Congestion and Marginal Losses

When there are binding transmission constraints and locational price differences, load pays more for energy than generation is paid to produce that energy.[1] The difference is congestion.[2] As a result, congestion belongs to load and should be returned to load. Congestion is not the difference in CLMP between nodes. Congestion is not the billing line item labeled congestion.[3]

Congestion is not a useful metric for determining whether there is a benefit to building more transmission. Analyses that use congestion to support the need for transmission expansion incorrectly count congestion as a cost to load without accounting for how the congestion dollars are or are not returned to the load through ARRs and FTRs.

If FTRs worked perfectly and were assigned directly to load, FTRs would return all congestion to the load that paid the congestion. Congestion is not a cost, it is an accounting result of a market based on locational energy prices in which all load in a constrained area pays the higher single market clearing locational price, resulting in excess payments by load that are not paid to generation, which should be returned to load.

Counterintuitively, congestion can actually increase when the transmission capacity between areas with lower cost generation and areas with higher cost generation is expanded but does not fully eliminate the need for some higher cost local generation. The smaller the amount of higher cost local generation needed to meet load, the more of the local load is met via low cost generation delivered over the transmission system and therefore the higher can be the difference between what load pays and generation receives, congestion.

For all these reasons, if done correctly and if FTRs/ARRs returned 100 percent of congestion to load, the cost/benefit analysis for transmission projects would include the total net change in production costs and would not include congestion. The change in production costs correctly measures the changes in cost to load that result from a project. There clearly can be benefits to transmission expansion but congestion is not the correct metric for measuring those benefits. The correct metric is the change in production costs which measures the reduction in the reliance on higher cost generation to meet load in the presence of a transmission constraint.

This issue also illustrates the unintended and negative consequences of misunderstanding congestion and FTRs. The unintended result is to overstate the benefits of transmission expansion by not correctly recognizing how congestion dollars should be returned to load. Even in the case where there is only a partial return of congestion to load, the actual return of congestion to load must be accounted for in order to correctly identify the benefits. Ignoring the return of congestion to load from ARRs/FTRs overstates the potential benefits of transmission expansion, and ignores the value of smaller upgrades that may not eliminate a constraint, but may reduce production costs and therefore the average cost of energy for load.

The locational marginal price (LMP) is the incremental price of energy at a bus. The LMP at a bus can be divided into three components: the system marginal price (SMP) or energy component, the congestion component (CLMP), and the marginal loss component (MLMP). SMP, MLMP and CLMP are the simultaneous products of the least cost, security constrained dispatch of system resources to meet system load and the use of a load-weighted reference bus. The relative values of SMP and CLMP are arbitrary and depend on the reference bus.

SMP is defined as the incremental price of energy for the system, given the current dispatch, at the load-weighted reference bus, or LMP net of losses and congestion. SMP is the LMP at the load-weighted reference bus. The load-weighted reference bus is not a fixed location but varies with the distribution of load at system load buses. For SMP, energy means the component of LMP not associated with a binding transmission constraint. All other locational prices that result from the least cost, security constrained market solution are higher or lower than this reference point price (SMP) as a result of binding constraints. The reference bus is a point of reference. For a given market solution, changing the reference bus does not change the LMP for any node on the system, but changes only the elements of the nodal prices that are positive or negative due to the binding constraints in that solution, further illustrating that the relative levels of SMP and LMP are arbitrary.

1 Load is generically referred to as withdrawals and generation is generically referred to as injections, unless specified otherwise.
2 The difference in losses is not part of congestion.
3 PJM billing examples can be found in *2022 Annual State of the Market Report for PJM*, Appendix F: Congestion and Marginal Losses.

CLMP is defined as the incremental price of meeting load at each bus when a transmission constraint is binding, based on the shadow price associated with the relief of a binding transmission constraint in the security constrained optimization. (The shadow price is the difference between the CLMPs across the transmission constraint.) There can be multiple binding transmission constraints. CLMPs are positive or negative depending on location relative to binding constraints and relative to the load-weighted reference bus. In an unconstrained system CLMPs will be zero. This means that CLMP at a bus is not congestion. The difference between CLMPs at buses is not congestion, it is just the absolute LMP difference between the two buses caused by transmission constraints, or the shadow price. CLMP is the portion of the LMP at a bus that indicates whether the LMP at that bus is higher or lower than the marginal price of energy SMP at the selected reference bus due to binding transmission constraints. The relative values of SMP and CLMP are arbitrary and depend on the reference bus.

MLMP is defined as the incremental price of losses at a bus, based on marginal loss factors in the security constrained optimization. Losses refer to energy lost to physical resistance in the transmission network as power is moved from generation to load.

Total losses refer to total system wide transmission losses as a result of moving power from injections to withdrawals on the system. Marginal losses are the incremental change in system losses caused by changes in load and generation.

Congestion is neither good nor bad, but is a direct measure of the extent to which there are multiple marginal generating units with different offers dispatched to serve load as a result of transmission constraints. Congestion occurs when available, least-cost energy cannot be delivered to all load because transmission facilities are not adequate to deliver that energy to one or more areas, and higher cost units in the constrained area(s) must be dispatched to meet the load.[4] When the least-cost available energy cannot be delivered to load in a transmission constrained area, higher cost units in the constrained area must be dispatched to meet that load. The result is that the price of energy in the constrained area is higher than in the unconstrained area because of the combination of transmission limitations and the cost of local generation. Congestion is the difference between the total cost of energy paid by load in the transmission constrained area based on the single higher price at load buses and the total revenue received by generation based on the prices at the generator buses to provide that energy, after virtual bids have been settled. Congestion equals the sum of day-ahead and balancing congestion. The actual incremental cost paid by load in the constrained area is the difference in price (shadow price) times the MW of load served by higher cost local generation. This is also the higher production costs that result from the constraint.

The energy, marginal losses and congestion metrics must be interpreted carefully.

In PJM accounting, the term total congestion refers to net implicit CLMP charges plus net explicit CLMP charges plus net inadvertent CLMP charges. The net implicit CLMP charges are the implicit withdrawal CLMP charges less implicit injection CLMP credits.

As with congestion, total system energy costs are more precisely termed net system energy costs and total marginal loss costs are more precisely termed net marginal loss costs. Ignoring interchange, total generation MWh must be greater than total load MWh in any hour in order to provide for losses. Since the hourly integrated energy component of LMP is the same for every bus within every hour, the net energy bill is negative (ignoring net interchange), with more generation credits than load payments in every hour.[5]

While PJM accounting focuses on CLMPs, the individual CLMP values at any bus are irrelevant to the calculation of congestion, as CLMPs are just an artificial deconstruction of LMP based on a selected reference bus. Holding aside the marginal loss component of LMP, differences in the LMPs are caused by binding constraints in the least cost security constrained dispatch

4 This is referred to as dispatching units out of economic merit order. Economic merit order is the order of all generator offers from lowest to highest cost. Congestion occurs when loadings on transmission facilities mean the next unit in merit order cannot be used and a higher cost unit must be used in its place. Dispatch within the constrained area follows merit order for the units available to relieve the constraint.

5 The total congestion and marginal losses for 2025 were calculated as of April 9, 2025, and are subject to change, based on continued PJM billing updates.

market solution and total congestion is the net surplus revenue that remains after all sources and sinks are credited or charged their LMPs. Changing the components of LMP by electing a different reference bus does not change the LMPs or the difference between LMPs for a given market solution, it merely changes the components of the LMP. This means that no particular importance should be assigned to the levels of SMP and CLMP at a bus.

Local congestion is the congestion paid by load at a specific bus or set of buses and is calculated on a constraint specific basis. For a given market solution, a change in the reference bus does not change the LMP at any bus and does not change total congestion paid by load and does not change the local congestion paid by load at a specific location. Holding aside the marginal loss component of LMP, local congestion is the sum of the total LMP charges to load at the defined set of buses minus the sum of the total LMP credits received by all generation that supplied that load, given the set of all binding transmission constraints, regardless of location. Local congestion reflects the underlying characteristics of the complete power system as it affects the defined area, including the nature and capability of transmission facilities, the offers and geographic distribution of generation facilities, the level and geographic distribution of incremental bids and offers and the geographic and temporal distribution of load. Local congestion fully reflects the least cost security constrained system solution and the LMPs that result from that solution.

PJM implemented fast start pricing in both day-ahead and real-time markets starting September 1, 2021. PJM's fast start pricing logic results in pricing run locational marginal prices (PLMP). PLMP is the price that load pays and generators receive in the PJM energy market.

While PLMP is the official settlement price, PJM continues to calculate LMP based on the logic that PJM uses to actually dispatch system resources and used prior to the introduction of fast start to consistently define dispatch and prices. The LMPs from the dispatch run are dispatch run locational marginal prices (DLMP). While the settlement prices are PLMP, settlement MW are based on the dispatch run in the day-ahead market and are metered output in the real-time market.

PJM inappropriately uses artificial constraints in the day-ahead and real-time markets to force specific resources (generation or demand response) to be marginal in order to have those resources set price. The resultant, artificially uniform source dfax and sink dfax of the artificial constraint can be modified, along with the line limits, by PJM to meet market outcome goals and are a source of often significant modeling differences between the day-ahead and real-time market. These modeling differences result in inefficient market outcomes and false arbitrage opportunities for virtual transactions. These artificial constraints have been used to hide uplift costs by making uplift costs negative congestion charges. The use of artificial constraints is an inappropriate use of PJM discretion as the market operator, putting PJM in the position of a market actor, arbitrarily changing market results, market prices, generation revenues, congestion costs and load charges.

Overview

Congestion Cost

- **Total Congestion.** Total congestion costs increased by $182.3 million or 56.8 percent, from $321.0 million in the first three months of 2024 to $503.3 million in the first three months of 2025.
- **Day-Ahead Congestion.** Day-ahead congestion costs increased by $304.8 million or 76.4 percent, from $398.7 million in the first three months of 2024 to $703.5 million in the first three months of 2025.
- **Balancing Congestion.** Negative balancing congestion costs increased by $122.5 million, from -$77.7 million in the first three months of 2024 to -$200.2 million in the first three months of 2025. Negative balancing explicit charges increased by $42.7 million, from -$51.8 million in the first three months of 2024 to -$94.5 million in the first three months of 2025.
- **Real-Time Congestion.** Real-time congestion costs increased by $463.7 million, from $390.5 million in the first three months of 2024 to $854.2 million in the first three months of 2025.

- **Monthly Congestion.** Monthly total congestion costs in the first three months of 2025 ranged from $124.5 million in February to $227.8 million in January.
- **Geographic Differences in CLMP.** Differences in CLMP between southern and eastern control zones in PJM were primarily a result of binding constraints on the Lenox – North Meshoppen Line, the AP South Interface, the Dune Acres – Michigan City Flowgate, the Chaparral – Carson Line, and the AEP – DOM Interface.
- **Congestion Frequency.** Congestion frequency continued to be significantly higher in the day-ahead energy market than in the real-time energy market in the first three months of 2025. The number of congestion event hours in the day-ahead energy market was about three times the number of congestion event hours in the real-time energy market.

  Day-ahead congestion frequency increased by 7.4 percent from 19,390 congestion event hours in the first three months of 2024 to 20,823 congestion event hours in the first three months of 2025.

  Real-time congestion frequency increased by 34.2 percent from 6,273 congestion event hours in the first three months of 2024 to 8,416 congestion event hours in the first three months of 2025.
- **Congested Facilities.** Day-ahead, congestion event hours decreased on transformers and lines and increased on interfaces and flowgates.

  The Lenox – North Meshoppen Line was the largest contributor to congestion costs in the first three months of 2025. With $88.3 million in total congestion costs, it accounted for 17.5 percent of the total PJM congestion costs in the first three months of 2025.
- **CT Price Setting Logic and Closed Loop Interface Related Congestion.** PJM's use of CT pricing logic officially ended with the implementation of fast start pricing on September 1, 2021. While CT pricing logic was officially discontinued, PJM continues to use a related logic to force inflexible units and demand response to be on the margin in both real time and day ahead. None of the PJM defined closed loop interfaces were binding in the first three months of 2024 or 2025.
- **Zonal Congestion.** AEP had the highest zonal congestion costs among all control zones in the first three months of 2025. AEP had $81.9 million in zonal congestion costs, comprised of $111.1 million in day-ahead congestion costs and -$29.2 million in balancing congestion costs.

Marginal Loss Cost

- **Total Marginal Loss Costs.** Total marginal loss costs increased by $211.9 million or 97.7 percent, from $217.0 million in the first three months of 2024 to $428.9 million in the first three months of 2025. The loss MWh in PJM increased by 682.0 GWh or 16.6 percent, from 4,112.8 GWh in the first three months of 2024 to 4,794.8 GWh in the first three months of 2025. The loss component of real-time LMP in the first three months of 2025 was $0.04, compared to $0.02 in the first three months of 2024.
- **Day-Ahead Marginal Loss Costs.** Day-ahead marginal loss costs increased by $213.5 million or 90.4 percent, from $236.2 million in the first three months of 2024 to $449.7 million in the first three months of 2025.
- **Balancing Marginal Loss Costs.** Negative balancing marginal loss costs increased by $1.6 million or 8.1 percent, from -$19.3 million in the first three months of 2024 to -$20.8 million in the first three months of 2025.
- **Total Marginal Loss Surplus.** The total marginal loss surplus increased by $85.9 million or 120.4 percent, from $71.4 million in the first three months of 2024, to $157.3 million in the first three months of 2025.
- **Monthly Total Marginal Loss Costs.** Monthly total marginal loss costs in the first three months of 2025 ranged from $90.2 million in March to $222.8 million in January.

System Energy Cost

- **Total System Energy Costs.** Total system energy costs decreased by $125.3 million or 86.1 percent, from -$145.6 million in the first three months of 2024 to -$270.9 million in the first three months of 2025.
- **Day-Ahead System Energy Costs.** Day-ahead system energy costs decreased by $131.8 million or 75.1 percent, from -$175.6 million in the first three months of 2024 to -$307.5 million in the first three months of 2025.

- **Balancing System Energy Costs.** Balancing system energy costs increased by $9.6 million or 32.4 percent, from $29.5 million in the first three months of 2024 to $39.0 million in the first three months of 2025.
- **Monthly Total System Energy Costs.** Monthly total system energy costs in the first three months of 2025 ranged from -$137.8 million in January to -$56.9 million in March.

Conclusion

Congestion is defined as the total payments by load in excess of the total payments to generation, excluding marginal losses. The level and distribution of congestion reflects the underlying characteristics of the power system, including the nature and defined capability of transmission facilities, the offers and geographic distribution of generation facilities, the level and geographic distribution of incremental bids and offers and the geographic and temporal distribution of load.

Total congestion costs increased by $182.3 million or 56.8 percent, from $321.0 million in the first three months of 2024 to $503.3 million in the first three months of 2025.

Monthly total congestion costs ranged from $124.5 million in February to $227.8 million in January in the first three months of 2025.

The current ARR/FTR design does not ensure that load receives the rights to all congestion revenues. The congestion offset provided by ARRs and self-scheduled FTRs in the first ten months of the 2024/2025 planning period was 51.3 percent. The cumulative offset of congestion by ARRs for the 2011/2012 planning period through the first ten months of the 2024/2025 planning period, using the rules effective for each planning period, was 68.7 percent. Load has received $4.8 billion less than load should have received from the 2011/2012 planning period through the first ten months of the 2024/2025 planning period.

Issues

Artificial Constraints, Closed Loop Interfaces and CT Pricing Logic

PJM has used, and in some cases, continues to use, artificial constraints in the day-ahead and real-time markets to force specific resources (generation or demand response) to be marginal in order to have those resources set price. Some of these artificial constraints, such as CT pricing logic and closed loop interfaces, result in negative congestion charges that are an artifact of the artificial nature of the constraints that cause generation to be paid more than load pays for energy affected by the constraint. PJM also makes use of artificial constraints that function like closed loop interfaces but which result in positive or negative balancing congestion. These constraints are called Real-Time Short-Term Marginal Value Overrides. These constraints are similar to a closed loop interface in that they enforce artificially uniform price effects, but unlike closed loop interfaces that only affect prices on the constrained side, these artificial constraints enforce artificially uniform price spreads between the two sides of the constraint through large uniform dfax on the constrained side and small uniform dfax on the unconstrained side. These artificial constraints take the form of interfaces or enforced contingencies (modifications) on existing constraints. The uniform source dfax and uniform sink dfax of the artificial constraint can be modified, along with the transmission line limits, by PJM to meet market outcome goals and are a source of often significant modeling differences between the day-ahead and real-time market. These modeling differences result in inefficient market outcomes and false arbitrage opportunities for virtual transactions. This is an inappropriate use of these tools as it puts PJM in the position of a market actor, arbitrarily changing market results, market prices, generation revenues, congestion costs and load charges. One of the side effects of these changes in parameters, besides causing modeling differences between the day-ahead and real-time market, is that the apparent location of the interface or parent constraint can move intraday relative to source and sink points.

While CT pricing logic was officially discontinued by PJM with the implementation of fast start pricing on September 1, 2021, PJM continues to use the same basic logic (Real-Time Short-Term Marginal Value Overrides) to force inflexible units to be on the margin in both real time and day ahead. PJM used CT pricing logic to force otherwise uneconomic resources to be marginal and set price in the day-ahead or real-time market solution. PJM used CT pricing logic to create an artificial constraint with a variable flow limit, paired with an artificial override of the inflexible resource's economic minimum, to make the resource marginal in PJM's LMP security constrained pricing logic. The purpose of forcing inflexible units to be marginal is to artificially reduce the uplift associated with the dispatch of inflexible resources.

Through the assumption of artificial flexibility of the affected unit and artificially creating a constraint for which the otherwise inflexible resource can be marginal, PJM's use of CT pricing logic forced the affected resource bus LMP to match the marginal offer of the resource. PJM adjusts the constraint limit based on the output of the resource. Sometimes the constraint limit does not match the flows on the constraint, and the constraint violates instead of binding, resulting in prices set by the transmission constraint penalty factor.

In the case of a closed loop interface, all buses within the interface were modeled with a distribution factor (dfax) of 1.0 to the constraint and therefore with the same constraint related congestion component of price at the marginal resource's bus. In the CT pricing logic case, the constraint affected the CLMP of constrained side buses in proportion to their dfax to that constraint.[6] One objective of making inflexible resources marginal was to artificially minimize the uplift costs associated with the inflexible resources that PJM commits for system security reasons.

The use of artificial constraints was and is a source of modeling differences between the day-ahead and real-time markets. When artificial constraints are not included in the day-ahead market in exactly the same way as in the real-time market, including specific constraints and limits, the differences between the day-ahead and real-time market model result in positive or negative balancing congestion.

Failure to model the same constraints in the day-ahead and real-time markets results in pricing and congestion settlement differences between the day-ahead and real-time market. Any modeling differences create false arbitrage opportunities for virtual bids and contribute to negative balancing congestion.

Use of artificial constraints, closed loop interfaces and CT price setting logic requires manipulation of the economic dispatch model. Closed loop interfaces and CT price setting logic, like fast start pricing logic that replaced it, force higher cost inflexible units to be marginal.

Like closed loop interfaces and CT pricing logic, some of the artificially enforced constraint results in negative congestion. As a result, more power is produced in the artificial closed loop or constrained area than would result without the artificial constraint. This means that there are more generation credits than load charges in the constrained area. The constrained area exports power, the lower cost generators outside the constrained area are backed down and prices are lower outside the constrained area as a result. All of the generation within the artificially constrained area is paid the higher CLMP, but only a smaller amount of load (in some cases no load) in the constrained area pays this higher CLMP. As a result, load pays less than generation receives in the artificially constrained area. This difference is negative congestion. In the day-ahead market this reduces the total congestion dollars that are available to FTR holders. In the balancing market these costs are allocated directly to load as negative balancing charges.

6 The constrained side means the higher priced side with a positive CLMP created by the constraint.

Locational Marginal Price (LMP)

Components

PJM uses a distributed load reference bus. With a distributed load reference bus, the energy component of LMP is a load-weighted system price. Some price effects of binding constraints may be included in the load-weighted reference bus price.

LMP at a bus reflects the incremental price of energy at that bus. LMP at any bus can be disaggregated into three components: the system marginal price (SMP), marginal loss component (MLMP), and congestion component (CLMP).

SMP, MLMP and CLMP are a product of the least cost, security constrained dispatch of system resources to meet system load. SMP is the incremental cost of system energy, given the current dispatch and given the choice of reference bus. SMP is LMP net of losses and congestion. Losses refer to energy lost to physical resistance in the transmission and distribution network as power is moved from generation to load. Marginal losses are the incremental change in system power losses caused by changes in the system load and generation patterns.[7] The first derivative of total losses with respect to the power flow is marginal losses. Congestion cost reflects the incremental cost of relieving transmission constraints while maintaining system power balance. Congestion occurs when available, least-cost energy cannot be delivered to all loads because transmission facilities are not adequate to deliver that energy. When the least-cost available energy cannot be delivered to load in a transmission constrained area, higher cost units in the constrained area must be dispatched to meet that load.[8] The result is that the price of energy in the constrained area is higher than in the unconstrained area because of the combination of transmission limitations and the cost of local generation. Load in the constrained area pays the higher price for all energy including energy from low cost generation and energy from high cost generation. Congestion is the difference between the total cost of energy paid by load in the transmission constrained area and the total revenue received by generation to meet the load in the transmission constrained area, net of losses. Congestion equals the sum of day-ahead and balancing congestion.

Table 11-1 shows the PJM real-time load-weighted average LMP components for the first three months of 2008 through 2025.[9]

The real-time load-weighted average LMP increased by $21.19 or 68.3 percent from $31.01 in the first three months of 2024 to $52.20 in the first three months of 2025. The real-time load-weighted average congestion component was $0.13 in the first three months of 2025, compared to $0.06 in the first three months of 2024. The real-time load-weighted average loss component in the first three months of 2025 was $0.04, compared to $0.02 in the first three months of 2024. The real-time load-weighted average system energy component increased by $21.10 or 68.2 percent from $30.92 in the first three months of 2024 to $52.03 in the first three months of 2025. Using a load-weighted reference bus, the real-time load-weighted average congestion component of LMP should be zero. PJM's load-weighted reference bus congestion component is zero at the time that LMPs are set based on state estimator data. Metering updates during the settlement process change the load weights after the fact, but the reference bus price (SMP) is not updated with these changes over time. As a result, the average congestion and loss components used in real-time settlement are not zero.

7 For additional information, see the *MMU Technical Reference for PJM Markets*, at "Marginal Losses," <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

8 This is referred to as dispatching units out of economic merit order. Economic merit order is the order of all generator offers from lowest to highest cost. Congestion occurs when loadings on transmission facilities mean the next unit in merit order cannot be used and a higher cost unit must be used in its place.

9 The PJM real-time, load-weighted price is weighted by accounting load, which differs from the state-estimated load used in determination of the energy component (SMP). In the real-time energy market, the distributed load reference bus is weighted by state-estimated load in real time. When the LMP is calculated in real time, the energy component equals the system load-weighted price. But real-time bus-specific loads are adjusted, after the fact, based on updated load information from meters. This meter adjusted load is accounting load that is used in settlements and is used to calculate reported PJM load-weighted prices. This after the fact adjustment means that the real-time energy market energy component of LMP (SMP) and the PJM real-time load-weighted LMP are not equal. The difference between the real-time energy component of LMP and the PJM wide real-time load-weighted average LMP is a result of the difference between state-estimated and metered loads used to weight the load-weighted reference bus and the load-weighted LMP. Without these adjustments, the congestion component of system average LMP would be zero.

Table 11-1 Real-time load-weighted average LMP components (Dollars per MWh): January through March, 2008 through 2025[10]

(Jan - Mar)	Real-Time LMP	Energy Component	Congestion Component	Loss Component
2008	$69.35	$69.27	$0.04	$0.04
2009	$49.60	$49.51	$0.05	$0.04
2010	$45.92	$45.81	$0.06	$0.05
2011	$46.35	$46.30	$0.03	$0.03
2012	$31.21	$31.18	$0.02	$0.00
2013	$37.41	$37.37	$0.02	$0.02
2014	$92.98	$93.08	($0.13)	$0.03
2015	$50.91	$50.89	($0.00)	$0.03
2016	$26.80	$26.75	$0.03	$0.01
2017	$30.28	$30.25	$0.02	$0.02
2018	$49.45	$49.39	$0.03	$0.03
2019	$30.16	$30.12	$0.02	$0.02
2020	$19.85	$19.83	$0.01	$0.01
2021	$30.84	$30.79	$0.03	$0.02
2022	$54.13	$54.03	$0.06	$0.04
2023	$30.28	$30.23	$0.02	$0.02
2024	$31.01	$30.92	$0.06	$0.02
2025	$52.20	$52.03	$0.13	$0.04

Table 11-2 shows the PJM day-ahead load-weighted average LMP components for the first three months of 2008 through 2025. The day-ahead load-weighted average LMP increased by $21.26, or 65.7 percent, from $32.34 in the first three months of 2024 to $53.60 in the first three months of 2025. The day-ahead load-weighted average congestion component increased by $0.10 from $0.01 in the first three months of 2024 to $0.11 in the first three months of 2025. The day-ahead load-weighted average loss component was $0.16 in the first three months of 2025, compared to $0.04 in the first three months of 2024. The day-ahead load-weighted average energy component increased by $21.04, or 65.2 percent, from $32.28 in the first three months of 2024 to $53.32 in the first three months of 2025. Using a load-weighted reference bus, the day-ahead load-weighted average congestion component of LMP should be zero. PJM's load-weighted reference bus congestion component is zero based on day-ahead firm load weights. Total billing however, includes price sensitive demand and virtual load congestion related charges, which makes the total load weights in accounting different than the load weights used to determine the SMP at the load-weighted reference bus. The resulting load-weighted average price from settlement for congestion and marginal losses components of price in day ahead is therefore not zero, although this component is not fully accurate.

10 Calculated values shown in Section 11, "Congestion and Marginal Losses," are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

Table 11-2 Day-ahead load-weighted average LMP components (Dollars per MWh): January through March, 2008 through 2025

(Jan - Mar)	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
2008	$68.00	$68.14	$0.05	($0.20)
2009	$49.44	$49.75	($0.18)	($0.13)
2010	$47.77	$47.74	$0.01	$0.02
2011	$47.14	$47.36	($0.11)	($0.11)
2012	$31.51	$31.45	$0.08	($0.03)
2013	$37.26	$37.19	$0.07	$0.01
2014	$94.96	$94.52	$0.43	$0.00
2015	$52.02	$51.55	$0.48	($0.02)
2016	$27.94	$27.80	$0.15	($0.00)
2017	$30.40	$30.39	$0.03	($0.02)
2018	$47.55	$47.36	$0.20	($0.01)
2019	$30.76	$30.66	$0.11	($0.01)
2020	$20.12	$20.14	($0.01)	($0.01)
2021	$31.58	$31.34	$0.19	$0.05
2022	$54.23	$53.26	$0.63	$0.34
2023	$32.16	$32.12	($0.01)	$0.05
2024	$32.34	$32.28	$0.01	$0.04
2025	$53.60	$53.32	$0.11	$0.16

Table 11-3 shows the PJM real-time load-weighted average LMP by constrained and unconstrained hours. A constrained hour is any hour during which one or more facilities are congested.

Table 11-3 Real-time load-weighted average LMP by constrained and unconstrained hours (Dollars per MWh): January 2024 through March 2025

	2024		2025	
	Constrained Hours	Unconstrained Hours	Constrained Hours	Unconstrained Hours
Jan	$43.09	$32.13	$63.62	$39.41
Feb	$24.92	$20.34	$48.92	$41.67
Mar	$23.10	$24.20	$42.11	$0.00
Apr	$27.27	$25.54		
May	$36.74	$18.92		
Jun	$33.68	$15.68		
Jul	$47.67	$18.96		
Aug	$37.24	$17.81		
Sep	$33.09	$15.18		
Oct	$32.52	$19.01		
Nov	$28.52	$26.30		
Dec	$35.03	$18.89		
Avg	$34.24	$21.86	$52.36	$39.59

Table 11-4 shows the monthly comparison of real-time constrained and unconstrained hours in the first three months of 2024 and the first three months of 2025. A constrained hour is any hour during which one or more facilities are congested. There were more real-time constrained hours in the first three months of 2025 than in the first three months of 2024.

Table 11-4 Real-time constrained and unconstrained hours by month: 2024 through March 2025

	2024		2025		Difference	
	Constrained Hours	Unconstrained Hours	Constrained Hours	Unconstrained Hours	Constrained Hours	Unconstrained Hours
Jan	721	23	711	33	(10)	10
Feb	686	10	670	2	(16)	(8)
Mar	701	43	743	1	42	(42)
Apr	660	60				
May	708	36				
Jun	704	16				
Jul	707	37				
Aug	669	75				
Sep	652	68				
Oct	690	54				
Nov	629	91				
Dec	741	3				
Total	8,268	516	2,124	36	16	(40)

Zonal Components

The load weighted congestion component of LMPs (CLMPs) provided in the following tables (Table 11-5 and Table 11-6) are not a metric of the amount of congestion paid by load in a zone. The listed CLMPs show whether prices (LMPs) in a zone are higher or lower than the load weighted average price in the PJM system due to transmission constraints.

The real-time components of LMP for each control zone are presented in Table 11-5 for the first three months of 2024 and 2025. In the first three months of 2025, DOM had the highest real-time congestion component of LMP, $12.19, and COMED had the lowest real-time congestion component of LMP, -$14.32.

Table 11-5 Zonal real-time load-weighted average LMP components (Dollars per MWh): January through March, 2024 and 2025

	2024 (Jan - Mar)				2025 (Jan - Mar)			
	Real-Time LMP	Energy Component	Congestion Component	Loss Component	Real-Time LMP	Energy Component	Congestion Component	Loss Component
ACEC	$28.33	$31.07	($3.25)	$0.52	$49.62	$52.38	($4.12)	$1.36
AEP	$30.77	$30.89	$0.26	($0.38)	$50.81	$51.70	$0.16	($1.05)
APS	$32.00	$31.12	$0.70	$0.17	$55.24	$52.36	$2.28	$0.60
ATSI	$30.09	$30.38	($0.19)	($0.10)	$48.40	$50.89	($2.11)	($0.38)
BGE	$36.83	$31.50	$4.10	$1.23	$64.49	$53.26	$8.77	$2.46
COMED	$26.06	$30.62	($3.04)	($1.51)	$33.31	$51.11	($14.32)	($3.49)
DAY	$32.74	$30.98	$1.12	$0.64	$48.40	$51.90	($3.68)	$0.18
DOM	$35.61	$31.03	$4.00	$0.58	$66.35	$52.67	$12.19	$1.48
DPL	$29.13	$31.55	($3.63)	$1.21	$54.40	$53.47	($1.67)	$2.60
DUKE	$31.27	$31.13	$0.47	($0.33)	$46.49	$52.12	($4.07)	($1.55)
DUQ	$28.80	$30.29	($0.99)	($0.50)	$47.32	$50.80	($2.54)	($0.94)
EKPC	$33.07	$32.66	$0.70	($0.29)	$51.83	$54.23	($0.90)	($1.50)
JCPLC	$28.62	$30.94	($2.94)	$0.61	$50.65	$52.07	($3.06)	$1.63
MEC	$30.32	$30.81	($0.79)	$0.30	$51.19	$52.05	($1.53)	$0.67
OVEC	$28.13	$29.89	($0.79)	($0.97)	$42.86	$50.37	($5.28)	($2.23)
PE	$32.29	$30.53	$1.40	$0.35	$56.04	$51.37	$3.72	$0.95
PECO	$27.04	$30.80	($3.89)	$0.13	$48.51	$52.03	($4.23)	$0.71
PEPCO	$36.54	$31.53	$3.99	$1.01	$64.59	$53.33	$9.10	$2.16
PPL	$27.37	$30.92	($3.42)	($0.13)	$47.70	$52.12	($4.62)	$0.20
PSEG	$29.89	$30.60	($1.30)	$0.58	$51.74	$51.59	($1.48)	$1.63
REC	$32.30	$30.32	$1.39	$0.60	$55.95	$51.14	$3.20	$1.61
PJM	$31.01	$30.92	$0.06	$0.02	$52.20	$52.03	$0.13	$0.04

The day-ahead components of LMP for each control zone are presented in Table 11-6 for the first three months of 2024 and 2025. In the first three months of 2025, PEPCO had the highest day-ahead congestion component of LMP, $7.84, and COMED had the lowest day-ahead congestion component of LMP, -$11.52.

Table 11-6 Zonal day-ahead load-weighted average LMP components (Dollars per MWh): January through March, 2024 and 2025

	2024 (Jan - Mar)				2025 (Jan - Mar)			
	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
ACEC	$29.57	$32.12	($3.04)	$0.48	$53.56	$53.47	($1.77)	$1.86
AEP	$32.08	$32.42	($0.02)	($0.32)	$52.15	$53.21	$0.07	($1.13)
APS	$33.19	$32.36	$0.64	$0.20	$55.32	$53.55	$0.99	$0.78
ATSI	$31.56	$31.55	($0.14)	$0.14	$51.78	$52.14	($0.23)	($0.13)
BGE	$38.09	$32.71	$4.23	$1.15	$64.67	$54.47	$7.47	$2.73
COMED	$27.75	$31.79	($2.56)	($1.48)	$37.23	$52.23	($11.52)	($3.48)
DAY	$34.22	$32.49	$0.94	$0.80	$52.03	$53.16	($1.29)	$0.16
DOM	$36.55	$32.52	$3.40	$0.64	$63.16	$54.22	$7.28	$1.65
DPL	$31.65	$33.00	($2.52)	$1.16	$58.59	$54.94	$0.43	$3.22
DUKE	$32.75	$32.49	$0.43	($0.17)	$50.38	$53.66	($1.63)	($1.64)
DUQ	$30.43	$31.77	($0.94)	($0.40)	$49.56	$52.45	($1.95)	($0.94)
EKPC	$33.95	$34.28	$0.14	($0.47)	$53.77	$56.98	($1.07)	($2.14)
JCPLC	$29.78	$31.97	($2.76)	$0.57	$54.05	$53.07	($1.02)	$2.00
MEC	$32.73	$32.11	$0.36	$0.26	$55.48	$53.03	$1.41	$1.03
OVEC	$28.83	$29.97	($0.19)	($0.94)	$39.20	$41.71	($0.65)	($1.86)
PE	$33.92	$31.33	$2.24	$0.35	$57.59	$51.58	$4.77	$1.24
PECO	$28.57	$32.12	($3.59)	$0.04	$52.43	$53.23	($1.91)	$1.10
PEPCO	$37.67	$32.83	$3.82	$1.01	$64.85	$54.50	$7.84	$2.51
PPL	$28.92	$31.97	($2.76)	($0.28)	$51.24	$53.27	($2.32)	$0.28
PSEG	$30.29	$31.79	($2.07)	$0.56	$53.48	$52.31	($0.81)	$1.99
REC	$32.86	$30.84	$1.47	$0.55	$55.72	$50.47	$3.52	$1.73
PJM	$32.34	$32.28	$0.01	$0.04	$53.60	$53.32	$0.11	$0.16

Hub Components

The real-time components of LMP for each hub are presented in Table 11-7 for the first three months of 2024 and 2025.[11]

Table 11-7 Hub real-time average LMP components (Dollars per MWh): January through March, 2024 and 2025

	2024 (Jan - Mar)				2025 (Jan - Mar)			
	Real-Time LMP	Energy Component	Congestion Component	Loss Component	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AEP Gen Hub	$27.47	$29.11	($0.55)	($1.10)	$42.64	$49.01	($4.04)	($2.34)
AEP-DAY Hub	$28.33	$29.11	($0.29)	($0.50)	$45.24	$49.01	($2.31)	($1.47)
ATSI Gen Hub	$29.31	$29.11	$0.71	($0.51)	$46.24	$49.01	($1.46)	($1.31)
Chicago Gen Hub	$24.01	$29.11	($3.37)	($1.74)	$31.06	$49.01	($14.10)	($3.85)
Chicago Hub	$25.01	$29.11	($2.74)	($1.36)	$31.78	$49.01	($14.02)	($3.21)
Dominion Hub	$32.18	$29.11	$3.02	$0.04	$58.25	$49.01	$8.81	$0.43
Eastern Hub	$26.89	$29.11	($3.16)	$0.95	$48.70	$49.01	($2.43)	$2.12
N Illinois Hub	$24.55	$29.11	($3.05)	($1.51)	$31.61	$49.01	($13.92)	($3.48)
New Jersey Hub	$27.50	$29.11	($2.11)	$0.50	$48.10	$49.01	($2.36)	$1.45
Ohio Hub	$28.39	$29.11	($0.24)	($0.48)	$45.33	$49.01	($2.11)	($1.58)
West Interface Hub	$29.43	$29.11	$0.77	($0.44)	$49.99	$49.01	$1.67	($0.69)
Western Hub	$30.96	$29.11	$1.50	$0.36	$52.72	$49.01	$2.86	$0.84

The day-ahead components of LMP for each hub are presented in Table 11-8 for the first three months of 2024 and 2025.

Table 11-8 Hub day-ahead average LMP components (Dollars per MWh): January through March, 2024 and 2025

	2024 (Jan - Mar)				2025 (Jan - Mar)			
	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AEP Gen Hub	$28.71	$30.21	($0.45)	($1.06)	$45.96	$50.03	($1.68)	($2.40)
AEP-DAY Hub	$29.57	$30.21	($0.21)	($0.44)	$47.91	$50.03	($0.67)	($1.45)
ATSI Gen Hub	$30.55	$30.21	$0.60	($0.26)	$49.21	$50.03	$0.13	($0.96)
Chicago Gen Hub	$25.67	$30.21	($2.82)	($1.72)	$34.73	$50.03	($11.47)	($3.84)
Chicago Hub	$26.43	$30.21	($2.44)	($1.34)	$35.43	$50.03	($11.40)	($3.20)
Dominion Hub	$32.64	$30.21	$2.36	$0.07	$55.81	$50.03	$5.30	$0.47
Eastern Hub	$28.88	$30.21	($2.31)	$0.97	$52.13	$50.03	($0.51)	$2.60
N Illinois Hub	$25.97	$30.21	($2.74)	($1.51)	$35.19	$50.03	($11.35)	($3.49)
New Jersey Hub	$28.33	$30.21	($2.38)	$0.49	$50.67	$50.03	($1.16)	$1.79
Ohio Hub	$29.59	$30.21	($0.19)	($0.43)	$47.95	$50.03	($0.55)	($1.53)
West Interface Hub	$30.41	$30.21	$0.53	($0.34)	$50.96	$50.03	$1.45	($0.52)
Western Hub	$32.61	$30.21	$2.04	$0.36	$53.91	$50.03	$2.76	$1.11

11 The real-time components of LMP are the simple average of the hourly components for each hub. Some hubs include only generation buses and do not include load buses. The real-time components of LMP were previously reported as the real-time, load-weighted, average of the hourly components of LMP.

Congestion

Congestion Accounting

In PJM accounting, total congestion costs equal net implicit CLMP charges, plus net explicit CLMP charges, plus net inadvertent CLMP charges. Implicit CLMP charges equal implicit withdrawal charges less implicit injection credits. Explicit CLMP charges are the net CLMP charges associated with the injection credits and withdrawal charges for point to point energy transactions. Inadvertent CLMP charges are not directly attributable to specific participants that are distributed on a load ratio basis. Each of these categories of congestion costs is comprised of day-ahead and balancing congestion costs.

While PJM accounting focuses on CLMPs, the individual CLMP values at any bus are irrelevant to the calculation of congestion, as CLMPs are just an artificial deconstruction of LMP based on a selected reference bus. Holding aside the marginal loss component of LMP, differences in the LMPs are caused by binding constraints in the least cost security constrained dispatch market solution, and total congestion is the net surplus revenue that remains after all sources and sinks are credited or charged their LMPs. Changing the components of LMP by electing a different reference bus does not change the LMPs or the difference between LMPs for a given market solution or actual congestion, it merely changes the components of the LMP.

Congestion occurs in the day-ahead and real-time energy markets.[12] Day-ahead congestion costs are based on day-ahead MWh while balancing congestion costs are based on deviations between day-ahead and real-time MWh priced at the congestion price in the real-time energy market.

Implicit CLMP charges are the CLMP charges calculated for energy injected or withdrawn at a location. The explicit CLMP charges are the CLMP charges calculated for transactions with a defined source and a sink. For example, implicit CLMP charges are calculated for network load and explicit CLMP charges are calculated for up to congestion transactions (UTCs). Inadvertent CLMP charges are CLMP charges resulting from the differences between the net actual energy flow and the net scheduled energy flow into or out of the PJM control area each hour.

12 When the term *congestion charge* is used in documents by PJM's Market Settlement Operations, it has the same meaning as the term *congestion costs* as used here.

CLMP charges and CLMP credits are calculated for both the day-ahead and balancing energy markets.

- **Day-Ahead Implicit Load CLMP Charges.** Day-ahead implicit withdrawal charges are calculated for all cleared demand, decrement bids and day-ahead energy market sale transactions. Day-ahead implicit withdrawal charges are calculated using MW and the load bus CLMP, the decrement bid bus CLMP or the CLMP at the source of the sale transaction.
- **Day-Ahead Implicit Generation CLMP Credits.** Day-ahead implicit injection credits are calculated for all cleared generation, increment offers and day-ahead energy market purchase transactions.[13] Day-ahead implicit injection credits are calculated using MW and the generator bus CLMP, the increment offer's bus CLMP or the CLMP at the sink of the purchase transaction.
- **Balancing Implicit Load CLMP Charges.** Balancing implicit withdrawal charges are calculated for all deviations between a PJM member's real-time load and energy sale transactions and their day-ahead cleared demand, decrement bids and energy sale transactions. Balancing implicit withdrawal charges are calculated using MW deviations and the real-time CLMP for each aggregate where a deviation exists.
- **Balancing Implicit Generation CLMP Credits.** Balancing implicit injection credits are calculated for all deviations between a PJM member's real-time generation and energy purchase transactions and the day-ahead cleared generation, increment offers and energy purchase transactions. Balancing implicit injection credits are calculated using MW deviations and the real-time CLMP for each aggregate where a deviation exists.

13 Internal bilateral transactions are included in the tariff definitions of Market Participant Energy Injections and Market Participant Energy Withdrawals. The purchase part of an internal bilateral transaction is an injection to the buyer and the sale part of an internal bilateral transaction is a withdrawal to the seller. The tariff (Attachment K) also says market participants will be charged implicit CLMP charges for all Market Participant Energy Withdrawals and will be credited implicit CLMP credits for all Market Participant Energy Injections. The seller of an internal bilateral transaction will be charged implicit CLMP charges at the source and the buyer of an internal bilateral transaction will be credited implicit CLMP credits at the sink. Internal bilateral transaction CLMP credits and charges sum to zero, as the IBT is merely a transfer of ownership injection and withdrawal MW and associated charges and credits between participants, meaning that the sum of all MW and all credits and all charges with and without IBTs are the same.

- **Explicit CLMP Charges.** Explicit CLMP charges are the net CLMP costs associated with point to point energy transactions. Day-ahead explicit CLMP charges equal the product of the transacted MW and CLMP differences between sources (origins) and sinks (destinations) in the day-ahead energy market. Balancing explicit CLMP charges equal the product of the deviations between the real-time and day-ahead transacted MW and the differences between the real-time CLMP at the transactions' sources and sinks. Explicit CLMP charges are calculated for internal purchase, import and export transaction, and up to congestion transactions (UTCs.)
- **Inadvertent CLMP Charges.** Inadvertent CLMP charges are charges resulting from the differences between the net actual energy flow and the net scheduled energy flow into or out of the PJM control area each hour. This inadvertent interchange of energy may be positive or negative, where positive interchange typically results in a charge while negative interchange typically results in a credit. Inadvertent CLMP charges are common costs, not directly attributable to specific participants that are distributed on a load ratio basis.[14]

The congestion accounting calculation equations are in Table 11-9.

Table 11-9 Congestion accounting calculations

Congestion Category	Calculation
Day-Ahead Implicit Withdrawal CLMP Charges	Day-Ahead Demand MWh * Day-Ahead CLMP
Day-Ahead Implicit Injection CLMP Credits	Day-Ahead Supply MWh * Day-Ahead CLMP
Day-Ahead Explicit CLMP Charges	Day-Ahead Transaction MW * (Day-Ahead Sink CLMP - Day-Ahead Source CLMP)
Day-Ahead Total Congestion Costs	Day-Ahead Implicit Withdrawal CLMP Charges - Day-Ahead Implicit Injection CLMP Credits + Day-Ahead Explicit CLMP Charges
Balancing Implicit Withdrawal CLMP Charges	Balancing Demand MWh * Real-Time CLMP
Balancing Implicit Injection CLMP Credits	Balancing Supply MWh * Real-Time CLMP
Balancing Explicit CLMP Costs	Balancing Transaction MW * (Real-Time Sink CLMP - Real-Time Source CLMP)
Balancing Total Congestion Costs	Balancing Implicit Withdrawal CLMP Charges - Balancing Implicit Injection CLMP Credits + Balancing Explicit CLMP Costs
Total Congestion Costs	Day-Ahead Total Congestion Costs + Balancing Total Congestion Costs

MWh Category	Definition
Day-Ahead Demand MWh	Cleared Demand, Decrement Bids, Energy Sale Transactions
Day-Ahead Supply MWh	Cleared Generation, Increment Bids, Energy Purchase Transactions
Real-Time Demand MWh	Load and Energy Sale Transactions
Real-Time Supply MWh	Generation and Energy Purchase Transactions
Balancing Demand MWh	Real-Time Demand MWh - Day-Ahead Demand MWh
Balancing Supply MWh	Real-Time Supply MWh - Day-Ahead Supply MWh

PJM billing items include Day-Ahead Transmission Congestion Charges, Day-Ahead Transmission Congestion Credits, Balancing Transmission Congestion Charges, and Balancing Transmission Congestion Credits. Those line items are calculated for each PJM member. The congestion bill shows the CLMP charges or credits collected from the PJM market participants. However, the sum of an individual customer's CLMP credits or charges on the customer's bill is not a measure of the congestion paid by that customer.

14 PJM Operating Agreement Schedule 1 §3.7.

The congestion paid by a customer is the difference between what the customer paid for energy and what all network sources of that energy were paid to serve that customer. A load customer's congestion bill, in contrast, merely indicates whether the LMP they paid for their withdrawals is higher or lower than the system energy price due to transmission constraints. The customer's bill does not measure congestion paid by the customer, only how much the customer was charged and credited for their MW positions. The congestion costs associated with specific constraints are the sum of the total day-ahead and balancing congestion costs associated with those constraints. Zonal congestion is calculated on a constraint by constraint basis. The congestion calculations are the total difference between what the zonal load pays in CLMP charges and what the generation that serves that load is paid, regardless of whether the zone is a net importer or a net exporter of generation. CLMPs can be both positive and negative and CLMP charges and CLMP credits can be both positive and negative. CLMP charges, positive or negative, are paid by withdrawals and CLMP credits, positive or negative, are paid to injections. Total congestion costs (the sum of charges and credits), when positive, measure the net congestion payment by a participant group and when negative, measure the net congestion credit paid to a participant group. Explicit CLMP charges, when positive, measure the CLMP payment from a PJM member and when negative, measure the CLMP credit paid to a PJM member. Explicit CLMP charges are calculated for up to congestion transactions (UTCs). In all cases, whether positive or negative, CLMP charges and credits merely indicate whether the LMP being paid by withdrawals or credited to injections is higher or lower than the system weighted average price due to binding transmission constraints.

The congestion accounting definitions are misleading. Load pays congestion. Congestion is the difference between what load pays for energy and what generation is paid for energy due to binding transmission constraints. Generation does not pay congestion. Some generation receives a price lower than SMP and some generation receives a price greater than SMP but that does not mean that generation is paying congestion. It means only that generation is being paid an LMP that is higher or lower than the system load-weighted average LMP.

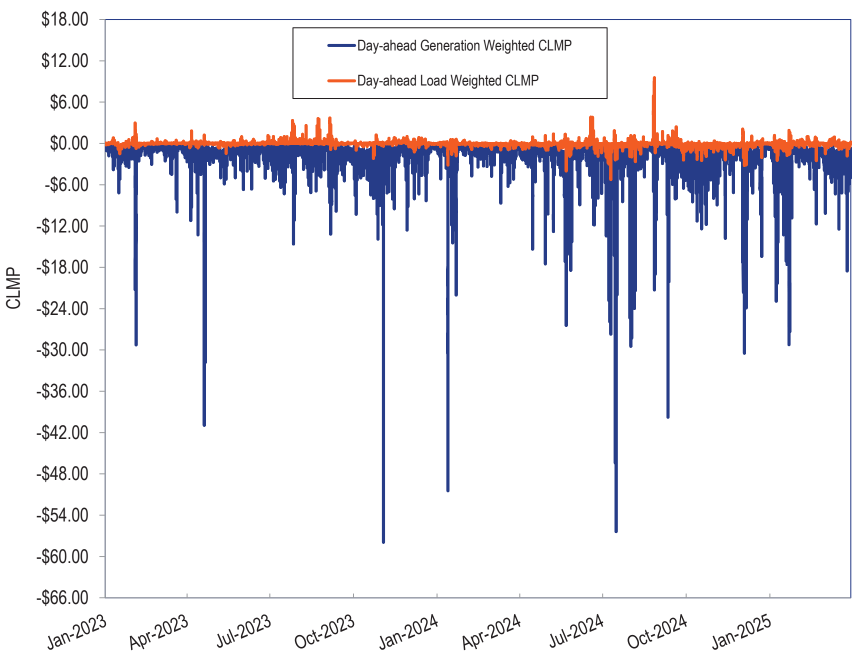
The CLMP is calculated with respect to the LMP at the system reference bus, also called the system marginal price (SMP). When a transmission constraint occurs, the resulting CLMP is positive on one side of the constraint and negative on the other side of the constraint and the corresponding CLMP costs are positive or negative. For each transmission constraint, the CLMP reflects the cost of a constraint at a pricing node and is equal to the product of the constraint shadow price and the distribution factor from the constraint to the pricing node. The total CLMP at a pricing node is the sum of all constraint contributions to LMP and is equal to the difference between the actual LMP that results from transmission constraints, excluding losses, and the SMP. If an area experiences lower prices because of a constraint, the CLMP in that area is negative.[15]

Load-weighted LMP components are calculated relative to a load-weighted, average LMP. At the load-weighted reference bus, which represents the load center of the system, the LMP calculation is designed to include no congestion or loss components, but it may include congestion. The load-weighted average CLMP across all load buses, calculated relative to that reference bus, is equal to, or very close to, zero, with non-zero results caused by state estimator error and after the fact meter updates. The sum of load related CLMP charges is logically zero and the small reported differences are the result of accounting issues. A positive CLMP at a load bus indicates that the load at that bus has a total energy price higher than the average LMP, due to transmission constraints. A negative CLMP at a load bus indicates that the load at that bus has a total energy price lower than the average LMP, due to transmission constraints. The LMPs at the load buses are a function of marginal generation bus LMPs determined through the least cost security constrained economic dispatch which accounts for transmission constraints and marginal losses. Due to transmission constraints, the average generation weighted CLMP for generation resources is lower than the LMP at the load-weighted reference bus price. Calculated relative to the load reference bus which has a CLMP of zero, this means that the average of the generation bus CLMPs is negative. This means that total generation CLMP credits are negative. Figure 11-1 shows the weighted average CLMPs of generation and

15 For an example of the congestion accounting methods used in this section, see *MMU Technical Reference for PJM Markets*, at "FTRs and ARRs," <http://www.monitoringanalytics.com/reports/Technical_References/docs/2010-som-pjm-technical-reference.pdf>.

load in the day-ahead market. Figure 11-1 shows that from January 2023 to March 2025, day-ahead generation weighted CLMPs were generally negative and day-ahead, load weighted CLMPs were generally positive, indicating that load was charged a higher weighted average LMP for energy as a result of transmission constraints than the weighted average LMP generation was paid to provide that energy. This means that total CLMP load payments are higher than total CLMP generation credits. The difference in load payments and generation credits (load charges minus generation credits) is congestion (Table 11-12 and Table 11-13). This result is a product of the least cost, security constrained dispatch and the use of a load-weighted reference bus that is used for the determination of the components of LMP. More generally, in a least cost, security constrained market solution the weighted average LMP at load buses is higher than the weighted average price at generation buses.

Figure 11-1 Day-ahead generation weighted CLMPs and day-ahead load-weighted CLMPs: January 2023 through March 2025



Total Congestion

Total congestion costs in PJM in the first three months of 2025 were $503.3 million, comprised of implicit withdrawal charges of $138.6 million, minus implicit injection credits of -$417.5 million, plus explicit charges of -$52.8 million. Total congestion is the difference between what load pays for energy and what generation is paid for energy, due to binding transmission constraints.

Table 11-10 shows total congestion for January through March, 2008 through 2025. Total congestion costs in Table 11-10 include congestion associated with PJM facilities and those associated with reciprocal, coordinated flowgates in MISO and in NYISO.[16] [17]

Table 11-10 Total congestion costs (Dollars (Millions)): January through March, 2008 through 2025[18]

(Jan - Mar)	Congestion Cost	Percent Change	Total PJM Billing	Percent of PJM Billing
2008	$486	NA	$7,718	6.3%
2009	$307	(36.8%)	$7,515	4.1%
2010	$345	12.4%	$8,415	4.1%
2011	$360	4.3%	$9,584	3.8%
2012	$122	(66.0%)	$6,938	1.8%
2013	$186	51.9%	$7,762	2.4%
2014	$1,236	564.8%	$21,070	5.9%
2015	$632	(48.9%)	$14,040	4.5%
2016	$292	(53.7%)	$9,500	3.1%
2017	$158	(45.9%)	$9,710	1.6%
2018	$661	318.4%	$14,520	4.6%
2019	$164	(75.2%)	$11,600	1.4%
2020	$85	(48.1%)	$8,750	1.0%
2021	$121	42.2%	$11,260	1.1%
2022	$510	321.5%	$18,080	2.8%
2023	$175	(65.6%)	$11,890	1.5%
2024	$321	82.9%	$12,350	2.6%
2025	$503	56.8%	$18,680	2.7%

16 See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C.," (December 11, 2008) Section 6.1, Effective Date: May 30, 2016. <http://www.pjm.com/documents/agreements.aspx>.

17 See "NYISO Tariffs New York Independent System Operator, Inc.," (June 21, 2017) 35.12.1, Effective Date: May 1, 2017. <http://www.pjm.com/documents/agreements.aspx>.

18 In Table 11-10, the MMU uses Total PJM Billing values provided by PJM. For 2019 and after, the MMU has modified the Total PJM Billing calculation to better reflect historical PJM total billing through the PJM settlement process.

CLMP charges and credits are not congestion. CLMP charges and credits reflect marginal energy price differences caused by binding system constraints. Congestion is the sum of all congestion related charges and credits. In a two settlement system all virtual bids have net zero MW after their day-ahead and balancing positions are cleared, which means that virtual bids are fully settled in terms of CLMP credits and charges at the close of the market for any particular day, with either a net loss or profit due to differences between day-ahead and real-time prices. Net payouts (negative credits) to virtual bids appear as negative adjustments to either day-ahead or balancing congestion and net charges to virtual bids appear as positive adjustments to either day-ahead or balancing congestion.

Table 11-11 shows total congestion by day-ahead and balancing component for January through March, 2008 through 2025.

Table 11-11 Total CLMP credits and charges by accounting category (Dollars (Millions)): January through March, 2008 through 2025

	Day-Ahead				Balancing					
(Jan - Mar)	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Inadvertent Charges	Congestion Costs
2008	$332.4	($220.0)	$39.9	$592.3	($46.0)	$29.5	($31.2)	($106.7)	$0.0	$485.6
2009	$120.2	($221.3)	$47.9	$389.5	($14.2)	($6.0)	($74.4)	($82.6)	($0.0)	$306.9
2010	$85.9	($293.1)	$12.9	$391.9	($5.7)	$12.1	($29.1)	($47.0)	($0.0)	$344.9
2011	$176.5	($226.7)	$4.1	$407.3	$21.6	$27.8	($41.2)	($47.4)	$0.0	$359.9
2012	$21.9	($131.4)	$27.5	$180.9	($5.1)	$11.3	($42.0)	($58.4)	$0.0	$122.4
2013	$85.0	($199.1)	$47.8	$331.9	($6.6)	$73.3	($66.0)	($145.9)	$0.0	$185.9
2014	$333.7	($1,193.9)	($94.3)	$1,433.3	$73.0	$208.9	($61.3)	($197.2)	$0.0	$1,236.1
2015	$327.0	($457.9)	($11.0)	$773.9	$5.4	$69.6	($78.0)	($142.2)	($0.0)	$631.7
2016	$120.2	($193.5)	$9.2	$322.9	($1.1)	$11.9	($17.7)	($30.8)	$0.0	$292.2
2017	$24.2	($137.7)	$3.0	$164.9	($0.3)	$7.5	$0.9	($6.9)	($0.0)	$158.0
2018	$130.9	($557.5)	($46.7)	$641.7	$12.8	$23.6	$30.1	$19.3	$0.0	$661.0
2019	$53.3	($137.7)	$11.2	$202.2	($1.8)	$20.1	($16.4)	($38.3)	$0.0	$163.9
2020	$13.5	($75.7)	$14.1	$103.3	($0.2)	$3.8	($14.2)	($18.2)	($0.0)	$85.1
2021	$82.3	($123.5)	$18.7	$224.5	($26.7)	$39.9	($36.8)	($103.4)	$0.0	$121.1
2022	$304.6	($364.6)	$32.2	$701.4	($46.4)	$79.6	($65.1)	($191.2)	$0.0	$510.3
2023	$53.7	($151.9)	$20.6	$226.2	$2.9	$7.0	($46.7)	($50.8)	$0.0	$175.5
2024	$110.2	($247.8)	$40.7	$398.7	($5.8)	$20.1	($51.8)	($77.7)	$0.0	$321.0
2025	$165.3	($496.6)	$41.7	$703.5	($26.7)	$79.1	($94.5)	($200.2)	($0.0)	$503.3

Charges and Credits versus Congestion: Virtual Transactions, Load and Generation

In PJM's two settlement system, there is a day-ahead market and a real-time, balancing market that make up a market day.

In a two settlement system all virtual bids have net zero MW after their day-ahead and balancing positions are cleared, which means that virtual bids are fully settled in terms of CLMP credits and charges at the close of each market day, with either a net loss or profit due to differences between day-ahead and real-time prices. Net payouts (negative credits) to virtual bids appear as negative adjustments to either day-ahead or balancing congestion and net charges to virtual bids appear as positive adjustments to either day-ahead or balancing congestion.

Unlike virtual bids, physical load and generation have net MW at the close of a market day's day-ahead and balancing settlement.

Generation does not pay congestion. Some generation receives a price lower than SMP and some generation receives a price greater than SMP but that does not mean that generation is paying congestion. It means that generation is being paid an LMP that is higher or lower than the system load-weighted average LMP.

The residual difference between total load charges (day-ahead and balancing) and generation credits (day-ahead and balancing) after virtual bids have settled their day-ahead and balancing positions is congestion. That is, congestion is the difference between what withdrawals (load) pay for energy and what injections (generation) are paid for energy due to binding transmission constraints, after virtual bids are settled at the end of the market day. Load is the source of the net surplus after generation is paid and virtuals are settled at the end of the market day. Load pays congestion.

Table 11-12 and Table 11-13 show the total CLMP charges and credits for each transaction type in the first three months of 2025 and 2024. Table 11-12 shows that in the first three months of 2025 DECs were paid $4.3 million in CLMP charges in the day-ahead market, were paid $24.7 million in CLMP credits in the balancing energy market, resulting in a net payment of $28.9 million. In the first three months of 2025, INCs paid $57.4 million in CLMP charges in the day-ahead market, were paid $82.8 million in CLMP credits in the balancing energy market resulting in a net payment of $25.4 million. In the first three months of 2025, up to congestion (UTCs) paid $42.2 million in CLMP charges in the day-ahead market, were paid $92.5 million in CLMP credits in the balancing market resulting in a total payment of $50.3 million in total CLMP credits.

Table 11-12 Total CLMP credits and charges by transaction type (Dollars (Millions)): January through March, 2025

	CLMP Credits and Charges (Millions)									
	Day-Ahead				Balancing					
Transaction Type	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Inadvertent Charges	Grand Total
DEC	($4.3)	$0.0	$0.0	($4.3)	($24.7)	$0.0	$0.0	($24.7)	$0.0	($28.9)
Demand	$28.4	$0.0	$0.0	$28.4	$22.5	$0.0	$0.0	$22.5	$0.0	$50.9
Demand Response	$0.4	$0.0	$0.0	$0.4	($0.7)	$0.0	$0.0	($0.7)	$0.0	($0.3)
Explicit Congestion Only	$0.0	$0.0	$0.1	$0.1	$0.0	$0.0	($0.0)	($0.0)	$0.0	$0.1
Explicit Congestion and Loss Only	$0.0	$0.0	($0.6)	($0.6)	$0.0	$0.0	($0.1)	($0.1)	$0.0	($0.7)
Export	($3.5)	$0.0	($0.2)	($3.7)	($20.5)	$0.0	($1.1)	($21.6)	$0.0	($25.3)
Generation	$0.0	($581.5)	$0.0	$581.5	$0.0	($3.1)	$0.0	$3.1	$0.0	$584.6
Import	$0.0	($2.2)	$0.0	$2.2	$0.0	$2.6	$0.0	($2.6)	$0.0	($0.4)
INC	$0.0	($57.4)	$0.0	$57.4	$0.0	$82.8	$0.0	($82.8)	$0.0	($25.4)
Internal Bilateral	$144.4	$144.6	$0.2	$0.0	($2.0)	($1.8)	$0.0	($0.2)	$0.0	($0.2)
Up to Congestion	$0.0	$0.0	$42.2	$42.2	$0.0	$0.0	($92.5)	($92.5)	$0.0	($50.3)
Wheel In	$0.0	($0.1)	($0.1)	$0.0	$0.0	($1.3)	($0.8)	$0.5	$0.0	$0.5
Wheel Out	($0.1)	$0.0	$0.0	($0.1)	($1.3)	$0.0	$0.0	($1.3)	$0.0	($1.5)
Total	$165.3	($496.6)	$41.7	$703.5	($26.7)	$79.1	($94.5)	($200.2)	$0.0	$503.3

Table 11-13 Total CLMP credits and charges by transaction type (Dollars (Millions)): January through March, 2024

	CLMP Credits and Charges (Millions)									
	Day-Ahead				Balancing					
Transaction Type	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Inadvertent Charges	Grand Total
DEC	$2.2	$0.0	$0.0	$2.2	($9.4)	$0.0	$0.0	($9.4)	$0.0	($7.1)
Demand	$0.6	$0.0	$0.0	$0.6	$7.6	$0.0	$0.0	$7.6	$0.0	$8.2
Demand Response	$0.1	$0.0	$0.0	$0.1	($0.2)	$0.0	$0.0	($0.2)	$0.0	($0.1)
Explicit Congestion Only	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Explicit Congestion and Loss Only	$0.0	$0.0	($0.5)	($0.5)	$0.0	$0.0	$0.0	$0.0	$0.0	($0.5)
Export	$0.3	$0.0	($0.3)	($0.0)	($0.6)	$0.0	($0.0)	($0.6)	$0.0	($0.7)
Generation	$0.0	($333.4)	$0.0	$333.4	$0.0	($11.6)	$0.0	$11.6	$0.0	$345.0
Import	$0.0	($0.3)	$0.0	$0.3	$0.0	$0.9	($0.0)	($0.9)	$0.0	($0.7)
INC	$0.0	($21.7)	$0.0	$21.7	$0.0	$34.0	$0.0	($34.0)	$0.0	($12.3)
Internal Bilateral	$107.0	$107.7	$0.6	($0.0)	($3.0)	($3.0)	$0.0	$0.0	$0.0	$0.0
Up to Congestion	$0.0	$0.0	$41.0	$41.0	$0.0	$0.0	($51.3)	($51.3)	$0.0	($10.4)
Wheel In	$0.0	($0.1)	($0.1)	($0.0)	$0.0	($0.2)	($0.5)	($0.2)	$0.0	($0.3)
Wheel Out	($0.1)	$0.0	$0.0	($0.1)	($0.2)	$0.0	$0.0	($0.2)	$0.0	($0.3)
Total	$110.2	($247.8)	$40.7	$398.7	($5.8)	$20.1	($51.8)	($77.7)	$0.0	$321.0

Table 11-14 shows the change in total CLMP credits and charges by transaction type in the first three months of 2024 and 2025. Total negative CLMP credits to generation increased by $239.6 million, and total CLMP charges to demand increased by $42.7 million. The total CLMP credits to up to congestion transactions (UTCs) decreased by $40.0 million in the first three months of 2025. Total day-ahead CLMP charges to UTCs increased by $1.2 million in the first three months of 2025. Balancing CLMP credits to UTCs decreased by $41.2 million in the first three months of 2025.

Table 11-14 Change in total CLMP credits and charges by transaction type (Dollars (Millions)): January through March, 2024 to 2025

	Change in CLMP Credits and Charges (Millions)									
	Day-Ahead				Balancing					
Transaction Type	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Inadvertent Charges	Grand Total
DEC	($6.5)	$0.0	$0.0	($6.5)	($15.3)	$0.0	$0.0	($15.3)	$0.0	($21.8)
Demand	$27.8	$0.0	$0.0	$27.8	$15.0	$0.0	$0.0	$15.0	$0.0	$42.7
Demand Response	$0.3	$0.0	$0.0	$0.3	($0.5)	$0.0	$0.0	($0.5)	$0.0	($0.2)
Explicit Congestion Only	$0.0	$0.0	$0.1	$0.1	$0.0	$0.0	($0.0)	($0.0)	$0.0	$0.1
Explicit Congestion and Loss Only	$0.0	$0.0	($0.1)	($0.1)	$0.0	$0.0	($0.2)	($0.2)	$0.0	($0.2)
Export	($3.8)	$0.0	$0.1	($3.7)	($19.9)	$0.0	($1.0)	($20.9)	$0.0	($24.6)
Generation	$0.0	($248.1)	$0.0	$248.1	$0.0	$8.5	$0.0	($8.5)	$0.0	$239.6
Import	$0.0	($1.9)	$0.0	$1.9	$0.0	$1.7	$0.0	($1.6)	$0.0	$0.3
INC	$0.0	($35.6)	$0.0	$35.6	$0.0	$48.7	$0.0	($48.7)	$0.0	($13.1)
Internal Bilateral	$37.4	$36.9	($0.4)	$0.0	$1.0	$1.2	$0.0	($0.2)	$0.0	($0.2)
Up to Congestion	$0.0	$0.0	$1.2	$1.2	$0.0	$0.0	($41.2)	($41.2)	$0.0	($40.0)
Wheel In	$0.0	($0.1)	($0.0)	$0.0	$0.0	($1.1)	($0.3)	$0.8	$0.0	$0.8
Wheel Out	($0.1)	$0.0	$0.0	($0.1)	($1.1)	$0.0	$0.0	($1.1)	$0.0	($1.2)
Total	$55.1	($248.8)	$0.9	$304.8	($20.9)	$58.9	($42.7)	($122.5)	$0.0	$182.3

Table 11-15 compares CLMP credits and charges for each transaction type between the dispatch run and pricing run in the first three months of 2025. Total CLMP charges to generation decreased by $3.2 million, and total CLMP charges to demand increased by $0.5 million from the dispatch run to the pricing run. The total CLMP credits to DECs decreased by $1.9 million, the total CLMP credits to INCs decreased by $2.1 million and the total CLMP credits to UTCs decreased by $3.6 million from the dispatch run to the pricing run.

Table 11-15 Total CLMP credits and charges by dispatch run and pricing run (Dollars (Millions)): January through March, 2025

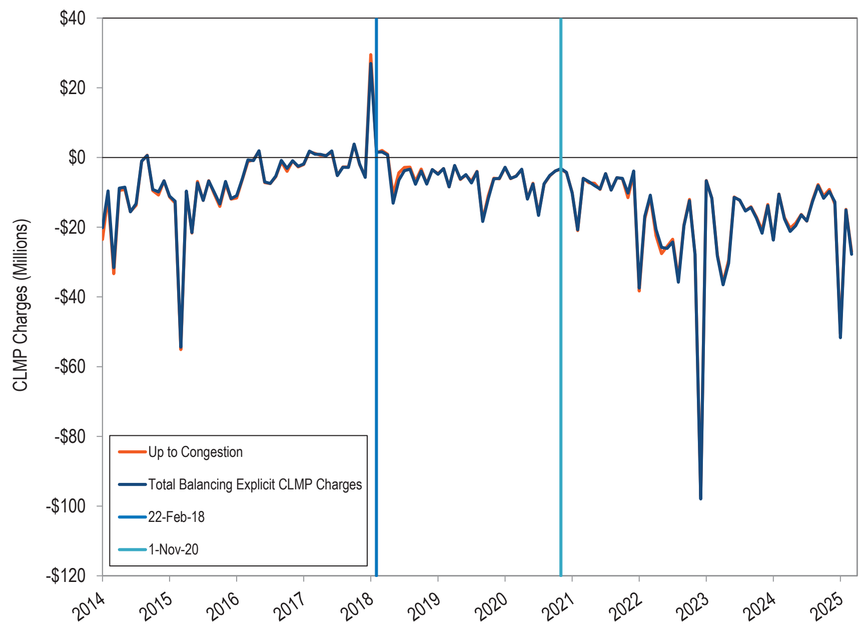
	CLMP Credits and Charges (Millions)								
	Dispatch Run			Pricing Run			Difference		
Transaction Type	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total
DEC	($4.6)	($22.4)	($27.0)	($4.3)	($24.7)	($28.9)	$0.4	($2.3)	($1.9)
Demand	$28.7	$21.7	$50.4	$28.4	$22.5	$50.9	($0.3)	$0.9	$0.5
Demand Response	$0.3	($0.7)	($0.3)	$0.4	($0.7)	($0.3)	$0.1	($0.0)	$0.0
Explicit Congestion Only	$0.1	($0.0)	$0.1	$0.1	($0.0)	$0.1	($0.0)	($0.0)	($0.0)
Explicit Congestion and Loss Only	($0.5)	($0.2)	($0.7)	($0.6)	($0.1)	($0.7)	($0.0)	$0.0	($0.0)
Export	($4.1)	($21.4)	($25.5)	($3.7)	($21.6)	($25.3)	$0.4	($0.2)	$0.2
Generation	$582.2	$5.6	$587.8	$581.5	$3.1	$584.6	($0.7)	($2.5)	($3.2)
Import	$2.3	($1.8)	$0.5	$2.2	($2.6)	($0.4)	($0.2)	($0.8)	($0.9)
INC	$57.1	($80.4)	($23.3)	$57.4	($82.8)	($25.4)	$0.3	($2.4)	($2.1)
Internal Bilateral	($0.0)	($0.2)	($0.2)	$0.0	($0.2)	($0.2)	$0.0	($0.0)	($0.0)
Up to Congestion	$41.6	($88.3)	($46.7)	$42.2	($92.5)	($50.3)	$0.6	($4.2)	($3.6)
Wheel In	$0.0	$0.5	$0.6	$0.0	$0.5	$0.5	$0.0	($0.0)	($0.0)
Wheel Out	($0.2)	($1.3)	($1.4)	($0.1)	($1.3)	($1.5)	$0.0	($0.0)	($0.0)
Total	$702.9	($188.7)	$514.3	$703.5	($200.2)	$503.3	$0.6	($11.6)	($11.0)

UTCs and Negative Balancing Explicit CLMP Charges

Figure 11-2 shows the change in up to congestion balancing explicit CLMP charges from January 2014 through March 2025. Figure 11-2 shows that UTCs account for almost all balancing explicit CLMP charges in PJM. As shown in Figure 11-2, UTCs are generally paid balancing CLMP credits, which take the form of negative balancing CLMP charges being allocated to UTC positions. In the first three months of 2025, 97.9 percent (-$92.5 million out of -$94.5 million) of negative balancing explicit CLMP charges was incurred by UTCs and 2.1 percent (-$1.9 out of -$94.5 million) was incurred by Explicit Congestion Only, Export, Import and Wheel In transactions (Table 11-12). The vertical line at February 22, 2018, marks the date on which the FERC order that limited UTC trading to hubs, residual metered load, and interfaces was effective.[19] The vertical line at November 1, 2020, marks the date on which the FERC order that required PJM to allocate uplift to up to congestion transactions was effective.[20]

Negative balancing explicit CLMP charges were substantially higher in December 2022 than in other months as a result of transmission constraint penalty factors in the real-time market in 2022. The total negative balancing explicit CLMP charges on December 7 and 8, 2022, and the Winter Storm Elliott days of December 23 through 26, 2022, were 64.1 percent (-$62.3 million out of -$97.2 million) of total negative balancing explicit CLMP charges in December 2022.

Figure 11-2 Monthly balancing explicit CLMP charges incurred by UTCs: January 2014 through March 2025



Balancing congestion is caused by settling real-time deviations from day-ahead positions at real-time prices. Whether balancing congestion is positive or negative depends on the differences between market solutions (changes in load and/or generation) and differences between the day-ahead and real-time market models including modeled constraints, the transfer capability (line limits) of the modeled constraints and the differences in deviations between day-ahead and real-time flows that result. The deviations are priced at the real-time LMPs.

For example, one source of negative balancing congestion is that the PJM system has less transmission transfer capability in the real-time market than is modeled in the day-ahead market. In order to reduce processing time in the presence of large number of virtual bids and offers, PJM only enforces or models a subset of its physical transmission limits in the day-ahead

19 For additional information about the FERC order, see the *2022 Annual State of the Market Report for PJM*, Appendix F: Congestion and Marginal Losses.
20 172 FERC ¶ 61,046 (2020).

market. Transmission constraints not modeled in the day-ahead market have unlimited transfer capability in the day-ahead market model. The inclusion of the actual, lower transmission capability in the real-time market requires the use of more high cost generation and the use of less low cost generation to serve load, which means a decrease in congestion.[21] The reduction in real-time congestion compared to day-ahead congestion creates negative balancing congestion.

As a day-ahead spread bid, UTCs can take advantage of and profit from LMP differences caused by modeling differences between the day-ahead and real-time market. UTCs clear between source and sink points with little or no price difference in the day-ahead market, and settle the resulting deviations at higher real-time price differences in the real-time market. The result is negative balancing congestion caused by and paid to UTCs in the form of CLMP credits. This is an example of false arbitrage because the UTCs cannot cause prices to converge and the profits to decrease. As a result of the FERC order requiring load to pay balancing congestion, load is responsible for paying the balancing congestion caused by UTCs.[22]

Table 11-16 provides an example of how UTCs can profit from differences in day-ahead and real-time models and generate negative balancing congestion. In the example, Bus A and Bus B are linked by a transmission line. In the day-ahead market the transmission limit is modeled as 9,999 MW (no limit is enforced in the day-ahead market solution). In the real-time market the physical limit between bus A and bus B is 50 MW. Generation at A has a price of $1.00 and Generation at B has a price of $6. There is 100 MW of load at bus A and 100 MW of load at bus B. There is a UTC of 200 MW that will source at bus A and sink at bus B if the spread in the prices between A and B is less than $1.

As a result of the fact that the transmission capability between A and B is unlimited in the day-ahead market, all of load at A and B can be met with the $1 generation at bus A. The constraint between A and B does not bind in day-ahead so the price at A and B is $1. The price spread between bus A and bus B is zero, which is less than the UTC spread requirement of $1, so the UTC clears. The UTC causes a 200 MW injection at A and 200 MW withdrawal at B, creating 200 MW of flow between bus A and bus B. The 300 MW of combined flow from generation at A and UTC injections at A to the load and UTC sink at B does not exceed the DA modeled limit between A and B. This means that all 200 MW of the UTC injection at A and 200 MW of withdrawal at B can clear without forcing a price spread between A and B. Total day-ahead congestion, which is the difference between CLMP charges and credits, is zero. There is no price difference between the two nodes and every MW of injection and every MW of withdrawal at bus A and bus B settles at the same price.

In the real-time market, the transmission line between bus A and bus B has a 50 MW limit. The UTC does not physically exist in the real-time market and therefore has deviations at Bus A (-200 MW) and at Bus B (+200 MW). The UTC must buy at bus A at the real-time price and sell at bus B at the real-time price to settle its deviations. The load at A (100 MW) and B (100 MW) does not change, so there are no load deviations. With only 50 MW of transmission capability between A and B, the generation at A cannot be used to meet total load on the system. Generation from A meets the load at A (100 MW) and can supply only 50 MW of the 100 MW of load at B. Due to the binding constraint between A and B, the remaining 50 MW of load at B must be met with local generation at B at a cost of $6 and the price at A remains $1.

The UTC must buy 200 MW at A at the real-time price of $1 and sell 200 MW at B at the real-time price of $6. The UTC pays $200 at A and is paid $1,200 at B. The result is a net payment to the UTC of $1,000 in balancing credits.

Table 11-16 shows the balancing credits and charges associated with the real-time deviations in the example. Total congestion (day-ahead plus balancing congestion) in this example is negative $1,250. Total CLMP credits (payments) to generation and the UTC exceed the total charges collected from load. The negative balancing congestion that results is paid by the load under the FERC order.[23]

21 Although it seems counter intuitive, as the amount of low cost generation decreases and the amount of high cost generation increases, the difference between load payments to generation and the payments received by generators goes down. High cost generation receives what load pays.

22 On September 15, 2016, FERC ordered PJM to allocate balancing congestion to load, rather than to FTRs, to modify PJM's Stage 1A ARR allocation process and to continue to use portfolio netting. 153 FERC ¶ 61,180 (2016).

23 153 FERC ¶ 61,180 (2016).

The UTC did not and could not contribute to price convergence between the day-ahead and real-time market and did not and could not improve efficiency in system dispatch or commitment. The UTC took advantage of the modeling differences between the day-ahead and real-time markets. The UTC did significantly increase payments by load. Load was required to pay the UTC $1,000 in negative balancing, over and above the costs of generation that was needed to meet real-time load. The differences in modeling would have resulted in only $250 in negative balancing congestion if there had been no UTCs.

Table 11-16 Example of UTC causing and profiting from negative balancing congestion

Prices	Bus A	Transfer Capability (Line Limit MW)	Bus B	
LMP DA	$1.00	9,999	$1.00	
LMP RT	$1.00	50	$6.00	
Day-Ahead MW	**Bus A**		**Bus B**	**Total MW**
Day-Ahead Generation	200		0	200
Day-Ahead Load	(100)		(100)	(200)
Day-Ahead UTC (+/-)	200		(200)	0
Total MW	300		(300)	0
Day-Ahead Credits and Charges	**Bus A**		**Bus B**	**Total Day-Ahead Congestion**
Total DA Gen Credits	$200.00		$0.00	
Total DA Load Charges	$100.00		$100.00	
Total DA UTC Credits	$200.00		($200.00)	
Total DA Credits	$300.00		($300.00)	$0.00
Total Day-Ahead Congestion (Charges - Credits)				$0.00
Balancing Deviation MW	**Bus A**		**Bus B**	**Total Deviations**
RT GEN Deviations	(50)		50	
RT Load Deviations	0		0	
DA UTC (+/-)	(200)		200	
Total Deviations	(250)		250	0
Balancing Credits and Charges	**Bus A**		**Bus B**	**Balancing Congestion Credits**
Total BA Gen Credits	($50.00)		$300.00	$250.00
Total BA Load Charges	$0.00		$0.00	
Total BA UTC Credits	($200.00)		$1,200.00	$1,000.00
Total BA Credits	($250.00)		$1,500.00	$1,250.00
Total Balancing Congestion (Charges - Credits)				($1,250.00)

Zonal and Load Aggregate Congestion

Zonal, and load aggregate, congestion is calculated on a constraint specific basis for a specific location or set of load pricing nodes (a zone or an aggregate). Local congestion is the difference between what load pays for energy and what generation is paid for energy due to individual binding transmission constraints. Local congestion includes all energy charges or credits incurred to serve a specific load, zone or load aggregate. Local congestion calculations account for the total difference between what the specified load pays and what the generation that serves that load is paid, regardless of whether the zone is a net importer or a net exporter of generation.

Local congestion is calculated on a constraint specific basis. Congestion is the total congestion payments by load at the buses within a defined area minus total CLMP credits received by generation that supplied that load, given the transmission constraints. Congestion reflects the underlying characteristics of the entire power system as it affects the defined area, including the nature and capability of transmission facilities, the offers and geographic distribution of generation facilities, the level and geographic distribution of decremental bids and incremental offers and the geographic and temporal distribution of load.

On a system wide basis, congestion results from transmission constraints that prevent the lowest cost generation from serving some load that must be served by higher cost generation.

The total congestion caused by a constraint is equal to the product of the constraint shadow price times the net flow on the binding constraint. (The shadow price is the difference between the CLMPs across the constraint.) Total congestion caused by the constraint can also be calculated using the CLMPs caused by the constraint at every bus and the net MW injections or MW withdrawals at every affected bus. Congestion associated with a specific constraint is equal to load CLMP charges (CLMP of that specific constraint at each bus times load MW at each bus) caused by that constraint in excess of generation CLMP credits (CLMP of that specific constraint at each bus times generation MW at each bus) caused by that constraint. Equivalently, total congestion caused by the constraint can also be calculated by the shadow price of the constraint times the market flow on that constraint.

Congestion paid by zonal load is a function of the load share of the total load market flow on all binding constraints. Congestion is the difference between what load pays for energy due to binding transmission constraints and what generation, whether inside or outside the load's zone, is paid to serve that load. This calculation is done for both day-ahead congestion and balancing congestion.

Table 11-17 shows day-ahead and balancing congestion by zone and the proportion of congestion resulting from constraints that are external to or internal to each zone, in the first three months of 2025. Constraints are internal to a zone if both the source and sink points of the constraint are in the zone. AEP had the largest zonal congestion costs among all control zones in the first three months of 2025. AEP had $81.9 million in zonal congestion costs, comprised of $111.1 million in zonal day-ahead congestion costs and -$29.2 million in zonal balancing congestion costs. The Lenox – North Meshoppen Line, the AP South Interface, the Dune Acres – Michigan City Flowgate, the Chaparral – Carson Line, and the AEP – DOM Interface contributed $33.6 million, or 41.0 percent of the AEP zonal congestion costs.[24]

Table 11-18 shows congestion costs by zone in the first three months of 2024.

Table 11-17 CLMP credits and charges and total congestion revenue collected by zone (Dollars (Millions)): January through March, 2025

	CLMP Credits and Charges (Millions)										
	Day-Ahead				Balancing				Congestion Costs		
Control Zone	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Internal to Zone	External to Zone	Grand Total
ACEC	$1.2	($4.8)	$0.4	$6.4	($0.3)	$0.9	($0.9)	($2.1)	$0.0	$4.2	$4.3
AEP	$25.6	($78.4)	$7.1	$111.1	($3.4)	$11.0	($14.7)	($29.2)	$12.7	$69.2	$81.9
APS	$18.4	($40.2)	$3.0	$61.6	($2.2)	$5.9	($7.2)	($15.3)	$6.9	$39.4	$46.3
ATSI	$14.1	($37.7)	$3.1	$54.9	($1.2)	$4.7	($6.6)	($12.5)	$0.5	$41.9	$42.4
BGE	$4.9	($19.6)	$1.7	$26.2	($1.0)	$3.0	($3.9)	($7.9)	$1.8	$16.5	$18.3
COMED	$7.5	($48.4)	$3.2	$59.1	($0.6)	$6.5	($7.5)	($14.6)	$5.2	$39.3	$44.5
DAY	$2.0	($9.7)	$0.8	$12.4	($0.3)	$1.1	($1.7)	($3.1)	$0.0	$9.3	$9.3
DOM	$24.2	($82.4)	$7.5	$114.1	($4.6)	$16.2	($18.6)	($39.5)	$9.2	$65.4	$74.6
DPL	$8.6	($11.4)	$0.9	$21.0	($2.9)	$2.2	($1.4)	($6.5)	$5.6	$8.8	$14.5
DUKE	$3.0	($13.7)	$1.2	$17.9	($0.5)	$1.7	($2.6)	($4.7)	$0.0	$13.2	$13.2
DUQ	$2.3	($5.0)	$0.5	$7.8	($0.3)	$0.9	($1.3)	($2.5)	$0.0	$5.3	$5.3
EKPC	$2.3	($9.4)	$0.8	$12.5	($0.5)	$1.4	($1.8)	($3.6)	$0.0	$8.8	$8.9
EXT	$3.0	($9.6)	$1.0	$13.6	($1.3)	$3.1	($3.4)	($7.8)	$0.9	$4.8	$5.8
JCPLC	$6.7	($12.6)	$1.1	$20.3	($0.8)	$2.5	($2.7)	($5.9)	$0.4	$14.0	$14.4
MEC	$5.1	($10.3)	$0.6	$16.0	($1.2)	$1.7	($1.6)	($4.5)	$0.5	$10.9	$11.4
OVEC	$0.2	($0.7)	$0.8	$1.6	($0.0)	$0.1	($0.1)	($0.2)	$0.7	$0.7	$1.4
PE	$5.1	($10.1)	$0.7	$15.9	($0.5)	$1.4	($1.8)	($3.7)	$4.6	$7.5	$12.1
PECO	$5.1	($21.5)	$1.7	$28.3	($1.3)	$3.8	($4.1)	($9.2)	$1.3	$17.8	$19.1
PEPCO	$4.8	($18.2)	$1.6	$24.5	($1.0)	$2.9	($3.6)	($7.4)	$0.1	$17.0	$17.1
PPL	$11.8	($27.9)	$1.9	$41.6	($1.4)	$4.2	($4.5)	($10.2)	$1.5	$29.9	$31.4
PSEG	$9.2	($24.5)	$1.9	$35.5	($1.3)	$3.8	($4.3)	($9.4)	$0.6	$25.5	$26.1
REC	$0.3	($0.7)	$0.1	$1.1	($0.0)	$0.1	($0.1)	($0.3)	$0.1	$0.7	$0.8
Total	$165.3	($496.6)	$41.7	$703.5	($26.7)	$79.1	($94.5)	($200.2)	$52.8	$450.5	$503.3

24 For additional information about the top 20 constraints that affected each zone, see the *2022 Annual State of the Market Report for PJM*, Appendix F: Congestion and Marginal Losses.

Table 11-18 CLMP credits and charges and total congestion revenue collected by zone (Dollars (Millions)): January through March, 2024

	CLMP Credits and Charges (Millions)										
	Day-Ahead				Balancing				Congestion Costs		
Control Zone	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Internal to Zone	External to Zone	Grand Total
ACEC	$1.0	($1.9)	$0.4	$3.2	($0.1)	$0.2	($0.5)	($0.8)	$0.2	$2.3	$2.4
AEP	$17.1	($38.2)	$6.9	$62.2	($0.9)	$3.1	($8.1)	($12.1)	$9.1	$41.0	$50.0
APS	$10.6	($17.0)	$3.0	$30.6	($0.4)	$1.5	($3.9)	($5.8)	$1.9	$22.9	$24.8
ATSI	$10.2	($16.1)	$3.6	$30.0	($0.4)	$1.6	($3.9)	($5.9)	$1.2	$22.9	$24.1
BGE	$4.0	($6.6)	$1.3	$12.0	($0.2)	$0.7	($2.0)	($3.0)	$0.1	$8.9	$9.0
COMED	$5.7	($60.4)	$4.9	$71.0	($0.0)	$2.1	($4.5)	($6.7)	$40.3	$24.0	$64.3
DAY	$1.6	($4.0)	$0.8	$6.5	($0.1)	$0.4	($1.1)	($1.5)	$0.0	$4.9	$4.9
DOM	$17.2	($25.0)	$5.3	$47.6	($1.1)	$2.9	($8.3)	($12.4)	$2.6	$32.6	$35.2
DPL	$5.5	($4.6)	$1.0	$11.1	($0.3)	$0.4	($1.2)	($1.9)	$4.4	$4.8	$9.2
DUKE	$2.6	($5.7)	$1.3	$9.6	($0.1)	$0.6	($1.6)	($2.3)	$0.1	$7.2	$7.3
DUQ	$2.0	($1.6)	$0.5	$4.1	($0.1)	$0.3	($0.8)	($1.1)	$0.0	$2.9	$3.0
EKPC	$1.9	($3.7)	$0.9	$6.5	($0.1)	$0.4	($1.1)	($1.6)	$0.0	$4.9	$4.9
EXT	$2.6	($10.7)	$1.2	$14.5	($0.2)	$0.8	($2.0)	($3.0)	$1.1	$10.4	$11.5
JCPLC	$2.7	($6.1)	$1.0	$9.9	($0.2)	$0.6	($1.6)	($2.4)	$0.3	$7.2	$7.5
MEC	$2.6	($4.2)	$0.7	$7.6	($0.3)	$0.5	($0.9)	($1.7)	$0.7	$5.2	$5.8
OVEC	$0.1	($0.3)	$0.3	$0.7	($0.0)	$0.0	($0.1)	($0.1)	$0.3	$0.3	$0.6
PE	$3.3	($5.1)	$0.9	$9.3	($0.1)	$0.4	($1.0)	($1.5)	$2.7	$5.1	$7.7
PECO	$3.4	($8.4)	$1.4	$13.2	($0.3)	$0.9	($2.3)	($3.5)	$1.4	$8.3	$9.7
PEPCO	$3.8	($5.3)	$1.2	$10.3	($0.2)	$0.7	($1.9)	($2.7)	$0.1	$7.5	$7.6
PPL	$6.6	($11.6)	$2.3	$20.4	($0.3)	$1.0	($2.6)	($3.9)	$2.7	$13.9	$16.6
PSEG	$5.1	($10.9)	$1.8	$17.9	($0.3)	$1.0	($2.4)	($3.7)	$0.4	$13.8	$14.2
REC	$0.3	($0.3)	$0.2	$0.8	($0.0)	$0.0	($0.1)	($0.1)	$0.2	$0.4	$0.7
Total	$110.2	($247.8)	$40.7	$398.7	($5.8)	$20.1	($51.8)	($77.7)	$69.6	$251.4	$321.0

In cases where PJM has used an artificial constraint that causes net negative congestion and/or there is no load bus on the constrained side of a binding constraint, the congestion of the artificial constraint is handled as a special case. In the first three months of 2025, the total congestion costs associated with these special cases were -$7.9 million or -1.6 percent of the total congestion costs. Table 11-17 and Table 11-18 include congestion allocations from these special case artificial constraints.

There are five categories of artificial constraint based specific allocation special cases that can cause negative congestion: congestion associated with artificial constraints with no downstream load bus (no load bus); congestion associated with artificial constraints with downstream load buses with zero value CLMPs (zero CLMP); congestion associated with closed loop interfaces (closed loop interfaces); congestion associated with CT price setting logic (CT price setting logic); and congestion associated with nontransmission artificial facility constraints in the day-ahead energy market and/or any unaccounted for difference between PJM billed CLMP charges and calculated congestion costs including rounding errors (unclassified).[25]

25 While CT pricing logic was officially discontinued by PJM on September 1, 2021, PJM continued to use a related logic to force inflexible units to be on the margin in both real time and day ahead. These results have been included in the CT Pricing Logic totals.

Table 11-19 and Table 11-20 show total congestion by type of special case, congestion, and total congestion by zone. Closed loop interfaces and CT pricing logic, and similar artificial constraints employed by PJM to force resources to be marginal, generally result in negative congestion on a constraint specific basis. PJM's use of both the closed loop interfaces and CT Pricing Logic forces the affected resource bus LMP to match the marginal offer of the resource. This causes higher CLMP payments to the affected generation than the CLMP load charges to any affected load, resulting in negative congestion associated with the constraint. None of the closed loop interfaces were binding in the first three months of 2024 or 2025. The congestion associated with Real-Time Short-Term Marginal Value Overrides is included in the Normal Constraint Congestion totals.

Table 11-19 CLMP charges and credits and total congestion collected by zone and special case logic (Dollars (Millions)): January through March, 2025

CLMP Credits and Charges (Millions)																	
	Day-Ahead							Balancing									
Control Zone	Load Bus Zero CLMP	CT Price Setting Logic	Closed Loop Interfaces	No Load Buses	Unclassified	Normal Constraint Congestion	Total	Load Bus Zero CLMP	CT Price Setting Logic	Closed Loop Interfaces	No Load Buses	Unclassified	Normal Constraint Congestion	Total	Grand Total	Special Cases Total	Percent of Special Cases
ACEC	$0.0	($0.1)	$0.0	$0.0	($0.0)	$6.5	$6.4	$0.0	$0.0	$0.0	$0.0	$0.0	($2.1)	($2.1)	$4.3	($0.1)	($0.0)
AEP	($0.0)	($1.8)	$0.0	$0.2	($0.0)	$112.6	$111.1	$0.0	$0.0	$0.0	$0.0	$0.0	($29.2)	($29.2)	$81.9	($1.5)	($0.0)
APS	($0.0)	($0.9)	$0.0	$0.0	($0.0)	$62.4	$61.6	$0.0	$0.0	$0.0	$0.0	$0.0	($15.3)	($15.3)	$46.3	($0.9)	($0.0)
ATSI	($0.0)	($0.6)	$0.0	$0.1	($0.0)	$55.5	$54.9	$0.0	($0.0)	$0.0	$0.0	$0.0	($12.5)	($12.5)	$42.4	($0.6)	($0.0)
BGE	($0.0)	($0.4)	$0.0	$0.0	($0.0)	$26.7	$26.2	$0.0	$0.0	$0.0	$0.0	$0.0	($7.9)	($7.9)	$18.3	($0.4)	($0.0)
COMED	$0.0	($1.3)	$0.0	$0.6	($0.0)	$59.8	$59.1	$0.0	$0.0	$0.0	$0.0	$0.0	($14.6)	($14.6)	$44.5	($0.7)	($0.0)
DAY	($0.0)	($0.2)	$0.0	$0.0	($0.0)	$12.7	$12.4	$0.0	$0.0	$0.0	$0.0	$0.0	($3.1)	($3.1)	$9.3	($0.2)	($0.0)
DOM	($0.0)	($1.7)	$0.0	$0.0	($0.0)	$115.7	$114.1	$0.0	$0.0	$0.0	$0.0	$0.0	($39.5)	($39.5)	$74.6	($1.7)	($0.0)
DPL	$0.0	($0.3)	$0.0	$0.0	($0.0)	$21.3	$21.0	$0.0	$0.0	$0.0	$0.0	$0.0	($6.5)	($6.5)	$14.5	($0.3)	($0.0)
DUKE	($0.0)	($0.3)	$0.0	$0.0	($0.0)	$18.3	$17.9	$0.0	$0.0	$0.0	$0.0	$0.0	($4.7)	($4.7)	$13.2	($0.3)	($0.0)
DUQ	($0.0)	($0.2)	$0.0	$0.0	($0.0)	$8.0	$7.8	$0.0	$0.0	$0.0	$0.0	$0.0	($2.5)	($2.5)	$5.3	($0.2)	($0.0)
EKPC	($0.0)	($0.3)	$0.0	$0.0	($0.0)	$12.8	$12.5	$0.0	$0.0	$0.0	$0.0	$0.0	($3.6)	($3.6)	$8.9	($0.3)	($0.0)
EXT	$0.8	($0.2)	$0.0	$0.0	($0.0)	$13.0	$13.6	$0.0	($0.0)	$0.0	$0.0	$0.0	($7.8)	($7.8)	$5.8	$0.6	$0.1
JCPLC	$0.4	($0.4)	$0.0	$0.0	($0.0)	$20.3	$20.3	$0.0	$0.0	$0.0	$0.0	$0.0	($5.9)	($5.9)	$14.4	$0.1	$0.0
MEC	($0.0)	($0.2)	$0.0	$0.1	($0.0)	$16.1	$16.0	$0.0	$0.0	$0.0	$0.0	$0.0	($4.5)	($4.5)	$11.4	($0.1)	($0.0)
OVEC	($0.0)	($0.0)	$0.0	$0.7	($0.0)	$0.9	$1.6	$0.0	($0.0)	$0.0	$0.0	$0.0	($0.2)	($0.2)	$1.4	$0.7	$0.5
PE	($0.0)	($0.2)	$0.0	$0.0	($0.0)	$16.1	$15.9	$0.0	$0.0	$0.0	$0.0	$0.0	($3.7)	($3.7)	$12.1	($0.2)	($0.0)
PECO	$0.0	($0.6)	$0.0	$0.4	($0.0)	$28.5	$28.3	$0.0	$0.0	$0.0	$0.0	$0.0	($9.2)	($9.2)	$19.1	($0.2)	($0.0)
PEPCO	($0.0)	($0.4)	$0.0	$0.0	($0.0)	$24.9	$24.5	$0.0	$0.0	$0.0	$0.0	$0.0	($7.4)	($7.4)	$17.1	($0.4)	($0.0)
PPL	$0.0	($0.6)	$0.0	$0.0	($0.0)	$42.3	$41.6	$0.0	$0.0	$0.0	$0.0	$0.0	($10.2)	($10.2)	$31.4	($0.6)	($0.0)
PSEG	$0.0	($0.6)	$0.0	$0.0	($0.0)	$36.1	$35.5	$0.0	$0.0	$0.0	$0.0	$0.0	($9.4)	($9.4)	$26.1	($0.6)	($0.0)
REC	($0.0)	($0.0)	$0.0	$0.0	($0.0)	$1.1	$1.1	$0.0	$0.0	$0.0	$0.0	$0.0	($0.3)	($0.3)	$0.8	($0.0)	($0.0)
Total	$1.2	($11.3)	$0.0	$2.1	($0.0)	$711.5	$703.5	$0.0	$0.0	$0.0	$0.0	$0.0	($200.3)	($200.2)	$503.3	($7.9)	($0.0)

Table 11-20 CLMP charges and credits and congestion collected by zone and special case logic (Dollars (Millions)): January through March, 2024

	CLMP Credits and Charges (Millions)																
	Day-Ahead							Balancing									
Control Zone	Load Bus Zero CLMP	CT Price Setting Logic	Closed Loop Interfaces	No Load Buses	Unclassified	Normal Constraint Congestion	Total	Load Bus Zero CLMP	CT Price Setting Logic	Closed Loop Interfaces	No Load Buses	Unclassified	Normal Constraint Congestion	Total	Grand Total	Special Cases Total	Percent of Special Cases
ACEC	$0.0	($0.0)	$0.0	$0.0	($0.0)	$3.2	$3.2	$0.0	($0.0)	$0.0	$0.0	$0.0	($0.8)	($0.8)	$2.4	($0.0)	(0.0%)
AEP	$0.0	($0.0)	$0.0	$0.6	($0.0)	$61.6	$62.2	$0.0	($0.0)	$0.0	$0.0	$0.0	($12.1)	($12.1)	$50.0	$0.6	1.1%
APS	$0.0	($0.0)	$0.0	$0.0	($0.0)	$30.6	$30.6	$0.0	($0.0)	$0.0	$0.0	$0.0	($5.8)	($5.8)	$24.8	($0.0)	(0.0%)
ATSI	$0.0	($0.0)	$0.0	$0.0	($0.0)	$30.0	$30.0	$0.0	$0.0	$0.0	$0.0	$0.0	($5.9)	($5.9)	$24.1	($0.0)	(0.0%)
BGE	$0.0	($0.0)	$0.0	$0.0	($0.0)	$12.0	$12.0	$0.0	($0.0)	$0.0	$0.0	$0.0	($3.0)	($3.0)	$9.0	($0.0)	(0.0%)
COMED	$0.0	($0.0)	$0.0	$1.6	($0.0)	$69.4	$71.0	$0.0	($0.0)	$0.0	$0.0	$0.0	($6.7)	($6.7)	$64.3	$1.6	2.5%
DAY	$0.0	($0.0)	$0.0	$0.0	($0.0)	$6.5	$6.5	$0.0	($0.0)	$0.0	$0.0	$0.0	($1.5)	($1.5)	$4.9	($0.0)	(0.0%)
DOM	$0.0	($0.0)	$0.0	$0.3	($0.0)	$47.3	$47.6	$0.0	($0.0)	$0.0	$0.0	$0.0	($12.4)	($12.4)	$35.2	$0.3	0.9%
DPL	$0.0	($0.0)	$0.0	$0.0	($0.0)	$11.1	$11.1	$0.0	($0.0)	$0.0	$0.0	$0.0	($1.9)	($1.9)	$9.2	($0.0)	(0.0%)
DUKE	$0.0	($0.0)	$0.0	$0.0	($0.0)	$9.6	$9.6	$0.0	($0.0)	$0.0	$0.0	$0.0	($2.3)	($2.3)	$7.3	($0.0)	(0.0%)
DUQ	$0.0	($0.0)	$0.0	$0.0	($0.0)	$4.1	$4.1	$0.0	($0.0)	$0.0	$0.0	$0.0	($1.1)	($1.1)	$3.0	($0.0)	(0.0%)
EKPC	$0.0	($0.0)	$0.0	$0.0	($0.0)	$6.5	$6.5	$0.0	($0.0)	$0.0	$0.0	$0.0	($1.6)	($1.6)	$4.9	($0.0)	(0.0%)
EXT	$1.1	($0.0)	$0.0	$0.0	($0.0)	$13.4	$14.5	$0.0	($0.0)	$0.0	$0.0	$0.0	($3.0)	($3.0)	$11.5	$1.1	9.5%
JCPLC	$0.3	($0.0)	$0.0	$0.0	($0.0)	$9.6	$9.9	$0.0	($0.0)	$0.0	$0.0	$0.0	($2.4)	($2.4)	$7.5	$0.3	3.5%
MEC	$0.0	($0.0)	$0.0	$0.0	($0.0)	$7.6	$7.6	$0.0	($0.0)	$0.0	$0.0	$0.0	($1.7)	($1.7)	$5.8	($0.0)	(0.0%)
OVEC	$0.0	($0.0)	$0.0	$0.3	($0.0)	$0.5	$0.7	$0.0	($0.0)	$0.0	$0.0	$0.0	($0.1)	($0.1)	$0.6	$0.3	43.6%
PE	$0.0	($0.0)	$0.0	$0.2	($0.0)	$9.1	$9.3	$0.0	($0.0)	$0.0	$0.0	$0.0	($1.5)	($1.5)	$7.7	$0.2	2.2%
PECO	$0.0	($0.0)	$0.0	$0.0	($0.0)	$13.2	$13.2	$0.0	($0.0)	$0.0	$0.0	$0.0	($3.5)	($3.5)	$9.7	$0.0	0.0%
PEPCO	$0.0	($0.0)	$0.0	$0.0	($0.0)	$10.3	$10.3	$0.0	($0.0)	$0.0	$0.0	$0.0	($2.7)	($2.7)	$7.6	($0.0)	(0.0%)
PPL	$0.0	($0.0)	$0.0	$0.0	($0.0)	$20.4	$20.4	$0.0	($0.0)	$0.0	$0.0	$0.0	($3.9)	($3.9)	$16.6	$0.0	0.2%
PSEG	$0.0	($0.0)	$0.0	$0.0	($0.0)	$17.9	$17.9	$0.0	($0.0)	$0.0	$0.0	$0.0	($3.7)	($3.7)	$14.2	($0.0)	(0.0%)
REC	$0.0	($0.0)	$0.0	$0.0	($0.0)	$0.8	$0.8	$0.0	($0.0)	$0.0	$0.0	$0.0	($0.1)	($0.1)	$0.7	($0.0)	(0.0%)
Total	$1.4	($0.0)	$0.0	$2.9	($0.0)	$394.4	$398.7	$0.0	($0.0)	$0.0	$0.0	$0.0	($77.7)	($77.7)	$321.0	$4.3	1.3%

Table 11-21 show total balancing congestion caused by each of the Real-Time Short-Term Marginal Value Overrides constraints PJM used in the first three months of 2025 (Table 11-21). The congestion associated with Real-Time Short-Term Marginal Value Overrides is included in the Normal Constraint Congestion totals. Real-Time Short-Term Marginal Value Overrides are artificial transmission contingencies on physical transmission elements. Real-Time Short-Term Marginal Value Overrides temporarily force a generator to be marginal. Real-Time Short-Term Marginal Value Overrides are typically in place for a period of from several hours to a few days. Real-Time Short-Term Marginal Value Overrides are similar to a closed loop interface in that they enforce artificially uniform price effects, but unlike closed loop interfaces that only affect prices on the constrained side, these artificial constraints enforce artificially uniform price spreads between the two sides of the constraint through large uniform dfax on the constrained side and small uniform dfax on the unconstrained side. The uniform source dfax and uniform sink dfax of the artificial constraint can be modified, along with the transmission line limits, by PJM to meet market outcome goals and are a source of significant modeling differences between the day-ahead and real-time market.

Table 11-21 CLMP charges and credits and congestion collected by Real-Time Short-Term Marginal Value Overrides by affected Constraint: January through March, 2025

				CLMP Credits and Charges (Millions)				
				Balancing				Percent of Total Congestion Caused by Real-Time Short-Term Marginal Value Overrides
No.	Constraint	Type	Location	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	
1	Gardners - Texas Eastern	Line	MEC	($0.3)	$0.1	($0.1)	($0.5)	100.2%
2	Easton - Emuni	Line	DPL	($0.0)	$0.0	$0.0	$0.0	(0.2%)
	Total			($0.4)	$0.1	($0.1)	($0.5)	100.0%

Fast Start Pricing Effect on Zonal Congestion

PJM implemented fast start pricing in both day-ahead and real-time markets starting September 1, 2021. Table 11-22 compares the congestion costs between the dispatch run and the pricing run in the first three months of 2025. The table shows that the implementation of fast starting pricing logic caused day-ahead total congestion costs to increase $0.6 million (or 0.1 percent), caused negative balancing congestion costs to decrease $11.6 million (or 6.1 percent), and caused total congestion costs to decrease $11.0 million (or 2.1 percent) from the dispatch run to the pricing run in the first three months of 2025. In comparing the two pricing results, the same MW, from the dispatch run in the day-ahead market and metered output in the real-time market, are used in the accounting cost calculations.

Table 11-22 Total congestion by dispatch and pricing run (Dollars (Millions)): January through March, 2025

	Congestion Costs (Millions)								
	Dispatch Run			Pricing Run			Difference		
Control Zone	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total
ACEC	$6.3	($2.0)	$4.3	$6.4	($2.1)	$4.3	$0.0	($0.1)	($0.1)
AEP	$110.6	($27.4)	$83.2	$111.1	($29.2)	$81.9	$0.5	($1.8)	($1.3)
APS	$61.7	($14.3)	$47.4	$61.6	($15.3)	$46.3	($0.2)	($1.0)	($1.1)
ATSI	$55.0	($11.7)	$43.2	$54.9	($12.5)	$42.4	($0.1)	($0.7)	($0.8)
BGE	$26.1	($7.4)	$18.7	$26.2	($7.9)	$18.3	$0.1	($0.5)	($0.4)
COMED	$58.8	($13.8)	$45.0	$59.1	($14.6)	$44.5	$0.3	($0.8)	($0.5)
DAY	$12.4	($2.9)	$9.4	$12.4	($3.1)	$9.3	$0.1	($0.2)	($0.1)
DOM	$113.6	($37.3)	$76.4	$114.1	($39.5)	$74.6	$0.4	($2.2)	($1.8)
DPL	$21.0	($6.2)	$14.8	$21.0	($6.5)	$14.5	($0.0)	($0.3)	($0.3)
DUKE	$17.9	($4.5)	$13.4	$17.9	($4.7)	$13.2	$0.1	($0.3)	($0.2)
DUQ	$7.8	($2.3)	$5.4	$7.8	($2.5)	$5.3	$0.0	($0.1)	($0.1)
EKPC	$12.5	($3.4)	$9.1	$12.5	($3.6)	$8.9	$0.1	($0.2)	($0.2)
EXT	$13.6	($7.4)	$6.2	$13.6	($7.8)	$5.8	$0.1	($0.5)	($0.4)
JCPLC	$20.3	($5.6)	$14.7	$20.3	($5.9)	$14.4	$0.1	($0.3)	($0.2)
MEC	$16.0	($4.3)	$11.7	$16.0	($4.5)	$11.4	($0.0)	($0.2)	($0.3)
OVEC	$1.6	($0.2)	$1.4	$1.6	($0.2)	$1.4	($0.0)	($0.0)	($0.0)
PE	$16.9	($3.5)	$13.3	$15.9	($3.7)	$12.1	($1.0)	($0.2)	($1.2)
PECO	$28.2	($8.7)	$19.5	$28.3	($9.2)	$19.1	$0.1	($0.5)	($0.4)
PEPCO	$24.4	($7.0)	$17.4	$24.5	($7.4)	$17.1	$0.1	($0.4)	($0.3)
PPL	$41.7	($9.6)	$32.1	$41.6	($10.2)	$31.4	($0.1)	($0.6)	($0.7)
PSEG	$35.6	($8.8)	$26.8	$35.5	($9.4)	$26.1	($0.1)	($0.5)	($0.6)
REC	$1.1	($0.3)	$0.8	$1.1	($0.3)	$0.8	($0.0)	($0.0)	($0.0)
Total	$702.9	($188.7)	$514.3	$703.5	($200.2)	$503.3	$0.6	($11.6)	($11.0)

Monthly Congestion

Table 11-23 shows day-ahead, balancing and inadvertent congestion costs by month for January 2024 through March 2025.

Total negative balancing congestion costs in the first three months of 2025 were highest in January. The top constraint that contributed to the total balancing congestion costs in the first three months of 2025 was the AEP – DOM Interface. The constraint accounted for 52.6 percent of the total balancing congestion costs in the first three months of 2025. The majority (30.2 percent) of negative balancing congestion costs for the AEP – DOM Interface were the result of Generation.

In the first three months of 2025 total congestion costs were highest in January and lowest in February.

Table 11-23 Monthly congestion costs by market (Dollars (Millions)): January 2024 through March 2025

	Congestion Costs (Millions)							
	2024				2025			
	Day-Ahead	Balancing	Inadvertent Charges	Total	Day-Ahead	Balancing	Inadvertent Charges	Total
Jan	$230.9	($35.0)	$0.0	$196.0	$361.5	($133.8)	($0.0)	$227.8
Feb	$67.8	($14.6)	$0.0	$53.2	$146.5	($22.0)	($0.0)	$124.5
Mar	$99.9	($28.2)	($0.0)	$71.8	$195.5	($44.4)	($0.0)	$151.0
Apr	$108.4	($28.2)	$0.0	$80.1				
May	$199.3	($26.7)	$0.0	$172.6				
Jun	$155.3	($27.5)	$0.0	$127.8				
Jul	$371.5	($41.0)	$0.0	$330.5				
Aug	$256.6	($18.3)	$0.0	$238.3				
Sep	$128.7	($13.2)	$0.0	$115.5				
Oct	$137.3	($22.0)	$0.0	$115.2				
Nov	$84.6	($18.5)	$0.0	$66.1				
Dec	$218.2	($31.0)	($0.0)	$187.3				
Total	$2,058.6	($304.2)	$0.0	$1,754.4	$703.5	($200.2)	($0.0)	$503.3

Figure 11-3 shows PJM monthly total congestion cost for January 2008 through March 2025.

Figure 11-3 Monthly total congestion cost (Dollars (Millions)): January 2008 through March 2025

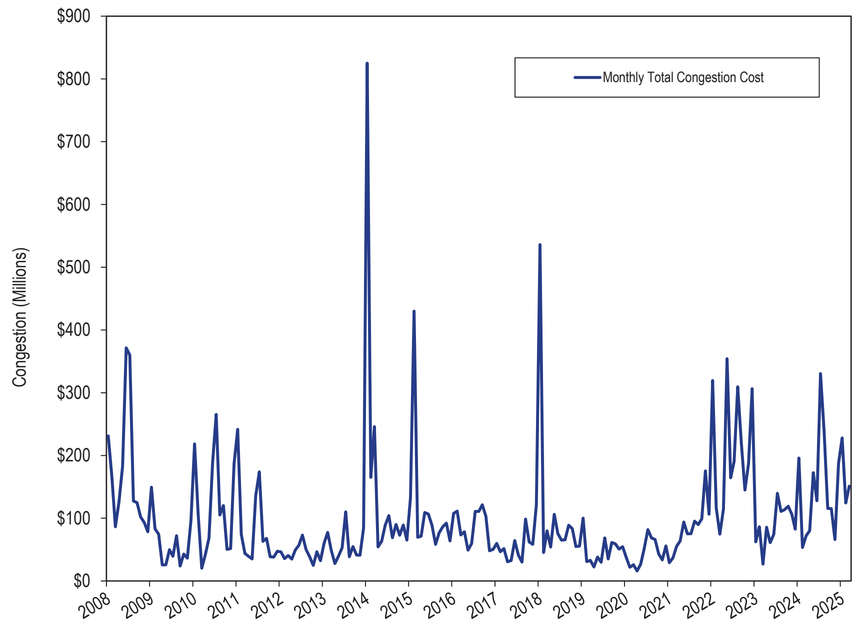


Table 11-24 shows monthly total CLMP credits and charges for each virtual transaction type for January 2024 through March 2025. Virtual transaction CLMP charges, when positive, are the total CLMP charges to the virtual transactions and when negative, are the total CLMP credits to the virtual transactions. The negative totals in Table 11-24 show that virtuals were paid, in net, CLMP credits in the first three months of 2025 and 2024. In the first three months of 2025, 48.1 percent of the total credits to virtuals went to UTCs, compared to 34.7 percent in the first three months of 2024. In the first three months of 2025, the average hourly cleared UTC MW decreased by 18.9 percent, compared to the first three months of 2024.

Table 11-24 Monthly CLMP charges by virtual transaction type (Dollars (Millions)): January 2024 through March 2025

		CLMP Credits and Charges (Millions)									
		DEC			INC			Up to Congestion			
Year		Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Grand Total
2024	Jan	$2.1	($6.6)	($4.6)	$5.5	($10.5)	($4.9)	$16.2	($23.6)	($7.4)	($16.9)
	Feb	($0.6)	$0.5	($0.1)	$6.9	($9.7)	($2.9)	$9.5	($10.5)	($1.0)	($4.0)
	Mar	$0.8	($3.2)	($2.5)	$9.3	($13.8)	($4.5)	$15.3	($17.3)	($2.0)	($8.9)
	Apr	($0.6)	$0.8	$0.3	$14.9	($18.2)	($3.3)	$16.8	($20.3)	($3.4)	($6.4)
	May	($2.8)	$4.1	$1.3	$12.6	($18.0)	($5.4)	$16.6	($18.8)	($2.2)	($6.3)
	Jun	$0.5	$0.7	$1.2	$6.0	($11.1)	($5.1)	$15.3	($16.3)	($1.1)	($4.9)
	Jul	($1.4)	($2.3)	($3.7)	$6.6	($20.3)	($13.7)	$12.0	($18.2)	($6.2)	($23.6)
	Aug	$3.4	($3.8)	($0.4)	$4.7	($5.7)	($1.1)	$10.0	($12.3)	($2.3)	($3.8)
	Sep	($5.4)	$5.9	$0.5	$4.0	($6.3)	($2.3)	$6.2	($7.8)	($1.6)	($3.3)
	Oct	($2.9)	$1.7	($1.2)	$6.2	($11.5)	($5.2)	$9.5	($11.0)	($1.5)	($7.9)
	Nov	($6.4)	$2.7	($3.8)	$12.3	($18.0)	($5.7)	$7.6	($9.2)	($1.6)	($11.1)
	Dec	($17.1)	$8.5	($8.7)	$14.8	($30.0)	($15.3)	$9.5	($13.4)	($3.8)	($27.8)
	Total	($30.5)	$9.0	($21.5)	$103.9	($173.2)	($69.3)	$144.5	($178.6)	($34.1)	($124.9)
2025	Jan	$3.3	($31.1)	($27.8)	$22.3	($35.9)	($13.6)	$16.8	($50.6)	($33.8)	($75.1)
	Feb	($5.2)	$4.2	($1.0)	$12.7	($17.4)	($4.7)	$11.2	($14.9)	($3.7)	($9.4)
	Mar	($2.3)	$2.2	($0.1)	$22.4	($29.5)	($7.1)	$14.2	($27.0)	($12.9)	($20.1)
	Total	($4.3)	($24.7)	($28.9)	$57.4	($82.8)	($25.4)	$42.2	($92.5)	($50.3)	($104.6)

Congested Facilities

A congestion event exists when a unit or units must be dispatched out of merit order to control for the potential impact of a contingency on a monitored facility or to control an actual overload. A congestion event hour exists when a specific facility is constrained for one or more five-minute intervals within an hour. A congestion event hour differs from a constrained hour, which is any hour during which one or more facilities are congested. If two facilities are constrained during an hour, the result is one constrained hour and two congestion event hours. Constraints are often simultaneous, so the number of congestion event hours usually exceeds the number of constrained hours and the number of congestion event hours usually exceeds the number of hours in a year.

In order to have a consistent metric for real-time and day-ahead congestion frequency, real-time congestion frequency is measured using the convention that an hour is constrained if any of its component five-minute intervals is constrained. This is consistent with the way in which PJM reports real-time congestion.

In the first three months of 2025, there were 20,823 day-ahead congestion event hours compared to 19,390 day-ahead congestion event hours in the first three months of 2024. Of the day-ahead congestion event hours in the first three months of 2025, only 4,228 (20.3 percent) were also constrained in the real-time energy market (Table 11-26). In the first three months of 2025, there were 8,416 real-time, congestion event hours compared to 6,273 real-time, congestion event hours in the first three months of 2024. Of the real-time congestion event hours in the first three months of 2025, 4,298 (51.1 percent) were also constrained in the day-ahead energy market (Table 11-27).

Congestion Event Hours

Table 11-25 compares the monthly day-ahead and real-time congestion event hours in the first three months of 2024 and 2025. Day-ahead congestion event hours are significantly greater than real-time congestion event hours.

Table 11-25 Monthly day-ahead and real-time congestion event hours: January 2024 through March 2025

	Day-Ahead Congestion Event Hours		Real-Time Congestion Event Hours	
	2024	2025	2024	2025
Jan	6,003	6,599	2,037	2,574
Feb	5,516	6,213	1,709	2,176
Mar	7,877	8,016	2,527	3,663
Apr	6,464		2,648	
May	6,833		2,930	
Jun	6,601		2,731	
Jul	6,379		2,397	
Aug	5,822		1,885	
Sep	5,974		1,884	
Oct	7,039		2,472	
Nov	5,782		1,808	
Dec	8,015		2,652	
Total	78,305	20,828	27,680	8,413

Table 11-26 and Table 11-27 compare day-ahead and real-time congestion event hours. Among the hours for which a facility is constrained in the day-ahead energy market, the number of hours during which the facility is also constrained in the real-time energy market are presented in Table 11-26.[26]

Among the hours for which a facility was constrained in the real-time energy market, the number of hours during which the facility was also constrained in the day-ahead energy market are presented in Table 11-27.

Congestion frequency continued to be significantly higher in the day-ahead energy market than in the real-time energy market in the first three months of 2025. The number of congestion event hours in the day-ahead energy market was about three times the number of congestion event hours in the real-time energy market.

26 Constraints are mapped to transmission facilities. In the day-ahead energy market, within a given hour, a single transmission facility may be associated with multiple constraints. In such situations, the same facility accounts for more than one congestion event hour for a given hour in the day-ahead energy market. Similarly in the real-time market a facility may account for more than one congestion event hour within a given hour.

In the real-time market, PJM has the ability to model and monitor almost all PJM transmission facilities. In the day-ahead market, PJM can model and monitor only a portion of PJM transmission facilities. This difference in modeling is the basis of false arbitrage and the source of significant virtual profits. While more constraints are modeled and monitored in the PJM real-time market than the day-ahead market, there is significantly more network flow in the day-ahead market than in the real-time market as a result of virtual bids and offers. Virtual bids and offers also contribute to day-ahead market flows that do not align with realized real-time physical flows. The number of congestion event hours in the day-ahead energy market was about three times the number of congestion event hours in the real-time energy market, despite the fact that only a portion of PJM transmission facilities are modeled in the day-ahead market.

Table 11-26 Congestion event hours (day-ahead against real-time): January through March, 2024 and 2025

	Congestion Event Hours					
	2024 (Jan - Mar)			2025 (Jan - Mar)		
Type	Day-Ahead Constrained	Corresponding Real-Time Constrained	Percent	Day-Ahead Constrained	Corresponding Real-Time Constrained	Percent
Flowgate	1,020	149	14.6%	3,219	603	18.7%
Interface	346	120	34.7%	723	130	18.0%
Line	13,721	2,244	16.4%	13,378	2,699	20.2%
Transformer	2,399	127	5.3%	2,019	86	4.3%
Other	1,904	743	39.0%	1,484	710	47.8%
Total	19,390	3,383	17.4%	20,823	4,228	20.3%

Table 11-27 Congestion event hours (real-time against day-ahead): January through March, 2024 and 2025

	Congestion Event Hours					
	2024 (Jan - Mar)			2025 (Jan - Mar)		
Type	Real-Time Constrained	Corresponding Day-Ahead Constrained	Percent	Real-Time Constrained	Corresponding Day-Ahead Constrained	Percent
Flowgate	700	149	21.3%	1,488	599	40.3%
Interface	219	181	82.6%	316	157	49.7%
Line	4,003	2,260	56.5%	5,350	2,720	50.8%
Transformer	236	127	53.8%	343	86	25.1%
Other	1,115	748	67.1%	919	736	80.1%
Total	6,273	3,465	55.2%	8,416	4,298	51.1%

Table 11-28 shows congestion costs by facility voltage class in the first three months of 2025. Congestion costs in the first three months of 2025 increased for all facility voltage classes except for 345 kV and 69 kV compared to the first three months of 2024.

Table 11-28 Congestion summary (By facility voltage): January through March, 2025

CLMP Credits and Charges (Millions)											
	Day-Ahead				Balancing					Event Hours	
Voltage (kV)	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Costs	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Costs	Total	Congestion Costs	Day-Ahead	Real-Time
765	$2.3	($11.1)	$1.6	$15.0	($1.2)	$2.3	($3.9)	($7.4)	$7.5	142	76
500	$51.6	($139.8)	$11.5	$202.9	($22.0)	$57.8	($33.3)	($113.0)	$89.9	939	358
345	($8.7)	($50.8)	$1.9	$44.0	($4.9)	($1.7)	($7.3)	($10.5)	$33.5	1,728	737
230	$58.7	($101.6)	$8.8	$169.1	$9.3	($2.5)	($24.5)	($12.7)	$156.3	5,766	1,549
161	($0.1)	($0.4)	$0.0	$0.4	$0.0	$0.2	($0.2)	($0.4)	$0.0	17	15
138	$42.3	($93.5)	$15.8	$151.5	($19.2)	($1.4)	($23.3)	($41.1)	$110.4	7,239	3,503
115	$15.8	($97.3)	$1.8	$114.8	$14.0	$22.6	($2.2)	($10.8)	$104.0	3,593	1,920
69	$3.2	($0.6)	($0.0)	$3.8	($2.4)	$1.1	$0.4	($3.1)	$0.7	1,351	199
13.2	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	0	0
1	$0.2	($1.6)	$0.2	$2.0	($0.4)	$0.5	($0.2)	($1.1)	$0.8	48	59
Unclassified	$0.0	$0.0	$0.0	($0.0)	$0.0	($0.0)	$0.0	$0.0	$0.0	NA	NA
Total	$165.3	($496.6)	$41.7	$703.5	($26.7)	$79.1	($94.5)	($200.2)	$503.3	20,823	8,416

Table 11-29 Congestion summary (By facility voltage): January through March, 2024

CLMP Credits and Charges (Millions)											
	Day-Ahead				Balancing					Event Hours	
Voltage (kV)	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Congestion Costs	Day-Ahead	Real-Time
765	($0.1)	($0.3)	$0.0	$0.2	$0.0	$0.0	($0.0)	($0.0)	$0.2	7	2
500	$32.8	($56.7)	$5.2	$94.7	($4.2)	$1.3	($9.8)	($15.4)	$79.4	774	224
345	($5.6)	($76.1)	$8.9	$79.4	($2.8)	$4.2	($12.8)	($19.7)	$59.7	1,761	600
230	$51.9	($35.9)	$11.5	$99.3	$6.4	$2.6	($8.5)	($4.7)	$94.6	5,680	1,445
161	$0.0	($0.1)	$0.0	$0.1	$0.1	$0.1	($0.8)	($0.8)	($0.7)	42	40
138	$20.6	($32.5)	$9.3	$62.3	($7.5)	($1.3)	($12.2)	($18.4)	$43.9	6,175	2,377
115	$6.8	($46.2)	$5.1	$58.1	$2.5	$12.8	($6.7)	($17.0)	$41.0	3,271	1,496
69	$3.6	($0.2)	$0.7	$4.5	($0.0)	$0.2	($0.3)	($0.5)	$4.0	1,675	40
13.2	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	5	0
1	$0.0	$0.0	$0.0	$0.0	($0.4)	$0.3	($0.5)	($1.2)	($1.2)	0	49
Unclassified	$0.0	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	NA	NA
Total	$110.2	($247.8)	$40.7	$398.7	($5.8)	$20.1	($51.8)	($77.7)	$321.0	19,390	6,273

Congestion by Facility Type and Voltage

Day-ahead, congestion event hours decreased on transformers and lines and increased on flowgates and interfaces in the first three months of 2025. Congestion event hours on lines decreased by 343 congestion event hours from 13,721 day-ahead, congestion event hours in the first three months of 2024 to 13,378 day-ahead congestion event hours in the first three months of 2025 (Table 11-30).

Real-time, congestion event hours increased on flowgates, interfaces, lines and transformers in the first three months of 2025 (Table 11-31). Lines increased by 1,347 congestion event hours from 4,003 real-time, congestion event hours in the first three months of 2024 to 5,350 real-time congestion event hours in the first three months of 2025.

Table 11-30 provides congestion event hour subtotals and congestion cost subtotals comparing the first three months of 2025 results by facility type: line, transformer, interface, flowgate and unclassified facilities.[27] [28]

Table 11-30 Congestion summary (By facility type): January through March, 2025

	CLMP Credits and Charges (Millions)										
	Day-Ahead				Balancing					Event Hours	
Type	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Congestion Costs	Day-Ahead	Real-Time
Flowgate	($3.4)	($88.4)	$13.7	$98.7	($2.4)	$0.9	($7.2)	($10.5)	$88.2	3,219	1,488
Interface	$52.0	($130.4)	$11.4	$193.8	($21.9)	$58.4	($32.3)	($112.5)	$81.3	723	316
Line	$90.1	($237.1)	$12.5	$339.7	($8.2)	$18.0	($50.1)	($76.3)	$263.3	13,378	5,350
Transformer	$2.4	($33.2)	$2.1	$37.7	($1.5)	($0.4)	($1.0)	($2.1)	$35.6	2,019	343
Other	$24.0	($7.6)	$2.0	$33.6	$7.4	$2.3	($3.9)	$1.2	$34.8	1,484	919
Unclassified	$0.0	$0.0	$0.0	($0.0)	$0.0	($0.0)	$0.0	$0.0	$0.0	NA	NA
Total	$165.3	($496.6)	$41.7	$703.5	($26.7)	$79.1	($94.5)	($200.2)	$503.3	20,823	8,416

Table 11-31 Congestion summary (By facility type): January through March, 2024

	CLMP Credits and Charges (Millions)										
	Day-Ahead				Balancing					Event Hours	
Type	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Congestion Costs	Day-Ahead	Real-Time
Flowgate	($1.0)	($17.2)	$5.4	$21.6	($1.3)	$0.6	($11.4)	($13.3)	$8.3	1,020	700
Interface	$25.8	($46.1)	$4.4	$76.2	($4.2)	$0.8	($9.8)	($14.9)	$61.4	346	219
Line	$38.0	($162.9)	$19.3	$220.2	($5.8)	$17.0	($26.0)	($48.8)	$171.4	13,721	4,003
Transformer	$7.1	($29.1)	$5.7	$41.9	($0.3)	$1.2	($0.9)	($2.4)	$39.5	2,399	236
Other	$40.3	$7.4	$5.8	$38.7	$5.8	$0.5	($3.6)	$1.7	$40.4	1,904	1,115
Unclassified	$0.0	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	NA	NA
Total	$110.2	($247.8)	$40.7	$398.7	($5.8)	$20.1	($51.8)	($77.7)	$321.0	19,390	6,273

27 Unclassified are congestion costs related to nontransmission facility constraints in the day-ahead energy market and any unaccounted for difference between PJM billed CLMP charges and calculated congestion costs including rounding errors. Nontransmission facility constraints include day-ahead market only constraints such as constraints on virtual transactions and constraints associated with phase-angle regulators.

28 The term flowgate refers to MISO reciprocal coordinated flowgates and NYISO M2M flowgates.

Constraint Frequency

Table 11-32 lists the constraints for the first three months of 2024 and 2025 that were most frequently binding and Table 11-33 shows the constraints which experienced the largest change in congestion event hours from the first three months of 2024 to the first three months of 2025. In Table 11-32, constraints are presented in descending order of total day-ahead event hours and real-time event hours in the first three months of 2025. In Table 11-33, the constraints are presented in descending order of absolute value of day-ahead event hour changes plus real-time event hour changes from the first three months of 2024 to the first three months of 2025.

Table 11-32 Top 25 constraints: January through March, 2024 and 2025

			(Jan - Mar)												
			Congestion Event Hours						Percent of Annual Hours						
			Day-Ahead			Real-Time			Day-Ahead			Real-Time			
No.	Constraint	Type	2024	2025	Change	2024	2025	Change	2024	2025	Change	2024	2025	Change	
1	Lenox - North Meshoppen	Line	1,392	1,893	501	1,327	1,578	251	63.8%	88%	24%	61%	73%	12%	
2	Dune Acres - Michigan City	Flowgate	0	1,305	1,305	0	31	31	0%	60%	60%	0%	1%	1%	
3	Nottingham	Other	1,313	700	(613)	565	449	(116)	60%	32%	(28%)	26%	21%	(5%)	
4	Kewanee	Other	458	676	218	522	445	(77)	21%	31%	10%	24%	21%	(3%)	
5	Jordan - West Frankfort	Flowgate	0	560	560	0	483	483	0%	26%	26%	0%	22%	22%	
6	Easton - Emuni	Line	400	684	284	0	128	128	18%	32%	13%	0%	6%	6%	
7	Haumesser Road - Steward	Line	292	489	197	415	322	(93)	13%	23%	9%	19%	15%	(4%)	
8	Dune Acres - Michigan City	Line	0	0	0	4	801	797	0%	0%	0%	0%	37%	37%	
9	Glendon - Hosensack	Line	0	504	504	0	195	195	0%	23%	23%	0%	9%	9%	
10	Chaparral - Carson	Line	161	584	423	0	0	0	7%	27%	20%	0%	0%	0%	
11	Gardners - Texas Eastern	Line	898	457	(441)	71	70	(1)	41%	21%	(20%)	3%	3%	(0%)	
12	DoeX530	Transformer	126	518	392	0	0	0	6%	24%	18%	0%	0%	0%	
13	East Towanda - Hillside	Line	800	444	(356)	543	66	(477)	37%	21%	(16%)	25%	3%	(22%)	
14	Prest - Tibb	Flowgate	61	221	160	42	284	242	3%	10%	7%	2%	13%	11%	
15	All Dam - Kittanning	Line	273	322	49	45	151	106	13%	15%	2%	2%	7%	5%	
16	AEP - DOM	Interface	98	241	143	110	215	105	4%	11%	7%	5%	10%	5%	
17	Meridian - Twin Branch	Line	87	279	192	119	162	43	4%	13%	9%	5%	8%	2%	
18	Chapparal - Carson	Line	0	0	0	87	390	303	0%	0%	0%	4%	18%	14%	
19	Cedar Grove - Clifton	Line	107	328	221	21	17	(4)	5%	15%	10%	1%	1%	(0%)	
20	Graceton - Manor	Line	0	260	260	0	77	77	0%	12%	12%	0%	4%	4%	
21	AP South	Interface	141	264	123	109	62	(47)	6%	12%	6%	5%	3%	(2%)	
22	Monroe - Lallendorf	Flowgate	0	166	166	8	157	149	0%	8%	8%	0%	7%	7%	
23	Loretto - Vienna	Line	173	255	82	2	58	56	8%	12%	4%	0%	3%	3%	
24	Bergen - Hudson	Line	604	292	(312)	0	0	0	28%	14%	(14%)	0%	0%	0%	
25	Mountain	Transformer	523	281	(242)	0	0	0	24%	13%	(11%)	0%	0%	0%	

Table 11-33 Top 25 constraints year to year change in occurrence: January through March, 2024 and 2025

			(Jan - Mar)											
			Congestion Event Hours						Percent of Annual Hours					
			Day-Ahead			Real-Time			Day-Ahead			Real-Time		
No.	Constraint	Type	2024	2025	Change	2024	2025	Change	2024	2025	Change	2024	2025	Change
1	Dune Acres - Michigan City	Flowgate	0	1,305	1,305	0	31	31	0%	60%	60%	0%	1%	1%
2	Jordan - West Frankfort	Flowgate	0	560	560	0	483	483	0%	26%	26%	0%	22%	22%
3	East Towanda - Hillside	Line	800	444	(356)	543	66	(477)	37%	21%	(16%)	25%	3%	(22%)
4	Dune Acres - Michigan City	Line	0	0	0	4	801	797	0%	0%	0%	0%	37%	37%
5	Lenox - North Meshoppen	Line	1,392	1,893	501	1,327	1,578	251	64%	88%	24%	61%	73%	12%
6	Nottingham	Other	1,313	700	(613)	565	449	(116)	60%	32%	(28%)	26%	21%	(5%)
7	Glendon - Hosensack	Line	0	504	504	0	195	195	0%	23%	23%	0%	9%	9%
8	Gardners - Texas Eastern	Line	898	457	(441)	71	70	(1)	41%	21%	(20%)	3%	3%	(0%)
9	Grabill - Robinson Park	Line	310	0	(310)	130	8	(122)	14%	0%	(14%)	6%	0%	(6%)
10	Chaparral - Carson	Line	161	584	423	0	0	0	7%	27%	20%	0%	0%	0%
11	Easton - Emuni	Line	400	684	284	0	128	128	18%	32%	13%	0%	6%	6%
12	Prest - Tibb	Flowgate	61	221	160	42	284	242	3%	10%	7%	2%	13%	11%
13	DoeX530	Transformer	126	518	392	0	0	0	6%	24%	18%	0%	0%	0%
14	Mehoopany - North Meshoppen	Line	438	74	(364)	0	3	3	20%	3%	(17%)	0%	0%	0%
15	Collins	Transformer	370	19	(351)	0	0	0	17%	1%	(16%)	0%	0%	0%
16	Graceton - Manor	Line	0	260	260	0	77	77	0%	12%	12%	0%	4%	4%
17	Rising - Bondville	Flowgate	155	1	(154)	182	0	(182)	7%	0%	(7%)	8%	0%	(8%)
18	Big Pine - Kiski Valley	Line	442	36	(406)	53	123	70	20%	2%	(19%)	2%	6%	3%
19	McGirr Road - Mendota	Line	361	42	(319)	0	0	0	17%	2%	(15%)	0%	0%	0%
20	Monroe - Lallendorf	Flowgate	0	166	166	8	157	149	0%	8%	8%	0%	7%	7%
21	Bergen - Hudson	Line	604	292	(312)	0	0	0	28%	14%	(14%)	0%	0%	0%
22	East Lima	Transformer	215	0	(215)	93	0	(93)	10%	0%	(10%)	4%	0%	(4%)
23	Desoto - Selma Parker	Line	295	1	(294)	11	0	(11)	14%	0%	(13%)	1%	0%	(1%)
24	Chapparal - Carson	Line	0	0	0	87	390	303	0%	0%	0%	4%	18%	14%
25	Sayreville - Sayreville	Line	422	141	(281)	0	0	0	19%	7%	(13%)	0%	0%	0%

Top Constraints

The top five constraints by congestion costs contributed $223.2 million, or 44.3 percent, of the total PJM congestion costs in the first three months of 2025. The top five constraints were the Lenox – North Meshoppen Line, the AP South Interface, the Dune Acres – Michigan City Flowgate, the Chaparral – Carson Line, and the AEP – DOM Interface. Table 11-34 and Table 11-35 show the top constraints contributing to congestion costs by facility for the first three months of 2025 and 2024.

The Lenox – North Meshoppen Line was the largest contributor to congestion costs in the first three months of 2025 with $88.3 million and 17.5 percent of total PJM congestion costs. The day-ahead congestion event hours of the Lenox – North Meshoppen Line increased from 1,392 in the first three months of 2024 to 1,893 in the first three months of 2025 and the real-time congestion event hours of the Lenox – North Meshoppen Line increased from 1,327 in the first three months of 2024 to 1,578 in the first three months of 2025 (Table 11-32). The frequent binding of the Lenox – North Meshoppen Line in both day-ahead and real-time was a result of exports into NY across the NYIS interface.

The AP South Interface was the second largest contributor to congestion costs in the first three months of 2025 with $70.9 million and 14.1 percent of total PJM congestion costs. The day-ahead congestion event hours of the AP South Interface increased from 141 in the first three months of 2024 to 264 in the first three months of 2025 and the real-time congestion event hours of the AP South Interface decreased from 109 in the first three months of 2024 to 62 in the first three months of 2025 (Table 11-32).

The Dune Acres – Michigan City Flowgate was the third largest contributor to congestion costs in the first three months of 2025 with $53.9 million and 10.7 percent of the total PJM congestion costs. The day-ahead congestion event hours of the Dune Acres – Michigan City Flowgate did not change from 0 in the first three months of 2024 to 0 in the first three months of 2025 and the real-time congestion event hours of the Dune Acres – Michigan City Flowgate increased from 4 in the first three months of 2024 to 801 in the first three months of 2025 (Table 11-32).

The Chaparral – Carson Line was the fourth largest contributor to congestion costs in the first three months of 2025 with $51.5 million and 10.2 percent of total PJM congestion costs. The day-ahead congestion event hours of the Chaparral – Carson Line increased from 161 in the first three months of 2024 to 584 in the first three months of 2025 and the real-time congestion event hours of the Chaparral – Carson Line did not change from 0 in the first three months of 2024 to 0 in the first three months of 2025 (Table 11-32).

The AEP – DOM Interface was the fifth largest contributor to congestion costs in the first three months of 2025 with -$41.4 million and -8.2 percent of total PJM congestion costs. The day-ahead congestion event hours of the AEP – DOM Interface increased from 98 in the first three months of 2024 to 241 in the first three months of 2025 and the real-time congestion event hours of the AEP – DOM Interface increased from 110 in the first three months of 2024 to 215 in the first three months of 2025 (Table 11-32).

The AEP – DOM Interface was the largest contributor to negative congestion costs in the first three months of 2025. The constraint accounted for 52.6 percent of the total balancing congestion costs in the first three months of 2025.

Table 11-34 Top 25 constraints affecting congestion costs: January through March, 2025[29]

				CLMP Credits and Charges (Millions)									
				Day-Ahead				Balancing					
No.	Constraint	Type	Location	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Congestion Costs	Percent of Total PJM Congestion Costs
1	Lenox - North Meshoppen	Line	PE	$4.8	($88.3)	$2.5	$95.6	$17.1	$21.7	($2.8)	($7.4)	$88.3	17.5%
2	AP South	Interface	500	$28.2	($42.0)	$4.0	$74.2	$0.5	$1.8	($1.9)	($3.3)	$70.9	14.1%
3	Dune Acres - Michigan City	Flowgate	MISO	$5.1	($39.3)	$10.0	$54.5	($0.1)	$0.1	($0.3)	($0.6)	$53.9	10.7%
4	Chaparral - Carson	Line	DOM	$7.0	($41.7)	$2.9	$51.5	$0.0	$0.0	$0.0	$0.0	$51.5	10.2%
5	AEP - DOM	Interface	500	$20.0	($37.9)	$6.0	$63.9	($21.7)	$54.9	($28.8)	($105.3)	($41.4)	(8.2%)
6	Bedington - Black Oak	Interface	500	$12.1	($30.8)	$1.9	$44.7	($0.7)	$1.6	($1.6)	($3.9)	$40.8	8.1%
7	Nottingham	Other	PECO	$22.7	($3.6)	$1.7	$27.9	$5.8	$1.4	($0.6)	$3.8	$31.7	6.3%
8	Meridian - Twin Branch	Line	AEP	$1.0	($29.0)	$2.1	$32.1	($2.2)	($1.4)	($1.9)	($2.6)	$29.4	5.9%
9	Dune Acres - Michigan City	Line	MISO	$0.0	$0.0	$0.0	$0.0	($9.5)	($1.7)	($16.2)	($24.0)	($24.0)	(4.8%)
10	Conastone - Northwest	Line	BGE	$4.5	($10.0)	$0.6	$15.0	$2.8	($9.5)	($4.2)	$8.1	$23.1	4.6%
11	Jordan - West Frankfort	Flowgate	MISO	($2.5)	($17.8)	$1.5	$16.8	$0.7	$0.7	($1.1)	($1.1)	$15.7	3.1%
12	Joshua Falls	Transformer	AEP	$2.2	($10.3)	$1.5	$14.0	$0.0	$0.0	$0.0	$0.0	$14.0	2.8%
13	Monroe - Lallendorf	Flowgate	MISO	($5.2)	$3.0	($2.9)	($11.1)	($0.6)	($1.1)	($0.3)	$0.3	($10.8)	(2.2%)
14	West	Interface	500	($6.7)	($17.1)	($0.6)	$9.9	$0.0	$0.0	$0.0	$0.0	$9.9	2.0%
15	Pleasant View - Ashburn	Line	DOM	$0.0	$0.0	$0.0	$0.0	$2.4	$4.1	($7.4)	($9.1)	($9.1)	(1.8%)
16	Northport - Albion	Flowgate	MISO	($2.0)	($12.8)	$0.7	$11.5	($1.4)	($0.7)	($2.2)	($2.9)	$8.6	1.7%
17	East Towanda - Hillside	Line	PE	($0.1)	($8.2)	$0.1	$8.2	$0.3	$0.0	($0.0)	$0.2	$8.4	1.7%
18	Cloverdale - Jacksons Ferry	Line	AEP	$0.0	$0.0	$0.0	$0.0	($1.0)	$2.6	($4.0)	($7.6)	($7.6)	(1.5%)
19	Graceton - Manor	Line	BGE	$3.6	($3.4)	$0.0	$7.1	$0.5	$0.4	$0.2	$0.3	$7.4	1.5%
20	Williams Grove	Line	PPL	($2.0)	($9.1)	($0.2)	$6.8	$0.0	$0.0	$0.0	$0.0	$6.8	1.4%
21	Chapparal - Carson	Line	DOM	$0.0	$0.0	$0.0	$0.0	($1.1)	$0.5	($4.5)	($6.1)	($6.1)	(1.2%)
22	Haumesser Road - Steward	Line	COMED	($0.8)	($6.6)	$0.2	$6.0	$0.2	$0.0	($0.2)	($0.1)	$5.9	1.2%
23	Glendon - Hosensack	Line	MEC	$8.9	$1.2	($0.0)	$7.7	($2.2)	($0.2)	$0.0	($2.1)	$5.7	1.1%
24	Capitol Hill - Chemical	Line	AEP	($1.4)	($6.5)	$0.1	$5.2	$0.0	$0.0	$0.0	$0.0	$5.2	1.0%
25	University Park - Olive	Flowgate	MISO	$0.9	($3.0)	$1.0	$4.9	$0.0	$0.0	$0.0	$0.0	$4.9	1.0%
	Top 25 Total			$100.3	($413.2)	$33.1	$546.6	($10.3)	$75.4	($77.7)	($163.3)	$383.2	76.2%
	All Other Constraints			$65.0	($83.4)	$8.6	$156.9	($16.4)	$3.7	($16.8)	($36.9)	$120.0	23.8%
	Total			$165.3	($496.6)	$41.7	$703.5	($26.7)	$79.1	($94.5)	($200.2)	$503.3	100.0%

29 All flowgates are mapped to MISO as Location if they are flowgates coordinated by both PJM and MISO regardless of the location of the flowgates.

Table 11-35 Top 25 constraints affecting congestion costs: January through March, 2024[30]

				CLMP Credits and Charges (Millions)									
				Day-Ahead				Balancing					
No.	Constraint	Type	Location	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Congestion Costs	Percent of Total PJM Congestion Costs
1	AP South	Interface	500	$20.4	($25.6)	$2.3	$48.3	($0.9)	$0.0	($3.4)	($4.4)	$43.9	13.7%
2	Nottingham	Other	PECO	$40.4	$9.3	$5.5	$36.6	$5.8	$0.7	($3.2)	$2.0	$38.6	12.0%
3	Lenox - North Meshoppen	Line	PE	$8.1	($35.8)	$4.6	$48.5	$3.4	$12.6	($6.2)	($15.4)	$33.1	10.3%
4	Braidwood - East Frankfort	Line	COMED	($4.6)	($40.4)	$0.1	$36.0	($0.1)	$2.2	($1.7)	($3.9)	$32.1	10.0%
5	East Towanda - Hillside	Line	PE	$3.5	($17.0)	$1.5	$22.0	$1.0	$0.9	($1.0)	($1.0)	$21.0	6.5%
6	Juniata	Transformer	500	$5.4	($9.1)	$0.3	$14.8	$0.0	$0.0	$0.0	$0.0	$14.8	4.6%
7	East Lima	Transformer	AEP	($1.8)	($11.7)	$0.4	$10.3	$0.0	$0.3	($0.5)	($0.8)	$9.6	3.0%
8	Mazon - La Salle	Line	COMED	$0.8	($8.6)	($0.0)	$9.4	($0.0)	$0.4	$0.1	($0.3)	$9.1	2.8%
9	Bedington - Black Oak	Interface	500	$2.5	($4.9)	$0.3	$7.7	$0.0	$0.0	$0.0	$0.0	$7.7	2.4%
10	Collins	Transformer	COMED	$0.4	($4.1)	$3.0	$7.5	$0.0	$0.0	$0.0	$0.0	$7.5	2.3%
11	Chaparral - Carson	Line	DOM	$0.9	($5.5)	$0.4	$6.8	$0.0	$0.0	$0.0	$0.0	$6.8	2.1%
12	AEP - DOM	Interface	500	$5.2	($9.4)	$2.0	$16.5	($3.3)	$0.8	($6.4)	($10.5)	$6.0	1.9%
13	Gardners - Texas Eastern	Line	MEC	($2.8)	($8.9)	$0.2	$6.3	($0.7)	($0.3)	($0.4)	($0.7)	$5.6	1.8%
14	Elimsport - Sunbury	Line	PPL	($3.1)	($8.6)	$0.0	$5.5	$0.1	($0.1)	($0.0)	$0.1	$5.6	1.7%
15	Desoto - Selma Parker	Line	AEP	($3.0)	($7.0)	$1.4	$5.4	($0.0)	($0.0)	($0.1)	($0.1)	$5.4	1.7%
16	Big Pine - Kiski Valley	Line	APS	$13.1	$9.9	$0.0	$3.2	($0.1)	($0.6)	$0.1	$0.6	$3.8	1.2%
17	Jackson - Three Mile Island	Line	MEC	$2.9	($0.1)	$0.4	$3.5	$0.1	($0.2)	($0.2)	$0.0	$3.5	1.1%
18	Cedar Creek - Silver Run	Line	DPL	($0.7)	($3.7)	$0.1	$3.1	($0.2)	$0.0	$0.0	($0.3)	$2.9	0.9%
19	Twin Branch - Meridian	Flowgate	MISO	$0.1	($2.3)	$0.5	$2.9	$0.0	$0.0	$0.0	$0.0	$2.9	0.9%
20	Rising - Bondville	Flowgate	MISO	$0.2	($3.5)	$1.4	$5.1	($0.4)	($0.3)	($2.6)	($2.7)	$2.4	0.8%
21	Highland - Commerce	Line	ATSI	($0.3)	($2.6)	$0.0	$2.3	$0.1	$0.1	$0.0	$0.0	$2.4	0.7%
22	Mahans Lane - Tidd	Line	AEP	$1.4	($0.9)	$0.3	$2.6	($0.0)	($0.1)	($0.3)	($0.3)	$2.4	0.7%
23	Lockwood - Richland	Line	AEP	($1.7)	($3.7)	$0.6	$2.6	($0.1)	($0.0)	($0.2)	($0.3)	$2.4	0.7%
24	Dumont - Stillwell	Line	AEP	$0.0	$0.0	$0.0	$0.0	($0.4)	$0.4	($1.6)	($2.4)	($2.4)	(0.7%)
25	Graceton - Safe Harbor	Line	BGE	$2.3	$0.4	$0.5	$2.4	$0.1	($0.2)	($0.3)	($0.1)	$2.3	0.7%
	Top 25 Total			$89.8	($193.6)	$26.0	$309.4	$4.3	$16.6	($27.8)	($40.1)	$269.3	83.9%
	All Other Constraints			$20.4	($54.1)	$14.8	$89.3	($10.1)	$3.6	($23.9)	($37.6)	$51.6	16.1%
	Total			$110.2	($247.8)	$40.7	$398.7	($5.8)	$20.1	($51.8)	($77.7)	$321.0	100.0%

30 All flowgates are mapped to MISO as Location if they are flowgates coordinated by both PJM and MISO regardless of the location of the flowgates.

Figure 11-4 shows the total hourly congestion costs of the top five constraints in the first three months of 2025. The Lenox – North Meshoppen Line was the top constraint.

Figure 11-4 Top five constraints affecting total congestion costs: January through March, 2025

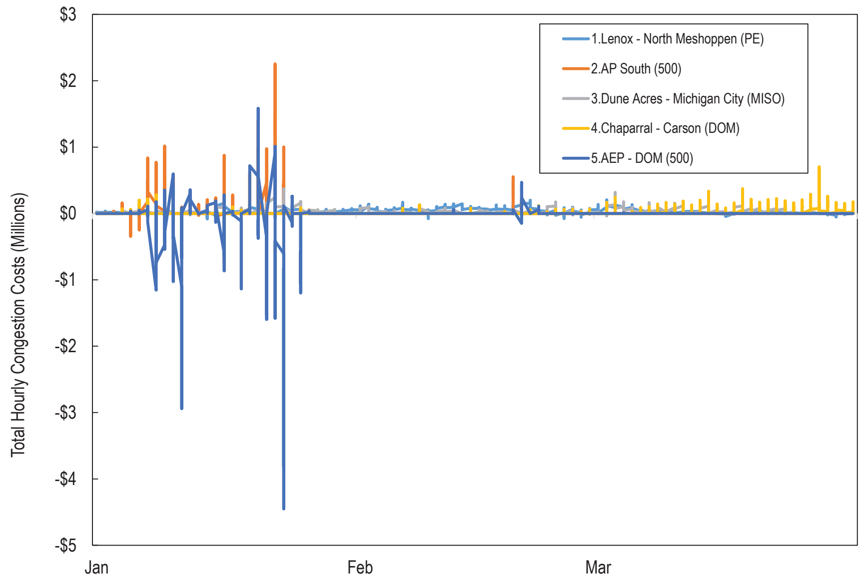


Figure 11-5 shows the total hourly balancing congestion costs of the top five constraints in the first three months of 2025.

Figure 11-5 Top five constraints affecting balancing congestion costs: January through March, 2025

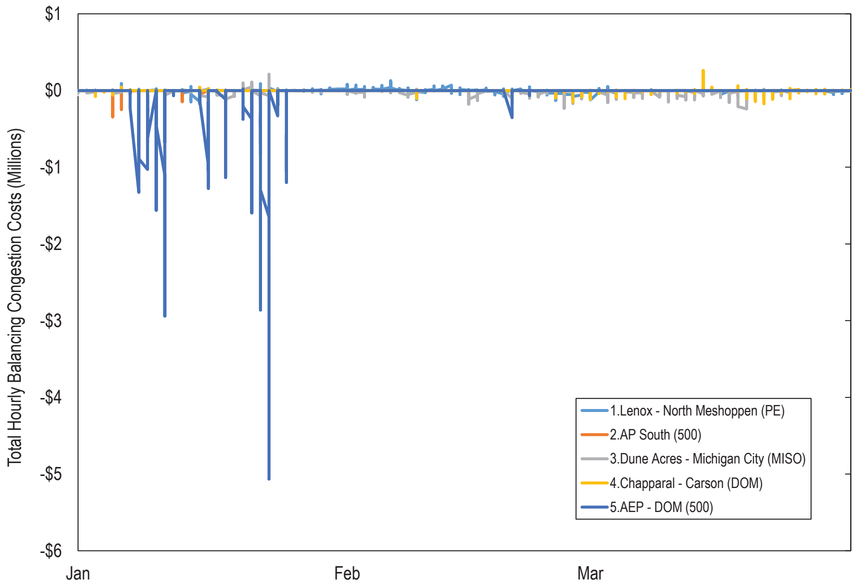


Figure 11-6 shows the total hourly day-ahead congestion costs of the top five constraints in the first three months of 2025.

Figure 11-6 Top five constraints affecting day-ahead congestion costs: January through March, 2025

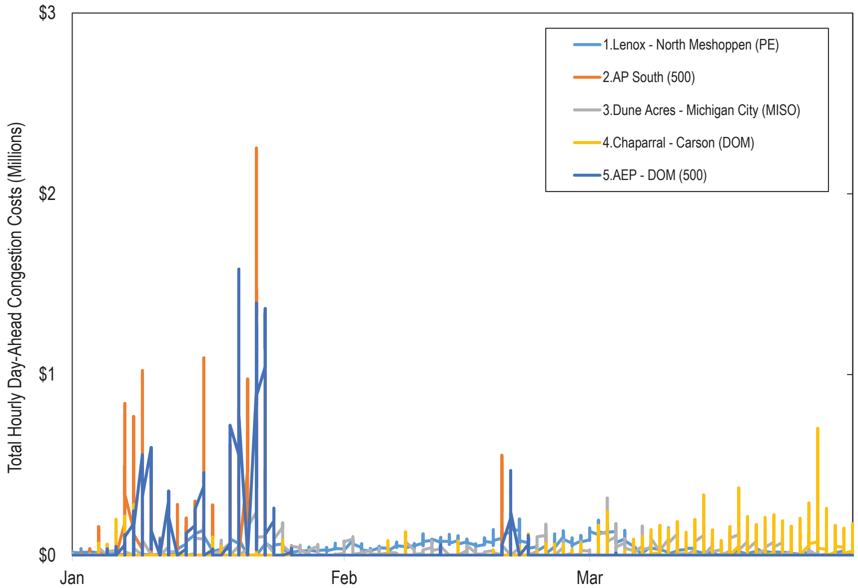


Figure 11-7 shows the locations of the top 10 constraints by total congestion costs on a contour map of the real-time, load-weighted average CLMP in the first three months of 2025.

Figure 11-7 Location of the top 10 constraints by total congestion costs: January through March, 2025

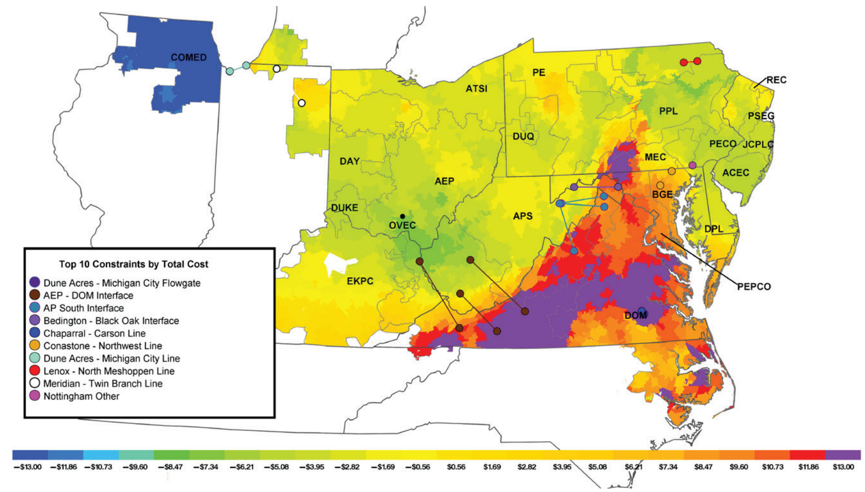


Figure 11-8 shows the locations of the top 10 constraints by balancing congestion costs on a contour map of the real-time load-weighted average CLMP in the first three months of 2025.

Figure 11-8 Location of top 10 constraints by balancing congestion costs: January through March, 2025

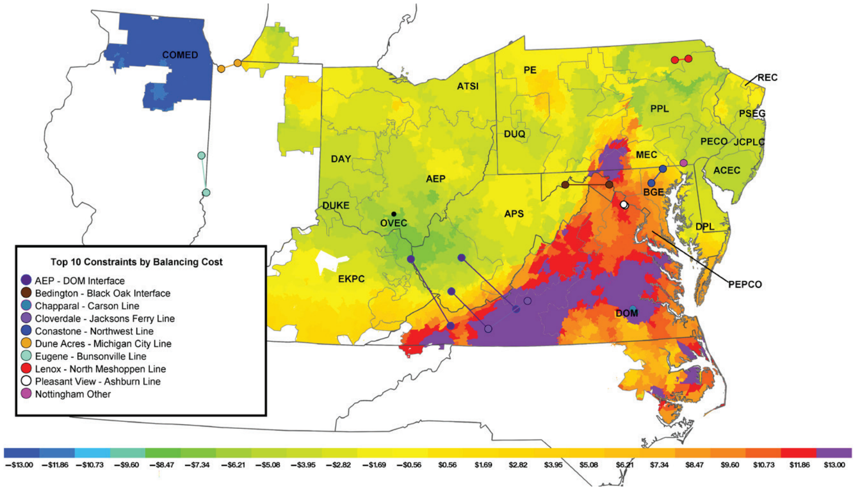
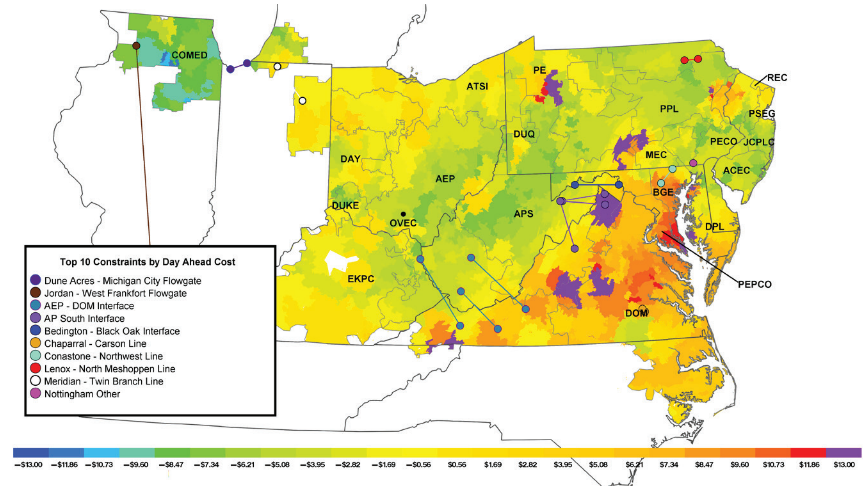


Figure 11-9 shows the locations of the top 10 constraints by day-ahead congestion costs on a contour map of the day-ahead load-weighted average CLMP in the first three months of 2025.

Figure 11-9 Location of top 10 constraints by day-ahead congestion costs: January through March, 2025



Comparing Figure 11-8 (Location of the top 10 constraints by balancing congestion costs) and Figure 11-9 (location of the top 10 constraints by day-ahead congestion costs) shows the significant differences between the day-ahead and real-time markets.

Congestion Event Summary: Impact of Changes in UTC Volumes

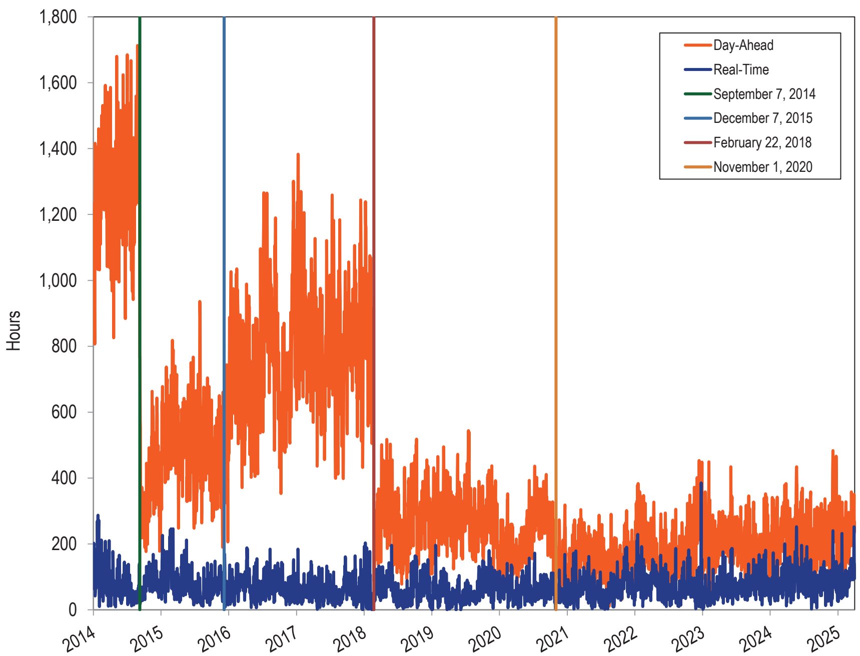
UTCs have a significant impact on congestion events in the day-ahead market and, as a result, contribute to differences between day-ahead and real-time congestion events. The greater the volume of UTCs, the greater the number of congestion events in the day-ahead market and the greater the differences between the day-ahead and real-time congestion events.[31]

31 A series of FERC orders has affected UTC activity which has in turn affected congestion events in the day-ahead market. See Appendix F: Congestion and Marginal Losses.

In the first three months of 2025, the average hourly cleared UTC MW decreased by 18.9 percent, compared to in the first three months of 2024. Day-ahead congestion event hours increased by 7.4 percent from 19,390 congestion event hours in the first three months of 2024 to 20,823 congestion event hours in the first three months of 2025 (Table 11-26).

Figure 11-10 shows the daily day-ahead and real-time congestion event hours for January 2014 through March 2025.

Figure 11-10 Daily congestion event hours: January 2014 through March 2025



Marginal Losses

Marginal Loss Accounting

Marginal losses occur in the day-ahead and real-time energy markets. PJM calculates marginal loss costs for each PJM member. The loss cost is based on the applicable day-ahead and real-time marginal loss component of LMP (MLMP). Losses are the difference between what load (withdrawals) pay for energy and what generation (injections) are paid for energy, due to transmission line losses.

Losses increase with distance between sources and sinks and the amount of power moved. Total loss collected (loss surplus) increases with load, holding distance and resistance constant. Every incremental increase in load has to be met with a slightly larger increment of generation. The result is that the total energy losses increase as load increases.

Ignoring interchange, total generation MWh must be greater than total load MWh in any hour in order to provide for losses. Total marginal loss costs, analogous to total congestion costs, are equal to the net of the withdrawal loss charges minus injection loss credits, plus explicit loss charges, incurred in both the day-ahead energy market and the balancing energy market.

Total marginal loss costs can be more accurately thought of as net marginal loss costs. Total marginal loss costs equal implicit marginal loss charges plus explicit marginal loss charges plus net inadvertent loss charges. Implicit marginal loss charges equal withdrawal loss charges minus injection loss credits. Net explicit marginal loss costs are the net marginal loss costs associated with point to point energy transactions. Net inadvertent loss charges are the losses associated with the hourly difference between the net actual energy flow and the net scheduled energy flow into or out of the PJM control area.[32] Unlike the other categories of marginal loss accounting, inadvertent loss charges are costs not directly attributable to specific participants. Inadvertent loss charges are assigned to participants based on real-time load (excluding losses) ratio share.[33] Each of these categories of marginal loss costs is comprised of day-ahead and balancing marginal loss costs.

32 PJM Operating Agreement Schedule 1 §3.7.
33 *Id.*

The accounting definitions can be misleading. Load pays losses. Losses are the difference between what load pays for energy and what generation is paid for energy due to losses. Generation does not pay losses. Some generation receives a price lower than SMP and some generation receives a price greater than SMP due to the MLMP but that does not mean that generation is paying or being paid losses. It means that generation is being paid an LMP that is higher or lower than the system load-weighted, average LMP due to losses on the system.

While PJM accounting focuses on MLMPs, the individual MLMP values at any bus are irrelevant to the calculation of total losses. Total losses are the net surplus revenue that remains after all sources and sinks are credited or charged their LMPs. Changing the components of LMP by electing a different reference bus does not change the LMPs or the difference between LMPs for a given market solution or losses, it merely changes the components of the LMP.

The MLMP component of LMP is the marginal cost of energy, due to losses associated with serving load at the bus. The MLMP at the load-weighted reference bus is the marginal cost of energy at the load-weighted reference bus (holding the proportion of load at every bus constant). Due to losses, MLMP is non zero at the load reference bus. The LMP at the load reference bus is the system marginal price of energy (SMP) plus the marginal cost of energy due to losses at the reference bus.

Load-weighted LMP components are calculated relative to a load-weighted, average LMP. LMPs at specific load buses will reflect the fact that marginal generators must produce more (or less) energy due to losses to serve that bus than is needed to serve the load weighted reference bus. The LMP at any bus is a function of the SMP, losses and congestion. Relative to the system marginal price (SMP) at the load weighted reference bus, the loss factor can be either positive or negative.

At the load-weighted reference bus, the LMP includes no congestion component, but does include a loss component. The load weighted average MLMP across all load buses, calculated relative to that reference bus is positive. The LMPs at the load buses are a function of marginal generation bus LMPs determined through the least cost security constrained economic dispatch which accounts for transmission constraints and marginal losses.

Other than the effect on the optimal dispatch point, LMP at the marginal generator bus, and therefore the payment to the generator, is not affected by marginal losses. By paying for losses based on marginal instead of average losses at the load bus, a revenue over collection occurs.

The residual difference between total marginal loss related load charges (day-ahead and balancing) and marginal loss related generation credits (day-ahead and balancing) after virtual bids have settled their marginal loss related credits and charges for their day-ahead and balancing positions is total loss. That is, losses are the difference between what withdrawals (load) are paying for energy and what injections (generation) are being paid for energy due to losses, after virtual bids marginal loss related charges and credits are settled at the end of the market day. Load is the source of the net loss surplus after generation is paid and virtuals are settled at the end of the market day. Load pays losses. Generation does not pay losses.

Day-ahead marginal loss costs are based on day-ahead MWh priced at the marginal loss price component of LMP. Balancing marginal loss costs are based on the load or generation deviations between the day-ahead and real-time energy markets priced at the marginal loss price component of LMP in the real-time energy market. If a participant has real-time generation or load that is greater than its day-ahead generation or load then the deviation will be positive. If there is a positive load deviation at a bus where the real-time LMP has a positive marginal loss component, positive balancing marginal loss costs will result. Similarly, if there is a positive load deviation at a bus where real-time LMP has a negative marginal loss component, negative balancing marginal loss costs will result. If a participant has real-time generation or load that is less than its day-ahead generation or load then the deviation will be negative. If there is a negative load deviation at a bus where real-time LMP has a positive marginal loss component, negative balancing marginal loss costs will result. Similarly, if there is a negative load deviation at a bus where real-time LMP has a negative marginal loss component, positive balancing marginal loss costs will result.

The total marginal loss surplus is the remaining loss amount from collection of marginal losses, after accounting for total system energy costs and net residual market adjustments. The marginal loss surplus is allocated to PJM market participants based on real-time load plus export ratio share as marginal loss credits.[34]

Day-Ahead Implicit Load MLMP Charges

- **Day-Ahead Implicit Load MLMP Charges.** Day-ahead implicit load MLMP charges are calculated for all cleared demand, decrement bids and day-ahead energy market sale transactions. Day-ahead implicit load MLMP charges are calculated using MW and the load bus MLMP, the decrement bid MLMP or the MLMP at the source of the sale transaction.
- **Day-Ahead Implicit Generation MLMP Credits.** Day-ahead implicit generation MLMP credits are calculated for all cleared generation and increment offers and day-ahead energy market purchase transactions. Day-ahead implicit generation MLMP credits are calculated using MW and the generator bus MLMP, the increment offer MLMP or the MLMP at the sink of the purchase transaction.
- **Balancing Implicit Load MLMP Charges.** Balancing implicit load MLMP charges are calculated for all deviations between a PJM member's real-time load and energy sale transactions and their day-ahead cleared demand, decrement bids and energy sale transactions. Balancing implicit load MLMP charges are calculated using MW deviations and the real-time MLMP for each bus where a deviation exists.
- **Balancing Implicit Generation MLMP Credits.** Balancing implicit Generation MLMP credits are calculated for all deviations between a PJM member's real-time generation and energy purchase transactions and the day-ahead cleared generation, increment offers and energy purchase transactions. Balancing implicit Generation MLMP credits are calculated using MW deviations and the real-time MLMP for each bus where a deviation exists.
- **Explicit Loss Charges.** Explicit loss charges are the net loss costs associated with point to point energy transactions, including UTCs. These costs equal the product of the transacted MW and MLMP differences between sources (origins) and sinks (destinations) in the day-ahead energy market. Balancing energy market explicit loss costs equal the product of the differences between the real-time and day-ahead transacted MW and the differences between the real-time MLMP at the transactions' sources and sinks.
- **Inadvertent Loss Charges.** Inadvertent loss charges are the net loss charges resulting from the differences between the net actual energy flow and the net scheduled energy flow into or out of the PJM control area each hour. This inadvertent interchange of energy may be positive or negative, where positive interchange typically results in a charge while negative interchange typically results in a credit. Inadvertent loss charges are common costs, not directly attributable to specific participants, which are distributed on a load plus export ratio basis.[35]

Total Marginal Loss Cost

Total marginal loss is the difference between what withdrawals (load) pay for energy and what injections (generation) are paid for energy due to losses, after generation is paid and virtuals' marginal loss related charges and credits are settled. Load pays losses.

The total marginal loss cost in PJM for the first three months of 2025 was $428.9 million, which was comprised of implicit withdrawal MLMP charges of $50.6 million minus implicit injection MLMP credits of -$382.1 million plus explicit loss charges of -$3.9 million plus inadvertent loss charges of $0.0 million (Table 11-37).

Monthly marginal loss costs in the first three months of 2025 ranged from $90.2 million in March to $222.8 million in January. Total marginal loss surplus increased in the first three months of 2025 by $85.9 million or 120.4 percent from $71.4 million in the first three months of 2024 to $157.3 million in the first three months of 2025.

Table 11-36 shows the total marginal loss component costs and the total PJM billing for the first three months, 2008 through 2025.

34 See PJM. "Manual 28: Operating Agreement Accounting," Rev. 98 (December 17, 2024).

35 PJM Operating Agreement Schedule 1 §3.7.

Table 11-36 Total loss component costs (Dollars (Millions)): January through March, 2008 through 2025[36 37]

(Jan - Mar)	Loss Costs	Percent Change	Total PJM Billing	Percent of PJM Billing
2008	$607	NA	$7,718	7.9%
2009	$454	(25.2%)	$7,515	6.0%
2010	$417	(8.2%)	$8,415	5.0%
2011	$410	(1.7%)	$9,584	4.3%
2012	$234	(42.8%)	$6,938	3.4%
2013	$278	18.5%	$7,762	3.6%
2014	$776	179.5%	$21,070	3.7%
2015	$425	(45.2%)	$14,040	3.0%
2016	$170	(60.0%)	$9,500	1.8%
2017	$172	0.9%	$9,710	1.8%
2018	$339	97.9%	$14,520	2.3%
2019	$204	(39.9%)	$11,600	1.8%
2020	$109	(46.8%)	$8,750	1.2%
2021	$210	93.2%	$11,260	1.9%
2022	$393	87.5%	$18,080	2.2%
2023	$201	(48.8%)	$11,890	1.7%
2024	$217	7.8%	$12,350	1.8%
2025	$429	97.7%	$18,680	2.3%

Table 11-37 shows PJM total marginal loss costs by accounting category for January through March, 2008 through 2025. Table 11-38 shows PJM total marginal loss costs by accounting category by market in the first three months of 2008 through 2025.

Table 11-37 Total marginal loss costs by accounting category (Dollars (Millions)): January through March, 2008 through 2025

	Marginal Loss Costs (Millions)				
(Jan - Mar)	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Inadvertent Charges	Total
2008	($52.1)	($634.0)	$25.1	$0.0	$606.9
2009	($21.3)	($460.6)	$14.7	$0.0	$454.0
2010	($3.8)	($414.1)	$6.3	($0.0)	$416.6
2011	($26.5)	($421.2)	$14.9	$0.0	$409.6
2012	($11.2)	($252.1)	($6.6)	$0.0	$234.3
2013	$8.0	($277.8)	($8.2)	($0.0)	$277.6
2014	($15.1)	($813.7)	($22.8)	$0.0	$775.9
2015	($4.0)	($434.0)	($4.9)	$0.0	$425.1
2016	($8.0)	($184.4)	($6.3)	$0.0	$170.1
2017	($13.0)	($196.2)	($11.6)	($0.0)	$171.5
2018	($13.2)	($356.7)	($4.0)	$0.0	$339.4
2019	($13.7)	($220.9)	($3.2)	$0.0	$203.9
2020	($9.8)	($122.1)	($3.8)	($0.0)	$108.5
2021	$2.1	($208.8)	($1.2)	$0.0	$209.7
2022	$85.9	($315.3)	($8.1)	($0.0)	$393.1
2023	$8.1	($196.3)	($3.2)	($0.0)	$201.2
2024	$11.5	($208.1)	($2.6)	$0.0	$217.0
2025	$50.6	($382.1)	($3.9)	($0.0)	$428.9

36 The loss costs include net inadvertent charges.
37 In Table 11-36, the MMU uses Total PJM Billing values provided by PJM. For 2019 and after, the MMU has modified the Total PJM Billing calculation to better reflect historical PJM total billing through the PJM settlement process.

Table 11-38 Total marginal loss costs by market (Dollars (Millions)): January through March, 2008 through 2025

	Marginal Loss Costs (Millions)									
	Day-Ahead				Balancing					
(Jan - Mar)	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Inadvertent Charges	Grand Total
2008	($17.1)	($603.7)	$31.3	$617.9	($35.0)	($30.2)	($6.2)	($11.0)	$0.0	$606.9
2009	($23.3)	($457.6)	$30.9	$465.2	$2.1	($3.0)	($16.3)	($11.2)	$0.0	$454.0
2010	($8.5)	($413.5)	$12.8	$417.8	$4.7	($0.6)	($6.5)	($1.2)	($0.0)	$416.6
2011	($37.1)	($430.1)	$26.0	$419.1	$10.6	$8.9	($11.1)	($9.5)	$0.0	$409.6
2012	($16.7)	($256.8)	$8.0	$248.1	$5.6	$4.7	($14.6)	($13.8)	$0.0	$234.3
2013	($0.1)	($288.2)	$8.1	$296.2	$8.1	$10.4	($16.3)	($18.6)	($0.0)	$277.6
2014	($48.6)	($847.4)	$32.3	$831.1	$33.5	$33.7	($55.1)	($55.3)	$0.0	$775.9
2015	($17.4)	($441.6)	$7.8	$432.0	$13.5	$7.6	($12.8)	($6.9)	$0.0	$425.1
2016	($10.7)	($186.3)	$7.6	$183.3	$2.7	$1.9	($14.0)	($13.2)	$0.0	$170.1
2017	($15.1)	($197.5)	$17.5	$199.9	$2.1	$1.3	($29.1)	($28.3)	($0.0)	$171.5
2018	($15.3)	($352.2)	$10.1	$347.0	$2.1	($4.5)	($14.1)	($7.5)	$0.0	$339.4
2019	($13.8)	($219.3)	$14.5	$219.9	$0.1	($1.6)	($17.7)	($16.1)	$0.0	$203.9
2020	($10.0)	($122.6)	$9.5	$122.0	$0.2	$0.4	($13.2)	($13.4)	($0.0)	$108.5
2021	$2.7	($208.8)	$9.0	$220.5	($0.6)	($0.0)	($10.2)	($10.8)	$0.0	$209.7
2022	$95.3	($314.8)	$15.3	$425.4	($9.4)	($0.5)	($23.4)	($32.3)	($0.0)	$393.1
2023	$10.1	($194.3)	$18.4	$222.8	($2.0)	($2.0)	($21.6)	($21.6)	($0.0)	$201.2
2024	$13.2	($205.9)	$17.2	$236.2	($1.7)	($2.2)	($19.7)	($19.3)	$0.0	$217.0
2025	$54.2	($377.0)	$18.5	$449.7	($3.6)	($5.1)	($22.3)	($20.8)	($0.0)	$428.9

Table 11-39 and Table 11-40 show PJM accounting based total loss costs for each transaction type in the first three months of 2025 and 2024.

Virtual transaction loss costs, when positive, measure the total loss costs to virtual transactions and when negative, measure the total loss credits to virtual transactions. In the first three months of 2025, DECs were paid $0.9 million in MLMP credits in the day-ahead market, paid $2.2 million in MLMP in the balancing energy market and paid $1.3 million in total MLMP charges. In the first three months of 2025, INCs paid $15.1 million in MLMP charges in the day-ahead market, were paid $18.1 million in MLMP credits in the balancing energy market and were paid $3.0 million in total MLMP credits. In the first three months of 2025, up to congestion paid $19.3 million in MLMP charges in the day-ahead market, were paid $21.9 million in MLMP credits in the balancing energy market and received $2.6 million in total MLMP credits.

Table 11-39 Total loss costs by transaction type (Dollars (Millions)): January through March, 2025

	Marginal Loss Costs (Millions)									
	Day-Ahead				Balancing					
Transaction Type	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Inadvertent Charges	Grand Total
DEC	($0.9)	$0.0	$0.0	($0.9)	$2.2	$0.0	$0.0	$2.2	$0.0	$1.3
Demand	$34.1	$0.0	$0.0	$34.1	$4.6	$0.0	$0.0	$4.6	$0.0	$38.7
Demand Response	$0.3	$0.0	$0.0	$0.3	($0.2)	$0.0	$0.0	($0.2)	$0.0	$0.0
Explicit Congestion and Loss Only	$0.0	$0.0	($1.0)	($1.0)	$0.0	$0.0	($0.1)	($0.1)	$0.0	($1.1)
Export	($5.7)	$0.0	($0.1)	($5.8)	($8.2)	$0.0	($0.3)	($8.4)	$0.0	($14.2)
Generation	$0.0	($387.8)	$0.0	$387.8	$0.0	($11.5)	$0.0	$11.5	$0.0	$399.3
Import	$0.0	($0.9)	$0.0	$0.9	$0.0	($9.8)	$0.0	$9.8	$0.0	$10.7
INC	$0.0	($15.1)	$0.0	$15.1	$0.0	$18.1	$0.0	($18.1)	$0.0	($3.0)
Internal Bilateral	$26.5	$26.8	$0.3	($0.0)	($2.0)	($1.9)	$0.0	($0.1)	$0.0	($0.1)
Up to Congestion	$0.0	$0.0	$19.3	$19.3	$0.0	$0.0	($21.9)	($21.9)	$0.0	($2.6)
Wheel In	$0.0	$0.0	($0.1)	($0.1)	$0.0	$0.0	($0.1)	($0.1)	$0.0	($0.2)
Total	$54.2	($377.0)	$18.5	$449.7	($3.6)	($5.1)	($22.3)	($20.8)	$0.0	$428.9

Table 11-40 Total loss costs by transaction type (Dollars (Millions)): January through March, 2024

	Marginal Loss Costs (Millions)									
	Day-Ahead				Balancing					
Transaction Type	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Inadvertent Charges	Grand Total
DEC	($1.7)	$0.0	$0.0	($1.7)	$1.7	$0.0	$0.0	$1.7	$0.0	($0.1)
Demand	$9.5	$0.0	$0.0	$9.5	$1.9	$0.0	$0.0	$1.9	$0.0	$11.5
Demand Response	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	$0.0	($0.0)	$0.0	($0.0)
Explicit Congestion and Loss Only	$0.0	$0.0	($0.5)	($0.5)	$0.0	$0.0	($0.0)	($0.0)	$0.0	($0.5)
Export	($3.2)	$0.0	($0.1)	($3.3)	($3.5)	$0.0	($0.2)	($3.8)	$0.0	($7.1)
Generation	$0.0	($206.3)	$0.0	$206.3	$0.0	($6.1)	$0.0	$6.1	$0.0	$212.4
Import	$0.0	($0.7)	$0.0	$0.7	$0.0	($3.1)	($0.0)	$3.1	$0.0	$3.8
INC	$0.0	($7.7)	$0.0	$7.7	$0.0	$8.8	$0.0	($8.8)	$0.0	($1.1)
Internal Bilateral	$8.7	$8.8	$0.2	($0.0)	($1.8)	($1.8)	$0.0	($0.0)	$0.0	($0.0)
Up to Congestion	$0.0	$0.0	$17.6	$17.6	$0.0	$0.0	($19.4)	($19.4)	$0.0	($1.8)
Wheel In	$0.0	$0.0	($0.0)	($0.0)	$0.0	$0.0	($0.1)	($0.1)	$0.0	($0.1)
Total	$13.2	($205.9)	$17.2	$236.2	($1.7)	($2.2)	($19.7)	($19.3)	$0.0	$217.0

Table 11-41 compares MLMP credits and charges for each transaction type between the dispatch run and pricing run in the first three months of 2025. Total MLMP charges to generation increased by $1.5 million, and total MLMP charges to demand increased by $0.5 million from the dispatch run to the pricing run. The total MLMP charges to DECs increased by $0.1 million, the total MLMP credits to INCs decreased by $1.0 million and the total CLMP credits to UTCs decreased by $1.4 million from the dispatch run to the pricing run.

Table 11-41 Total loss costs by dispatch and pricing run (Dollars (Millions)): January through March, 2025

	Marginal Loss Costs (Millions)								
	Dispatch Run			Pricing Run			Difference		
Transaction Type	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total
DEC	($0.9)	$2.2	$1.2	($0.9)	$2.2	$1.3	$0.0	$0.1	$0.1
Demand	$34.0	$4.2	$38.2	$34.1	$4.6	$38.7	$0.1	$0.3	$0.5
Demand Response	$0.3	($0.2)	$0.0	$0.3	($0.2)	$0.0	$0.0	($0.0)	($0.0)
Explicit Congestion and Loss Only	($1.0)	($0.1)	($1.1)	($1.0)	($0.1)	($1.1)	($0.0)	($0.0)	($0.0)
Export	($5.8)	($8.0)	($13.7)	($5.8)	($8.4)	($14.2)	($0.0)	($0.5)	($0.5)
Generation	$386.9	$10.9	$397.8	$387.8	$11.5	$399.3	$0.9	$0.5	$1.5
Import	$0.9	$9.2	$10.1	$0.9	$9.8	$10.7	$0.0	$0.6	$0.6
INC	$15.0	($17.0)	($2.0)	$15.1	($18.1)	($3.0)	$0.0	($1.1)	($1.0)
Internal Bilateral	($0.0)	($0.1)	($0.1)	$0.0	($0.1)	($0.1)	$0.0	($0.0)	($0.0)
Up to Congestion	$19.3	($20.4)	($1.1)	$19.3	($21.9)	($2.6)	$0.0	($1.5)	($1.4)
Wheel In	($0.1)	($0.1)	($0.2)	($0.1)	($0.1)	($0.2)	($0.0)	($0.0)	($0.0)
Total	$448.6	($19.4)	$429.2	$449.7	($20.8)	$428.9	$1.1	($1.5)	($0.4)

Monthly Marginal Loss Costs

Table 11-42 shows a monthly summary of marginal loss costs by market type for January 2024 through March 2025.

Table 11-42 Monthly marginal loss costs (Millions): January 2024 through March 2025

	Marginal Loss Costs (Millions)							
	2024				2025			
	Day-Ahead	Balancing	Inadvertent Charges	Total	Day-Ahead	Balancing	Inadvertent Charges	Total
Jan	$137.5	($9.5)	$0.0	$128.1	$233.1	($10.4)	($0.0)	$222.8
Feb	$52.0	($4.7)	$0.0	$47.3	$121.0	($5.1)	($0.0)	$115.9
Mar	$46.7	($5.1)	($0.0)	$41.5	$95.6	($5.4)	($0.0)	$90.2
Apr	$48.6	($4.0)	$0.0	$44.6				
May	$72.6	($4.3)	$0.0	$68.2				
Jun	$84.8	($5.0)	$0.0	$79.7				
Jul	$136.4	($6.7)	$0.0	$129.8				
Aug	$103.8	($6.4)	$0.0	$97.4				
Sep	$62.9	($4.4)	$0.0	$58.5				
Oct	$67.1	($4.2)	$0.0	$63.0				
Nov	$59.3	($2.5)	($0.0)	$56.8				
Dec	$106.5	($5.8)	($0.0)	$100.7				
Total	$978.2	($62.6)	$0.0	$915.6	$449.7	($20.8)	($0.0)	$428.9

Figure 11-11 shows PJM monthly marginal loss costs for January 2008 through March 2025.

Figure 11-11 Monthly marginal loss cost (Dollars (Millions)): January 2008 through March 2025

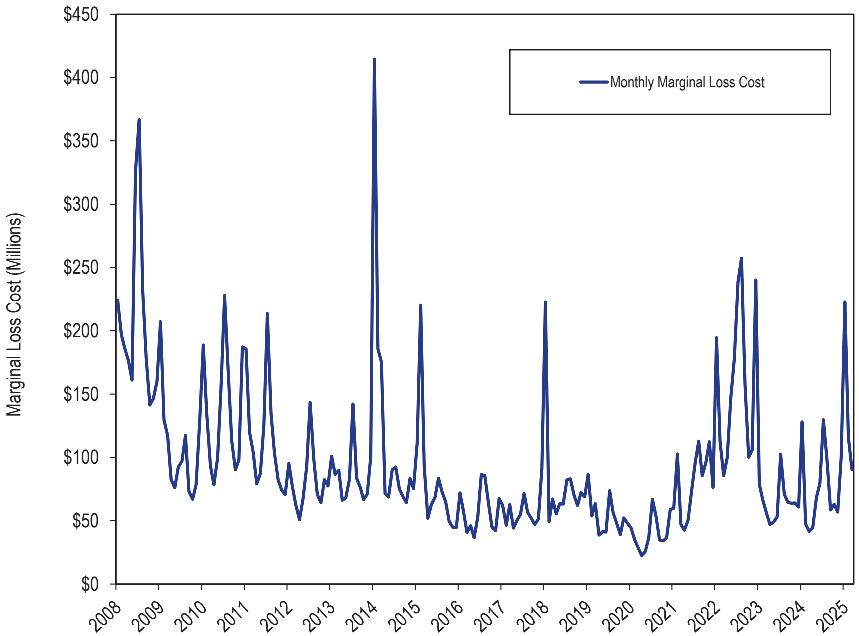


Table 11-43 shows the monthly total loss charges for each virtual transaction type for January 2024 through March 2025. In the first three months of 2025, 60.1 percent of the total credits to virtuals went to UTCs, compared to 61.5 percent in the first three months of 2024.

Table 11-43 Monthly loss charges by virtual transaction type (Dollars (Millions)): January 2024 through March 2025

Marginal Loss Charges (Millions)											
		DEC			INC			Up to Congestion			
Year		Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Grand Total
2024	Jan	($0.5)	$0.5	($0.1)	$3.2	($3.6)	($0.4)	$9.0	($9.5)	($0.5)	($0.9)
	Feb	($0.7)	$0.7	$0.0	$2.0	($2.5)	($0.5)	$4.0	($4.9)	($0.8)	($1.3)
	Mar	($0.5)	$0.5	($0.0)	$2.5	($2.7)	($0.2)	$4.6	($5.1)	($0.5)	($0.7)
	Apr	($0.7)	$0.8	$0.1	$3.8	($3.5)	$0.3	$4.3	($4.2)	$0.2	$0.6
	May	($0.3)	$0.5	$0.2	$4.0	($4.2)	($0.2)	$4.7	($5.1)	($0.3)	($0.4)
	Jun	($0.6)	$1.0	$0.4	$2.5	($2.9)	($0.5)	$4.8	($5.1)	($0.3)	($0.4)
	Jul	$0.2	$0.9	$1.1	$3.1	($3.9)	($0.8)	$5.6	($5.8)	($0.2)	$0.0
	Aug	($0.2)	$0.7	$0.5	$2.3	($2.5)	($0.1)	$4.1	($4.6)	($0.5)	($0.1)
	Sep	($0.7)	$0.6	($0.0)	$1.6	($1.5)	$0.1	$2.9	($3.6)	($0.7)	($0.6)
	Oct	($0.6)	$0.8	$0.2	$3.4	($3.0)	$0.4	$4.0	($4.0)	($0.0)	$0.5
	Nov	($0.7)	$0.6	($0.0)	$2.9	($3.0)	($0.1)	$2.5	($2.8)	($0.3)	($0.4)
	Dec	$0.3	$0.2	$0.5	$4.2	($4.7)	($0.5)	$5.4	($5.5)	($0.0)	($0.1)
	Total	($5.1)	$7.8	$2.7	$35.5	($38.0)	($2.5)	$56.0	($60.1)	($4.1)	($3.9)
2025	Jan	($0.1)	$1.1	$1.0	$6.3	($7.6)	($1.3)	$9.4	($9.9)	($0.5)	($0.8)
	Feb	($0.4)	$0.4	($0.0)	$3.6	($4.8)	($1.1)	$5.5	($7.0)	($1.6)	($2.7)
	Mar	($0.4)	$0.8	$0.3	$5.1	($5.7)	($0.5)	$4.5	($4.9)	($0.5)	($0.7)
	Total	($0.9)	$2.2	$1.3	$15.1	($18.1)	($3.0)	$19.3	($21.9)	($2.6)	($4.3)

Marginal Loss Costs and Loss Credits

Total marginal loss surplus is calculated by adding the total system energy costs (which are negative), the total marginal loss costs (which are positive) and net residual market adjustments (which can be net positive or negative). The total system energy costs are equal to the net implicit energy charges (implicit withdrawal charges minus implicit injection credits) plus net inadvertent energy charges. Total marginal loss costs are equal to the net implicit marginal loss charges (implicit load MLMP charges less implicit generation MLMP credits) plus net explicit loss charges plus net inadvertent loss charges.

Ignoring interchange, total generation MWh must be greater than total load MWh in any hour in order to provide for losses. Since the hourly integrated energy component of LMP is the same for every bus within every hour, the net energy bill is negative (ignoring net interchange), with more injection credits than withdrawal charges in every hour. The greater the level of load the greater the difference between energy charges collected from load (SMP x load MW) and credited to generation (SMP x generation MW). Total system energy costs plus total marginal loss costs plus net residual market adjustments equal marginal loss credits which are distributed to the PJM market participants according to the ratio of their real-time load plus their real-time exports to total PJM real-time load plus real-time exports as marginal loss credits. The net residual market adjustment is calculated as known day-ahead error value minus day-ahead loss MW congestion value and minus balancing loss MW congestion value.

Table 11-44 shows the total system energy costs, the total marginal loss costs collected, the net residual market adjustments and total marginal loss surplus redistributed for January through March, 2008 through 2025. The total marginal loss surplus increased by $85.9 million or 120.4 percent in the first three months of 2025 from the first three months of 2024.

Table 11-44 Marginal loss surplus (Dollars (Millions)): January through March, 2008 through 2025[38]

Marginal Loss Surplus (Millions)						
			Net Residual Market Adjustments			
(Jan - Mar)	System Energy Cost	Marginal Loss Costs	Known Day-Ahead Error	Day-Ahead Loss MW Congestion	Balancing Loss MW Congestion	Total Marginal Loss Surplus
2008	($288.2)	$606.9	$0.0	$0.0	$0.0	$318.7
2009	($218.3)	$454.0	($0.0)	($0.4)	($0.1)	$236.2
2010	($207.6)	$416.6	$0.0	($0.9)	($0.0)	$209.9
2011	($209.9)	$409.6	$0.0	$0.0	($0.0)	$199.7
2012	($136.4)	$234.3	($0.0)	($0.5)	$0.0	$98.3
2013	($177.9)	$277.6	$0.1	$0.3	$0.0	$99.4
2014	($515.3)	$775.9	$0.0	$3.1	$0.2	$257.2
2015	($271.7)	$425.1	($0.5)	$2.9	($0.0)	$150.0
2016	($113.6)	$170.1	$0.0	$0.8	($0.0)	$55.7
2017	($122.1)	$171.5	$0.0	$0.2	($0.0)	$49.2
2018	($226.6)	$339.4	($0.0)	$1.2	($0.0)	$111.6
2019	($136.3)	$203.9	$0.0	$0.7	($0.0)	$66.9
2020	($75.3)	$108.5	($0.0)	($0.0)	($0.0)	$33.2
2021	($131.5)	$209.7	($0.0)	$1.0	($0.0)	$77.2
2022	($260.8)	$393.1	($0.0)	$3.8	($0.0)	$128.5
2023	($135.6)	$201.2	$0.0	($0.0)	($0.0)	$65.7
2024	($145.6)	$217.0	$0.0	$0.1	($0.1)	$71.4
2025	($270.9)	$428.9	($0.0)	$0.7	$0.0	$157.3

38 The net residual market adjustments included in the table are comprised of the known day-ahead error value minus the sum of the day-ahead loss MW congestion value, balancing loss MW congestion value and measurement error caused by missing data.

System Energy Costs

Energy Accounting

The system energy component of LMP is the system reference bus LMP, also called the system marginal price (SMP). The system energy cost is based on the day-ahead and real-time energy components of LMP. Total system energy costs, analogous to total congestion costs or total loss costs, are equal to the withdrawal energy charges minus injection energy credits, in both the day-ahead energy market and the balancing energy market, plus net inadvertent energy charges. Total system energy costs can be more accurately thought of as net system energy costs. Due to line losses associated with moving energy from generation to load, more energy is injected by generation than is withdrawn by load. Total system energy charges are negative because there are, due to losses, more generation MW being paid SMP (energy component of price) than load MW paying SMP (the energy component of price).

Total System Energy Costs

The total system energy cost for the first three months of 2025 was -$270.9 million, which was comprised of implicit withdrawal energy charges of $16,405.9 million, implicit injection energy credits of $16,674.4 million, explicit energy charges of $0.0 million and inadvertent energy charges of -$2.4 million. The monthly system energy costs for the first three months of 2025 ranged from -$137.8 million in January to -$56.9 million in March. Table 11-45 shows total system energy costs and total PJM billing, for January through March, 2008 through 2025.

Table 11-45 Total system energy costs (Dollars (Millions)): January through March, 2008 through 2025[39 40]

(Jan - Mar)	System Energy Costs	Percent Change	Total PJM Billing	Percent of PJM Billing
2008	($288)	NA	$7,718	(3.7%)
2009	($218)	(24.2%)	$7,515	(2.9%)
2010	($208)	(4.9%)	$8,415	(2.5%)
2011	($210)	1.1%	$9,584	(2.2%)
2012	($136)	(35.0%)	$6,938	(2.0%)
2013	($178)	30.4%	$7,762	(2.3%)
2014	($515)	189.7%	$21,070	(2.4%)
2015	($272)	(47.3%)	$14,040	(1.9%)
2016	($114)	(58.2%)	$9,500	(1.2%)
2017	($122)	7.5%	$9,710	(1.3%)
2018	($227)	85.6%	$14,520	(1.6%)
2019	($136)	(39.8%)	$11,600	(1.2%)
2020	($75)	(44.8%)	$8,750	(0.9%)
2021	($132)	74.6%	$11,260	(1.2%)
2022	($261)	98.3%	$18,080	(1.4%)
2023	($136)	(48.0%)	$11,890	(1.1%)
2024	($146)	7.4%	$12,350	(1.2%)
2025	($271)	86.1%	$18,680	(1.5%)

System energy costs for January through March, 2008 through 2025 are shown in Table 11-46 and Table 11-47. Table 11-46 shows PJM system energy costs by accounting category and Table 11-47 shows PJM system energy costs by market category.

Table 11-46 Total system energy costs by accounting category (Dollars (Millions)): January through March, 2008 through 2025

	System Energy Costs (Millions)				
(Jan - Mar)	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Inadvertent Charges	Total
2008	$28,435.7	$28,723.9	$0.0	$0.0	($288.2)
2009	$14,058.4	$14,277.4	$0.0	$0.7	($218.3)
2010	$13,424.4	$13,629.0	$0.0	($3.0)	($207.6)
2011	$11,943.9	$12,160.7	$0.0	$6.9	($209.9)
2012	$8,485.4	$8,628.7	$0.0	$6.8	($136.4)
2013	$10,357.2	$10,535.1	$0.0	($0.0)	($177.9)
2014	$28,506.2	$29,014.7	$0.0	($6.9)	($515.3)
2015	$15,702.1	$15,976.4	$0.0	$2.6	($271.7)
2016	$7,764.7	$7,879.3	$0.0	$1.0	($113.6)
2017	$8,789.3	$8,910.2	$0.0	($1.3)	($122.1)
2018	$13,910.8	$14,142.2	$0.0	$4.7	($226.6)
2019	$8,856.0	$8,993.5	$0.0	$1.2	($136.3)
2020	$5,541.1	$5,616.0	$0.0	($0.4)	($75.3)
2021	$8,663.3	$8,795.5	$0.0	$0.6	($131.5)
2022	$15,137.8	$15,398.2	$0.0	($0.4)	($260.8)
2023	$8,785.6	$8,920.1	$0.0	($1.1)	($135.6)
2024	$9,545.8	$9,692.0	$0.0	$0.6	($145.6)
2025	$16,405.9	$16,674.4	$0.0	($2.4)	($270.9)

39 The system energy costs include net inadvertent charges.
40 In Table 11-45, the MMU uses Total PJM Billing values provided by PJM. For 2019 and after, the MMU has modified the Total PJM Billing calculation to better reflect historical PJM total billing through the PJM settlement process.

Table 11-47 Total system energy costs by market (Dollars (Millions)): January through March, 2008 through 2025

(Jan - Mar)	Day-Ahead Implicit Withdrawal Charges	Day-Ahead Implicit Injection Credits	Day-Ahead Explicit Charges	Day-Ahead Total	Balancing Implicit Withdrawal Charges	Balancing Implicit Injection Credits	Balancing Explicit Charges	Balancing Total	Inadvertent Charges	Grand Total
2008	$20,253.8	$20,579.6	$0.0	($325.8)	$8,182.0	$8,144.3	$0.0	$37.6	$0.0	($288.2)
2009	$14,129.6	$14,375.6	$0.0	($246.0)	($71.2)	($98.2)	$0.0	$27.0	$0.7	($218.3)
2010	$13,408.9	$13,619.2	$0.0	($210.2)	$15.5	$9.8	$0.0	$5.6	($3.0)	($207.6)
2011	$12,055.5	$12,259.3	$0.0	($203.9)	($111.6)	($98.6)	$0.0	($12.9)	$6.9	($209.9)
2012	$8,534.4	$8,649.0	$0.0	($114.6)	($49.0)	($20.4)	$0.0	($28.6)	$6.8	($136.4)
2013	$10,387.2	$10,580.9	$0.0	($193.7)	($29.9)	($45.8)	$0.0	$15.9	($0.0)	($177.9)
2014	$28,412.1	$29,082.9	$0.0	($670.9)	$94.2	($68.3)	$0.0	$162.4	($6.9)	($515.3)
2015	$15,764.8	$16,077.5	$0.0	($312.6)	($62.7)	($101.1)	$0.0	$38.4	$2.6	($271.7)
2016	$7,847.5	$7,997.9	$0.0	($150.4)	($82.8)	($118.6)	$0.0	$35.8	$1.0	($113.6)
2017	$8,927.5	$9,111.3	$0.0	($183.8)	($138.1)	($201.1)	$0.0	$63.0	($1.3)	($122.1)
2018	$13,877.2	$14,123.7	$0.0	($246.5)	$33.6	$18.5	$0.0	$15.1	$4.7	($226.6)
2019	$8,965.4	$9,131.8	$0.0	($166.4)	($109.4)	($138.4)	$0.0	$28.9	$1.2	($136.3)
2020	$5,612.2	$5,708.5	$0.0	($96.3)	($71.1)	($92.5)	$0.0	$21.4	($0.4)	($75.3)
2021	$8,749.4	$8,901.4	$0.0	($152.0)	($86.0)	($105.9)	$0.0	$19.8	$0.6	($131.5)
2022	$15,372.2	$15,651.2	$0.0	($279.1)	($234.4)	($253.0)	$0.0	$18.7	($0.4)	($260.8)
2023	$8,872.5	$9,054.2	$0.0	($181.7)	($86.9)	($134.1)	$0.0	$47.2	($1.1)	($135.6)
2024	$9,647.5	$9,823.1	$0.0	($175.6)	($101.7)	($131.1)	$0.0	$29.5	$0.6	($145.6)
2025	$16,160.2	$16,467.6	$0.0	($307.5)	$245.7	$206.7	$0.0	$39.0	($2.4)	($270.9)

Table 11-48 and Table 11-49 show the total system energy costs for each transaction type in the first three months of 2025 and 2024. In the first three months of 2025, generation was paid $11,850.0 million and demand paid $11,099.4 million in net energy payment. In the first three months of 2024, generation was paid $6,801.0 million and demand paid $6,339.9 million in net energy payment.

Table 11-48 Total system energy costs by transaction type (Dollars (Millions)): January through March, 2025

Transaction Type	Day-Ahead Implicit Withdrawal Charges	Day-Ahead Implicit Injection Credits	Day-Ahead Explicit Charges	Day-Ahead Total	Balancing Implicit Withdrawal Charges	Balancing Implicit Injection Credits	Balancing Explicit Charges	Balancing Total	Grand Total
DEC	$559.0	$0.0	$0.0	$559.0	($561.2)	$0.0	$0.0	($561.2)	($2.3)
Demand	$10,900.3	$0.0	$0.0	$10,900.3	$199.1	$0.0	$0.0	$199.1	$11,099.4
Demand Response	($14.0)	$0.0	$0.0	($14.0)	$12.6	$0.0	$0.0	$12.6	($1.4)
Export	$517.0	$0.0	$0.0	$517.0	$219.1	$0.0	$0.0	$219.1	$736.2
Generation	$0.0	$11,602.5	$0.0	($11,602.5)	$0.0	$247.5	$0.0	($247.5)	($11,850.0)
Import	$0.0	$24.1	$0.0	($24.1)	$0.0	$225.4	$0.0	($225.4)	($249.5)
INC	$0.0	$643.2	$0.0	($643.2)	$0.0	($642.3)	$0.0	$642.3	($0.9)
Internal Bilateral	$4,196.5	$4,196.5	$0.0	($0.0)	$368.8	$368.8	$0.0	$0.0	$0.0
Wheel In	$0.0	$1.4	$0.0	($1.4)	$0.0	$7.4	$0.0	($7.4)	($8.7)
Wheel Out	$1.4	$0.0	$0.0	$1.4	$7.4	$0.0	$0.0	$7.4	$8.7
Total	$16,160.2	$16,467.6	$0.0	($307.5)	$245.7	$206.7	$0.0	$39.0	($268.5)

Table 11-49 Total system energy costs by transaction type by (Dollars (Millions)): January through March, 2024

	System Energy Costs (Millions)								
	Day-Ahead				Balancing				
Transaction Type	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Grand Total
DEC	$368.0	$0.0	$0.0	$368.0	($357.0)	$0.0	$0.0	($357.0)	$11.0
Demand	$6,262.8	$0.0	$0.0	$6,262.8	$77.1	$0.0	$0.0	$77.1	$6,339.9
Demand Response	($2.7)	$0.0	$0.0	($2.7)	$2.0	$0.0	$0.0	$2.0	($0.7)
Export	$296.3	$0.0	$0.0	$296.3	$133.6	$0.0	$0.0	$133.6	$429.9
Generation	$0.0	$6,742.8	$0.0	($6,742.8)	$0.0	$58.2	$0.0	($58.2)	($6,801.0)
Import	$0.0	$20.2	$0.0	($20.2)	$0.0	$97.1	$0.0	($97.1)	($117.3)
INC	$0.0	$337.1	$0.0	($337.1)	$0.0	($329.1)	$0.0	$329.1	($8.0)
Internal Bilateral	$2,721.1	$2,721.1	$0.0	($0.0)	$33.2	$33.2	$0.0	$0.0	$0.0
Wheel In	$0.0	$1.9	$0.0	($1.9)	$0.0	$9.5	$0.0	($9.5)	($11.4)
Wheel Out	$1.9	$0.0	$0.0	$1.9	$9.5	$0.0	$0.0	$9.5	$11.4
Total	$9,647.5	$9,823.1	$0.0	($175.6)	($101.7)	($131.1)	$0.0	$29.5	($146.2)

Table 11-50 compares the total system energy costs for each transaction type between the dispatch run and the pricing run in the first three months of 2025. The system energy charges to demand increased $39.0 million, and the energy credits to generation decreased $41.2 million from the dispatch run to the pricing run. The energy charges to DEC decreased $36.1 million, the energy credits to INC increased $39.0 million from the dispatch run to the pricing run.

Table 11-50 Total system energy costs by dispatch and pricing run (Dollars (Millions)): January through March, 2025

	System Energy Costs (Millions)								
	Dispatch Run			Pricing Run			Difference		
Transaction Type	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total
DEC	$557.9	($524.0)	$33.9	$559.0	($561.2)	($2.3)	$1.1	($37.2)	($36.1)
Demand	$10,875.1	$185.3	$11,060.5	$10,900.3	$199.1	$11,099.4	$25.2	$13.7	$39.0
Demand Response	($14.0)	$11.7	($2.3)	($14.0)	$12.6	($1.4)	($0.0)	$0.9	$0.9
Export	$515.9	$206.9	$722.8	$517.0	$219.1	$736.2	$1.2	$12.2	$13.4
Generation	($11,575.6)	($233.2)	($11,808.8)	($11,602.5)	($247.5)	($11,850.0)	($26.9)	($14.4)	($41.2)
Import	($24.1)	($211.2)	($235.2)	($24.1)	($225.4)	($249.5)	($0.0)	($14.2)	($14.3)
INC	($641.9)	$602.1	($39.8)	($643.2)	$642.3	($0.9)	($1.3)	$40.2	$39.0
Internal Bilateral	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Wheel In	($1.4)	($6.9)	($8.2)	($1.4)	($7.4)	($8.7)	($0.0)	($0.5)	($0.5)
Wheel Out	$1.4	$6.9	$8.2	$1.4	$7.4	$8.7	$0.0	$0.5	$0.5
Total	($306.8)	$37.7	($269.1)	($307.5)	$39.0	($268.5)	($0.7)	$1.3	$0.6

Monthly System Energy Costs

Table 11-51 shows a monthly summary of system energy costs by market type for January 2024 through March 2025. Total balancing system energy costs in the first three months of 2025 increased in every month compared to the first three months of 2024. Monthly total system energy costs in the first three months of 2025 ranged from -$137.8 million in January to -$56.9 million in March.

Table 11-51 Monthly system energy costs (Dollars (Millions)): January 2024 through March 2025

System Energy Costs (Millions)								
	2024				2025			
	Day-Ahead	Balancing	Inadvertent Charges	Total	Day-Ahead	Balancing	Inadvertent Charges	Total
Jan	($99.5)	$12.5	$0.7	($86.3)	($153.9)	$16.7	($0.6)	($137.8)
Feb	($39.3)	$7.7	$0.0	($31.7)	($85.3)	$9.8	($0.8)	($76.2)
Mar	($36.8)	$9.3	($0.1)	($27.6)	($68.3)	$12.4	($1.0)	($56.9)
Apr	($36.3)	$7.2	$0.3	($28.8)				
May	($51.6)	$9.0	$1.0	($41.6)				
Jun	($58.1)	$7.2	$2.0	($49.0)				
Jul	($88.1)	$9.9	$3.3	($74.9)				
Aug	($68.7)	$9.6	$1.5	($57.6)				
Sep	($44.4)	$6.3	$0.7	($37.4)				
Oct	($47.2)	$7.5	$0.3	($39.4)				
Nov	($42.5)	$5.5	($0.1)	($37.1)				
Dec	($73.3)	$10.9	($0.4)	($62.9)				
Total	($685.9)	$102.6	$9.2	($574.1)	($307.5)	$39.0	($2.4)	($270.9)

Figure 11-12 shows PJM monthly system energy costs for January 2008 through March 2025. Ignoring interchange, total generation MWh must be greater than total load MWh in any hour in order to provide for losses. Since the hourly integrated energy component of LMP (SMP) is the same for every bus in the market in every hour, the net energy bill is always negative (ignoring net interchange): (SMP x withdrawals + SMP x injections) < 0. Assuming power balance is maintained in the presence of losses, the greater the level of load the greater the difference between energy charges collected from load (SMP x load MW) and credited to generation (SMP x generation MW). With higher load levels, there are generally higher SMPs and more negative total energy charges.

Figure 11-12 Monthly system energy costs (Millions): January 2008 through March 2025

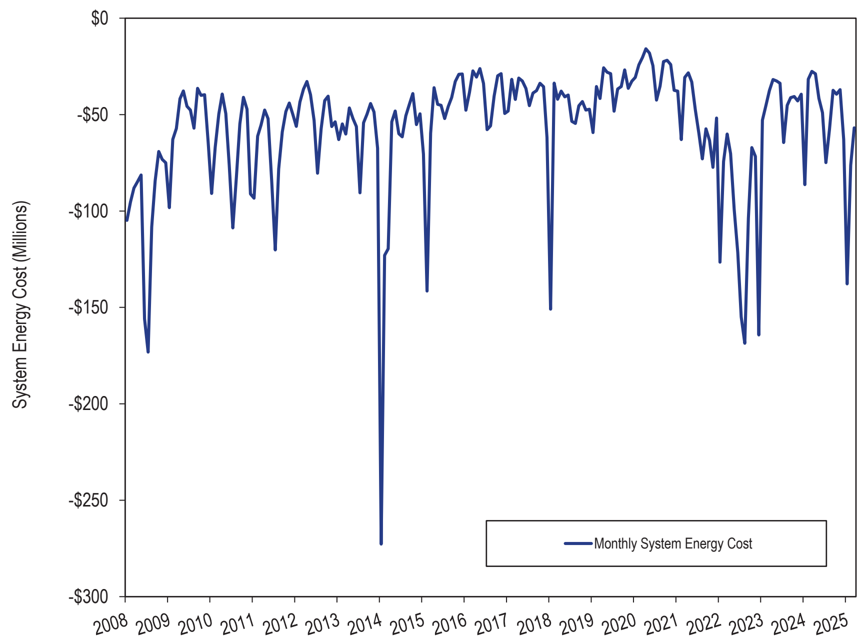


Table 11-52 shows the monthly total system energy costs for each virtual transaction type in the first three months of 2025 and 2024. In the first three months of 2025, DECs paid $559.0 million in energy charges compared to $368.0 million in the first three months of 2024 in the day-ahead market, were paid $561.2 million in energy credits compared to $357.0 million in the first three months of 2024 in the balancing energy market and paid $2.3 million in total energy charges compared to $11.0 million in total energy credits in the first three months of 2024. In the first three months of 2025, INCs were paid $643.2 million in energy credits compared to $337.1 million in the first three months of 2024 in the day-ahead market, paid $642.3 million in energy charges compared to $329.1 million in the first three months of 2024 in the balancing market and were paid $0.9 million in total energy credits compared to $8.0 million in total energy charges in the first three months of

2024. The system energy costs are zero for UTCs because the system energy costs for UTCs equal the difference in the energy component between source and sink and the energy component is the same at all buses.

Table 11-52 Monthly energy charges by virtual transaction type (Dollars (Millions)): January 2024 through March 2025

		Energy Charges (Millions)						
		DEC			INC			
Year		Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Grand Total
2024	Jan	$185.4	($164.2)	$21.2	($151.0)	$135.1	($15.9)	$5.3
	Feb	$85.7	($90.4)	($4.7)	($90.6)	$94.5	$3.9	($0.9)
	Mar	$96.9	($102.4)	($5.5)	($95.4)	$99.5	$4.0	($1.4)
	Apr	$100.5	($101.1)	($0.6)	($110.1)	$110.9	$0.8	$0.2
	May	$131.5	($144.1)	($12.6)	($136.9)	$151.1	$14.2	$1.7
	Jun	$132.9	($135.7)	($2.8)	($104.8)	$107.1	$2.3	($0.4)
	Jul	$182.2	($197.0)	($14.9)	($133.9)	$145.2	$11.3	($3.6)
	Aug	$176.2	($179.7)	($3.5)	($102.0)	$102.9	$0.9	($2.6)
	Sep	$130.7	($133.6)	($2.9)	($80.3)	$82.9	$2.6	($0.3)
	Oct	$115.9	($111.0)	$4.9	($124.2)	$118.0	($6.2)	($1.3)
	Nov	$102.4	($95.9)	$6.5	($112.2)	$105.7	($6.5)	($0.0)
	Dec	$166.0	($154.8)	$11.2	($152.4)	$145.6	($6.8)	$4.4
	Total	$1,606.3	($1,609.9)	($3.6)	($1,393.9)	$1,398.5	$4.7	$1.1
2025	Jan	$232.3	($228.2)	$4.1	($269.2)	$261.9	($7.3)	($3.2)
	Feb	$167.5	($168.2)	($0.7)	($192.3)	$191.8	($0.5)	($1.2)
	Mar	$159.2	($164.8)	($5.6)	($181.7)	$188.6	$6.9	$1.3
	Total	$559.0	($561.2)	($2.3)	($643.2)	$642.3	($0.9)	($3.1)