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 $87.4 million, or 96.2 percent, in 2021 compared to 2020, from $90.9 million to $178.3 million.
- **Energy Uplift Charges Categories.** The increase of $87.4 million in 2021 was comprised of a $4.4 million increase in day-ahead operating reserve charges, an $82.5 million increase in balancing operating reserve charges, and a $0.5 million increase in reactive services charges.
- **Average Effective Operating Reserve Rates in the Eastern Region.** Day-ahead load, exports, DECs and UTCs paid $0.016 per MWh in the Eastern Region. Real-time load and exports paid $0.084 per MWh. Deviations (which include deviations from load, imports, exports, generators, INCs, DECs and UTCs) paid $0.467 per MWh in the Eastern Region.
- **Average Effective Operating Reserve Rates in the Western Region.** Day-ahead load, exports, DECs and UTCs paid $0.210 per MWh in the Western Region. Real-time load and exports paid $0.073 per MWh. Deviations (which include deviations from load,

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.

imports, exports, generators, INCs, DECs and UTCs) paid $0.416 per MWh in the Western Region.

- **Reactive Services Rates.** PPL and COMED were the two zones with the highest local reactive services (voltage support) rates, excluding reactive capability payments. PPL had a rate of $0.017 per MWh and COMED had a rate of $0.002 per MWh.

Energy Uplift Credits

- **Types of credits.** In 2021, energy uplift credits were $178.3 million, including $13.7 million in day-ahead generator credits, $127.5 million in balancing generator credits, $30.3 million in lost opportunity cost credits, and $4.8 million in local constraint control credits. Dispatch differential lost opportunity credits, implemented as part of fast start pricing on September 1, 2021, were $0.7 million.
- **Types of units.** In 2021, coal units received 72.0 percent of day-ahead generator credits, and combustion turbines received 92.8 percent of balancing generator credits and 95.6 percent of lost opportunity cost credits. Since September 1, 2021, combined cycle units and combustion turbines have received 66.6 percent of dispatch differential lost opportunity credits.
- **Economic and Noneconomic Generation.** In 2021, 89.5 percent of the day-ahead generation eligible for operating reserve credits was economic and 65.9 percent of the real-time generation eligible for operating reserve credits was economic.
- **Day-Ahead Unit Commitment for Reliability.** In 2021, 0.2 percent of the total day-ahead generation MWh was scheduled as must run for reliability by PJM, of which 50.6 percent received energy uplift payments.
- **Concentration of Energy Uplift Credits.** In 2021, the top 10 units receiving energy uplift credits received 41.6 percent of all credits and the top 10 organizations received 87.3 percent of all credits. The HHI for day-ahead operating reserves was 7876, the HHI for balancing operating reserves was 2637 and the HHI for lost opportunity cost was 5728, all of which are classified as highly concentrated.
- **Lost Opportunity Cost Credits.** Lost opportunity cost credits increased by $11.0 million or 56.8 percent, in 2021 compared to 2020, from $19.3 million to $30.3 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 96.7 percent of the $17.2 million. The day-ahead generation paid LOC credits for this reason decreased by 718.3 GWh or 55.7 percent during 2021, compared to 2020, from 1,288.7 GWh to 570.4 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 $14.8 million, of which PJM has resettled $1.5 million, or 9.9 percent.
- **Daily Uplift.** In 2021, balancing operating reserve charges would have been $27.0 million or 21.2 percent lower if they had been calculated on a daily basis rather than a segmented basis. In 2020, balancing operating reserve credits would have been $10.7 million or 18.5 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 2021, 88.9 percent of all uplift charges allocated regionally (day-ahead operating reserves and balancing operating reserves) were paid by transactions at control zones, 4.3 percent by transactions at hubs and aggregates, and 6.7 percent by transactions at interchange interfaces.
- In 2021, generators in the Eastern Region received 38.7 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.
- In 2021, generators in the Western Region received 58.0 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.
- In 2021, external generators received 3.8 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 initiate an analysis of the reasons why a significant number of combustion turbines and diesels scheduled in the day-ahead energy market are not called in real time when they are economic. (Priority: Medium. First Reported 2012. Status: Partially adopted, 2019.)
- 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. (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 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. (Priority: Medium. First reported 2020. 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 or set price based on short run marginal costs plus start up and no load costs. 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

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

incentives for market participants to provide flexible solutions including replacing inefficient units with flexible, efficient units.

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

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

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 reliance on dispatcher logs for this purpose is impractical, inefficient, and incorrect. PJM

7 See 173 FERC ¶ 61,244 (2020).

8 On March 21, 2019, FERC accepted PJM's Order No. 844 compliance filing. 166 FERC ¶ 61,210 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.

9 See 172 FERC ¶ 61,046.

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).

needs to define and implement 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 $14.8 million of incorrect uplift credits.

While energy uplift charges are an appropriate part of the cost of energy, market efficiency would be improved by ensuring that the level and variability of these charges are as low as possible consistent with the reliable operation of the system and consistent with pricing at short run marginal cost. The goal should be to minimize the total incurred energy uplift charges and to increase the transactions over which those charges are spread in order to reduce the impact of energy uplift charges on markets. The result would be to reduce the level of per MWh charges, to reduce the uncertainty associated with uplift charges and to reduce the impact of energy uplift charges on decisions about how and when to participate in PJM markets. The result would also be to increase incentives for flexible operation and to decrease incentives for the continued operation of inflexible and uneconomic resources. PJM does not need a flexibility product. PJM needs to provide incentives to existing and new entrant resources to unlock the significant flexibility potential that already exists and to stop creating 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 2020 and 2021.[11] In 2021, energy uplift credits increased by $87.4 million or 96.2 percent compared to 2020.

The dispatch differential lost opportunity cost is a new credit in the balancing market, introduced as a result of fast start pricing on September 1, 2021. The credit is intended to address the situation in which resources are dispatched down to accommodate inflexible fast start resources. Units eligible for the dispatch differential credit include pool scheduled and dispatchable, self scheduled units dispatched to an output below the output that would be economic for them at the prevailing fast start prices in the real-time market. Because fast start pricing was introduced on September 1, 2021, Table 4-1 reflects only four months of data for the dispatch differential lost opportunity cost credit.

11 Billing data can be modified by PJM Settlements at any time to reflect changes in the evaluation of energy uplift. The billing data reflected in this report were current on January 12, 2022.

Table 4-1 Energy uplift credits by category: 2020 and 2021[12]

Category	Type	2020 Credits (Millions)	2021 Credits (Millions)	Change	Percent Change	2020 Share	2021 Share
Day-Ahead	Generators	$9.3	$13.7	$4.4	47.3%	10.2%	7.7%
	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	$58.2	$127.5	$69.4	119.2%	64.0%	71.5%
	Imports	$0.0	$0.0	$0.0	NA	0.0%	0.0%
	Load Response	$0.0	$0.0	$0.0	NA	0.0%	0.0%
	Local Constraints Control	$3.4	$4.8	$1.4	41.1%	3.8%	2.7%
	Lost Opportunity Cost	$19.4	$30.3	$11.0	56.8%	21.3%	17.0%
	Dispatch Differential Lost Opportunity Cost	NA	$0.69	$0.0	NA	0.0%	0.4%
Reactive Services	Day-Ahead	$0.1	$0.3	$0.2	315.1%	0.1%	0.1%
	Local Constraints Control	$0.0	$0.0	$0.0	NA	0.0%	0.0%
	Lost Opportunity Cost	$0.0	$0.0	$0.0	NA	0.0%	0.0%
	Reactive Services	$0.4	$0.6	$0.3	72.9%	0.4%	0.4%
	Synchronous Condensing	$0.0	$0.0	$0.0	NA	0.0%	0.0%
Synchronous Condensing		$0.0	$0.0	$0.0	NA	0.0%	0.0%
Black Start Services	Day-Ahead	$0.0	$0.0	$0.0	NA	0.0%	0.0%
	Balancing	$0.0	$0.0	($0.0)	NA	0.0%	0.0%
	Testing	$0.2	$0.3	$0.1	36.1%	0.3%	0.2%
Total		$90.9	$178.3	$87.4	96.2%	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 2020 and 2021. Uplift credits increased for all unit types. A combination of factors led to increased uplift payments in 2021, including increased real-time generation from CTs, higher natural gas prices, and increased load.

Uplift credits paid to combustion turbines increased by $79.1 million or 106.5 percent in 2021 compared to the same period in 2020. This increase can largely be attributed to higher natural gas prices, higher energy prices, and higher reliance on CT generation in real time.

Uplift credits paid to coal units increased by $2.2 million or 19.5 percent in 2021 compared with the same period in 2020. These high uplift payments can largely be attributed to a small number of coal units in the BGE and PEPCO Zones committed for reliability.

In 2021, uplift credits to wind units were $0.3 million, down by 48.0 percent compared to 2020.

Table 4-2 Total energy uplift credits by unit type: 2020 and 2021[13] [14]

Unit Type	2020 Credits (Millions)	2021 Credits (Millions)	Change	Percent Change	2020 Share	2021 Share
Combined Cycle	$2.5	$5.9	$3.4	134.5%	2.8%	3.3%
Combustion Turbine	$74.3	$153.4	$79.1	106.5%	81.8%	86.1%
Diesel	$0.8	$1.6	$0.8	106.9%	0.9%	0.9%
Hydro	$0.0	$0.2	$0.1	1,784.7%	0.0%	0.1%
Nuclear	$0.0	$0.0	($0.0)	(66.5%)	0.0%	0.0%
Solar	$0.0	$0.0	$0.0	885.1%	0.0%	0.0%
Steam - Coal	$11.3	$13.5	$2.2	19.5%	12.4%	7.6%
Steam - Other	$1.3	$3.3	$2.0	159.3%	1.4%	1.9%
Wind	$0.7	$0.3	($0.3)	(48.0%)	0.7%	0.2%
Total	$90.9	$178.3	$87.4	96.2%	100.0%	100.0%

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

Table 4-3 shows the distribution of energy uplift credits by category and by unit type in 2021. The characteristics of the different unit types explain why uplift in specific categories is paid primarily to specific unit types. For example, the majority of day-ahead credits, 82.0 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. Combustion turbines, which, unlike other unit types, can be committed and decommitted in the real-time market, received 92.8 percent of balancing credits and 93.3 percent of lost opportunity cost credits. Combustion turbines committed in the real-time market may require 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: 2021

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	11.2%	2.6%	0.0%	1.1%	1.7%	16.5%	0.0%	41.4%	30.8%
Combustion Turbine	6.7%	92.8%	0.0%	97.3%	93.3%	81.2%	0.0%	58.6%	35.8%
Diesel	0.1%	0.7%	0.0%	1.1%	2.2%	0.2%	0.0%	0.0%	0.4%
Hydro	0.0%	0.0%	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%	17.1%
Nuclear	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.3%
Solar	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Steam - Coal	72.0%	2.7%	0.0%	0.0%	0.6%	0.1%	0.0%	0.0%	10.3%
Steam - Other	10.0%	1.2%	0.0%	0.4%	1.4%	2.1%	0.0%	0.0%	1.2%
Wind	0.0%	0.1%	0.0%	0.0%	0.6%	0.0%	0.0%	0.0%	4.1%
Total (Millions)	$13.7	$127.5	$0.0	$4.8	$30.3	$0.9	$0.0	$0.3	$0.7

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 reactive transfer interface control needed to maintain system reliability in a zone or reactive service.[15] Participants can submit units as self scheduled (must run), meaning that the unit must be committed, but a unit submitted as must run by a participant is not eligible for day-ahead operating reserve credits.[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 the subset of that generation committed for reliability by PJM. Day-ahead generation committed for reliability by PJM increased by 106.1 percent from 2020 to 2021, from 665.7 GWh in 2020 to 1,371.7 GWh. The increase in day-ahead generation committed for reliability by PJM was due to an increased need to commit uneconomic units in the PEPCO and BGE Zones for reliability.

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>.

Table 4-4 Day-ahead generation committed for reliability (GWh): 2020 and 2021

	2020			2021			
	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	71,116	0	0.0%	73,635	95	0.1%	NA
Feb	65,827	5	0.0%	71,354	13	0.0%	177.1%
Mar	63,058	6	0.0%	64,713	209	0.3%	3,352.1%
Apr	55,091	41	0.1%	57,137	13	0.0%	(68.1%)
May	58,114	117	0.2%	60,957	26	0.0%	(78.0%)
Jun	69,651	60	0.1%	72,987	126	0.2%	110.0%
Jul	85,585	63	0.1%	80,025	103	0.1%	63.5%
Aug	79,173	88	0.1%	81,744	86	0.1%	(2.7%)
Sep	65,105	145	0.2%	66,913	410	0.6%	182.2%
Oct	59,974	107	0.2%	61,610	15	0.0%	(85.5%)
Nov	60,078	7	0.0%	62,746	181	0.3%	2,525.5%
Dec	71,591	27	0.0%	69,036	96	0.1%	257.9%
Total	804,363	666	0.1%	822,857	1,372	0.2%	106.1%

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 2021 were $13.7 million. The top 10 units received $10.0 million or 73.2 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 2021, 50.6 percent of the day-ahead generation committed for reliability by PJM was paid operating reserve credits, 49.8 percent was paid day-ahead operating reserve credits and 0.8 percent was paid reactive services credits. The remaining 49.4 percent of the day-ahead generation committed for reliability was economic, meaning that the generation was not paid operating reserve credits because prices covered the generators' offers.

Table 4-5 Day-ahead generation committed for reliability by category (GWh): 2021

	Reactive Services (GWh)	Day-Ahead Operating Reserves (GWh)	Economic (GWh)	Total (GWh)
Jan	7.0	44.3	43.2	94.6
Feb	1.3	4.1	7.5	12.9
Mar	0.0	179.6	29.5	209.1
Apr	0.0	7.2	5.9	13.1
May	0.0	20.6	5.1	25.8
Jun	0.0	101.8	23.8	125.6
Jul	0.0	16.9	85.6	102.5
Aug	0.0	30.7	54.9	85.6
Sep	2.7	160.2	246.9	409.8
Oct	0.0	13.1	2.4	15.5
Nov	0.0	45.0	135.8	180.8
Dec	0.0	60.2	36.2	96.4
Total	11.0	683.7	677.0	1,371.7
Share	0.8%	49.8%	49.4%	100.0%

Total day-ahead operating reserve credits in 2021 were $13.7 million, of which $7.5 million or 54.8 percent was paid to units committed for reliability by PJM, and not scheduled to provide reactive services. An additional 5.1 percent, or $0.7 million, was 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 $118.3 million or 92.8 percent of all balancing operating reserve (BOR) credits in 2021. The majority of these credits, 98.6 percent, are paid to CTs that are 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.

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 that 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 PJM dispatcher is able to identify units that are not following the dispatch signals, and after agreement with the generator, the dispatch reason is changed to self scheduled. PJM dispatchers should not be required to decide which units qualify for uplift.

PJM's position 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 followed 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 for generators increased by 119.2 percent in 2021 compared to 2020. Higher natural gas prices and higher LMPs combined with PJM's need to run CTs more frequently resulted in increased balancing operating reserve credits during the 2021. The overall increase in credits in the DOM, COMED, and AEP Zones accounted for 60.0 percent of the total annual increase in balancing operating reserve credits.

Table 4-6 shows the monthly day-ahead and real-time generation by combustion turbines. In 2021, generation by combustion turbines was 31.2 percent higher in the real-time energy market than in the day-ahead energy market, although this varied by month. Table 4-6 shows that only 2.2 percent of generation from combustion turbines in the day-ahead market was uneconomic, while 39.0 percent of generation from combustion turbines in the real-time market was uneconomic and required $118.3 million in BOR credits. This increase in uneconomic real-time generation resulted in increased BOR credits during 2021.

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.

Table 4-6 Characteristics of day-ahead and real-time generation by combustion turbines eligible for operating reserve credits: 2021

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	240	6.5%	$0.0	483	62.7%	$4.4	0.5
Feb	298	5.8%	$0.1	485	57.4%	$9.9	0.6
Mar	309	2.1%	$0.1	471	51.6%	$4.5	0.7
Apr	662	2.1%	$0.0	1,270	62.5%	$16.0	0.5
May	845	1.7%	$0.2	890	48.5%	$5.0	0.9
Jun	1,541	2.3%	$0.0	2,042	39.3%	$12.2	0.8
Jul	1,767	2.7%	$0.1	2,514	38.4%	$16.7	0.7
Aug	2,300	2.7%	$0.3	3,190	34.0%	$18.1	0.7
Sep	1,027	1.3%	$0.0	1,144	21.8%	$3.6	0.9
Oct	1,430	1.9%	$0.0	1,803	28.5%	$11.0	0.8
Nov	1,652	1.1%	$0.1	1,734	35.5%	$13.0	1.0
Dec	529	1.6%	$0.0	497	33.5%	$3.9	1.1
Total	12,599	2.2%	$0.9	16,524	39.0%	$118.3	0.8

Balancing operating reserve credits to generators in 2021 were $118.3 million, of which $116.0 million, or 91.5 percent, was paid to combustion turbines operating without or outside a day-ahead schedule (Table 4-7).

Table 4-7 and Table 4-8 show real-time generation by combustion turbines by day-ahead commitment status in 2021 and 2020. CTs that operated on a day-ahead schedule during 2021 constituted 56.2 percent of real-time generation by CTs, of which 28.0 percent (15.7 percent of real-time generation) was uneconomic in the real-time market and received $1.6 million in BOR credits. CTs that operated on a day-ahead schedule in 2020 constituted 69.4 percent of real-time generation by CTs, of which 22.0 percent (15.3 percent of real-time generation) was uneconomic in the real-time market and received zero BOR credits.

In 2021, 43.8 percent of real-time generation by CTs was from CTs that operated outside of a day-ahead schedule, of which 53.1 percent (23.3 percent of real-time generation) was uneconomic in the real-time market and received $ 116.6 million in BOR credits. In 2020, 30.6 percent of real-time generation by CTs was from CTs that operated outside of a day-ahead schedule, of which 46.5 percent (14.2 percent of real-time generation) was uneconomic in the real-time market and received $ 116.6 million in BOR credits.

In 2021, real-time CT generation operating consistent with their day-ahead schedule decreased significantly compared to 2020, while real-time generation operating outside of a day-ahead schedule increased significantly. This shift of real-time generation operating consistent with their day-ahead schedule to real-time generation operating outside of a day-ahead schedule is a major contributing factor to the increase of BOR. Balancing operating reserves for real-time generation committed on a day-ahead schedule are calculated differently than for real-time generation committed outside of a day-ahead schedule, and this difference resulted in increased credits.

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 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) while in real time there are shorter segments defined by the minimum run time. 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: 2021

	Real-Time CT Generation Operating on a Day-Ahead Schedule				Real-Time CT Generation Operating Outside of a Day-Ahead Schedule			
Month	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)
Jan	154	31.8%	44.2%	$0.1	330	68.2%	71.3%	$4.3
Feb	184	38.0%	32.3%	$0.2	301	62.0%	72.8%	$9.7
Mar	214	45.5%	37.1%	$0.1	257	54.5%	63.7%	$4.4
Apr	511	40.2%	44.9%	$0.1	759	59.8%	74.4%	$15.9
May	528	59.3%	41.1%	$0.0	362	40.7%	59.3%	$4.9
Jun	1,153	56.4%	30.6%	$0.2	890	43.6%	50.5%	$12.0
Jul	1,447	57.5%	28.4%	$0.3	1,068	42.5%	51.9%	$16.5
Aug	1,908	59.8%	22.9%	$0.3	1,282	40.2%	50.4%	$17.8
Sep	792	69.2%	19.2%	$0.1	352	30.8%	27.6%	$3.4
Oct	1,122	62.2%	22.8%	$0.2	681	37.8%	38.0%	$10.8
Nov	977	56.3%	27.2%	$0.1	757	43.7%	46.2%	$12.9
Dec	291	58.5%	24.4%	$0.0	206	41.5%	46.4%	$3.9
Total	9,280	56.2%	28.0%	$1.6	7,244	43.8%	53.1%	$116.6

Table 4-8 Real-time generation by combustion turbines by day-ahead commitment: 2020

	Real-Time CT Generation Operating on a Day-Ahead Schedule				Real-Time CT Generation Operating Outside of a Day-Ahead Schedule			
Month	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)
Jan	363	66.1%	3.8%	$0.0	186	33.9%	36.4%	$1.5
Feb	241	76.1%	4.3%	$0.0	76	23.9%	32.3%	$0.6
Mar	316	69.1%	4.8%	$0.0	141	30.9%	27.9%	$0.8
Apr	257	65.2%	16.9%	$0.0	137	34.8%	40.3%	$0.8
May	579	70.2%	15.2%	$0.1	246	29.8%	45.2%	$1.7
Jun	1,210	71.2%	22.8%	$0.1	489	28.8%	32.6%	$4.4
Jul	3,255	77.2%	19.2%	$0.2	962	22.8%	36.4%	$7.7
Aug	1,750	70.6%	26.1%	$0.3	727	29.4%	38.0%	$7.1
Sep	1,015	74.6%	24.0%	$0.1	345	25.4%	38.0%	$2.7
Oct	1,030	66.5%	33.3%	$0.0	520	33.5%	62.1%	$6.2
Nov	611	63.3%	33.0%	$0.1	354	36.7%	75.2%	$7.4
Dec	262	29.6%	32.2%	$0.0	622	70.4%	69.4%	$11.3
Total	10,888	69.4%	22.0%	$0.9	4,805	30.6%	46.5%	$52.1

Lost Opportunity Cost Credits

Balancing operating reserve lost opportunity cost (LOC) credits are intended to provide an incentive for units to follow PJM's dispatch instructions when PJM's dispatch instructions deviate from a unit's desired or scheduled output. LOC credits are paid under two different 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 4-9 shows monthly day-ahead and real-time LOC credits in 2020 and 2021. In 2021, LOC credits increased by $11.0 million or 56.8 percent compared to 2020, comprising of a $10.6 million increase in day-ahead LOC and a $0.4 million increase in real-time LOC.

In 2021, wind units received $0.2 million of real-time LOC, up by 9.0 percent from 2020. In 2021, real-time LOC credits to wind units were 56.7 percent of the uplift payments to wind units. Wind units in the AEP and COMED

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

Zones received 98.5 percent of real-time LOC credits to wind units. 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 4-9 Monthly lost opportunity cost credits (Millions): 2020 and 2021

	2020			2021		
	Day-Ahead Lost Opportunity Cost	Real-Time Lost Opportunity Cost	Total	Day-Ahead Lost Opportunity Cost	Real-Time Lost Opportunity Cost	Total
Jan	$0.5	$0.0	$0.5	$0.4	$0.0	$0.4
Feb	$0.4	$0.0	$0.4	$0.5	$0.0	$0.6
Mar	$0.6	$0.1	$0.6	$3.5	$0.0	$3.5
Apr	$0.3	$0.5	$0.9	$0.6	$0.0	$0.6
May	$0.8	$0.0	$0.8	$2.8	$0.1	$2.9
Jun	$3.3	$0.1	$3.4	$3.0	$0.1	$3.1
Jul	$4.2	$0.1	$4.2	$1.8	$0.1	$1.8
Aug	$4.4	$0.1	$4.5	$1.5	$0.1	$1.6
Sep	$1.6	$0.0	$1.7	$2.5	$0.5	$3.0
Oct	$0.9	$0.0	$0.9	$2.2	$0.2	$2.4
Nov	$0.8	$0.0	$0.8	$6.7	$0.5	$7.2
Dec	$0.4	$0.2	$0.6	$3.2	$0.0	$3.2
Total	$18.2	$1.2	$19.3	$28.7	$1.6	$30.3
Share	93.9%	6.1%	100.0%	94.7%	5.3%	100.0%

Table 4-10 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 2021, 10.9 percent of day-ahead generation by combustion turbines and diesels was not requested in real time, 3.7 percentage points lower than in 2020. In 2021 compared to 2020, day-ahead generation by combustion turbines decreased by 11.8 percent, day-ahead generation not requested in real time decreased by 34.2 percent, and day-ahead generation not requested in real time receiving lost opportunity costs decreased by 55.7 percent. 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 4-10 Day-ahead generation from combustion turbines and diesels (GWh): 2020 and 2021

	2020			2021		
	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	873	171	73	486	69	17
Feb	653	114	49	507	53	12
Mar	729	103	55	527	64	16
Apr	656	95	36	957	62	15
May	1,126	188	80	1,153	213	55
Jun	2,278	437	243	1,869	223	76
Jul	4,759	588	271	2,179	149	46
Aug	2,728	384	180	2,804	162	32
Sep	1,696	341	129	1,358	131	47
Oct	1,677	155	83	1,811	143	48
Nov	1,051	119	66	2,109	378	144
Dec	641	59	23	888	165	63
Total	18,867	2,754	1,289	16,649	1,811	570
Share	100.0%	14.6%	6.8%	100.0%	10.9%	3.4%

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 4-11 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 4-11 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 4-12 shows day-ahead and real-time generation by commitment and dispatch status.

Table 4-12 Day-ahead and real-time generation by offer status and eligibility to set LMP (GWh): 2021

	Self Scheduled			Pool Scheduled						Total Generation
	Dispatchable	Economic Minimum	Block Loaded	Dispatchable	Economic Minimum	Block Loaded	Total GWh	Total Pool Scheduled	Total Self Scheduled	Eligible to Set Price
Day-Ahead Generation	87,063	192,356	177,981	168,649	174,962	21,846	822,857	365,457	457,400	255,712
Share of Day-Ahead	10.6%	23.4%	21.6%	20.5%	21.3%	2.7%	100.0%	44.4%	55.6%	31.1%
Real-Time Generation	76,894	182,971	179,154	168,902	193,632	26,385	827,938	388,919	439,019	245,796
Share of Real-Time	9.3%	22.1%	21.6%	20.4%	23.4%	3.2%	100.0%	47.0%	53.0%	29.7%

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.

The MMU analyzed PJM's day-ahead and real-time generation eligible for operating reserve credits to determine the shares of economic and noneconomic generation. Each unit's hourly generation was determined to be economic or noneconomic based on the unit's hourly incremental offer, excluding the hourly no load and any applicable startup cost. A unit could be economic for every hour during a day or segment, but still receive operating reserve credits because the energy revenues did not cover the hourly no load and startup cost. A unit could be noneconomic

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.

22 The analysis of economic and noneconomic generation is based on units' incremental offers, the value used by PJM to calculate LMP. The analysis does not include no load or startup costs.

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 4-13 shows the day-ahead and real-time economic and noneconomic generation from units eligible for operating reserve credits as defined by PJM. In 2021, 89.5 percent of the day-ahead generation MWh eligible for operating reserve credits was economic and 65.9 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.

Table 4-13 Economic and noneconomic generation from units eligible for operating reserve credits (GWh): 2021

Energy Market	Economic Generation	Noneconomic Generation	Total Eligible Generation	Economic Generation Percent	Noneconomic Generation Percent
Day-Ahead	327,240	38,217	365,457	89.5%	10.5%
Real-Time	216,543	112,033	328,576	65.9%	34.1%

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 4-14 shows the generation receiving day-ahead and balancing operating reserve credits. In 2021, 1.0 percent of the day-ahead generation eligible for operating reserve credits received credits and 2.9 percent of the real-time generation eligible for operating reserve credits received credits.

Table 4-14 Generation receiving operating reserve credits (GWh): 2021

Energy Market	Generation Eligible for Operating Reserve Credits	Generation Receiving Operating Reserve Credits	Generation Receiving Operating Reserve Credits Percent
Day-Ahead	365,457	3,590	1.0%
Real-Time	328,576	6,363	1.9%

Uplift Resettlement

Some units have been incorrectly paid uplift despite not meeting uplift eligibility requirements, such as 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 totaled $14.8 million. Of that amount, PJM has agreed and resettled 9.9 percent of the requests, 84.3 percent remains pending. The remaining 5.8 percent occurred prior to January 2020 and would now require a directive from FERC for them to be resettled. The MMU continues to bring new cases to the attention of PJM.

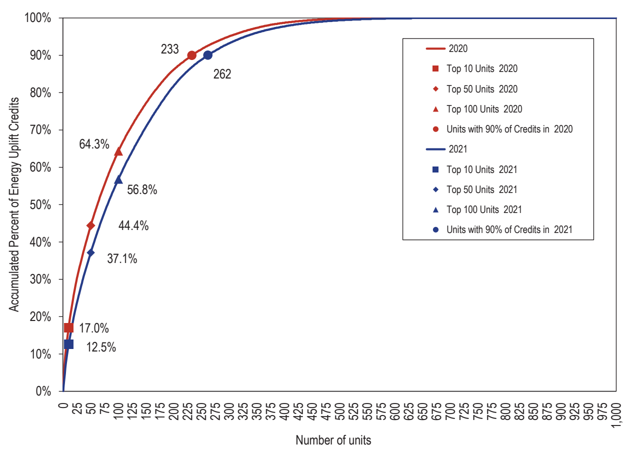
The MMU identifies units that are not following the dispatch signal and that are therefore not eligible to receive uplift payments. These findings are communicated to unit owners and to PJM. The units are identified by comparing their actual generation to the dispatch level that they should have achieved 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 13.1 percent of total energy uplift credits in 2021, compared to 17.0 percent in 2020. In 2021, 261 units received 90 percent of all energy uplift credits, compared to 233 units in 2020.

Figure 4-1 Cumulative share of energy uplift credits by unit: 2020 and 2021



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.

Table 4-15 shows the credits received by the top 10 units and top 10 organizations in each of the energy uplift categories paid to generators in 2021.

Table 4-15 Top 10 units and organizations energy uplift credits: 2021

		Top 10 Units		Top 10 Organizations	
Category	Type	Credits (Millions)	Credits Share	Credits (Millions)	Credits Share
Day-Ahead	Generators	$10.0	73.2%	$0.0	0.0%
Balancing	Canceled Resources	$0.0	0.0%	$0.0	0.0%
	Generators	$16.6	13.0%	$91.3	71.6%
	Local Constraints Control	$4.6	95.2%	$4.8	100.0%
	Lost Opportunity Cost	$5.1	17.0%	$22.6	74.5%
	Dispatch Differential Lost Opportunity Cost	$0.16	22.6%	$0.4	64.7%
Reactive Services		$0.9	94.4%	$0.9	99.9%
Synchronous Condensing		$0.0	0.0%	$0.0	0.0%
Black Start Services		$0.1	41.6%	$0.3	87.3%
Total		$22.4	12.5%	$120.9	67.8%

Table 4-16 shows balancing operating reserve credits received by the top 10 units identified for reliability or for deviations in each region. In 2021, 69.8 percent of all credits paid to these units were allocated as charges to deviations while the remaining 30.2 percent were paid for reliability reasons.

Table 4-16 Balancing operating reserve credits to top 10 units as charged by category and region: 2021

	Reliability			Deviations			
	RTO	East	West	RTO	East	West	Total
Credits (Millions)	$4.4	$0.6	$0.0	$9.9	$1.7	$0.0	$16.6
Share	26.5%	3.7%	0.0%	59.8%	10.0%	0.0%	100.0%

In 2021, 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 4-17 shows the average HHI for each category. HHI for day-ahead operating reserve credits to generators was 7876, for balancing operating reserve credits to generators was 2637, for lost opportunity cost credits was 5728 and for reactive services credits was 2770. All of these HHI values are characterized as highly concentrated.

Table 4-17 Daily energy uplift credits HHI: 2021

Category	Type	Average	Minimum	Maximum	Highest Market Share (One day)	Highest Market Share (All days)
Day-Ahead	Generators	7876	1842	10000	100.0%	42.6%
	Imports	10000	10000	10000	100.0%	100.0%
	Load Response	10000	10000	10000	100.0%	100.0%
Balancing	Canceled Resources	NA	NA	NA	NA	NA
	Generators	2637	684	10000	100.0%	22.6%
	Imports	NA	NA	NA	NA	NA
	Load Response	NA	NA	NA	NA	NA
	Lost Opportunity Cost	5728	1206	10000	100.0%	18.5%
	Dispatch Differential Lost Opportunity Cost	2770	576	10000	100.0%	15.6%
Reactive Services		9683	5088	10000	100.0%	75.8%
Synchronous Condensing		NA	NA	NA	NA	NA
Black Start Services		9758	5005	10000	100.0%	17.6%
Total		2770	576	10000	96.1%	20.1%

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 4-16 excludes local constraint control categories.
26 Concentration is measured using the entity (or entities) to which the uplift credit is paid.

Unit Specific Uplift Payments

FERC Order No. 844 allows PJM and the MMU to publish unit specific uplift payments by category by month. Table 4-18 through Table 4-21 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 12.5 percent of all credits, with the top recipient receiving 1.8 percent. The top 10 units receiving day-ahead operating reserves received 73.2 percent. The top 10 recipients of balancing operating reserves received 13.0 percent of balancing operating reserve credits. The top 10 recipients of lost opportunity cost credits received 17.0 percent of total lost opportunity cost credits.

Table 4-18 Top 10 recipients of total uplift: 2021

Rank	Unit Name	Zone	Total Uplift Credit	Share of Total Uplift Credits
1	BC BRANDON SHORES 2 F	BGE	$3,123,920	1.8%
2	VP MARSHRUN 1 CT	DOM	$2,719,508	1.5%
3	VP MARSHRUN 2 CT	DOM	$2,565,030	1.4%
4	VP MARSHRUN 3 CT	DOM	$2,557,802	1.4%
5	VP LOUISA 5 CT	DOM	$2,343,764	1.3%
6	DPL INDIAN RIVER 4 F	DPL	$2,004,671	1.1%
7	BC BRANDON SHORES 1 F	BGE	$1,978,429	1.1%
8	FE LEMOYNE 1 CT	ATSI	$1,827,833	1.0%
9	DAY GREENVILLE 1 CT	DAY	$1,695,954	1.0%
10	DAY GREENVILLE 4 CT	DAY	$1,549,296	0.9%
Total of Top 10			$22,366,207	12.5%
Total Uplift Credits			$178,267,192	100.0%

Table 4-19 Top 10 recipients of day-ahead generation credits: 2021

Rank	Unit Name	Zone	Day-Ahead Operating Reserve Credit	Share of Day-Ahead Operating Reserve Credits
1	BC BRANDON SHORES 2 F	BGE	$2,840,819	20.8%
2	BC BRANDON SHORES 1 F	BGE	$1,536,104	11.2%
3	PEP MORGANTOWN 1 F	PEPCO	$1,487,880	10.9%
4	DPL INDIAN RIVER 4 F	DPL	$1,393,021	10.2%
5	PEP MORGANTOWN 2 F	PEPCO	$815,486	6.0%
6	DPL WILDCAT POINT 1 CC	DPL	$500,010	3.7%
7	PL BRUNNER ISLAND 3 F	PPL	$408,378	3.0%
8	PL BRUNNER ISLAND 1 F	PPL	$387,299	2.8%
9	PEP CHALKPOINT 3 F	PEPCO	$352,550	2.6%
10	VP BRUNSWICK 1CC	DOM	$280,850	2.1%
Total of Top 10			$10,002,396	73.2%
Total day-ahead operating reserve credits			$13,662,162	100.0%

Table 4-20 Top 10 recipients of balancing operating reserve credits: 2021

Rank	Unit Name	Zone	Balancing Operating Reserve Credit	Share of Balancing Operating Reserve Credits
1	VP MARSHRUN 1 CT	DOM	$2,571,776	2.0%
2	VP MARSHRUN 3 CT	DOM	$2,390,266	1.9%
3	VP MARSHRUN 2 CT	DOM	$2,370,595	1.9%
4	VP LOUISA 5 CT	DOM	$2,227,587	1.7%
5	FE LEMOYNE 1 CT	ATSI	$1,361,459	1.1%
6	FE LEMOYNE 2 CT	ATSI	$1,176,797	0.9%
7	AEP ROBERT P MONE 2 CT	AEP	$1,145,841	0.9%
8	AEP ROBERT P MONE 3 CT	AEP	$1,143,296	0.9%
9	FE LEMOYNE 3 CT	ATSI	$1,113,152	0.9%
10	AEP ROBERT P MONE 1 CT	AEP	$1,098,235	0.9%
Total of Top 10			$16,599,004	13.0%
Total balancing operating reserve credits			$127,525,881	100.0%

Table 4-21 Top 10 recipients of lost opportunity cost credits: 2021

Rank	Unit Name	Zone	Lost Opportunity Cost Credit	Share of Lost Opportunity Cost Credits
1	DPL COMM CHESAPEAKE - NEW CHURCH 3 CT	DPL	$745,783	2.5%
2	DPL COMM CHESAPEAKE - NEW CHURCH 4 CT	DPL	$556,642	1.8%
3	DPL COMM CHESAPEAKE - NEW CHURCH 5 CT	DPL	$501,089	1.7%
4	EKPC BLUEGRASS 1 CT	External	$492,360	1.6%
5	COM 900 ELWOOD 6 CT	COMED	$487,729	1.6%
6	VP DOSWELL 3 CT	DOM	$483,384	1.6%
7	VP REMINGTON 4 CT	DOM	$473,966	1.6%
8	VP FOUR RIVERS 1 CT	DOM	$471,837	1.6%
9	VP REMINGTON 1 CT	DOM	$467,465	1.5%
10	FE LEMOYNE 1 CT	ATSI	$462,919	1.5%
Total of Top 10			$5,143,175	17.0%
Total lost opportunity cost credits			$30,327,914	100.0%

Table 4-22 Top 10 recipients of dispatch differential lost opportunity cost credits: 2021

Rank	Unit Name	Zone	Dispatch Differential Lost Opportunity Cost Credit	Share of Lost Opportunity Cost Credits
1	AP LKLYN 1-4 H	AP	$57,072	8.2%
2	VP DOSWELL 2 CT	DOM	$13,447	1.9%
3	PL HUMMEL STATION 1 CC	PPL	$13,336	1.9%
4	VP DOSWELL 3 CT	DOM	$12,884	1.9%
5	FE LORDSTOWN ENERGY CENTER 1 CC	ATSI	$11,610	1.7%
6	PL SAFEHARBOR 11 H	PPL	$11,223	1.6%
7	PN KEYSTONE 1 F	PE	$10,567	1.5%
8	VP FOUR RIVERS 60 CC	DOM	$9,532	1.4%
9	VP FOUR RIVERS 50 CC	DOM	$8,518	1.2%
10	VP FLUVANNA CC	DOM	$8,445	1.2%
Total of Top 10			$156,635	22.6%
Total dispatch differential lost opportunity cost credits			$694,605.1	2.3%

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 4-23 and Table 4-24 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 4-23 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)	in RTO, Eastern or Western Region
		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	Balancing Operating Reserve for Deviations	Deviations	in RTO Region
Lost Opportunity Cost (LOC)	Balancing Operating Reserve LOC			
Real-Time Import Transactions	Balancing Operating Reserve Transaction			
Economic Load Response Resources	Balancing Operating Reserves for Load Response	Balancing Operating Reserve for Load Response	Deviations	in RTO Region

Table 4-24 Reactive services, synchronous condensing and black start services credits and charges

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

Energy Uplift Charges Results

Energy Uplift Charges

Total energy uplift charges increased by $87.4 million, or 96.2 percent, in 2021 compared to 2020, from $90.9 million to $178.3 million.

Table 4-25 Total energy uplift charges: 2001 through 2021[27]

	Total Energy Uplift Charges (Millions)	Change (Millions)	Percent Change	Energy Uplift as a Percent of Total PJM Billing
2001	$284.0	$67.0	30.9%	8.5%
2002	$273.7	($10.3)	(3.6%)	5.8%
2003	$376.5	$102.8	37.6%	5.4%
2004	$537.6	$161.1	42.8%	6.1%
2005	$712.6	$175.0	32.6%	3.1%
2006	$365.6	($347.0)	(48.7%)	1.7%
2007	$503.3	$137.7	37.7%	1.6%
2008	$474.3	($29.0)	(5.8%)	1.4%
2009	$322.7	($151.6)	(32.0%)	1.2%
2010	$623.2	$300.5	93.1%	1.8%
2011	$603.4	($19.8)	(3.2%)	1.7%
2012	$649.8	$46.4	7.7%	2.2%
2013	$843.0	$193.2	29.7%	2.5%
2014	$961.2	$118.2	14.0%	1.9%
2015	$312.0	($649.2)	(67.5%)	0.7%
2016	$136.7	($175.3)	(56.2%)	0.4%
2017	$127.3	($9.4)	(6.9%)	0.3%
2018	$198.2	$70.9	55.7%	0.4%
2019	$88.5	($109.7)	(55.3%)	0.2%
2020	$90.9	($107.3)	(54.1%)	0.2%
2021	$178.3	$87.4	96.2%	0.5%

Table 4-26 shows total energy uplift charges by category in 2020 and 2021.[28] The increase of $87.4 million is comprised of a $4.4 million increase in day-ahead operating reserve charges, an $82.5 million increase in balancing operating reserve charges, a $0.5 million increase in reactive service charges, and a $.1 million increase in black start services charges.

Table 4-26 Total energy uplift charges by category: 2020 and 2021[29]

Category	2020 Charges (Millions)	2021 Charges (Millions)	Change (Millions)	Percent Change
Day-Ahead Operating Reserves	$9.3	$13.7	$4.4	47.1%
Balancing Operating Reserves	$80.9	$163.4	$82.5	101.9%
Reactive Services	$0.4	$0.9	$0.5	112.2%
Synchronous Condensing	$0.0	$0.0	$0.0	0.0%
Black Start Services	$0.2	$0.3	$0.1	34.9%
Total	$90.9	$178.3	$87.4	96.2%
Energy Uplift as a Percent of Total PJM Billing	0.3%	0.3%	0.1%	31.5%

27 In Table 4-25, 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.

28 Table 4-25 includes all categories of charges as defined in Table 4-23 and Table 4-24 and includes all PJM Settlements billing adjustments. Billing data can be modified by PJM Settlements at any time to reflect changes in the evaluation of energy uplift. The billing data reflected in this report were current on January 12, 2022.

29 In Table 4-26, 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 4-27 compares monthly energy uplift charges by category for 2020 and 2021.

Table 4-27 Monthly energy uplift charges: 2020 and 2021

	2020 Charges (Millions)						2021 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	$0.1	$4.0	$0.0	$0.0	$0.0	$4.1	$0.7	$6.8	$0.7	$0.0	$0.0	$8.2
Feb	$0.2	$1.2	$0.0	$0.0	$0.0	$1.4	$0.9	$13.6	$0.1	$0.0	$0.0	$14.6
Mar	$0.0	$1.6	$0.0	$0.0	$0.0	$1.7	$2.8	$8.5	$0.0	$0.0	$0.1	$11.4
Apr	$0.8	$2.0	$0.1	$0.0	$0.1	$2.9	$0.8	$17.0	$0.0	$0.0	$0.0	$17.8
May	$1.0	$2.7	$0.3	$0.0	$0.0	$4.0	$0.6	$8.7	$0.0	$0.0	$0.0	$9.3
Jun	$0.9	$8.5	$0.0	$0.0	$0.0	$9.5	$1.3	$16.5	$0.0	$0.0	$0.0	$17.8
Jul	$1.2	$13.0	$0.0	$0.0	$0.0	$14.2	$0.6	$19.7	$0.0	$0.0	$0.0	$20.3
Aug	$0.8	$12.6	$0.0	$0.0	$0.0	$13.4	$1.1	$21.2	$0.0	$0.0	$0.0	$22.3
Sep	$2.1	$5.4	$0.0	$0.0	$0.0	$7.5	$1.9	$7.3	$0.0	$0.0	$0.0	$9.2
Oct	$1.1	$8.0	$0.0	$0.0	$0.1	$9.1	$0.4	$14.2	$0.0	$0.0	$0.1	$14.7
Nov	$0.6	$8.8	$0.0	$0.0	$0.0	$9.4	$0.8	$21.6	$0.2	$0.0	$0.0	$22.6
Dec	$0.5	$13.2	$0.0	$0.0	$0.0	$13.7	$1.6	$8.3	$0.0	$0.0	$0.0	$9.9
Total	$9.3	$80.9	$0.4	$0.0	$0.2	$90.9	$13.7	$163.4	$0.9	$0.0	$0.3	$178.3
Share	10.2%	89.1%	0.5%	0.0%	0.3%	100.0%	7.7%	91.7%	0.5%	0.0%	0.2%	100.0%

Table 4-28 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.[30 31] Day-ahead operating reserve charges increased by $4.4 million 47.1 percent in 2021 compared to 2020.

Table 4-28 Day-ahead operating reserve charges: 2020 and 2021

Type	2020 Charges (Millions)	2021 Charges (Millions)	Change (Millions)	2020 Share	2021 Share
Day-Ahead Operating Reserve Charges	$9.3	$13.7	$4.4	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	$9.3	$13.7	$4.4	100.0%	100.0%

Table 4-29 shows the composition of the balancing operating reserve charges. Balancing operating reserve charges consist of balancing operating reserve reliability charges (credits to generators), balancing operating reserve deviation charges (credits to generators and import transactions), balancing operating reserve charges for economic load response and balancing local constraint charges. Balancing operating reserve charges increased by $82.5 million or 101.9 percent in 2021 compared to 2020.

Table 4-29 Balancing operating reserve charges: 2020 and 2021

Type	2020 Charges (Millions)	2021 Charges (Millions)	Change (Millions)	2020 Share	2021 Share
Balancing Operating Reserve Reliability Charges	$27.2	$62.9	$35.7	33.6%	38.5%
Balancing Operating Reserve Deviation Charges	$50.3	$95.7	$45.3	62.2%	58.5%
Balancing Operating Reserve Charges for Load Response	$0.0	$0.0	$0.0	0.0%	0.0%
Balancing Local Constraint Charges	$3.4	$4.8	$1.4	4.2%	3.0%
Total	$80.9	$163.4	$82.5	100.0%	100.0%

30 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.

31 See the *2021 Quarterly State of the Market Report for PJM: January through June*, Section 13, Financial Transmission Rights and Auction Revenue Rights.

Table 4-30 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 2021, energy lost opportunity cost deviation charges increased by $11.0 million or 56.8 percent, and make whole deviation charges increased by $34.3 million or 110.7 percent compared to 2020.

Table 4-30 Balancing operating reserve deviation charges: 2020 and 2021

Charge Attributable To	2020 Charges (Millions)	2021 Charges (Millions)	Change (Millions)	2020 Share	2021 Share
Make Whole Payments to Generators and Imports	$31.0	$65.3	$34.3	61.6%	68.3%
Energy Lost Opportunity Cost	$19.3	$30.3	$11.0	38.4%	31.7%
Canceled Resources	$0.0	$0.0	$0.0	0.0%	0.0%
Total	$50.3	$95.7	$45.3	100.0%	100.0%

Table 4-31 shows reactive services, synchronous condensing and black start services charges. Reactive services charges increased by $0.5 million or 47.5 percent in 2021, compared to 2020.

Table 4-31 Additional energy uplift charges: 2020 and 2021

Type	2020 Charges (Millions)	2021 Charges (Millions)	Change (Millions)	2020 Share	2021 Share
Reactive Services Charges	$0.4	$0.9	$0.5	65.0%	47.5%
Synchronous Condensing Charges	$0.0	$0.0	$0.0	0.0%	0.0%
Black Start Services Charges	$0.2	$0.3	$0.1	35.0%	16.3%
Total	$0.7	$1.9	$1.3	100.0%	100.0%

Table 4-32 and Table 4-33 show the amount and shares of regional balancing charges in 2020 and 2021. Regional balancing operating reserve charges consist of balancing operating reserve reliability and deviation charges. These charges are allocated regionally across PJM. In 2021, the largest share of regional charges was paid by real-time load which paid 37.8 percent of all regional balancing charges. The regional balancing charges allocation table does not include charges attributed for resources controlling local constraints.

In 2021, regional balancing operating reserve charges increased by $81.1 million compared to 2020. Balancing operating reserve reliability charges increased by $35.7 million or 131.5 percent, and balancing operating reserve deviation charges increased by $45.3 million, or 90.0 percent.

Table 4-32 Regional balancing charges allocation (Millions): 2020

Charge	Allocation	RTO		East		West		Total	
Reliability Charges	Real-Time Load	$22.0	28.4%	$3.5	4.6%	$0.3	0.3%	$25.8	33.3%
	Real-Time Exports	$1.2	1.5%	$0.1	0.2%	$0.0	0.0%	$1.3	1.7%
	Total	$23.2	29.9%	$3.7	4.8%	$0.3	0.4%	$27.2	35.1%
Deviation Charges	Demand	$31.2	40.3%	$2.7	3.4%	$0.3	0.4%	$34.2	44.2%
	Supply	$5.7	7.3%	$0.5	0.7%	$0.1	0.1%	$6.3	8.1%
	Generator	$9.0	11.6%	$0.7	1.0%	$0.1	0.1%	$9.9	12.7%
	Total	$45.9	59.2%	$3.9	5.1%	$0.5	0.6%	$50.3	64.9%
Total Regional Balancing Charges		$69.1	89.2%	$7.6	9.8%	$0.8	1.0%	$77.5	100%

Table 4-33 Regional balancing charges allocation (Millions): 2021

Charge	Allocation	RTO		East		West		Total	
Reliability Charges	Real-Time Load	$54.6	34.4%	$4.7	3.0%	$0.6	0.4%	$59.9	37.8%
	Real-Time Exports	$2.7	1.7%	$0.2	0.1%	$0.0	0.0%	$3.0	1.9%
	Total	$57.3	36.2%	$4.9	3.1%	$0.6	0.4%	$62.9	39.7%
Deviation Charges	Demand	$64.1	40.4%	$4.2	2.6%	$0.7	0.5%	$69.0	43.5%
	Supply	$8.9	5.6%	$0.7	0.4%	$0.1	0.1%	$9.7	6.1%
	Generator	$15.8	9.9%	$1.1	0.7%	$0.1	0.1%	$17.0	10.7%
	Total	$88.7	55.9%	$6.0	3.8%	$1.0	0.6%	$95.7	60.3%
Total Regional Balancing Charges		$146.0	92.1%	$10.9	6.9%	$1.6	1.0%	$158.6	100%

Operating Reserve Rates

Under the operating reserves cost allocation rules, PJM calculates nine separate rates, a day-ahead operating reserve rate, a reliability rate for each region, a deviation rate for each region, a lost opportunity cost rate and a canceled resources rate for the entire RTO region. Table 4-34 shows how these charges are allocated.[32]

Figure 4-2 shows the daily day-ahead operating reserve rate for 2020 and 2021. The average rate in 2021 was $0.016 per MWh, $0.004 per MWh higher than the average in 2020. The highest rate in 2021 occurred on August 26, when units were called on by PJM for transmission constraints, and the rate reached $0.210 per MWh, $0.045 per MWh higher than the $0.164 per MWh reached in 2020, on April 6. 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 2020 through 2021.

Figure 4-2 Daily day-ahead operating reserve rate ($/MWh): 2020 and 2021

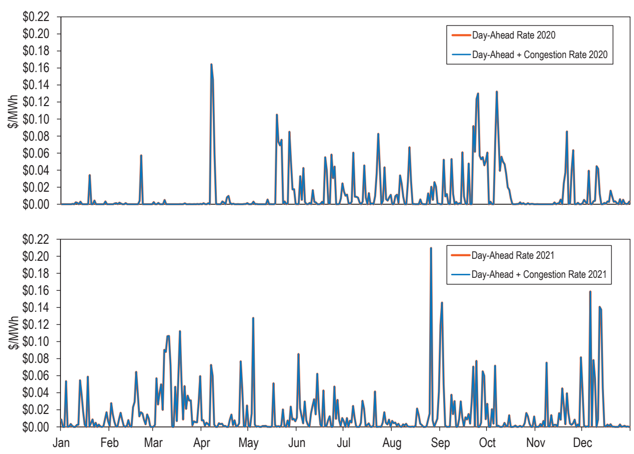


Figure 4-3 shows the RTO and the regional reliability rates for 2020 and 2021. The average RTO reliability rate in 2021 increased to $0.071 per MWh from $0.030 in 2020, indicating a higher need for uplift credits for reliability in 2021. The highest RTO reliability rate in 2021 occurred on June 29 when the rate reached $0.661 per MWh, $0.205 per MWh higher than the $0.457 per MWh rate reached in 2020, on November 19.

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

Figure 4-3 Daily balancing operating reserve reliability rates ($/MWh): 2020 and 2021

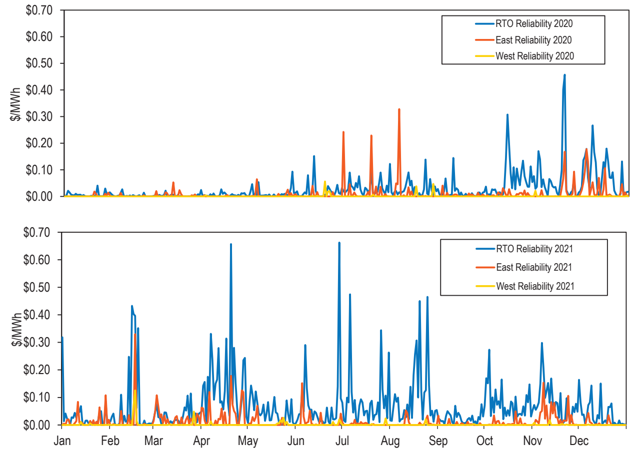


Figure 4-4 shows the RTO and regional deviation rates for 2020 and 2021. The average RTO deviation rate in 2021 was $0.268 per MWh. The highest daily rate in 2021 occurred on August 18, when the RTO deviation rate reached $2.417 per MWh, $1.195 per MWh more than the $1.222 per MWh rate reached in 2020, on August 20.

Figure 4-4 Daily balancing operating reserve deviation rates ($/MWh): 2020 and 2021

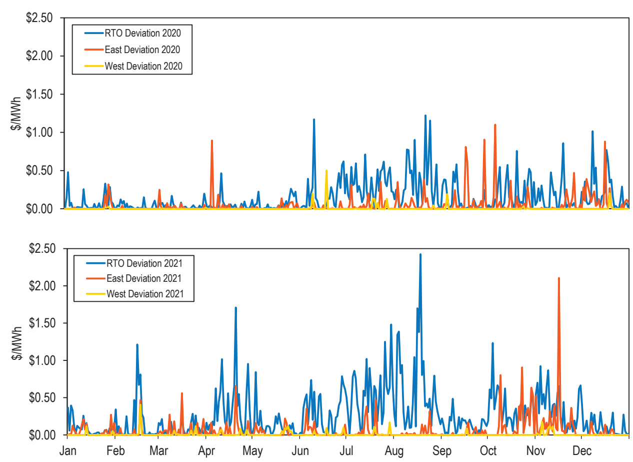


Figure 4-5 shows the daily lost opportunity cost rate and the daily canceled resources rate for 2020 and 2021. The average lost opportunity cost rate in 2020 was $0.139 per MWh. The highest lost opportunity cost rate in 2021 occurred on December 8, when it reached $1.936 per MWh, $0.013 per MWh greater than the $1.923 per MWh rate reached in 2020, on June 2.

Figure 4-5 Daily lost opportunity cost and canceled resources rates ($/MWh): 2020 and 2021

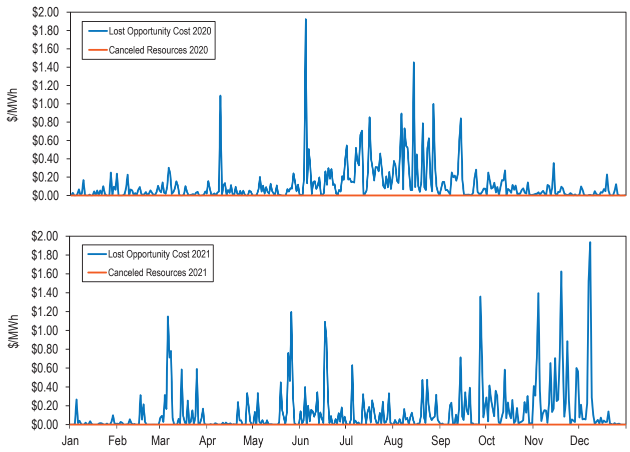


Table 4-34 shows the average rates for each region in each category for 2020 and 2021.

Table 4-34 Operating reserve rates ($/MWh): 2020 and 2021

Rate	2020 ($/MWh)	2021 ($/MWh)	Difference ($/MWh)	Percent Difference
Day-Ahead	0.012	0.016	0.004	35.8%
Day-Ahead with Unallocated Congestion	0.012	0.016	0.004	35.8%
RTO Reliability	0.030	0.071	0.042	140.6%
East Reliability	0.010	0.013	0.003	27.5%
West Reliability	0.001	0.002	0.001	129.8%
RTO Deviation	0.161	0.268	0.107	66.3%
East Deviation	0.050	0.060	0.010	19.7%
West Deviation	0.006	0.009	0.003	52.6%
Lost Opportunity Cost	0.117	0.139	0.022	18.8%
Canceled Resources	0.000	0.000	NA	N/A
Dispatch Differential Lost Opportunity Cost	NA	0.001	NA	N/A

Table 4-35 shows the operating reserve cost of a one MW transaction in 2021. For example, in the Eastern Region an increment offer resulting in a one MW deviation or a one MW load deviation paid an average rate of $0.467 per MWh. The rates in Table 4-35 include all operating reserve charges including RTO deviation charges. The rates also include charges for UTCs, which were implemented on November 1, 2020 and which are treated identically to DECs. Table 4-35 includes both the average level of operating reserve charges by transaction types and the uncertainty reflected in the maximum, minimum and standard deviation levels.

Table 4-35 Operating reserve rates statistics ($/MWh): 2021

		Rates Charged ($/MWh)			
Region	Transaction	Maximum	Average	Minimum	Standard Deviation
East	INC	3.012	0.467	<0.001	0.476
	DEC	3.029	0.482	<0.001	0.476
	DA Load	0.210	0.016	<0.001	0.028
	RT Load	0.835	0.084	<0.001	0.106
	Deviation	3.012	0.467	<0.001	0.476
West	INC	2.434	0.416	<0.001	0.429
	DEC	2.449	0.431	<0.001	0.430
	DA Load	0.210	0.016	<0.001	0.028
	RT Load	0.682	0.073	<0.001	0.095
	Deviation	2.434	0.416	<0.001	0.429

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.[33] 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 4-36 shows the reactive services rates associated with local voltage support in 2020 and 2021. Table 4-36 shows that in 2021 only three zones incurred reactive services charges, in addition to reactive capability charges. Real-time load in the PPL Zone, where reactive service charges were the highest, paid an average of $0.017 per MWh for reactive services. Reactive service charges were second highest in the COMED Zone, where the average rate was $0.002 per MWh.

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

Table 4-36 Local voltage support rates: 2020 and 2021

Control Zone	2020 ($/MWh)	2021 ($/MWh)	Difference ($/MWh)	Percent Difference
ACEC	0.000	0.000	0.000	0.0%
AEP	0.000	0.000	0.000	731.1%
APS	0.000	0.000	0.000	0.0%
ATSI	0.000	0.000	0.000	0.0%
BGE	0.000	0.000	0.000	0.0%
COMED	0.000	0.002	0.002	NA
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	0.000	0.000	0.0%
DPL	0.000	0.000	(0.000)	(89.8%)
EKPC	0.004	0.000	(0.004)	(97.4%)
JCPLC	0.008	0.000	(0.008)	(100.0%)
MEC	0.000	0.000	0.000	58.7%
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	0.000	0.000	0.0%
PPL	0.004	0.017	0.013	290.8%
PSEG	0.000	0.000	0.000	0.0%
REC	0.000	0.000	0.000	0.0%

Balancing Operating Reserve Determinants

Table 4-37 shows the determinants used to allocate the regional balancing operating reserve charges in 2020 and 2021. Total real-time load and real-time exports were 803,908 GWh, 2.7 percent higher in 2021 compared to 2020. Total deviations summed across the demand, supply, and generator categories were 217,861 GWh, 32.0 percent higher in 2021 compared to 2020.

Table 4-37 Balancing operating reserve determinants (GWh): 2020 and 2021

		Reliability Charge Determinants (GWh)			Deviation Charge Determinants (GWh)			
		Real-Time Load	Real-Time Exports	Reliability Total	Demand Deviations (MWh)	Supply Deviations (MWh)	Generator Deviations (MWh)	Deviations Total
2020	RTO	742,987	39,888	782,875	110,104	22,539	32,369	165,012
	East	355,089	13,276	368,364	51,472	12,132	15,275	78,879
	West	387,898	26,612	414,510	57,946	10,101	17,094	85,141
2021	RTO	767,425	36,483	803,908	158,278	21,997	37,585	217,861
	East	368,851	16,165	385,016	71,314	10,687	18,194	100,194
	West	398,574	20,318	418,892	84,516	11,039	19,391	114,946
Difference	RTO	24,438	(3,405)	21,033	48,174	(541)	5,216	52,849
	East	13,763	2,889	16,652	19,842	(1,446)	2,919	21,315
	West	10,676	(6,294)	4,381	26,569	938	2,298	29,806

Under PJM's operating reserve rules, balancing operating reserve charges are allocated regionally. PJM defined the Eastern and Western regions, in addition to the RTO region to allocate the cost of balancing operating reserves. These regions consist of three location types: zones, hubs/aggregates, and interfaces. The deviations, calculated between day-ahead and real-time generation, are aggregated regionally by location type, depending on where the charge occurs.

Credits paid to generators that are defined as operating for reliability purposes are charged to real-time load and exports. Credits paid to generators and credits paid to import transactions, such as energy lost opportunity credits and cancellation credits, are charged to deviations

Deviations fall into three categories: demand, supply and generator deviations. Table 4-38 shows the different categories by type of transactions that incurred deviations. In 2021, 49.4 percent of all RTO deviations were incurred by virtual transactions, or by a transaction that combines virtuals with exports or load. In 2021, 97.6 percent of transactions including an INC were exclusively INCs and were not combined with any other supply transactions such as imports. In 2021, 98.8 percent of transactions including a DEC were exclusively DECs and were not combined with any other demand transactions such as UTCs, exports, or load. In 2021, 95.7 percent of transactions including a UTC were exclusively UTCs and were not combined with any other demand transactions such as DECs, exports, or load. In 2021, 11.7 percent of day-ahead operating reserve charges were paid by virtuals (DECs and UTCs). In 2021, 28.5 percent of balancing operating reserve charges were paid by virtuals (DECs, UTCs, and INCs). In 2021, UTCs paid 14.1 percent of total uplift charges, DECs paid 6.1 percent of total uplift charges, and INCs paid 5.8 percent of total uplift charges.

Table 4-38 Deviations by transaction type: 2021

Deviation Category	Transaction	Deviation (GWh)			Share		
		RTO	East	West	RTO	East	West
Demand	DECs Only	24,448	13,292	10,675	11.2%	13.3%	9.3%
	UTCs Only	61,494	22,440	37,087	28.2%	22.4%	32.3%
	Load Only	62,878	32,059	30,819	28.9%	32.0%	26.8%
	Exports Only	6,612	2,776	3,836	3.0%	2.8%	3.3%
	Combination of Load or Exports without DECs & UTCs	2,841	742	2,099	1.3%	0.7%	1.8%
	Combination of Load or Exports with DECs & UTCs	5	5	0	0.0%	0.0%	0.0%
Supply	INCs Only	18,435	7,989	10,175	8.5%	8.0%	8.9%
	Combination of Imports & INCs	459	425	34	0.2%	0.4%	0.0%
	Imports Only	3,103	2,273	830	1.4%	2.3%	0.7%
Generators		37,585	18,194	19,391	17.3%	18.2%	16.9%
Total		217,861	100,194	114,946	100.0%	100.0%	100.0%

Geography of Charges and Credits

Table 4-39 shows the geography of charges and credits in 2021. Table 4-39 includes only day-ahead operating reserve charges and balancing operating reserve reliability and deviation charges since these categories are allocated regionally, while other charges, such as reactive services, synchronous condensing and black start services are allocated by control zone, and balancing local constraint charges are charged to the requesting party.

Charges are categorized by the location (control zone, hub, aggregate or interface) where they are allocated according to PJM's operating reserve rules. Credits are categorized by the location where the resources are located. The shares columns reflect the operating reserve credits and charges balance for each location. For example, transactions in the PPL Control Zone paid 5.0 percent of all operating reserve charges allocated regionally while resources in the PPL Control Zone were paid 2.1 percent of the corresponding credits. The PPL Control Zone received less operating reserve credits than operating reserve charges paid and had 10.2 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 3.9 percent of all operating reserve charges allocated regionally, and resources in the BGE Control Zone were paid 4.7 percent of the corresponding credits. The BGE Control Zone received more operating reserve credits than operating reserve charges paid and had 2.7 percent of the surplus. The surplus is the net of the credits and charges paid at a location. Table 4-39 also shows that 88.9 percent of all charges were allocated in control zones, 4.3 percent in hubs and aggregates and 6.7 percent in interfaces.

Table 4-39 Geography of regional charges and credits: 2021

Location		Charges (Millions)	Credits (Millions)	Balance	Shares Total Charges	Total Credits	Deficit	Surplus
Zones	ACEC	$2.7	$1.7	($1.0)	1.6%	1.0%	2.0%	0.0%
	AEP	$25.5	$24.9	($0.5)	14.7%	14.5%	1.1%	0.0%
	APS	$7.9	$4.6	($3.3)	4.6%	2.7%	6.7%	0.0%
	ATSI	$10.8	$10.9	$0.1	6.2%	6.3%	0.0%	0.2%
	BGE	$6.8	$8.1	$1.4	3.9%	4.7%	0.0%	2.7%
	COMED	$18.1	$36.1	$18.0	10.5%	20.9%	0.0%	35.2%
	DAY	$3.2	$5.3	$2.1	1.9%	3.1%	0.0%	4.0%
	DUKE	$5.2	$3.2	($2.0)	3.0%	1.9%	3.9%	0.0%
	DUQ	$2.5	$0.1	($2.3)	1.4%	0.1%	4.6%	0.0%
	DOM	$20.1	$32.2	$12.1	11.6%	18.7%	0.0%	23.8%
	DPL	$4.2	$11.1	$6.9	2.4%	6.4%	0.0%	13.5%
	EKPC	$3.1	$7.5	$4.4	1.8%	4.4%	0.0%	8.7%
	External	$0.0	$6.1	$6.1	0.0%	3.5%	0.0%	11.9%
	JCPLC	$4.0	$1.9	($2.2)	2.3%	1.1%	4.3%	0.0%
	MEC	$3.4	$2.1	($1.3)	2.0%	1.2%	2.7%	0.0%
	OVEC	$0.5	$0.0	($0.5)	0.3%	0.0%	1.0%	0.0%
	PECO	$7.2	$1.4	($5.8)	4.1%	0.8%	11.6%	0.0%
	PE	$4.5	$3.5	($1.0)	2.6%	2.0%	2.0%	0.0%
	PEPCO	$5.8	$4.9	($0.9)	3.3%	2.8%	1.8%	0.0%
	PPL	$8.6	$3.6	($5.1)	5.0%	2.1%	10.2%	0.0%
	PSEG	$8.5	$3.2	($5.4)	4.9%	1.8%	10.7%	0.0%
	REC	$1.2	$0.0	($1.2)	0.7%	0.0%	2.3%	0.0%
	All Zones	$153.7	$172.2	$18.5	88.9%	100.0%	65.1%	100.0%
Hubs and Aggregates	AEP - Dayton	$2.0	$0.0	($2.0)	1.1%	0.0%	3.9%	0.0%
	Dominion	$1.2	$0.0	($1.2)	0.7%	0.0%	2.4%	0.0%
	Eastern	$0.5	$0.0	($0.5)	0.3%	0.0%	1.0%	0.0%
	New Jersey	$0.6	$0.0	($0.6)	0.4%	0.0%	1.2%	0.0%
	Ohio	$0.8	$0.0	($0.8)	0.4%	0.0%	1.5%	0.0%
	Western Interface	$0.0	$0.0	$0.0	0.0%	0.0%	0.0%	0.0%
	Western	$2.5	$0.0	($2.5)	1.4%	0.0%	5.0%	0.0%
	RTEP B0328 Source	$0.0	$0.0	$0.0	0.0%	0.0%	0.0%	0.0%
	All Hubs and Aggregates	$7.5	$0.0	($7.5)	4.3%	0.0%	15.0%	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	$1.0	$0.0	($1.0)	0.6%	0.0%	1.9%	0.0%
	IMO	$0.4	$0.0	($0.4)	0.2%	0.0%	0.8%	0.0%
	Linden	$0.6	$0.0	($0.6)	0.3%	0.0%	1.1%	0.0%
	MISO	$4.9	$0.0	($4.9)	2.8%	0.0%	9.8%	0.0%
	NCMPA Imp	$0.0	$0.0	$0.0	0.0%	0.0%	0.0%	0.0%
	Neptune	$0.4	$0.0	($0.4)	0.2%	0.0%	0.8%	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	$1.8	$0.0	($1.8)	1.0%	0.0%	3.6%	0.0%
	South Exp	$0.6	$0.0	($0.6)	0.3%	0.0%	1.2%	0.0%
	South Imp	$0.3	$0.0	($0.3)	0.2%	0.0%	0.6%	0.0%
	South	$1.7	$0.0	($1.7)	1.0%	0.0%	3.5%	0.0%
	All Interfaces	$11.7	$0.0	($11.7)	6.7%	0.0%	19.9%	0.0%
	Total	$172.9	$172.2	($0.7)	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).[34] 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 4-40 shows balancing operating reserve credits calculated using intraday segments and balancing operating reserve payments calculated on a daily basis. In 2021, balancing operating reserve credits would have been $27.0 million or 21.2 percent lower if they were calculated on a daily basis. In 2020, balancing operating reserve credits would have been $10.7 million or 18.5 percent lower if they were calculated on a daily basis.

Table 4-40 Intraday segments and daily balancing operating reserve credits: 2020 and 2021

	2020 BOR Credits (Millions)			2021 BOR Credits (Millions)		
	Intraday Segments Calculation	Daily Calculation	Difference	Intraday Segments Calculation	Daily Calculation	Difference
Jan	$1.6	$1.3	($0.3)	$4.8	$4.2	($0.5)
Feb	$0.7	$0.5	($0.2)	$10.5	$9.4	($1.2)
Mar	$0.9	$0.7	($0.2)	$5.0	$4.0	($1.0)
Apr	$1.1	$0.9	($0.2)	$16.4	$15.0	($1.3)
May	$1.9	$1.6	($0.3)	$5.8	$4.7	($1.1)
Jun	$5.1	$4.1	($1.0)	$13.0	$9.8	($3.2)
Jul	$8.8	$5.7	($3.0)	$17.8	$14.0	($3.8)
Aug	$8.1	$6.0	($2.1)	$19.6	$14.5	($5.1)
Sep	$3.7	$2.8	($0.9)	$4.2	$2.4	($1.8)
Oct	$6.8	$5.9	($0.9)	$11.6	$8.7	($2.9)
Nov	$7.8	$7.0	($0.8)	$14.0	$9.9	($4.1)
Dec	$11.8	$11.0	($0.9)	$4.9	$4.0	($0.9)
Total	$58.2	$47.4	($10.7)	$127.5	$100.5	($27.0)

Prior to April 1, 2018, for purposes of calculating LOC credits, each hour was defined as a unique segment. Following the implementation of five minute settlements on April 1, 2018, LOC credits are calculated with each five minute interval defined as a unique segment. Thus a profit in one five minute segment, resulting from the real-time LMP being lower than the day-ahead LMP, is not used to offset a loss in any other five minute segment. This change in settlements causes an increase in LOC credits compared to hourly settlement as generators are made whole for any losses incurred in a five minute interval while previously gains and losses were netted within the hour. Table 4-41 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 2021, LOC credits would have been $2.9 million or 10.2 percent lower if they had been settled on an hourly basis rather than on a five minute basis. In 2021, LOC credits would have been $7.2 million or 25.2 percent lower if they had been settled on the recommended daily basis rather than being settled on a five minute basis.

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

Table 4-41 Comparison of five minute, hourly, and daily settlement of day-ahead lost opportunity cost credits: 2021

	2021 Day-Ahead LOC Credits (Millions)				
	Five Minute Settlement (Status Quo)	Hourly Settlement (Pre-April 2018)	Difference	Daily Settlement (Recommendation)	Difference
Jan	$0.4	$0.3	($0.1)	$0.2	($0.1)
Feb	$0.5	$0.5	($0.1)	$0.4	($0.2)
Mar	$3.5	$3.1	($0.4)	$2.3	($1.2)
Apr	$0.6	$0.6	$0.0	$0.5	($0.1)
May	$2.8	$2.5	($0.3)	$2.3	($0.5)
Jun	$3.0	$2.8	($0.2)	$2.4	($0.6)
Jul	$1.8	$1.6	($0.2)	$1.4	($0.3)
Aug	$1.5	$1.3	($0.2)	$1.1	($0.4)
Sep	$2.5	$2.3	($0.2)	$2.0	($0.5)
Oct	$2.2	$2.0	($0.2)	$1.7	($0.5)
Nov	$6.7	$6.0	($0.7)	$4.9	($1.8)
Dec	$3.2	$2.9	($0.4)	$2.4	($0.8)
Total	$28.7	$25.8	($2.9)	$21.5	($7.2)

Uplift Credits and Offer Capping

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

Table 4-42 shows the uplift credits paid to units that were committed and dispatched on cost offers in 2021. Units received $95.3 million or 74.7 percent of balancing operating reserve credits and $9.4 million or 69.0 percent of day-ahead operating reserve credits in 2021 using price-based offers. Units received $19.1 million or 15.0 percent of balancing operating reserves and $3.7 million or 26.9 percent of day-ahead operating reserves in 2021 using cost-based offers.

Table 4-42 Operating Reserve Credits by Offer Type: 2021

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	$3.7	$19.1	$0.3	$0.6	$23.7
Price	$9.4	$95.3	$0.0	$0.0	$104.7
Price PLS	$0.6	$9.7	$0.0	$0.0	$10.3
Cost & Price	$0.0	$3.0	$0.0	$0.0	$3.0
Cost & PLS	$0.0	$0.3	$0.0	$0.0	$0.3
Price & PLS	$0.0	$0.0	$0.0	$0.0	$0.0
Total	$13.7	$127.5	$0.3	$0.6	$142.0
Share	9.6%	89.8%	0.2%	0.4%	100.0%

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

Table 4-43 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, 32.2 percent went to units that were committed on price schedules less flexible than PLS.

Table 4-43 Day-ahead operating reserve credits during weather alerts by commitment schedule: 2021

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)	$24,689	2.8%
Committed on price schedule as flexible as PLS	$2,435	0.3%
Committed on price schedule less flexible than PLS	$280,201	32.2%
Committed on price PLS	$562,012	64.6%
Total	$869,337	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 $0.7 million. Table 4-3 shows that 30.8 percent of the dispatch differential lost opportunity cost credit was paid to combined cycle units and 35.8 percent to combustion turbines. In some cases, PJM paid dispatch differential payments to resources that did not follow PJM dispatch instructions. PJM should not make these payments as they are directly counter to the logic of fast start pricing as well as to tariff rules.

The MMU recommends that PJM not make such payments and require refunds where it has 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 4-44 shows the amount of uplift paid to fast start units by major uplift category. Fast start units received $29.8 million in balancing operating reserve credits, or 23.4 percent of total balancing operating reserves. Fast start units received $5.7 million in day-ahead lost opportunity costs, or 19.8 percent of all lost opportunity costs. Fast start units received $0.1 million in day-ahead operating credits, or 0.9 percent of total day-ahead operating reserve credits.

Table 4-44 Monthly day-ahead operating reserves, balancing operating reserves, and day-ahead lost opportunity cost credits for fast start units: 2021

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	1.5%	$2.0	42.1%	$0.2	42.4%
Feb	$0.0	3.1%	$2.2	20.8%	$0.2	40.7%
Mar	$0.1	8.4%	$1.7	35.1%	$1.7	47.3%
Apr	$0.0	0.2%	$3.7	22.4%	$0.0	4.9%
May	$0.0	0.5%	$1.5	26.0%	$0.3	9.1%
Jun	$0.0	0.6%	$2.8	21.6%	$0.4	14.2%
Jul	$0.0	0.6%	$3.4	19.0%	$0.3	15.8%
Aug	$0.0	0.3%	$3.8	19.4%	$0.3	20.4%
Sep	$0.0	0.5%	$1.2	28.9%	$0.3	12.0%
Oct	$0.0	0.3%	$3.4	29.0%	$0.4	18.7%
Nov	$0.0	1.0%	$2.7	19.2%	$1.3	18.6%
Dec	$0.0	0.0%	$1.5	30.5%	$0.4	12.1%
Total	$0.1	0.9%	$29.8	23.4%	$5.7	34.2%

Table 4-45 shows the day-ahead, balancing operating reserves, and day-ahead lost opportunity cost credits for combustion turbines by month.

Table 4-45 Day ahead operating reserves, balancing operating reserves, day-ahead lost opportunity cost credits for fast start combustion turbines: 2021

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	1.5%	$1.9	40.4%	$0.1	37.9%
Feb	$0.0	2.5%	$2.1	19.9%	$0.2	36.1%
Mar	$0.1	2.2%	$1.7	34.1%	$1.6	46.8%
Apr	$0.0	0.2%	$3.6	21.8%	$0.0	4.6%
May	$0.0	0.4%	$1.5	25.6%	$0.2	8.7%
Jun	$0.0	0.3%	$2.6	20.4%	$0.4	13.8%
Jul	$0.0	0.8%	$3.3	18.6%	$0.3	15.4%
Aug	$0.0	0.2%	$3.7	18.9%	$0.3	17.2%
Sep	$0.0	0.2%	$1.2	28.5%	$0.3	10.9%
Oct	$0.0	0.5%	$3.3	28.6%	$0.4	16.4%
Nov	$0.0	0.9%	$2.6	18.8%	$1.2	17.9%
Dec	$0.0	0.0%	$1.5	29.9%	$0.3	10.8%
Total	$0.1	0.9%	$29.1	22.8%	$5.4	32.4%