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] Congestion is not the difference in CLMP between nodes.

The locational marginal price (LMP) is the incremental price of energy at a bus. The LMP at a bus is the sum of 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 products of the least cost, security constrained dispatch of system resources to meet system load.

SMP is 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. SMP is the system energy price.

CLMP is 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. The relative values of SMP and CLMP are arbitrary and depend on the reference bus.

MLMP is 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.[3] 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 higher price for all energy including energy from low cost and energy from high cost generation while generators are paid the price at their bus. Congestion is the difference between what load pays based on the higher price at load buses and what generators receive based on the price at the generator buses.

The energy, marginal losses and congestion metrics must be interpreted carefully. The term total congestion refers to what is actually net congestion, which is calculated as net implicit congestion charges plus net explicit congestion charges plus net inadvertent congestion charges. The net implicit congestion charges are the implicit withdrawal congestion charges less implicit injection congestion credits. The same point applies to total system energy costs and total marginal loss costs in the same way. 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.[4]

Local congestion is the congestion paid by load at a specific bus or set of buses and is calculated on a

1 Withdrawals are generically referred to as load and injections are generically referred to as generation, unless specified otherwise.

2 The difference in losses is not part of congestion.

3 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.

4 The total congestion and marginal losses for 2019 were calculated as of January 17, 2020, and are subject to change, based on continued PJM billing updates.

constraint specific basis. Local congestion is the total congestion charges to load at the defined set of buses minus total congestion 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.

Overview

Congestion Cost

- **Total Congestion.** Total congestion costs decreased by $726.6 million or 55.5 percent, from $1,309.9 million in 2018 to $583.3 million in 2019.
- **Day-Ahead Congestion.** Day-ahead congestion costs decreased by $664.9 million or 48.2 percent, from $1,378.9 million in 2018 to $714.0 million in 2019.
- **Balancing Congestion.** Negative balancing congestion costs increased by $61.6 million or 89.3 percent, from -$69.0 million in 2018 to -$130.7 million in 2019. Negative balancing explicit charges increased by $64.8 million, from -$18.5 million in 2018 to -$83.3 million in 2019.
- **Real-Time Congestion.** Real-time congestion costs decreased by $732.8 million or 49.3 percent, from $1,485.1 million in 2018 to $752.3 million in 2019.
- **Monthly Congestion.** Monthly total congestion costs in 2019 ranged from $22.2 million in April to $100.2 million in January.
- **Geographic Differences in CLMP.** Differences in CLMP among eastern, southern and western control zones in PJM were primarily a result of congestion on the Conastone - Peach Bottom Line, the Conastone Flow Circuit Breaker, the Tanners Creek - Miami Fort Flowgate, the Coolspring – Milford Line, and the Graceton - Safe Harbor Line.
- **Congestion Frequency.** Congestion frequency continued to be significantly higher in the Day-Ahead Energy Market than in the Real-Time Energy Market in 2019. The number of congestion event hours in the Day-Ahead Energy Market was about five times the number of congestion event hours in the Real-Time Energy Market.

  Day-ahead congestion frequency decreased by 22.2 percent from 132,598 congestion event hours in 2018 to 103,140 congestion event hours in 2019. The majority (95.5 percent) of the decrease occurred in January and February of 2019. The decrease was largely a result of the unusually high levels of cleared up to congestion (UTC) transactions in January and February, 2018.

  Real-time congestion frequency decreased by 7.8 percent from 22,910 congestion event hours in 2018 to 21,122 congestion event hours in 2019.
- **Congested Facilities.** Day-ahead, congestion event hours decreased on all types of facilities.

  The Conastone - Peach Bottom Line was the largest contributor to congestion costs in 2019. With $111.0 million in total congestion costs, it accounted for 19.0 percent of the total PJM congestion costs in 2019.
- **CT Price Setting Logic and Closed Loop Interface Related Congestion.** CT Price Setting Logic caused -$1.9 million of day-ahead congestion in 2019 and -$5.8 million of balancing congestion in 2019. None of the closed loop interfaces was binding in 2019 or 2018.
- **Zonal Congestion.** AEP had the largest zonal congestion costs among all control zones in 2019. AEP had $100.4 million in zonal congestion costs, comprised of $121.8 million in zonal day-ahead congestion costs and -$21.4 million in zonal balancing congestion costs. The Conastone - Peach Bottom Line, the Conastone Flow Circuit Breaker, the Tanners Creek - Miami Fort Flowgate, the Graceton - Safe Harbor Line and the AP South Interface contributed $31.8 million, or 31.7 percent of the AEP zonal congestion costs.

Marginal Loss Cost

- **Total Marginal Loss Costs.** Total marginal loss costs decreased by $318.1 million or 33.1 percent, from $960.1 million in 2018 to $642.0 million in 2019. The loss MWh in PJM decreased by 411.9 GWh or 2.6 percent, from 15,620.4 GWh in 2018 to 15,208.5

GWh in 2019. The loss component of real-time LMP in 2019 was $0.02, compared to $0.02 in 2018.

- **Monthly Total Marginal Loss Costs.** Monthly total marginal loss costs in 2019 ranged from $38.8 million in April to $86.5 million in January.
- **Day-Ahead Marginal Loss Costs.** Day-ahead marginal loss costs decreased by $300.7 million or 30.2 percent, from $997.2 million in 2018 to $696.5 million in 2019.
- **Balancing Marginal Loss Costs.** Negative balancing marginal loss costs increased by $17.4 million or 47.0 percent, from -$37.0 million in 2018 to -$54.5 million in 2019.
- **Total Marginal Loss Surplus.** The total marginal loss surplus decreased in 2019 by $118.7 million or 36.8 percent, from $322.4 million in 2018, to $203.7 million in 2019.

System Energy Cost

- **Total System Energy Costs.** Total system energy costs increased by $201.5 million or 31.6 percent, from -$636.7 million in 2018 to -$435.2 million in 2019.
- **Day-Ahead System Energy Costs.** Day-ahead system energy costs increased by $182.4 million or 25.7 percent, from -$711.0 million in 2018 to -$528.6 million in 2019.
- **Balancing System Energy Costs.** Balancing system energy costs increased by $25.1 million or 36.0 percent, from $69.7 million in 2018 to $94.9 million in 2019.
- **Monthly Total System Energy Costs.** Monthly total system energy costs in 2019 ranged from -$59.3 million in January to -$25.7 million in April.

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 in 2019 decreased significantly from 2018. The decrease was a result of high day-ahead congestion in January 2018 which was a result of high gas costs and associated LMPs in the early part of January 2018.

The monthly total congestion costs ranged from $22.2 million in April to $100.2 million in January 2019.

The impact of UTCs on the frequency of day-ahead congestion was illustrated by the significant reduction in day-ahead congestion event hours following the decrease in up to congestion (UTC) transaction activities that resulted from the February 20, 2018, FERC order that limited UTC trading to hubs, residual metered load, and interfaces.[5]

The current ARR/FTR design does not serve as an efficient way to ensure that load receives all the congestion revenues, and has the ability to receive the auction revenues associated with rights to all the potential congestion revenues. Total ARR and self scheduled FTR revenue offset only 74.5 percent of total congestion including congestion in the Day-Ahead Energy Market and the balancing energy market, for the 2011/2012 planning period through the 2016/2017 planning period, before the FERC decision to allocate balancing congestion and M2M payments to load.[6] For the 2017/2018 planning period, after the implementation of the FERC decision to reallocate balancing congestion and M2M payments to load, ARR and self scheduled FTR revenue offset 50.0 percent of total congestion. For the 2018/2019 planning period, ARR and self scheduled FTR revenue offset 92.1 percent of total congestion. For the first seven months of the 2019/2020 planning period, over 106.1 percent of total congestion was offset by ARR credit allocations to ARR holders, including full allocation of all surplus.

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

5 162 FERC ¶ 61,139 (2018).
6 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.

and set price in the day-ahead or real-time market solution. PJM uses a closed loop interface or 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 LMP security constraint 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 both the closed loop interface and CT pricing logic forces the affected resource bus LMP to match the marginal offer of the resource. In the case of a closed loop interface, all buses within the interface are modeled as having a distribution factor (DFAX) of 1.0 to the constraint and therefore have 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] The 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 market. 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-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 the 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 output in the system solution, the closed loop interface and CT price setting logic constraints are forcing the use of the relatively high cost resource. 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 than consumed 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

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

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 congestion 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 congestion costs are now determined by netting the bus specific hourly deviations across every bus in a zone or subzonal aggregate and pricing the resulting deviation in zone 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 new 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 congestion credits and charges to all other balancing MW deviations at all other bus or aggregates have not changed. This means that the new rules resulted in a decrease in total balancing 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 congestion charges from deviations at aggregates and zones (reduced due to the rule change) and bus specific balancing congestion credits (not been 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 basis as the result of a FERC order.

Table 11-1 shows the total balancing implicit congestion charges that would have resulted from applying the pre and post April 1, 2018, settlement rules for 2017, 2018 and 2019. Table 11-1 also shows the actual total balancing implicit congestion charges for 2017, 2018 and 2019 based on the methods in place at the time. The only difference is that the actual balancing implicit congestion charges in 2018 reflect the fact that in the first quarter of 2018 the balancing implicit congestion charges were calculated under the pre April 1, 2018, settlement rule and in the rest of 2018, the balancing implicit congestion charges were calculated under the post April 1, 2018, settlement rule. Table 11-1 shows that the April 1, 2018, settlement rule, if applied to 2017, 2018 and 2019, 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 $11.5 million (32.1 percent) in 2019 and by $15.6 million (35.6 percent) in 2018.

Table 11-1 Total balancing implicit congestion charge (Dollars (Millions)) (old method and new method): 2017 through 2019

	Balancing Implicit Congestion Charges ($ Million)									
	Old Method			New Method			Actual			
	Withdrawal Charges	Injection Credits	Total	Withdrawal Charges	Injection Credits	Total	Withdrawal Charges	Injection Credits	Total	Change Between New and Old
2017	$22.2	$47.2	($25.0)	$14.2	$45.9	($31.7)	$22.2	$47.2	($25.0)	($6.7)
2018	$18.9	$62.8	($43.9)	$0.1	$59.7	($59.6)	$11.5	$62.0	($50.5)	($15.6)
2019	$17.9	$53.8	($35.8)	$3.7	$51.1	($47.4)	$3.7	$51.1	($47.4)	($11.5)

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 congestion charges will be lower using the new

8 See PJM, "Manual 28: Operating Agreement Accounting," Rev. 83 (Dec. 3, 2019).

method. When the total day-ahead factor weighted real-time bus CLMP is higher than real-time zonal CLMP, the balancing implicit congestion charges will be higher using the new method. Table 11-2 presents three cases to explain the calculation.

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 congestion 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 congestion 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 congestion charges using the new method (-$4.2) are equal under the old method (-$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).

Table 11-2 Example of balancing implicit congestion charge calculation under 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)

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 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 by withdrawals (load) in the transmission constrained area and the total revenue received by injections (generation) to meet the withdrawals (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 2008 through 2019.[11]

The real-time, load-weighted average LMP decreased $10.92 or 28.6 percent from $38.24 in 2018 to $27.32 in 2019. The real-time, load-weighted average congestion component decreased by $0.02 from $0.04 in 2018 to $0.02 in 2019. The real-time, load-weighted average loss component in 2019 was $0.02 compared to $0.02 in 2018. The real-time, load-weighted average system energy component decreased by $10.91 or 28.6 percent from $38.19 in 2018 to $27.28 in 2019.

Table 11-3 PJM real-time, load-weighted average LMP components (Dollars per MWh): 2008 through 2019[12]

	Real-Time LMP	Energy Component	Congestion Component	Loss Component
2008	$71.13	$71.02	$0.06	$0.05
2009	$39.05	$38.97	$0.05	$0.03
2010	$48.35	$48.23	$0.08	$0.04
2011	$45.94	$45.87	$0.05	$0.02
2012	$35.23	$35.18	$0.04	$0.01
2013	$38.66	$38.64	$0.01	$0.02
2014	$53.14	$53.13	($0.02)	$0.02
2015	$36.16	$36.11	$0.04	$0.02
2016	$29.23	$29.18	$0.04	$0.01
2017	$30.99	$30.96	$0.02	$0.01
2018	$38.24	$38.19	$0.04	$0.02
2019	$27.32	$27.28	$0.02	$0.02

Table 11-4 shows the PJM day-ahead, load-weighted, average LMP components for 2008 through 2019.[13] The day-ahead, load-weighted average LMP decreased $10.74, or 28.3 percent, from $37.97 in 2018 to $27.23 in 2019. The day-ahead, load-weighted average congestion component decreased $0.08 from $0.16 in 2018 to $0.08 in 2019. The day-ahead, load-weighted average loss component was -$0.01 in 2018 and -$0.01 in 2019. The day-ahead, load-weighted average energy component decreased $10.66, or 28.2 percent, from $37.83 in 2018 to $27.17 in 2019.

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

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.

Table 11-4 PJM day-ahead, load-weighted average LMP components (Dollars per MWh): 2008 through 2019

	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
2008	$70.25	$70.56	($0.08)	($0.22)
2009	$38.82	$38.96	($0.04)	($0.09)
2010	$47.65	$47.67	$0.05	($0.07)
2011	$45.19	$45.40	($0.06)	($0.15)
2012	$34.55	$34.46	$0.11	($0.01)
2013	$38.93	$38.79	$0.13	$0.00
2014	$53.62	$53.38	$0.26	($0.02)
2015	$36.73	$36.51	$0.24	($0.01)
2016	$29.68	$29.55	$0.14	($0.01)
2017	$30.85	$30.81	$0.05	($0.02)
2018	$37.97	$37.83	$0.16	($0.01)
2019	$27.23	$27.17	$0.08	($0.01)

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

Table 11-5 PJM real-time, load-weighted average LMP by constrained and unconstrained hours (Dollars per MWh): 2018 and 2019

	2018		2019	
	Constrained Hours	Unconstrained Hours	Constrained Hours	Unconstrained Hours
Jan	$96.69	$24.03	$33.75	$21.61
Feb	$27.00	$23.93	$28.99	$23.33
Mar	$33.35	$23.64	$30.81	$24.22
Apr	$35.74	$24.92	$27.04	$24.43
May	$38.78	$17.24	$24.92	$20.27
Jun	$34.55	$21.81	$24.94	$19.28
Jul	$37.08	$26.09	$32.29	$20.04
Aug	$38.64	$25.11	$24.63	$21.02
Sep	$36.83	$26.29	$29.79	$17.03
Oct	$35.27	$26.11	$27.97	$23.45
Nov	$37.64	$26.58	$28.54	$19.94
Dec	$34.60	$24.19	$24.37	$16.20
Avg	$41.15	$24.71	$28.33	$21.07

Zonal Components

The real-time components of LMP for each control zone are presented in Table 11-6 for 2018 and 2019. In 2019, BGE had the highest real-time congestion component of all control zones, $2.47, and AECO had the lowest real-time congestion component, -$2.39.

Table 11-6 Zonal and PJM real-time, load-weighted average LMP components (Dollars per MWh): 2018 and 2019

	2018				2019			
	Real-Time LMP	Energy Component	Congestion Component	Loss Component	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AECO	$37.06	$37.68	($1.45)	$0.83	$25.07	$27.28	($2.39)	$0.17
AEP	$37.79	$38.16	$0.08	($0.44)	$28.21	$27.24	$1.00	($0.03)
APS	$39.78	$38.40	$1.12	$0.25	$27.83	$27.28	$0.52	$0.03
ATSI	$40.19	$37.60	$1.99	$0.60	$28.06	$27.16	$0.50	$0.41
BGE	$44.03	$38.86	$3.81	$1.36	$30.82	$27.49	$2.47	$0.86
ComEd	$30.05	$37.42	($5.52)	($1.84)	$24.72	$27.12	($1.54)	($0.86)
DAY	$38.96	$38.12	$0.17	$0.66	$29.52	$27.38	$1.12	$1.02
DEOK	$39.16	$38.10	$1.99	($0.93)	$28.49	$27.33	$1.17	($0.00)
DLCO	$39.98	$37.68	$2.16	$0.14	$27.69	$27.18	$0.56	($0.05)
Dominion	$43.16	$39.04	$3.61	$0.52	$29.08	$27.39	$1.42	$0.28
DPL	$43.76	$39.07	$3.15	$1.54	$27.71	$27.54	($0.39)	$0.56
EKPC	$36.20	$39.71	($2.30)	($1.21)	$28.18	$27.69	$0.65	($0.16)
JCPL	$37.08	$38.08	($1.65)	$0.65	$25.40	$27.49	($2.18)	$0.09
Met-Ed	$37.06	$38.09	($1.36)	$0.33	$26.34	$27.26	($0.74)	($0.18)
OVEC	$30.89	$32.12	($0.25)	($0.97)	$26.23	$26.39	$0.52	($0.68)
PECO	$36.36	$38.11	($2.11)	$0.37	$24.75	$27.25	($2.33)	($0.17)
PENELEC	$37.90	$37.69	($0.19)	$0.40	$26.17	$27.03	($0.76)	($0.10)
Pepco	$42.60	$38.72	$2.97	$0.91	$29.68	$27.46	$1.69	$0.53
PPL	$35.95	$38.34	($2.37)	($0.02)	$24.85	$27.25	($1.97)	($0.42)
PSEG	$36.68	$37.57	($1.48)	$0.59	$25.28	$27.14	($1.84)	($0.02)
RECO	$37.40	$37.81	($0.97)	$0.56	$25.72	$27.39	($1.64)	($0.03)
PJM	$38.24	$38.19	$0.04	$0.02	$27.32	$27.28	$0.02	$0.02

The day-ahead components of LMP for each control zone are presented in Table 11-7 for 2018 and 2019. In 2019, BGE had the highest day-ahead congestion component of all control zones, $2.89, and PECO had the lowest day-ahead congestion component, -$2.46.

Table 11-7 Zonal and PJM day-ahead, load-weighted average LMP components (Dollars per MWh): 2018 and 2019

	2018				2019			
	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AECO	$36.71	$37.52	($1.32)	$0.51	$24.92	$27.21	($2.36)	$0.07
AEP	$37.46	$37.86	($0.04)	($0.37)	$28.02	$27.21	$0.84	($0.03)
APS	$39.15	$37.82	$1.12	$0.21	$27.84	$27.16	$0.67	$0.01
ATSI	$39.03	$37.31	$1.18	$0.54	$28.14	$27.04	$0.68	$0.43
BGE	$43.79	$38.37	$4.22	$1.20	$30.93	$27.33	$2.89	$0.71
ComEd	$30.13	$37.12	($5.40)	($1.58)	$24.62	$26.95	($1.61)	($0.71)
DAY	$38.86	$37.75	$0.35	$0.75	$29.27	$27.22	$1.08	$0.98
DEOK	$40.11	$37.73	$2.96	($0.58)	$28.64	$27.24	$1.36	$0.04
DLCO	$39.10	$37.45	$1.50	$0.15	$27.72	$27.03	$0.75	($0.07)
Dominion	$43.29	$38.69	$4.03	$0.57	$29.33	$27.32	$1.82	$0.19
DPL	$42.48	$38.74	$2.63	$1.12	$27.44	$27.51	($0.47)	$0.40
EKPC	$36.01	$39.39	($2.29)	($1.09)	$27.97	$27.69	$0.57	($0.29)
JCPL	$36.65	$37.74	($1.46)	$0.37	$25.04	$27.28	($2.27)	$0.03
Met-Ed	$36.78	$37.61	($0.80)	($0.03)	$25.78	$27.15	($1.07)	($0.30)
OVEC	$0.00	$0.00	$0.00	$0.00	$28.03	$27.64	$0.99	($0.60)
PECO	$35.96	$37.65	($1.76)	$0.06	$24.38	$27.12	($2.46)	($0.28)
PENELEC	$37.59	$37.75	($0.41)	$0.25	$26.89	$27.36	($0.50)	$0.03
Pepco	$42.61	$38.35	$3.35	$0.91	$29.99	$27.39	$2.13	$0.48
PPL	$35.68	$37.78	($1.73)	($0.37)	$24.39	$27.15	($2.23)	($0.52)
PSEG	$37.05	$37.56	($0.91)	$0.40	$25.13	$27.08	($1.90)	($0.05)
RECO	$37.36	$37.69	($0.71)	$0.38	$25.93	$27.36	($1.41)	($0.02)
PJM	$37.97	$37.83	$0.16	($0.01)	$27.23	$27.17	$0.08	($0.01)

Hub Components

The real-time components of LMP for each hub are presented in Table 11-8 for 2018 and 2019.[14]

Table 11-8 Hub real-time, average LMP components (Dollars per MWh): 2018 and 2019

	2018				2019			
	Real-Time LMP	Energy Component	Congestion Component	Loss Component	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AEP Gen Hub	$33.29	$36.04	($1.34)	($1.41)	$26.03	$26.25	$0.48	($0.71)
AEP-DAY Hub	$34.74	$36.04	($0.71)	($0.58)	$27.16	$26.25	$0.97	($0.06)
ATSI Gen Hub	$36.94	$36.04	$1.01	($0.11)	$26.77	$26.25	$0.57	($0.05)
Chicago Gen Hub	$28.08	$36.04	($5.73)	($2.22)	$23.53	$26.25	($1.59)	($1.14)
Chicago Hub	$28.61	$36.04	($5.71)	($1.72)	$23.91	$26.25	($1.59)	($0.76)
Dominion Hub	$39.55	$36.04	$3.31	$0.20	$27.53	$26.25	$1.22	$0.06
Eastern Hub	$38.35	$36.04	$1.12	$1.19	$25.28	$26.25	($1.37)	$0.40
N Illinois Hub	$28.40	$36.04	($5.73)	($1.91)	$23.74	$26.25	($1.61)	($0.90)
New Jersey Hub	$34.57	$36.04	($1.97)	$0.51	$24.03	$26.25	($2.19)	($0.03)
Ohio Hub	$34.56	$36.04	($0.89)	($0.58)	$27.29	$26.25	$1.05	($0.02)
West Interface Hub	$38.13	$36.04	$2.37	($0.28)	$26.79	$26.25	$0.73	($0.19)
Western Hub	$36.95	$36.04	$0.77	$0.14	$26.70	$26.25	$0.53	($0.09)

The day-ahead components of LMP for each hub are presented in Table 11-9 for 2018 and 2019.

Table 11-9 Hub day-ahead, average LMP components (Dollars per MWh): 2018 and 2019

	2018				2019			
	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AEP Gen Hub	$33.45	$35.84	($1.14)	($1.26)	$25.80	$25.99	$0.48	($0.67)
AEP-DAY Hub	$34.82	$35.84	($0.53)	($0.49)	$26.77	$25.99	$0.83	($0.04)
ATSI Gen Hub	$36.23	$35.84	$0.45	($0.06)	$26.71	$25.99	$0.70	$0.03
Chicago Gen Hub	$28.09	$35.84	($5.77)	($1.99)	$23.33	$25.99	($1.66)	($0.99)
Chicago Hub	$28.67	$35.84	($5.72)	($1.46)	$23.71	$25.99	($1.66)	($0.61)
Dominion Hub	$39.60	$35.84	$3.45	$0.30	$27.43	$25.99	$1.48	($0.03)
Eastern Hub	$38.04	$35.84	$1.27	$0.93	$25.08	$25.99	($1.20)	$0.29
N Illinois Hub	$28.44	$35.84	($5.72)	($1.68)	$23.54	$25.99	($1.66)	($0.78)
New Jersey Hub	$34.72	$35.84	($1.42)	$0.29	$23.87	$25.99	($2.05)	($0.07)
Ohio Hub	$34.68	$35.84	($0.66)	($0.50)	$26.83	$25.99	$0.85	($0.01)
West Interface Hub	$37.72	$35.84	$2.10	($0.22)	$26.75	$25.99	$0.93	($0.17)
Western Hub	$36.69	$35.84	$0.77	$0.08	$26.69	$25.99	$0.76	($0.06)

Congestion

Congestion Accounting

Total congestion costs equal net implicit congestion charges, plus net explicit congestion charges, plus net inadvertent congestion charges. Implicit congestion charges equal implicit withdrawal charges less implicit injection credits. Explicit congestion charges are the net congestion charges associated with the injection credits and withdrawal charges for point to point energy transactions. Inadvertent congestion charges are common costs, 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. 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 congestion charges are the congestion charges calculated for energy injected or withdrawn at a location. The explicit congestion charges are the congestion charges calculated for transactions with a defined source and a sink.

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.

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.

For example, implicit congestion charges are calculated for network load and explicit congestion charges are calculated for up to congestion transactions (UTCs). Inadvertent congestion charges are congestion 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.

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 congestion charge or credit collected from the PJM market participants. However, the sum of an individual customer's congestion 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 does not measure congestion and should not indicate that it does measure congestion.

Congestion charges and congestion credits are calculated for both the Day-Ahead and balancing energy markets.

- **Day-Ahead Implicit Withdrawal Congestion 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, as applicable.
- **Day-Ahead Implicit Injection Congestion Credits.** Day-ahead implicit injection credits are calculated for all cleared generation, increment offers and day-ahead energy market purchase transactions. 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, as applicable.
- **Balancing Implicit Withdrawal Congestion 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 Injection Congestion 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.
- **Explicit Congestion Charges.** Explicit congestion charges are the net congestion costs associated with point to point energy transactions. Day-ahead explicit congestion 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 congestion 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 congestion charges are calculated for internal purchase, import and export transaction, and up to congestion transactions (UTCs.)
- **Inadvertent Congestion Charges.** Inadvertent congestion charges are congestion 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 congestion charges are common costs, not directly attributable to specific participants that are distributed on a load ratio basis.[16]

16 PJM Operating Agreement Schedule 1 §3.7.

The congestion calculation equations are in Table 11-10.

Table 11-10 Congestion calculations

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

The congestion costs associated with specific constraints are the sum of the total day-ahead and balancing congestion costs associated with those constraints. Zonal congestion is calculated on a constraint by constraint basis. The congestion calculations are the total difference between what the zonal load pays in congestion 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 congestion charges and congestion credits can be both positive and negative. Congestion charges, positive or negative, are paid by withdrawals and congestion 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 congestion charges, when positive, measure the congestion payment to a PJM member and when negative, measure the congestion credit paid to a PJM member. Explicit congestion charges are calculated for up to congestion transactions (UTCs).

The accounting definitions can be misleading. Load pays congestion. 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. 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 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 at 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.[17]

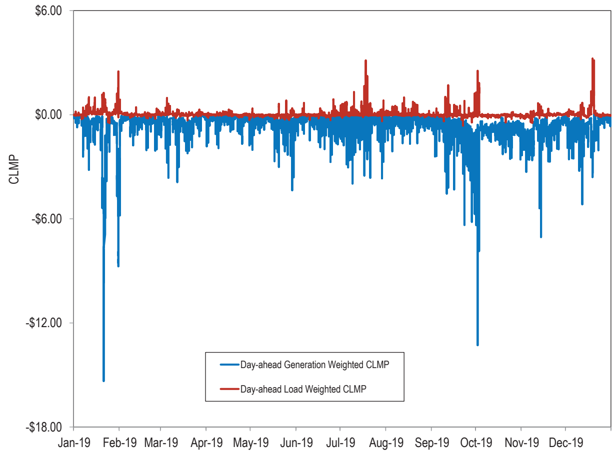
Load-weighted LMP components are calculated relative to a load weighted average LMP. At the load weighted

17 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>.

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 congestion charges is logically zero and the small 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 congestion 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 2019, day-ahead generation weighted CLMPs were generally negative and day-ahead load weighted CLMPs were generally positive. Figure 11-1 also shows that in 2019, load paid more for energy as a result of transmission constraints than generation was paid to provide that energy. Figure 11-1 shows that CLMP related charges to load are slightly positive and total CLMP related credits to generation are relatively negative. Total CLMP related load payments are higher than total CLMP related generation credits. The difference in load payments and generation credits (load charges minus generation credits) is congestion (See Table 11-13 and Table 11-14).

Figure 11-1 Day-ahead generation weighted CLMPs and day-ahead load weighted CLMPs: 2019



Total Congestion

Total congestion costs in PJM in 2019 were $583.3 million, comprised of implicit withdrawal charges of $249.7 million, implicit injection credits of -$361.2 million and explicit charges of -$27.6 million. Total congestion is the difference between that withdrawals (load) pay for energy and what injections (generation) pay for energy due to binding transmission constraints.

Table 11-11 shows total congestion for 2008 through 2019. Total congestion costs in Table 11-11 include congestion costs associated with PJM facilities and those associated with reciprocal, coordinated flowgates in MISO and in NYISO.[18 19]

Table 11-11 Total PJM congestion costs (Dollars (Millions)): 2008 through 2019

	Congestion Costs (Millions)			
	Congestion Cost	Percent Change	Total PJM Billing	Percent of PJM Billing
2008	$2,052	NA	$34,300	6.0%
2009	$719	(65.0%)	$26,550	2.7%
2010	$1,423	98.0%	$34,770	4.1%
2011	$999	(29.8%)	$35,890	2.8%
2012	$529	(47.0%)	$29,180	1.8%
2013	$677	28.0%	$33,860	2.0%
2014	$1,932	185.5%	$50,030	3.9%
2015	$1,385	(28.3%)	$42,630	3.2%
2016	$1,024	(26.1%)	$39,050	2.6%
2017	$698	(31.9%)	$40,170	1.7%
2018	$1,310	87.8%	$49,790	2.6%
2019	$583	(55.5%)	$39,200	1.5%

18 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>.

19 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>.

Congestion charges and credits are not in and of themselves congestion. Congestion charges and credits are adjustments to energy charges and credits reflecting 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 congestion 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 2008 through 2019. Table 11-13 and Table 11-14 show that the decrease in balancing explicit charges was the result of the decrease in balancing explicit charges incurred by up to congestion transactions (UTCs) in 2019 from 2018. Table 11-39 shows that the balancing explicit charges incurred by UTCs were $29.5 million in January of 2018.

Table 11-12 Total PJM congestion credits and charges by accounting category by market (Dollars (Millions)): 2008 through 2019

	Congestion Costs (Millions)									
	Day-Ahead				Balancing					
	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Inadvertent Charges	Grand Total
2008	$1,260.3	($1,133.1)	$203.0	$2,596.5	($225.9)	$79.2	($239.5)	($544.6)	$0.0	$2,051.8
2009	$292.3	($525.2)	$83.9	$901.4	($39.0)	$10.1	($133.4)	($182.4)	$0.0	$719.0
2010	$376.4	($1,239.8)	$96.9	$1,713.1	($37.5)	$72.8	($179.5)	($289.8)	($0.0)	$1,423.3
2011	$400.5	($777.6)	$66.9	$1,245.0	$53.5	$109.5	($190.0)	($246.0)	$0.0	$999.0
2012	$122.7	($525.3)	$131.9	$779.9	($7.6)	$57.9	($185.4)	($250.9)	$0.0	$529.0
2013	$281.2	($592.5)	$137.6	$1,011.3	$5.9	$131.3	($209.0)	($334.4)	$0.0	$676.9
2014	$595.5	($1,671.2)	($35.4)	$2,231.3	$52.7	$218.1	($133.6)	($299.1)	$0.0	$1,932.2
2015	$614.2	($967.6)	$50.3	$1,632.1	$0.6	$69.8	($177.6)	($246.9)	$0.0	$1,385.3
2016	$405.3	($654.1)	$41.0	$1,100.4	($4.5)	$28.4	($43.9)	($76.8)	($0.0)	$1,023.7
2017	$187.6	($554.1)	($8.6)	$733.1	$22.2	$47.2	($10.4)	($35.5)	$0.0	$697.6
2018	$349.3	($1,048.6)	($18.9)	$1,378.9	$11.5	$62.0	($18.5)	($69.0)	$0.0	$1,309.9
2019	$246.0	($412.3)	$55.7	$714.0	$3.7	$51.1	($83.3)	($130.7)	$0.0	$583.3

Table 11-13 and Table 11-14 show the total congestion charges and credits for each transaction type in 2019 and 2018. Table 11-13 shows that in 2019 DECs paid $14.8 million in congestion charges in the day-ahead market, were paid $17.3 million in congestion credits in the balancing energy market, resulting in a net payment of $2.4 million in total congestion credits. In 2019, INCs paid $15.5 million in congestion charges in the day-ahead market, were paid $28.2 million in congestion credits in the balancing energy market resulting in a net payment of $12.7 million in total congestion credits. In 2019, up to congestion (UTCs) paid $54.2 million in congestion charges in the day-ahead market, were paid $81.6 million in congestion credits in the balancing market resulting in a total payment of $27.4 million in total congestion credits.

Table 11-13 Total PJM congestion credits and charges by transaction type by market (Dollars (Millions)): 2019

	Congestion 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	$14.8	$0.0	$0.0	$14.8	($17.3)	$0.0	$0.0	($17.3)	$0.0	($2.4)
Demand	$49.0	$0.0	$0.0	$49.0	$23.9	$0.0	$0.0	$23.9	$0.0	$72.9
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	$1.7	$1.7	$0.0	$0.0	($0.6)	($0.6)	$0.0	$1.1
Explicit Congestion and Loss Only	$0.0	$0.0	$0.1	$0.1	$0.0	$0.0	$0.0	$0.0	$0.0	$0.1
Export	($32.8)	$0.0	($0.4)	($33.2)	($1.9)	$0.0	($0.6)	($2.5)	$0.0	($35.7)
Generation	$0.0	($613.5)	$0.0	$613.5	$0.0	$26.5	$0.0	($26.5)	$0.0	$587.0
Import	$0.0	$1.7	$0.0	($1.7)	$0.0	($2.7)	($0.2)	$2.5	$0.0	$0.8
INC	$0.0	($15.5)	$0.0	$15.5	$0.0	$28.2	$0.0	($28.2)	$0.0	($12.7)
Internal Bilateral	$214.9	$215.0	$0.1	$0.0	($0.9)	($0.9)	$0.0	($0.0)	$0.0	$0.0
Up to Congestion	$0.0	$0.0	$54.2	$54.2	$0.0	$0.0	($81.6)	($81.6)	$0.0	($27.4)
Wheel In	$0.0	$0.0	$0.0	$0.0	$0.0	($0.1)	($0.3)	($0.2)	$0.0	($0.2)
Wheel Out	$0.0	$0.0	$0.0	$0.0	($0.1)	$0.0	$0.0	($0.1)	$0.0	($0.1)
Total	$246.0	($412.3)	$55.7	$714.0	$3.7	$51.1	($83.3)	($130.7)	$0.0	$583.3

Table 11-14 Total PJM congestion credits and charges by transaction type by market (Dollars (Millions)): 2018

	Congestion 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	$25.3	$0.0	$0.0	$25.3	($32.7)	$0.0	$0.0	($32.7)	$0.0	($7.4)
Demand	$101.0	$0.0	$0.0	$101.0	$56.3	$0.0	$0.0	$56.3	$0.0	$157.3
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	$2.2	$2.2	$0.0	$0.0	($0.8)	($0.8)	$0.0	$1.4
Explicit Congestion and Loss Only	$0.0	$0.0	($0.1)	($0.1)	$0.0	$0.0	($0.0)	($0.0)	$0.0	($0.2)
Export	($59.9)	$0.0	($1.0)	($60.9)	($14.7)	$0.0	($5.8)	($20.5)	$0.0	($81.5)
Generation	$0.0	($1,304.8)	$0.0	$1,304.8	$0.0	$70.9	$0.0	($70.9)	$0.0	$1,233.9
Grandfathered Overuse	$0.0	$0.0	($0.6)	($0.6)	$0.0	$0.0	$0.0	$0.0	$0.0	($0.5)
Import	$0.0	($6.2)	$0.0	$6.2	$0.0	($41.5)	($3.5)	$38.0	$0.0	$44.2
INC	$0.0	($20.5)	$0.0	$20.5	$0.0	$30.0	$0.0	($30.0)	$0.0	($9.5)
Internal Bilateral	$282.8	$282.8	$0.0	($0.0)	$3.4	$3.4	$0.0	($0.0)	$0.0	($0.0)
Up to Congestion	$0.0	$0.0	($19.4)	($19.4)	$0.0	$0.0	($7.9)	($7.9)	$0.0	($27.4)
Wheel In	$0.0	$0.0	$0.0	$0.0	$0.0	($0.8)	($0.5)	$0.3	$0.0	$0.3
Wheel Out	$0.0	$0.0	$0.0	$0.0	($0.8)	$0.0	$0.0	($0.8)	$0.0	($0.8)
Total	$349.3	($1,048.6)	($18.9)	$1,378.9	$11.5	$62.0	($18.5)	($69.0)	$0.0	$1,309.9

Table 11-15 shows the change in total congestion credits and charges incurred by transaction type from 2018 to 2019. Total negative congestion credits incurred by generation decreased by $646.9 million, and total congestion charges incurred by demand decreased by $84.4 million. The total congestion credits to up to congestion transactions (UTCs) did not change, from $27.4 million in 2018 to $27.4 million in 2019. Total day-ahead congestion credits to UTCs decreased by $73.7 million from $19.4 million in 2018 to -$54.2 million in 2019. Over the same period balancing congestion credits to UTCs increased by $73.7 million, from $7.9 million in 2018 to $81.6 million in 2019.

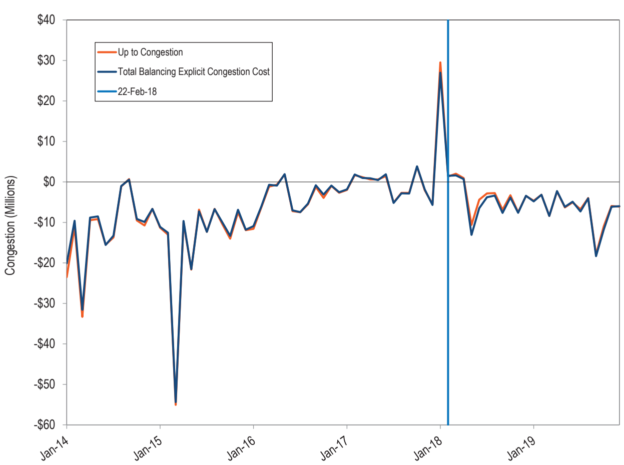
Table 11-15 Change in total PJM congestion credits and charges by transaction type by market: 2018 to 2019 (Dollars (Millions))

	Change in Congestion 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	($10.5)	$0.0	$0.0	($10.5)	$15.5	$0.0	$0.0	$15.5	$0.0	$4.9
Demand	($52.0)	$0.0	$0.0	($52.0)	($32.4)	$0.0	$0.0	($32.4)	$0.0	($84.4)
Demand Response	$0.1	$0.0	$0.0	$0.1	($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	($0.3)
Explicit Congestion and Loss Only	$0.0	$0.0	$0.2	$0.2	$0.0	$0.0	$0.0	$0.0	$0.0	$0.3
Export	$27.1	$0.0	$0.7	$27.7	$12.8	$0.0	$5.3	$18.0	$0.0	$45.8
Generation	$0.0	$691.2	$0.0	($691.2)	$0.0	($44.3)	$0.0	$44.3	$0.0	($646.9)
Grandfathered Overuse	$0.0	$0.0	$0.6	$0.6	$0.0	$0.0	($0.0)	($0.0)	$0.0	$0.5
Import	$0.0	$7.9	$0.0	($7.9)	$0.0	$38.7	$3.2	($35.5)	$0.0	($43.4)
INC	$0.0	$4.9	$0.0	($4.9)	$0.0	($1.8)	$0.0	$1.8	$0.0	($3.1)
Internal Bilateral	($67.9)	($67.8)	$0.1	$0.0	($4.3)	($4.3)	($0.0)	$0.0	$0.0	$0.0
Up to Congestion	$0.0	$0.0	$73.7	$73.7	$0.0	$0.0	($73.7)	($73.7)	$0.0	($0.0)
Wheel In	$0.0	$0.0	$0.0	$0.0	$0.0	$0.7	$0.1	($0.6)	$0.0	($0.6)
Wheel Out	$0.0	$0.0	$0.0	$0.0	$0.7	$0.0	$0.0	$0.7	$0.0	$0.7
Total	($103.3)	$636.3	$74.6	($664.9)	($7.8)	($11.0)	($64.8)	($61.6)	$0.0	($726.6)

UTCs and Negative Balancing Explicit Congestion Charges

Figure 11-2 shows the change in up to congestion balancing explicit congestion charges from 2014 through 2018. Figure 11-2 shows that UTCs account for almost all negative balancing explicit congestion charges in PJM. As shown in Figure 11-2, UTCs are generally paid balancing congestion, which takes the form of negative balancing congestion charges being allocated to UTC positions. In 2019, 97.9 percent (-$81.6 million out of -$83.3 million) of negative balancing explicit congestion charges was incurred by UTCs (Table 11-13).

Figure 11-2 Monthly balancing explicit congestion charges incurred by up to congestion: 2014 through 2019



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 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 reduction in 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.[20] The reduction in real-time congestion compared to day-ahead congestion creates negative balancing congestion.

20 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.

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 differences 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. 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.[21]

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 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 congestion 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 $1and 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 congestion 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.[22]

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 $250 in negative balancing congestion if there had been no UTCs.

21 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

22 153 FERC ¶ 61,180.

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 Congestion

Zonal congestion is calculated on a constraint specific basis. Local congestion is the difference between what withdrawals (load) pay for energy and what injections (generation) are paid for energy due to individual binding transmission constraints. Local congestion includes all energy charges or credits incurred to serve zonal load. Local congestion calculations account for the total difference between what the zonal load pays in congestion 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.

Local congestion is calculated on a constraint specific basis. This constraint based congestion is the total congestion payments by withdrawals (load) at the buses within a defined area minus total congestion credits received by all injections (generation) that supplied that load, given the transmission constraints, regardless of location. Constraint based 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.

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 congestion charges (CLMP of that specific constraint at each bus times load MW at each bus) caused by that constraint in excess of generation congestion 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 allocating the congestion of an individual constraint, the reference bus for each constraint calculation is moved to 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 (withdrawal payments in excess of injection credits), constraint specific congestion is appropriately assigned to downstream (positive CLMP) load buses that paid the congestion caused by the constraint, in proportion to the congestion 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 the day-ahead and balancing congestion by zone for 2019. Table 11-18 shows the congestion costs by zone for 2018.

Table 11-17 Day-ahead and balancing congestion by zone (Dollars (Millions)): 2019

Congestion Costs (Millions)									
	Day-Ahead				Balancing				
Control Zone	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Grand Total
AECO	$3.7	($4.4)	$0.9	$9.0	$0.1	$0.7	($1.1)	($1.6)	$7.4
AEP	$46.5	($64.8)	$10.5	$121.8	$0.9	$8.4	($13.9)	($21.4)	$100.4
APS	$22.3	($24.8)	$2.4	$49.5	$0.5	$3.1	($5.0)	($7.7)	$41.8
ATSI	$18.2	($31.9)	$3.7	$53.7	$0.5	$3.9	($7.0)	($10.4)	$43.3
BGE	$10.6	($13.8)	$1.2	$25.7	$0.1	$2.2	($3.4)	($5.4)	$20.2
ComEd	$21.1	($60.4)	$13.2	$94.6	($1.1)	$5.9	($7.3)	($14.3)	$80.3
DAY	$5.1	($8.1)	$1.2	$14.3	$0.1	$1.1	($2.0)	($3.0)	$11.4
DEOK	$9.1	($11.8)	$1.9	$22.7	$0.2	$1.7	($3.1)	($4.6)	$18.1
DLCO	$2.9	($5.0)	$0.5	$8.5	$0.1	$0.8	($1.4)	($2.1)	$6.4
Dominion	$29.1	($51.3)	$4.3	$84.7	$1.1	$6.8	($10.6)	($16.2)	$68.5
DPL	$17.8	($10.7)	$2.9	$31.4	$0.0	$1.2	($2.3)	($3.4)	$27.9
EKPC	$4.1	($6.1)	$0.8	$11.0	$0.1	$0.9	($1.4)	($2.1)	$8.9
EXT	$0.2	($0.1)	$0.2	$0.6	($0.3)	$0.4	($2.8)	($3.5)	($2.9)
JCPL	$4.7	($13.6)	$1.2	$19.5	$0.2	$1.5	($2.4)	($3.6)	$15.9
Met-Ed	$5.3	($10.2)	$0.7	$16.3	($0.2)	$1.1	($2.0)	($3.3)	$13.0
OVEC	($0.0)	($0.0)	$0.3	$0.3	$0.0	$0.0	$0.1	$0.1	$0.4
PECO	$4.9	($22.9)	$1.7	$29.5	$0.4	$2.7	($4.1)	($6.4)	$23.1
PENELEC	$9.2	($8.5)	$1.0	$18.6	($0.1)	$1.2	($1.8)	($3.0)	$15.6
Pepco	$9.8	($12.3)	$1.2	$23.3	$0.3	$1.9	($3.0)	($4.7)	$18.6
PPL	$11.2	($24.6)	$3.3	$39.1	$0.3	$2.5	($4.1)	($6.4)	$32.8
PSEG	$9.9	($26.3)	$2.3	$38.5	$0.3	$2.9	($4.4)	($7.1)	$31.4
RECO	$0.4	($0.9)	$0.2	$1.5	($0.0)	$0.1	($0.4)	($0.5)	$1.0
Total	$246.0	($412.3)	$55.7	$714.0	$3.7	$51.1	($83.3)	($130.7)	$583.3

Table 11-18 Day-ahead and balancing congestion by zone (Dollars (Millions)): 2018

Congestion Costs (Millions)									
	Day-Ahead				Balancing				
Control Zone	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Grand Total
AECO	$4.8	($12.0)	$0.1	$16.9	$0.1	$0.7	($0.3)	($0.9)	$16.0
AEP	$64.3	($172.7)	($2.1)	$234.9	$1.9	$9.4	($3.6)	($11.1)	$223.8
APS	$21.1	($60.6)	($1.8)	$79.9	$1.0	$3.4	($1.0)	($3.4)	$76.5
ATSI	$24.7	($79.8)	($1.6)	$102.9	$0.9	$3.9	($2.6)	($5.5)	$97.4
BGE	$13.8	($36.0)	($1.6)	$48.1	$0.7	$2.4	($0.5)	($2.2)	$45.9
ComEd	$7.4	($162.3)	$2.5	$172.3	$1.4	$7.8	($2.6)	($9.0)	$163.2
DAY	$5.2	($23.3)	($0.5)	$27.9	$0.3	$1.1	($0.6)	($1.4)	$26.5
DEOK	$8.8	($42.3)	($0.3)	$50.8	$0.4	$1.6	($0.9)	($2.1)	$48.7
DLCO	$3.2	($14.5)	($0.4)	$17.3	$0.2	$0.8	($0.6)	($1.1)	$16.2
Dominion	$50.5	($113.5)	($5.1)	$158.9	$2.9	$8.6	($1.0)	($6.8)	$152.1
DPL	$70.3	($13.9)	$3.7	$87.8	($0.3)	$0.9	($1.1)	($2.3)	$85.5
EKPC	$5.2	($19.5)	($0.7)	$24.0	$0.3	$0.9	($0.1)	($0.7)	$23.4
EXT	$0.3	($0.5)	$0.6	$1.4	($0.0)	$5.8	$0.7	($5.2)	($3.8)
JCPL	$8.0	($32.1)	($0.9)	$39.2	$0.3	$1.4	($0.6)	($1.7)	$37.5
Met-Ed	$4.9	($27.7)	($1.0)	$31.6	$0.2	$1.6	($0.2)	($1.6)	$29.9
OVEC	$0.0	$0.0	($0.0)	($0.0)	$0.0	($0.0)	$0.0	$0.0	$0.0
PECO	$10.5	($54.2)	($2.3)	$62.4	$0.6	$2.6	($0.8)	($2.8)	$59.6
PENELEC	$3.7	($29.4)	($1.0)	$32.1	($0.6)	$1.3	($0.3)	($2.2)	$29.9
Pepco	$14.5	($31.7)	($1.6)	$44.6	$0.6	$2.2	($0.4)	($1.9)	$42.6
PPL	$13.5	($59.9)	($3.4)	$69.9	$0.5	$2.8	($0.3)	($2.6)	$67.3
PSEG	$14.1	($61.0)	($1.7)	$73.4	$0.0	$2.9	($1.1)	($4.0)	$69.4
RECO	$0.5	($1.9)	$0.2	$2.6	($0.0)	$0.1	($0.4)	($0.5)	$2.0
Total	$349.3	($1,048.6)	($18.9)	$1,378.9	$11.5	$62.0	($18.5)	($69.0)	$1,309.9

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 these special cases the associated congestion is assigned to the control zone or residual load aggregate where the congestion is incurred and/or there are positive CLMPs from that constraint. In 2019, the total congestion costs associated with the special cases were -$1.5 million. 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); 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 congestion charges and calculated congestion costs including rounding errors (unclassified).

Table 11-19 and Table 11-20 show the allocation of total congestion by each special case allocation method, congestion allocated by the standard method and total allocation 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 2018 or in 2019.

Table 11-19 Day-ahead and total balancing congestion assigned by zone and special case logic (Dollars (Millions)): 2019

	Congestion Costs (Millions)														
	Day-Ahead							Balancing							
Control Zone	Load Bus Zero CLMP	CT Price Setting Logic	Closed Loop Interfaces	No Load Buses	Unclassified	Allocation	Total	Load Bus Zero CLMP	CT Price Setting Logic	Closed Loop Interfaces	No Load Buses	Unclassified	Allocation	Total	Grand Total
AECO	($0.0)	$0.0	$0.0	$0.0	$0.0	$9.0	$9.0	$0.0	($0.0)	$0.0	$0.0	($0.0)	($1.6)	($1.6)	$7.4
AEP	$0.0	($0.1)	$0.0	$2.0	($0.0)	$119.9	$121.8	($0.0)	($0.7)	$0.0	$0.0	($0.4)	($20.3)	($21.4)	$100.4
APS	$0.0	($0.0)	$0.0	$0.0	($0.0)	$49.5	$49.5	$0.0	$0.0	$0.0	($0.0)	$0.0	($7.7)	($7.7)	$41.8
ATSI	$0.0	($0.0)	$0.0	$0.0	$0.0	$53.8	$53.7	$0.0	($0.3)	$0.0	$0.0	($0.0)	($10.1)	($10.4)	$43.3
BGE	$0.0	($0.0)	$0.0	$0.1	$0.0	$25.5	$25.7	($0.0)	($0.0)	$0.0	$0.0	$0.0	($5.4)	($5.4)	$20.2
ComEd	$0.0	($1.6)	$0.0	$2.1	($0.0)	$94.2	$94.6	($0.0)	($0.9)	$0.0	$0.0	($0.0)	($13.3)	($14.3)	$80.3
DAY	$0.0	$0.0	$0.0	$0.0	$0.0	$14.3	$14.3	$0.0	($0.1)	$0.0	$0.0	($0.0)	($2.8)	($3.0)	$11.4
DEOK	$0.0	($0.0)	$0.0	$0.0	$0.0	$22.7	$22.7	$0.0	($0.1)	$0.0	($0.0)	($0.0)	($4.5)	($4.6)	$18.1
DLCO	$0.0	($0.0)	$0.0	$0.0	$0.0	$8.5	$8.5	$0.0	($0.0)	$0.0	$0.0	$0.0	($2.1)	($2.1)	$6.4
Dominion	$0.0	($0.0)	$0.0	$0.1	$0.0	$84.6	$84.7	$0.0	$0.0	$0.0	($0.0)	($0.1)	($16.2)	($16.2)	$68.5
DPL	$0.0	($0.1)	$0.0	$0.1	$0.0	$31.3	$31.4	$0.0	$0.0	$0.0	$0.0	($0.0)	($3.4)	($3.4)	$27.9
EKPC	$0.0	($0.0)	$0.0	$0.0	$0.0	$11.1	$11.0	$0.0	$0.0	$0.0	$0.0	$0.0	($2.2)	($2.1)	$8.9
EXT	$0.0	($0.0)	$0.0	$0.4	$0.2	$0.0	$0.6	($0.0)	($3.3)	$0.0	($0.0)	($0.2)	$0.0	($3.5)	($2.9)
JCPL	($0.0)	($0.0)	$0.0	$0.0	$0.0	$19.5	$19.5	$0.0	($0.1)	$0.0	($0.0)	$0.0	($3.6)	($3.6)	$15.9
Met-Ed	$0.0	$0.0	$0.0	$1.4	($0.0)	$14.8	$16.3	$0.0	$0.0	$0.0	($0.1)	($0.0)	($3.2)	($3.3)	$13.0
OVEC	$0.0	$0.0	$0.0	$0.3	($0.0)	$0.0	$0.3	$0.0	$0.1	$0.0	$0.0	$0.0	($0.0)	$0.1	$0.4
PECO	$0.0	$0.1	$0.0	$0.0	($0.0)	$29.4	$29.5	$0.0	($0.1)	$0.0	($0.0)	($0.0)	($6.3)	($6.4)	$23.1
PENELEC	$0.0	($0.0)	$0.0	$0.2	($0.0)	$18.5	$18.6	$0.0	$0.0	$0.0	($0.1)	$0.1	($3.0)	($3.0)	$15.6
Pepco	$0.0	($0.0)	$0.0	($0.0)	$0.0	$23.3	$23.3	$0.0	$0.0	$0.0	$0.0	($0.0)	($4.7)	($4.7)	$18.6
PPL	$0.0	$0.0	$0.0	$0.2	($0.0)	$39.0	$39.1	($0.0)	($0.1)	$0.0	$0.0	($0.0)	($6.3)	($6.4)	$32.8
PSEG	($0.0)	$0.1	$0.0	$0.0	($0.0)	$38.4	$38.5	$0.0	($0.0)	$0.0	($0.0)	$0.0	($7.1)	($7.1)	$31.4
RECO	$0.0	$0.0	$0.0	$0.0	$0.0	$1.5	$1.5	$0.0	($0.3)	$0.0	$0.0	$0.0	($0.2)	($0.5)	$1.0
Total	$0.0	($1.9)	$0.0	$6.9	$0.2	$708.8	$714.0	($0.0)	($5.8)	$0.0	($0.2)	($0.8)	($123.9)	($130.7)	$583.3

Table 11-20 Day-ahead and total balancing congestion assigned by zone and special case logic (Dollars (Millions)): 2018

	Congestion Costs (Millions)														
	Day-Ahead							Balancing							
Control Zone	Load Bus Zero CLMP	CT Price Setting Logic	Closed Loop Interfaces	No Load Buses	Unclassified	Allocation	Total	Load Bus Zero CLMP	CT Price Setting Logic	Closed Loop Interfaces	No Load Buses	Unclassified	Allocation	Total	Grand Total
AECO	($0.0)	$0.1	$0.0	$0.3	$0.0	$16.4	$16.9	$0.0	($0.0)	$0.0	$0.0	($0.0)	($0.8)	($0.9)	$16.0
AEP	$0.3	$0.0	$0.0	$0.5	($0.0)	$234.1	$234.9	$0.0	($2.3)	$0.0	($0.0)	$0.2	($9.0)	($11.1)	$223.8
APS	$0.0	($0.3)	$0.0	$0.0	($0.0)	$80.2	$79.9	$0.0	($0.1)	$0.0	$0.0	($0.0)	($3.3)	($3.4)	$76.5
ATSI	$0.0	$0.5	$0.0	$0.2	$0.0	$102.2	$102.9	$0.0	($0.2)	$0.0	$0.0	($0.0)	($5.3)	($5.5)	$97.4
BGE	$0.0	($0.0)	$0.0	$0.0	$0.0	$48.1	$48.1	$0.0	($0.1)	$0.0	($0.0)	($0.0)	($2.1)	($2.2)	$45.9
ComEd	$1.4	($1.0)	$0.0	$7.4	($0.0)	$164.4	$172.3	($0.0)	($2.1)	$0.0	$0.2	$0.3	($7.5)	($9.0)	$163.2
DAY	$0.0	$0.1	$0.0	$0.0	$0.0	$27.8	$27.9	$0.0	($0.2)	$0.0	$0.0	$0.2	($1.4)	($1.4)	$26.5
DEOK	$0.2	$0.2	$0.0	$2.0	$0.0	$48.5	$50.8	$0.0	$0.0	$0.0	$0.0	$0.1	($2.2)	($2.1)	$48.7
DLCO	$0.0	$0.0	$0.0	$0.0	($0.0)	$17.3	$17.3	$0.0	($0.0)	$0.0	$0.0	$0.0	($1.1)	($1.1)	$16.2
Dominion	$0.0	$0.2	$0.0	$0.4	$0.0	$158.3	$158.9	$0.0	($0.0)	$0.0	($0.0)	($0.0)	($6.7)	($6.8)	$152.1
DPL	$0.1	$0.5	$0.0	$0.4	$0.0	$86.8	$87.8	$0.0	($0.1)	$0.0	$0.0	($0.1)	($2.1)	($2.3)	$85.5
EKPC	$0.0	($0.0)	$0.0	$0.0	$0.0	$24.0	$24.0	$0.0	$0.1	$0.0	$0.0	$0.1	($0.8)	($0.7)	$23.4
EXT	$0.0	$0.1	$0.0	$0.9	$0.4	$0.0	$1.4	$0.0	($4.0)	$0.0	($0.0)	($1.1)	$0.0	($5.2)	($3.8)
JCPL	$0.0	$0.7	$0.0	$0.0	$0.0	$38.5	$39.2	$0.0	($0.1)	$0.0	$0.0	($0.0)	($1.6)	($1.7)	$37.5
Met-Ed	$0.0	$0.2	$0.0	$3.1	$0.0	$28.3	$31.6	($0.0)	($0.0)	$0.0	($0.5)	$0.0	($1.1)	($1.6)	$29.9
OVEC	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	$0.0
PECO	$0.0	($0.6)	$0.0	$0.4	($0.0)	$62.6	$62.4	($0.0)	($0.1)	$0.0	$0.0	$0.0	($2.7)	($2.8)	$59.6
PENELEC	$0.3	$0.1	$0.0	$0.8	($0.0)	$30.8	$32.1	$0.0	$0.1	$0.0	$0.0	$0.1	($2.4)	($2.2)	$29.9
Pepco	$0.0	$0.1	$0.0	$0.0	$0.0	$44.5	$44.6	$0.0	$0.1	$0.0	$0.0	($0.0)	($2.1)	($1.9)	$42.6
PPL	$0.1	($2.0)	$0.0	$1.0	($0.0)	$70.8	$69.9	$0.0	$0.1	$0.0	$0.0	$0.0	($2.7)	($2.6)	$67.3
PSEG	$0.0	($0.2)	$0.0	$1.0	($0.0)	$72.6	$73.4	$0.0	($0.7)	$0.0	$0.0	($0.0)	($3.3)	($4.0)	$69.4
RECO	$0.0	($0.1)	$0.0	$0.0	$0.0	$2.6	$2.6	$0.0	($0.4)	$0.0	$0.0	$0.0	($0.1)	($0.5)	$2.0
Total	$2.4	($1.3)	$0.0	$18.5	$0.4	$1,358.8	$1,378.9	($0.0)	($10.2)	$0.0	($0.3)	($0.4)	($58.2)	($69.0)	$1,309.9

Monthly Congestion

Table 11-21 shows day-ahead, balancing and inadvertent congestion costs by month for 2018 and 2019.

Table 11-21 Monthly PJM congestion costs by market (Dollars (Millions)): 2018 and 2019

	Congestion Costs (Millions)							
	2018				2019			
	Day-Ahead	Balancing	Inadvertent Charges	Total	Day-Ahead	Balancing	Inadvertent Charges	Total
Jan	$517.7	$18.2	$0.0	$535.9	$120.7	($20.6)	$0.0	$100.2
Feb	$43.8	$1.4	($0.0)	$45.2	$36.4	($5.5)	$0.0	$30.9
Mar	$80.2	($0.3)	$0.0	$79.9	$45.0	($12.2)	$0.0	$32.8
Apr	$57.4	($3.3)	$0.0	$54.1	$25.4	($3.2)	$0.0	$22.2
May	$122.2	($16.0)	$0.0	$106.2	$47.5	($9.5)	($0.0)	$38.0
Jun	$95.2	($19.9)	$0.0	$75.3	$36.4	($6.5)	$0.0	$29.9
Jul	$70.8	($5.8)	$0.0	$65.0	$75.1	($6.5)	$0.0	$68.5
Aug	$69.2	($3.5)	$0.0	$65.7	$40.2	($5.0)	($0.0)	$35.2
Sep	$95.2	($6.3)	($0.0)	$88.9	$84.6	($23.4)	($0.0)	$61.2
Oct	$95.0	($11.8)	($0.0)	$83.3	$72.5	($13.5)	($0.0)	$59.0
Nov	$69.1	($14.2)	($0.0)	$54.9	$67.0	($16.2)	($0.0)	$50.8
Dec	$63.0	($7.6)	$0.0	$55.5	$63.0	($8.6)	$0.0	$54.5
Total	$1,378.9	($69.0)	$0.0	$1,309.9	$714.0	($130.7)	$0.0	$583.3

Figure 11-3 shows PJM monthly total congestion cost for 2008 through 2019.

Figure 11-3 PJM monthly total congestion cost (Dollars (Millions)): 2008 through 2019

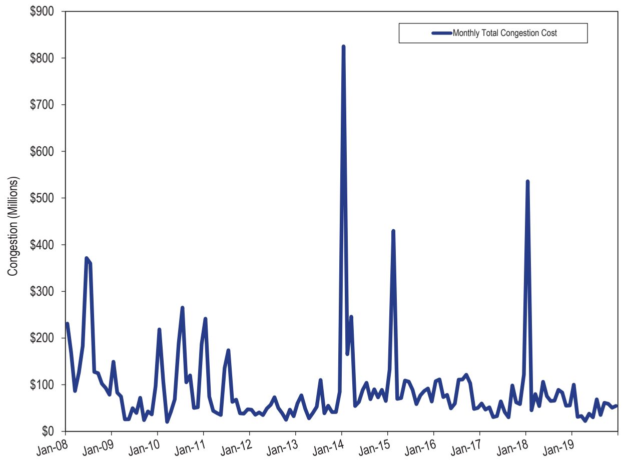


Table 11-22 Monthly PJM congestion charges by virtual transaction type and by market (Dollars (Millions)): 2018 and 2019

		Congestion Charges (Millions)									
		DEC			INC			Up to Congestion			
Year		Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Grand Total
2018	Jan	$4.1	($6.5)	($2.4)	$4.5	($8.1)	($3.6)	($40.8)	$29.5	($11.3)	($17.2)
	Feb	$1.8	$0.4	$2.2	$1.2	($0.8)	$0.4	($0.5)	$1.3	$0.9	$3.5
	Mar	$0.9	($2.8)	($1.9)	$1.4	($3.2)	($1.8)	($5.1)	$2.0	($3.1)	($6.8)
	Apr	$0.4	($0.7)	($0.4)	$1.8	($1.4)	$0.4	($1.0)	$1.0	($0.1)	($0.1)
	May	$1.5	($4.1)	($2.6)	$4.5	($6.9)	($2.5)	$1.7	($10.6)	($8.9)	($14.0)
	Jun	$3.6	($2.4)	$1.1	$3.0	($3.7)	($0.7)	$5.6	($4.4)	$1.2	$1.6
	Jul	$1.3	($2.4)	($1.1)	$0.8	($0.7)	$0.1	$2.3	($2.8)	($0.5)	($1.5)
	Aug	$2.4	($3.1)	($0.6)	$0.2	($0.2)	$0.1	$3.4	($2.8)	$0.7	$0.1
	Sep	$2.1	($1.6)	$0.5	$1.4	($1.5)	($0.1)	$4.8	($6.9)	($2.1)	($1.7)
	Oct	$1.5	($2.6)	($1.1)	$2.4	($3.2)	($0.8)	$2.5	($3.3)	($0.8)	($2.7)
	Nov	$2.1	($3.3)	($1.2)	$0.4	($2.3)	($1.9)	$4.3	($7.5)	($3.2)	($6.3)
	Dec	$3.7	($3.5)	$0.1	($1.2)	$2.0	$0.8	$3.4	($3.5)	($0.1)	$0.8
	Total	$25.3	($32.7)	($7.4)	$20.5	($30.0)	($9.5)	($19.4)	($7.9)	($27.4)	($44.3)
2019	Jan	$3.5	($4.0)	($0.6)	$1.2	($3.6)	($2.4)	$5.1	($4.6)	$0.5	($2.5)
	Feb	$0.8	($1.4)	($0.6)	$1.0	($1.1)	($0.1)	$2.0	($3.2)	($1.2)	($1.8)
	Mar	$0.7	($1.5)	($0.7)	$1.4	($2.3)	($0.8)	$4.0	($8.4)	($4.4)	($6.0)
	Apr	$0.6	($0.1)	$0.5	$1.1	($1.4)	($0.3)	$2.8	($2.3)	$0.5	$0.7
	May	$0.4	($0.0)	$0.4	$2.4	($3.0)	($0.6)	$5.4	($6.3)	($0.9)	($1.2)
	Jun	$0.8	($0.6)	$0.2	$1.2	($1.3)	($0.2)	$3.3	($5.0)	($1.7)	($1.7)
	Jul	$2.2	($0.7)	$1.5	$0.4	($2.0)	($1.6)	$4.1	($6.8)	($2.6)	($2.8)
	Aug	$1.1	($0.9)	$0.2	$0.1	($0.3)	($0.2)	$2.9	($4.0)	($1.1)	($1.1)
	Sep	$1.6	($2.0)	($0.3)	$3.0	($5.2)	($2.3)	$7.7	($17.9)	($10.3)	($12.9)
	Oct	$1.2	($2.3)	($1.1)	$3.0	($5.0)	($2.0)	$6.3	($10.9)	($4.6)	($7.7)
	Nov	$0.9	($3.1)	($2.1)	$0.6	($2.5)	($2.0)	$6.5	($5.9)	$0.5	($3.5)
	Dec	$1.1	($0.8)	$0.3	$0.3	($0.4)	($0.1)	$4.0	($6.1)	($2.1)	($1.9)
	Total	$14.8	($17.3)	($2.4)	$15.5	($28.2)	($12.7)	$54.2	($81.6)	($27.4)	($42.5)

Table 11-22 shows monthly total congestion credits and charges for each virtual transaction type in 2018 and 2019. Virtual transaction congestion charges, when positive, are the total congestion charges to the virtual transactions and when negative, are the total congestion credits to the virtual transactions. The negative totals in Table 11-22 show that virtuals were paid, in net, congestion credits in 2019 and in 2018. In 2019, 64.4 percent of the total credits to virtuals went to UTCs, compared to 61.8 percent in 2018.

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. Thus, if two facilities are constrained during an hour, the result is two congestion event hours and one constrained hour. 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 2019, there were 103,140 day-ahead, congestion event hours compared to 132,598 day-ahead congestion event hours in 2018. Of the day-ahead congestion event hours in 2019, only 9,507 (9.2 percent) were also constrained in the Real-Time Energy Market (Table 11-25). In 2019, there were 21,122 real-time, congestion event hours compared to 22,910 real-time, congestion event hours in 2018. Of the real-time congestion event hours in 2019, 9,770 (46.3 percent) were also constrained in the Day-Ahead Energy Market (Table 11-26).

The top five constraints by congestion costs contributed $177.8 million, or 30.5 percent, of the total PJM congestion costs in 2019. The top five constraints were the Conastone - Peach Bottom Line, the Conastone Flow Circuit Breaker the Tanners Creek - Miami Fort Flowgate, the Coolspring - Milford Line, and the Graceton – Safe Harbor Line.

The change in the location of the top 10 constraints between 2018 and 2019 was primarily a result of the high gas prices in January 2018 (Figure 11-4).

Congestion by Facility Type and Voltage

Day-ahead, congestion event hours decreased on all types of facilities largely as a result of the decrease in cleared up to congestion (UTC) transactions from January and February, 2018, to January and February, 2019.[23]

Real-time, congestion event hours decreased on transformers, and lines and increased on interfaces and flowgates in 2019.

Day-ahead congestion costs decreased on all types of facilities in 2019 compared to 2018. Day-ahead negative implicit injection credits decreased on all types of facilities in 2019 compared to 2018.

Balancing congestion costs decreased on all types of facilities except lines in 2019 compared to 2018 (Table 11-24). Table 11-23 provides congestion event hour subtotals and congestion cost subtotals comparing 2019 results by facility type: line, transformer, interface, flowgate and unclassified facilities.[24 25]

Table 11-23 Congestion summary (By facility type): 2019

	Congestion Costs (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	Grand Total	Day-Ahead	Real-Time
Flowgate	($25.3)	($101.1)	$8.5	$84.4	$4.0	$8.6	($55.3)	($59.9)	$24.5	11,396	6,219
Interface	$9.2	($42.4)	$0.8	$52.4	$1.4	$7.3	$0.8	($5.0)	$47.4	1,523	714
Line	$203.9	($182.3)	$36.3	$422.5	$3.0	$22.5	($21.0)	($40.5)	$382.1	65,750	10,958
Transformer	$31.3	($58.7)	$7.8	$97.8	($5.5)	$8.7	($4.2)	($18.4)	$79.4	19,411	1,416
Other	$26.8	($27.6)	$2.2	$56.6	$0.6	$3.9	($2.8)	($6.1)	$50.5	5,060	1,815
Unclassified	$0.1	($0.1)	$0.0	$0.2	$0.1	$0.2	($0.8)	($0.8)	($0.6)	NA	NA
Total	$246.0	($412.3)	$55.7	$714.0	$3.7	$51.1	($83.3)	($130.7)	$583.3	103,140	21,122

Table 11-24 Congestion summary (By facility type): 2018

	Congestion Costs (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	Grand Total	Day-Ahead	Real-Time
Flowgate	($56.0)	($338.9)	($36.4)	$246.4	$2.0	$7.3	($2.9)	($8.2)	$238.2	19,816	5,585
Interface	$65.0	($163.6)	($13.9)	$214.6	$15.2	$22.8	$11.1	$3.6	$218.2	2,316	397
Line	$257.2	($387.3)	$28.1	$672.5	($10.1)	$29.3	($25.6)	($65.0)	$607.5	78,969	14,310
Transformer	$64.4	($142.9)	$1.8	$209.2	$0.4	$2.9	$4.0	$1.5	$210.6	28,288	1,568
Other	$18.5	($15.8)	$1.4	$35.8	$3.0	($1.0)	($4.4)	($0.4)	$35.4	3,209	1,050
Unclassified	$0.2	($0.1)	$0.1	$0.4	$1.0	$0.7	($0.7)	($0.4)	$0.0	NA	NA
Total	$349.3	($1,048.6)	($18.9)	$1,378.9	$11.5	$62.0	($18.5)	($69.0)	$1,309.9	132,598	22,910

23 162 FERC ¶ 61,139.

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

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

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 2019, there were 103,140 congestion event hours in the Day-Ahead Energy Market. Of those day-ahead congestion event hours, only 9,507 (9.2 percent) were also constrained in the Real-Time Energy Market. In 2018, of the 132,598 day-ahead congestion event hours, only 10,093 (7.6 percent) were binding in the Real-Time Energy Market.[26]

Among the hours for which a facility was constrained in the Real-Time Energy Market, the number of hours during which the facility was also constrained in the Day-Ahead Energy Market are presented in Table 11-26. In 2019, of the 21,122 congestion event hours in the Real-Time Energy Market, 9,770 (46.3 percent) were also constrained in the Day-Ahead Energy Market. In 2018, of the 22,910 real-time congestion event hours, 10,184 (44.5 percent) were also in the Day-Ahead Energy Market.

Table 11-25 Congestion event hours (day-ahead against real-time): 2018 and 2019

	Congestion Event Hours					
	2018			2019		
Type	Day-Ahead Constrained	Corresponding Real-Time Constrained	Percent	Day-Ahead Constrained	Corresponding Real-Time Constrained	Percent
Interface	2,316	239	10.3%	1,523	500	32.8%
Transformer	28,288	762	2.7%	19,411	773	4.0%
Flowgate	19,816	2,017	10.2%	11,396	1,664	14.6%
Line	78,969	6,518	8.3%	65,750	5,451	8.3%
Other	3,209	557	17.4%	5,060	1,119	22.1%
Total	132,598	10,093	7.6%	103,140	9,507	9.2%

Table 11-26 Congestion event hours (real-time against day-ahead): 2018 and 2019

	Congestion Event Hours					
	2018			2019		
Type	Real-Time Constrained	Corresponding Day-Ahead Constrained	Percent	Real-Time Constrained	Corresponding Day-Ahead Constrained	Percent
Interface	397	264	66.5%	714	514	72.0%
Transformer	1,568	757	48.3%	1,416	781	55.2%
Flowgate	5,585	2,019	36.2%	6,219	1,681	27.0%
Line	14,310	6,575	45.9%	10,958	5,654	51.6%
Other	1,050	569	54.2%	1,815	1,140	62.8%
Total	22,910	10,184	44.5%	21,122	9,770	46.3%

26 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 11-27 shows congestion costs by facility voltage class for 2019. Congestion costs in 2019 decreased for all facilities compared to 2018.

Table 11-27 Congestion summary (By facility voltage): 2019

	Congestion Costs (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	Grand Total	Day-Ahead	Real-Time
765	($0.0)	($1.9)	$1.3	$3.2	($0.1)	$0.2	($0.2)	($0.5)	$2.6	249	46
500	$134.1	($57.0)	$1.6	$192.7	$4.1	$9.7	($0.8)	($6.4)	$186.4	7,527	4,618
345	($4.5)	($80.4)	$14.2	$90.2	$0.8	$4.1	($17.3)	($20.6)	$69.6	11,801	1,438
230	$63.1	($110.1)	$6.2	$179.3	($0.8)	$13.6	($5.8)	($20.2)	$159.2	16,176	4,495
212	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	117	0
161	($2.2)	($9.9)	($0.2)	$7.5	$0.1	$0.5	($2.9)	($3.4)	$4.2	1,620	598
138	$24.3	($123.4)	$27.3	$175.1	$0.2	$12.8	($54.0)	($66.6)	$108.5	33,362	7,539
115	$14.5	($19.2)	$0.8	$34.5	($0.8)	$6.5	($1.0)	($8.3)	$26.2	8,944	1,520
69	$15.8	($10.5)	$4.4	$30.7	$0.1	$3.5	($0.5)	($3.9)	$26.8	21,095	868
35	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	17	0
34	$0.4	$0.1	$0.0	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	1,338	0
13	$0.1	$0.0	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	561	0
12	$0.1	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	333	0
Unclassified	$0.1	($0.1)	$0.0	$0.2	$0.1	$0.2	($0.8)	($0.8)	($0.6)	NA	NA
Total	$246.0	($412.3)	$55.7	$714.0	$3.7	$51.1	($83.3)	($130.7)	$583.3	103,140	21,122

Table 11-28 Congestion summary (By facility voltage): 2018

	Congestion Costs (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	Grand Total	Day-Ahead	Real-Time
765	$0.5	($1.6)	$0.2	$2.3	$0.7	$0.3	($0.0)	$0.4	$2.6	106	21
500	$89.2	($183.2)	($13.6)	$258.7	$16.6	$21.2	$11.5	$6.9	$265.6	3,951	994
345	$12.2	($271.6)	$1.1	$284.9	$0.3	($0.9)	($12.6)	($11.5)	$273.4	20,762	2,785
230	$182.3	($70.1)	$4.5	$256.9	($1.2)	$7.7	($1.2)	($10.1)	$246.8	22,259	5,686
212	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	43	0
161	$1.4	($4.4)	($0.5)	$5.3	$0.3	($0.4)	$0.5	$1.1	$6.4	356	85
138	($2.2)	($455.0)	($14.0)	$438.8	$2.8	$26.3	($10.0)	($33.5)	$405.3	50,411	9,324
115	$7.3	($71.7)	($3.1)	$75.9	($0.7)	$3.7	$0.4	($4.0)	$71.9	14,078	1,996
69	$58.2	$9.6	$6.1	$54.7	($8.2)	$3.4	($6.4)	($17.9)	$36.7	17,281	1,958
34	$0.1	$0.0	$0.3	$0.4	$0.0	$0.1	$0.0	($0.0)	$0.4	2,127	61
18	($0.0)	($0.3)	$0.1	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	309	0
13.2	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	55	0
13	$0.0	($0.1)	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	291	0
12	$0.0	($0.1)	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	569	0
Unclassified	$0.2	($0.1)	$0.1	$0.4	$1.0	$0.7	($0.7)	($0.4)	$0.0	NA	NA
Total	$349.3	($1,048.6)	($18.9)	$1,378.9	$11.5	$62.0	($18.5)	($69.0)	$1,309.9	132,598	22,910

Constraint Frequency

Table 11-29 lists the constraints for 2018 and 2019 that were most frequently binding and Table 11-30 shows the constraints which experienced the largest change in congestion event hours from 2018 to 2019. In Table 11-29, constraints are presented in descending order of total day-ahead event hours and real-time event hours for 2019. 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 2018 to 2019.

Table 11-29 Top 25 constraints with frequent occurrence: 2018 and 2019

			Event Hours						Percent of Annual Hours					
			Day-Ahead			Real-Time			Day-Ahead			Real-Time		
No.	Constraint	Type	2018	2019	Change	2018	2019	Change	2018	2019	Change	2018	2019	Change
1	Conastone - Peach Bottom	Line	1,100	4,999	3,899	422	3,250	2,828	13%	57%	45%	5%	37%	32%
2	Easton - Emuni	Line	3,831	4,833	1,002	2	9	7	44%	55%	11%	0%	0%	0%
3	Monroe - Vineland	Line	2,858	4,560	1,702	500	108	(392)	33%	52%	19%	6%	1%	(4%)
4	Berwick - Koonsville	Line	1,425	3,025	1,600	6	33	27	16%	35%	18%	0%	0%	0%
5	Face Rock	Other	921	2,552	1,631	73	484	411	11%	29%	19%	1%	6%	5%
6	Marblehead	Flowgate	411	1,760	1,349	484	1,103	619	5%	20%	15%	6%	13%	7%
7	Graceton - Safe Harbor	Line	3,361	1,631	(1,730)	2,046	563	(1,483)	38%	19%	(20%)	23%	6%	(17%)
8	East Towanda - Hillside	Line	616	1,161	545	216	781	565	7%	13%	6%	2%	9%	6%
9	Gardners - Texas Eastern	Line	2,911	1,787	(1,124)	439	131	(308)	33%	20%	(13%)	5%	1%	(4%)
10	Roxana - Praxair	Flowgate	1,132	1,274	142	481	603	122	13%	15%	2%	5%	7%	1%
11	DoeX530	Transformer	0	1,853	1,853	0	0	0	0%	21%	21%	0%	0%	0%
12	PA Central	Interface	0	872	872	0	665	665	0%	10%	10%	0%	8%	8%
13	Marquis - Dept of Energy	Line	952	1,494	542	0	0	0	11%	17%	6%	0%	0%	0%
14	Mountain	Transformer	1,035	1,390	355	0	0	0	12%	16%	4%	0%	0%	0%
15	Lenox - North Meshoppen	Line	74	569	495	110	757	647	1%	6%	6%	1%	9%	7%
16	Nottingham	Other	1,157	809	(348)	390	468	78	13%	9%	(4%)	4%	5%	1%
17	New Carlisle - Olive	Line	356	1,080	724	0	0	0	4%	12%	8%	0%	0%	0%
18	Bosserman - New Carlisle	Line	52	1,009	957	21	4	(17)	1%	12%	11%	0%	0%	(0%)
19	Bagley - Graceton	Line	595	826	231	214	126	(88)	7%	9%	3%	2%	1%	(1%)
20	Butler - Sherman	Line	494	947	453	0	0	0	6%	11%	5%	0%	0%	0%
21	Powerton - Toulon	Line	156	845	689	3	78	75	2%	10%	8%	0%	1%	1%
22	Vermilion - Tilton	Flowgate	293	912	619	0	0	0	3%	10%	7%	0%	0%	0%
23	Quad Cities	Transformer	2,614	891	(1,723)	0	0	0	30%	10%	(20%)	0%	0%	0%
24	Preston - Tanyard	Line	918	889	(29)	11	1	(10)	10%	10%	(0%)	0%	0%	(0%)
25	Boonetown - South Reading	Line	0	553	553	0	333	333	0%	6%	6%	0%	4%	4%

Table 11-30 Top 25 constraints with largest year to year change in occurrence: 2018 and 2019

			Event Hours						Percent of Annual Hours					
			Day-Ahead			Real-Time			Day-Ahead			Real-Time		
No.	Constraint	Type	2018	2019	Change	2018	2019	Change	2018	2019	Change	2018	2019	Change
1	Conastone - Peach Bottom	Line	1,100	4,999	3,899	422	3,250	2,828	13%	57%	45%	5%	37%	32%
2	Graceton - Safe Harbor	Line	3,361	1,631	(1,730)	2,046	563	(1,483)	38%	19%	(20%)	23%	6%	(17%)
3	Face Rock	Other	921	2,552	1,631	73	484	411	11%	29%	19%	1%	6%	5%
4	Marblehead	Flowgate	411	1,760	1,349	484	1,103	619	5%	20%	15%	6%	13%	7%
5	DoeX530	Transformer	0	1,853	1,853	0	0	0	0%	21%	21%	0%	0%	0%
6	Quad Cities	Transformer	2,614	891	(1,723)	0	0	0	30%	10%	(20%)	0%	0%	0%
7	Newton	Flowgate	1,283	16	(1,267)	426	13	(413)	15%	0%	(14%)	5%	0%	(5%)
8	Lakeview - Greenfield	Line	1,356	36	(1,320)	352	13	(339)	15%	0%	(15%)	4%	0%	(4%)
9	Berwick - Koonsville	Line	1,425	3,025	1,600	6	33	27	16%	35%	18%	0%	0%	0%
10	North Salisbury - Rockawalkin	Line	1,610	22	(1,588)	0	0	0	18%	0%	(18%)	0%	0%	0%
11	PA Central	Interface	0	872	872	0	665	665	0%	10%	10%	0%	8%	8%
12	Brokaw - Leroy	Flowgate	1,232	0	(1,232)	261	0	(261)	14%	0%	(14%)	3%	0%	(3%)
13	Gardners - Texas Eastern	Line	2,911	1,787	(1,124)	439	131	(308)	33%	20%	(13%)	5%	1%	(4%)
14	Emilie - Falls	Line	1,593	427	(1,166)	329	95	(234)	18%	5%	(13%)	4%	1%	(3%)
15	Olive	Transformer	1,352	119	(1,233)	153	0	(153)	15%	1%	(14%)	2%	0%	(2%)
16	Delaware - Hogan	Line	1,227	65	(1,162)	235	29	(206)	14%	1%	(13%)	3%	0%	(2%)
17	Quad Cities - Cordova	Flowgate	1,522	181	(1,341)	0	0	0	17%	2%	(15%)	0%	0%	0%
18	Monroe - Vineland	Line	2,858	4,560	1,702	500	108	(392)	33%	52%	19%	6%	1%	(4%)
19	Flint Lake - Luchtman Road	Flowgate	890	0	(890)	365	0	(365)	10%	0%	(10%)	4%	0%	(4%)
20	Zion	Line	1,193	0	(1,193)	0	0	0	14%	0%	(14%)	0%	0%	0%
21	Cedar Grove Sub - Roseland	Line	1,368	246	(1,122)	64	16	(48)	16%	3%	(13%)	1%	0%	(1%)
22	Lenox - North Meshoppen	Line	74	569	495	110	757	647	1%	6%	6%	1%	9%	7%
23	East Towanda - Hillside	Line	616	1,161	545	216	781	565	7%	13%	6%	2%	9%	6%
24	Waukegan	Transformer	1,083	19	(1,064)	0	0	0	12%	0%	(12%)	0%	0%	0%
25	Fargo	Flowgate	1,308	503	(805)	510	290	(220)	15%	6%	(9%)	6%	3%	(3%)

Constraint Costs

Table 11-31 and Table 11-32 show the top constraints affecting congestion costs by facility for 2019 and 2018. The Conastone - Peach Bottom Line was the largest contributor to congestion costs in 2019, with $111.0 million in total congestion costs and 19.0 percent of the total PJM congestion costs in 2019.

Table 11-31 Top 25 constraints affecting PJM congestion costs (By facility): 2019[27]

				Congestion Costs (Millions)									Percent of Total PJM Congestion Costs
				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	Grand Total	2019
1	Conastone - Peach Bottom	Line	500	$108.1	($2.5)	($0.1)	$110.5	$3.6	$6.0	$2.8	$0.4	$111.0	19.0%
2	Conastone	Other	500	$16.4	($0.6)	$0.4	$17.3	($0.9)	($3.0)	($0.8)	$1.3	$18.6	3.2%
3	Tanners Creek - Miami Fort	Flowgate	MISO	($6.8)	($24.2)	$0.3	$17.6	$0.0	$0.0	$0.0	$0.0	$17.6	3.0%
4	Coolspring - Milford	Line	DPL	($0.6)	($16.2)	$0.2	$15.9	($0.1)	($0.6)	($0.7)	($0.2)	$15.7	2.7%
5	Graceton - Safe Harbor	Line	BGE	$15.4	$0.3	$0.1	$15.2	$0.5	$1.2	$0.4	($0.3)	$14.9	2.6%
6	AP South	Interface	500	$9.1	($5.7)	($0.2)	$14.6	$0.2	$0.3	$0.1	($0.1)	$14.5	2.5%
7	Wescosville	Transformer	PPL	$9.3	($7.5)	($0.0)	$16.7	($0.1)	$2.0	($0.5)	($2.6)	$14.1	2.4%
8	Siegfried	Transformer	PPL	$6.8	($13.7)	$0.4	$20.9	($1.6)	$5.2	($0.1)	($6.8)	$14.1	2.4%
9	Face Rock	Other	PPL	$0.5	($13.4)	$0.8	$14.6	$1.2	$2.6	$0.1	($1.3)	$13.4	2.3%
10	Roxana - Praxair	Flowgate	MISO	($1.2)	($4.1)	$2.9	$5.7	$3.3	$4.2	($17.6)	($18.5)	($12.8)	(2.2%)
11	East	Interface	500	($6.0)	($20.4)	$0.1	$14.6	$0.9	$4.0	$0.9	($2.2)	$12.4	2.1%
12	Bagley - Graceton	Line	BGE	$8.0	($2.3)	$0.2	$10.5	$0.3	$0.5	$0.3	$0.1	$10.5	1.8%
13	Conastone - Northwest	Line	BGE	$7.0	($3.0)	$0.4	$10.4	$0.0	($0.0)	($0.3)	($0.3)	$10.2	1.7%
14	Cedar Creek - Red Lion	Line	DPL	$1.6	($7.9)	$0.9	$10.5	($0.8)	($0.6)	($0.7)	($1.0)	$9.5	1.6%
15	Nottingham	Other	PECO	$12.3	$2.7	($0.1)	$9.5	$0.0	$0.0	$0.0	$0.0	$9.5	1.6%
16	Palisades - Argenta	Flowgate	MISO	($0.4)	($9.8)	$0.5	$9.9	$0.0	($0.1)	($0.9)	($0.8)	$9.1	1.6%
17	PA Central	Interface	500	$1.2	($9.7)	$0.6	$11.5	$0.3	$2.9	($0.1)	($2.7)	$8.8	1.5%
18	Pleasant View - Ashburn	Line	Dominion	$6.9	($1.8)	$0.3	$9.0	$0.8	$1.2	($0.1)	($0.6)	$8.4	1.4%
19	CPL - DOM	Interface	500	$3.5	($4.2)	$0.1	$7.8	$0.0	$0.0	$0.0	$0.0	$7.8	1.3%
20	Tanners Creek - Miami Fort	Line	AEP	($0.0)	($0.1)	$0.0	$0.1	($0.1)	$1.4	($4.9)	($6.3)	($6.3)	(1.1%)
21	Gardners - Texas Eastern	Line	Met-Ed	($0.5)	($8.1)	$0.2	$7.9	($1.0)	$0.2	($0.4)	($1.6)	$6.3	1.1%
22	Greentown	Flowgate	MISO	($0.2)	($1.7)	($0.1)	$1.5	($0.6)	$0.9	($6.2)	($7.7)	($6.1)	(1.1%)
23	Harwood - Susquehanna	Line	PPL	$0.3	($5.5)	$0.2	$6.1	$0.0	$0.0	$0.0	$0.0	$6.1	1.0%
24	Smithton - Yukon	Line	APS	($3.6)	($9.2)	$0.4	$6.1	$0.9	$0.2	($0.7)	($0.1)	$6.0	1.0%
25	East Towanda - Hillside	Line	PENELEC	($1.5)	($7.3)	($0.1)	$5.7	$0.1	$0.2	($0.0)	($0.1)	$5.5	1.0%
	Top 25 Total			$185.6	($175.9)	$8.5	$370.1	$6.9	$28.8	($29.5)	($51.3)	$318.8	54.6%
	All Other Constraints			$60.4	($236.4)	$47.2	$343.9	($3.2)	$22.3	($53.8)	($79.4)	$264.6	45.4%
	Total			$246.0	($412.3)	$55.7	$714.0	$3.7	$51.1	($83.3)	($130.7)	$583.3	100.0%

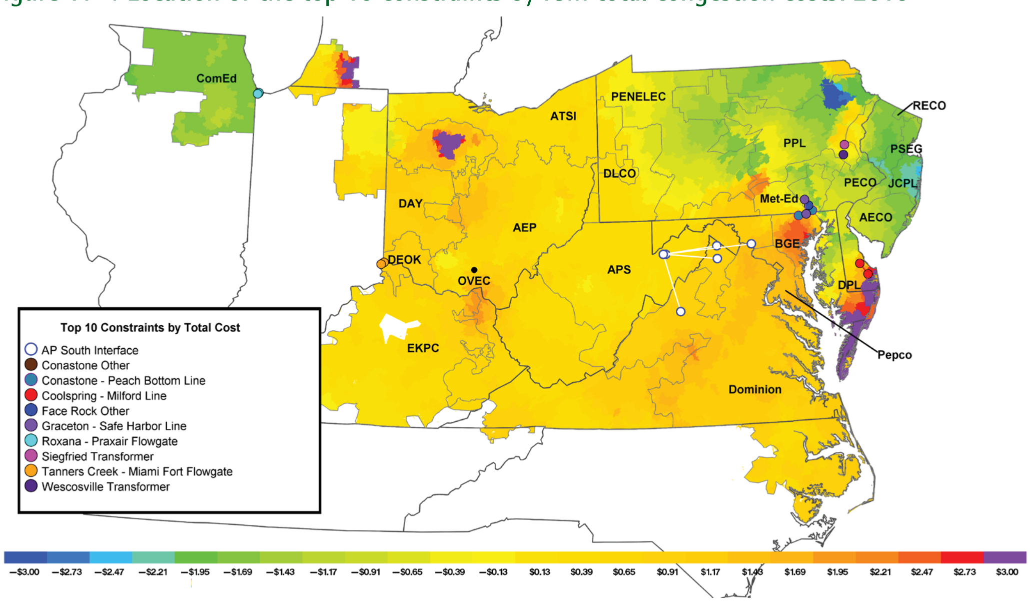
27 All flowgates are mapped to MISO as Location if they are flowgates coordinated by both PJM and MISO regardless of the location of the flowgates.

Table 11-32 Top 25 constraints affecting PJM congestion costs (By facility): 2018[28]

				Congestion Costs (Millions)									Percent of Total PJM Congestion Costs
				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	Grand Total	2018
1	AEP - DOM	Interface	500	$55.6	($66.9)	($5.3)	$117.2	$13.4	$18.7	$9.0	$3.8	$121.0	9.2%
2	Cloverdale	Transformer	AEP	$46.0	($40.9)	($0.8)	$86.1	($1.6)	$0.6	$3.6	$1.4	$87.5	6.7%
3	Tanners Creek - Miami Fort	Flowgate	MISO	($20.8)	($94.1)	($2.9)	$70.4	$0.0	$0.0	$0.0	$0.0	$70.4	5.4%
4	Graceton - Safe Harbor	Line	BGE	$95.3	$31.1	$2.4	$66.6	$0.6	$4.6	($1.6)	($5.6)	$61.0	4.7%
5	5004/5005 Interface	Interface	500	($15.4)	($54.4)	($4.4)	$34.6	$0.8	$1.7	$2.1	$1.1	$35.7	2.7%
6	Batesville - Hubble	Flowgate	MISO	($13.1)	($55.9)	($10.3)	$32.5	($0.6)	($2.2)	$0.3	$2.0	$34.5	2.6%
7	Conastone - Peach Bottom	Line	500	$29.8	$0.7	($0.2)	$28.9	$1.6	$0.8	($0.0)	$0.7	$29.6	2.3%
8	Pleasant View - Ashburn	Line	Dominion	$17.8	($8.4)	($0.9)	$25.4	$1.1	$1.1	$0.6	$0.6	$25.9	2.0%
9	Lakeview - Greenfield	Line	ATSI	($20.4)	($57.3)	($1.5)	$35.3	($1.4)	$8.9	$0.3	($10.0)	$25.3	1.9%
10	Bedington - Black Oak	Interface	500	$10.2	($14.0)	($1.4)	$22.7	$0.6	$0.7	$0.6	$0.5	$23.2	1.8%
11	Gardners - Texas Eastern	Line	Met-Ed	($5.1)	($26.6)	($0.2)	$21.3	($0.3)	$0.1	$1.4	$1.0	$22.3	1.7%
12	Wescosville	Transformer	PPL	$3.2	($17.5)	($0.6)	$20.1	$0.4	$0.1	$0.9	$1.2	$21.3	1.6%
13	North Salisbury - Rockawalkin	Line	DPL	$26.4	$7.3	$1.7	$20.8	$0.0	$0.0	$0.0	$0.0	$20.8	1.6%
14	AP South	Interface	500	$14.1	($8.3)	($1.6)	$20.8	$0.1	$0.1	($0.0)	($0.0)	$20.8	1.6%
15	Capitol Hill - Chemical	Line	AEP	$12.3	($5.0)	$0.5	$17.9	$0.8	($0.8)	($0.1)	$1.5	$19.4	1.5%
16	Nottingham	Other	PECO	$20.5	$2.6	$0.7	$18.7	$0.0	$0.0	$0.0	$0.0	$18.7	1.4%
17	Maple - Jackson	Line	ATSI	($13.1)	($28.6)	$2.1	$17.7	$0.4	$0.8	($0.9)	($1.3)	$16.4	1.3%
18	Person - Sedge Hill	Line	Dominion	$16.9	$2.3	$1.7	$16.3	($0.2)	($0.9)	($1.0)	($0.4)	$15.9	1.2%
19	Cedar Creek - Red Lion	Line	DPL	$2.4	($12.1)	$0.8	$15.3	($0.8)	($1.8)	($0.6)	$0.4	$15.7	1.2%
20	Conastone - Northwest	Line	BGE	$14.6	($0.9)	($0.6)	$15.0	($1.1)	($0.4)	$0.8	$0.0	$15.0	1.1%
21	Northport - Albion	Flowgate	MISO	($2.3)	($18.4)	($3.8)	$12.3	($0.2)	($1.1)	$1.3	$2.2	$14.5	1.1%
22	Brokaw - Leroy	Flowgate	MISO	$0.8	($12.3)	($4.4)	$8.6	$0.5	($1.3)	$3.0	$4.8	$13.5	1.0%
23	Krendale - Shanorma	Line	APS	($8.4)	($19.9)	$1.3	$12.8	$0.0	$0.0	$0.0	$0.0	$12.8	1.0%
24	Emilie - Falls	Line	PECO	$3.4	($7.6)	$0.4	$11.4	$0.2	$0.4	$0.4	$0.2	$11.6	0.9%
25	North Salisbury - Rockawalkin	Line	DPL	$0.0	$0.0	$0.0	$0.0	($4.6)	$4.2	($2.8)	($11.5)	($11.5)	(0.9%)
	Top 25 Total			$270.8	($505.1)	($27.3)	$748.6	$9.8	$34.5	$17.3	($7.4)	$741.2	56.6%
	All Other Constraints			$78.4	($543.5)	$8.4	$630.3	$1.7	$27.5	($35.9)	($61.6)	$568.7	43.4%
	Total			$349.3	($1,048.6)	($18.9)	$1,378.9	$11.5	$62.0	($18.5)	($69.0)	$1,309.9	100.0%

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 2019. Three of the top 10 constraints are located in the BGE Zone: the Conastone - Peach Bottom Line, the Conastone Flow Circuit Breaker, and the Graceton - Safe Harbor Line.

Figure 11-4 Location of the top 10 constraints by PJM total congestion costs: 2019



28 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 11-5 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 2019.

Figure 11-5 Location of top 10 constraints by balancing congestion costs: 2019

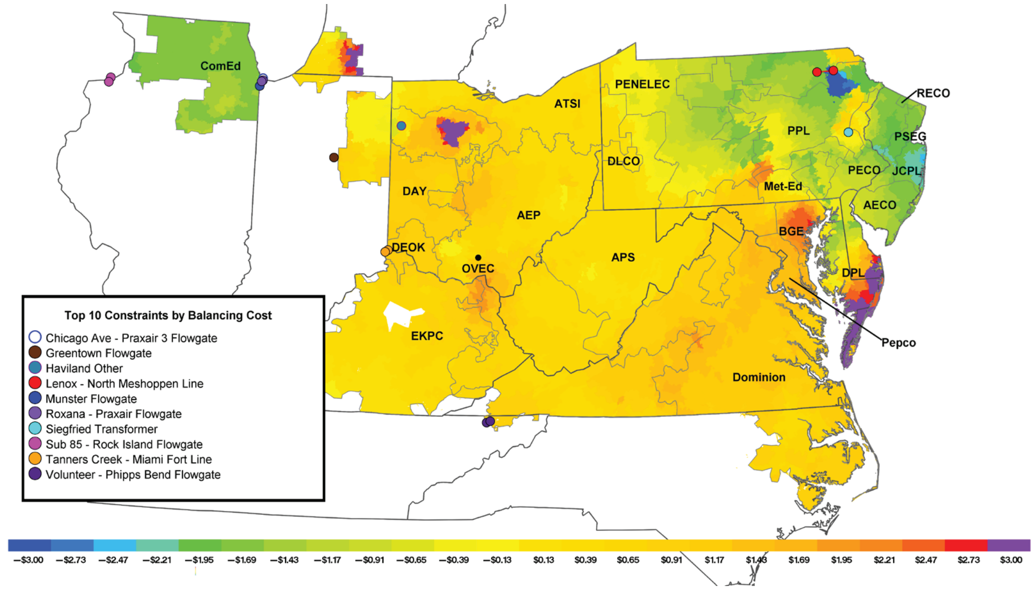
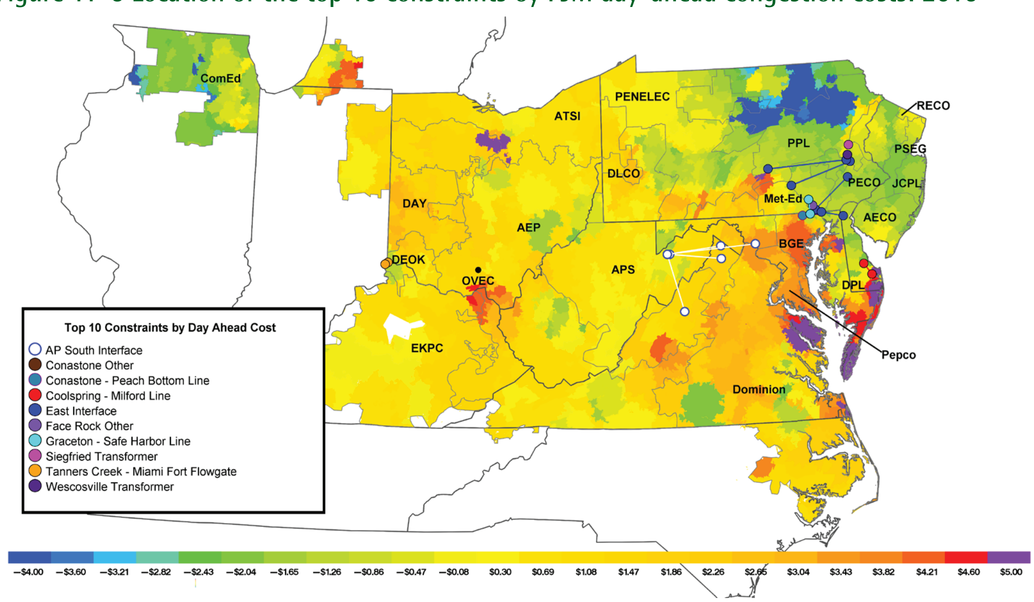


Figure 11-6 shows the locations of the top 10 constraints by day-ahead congestion costs on a contour map of the day-ahead, load-weighted average CLMP in 2019.

Figure 11-6 Location of the top 10 constraints by PJM day-ahead congestion costs: 2019

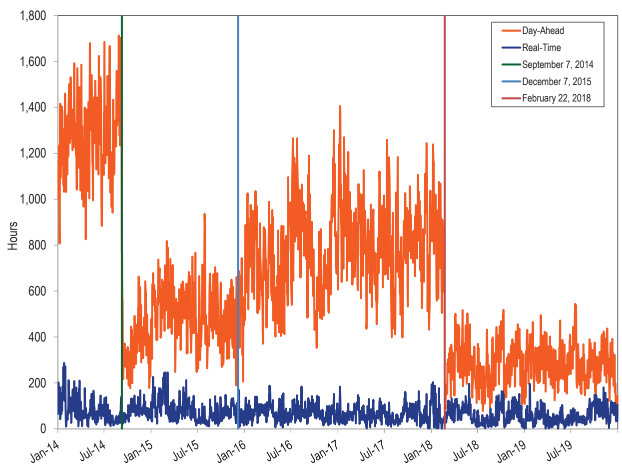


Congestion Event Summary: Impact of Changes in UTC Volumes

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. In 2019, the average hourly cleared UTC MW increased, compared to 2018. Day-ahead congestion event hours decreased by 22.2 percent from 132,598 congestion event hours in 2018 to 103,140 congestion event hours in 2019 (Table 11-25). The majority (95.5 percent) of decrease in day-ahead congestion event hours in 2019 occurred in January and February.

Figure 11-7 shows the daily day-ahead and real-time congestion event hours for 2014 through 2019.

Figure 11-7 Daily congestion event hours: 2014 through 2019



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). Each PJM member is charged for the cost of losses on the transmission system. Total marginal loss costs, analogous to total congestion costs, are equal to the net of the withdrawal loss charges minus injection loss credits, plus explicit loss charges, incurred in both the Day-Ahead Energy Market and the balancing energy market.

Total marginal loss costs can be more accurately thought of as net marginal loss costs. Total marginal loss costs equal implicit marginal loss charges plus explicit marginal loss charges plus net inadvertent loss charges. Implicit marginal loss charges equal withdrawal loss charges minus injection loss credits. Net explicit marginal loss costs are the net marginal loss costs associated with point to point energy transactions. Net inadvertent loss charges are the losses associated with the hourly difference between the net actual energy flow and the net scheduled energy flow into or out of the PJM control area.[29] Unlike the other categories of marginal loss accounting, inadvertent loss charges are common costs not directly attributable to specific participants. Inadvertent loss charges are assigned to participants based on real-time load (excluding losses) ratio share.[30] Each of these categories of marginal loss costs is comprised of day-ahead and balancing marginal loss costs.

Marginal loss costs can be both positive and negative and consequently withdrawal loss charges and injection loss credits can also be both positive and negative. Total loss costs, when positive, measure the total loss payment by a PJM member and when negative, measure the total loss credit paid to a PJM member. Withdrawal loss charges, when positive, measure the total loss payment by a PJM member and when negative, measure the total loss credit paid to a PJM member. Injection loss credits, when negative, measure the total loss payment by a PJM member and when positive, measure the total loss credit paid to a PJM member.

The loss component of LMP is calculated with respect to the system marginal price (SMP). An increase in generation at a bus that results in an increase in losses will cause the marginal loss component of that bus to be negative. If the increase in generation at the bus results in a decrease of system losses, then the marginal loss component is positive.

Day-ahead marginal loss costs are based on day-ahead MWh priced at the marginal loss price component of

29 PJM Operating Agreement Schedule 1 §3.7.
30 *Id.*

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 loss surplus is the remaining loss amount from collection of marginal losses, after accounting for total system energy costs and net residual market adjustments that is allocated to PJM market participants based on real-time load plus export ratio share as marginal loss credits.[31]

- **Day-Ahead Implicit Withdrawal Loss Charges.** Day-ahead implicit withdrawal loss charges are calculated for all cleared demand, decrement bids and day-ahead energy market sale transactions. Day-ahead implicit withdrawal loss 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 Injection Loss Credits.** Day-ahead implicit injection loss credits are calculated for all cleared generation and increment offers and day-ahead energy market purchase transactions. Day-ahead implicit injection loss 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 Withdrawal Loss Charges.** Balancing implicit withdrawal loss 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 loss charges are calculated using MW deviations and the real-time MLMP for each bus where a deviation exists.
- **Balancing Implicit Injection Loss Credits.** Balancing implicit injection loss 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 loss 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.[32]

31 See PJM. "Manual 28: Operating Agreement Accounting," Rev. 83 (Dec. 3, 2019).

32 PJM Operating Agreement Schedule 1 §3.7.

Total Marginal Loss Cost

The total marginal loss cost in PJM for 2019 was $642.0 million, which was comprised of implicit withdrawal loss charges of -$44.7 million, implicit injection loss credits of -$703.4 million, explicit loss charges of -$16.6 million and inadvertent loss charges of $0.0 million (Table 11-34).

Monthly marginal loss costs in 2019 ranged from $38.8 million in April to $86.5 million in January. Total marginal loss surplus decreased in 2019 by $118.7 million or 36.8 percent from $322.4 million in 2018 to $203.7 million in 2019.

Table 11-33 shows the total marginal loss component costs and the total PJM billing for 2008 through 2019.

Table 11-33 Total PJM loss component costs (Dollars (Millions)): 2008 through 2019[33]

	Loss Costs	Percent Change	Total PJM Billing	Percent of PJM Billing
2008	$2,497	NA	$34,300	7.3%
2009	$1,268	(49.2%)	$26,550	4.8%
2010	$1,635	29.0%	$34,770	4.7%
2011	$1,380	(15.6%)	$35,890	3.8%
2012	$982	(28.8%)	$29,180	3.4%
2013	$1,035	5.5%	$33,860	3.1%
2014	$1,466	41.6%	$50,030	2.9%
2015	$969	(33.9%)	$42,630	2.3%
2016	$697	(28.1%)	$39,050	1.8%
2017	$691	(0.8%)	$40,170	1.7%
2018	$960	39.0%	$49,790	1.9%
2019	$642	(33.1%)	$39,200	1.6%

Table 11-34 shows PJM total marginal loss costs by accounting category for 2008 through 2019. Table 11-35 shows PJM total marginal loss costs by accounting category by market for 2008 through 2019.

Table 11-34 Total PJM marginal loss costs by accounting category (Dollars (Millions)): 2008 through 2019

	Marginal Loss Costs (Millions)				
	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Inadvertent Charges	Total
2008	($237.2)	($2,641.5)	$92.4	$0.0	$2,496.7
2009	($78.5)	($1,314.3)	$32.0	($0.0)	$1,267.7
2010	($122.3)	($1,707.0)	$50.2	($0.0)	$1,634.8
2011	($174.0)	($1,551.9)	$1.6	$0.0	$1,379.5
2012	($11.1)	($1,036.8)	($44.0)	$0.0	$981.7
2013	($4.1)	($1,083.3)	($43.9)	($0.0)	$1,035.3
2014	($59.2)	($1,581.3)	($56.0)	$0.0	$1,466.1
2015	($31.7)	($1,021.0)	($20.5)	$0.0	$968.7
2016	($55.0)	($782.1)	($30.6)	($0.0)	$696.5
2017	($40.9)	($766.9)	($35.1)	$0.0	$690.8
2018	($42.2)	($1,014.3)	($11.9)	$0.0	$960.1
2019	($44.7)	($703.4)	($16.6)	($0.0)	$642.0

33 The loss costs include net inadvertent charges.

Table 11-35 Total PJM marginal loss costs by accounting category by market (Dollars (Millions)): 2008 through 2019

	Marginal Loss Costs (Millions)									
	Day-Ahead				Balancing					
	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Inadvertent Charges	Grand Total
2008	($158.1)	($2,582.2)	$134.3	$2,558.4	($79.1)	($59.4)	($42.0)	($61.7)	$0.0	$2,496.7
2009	($84.7)	($1,311.7)	$65.4	$1,292.3	$6.2	($2.7)	($33.5)	($24.6)	($0.0)	$1,267.7
2010	($146.3)	($1,716.1)	$95.8	$1,665.6	$23.9	$9.1	($45.6)	($30.8)	($0.0)	$1,634.8
2011	($215.4)	($1,592.1)	$53.8	$1,430.5	$41.4	$40.2	($52.2)	($51.0)	$0.0	$1,379.5
2012	($43.0)	($1,060.3)	($13.4)	$1,003.8	$32.0	$23.4	($30.6)	($22.1)	$0.0	$981.7
2013	($37.1)	($1,112.4)	$62.4	$1,137.8	$33.0	$29.1	($106.4)	($102.5)	($0.0)	$1,035.3
2014	($113.9)	($1,618.8)	$66.6	$1,571.4	$54.7	$37.5	($122.5)	($105.3)	$0.0	$1,466.1
2015	($53.4)	($1,032.2)	$33.8	$1,012.6	$21.7	$11.3	($54.3)	($43.9)	$0.0	$968.7
2016	($61.7)	($781.6)	$53.4	$773.2	$6.8	($0.5)	($84.0)	($76.7)	($0.0)	$696.5
2017	($52.2)	($767.2)	$54.9	$769.9	$11.3	$0.3	($90.0)	($79.1)	$0.0	$690.8
2018	($48.3)	($1,003.8)	$41.7	$997.2	$6.1	($10.5)	($53.7)	($37.0)	$0.0	$960.1
2019	($47.1)	($700.3)	$43.3	$696.5	$2.4	($3.1)	($60.0)	($54.5)	($0.0)	$642.0

Table 11-36 and Table 11-37 show the total loss costs for each transaction type in 2019 and 2018. In 2019, generation paid loss costs of $677.6 million, 105.5 percent of total loss costs. In 2018, generation paid loss costs of $976.7 million, 101.7 percent of total loss costs.

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 2019, DECs were paid $4.5 million in loss credits in the day-ahead market, paid $6.1 million in loss charges in the balancing energy market and paid $1.6 million in total loss payments. In 2019, INCs paid $10.5 million in loss charges in the day-ahead market, were paid $12.7 million in loss credits in the balancing energy market and were paid $2.2 million in total loss credits. In 2019, up to congestion paid $43.7 million in loss charges in the day-ahead market, were paid $60.1 million in loss credits in the balancing energy market and received $16.4 million in total loss credits.

Table 11-36 Total PJM loss costs by transaction type by market (Dollars (Millions)): 2019

	Marginal Loss Costs (Millions)									
	Day-Ahead				Balancing					
Transaction Type	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Inadvertent Charges	Grand Total
DEC	($4.5)	$0.0	$0.0	($4.5)	$6.1	$0.0	$0.0	$6.1	$0.0	$1.6
Demand	($5.8)	$0.0	$0.0	($5.8)	$6.0	$0.0	$0.0	$6.0	$0.0	$0.1
Demand Response	($0.0)	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Explicit Congestion and Loss Only	$0.0	$0.0	($0.5)	($0.5)	$0.0	$0.0	($0.0)	($0.0)	$0.0	($0.5)
Export	($17.0)	$0.0	($0.0)	($17.0)	($8.6)	$0.0	$0.4	($8.3)	$0.0	($25.3)
Generation	$0.0	($668.5)	$0.0	$668.5	$0.0	($9.1)	$0.0	$9.1	$0.0	$677.6
Import	$0.0	($1.7)	$0.0	$1.7	$0.0	($5.7)	($0.1)	$5.6	$0.0	$7.3
INC	$0.0	($10.5)	$0.0	$10.5	$0.0	$12.7	$0.0	($12.7)	$0.0	($2.2)
Internal Bilateral	($19.7)	($19.5)	$0.2	$0.0	($1.0)	($1.0)	$0.0	($0.0)	$0.0	$0.0
Up to Congestion	$0.0	$0.0	$43.7	$43.7	$0.0	$0.0	($60.1)	($60.1)	$0.0	($16.4)
Wheel In	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($0.2)	($0.2)	$0.0	($0.2)
Total	($47.1)	($700.3)	$43.3	$696.5	$2.4	($3.1)	($60.0)	($54.5)	$0.0	$642.0

Table 11-37 Total PJM loss costs by transaction type by market (Dollars (Millions)): 2018

	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	($2.0)	$0.0	$0.0	($2.0)	$2.7	$0.0	$0.0	$2.7	$0.0	$0.7
Demand	($7.6)	$0.0	$0.0	($7.6)	$12.2	$0.0	$0.0	$12.2	$0.0	$4.6
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	($0.7)	($0.7)	$0.0	$0.0	($0.1)	($0.1)	$0.0	($0.7)
Export	($24.6)	$0.0	$0.0	($24.6)	($9.3)	$0.0	$0.4	($8.9)	$0.0	($33.5)
Generation	$0.0	($973.2)	$0.0	$973.2	$0.0	($3.5)	$0.0	$3.5	$0.0	$976.7
Grandfathered Overuse	$0.0	$0.0	($0.4)	($0.4)	$0.0	$0.0	($0.1)	($0.1)	$0.0	($0.5)
Import	$0.0	($3.4)	$0.0	$3.4	$0.0	($22.5)	($0.5)	$22.1	$0.0	$25.5
INC	$0.0	($13.6)	$0.0	$13.6	$0.0	$15.0	$0.0	($15.0)	$0.0	($1.4)
Internal Bilateral	($14.0)	($13.6)	$0.5	$0.0	$0.5	$0.5	($0.0)	($0.0)	$0.0	($0.0)
Up to Congestion	$0.0	$0.0	$42.3	$42.3	$0.0	$0.0	($53.3)	($53.3)	$0.0	($11.0)
Wheel In	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($0.1)	($0.1)	$0.0	($0.1)
Total	($48.3)	($1,003.8)	$41.7	$997.2	$6.1	($10.5)	($53.7)	($37.0)	$0.0	$960.1

Monthly Marginal Loss Costs

Table 11-38 shows a monthly summary of marginal loss costs by market type for 2018 and 2019.

Table 11-38 Monthly marginal loss costs by market (Millions): 2018 and 2019

	Marginal Loss Costs (Millions)							
	2018				2019			
	Day-Ahead	Balancing	Inadvertent Charges	Total	Day-Ahead	Balancing	Inadvertent Charges	Total
Jan	$227.1	($4.3)	$0.0	$222.8	$92.3	($5.8)	$0.0	$86.5
Feb	$52.7	($3.2)	$0.0	$49.5	$57.2	($3.3)	$0.0	$53.9
Mar	$67.2	$0.0	$0.0	$67.2	$70.5	($7.0)	$0.0	$63.5
Apr	$56.3	($0.9)	$0.0	$55.4	$42.7	($3.9)	$0.0	$38.8
May	$64.5	($1.1)	$0.0	$63.4	$45.2	($3.9)	($0.0)	$41.3
Jun	$66.5	($3.4)	($0.0)	$63.2	$43.9	($2.8)	($0.0)	$41.1
Jul	$85.7	($3.5)	$0.0	$82.2	$77.3	($3.5)	$0.0	$73.8
Aug	$87.7	($4.6)	$0.0	$83.1	$60.6	($4.4)	($0.0)	$56.3
Sep	$73.2	($2.9)	$0.0	$70.2	$53.0	($5.4)	($0.0)	$47.6
Oct	$65.0	($3.0)	($0.0)	$62.1	$42.6	($3.6)	($0.0)	$39.0
Nov	$77.6	($5.4)	($0.0)	$72.2	$58.2	($6.0)	($0.0)	$52.2
Dec	$73.7	($4.8)	($0.0)	$68.9	$53.1	($4.9)	($0.0)	$48.1
Total	$997.2	($37.0)	$0.0	$960.1	$696.5	($54.5)	($0.0)	$642.0

Figure 11-8 shows PJM monthly marginal loss costs for 2008 through 2019.

Figure 11-8 PJM monthly marginal loss costs (Dollars (Millions)): 2008 through 2019

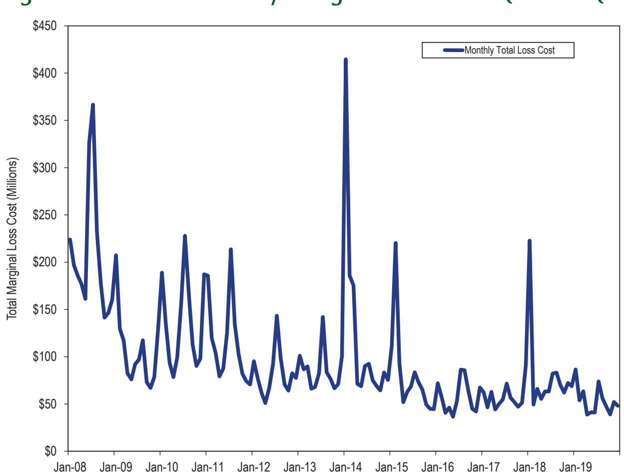


Table 11-39 shows the monthly total loss costs for each virtual transaction type in 2018 and 2019.

Table 11-39 Monthly PJM loss charges by virtual transaction type and by market (Dollars (Millions)): 2018 and 2019

		Marginal Loss Charges (Millions)									
		DEC			INC			Up to Congestion			
Year		Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Grand Total
2018	Jan	$0.2	($0.5)	($0.3)	$2.1	($2.4)	($0.2)	$6.6	($8.5)	($1.9)	($2.5)
	Feb	($0.2)	$0.0	($0.1)	$0.5	($0.5)	($0.1)	$2.5	($3.9)	($1.4)	($1.6)
	Mar	($0.0)	$0.2	$0.2	$1.3	($1.4)	($0.1)	$1.2	($1.5)	($0.3)	($0.2)
	Apr	($0.1)	$0.2	$0.1	$1.1	($1.2)	($0.2)	$1.5	($2.1)	($0.6)	($0.7)
	May	($0.5)	$0.5	$0.0	$1.1	($1.2)	($0.1)	$2.2	($2.8)	($0.6)	($0.7)
	Jun	($0.3)	$0.5	$0.2	$1.1	($1.1)	($0.0)	$3.0	($3.5)	($0.4)	($0.3)
	Jul	($0.1)	$0.2	$0.1	$0.8	($0.8)	($0.0)	$3.8	($4.4)	($0.7)	($0.6)
	Aug	($0.2)	$0.1	($0.1)	$1.0	($1.1)	($0.1)	$4.4	($5.8)	($1.3)	($1.5)
	Sep	($0.3)	$0.5	$0.3	$1.2	($1.4)	($0.1)	$3.8	($4.6)	($0.7)	($0.6)
	Oct	($0.3)	$0.4	$0.1	$1.2	($1.3)	($0.1)	$3.3	($4.0)	($0.7)	($0.6)
	Nov	($0.0)	$0.2	$0.1	$1.5	($1.6)	($0.1)	$5.4	($6.5)	($1.1)	($1.1)
	Dec	($0.2)	$0.4	$0.1	$0.7	($0.9)	($0.2)	$4.6	($5.8)	($1.3)	($1.3)
	Total	($2.0)	$2.7	$0.7	$13.6	($15.0)	($1.4)	$42.3	($53.3)	($11.0)	($11.8)
2019	Jan	($0.2)	$0.4	$0.2	$1.1	($1.4)	($0.3)	$5.4	($6.5)	($1.1)	($1.2)
	Feb	($0.4)	$0.3	($0.1)	$0.8	($1.0)	($0.3)	$3.1	($4.4)	($1.3)	($1.6)
	Mar	($0.2)	$0.2	$0.0	$1.4	($1.5)	($0.1)	$6.0	($6.9)	($0.9)	($1.0)
	Apr	($0.3)	$0.3	$0.0	$0.7	($0.8)	($0.1)	$3.3	($4.1)	($0.8)	($0.9)
	May	($0.7)	$0.9	$0.2	$0.9	($0.8)	$0.0	$3.2	($4.2)	($0.9)	($0.7)
	Jun	($0.5)	$0.7	$0.2	$0.6	($0.7)	($0.1)	$1.8	($3.4)	($1.6)	($1.5)
	Jul	($0.7)	$1.0	$0.3	$0.9	($1.1)	($0.2)	$3.3	($4.8)	($1.4)	($1.4)
	Aug	($0.5)	$0.5	$0.0	$0.6	($0.6)	($0.0)	$3.2	($4.5)	($1.3)	($1.3)
	Sep	($0.5)	$0.9	$0.4	$0.9	($1.2)	($0.4)	$3.1	($5.5)	($2.3)	($2.3)
	Oct	($0.2)	$0.4	$0.2	$0.8	($1.2)	($0.3)	$2.5	($3.8)	($1.3)	($1.5)
	Nov	($0.3)	$0.4	$0.1	$1.2	($1.3)	($0.2)	$4.6	($6.3)	($1.7)	($1.8)
	Dec	($0.1)	$0.1	$0.1	$0.7	($1.0)	($0.2)	$4.1	($5.7)	($1.6)	($1.8)
	Total	($4.5)	$6.1	$1.6	$10.5	($12.7)	($2.2)	$43.7	($60.1)	($16.4)	($17.0)

Marginal Loss Costs and Loss Credits

Total loss surplus are 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 withdrawal loss charges less implicit injection loss 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. 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 2008 through 2019. The total marginal loss surplus decreased $118.7 million in 2019 from 2018.

Table 11-40 Marginal loss surplus (Dollars (Millions)): 2008 through 2019[34]

	Marginal Loss Surplus (Millions)					
			Net Residual Market Adjustment			
	System Energy Costs	Marginal Loss Costs	Known Day-Ahead Error	Day-Ahead Loss MW Congestion	Balancing Loss MW Congestion	Total
2008	($1,193.2)	$2,496.7	$0.0	$0.0	$0.0	$1,303.5
2009	($628.8)	$1,267.7	($0.0)	($0.4)	($0.1)	$639.4
2010	($797.9)	$1,634.8	$0.0	($0.7)	($0.0)	$837.7
2011	($793.8)	$1,379.5	$0.1	$0.7	($0.0)	$585.2
2012	($593.0)	$981.7	$0.1	($1.0)	$0.1	$389.6
2013	($687.6)	$1,035.3	$0.0	$2.0	($0.0)	$345.7
2014	($977.7)	$1,466.1	$0.0	($0.0)	($0.0)	$488.4
2015	($627.4)	$968.7	($0.0)	$6.3	$0.1	$335.0
2016	($466.3)	$696.5	($0.0)	$5.1	($0.1)	$225.2
2017	($475.2)	$690.8	($0.0)	$3.2	($0.2)	$212.6
2018	($636.7)	$960.1	$0.0	$1.1	($0.1)	$322.4
2019	($435.2)	$642.0	($0.0)	$3.2	($0.1)	$203.7

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 2019 was -$435.2 million, which was comprised of implicit withdrawal energy charges of $30,647.4 million, implicit injection energy credits of $31,081.1 million, explicit energy charges of $0.0 million and inadvertent energy charges of -$1.5 million. The monthly system energy costs for 2019 ranged from -$59.3 million in January to -$25.7 million in April.

Table 11-41 shows total system energy costs and total PJM billing, for 2008 through 2019.

Table 11-41 Total PJM system energy costs (Dollars (Millions)): 2008 through 2019[35]

	System Energy Costs	Percent Change	Total PJM Billing	Percent of PJM Billing
2008	($1,193)	NA	$34,300	(3.5%)
2009	($629)	(47.3%)	$26,550	(2.4%)
2010	($798)	26.9%	$34,770	(2.3%)
2011	($794)	(0.5%)	$35,890	(2.2%)
2012	($593)	(25.3%)	$29,180	(2.0%)
2013	($688)	15.9%	$33,860	(2.0%)
2014	($978)	42.2%	$50,030	(2.0%)
2015	($627)	(35.8%)	$42,630	(1.5%)
2016	($466)	(25.7%)	$39,050	(1.2%)
2017	($475)	1.9%	$40,170	(1.2%)
2018	($637)	34.0%	$49,790	(1.3%)
2019	($435)	(31.6%)	$39,200	(1.1%)

System energy costs for 2008 through 2019 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 PJM system energy costs by accounting category (Dollars (Millions)): 2008 through 2019

	System Energy Costs (Millions)				
	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Inadvertent Charges	Total
2008	$105,665.6	$106,860.0	$0.0	$1.2	($1,193.2)
2009	$42,535.2	$43,165.7	$0.0	$1.7	($628.8)
2010	$53,101.5	$53,886.9	$0.0	($12.6)	($797.9)
2011	$47,658.9	$48,481.0	$0.0	$28.3	($793.8)
2012	$37,471.3	$38,073.5	$0.0	$9.1	($593.0)
2013	$42,774.3	$43,454.6	$0.0	($7.4)	($687.6)
2014	$60,258.5	$61,232.0	$0.0	($4.2)	($977.7)
2015	$40,601.8	$41,231.9	$0.0	$2.7	($627.4)
2016	$34,053.6	$34,510.1	$0.0	($9.8)	($466.3)
2017	$35,152.1	$35,634.4	$0.0	$7.1	($475.2)
2018	$43,803.8	$44,445.1	$0.0	$4.6	($636.7)
2019	$30,647.4	$31,081.1	$0.0	($1.5)	($435.2)

34 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.

35 The system energy costs include net inadvertent charges.

Table 11-43 Total PJM system energy costs by market category (Dollars (Millions)): 2008 through 2019

	System Energy Costs (Millions)									
	Day-Ahead				Balancing					
	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Inadvertent Charges	Grand Total
2008	$81,789.8	$83,120.0	$0.0	($1,330.1)	$23,875.8	$23,740.0	$0.0	$135.7	$1.2	($1,193.2)
2009	$42,683.8	$43,351.2	$0.0	($667.4)	($148.5)	($185.5)	$0.0	$36.9	$1.7	($628.8)
2010	$53,164.9	$53,979.1	$0.0	($814.1)	($63.4)	($92.2)	$0.0	$28.8	($12.6)	($797.9)
2011	$48,144.9	$48,880.0	$0.0	($735.2)	($485.9)	($399.1)	$0.0	($86.9)	$28.3	($793.8)
2012	$37,641.2	$38,251.1	$0.0	($609.9)	($169.9)	($177.6)	$0.0	$7.7	$9.1	($593.0)
2013	$42,795.2	$43,628.9	$0.0	($833.7)	($20.9)	($174.4)	$0.0	$153.5	($7.4)	($687.6)
2014	$60,325.2	$61,668.9	$0.0	($1,343.7)	($66.7)	($436.9)	$0.0	$370.2	($4.2)	($977.7)
2015	$40,837.8	$41,595.7	$0.0	($757.9)	($236.0)	($363.8)	$0.0	$127.8	$2.7	($627.4)
2016	$34,245.1	$34,885.7	$0.0	($640.6)	($191.5)	($375.6)	$0.0	$184.0	($9.8)	($466.3)
2017	$35,490.1	$36,138.6	$0.0	($648.5)	($338.0)	($504.2)	$0.0	$166.2	$7.1	($475.2)
2018	$43,948.7	$44,659.7	$0.0	($711.0)	($142.9)	($212.6)	$0.0	$69.7	$4.6	($636.7)
2019	$31,034.3	$31,562.9	$0.0	($528.6)	($386.9)	($481.8)	$0.0	$94.9	($1.5)	($435.2)

Table 11-44 and Table 11-45 show the total system energy costs for each transaction type in 2019 and 2018. In 2019, generation was paid $22,210.6 million and demand paid $21,012.3 million in net energy payment. In 2018, generation was paid $31,247.1 million and demand paid $30,094.6 million in net energy payment.

Table 11-44 Total PJM system energy costs by transaction type by market (Dollars (Millions)): 2019

	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	$917.1	$0.0	$0.0	$917.1	($932.0)	$0.0	$0.0	($932.0)	($14.8)
Demand	$20,912.4	$0.0	$0.0	$20,912.4	$99.9	$0.0	$0.0	$99.9	$21,012.3
Demand Response	($0.8)	$0.0	$0.0	($0.8)	$0.7	$0.0	$0.0	$0.7	($0.0)
Export	$661.1	$0.0	$0.0	$661.1	$401.1	$0.0	$0.0	$401.1	$1,062.2
Generation	$0.0	$22,247.2	$0.0	($22,247.2)	$0.0	($36.6)	$0.0	$36.6	($22,210.6)
Import	$0.0	$86.1	$0.0	($86.1)	$0.0	$195.2	$0.0	($195.2)	($281.4)
INC	$0.0	$685.1	$0.0	($685.1)	$0.0	($683.7)	$0.0	$683.7	($1.4)
Internal Bilateral	$8,544.4	$8,544.4	$0.0	$0.0	$26.4	$26.4	$0.0	$0.0	$0.0
Wheel In	$0.0	$0.0	$0.0	$0.0	$0.0	$17.0	$0.0	($17.0)	($17.0)
Wheel Out	$0.0	$0.0	$0.0	$0.0	$17.0	$0.0	$0.0	$17.0	$17.0
Total	$31,034.3	$31,562.9	$0.0	($528.6)	($386.9)	($481.8)	$0.0	$94.9	($433.7)

Table 11-45 Total PJM system energy costs by transaction type by market (Dollars (Millions)): 2018

	System Energy Costs (Millions)								
	Day-Ahead				Balancing				
Transaction Type	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Grand Total
DEC	$1,010.9	$0.0	$0.0	$1,010.9	($1,019.5)	$0.0	$0.0	($1,019.5)	($8.6)
Demand	$29,631.7	$0.0	$0.0	$29,631.7	$462.9	$0.0	$0.0	$462.9	$30,094.6
Demand Response	($1.0)	$0.0	$0.0	($1.0)	$1.0	$0.0	$0.0	$1.0	$0.0
Export	$858.4	$0.0	$0.0	$858.4	$386.7	$0.0	$0.0	$386.7	$1,245.1
Generation	$0.0	$31,211.7	$0.0	($31,211.7)	$0.0	$35.3	$0.0	($35.3)	($31,247.1)
Import	$0.0	$139.1	$0.0	($139.1)	$0.0	$579.1	$0.0	($579.1)	($718.2)
INC	$0.0	$860.1	$0.0	($860.1)	$0.0	($853.0)	$0.0	$853.0	($7.1)
Internal Bilateral	$12,448.8	$12,448.8	$0.0	($0.0)	$14.8	$14.8	$0.0	($0.0)	($0.0)
Wheel In	$0.0	$0.0	$0.0	$0.0	$0.0	$11.2	$0.0	($11.2)	($11.2)
Wheel Out	$0.0	$0.0	$0.0	$0.0	$11.2	$0.0	$0.0	$11.2	$11.2
Total	$43,948.7	$44,659.7	$0.0	($711.0)	($142.9)	($212.6)	$0.0	$69.7	($641.3)

Monthly System Energy Costs

Table 11-46 shows a monthly summary of system energy costs by market type for 2018 and 2019. Total balancing system energy costs in 2019 increased from 2018. Monthly total system energy costs in 2019 ranged from -$59.3 million in January to -$25.7 million in April.

Table 11-46 Monthly system energy costs by market type (Dollars (Millions)): 2018 and 2019

	2018				2019			
	Day-Ahead	Balancing	Inadvertent Charges	Total	Day-Ahead	Balancing	Inadvertent Charges	Total
Jan	($160.3)	$4.9	$4.6	($150.9)	($69.5)	$9.8	$0.4	($59.3)
Feb	($41.2)	$7.4	$0.1	($33.6)	($42.8)	$6.9	$0.5	($35.4)
Mar	($45.0)	$2.9	$0.1	($42.1)	($54.2)	$12.3	$0.2	($41.6)
Apr	($40.4)	$2.6	($0.0)	($37.8)	($34.2)	$8.1	$0.4	($25.7)
May	($46.5)	$5.4	$0.3	($40.8)	($34.5)	$6.6	($0.1)	($28.0)
Jun	($47.0)	$7.2	($0.1)	($39.9)	($32.8)	$4.2	($0.2)	($28.8)
Jul	($59.6)	$5.7	$0.5	($53.5)	($54.7)	$6.3	$0.1	($48.3)
Aug	($60.7)	$5.7	$0.3	($54.6)	($44.3)	$8.2	($0.6)	($36.7)
Sep	($50.8)	$5.3	($0.0)	($45.4)	($40.7)	$5.8	($0.5)	($35.4)
Oct	($47.2)	$4.5	($0.6)	($43.2)	($33.6)	$7.4	($0.6)	($26.8)
Nov	($57.2)	$9.8	($0.2)	($47.6)	($45.9)	$10.3	($0.8)	($36.4)
Dec	($55.2)	$8.4	($0.4)	($47.2)	($41.5)	$9.1	($0.3)	($32.7)
Total	($711.0)	$69.7	$4.6	($636.7)	($528.6)	$94.9	($1.5)	($435.2)

System Energy Costs (Millions)

Figure 11-9 shows PJM monthly system energy costs for 2008 through 2019.

Figure 11-9 PJM monthly system energy costs (Millions): 2008 through 2019

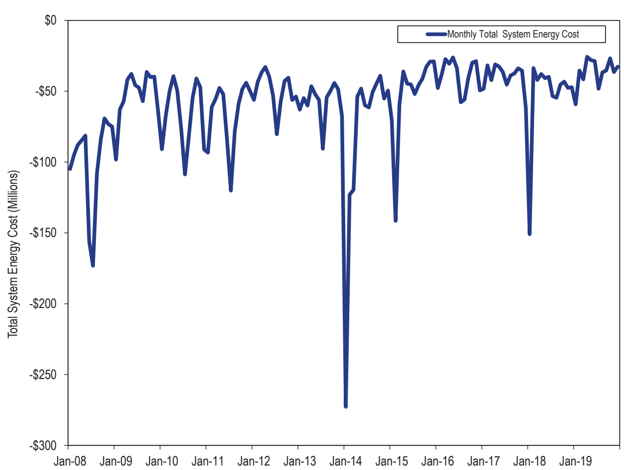


Table 11-47 shows the monthly total system energy costs for each virtual transaction type in 2019 and year of 2018. In 2019, DECs paid $917.1 million in energy charges in the day-ahead market, were paid $932.0 million in energy credits in the balancing energy market and were paid $14.8 million in total energy credits. In 2019, INCs were paid $685.1 million in energy credits in the day-ahead market, paid $683.7 million in energy charges in the balancing market and were paid $1.4 million in total energy credits. In 2018, DECs paid $1,010.9 million in energy charges in the day-ahead market, were paid $1,019.5 million in energy credits in the balancing energy market and were paid $8.6 million in total energy credits. In 2018, INCs were paid $860.1 million in energy credits in the day-ahead market, paid $853.0 million in energy charges in the balancing energy market and were paid $7.1 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 PJM energy charges by virtual transaction type and by market (Dollars (Millions)): 2018 and 2019

		DEC			INC			
Year		Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Grand Total
2018	Jan	$172.4	($183.2)	($10.8)	($136.9)	$138.3	$1.4	($9.4)
	Feb	$47.3	($45.1)	$2.2	($46.3)	$44.2	($2.1)	$0.1
	Mar	$65.6	($67.2)	($1.6)	($66.0)	$66.5	$0.4	($1.2)
	Apr	$66.2	($67.6)	($1.4)	($76.3)	$76.8	$0.5	($0.9)
	May	$86.7	($94.7)	($8.0)	($73.7)	$78.0	$4.3	($3.7)
	Jun	$77.1	($74.5)	$2.6	($53.8)	$52.7	($1.0)	$1.6
	Jul	$76.5	($71.6)	$4.9	($48.7)	$43.9	($4.7)	$0.2
	Aug	$75.8	($75.3)	$0.6	($57.4)	$57.4	($0.0)	$0.6
	Sep	$94.5	($98.5)	($4.0)	($65.6)	$67.4	$1.8	($2.2)
	Oct	$86.7	($82.4)	$4.3	($85.8)	$82.1	($3.7)	$0.6
	Nov	$83.1	($80.9)	$2.2	($88.9)	$86.6	($2.3)	($0.2)
	Dec	$79.0	($78.4)	$0.6	($60.8)	$59.2	($1.6)	($1.0)
	Total	$1,010.9	($1,019.5)	($8.6)	($860.1)	$853.0	($7.1)	($15.7)
2019	Jan	$104.4	($97.7)	$6.7	($71.7)	$67.1	($4.6)	$2.1
	Feb	$64.0	($66.8)	($2.8)	($52.5)	$54.0	$1.6	($1.2)
	Mar	$76.6	($77.4)	($0.8)	($66.7)	$65.4	($1.2)	($2.0)
	Apr	$60.3	($59.7)	$0.6	($59.0)	$58.5	($0.5)	$0.1
	May	$81.9	($79.1)	$2.9	($56.1)	$53.9	($2.2)	$0.6
	Jun	$75.8	($75.3)	$0.4	($47.1)	$46.5	($0.6)	($0.2)
	Jul	$105.6	($106.1)	($0.5)	($60.7)	$61.7	$1.0	$0.5
	Aug	$72.4	($69.7)	$2.7	($49.2)	$46.0	($3.2)	($0.5)
	Sep	$101.3	($112.4)	($11.0)	($50.9)	$56.2	$5.3	($5.7)
	Oct	$62.6	($75.9)	($13.3)	($57.5)	$63.2	$5.7	($7.6)
	Nov	$59.6	($58.8)	$0.8	($70.8)	$68.7	($2.1)	($1.3)
	Dec	$52.7	($53.3)	($0.5)	($43.0)	$42.6	($0.4)	($0.9)
	Total	$917.1	($932.0)	($14.8)	($685.1)	$683.7	($1.4)	($16.2)

Energy Charges (Millions)