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]

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. 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. (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. 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] The result is that the price of energy in the constrained area(s) is higher than in the unconstrained area. Load in the constrained area pays the single higher price for all the energy used, including energy from low cost and energy from high cost generation, while generators are each paid the price at their individual bus. Congestion is the difference between what load pays based on the single higher price at load buses and what generators receive based on the lower prices at the individual generator buses due to binding transmission constraints.

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 *2020 State of the Market Report for PJM*, Appendix F: Congestion and Marginal Losses.
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.

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 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.

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 elected 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.

5 The total congestion and marginal losses for the first three months of 2021 were calculated as of April 12, 2021, and are subject to change, based on continued PJM billing updates.

Overview

Congestion Cost

- **Total Congestion.** Total congestion costs increased by $35.9 million or 42.2 percent, from $85.1 million in the first three months of 2020 to $121.0 million in the first three months of 2021.
- **Day-Ahead Congestion.** Day-ahead congestion costs increased by $121.1 million or 117.2 percent, from $103.3 million in the first three months of 2020 to $224.5 million in the first three months of 2021.
- **Balancing Congestion.** Negative balancing congestion costs increased by $85.2 million, from -$18.2 million in the first three months of 2020 to -$103.4 million in the first three months of 2021. Negative balancing explicit charges increased by $22.7 million, from -$14.2 million in the first three months of 2020 to -$36.9 million in the first three months of 2021.
- **Real-Time Congestion.** Real-time congestion costs increased by $220.2 million, from $87.7 million in the first three months of 2020 to $308.0 million in the first three months of 2021.
- **Monthly Congestion.** Monthly total congestion costs in the first three months of 2021 ranged from $29.1 million in January to $55.2 million in March.
- **Geographic Differences in CLMP.** Differences in CLMP among eastern, southern and western control zones in PJM were primarily a result of

congestion on the Vienna Transformer, the Bagley - Raphael Road Line, the Bagley - Graceton Line, the Conastone Transformer, and the Harwood - Susquehanna Line.

- **Congestion Frequency.** Congestion frequency continued to be significantly higher in the day-ahead energy market than in the real-time energy market in the first three months of 2021. 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 decreased by 14.4 percent from 17,087 congestion event hours in the first three months of 2020 to 14,618 congestion event hours in the first three months of 2021.

  Real-time congestion frequency decreased by 0.6 percent from 5,515 congestion event hours in the first three months of 2020 to 5,484 congestion event hours in the first three months of 2021.

- **Congested Facilities.** The monthly average of daily day-ahead congestion event hours decreased in November 2020 as a result of decreased UTC activity due to a FERC order issued effective November 1, 2020, directing PJM to charge uplift to up to congestion transactions.[6] Day-ahead, congestion event hours decreased on all types of facilities except lines. The congestion event hours on the PA Central Interface decreased from 1,340 hours in the first three months of 2020 to 0 hours in the first three months of 2021.

  The Vienna Transformer was the largest contributor to congestion costs in the first three months of 2021. With $14.4 million in total congestion costs, it accounted for 11.9 percent of the total PJM congestion costs in the first three months of 2021.

- **CT Price Setting Logic and Closed Loop Interface Related Congestion.** CT Price Setting Logic caused -$0.0 million of day-ahead congestion in the first three months of 2021 and -$5.2 million of balancing congestion in the first three months of 2021. None of the closed loop interfaces was binding in the first three months of 2021 or 2020.

- **Zonal Congestion.** AEP had the highest zonal congestion costs among all control zones in the first three months of 2021. AEP had $16.3 million in zonal congestion costs, comprised of $31.8 million in day-ahead congestion costs and -$15.6 million in balancing congestion costs.

Marginal Loss Cost

- **Total Marginal Loss Costs.** Total marginal loss costs increased by $101.2 million or 93.2 percent, from $108.5 million in the first three months of 2020 to $209.7 million in the first three months of 2021. The loss MWh in PJM increased by 395.4 GWh or 10.9 percent, from 3,613.6 GWh in the first three months of 2020 to 4,009.0 GWh in the first three months of 2021. The loss component of real-time LMP in the first three months of 2021 was $0.02, compared to $0.01 in the first three months of 2020.
- **Day-Ahead Marginal Loss Costs.** Day-ahead marginal loss costs increased by $98.6 million or 80.8 percent, from $122.0 million in the first three months of 2020 to $220.5 million in the first three months of 2021.
- **Balancing Marginal Loss Costs.** Negative balancing marginal loss costs decreased by $2.6 million or 19.5 percent, from -$13.4 million in the first three months of 2020 to -$10.8 million in the first three months of 2021.
- **Total Marginal Loss Surplus.** The total marginal loss surplus increased by $43.8 million or 131.9 percent, from $33.2 million in the first three months of 2020, to $77.1 million in the first three months of 2021.
- **Monthly Total Marginal Loss Costs.** Monthly total marginal loss costs in the first three months of 2021 ranged from $47.2 million in March to $102.7 million in February.

System Energy Cost

- **Total System Energy Costs.** Total system energy costs decreased by $56.4 million or 74.8 percent, from -$75.3 million in the first three months of 2020 to -$131.7 million in the first three months of 2021.
- **Day-Ahead System Energy Costs.** Day-ahead system energy costs decreased by $55.7 million or 57.8 percent, from -$96.3 million in the first three months of 2020 to -$152.0 million in the first three months of 2021.

6 172 FERC ¶ 61,046 (2020).

- **Balancing System Energy Costs.** Balancing system energy costs decreased by $1.7 million or 8.1 percent, from $21.4 million in the first three months of 2020 to $19.7 million in the first three months of 2021.
- **Monthly Total System Energy Costs.** Monthly total system energy costs in the first three months of 2021 ranged from -$63.1 million in February to -$30.8 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 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 $35.9 million or 42.2 percent, from $85.1 million in the first three months of 2020 to $121.0 million in the first three months of 2021. The total day-ahead congestion costs and negative balancing congestion costs increased significantly compared to the first three months of 2020. This was the combined result of higher demand and higher prices, cold weather in February of 2021, CT pricing logic, and transmission facility outages in March.

The monthly total congestion costs ranged from $29.1 million in January to $55.2 million in March in the first three months of 2021.

The current ARR/FTR design does not serve as an efficient way to ensure that load receives the rights to all congestion revenues. The congestion offset for the first ten months of the 2020/2021 planning period was 45.8 percent. The cumulative offset of congestion by ARRs for the 2011/2012 planning period through the first 10 months of the 2020/2021 planning period, using the rules effective for each planning period, was 74.1 percent. Load has been underpaid by $2.3 billion from the 2011/2012 planning period through the first 10 months of the 2020/2021 planning period.

Issues

Closed Loop Interfaces and CT Pricing Logic

PJM uses closed loop interfaces and CT pricing logic to force otherwise uneconomic resources to be marginal and set price in the day-ahead or real-time market solution. PJM uses 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.

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 attempts to force the affected resource bus LMP to match the marginal offer of the resource. PJM does this by adjusting 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 are 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 affects the CLMP of downstream (constrained side) buses in proportion to their dfax to that constraint.[7] One objective of making inflexible resources marginal is to artificially minimize the uplift costs associated with the inflexible resources that PJM commits for system security reasons.

The use of closed loop interfaces and CT pricing logic can be a source of modeling differences between the day-ahead and real-time markets. If closed loop interfaces and CT pricing logic 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 will result in positive or negative balancing congestion.

Failure to model the same constraints in the day-ahead and real-time markets will result in pricing and congestion settlement differences between the day-

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

ahead and real-time market. Any modeling differences create false arbitrage opportunities for virtual bids and contribute to negative balancing congestion. PJM attempts to incorporate its real-time use of closed loop interfaces and CT pricing logic in the day-ahead market, although the matching is necessarily imperfect and with a lag.

Use of closed loop interfaces and CT price setting logic requires manipulation of the economic dispatch model. Closed loop interfaces and CT price setting logic force higher cost inflexible units to be marginal. Unlike constraints that restrict the use of lower cost resources in the system solution, the closed loop interface and CT price setting logic constraints are forcing the use of higher cost resources. The sign of the shadow price of this artificial constraint in the optimization solution, unlike normal security constraints in a least cost dispatch optimization, is therefore positive because relaxing this constraint will cause system costs to go up, not down. Increasing the limit (relaxing) for a closed loop interface or CT price setting logic constraint requires an increase in the output from the high cost unit from within the artificially constrained area, and a decrease in output from low price generation from outside the artificially constrained area. This means that increasing the limit of a closed loop interface or CT price setting logic constraint causes a net increase in incremental cost for any increase in the flow limit of the constraint and a positive, rather than the usual negative, shadow price for the modeled transmission constraint.

The nature of the closed loop interface or CT price setting logic constraint is that more power is produced in the artificial closed loop or constrained area than would result without the closed loop. This means that there are more high CLMP generation credits than high CLMP load charges associated with the constrained area within the closed loop interface or CT price setting logic constraint. The rest of the system receives power from the closed loop/constrained area, the lower cost generators outside the closed loop/constrained area are backed down and prices are lower outside the loop than they would have been without the closed loop. While all of the generation within the artificially constrained area is paid the higher CLMP in the form of generation credits, a smaller amount of load (in some cases no load) pays this higher CLMP in the form of load charges within the loop. The residual energy is delivered and paid for at a lower CLMP outside the closed loop/constrained area. The result is that PJM pays out more to generators in the closed loop than it collects from load. The result of using closed loops and CT price setting logic is that uneconomic generation costs that would otherwise be collected as uplift are being realized as 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 rather than to deviations as uplift charges.

Balancing Congestion Cost Calculation Logic Change

Effective April 1, 2018, PJM made a significant change to the calculation and allocation of balancing congestion costs.[8]

Prior to April 1, 2018, balancing implicit CLMP charges calculated at the zonal and aggregate level were determined by bus specific deviations between day-ahead and real-time MWh priced at the bus specific congestion price in the real-time energy market.

As of April 1, 2018, at the time of the introduction of five minute settlements, PJM modified the calculation so that zonal and aggregate balancing implicit CLMP charges are determined by netting the bus specific hourly deviations across every bus in a zone or subzonal aggregate and pricing the resulting deviation in zonal or aggregate total deviations at the zonal or aggregate congestion price in the real-time energy market. As a result, the allocation of balancing implicit congestion was reduced for MW deviations associated with load and virtual bids that settle at zones and aggregates.

Another result of the change in rules was to increase negative balancing charges billed to load on a load ratio basis. While total load deviations and associated balancing charges at load aggregates were reduced by netting, the rules for determining balancing CLMP credits and charges to all other balancing MW deviations at all other bus or aggregates did not change. This means that the change in rules resulted in a decrease in total balancing

8 See PJM, "Manual 28: Operating Agreement Accounting," Rev. 84 (Dec.17, 2020).

implicit charges while having no effect on the calculation of total balancing implicit credits. The net result has been an increase in negative balancing congestion costs, which is the difference between balancing CLMP charges from deviations at aggregates and zones (reduced due to the rule change) and bus specific balancing CLMP credits (not affected by the rule change). This has caused an increase in total negative balancing charges.

The netting of zonal and aggregate deviations decreased the allocation of balancing charges to load deviations and increased total negative balancing congestion. Negative balancing congestion is assigned to load and exports on a load ratio share basis as the result of a FERC order.

Table 11-1 shows the total balancing implicit CLMP charges that would have resulted from applying the pre and post April 1, 2018, settlement rules for the first three months of 2017 through 2021. Table 11-1 also shows the actual total balancing implicit CLMP charges for the first three months of 2017 through 2021 based on the methods in place at the time. Table 11-1 shows that the April 1, 2018, settlement rule, if applied to the first three months of 2017 through 2021 except the first three months of 2020, would have caused negative balancing congestion costs to increase. Table 11-1 shows that the post April 1, 2018, settlement rule caused negative total balancing implicit charges to increase by $4.6 million (7.5 percent) in the first three months of 2021.

Table 11-1 Total balancing implicit CLMP charge (Dollars (Millions)) (old method and new method): January through March, 2017 through 2021

Balancing Implicit CLMP Charges ($ Million)										
	Old Method			New Method			Method Used			
(Jan - Mar)	Withdrawal Charges	Injection Credits	Total	Withdrawal Charges	Injection Credits	Total	Withdrawal Charges	Injection Credits	Total	Change Between New and Old
2017	($0.3)	$7.5	($7.8)	($1.8)	$7.4	($9.2)	($0.3)	$7.5	($7.8)	($1.3)
2018	$12.8	$23.6	($10.8)	$1.4	$21.3	($19.9)	$12.8	$23.6	($10.8)	($9.1)
2019	($1.1)	$20.1	($21.2)	($1.8)	$20.1	($21.9)	($1.8)	$20.1	($21.9)	($0.6)
2020	($0.3)	$3.8	($4.1)	($0.2)	$3.8	($4.0)	($0.2)	$3.8	($4.0)	$0.1
2021	($21.6)	$40.3	($61.9)	($26.7)	$39.9	($66.6)	($26.7)	$39.9	($66.6)	($4.6)

The differences in results between the old method and the new method result from the use of zonal CLMP and zonal net deviations in place of the use of bus specific CLMPS and bus specific deviations.

When the total day-ahead factor weighted real-time bus CLMP is lower than real-time zonal CLMP, the balancing implicit CLMP charges will be lower using the new method. When the total day-ahead factor weighted real-time bus CLMP is higher than real-time zonal CLMP, the balancing implicit CLMP charges will be higher using the new method. Table 11-2 presents three cases to explain the calculation. The day-ahead load factor or real-time load factor for an aggregate equals the load at each bus divided by the total aggregate load.

Case 1 (Table 11-2) shows the case in which the total day-ahead factor weighted real-time bus CLMP ($1.1) is less than the real-time zonal CLMP ($1.6). The total balancing implicit CLMP charges using the new method (-$4.2) are lower than under the old method ($1.8).

Case 2 (Table 11-2) shows the case in which the total day-ahead factor weighted real-time bus CLMP ($1.9) is larger than the real-time zonal CLMP ($1.5). The total balancing implicit CLMP charges using the new method ($2.0) are higher than under the old method (-$1.2).

Case 3 (Table 11-2) shows that the total day-ahead factor weighted real-time bus CLMP ($1.6) is equal to the real-time zonal CLMP ($1.6). The total balancing implicit CLMP charges using the new method (-$4.2) are equal under the old method (-$4.2).

Table 11-2 Example of balancing implicit CLMP charge calculation (old method and new method)

									Balancing Implicit Withdrawal Charges	
Case 1	Real-Time CLMP	Real-Time Load	Real-Time Load Factor	Real-Time CLMP * Real-Time Load Factor	Day-Ahead Load Factor	Real-Time CLMP * Day-Ahead Load Factor	Day-Ahead Load	Balancing Load	Old Method	New Method
Bus A	$1.0	4.0	0.4	$0.4	0.9	$0.9	10.8	(6.8)	($6.80)	
Bus B	$2.0	6.0	0.6	$1.2	0.1	$0.2	1.2	4.8	$9.60	
Zonal		10.0		$1.6		$1.1	12.0		$2.8	($3.20)
Balancing Implicit Injection Credits									$1.0	$1.0
Balancing Implicit Congestion Charges									$1.8	($4.2)
Case 2										
Bus A	$1.0	5.0	0.5	$0.5	0.1	$0.1	0.8	4.2	$4.20	
Bus B	$2.0	5.0	0.5	$1.0	0.9	$1.8	7.2	(2.2)	($4.40)	
Zonal		10.0		$1.5		$1.9	8.0		($0.2)	$3.00
Balancing Implicit Injection Credits									$1.0	$1.0
Balancing Implicit Congestion Charges									($1.2)	$2.0
Case 3										
Bus A	$1.0	4.0	0.4	$0.4	0.4	$0.4	4.8	(0.8)	($0.80)	
Bus B	$2.0	6.0	0.6	$1.2	0.6	$1.2	7.2	(1.2)	($2.40)	
Zonal		10.0		$1.6		$1.6	12.0		($3.2)	($3.20)
Balancing Implicit Injection Credits									$1.0	$1.0
Balancing Implicit Congestion Charges									($4.2)	($4.2)

Locational Marginal Price (LMP)

Components

On June 1, 2007, PJM changed from a single node reference bus to a distributed load reference bus. While the use of a single node reference bus or a distributed load reference bus has no effect on the total LMP, the use of a single node reference bus or a distributed load reference bus does affect the components of LMP. With a distributed load reference bus, the energy component of LMP is a load-weighted system price. No congestion or losses are 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.[9] 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

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

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.[10] 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 11-3 shows the PJM real-time, load-weighted, average LMP components for January through March, 2008 through 2021.[11]

The real-time, load-weighted, average LMP increased $10.99 or 55.3 percent from $19.85 in the first three months of 2020 to $30.84 in the first three months of 2021. The real-time, load-weighted, average congestion component was $0.01 in the first three months of 2020 and $0.03 in the first three months of 2021. Using a load-weighted reference bus, the real-time, load-weighted, average congestion component of LMP should be zero. PJM's load-weighted reference bus congestion component is zero at the time that LMPs are set based on state estimator data. Metering updates during the settlement process change the load weights after the fact, but the reference bus price (SMP) is not updated with these changes over time. As a result, the average congestion and loss component used in real-time settlement is not zero, although this component is not fully accurate. The real-time, load-weighted, average loss component in the first three months of 2021 was $0.02 compared to $0.01 in the first three months of 2020. The real-time, load-weighted, average system energy component increased by $10.96 or 55.3 percent from $19.83 in the first three months of 2020 to $30.79 in the first three months of 2021.

Table 11-3 Real-time, load-weighted, average LMP components (Dollars per MWh): January through March, 2008 through 2021[12]

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

Table 11-4 shows the PJM day-ahead, load-weighted, average LMP components for the first three months of 2008 through 2021.[13] The day-ahead, load-weighted, average LMP increased $11.46, or 57.0 percent, from $20.12 in the first three months of 2020 to $31.58 in the first three months of 2021. The day-ahead, load-weighted, average congestion component increased $0.20 from -$0.01 in the first three months of 2020 to $0.19 in the first three months of 2021. The day-ahead, load-weighted, average loss component was -$0.01 in the first three months of 2020 and $0.05 in the first three months of 2021. The day-ahead, load-weighted, average energy component increased $11.20,

10 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.

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

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

13 In the real-time energy market, the energy component (SMP) equals the system load-weighted price, with the caveat about state-estimated versus metered load. However, in the day-ahead energy market the day-ahead energy component of LMP (SMP) and the PJM day-ahead, load-weighted LMP are not equal. The difference between the day-ahead energy component of LMP and the PJM day-ahead, load-weighted LMP is a result of the difference in the types of load used to weight the load-weighted reference bus and the load-weighted LMP. In the day-ahead energy market, the distributed load reference bus is weighted by fixed-demand bids only and the day-ahead SMP is, therefore, a system fixed demand weighted price. The day-ahead, load-weighted LMP calculation uses all types of demand, including fixed, price-sensitive and decrement bids.

or 55.6 percent, from $20.14 in the first three months of 2020 to $31.34 in the first three months of 2021. Using a load-weighted reference bus, the day-ahead, load-weighted, average congestion component of LMP should be zero. PJM's load-weighted reference bus congestion component is zero based on day-ahead firm load weights. Total billing however, includes price sensitive demand and virtual load congestion related charges, which makes the total load weights in accounting different than the load weights used to determine the SMP at the load-weighted reference bus. The resulting load-weighted average price from settlement for congestion and marginal losses components of price in day ahead is therefore not zero, although this component is not fully accurate.

Table 11-4 Day-ahead, load-weighted, average LMP components (Dollars per MWh): January through March, 2008 through 2021

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

Table 11-5 shows the PJM real-time, load-weighted, average LMP by constrained and unconstrained hours.

Table 11-5 Real-time, load-weighted, average LMP by constrained and unconstrained hours (Dollars per MWh): January 2020 through March 2021

	2020		2021	
	Constrained Hours	Unconstrained Hours	Constrained Hours	Unconstrained Hours
Jan	$22.30	$15.73	$25.96	$21.31
Feb	$19.56	$17.12	$45.23	$23.19
Mar	$18.28	$16.13	$26.57	$19.67
Apr	$17.63	$17.39		
May	$18.81	$12.20		
Jun	$21.64	$14.18		
Jul	$28.58	$15.77		
Aug	$26.01	$17.43		
Sep	$19.94	$12.31		
Oct	$22.19	$22.78		
Nov	$20.86	$26.31		
Dec	$27.28	$21.27		
Avg	$22.29	$17.59	$32.09	$22.14

Zonal Components

The real-time components of LMP for each control zone are presented in Table 11-6 for the first three months of 2020 and 2021. In the first three months of 2021, DPL had the highest real-time congestion component of all control zones, $8.25, and JCPLC had the lowest real-time congestion component, -$4.76.

Table 11-6 Zonal and PJM real-time, load-weighted, average LMP components (Dollars per MWh): January through March, 2020 and 2021

	2020 (Jan - Mar)				2021 (Jan - Mar)			
	Real-Time LMP	Energy Component	Congestion Component	Loss Component	Real-Time LMP	Energy Component	Congestion Component	Loss Component
ACEC	$19.23	$19.84	($0.54)	($0.08)	$27.35	$30.82	($3.82)	$0.35
AEP	$20.23	$19.80	$0.30	$0.12	$31.07	$30.71	$0.46	($0.11)
APS	$20.09	$19.84	$0.25	$0.00	$30.16	$30.78	($0.49)	($0.13)
ATSI	$20.36	$19.78	$0.31	$0.27	$28.76	$30.60	($1.68)	($0.16)
BGE	$21.30	$19.91	$0.89	$0.50	$35.61	$31.01	$3.75	$0.86
COMED	$18.80	$19.73	($0.50)	($0.43)	$29.52	$30.71	($0.32)	($0.86)
DAY	$21.29	$19.86	$0.45	$0.98	$32.85	$30.90	$0.75	$1.19
DOM	$20.29	$19.87	$0.38	$0.04	$33.04	$30.93	$1.72	$0.39
DPL	$19.54	$19.91	($0.62)	$0.25	$40.22	$31.02	$8.25	$0.95
DUKE	$20.42	$19.82	$0.40	$0.20	$32.09	$30.98	$1.06	$0.06
DUQ	$20.22	$19.77	$0.47	($0.02)	$28.54	$30.56	($1.29)	($0.73)
EKPC	$20.46	$19.94	$0.37	$0.15	$33.06	$31.56	$1.36	$0.13
JCPLC	$19.34	$19.87	($0.49)	($0.04)	$26.44	$30.76	($4.76)	$0.43
MEC	$19.45	$19.88	($0.21)	($0.22)	$28.37	$30.67	($2.34)	$0.05
OVEC	$19.64	$19.52	$0.37	($0.25)	$29.61	$30.19	$0.20	($0.78)
PE	$19.46	$19.81	($0.16)	($0.19)	$29.13	$30.54	($1.01)	($0.40)
PECO	$18.92	$19.84	($0.67)	($0.26)	$26.84	$30.71	($3.88)	$0.00
PEPCO	$20.86	$19.94	$0.65	$0.26	$33.06	$31.12	$1.38	$0.56
PPL	$18.14	$19.86	($1.35)	($0.38)	$27.01	$30.69	($3.38)	($0.30)
PSEG	$19.34	$19.80	($0.36)	($0.10)	$32.43	$30.60	$1.47	$0.36
REC	$19.32	$19.86	($0.44)	($0.10)	$38.14	$30.48	$7.36	$0.30
PJM	$19.85	$19.83	$0.01	$0.01	$30.84	$30.79	$0.03	$0.02

The day-ahead components of LMP for each control zone are presented in Table 11-7 for the first three months of 2020 and 2021. In the first three months of 2021, DPL had the highest day-ahead congestion component of all control zones, $3.85, and JCPLC had the lowest day-ahead congestion component, -$3.34.

Table 11-7 Zonal and PJM day-ahead, load-weighted, average LMP components (Dollars per MWh): January through March, 2020 and 2021

	2020 (Jan - Mar)				2021 (Jan - Mar)			
	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
ACEC	$18.95	$20.11	($1.03)	($0.13)	$28.36	$31.05	($2.99)	$0.31
AEP	$20.56	$20.09	$0.37	$0.10	$31.72	$31.36	$0.44	($0.09)
APS	$20.45	$20.17	$0.29	($0.01)	$31.17	$31.23	$0.06	($0.12)
ATSI	$20.81	$20.11	$0.34	$0.36	$30.99	$31.04	($0.09)	$0.04
BGE	$22.18	$20.27	$1.51	$0.40	$35.61	$31.27	$3.47	$0.88
COMED	$19.10	$20.02	($0.57)	($0.36)	$29.99	$31.33	($0.58)	($0.76)
DAY	$21.67	$20.16	$0.60	$0.90	$34.00	$31.54	$0.98	$1.49
DOM	$20.73	$20.19	$0.59	($0.04)	$33.03	$31.31	$1.43	$0.29
DPL	$19.40	$20.26	($1.00)	$0.15	$36.10	$31.17	$3.85	$1.09
DUKE	$20.83	$20.13	$0.58	$0.13	$32.92	$31.44	$1.34	$0.15
DUQ	$20.73	$20.11	$0.58	$0.04	$30.09	$30.93	($0.14)	($0.70)
EKPC	$20.87	$20.35	$0.53	($0.02)	$33.21	$32.44	$0.91	($0.14)
JCPLC	$19.12	$20.22	($1.04)	($0.06)	$28.09	$31.01	($3.34)	$0.42
MEC	$19.41	$20.18	($0.48)	($0.29)	$29.59	$30.96	($1.35)	($0.03)
OVEC	$20.40	$20.14	$0.56	($0.30)	$32.03	$32.94	($0.08)	($0.83)
PE	$20.00	$20.24	($0.26)	$0.02	$30.96	$31.38	($0.33)	($0.09)
PECO	$18.57	$20.15	($1.27)	($0.31)	$27.87	$30.97	($3.05)	($0.05)
PEPCO	$21.57	$20.30	$1.04	$0.23	$33.88	$31.47	$1.80	$0.61
PPL	$18.23	$20.17	($1.47)	($0.47)	$28.23	$30.88	($2.22)	($0.43)
PSEG	$19.12	$20.12	($0.89)	($0.11)	$30.82	$30.91	($0.53)	$0.45
REC	$19.52	$20.24	($0.62)	($0.10)	$35.57	$31.74	$3.31	$0.53
PJM	$20.12	$20.14	($0.01)	($0.01)	$31.58	$31.34	$0.19	$0.05

Hub Components

The real-time components of LMP for each hub are presented in Table 11-8 for the first three months of 2020 and 2021.[14]

Table 11-8 Hub real-time, average LMP components (Dollars per MWh): January through March, 2020 and 2021

	2020 (Jan - Mar)				2021 (Jan - Mar)			
	Real-Time LMP	Energy Component	Congestion Component	Loss Component	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AEP Gen Hub	$19.39	$19.39	$0.33	($0.33)	$27.86	$29.73	($0.89)	($0.98)
AEP-DAY Hub	$19.77	$19.39	$0.27	$0.11	$29.83	$29.73	$0.32	($0.22)
ATSI Gen Hub	$19.70	$19.39	$0.29	$0.01	$27.73	$29.73	($1.39)	($0.61)
Chicago Gen Hub	$18.13	$19.39	($0.61)	($0.65)	$27.74	$29.73	($0.78)	($1.21)
Chicago Hub	$18.47	$19.39	($0.54)	($0.38)	$28.37	$29.73	($0.52)	($0.84)
Dominion Hub	$19.52	$19.39	$0.27	($0.14)	$31.68	$29.73	$1.82	$0.13
Eastern Hub	$18.98	$19.39	($0.60)	$0.19	$37.95	$29.73	$7.44	$0.78
N Illinois Hub	$18.38	$19.39	($0.53)	($0.48)	$28.24	$29.73	($0.51)	($0.98)
New Jersey Hub	$18.84	$19.39	($0.45)	($0.10)	$28.56	$29.73	($1.50)	$0.32
Ohio Hub	$19.78	$19.39	$0.25	$0.14	$30.03	$29.73	$0.47	($0.17)
West Interface Hub	$19.61	$19.39	$0.35	($0.14)	$28.90	$29.73	($0.32)	($0.51)
Western Hub	$19.72	$19.39	$0.46	($0.14)	$29.83	$29.73	$0.35	($0.25)

The day-ahead components of LMP for each hub are presented in Table 11-9 for the first three months of 2020 and 2021.

Table 11-9 Hub day-ahead, average LMP components (Dollars per MWh): January through March, 2020 and 2021

	2020 (Jan - Mar)				2021 (Jan - Mar)			
	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AEP Gen Hub	$19.72	$19.69	$0.36	($0.33)	$29.13	$30.07	$0.01	($0.94)
AEP-DAY Hub	$20.14	$19.69	$0.36	$0.09	$30.33	$30.07	$0.40	($0.13)
ATSI Gen Hub	$20.15	$19.69	$0.37	$0.09	$29.60	$30.07	($0.07)	($0.39)
Chicago Gen Hub	$18.40	$19.69	($0.72)	($0.57)	$28.03	$30.07	($0.92)	($1.11)
Chicago Hub	$18.81	$19.69	($0.59)	($0.29)	$28.70	$30.07	($0.66)	($0.71)
Dominion Hub	$19.90	$19.69	$0.43	($0.21)	$31.36	$30.07	$1.27	$0.02
Eastern Hub	$18.82	$19.69	($0.98)	$0.12	$34.03	$30.07	$3.04	$0.93
N Illinois Hub	$18.68	$19.69	($0.59)	($0.42)	$28.47	$30.07	($0.70)	($0.89)
New Jersey Hub	$18.62	$19.69	($0.95)	($0.12)	$28.59	$30.07	($1.84)	$0.36
Ohio Hub	$20.16	$19.69	$0.36	$0.11	$30.39	$30.07	$0.41	($0.08)
West Interface Hub	$20.01	$19.69	$0.43	($0.10)	$30.06	$30.07	$0.42	($0.42)
Western Hub	$20.19	$19.69	$0.55	($0.05)	$30.60	$30.07	$0.64	($0.11)

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

Congestion

Congestion Accounting

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

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

Congestion occurs in the day-ahead and real-time energy markets.[15] Day-ahead congestion costs are based on day-ahead MWh while balancing congestion costs are based on deviations between day-ahead and real-time MWh priced at the congestion price in the real-time energy market.

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

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 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.[16] Day-ahead implicit injection credits are calculated using MW and the generator bus CLMP, the increment offer's 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.

15 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.

16 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.[17]

The congestion accounting calculation equations are in Table 11-10.

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 is correct, but the 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

Table 11-10 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

17 PJM Operating Agreement Schedule 1 §3.7.

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. Congestion costs 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 congestion payment to a PJM member and when negative, measure the congestion credit paid to a PJM member. Explicit CLMP charges are calculated for up to congestion transactions (UTCs).

The congestion accounting definitions can be 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.

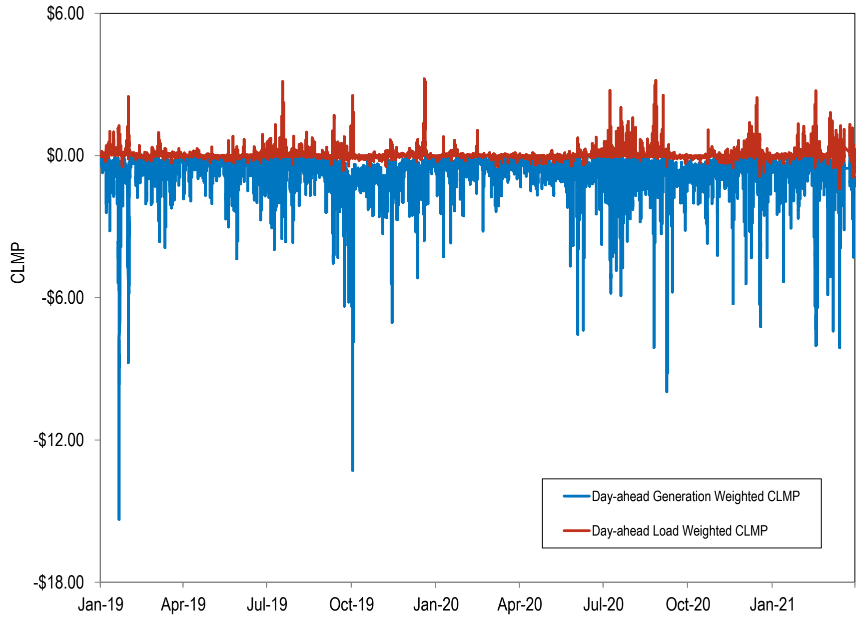
The CLMP is calculated with respect to the LMP at the system reference bus, also called the system marginal price (SMP). When a transmission constraint occurs, the resulting CLMP is positive on one side of the constraint and negative on the other side of the constraint and the corresponding congestion 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.[18]

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

Load-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 includes no congestion or loss components, by definition. 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 in January 2019 through March 2021, 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 11-13 and Table 11-14). This result is a product of the least cost, security constrained dispatch and the use of a load-weighted reference bus that is used for the determination of the components of LMP. More generally, in a least cost, security constrained market solution the weighted average LMP at load buses is higher than the weighted average price at generation buses.

Figure 11-1 Day-ahead generation weighted CLMPs and day-ahead load-weighted CLMPs: January 2019 through March 2021



Total Congestion

Total congestion costs in PJM in the first three months of 2021 were $121.0 million, comprised of implicit withdrawal charges of $55.6 million, explicit charges of -$18.2 million and implicit injection credits of -$83.6 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 11-11 shows total congestion for the first three months of 2008 through 2021. Total congestion costs in Table 11-11 include congestion associated with PJM facilities and those associated with reciprocal, coordinated flowgates in MISO and in NYISO.[19] [20]

19 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>.
20 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>.

Table 11-11 Total congestion costs (Dollars (Millions)): January through March, 2008 through 2021

	Congestion Costs (Millions)			
(Jan - Mar)	Congestion Cost	Percent Change	Total PJM Billing	Percent of PJM Billing
2008	$486	NA	$7,718	6.3%
2009	$307	(36.8%)	$7,515	4.1%
2010	$345	12.4%	$8,415	4.1%
2011	$360	4.3%	$9,584	3.8%
2012	$122	(66.0%)	$6,938	1.8%
2013	$186	51.9%	$7,762	2.4%
2014	$1,236	564.8%	$21,070	5.9%
2015	$632	(48.9%)	$14,040	4.5%
2016	$292	(53.7%)	$9,500	3.1%
2017	$158	(45.9%)	$9,710	1.6%
2018	$661	318.4%	$14,520	4.6%
2019	$164	(75.2%)	$10,980	1.5%
2020	$85	(48.1%)	$8,110	1.0%
2021	$121	42.2%	$10,400	1.2%

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 11-12 shows total congestion by day-ahead and balancing component for the first three months of 2008 through 2021.

Table 11-12 Total CLMP credits and charges by accounting category (Dollars (Millions)): January through March, 2008 through 2021

	CLMP Credits and Charges (Millions)									
	Day-Ahead				Balancing					
(Jan - Mar)	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Inadvertent Charges	Congestion Costs
2008	$332.4	($220.0)	$39.9	$592.3	($46.0)	$29.5	($31.2)	($106.7)	$0.0	$485.6
2009	$120.2	($221.3)	$47.9	$389.5	($14.2)	($6.0)	($74.4)	($82.6)	($0.0)	$306.9
2010	$85.9	($293.1)	$12.9	$391.9	($5.7)	$12.1	($29.1)	($47.0)	($0.0)	$344.9
2011	$176.5	($226.7)	$4.1	$407.3	$21.6	$27.8	($41.2)	($47.4)	$0.0	$359.9
2012	$21.9	($131.4)	$27.5	$180.9	($5.1)	$11.3	($42.0)	($58.4)	$0.0	$122.4
2013	$85.0	($199.1)	$47.8	$331.9	($6.6)	$73.3	($66.0)	($145.9)	$0.0	$185.9
2014	$333.7	($1,193.9)	($94.3)	$1,433.3	$73.0	$208.9	($61.3)	($197.2)	$0.0	$1,236.1
2015	$327.0	($457.9)	($11.0)	$773.9	$5.4	$69.6	($78.0)	($142.2)	($0.0)	$631.7
2016	$120.2	($193.5)	$9.2	$322.9	($1.1)	$11.9	($17.7)	($30.8)	$0.0	$292.2
2017	$24.2	($137.7)	$3.0	$164.9	($0.3)	$7.5	$0.9	($6.9)	($0.0)	$158.0
2018	$130.9	($557.5)	($46.7)	$641.7	$12.8	$23.6	$30.1	$19.3	$0.0	$661.0
2019	$53.3	($137.7)	$11.2	$202.2	($1.8)	$20.1	($16.4)	($38.3)	$0.0	$163.9
2020	$13.5	($75.7)	$14.1	$103.3	($0.2)	$3.8	($14.2)	($18.2)	($0.0)	$85.1
2021	$82.3	($123.5)	$18.7	$224.5	($26.7)	$39.9	($36.9)	($103.4)	$0.0	$121.0

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) are paying for energy and what injections (generation) are being 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 11-13 and Table 11-14 show the total CLMP charges and credits for each transaction type in the first three months of 2021 and 2020. Table 11-13 shows that in the first three months of 2021 DECs paid $21.5 million in CLMP charges in the day-ahead market, were paid $40.4 million in CLMP credits in the balancing energy market, resulting in a net payment of $18.9 million in total CLMP credits. In the first three months of 2021, INCs paid $5.1 million in CLMP charges in the day-ahead market, were paid $12.3 million in CLMP credits in the balancing energy market resulting in a net payment of $7.2 million in total CLMP credits. In the first three months of 2021, up to congestion (UTCs) paid $16.8 million in CLMP charges in the day-ahead market, were paid $36.9 million in CLMP credits in the balancing market resulting in a total payment of $20.1 million in total CLMP credits.

Table 11-13 Total CLMP credits and charges by transaction type (Dollars (Millions)): January through March, 2021

	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	$21.5	$0.0	$0.0	$21.5	($40.4)	$0.0	$0.0	($40.4)	$0.0	($18.9)
Demand	$16.4	$0.0	$0.0	$16.4	$3.1	$0.0	$0.0	$3.1	$0.0	$19.5
Demand Response	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	$0.0	($0.0)	$0.0	$0.0
Explicit Congestion Only	$0.0	$0.0	$1.3	$1.3	$0.0	$0.0	($0.1)	($0.1)	$0.0	$1.2
Explicit Congestion and Loss Only	$0.0	$0.0	($0.2)	($0.2)	$0.0	$0.0	($0.0)	($0.0)	$0.0	($0.2)
Export	$4.1	$0.0	($0.1)	$4.0	$10.3	$0.0	$0.1	$10.4	$0.0	$14.5
Generation	$0.0	($159.4)	$0.0	$159.4	$0.0	$21.7	$0.0	($21.7)	$0.0	$137.7
Import	$0.0	($0.1)	$0.0	$0.1	$0.0	$5.6	$0.0	($5.6)	$0.0	($5.5)
INC	$0.0	($5.1)	$0.0	$5.1	$0.0	$12.3	$0.0	($12.3)	$0.0	($7.2)
Internal Bilateral	$40.2	$41.0	$0.8	$0.0	($0.4)	($0.4)	$0.0	$0.0	$0.0	$0.0
Up to Congestion	$0.0	$0.0	$16.8	$16.8	$0.0	$0.0	($36.9)	($36.9)	$0.0	($20.1)
Wheel In	$0.0	$0.0	$0.0	$0.0	$0.0	$0.8	$0.1	($0.6)	$0.0	($0.6)
Wheel Out	$0.0	$0.0	$0.0	$0.0	$0.8	$0.0	$0.0	$0.8	$0.0	$0.8
Total	$82.3	($123.5)	$18.7	$224.5	($26.7)	$39.9	($36.9)	($103.4)	$0.0	$121.0

Table 11-14 Total CLMP credits and charges by transaction type (Dollars (Millions)): January through March, 2020

	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	($0.4)	$0.0	$0.0	($0.4)	($0.9)	$0.0	$0.0	($0.9)	$0.0	($1.4)
Demand	($1.7)	$0.0	$0.0	($1.7)	$1.4	$0.0	$0.0	$1.4	$0.0	($0.3)
Demand Response	($0.0)	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)
Explicit Congestion Only	$0.0	$0.0	$0.7	$0.7	$0.0	$0.0	($0.3)	($0.3)	$0.0	$0.4
Explicit Congestion and Loss Only	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	$0.0	$0.0
Export	($6.0)	$0.0	($0.0)	($6.0)	($0.5)	$0.0	$0.3	($0.1)	$0.0	($6.2)
Generation	$0.0	($93.5)	$0.0	$93.5	$0.0	($0.9)	$0.0	$0.9	$0.0	$94.4
Import	$0.0	($0.1)	$0.0	$0.1	$0.0	$0.1	($0.0)	($0.1)	$0.0	($0.0)
INC	$0.0	($4.0)	$0.0	$4.0	$0.0	$4.8	$0.0	($4.8)	$0.0	($0.8)
Internal Bilateral	$21.6	$21.8	$0.2	($0.0)	($0.3)	($0.3)	$0.0	($0.0)	$0.0	($0.0)
Up to Congestion	$0.0	$0.0	$13.3	$13.3	$0.0	$0.0	($14.2)	($14.2)	$0.0	($1.0)
Wheel In	$0.0	$0.0	$0.0	$0.0	$0.0	$0.1	$0.0	($0.1)	$0.0	($0.1)
Wheel Out	$0.0	$0.0	$0.0	$0.0	$0.1	$0.0	$0.0	$0.1	$0.0	$0.1
Total	$13.5	($75.7)	$14.1	$103.3	($0.2)	$3.8	($14.2)	($18.2)	$0.0	$85.1

Table 11-15 shows the change in total CLMP credits and charges incurred by transaction type from the first three months of 2020 to the first three months of 2021. Total negative CLMP credits incurred by generation increased by $43.3 million, and total CLMP charges incurred by demand increased by $19.8 million. The total CLMP credits to up to congestion transactions (UTCs) increased from $1.0 million in the first three months of 2020 to $20.1 million in the first three months of 2021. Total day-ahead CLMP charges to UTCs increased by $3.6 million from $13.3 million in the first three months of 2020 to $16.8 million in the first three months of 2021. Over the same period balancing CLMP credits to UTCs increased by $22.7 million, from $14.2 million in the first three months of 2020 to $36.9 million in the first three months of 2021.

Table 11-15 Change in total CLMP credits and charges by transaction type (Dollars (Millions)): January through March, 2020 to 2021

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	$22.0	$0.0	$0.0	$22.0	($39.5)	$0.0	$0.0	($39.5)	$0.0	($17.5)
Demand	$18.1	$0.0	$0.0	$18.1	$1.7	$0.0	$0.0	$1.7	$0.0	$19.8
Demand Response	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	$0.0	($0.0)	$0.0	$0.0
Explicit Congestion Only	$0.0	$0.0	$0.6	$0.6	$0.0	$0.0	$0.2	$0.2	$0.0	$0.8
Explicit Congestion and Loss Only	$0.0	$0.0	($0.2)	($0.2)	$0.0	$0.0	($0.0)	($0.0)	$0.0	($0.2)
Export	$10.2	$0.0	($0.1)	$10.1	$10.8	$0.0	($0.3)	$10.6	$0.0	$20.6
Generation	$0.0	($65.9)	$0.0	$65.9	$0.0	$22.6	$0.0	($22.6)	$0.0	$43.3
Import	$0.0	$0.0	$0.0	($0.0)	$0.0	$5.5	$0.0	($5.5)	$0.0	($5.5)
INC	$0.0	($1.1)	$0.0	$1.1	$0.0	$7.5	$0.0	($7.5)	$0.0	($6.4)
Internal Bilateral	$18.6	$19.2	$0.6	$0.0	($0.2)	($0.2)	$0.0	$0.0	$0.0	$0.0
Up to Congestion	$0.0	$0.0	$3.6	$3.6	$0.0	$0.0	($22.7)	($22.7)	$0.0	($19.1)
Wheel In	$0.0	$0.0	$0.0	$0.0	$0.0	$0.6	$0.1	($0.5)	$0.0	($0.5)
Wheel Out	$0.0	$0.0	$0.0	$0.0	$0.6	$0.0	$0.0	$0.6	$0.0	$0.6
Total	$68.8	($47.8)	$4.5	$121.1	($26.5)	$36.1	($22.7)	($85.2)	$0.0	$35.9

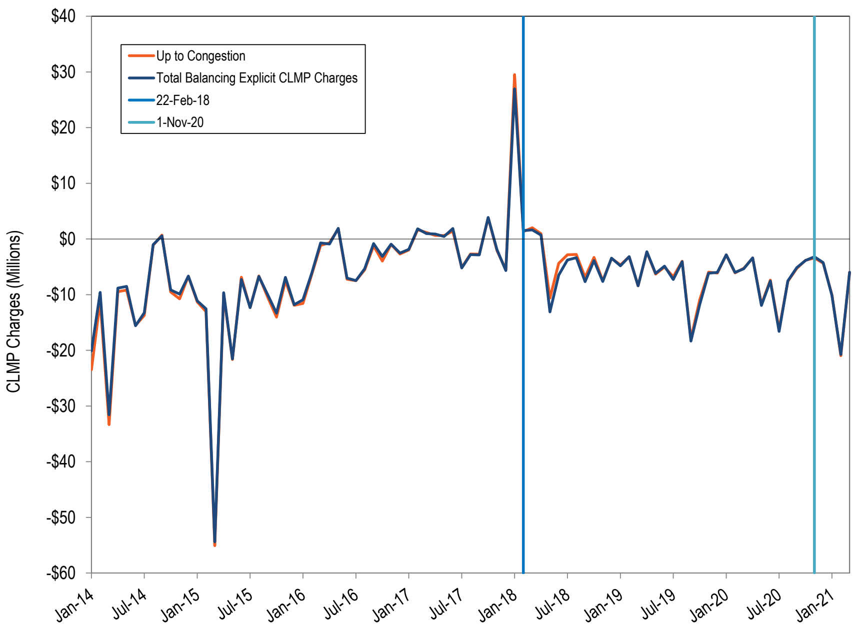
UTCs and Negative Balancing Explicit CLMP Charges

Figure 11-2 shows the change in up to congestion balancing explicit CLMP charges from January 2014 through March 2021. Figure 11-2 shows that UTCs account for almost all balancing explicit CLMP charges in PJM. As shown in Figure 11-2, UTCs are generally paid balancing CLMP credits, which take the form of negative balancing CLMP charges being allocated to UTC positions. In the first three months of 2021, 100.2 percent (-$36.9 million out of -$36.9 million) of negative balancing explicit CLMP charges was incurred by UTCs and -0.2 percent ($0.1 out of -$36.9 million) was incurred by Explicit Congestion Only, Export, Import and Wheel In transactions (Table 11-13). 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.[21] 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.[22]

21 For additional information about the FERC order, see the *2020 State of the Market Report for PJM*, Appendix F: Congestion and Marginal Losses.

22 172 FERC ¶ 61,046 (2020).

Figure 11-2 Monthly balancing explicit CLMP charges incurred by UTC: January 2014 through March 2021



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 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.[23] 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.[24]

Table 11-17 provides an example of how UTCs can profit from differences in day-ahead and real-time models and generate negative balancing congestion. In the example, Bus A and Bus B are linked by a transmission line. In the day-ahead market the transmission limit is modeled as 9,999 MW (no limit is enforced in the day-ahead market solution). In the real-time market the physical limit between bus A and bus B is 50 MW. Generation at A has a price of $1.00 and Generation at B has a price of $6. There is 100 MW of load at bus A and 100 MW of load at bus B. There is a UTC of 200 MW that will source at bus A and sink at bus B if the spread in the prices between A and B is less than $1.

As a result of the fact that the transmission capability between A and B is unlimited in the day-ahead market, all of load at A and B can be met with the $1 generation at bus A. The constraint between A and B does not bind in

23 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.

24 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.

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

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

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

Table 11-16 shows the balancing credits and charges associated with the real-time deviations in the example. Total congestion (day-ahead plus balancing congestion) in this example is negative $1,250. Total CLMP credits (payments) to generation and the UTC exceed the total charges collected from load. The negative balancing congestion that results is paid by the load under the FERC order.[25]

25 153 FERC ¶ 61,180.

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

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

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

Zonal and Load Aggregate Congestion

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

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

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

The total congestion caused by a constraint is equal to the product of the constraint shadow price times the net flow on the binding constraint. 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.

Constraint specific CLMPs are determined relative to a reference bus, where there is no congestion and no losses. For purposes of calculating the congestion from an individual constraint, the reference bus for each constraint calculation is the point that is just upstream of the constraint (the bus with the greatest negative price effect from the constraint), allowing any positive price effects of the constraint to be reflected as a positive CLMP.

In order to define the load that is actually paying congestion, congestion is appropriately assigned to downstream (positive CLMP) load buses that paid the congestion caused by the constraint, in proportion to the CLMP charges collected from that load due to that constraint. The congestion collected from each load bus due to a constraint is equal to the CLMP caused by that constraint times the MW of load at that load bus. This calculation is done for both day-ahead congestion and balancing congestion.

Table 11-17 shows day-ahead and balancing congestion by zone for the first three months of 2021. AEP had the largest zonal congestion costs among all control zones in the first three months of 2021. AEP had $16.3 million in zonal congestion costs, comprised of $31.8 million in zonal day-ahead congestion costs and -$15.6 million in zonal balancing congestion costs. The Cedar Grove Sub - William Line, the Conastone Transformer, the Bagley - Raphael Road Line, the Bagley - Graceton Line, and the East Lima - Haviland Line contributed $4.9 million, or 30.1 percent of the AEP zonal congestion costs.[26]

Table 11-18 shows the congestion costs by zone for the first three months of 2020.

26 For additional information about the top 20 constraints that affected each zone, see the *2020 State of the Market Report for PJM*, Appendix F: Congestion and Marginal Losses.

Table 11-17 Day-ahead and balancing congestion by zone (Dollars (Millions)): January through March, 2021

	CLMP Credits and Charges (Millions)								
	Day-Ahead				Balancing				
Control Zone	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Congestion Costs
ACEC	$0.6	($1.1)	$0.2	$1.8	($0.2)	$0.4	($0.4)	($1.0)	$0.9
AEP	$7.8	($21.8)	$2.3	$31.8	($3.8)	$6.0	($5.7)	($15.6)	$16.3
APS	$7.7	($7.8)	$1.2	$16.7	($1.5)	$2.4	($2.2)	($6.1)	$10.6
ATSI	$4.1	($12.1)	$1.3	$17.6	($1.9)	$2.9	($2.8)	($7.6)	$10.0
BGE	$2.8	($4.3)	$0.7	$7.7	($0.8)	$1.5	($1.4)	($3.7)	$4.0
COMED	$8.6	($16.4)	$2.5	$27.6	($2.8)	$4.6	($4.2)	($11.5)	$16.1
DAY	$0.6	($2.9)	$0.3	$3.8	($0.5)	$0.8	($0.8)	($2.1)	$1.7
DOM	$8.6	($14.8)	$2.0	$25.4	($3.0)	$5.0	($4.7)	($12.7)	$12.7
DPL	$13.2	($1.2)	$0.7	$15.1	($1.6)	$0.6	($0.8)	($3.0)	$12.2
DUKE	$0.9	($4.9)	$0.6	$6.4	($0.8)	$1.2	($1.2)	($3.2)	$3.3
DUQ	$0.3	($1.7)	$0.1	$2.1	($0.4)	$0.6	($0.5)	($1.5)	$0.7
EKPC	$0.7	($2.5)	$0.2	$3.4	($0.4)	$0.7	($0.7)	($1.9)	$1.6
EXT	$3.1	($3.3)	$0.8	$7.3	($2.7)	$3.6	($2.5)	($8.9)	($1.5)
JCPLC	$1.5	($2.7)	$0.3	$4.5	($0.5)	$0.8	($0.7)	($2.0)	$2.4
MEC	$1.9	($2.3)	$0.3	$4.5	($0.4)	$0.7	($0.6)	($1.7)	$2.8
OVEC	$0.1	($0.1)	$0.0	$0.2	($0.0)	$0.1	($0.1)	($0.1)	$0.1
PE	$4.1	($2.2)	$0.7	$7.0	($0.7)	$1.0	($1.0)	($2.7)	$4.3
PECO	$5.3	($4.7)	$0.7	$10.8	($1.0)	$1.6	($1.5)	($4.1)	$6.7
PEPCO	$2.3	($3.8)	$0.6	$6.7	($0.8)	$1.3	($1.2)	($3.3)	$3.4
PPL	$3.8	($6.9)	$1.3	$12.0	($1.1)	$1.8	($1.7)	($4.5)	$7.4
PSEG	$3.6	($5.9)	$1.1	$10.6	($1.7)	$2.2	($2.3)	($6.1)	$4.5
REC	$0.6	($0.2)	$0.8	$1.5	($0.1)	$0.1	($0.1)	($0.3)	$1.2
Total	$82.3	($123.5)	$18.7	$224.5	($26.7)	$39.9	($36.9)	($103.4)	$121.0

Table 11-18 Day-ahead and balancing congestion by zone (Dollars (Millions)): January through March, 2020

	CLMP Credits and Charges (Millions)								
	Day-Ahead				Balancing				
Control Zone	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Congestion Costs
ACEC	$0.2	($0.7)	$0.2	$1.1	($0.0)	$0.0	($0.2)	($0.2)	$0.9
AEP	($0.1)	($14.2)	$2.1	$16.2	($0.0)	$0.6	($2.3)	($3.0)	$13.2
APS	$3.9	($2.7)	$0.8	$7.4	($0.0)	$0.3	($0.9)	($1.2)	$6.2
ATSI	$2.1	($5.9)	$1.1	$9.2	($0.0)	$0.3	($1.2)	($1.5)	$7.7
BGE	$0.7	($2.5)	$0.4	$3.6	($0.0)	$0.2	($0.5)	($0.7)	$2.9
COMED	($2.1)	($14.4)	$2.9	$15.1	$0.0	$0.4	($1.6)	($2.0)	$13.2
DAY	($0.2)	($2.0)	$0.3	$2.1	($0.0)	$0.1	($0.3)	($0.4)	$1.7
DOM	$1.0	($9.5)	$1.4	$11.9	($0.0)	$0.4	($1.8)	($2.2)	$9.7
DPL	$1.5	($1.5)	$0.5	$3.5	($0.0)	$0.1	($0.4)	($0.5)	$3.0
DUKE	$0.0	($2.5)	$0.4	$2.9	($0.0)	$0.1	($0.5)	($0.6)	$2.3
DUQ	($0.0)	($1.2)	$0.2	$1.4	($0.0)	$0.1	($0.2)	($0.3)	$1.1
EKPC	($0.0)	($1.4)	$0.2	$1.6	($0.0)	$0.1	($0.3)	($0.3)	$1.3
EXT	($0.1)	($2.0)	$0.4	$2.3	$0.0	$0.1	($0.5)	($0.6)	$1.7
JCPLC	$0.3	($1.9)	$0.3	$2.5	($0.0)	$0.1	($0.4)	($0.5)	$2.0
MEC	$0.7	($1.2)	$0.2	$2.1	($0.0)	$0.1	($0.3)	($0.4)	$1.7
OVEC	$0.0	($0.1)	$0.1	$0.3	($0.0)	$0.0	($0.0)	($0.0)	$0.2
PE	$1.9	($0.4)	$0.3	$2.6	($0.0)	$0.1	($0.3)	($0.4)	$2.2
PECO	$0.3	($3.4)	$0.5	$4.2	($0.0)	$0.2	($0.7)	($0.9)	$3.3
PEPCO	$0.6	($2.3)	$0.4	$3.2	($0.0)	$0.1	($0.5)	($0.6)	$2.6
PPL	$1.5	($3.0)	$0.8	$5.4	($0.0)	$0.2	($0.7)	($0.9)	$4.5
PSEG	$1.1	($3.0)	$0.6	$4.6	($0.0)	$0.2	($0.7)	($0.9)	$3.7
REC	$0.0	($0.1)	$0.0	$0.1	($0.0)	$0.0	($0.0)	($0.0)	$0.1
Total	$13.5	($75.7)	$14.1	$103.3	($0.2)	$3.8	($14.2)	($18.2)	$85.1

In cases where the constraint causes net negative congestion and/or there is no load bus on the constrained side of a binding constraint, the congestion of the constraint is handled as a special case. In the first three months of 2021, the total congestion costs associated with the special cases were -$4.0 million or -3.3 percent of the total congestion costs. Table 11-17 and Table 11-18 include congestion allocations from these special case constraints.

There are five categories of constraint specific allocation special cases: congestion associated with constraints with no downstream load bus (no load bus); congestion associated with 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; and congestion associated with nontransmission 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).

Table 11-19 and Table 11-20 show total congestion by type of special case, congestion, and total congestion by zone. Closed loop interfaces and CT pricing logic generally result in negative congestion on a constraint specific basis. PJM's use of both the closed loop interfaces and CT Pricing Logic forces the affected resource bus LMP to match the marginal offer of the resource. This causes higher CLMP payments to the affected generation than the CLMP load charges to any affected load, resulting in negative congestion associated with the constraint. None of the closed loop interfaces were binding in the first three months of 2021 and 2020.

Table 11-19 Day-ahead and total balancing congestion assigned by zone and special case logic (Dollars (Millions)): January through March, 2021

	Congestion Costs (Millions)																
	Day-Ahead							Balancing									
Control Zone	Load Bus Zero CLMP	CT Price Setting Logic	Closed Loop Interfaces	No Load Buses	Unclassified	Contribution	Total	Load Bus Zero CLMP	CT Price Setting Logic	Closed Loop Interfaces	No Load Buses	Unclassified	Contribution	Total	Grand Total	Special Cases Total	Percent of Special Cases
ACEC	$0.0	($0.0)	$0.0	$0.0	$0.0	$1.8	$1.8	$0.0	($0.0)	$0.0	$0.0	($0.0)	($0.9)	($1.0)	$0.9	($0.0)	(4.8%)
AEP	$0.0	$0.0	$0.0	$0.1	$0.0	$31.7	$31.8	$0.0	($0.4)	$0.0	$0.0	($0.2)	($15.0)	($15.6)	$16.3	($0.5)	(2.9%)
APS	$0.0	($0.0)	$0.0	$0.2	$0.0	$16.5	$16.7	$0.0	($0.2)	$0.0	($0.0)	($0.1)	($5.8)	($6.1)	$10.6	($0.1)	(1.0%)
ATSI	$0.0	($0.0)	$0.0	$0.0	$0.0	$17.6	$17.6	$0.0	($0.2)	$0.0	$0.0	($0.1)	($7.3)	($7.6)	$10.0	($0.3)	(3.0%)
BGE	$0.0	$0.0	$0.0	$0.0	$0.0	$7.7	$7.7	$0.0	($0.1)	$0.0	($0.0)	($0.0)	($3.5)	($3.7)	$4.0	($0.1)	(3.6%)
COMED	$0.5	$0.0	$0.0	$1.4	$0.0	$25.7	$27.6	$0.0	($0.3)	$0.0	($0.0)	($0.1)	($11.1)	($11.5)	$16.1	$1.5	9.1%
DAY	$0.0	$0.0	$0.0	$0.0	($0.0)	$3.8	$3.8	$0.0	($0.1)	$0.0	$0.0	($0.0)	($2.0)	($2.1)	$1.7	($0.1)	(4.8%)
DOM	$0.0	$0.0	$0.0	$0.0	$0.0	$25.4	$25.4	$0.0	($0.4)	$0.0	$0.0	($0.2)	($12.2)	($12.7)	$12.7	($0.5)	(3.9%)
DPL	$0.0	($0.0)	$0.0	$0.0	$0.0	$15.1	$15.1	$0.0	($0.1)	$0.0	$0.0	($0.0)	($2.9)	($3.0)	$12.2	($0.1)	(0.7%)
DUKE	$0.0	$0.0	$0.0	$0.0	$0.0	$6.4	$6.4	($0.0)	($0.1)	$0.0	($0.0)	($0.0)	($3.1)	($3.2)	$3.3	($0.1)	(3.9%)
DUQ	$0.0	$0.0	$0.0	$0.0	$0.0	$2.1	$2.1	$0.0	($0.0)	$0.0	$0.0	($0.0)	($1.4)	($1.5)	$0.7	($0.1)	(8.7%)
EKPC	$0.0	$0.0	$0.0	$0.0	$0.0	$3.4	$3.4	$0.0	($0.1)	$0.0	$0.0	($0.0)	($1.8)	($1.9)	$1.6	($0.1)	(4.7%)
EXT	$0.2	($0.0)	$0.0	$0.0	$0.0	$7.1	$7.3	($0.0)	($2.7)	$0.0	$0.0	($0.0)	($6.1)	($8.9)	($1.5)	($2.5)	164.5%
JCPLC	$0.0	($0.0)	$0.0	$0.0	$0.0	$4.5	$4.5	$0.0	($0.1)	$0.0	$0.0	($0.0)	($1.9)	($2.0)	$2.4	($0.1)	(4.1%)
MEC	$0.0	($0.0)	$0.0	$0.0	$0.0	$4.5	$4.5	$0.0	($0.0)	$0.0	$0.0	($0.0)	($1.6)	($1.7)	$2.8	($0.0)	(1.6%)
OVEC	$0.0	$0.0	$0.0	$0.0	$0.0	$0.2	$0.2	$0.0	($0.0)	$0.0	$0.0	($0.0)	($0.1)	($0.1)	$0.1	($0.0)	(7.4%)
PE	$0.0	($0.0)	$0.0	$0.0	$0.0	$7.0	$7.0	$0.0	($0.1)	$0.0	($0.0)	($0.0)	($2.6)	($2.7)	$4.3	($0.1)	(2.4%)
PECO	$0.0	($0.0)	$0.0	$0.0	$0.0	$10.8	$10.8	$0.0	($0.1)	$0.0	$0.0	($0.1)	($3.9)	($4.1)	$6.7	($0.2)	(2.7%)
PEPCO	$0.0	$0.0	$0.0	$0.0	$0.0	$6.7	$6.7	$0.0	($0.1)	$0.0	$0.0	($0.0)	($3.1)	($3.3)	$3.4	($0.1)	(4.0%)
PPL	$0.0	($0.0)	$0.0	$0.0	$0.0	$12.0	$12.0	($0.0)	($0.1)	$0.0	$0.0	($0.1)	($4.3)	($4.5)	$7.4	($0.2)	(2.7%)
PSEG	$0.0	($0.0)	$0.0	$0.0	$0.0	$10.6	$10.6	$0.0	($0.1)	$0.0	$0.0	($0.1)	($6.0)	($6.1)	$4.5	($0.2)	(4.2%)
REC	$0.0	($0.0)	$0.0	$0.0	$0.0	$1.5	$1.5	$0.0	($0.0)	$0.0	$0.0	($0.0)	($0.3)	($0.3)	$1.2	($0.0)	(0.4%)
Total	$0.6	($0.0)	$0.0	$1.8	$0.0	$222.0	$224.5	($0.0)	($5.2)	$0.0	($0.0)	($1.2)	($97.0)	($103.4)	$121.0	($4.0)	(3.3%)

Table 11-20 Day-ahead and total balancing congestion assigned by zone and special case logic (Dollars (Millions)): January through March, 2020

	Congestion Costs (Millions)																
	Day-Ahead							Balancing									
Control Zone	Load Bus Zero CLMP	CT Price Setting Logic	Closed Loop Interfaces	No Load Buses	Unclassified	Contribution	Total	Load Bus Zero CLMP	CT Price Setting Logic	Closed Loop Interfaces	No Load Buses	Unclassified	Contribution	Total	Grand Total	Special Cases Total	Percent of Special Cases
ACEC	$0.0	($0.0)	$0.0	$0.0	$0.0	$1.1	$1.1	($0.0)	($0.0)	$0.0	($0.0)	($0.0)	($0.2)	($0.2)	$0.9	($0.0)	(0.1%)
AEP	$0.0	($0.0)	$0.0	$0.0	$0.0	$16.1	$16.2	($0.0)	($0.0)	$0.0	($0.0)	($0.0)	($2.9)	($3.0)	$13.2	($0.0)	(0.0%)
APS	$0.0	($0.0)	$0.0	$0.0	$0.0	$7.4	$7.4	($0.0)	($0.0)	$0.0	($0.0)	($0.0)	($1.2)	($1.2)	$6.2	($0.0)	(0.0%)
ATSI	$0.0	($0.0)	$0.0	$0.0	$0.0	$9.2	$9.2	($0.0)	($0.0)	$0.0	($0.0)	($0.0)	($1.5)	($1.5)	$7.7	($0.0)	(0.1%)
BGE	$0.0	($0.0)	$0.0	$0.0	$0.0	$3.6	$3.6	($0.0)	($0.0)	$0.0	($0.0)	($0.0)	($0.7)	($0.7)	$2.9	($0.0)	(0.1%)
COMED	$0.2	($0.0)	$0.0	$0.7	$0.0	$14.2	$15.1	($0.0)	($0.0)	$0.0	($0.0)	($0.0)	($2.0)	($2.0)	$13.2	$0.9	6.7%
DAY	$0.0	($0.0)	$0.0	$0.0	$0.0	$2.1	$2.1	($0.0)	($0.0)	$0.0	($0.0)	($0.0)	($0.4)	($0.4)	$1.7	($0.0)	(0.1%)
DOM	$0.0	$0.0	$0.0	$0.0	$0.0	$11.9	$11.9	($0.0)	($0.0)	$0.0	($0.0)	($0.0)	($2.2)	($2.2)	$9.7	($0.0)	(0.1%)
DPL	$0.0	($0.0)	$0.0	$0.0	$0.0	$3.5	$3.5	($0.0)	($0.0)	$0.0	($0.0)	($0.0)	($0.5)	($0.5)	$3.0	($0.0)	(0.0%)
DUKE	$0.0	($0.0)	$0.0	$0.0	$0.0	$2.9	$2.9	($0.0)	($0.0)	$0.0	($0.0)	($0.0)	($0.6)	($0.6)	$2.3	($0.0)	(0.1%)
DUQ	$0.0	($0.0)	$0.0	$0.0	$0.0	$1.4	$1.4	($0.0)	($0.0)	$0.0	($0.0)	($0.0)	($0.3)	($0.3)	$1.1	($0.0)	(0.1%)
EKPC	$0.0	($0.0)	$0.0	$0.0	$0.0	$1.6	$1.6	($0.0)	($0.0)	$0.0	($0.0)	($0.0)	($0.3)	($0.3)	$1.3	($0.0)	(0.1%)
EXT	$0.0	($0.0)	$0.0	$0.0	$0.0	$2.3	$2.3	($0.0)	($0.0)	$0.0	($0.0)	($0.0)	($0.6)	($0.6)	$1.7	$0.0	0.2%
JCPLC	$0.0	($0.0)	$0.0	$0.0	$0.0	$2.5	$2.5	($0.0)	($0.0)	$0.0	($0.0)	($0.0)	($0.5)	($0.5)	$2.0	($0.0)	(0.1%)
MEC	$0.0	($0.0)	$0.0	$0.1	$0.0	$2.0	$2.1	($0.0)	($0.0)	$0.0	($0.1)	($0.0)	($0.3)	($0.4)	$1.7	$0.0	0.5%
OVEC	$0.0	($0.0)	$0.0	$0.1	$0.0	$0.2	$0.3	($0.0)	($0.0)	$0.0	($0.0)	($0.0)	($0.0)	($0.0)	$0.2	$0.1	43.6%
PE	$0.0	($0.0)	$0.0	$0.0	$0.0	$2.6	$2.6	($0.0)	($0.0)	$0.0	($0.0)	($0.0)	($0.4)	($0.4)	$2.2	($0.0)	(0.6%)
PECO	($0.0)	($0.0)	$0.0	$0.0	$0.0	$4.2	$4.2	($0.0)	($0.0)	$0.0	($0.0)	($0.0)	($0.9)	($0.9)	$3.3	($0.0)	(0.1%)
PEPCO	$0.0	($0.0)	$0.0	$0.0	$0.0	$3.2	$3.2	($0.0)	($0.0)	$0.0	($0.0)	($0.0)	($0.6)	($0.6)	$2.6	($0.0)	(0.1%)
PPL	$0.0	($0.0)	$0.0	$0.0	$0.0	$5.4	$5.4	($0.0)	($0.0)	$0.0	($0.0)	($0.0)	($0.9)	($0.9)	$4.5	($0.0)	(0.1%)
PSEG	$0.0	($0.0)	$0.0	$0.0	$0.0	$4.6	$4.6	($0.0)	($0.0)	$0.0	($0.0)	($0.0)	($0.9)	($0.9)	$3.7	($0.0)	(0.2%)
REC	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.1	$0.1	($0.0)	($0.0)	$0.0	($0.0)	($0.0)	($0.0)	($0.0)	$0.1	($0.0)	(0.2%)
Total	$0.2	($0.0)	$0.0	$0.9	$0.1	$102.2	$103.3	($0.0)	($0.0)	$0.0	($0.2)	($0.0)	($18.0)	($18.2)	$85.1	$0.9	1.1%

Monthly Congestion

Table 11-21 shows day-ahead, balancing and inadvertent congestion costs by month for January 2020 through March 2021. Compared to the first three months of 2020, total congestion costs decreased in January, increased in February and increased in March. Total day-ahead congestion costs increased in January through March and total negative balancing congestion costs increased in January through March.

The top two constraints that contributed most to day-ahead and balancing congestion costs were the Cedar Grove Sub – William Line and the Vienna Transformer. The high shadow prices of Cedar Grove Sub – William Line were primarily a result of high prices due to cold weather. The high shadow prices of the Vienna Transformer were a result of a trip of generation units and a transmission outage in DPL in March.

CT pricing logic was also a factor that contributed to the high negative balancing congestion costs in the first three months of 2021. The top three constraints that contributed most to the negative balancing congestion costs resulting from CT pricing logic were the Terminal Transformer, the Coffeen North – Roxford Flowgate and the Bergenfield – Leonia Line.

Table 11-21 Monthly congestion costs by market (Dollars (Millions)): January 2020 through March 2021

	Congestion Costs (Millions)							
	2020				2021			
	Day-Ahead	Balancing	Inadvertent Charges	Total	Day-Ahead	Balancing	Inadvertent Charges	Total
Jan	$43.3	($5.6)	$0.0	$37.6	$53.2	($24.1)	($0.0)	$29.1
Feb	$28.7	($7.0)	($0.0)	$21.7	$90.3	($53.5)	$0.0	$36.8
Mar	$31.4	($5.6)	($0.0)	$25.8	$81.0	($25.8)	$0.0	$55.2
Apr	$24.2	($8.2)	$0.0	$16.0				
May	$46.1	($19.5)	$0.0	$26.6				
Jun	$62.8	($10.7)	$0.0	$52.0				
Jul	$105.6	($23.8)	$0.0	$81.7				
Aug	$82.5	($14.0)	($0.0)	$68.5				
Sep	$78.1	($11.9)	$0.0	$66.1				
Oct	$52.5	($9.3)	$0.0	$43.2				
Nov	$41.3	($7.8)	$0.0	$33.5				
Dec	$66.2	($10.5)	$0.0	$55.8				
Total	$662.5	($133.9)	$0.0	$528.6	$224.5	($103.4)	$0.0	$121.0

Figure 11-3 shows PJM monthly total congestion cost for the January 2008 through March 2021.

Figure 11-3 Monthly total congestion cost (Dollars (Millions)): January 2008 through March 2021

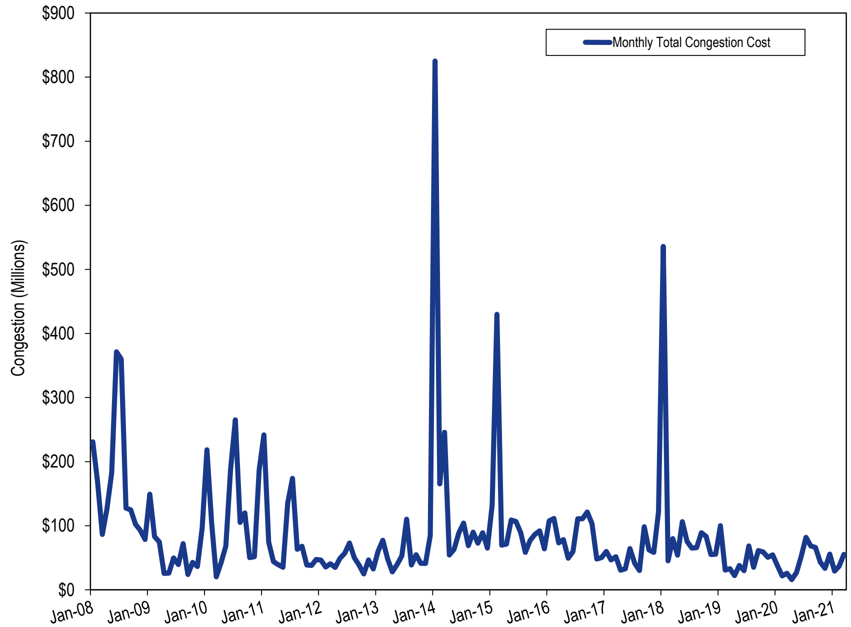


Table 11-22 shows monthly total CLMP credits and charges for each virtual transaction type in January 2020 through March 2021. Virtual transaction CLMP charges, when positive, are the total CLMP charges to the virtual transactions and when negative, are the total CLMP credits to the virtual transactions. The negative totals in Table 11-22 show that virtuals were paid, in net, CLMP credits in the first three months of 2021 and 2020. In the first three months of 2021, 43.5 percent of the total credits to virtuals went to UTCs, compared to 31.0 percent in the first three months of 2020.

Table 11-22 Monthly CLMP charges by virtual transaction type and by market (Dollars (Millions)): January 2020 through March 2021

		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
2020	Jan	$0.2	($0.6)	($0.4)	$1.4	($1.8)	($0.4)	$3.7	($2.9)	$0.8	($0.0)
	Feb	$0.2	($0.2)	($0.1)	$1.3	($1.5)	($0.1)	$4.8	($6.1)	($1.3)	($1.5)
	Mar	($0.8)	($0.1)	($0.9)	$1.3	($1.6)	($0.2)	$4.8	($5.3)	($0.5)	($1.6)
	Apr	($0.6)	$0.8	$0.2	$1.9	($5.0)	($3.0)	$2.7	($3.4)	($0.7)	($3.5)
	May	$0.6	($0.6)	$0.0	$2.7	($5.1)	($2.4)	$7.3	($11.7)	($4.4)	($6.8)
	Jun	$1.0	($1.6)	($0.6)	$1.7	($2.8)	($1.2)	$7.7	($7.4)	$0.3	($1.5)
	Jul	$5.1	($3.7)	$1.4	$0.9	($3.5)	($2.6)	$9.1	($16.2)	($7.1)	($8.3)
	Aug	$5.1	($7.4)	($2.4)	$0.6	($1.9)	($1.3)	$5.8	($7.6)	($1.8)	($5.5)
	Sep	$2.5	($5.9)	($3.4)	$1.7	($1.5)	$0.1	$6.9	($5.3)	$1.6	($1.7)
	Oct	$1.0	($2.0)	($1.0)	$1.6	($3.2)	($1.6)	$2.8	($3.8)	($1.1)	($3.7)
	Nov	($1.1)	$1.4	$0.3	$3.0	($5.4)	($2.5)	$2.7	($3.4)	($0.7)	($2.9)
	Dec	$3.0	($6.2)	($3.2)	($1.0)	($1.3)	($2.4)	$2.5	($4.3)	($1.8)	($7.4)
	Total	$16.1	($26.2)	($10.1)	$17.0	($34.6)	($17.6)	$60.8	($77.5)	($16.7)	($44.4)
2021	Jan	$3.0	($8.0)	($5.0)	$0.5	($0.1)	$0.4	$4.0	($10.0)	($6.0)	($10.5)
	Feb	$11.8	($24.7)	($12.9)	$0.6	($4.0)	($3.5)	$7.9	($20.9)	($13.0)	($29.4)
	Mar	$6.7	($7.7)	($1.0)	$4.0	($8.1)	($4.2)	$4.9	($6.0)	($1.1)	($6.2)
	Total	$21.5	($40.4)	($18.9)	$5.1	($12.3)	($7.2)	$16.8	($36.9)	($20.1)	($46.2)

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 three months of 2021, there were 14,618 day-ahead, congestion event hours compared to 17,087 day-ahead congestion event hours in the first three months of 2020. Of the day-ahead congestion event hours in the first three months of 2021, only 2,498 (17.1 percent) were also constrained in the real-time energy market (Table 11-25). In the first three months of 2021, there were 5,484 real-time, congestion event hours compared to 5,515 real-time, congestion event hours in the first three months of 2020. Of the real-time congestion event hours in the first three months of 2021, 2,505 (45.7 percent) were also constrained in the day-ahead energy market (Table 11-26).

The top five constraints by congestion costs contributed $55.7 million, or 46.0 percent, of the total PJM congestion costs in the first three months of 2021. The top five constraints were the Vienna Transformer, the Bagley - Raphael Road Line, the Bagley - Graceton Line, the Conastone Transformer, and the Harwood – Susquehanna Line.

Several of the top constraints by congestion costs are located in the BGE Zone in the first three months of 2020 and 2021 (Figure 11-4).

Congestion by Facility Type and Voltage

Day-ahead, congestion event hours decreased on all types of facilities except lines. Interfaces decreased 1,360 congestion event hours from 1,385 day-ahead, congestion event hours in the first three months of 2020 to 25 day-ahead congestion event hours in the first three months of 2021. Of the 1,360 congestion event hours decrease, 98.5 percent of the decreased hours were on the PA Central Interface.

Real-time, congestion event hours increased on lines and transformers and decreased on flowgates and interfaces in the first three months of 2021. Interfaces decreased 1,106 congestion event hours from 1,129 real-time, congestion event hours in the first three months of 2020 to 23 real-time congestion event hours in the first three months of 2021. Of the 1,106 congestion event hours decrease, 101.8 percent of the decreased hours were on the PA Central Interface.

Day-ahead congestion costs increased on all types of facilities except interfaces in the first three months of 2021 compared to the first three months of 2020. The decrease of day-ahead congestion costs on interfaces was primarily a result of the decrease in day-ahead congestion event hours on the PA Central Interface.

Negative balancing congestion costs increased on all types of facilities except interfaces in the first three months of 2021 compared to the first three months of 2020 (Table 11-24). Table 11-23 provides congestion event hour subtotals and congestion cost subtotals comparing the first three months of 2021 results by facility type: line, transformer, interface, flowgate and unclassified facilities.[27] [28]

Table 11-23 Congestion summary (By facility type): January through March, 2021

	CLMP Credits and Charges (Millions)										
	Day-Ahead				Balancing					Event Hours	
Type	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Congestion Costs	Day-Ahead	Real-Time
Flowgate	($1.8)	($26.5)	$1.7	$26.4	$1.0	$9.4	($4.6)	($13.1)	$13.3	1,649	951
Interface	($0.0)	($1.5)	$0.1	$1.6	($0.0)	$0.1	($0.1)	($0.3)	$1.4	25	23
Line	$58.2	($74.3)	$14.6	$147.1	($15.8)	$27.1	($28.8)	($71.7)	$75.4	10,879	3,673
Transformer	$21.0	($20.3)	$1.5	$42.7	($13.3)	$0.3	($1.3)	($14.9)	$27.9	1,555	396
Other	$5.0	($0.9)	$0.7	$6.7	$1.7	$2.5	($1.5)	($2.4)	$4.3	510	441
Unclassified	$0.0	$0.0	($0.0)	$0.0	($0.1)	$0.6	($0.5)	($1.2)	($1.2)	NA	NA
Total	$82.3	($123.5)	$18.7	$224.5	($26.7)	$39.9	($36.9)	($103.4)	$121.0	14,618	5,484

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

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

Table 11-24 Congestion summary (By facility type): January through March, 2020

	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	($7.7)	($21.0)	$6.5	$19.9	($0.4)	$0.1	($9.4)	($9.9)	$10.0	2,002	1,011
Interface	$1.2	($12.7)	$0.8	$14.7	$0.3	$1.5	($1.2)	($2.4)	$12.3	1,385	1,129
Line	$13.1	($35.5)	$4.5	$53.2	($0.3)	$1.5	($3.0)	($4.9)	$48.3	9,935	2,730
Transformer	$0.1	($5.5)	$1.3	$6.9	$0.1	$0.2	($0.1)	($0.2)	$6.8	2,342	376
Other	$6.6	($1.0)	$0.9	$8.5	$0.2	$0.5	($0.5)	($0.8)	$7.7	1,423	269
Unclassified	$0.0	($0.0)	$0.0	$0.1	$0.0	($0.0)	($0.0)	($0.0)	$0.1	NA	NA
Total	$13.5	($75.7)	$14.1	$103.3	($0.2)	$3.8	($14.2)	($18.2)	$85.1	17,087	5,515

Table 11-25 and Table 11-26 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 11-25. In the first three months of 2021, there were 14,618 congestion event hours in the day-ahead energy market. Of those day-ahead congestion event hours, only 2,498 (17.1 percent) were also constrained in the real-time energy market. In the first three months of 2020, of the 17,087 day-ahead congestion event hours, only 3,142 (18.4 percent) were binding in the real-time energy market.[29]

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 11-26. In the first three months of 2021, of the 5,484 congestion event hours in the real-time energy market, 2,505 (45.7 percent) were also constrained in the day-ahead energy market. In the first three months of 2020, of the 5,515 real-time congestion event hours, 3,195 (57.9 percent) were also in the day-ahead energy market.

Congestion frequency continued to be significantly higher in the day-ahead energy market than in the real-time energy market in the first three months of 2021. 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 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.

29 Constraints are mapped to transmission facilities. In the day-ahead energy market, within a given hour, a single facility may be associated with multiple constraints. In such situations, the same facility accounts for more than one constraint-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 constraint-hour within a given hour.

Table 11-25 Congestion event hours (day-ahead against real-time): January through March, 2020 and 2021

Congestion Event Hours						
	2020 (Jan - Mar)			2021 (Jan - Mar)		
Type	Day-Ahead Constrained	Corresponding Real-Time Constrained	Percent	Day-Ahead Constrained	Corresponding Real-Time Constrained	Percent
Interface	1,385	942	68.0%	25	7	28.0%
Transformer	2,342	191	8.2%	1,555	268	17.2%
Flowgate	2,002	335	16.7%	1,649	231	14.0%
Line	9,935	1,514	15.2%	10,879	1,789	16.4%
Other	1,423	160	11.2%	510	203	39.8%
Total	17,087	3,142	18.4%	14,618	2,498	17.1%

Table 11-26 Congestion event hours (real-time against day-ahead): January through March, 2020 and 20211

Congestion Event Hours						
	2020 (Jan - Mar)			2021 (Jan - Mar)		
Type	Real-Time Constrained	Corresponding Day-Ahead Constrained	Percent	Real-Time Constrained	Corresponding Day-Ahead Constrained	Percent
Interface	1,129	979	86.7%	23	7	30.4%
Transformer	376	191	50.8%	396	272	68.7%
Flowgate	1,011	337	33.3%	951	231	24.3%
Line	2,730	1,528	56.0%	3,673	1,792	48.8%
Other	269	160	59.5%	441	203	46.0%
Total	5,515	3,195	57.9%	5,484	2,505	45.7%

Table 11-27 shows congestion costs by facility voltage class for the first three months of 2021. Congestion costs in the first three months of 2021 increased for all facility voltage classes except 500 kV and 345 kV facilities compared to the first three months of 2020.

Table 11-27 Congestion summary (By facility voltage): January through March, 2021

	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	($0.3)	($1.2)	$0.2	$1.1	($0.5)	$0.3	($0.4)	($1.2)	($0.1)	16	5
500	$6.3	($9.1)	$0.3	$15.7	$0.3	$1.2	($0.6)	($1.5)	$14.2	283	218
345	($1.8)	($15.6)	$1.4	$15.2	($4.1)	$5.3	($3.2)	($12.6)	$2.6	1,017	452
230	$44.7	($37.5)	$11.1	$93.2	($20.7)	$14.1	($18.9)	($53.7)	$39.5	4,842	2,424
161	($2.0)	($6.4)	$0.3	$4.7	($0.1)	$0.5	($0.9)	($1.4)	$3.2	248	258
138	$24.5	($50.3)	$4.2	$79.0	($0.9)	$16.5	($11.8)	($29.2)	$49.9	5,530	1,839
115	$6.9	($3.2)	$0.4	$10.4	($0.5)	$0.2	($0.2)	($0.9)	$9.6	834	190
69	$3.9	($0.2)	$1.0	$5.1	($0.1)	$1.3	($0.4)	($1.7)	$3.4	1,848	98
Unclassified	$0.0	$0.0	($0.0)	$0.0	($0.1)	$0.6	($0.5)	($1.2)	($1.2)	NA	NA
Total	$82.3	($123.5)	$18.7	$224.5	($26.7)	$39.9	($36.9)	($103.4)	$121.0	14,618	5,484

Table 11-28 Congestion summary (By facility voltage): January through March, 2020

	CLMP Credits and Charges (Millions)										
	Day-Ahead				Balancing					Event Hours	
Voltage (kV)	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Congestion Costs	Day-Ahead	Real-Time
765	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	0	0
500	$5.8	($16.1)	$1.2	$23.1	$0.3	$1.9	($1.4)	($3.1)	$20.0	1,904	1,247
345	($2.4)	($6.3)	$2.7	$6.6	($0.1)	$0.3	($1.9)	($2.4)	$4.2	1,783	199
230	$13.5	($15.8)	$2.2	$31.5	$0.3	$1.0	($1.5)	($2.2)	$29.3	3,466	1,342
161	($1.9)	($5.1)	$1.0	$4.2	($0.1)	$0.5	($1.6)	($2.2)	$2.0	466	369
138	($11.5)	($34.0)	$6.3	$28.8	$0.2	($0.4)	($7.6)	($7.0)	$21.8	4,691	1,400
115	$9.0	$3.1	$0.2	$6.0	($0.8)	$0.4	$0.1	($1.1)	$4.9	1,914	895
69	$0.9	($1.6)	$0.6	$3.0	$0.0	$0.2	($0.1)	($0.3)	$2.7	2,863	63
Unclassified	$0.0	($0.0)	$0.0	$0.1	$0.0	($0.0)	($0.0)	($0.0)	$0.1	NA	NA
Total	$13.5	($75.7)	$14.1	$103.3	($0.2)	$3.8	($14.2)	($18.2)	$85.1	17,087	5,515

Constraint Frequency

Table 11-29 lists the constraints for the first three months of 2020 and 2021 that were most frequently binding and Table 11-30 shows the constraints which experienced the largest change in congestion event hours from the first three months of 2020 to the first three months of 2021. In Table 11-29, constraints are presented in descending order of total day-ahead event hours and real-time event hours for the first three months of 2021. In Table 11-30, the constraints are presented in descending order of absolute value of day-ahead event hour changes plus real-time event hour changes from the first three months of 2020 to the first three months of 2021.

Table 11-29 Top 25 constraints: January through March, 2020 and 2021

			Event Hours						Percent of Annual Hours					
			Day-Ahead (Jan - Mar)			Real-Time (Jan - Mar)			Day-Ahead (Jan - Mar)			Real-Time (Jan - Mar)		
No.	Constraint	Type	2020	2021	Change	2020	2021	Change	2020	2021	Change	2020	2021	Change
1	Cedar Grove Sub - William	Line	0	1,137	1,137	0	568	568	0.0%	53%	53%	0%	26%	26%
2	Bagley - Raphael Road	Line	0	606	606	0	424	424	0%	28%	28%	0%	20%	20%
3	Berwick - Koonsville	Line	50	842	792	0	1	1	2%	39%	37%	0%	0%	0%
4	East Lima - Haviland	Line	122	410	288	0	243	243	6%	19%	13%	0%	11%	11%
5	Bagley - Graceton	Line	569	371	(198)	179	275	96	26%	17%	(9%)	8%	13%	5%
6	Vienna	Transformer	0	499	499	0	139	139	0%	23%	23%	0%	6%	6%
7	Nottingham	Other	595	317	(278)	200	267	67	27%	15%	(13%)	9%	12%	3%
8	Essex - McCarter	Line	0	328	328	0	106	106	0%	15%	15%	0%	5%	5%
9	Harwood - Susquehanna	Line	199	277	78	128	147	19	9%	13%	4%	6%	7%	1%
10	Benton Harbor - Crystal	Line	0	290	290	0	97	97	0%	13%	13%	0%	4%	4%
11	Maple St - Chrysler	Flowgate	6	232	226	0	136	136	0%	11%	10%	0%	6%	6%
12	Gardners - Texas Eastern	Line	131	318	187	4	39	35	6%	15%	9%	0%	2%	2%
13	Ramapo (ConEd) - S Mahwah (RECO)	Line	0	349	349	0	0	0	0%	16%	16%	0%	0%	0%
14	Quad Cities	Transformer	285	328	43	0	0	0	13%	15%	2%	0%	0%	0%
15	Sub 85 - Sub 18	Flowgate	0	148	148	0	158	158	0%	7%	7%	0%	7%	7%
16	Cumberland - Juniata	Line	119	212	93	70	89	19	5%	10%	4%	3%	4%	1%
17	Bergen - Leonia	Line	7	294	287	0	0	0	0%	14%	13%	0%	0%	0%
18	College Corner - Collinsville	Line	12	179	167	0	101	101	1%	8%	8%	0%	5%	5%
19	All Dam - Kittanning	Line	184	250	66	46	13	(33)	8%	12%	3%	2%	1%	(2%)
20	Graceton - Safe Harbor	Line	96	184	88	28	77	49	4%	9%	4%	1%	4%	2%
21	Butler - Karns City	Line	41	247	206	0	13	13	2%	11%	10%	0%	1%	1%
22	Monroe - Vineland	Line	551	241	(310)	11	0	(11)	25%	11%	(14%)	1%	0%	(1%)
23	Sandburg	Flowgate	176	130	(46)	110	105	(5)	8%	6%	(2%)	5%	5%	(0%)
24	Haumesser Road - Steward	Line	266	68	(198)	197	161	(36)	12%	3%	(9%)	9%	7%	(2%)
25	East Side - North Delphos	Line	0	151	151	0	65	65	0%	7%	7%	0%	3%	3%

Table 11-30 Top 25 constraints with largest year to year change in occurrence: January through March, 2020 and 2021

			Event Hours						Percent of Annual Hours					
			Day-Ahead			Real-Time			Day-Ahead			Real-Time		
			(Jan - Mar)			(Jan - Mar)			(Jan - Mar)			(Jan - Mar)		
No.	Constraint	Type	2020	2021	Change	2020	2021	Change	2020	2021	Change	2020	2021	Change
1	PA Central	Interface	1,340	0	(1,340)	1,126	0	(1,126)	61%	0%	(61%)	52%	0%	(52%)
2	Cedar Grove Sub - William	Line	0	1,137	1,137	0	568	568	0%	53%	53%	0%	26%	26%
3	Lenox - North Meshoppen	Line	968	44	(924)	782	49	(733)	44%	2%	(42%)	36%	2%	(34%)
4	Bagley - Raphael Road	Line	0	606	606	0	424	424	0%	28%	28%	0%	20%	20%
5	Berwick - Koonsville	Line	50	842	792	0	1	1	2%	39%	37%	0%	0%	0%
6	DoeX530	Transformer	691	7	(684)	0	0	0	32%	0%	(31%)	0%	0%	0%
7	Vienna	Transformer	0	499	499	0	139	139	0%	23%	23%	0%	6%	6%
8	Mountain	Transformer	558	10	(548)	0	0	0	26%	0%	(25%)	0%	0%	0%
9	East Lima - Haviland	Line	122	410	288	0	243	243	6%	19%	13%	0%	11%	11%
10	Logtown - North Delphos	Line	402	0	(402)	110	0	(110)	18%	0%	(18%)	5%	0%	(5%)
11	Prince George	Transformer	238	0	(238)	236	0	(236)	11%	0%	(11%)	11%	0%	(11%)
12	Face Rock	Other	610	118	(492)	41	65	24	28%	5%	(22%)	2%	3%	1%
13	Mohomet - ChampTP	Flowgate	336	0	(336)	104	1	(103)	15%	0%	(15%)	5%	0%	(5%)
14	Essex - McCarter	Line	0	328	328	0	106	106	0%	15%	15%	0%	5%	5%
15	Paradise - BR Tap	Flowgate	231	15	(216)	208	8	(200)	11%	1%	(10%)	10%	0%	(9%)
16	Easton - East Muni	Line	402	0	(402)	0	0	0	18%	0%	(18%)	0%	0%	0%
17	Benton Harbor - Crystal	Line	0	290	290	0	97	97	0%	13%	13%	0%	4%	4%
18	Sub 85 - Rock Island	Flowgate	218	0	(218)	154	0	(154)	10%	0%	(10%)	7%	0%	(7%)
19	Maple St - Chrysler	Flowgate	6	232	226	0	136	136	0%	11%	10%	0%	6%	6%
20	Butler - Sherman	Line	354	3	(351)	0	0	0	16%	0%	(16%)	0%	0%	0%
21	Ramapo (ConEd) - S Mahwah (RECO)	Line	0	349	349	0	0	0	0%	16%	16%	0%	0%	0%
22	Seward - Towanda	Line	368	30	(338)	0	0	0	17%	1%	(15%)	0%	0%	0%
23	Monroe - Vineland	Line	551	241	(310)	11	0	(11)	25%	11%	(14%)	1%	0%	(1%)
24	Powerton - Towerline	Flowgate	342	86	(256)	51	0	(51)	16%	4%	(12%)	2%	0%	(2%)
25	Sub 85 - Sub 18	Flowgate	0	148	148	0	158	158	0%	7%	7%	0%	7%	7%

Constraint Costs

Table 11-31 and Table 11-32 show the top constraints contributing to congestion costs by facility for the first three months of 2021 and 2020. The Vienna Transformer was the largest contributor to congestion costs in the first three months of 2021, with $14.4 million in total congestion costs and 11.9 percent of the total PJM congestion costs in the first three months of 2021. The high shadow prices of the Vienna Transformer were a result of a trip of generation units and a transmission outage in DPL in March.

Table 11-31 Top 25 constraints affecting congestion costs (By facility): January through March, 2021[30]

				CLMP Credits and Charges (Millions)									
				Day-Ahead				Balancing					
No.	Constraint	Type	Location	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Congestion Costs	Percent of Total PJM Congestion Costs
1	Vienna	Transformer	DPL	$12.5	($8.3)	$0.5	$21.3	($9.6)	($2.2)	$0.4	($6.9)	$14.4	11.9%
2	Bagley - Raphael Road	Line	BGE	$9.0	($1.3)	$1.1	$11.4	$1.1	$0.9	($1.0)	($0.8)	$10.6	8.8%
3	Bagley - Graceton	Line	BGE	$8.7	($1.6)	$0.5	$10.7	$0.3	$0.6	($0.0)	($0.4)	$10.4	8.6%
4	Conastone	Transformer	500	$5.7	($4.9)	$0.1	$10.7	$0.2	$0.4	($0.2)	($0.3)	$10.4	8.6%
5	Harwood - Susquehanna	Line	PPL	$3.1	($7.1)	$0.2	$10.3	$0.1	$0.4	($0.0)	($0.4)	$10.0	8.2%
6	Cedar Grove Sub - William	Line	PSEG	$8.7	($9.5)	$5.2	$23.3	($9.9)	$8.9	($11.7)	($30.5)	($7.2)	(6.0%)
7	Cumberland - Juniata	Line	PPL	$0.7	($5.7)	$0.3	$6.8	$0.2	$0.0	($0.2)	($0.0)	$6.7	5.6%
8	Bergenfield - Leonia	Line	PSEG	$0.0	$0.0	$0.0	$0.0	($3.4)	$1.1	($1.9)	($6.4)	($6.4)	(5.3%)
9	Terminal	Transformer	DEOK	($0.3)	($1.0)	$0.2	$0.9	($3.4)	$1.8	($0.9)	($6.0)	($5.1)	(4.2%)
10	East Lima - Haviland	Line	AEP	($10.1)	($15.6)	$0.4	$5.9	($0.6)	$0.2	($0.2)	($1.0)	$4.9	4.1%
11	Nottingham	Other	PECO	$4.9	$0.7	$0.6	$4.8	$0.0	$0.0	$0.0	$0.0	$4.8	3.9%
12	Krendale - Shanor Manor	Line	APS	($2.4)	($7.3)	($0.1)	$4.8	$0.0	$0.0	$0.0	$0.0	$4.8	3.9%
13	Five Forks - Rock Ridge Tap	Line	BGE	$0.9	($2.9)	$0.3	$4.1	$0.0	$0.0	($0.0)	($0.0)	$4.1	3.4%
14	Quad Cities - Rock Creek	Flowgate	MISO	$0.1	($3.4)	$0.4	$3.9	$0.3	$0.1	($0.4)	($0.2)	$3.7	3.0%
15	Lanesville - Interstate	Flowgate	MISO	$0.7	($1.0)	$0.0	$1.7	$0.4	$5.2	($0.4)	($5.2)	($3.5)	(2.9%)
16	Benton Harbor - Chrystal	Flowgate	MISO	$1.1	($2.0)	$0.3	$3.4	$0.0	$0.0	$0.0	$0.0	$3.4	2.8%
17	Dauphin - Juniata	Line	PPL	($0.8)	($3.9)	$0.3	$3.4	$0.0	$0.0	$0.0	$0.0	$3.4	2.8%
18	Benton Harbor - Crystal	Line	AEP	$2.7	$0.0	$0.3	$2.9	($2.2)	$1.5	($2.6)	($6.3)	($3.3)	(2.7%)
19	Graceton - Safe Harbor	Line	BGE	$2.5	($0.5)	$0.3	$3.3	$0.4	$0.4	($0.1)	($0.1)	$3.2	2.6%
20	Will County - Goodings Grove	Line	ComEd	$4.4	$2.1	$0.5	$2.8	$0.0	$0.0	$0.0	$0.0	$2.8	2.3%
21	Bergen - Leonia	Line	PSEG	$2.1	$0.1	$0.8	$2.8	$0.0	$0.0	$0.0	$0.0	$2.8	2.3%
22	Sub 85 - Sub 18	Flowgate	MISO	($1.8)	($4.8)	$0.3	$3.4	$0.3	$0.7	($0.5)	($0.9)	$2.5	2.0%
23	Gardners - Texas Eastern	Line	Met-Ed	$0.3	($2.0)	($0.0)	$2.3	($0.0)	$0.1	$0.0	($0.1)	$2.2	1.8%
24	Tanners Creek - Miami Fort	Flowgate	MISO	($0.6)	($2.7)	$0.2	$2.2	$0.0	$0.0	$0.0	$0.0	$2.2	1.8%
25	Cook - Olive	Line	AEP	$0.0	$0.0	$0.0	$0.0	$0.2	$2.1	($0.2)	($2.1)	($2.1)	(1.7%)
	Top 25 Total			$52.0	($82.6)	$12.4	$147.0	($25.6)	$22.2	($19.7)	($67.5)	$79.5	65.6%
	All Other Constraints			$30.3	($40.9)	$6.2	$77.5	($1.0)	$17.7	($17.2)	($35.9)	$41.6	34.4%
	Total			$82.3	($123.5)	$18.7	$224.5	($26.7)	$39.9	($36.9)	($103.4)	$121.0	100.0%

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

Table 11-32 Top 25 constraints affecting congestion costs (By facility): January through March, 2020[31]

				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	PA Central	Interface	500	$1.1	($12.4)	$0.8	$14.3	$0.3	$1.5	($1.2)	($2.4)	$11.9	14.0%
2	Bagley - Graceton	Line	BGE	$5.8	($1.3)	$0.4	$7.6	$0.1	$0.1	($0.1)	($0.1)	$7.6	8.9%
3	Harwood - Susquehanna	Line	PPL	$1.0	($4.8)	$0.0	$5.9	($0.1)	$0.4	($0.1)	($0.5)	$5.3	6.3%
4	Conastone - Peach Bottom	Line	500	$3.5	($1.5)	$0.2	$5.3	($0.0)	($0.0)	$0.0	$0.0	$5.3	6.2%
5	Cumberland - Juniata	Line	PPL	($1.2)	($5.2)	$0.3	$4.3	$0.0	($0.0)	($0.2)	($0.2)	$4.1	4.8%
6	Mohomet - ChampTP	Flowgate	MISO	($0.5)	($3.7)	$1.8	$4.9	($0.1)	($0.4)	($1.6)	($1.3)	$3.6	4.3%
7	Logtown - North Delphos	Line	AEP	($5.6)	($8.6)	$0.7	$3.7	$0.1	$0.4	($0.4)	($0.6)	$3.1	3.7%
8	Quad Cities - Cordova	Flowgate	MISO	($1.9)	($3.8)	$1.1	$3.0	$0.0	$0.0	$0.0	$0.0	$3.0	3.5%
9	Nottingham	Other	ATSI	$3.3	$0.8	$0.4	$2.9	$0.2	$0.0	($0.2)	$0.0	$2.9	3.4%
10	Nottingham	Other	PECO	$2.8	$0.7	$0.2	$2.3	$0.0	$0.0	$0.0	$0.0	$2.3	2.7%
11	Lenox - North Meshoppen	Line	PENELEC	($0.5)	($3.1)	$0.0	$2.6	$0.0	$0.5	$0.0	($0.5)	$2.1	2.5%
12	Paradise - BR Tap	Flowgate	MISO	($1.5)	($3.5)	$0.2	$2.2	$0.0	$0.0	($0.2)	($0.2)	$2.0	2.4%
13	Seward - Towanda	Line	PENELEC	$8.5	$6.8	$0.1	$1.9	$0.0	$0.0	$0.0	$0.0	$1.9	2.2%
14	Face Rock	Other	PPL	$0.0	($1.7)	$0.2	$1.9	$0.0	$0.2	$0.0	($0.1)	$1.8	2.1%
15	Westraver - Yukon	Line	APS	($0.8)	($2.5)	$0.2	$1.9	($0.0)	$0.1	($0.1)	($0.2)	$1.7	2.0%
16	Haumesser Road - Steward	Line	ComEd	($0.7)	($1.9)	$0.2	$1.4	$0.1	($0.4)	($0.2)	$0.3	$1.7	2.0%
17	Powerton - Towerline	Flowgate	MISO	($1.0)	($1.7)	$0.8	$1.6	$0.0	($0.0)	($0.0)	$0.0	$1.6	1.9%
18	Quad Cities - Cordova Energy	Line	ComEd	$0.0	$0.0	$0.0	$0.0	($0.1)	$0.4	($0.9)	($1.5)	($1.5)	(1.7%)
19	Danville - East Danville	Line	AEP	($0.8)	($2.2)	($0.0)	$1.4	$0.0	($0.0)	$0.0	$0.0	$1.4	1.7%
20	Three Mile Island	Transformer	500	$0.6	($0.7)	$0.1	$1.4	$0.1	$0.1	$0.0	($0.0)	$1.4	1.6%
21	Northeast - Raphael Road	Line	BGE	$1.6	$0.1	$0.1	$1.6	$0.1	$0.2	($0.1)	($0.2)	$1.4	1.6%
22	Peters - Union Jct	Line	APS	($0.8)	($1.9)	$0.1	$1.2	$0.1	$0.0	($0.0)	($0.0)	$1.2	1.4%
23	Blooming Grove - Paupack	Line	PPL	$0.3	($0.7)	$0.0	$1.1	$0.0	$0.0	$0.0	$0.0	$1.1	1.2%
24	Collins	Transformer	ComEd	($0.1)	($0.5)	$0.6	$1.0	$0.0	$0.0	$0.0	$0.0	$1.0	1.2%
25	Prince George	Transformer	Dominion	($0.6)	($1.4)	$0.0	$0.9	($0.0)	($0.1)	($0.0)	$0.0	$0.9	1.1%
	Top 25 Total			$12.8	($54.8)	$8.5	$76.1	$0.9	$3.0	($5.2)	($7.3)	$68.9	80.9%
	All Other Constraints			$0.7	($20.9)	$5.6	$27.2	($1.0)	$0.9	($9.0)	($10.9)	$16.3	19.1%
	Total			$13.5	($75.7)	$14.1	$103.3	($0.2)	$3.8	($14.2)	($18.2)	$85.1	100.0%

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

Figure 11-4 shows the locations of the top 10 constraints by total congestion costs on a contour map of the real-time, load-weighted average CLMP in the first three months of 2021. Three of the top 10 constraints are located in the BGE Zone: the Bagley - Raphael Road Line, the Bagley - Graceton Line and the Conastone Transformer. Multiple constraints in the BGE Control Zone have been in the top 10 constraints by total congestion costs since 2016.

Figure 11-4 Location of the top 10 constraints by total congestion costs: January through March, 2021

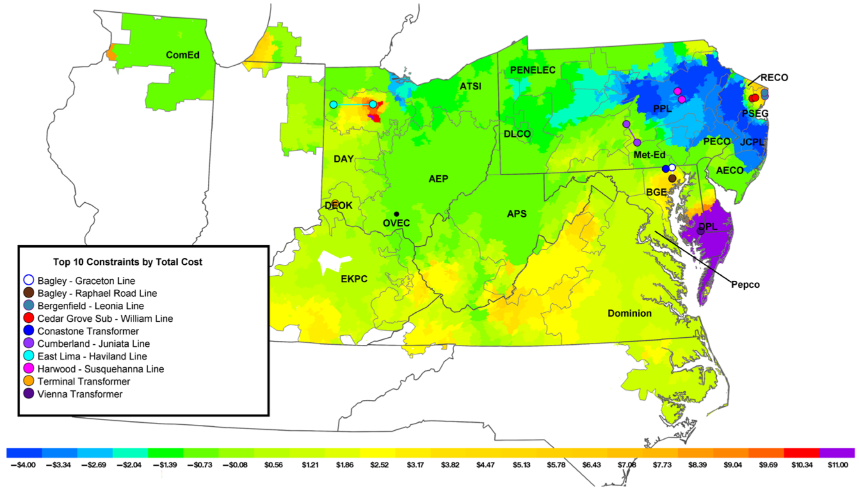


Figure 11-5 shows the locations of the top 10 constraints by balancing congestion costs on a contour map of the real-time, load-weighted, average CLMP in the first three months of 2021.

Figure 11-5 Location of top 10 constraints by balancing congestion costs: January through March, 2021

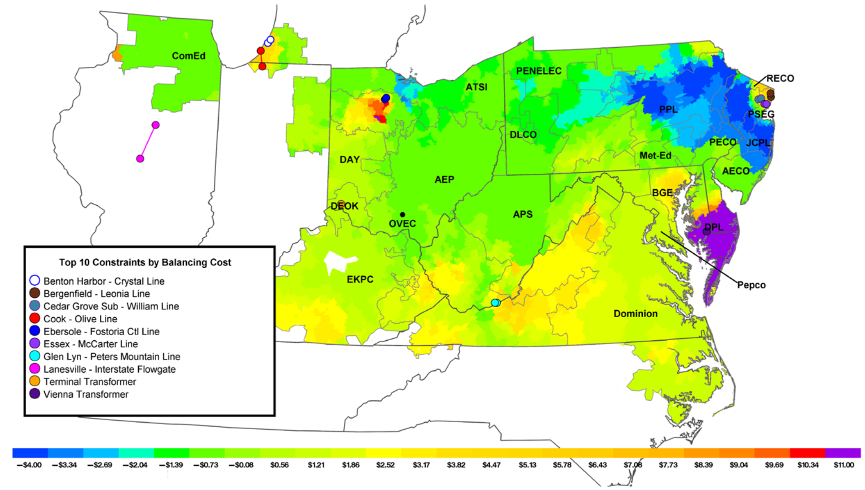
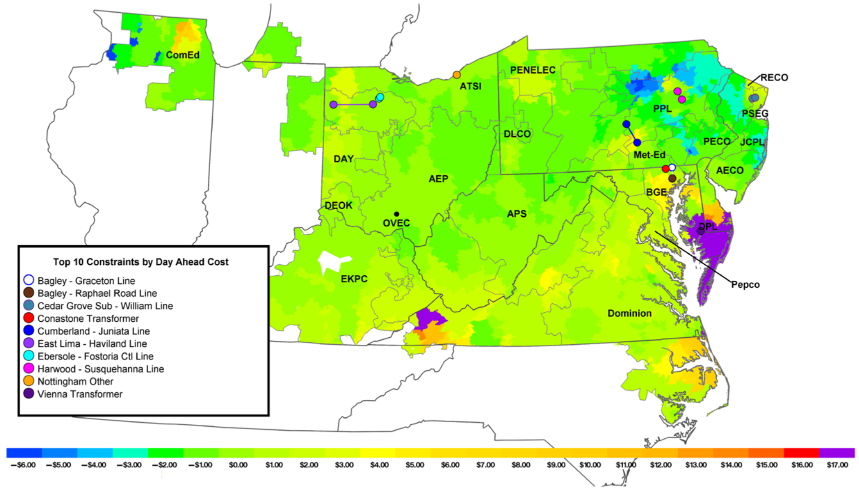


Figure 11-6 shows the locations of the top 10 constraints by day-ahead congestion costs on a contour map of the day-ahead, load-weighted, average CLMP in the first three months of 2021.

Figure 11-6 Location of the top 10 constraints by day-ahead congestion costs: January through March, 2021



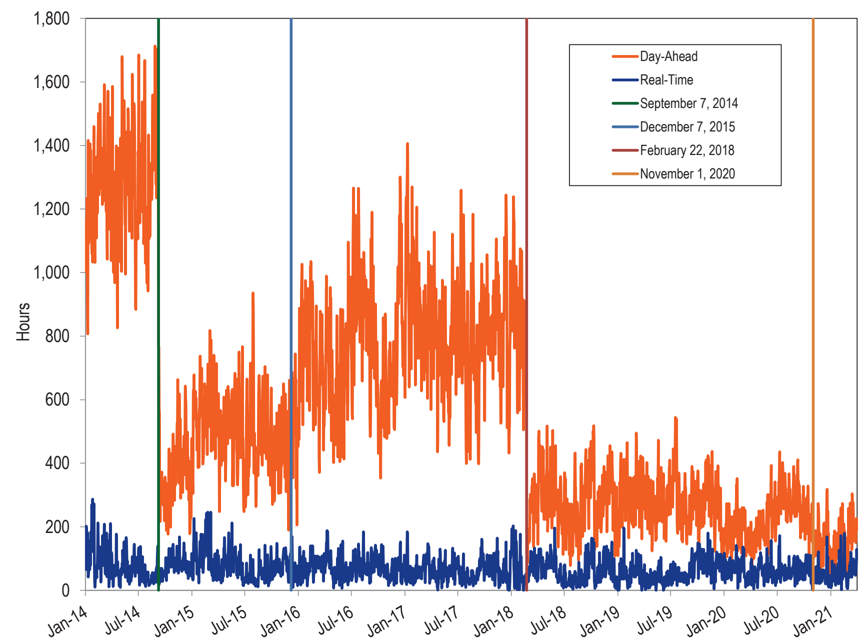
Congestion Event Summary: Impact of Changes in UTC Volumes

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.[32]

In the first three months of 2021, the average hourly cleared UTC MW decreased by 55.2 percent, compared to the first three months of 2020. Day-ahead congestion event hours decreased by 14.4 percent from 17,087 congestion event hours in the first three months of 2020 to 14,618 congestion event hours in the first three months of 2021 (Table 11-25).

Figure 11-7 shows the daily day-ahead and real-time congestion event hours for January 2014 through March 2021.

Figure 11-7 Daily congestion event hours: January 2014 through March 2021



32 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.

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.[33] 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.[34] Each of these categories of marginal loss costs is comprised of day-ahead and balancing marginal loss costs.

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.

33 PJM Operating Agreement Schedule 1 §3.7.

34 *Id.*

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.[35]

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

35 See PJM. "Manual 28: Operating Agreement Accounting," Rev. 84 (Dec. 17, 2020).

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, that are distributed on a load plus export ratio basis.[36]

Total Marginal Loss Cost

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

The total marginal loss cost in PJM for the first three months of 2021 was $209.7 million, which was comprised of implicit load MLMP charges of $2.1 million minus implicit generation MLMP credits of -$208.8 million plus explicit loss charges of -$1.2 million plus inadvertent loss charges of $0.0 million (Table 11-34).

Monthly marginal loss costs in the first three months of 2021 ranged from $47.2 million in March to $102.7 million in February. Total marginal loss surplus increased in the first three months of 2021 by $43.8 million or 131.9 percent from $33.2 million in the first three months of 2020 to $77.1 million in the first three months of 2021.

Table 11-33 shows the total marginal loss component costs and the total PJM billing for the first three months of 2008 through 2021.

Table 11-33 Total loss component costs (Dollars (Millions)): January through March, 2008 through 2021[37]

(Jan - Mar)	Loss Costs	Percent Change	Total PJM Billing	Percent of PJM Billing
2008	$607	NA	$7,718	7.9%
2009	$454	(25.2%)	$7,515	6.0%
2010	$417	(8.2%)	$8,415	5.0%
2011	$410	(1.7%)	$9,584	4.3%
2012	$234	(42.8%)	$6,938	3.4%
2013	$278	18.5%	$7,762	3.6%
2014	$776	179.5%	$21,070	3.7%
2015	$425	(45.2%)	$14,040	3.0%
2016	$170	(60.0%)	$9,500	1.8%
2017	$172	0.9%	$9,710	1.8%
2018	$339	97.9%	$14,520	2.3%
2019	$204	(39.9%)	$10,980	1.9%
2020	$109	(46.8%)	$8,110	1.3%
2021	$210	93.2%	$10,400	2.0%

36 PJM Operating Agreement Schedule 1 §3.7.

37 The loss costs include net inadvertent charges.

Table 11-34 shows PJM total marginal loss costs by accounting category for the first three months of 2008 through 2021. Table 11-35 shows PJM total marginal loss costs by accounting category by market for the first three months of 2008 through 2021.

Table 11-34 Total marginal loss costs by accounting category (Dollars (Millions)): January through March, 2008 through 2021

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

Table 11-35 Total marginal loss costs by accounting category by market (Dollars (Millions)): January through March, 2008 through 2021

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

Table 11-36 and Table 11-37 show PJM accounting based total loss costs for each transaction type in the first three months of 2021 and 2020.

Virtual transaction loss costs, when positive, measure the total loss costs to virtual transactions and when negative, measure the total loss credits to virtual transaction. In the first three months of 2021, DECs paid $1.6 million in LLMP charges in the day-ahead market, were paid $0.6 million in LLMP credits in the balancing energy market and paid $1.0 million in total LLMP charges. In the first three months of 2021, INCs paid $2.8 million in LLMP charges in the day-ahead market, were paid $3.3 million in LLMP credits in the balancing energy market and were paid $0.5 million in total LLMP credits. In the first three months of 2021, up to congestion paid $9.1 million in LLMP charges in the day-ahead market, were paid $10.5 million in LLMP credits in the balancing energy market and received $1.4 million in total LLMP credits.

Table 11-36 Total loss costs by transaction type by market (Dollars (Millions)): January through March, 2021

	Marginal Loss Costs (Millions)									
	Day-Ahead				Balancing					
Transaction Type	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Inadvertent Charges	Grand Total
DEC	$1.6	$0.0	$0.0	$1.6	($0.6)	$0.0	$0.0	($0.6)	$0.0	$1.0
Demand	$8.7	$0.0	$0.0	$8.7	$1.0	$0.0	$0.0	$1.0	$0.0	$9.6
Demand Response	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	$0.0	($0.0)	$0.0	$0.0
Explicit Congestion and Loss Only	$0.0	$0.0	($0.2)	($0.2)	$0.0	$0.0	($0.0)	($0.0)	$0.0	($0.2)
Export	($4.3)	$0.0	($0.0)	($4.3)	($0.5)	$0.0	$0.2	($0.3)	$0.0	($4.6)
Generation	$0.0	($202.3)	$0.0	$202.3	$0.0	($2.0)	$0.0	$2.0	$0.0	$204.3
Import	$0.0	($0.5)	$0.0	$0.5	$0.0	($0.9)	$0.0	$0.9	$0.0	$1.4
INC	$0.0	($2.8)	$0.0	$2.8	$0.0	$3.3	$0.0	($3.3)	$0.0	($0.5)
Internal Bilateral	($3.3)	($3.1)	$0.1	$0.0	($0.5)	($0.5)	$0.0	($0.0)	$0.0	($0.0)
Up to Congestion	$0.0	$0.0	$9.1	$9.1	$0.0	$0.0	($10.5)	($10.5)	$0.0	($1.4)
Wheel In	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Total	$2.7	($208.8)	$9.0	$220.5	($0.6)	($0.0)	($10.2)	($10.8)	$0.0	$209.7

Table 11-37 Total loss costs by transaction type by market (Dollars (Millions)): January through March, 2020

	Marginal Loss Costs (Millions)									
	Day-Ahead				Balancing					
Transaction Type	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Inadvertent Charges	Grand Total
DEC	($0.6)	$0.0	$0.0	($0.6)	$0.7	$0.0	$0.0	$0.7	$0.0	$0.1
Demand	($1.0)	$0.0	$0.0	($1.0)	$0.6	$0.0	$0.0	$0.6	$0.0	($0.4)
Demand Response	($0.0)	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)
Explicit Congestion and Loss Only	$0.0	$0.0	($0.0)	($0.0)	$0.0	$0.0	($0.0)	($0.0)	$0.0	($0.0)
Export	($2.5)	$0.0	($0.0)	($2.5)	($0.8)	$0.0	$0.1	($0.6)	$0.0	($3.2)
Generation	$0.0	($114.6)	$0.0	$114.6	$0.0	($1.3)	$0.0	$1.3	$0.0	$115.9
Import	$0.0	($0.3)	$0.0	$0.3	$0.0	($0.4)	($0.0)	$0.4	$0.0	$0.6
INC	$0.0	($1.9)	$0.0	$1.9	$0.0	$2.4	$0.0	($2.4)	$0.0	($0.5)
Internal Bilateral	($5.9)	($5.8)	$0.1	($0.0)	($0.3)	($0.3)	$0.0	($0.0)	$0.0	($0.0)
Up to Congestion	$0.0	$0.0	$9.4	$9.4	$0.0	$0.0	($13.4)	($13.4)	$0.0	($3.9)
Wheel In	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	$0.0	($0.0)
Total	($10.0)	($122.6)	$9.5	$122.0	$0.2	$0.4	($13.2)	($13.4)	$0.0	$108.5

Monthly Marginal Loss Costs

Table 11-38 shows a monthly summary of marginal loss costs by market type for January 2020 through March 2021.

Table 11-38 Monthly marginal loss costs by market (Millions): January 2020 through March 2021

	Marginal Loss Costs (Millions)							
	2020				2021			
	Day-Ahead	Balancing	Inadvertent Charges	Total	Day-Ahead	Balancing	Inadvertent Charges	Total
Jan	$49.8	($5.3)	($0.0)	$44.5	$62.0	($2.1)	($0.0)	$59.9
Feb	$39.8	($4.6)	($0.0)	$35.2	$107.7	($5.1)	$0.0	$102.7
Mar	$32.4	($3.5)	($0.0)	$28.8	$50.8	($3.7)	$0.0	$47.2
Apr	$25.9	($3.4)	($0.0)	$22.5				
May	$30.4	($4.8)	$0.0	$25.7				
Jun	$41.0	($4.3)	$0.0	$36.7				
Jul	$73.2	($6.1)	$0.0	$67.0				
Aug	$59.8	($5.8)	($0.0)	$54.0				
Sep	$39.1	($4.4)	$0.0	$34.8				
Oct	$37.0	($3.0)	$0.0	$34.0				
Nov	$37.8	($1.4)	$0.0	$36.4				
Dec	$59.9	($1.1)	$0.0	$58.8				
Total	$526.3	($47.7)	$0.0	$478.5	$220.5	($10.8)	$0.0	$209.7

Figure 11-8 shows PJM monthly marginal loss costs for January 2008 through March 2021.

Figure 11-8 Monthly marginal loss costs (Dollars (Millions)): January 2008 through March 2021

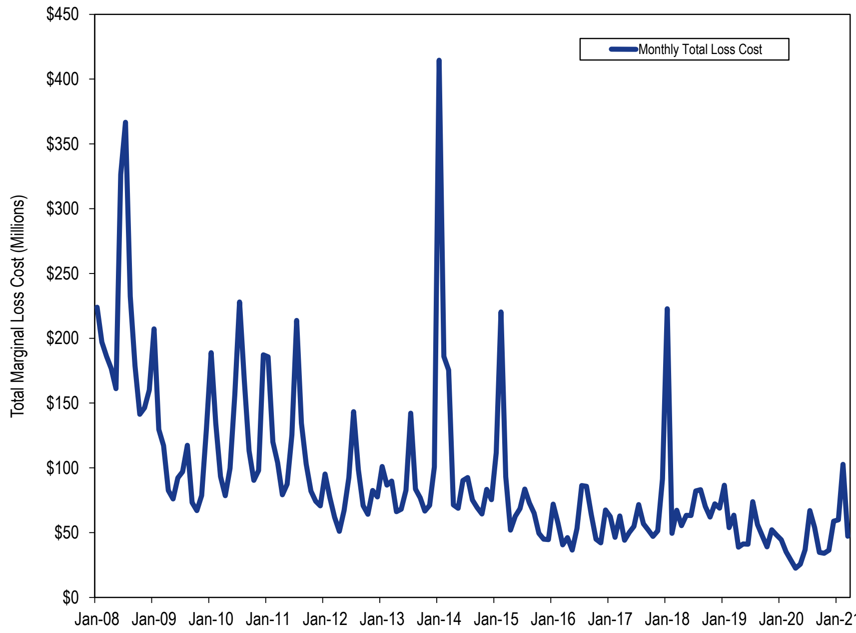


Table 11-39 shows the monthly total loss costs for each virtual transaction type in January 2020 through March 2021.

Table 11-39 Monthly loss charges by virtual transaction type and by market (Dollars (Millions)): January 2020 through March 2021

		Marginal Loss Charges (Millions)									
		DEC			INC			Up to Congestion			
Year		Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Grand Total
2020	Jan	($0.1)	$0.1	($0.0)	$0.7	($0.9)	($0.2)	$3.7	($5.2)	($1.5)	($1.7)
	Feb	($0.1)	$0.2	$0.0	$0.6	($0.8)	($0.2)	$3.2	($4.4)	($1.2)	($1.3)
	Mar	($0.3)	$0.4	$0.1	$0.6	($0.7)	($0.1)	$2.5	($3.7)	($1.2)	($1.3)
	Apr	($0.2)	$0.4	$0.1	$0.6	($0.7)	($0.1)	$2.3	($3.5)	($1.2)	($1.1)
	May	($0.1)	$0.2	$0.1	$0.8	($0.8)	$0.0	$3.7	($4.8)	($1.1)	($0.9)
	Jun	($0.2)	$0.5	$0.2	$0.5	($0.6)	($0.1)	$3.1	($4.6)	($1.4)	($1.3)
	Jul	($0.3)	$0.8	$0.4	$0.9	($0.9)	($0.0)	$5.1	($6.5)	($1.4)	($1.0)
	Aug	($0.1)	$0.4	$0.3	$0.6	($0.7)	($0.1)	$4.1	($6.2)	($2.2)	($2.0)
	Sep	($0.1)	$0.2	$0.2	$0.5	($0.6)	($0.1)	$2.8	($4.2)	($1.4)	($1.4)
	Oct	$0.0	$0.1	$0.2	$0.7	($0.8)	($0.1)	$2.5	($3.0)	($0.6)	($0.5)
	Nov	($0.5)	$0.6	$0.1	$0.7	($0.8)	($0.0)	$1.6	($2.1)	($0.4)	($0.4)
	Dec	$0.3	$0.1	$0.4	$0.7	($0.9)	($0.3)	$1.9	($2.4)	($0.5)	($0.4)
	Total	($1.8)	$3.9	$2.1	$7.7	($9.0)	($1.3)	$36.5	($50.6)	($14.1)	($13.3)
2021	Jan	$0.3	($0.1)	$0.2	$0.8	($1.1)	($0.3)	$2.2	($2.6)	($0.4)	($0.5)
	Feb	$1.1	($0.7)	$0.4	$0.8	($0.9)	($0.1)	$4.5	($4.7)	($0.2)	$0.1
	Mar	$0.2	$0.2	$0.4	$1.2	($1.3)	($0.2)	$2.5	($3.2)	($0.7)	($0.5)
	Total	$1.6	($0.6)	$1.0	$2.8	($3.3)	($0.5)	$9.1	($10.5)	($1.4)	($0.8)

Marginal Loss Costs and Loss Credits

Total marginal loss surplus is calculated by adding the total system energy costs, the total marginal loss costs and net residual market adjustments. 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 11-40 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 three months of 2008 through 2021. The total marginal loss surplus increased $43.8 million or 131.9 percent in the first three months of 2021 from the first three months of 2020.

Table 11-40 Marginal loss surplus (Dollars (Millions)): January through March, 2008 through 2021[38]

	Marginal Loss Surplus (Millions)					
(Jan - Mar)	System Energy Cost	Marginal Loss Costs	Net Residual Market Adjustments			Total Marginal Loss Surplus
			Known Day-Ahead Error	Day-Ahead Loss MW Congestion	Balancing Loss MW Congestion	
2008	($288.2)	$606.9	$0.0	$0.0	$0.0	$318.7
2009	($218.3)	$454.0	($0.0)	($0.4)	($0.1)	$236.2
2010	($207.6)	$416.6	$0.0	($0.9)	($0.0)	$209.9
2011	($209.9)	$409.6	$0.0	$0.0	($0.0)	$199.7
2012	($136.4)	$234.3	($0.0)	($0.5)	$0.0	$98.3
2013	($177.9)	$277.6	$0.1	$0.3	$0.0	$99.4
2014	($515.3)	$775.9	$0.0	$3.1	$0.2	$257.2
2015	($271.7)	$425.1	($0.5)	$2.9	($0.0)	$150.0
2016	($113.6)	$170.1	$0.0	$0.8	($0.0)	$55.7
2017	($122.1)	$171.5	$0.0	$0.2	($0.0)	$49.2
2018	($226.6)	$339.4	($0.0)	$1.2	($0.0)	$111.6
2019	($136.3)	$203.9	$0.0	$0.7	($0.0)	$66.9
2020	($75.3)	$108.5	($0.0)	($0.0)	($0.0)	$33.2
2021	($131.7)	$209.7	($0.0)	$1.0	($0.0)	$77.1

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, incurred 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.

Total System Energy Costs

The total system energy cost for the first three months of 2021 was -$131.7 million, which was comprised of implicit withdrawal energy charges of $8,663.3 million, implicit injection energy credits of $8,795.7 million, explicit energy charges of $0.0 million and inadvertent energy charges of $0.6 million. The monthly system energy costs for the first three months of 2021 ranged from -$63.1 million in February to -$30.8 million in March.

Table 11-41 shows total system energy costs and total PJM billing, for the first three months of 2008 through 2021.

Table 11-41 Total system energy costs (Dollars (Millions)): January through March, 2008 through 2021[39]

(Jan - Mar)	System Energy Costs	Percent Change	Total PJM Billing	Percent of PJM Billing
2008	($288)	NA	$7,718	(3.7%)
2009	($218)	(24.2%)	$7,515	(2.9%)
2010	($208)	(4.9%)	$8,415	(2.5%)
2011	($210)	1.1%	$9,584	(2.2%)
2012	($136)	(35.0%)	$6,938	(2.0%)
2013	($178)	30.4%	$7,762	(2.3%)
2014	($515)	189.7%	$21,070	(2.4%)
2015	($272)	(47.3%)	$14,040	(1.9%)
2016	($114)	(58.2%)	$9,500	(1.2%)
2017	($122)	7.5%	$9,710	(1.3%)
2018	($227)	85.6%	$14,520	(1.6%)
2019	($136)	(39.8%)	$10,980	(1.2%)
2020	($75)	(44.8%)	$8,110	(0.9%)
2021	($132)	74.8%	$10,400	(1.3%)

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

39 The system energy costs include net inadvertent charges.

System energy costs for the first three months of 2008 through 2021 are shown in Table 11-42 and Table 11-43. Table 11-42 shows PJM system energy costs by accounting category and Table 11-43 shows PJM system energy costs by market category.

Table 11-42 Total system energy costs by accounting category (Dollars (Millions)): January through March, 2008 through 2021

	System Energy Costs (Millions)				
(Jan - Mar)	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Inadvertent Charges	Total
2008	$28,435.7	$28,723.9	$0.0	$0.0	($288.2)
2009	$14,058.4	$14,277.4	$0.0	$0.7	($218.3)
2010	$13,424.4	$13,629.0	$0.0	($3.0)	($207.6)
2011	$11,943.9	$12,160.7	$0.0	$6.9	($209.9)
2012	$8,485.4	$8,628.7	$0.0	$6.8	($136.4)
2013	$10,357.2	$10,535.1	$0.0	($0.0)	($177.9)
2014	$28,506.2	$29,014.7	$0.0	($6.9)	($515.3)
2015	$15,702.1	$15,976.4	$0.0	$2.6	($271.7)
2016	$7,764.7	$7,879.3	$0.0	$1.0	($113.6)
2017	$8,789.3	$8,910.2	$0.0	($1.3)	($122.1)
2018	$13,910.8	$14,142.2	$0.0	$4.7	($226.6)
2019	$8,856.0	$8,993.5	$0.0	$1.2	($136.3)
2020	$5,541.1	$5,616.0	$0.0	($0.4)	($75.3)
2021	$8,663.3	$8,795.7	$0.0	$0.6	($131.7)

Table 11-43 Total system energy costs by market category (Dollars (Millions)): January through March, 2008 through 2021

	System Energy Costs (Millions)									
	Day-Ahead				Balancing					
(Jan - Mar)	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Inadvertent Charges	Grand Total
2008	$20,253.8	$20,579.6	$0.0	($325.8)	$8,182.0	$8,144.3	$0.0	$37.6	$0.0	($288.2)
2009	$14,129.6	$14,375.6	$0.0	($246.0)	($71.2)	($98.2)	$0.0	$27.0	$0.7	($218.3)
2010	$13,408.9	$13,619.2	$0.0	($210.2)	$15.5	$9.8	$0.0	$5.6	($3.0)	($207.6)
2011	$12,055.5	$12,259.3	$0.0	($203.9)	($111.6)	($98.6)	$0.0	($12.9)	$6.9	($209.9)
2012	$8,534.4	$8,649.0	$0.0	($114.6)	($49.0)	($20.4)	$0.0	($28.6)	$6.8	($136.4)
2013	$10,387.2	$10,580.9	$0.0	($193.7)	($29.9)	($45.8)	$0.0	$15.9	($0.0)	($177.9)
2014	$28,412.1	$29,082.9	$0.0	($670.9)	$94.2	($68.3)	$0.0	$162.4	($6.9)	($515.3)
2015	$15,764.8	$16,077.5	$0.0	($312.6)	($62.7)	($101.1)	$0.0	$38.4	$2.6	($271.7)
2016	$7,847.5	$7,997.9	$0.0	($150.4)	($82.8)	($118.6)	$0.0	$35.8	$1.0	($113.6)
2017	$8,927.5	$9,111.3	$0.0	($183.8)	($138.1)	($201.1)	$0.0	$63.0	($1.3)	($122.1)
2018	$13,877.2	$14,123.7	$0.0	($246.5)	$33.6	$18.5	$0.0	$15.1	$4.7	($226.6)
2019	$8,965.4	$9,131.8	$0.0	($166.4)	($109.4)	($138.4)	$0.0	$28.9	$1.2	($136.3)
2020	$5,612.2	$5,708.5	$0.0	($96.3)	($71.1)	($92.5)	$0.0	$21.4	($0.4)	($75.3)
2021	$8,749.4	$8,901.4	$0.0	($152.0)	($86.0)	($105.7)	$0.0	$19.7	$0.6	($131.7)

Table 11-44 and Table 11-45 show the total system energy costs for each transaction type in the first three months of 2021 and 2020. In the first three months of 2021, generation was paid $6,535.9 million and demand paid $6,067.3 million in net energy payment. In the first three months of 2020, generation was paid $3,980.6 million and demand paid $3,763.2 million in net energy payment.

Table 11-44 Total system energy costs by transaction type by market (Dollars (Millions)): January through March, 2021

	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	$327.3	$0.0	$0.0	$327.3	($322.7)	$0.0	$0.0	($322.7)	$4.5
Demand	$6,007.6	$0.0	$0.0	$6,007.6	$59.7	$0.0	$0.0	$59.7	$6,067.3
Demand Response	($0.2)	$0.0	$0.0	($0.2)	$0.2	$0.0	$0.0	$0.2	($0.0)
Export	$243.7	$0.0	$0.0	$243.7	$156.8	$0.0	$0.0	$156.8	$400.5
Generation	$0.0	$6,566.9	$0.0	($6,566.9)	$0.0	($31.0)	$0.0	$31.0	($6,535.9)
Import	$0.0	$16.3	$0.0	($16.3)	$0.0	$51.6	$0.0	($51.6)	($67.8)
INC	$0.0	$147.2	$0.0	($147.2)	$0.0	($146.3)	$0.0	$146.3	($0.9)
Internal Bilateral	$2,171.0	$2,171.0	$0.0	($0.0)	$11.9	$11.9	$0.0	$0.0	$0.0
Wheel In	$0.0	$0.0	$0.0	$0.0	$0.0	$8.1	$0.0	($8.1)	($8.1)
Wheel Out	$0.0	$0.0	$0.0	$0.0	$8.1	$0.0	$0.0	$8.1	$8.1
Total	$8,749.4	$8,901.4	$0.0	($152.0)	($86.0)	($105.7)	$0.0	$19.7	($132.3)

Table 11-45 Total system energy costs by transaction type by market (Dollars (Millions)): January through March, 2020

	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	$131.3	$0.0	$0.0	$131.3	($129.7)	$0.0	$0.0	($129.7)	$1.6
Demand	$3,772.5	$0.0	$0.0	$3,772.5	($9.3)	$0.0	$0.0	($9.3)	$3,763.2
Demand Response	($0.0)	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	($0.0)
Export	$127.1	$0.0	$0.0	$127.1	$53.6	$0.0	$0.0	$53.6	$180.7
Generation	$0.0	$4,002.0	$0.0	($4,002.0)	$0.0	($21.4)	$0.0	$21.4	($3,980.6)
Import	$0.0	$14.5	$0.0	($14.5)	$0.0	$23.1	$0.0	($23.1)	($37.6)
INC	$0.0	$110.6	$0.0	($110.6)	$0.0	($108.4)	$0.0	$108.4	($2.2)
Internal Bilateral	$1,581.3	$1,581.3	$0.0	($0.0)	$6.6	$6.6	$0.0	($0.0)	($0.0)
Wheel In	$0.0	$0.0	$0.0	$0.0	$0.0	$7.7	$0.0	($7.7)	($7.7)
Wheel Out	$0.0	$0.0	$0.0	$0.0	$7.7	$0.0	$0.0	$7.7	$7.7
Total	$5,612.2	$5,708.5	$0.0	($96.3)	($71.1)	($92.5)	$0.0	$21.4	($74.9)

Monthly System Energy Costs

Table 11-46 shows a monthly summary of system energy costs by market type for January 2020 through March 2021. Total balancing system energy costs in the first three months of 2021 decreased from the first three months of 2020. Monthly total system energy costs in the first three months of 2021 ranged from -$63.1 million in February to -$30.8 million in March.

Table 11-46 Monthly system energy costs by market type (Dollars (Millions)): January 2020 through March 2021

	System Energy Costs (Millions)							
	2020				2021			
	Day-Ahead	Balancing	Inadvertent Charges	Total	Day-Ahead	Balancing	Inadvertent Charges	Total
Jan	($40.0)	$9.4	($0.1)	($30.7)	($42.7)	$5.0	($0.1)	($37.8)
Feb	($30.7)	$6.8	($0.3)	($24.2)	($73.5)	$9.6	$0.7	($63.1)
Mar	($25.5)	$5.2	($0.1)	($20.4)	($35.8)	$5.1	$0.0	($30.8)
Apr	($21.1)	$5.2	($0.0)	($15.9)				
May	($25.4)	$6.9	$0.4	($18.1)				
Jun	($32.8)	$7.6	$0.6	($24.6)				
Jul	($52.4)	$9.0	$0.9	($42.5)				
Aug	($44.9)	$9.9	($0.2)	($35.2)				
Sep	($30.7)	$7.6	$0.6	($22.5)				
Oct	($29.4)	$7.3	$0.3	($21.9)				
Nov	($27.3)	$2.3	$0.1	($24.9)				
Dec	($41.2)	$2.7	$0.2	($38.3)				
Total	($401.4)	$79.9	$2.5	($319.0)	($152.0)	$19.7	$0.6	($131.7)

Figure 11-9 shows PJM monthly system energy costs for January through March, 2008 through 2021. 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 11-9 Monthly system energy costs (Millions): January 2008 through March 2021

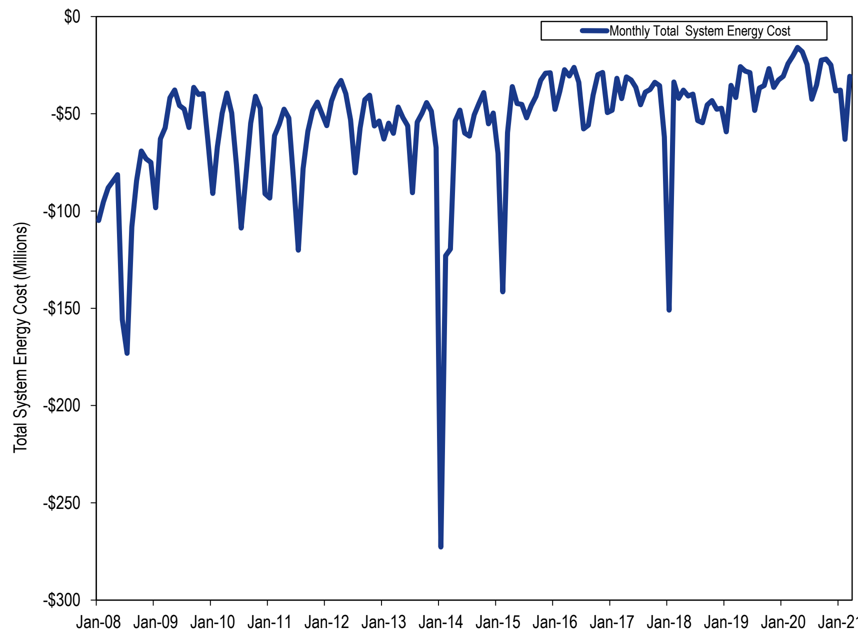


Table 11-47 shows the monthly total system energy costs for each virtual transaction type in the first three months of 2021 and year of 2020. In the first three months of 2021, DECs paid $327.3 million in energy charges in the day-ahead market, were paid $322.7 million in energy credits in the balancing energy market and paid $4.5 million in total energy charges. In the first three months of 2021, INCs were paid $147.2 million in energy credits in the day-ahead market, paid $146.3 million in energy charges in the balancing market and were paid $0.9 million in total energy credits. In the first three months of 2020, DECs paid $131.3 million in energy charges in the day-ahead market, were paid $129.7 million in energy credits in the balancing energy market and paid $1.6 million in total energy charges. In the first three months of 2020, INCs were paid $110.6 million in energy credits in the day-ahead market, paid $108.4 million in energy charges in the balancing energy market and were paid $2.2 million in total energy credits. 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 11-47 Monthly energy charges by virtual transaction type and by market (Dollars (Millions)): January 2020 through March 2021

		Energy Charges (Millions)						
		DEC			INC			
Year		Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Grand Total
2020	Jan	$44.4	($43.3)	$1.0	($44.0)	$43.2	($0.8)	$0.2
	Feb	$43.0	($42.4)	$0.6	($34.5)	$33.5	($1.0)	($0.3)
	Mar	$43.9	($44.0)	($0.1)	($32.1)	$31.7	($0.4)	($0.5)
	Apr	$42.4	($43.8)	($1.4)	($32.4)	$33.6	$1.2	($0.2)
	May	$59.9	($62.4)	($2.5)	($34.7)	$35.2	$0.5	($2.0)
	Jun	$79.9	($83.8)	($3.9)	($32.4)	$33.2	$0.8	($3.1)
	Jul	$116.8	($119.2)	($2.4)	($48.7)	$49.9	$1.2	($1.2)
	Aug	$99.9	($105.4)	($5.5)	($35.0)	$35.7	$0.7	($4.8)
	Sep	$77.6	($76.2)	$1.4	($33.4)	$32.6	($0.8)	$0.6
	Oct	$78.9	($81.4)	($2.5)	($39.2)	$40.9	$1.7	($0.8)
	Nov	$72.4	($74.8)	($2.4)	($38.4)	$38.8	$0.4	($2.1)
	Dec	$92.6	($95.1)	($2.5)	($40.5)	$41.4	$0.9	($1.6)
	Total	$851.8	($871.8)	($20.0)	($445.5)	$449.8	$4.3	($15.7)
2021	Jan	$76.5	($76.2)	$0.3	($41.9)	$41.6	($0.3)	($0.0)
	Feb	$167.0	($157.6)	$9.4	($54.4)	$51.4	($3.0)	$6.5
	Mar	$83.8	($89.0)	($5.2)	($50.9)	$53.3	$2.4	($2.8)
	Total	$327.3	($322.7)	$4.5	($147.2)	$146.3	($0.9)	$3.7