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 *2023 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 2024 were calculated as of October 10, 2024, 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 $625.4 million or 82.2 percent, from $760.4 million in the first nine months of 2023 to $1,385.8 million in the first nine months of 2024.
- **Day-Ahead Congestion.** Day-ahead congestion costs increased by $641.2 million or 65.6 percent, from $977.3 million in the first nine months of 2023 to $1,618.5 million in the first nine months of 2024.
- **Balancing Congestion.** Negative balancing congestion costs increased by $15.8 million, from -$216.9 million in the first nine months of 2023 to -$232.7 million in the first nine months of 2024. Negative balancing explicit charges decreased by $18.9 million, from $166.9 million in the first nine months of 2023 to $148.0 million in the first nine months of 2024.
- **Real-Time Congestion.** Real-time congestion costs increased by $682.2 million, from $977.1 million in the first nine months of 2023 to $1,659.3 million in the first nine months of 2024.

- **Monthly Congestion.** Monthly total congestion costs in the first nine months of 2024 ranged from $53.2 million in February to $330.5 million in July.
- **Geographic Differences in CLMP.** Differences in CLMP between southern and eastern control zones in PJM were primarily a result of binding constraints on the Nottingham Series Reactor, the Yorkana Circuit Breaker, the Lenox – North Meshoppen Line, the AP South Interface, and the Conastone Transformer.
- **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 nine months of 2024. 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 2.1 percent from 56,273 congestion event hours in the first nine months of 2023 to 57,459 congestion event hours in the first nine months of 2024.

  Real-time congestion frequency increased by 33.2 percent from 15,582 congestion event hours in the first nine months of 2023 to 20,748 congestion event hours in the first nine months of 2024.
- **Congested Facilities.** Day-ahead, congestion event hours decreased on flowgates and increased on interfaces, lines and transformers.

  The Nottingham Series Reactor was the largest contributor to congestion costs in the first nine months of 2024. With $93.1 million in total congestion costs, it accounted for 6.7 percent of the total PJM congestion costs in the first nine months of 2024.
- **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 nine months of 2023 or 2024.
- **Zonal Congestion.** AEP had the highest zonal congestion costs among all control zones in the first nine months of 2024. AEP had $220.5 million in zonal congestion costs, comprised of $255.9 million in day-ahead congestion costs and -$35.4 million in balancing congestion costs.

Marginal Loss Cost

- **Total Marginal Loss Costs.** Total marginal loss costs increased by $106.7 million or 18.1 percent, from $588.5 million in the first nine months of 2023 to $695.2 million in the first nine months of 2024. The loss MWh in PJM increased by 683.5 GWh or 6.0 percent, from 11,383.1 GWh in the first nine months of 2023 to 12,066.6 GWh in the first nine months of 2024. The loss component of real-time LMP in the first nine months of 2024 was $0.03, compared to $0.02 in the first nine months of 2023.
- **Day-Ahead Marginal Loss Costs.** Day-ahead marginal loss costs increased by $98.4 million or 15.2 percent, from $646.9 million in the first nine months of 2023 to $745.3 million in the first nine months of 2024.
- **Balancing Marginal Loss Costs.** Negative balancing marginal loss costs decreased by $8.3 million or 14.2 percent, from -$58.4 million in the first nine months of 2023 to -$50.1 million in the first nine months of 2024.
- **Total Marginal Loss Surplus.** The total marginal loss surplus decreased by $55.7 million or 11.4 percent, from $202.7 million in the first nine months of 2023, to $258.5 million in the first nine months of 2024.
- **Monthly Total Marginal Loss Costs.** Monthly total marginal loss costs in the first nine months of 2024 ranged from $41.5 million in March to $129.8 million in July.

System Energy Cost

- **Total System Energy Costs.** Total system energy costs decreased by $50.2 million or 13.1 percent, from -$384.6 million in the first nine months of 2023 to -$434.8 million in the first nine months of 2024.
- **Day-Ahead System Energy Costs.** Day-ahead system energy costs decreased by $9.0 million or 1.8 percent, from -$513.9 million in the first nine months of 2023 to -$522.9 million in the first nine months of 2024.

- **Balancing System Energy Costs.** Balancing system energy costs decreased by $47.5 million or 37.6 percent, from $126.1 million in the first nine months of 2023 to $78.7 million in the first nine months of 2024.
- **Monthly Total System Energy Costs.** Monthly total system energy costs in the first nine months of 2024 ranged from -$86.3 million in January to -$27.6 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 $625.4 million or 82.2 percent, from $760.4 million in the first nine months of 2023 to $1,385.8 million in the first nine months of 2024.

Monthly total congestion costs ranged from $53.2 million in February to $330.5 million in July in the first nine months of 2024.

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 four months of the 2024/2025 planning period was 55.1 percent. The cumulative offset of congestion by ARRs for the 2011/2012 planning period through the first four months of the 2024/2025 planning period, using the rules effective for each planning period, was 69.9 percent. Load has received $4.4 billion less than load should have received from the 2011/2012 planning period through the first four 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 (.9999) and small uniform dfax on the unconstrained side (.00095 to .00098). 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 by constrained and unconstrained hours. A constrained hour is any hour during which one or more facilities are congested.

Table 11-1 Real-time load-weighted average LMP by constrained and unconstrained hours (Dollars per MWh): January 2023 through September 2024

	2023		2024	
	Constrained Hours	Unconstrained Hours	Constrained Hours	Unconstrained Hours
Jan	$37.40	$31.27	$43.09	$32.14
Feb	$26.93	$22.03	$24.92	$20.34
Mar	$28.42	$28.44	$23.10	$24.20
Apr	$29.45	$25.92	$27.27	$25.54
May	$28.66	$23.00	$36.74	$18.92
Jun	$27.45	$22.45	$33.68	$15.68
Jul	$37.54	$27.31	$47.67	$18.96
Aug	$31.50	$21.66	$35.65	$17.81
Sep	$31.87	$10.09	$33.09	$15.18
Oct	$34.79	$14.66		
Nov	$33.21	$28.03		
Dec	$28.15	$17.41		
Avg	$31.39	$26.56	$34.62	$20.83

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.

Table 11-2 shows the monthly comparison of real-time constrained and unconstrained hours in 2023 and the first nine months of 2024. A constrained hour is any hour during which one or more facilities are congested. There are more constrained hours in the first nine months of 2024 than in the first nine months of 2023.

Table 11-2 Real-time constrained and unconstrained hours by month: January 2023 through September 2024

	2023		2024		Difference	
	Constrained Hours	Unconstrained Hours	Constrained Hours	Unconstrained Hours	Constrained Hours	Unconstrained Hours
Jan	534	210	721	23	187	(187)
Feb	543	129	686	10	143	(119)
Mar	690	54	701	43	11	(11)
Apr	690	30	660	60	(30)	30
May	664	80	708	36	44	(44)
Jun	670	50	704	16	34	(34)
Jul	717	27	707	37	(10)	10
Aug	729	15	669	75	(60)	60
Sep	703	17	652	68	(51)	51
Oct	739	5				
Nov	680	40				
Dec	730	14				
Total	8,089	671	6,208	368	268	(244)

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.[9] 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

9 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.

net actual energy flow and the net scheduled energy flow into or out of the PJM control area each hour.

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.[10] 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.

10 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.[11]

11 PJM Operating Agreement Schedule 1 §3.7.

The congestion accounting calculation equations are in Table 11-3.

Table 11-3 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.

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.

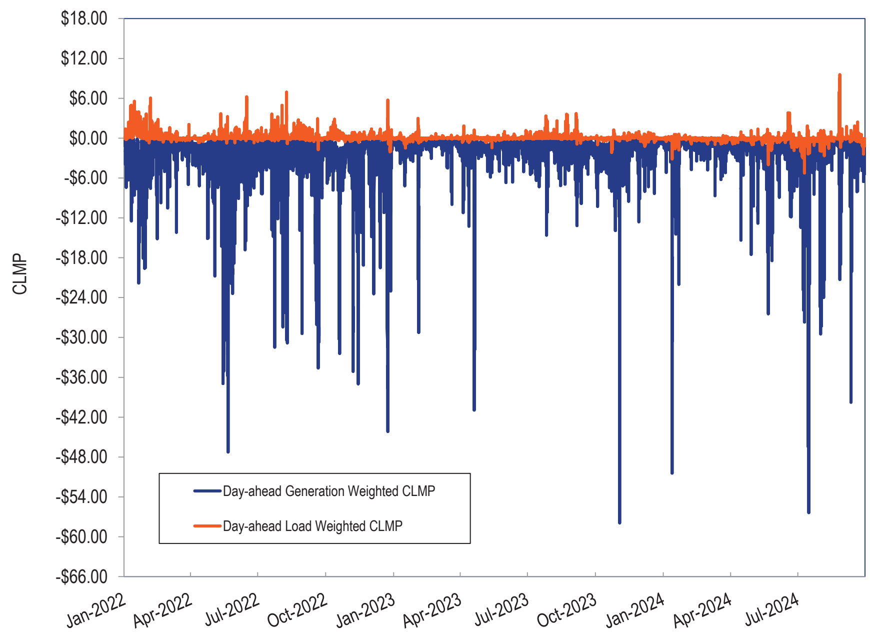
The congestion accounting definitions are misleading. Load pays congestion. Congestion is the difference between what load pays for energy and what generation is paid for energy due to binding transmission constraints. Generation does not pay congestion. Some generation receives a price lower than SMP 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.[12]

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 load in the day-ahead market. Figure 11-1 shows that from January 2022 to September 2024, 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 11-6 and Table 11-7). 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.

12 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>.

Figure 11-1 Day-ahead generation weighted CLMPs and day-ahead load-weighted CLMPs: January 2022 through September 2024



Total Congestion

Total congestion costs in PJM in the first nine months of 2024 were $1,385.8 million, comprised of implicit withdrawal charges of $529.1 million, minus implicit injection credits of -$886.4 million, and plus explicit charges of -$29.7 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 11-4 shows total congestion for the first nine months of 2008 through 2024. Total congestion costs in Table 11-4 include congestion associated with PJM facilities and those associated with reciprocal, coordinated flowgates in MISO and in NYISO.[13 14]

Table 11-4 Total congestion costs (Dollars (Millions)): January through September, 2008 through 2024[15]

(Jan - Sep)	Congestion Cost	Percent Change	Total PJM Billing	Percent of PJM Billing
2008	$1,778	NA	$26,979	6.6%
2009	$544	(69.4%)	$19,927	2.7%
2010	$1,134	108.7%	$26,249	4.3%
2011	$875	(22.9%)	$28,836	3.0%
2012	$425	(51.4%)	$22,119	1.9%
2013	$510	19.9%	$25,153	2.0%
2014	$1,705	234.6%	$40,770	4.2%
2015	$1,143	(33.0%)	$33,710	3.4%
2016	$822	(28.1%)	$29,490	2.8%
2017	$455	(44.6%)	$29,510	1.5%
2018	$1,116	145.1%	$37,950	2.9%
2019	$419	(62.5%)	$31,850	1.3%
2020	$396	(5.5%)	$27,070	1.5%
2021	$615	55.1%	$37,520	1.6%
2022	$1,863	203.2%	$66,110	2.8%
2023	$760	(59.2%)	$36,380	2.1%
2024	$1,386	82.2%	$39,070	3.5%

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 11-5 shows total congestion by day-ahead and balancing component for January through September, 2008 through 2024.

13 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>.
14 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>.
15 In Table 11-4, 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 11-5 Total CLMP credits and charges by accounting category (Dollars (Millions)): January through September, 2008 through 2024

	Day-Ahead				Balancing					
(Jan - Sep)	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Inadvertent Charges	Congestion Costs
2008	$1,126.9	($971.2)	$152.8	$2,250.9	($204.9)	$90.5	($177.3)	($472.7)	$0.0	$1,778.2
2009	$245.7	($385.0)	$73.8	$704.6	($35.1)	$4.1	($121.9)	($161.0)	$0.0	$543.6
2010	$301.7	($932.7)	$69.5	$1,303.9	($11.5)	$39.3	($118.7)	($169.6)	($0.0)	$1,134.3
2011	$389.3	($628.2)	$45.6	$1,063.2	$52.7	$92.6	($148.4)	($188.3)	$0.0	$874.9
2012	$106.6	($409.8)	$86.7	$603.2	($3.3)	$37.1	($137.6)	($178.0)	$0.0	$425.2
2013	$227.1	($452.6)	$121.6	$801.4	$6.8	$112.2	($186.4)	($291.8)	$0.0	$509.6
2014	$505.4	($1,497.8)	($38.5)	$1,964.6	$73.1	$224.4	($107.9)	($259.2)	$0.0	$1,705.4
2015	$539.3	($783.2)	$24.6	$1,347.1	$11.4	$69.9	($145.6)	($204.1)	$0.0	$1,143.0
2016	$313.0	($529.0)	$35.7	$877.8	$1.9	$20.0	($37.3)	($55.5)	($0.0)	$822.2
2017	$105.1	($375.1)	$2.3	$482.5	$12.5	$32.9	($6.7)	($27.1)	$0.0	$455.4
2018	$249.0	($931.9)	($29.3)	$1,151.7	$18.2	$50.1	($3.6)	($35.5)	$0.0	$1,116.2
2019	$178.3	($295.2)	$37.9	$511.4	$6.2	$39.2	($59.4)	($92.3)	$0.0	$419.1
2020	$139.3	($307.2)	$55.9	$502.5	($8.8)	$31.3	($66.3)	($106.3)	$0.0	$396.1
2021	$324.5	($413.3)	$51.6	$789.5	($26.8)	$67.5	($80.6)	($174.9)	$0.0	$614.6
2022	$995.5	($1,178.1)	$109.9	$2,283.5	$9.7	$212.7	($217.3)	($420.3)	($0.0)	$1,863.2
2023	$376.2	($492.3)	$108.8	$977.3	$13.4	$63.4	($166.9)	($216.9)	$0.0	$760.4
2024	$511.8	($988.4)	$118.3	$1,618.5	$17.4	$102.1	($148.0)	($232.7)	$0.0	$1,385.8

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 11-6 and Table 11-7 show the total CLMP charges and credits for each transaction type in the first nine months of 2024 and 2023. Table 11-6 shows that in the first nine months of 2024 DECs were paid $4.1 million in CLMP charges in the day-ahead market, were paid $3.8 million in CLMP credits in the balancing energy market, resulting in a net payment of $7.9 million. In the first nine months of 2024, INCs paid $70.6 million in CLMP charges in the day-ahead market, were paid $113.7 million in CLMP credits in the balancing energy market resulting in a net payment of $43.1 million. In the first nine months of 2024, up to congestion (UTCs) paid $117.9 million in CLMP charges in the day-ahead market, were paid $145.0 million in CLMP credits in the balancing market resulting in a total payment of $27.1 million in total CLMP credits.

Table 11-6 Total CLMP credits and charges by transaction type (Dollars (Millions)): January through September, 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	($4.1)	$0.0	$0.0	($4.1)	($3.8)	$0.0	$0.0	($3.8)	$0.0	($7.9)
Demand	$82.6	$0.0	$0.0	$82.6	$48.6	$0.0	$0.0	$48.6	$0.0	$131.2
Demand Response	$0.1	$0.0	$0.0	$0.1	$0.2	$0.0	$0.0	$0.2	$0.0	$0.3
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	($0.7)	($0.7)	$0.0	$0.0	$0.1	$0.1	$0.0	($0.6)
Export	($46.6)	$0.0	($0.5)	($47.1)	($17.1)	$0.0	($1.4)	($18.5)	$0.0	($65.6)
Generation	$0.0	($1,396.1)	$0.0	$1,396.1	$0.0	$11.5	$0.0	($11.5)	$0.0	$1,384.6
Import	$0.0	($3.5)	$0.0	$3.5	$0.0	($12.6)	$0.0	$12.6	$0.0	$16.1
INC	$0.0	($70.6)	$0.0	$70.6	$0.0	$113.7	$0.0	($113.7)	$0.0	($43.1)
Internal Bilateral	$480.2	$482.0	$1.9	($0.0)	($8.8)	($8.8)	$0.0	($0.0)	$0.0	($0.0)
Up to Congestion	$0.0	$0.0	$117.9	$117.9	$0.0	$0.0	($145.0)	($145.0)	$0.0	($27.1)
Wheel In	$0.0	($0.3)	($0.4)	($0.0)	$0.0	($1.7)	($1.6)	$0.0	$0.0	$0.0
Wheel Out	($0.3)	$0.0	$0.0	($0.3)	($1.7)	$0.0	$0.0	($1.7)	$0.0	($2.0)
Total	$511.8	($988.4)	$118.3	$1,618.5	$17.4	$102.1	($148.0)	($232.7)	$0.0	$1,385.8

Table 11-7 Total CLMP credits and charges by transaction type (Dollars (Millions)): January through September, 2023

	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	$18.5	$0.0	$0.0	$18.5	($24.4)	$0.0	$0.0	($24.4)	$0.0	($5.9)
Demand	$33.6	$0.0	$0.0	$33.6	$51.2	$0.0	$0.0	$51.2	$0.0	$84.8
Demand Response	($0.0)	$0.0	$0.0	($0.0)	($0.0)	$0.0	$0.0	($0.0)	$0.0	($0.1)
Explicit Congestion Only	$0.0	$0.0	$1.0	$1.0	$0.0	$0.0	($0.2)	($0.2)	$0.0	$0.8
Explicit Congestion and Loss Only	$0.0	$0.0	$0.3	$0.3	$0.0	$0.0	($0.0)	($0.0)	$0.0	$0.2
Export	($47.7)	$0.0	($0.4)	($48.1)	($6.5)	$0.0	($1.2)	($7.7)	$0.0	($55.8)
Generation	$0.0	($834.6)	$0.0	$834.6	$0.0	$20.9	$0.0	($20.9)	$0.0	$813.7
Import	$0.0	($0.4)	$0.0	$0.4	$0.0	$0.0	$0.0	($0.0)	$0.0	$0.4
INC	$0.0	($30.6)	$0.0	$30.6	$0.0	$49.4	$0.0	($49.4)	$0.0	($18.7)
Internal Bilateral	$371.9	$373.3	$1.4	$0.0	($6.7)	($6.7)	$0.0	$0.0	$0.0	$0.0
Up to Congestion	$0.0	$0.0	$106.5	$106.5	$0.0	$0.0	($164.4)	($164.4)	$0.0	($57.9)
Wheel In	$0.0	$0.0	$0.0	$0.0	$0.0	($0.1)	($1.1)	($1.0)	$0.0	($1.0)
Wheel Out	$0.0	$0.0	$0.0	$0.0	($0.1)	$0.0	$0.0	($0.1)	$0.0	($0.1)
Total	$376.2	($492.3)	$108.8	$977.3	$13.4	$63.4	($166.9)	($216.9)	$0.0	$760.4

Table 11-8 shows the change in total CLMP credits and charges by transaction type in the first nine months of 2023 and 2024. Total negative CLMP credits to generation increased by $570.9 million, and total CLMP charges to demand increased by $46.4 million. The total CLMP credits to up to congestion transactions (UTCs) increased by $30.8 million in the first nine months of 2024. Total day-ahead CLMP charges to UTCs increased by $11.4 million in the first nine months of 2024. Balancing CLMP credits to UTCs increased by $19.4 million in the first nine months of 2024.

Table 11-8 Change in total CLMP credits and charges by transaction type (Dollars (Millions)): January through September, 2023 to 2024

	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	($22.6)	$0.0	$0.0	($22.6)	$20.6	$0.0	$0.0	$20.6	$0.0	($2.0)
Demand	$49.0	$0.0	$0.0	$49.0	($2.6)	$0.0	$0.0	($2.6)	$0.0	$46.4
Demand Response	$0.1	$0.0	$0.0	$0.1	$0.2	$0.0	$0.0	$0.2	$0.0	$0.3
Explicit Congestion Only	$0.0	$0.0	($1.0)	($1.0)	$0.0	$0.0	$0.2	$0.2	$0.0	($0.8)
Explicit Congestion and Loss Only	$0.0	$0.0	($1.0)	($1.0)	$0.0	$0.0	$0.1	$0.1	$0.0	($0.8)
Export	$1.1	$0.0	($0.1)	$1.0	($10.6)	$0.0	($0.2)	($10.8)	$0.0	($9.7)
Generation	$0.0	($561.5)	$0.0	$561.5	$0.0	($9.4)	$0.0	$9.4	$0.0	$570.9
Import	$0.0	($3.1)	$0.0	$3.1	$0.0	($12.6)	$0.0	$12.6	$0.0	$15.7
INC	$0.0	($39.9)	$0.0	$39.9	$0.0	$64.3	$0.0	($64.3)	$0.0	($24.4)
Internal Bilateral	$108.3	$108.7	$0.5	($0.0)	($2.1)	($2.1)	$0.0	($0.0)	$0.0	($0.0)
Up to Congestion	$0.0	$0.0	$11.4	$11.4	$0.0	$0.0	$19.4	$19.4	$0.0	$30.8
Wheel In	$0.0	($0.3)	($0.4)	($0.0)	$0.0	($1.6)	($0.6)	$1.0	$0.0	$1.0
Wheel Out	($0.3)	$0.0	$0.0	($0.3)	($1.6)	$0.0	$0.0	($1.6)	$0.0	($1.9)
Total	$135.6	($496.1)	$9.5	$641.2	$3.9	$38.6	$18.9	($15.8)	$0.0	$625.4

Table 11-9 compares CLMP credits and charges for each transaction type between the dispatch run and pricing run in the first nine months of 2024. Total CLMP charges to generation decreased by $79.5 million, and total CLMP charges to demand increased by $1.0 million from the dispatch run to the pricing run. The total CLMP credits to DECs increased by $0.0 million, the total CLMP credits to INCs decreased by $1.8 million and the total CLMP credits to UTCs decreased by $9.2 million from the dispatch run to the pricing run.

Table 11-9 Total CLMP credits and charges by dispatch run and pricing run (Dollars (Millions)): January through September, 2024

	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	($6.2)	($1.7)	($7.9)	($4.1)	($3.8)	($7.9)	$2.1	($2.2)	($0.0)
Demand	$85.5	$44.8	$130.2	$82.6	$48.6	$131.2	($2.8)	$3.8	$1.0
Demand Response	$0.1	$0.2	$0.3	$0.1	$0.2	$0.3	$0.0	($0.0)	($0.0)
Explicit Congestion Only	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	($0.0)
Explicit Congestion and Loss Only	($0.7)	$0.1	($0.6)	($0.7)	$0.1	($0.6)	$0.0	$0.0	$0.0
Export	($47.1)	($16.5)	($63.6)	($47.1)	($18.5)	($65.6)	($0.0)	($1.9)	($2.0)
Generation	$1,473.3	($9.2)	$1,464.2	$1,396.1	($11.5)	$1,384.6	($77.3)	($2.3)	($79.5)
Import	$3.5	$12.7	$16.2	$3.5	$12.6	$16.1	($0.0)	($0.1)	($0.1)
INC	$70.0	($111.4)	($41.3)	$70.6	($113.7)	($43.1)	$0.5	($2.3)	($1.8)
Internal Bilateral	$0.0	($0.0)	($0.0)	($0.0)	($0.0)	($0.0)	($0.0)	$0.0	$0.0
Up to Congestion	$117.1	($135.1)	($17.9)	$117.9	($145.0)	($27.1)	$0.8	($10.0)	($9.2)
Wheel In	($0.0)	$0.2	$0.2	($0.0)	$0.0	$0.0	($0.0)	($0.1)	($0.1)
Wheel Out	($0.3)	($1.6)	($2.0)	($0.3)	($1.7)	($2.0)	($0.0)	($0.0)	($0.0)
Total	$1,695.2	($217.6)	$1,477.6	$1,618.5	($232.7)	$1,385.8	($76.7)	($15.1)	($91.8)

UTCs and Negative Balancing Explicit CLMP Charges

Figure 11-2 shows the change in up to congestion balancing explicit CLMP charges from 2014 through the first nine months of 2024. 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 nine months of 2024, 62.3 percent (-$145.0 million out of -$232.7 million) of negative balancing explicit CLMP charges was incurred by UTCs and 2.7 percent (-$6.2 out of -$232.7 million) was incurred by Explicit Congestion Only, Export, Import and Wheel In transactions (Table 11-6). 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.[16] 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.[17]

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.

16 For additional information about the FERC order, see the *2023 Annual State of the Market Report for PJM*, Appendix F: Congestion and Marginal Losses.
17 172 FERC ¶ 61,046 (2020).

Figure 11-2 Monthly balancing explicit CLMP charges incurred by UTC: January 2014 through September 2024

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 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.[18] 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.[19]

Table 11-10 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

18 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.

19 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).

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 11-10 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.[20]

20 153 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 11-10 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 11-11 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, for the first nine months of 2024. 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 nine months of 2024. AEP had $220.5 million in zonal congestion costs, comprised of $255.9 million in zonal day-ahead congestion costs and -$35.4 million in zonal balancing congestion costs. The Nottingham Series Reactor, the Yorkana Circuit Breaker, the Lenox – North Meshoppen Line, the Chaparral – Carson Line, and the Conastone Transformer contributed $55.7 million, or 21.8 percent of the AEP zonal congestion costs.[21]

21 For additional information about the top 20 constraints that affected each zone, see the *2023 Annual State of the Market Report for PJM*, Appendix F: Congestion and Marginal Losses.

Table 11-12 shows the congestion costs by zone for the first nine months of 2023.

Table 11-11 CLMP credits and charges and total congestion revenue collected by zone (Dollars (Millions)): January through September, 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	$4.6	($10.8)	$1.2	$16.6	$0.1	$1.2	($1.7)	($2.8)	$0.5	$13.3	$13.8
AEP	$75.0	($159.9)	$21.0	$255.9	$3.1	$15.4	($23.2)	($35.4)	$31.9	$188.6	$220.5
APS	$39.0	($65.8)	$7.8	$112.7	$1.2	$6.8	($10.3)	($15.9)	$4.4	$92.4	$96.8
ATSI	$40.4	($82.7)	$10.9	$133.9	$1.7	$8.1	($11.8)	($18.2)	$6.4	$109.3	$115.7
BGE	$22.0	($36.9)	$4.0	$62.9	$1.3	$4.3	($6.0)	($9.0)	$4.2	$49.6	$53.9
COMED	$55.4	($153.0)	$13.6	$222.0	$3.2	$11.3	($13.9)	($22.1)	$80.8	$119.1	$199.9
DAY	$8.2	($19.7)	$2.8	$30.6	$0.5	$2.1	($3.1)	($4.8)	$0.0	$25.9	$25.9
DOM	$84.3	($128.1)	$16.3	$228.6	$3.6	$16.1	($23.5)	($36.0)	$54.6	$138.0	$192.6
DPL	$28.1	($21.3)	$2.6	$52.0	($1.2)	$1.8	($3.2)	($6.3)	$24.4	$21.3	$45.7
DUKE	$13.5	($28.7)	$4.3	$46.4	$0.7	$3.3	($4.8)	($7.3)	$2.3	$36.8	$39.1
DUQ	$7.1	($12.5)	$1.6	$21.1	$0.4	$1.7	($2.4)	($3.7)	$0.5	$16.9	$17.4
EKPC	$7.4	($15.7)	$2.3	$25.5	$0.3	$1.6	($2.6)	($4.0)	$0.0	$21.4	$21.5
EXT	$9.0	($21.6)	$2.5	$33.1	$0.3	$2.7	($4.5)	($6.8)	$1.4	$24.9	$26.3
JCPLC	$13.1	($29.1)	$3.1	$45.2	$0.3	$3.3	($4.7)	($7.8)	$1.1	$36.3	$37.4
MEC	$10.7	($16.4)	$1.8	$28.9	($0.6)	$1.8	($2.6)	($5.0)	$2.8	$21.2	$24.0
OVEC	$0.4	($0.9)	$1.1	$2.3	$0.0	$0.1	($0.2)	($0.3)	$0.9	$1.1	$2.1
PE	$12.4	($18.7)	$2.4	$33.5	$0.2	$1.9	($2.9)	($4.6)	$4.5	$24.4	$28.9
PECO	$16.0	($42.6)	$4.2	$62.8	$0.4	$4.7	($6.7)	($10.9)	$7.5	$44.4	$51.9
PEPCO	$19.1	($29.7)	$3.6	$52.3	$1.0	$3.9	($5.5)	($8.3)	$0.2	$43.8	$44.0
PPL	$24.3	($46.2)	$5.7	$76.2	$0.3	$4.5	($6.9)	($11.0)	$10.6	$54.6	$65.2
PSEG	$20.7	($46.8)	$5.0	$72.5	$0.5	$5.2	($7.3)	($12.0)	$0.4	$60.1	$60.5
REC	$1.2	($1.5)	$0.5	$3.3	$0.0	$0.2	($0.3)	($0.4)	$0.9	$2.0	$2.9
Total	$511.8	($988.4)	$118.3	$1,618.5	$17.4	$102.1	($148.0)	($232.7)	$240.4	$1,145.4	$1,385.8

Table 11-12 CLMP credits and charges and total congestion revenue collected by zone (Dollars (Millions)): January through September, 2023

	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	$3.3	($4.8)	$0.9	$9.1	($0.0)	$0.6	($1.8)	($2.4)	$0.3	$6.3	$6.7
AEP	$50.3	($81.3)	$19.6	$151.2	$2.7	$9.6	($25.2)	($32.1)	$18.0	$101.2	$119.2
APS	$24.0	($31.0)	$6.3	$61.4	$1.1	$4.1	($10.5)	($13.5)	$2.7	$45.1	$47.9
ATSI	$23.1	($42.5)	$9.1	$74.7	$1.5	$4.9	($13.0)	($16.4)	$2.5	$55.8	$58.3
BGE	$16.7	($17.1)	$3.9	$37.6	$1.1	$2.7	($6.2)	($7.8)	$6.6	$23.2	$29.8
COMED	$60.5	($77.9)	$12.7	$151.1	$2.9	$8.1	($17.4)	($22.6)	$50.7	$77.9	$128.6
DAY	$5.6	($11.5)	$2.6	$19.7	$0.4	$1.3	($3.5)	($4.4)	$0.0	$15.3	$15.3
DOM	$64.2	($63.1)	$18.4	$145.8	$3.1	$11.3	($29.2)	($37.4)	$10.9	$97.6	$108.4
DPL	$16.4	($15.1)	$1.9	$33.5	($1.9)	$0.4	($3.4)	($5.7)	$18.7	$9.1	$27.8
DUKE	$10.8	($16.0)	$4.3	$31.1	$0.6	$2.1	($5.5)	($6.9)	$1.7	$22.5	$24.2
DUQ	$4.9	($5.8)	$1.3	$12.1	$0.3	$1.0	($2.6)	($3.4)	$0.1	$8.6	$8.7
EKPC	$5.0	($8.4)	$2.1	$15.4	$0.3	$1.0	($2.7)	($3.4)	$0.1	$11.9	$12.0
EXT	$8.9	($8.4)	$2.0	$19.2	$1.1	$2.6	($6.1)	($7.7)	$0.9	$10.7	$11.6
JCPLC	$11.7	($13.8)	$2.6	$28.0	$0.0	$1.7	($5.1)	($6.8)	$3.1	$18.2	$21.2
MEC	$8.0	($7.6)	$1.7	$17.2	($0.4)	$1.0	($3.0)	($4.4)	$2.8	$9.9	$12.8
OVEC	$0.4	($0.6)	$0.5	$1.6	$0.0	$0.1	($0.2)	($0.2)	$0.4	$0.9	$1.3
PE	$7.5	($9.8)	$1.8	$19.1	$0.2	$1.1	($3.2)	($4.1)	$1.7	$13.3	$15.0
PECO	$11.5	($19.8)	$3.5	$34.7	($0.1)	$2.2	($7.0)	($9.4)	$4.3	$21.0	$25.3
PEPCO	$14.4	($14.9)	$3.6	$32.8	$0.9	$2.4	($5.7)	($7.2)	$0.2	$25.4	$25.6
PPL	$14.6	($21.3)	$5.2	$41.1	($0.4)	$2.4	($7.5)	($10.3)	$2.2	$28.6	$30.8
PSEG	$13.5	($21.0)	$3.9	$38.4	$0.0	$2.6	($7.8)	($10.4)	$0.8	$27.2	$28.0
REC	$1.0	($0.7)	$0.8	$2.5	($0.0)	$0.1	($0.3)	($0.4)	$1.1	$1.0	$2.1
Total	$376.2	($492.3)	$108.8	$977.3	$13.4	$63.4	($166.9)	($216.9)	$129.7	$630.7	$760.4

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 nine months of 2024, the total congestion costs associated with these special cases were $7.6 million or 0.5 percent of the total congestion costs. Table 11-11 and Table 11-12 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).[22]

22 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 11-13 and Table 11-14 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 nine months of 2024 or 2023. The congestion associated with Real-Time Short-Term Marginal Value Overrides is included in the Normal Constraint Congestion totals.

Table 11-13 CLMP charges and credits and total congestion collected by zone and special case logic (Dollars (Millions)): January through September, 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	$16.6	$16.6	$0.0	($0.0)	$0.0	($0.0)	$0.0	($2.8)	($2.8)	$13.8	($0.0)	(0.3%)
AEP	$0.0	($0.0)	$0.0	$1.1	$0.0	$254.9	$255.9	$0.0	($0.5)	$0.0	($0.0)	$0.0	($35.0)	($35.4)	$220.5	$0.6	0.3%
APS	$0.0	($0.0)	$0.0	$0.0	$0.0	$112.7	$112.7	$0.0	($0.2)	$0.0	($0.0)	$0.0	($15.7)	($15.9)	$96.8	($0.2)	(0.2%)
ATSI	$0.0	($0.0)	$0.0	$0.2	$0.0	$133.7	$133.9	$0.0	($0.2)	$0.0	$0.0	$0.0	($18.0)	($18.2)	$115.7	($0.0)	(0.0%)
BGE	$0.0	($0.0)	$0.0	$0.0	$0.0	$62.9	$62.9	$0.0	($0.1)	$0.0	($0.0)	$0.0	($8.9)	($9.0)	$53.9	($0.1)	(0.2%)
COMED	$0.6	($0.0)	$0.0	$3.3	$0.0	$218.1	$222.0	$0.0	($0.5)	$0.0	$0.0	$0.0	($21.6)	($22.1)	$199.9	$3.4	1.7%
DAY	$0.0	($0.0)	$0.0	$0.0	$0.0	$30.6	$30.6	$0.0	($0.1)	$0.0	($0.0)	$0.0	($4.7)	($4.8)	$25.9	($0.1)	(0.3%)
DOM	$0.0	($0.0)	$0.0	$0.4	$0.0	$228.3	$228.6	$0.0	($0.4)	$0.0	($0.0)	$0.0	($35.6)	($36.0)	$192.6	($0.1)	(0.1%)
DPL	$0.0	($0.0)	$0.0	$0.0	$0.0	$52.0	$52.0	$0.0	($0.1)	$0.0	($0.0)	$0.0	($6.2)	($6.3)	$45.7	($0.1)	(0.1%)
DUKE	$0.0	($0.0)	$0.0	$0.0	$0.0	$46.4	$46.4	$0.0	($0.1)	$0.0	($0.0)	$0.0	($7.2)	($7.3)	$39.1	($0.1)	(0.3%)
DUQ	$0.0	($0.0)	$0.0	$0.0	$0.0	$21.1	$21.1	$0.0	($0.0)	$0.0	($0.0)	$0.0	($3.7)	($3.7)	$17.4	($0.1)	(0.3%)
EKPC	$0.0	($0.0)	$0.0	$0.0	$0.0	$25.5	$25.5	$0.0	($0.0)	$0.0	($0.0)	$0.0	($3.9)	($4.0)	$21.5	($0.1)	(0.2%)
EXT	$1.4	($0.0)	$0.0	$0.0	$0.0	$31.7	$33.1	$0.0	($0.2)	$0.0	($0.0)	$0.0	($6.7)	($6.8)	$26.3	$1.2	4.6%
JCPLC	$1.2	($0.0)	$0.0	$0.0	$0.0	$44.1	$45.2	$0.0	($0.1)	$0.0	($0.0)	$0.0	($7.7)	($7.8)	$37.4	$1.1	2.8%
MEC	$0.0	($0.0)	$0.0	$0.0	$0.0	$28.9	$28.9	$0.0	($0.1)	$0.0	$0.0	$0.0	($4.9)	($5.0)	$24.0	($0.1)	(0.2%)
OVEC	$0.0	($0.0)	$0.0	$0.9	$0.0	$1.4	$2.3	$0.0	($0.0)	$0.0	$0.0	$0.0	($0.3)	($0.3)	$2.1	$0.9	45.6%
PE	$0.0	($0.0)	$0.0	$0.2	$0.0	$33.3	$33.5	$0.0	($0.1)	$0.0	$0.0	$0.0	($4.5)	($4.6)	$28.9	$0.1	0.4%
PECO	($0.0)	($0.0)	$0.0	$0.1	$0.0	$62.8	$62.8	$0.0	($0.1)	$0.0	($0.0)	$0.0	($10.8)	($10.9)	$51.9	($0.1)	(0.2%)
PEPCO	$0.0	($0.0)	$0.0	$0.1	$0.0	$52.3	$52.3	$0.0	($0.1)	$0.0	($0.0)	$0.0	($8.2)	($8.3)	$44.0	($0.0)	(0.0%)
PPL	$0.1	($0.0)	$0.0	$1.5	$0.0	$74.6	$76.2	$0.0	($0.1)	$0.0	$0.0	$0.0	($10.9)	($11.0)	$65.2	$1.5	2.3%
PSEG	$0.0	($0.0)	$0.0	$0.0	$0.0	$72.5	$72.5	$0.0	($0.2)	$0.0	($0.0)	$0.0	($11.9)	($12.0)	$60.5	($0.2)	(0.3%)
REC	$0.0	($0.0)	$0.0	$0.0	$0.0	$3.3	$3.3	$0.0	($0.0)	$0.0	($0.0)	$0.0	($0.4)	($0.4)	$2.9	($0.0)	(0.2%)
Total	$3.2	($0.2)	$0.0	$7.8	$0.0	$1,607.7	$1,618.5	$0.0	($3.3)	$0.0	($0.0)	$0.0	($229.4)	($232.7)	$1,385.8	$7.6	0.5%

Table 11-14 CLMP charges and credits and congestion collected by zone and special case logic (Dollars (Millions)): January through September, 2023

Control Zone	Day-Ahead Load Bus Zero CLMP	Day-Ahead CT Price Setting Logic	Day-Ahead Closed Loop Interfaces	Day-Ahead No Load Buses	Day-Ahead Unclassified	Day-Ahead Normal Constraint Congestion	Day-Ahead Total	Balancing Load Bus Zero CLMP	Balancing CT Price Setting Logic	Balancing Closed Loop Interfaces	Balancing No Load Buses	Balancing Unclassified	Balancing Normal Constraint Congestion	Balancing Total	Grand Total	Special Cases Total	Percent of Special Cases
ACEC	$0.0	($0.0)	$0.0	$0.0	$0.0	$9.1	$9.1	$0.0	($0.0)	$0.0	($0.0)	$0.0	($2.4)	($2.4)	$6.7	($0.0)	(0.4%)
AEP	$0.0	($0.0)	$0.0	$0.6	$0.0	$150.7	$151.2	$0.0	($0.3)	$0.0	($0.0)	$0.0	($31.7)	($32.1)	$119.2	$0.2	0.2%
APS	$0.0	($0.1)	$0.0	$0.0	$0.0	$61.4	$61.4	$0.0	($0.1)	$0.0	($0.0)	$0.0	($13.3)	($13.5)	$47.9	($0.2)	(0.4%)
ATSI	$0.0	($0.0)	$0.0	$0.3	$0.0	$74.4	$74.7	$0.0	($0.2)	$0.0	($0.0)	$0.0	($16.3)	($16.4)	$58.3	$0.1	0.2%
BGE	$0.0	($0.0)	$0.0	$0.0	$0.0	$37.7	$37.6	$0.0	($0.1)	$0.0	($0.0)	$0.0	($7.7)	($7.8)	$29.8	($0.1)	(0.4%)
COMED	$0.4	($0.0)	$0.0	$3.2	$0.0	$147.6	$151.1	$0.0	($0.3)	$0.0	($0.0)	$0.0	($22.2)	($22.6)	$128.6	$3.2	2.5%
DAY	$0.0	($0.0)	$0.0	$0.0	$0.0	$19.7	$19.7	$0.0	($0.0)	$0.0	($0.0)	$0.0	($4.4)	($4.4)	$15.3	($0.1)	(0.3%)
DOM	$0.0	($0.2)	$0.0	$0.1	$0.0	$145.8	$145.8	$0.0	($0.3)	$0.0	($0.0)	$0.0	($37.0)	($37.4)	$108.4	($0.4)	(0.3%)
DPL	$0.0	($0.0)	$0.0	$0.0	$0.0	$33.4	$33.5	$0.0	($0.0)	$0.0	($0.0)	$0.0	($5.6)	($5.7)	$27.8	($0.0)	(0.1%)
DUKE	$0.0	($0.0)	$0.0	$0.0	$0.0	$31.2	$31.1	$0.0	($0.1)	$0.0	($0.0)	$0.0	($6.9)	($6.9)	$24.2	($0.1)	(0.3%)
DUQ	$0.0	($0.0)	$0.0	$0.0	$0.0	$12.1	$12.1	$0.0	($0.0)	$0.0	($0.0)	$0.0	($3.3)	($3.4)	$8.7	($0.0)	(0.4%)
EKPC	$0.0	($0.0)	$0.0	$0.0	$0.0	$15.4	$15.4	$0.0	($0.0)	$0.0	($0.0)	$0.0	($3.4)	($3.4)	$12.0	($0.0)	(0.3%)
EXT	$0.8	($0.0)	$0.0	$0.1	$0.0	$18.3	$19.2	$0.0	($0.1)	$0.0	($0.0)	($0.0)	($7.5)	($7.7)	$11.6	$0.8	6.7%
JCPLC	$3.0	($0.0)	$0.0	$0.0	$0.0	$25.0	$28.0	$0.0	($0.1)	$0.0	($0.0)	$0.0	($6.7)	($6.8)	$21.2	$2.9	13.8%
MEC	$0.0	($0.0)	$0.0	$0.1	$0.0	$17.2	$17.2	$0.0	($0.0)	$0.0	($0.0)	$0.0	($4.4)	($4.4)	$12.8	$0.0	0.1%
OVEC	$0.0	($0.0)	$0.0	$0.4	$0.0	$1.2	$1.6	$0.0	($0.0)	$0.0	($0.0)	$0.0	($0.2)	($0.2)	$1.3	$0.4	29.2%
PE	$0.0	($0.0)	$0.0	$0.1	$0.0	$19.0	$19.1	$0.0	($0.0)	$0.0	($0.0)	$0.0	($4.1)	($4.1)	$15.0	$0.1	0.5%
PECO	($0.0)	($0.0)	$0.0	$0.0	$0.0	$34.7	$34.7	$0.0	($0.1)	$0.0	($0.0)	$0.0	($9.3)	($9.4)	$25.3	($0.1)	(0.3%)
PEPCO	$0.0	($0.0)	$0.0	$0.0	$0.0	$32.9	$32.8	$0.0	($0.1)	$0.0	($0.0)	$0.0	($7.2)	($7.2)	$25.6	($0.1)	(0.4%)
PPL	$0.0	($0.0)	$0.0	$0.0	$0.0	$41.1	$41.1	$0.0	($0.1)	$0.0	($0.0)	$0.0	($10.2)	($10.3)	$30.8	($0.1)	(0.4%)
PSEG	$0.0	($0.0)	$0.0	$0.0	$0.0	$38.4	$38.4	$0.0	($0.1)	$0.0	($0.0)	$0.0	($10.3)	($10.4)	$28.0	($0.1)	(0.4%)
REC	$0.0	($0.0)	$0.0	$0.0	$0.0	$2.5	$2.5	$0.0	($0.0)	$0.0	($0.0)	$0.0	($0.4)	($0.4)	$2.1	($0.0)	(0.2%)
Total	$4.2	($0.5)	$0.0	$5.0	$0.0	$968.6	$977.3	$0.0	($2.2)	$0.0	($0.2)	$0.0	($214.6)	($216.9)	$760.4	$6.4	0.8%

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 11-15 compares the congestion costs between the dispatch run and the pricing run in the first nine months of 2024. The table shows that the implementation of fast starting pricing logic caused day-ahead total congestion costs to decrease $76.7 million (or 4.5 percent), caused negative balancing congestion costs to decrease $15.1 million (or 6.9 percent), and caused total congestion costs to decrease $91.8 million (or 6.2 percent) from the dispatch run to the pricing run in the first nine months of 2024. 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 11-15 Total congestion by dispatch and pricing run (Dollars (Millions)): January through September, 2024

	Congestion Costs (Millions)								
	Dispatch Run			Pricing Run			Difference		
Control Zone	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total
ACEC	$16.6	($2.6)	$14.0	$16.6	($2.8)	$13.8	($0.0)	($0.2)	($0.2)
AEP	$267.0	($33.2)	$233.9	$255.9	($35.4)	$220.5	($11.1)	($2.3)	($13.4)
APS	$113.7	($14.9)	$98.9	$112.7	($15.9)	$96.8	($1.1)	($1.0)	($2.1)
ATSI	$135.3	($17.1)	$118.3	$133.9	($18.2)	$115.7	($1.4)	($1.2)	($2.6)
BGE	$63.1	($8.4)	$54.7	$62.9	($9.0)	$53.9	($0.2)	($0.6)	($0.8)
COMED	$275.0	($20.8)	$254.2	$222.0	($22.1)	$199.9	($53.0)	($1.3)	($54.3)
DAY	$30.7	($4.5)	$26.2	$30.6	($4.8)	$25.9	($0.0)	($0.3)	($0.3)
DOM	$229.3	($33.6)	$195.7	$228.6	($36.0)	$192.6	($0.7)	($2.4)	($3.1)
DPL	$52.0	($5.6)	$46.4	$52.0	($6.3)	$45.7	$0.0	($0.7)	($0.6)
DUKE	$46.4	($6.9)	$39.5	$46.4	($7.3)	$39.1	$0.0	($0.5)	($0.4)
DUQ	$21.4	($3.5)	$17.9	$21.1	($3.7)	$17.4	($0.3)	($0.2)	($0.5)
EKPC	$25.5	($3.7)	$21.8	$25.5	($4.0)	$21.5	($0.0)	($0.3)	($0.3)
EXT	$41.0	($6.4)	$34.5	$33.1	($6.8)	$26.3	($7.9)	($0.4)	($8.3)
JCPLC	$45.4	($7.3)	$38.1	$45.2	($7.8)	$37.4	($0.1)	($0.5)	($0.6)
MEC	$29.0	($4.7)	$24.3	$28.9	($5.0)	$24.0	($0.1)	($0.3)	($0.3)
OVEC	$2.3	($0.2)	$2.1	$2.3	($0.3)	$2.1	($0.0)	($0.0)	($0.0)
PE	$33.8	($4.3)	$29.5	$33.5	($4.6)	$28.9	($0.3)	($0.3)	($0.6)
PECO	$62.9	($10.2)	$52.7	$62.8	($10.9)	$51.9	($0.1)	($0.7)	($0.8)
PEPCO	$52.5	($7.8)	$44.7	$52.3	($8.3)	$44.0	($0.1)	($0.5)	($0.7)
PPL	$76.4	($10.3)	$66.1	$76.2	($11.0)	$65.2	($0.1)	($0.7)	($0.9)
PSEG	$72.7	($11.2)	$61.5	$72.5	($12.0)	$60.5	($0.2)	($0.8)	($1.0)
REC	$3.3	($0.4)	$2.9	$3.3	($0.4)	$2.9	($0.0)	($0.0)	($0.0)
Total	$1,695.2	($217.6)	$1,477.6	$1,618.5	($232.7)	$1,385.8	($76.7)	($15.1)	($91.8)

Monthly Congestion

Table 11-16 shows day-ahead, balancing and inadvertent congestion costs by month for 2023 through the first nine months of 2024.

Total negative balancing congestion costs in the first nine months of 2024 were highest in July. The top constraint that contributed to the total balancing congestion costs in the first nine months of 2024 was the Lenox – North Meshoppen Line. The constraint accounted for 10.7 percent of the total balancing congestion costs in the first nine months of 2024. The majority (61.1 percent) of negative balancing congestion costs for the Lenox – North Meshoppen Line were the result of Increments.

In the first nine months of 2024, total congestion costs were highest in July and lowest in February.

Table 11-16 Monthly congestion costs by market (Dollars (Millions)): January 2023 through September 2024

	Congestion Costs (Millions)							
	2023				2024			
	Day-Ahead	Balancing	Inadvertent Charges	Total	Day-Ahead	Balancing	Inadvertent Charges	Total
Jan	$69.3	($7.0)	($0.0)	$62.2	$230.9	($35.0)	$0.0	$196.0
Feb	$102.8	($16.4)	$0.0	$86.4	$67.8	($14.6)	$0.0	$53.2
Mar	$54.2	($27.3)	$0.0	$26.8	$99.9	($28.2)	($0.0)	$71.8
Apr	$128.9	($43.4)	($0.0)	$85.5	$108.4	($28.2)	$0.0	$80.1
May	$96.9	($35.9)	$0.0	$61.0	$199.3	($26.7)	$0.0	$172.6
Jun	$87.1	($12.7)	$0.0	$74.4	$155.3	($27.5)	$0.0	$127.8
Jul	$166.2	($26.7)	$0.0	$139.6	$371.5	($41.0)	$0.0	$330.5
Aug	$133.6	($22.8)	$0.0	$110.8	$256.6	($18.3)	$0.0	$238.3
Sep	$138.3	($24.7)	$0.0	$113.6	$128.7	($13.2)	$0.0	$115.5
Oct	$153.2	($34.0)	$0.0	$119.2				
Nov	$135.1	($28.7)	$0.0	$106.4				
Dec	$98.9	($16.3)	$0.0	$82.6				
Total	$1,364.5	($295.9)	$0.0	$1,068.6	$1,618.5	($232.7)	$0.0	$1,385.8

Figure 11-3 shows PJM monthly total congestion cost for January 2008 through September 2024.

Figure 11-3 Monthly total congestion cost (Dollars (Millions)): January 2008 through September 2024

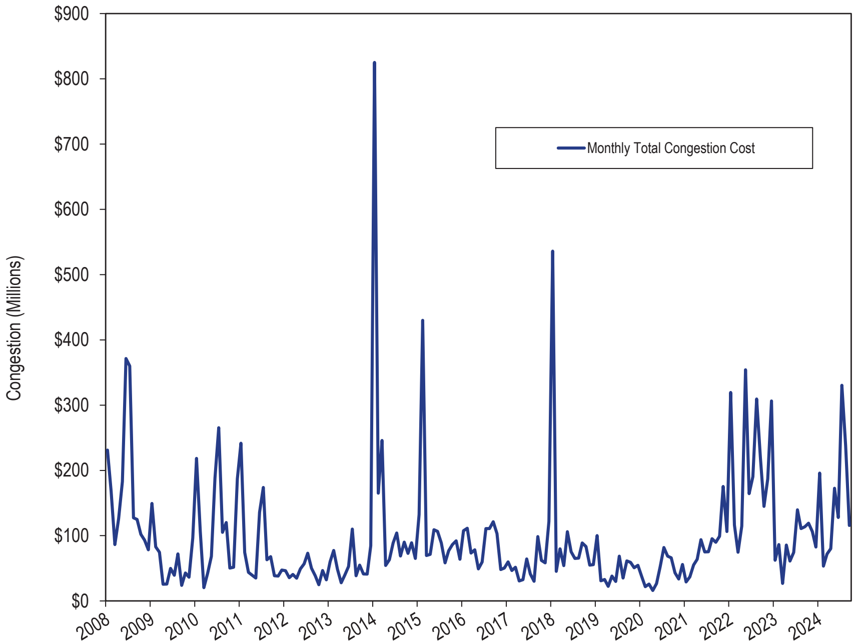


Table 11-17 shows monthly total CLMP credits and charges for each virtual transaction type for 2023 through the first nine months of 2024. Virtual transaction CLMP charges, when positive, are the total CLMP charges to the virtual transactions and when negative, are the total CLMP credits to the virtual transactions. The negative totals in Table 11-17 show that virtuals were paid, in net, CLMP credits in the first nine months of 2024 and 2023. In the first nine months of 2024, 34.7 percent of the total credits to virtuals went to UTCs, compared to 70.2 percent in the first nine months of 2023. In the first nine months of 2024, the average hourly cleared UTC MW decreased by 50.6 percent, compared to the first nine months of 2023.

Table 11-17 Monthly CLMP charges by virtual transaction type (Dollars (Millions)): January 2023 through September 2024

		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
2023	Jan	($1.9)	$0.3	($1.6)	$2.3	($1.7)	$0.6	$6.4	($6.6)	($0.2)	($1.1)
	Feb	$5.6	($3.1)	$2.5	$3.8	($3.5)	$0.3	$5.5	($11.7)	($6.1)	($3.4)
	Mar	($2.9)	$2.2	($0.7)	$4.4	($5.2)	($0.8)	$8.6	($27.9)	($19.3)	($20.8)
	Apr	($3.8)	$2.6	($1.1)	$7.9	($14.2)	($6.3)	$18.0	($35.8)	($17.8)	($25.2)
	May	($2.4)	$1.5	($0.9)	$4.4	($6.4)	($2.0)	$20.4	($29.4)	($9.1)	($12.0)
	Jun	$1.3	($1.8)	($0.5)	$1.0	($2.4)	($1.5)	$14.9	($11.3)	$3.6	$1.6
	Jul	$7.7	($10.7)	($3.0)	$1.4	($4.2)	($2.8)	$12.9	($12.3)	$0.6	($5.2)
	Aug	$9.8	($8.9)	$0.9	$2.2	($3.8)	($1.6)	$9.6	($15.2)	($5.6)	($6.3)
	Sep	$5.1	($6.5)	($1.5)	$3.4	($8.0)	($4.6)	$10.2	($14.1)	($4.0)	($10.0)
	Oct	($1.9)	$3.3	$1.4	$8.4	($16.8)	($8.5)	$13.1	($17.1)	($4.0)	($11.1)
	Nov	$0.2	($3.7)	($3.6)	$2.7	($5.6)	($2.9)	$14.3	($20.9)	($6.6)	($13.0)
	Dec	$3.3	($3.0)	$0.3	($1.6)	($1.7)	($3.3)	$11.0	($13.5)	($2.5)	($5.6)
	Total	$20.1	($27.9)	($7.8)	$40.2	($73.6)	($33.4)	$144.9	($215.9)	($71.0)	($112.2)
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)
	Total	($4.1)	($3.8)	($7.9)	$70.6	($113.7)	($43.1)	$117.9	($145.0)	($27.1)	($78.2)

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 nine months of 2024, there were 57,459 day-ahead congestion event hours compared to 56,273 day-ahead congestion event hours in the first nine months of 2023. Of the day-ahead congestion event hours in the first nine months of 2024, only 10,027 (17.5 percent) were also constrained in the real-time energy market (Table 11-19). In the first nine months of 2024, there were 20,748 real-time, congestion event hours compared to 15,582 real-time, congestion event hours in the first nine months of 2023. Of the real-time congestion event hours in the first nine months of 2024, 10,210 (49.2 percent) were also constrained in the day-ahead energy market (Table 11-20).

Congestion Event Hours

Table 11-18 compares the monthly day-ahead and real-time congestion event hours for 2023 and the first nine months of 2024. Day-ahead congestion event hours are significantly greater than real-time congestion event hours.

Table 11-18 Monthly day-ahead and real-time congestion event hours: January 2023 through September 2024

	Day-Ahead Congestion Event Hours		Real-Time Congestion Event Hours	
	2023	2024	2023	2024
Jan	6,272	6,003	1,113	2,037
Feb	6,223	5,516	1,210	1,709
Mar	6,111	7,877	1,717	2,527
Apr	6,816	6,464	2,406	2,648
May	6,769	6,833	1,708	2,930
Jun	5,930	6,601	1,487	2,731
Jul	6,728	6,379	1,940	2,397
Aug	5,594	5,822	1,828	1,885
Sep	5,842	5,974	2,172	1,884
Oct	5,739		2,530	
Nov	4,998		2,423	
Dec	6,512		2,152	
Total	73,534	57,469	22,686	20,748

Table 11-19 and Table 11-20 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 11-19.[23]

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 11-20.

Congestion frequency continued to be significantly higher in the day-ahead energy market than in the real-time energy market in the first nine months of 2024. 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.

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

23 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.

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 11-19 Congestion event hours (day-ahead against real-time): January through September, 2023 and 2024

	Congestion Event Hours					
	2023 (Jan - Sep)			2024 (Jan - Sep)		
Type	Day-Ahead Constrained	Corresponding Real-Time Constrained	Percent	Day-Ahead Constrained	Corresponding Real-Time Constrained	Percent
Flowgate	5,496	1,332	24.2%	4,825	1,022	21.2%
Interface	462	15	3.2%	531	120	22.6%
Line	38,491	4,467	11.6%	39,370	6,019	15.3%
Transformer	6,818	447	6.6%	6,969	548	7.9%
Other	5,006	2,455	49.0%	5,764	2,318	40.2%
Total	56,273	8,716	15.5%	57,459	10,027	17.5%

Table 11-20 Congestion event hours (real-time against day-ahead): January through September, 2023 and 2024

	Congestion Event Hours					
	2023 (Jan - Sep)			2024 (Jan - Sep)		
Type	Real-Time Constrained	Corresponding Day-Ahead Constrained	Percent	Real-Time Constrained	Corresponding Day-Ahead Constrained	Percent
Flowgate	4,155	1,331	32.0%	3,879	1,022	26.3%
Interface	35	18	51.4%	224	181	80.8%
Line	7,789	4,534	58.2%	12,117	6,110	50.4%
Transformer	731	462	63.2%	1,164	552	47.4%
Other	2,872	2,460	85.7%	3,364	2,345	69.7%
Total	15,582	8,805	56.5%	20,748	10,210	49.2%

Table 11-21 shows congestion costs by facility voltage class for the first nine months of 2024. Congestion costs in the first nine months of 2024 increased for all facility voltage classes except for 161 kV and 1 kV compared to the first nine months of 2023.

Table 11-21 Congestion summary (By facility voltage): January through September, 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	($6.5)	($24.6)	$2.5	$20.6	$1.8	$6.3	($2.2)	($6.8)	$13.8	354	65
500	$132.3	($147.5)	$8.8	$288.5	$3.1	$11.1	($16.1)	($24.0)	$264.5	2,131	778
345	$1.7	($158.8)	$25.4	$185.9	($7.5)	$30.6	($33.6)	($71.7)	$114.2	5,607	2,384
230	$297.9	($371.7)	$37.5	$707.2	$24.8	$21.3	($32.2)	($28.7)	$678.5	17,124	5,665
161	($0.1)	($0.3)	$0.1	$0.2	$0.2	$0.5	($1.3)	($1.6)	($1.4)	79	114
138	$56.3	($181.5)	$34.6	$272.4	($8.5)	$9.2	($49.3)	($67.0)	$205.4	18,608	8,074
115	$6.1	($109.8)	$7.2	$123.1	$5.5	$22.8	($10.4)	($27.7)	$95.4	8,054	3,307
69	$24.1	$5.8	$2.1	$20.4	($1.5)	($0.1)	($1.8)	($3.2)	$17.2	5,476	293
23	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	21	0
13.2	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	5	0
4.1	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	0	0
1	$0.0	$0.0	$0.0	$0.0	($0.4)	$0.4	($1.1)	($1.9)	($1.9)	0	68
Unclassified	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	NA	NA
Total	$511.8	($988.5)	$118.3	$1,618.5	$17.3	$102.1	($148.0)	($232.7)	$1,385.8	57,459	20,748

Table 11-22 Congestion summary (By facility voltage): January through September, 2023

	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	($0.1)	($0.4)	$0.4	$0.7	($0.0)	$0.0	($0.2)	($0.2)	$0.5	31	1
500	$47.9	($45.7)	$12.2	$105.9	$4.2	$5.0	($5.2)	($6.0)	$100.0	1,914	507
345	($6.4)	($84.6)	$15.0	$93.2	($1.6)	$6.3	($10.4)	($18.3)	$74.9	6,937	1,402
230	$316.8	($153.7)	$56.2	$526.7	$14.4	$34.8	($105.7)	($126.1)	$400.6	20,058	6,481
161	($0.4)	($1.8)	$0.7	$2.1	$0.1	$0.5	($0.3)	($0.6)	$1.4	326	85
138	$4.5	($145.3)	$17.5	$167.4	($5.6)	($1.2)	($37.8)	($42.2)	$125.2	15,983	4,851
115	$6.8	($62.0)	$5.9	$74.7	$2.0	$18.1	($7.2)	($23.3)	$51.4	6,979	2,184
69	$7.1	$1.2	$0.7	$6.6	($0.1)	$0.0	$0.0	($0.2)	$6.4	4,038	43
23	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	0	0
13.2	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	0	0
4.1	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	7	0
1	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	$0.0	($0.0)	($0.0)	0	27
Unclassified	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	NA	NA
Total	$376.2	($492.3)	$108.8	$977.3	$13.5	$63.5	($166.9)	($216.9)	$760.4	56,273	15,581

Congestion by Facility Type and Voltage

Day-ahead, congestion event hours decreased on flowgates and increased on interfaces, lines and transformers in the first nine months of 2024. Congestion event hours on lines increased by 879 congestion event hours from 38,491 day-ahead, congestion event hours in the first nine months of 2023 to 39,370 day-ahead congestion event hours in the first nine months of 2024 (Table 11-23).

Real-time, congestion event hours decreased on flowgates and increased on interfaces, lines and transformers in the first nine months of 2024 (Table 11-24). Lines increased by 3,122 congestion event hours from 7,788 real-time, congestion event hours in the first nine months of 2023 to 12,117 real-time congestion event hours in the first nine months of 2024.

Table 11-23 provides congestion event hour subtotals and congestion cost subtotals comparing the first nine months of 2024 results by facility type: line, transformer, interface, flowgate and unclassified facilities.[24] [25]

Table 11-23 Congestion summary (By facility type): January through September, 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	($2.4)	($78.1)	$25.3	$101.0	($3.5)	$6.4	($36.1)	($46.0)	$55.0	4,825	3,879
Interface	$38.3	($56.0)	$5.2	$99.5	($4.1)	$0.9	($10.0)	($15.0)	$84.4	531	224
Line	$233.7	($616.0)	$56.7	$906.4	$3.3	$57.3	($75.6)	($129.6)	$776.8	39,370	12,117
Transformer	$104.7	($148.9)	$16.2	$269.8	$5.3	$20.1	($11.4)	($26.2)	$243.6	6,969	1,164
Other	$137.4	($89.6)	$14.9	$241.8	$16.3	$17.3	($14.9)	($15.9)	$225.9	5,764	3,364
Unclassified	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	NA	NA
Total	$511.8	($988.4)	$118.3	$1,618.5	$17.4	$102.1	($148.0)	($232.7)	$1,385.8	57,459	20,748

Table 11-24 Congestion summary (By facility type): January through September, 2023

	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	($30.9)	($91.1)	$8.6	$68.8	($5.2)	($0.4)	($40.6)	($45.4)	$23.4	5,496	4,155
Interface	$13.4	($31.6)	$2.6	$47.6	$0.1	$0.7	($0.5)	($1.0)	$46.5	462	35
Line	$232.5	($331.9)	$65.5	$629.9	$3.0	$34.8	($76.1)	($107.9)	$522.0	38,491	7,788
Transformer	$29.4	($40.7)	$12.7	$82.8	($2.8)	$7.3	($3.6)	($13.8)	$69.0	6,818	731
Other	$131.8	$3.0	$19.4	$148.2	$18.3	$21.0	($46.0)	($48.8)	$99.4	5,006	2,872
Unclassified	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	NA	NA
Total	$376.2	($492.3)	$108.8	$977.3	$13.5	$63.5	($166.9)	($216.9)	$760.4	56,273	15,581

24 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.
25 The term flowgate refers to MISO reciprocal coordinated flowgates and NYISO M2M flowgates.

Constraint Frequency

Table 11-25 lists the constraints for the first nine months of 2023 and 2024 that were most frequently binding and Table 11-26 shows the constraints which experienced the largest change in congestion event hours from the first nine months of 2023 to the first nine months of 2024. In Table 11-25, constraints are presented in descending order of total day-ahead event hours and real-time event hours for the first nine months of 2024. In Table 11-26, 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 nine months of 2023 to the first nine months of 2024.

Table 11-25 Top 25 constraints: January through September, 2023 and 2024

			(Jan - Sep)											
			Congestion Event Hours						Percent of Annual Hours					
			Day-Ahead			Real-Time			Day-Ahead			Real-Time		
No.	Constraint	Type	2023	2024	Change	2023	2024	Change	2023	2024	Change	2023	2024	Change
1	Lenox - North Meshoppen	Line	1,742	3,421	1,679	1,789	2,902	1,113	26.6%	52%	25%	27%	44%	17%
2	Nottingham	Other	4,406	3,029	(1,377)	2,535	1,421	(1,114)	67%	46%	(21%)	39%	22%	(17%)
3	Kewanee	Other	211	1,479	1,268	62	1,225	1,163	3%	22%	19%	1%	19%	18%
4	East Towanda - Hillside	Line	353	1,143	790	327	792	465	5%	17%	12%	5%	12%	7%
5	Haumesser Road - Steward	Line	402	1,022	620	161	810	649	6%	16%	9%	2%	12%	10%
6	Graceton - Safe Harbor	Line	3,030	1,119	(1,911)	1,490	611	(879)	46%	17%	(29%)	23%	9%	(13%)
7	Prest - Tibb	Flowgate	275	789	514	391	858	467	4%	12%	8%	6%	13%	7%
8	Gardners - Texas Eastern	Line	1,227	1,429	202	140	74	(66)	19%	22%	3%	2%	1%	(1%)
9	Sayreville - Sayreville	Line	1,717	1,379	(338)	0	0	0	26%	21%	(5%)	0%	0%	0%
10	Rising - Bondville	Flowgate	0	683	683	0	576	576	0%	10%	10%	0%	9%	9%
11	Yorkana	Other	0	811	811	0	448	448	0%	12%	12%	0%	7%	7%
12	Grabill - Robinson Park	Line	0	868	868	9	158	149	0%	13%	13%	0%	2%	2%
13	Easton - Emuni	Line	1,900	977	(923)	0	0	0	29%	15%	(14%)	0%	0%	0%
14	Mountain	Transformer	1,775	932	(843)	0	0	0	27%	14%	(13%)	0%	0%	0%
15	Highland - Commerce	Line	194	501	307	80	396	316	3%	8%	5%	1%	6%	5%
16	Hinshaw - Burr Oak	Flowgate	0	506	506	0	385	385	0%	8%	8%	0%	6%	6%
17	Fremont - Fremont	Line	846	861	15	0	0	0	13%	13%	0%	0%	0%	0%
18	Big Pine - Kiski Valley	Line	91	704	613	28	102	74	1%	11%	9%	0%	2%	1%
19	Bergen - Hudson	Line	940	784	(156)	0	0	0	14%	12%	(2%)	0%	0%	0%
20	Preston - Tanyard	Line	389	745	356	0	2	2	6%	11%	5%	0%	0%	0%
21	Salt Springs - Masury	Line	81	434	353	3	303	300	1%	7%	5%	0%	5%	5%
22	Collins	Transformer	669	726	57	0	0	0	10%	11%	1%	0%	0%	0%
23	Monroe - Vineland	Line	726	665	(61)	8	33	25	11%	10%	(1%)	0%	1%	0%
24	Lockwood - Richland	Line	16	600	584	2	95	93	0%	9%	9%	0%	1%	1%
25	All Dam - Kittanning	Line	325	592	267	38	76	38	5%	9%	4%	1%	1%	1%

Table 11-26 Top 25 constraints year to year change in occurrence: January through September, 2023 and 2024

			(Jan - Sep)											
			Congestion Event Hours						Percent of Annual Hours					
			Day-Ahead			Real-Time			Day-Ahead			Real-Time		
No.	Constraint	Type	2023	2024	Change	2023	2024	Change	2023	2024	Change	2023	2024	Change
1	Lenox - North Meshoppen	Line	1,742	3,421	1,679	1,789	2,902	1,113	27%	52%	25%	27%	44%	17%
2	Graceton - Safe Harbor	Line	3,030	1,119	(1,911)	1,490	611	(879)	46%	17%	(29%)	23%	9%	(13%)
3	Nottingham	Other	4,406	3,029	(1,377)	2,535	1,421	(1,114)	67%	46%	(21%)	39%	22%	(17%)
4	Kewanee	Other	211	1,479	1,268	62	1,225	1,163	3%	22%	19%	1%	19%	18%
5	Allen - R.P. Mone	Line	1,459	92	(1,367)	88	154	66	22%	1%	(21%)	1%	2%	1%
6	Weedman - Mahomet	Flowgate	622	0	(622)	651	0	(651)	9%	0%	(9%)	10%	0%	(10%)
7	Haumesser Road - Steward	Line	402	1,022	620	161	810	649	6%	16%	9%	2%	12%	10%
8	Yorkana	Other	0	811	811	0	448	448	0%	12%	12%	0%	7%	7%
9	Rising - Bondville	Flowgate	0	683	683	0	576	576	0%	10%	10%	0%	9%	9%
10	East Towanda - Hillside	Line	353	1,143	790	327	792	465	5%	17%	12%	5%	12%	7%
11	Chicago Ave - Praxair	Flowgate	694	17	(677)	539	4	(535)	11%	0%	(10%)	8%	0%	(8%)
12	Grabill - Robinson Park	Line	0	868	868	9	158	149	0%	13%	13%	0%	2%	2%
13	Prest - Tibb	Flowgate	275	789	514	391	858	467	4%	12%	8%	6%	13%	7%
14	Conastone - Northwest	Line	973	319	(654)	482	190	(292)	15%	5%	(10%)	7%	3%	(4%)
15	Turkey Hill - Hilgard	Flowgate	513	19	(494)	458	11	(447)	8%	0%	(8%)	7%	0%	(7%)
16	Easton - Emuni	Line	1,900	977	(923)	0	0	0	29%	15%	(14%)	0%	0%	0%
17	Hinshaw - Burr Oak	Flowgate	0	506	506	0	385	385	0%	8%	8%	0%	6%	6%
18	Garrett - Garrett Tap	Line	870	11	(859)	0	0	0	13%	0%	(13%)	0%	0%	0%
19	Mountain	Transformer	1,775	932	(843)	0	0	0	27%	14%	(13%)	0%	0%	0%
20	Mahomet - OCB	Flowgate	447	29	(418)	435	47	(388)	7%	0%	(6%)	7%	1%	(6%)
21	Big Pine - Kiski Valley	Line	91	704	613	28	102	74	1%	11%	9%	0%	2%	1%
22	Lockwood - Richland	Line	16	600	584	2	95	93	0%	9%	9%	0%	1%	1%
23	Salt Springs - Masury	Line	81	434	353	3	303	300	1%	7%	5%	0%	5%	5%
24	Mardela - Vienna	Line	12	530	518	3	116	113	0%	8%	8%	0%	2%	2%
25	Highland - Commerce	Line	194	501	307	80	396	316	3%	8%	5%	1%	6%	5%

Top Constraints

The top five constraints by congestion costs contributed $368.7 million, or 26.6 percent, of the total PJM congestion costs in the first nine months of 2024. The top five constraints were the Nottingham Series Reactor, the Yorkana Circuit Breaker, the Lenox – North Meshoppen Line, the AP South Interface, and the Conastone Transformer. Table 11-27 and Table 11-28 show the top constraints contributing to congestion costs by facility for the first nine months of 2024 and the first nine months of 2023.

The Nottingham Series Reactor was the largest contributor to congestion costs in the first nine months of 2024 with $93.1 million and 6.7 percent of total PJM congestion costs. The day-ahead congestion event hours of the Nottingham Series Reactor decreased from 4,406 in the first nine months of 2023 to 3,029 in the first nine months of 2024 and the real-time congestion event hours of the Nottingham Series Reactor decreased from 2,535 in the first nine months of 2023 to 1,421 in first nine months of 2024 (Table 11-25). The frequent binding of the Nottingham Series Reactor in both day-ahead and real-time was a result of a consistent gas price spread between cheaper PA gas and more expensive gas in DC, MD, and VA.

The Yorkana Circuit Breaker was the second largest contributor to congestion costs in the first nine months of 2024 with $87.6 million and 6.3 percent of total PJM congestion costs. The day-ahead congestion event hours of the Yorkana Circuit Breaker increased from 0 in the first nine months of 2023 to 811 in the first nine months of 2024 and the real-time congestion event hours of the Yorkana Circuit Breaker increased from 0 in the first nine months of 2023 to 448 in the first nine months of 2024 (Table 11-25). The frequent binding of the Yorkana Circuit Breaker in both day-ahead and real-time was a result of multiple unplanned Conastone 500 kV transformer outages.

The Lenox – North Meshoppen Line was the third largest contributor to congestion costs in the first nine months of 2024 with $66.6 million and 4.8 percent of total PJM congestion costs. The day-ahead congestion event hours of the Lenox – North Meshoppen Line increased from 1,752 in the first nine months of 2023 to 3,421 in the first nine months of 2024 and the real-time congestion event hours of the Lenox – North Meshoppen Line increased from 1,789 in the first nine months of 2023 to 2,902 in the first nine months of 2024 (Table 11-25). 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 during normal, cold conditions, due to price differences between PJM (relatively low) and NYISO (relatively high).

The AP South Interface was the fourth largest contributor to congestion costs in the first nine months of 2024 with $62.7 million and 4.5 percent of total PJM congestion costs. The frequent binding of the AP South interface in both day-ahead and real-time was a result of increased gas prices on the eastern part of the grid due to cold weather and pipeline restrictions during a cold weather alert in the middle of January.

The Conastone Transformer (Conastone 500kv #4 Transformer) was the fifth largest contributor to congestion costs in the first nine months of 2024 with $58.6 million and 4.2 percent of the total PJM congestion costs. The frequent binding of the Conastone Transformer (Conastone 500kV #4 Transformer) in both day-ahead and real-time was a result of the Conastone 500kV #2 Transformer outage.

The Lenox – North Meshoppen Line was the largest contributor to negative congestion costs in the first nine months of 2024. The Lenox – North Meshoppen Line constraint was binding due to an outage during July 22 - 26, August 6, and September 3 – 6 in 2024. In the real-time market, the Lenox – North Meshoppen Line had constraint violations on July 5th, 9th, 12th, and 30th, August 1, and August 6 of 2024 for which the transmission penalty factors were set to $2,000. The majority (61.1 percent) of negative balancing congestion costs for the Lenox – North Meshoppen Line were the result of INCs.

Table 11-27 Top 25 constraints affecting congestion costs: January through September, 2024[26]

				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	Nottingham	Other	PECO	$101.5	$22.2	$11.8	$91.1	$12.1	$2.1	($8.0)	$2.0	$93.1	6.7%
2	Yorkana	Other	MEC	$46.0	($41.6)	$2.5	$90.1	$5.3	$4.9	($2.9)	($2.5)	$87.6	6.3%
3	Lenox - North Meshoppen	Line	PE	$9.7	($75.8)	$6.1	$91.6	$6.9	$22.8	($9.0)	($25.0)	$66.6	4.8%
4	AP South	Interface	500	$31.6	($32.9)	$2.7	$67.1	($0.9)	$0.0	($3.5)	($4.4)	$62.7	4.5%
5	Conastone	Transformer	500	$27.4	($31.4)	$1.8	$60.5	$4.0	$3.3	($2.7)	($1.9)	$58.6	4.2%
6	Pleasant View	Other	DOM	($10.3)	($64.0)	$0.0	$53.7	$1.8	($0.1)	$0.3	$2.2	$55.9	4.0%
7	Chaparral - Carson	Line	DOM	$9.0	($42.6)	$2.7	$54.3	$0.0	$0.0	$0.0	$0.0	$54.3	3.9%
8	Goose Creek	Transformer	DOM	$33.7	($20.8)	$1.2	$55.8	$2.6	$3.5	($2.6)	($3.6)	$52.2	3.8%
9	Graceton - Safe Harbor	Line	BGE	$30.2	($3.0)	$3.2	$36.4	$4.4	$2.2	($3.0)	($0.8)	$35.6	2.6%
10	Braidwood - East Frankfort	Line	COMED	($4.8)	($41.8)	$0.2	$37.2	($0.1)	$2.2	($1.7)	($3.9)	$33.3	2.4%
11	Conastone - Northwest	Line	BGE	$21.0	($10.3)	$2.2	$33.6	$4.4	$3.2	($1.8)	($0.6)	$32.9	2.4%
12	Coolspring - Milford	Line	DPL	$1.2	($34.7)	$0.0	$36.0	($7.9)	($2.2)	($0.1)	($5.8)	$30.2	2.2%
13	Plymouth Meeting - Whitpain	Line	PECO	($0.7)	($31.2)	$0.3	$30.8	$1.4	$1.7	($0.7)	($0.9)	$29.9	2.2%
14	Elk Run D.P. - Rollins Ford	Line	DOM	$0.3	($27.6)	$0.8	$28.7	$0.0	$0.0	$0.0	$0.0	$28.7	2.1%
15	George Washington - Kammer	Line	AEP	($4.9)	($28.0)	$2.1	$25.2	$1.4	($1.2)	($1.4)	$1.2	$26.4	1.9%
16	East Towanda - Hillside	Line	PE	$3.9	($19.9)	$1.7	$25.5	$1.1	$1.3	($1.1)	($1.4)	$24.0	1.7%
17	Cedar Creek - Silver Run	Line	DPL	($3.4)	($27.4)	$0.3	$24.3	($1.2)	($0.5)	$0.1	($0.7)	$23.6	1.7%
18	Juniata	Transformer	500	$10.4	($13.3)	$0.3	$24.0	($0.2)	$0.3	($0.1)	($0.6)	$23.5	1.7%
19	Pleasant View - Ashburn	Line	DOM	$9.9	($11.6)	$1.6	$23.2	$1.9	$1.5	($0.4)	($0.0)	$23.1	1.7%
20	Ashburn - Goose Creek	Line	DOM	$8.9	($10.8)	$0.7	$20.4	$0.0	$0.0	$0.0	$0.0	$20.4	1.5%
21	Fremont - Fremont	Line	AEP	($3.0)	($18.3)	$2.2	$17.5	$0.0	$0.0	$0.0	$0.0	$17.5	1.3%
22	Collins	Transformer	COMED	$1.4	($8.9)	$6.4	$16.7	$0.0	$0.0	$0.0	$0.0	$16.7	1.2%
23	Dickerson - Dickerson Station	Line	PEPCO	$14.9	($2.7)	$0.7	$18.3	$0.8	$1.6	($1.1)	($1.9)	$16.4	1.2%
24	Davis Besse	Other	ATSI	$0.0	$0.0	$0.0	$0.0	($1.8)	$10.9	($2.9)	($15.6)	($15.6)	(1.1%)
25	Charlottesville - Proffit D.P.	Line	DOM	$9.2	($4.2)	$1.2	$14.6	$0.2	($0.5)	($0.5)	$0.2	$14.8	1.1%
	Top 25 Total			$343.1	($580.7)	$52.9	$976.7	$36.3	$57.2	($43.0)	($63.9)	$912.8	65.9%
	All Other Constraints			$168.7	($407.8)	$65.3	$641.8	($18.9)	$44.9	($105.0)	($168.8)	$473.0	34.1%
	Total			$511.8	($988.4)	$118.3	$1,618.5	$17.4	$102.1	($148.0)	($232.7)	$1,385.8	100.0%

26 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 11-28 Top 25 constraints affecting congestion costs: January through September, 2023[27]

				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	Nottingham	Other	PECO	$129.1	$7.0	$17.8	$139.9	$15.9	$13.1	($12.0)	($9.3)	$130.6	17.2%
2	Conastone - Northwest	Line	BGE	$58.9	($16.6)	$5.2	$80.7	$7.2	$6.3	($3.4)	($2.4)	$78.3	10.3%
3	Graceton - Safe Harbor	Line	BGE	$66.1	($1.2)	$7.8	$75.1	$7.7	$5.3	($4.2)	($1.8)	$73.3	9.6%
4	Coolspring - Milford	Line	DPL	$3.4	($50.5)	$0.1	$53.9	($9.1)	($5.1)	($0.8)	($4.8)	$49.1	6.5%
5	Dresden	Transformer	COMED	$7.7	($16.5)	$0.7	$24.9	($1.6)	$1.7	$0.1	($3.2)	$21.7	2.9%
6	Beaumeade	Other	DOM	$1.5	($0.4)	$0.9	$2.8	$1.9	$2.1	($23.1)	($23.3)	($20.4)	(2.7%)
7	AP South	Interface	500	$8.4	($9.8)	$1.6	$19.8	$0.1	$0.6	($0.4)	($0.9)	$19.0	2.5%
8	Allen - R.P. Mone	Line	AEP	($5.0)	($19.7)	$3.3	$18.0	($0.6)	($0.7)	($0.0)	$0.1	$18.1	2.4%
9	Lenox - North Meshoppen	Line	PE	$5.0	($29.6)	$2.3	$36.9	$2.4	$16.9	($4.5)	($19.0)	$17.9	2.4%
10	Conastone	Transformer	500	$9.7	($8.4)	$0.6	$18.7	$2.4	$3.0	($0.9)	($1.4)	$17.3	2.3%
11	Cedar Creek - Silver Run	Line	DPL	($1.0)	($19.5)	$0.4	$18.9	($3.8)	($2.3)	($0.3)	($1.8)	$17.2	2.3%
12	Will County - Goodings Grove	Line	COMED	$25.2	$7.3	($2.3)	$15.6	$0.0	$0.0	$0.0	$0.0	$15.6	2.1%
13	Gardners - Texas Eastern	Line	MEC	($4.0)	($20.0)	$0.1	$16.1	$0.1	$0.3	($0.4)	($0.6)	$15.5	2.0%
14	Conastone - Peach Bottom	Line	500	$13.0	($1.1)	$2.1	$16.1	$1.5	$0.8	($1.4)	($0.7)	$15.4	2.0%
15	Bedington - Black Oak	Interface	500	$4.3	($9.6)	$1.1	$15.1	$0.0	$0.0	$0.0	$0.0	$15.1	2.0%
16	Brambleton - Evergreen Mills	Line	DOM	$14.6	($21.8)	$1.3	$37.8	$2.8	$2.2	($24.3)	($23.8)	$14.0	1.8%
17	Pleasant View	Other	DOM	$1.7	($0.1)	$0.4	$2.1	$0.9	$5.4	($10.7)	($15.2)	($13.0)	(1.7%)
18	Doubs - Goose Creek	Line	APS	$7.9	$2.5	$5.6	$11.0	$0.0	$0.0	$0.0	$0.0	$11.0	1.4%
19	Fremont - Fremont	Line	AEP	($2.7)	($11.6)	$1.7	$10.5	$0.0	$0.0	$0.0	$0.0	$10.5	1.4%
20	Collins	Transformer	COMED	($1.0)	($4.6)	$4.8	$8.4	$0.0	$0.0	$0.0	$0.0	$8.4	1.1%
21	Mahomet - OCB	Flowgate	MISO	($5.5)	($13.4)	$1.0	$9.0	($0.1)	($1.7)	($2.3)	($0.7)	$8.2	1.1%
22	George Washington - Kammer	Line	AEP	($1.6)	($8.8)	$0.8	$8.0	$0.6	$0.5	($0.3)	($0.3)	$7.8	1.0%
23	Juniata	Transformer	500	$2.4	($3.9)	$0.1	$6.4	($0.1)	($0.3)	($0.1)	$0.1	$6.5	0.9%
24	Weedman - Mahomet	Flowgate	MISO	($3.9)	($11.6)	$0.9	$8.7	($0.3)	($1.7)	($3.7)	($2.3)	$6.3	0.8%
25	Goodings Grove - Elwood	Line	COMED	$0.1	($5.9)	$0.1	$6.2	$0.0	$0.0	($0.0)	($0.1)	$6.1	0.8%
	Top 25 Total			$334.4	($268.1)	$58.2	$660.7	$28.0	$46.3	($92.9)	($111.2)	$549.5	72.3%
	All Other Constraints			$41.9	($224.3)	$50.5	$316.7	($14.6)	$17.2	($74.0)	($105.7)	$211.0	27.7%
	Total			$376.2	($492.3)	$108.8	$977.3	$13.5	$63.5	($166.9)	($216.9)	$760.4	100.0%

27 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 nine months of 2024. The Nottingham Series Reactor was the top constraint.

Figure 11-4 Top five constraints affecting total congestion costs: January through September, 2024

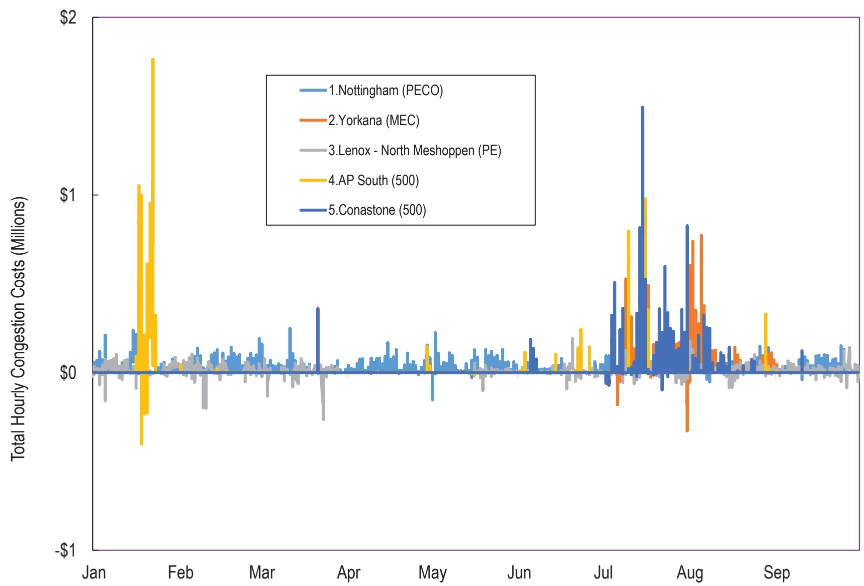


Figure 11-5 shows the total hourly balancing congestion costs of the top five constraints in the first nine months of 2024.

Figure 11-5 Top five constraints affecting balancing congestion costs: January through September, 2024

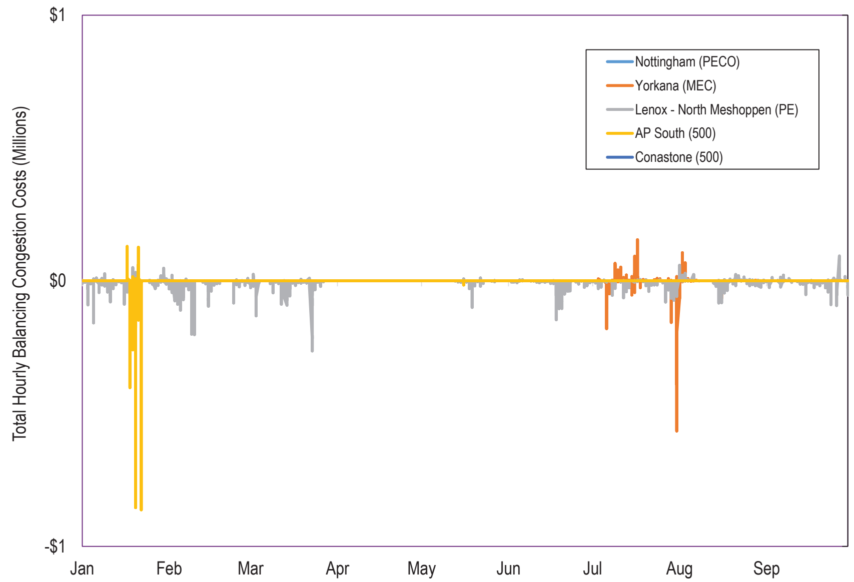


Figure 11-6 shows the total hourly day-ahead congestion costs of the top five constraints in the first nine months of 2024.

Figure 11-6 Top five constraints affecting day-ahead congestion costs: January through September, 2024

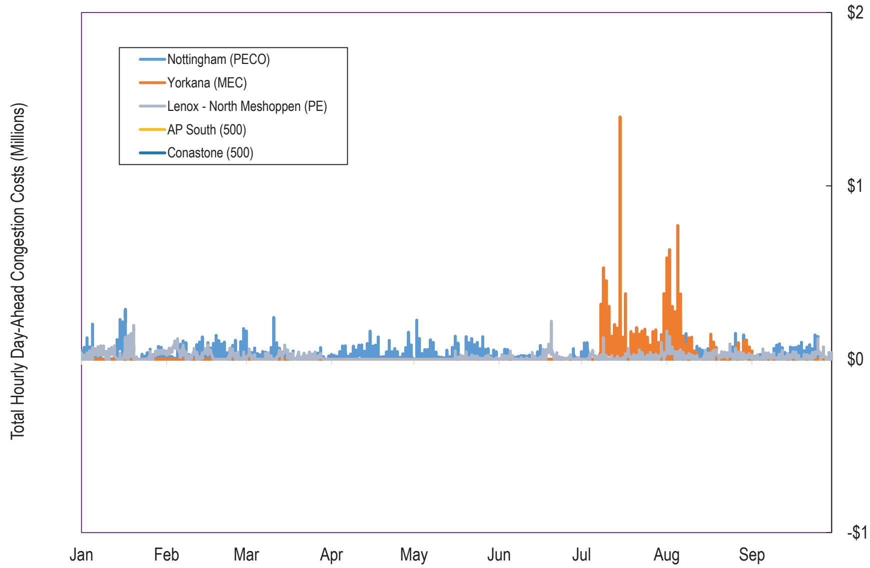


Figure 11-7 shows the locations of the top 10 constraints by total congestion costs on a contour map of the real-time, load-weighted average CLMP in the first nine months of 2024.

Figure 11-7 Location of the top 10 constraints by total congestion costs: January through September, 2024

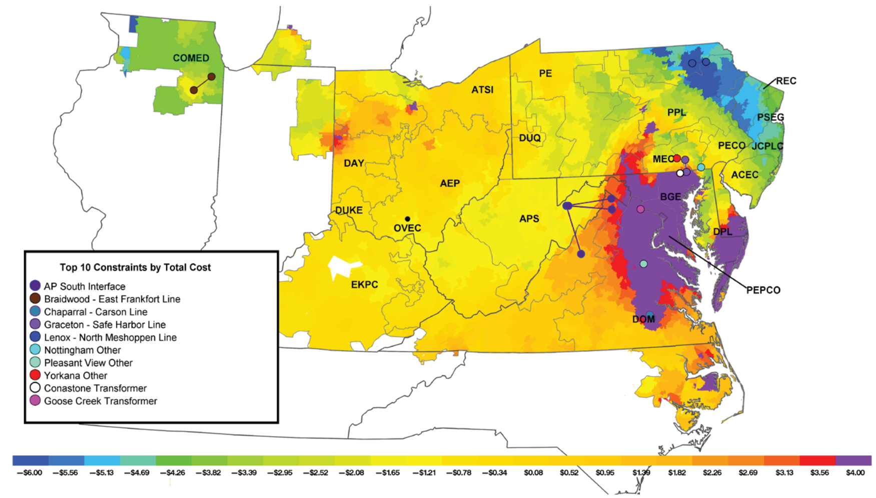


Figure 11-8 shows the locations of the top 10 constraints by balancing congestion costs on a contour map of the real-time load-weighted average CLMP in the first nine months of 2024.

Figure 11-8 Location of top 10 constraints by balancing congestion costs: January through September, 2024

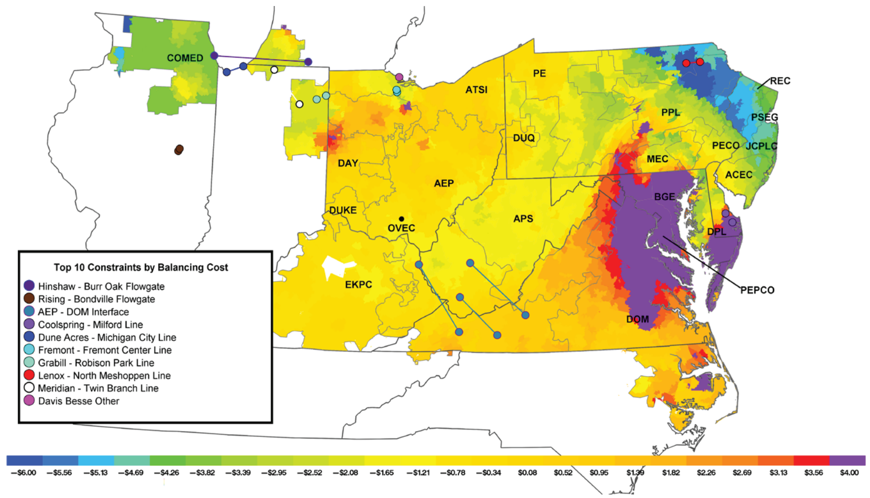
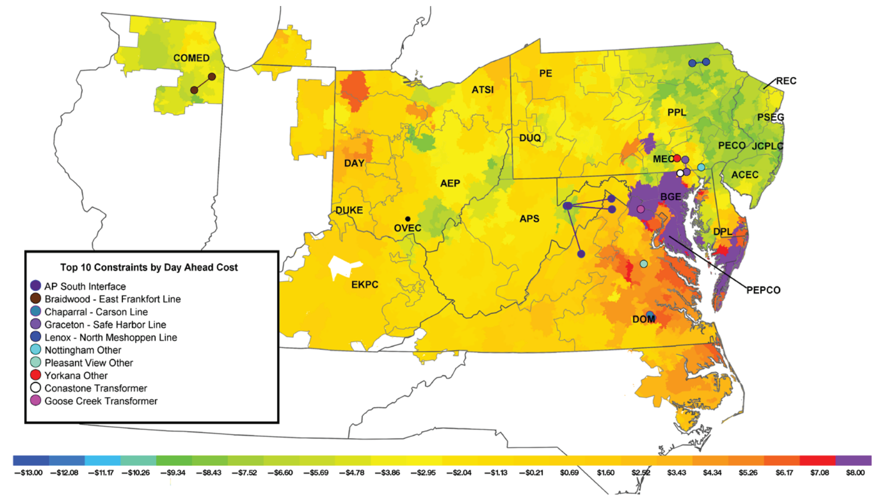


Figure 11-9 shows the locations of the top 10 constraints by day-ahead congestion costs on a contour map of the day-ahead load-weighted average CLMP in the first nine months of 2024.

Figure 11-9 Location of top 10 constraints by day-ahead congestion costs: January through September, 2024



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

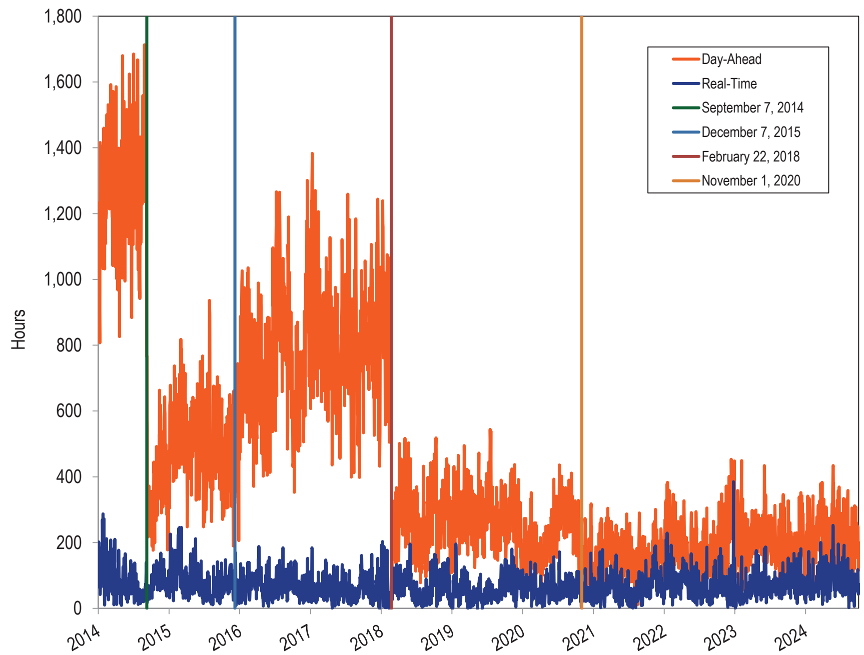
UTCs have a significant impact on congestion events in the day-ahead market and, as a result, contribute to differences between day-ahead and real-time congestion events. The greater the volume of UTCs, the greater the number of congestion events in the day-ahead market and the greater the differences between the day-ahead and real-time congestion events.[28]

28 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 nine months of 2024, the average hourly cleared UTC MW decreased by 50.6 percent, compared to in the first nine months of 2023. Day-ahead congestion event hours increased by 2.1 percent from 56,273 congestion event hours in the first nine months of 2023 to 57,459 congestion event hours in the first nine months of 2024 (Table 11-19).

Figure 11-10 shows the daily day-ahead and real-time congestion event hours for January 2014 through September 2024.

Figure 11-10 Daily congestion event hours: January 2014 through September 2024



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.[29] 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.[30] Each of these categories of marginal loss costs is comprised of day-ahead and balancing marginal loss costs.

29 PJM Operating Agreement Schedule 1 §3.7.
30 *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.[31]

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.[32]

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 nine months of 2024 was $695.2 million, which was comprised of implicit withdrawal MLMP charges of $72.1 million minus implicit injection MLMP credits of -$629.0 million plus explicit loss charges of -$6.0 million plus inadvertent loss charges of $0.0 million (Table 11-30).

Monthly marginal loss costs in the first nine months of 2024 ranged from $41.5 million in March to $129.8 million in July. Total marginal loss surplus decreased in the first nine months of 2024 by $55.7 million or 11.4 percent from $202.7 million in the first nine months of 2023 to $258.5 million in the first nine months of 2024.

Table 11-29 shows the total marginal loss component costs and the total PJM billing for the first nine months of 2008 through 2024.

31 See PJM. "Manual 28: Operating Agreement Accounting," Rev. 96 (Sept. 1, 2024).

32 PJM Operating Agreement Schedule 1 §3.7.

Table 11-29 Total loss component costs (Dollars (Millions)): January through September, 2008 through 2024[33] [34]

(Jan - Sep)	Loss Costs	Percent Change	Total PJM Billing	Percent of PJM Billing
2008	$2,049	NA	$26,979	7.6%
2009	$992	(51.6%)	$19,927	5.0%
2010	$1,259	26.9%	$26,249	4.8%
2011	$1,153	(8.5%)	$28,836	4.0%
2012	$758	(34.3%)	$22,119	3.4%
2013	$797	5.2%	$25,153	3.2%
2014	$1,243	56.0%	$40,770	3.0%
2015	$830	(33.3%)	$33,710	2.5%
2016	$542	(34.7%)	$29,490	1.8%
2017	$501	(7.5%)	$29,510	1.7%
2018	$757	51.1%	$37,950	2.0%
2019	$503	(33.6%)	$31,850	1.6%
2020	$349	(30.5%)	$27,070	1.3%
2021	$670	91.9%	$37,520	1.8%
2022	$1,472	119.6%	$66,110	2.2%
2023	$588	(60.0%)	$36,380	1.6%
2024	$695	18.1%	$39,070	1.8%

Table 11-30 shows PJM total marginal loss costs by accounting category for the first nine months of 2008 through 2024. Table 11-31 shows PJM total marginal loss costs by accounting category by market for the first nine months of 2008 through 2024.

Table 11-30 Total marginal loss costs by accounting category (Dollars (Millions)): January through September, 2008 through 2024

	Marginal Loss Costs (Millions)				
(Jan - Sep)	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Inadvertent Charges	Total
2008	($210.3)	($2,185.9)	$73.3	$0.0	$2,048.9
2009	($62.0)	($1,028.3)	$26.1	$0.0	$992.4
2010	($73.8)	($1,301.6)	$31.5	($0.0)	$1,259.3
2011	($138.8)	($1,277.7)	$13.7	$0.0	$1,152.6
2012	($17.3)	($790.0)	($15.1)	$0.0	$757.6
2013	($3.3)	($834.4)	($34.1)	($0.0)	$797.0
2014	($47.6)	($1,343.7)	($52.9)	$0.0	$1,243.1
2015	($26.1)	($872.8)	($16.9)	$0.0	$829.8
2016	($41.7)	($605.4)	($21.8)	($0.0)	$541.9
2017	($38.6)	($568.1)	($28.4)	$0.0	$501.0
2018	($32.7)	($798.6)	($8.9)	$0.0	$757.0
2019	($35.5)	($550.1)	($12.0)	$0.0	$502.7
2020	($25.8)	($387.4)	($12.4)	$0.0	$349.2
2021	$3.3	($673.5)	($6.7)	$0.0	$670.2
2022	$132.6	($1,373.8)	($34.3)	($0.0)	$1,472.0
2023	$8.5	($587.6)	($7.7)	$0.0	$588.5
2024	$72.1	($629.0)	($6.0)	$0.0	$695.2

33 The loss costs include net inadvertent charges.
34 In Table 11-29, 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 11-31 Total marginal loss costs by market (Dollars (Millions)): January through September, 2008 through 2024

	Marginal Loss Costs (Millions)									
	Day-Ahead				Balancing					
(Jan - Sep)	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Inadvertent Charges	Grand Total
2008	($132.3)	($2,133.4)	$100.8	$2,101.8	($77.9)	($52.5)	($27.4)	($52.9)	$0.0	$2,048.9
2009	($65.9)	($1,025.7)	$53.2	$1,013.0	$3.9	($2.6)	($27.1)	($20.6)	$0.0	$992.4
2010	($94.4)	($1,307.1)	$61.5	$1,274.2	$20.6	$5.6	($30.0)	($14.9)	($0.0)	$1,259.3
2011	($174.3)	($1,313.6)	$51.7	$1,191.1	$35.5	$36.0	($38.0)	($38.5)	$0.0	$1,152.6
2012	($42.2)	($805.6)	$12.7	$776.0	$24.9	$15.6	($27.8)	($18.5)	$0.0	$757.6
2013	($30.3)	($857.9)	$44.0	$871.6	$27.0	$23.5	($78.1)	($74.6)	($0.0)	$797.0
2014	($95.5)	($1,380.8)	$62.7	$1,347.9	$47.9	$37.1	($115.6)	($104.8)	$0.0	$1,243.1
2015	($47.0)	($883.1)	$24.7	$860.8	$20.9	$10.3	($41.6)	($31.0)	$0.0	$829.8
2016	($48.4)	($606.0)	$37.8	$595.4	$6.6	$0.5	($59.5)	($53.4)	($0.0)	$541.9
2017	($45.9)	($568.9)	$43.1	$566.0	$7.3	$0.8	($71.5)	($65.0)	$0.0	$501.0
2018	($38.5)	($790.8)	$28.6	$780.9	$5.8	($7.8)	($37.5)	($23.9)	$0.0	$757.0
2019	($37.4)	($547.8)	$32.2	$542.6	$1.9	($2.3)	($44.2)	($39.9)	$0.0	$502.7
2020	($27.8)	($388.8)	$30.5	$391.5	$2.0	$1.4	($42.9)	($42.3)	$0.0	$349.2
2021	$2.0	($668.7)	$24.7	$695.4	$1.3	($4.9)	($31.4)	($25.2)	$0.0	$670.2
2022	$136.8	($1,371.2)	$65.6	$1,573.6	($4.2)	($2.6)	($99.9)	($101.5)	($0.0)	$1,472.0
2023	$8.0	($585.1)	$53.9	$646.9	$0.6	($2.6)	($61.5)	($58.4)	$0.0	$588.5
2024	$70.8	($631.6)	$42.9	$745.3	$1.3	$2.6	($48.9)	($50.1)	$0.0	$695.2

Table 11-32 and Table 11-33 show PJM accounting based total loss costs for each transaction type in the first nine months of 2024 and 2023.

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 nine months of 2024, DECs were paid $4.1 million in MLMP credits in the day-ahead market, paid $6.2 million in MLMP in the balancing energy market and paid $2.2million in total MLMP charges. In the first nine months of 2024, INCs paid $25.0 million in MLMP charges in the day-ahead market, were paid $27.3 million in MLMP credits in the balancing energy market and were paid $2.3 million in total MLMP credits. In the first nine months of 2024, up to congestion paid $44.0 million in MLMP charges in the day-ahead market, were paid $47.8 million in MLMP credits in the balancing energy market and received $3.7 million in total MLMP credits.

Table 11-32 Total loss costs by transaction type (Dollars (Millions)): January through September, 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	($4.1)	$0.0	$0.0	($4.1)	$6.2	$0.0	$0.0	$6.2	$0.0	$2.2
Demand	$47.0	$0.0	$0.0	$47.0	$7.5	$0.0	$0.0	$7.5	$0.0	$54.5
Demand Response	$0.1	$0.0	$0.0	$0.1	($0.1)	$0.0	$0.0	($0.1)	$0.0	$0.0
Explicit Congestion and Loss Only	$0.0	$0.0	($1.3)	($1.3)	$0.0	$0.0	($0.0)	($0.0)	$0.0	($1.3)
Export	($14.0)	$0.0	($0.2)	($14.2)	($8.3)	$0.0	($0.8)	($9.1)	$0.0	($23.3)
Generation	$0.0	($646.2)	$0.0	$646.2	$0.0	($11.0)	$0.0	$11.0	$0.0	$657.2
Import	$0.0	($2.6)	$0.0	$2.6	$0.0	($9.6)	$0.0	$9.6	$0.0	$12.3
INC	$0.0	($25.0)	$0.0	$25.0	$0.0	$27.3	$0.0	($27.3)	$0.0	($2.3)
Internal Bilateral	$41.8	$42.2	$0.4	($0.0)	($4.1)	($4.1)	$0.0	($0.0)	$0.0	($0.0)
Up to Congestion	$0.0	$0.0	$44.0	$44.0	$0.0	$0.0	($47.8)	($47.8)	$0.0	($3.7)
Wheel In	$0.0	$0.0	($0.1)	($0.1)	$0.0	$0.0	($0.3)	($0.3)	$0.0	($0.3)
Total	$70.8	($631.6)	$42.9	$745.3	$1.3	$2.6	($48.9)	($50.1)	$0.0	$695.1

Table 11-33 Total loss costs by transaction type (Dollars (Millions)): January through September, 2023

	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	($3.1)	$0.0	$0.0	($3.1)	$4.8	$0.0	$0.0	$4.8	$0.0	$1.6
Demand	$9.6	$0.0	$0.0	$9.6	$7.1	$0.0	$0.0	$7.1	$0.0	$16.7
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	($1.0)	($1.0)	$0.0	$0.0	($0.0)	($0.0)	$0.0	($1.0)
Export	($13.0)	$0.0	($0.1)	($13.1)	($7.5)	$0.0	($0.7)	($8.2)	$0.0	($21.3)
Generation	$0.0	($580.7)	$0.0	$580.7	$0.0	($10.6)	$0.0	$10.6	$0.0	$591.3
Import	$0.0	($2.2)	$0.0	$2.2	$0.0	($5.5)	$0.0	$5.5	$0.0	$7.8
INC	$0.0	($16.9)	$0.0	$16.9	$0.0	$17.3	$0.0	($17.3)	$0.0	($0.5)
Internal Bilateral	$14.5	$14.7	$0.3	($0.0)	($3.8)	($3.8)	$0.0	($0.0)	$0.0	($0.0)
Up to Congestion	$0.0	$0.0	$54.7	$54.7	$0.0	$0.0	($60.7)	($60.7)	$0.0	($6.0)
Wheel In	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($0.1)	($0.1)	$0.0	($0.1)
Total	$8.0	($585.1)	$53.9	$646.9	$0.6	($2.6)	($61.5)	($58.4)	$0.0	$588.5

Table 11-34 compares MLMP credits and charges for each transaction type between the dispatch run and pricing run in the first nine months of 2024. Total MLMP charges to generation increased by $2.0 million, and total MLMP charges to demand increased by $0.8 million from the dispatch run to the pricing run. The total MLMP charges to DECs increased by $0.4 million, the total MLMP credits to INCs decreased by $2.2 million and the total CLMP credits to UTCs decreased by $3.9 million from the dispatch run to the pricing run.

Table 11-34 Total loss costs by dispatch and pricing run (Dollars (Millions)): January through September, 2024

	Marginal Loss Costs (Millions)								
	Dispatch Run			Pricing Run			Difference		
Transaction Type	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total
DEC	($4.1)	$5.8	$1.7	($4.1)	$6.2	$2.2	($0.0)	$0.4	$0.4
Demand	$46.7	$6.9	$53.6	$47.0	$7.5	$54.5	$0.2	$0.6	$0.8
Demand Response	$0.1	($0.1)	$0.0	$0.1	($0.1)	$0.0	$0.0	($0.0)	($0.0)
Explicit Congestion and Loss Only	($1.3)	($0.0)	($1.3)	($1.3)	($0.0)	($1.3)	($0.0)	($0.0)	($0.0)
Export	($14.2)	($8.5)	($22.7)	($14.2)	($9.1)	($23.3)	($0.0)	($0.6)	($0.6)
Generation	$644.9	$10.3	$655.2	$646.2	$11.0	$657.2	$1.3	$0.7	$2.0
Import	$2.6	$8.8	$11.4	$2.6	$9.6	$12.3	$0.0	$0.8	$0.8
INC	$25.0	($25.1)	($0.1)	$25.0	($27.3)	($2.3)	$0.0	($2.2)	($2.2)
Internal Bilateral	$0.0	($0.0)	($0.0)	$0.0	($0.0)	($0.0)	($0.0)	($0.0)	($0.0)
Up to Congestion	$43.9	($43.8)	$0.2	$44.0	($47.8)	($3.7)	$0.1	($4.0)	($3.9)
Wheel In	($0.1)	($0.2)	($0.3)	($0.1)	($0.3)	($0.3)	($0.0)	($0.0)	($0.0)
Total	$743.7	($45.9)	$697.7	$745.3	($50.1)	$695.1	$1.6	($4.2)	($2.6)

Monthly Marginal Loss Costs

Table 11-35 shows a monthly summary of marginal loss costs by market type for 2023 through the first nine months of 2024.

Table 11-35 Monthly marginal loss costs (Millions): January 2023 through September 2024

	Marginal Loss Costs (Millions)							
	2023				2024			
	Day-Ahead	Balancing	Inadvertent Charges	Total	Day-Ahead	Balancing	Inadvertent Charges	Total
Jan	$88.3	($9.5)	($0.0)	$78.8	$137.5	($9.5)	$0.0	$128.1
Feb	$73.0	($6.7)	($0.0)	$66.3	$52.0	($4.7)	$0.0	$47.3
Mar	$61.5	($5.4)	$0.0	$56.1	$46.7	($5.1)	($0.0)	$41.5
Apr	$51.2	($4.2)	$0.0	$47.0	$48.6	($4.0)	$0.0	$44.6
May	$57.2	($8.0)	($0.0)	$49.1	$72.6	($4.3)	$0.0	$68.2
Jun	$59.0	($6.1)	$0.0	$52.9	$84.8	($5.0)	$0.0	$79.7
Jul	$109.7	($7.2)	$0.0	$102.5	$136.4	($6.7)	$0.0	$129.8
Aug	$77.0	($5.9)	$0.0	$71.0	$103.8	($6.4)	$0.0	$97.4
Sep	$70.0	($5.4)	$0.0	$64.6	$62.9	($4.4)	$0.0	$58.5
Oct	$68.5	($4.7)	$0.0	$63.8				
Nov	$69.0	($4.9)	$0.0	$64.1				
Dec	$65.8	($5.0)	$0.0	$60.8				
Total	$850.2	($73.0)	$0.0	$777.2	$745.3	($50.1)	$0.0	$695.2

Figure 11-11 shows PJM monthly marginal loss costs for 2008 through the first nine months of 2024.

Figure 11-11 Monthly marginal loss cost (Dollars (Millions)): January 2008 through September 2024

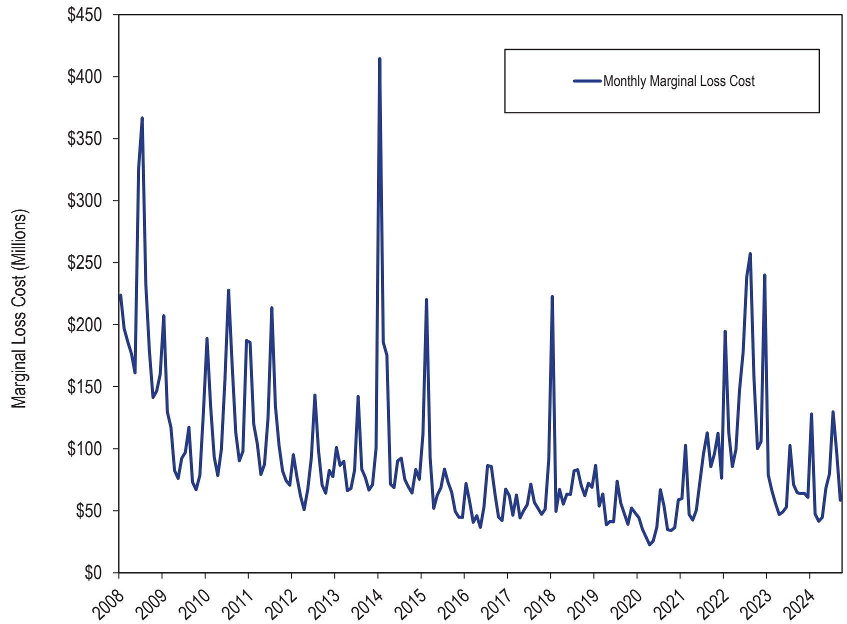


Table 11-36 shows the monthly total loss charges for each virtual transaction type for 2023 through the first nine months of 2024. In the first nine months of 2024, 95.6 percent of the total credits to virtuals went to UTCs, compared to 124.4 percent in the first nine months of 2023.

Table 11-36 Monthly loss charges by virtual transaction type (Dollars (Millions)): January 2023 through September 2024

		Marginal Loss Charges (Millions)									
		DEC			INC			Up to Congestion			
Year		Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Grand Total
2023	Jan	($0.1)	$0.2	$0.1	$2.4	($3.0)	($0.5)	$8.2	($9.9)	($1.7)	($2.1)
	Feb	$0.6	($0.2)	$0.5	$2.4	($2.5)	($0.1)	$5.6	($5.8)	($0.3)	$0.1
	Mar	($0.6)	$0.7	$0.1	$1.9	($2.2)	($0.4)	$5.0	($5.7)	($0.7)	($1.0)
	Apr	($0.7)	$0.6	($0.0)	$2.0	($2.0)	$0.0	$4.6	($5.1)	($0.4)	($0.4)
	May	($0.4)	$0.6	$0.1	$2.0	($1.8)	$0.2	$8.5	($8.4)	$0.1	$0.4
	Jun	($0.7)	$0.6	($0.1)	$1.3	($1.1)	$0.3	$6.4	($6.1)	$0.3	$0.5
	Jul	($0.7)	$1.3	$0.6	$1.8	($1.6)	$0.1	$7.3	($8.3)	($1.0)	($0.3)
	Aug	($0.5)	$0.6	$0.1	$1.6	($1.6)	$0.0	$4.6	($5.9)	($1.3)	($1.2)
	Sep	($0.1)	$0.3	$0.2	$1.6	($1.6)	($0.1)	$4.4	($5.4)	($1.0)	($0.8)
	Oct	($0.2)	$0.1	($0.0)	$3.8	($3.7)	$0.1	$4.4	($4.2)	$0.2	$0.2
	Nov	($0.4)	$0.5	$0.1	$2.4	($2.9)	($0.4)	$5.4	($5.6)	($0.2)	($0.5)
	Dec	$0.1	$0.0	$0.1	$1.6	($1.8)	($0.3)	$4.8	($5.4)	($0.6)	($0.8)
	Total	($3.6)	$5.3	$1.8	$24.7	($25.7)	($1.0)	$69.3	($75.8)	($6.6)	($5.8)
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)
	Total	($4.1)	$6.2	$6.0	$25.0	($27.3)	($2.3)	$44.0	($47.8)	($3.7)	($3.9)

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 11-37 shows the total system energy costs, the total marginal loss costs collected, the net residual market adjustments and total marginal loss surplus redistributed for the first nine months of 2008 through 2024. The total marginal loss surplus decreased by $55.7 million or 11.4 percent in the first nine months of 2024 from the first nine months of 2023.

Table 11-37 Marginal loss surplus (Dollars (Millions)): January through September, 2008 through 2024[35]

Marginal Loss Surplus (Millions)						
			Net Residual Market Adjustments			
(Jan - Sep)	System Energy Cost	Marginal Loss Costs	Known Day-Ahead Error	Day-Ahead Loss MW Congestion	Balancing Loss MW Congestion	Total Marginal Loss Surplus
2008	($976.0)	$2,048.9	$0.0	$0.0	$0.0	$1,073.0
2009	($484.6)	$992.4	($0.0)	($0.4)	($0.1)	$508.3
2010	($618.6)	$1,259.3	$0.0	($0.6)	($0.1)	$641.5
2011	($651.3)	$1,152.6	$0.1	$1.3	($0.0)	$500.1
2012	($442.6)	$757.6	$0.1	($0.7)	$0.0	$315.7
2013	($527.2)	$797.0	$0.0	$1.7	$0.0	$268.0
2014	($833.9)	$1,243.1	($0.0)	$5.1	$0.1	$404.1
2015	($536.5)	$829.8	($0.3)	$4.7	($0.1)	$288.3
2016	($358.3)	$541.9	$0.0	$2.8	($0.2)	$181.0
2017	($344.0)	$501.0	$0.0	$0.7	($0.1)	$156.5
2018	($498.7)	$757.0	($0.0)	$1.9	($0.1)	$256.4
2019	($339.3)	$502.7	($0.0)	$1.3	($0.1)	$162.1
2020	($234.0)	$349.2	($0.0)	$1.1	($0.1)	$114.2
2021	($430.7)	$670.2	($0.0)	$2.5	($0.1)	$237.0
2022	($979.1)	$1,472.0	($0.0)	$5.6	($0.2)	$487.6
2023	($384.6)	$588.5	($0.0)	$1.3	($0.2)	$202.7
2024	($434.8)	$695.2	($0.0)	$2.1	($0.2)	$258.5

35 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 nine months of 2024 was -$434.8 million, which was comprised of implicit withdrawal energy charges of $29,702.8 million, implicit injection energy credits of $30,147.1 million, explicit energy charges of $0.0 million and inadvertent energy charges of $9.4 million. The monthly system energy costs for the first nine months of 2024 ranged from -$86.3 million in January to -$27.6 million in March. Table 11-38 shows total system energy costs and total PJM billing, for the first nine months of 2008 through 2024.

Table 11-38 Total system energy costs (Dollars (Millions)): January through September, 2008 through 2024[36 37]

(Jan - Sep)	System Energy Costs	Percent Change	Total PJM Billing	Percent of PJM Billing
2008	($976)	NA	$26,979	(3.6%)
2009	($485)	(50.3%)	$19,927	(2.4%)
2010	($619)	27.6%	$26,249	(2.4%)
2011	($651)	5.3%	$28,836	(2.3%)
2012	($443)	(32.0%)	$22,119	(2.0%)
2013	($527)	19.1%	$25,153	(2.1%)
2014	($834)	58.2%	$40,770	(2.0%)
2015	($537)	(35.7%)	$33,710	(1.6%)
2016	($358)	(33.2%)	$29,490	(1.2%)
2017	($344)	(4.0%)	$29,510	(1.2%)
2018	($499)	45.0%	$37,950	(1.3%)
2019	($339)	(32.0%)	$31,850	(1.1%)
2020	($234)	(31.0%)	$27,070	(0.9%)
2021	($431)	84.0%	$37,520	(1.1%)
2022	($979)	127.3%	$66,110	(1.5%)
2023	($385)	(60.7%)	$36,380	(1.1%)
2024	($435)	13.1%	$39,070	(1.1%)

System energy costs for the first nine months of 2008 through 2024 are shown in Table 11-39 and Table 11-40. Table 11-39 shows PJM system energy costs by accounting category and Table 11-40 shows PJM system energy costs by market category.

36 The system energy costs include net inadvertent charges.
37 In Table 11-38, 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 11-39 Total system energy costs by accounting category (Dollars (Millions)): January through September, 2008 through 2024

	System Energy Costs (Millions)				
(Jan - Sep)	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Inadvertent Charges	Total
2008	$91,391.9	$92,368.9	$0.0	$1.0	($976.0)
2009	$32,472.4	$32,960.8	$0.0	$3.8	($484.6)
2010	$41,562.3	$42,169.5	$0.0	($11.4)	($618.6)
2011	$38,515.2	$39,193.0	$0.0	$26.5	($651.3)
2012	$28,303.5	$28,754.0	$0.0	$7.9	($442.6)
2013	$32,756.8	$33,279.9	$0.0	($4.2)	($527.2)
2014	$50,415.3	$51,245.6	$0.0	($3.6)	($833.9)
2015	$33,772.7	$34,311.9	$0.0	$2.6	($536.5)
2016	$25,858.3	$26,213.7	$0.0	($2.9)	($358.3)
2017	$26,082.1	$26,430.6	$0.0	$4.5	($344.0)
2018	$33,871.7	$34,376.1	$0.0	$5.7	($498.7)
2019	$23,696.4	$24,035.9	$0.0	$0.2	($339.3)
2020	$17,364.8	$17,600.7	$0.0	$1.9	($234.0)
2021	$28,853.8	$29,288.0	$0.0	$3.5	($430.7)
2022	$64,425.9	$65,400.0	$0.0	($5.0)	($979.1)
2023	$26,456.4	$26,844.2	$0.0	$3.2	($384.6)
2024	$29,702.8	$30,147.1	$0.0	$9.4	($434.8)

Table 11-40 Total system energy costs by market (Dollars (Millions)): January through September, 2008 through 2024

	System Energy Costs (Millions)									
	Day-Ahead				Balancing					
(Jan - Sep)	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Inadvertent Charges	Grand Total
2008	$67,568.7	$68,653.8	$0.0	($1,085.1)	$23,823.2	$23,715.1	$0.0	$108.1	$1.0	($976.0)
2009	$32,628.0	$33,162.4	$0.0	($534.4)	($155.6)	($201.6)	$0.0	$45.9	$3.8	($484.6)
2010	$41,665.6	$42,289.1	$0.0	($623.5)	($103.4)	($119.7)	$0.0	$16.3	($11.4)	($618.6)
2011	$38,908.1	$39,530.7	$0.0	($622.6)	($392.9)	($337.7)	$0.0	($55.3)	$26.5	($651.3)
2012	$28,423.3	$28,853.1	$0.0	($429.8)	($119.9)	($99.2)	$0.0	($20.7)	$7.9	($442.6)
2013	$32,797.0	$33,398.3	$0.0	($601.3)	($40.2)	($118.4)	$0.0	$78.2	($4.2)	($527.2)
2014	$50,428.5	$51,603.0	$0.0	($1,174.5)	($13.2)	($357.4)	$0.0	$344.2	($3.6)	($833.9)
2015	$33,910.7	$34,549.7	$0.0	($639.0)	($138.0)	($237.8)	$0.0	$99.8	$2.6	($536.5)
2016	$25,986.4	$26,469.9	$0.0	($483.5)	($128.1)	($256.2)	$0.0	$128.1	($2.9)	($358.3)
2017	$26,360.1	$26,844.5	$0.0	($484.4)	($278.0)	($413.9)	$0.0	$135.9	$4.5	($344.0)
2018	$33,957.1	$34,508.6	$0.0	($551.4)	($85.4)	($132.5)	$0.0	$47.1	$5.7	($498.7)
2019	$24,004.0	$24,411.6	$0.0	($407.6)	($307.7)	($375.7)	$0.0	$68.0	$0.2	($339.3)
2020	$17,564.2	$17,867.8	$0.0	($303.6)	($199.4)	($267.1)	$0.0	$67.7	$1.9	($234.0)
2021	$28,994.9	$29,470.3	$0.0	($475.4)	($141.2)	($182.4)	$0.0	$41.2	$3.5	($430.7)
2022	$64,959.1	$66,075.9	$0.0	($1,116.7)	($533.3)	($675.9)	$0.0	$142.6	($5.0)	($979.1)
2023	$26,750.4	$27,264.3	$0.0	($513.9)	($294.0)	($420.1)	$0.0	$126.1	$3.2	($384.6)
2024	$30,182.6	$30,705.5	$0.0	($522.9)	($479.8)	($558.5)	$0.0	$78.7	$9.4	($434.8)

Table 11-41 and Table 11-42 show the total system energy costs for each transaction type in the first nine months of 2024 and 2023. In the first nine months of 2024, generation was paid $21,386.7 million and demand paid $20,183.0 million in net energy payment. In the first nine months of 2023, generation was paid $21,507.3 million and demand paid $20,015.0 million in net energy payment.

Table 11-41 Total system energy costs by transaction type (Dollars (Millions)): January through September, 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	$1,222.0	$0.0	$0.0	$1,222.0	($1,248.2)	$0.0	$0.0	($1,248.2)	($26.3)
Demand	$19,875.4	$0.0	$0.0	$19,875.4	$307.6	$0.0	$0.0	$307.6	$20,183.0
Demand Response	($8.8)	$0.0	$0.0	($8.8)	$8.6	$0.0	$0.0	$8.6	($0.3)
Export	$786.9	$0.0	$0.0	$786.9	$343.3	$0.0	$0.0	$343.3	$1,130.2
Generation	$0.0	$21,329.1	$0.0	($21,329.1)	$0.0	$57.5	$0.0	($57.5)	($21,386.7)
Import	$0.0	$64.2	$0.0	($64.2)	$0.0	$304.3	$0.0	($304.3)	($368.4)
INC	$0.0	$1,005.0	$0.0	($1,005.0)	$0.0	($1,029.2)	$0.0	$1,029.2	$24.2
Internal Bilateral	$8,302.1	$8,302.1	$0.0	($0.0)	$82.4	$82.4	$0.0	($0.0)	($0.0)
Wheel In	$0.0	$5.0	$0.0	($5.0)	$0.0	$26.6	$0.0	($26.6)	($31.6)
Wheel Out	$5.0	$0.0	$0.0	$5.0	$26.6	$0.0	$0.0	$26.6	$31.6
Total	$30,182.6	$30,705.5	$0.0	($522.9)	($479.8)	($558.5)	$0.0	$78.7	($444.3)

Table 11-42 Total system energy costs by transaction type by (Dollars (Millions)): January through September, 2023

	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	$1,054.5	$0.0	$0.0	$1,054.5	($1,032.2)	$0.0	$0.0	($1,032.2)	$22.3
Demand	$18,009.5	$0.0	$0.0	$18,009.5	$186.5	$0.0	$0.0	$186.5	$18,196.0
Demand Response	($2.1)	$0.0	$0.0	($2.1)	$1.8	$0.0	$0.0	$1.8	($0.4)
Export	$769.7	$0.0	$0.0	$769.7	$433.7	$0.0	$0.0	$433.7	$1,203.5
Generation	$0.0	$19,429.5	$0.0	($19,429.5)	$0.0	$60.5	$0.0	($60.5)	($19,490.0)
Import	$0.0	$74.9	$0.0	($74.9)	$0.0	$224.3	$0.0	($224.3)	($299.2)
INC	$0.0	$841.1	$0.0	($841.1)	$0.0	($821.2)	$0.0	$821.2	($20.0)
Internal Bilateral	$6,918.8	$6,918.8	$0.0	$0.0	$89.6	$89.6	$0.0	$0.0	$0.0
Wheel In	$0.0	$0.0	$0.0	$0.0	$0.0	$26.6	$0.0	($26.6)	($26.6)
Wheel Out	$0.0	$0.0	$0.0	$0.0	$26.6	$0.0	$0.0	$26.6	$26.6
Total	$26,750.4	$27,264.3	$0.0	($513.9)	($294.0)	($420.1)	$0.0	$126.1	($387.8)

Table 11-43 compares the total system energy costs for each transaction type between the dispatch run and the pricing run in the first nine months of 2024. The system energy charges to demand increased $71.9 million, and the energy credits to generation decreased $46.8 million from the dispatch run to the pricing run. The energy charges to DEC decreased $97.8 million, the energy credits to INC increased $81.2 million from the dispatch run to the pricing run.

Table 11-43 Total system energy costs by dispatch and pricing run (Dollars (Millions)): January through September, 2024

System Energy Costs (Millions)									
	Dispatch Run			Pricing Run			Difference		
Transaction Type	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total
DEC	$1,219.4	($1,147.9)	$71.5	$1,222.0	($1,248.2)	($26.3)	$2.5	($100.4)	($97.8)
Demand	$19,834.4	$276.7	$20,111.1	$19,875.4	$307.6	$20,183.0	$41.0	$30.9	$71.9
Demand Response	($8.8)	$7.9	($0.9)	($8.8)	$8.6	($0.3)	($0.0)	$0.7	$0.7
Export	$785.2	$323.9	$1,109.1	$786.9	$343.3	$1,130.2	$1.6	$19.4	$21.1
Generation	($21,284.8)	($55.1)	($21,339.9)	($21,329.1)	($57.5)	($21,386.7)	($44.3)	($2.4)	($46.8)
Import	($64.1)	($277.9)	($341.9)	($64.2)	($304.3)	($368.4)	($0.1)	($26.4)	($26.5)
INC	($1,003.3)	$946.3	($57.0)	($1,005.0)	$1,029.2	$24.2	($1.7)	$83.0	$81.2
Internal Bilateral	$0.0	($0.0)	$0.0	$0.0	($0.0)	($0.0)	$0.0	($0.0)	($0.0)
Wheel In	($5.0)	($24.3)	($29.3)	($5.0)	($26.6)	($31.6)	($0.0)	($2.3)	($2.3)
Wheel Out	$5.0	$24.3	$29.3	$5.0	$26.6	$31.6	$0.0	$2.3	$2.3
Total	($521.9)	$73.8	($448.1)	($522.9)	$78.7	($444.3)	($1.0)	$4.9	$3.8

Monthly System Energy Costs

Table 11-44 shows a monthly summary of system energy costs by market type for 2023 through the first nine months of 2024. Total balancing system energy costs in the first nine months of 2024 decreased in every month compared to the first nine months of 2023 except for August. Monthly total system energy costs in the first nine months of 2024 ranged from -$86.3 million in January to -$27.6 million in March.

Table 11-44 Monthly system energy costs (Dollars (Millions)): January 2023 through September 2024

System Energy Costs (Millions)								
	2023				2024			
	Day-Ahead	Balancing	Inadvertent Charges	Total	Day-Ahead	Balancing	Inadvertent Charges	Total
Jan	($73.0)	$20.8	($0.7)	($52.9)	($99.5)	$12.5	$0.7	($86.3)
Feb	($59.1)	$14.4	($0.4)	($45.1)	($39.3)	$7.7	$0.0	($31.7)
Mar	($49.6)	$12.1	$0.0	($37.5)	($36.8)	$9.3	($0.1)	($27.6)
Apr	($47.1)	$15.0	$0.3	($31.8)	($36.3)	$7.2	$0.3	($28.8)
May	($51.0)	$18.4	($0.0)	($32.6)	($51.6)	$9.0	$1.0	($41.6)
Jun	($48.9)	$14.4	$0.8	($33.8)	($58.1)	$7.2	$2.0	($49.0)
Jul	($79.5)	$13.5	$1.6	($64.5)	($88.1)	$9.9	$3.3	($74.9)
Aug	($55.4)	$9.2	$0.9	($45.2)	($68.7)	$9.6	$1.5	($57.6)
Sep	($50.3)	$8.4	$0.8	($41.2)	($44.4)	$6.3	$0.7	($37.4)
Oct	($51.1)	$9.6	$0.9	($40.6)				
Nov	($51.6)	$8.6	$0.1	($42.9)				
Dec	($49.4)	$9.8	$0.2	($39.4)				
Total	($666.0)	$154.2	$4.3	($507.5)	($522.9)	$78.7	$9.4	($434.8)

Figure 11-12 shows PJM monthly system energy costs for 2008 through the first nine months of 2024. 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 September 2024

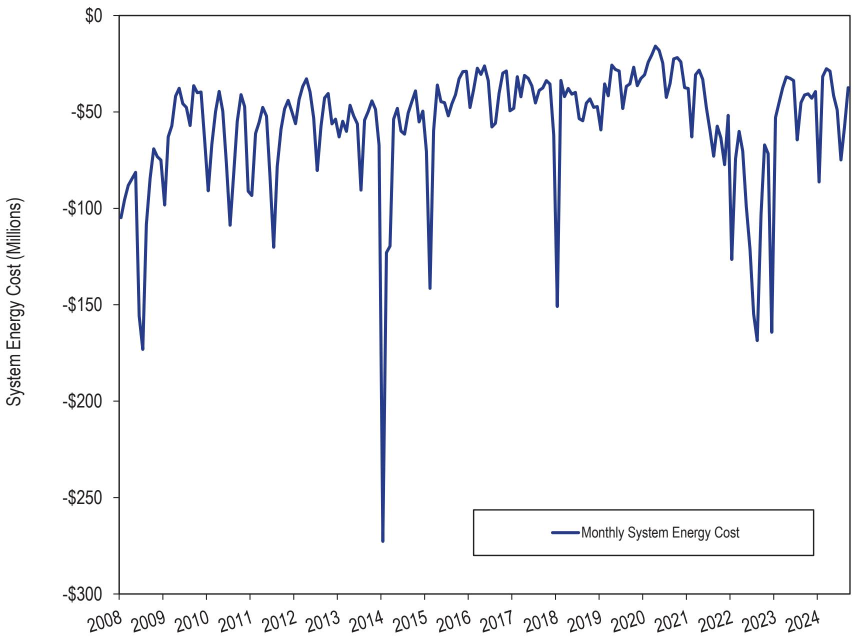


Table 11-45 shows the monthly total system energy costs for each virtual transaction type in the first nine months of 2024 and year of 2023. In the first nine months of 2024, DECs paid $1,222.0 million in energy charges compared to $1,364.5 million in the first nine months of 2023 in the day-ahead market, were paid $1,248.2 million in energy credits compared to $1,339.3 million in the first nine months of 2023 in the balancing energy market and paid $26.3 million in total energy charges compared to $25.3 million in total energy credits in the first nine months of 2023. In the first nine months of 2024, INCs were paid $1,005.0 million in energy credits compared to $1,201.2 million in the first nine months of 2023 in the day-ahead market, paid $1,029.2 million in energy charges compared to $1,178.5 million in the first nine months of 2023 in the balancing market and were paid $24.2 million in total energy credits compared to $22.6 million in total energy charges in the first nine months of 2023. 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 11-45 Monthly energy charges by virtual transaction type (Dollars (Millions)): January 2023 through September 2024

		Energy Charges (Millions)						
		DEC			INC			
Year		Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Grand Total
2023	Jan	$124.3	($121.1)	$3.2	($105.9)	$103.3	($2.6)	$0.7
	Feb	$102.2	($84.4)	$17.8	($98.3)	$84.1	($14.1)	$3.7
	Mar	$101.0	($102.2)	($1.2)	($94.5)	$94.2	($0.3)	($1.5)
	Apr	$78.6	($76.9)	$1.7	($106.0)	$104.6	($1.4)	$0.3
	May	$92.1	($90.2)	$1.8	($99.1)	$97.5	($1.6)	$0.2
	Jun	$115.4	($113.1)	$2.3	($81.5)	$79.4	($2.0)	$0.3
	Jul	$167.5	($162.5)	$5.0	($100.7)	$99.0	($1.6)	$3.3
	Aug	$148.2	($154.5)	($6.3)	($70.7)	$73.7	$3.0	($3.3)
	Sep	$125.2	($127.2)	($2.1)	($84.5)	$85.2	$0.7	($1.3)
	Oct	$111.8	($109.7)	$2.1	($150.4)	$148.1	($2.4)	($0.2)
	Nov	$96.8	($95.6)	$1.2	($115.0)	$113.9	($1.1)	$0.0
	Dec	$101.4	($101.8)	($0.3)	($94.6)	$95.4	$0.9	$0.6
	Total	$1,364.5	($1,339.3)	$25.3	($1,201.2)	$1,178.5	($22.6)	$2.6
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)
	Total	$1,222.0	($1,248.2)	($26.3)	($1,005.0)	$1,029.2	$24.2	($2.1)