a proposed tariff change at FERC to allocate uplift to UTC transactions in the same way uplift is allocated to other virtual transactions, as a separate injection and withdrawal deviation. FERC rejected the proposed tariff change. See 162 FERC ¶ 61,019 (2018).

reliance on dispatcher logs for this purpose is impractical, inefficient, and incorrect. PJM needs to define and implement systematic and verifiable rules for determining when units are following dispatch as a primary screen for eligibility for uplift payments. PJM should not pay uplift to units that do not follow dispatch.

The MMU notifies PJM and generators of instances in which, based on the PJM dispatch signal and the real-time output of the unit, it is clear that the unit did not operate as requested by PJM. The MMU sends requests for resettlements to PJM to make the units with the most extreme overpayments ineligible for uplift credits. Since 2018, the MMU has requested that PJM require the return of $14.9 million of incorrect uplift credits of which PJM has resettled only 9.8 percent. In addition, PJM has refused to accept the return of incorrectly paid uplift credits by generators when the MMU has identified such cases.

While energy uplift charges are an appropriate part of the cost of energy, market efficiency would be improved by ensuring that the level and variability of these charges are as low as possible consistent with the reliable operation of the system and consistent with pricing at short run marginal cost. The goal should be to minimize the total incurred energy uplift charges and to increase the transactions over which those charges are spread in order to reduce the impact of energy uplift charges on markets. The result would be to reduce the level of per MWh charges, to reduce the uncertainty associated with uplift charges and to reduce the impact of energy uplift charges on decisions about how and when to participate in PJM markets. The result would also be to increase incentives for flexible operation and to decrease incentives for the continued operation of inflexible and uneconomic resources. PJM does not need a new flexibility product. PJM needs to provide incentives to existing and new entrant resources to unlock the significant flexibility potential that already exists, to end incentives for inflexibility and to stop creating new incentives for inflexibility.

Energy Uplift Credits Results

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

Table 4-1 shows the totals for each credit category for the first six months of 2021 and 2022.[11] In the first six months of 2022, energy uplift credits increased by $2.8 million or 3.6 percent compared to 2021.

The dispatch differential lost opportunity cost is a credit paid to resources that, in order to accommodate inflexible fast start resources, are dispatched down to an output below the level that is economic for them at the market prices that result from fast start pricing. Because fast start pricing was introduced on September 1, 2021, the dispatch differential lost opportunity cost credit did not exist for the first six months of 2021.

11 Billing data can be modified by PJM Settlements at any time to reflect changes in the evaluation of energy uplift. The billing data reflected in this report were current on July 8, 2022.

Table 4-1 Energy uplift credits by category: January through June, 2021 and 2022[12]

Category	Type	(Jan - Jun) 2021 Credits (Millions)	(Jan - Jun) 2022 Credits (Millions)	Change	Percent Change	2021 Share	2022 Share
Day-Ahead	Generators	$7.2	$8.8	$1.6	21.9%	9.1%	10.7%
	Imports	$0.0	$0.0	$0.0	NA	0.0%	0.0%
	Load Response	$0.0	$0.0	$0.0	NA	0.0%	0.0%
Balancing	Canceled Resources	$0.0	$0.0	$0.0	NA	0.0%	0.0%
	Generators	$55.4	$55.0	($0.5)	(0.8%)	69.9%	67.0%
	Imports	$0.0	$0.0	$0.0	NA	0.0%	0.0%
	Load Response	$0.0	$0.0	$0.0	NA	0.0%	0.0%
	Local Constraints Control	$4.6	$1.2	($3.4)	(73.7%)	5.9%	1.5%
	Lost Opportunity Cost	$11.1	$14.0	$2.9	25.8%	14.0%	17.0%
	Dispatch Differential Lost Opportunity Cost	NA	$1.9				2.3%
Reactive Services	Day-Ahead	$0.3	$0.7	$0.5	186.9%	0.3%	0.9%
	Local Constraints Control	$0.0	$0.0	$0.0	NA	0.0%	0.0%
	Lost Opportunity Cost	$0.0	$0.0	($0.0)	(99.5%)	0.0%	0.0%
	Reactive Services	$0.5	$0.2	($0.2)	(47.4%)	0.6%	0.3%
	Synchronous Condensing	$0.0	$0.0	$0.0	NA	0.0%	0.0%
Synchronous Condensing		$0.0	$0.0	$0.0	NA	0.0%	0.0%
Black Start Services	Day-Ahead	$0.0	$0.0	$0.0	NA	0.0%	0.0%
	Balancing	$0.0	$0.0	$0.0	NA	0.0%	0.0%
	Testing	$0.2	$0.3	$0.2	82.2%	0.2%	0.4%
Total		$79.3	$82.1	$2.8	3.6%	100.0%	100.0%

Characteristics of Credits

Types of Units

Table 4-2 shows the distribution of total energy uplift credits by unit type for the first six months of 2021 and 2022. A combination of factors led to decreased uplift payments for day ahead operating reserves and balancing operating reserves including reduced need for reliability generation by coal units, decreased real-time generation from CTs, higher natural gas prices, and higher LMPs.

Uplift credits paid to combustion turbines decreased by $6.7 million or 9.8 percent in the first six months of 2022 compared to the same period in 2021. This decrease can largely be attributed to significantly higher LMPs, resulting in reduced noneconomic generation by CTs in real-time and to overall reduced reliance on CT generation in real time from CTs that did not clear day ahead. In the first six months of 2022, CTs received 83.0 percent of lost opportunity cost credits, which increased by $2.9 million or 25.8 percent from the first six months of 2021.

Uplift credits paid to steam coal units decreased by $0.5 million or 7.8 percent during the first six months of 2022 compared to the same time period of 2021. The decrease in payments to coal units can be attributed to a small number of coal units in the BDPL and PEPCO Zones committed for reliability. Uplift credits paid to other (gas or oil fired) steam units increased by $5.1 million or 1,228 percent during the first six months of 2022 compared to the same time period of 2021. The increase in payments to non-coal burning steam units can be attributed to a small number of units in the PEPCO, BGE, and PPL Zones.

12 Year to year change is rounded to one tenth of a million, and includes values less than $0.05 million.

In the first six months of 2022, uplift credits to wind units were $0.2 million, up by 38.2 percent compared to 2021. During the first six months of 2022, uplift credits to combined cycle units increased by $3.9 million or 159.1 percent compared to the same period last year.

Table 4-2 Total energy uplift credits by unit type January through June, 2021 and 2022[13 14]

Unit Type	(Jan - Jun) 2021 Credits (Millions)	(Jan - Jun) 2022 Credits (Millions)	Change	Percent Change	(Jan - Jun) 2021 Share	(Jan - Jun) 2022 Share
Combined Cycle	$2.5	$6.4	$3.9	159.1%	3.1%	7.8%
Combustion Turbine	$68.5	$61.8	($6.7)	(9.8%)	86.4%	75.2%
Diesel	$0.8	$1.3	$0.5	60.3%	1.0%	1.5%
Hydro	$0.0	$0.4	$0.4	0.0%	0.0%	0.5%
Nuclear	$0.0	$0.0	$0.0	0.0%	0.0%	0.0%
Solar	$0.0	$0.1	$0.1	1,375.4%	0.0%	0.1%
Steam - Coal	$6.9	$6.4	($0.5)	(7.8%)	8.8%	7.8%
Steam - Other	$0.4	$5.5	$5.1	1,228.0%	0.5%	6.7%
Wind	$0.2	$0.2	$0.1	38.2%	0.2%	0.3%
Total	$79.3	$82.1	$2.8	3.6%	100.0%	100.0%

Table 4-3 shows the distribution of energy uplift credits by category and by unit type in the first six months of 2022. The characteristics of the different unit types explain why uplift in specific categories is paid primarily to specific unit types. For example, the highest share of day-ahead credits, 49.0 percent, went to steam units because 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 credits. The PJM market rules permit combustion turbines, 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 86.1 percent of balancing credits and 83.0 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 4-3 Energy uplift credits by unit type: January through June, 2022

Unit Type	Day-Ahead Generator	Balancing Generator	Canceled Resources	Local Constraints Control	Lost Opportunity Cost	Reactive Services	Synchronous Condensing	Black Start Services	Dispatch Differential Lost Opportunity Cost
Combined Cycle	8.6%	6.7%	0.0%	0.0%	10.3%	0.0%	0.0%	26.8%	25.9%
Combustion Turbine	4.4%	86.1%	0.0%	91.1%	83.0%	23.9%	0.0%	73.1%	43.8%
Diesel	0.1%	1.0%	0.0%	6.6%	4.2%	0.6%	0.0%	0.1%	0.3%
Hydro	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	23.3%
Nuclear	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Solar	0.0%	0.0%	0.0%	0.0%	0.5%	0.0%	0.0%	0.0%	0.1%
Steam - Coal	49.0%	3.0%	0.0%	0.0%	0.8%	26.7%	0.0%	0.0%	4.3%
Steam - Other	37.9%	3.1%	0.0%	0.0%	0.0%	48.8%	0.0%	0.0%	0.5%
Wind	0.0%	0.0%	0.0%	2.3%	1.1%	0.0%	0.0%	0.0%	1.8%
Total (Millions)	$8.8	$55.0	$0.0	$1.2	$14.0	$1.0	$0.0	$0.3	$1.9

13 Table 4-2 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.

Day-Ahead Unit Commitment for Reliability

PJM may 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 and reactive transfer interface control needed to maintain system reliability in a zone or reactive service.[15] Participants can submit units as self scheduled, meaning that the unit must be committed, but a unit submitted as must run by a participant is not eligible for day-ahead operating reserve credits.[16] Units committed for reliability by PJM are eligible for day-ahead operating reserve credits and may set LMP if raised above economic minimum and follow the dispatch signal.

Table 4-4 shows total day-ahead generation and day-ahead generation committed for reliability by PJM. Day-ahead generation committed for reliability by PJM increased by 45.2 percent from the first six months of 2021 to the first six months of 2022, from 481.0 GWh in 2021 to 698.5 GWh in 2022. The increase in day-ahead generation committed for reliability by PJM was due to an increased need to commit uneconomic units in the BGE, PPL, and DOM Zones for reliability. Reliability needs in the PEPCO Zone decreased during the first six months of 2022 compared to 2021.

Table 4-4 Day-ahead generation committed for reliability (GWh): January 2021 through June 2022

	2021			2022			
	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	Percent Change of PJM Day-Ahead Must Run Generation
Jan	73,635	95	0.1%	81,373	0	0.0%	
Feb	71,354	13	0.0%	68,253	37	0.1%	191.6%
Mar	64,713	209	0.3%	66,579	4	0.0%	(98.2%)
Apr	57,137	13	0.0%	57,663	8	0.0%	(38.2%)
May	60,957	26	0.0%	63,309	389	0.6%	1,407.1%
Jun	72,987	126	0.2%	70,849	261	0.4%	107.5%
Jul	80,025	103	0.1%				NA
Aug	81,744	86	0.1%				NA
Sep	66,913	410	0.6%				NA
Oct	61,610	15	0.0%				NA
Nov	62,746	181	0.3%				NA
Dec	69,036	96	0.1%				NA
Total (Jan - Jun)	400,783	481	0.1%	408,026	698	0.2%	45.2%
Total	822,857	1,372	0.2%				

Pool scheduled units and units committed for reliability are made whole in the day-ahead energy market if their total cost-based offer (including no load and startup costs) is greater than the revenues from the day-ahead energy market. Such units are paid day-ahead uplift (operating reserve credits). Total day-ahead operating reserve credits in the first six months of 2021 were $8.8 million. The top 10 units received $6.9 million or 79.0 percent of all day-ahead operating reserve credits. These units were large units with operating parameters less flexible than PLS parameters, including long minimum run times.

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 4-5 shows the total day-ahead generation committed for reliability by PJM by category. In the first six months of 2022, 32.9 percent of the day-ahead generation committed for reliability by PJM was paid day-ahead operating reserve credits. The remaining 67.1 percent of the day-ahead generation

15 See OA Schedule 1 § 3.2.3(b).
16 See PJM. "PJM Markets Gateway User Guide," Section Managing Unit Data (version July 16, 2018) at 33, <http://www.pjm.com/-/media/etools/markets-gateway/markets-gateway-user-guide.ashx?la=en>.

committed for reliability was economic, meaning that the generation was not paid operating reserve credits because prices covered the generators' offers.

Table 4-5 Day-ahead generation committed for reliability by category (GWh): January through June, 2022

	Reactive Services (GWh)	Day-Ahead Operating Reserves (GWh)	Economic (GWh)	Total (GWh)
Jan	0.0	17.9	19.6	37.5
Feb	0.0	3.7	0.0	3.7
Mar	0.0	8.1	0.0	8.1
Apr	17.1	79.9	291.5	388.5
May	0.0	102.9	157.9	260.7
Jun	0.0	0.0	0.0	0.0
Total (Jan - Jun)	17.1	212.5	468.9	698.5
Share	2.4%	30.4%	67.1%	100.0%

Total day-ahead operating reserve credits in the first six months of 2022 were $8.8 million, of which $4.9 million or 56.0 percent was paid to units committed for reliability by PJM, and not scheduled to provide reactive services. There was no additional day-ahead operating reserves paid to units scheduled to provide reactive services.

Balancing Operating Reserve Credits

Balancing operating reserve (BOR) credits are paid to resources that operate as requested by PJM that do not recover their operating costs from market revenues. BOR credits are calculated as the difference between a resource's revenues (day-ahead market, balancing market, reserve markets, reactive service credits, and day-ahead operating reserve credits) and its real-time offer (startup, no load, and energy offer). Combustion turbines (CTs) received $47.3 million or 86.1 percent of all balancing operating reserve (BOR) credits in the first six month of 2022. The majority of these credits, 98.6 percent, were paid to CTs committed in real time either without or outside of a day-ahead schedule.[17] Uplift is higher than necessary because settlement rules do not include all revenues and costs for the entire day.

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

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

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

Balancing operating reserve credits to generators decreased by 0.8 percent in the first six months of 2022 compared to the first six months of 2021. Higher LMPs combined with PJM's reduced need to run CTs resulted in slightly decreased balancing operating reserve credits during the first six months of 2022. This slight increase concealed offsetting regional differences. Balancing operating reserve credits paid to units in the COMED zone decreased by 57.9 percent but credits paid to units in the DOM zone increased by 62.0 percent.

Table 4-6 shows monthly day-ahead and real-time generation by combustion turbines. In the first six months of 2022, generation by combustion turbines was 2.9 percent lower in the real-time energy market than in the day-ahead energy market, although this varied by month. Table 4-6 shows that only

1.5 percent of generation from combustion turbines in the day-ahead market was uneconomic, while 28.2 percent of generation from combustion turbines in the real-time market was uneconomic and required $47.3 million in BOR credits. The relatively low level of uneconomic real-time generation resulted in reduced BOR credits during the first six months of 2022.

Table 4-6 Characteristics of day-ahead and real-time generation by combustion turbines eligible for operating reserve credits: January through June, 2022

Month	Day-Ahead Generation (GWh)	Percent of Day-Ahead Generation that was Noneconomic	Day-Ahead Generator Credits (Millions)	Real-Time Generation (GWh)	Percent of Real-Time Generation that was Noneconomic	Balancing Generator Credits (Millions)	Ratio of Day-Ahead to Real-Time Generation
Jan	1,754	0.9%	$0.0	1,056	23.4%	$9.2	1.7
Feb	561	3.0%	$0.0	361	19.6%	$2.2	1.6
Mar	254	2.2%	$0.0	306	52.3%	$4.9	0.8
Apr	416	2.2%	$0.0	738	39.7%	$11.0	0.6
May	776	1.0%	$0.1	1,031	30.3%	$8.8	0.8
Jun	1,563	1.6%	$0.2	1,685	22.2%	$11.1	0.9
Total (Jan - Jun)	5,325	1.5%	$0.4	5,177	28.2%	$47.3	1.0

Balancing operating reserve credits to generators in the first six months of 2022 were $47.3 million, of which $46.7 million, or 84.9 percent, was paid to combustion turbines operating without or outside a day-ahead schedule (Table 4-7).

Table 4-7 shows real-time generation by combustion turbines by day-ahead commitment status in the first six months of 2022 and 2021. In the first six months of 2022, 62.5 percent of real-time CT generation was from CTs that operated on a day-ahead schedule. In the first six months of 2022, 37.5 percent of real-time CT generation was from CTs that operated outside of a day-ahead schedule.

In the first six months of 2022, real-time CT generation operating consistent with their day-ahead schedule increased compared to the first six months of 2021 and this shift was a major contributing factor to the decrease of BOR. CTs that operate on a day-ahead schedule tend to receive lower BOR credits because it is more likely that the day-ahead LMPs will support (prices above offer) committing the units. Day-ahead LMPs support committing the units because the day-ahead model optimizes the system for all 24 hours, unlike in real time when PJM uses ITSCED to optimize CT commitments with an approximately two hour look ahead. In addition, uplift rules continue to define all day-ahead scheduled hours as one segment for the uplift calculation (in which profits and losses during all hours offset each other). The shorter segments in real-time are defined by the minimum run time and allow for fewer offsets, amounting to greater amounts of uplift. Losses during the minimum run time segment are not offset by profits made in other segments on that day.

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

Table 4-7 Real-time generation by combustion turbines by day-ahead commitment: January 2021 through June 2022

		Real-Time CT Generation Operating on a Day-Ahead Schedule				Real-Time CT Generation Operating Outside of a Day-Ahead Schedule			
Month-Year		Generation (GWh)	Share of Real-Time Generation	Percent of Real-Time Generation that is Noneconomic	Balancing Generator Credits (Millions)	Generation (GWh)	Share of Real Time Generation	Percent of Real-Time Generation that is Noneconomic	Balancing Generator Credits (Millions)
2021	Jan 2021	154	31.8%	44.2%	$0.1	330	68.2%	71.3%	$4.3
	Feb 2021	184	38.0%	32.3%	$0.2	301	62.0%	72.8%	$9.7
	Mar 2021	214	45.5%	37.1%	$0.1	257	54.5%	63.7%	$4.4
	Apr 2021	511	40.2%	44.9%	$0.1	759	59.8%	74.4%	$15.9
	May 2021	528	59.3%	41.1%	$0.0	362	40.7%	59.3%	$4.9
	Jun 2021	1,153	56.4%	30.6%	$0.2	890	43.6%	50.5%	$12.0
	Jul 2021	1,447	57.5%	0.0%	$0.3	1,068	0.0%	0.0%	$16.5
	Aug 2021	1,908	59.8%	0.0%	$0.3	1,282	0.0%	0.0%	$17.8
	Sep 2021	792	69.2%	0.0%	$0.1	352	0.0%	0.0%	$3.4
	Oct 2021	1,122	62.2%	0.0%	$0.2	681	0.0%	0.0%	$10.8
	Nov 2021	977	56.3%	0.0%	$0.1	757	0.0%	0.0%	$12.9
	Dec 2021	291	58.5%	0.0%	$0.0	206	0.0%	0.0%	$3.9
	Total 2021 (Jan - Jun)	2,744	48.6%	36.7%	$0.6	2,898	51.4%	63.7%	$51.3
	Total 2021	9,280	56.2%	28.0%	$1.6	7,244	43.8%	53.1%	$116.6
2022	Jan 2022	840	79.5%	15.4%	$0.1	217	20.5%	54.6%	$9.1
	Feb 2022	297	82.3%	12.7%	$0.1	64	17.7%	51.8%	$2.2
	Mar 2022	126	41.1%	33.8%	$0.1	180	58.9%	65.2%	$4.9
	Apr 2022	281	38.1%	25.7%	$0.1	457	61.9%	48.3%	$10.9
	May 2022	551	53.4%	26.0%	$0.0	480	46.6%	35.2%	$8.8
	Jun 2022	1,139	67.6%	18.8%	$0.4	545	32.4%	29.5%	$10.7
	Total (Jan - Jun)	3,233	62.5%	19.7%	$0.6	1,943	37.5%	42.2%	$46.7

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.[18] The first scenario occurs if a unit of any type generating in real time with an offer price lower than the real-time LMP at the unit's bus is manually reduced or suspended by PJM due to a transmission constraint or other reliability issue. In this scenario the unit will receive a credit for LOC based on its desired output. Such units are not actually forgoing an option to increase output because the reliability of the system and in some cases the generator depend on reducing output. This LOC is referred to as real-time LOC. The second scenario occurs if a combustion turbine or diesel engine clears the day-ahead energy market, but is not committed in real time. In this scenario the unit will receive a credit which covers any lost profit in the day-ahead financial position of the unit plus the balancing energy market position. This LOC is referred to as day-ahead LOC.

Table 4-8 shows monthly day-ahead and real-time LOC credits in the first six months of 2021 and 2022. In the first six months of 2022, LOC credits increased by $2.9 million or 25.8 percent compared to the first six months of 2021, comprised of a $1.2 million increase in day-ahead LOC and a $1.7 million increase in real-time LOC.

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

In the first six months of 2022, wind units received $0.2 million of real-time LOC, up by $0.1 million compared to the first six months of 2021. Wind units are not required to procure CIRs equal to the maximum facility output, but are paid uplift when PJM requests that the units reduce output below the maximum facility output but above the CIR level. Units do not have a right to inject power at levels greater than the CIR level that they pay for and therefore should not be paid uplift when system conditions do not permit output at a level greater than the CIR. The real-time lost opportunity costs credits paid to wind units should be based on the lowest of the desired output, the estimated output based on actual wind conditions, or the capacity interconnection rights (CIRs).

Table 4-8 Monthly lost opportunity cost credits (Millions): January 2021 through June 2022

	2021			2022		
	Day-Ahead Lost Opportunity Cost	Real-Time Lost Opportunity Cost	Total	Day-Ahead Lost Opportunity Cost	Real-Time Lost Opportunity Cost	Total
Jan	$0.4	$0.0	$0.4	$3.3	$0.4	$3.7
Feb	$0.5	$0.0	$0.6	$1.4	$0.4	$1.8
Mar	$3.5	$0.0	$3.5	$0.5	$0.0	$0.5
Apr	$0.6	$0.0	$0.6	$0.8	$0.6	$1.4
May	$2.8	$0.1	$2.9	$1.0	$0.1	$1.1
Jun	$3.0	$0.1	$3.1	$5.1	$0.4	$5.6
Jul	$1.8	$0.1	$1.8			
Aug	$1.5	$0.1	$1.6			
Sep	$2.5	$0.5	$3.0			
Oct	$2.2	$0.2	$2.3			
Nov	$6.7	$0.5	$7.2			
Dec	$3.2	$0.0	$3.2			
Total (Jan - Jun)	$10.8	$0.3	$11.1	$12.0	$1.9	$14.0
Share (Jan - Jun)	97.5%	2.5%	100.0%	86.1%	13.9%	100.0%
Total	$28.6	$1.6	$30.2	$12.0	$1.9	$14.0
Share	94.7%	5.3%	100.0%	86.1%	13.9%	100.0%

Table 4-9 shows day-ahead generation for combustion turbines and diesels, including scheduled day-ahead generation, scheduled day-ahead generation not requested in real time, and day-ahead generation receiving LOC credits. In the first six months of 2022, 10.9 percent of day-ahead generation by combustion turbines and diesels was not requested in real time, .1.5 percentage points lower than in the first six months of 2021. In the first six months of 2022, day-ahead generation by combustion turbines increased by 28.9 percent, day-ahead generation not requested in real time increased by 13.4 percent, and day-ahead generation not requested in real time receiving lost opportunity costs increased by 23.8 percent, compared to the same time period in 2021. Unlike steam units, combustion turbines that clear the day-ahead energy market have to be instructed by PJM to come online in real time.

Table 4-9 Day-ahead generation from combustion turbines and diesels (GWh): January 2021 through June 2022

	2021			2022		
	Day-Ahead Generation (GWh)	Day-Ahead Generation Not Requested in Real Time (GWh)	Day-Ahead Generation Not Requested in Real Time Receiving LOC Credits (GWh)	Day-Ahead Generation (GWh)	Day-Ahead Generation Not Requested in Real Time (GWh)	Day-Ahead Generation Not Requested in Real Time Receiving LOC Credits (GWh)
Jan	486	69	17	2,262	306	101
Feb	507	53	12	753	110	38
Mar	527	64	16	448	60	14
Apr	957	62	15	675	56	19
May	1,153	213	55	1,069	104	21
Jun	1,869	223	76	1,882	138	44
Jul	2,179	149	46			
Aug	2,804	162	32			
Sep	1,358	130	46			
Oct	1,811	140	46			
Nov	2,109	373	142			
Dec	888	159	61			
Total (Jan - Jun)	5,499	683	191	7,089	775	237
Share (Jan - Jun)	100.0%	12.4%	3.5%	100.0%	10.9%	3.3%

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 4-10 provides a description of commitment and dispatch status, uplift eligibility and the ability to set price.[19] 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.[20]

Table 4-10 Dispatch status, commitment status and uplift eligibility[21]

		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

Table 4-11 shows day-ahead and real-time generation by commitment and dispatch status.

Table 4-11 Day-ahead and real-time generation by offer status and eligibility to set LMP (GWh): January through June, 2022

	Self Scheduled			Pool Scheduled						
	Dispatchable	Economic Minimum	Block Loaded	Dispatchable	Economic Minimum	Block Loaded	Total GWh	Total Pool Scheduled	Total Self Scheduled	Total Generation Eligible to Set Price
Day-Ahead Generation	39,478	87,838	99,614	84,339	84,855	11,901	408,026	181,096	226,931	123,817
Share of Day-Ahead	9.7%	21.5%	24.4%	20.7%	20.8%	2.9%	100.0%	44.4%	55.6%	30.3%
Real-Time Generation	34,993	85,618	98,157	83,057	92,557	13,575	407,957	189,189	218,768	118,050
Share of Real-Time	8.6%	21.0%	24.1%	20.4%	22.7%	3.3%	100.0%	46.4%	53.6%	28.9%

19 PJM has modified the basic rules of eligibility to set price using its CT price setting logic.
20 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.
21 PJM allows block loaded CTs to set LMP by relaxing the economic minimum by 10 to 20 percent using CT price setting logic.

Economic and Noneconomic Generation[22]

Economic generation includes units scheduled day ahead by PJM, or that produce energy in real time, at an incremental offer less than or equal to the LMP at the unit's bus. Noneconomic generation includes units scheduled day ahead by PJM, or that produce energy in real time, at an incremental offer greater than the LMP at the unit's bus.

Each unit's hourly generation was determined to be economic or noneconomic based on the unit's hourly incremental offer, excluding the hourly no load and any applicable startup cost. A unit could be economic for every hour during a day or segment, but still receive operating reserve credits because the energy revenues did not cover the hourly no load and startup cost. A unit could be noneconomic for multiple hours and not receive operating reserve credits when the total revenues covered the total offer (including no load and startup cost) for the entire day or segment.

Table 4-12 shows the day-ahead and real-time economic and noneconomic generation from units eligible for operating reserve credits, which are defined by PJM as pool scheduled and dispatchable units. In the first six months of 2022, 89.4 percent of the day-ahead generation MWh eligible for operating reserve credits was economic and 64.0 percent of the real-time generation MWh eligible for operating reserve credits was economic. A unit's generation MWh may be noneconomic for a portion of their daily generation and economic for the rest.

Noneconomic generation only leads to operating reserve credits when a unit is unable to recover its operating costs for the entire day or segment. Table 4-12 shows the generation receiving day-ahead and balancing operating reserve credits. In the first six months of 2022, 0.6 percent of the day-ahead generation eligible for operating reserve credits received credits and 1.2 percent of the real-time generation eligible for operating reserve credits received credits.

22 The analysis of economic and noneconomic generation is based on units' incremental offers and does not include no load or startup costs.

Table 4-12 Economic and noneconomic generation from units eligible for operating reserve credits (GWh): January through June, 2022

	Energy Market	
Generation	Day-Ahead	Real-Time
Economic Generation	161,803	99,106
Noneconomic Generation	19,283	55,674
Total Eligible Generation	181,086	154,780
Economic Generation Percent	89.4%	64.0%
Noneconomic Generation Percent	10.6%	36.0%
Generation Receiving Operating Reserve Credits	1,143	1,830
Generation Receiving Operating Reserve Credits Percent	0.6%	1.2%

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. Since 2018, the cumulative resettlement requests total $14.9 million, of which PJM has agreed and resettled 9.8 percent, disagreed with 1.5 percent, and 75.4 percent remain pending. The remaining 13.3 percent occurred prior to June 2020 and would now require a directive from FERC for them to be resettled. PJM has refused to accept the return of incorrectly paid uplift credits by generators when the MMU has identified such cases. The MMU continues to bring new cases to the attention of PJM.

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

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.[23]

Figure 4-1 shows the concentration of energy uplift credits. The top 10 units received 16.8 percent of total energy uplift credits in the first six months of 2022, compared to 16.8 percent in the same time period in 2021. In the first six months of 2022, 256 units received 90 percent of all energy uplift credits, compared to 236 units in the same time period in 2021.

Figure 4-1 Cumulative share of energy uplift credits by unit: January through June, 2021 and 2022

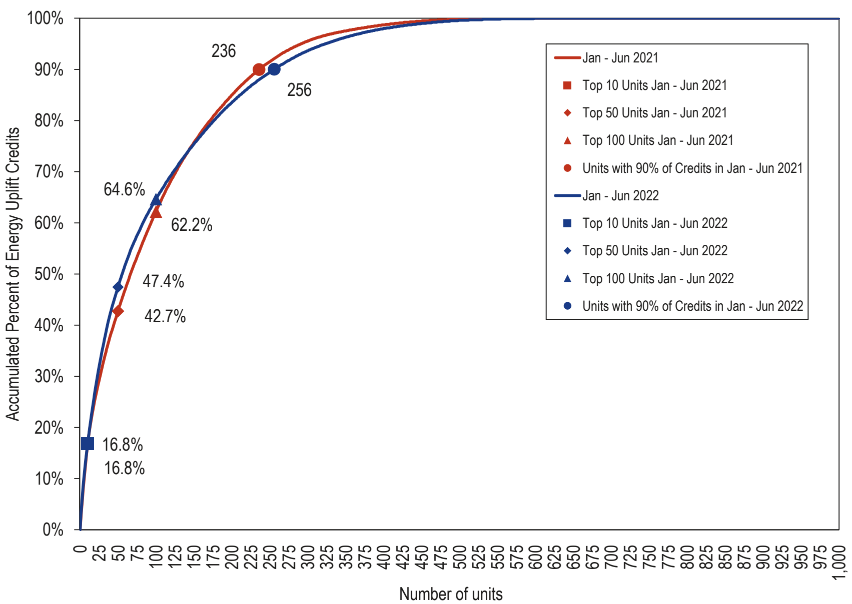

Table 4-13 shows the credits received by the top 10 units and top 10 organizations in each of the energy uplift categories paid to generators in the first six months of 2021 and 2022.

Table 4-13 Top 10 units and organizations energy uplift credits: January through June, 2022

		Top 10 Units		Top 10 Organizations	
Category	Type	Credits (Millions)	Credits Share	Credits (Millions)	Credits Share
Day-Ahead	Generators	$6.9	79.0%	$8.5	97.5%
Balancing	Canceled Resources	$0.0	0.0%	$0.0	0.0%
	Generators	$11.1	20.3%	$41.4	75.2%
	Local Constraints Control	$1.1	93.1%	$1.2	100.0%
	Lost Opportunity Cost	$4.5	32.1%	$10.3	73.8%
	Dispatch Differential Lost Opportunity Cost	$0.43	23.0%	$1.3	70.2%
Reactive Services		$1.0	100.0%	$1.0	100.0%
Synchronous Condensing		$0.0	0.0%	$0.0	0.0%
Black Start Services		$0.1	42.0%	$0.3	89.3%
Total		$13.8	16.8%	$61.1	74.4%

In the first six months of 2022, concentration in all energy uplift credit categories was high.[24] [25] The HHI for energy uplift credits was calculated based on each organization's share of daily credits for each category.[26] Table 4-14 shows the average HHI for each category. HHI for day-ahead operating reserve credits to generators was 8404, for balancing operating reserve credits to generators was 2647, for lost opportunity cost credits was 5096 and for reactive services credits was 3459. All of these HHI values are characterized as highly concentrated.

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

24 See the *2020 State of the Market Report for PJM*, Volume II, Section 3: "Energy Market" at "Market Concentration" for a discussion of concentration ratios and the Herfindahl-Hirschman Index (HHI).

25 Table 4-17 excludes local constraint control categories.

26 Concentration is measured using the entity (or entities) to which the uplift credit is paid.

Table 4-14 Daily energy uplift credits HHI: January through June, 2022

Category	Type	Average	Minimum	Maximum	Highest Market Share (One day)	Highest Market Share (All days)
Day-Ahead	Generators	8404	2138	10000	100.0%	63.2%
	Imports	10000	10000	10000	100.0%	81.5%
	Load Response	10000	10000	10000	100.0%	100.0%
Balancing	Canceled Resources	NA	NA	NA	NA	NA
	Generators	2647	901	10000	100.0%	14.4%
	Imports	NA	NA	NA	NA	NA
	Load Response	NA	NA	NA	NA	NA
	Lost Opportunity Cost	5096	1477	10000	100.0%	26.3%
	Dispatch Differential Lost Opportunity Cost	3459	643	10000	100.0%	20.1%
Reactive Services		9428	5428	10000	100.0%	49.9%
Synchronous Condensing		NA	NA	NA	NA	NA
Black Start Services		9619	4457	10000	100.0%	21.5%
Total		3459	643	10000	99.7%	12.2%

Unit Specific Uplift Payments

FERC Order No. 844 allows PJM and the MMU to publish unit specific uplift payments by category by month. Table 4-15 through Table 4-18 show the top 10 recipients of total uplift, day-ahead operating reserve credits and lost opportunity cost credits. The top 10 units receiving uplift credits received 16.8 percent of all credits, with the top recipient receiving 2.9 percent. The top 10 units receiving day-ahead operating reserves received 79.0 percent. The top 10 recipients of balancing operating reserves received 20.3 percent of balancing operating reserve credits. The top 10 recipients of lost opportunity cost credits received 32.1 percent of total lost opportunity cost credits.

Table 4-15 Top 10 recipients of total uplift: January through June, 2022

Rank	Unit Name	Zone	Total Uplift Credit	Share of Total Uplift Credits
1	BC BRANDON SHORES 1 F	BGE	$2,411,261	2.9%
2	VP MARSHRUN 2 CT	DOM	$1,546,841	1.9%
3	VP MARSHRUN 3 CT	DOM	$1,519,963	1.9%
4	VP MARSHRUN 1 CT	DOM	$1,388,643	1.7%
5	VP FOUR RIVERS 1 CT	DOM	$1,313,407	1.6%
6	VP LOUISA 5 CT	DOM	$1,301,518	1.6%
7	VP DOSWELL 3 CT	DOM	$1,161,483	1.4%
8	BC WAGNER 4 F	BGE	$1,098,156	1.3%
9	PL BRUNNER ISLAND 3 F	PPL	$1,025,837	1.2%
10	AEP ROBERT P MONE 3 CT	AEP	$1,005,550	1.2%
Total of Top 10			$13,772,658	16.8%
Total Uplift Credits			$82,114,716	100.0%

Table 4-16 Top 10 recipients of day-ahead generation credits: January through June, 2022

Rank	Unit Name	Zone	Day-Ahead Operating Reserve Credit	Share of Day-Ahead Operating Reserve Credits
1	BC BRANDON SHORES 1 F	BGE	$1,702,180	19.4%
2	PL BRUNNER ISLAND 3 F	PPL	$861,288	9.8%
3	BC BRANDON SHORES 2 F	BGE	$770,692	8.8%
4	PL BRUNNER ISLAND 2 F	PPL	$704,857	8.1%
5	VP YORKTOWN 3 F	DOM	$699,950	8.0%
6	BC WAGNER 4 F	BGE	$623,864	7.1%
7	BC WAGNER 1 F	BGE	$572,485	6.5%
8	PEP MORGANTOWN 2 F	PEPCO	$391,168	4.5%
9	PEP CHALKPOINT 4 F	PEPCO	$387,724	4.4%
10	PL BRUNNER ISLAND 1 F	PPL	$198,929	2.3%
Total of Top 10			$6,913,136	79.0%
Total day-ahead operating reserve credits			$8,754,235	100.0%

Table 4-17 Top 10 recipients of balancing operating reserve credits: January through June, 2022

Rank	Unit Name	Zone	Balancing Operating Reserve Credit	Share of Balancing Operating Reserve Credits
1	VP MARSHRUN 2 CT	DOM	$1,501,411	2.7%
2	VP MARSHRUN 3 CT	DOM	$1,482,798	2.7%
3	VP MARSHRUN 1 CT	DOM	$1,332,043	2.4%
4	VP LOUISA 5 CT	DOM	$1,220,737	2.2%
5	VP FOUR RIVERS 1 CT	DOM	$1,198,101	2.2%
6	VP DOSWELL 3 CT	DOM	$1,038,798	1.9%
7	AEP ROBERT P MONE 3 CT	AEP	$914,026	1.7%
8	VP DOSWELL 2 CT	DOM	$895,122	1.6%
9	VP REMINGTON 3 CT	DOM	$803,537	1.5%
10	VP REMINGTON 4 CT	DOM	$753,800	1.4%
Total of Top 10			$11,140,374	20.3%
Total balancing operating reserve credits			$54,981,622	100.0%

Table 4-18 Top 10 recipients of lost opportunity cost credits: January through June, 2022

Rank	Unit Name	Zone	Lost Opportunity Cost Credit	Share of Lost Opportunity Cost Credits
1	DAY DARBY 3 CT	AEP	$600,623	4.3%
2	DAY DARBY 1 CT	AEP	$599,215	4.3%
3	DAY DARBY 2 CT	AEP	$597,418	4.3%
4	DAY DARBY 4 CT	AEP	$539,894	3.9%
5	DAY DARBY 5 CT	AEP	$535,166	3.8%
6	DAY DARBY 6 CT	AEP	$533,934	3.8%
7	PL LACKAWANNA COUNTY 3 CC	PPL	$316,779	2.3%
8	PN FAIRVIEW 1 CC	PE	$257,089	1.8%
9	PN FAIRVIEW 2 CC	PE	$256,333	1.8%
10	EKPC BLUEGRASS 2 CT	External	$247,220	1.8%
Total of Top 10			$4,483,672	32.1%
Total lost opportunity cost credits			$13,963,285	100.0%

Table 4-19 Top 10 recipients of dispatch differential lost opportunity cost credits: January through June, 2022

Rank	Unit Name	Zone	Dispatch Differential Lost Opportunity Cost Credit	Share of Dispatch Differential Lost Opportunity Cost Credits
1	PL SAFEHARBOR 4 H	PPL	$75,722	4.0%
2	PL HOLTWOOD 19	PPL	$72,224	3.9%
3	PL SAFEHARBOR 12 H	PPL	$63,970	3.4%
4	AP LKLYN 1-4 H	AP	$33,928	1.8%
5	DPL COMM CHESAPEAKE - NEW CHURCH 6 CT	DPL	$32,017	1.7%
6	PL SAFEHARBOR 8 H	PPL	$31,462	1.7%
7	JC WOODBRIDGE 2 CC	JCPLC	$31,145	1.7%
8	DPL EDGEMOOR 10 CT	DPL	$30,842	1.6%
9	DPL COMM CHESAPEAKE - NEW CHURCH 7 CT	DPL	$29,998	1.6%
10	PL HOLTWOOD 2	PPL	$29,776	1.6%
Total of Top 10			$431,084	23.0%
Total dispatch differential lost opportunity cost credits			$1,870,949	13.4%

Credits and Charges Categories

Energy uplift charges include day-ahead and balancing operating reserves, reactive services, synchronous condensing and black start services categories. Total energy uplift credits paid to PJM participants equal the total energy uplift charges paid by PJM participants. Table 4-20 and Table 4-21 show the categories of credits and charges and their relationship. These tables show how the charges are allocated. The dispatch differential lost opportunity cost credit is a new balancing credit that was introduced during the implementation of fast start pricing on September 1, 2021. The new credit is charged and allocated to PJM members in proportion to their real-time load and exports for generator credits provided for reliability.

Table 4-20 Day-ahead and balancing operating reserve credits and charges

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

Table 4-21 Reactive services, synchronous condensing and black start services credits and charges

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

Energy Uplift Charges Results

Energy Uplift Charges

Total energy uplift charges increased by $2.8 million, or 3.6 percent, in the first six months of 2022 compared to the first six months of 2021, from $79.3 million to $82.1 million.

Table 4-22 shows total energy uplift charges by category in the first six months of 2021 and 2022.[27] The increase of $2.8 million is comprised of a $1.6 million increase in day-ahead operating reserve charges, a $0.9 million decrease in balancing operating reserve charges, a $0.3 million increase in reactive service charges, and $0.2 million increase in black start services charges.

Table 4-22 Total energy uplift charges by category: January through June, 2022[28]

Category	(Jan - Jun) 2021 Charges (Millions)	(Jan - Jun) 2022 Charges (Millions)	Change (Millions)	Percent Change
Day-Ahead Operating Reserves	$7.2	$8.8	$1.6	21.9%
Balancing Operating Reserves	$71.2	$72.0	$0.9	1.2%
Reactive Services	$0.7	$1.0	$0.3	34.5%
Synchronous Condensing	$0.0	$0.0	$0.0	0.0%
Black Start Services	$0.2	$0.3	$0.2	82.2%
Total	$79.3	$82.1	$2.8	3.6%
Energy Uplift as a Percent of Total PJM Billing	0.4%	0.2%	(0.1%)	(41.5%)

27 Table 4-22 includes all categories of charges as defined in Table 4-20 and Table 4-21 and includes all PJM Settlements billing adjustments. Billing data can be modified by PJM Settlements at any time to reflect changes in the evaluation of energy uplift. The billing data reflected in this report were current on July 8, 2022.

28 In Table 4-22, the MMU uses Total PJM Billing values provided by PJM. For 2019 and after, the Total PJM Billing calculation was modified to better reflect PJM total billing through the PJM settlement process.

Table 4-23 compares monthly energy uplift charges by category for the first six months of 2021 and 2022.

Table 4-23 Monthly energy uplift charges: January 2021 through June 2022

	2021 Charges (Millions)						2022 Charges (Millions)					
	Day-Ahead	Balancing	Reactive Services	Synchronous Condensing	Black Start Services	Total	Day-Ahead	Balancing	Reactive Services	Synchronous Condensing	Black Start Services	Total
Jan	$0.7	$6.8	$0.7	$0.0	$0.0	$8.2	$0.7	$14.6	$0.0	$0.0	$0.0	$15.3
Feb	$0.9	$13.6	$0.1	$0.0	$0.0	$14.6	$0.5	$5.1	$0.0	$0.0	$0.1	$5.6
Mar	$2.8	$8.5	$0.0	$0.0	$0.1	$11.4	$0.5	$7.0	$0.2	$0.0	$0.0	$7.8
Apr	$0.8	$17.0	$0.0	$0.0	$0.0	$17.8	$0.6	$13.4	$0.0	$0.0	$0.1	$14.1
May	$0.6	$8.7	$0.0	$0.0	$0.0	$9.3	$2.3	$12.0	$0.8	$0.0	$0.1	$15.2
Jun	$1.3	$16.5	$0.0	$0.0	$0.0	$17.8	$4.1	$20.0	$0.0	$0.0	$0.0	$24.1
Jul	$0.6	$19.7	$0.0	$0.0	$0.0	$20.3						
Aug	$1.1	$21.2	$0.0	$0.0	$0.0	$22.3						
Sep	$1.9	$7.3	$0.0	$0.0	$0.0	$9.2						
Oct	$0.4	$14.2	$0.0	$0.0	$0.1	$14.7						
Nov	$0.8	$21.6	$0.2	$0.0	$0.0	$22.6						
Dec	$1.6	$8.2	$0.0	$0.0	$0.0	$9.9						
Total (Jan - Jun)	$7.2	$71.2	$0.7	$0.0	$0.2	$79.3	$8.8	$72.0	$1.0	$0.0	$0.3	$82.1
Share (Jan - Jun)	9.1%	89.8%	0.9%	0.0%	0.2%	100.0%	10.7%	87.7%	1.2%	0.0%	0.4%	100.0%

Table 4-24 shows the composition of day-ahead operating reserve charges. Day-ahead operating reserve charges include payments for credits to generators and import transactions, day-ahead operating reserve charges for economic load response resources and day-ahead operating reserve charges from unallocated congestion charges.[29] [30] Day-ahead operating reserve charges increased by $1.6 million or 21.9 percent in the first six months of 2022 compared to 2021.

Table 4-24 Day-ahead operating reserve charges: January through June, 2021 and 2022

Type	(Jan - Jun) 2021 Charges (Millions)	(Jan - Jun) 2022 Charges (Millions)	Change (Millions)	(Jan - Jun) 2021 Share	(Jan - Jun) 2022 Share
Day-Ahead Operating Reserve Charges	$7.2	$8.8	$1.6	100.0%	100.0%
Day-Ahead Operating Reserve Charges for Load Response	$0.0	$0.0	($0.0)	0.0%	0.0%
Unallocated Congestion Charges	$0.0	$0.0	$0.0	0.0%	0.0%
Total	$7.2	$8.8	$1.6	100.0%	100.0%

Table 4-25 shows the composition of the balancing operating reserve charges. Balancing operating reserve charges consist of balancing operating reserve reliability charges (credits to generators), balancing operating reserve deviation charges (credits to generators and import transactions), balancing operating reserve charges for economic load response and balancing local constraint charges. Balancing operating reserve charges decreased by $0.9 million or 1.2 percent in the first six months of 2022 compared to 2021.

29 See PJM Operating Agreement Schedule 1 § 3.2.3(c). Unallocated congestion charges are added to the total costs of day-ahead operating reserves. Congestion charges have been allocated to day-ahead operating reserves only 10 times since 1999, totaling $26.9 million.
30 See the *2021 Quarterly State of the Market Report for PJM: January through June*, Section 13, Financial Transmission Rights and Auction Revenue Rights.

Table 4-25 Balancing operating reserve charges: January through June, 2021 and 2022

Type	(Jan - Jun) 2021 Charges (Millions)	(Jan - Jun) 2022 Charges (Millions)	Change (Millions)	(Jan - Jun) 2021 Share	(Jan - Jun) 2022 Share
Balancing Operating Reserve Reliability Charges	$31.1	$26.7	($4.4)	43.8%	37.1%
Balancing Operating Reserve Deviation Charges	$35.4	$44.1	$8.7	49.7%	61.2%
Balancing Operating Reserve Charges for Load Response	$0.0	$0.0	($0.0)	0.0%	0.0%
Balancing Local Constraint Charges	$4.6	$1.2	($3.4)	6.5%	1.7%
Total	$71.2	$72.0	$0.9	100.0%	100.0%

Table 4-26 shows the composition of the balancing operating reserve deviation charges. Balancing operating reserve deviation charges are the sum of: make whole credits paid to generators and import transactions, energy lost opportunity costs paid to generators, and payments to resources scheduled by PJM but canceled by PJM before coming online. In the first six months of 2022, energy lost opportunity cost deviation charges decreased by $2.9 million or 25.8 percent, and make whole deviation charges decreased by $5.9 million or 24.2 percent compared to 2021.

Table 4-26 Balancing operating reserve deviation charges: January through June, 2021 and 2022

Charge Attributable To	(Jan - Jun) 2021 Charges (Millions)	(Jan - Jun) 2022 Charges (Millions)	Change (Millions)	(Jan - Jun) 2021 Share	(Jan - Jun) 2022 Share
Make Whole Payments to Generators and Imports	$24.3	$30.2	$5.9	68.6%	68.4%
Energy Lost Opportunity Cost	$11.1	$14.0	$2.9	31.4%	31.6%
Canceled Resources	$0.0	$0.0	$0.0	0.0%	0.0%
Total	$35.4	$44.1	$8.7	100.0%	100.0%

Table 4-27 shows reactive services, synchronous condensing and black start services charges. Reactive services charges decreased by $5.9 million or 24.2 percent in the first six months of 2022, compared to the first six months of 2021.

Table 4-27 Additional energy uplift charges: January through June, 2021 and 2022

Type	(Jan - Jun) 2021 Charges (Millions)	(Jan - Jun) 2022 Charges (Millions)	Change (Millions)	(Jan - Jun) 2021 Share	(Jan - Jun) 2022 Share
Reactive Services Charges	$0.7	$1.0	$0.3	80.1%	74.8%
Synchronous Condensing Charges	$0.0	$0.0	$0.0	0.0%	0.0%
Black Start Services Charges	$0.2	$0.3	$0.2	19.9%	25.2%
Total	$0.9	$1.3	$0.4	100.0%	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 4-28 illustrates the composition of charges and the transactions included in the charge calculation. For example, balancing operating reserve charges for deviations are calculated by adding the RTO deviation rate, the regional deviation rates, the LOC rate, and the canceled resources rate. For example, the INCs are responsible for paying the RTO deviation rate, the regional deviation rate, the LOC rate, and the canceled resources rate.

Figure 4-2 shows the daily day-ahead operating reserve rate for 2021 and the first six months of 2022. The average rate during the first six months of 2022 was $0.019 per MWh, $0.003 per MWh higher than the average in the same time period in 2021. The highest rate during the first six months of 2022 occurred on May 22 and the rate reached $0.196 per MWh, $ 0.068 per MWh higher than the $0.128 per MWh reached in in the first six months of 2021, on May 4. Figure 4-2 also shows the daily day-ahead operating reserve rate including the congestion charges allocated to day-ahead operating reserves. There were no congestion charges allocated to day-ahead operating reserves in the first six months of 2021 or 2022.

Table 4-28 Composition of charges[31]

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

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

31 The lost opportunity cost and canceled resources rates are not posted separately by PJM. PJM adds the lost opportunity cost and the canceled resources rates to the deviation rate for the RTO Region since these three charges are allocated following the same rules.

Figure 4-2 Daily day-ahead operating reserve rate ($/MWh): January 2021 through June 2022

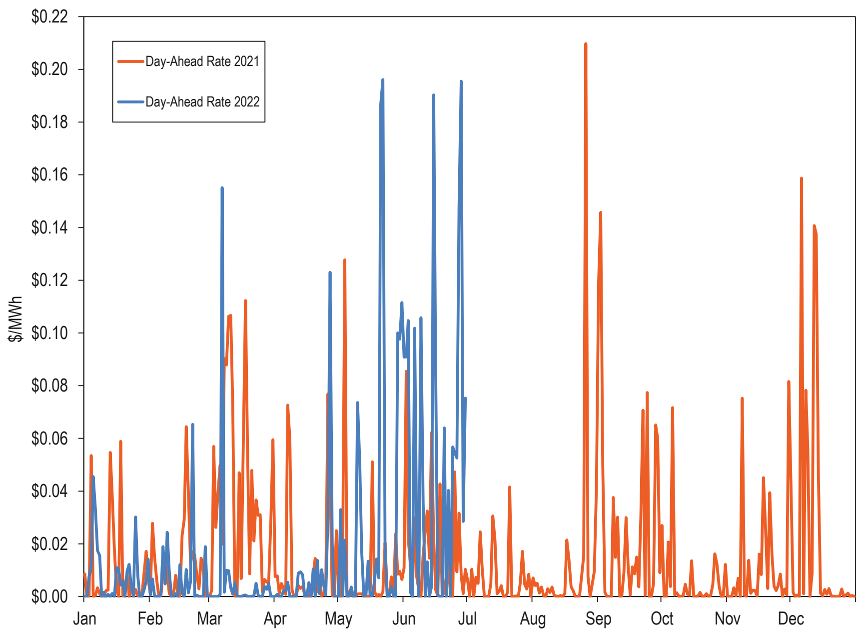

Figure 4-3 shows the RTO and the regional reliability rates for 2021 and the first six months of 2022. The average RTO reliability rate in the first six months of 2022 decreased to $ 0.056 per MWh from $0.070 in 2021. The highest RTO reliability rate in the first six months of 2022 occurred on January 27 when the rate reached $0.456 per MWh, $0.207 per MWh lower than the $0.662 per MWh rate reached in the first six months of 2021, on June 29.

Figure 4-3 Daily balancing operating reserve reliability rates ($/MWh): January 2021 through June 2022

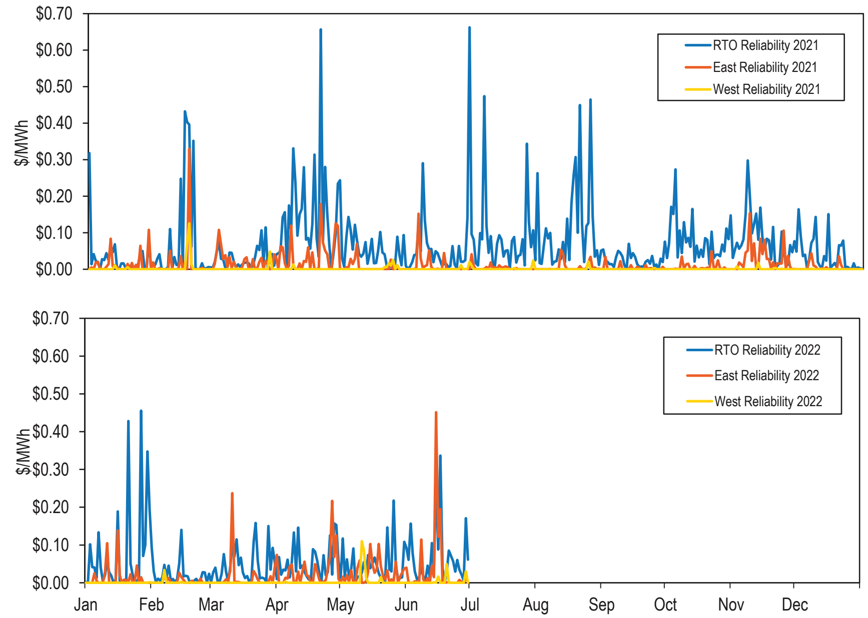

Figure 4-4 shows the RTO and regional deviation rates for 2021 and the first six months of 2022. The average RTO deviation rate in the first six months of 2022 was $0.163 per MWh. The highest daily rate during the first six months of 2022 occurred on April 9, when the RTO deviation rate reached $0.877 per MWh, $0.833 per MWh less than the $1.710 per MWh rate reached in the first six months of 2021, on April 19.

Figure 4-4 Daily balancing operating reserve deviation rates ($/MWh): January 2021 through June 2022

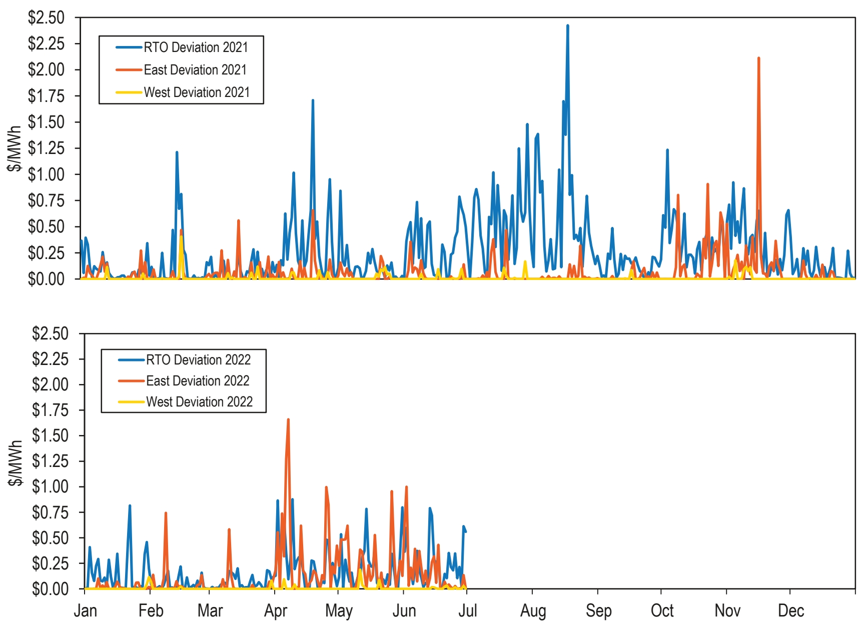

Figure 4-5 shows the daily lost opportunity cost rate and the daily canceled resources rate for 2021 and the first six months of 2022. The average lost opportunity cost rate in the first six months of 2021 was $0.099 per MWh. The highest lost opportunity cost rate in the first six months of 2022 occurred on June 13, when it reached $3.777 per MWh, $2.581 per MWh more than the $1.197 per MWh rate reached in the first six months of 2021, on May 25.

Figure 4-5 Daily lost opportunity cost and canceled resources rates ($/MWh): January 2021 through June 2022

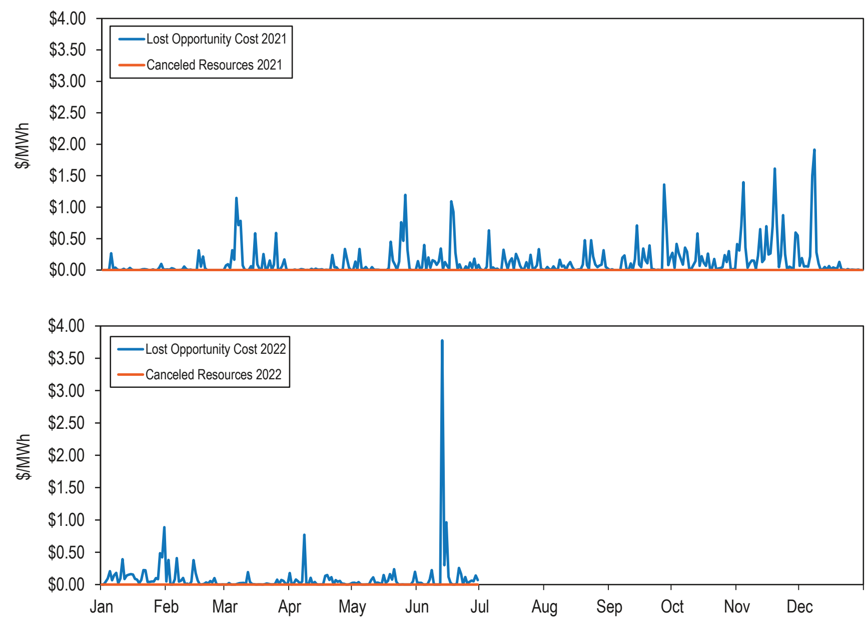

Table 4-29 shows the average rates for each region in each category for the first six months of 2021 and 2022.

Table 4-29 Operating reserve rates ($/MWh): January through June, 2021 and 2022

Rate	(Jan - Jun) 2021 ($/MWh)	(Jan - Jun) 2022 ($/MWh)	Difference ($/MWh)	Percent Difference
Day-Ahead	0.017	0.019	0.003	16.5%
Day-Ahead with Unallocated Congestion	0.017	0.019	0.003	16.5%
RTO Reliability	0.070	0.056	(0.014)	(20.6%)
East Reliability	0.018	0.021	0.003	18.7%
West Reliability	0.003	0.002	(0.000)	(17.3%)
RTO Deviation	0.190	0.163	(0.027)	(14.4%)
East Deviation	0.048	0.124	0.076	159.4%
West Deviation	0.011	0.005	(0.005)	(49.8%)
Lost Opportunity Cost	0.099	0.102	0.003	3.1%
Canceled Resources	0.000	0.000	NA	NA
Dispatch Differential Lost Opportunity Cost	NA	0.005	NA	NA

Reactive Services Rates

Reactive services charges associated with local voltage support are allocated to real-time load in the control zone or zones where the service is provided. These charges result from uplift payments to units committed by PJM to support reactive/voltage requirements that do not recover their energy offer through LMP payments if they are committed out of merit to provide reactive, or incur opportunity costs associated with reduced energy output. These charges are separate from the reactive service capability revenue requirement charges which are a fixed annual charge based on approved FERC filings.[32] Reactive services charges associated with supporting reactive transfer interfaces above 345 kV are allocated daily to real-time load across the entire RTO based on the real-time load ratio share of each network customer.

While reactive services rates are not posted by PJM, a local voltage support rate for each control zone can be calculated and a reactive transfer interface support rate can be calculated for the entire RTO. Table 4-30 shows the reactive services rates associated with local voltage support in the first six months of 2021 and 2022. Table 4-30 shows that in 2022 only five zones incurred reactive services charges.

Table 4-30 Local voltage support rates: January through June, 2021 and 2022

Control Zone	(Jan - Jun) 2021 ($/MWh)	(Jan - Jun) 2022 ($/MWh)	Difference ($/MWh)	Percent Difference
ACEC	0.000	0.000	0.000	0.0%
AEP	0.000	0.000	(0.000)	(100.0%)
APS	0.000	0.000	0.000	0.0%
ATSI	0.000	0.000	0.000	0.0%
BGE	0.000	0.018	0.018	NA
COMED	0.000	0.000	0.000	0.0%
DAY	0.000	0.000	0.000	0.0%
DUKE	0.000	0.000	0.000	0.0%
DUQ	0.000	0.000	0.000	0.0%
DOM	0.000	0.004	0.004	NA
DPL	0.000	0.001	0.001	NA
EKPC	0.000	0.000	0.000	0.0%
JCPLC	0.000	0.000	0.000	0.0%
MEC	0.001	0.001	0.000	1.6%
OVEC	0.000	0.000	0.000	0.0%
PECO	0.000	0.000	0.000	0.0%
PE	0.000	0.000	0.000	0.0%
PEPCO	0.000	0.036	0.036	NA
PPL	0.034	0.000	(0.034)	(100.0%)
PSEG	0.000	0.000	0.000	0.0%
REC	0.000	0.000	0.000	0.0%

Geography of Charges and Credits

Table 4-31 shows the geography of charges and credits in the first six months of 2022. Table 4-31 includes only day-ahead operating reserve charges and balancing operating reserve reliability and deviation charges since these categories are allocated regionally, while other charges, such as reactive services, synchronous condensing and black start services are allocated by control zone, and balancing local constraint charges are charged to the requesting party.

Charges are categorized by the location (control zone, hub, aggregate or interface) where they are allocated according to PJM's operating reserve rules. Credits are categorized by the location where the resources are located. The shares columns reflect the operating reserve credits and charges balance for

32 See *2021 State of the Market Report for PJM*, Volume 2; Section 10: Ancillary Service Markets.

each location. For example, transactions in the PPL Control Zone paid 5.0 percent of all operating reserve charges allocated regionally while resources in the PPL Control Zone were paid 5.3 percent of the corresponding credits. The PPL Control Zone received fewer operating reserve credits than operating reserve charges paid and had 0.7 percent of the deficit. The deficit is the net of the credits and charges paid at a location. Transactions in the BGE Control Zone paid 3.6 percent of all operating reserve charges allocated regionally, and resources in the BGE Control Zone were paid 7.7 percent of the corresponding credits. The BGE Control Zone received fewer operating reserve credits than operating reserve charges paid and had 14.1 percent of the surplus. The surplus is the net of the credits and charges paid at a location. Table 4-31 also shows that 86.2 percent of all charges were allocated in control zones, 6.2 percent in hubs and aggregates and 7.7 percent in interfaces.

Table 4-31 Geography of regional charges and credits: January through June, 2022

					Shares			
Location		Charges (Millions)	Credits (Millions)	Balance	Total Charges	Total Credits	Deficit	Surplus
Zones	ACEC	$1.0	$1.1	$0.1	1.3%	1.4%	0.0%	0.3%
	AEP	$11.1	$14.2	$3.1	13.6%	17.8%	0.0%	13.6%
	APS	$3.2	$2.1	($1.1)	3.9%	2.7%	4.7%	0.0%
	ATSI	$4.5	$3.3	($1.2)	5.5%	4.1%	5.4%	0.0%
	BGE	$2.9	$6.2	$3.2	3.6%	7.7%	0.0%	14.1%
	COMED	$7.8	$5.7	($2.1)	9.6%	7.2%	9.2%	0.0%
	DAY	$1.4	$3.1	$1.7	1.8%	3.9%	0.0%	7.4%
	DUKE	$2.5	$0.9	($1.6)	3.0%	1.1%	7.1%	0.0%
	DUQ	$1.0	$0.1	($0.9)	1.3%	0.1%	4.2%	0.0%
	DOM	$10.8	$21.4	$10.6	13.3%	26.9%	0.0%	46.5%
	DPL	$2.0	$2.5	$0.6	2.4%	3.2%	0.0%	2.5%
	EKPC	$1.5	$3.1	$1.7	1.8%	3.9%	0.0%	7.3%
	External	$0.0	$1.7	$1.7	0.0%	2.2%	0.0%	7.5%
	JCPLC	$1.9	$0.6	($1.2)	2.3%	0.8%	5.4%	0.0%
	MEC	$1.6	$1.5	($0.2)	2.0%	1.8%	0.8%	0.0%
	OVEC	$0.4	$0.0	($0.3)	0.4%	0.1%	1.4%	0.0%
	PECO	$3.4	$0.5	($2.9)	4.2%	0.7%	12.9%	0.0%
	PE	$2.3	$2.4	$0.0	2.8%	3.0%	0.0%	0.2%
	PEPCO	$2.7	$2.0	($0.7)	3.3%	2.5%	3.1%	0.0%
	PPL	$4.0	$4.2	$0.1	5.0%	5.3%	0.0%	0.7%
	PSEG	$3.7	$2.8	($0.9)	4.6%	3.5%	4.0%	0.0%
	REC	$0.4	$0.0	($0.4)	0.5%	0.0%	1.8%	0.0%
	All Zones	$70.2	$79.6	$9.4	86.2%	100.0%	60.1%	100.0%
Hubs and Aggregates	AEP - Dayton	$0.7	$0.0	($0.7)	0.9%	0.0%	3.2%	0.0%
	Dominion	$0.7	$0.0	($0.7)	0.9%	0.0%	3.3%	0.0%
	Eastern	$0.4	$0.0	($0.4)	0.5%	0.0%	2.0%	0.0%
	New Jersey	$0.5	$0.0	($0.5)	0.6%	0.0%	2.1%	0.0%
	Ohio	$0.7	$0.0	($0.7)	0.9%	0.0%	3.2%	0.0%
	Western Interface	$0.0	$0.0	$0.0	0.0%	0.0%	0.0%	0.0%
	Western	$2.0	$0.0	($2.0)	2.4%	0.0%	8.8%	0.0%
	RTEP B0328 Source	$0.0	$0.0	$0.0	0.0%	0.0%	0.0%	0.0%
	All Hubs and Aggregates	$5.0	$0.0	($5.0)	6.2%	0.0%	22.5%	0.0%
Interfaces	CPLE Exp	$0.0	$0.0	$0.0	0.0%	0.0%	0.0%	0.0%
	CPLE Imp	$0.0	$0.0	$0.0	0.0%	0.0%	0.0%	0.0%
	Duke Exp	$0.0	$0.0	$0.0	0.0%	0.0%	0.0%	0.0%
	Duke Imp	$0.0	$0.0	$0.0	0.0%	0.0%	0.0%	0.0%
	Hudson	$0.3	$0.0	($0.3)	0.4%	0.0%	1.5%	0.0%
	IMO	$0.4	$0.0	($0.4)	0.5%	0.0%	2.0%	0.0%
	Linden	$0.2	$0.0	($0.2)	0.3%	0.0%	1.0%	0.0%
	MISO	$1.6	$0.0	($1.6)	2.0%	0.0%	7.3%	0.0%
	NCMPA Imp	$0.0	$0.0	$0.0	0.0%	0.0%	0.0%	0.0%
	Neptune	$0.2	$0.0	($0.2)	0.3%	0.0%	1.1%	0.0%
	NIPSCO	$0.0	$0.0	$0.0	0.0%	0.0%	0.0%	0.0%
	Northwest	$0.0	$0.0	$0.0	0.0%	0.0%	0.0%	0.0%
	NYIS	$1.0	$0.0	($1.0)	1.2%	0.0%	4.5%	0.0%
	South Exp	$0.0	$0.0	$0.0	0.0%	0.0%	0.0%	0.0%
	South Imp	$0.0	$0.0	$0.0	0.0%	0.0%	0.0%	0.0%
	South	$2.4	$0.0	($2.4)	2.9%	0.0%	10.6%	0.0%
	All Interfaces	$6.2	$0.0	($6.2)	7.7%	0.0%	17.4%	0.0%
	Total	$81.4	$79.6	($1.9)	100.0%	100.0%	100.0%	100.0%

Energy Uplift Issues

Intraday Segments Uplift Settlement

PJM pays uplift separately for multiple segmented blocks of time during the operating day (intraday).[33] The use of intraday segments to calculate the need for uplift payments results in higher uplift payments than necessary to make units whole, including uplift payments to units that are profitable on a daily basis. The MMU recommends eliminating intraday segments from the calculation of uplift payments and returning to calculating the need for uplift based on the entire 24 hour operating day.

Table 4-32 shows balancing operating reserve credits calculated using intraday segments and balancing operating reserve payments calculated on a daily basis. In the first six months of 2022, balancing operating reserve credits would have been $12.1 million or 21.9 percent lower if they were calculated on a daily basis. In the first six months of 2021, balancing operating reserve credits would have been $8.4 million or 15.2 percent lower if they were calculated on a daily basis.

Table 4-32 Intraday segments and daily balancing operating reserve credits: January 2021 through June 2022

	2021 BOR Credits (Millions)			2022 BOR Credits (Millions)		
	Intraday Segments Calculation	Daily Calculation	Difference	Intraday Segments Calculation	Daily Calculation	Difference
Jan	$4.8	$4.2	($0.5)	$10.2	$8.5	($1.8)
Feb	$10.5	$9.4	($1.2)	$3.2	$2.5	($0.7)
Mar	$5.0	$4.0	($1.0)	$5.3	$4.5	($0.8)
Apr	$16.4	$15.0	($1.3)	$11.9	$9.9	($1.9)
May	$5.8	$4.7	($1.1)	$10.6	$7.9	($2.7)
Jun	$13.0	$9.8	($3.2)	$13.8	$9.7	($4.1)
Jul	$17.8	$14.0	($3.8)			
Aug	$19.6	$14.5	($5.1)			
Sep	$4.2	$2.4	($1.8)			
Oct	$11.6	$8.7	($2.9)			
Nov	$14.0	$9.9	($4.1)			
Dec	$4.9	$4.0	($0.9)			
Total (Jan - Jun)	$55.4	$47.0	($8.4)	$55.0	$42.9	($12.1)

33 See PJM "Manual 28: Operating Reserve Accounting," Rev. 85 (Sep. 1, 2021).

Prior to April 1, 2018, for purposes of calculating LOC credits, each hour was defined as a unique segment. Following the implementation of five minute settlements on April 1, 2018, LOC credits are calculated with each five minute interval defined as a unique segment. Thus a profit in one five minute segment, resulting from the real-time LMP being lower than the day-ahead LMP, is not used to offset a loss in any other five minute segment. This change in settlements causes an increase in LOC credits compared to hourly settlement as generators are made whole for any losses incurred in a five minute interval while previously gains and losses were netted within the hour. Table 4-33 shows the impact on day-ahead LOC credits to CTs that are committed DA but not RT. The table shows the LOC credits calculated in three ways: with the five minute settlement calculations implemented in April 2018; with hourly settlements prior to the change in April 2018; and with daily settlements. In the first six months of 2022, LOC credits would have been $ 1.6 million or 13.4 percent lower if they had been settled on an hourly basis rather than on a five minute basis. In the first six months of 2022, LOC credits would have been $3.6 million or 30.0 percent lower if they had been settled on the recommended daily basis rather than being settled on a five minute basis.

Table 4-33 Comparison of five minute, hourly, and daily settlement of day-ahead lost opportunity cost credits: January through June, 2022

	2022 Day-Ahead LOC Credits (Millions)				
	Five Minute Settlement (Status Quo)	Hourly Settlement (Pre-April 2018)	Difference	Daily Settlement (Recommendation)	Difference
Jan	$3.3	$2.7	($0.6)	$1.8	($1.5)
Feb	$1.4	$1.2	($0.2)	$1.0	($0.4)
Mar	$0.5	$0.4	($0.1)	$0.3	($0.2)
Apr	$0.8	$0.6	($0.2)	$0.4	($0.3)
May	$1.0	$0.7	($0.3)	$0.4	($0.6)
Jun	$5.1	$4.8	($0.3)	$4.6	($0.6)
Total (Jan - Jun)	$12.0	$10.4	($1.6)	$8.4	($3.6)

Uplift Credits by Offer Type

Absent 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 market power in the energy market.[34] If the TPS test is failed, market power mitigation is applied by offer capping the resources of the owners identified as having local market power. Offer capping is designed to set offers at competitive levels.

Table 4-34 shows the uplift credits paid to committed and dispatched units in the first six months of 2022 by offer type. Units received $32.4 million or 58.9 percent of balancing operating reserve credits and $3.8 million or 43.2 percent of day-ahead operating reserve credits in the first six months of 2022 using price-based offers. Units received $18.1 million or 33.0 percent of balancing operating reserves and $4.6 million or 52.6 percent of day-ahead operating reserves in the first six months of 2022 using cost-based offers.

Table 4-34 Operating Reserve Credits by Offer Type: January through June, 2022

Offer Type	Day Ahead Operating Reserve Credits (Millions)	Balancing Operating Reserve Credits (Millions)	Day Ahead Reactive Credits (Millions)	Real Time Reactive Credits (Millions)	Total
Cost	$4.6	$18.1	$0.5	$0.2	$23.5
Price	$3.8	$32.4	$0.3	$0.0	$36.4
Price PLS	$0.4	$3.2	$0.0	$0.0	$3.5
Cost & Price	$0.0	$1.1	$0.0	$0.0	$1.1
Cost & PLS	$0.0	$0.1	$0.0	$0.0	$0.1
Price & PLS	$0.0	$0.0	$0.0	$0.0	$0.0
Total	$8.8	$55.0	$0.7	$0.2	$64.7
Share	13.5%	84.9%	1.2%	0.4%	100.0%

Table 4-35 shows day-ahead operating reserve credits paid to units called on days with hot and cold weather alerts, classified by commitment schedule type. Of all the day-ahead credits received during days with weather alerts, 25.9 percent went to units that were committed on price PLS schedules and 1.5 percent went to units committed on price schedules as flexible as PLS.

Table 4-35 Day-ahead operating reserve credits during weather alerts by commitment schedule: January through June, 2022

Commitment Type During Hot and Cold Weather Alerts	Day Ahead Operating Reserve Credits	Share of DAOR during Hot and Cold Weather Alerts
Committed on cost (cost capped)	$999,243	70.5%
Committed on price schedule as flexible as PLS	$21,648	1.5%
Committed on price schedule less flexible than PLS	$29,916	2.1%
Committed on price PLS	$366,742	25.9%
Total	$1,417,550	100.0%

Fast Start Pricing

The implementation of fast start pricing on September 1, 2021, included a new credit intended 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. With fast start pricing, cleared and dispatched MW are determined in the dispatch run, identical to the combined dispatch and pricing process prior to fast start, while LMPs are determined in the pricing run, which calculates prices based on the counterfactual assumption that the fast start resources are flexible and can back down to a low economic minimum MW. Fast start pricing creates a divergence between the pricing run LMP that signals a higher MW for some resources and the lower dispatch run MW to which PJM dispatches the resource based on its offer curve. The resources dispatched down would produce more MWh if they responded to the actual market LMP from the pricing run. The resulting dispatch differential lost opportunity cost credit is the revenue lost by the resource as a result of operating at the lower dispatch MW rather than the MW on its offer curve corresponding to the actual market LMP from the pricing run. Table 4-1 shows that the dispatch differential lost opportunity cost for the first four months of the implementation of fast start pricing was $0.6 million. Table 4-3 shows that 35.9 percent of the dispatch differential lost opportunity cost credit was paid to combined cycle units and 45.5 percent to combustion turbines. In some cases, PJM paid dispatch differential payments to resources that did not follow PJM dispatch instructions. PJM should not make these payments as

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

they are directly counter to the logic of fast start pricing as well as to tariff rules.

The MMU recommends that PJM not make such payments and require refunds where it has already done so. This is part of the broader recommendation that PJM stop paying uplift to resources that do not follow dispatch.

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

There is not enough data on the implementation of fast start pricing after one month to support clear conclusions about the separable impacts of fast start pricing on uplift.

Table 4-36 shows the amount of uplift paid to fast start units by major uplift category. Fast start units received $12.1 million in balancing operating reserve credits, or 22.1 percent of total balancing operating reserves. Fast start units received $4.2 million in day-ahead lost opportunity costs, or 35.0 percent of all lost opportunity costs. Fast start units received less than $0.1 million in day-ahead operating credits, or 0.4 percent of total day ahead operating reserve credits.

Table 4-36 Monthly Day-ahead operating reserves, balancing operating reserves, and day-ahead lost opportunity cost credits for fast start units: January through June, 2022

Month	Day-Ahead Operating Reserves	Share of Monthly Day-Ahead Operating Reserves	Balancing Operating Reserves	Share of Monthly Balancing Operating Reserves	Day Ahead Lost Opportunity Cost Credits	Share of Monthly Day Ahead Lost Opportunity Cost Credits
Jan	$0.0	0.5%	$1.7	16.6%	$1.2	34.9%
Feb	$0.0	0.0%	$0.6	19.5%	$0.6	43.5%
Mar	$0.0	0.1%	$1.7	32.5%	$0.1	13.0%
Apr	$0.0	0.2%	$2.9	24.7%	$0.1	18.8%
May	$0.0	0.0%	$2.5	23.7%	$0.2	16.8%
Jun	$0.0	0.8%	$2.7	19.3%	$2.1	40.7%
Total (Jan - Jun)	$0.0	0.4%	$12.1	22.1%	$4.2	35.0%

Table 4-37 shows the day-ahead, balancing operating reserves, and day-ahead lost opportunity cost credits for combustion turbines by month.

Table 4-37 Day-ahead operating reserves, balancing operating reserves, day-ahead lost opportunity cost credits for fast start combustion turbines: January through June, 2022

Month	Day-Ahead Operating Reserves	Share of Monthly Day-Ahead Operating Reserves	Balancing Operating Reserves	Share of Monthly Day Ahead Operating Reserves	Day Ahead Lost Opportunity Cost Credits	Share of Monthly Day Ahead Lost Opportunity Cost Credits
Jan	$0.0	0.5%	$1.6	15.9%	$1.0	28.6%
Feb	$0.0	0.0%	$0.0	0.0%	$0.6	42.3%
Mar	$0.0	0.1%	$0.6	10.6%	$0.1	11.7%
Apr	$0.0	0.2%	$2.8	23.9%	$0.1	16.4%
May	$0.0	1.4%	$2.4	22.8%	$0.1	15.5%
Jun	$0.0	0.0%	$2.6	18.9%	$2.1	40.2%
Total (Jan - Jun)	$0.0	0.4%	$10.5	19.1%	$4.2	35.0%