Congestion and Marginal Losses

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 of LMP (CLMP), and the marginal loss component of LMP (MLMP).[1] 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.

CLMP is the incremental price of congestion at each bus, based on the shadow prices associated with the relief of binding constraints in the security constrained optimization. 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.

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 the 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.[2]

Congestion is neither good nor bad, but is a direct measure of the extent to which there are multiple marginal generating units 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.

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 costs plus net explicit congestion costs plus net inadvertent congestion charges. The net implicit congestion costs are the load congestion payments less generation congestion credits. This section refers to total energy costs and total marginal loss costs in the same way. As with congestion, total energy costs are more precisely termed net 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.

The components of LMP are the basis for calculating participant and location specific congestion costs and marginal loss costs.[4]

Overview

Congestion Cost

- **Total Congestion.** Total congestion costs decreased by $339.5 million or 53.7 percent, from $631.7 million in the first three months of 2015 to $292.2 million in the first three months of 2016.

1 On June 1, 2013, PJM integrated the East Kentucky Power Cooperative (EKPC) Control Zone. The metrics reported in this section treat EKPC as part of MISO for the first hour of June 2013 and as part of PJM for the second hour of June 2013 through 2014.
2 See 2014 SOM Technical Appendices for a full discussion of the relationship between marginal, average and total losses.
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 were calculated as of April 18, 2016, and are subject to change, based on continued PJM billing updates.

- **Day-Ahead Congestion.** Day-ahead congestion costs decreased by $451.0 million or 58.3 percent, from $773.9 million in the first three months of 2015 to $322.9 million in the first three months of 2016.
- **Balancing Congestion.** Balancing congestion costs increased by $111.5 million or 78.4 percent, from -$142.2 million in the first three months of 2015 to -$30.8 million in the first three months of 2016.
- **Real-Time Congestion.** Real-time congestion costs decreased by $284.7 million or 49.2 percent, from $579.0 million in the first three months of 2015 to $294.3 million in the first three months of 2016.
- **Monthly Congestion.** In the first three months of 2016, 38.1 percent ($111.3 million) of total congestion cost was incurred in February. Monthly total congestion costs in the first three months of 2016 ranged from $73.3 million in March to $111.3 million in February.
- **Geographic Differences in CLMP.** Differences in CLMP among eastern, southern and western control zones in PJM were primarily a result of congestion on the Graceton Transformer, the Bagley – Graceton Line, the Conastone – Northwest Line the Milford – Steele Line and the Person - Halifax Flowgate.
- **Congestion Frequency.** Congestion frequency continued to be significantly higher in the Day-Ahead Energy Market than in the Real-Time Energy Market in the first three months of 2016. The number of congestion event hours in the Day-Ahead Energy Market was about ten times higher than the number of congestion event hours in the Real-Time Energy Market.

  Day-ahead congestion frequency increased by 31.7 percent from 50,384 congestion event hours in the first three months of 2015 to 66,373 congestion event hours in the first three months of 2016. The day-ahead congestion event hours decreased significantly after September 8, 2014. The reduction was the result of the reduction in up to congestion (UTC) activity which was a result of FERC's UTC uplift refund notice, retroactive to September 8, 2014.

  Real-time congestion frequency decreased by 30.5 percent from 9,735 congestion event hours in the first three months of 2015 to 6,763 congestion event hours in the first three months of 2016.
- **Congested Facilities.** Day-ahead, congestion-event hours decreased on flowgates and interfaces and increased on lines and transformers. Real-time, congestion-event hours decreased on all types of facilities.

  The Graceton Transformer was the largest contributor to congestion costs in the first three months of 2016. With $29.8 million in total congestion costs, it accounted for 10.2 percent of the total PJM congestion costs in the first three months of 2016.
- **Zonal Congestion.** ComEd had the largest total congestion costs among all control zones in the first three months of 2016. ComEd had $69.7 million in total congestion costs, comprised of -$88.1 million in total load congestion payments, -$163.4 million in total generation congestion credits and -$5.7 million in explicit congestion costs. The Mercer IP – Galesburg Flowgate, the Cherry Valley Flowgate, the Cherry Valley Transformer, the Cherry Valley – Silver Lake Flowgate, and the Person - Halifax Flowgate contributed $37.6 million, or 53.9 percent of the total ComEd control zone congestion costs.
- Ownership. In the first three months of 2016, financial entities as a group were net recipients of congestion credits and physical entities were net payers of congestion charges. Explicit costs are the primary source of congestion credits to financial entities. In the first three months of 2016, financial entities received $16.7 million in congestion credits, a decrease of $52.5 million or 75.9 percent compared to the first three months of 2015. In the first three months of 2016, physical entities paid $308.8 million in congestion charges, a decrease of $392.0 million or 55.9 percent compared to the first three months of 2015. UTCs are in the explicit congestion cost category and comprise most of that category. The total explicit cost is equal to day-ahead explicit cost plus balancing explicit cost. In the first three months of 2016, the total explicit cost is -$8.5 million and 153.0 percent of the total explicit cost is comprised of congestion cost by UTCs, which is -$13.0 million.

Marginal Loss Cost

- **Total Marginal Loss Costs.** Total marginal loss costs decreased by $255.0 million or 60.0 percent, from $425.1 million in the first three months of 2015 to $170.1 million in the first three months of 2016. The loss MWh in PJM decreased by 1,247.3 GWh or 24.3 percent, from 5,126.6 GWh in the first three months of 2015 to 3,879.2 GWh in the first three months of 2016. The loss component of LMP decreased from $0.03 in the first three months of 2015 to $0.01 in the first three months of 2016.
- **Monthly Total Marginal Loss Costs.** Monthly total marginal loss costs in the first three months of 2016 ranged from $40.6 million in March to $72.0 million in January.
- **Day-Ahead Marginal Loss Costs.** Day-ahead marginal loss costs decreased by $248.7 million or 57.6 percent, from $432.0 million in the first three months of 2015 to $183.3 million in the first three months of 2016.
- **Balancing Marginal Loss Costs.** Balancing marginal loss costs decreased by $6.3 million or 91.3 percent, from -$6.9 million in the first three months of 2015 to -$13.2 million in the first three months of 2016.
- **Total Marginal Loss Surplus.** The total marginal loss surplus decreased in the first three months of 2016 by $94.3 million or 62.9 percent, from $150.0 million in the first three months of 2015, to $55.7 million in the first three months of 2016.

Energy Cost

- **Total Energy Costs.** Total energy costs increased by $158.0 million or 58.2 percent, from -$271.7 million in the first three months of 2015 to -$113.6 million in the first three months of 2016.
- **Day-Ahead Energy Costs.** Day-ahead energy costs increased by $162.2 million or 51.9 percent, from -$312.6 million in the first three months of 2015 to -$150.4 million in the first three months of 2016.
- **Balancing Energy Costs.** Balancing energy costs decreased by $2.6 million or 6.8 percent, from $38.4 million in the first three months of 2015 to $35.8 million in the first three months of 2016.
- Monthly Total Energy Costs. Monthly total energy costs in the first three months of 2016 ranged from -$47.7 million in January to -$27.4 million in March.

Conclusion

Congestion, as defined, is the total congestion payments by load in excess of the total congestion credits received by generation. 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.

The current ARR/FTR design does not serve as an efficient way to ensure that load receives all the congestion revenues or has the ability to receive the auction revenues associated with all the potential congestion revenues. Total ARR and self scheduled FTR revenue offset only 63.8 percent of total congestion costs including congestion in the Day-Ahead Energy Market and the balancing energy market for the 2014 to 2015 planning period. For the first ten months of the 2015 to 2016 planning period ARRs and self scheduled FTRs offset 83.6 percent of total congestion costs.

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 will affect the components of LMP. With a distributed load reference bus, the energy component is a load-weighted system price. There is no congestion or losses included in the load weighted reference bus price, unlike the case with a single node reference bus.

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

SMP, MLMP and CLMP are a product of the least cost, security constrained dispatch of system resources to meet system load. SMP is the incremental cost of 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. The greater the resistance of the system to flows of energy from generation to loads, the greater the losses of the system and the greater the proportion of energy needed to meet a given level of load. Marginal losses are the incremental change in system power losses caused by changes in the system load and generation patterns.[5] The first derivative of total losses with respect to the power flow equals 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.[6] The result is that the price of energy in the constrained area is higher than in the unconstrained area because of the combination of transmission limitations and the cost of local generation. Congestion is the difference between the total cost of energy paid by load in the transmission constrained area and the total revenue received by generation in the transmission constrained area.

5 For additional information, see the MMU Technical Reference for PJM Markets, at "Marginal Losses," <http://www.monitoringanalytics.com/reports/Technical_References/docs/2010-som-pjm-technical-reference.pdf>.

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

Table 11-1 shows the PJM real-time, load-weighted average LMP components for January through March of 2009 through 2016.[7]

The load-weighted average real-time LMP decreased $24.11 or 47.4 percent from $50.91 in the first three months of 2015 to $26.80 in the first three months of 2016. The load-weighted average congestion component increased $0.03 from $0.00 in the first three months of 2015 to $0.03 in the first three months of 2016. The load-weighted average loss component decreased $0.02 from $0.03 in the first three months of 2015 to $0.01 in the first three months of 2016. The load-weighted average energy component decreased $24.13 or 47.4 percent from $50.89 in the first three months of 2015 to $26.75 in the first three months of 2016.

Table 11-1 PJM real-time, load-weighted average LMP components (Dollars per MWh): January through March of 2009 through 2016[8]

(Jan - Mar)	Real-Time LMP	Energy Component	Congestion Component	Loss Component
2009	$49.60	$49.51	$0.05	$0.04
2010	$45.92	$45.81	$0.06	$0.05
2011	$46.35	$46.30	$0.03	$0.03
2012	$31.21	$31.18	$0.02	$0.00
2013	$37.41	$37.37	$0.02	$0.02
2014	$92.98	$93.08	($0.13)	$0.03
2015	$50.91	$50.89	($0.00)	$0.03
2016	$26.80	$26.75	$0.03	$0.01

Table 11-2 shows the PJM day-ahead, load-weighted average LMP components for January through March of 2009 through 2016.[9]

7 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 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.

8 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.

9 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.

The load-weighted average day-ahead LMP decreased $24.08 or 46.3 percent from $52.02 in the first three months of 2015 to $27.94 in 2016. The load-weighted average congestion component decreased $0.34 or 69.8 percent from $0.48 in 2015 to $0.15 in the first three months of 2016. The load-weighted average loss component increased $0.02 or 83.2 percent from -$0.02 in 2015 to -$0.00 in the first three months of 2016. The load-weighted average energy component decreased $23.76 or 46.1 percent from $51.55 in the first three months of 2015 to $27.80 in the first three months of 2016.

Table 11-2 PJM day-ahead, load-weighted average LMP components (Dollars per MWh): January through March of 2009 through 2016

(Jan - Mar)	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
2009	$49.44	$49.75	($0.18)	($0.13)
2010	$47.77	$47.74	$0.01	$0.02
2011	$47.14	$47.36	($0.11)	($0.11)
2012	$31.51	$31.45	$0.08	($0.03)
2013	$37.26	$37.19	$0.07	$0.01
2014	$94.96	$94.52	$0.43	$0.00
2015	$52.02	$51.55	$0.48	($0.02)
2016	$27.94	$27.80	$0.15	($0.00)

Zonal Components

The real-time components of LMP for each control zone are presented in Table 11-3 for the first three months of 2015 and the first three months of 2016. In the first three months of 2016, BGE had the highest real-time congestion component of all control zones and PECO had the lowest real-time congestion component.

Table 11-3 Zonal and PJM real-time, load-weighted average LMP components (Dollars per MWh): January through March of 2015 and 2016

	2015 (Jan - Mar)				2016 (Jan - Mar)			
	Real-Time LMP	Energy Component	Congestion Component	Loss Component	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AECO	$60.14	$50.47	$6.82	$2.85	$25.73	$26.67	($1.34)	$0.39
AEP	$42.23	$50.89	($6.72)	($1.94)	$26.49	$26.73	$0.09	($0.32)
AP	$53.65	$51.12	$2.12	$0.41	$27.63	$26.85	$0.60	$0.17
ATSI	$41.94	$49.68	($7.61)	($0.13)	$26.03	$26.46	($0.87)	$0.44
BGE	$62.50	$52.03	$7.34	$3.14	$36.11	$27.05	$7.89	$1.16
ComEd	$36.14	$49.43	($9.43)	($3.86)	$23.45	$26.33	($1.64)	($1.24)
DAY	$41.35	$50.46	($8.18)	($0.93)	$26.08	$26.69	($0.99)	$0.38
DEOK	$39.49	$50.76	($7.97)	($3.30)	$25.42	$26.68	($0.61)	($0.65)
DLCO	$36.84	$50.04	($11.59)	($1.62)	$25.68	$26.52	($0.69)	($0.15)
Dominion	$59.35	$52.79	$5.64	$0.91	$31.29	$27.20	$3.96	$0.14
DPL	$68.76	$52.38	$12.05	$4.33	$30.56	$27.17	$2.35	$1.04
EKPC	$40.63	$53.27	($9.41)	($3.23)	$25.78	$27.28	($0.77)	($0.73)
JCPL	$60.26	$50.22	$6.97	$3.06	$23.79	$26.69	($3.33)	$0.43
Met-Ed	$59.58	$50.65	$6.94	$1.99	$23.63	$26.76	($3.40)	$0.27
PECO	$59.70	$50.61	$6.72	$2.36	$23.29	$26.73	($3.70)	$0.26
PENELEC	$53.46	$50.04	$2.27	$1.15	$25.29	$26.56	($1.76)	$0.49
Pepco	$60.19	$51.94	$6.14	$2.10	$32.38	$27.06	$4.62	$0.70
PPL	$60.18	$50.86	$7.61	$1.71	$23.88	$26.82	($3.15)	$0.21
PSEG	$66.47	$49.71	$13.75	$3.01	$23.95	$26.50	($2.99)	$0.44
RECO	$68.51	$49.49	$16.06	$2.95	$23.79	$26.55	($3.23)	$0.47
PJM	$50.91	$50.89	($0.00)	$0.03	$26.80	$26.75	$0.03	$0.01

The day-ahead components of LMP for each control zone are presented in Table 11-4 for the first three months of 2015 and the first three months of 2016. In the first three months of 2016, BGE had the highest day-ahead congestion component of all control zones and PECO had the lowest day-ahead congestion component.

Table 11-4 Zonal and PJM day-ahead, load-weighted average LMP components (Dollars per MWh): January through March of 2015 and 2016

	2015 (Jan - Mar)				2016 (Jan - Mar)			
	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AECO	$62.12	$50.83	$9.47	$1.82	$25.38	$27.56	($2.37)	$0.18
AEP	$42.83	$51.92	($7.70)	($1.38)	$27.30	$27.81	($0.27)	($0.24)
AP	$52.75	$51.66	$1.10	($0.02)	$28.84	$27.84	$0.95	$0.06
ATSI	$42.45	$50.50	($8.11)	$0.06	$27.04	$27.56	($0.89)	$0.37
BGE	$64.68	$52.24	$10.32	$2.13	$38.70	$28.14	$9.59	$0.97
ComEd	$35.21	$50.54	($12.60)	($2.73)	$24.21	$27.42	($2.14)	($1.07)
DAY	$41.43	$51.47	($9.79)	($0.25)	$27.02	$27.67	($1.02)	$0.37
DEOK	$39.70	$51.54	($9.39)	($2.44)	$26.55	$27.77	($0.66)	($0.56)
DLCO	$36.93	$50.73	($11.84)	($1.96)	$26.71	$27.63	($0.66)	($0.26)
Dominion	$64.37	$53.47	$10.07	$0.83	$33.27	$28.25	$4.77	$0.25
DPL	$70.58	$52.47	$14.92	$3.18	$32.49	$28.11	$3.58	$0.81
EKPC	$41.02	$54.54	($10.42)	($3.10)	$26.41	$28.26	($1.18)	($0.67)
JCPL	$62.97	$51.05	$9.57	$2.35	$24.08	$27.75	($3.97)	$0.30
Met-Ed	$59.99	$50.97	$8.13	$0.88	$23.96	$27.64	($3.73)	$0.05
PECO	$61.73	$51.05	$9.33	$1.36	$23.56	$27.72	($4.24)	$0.08
PENELEC	$52.10	$50.60	$0.78	$0.72	$26.45	$27.85	($1.73)	$0.33
Pepco	$63.05	$51.95	$9.58	$1.52	$34.70	$28.06	$6.03	$0.62
PPL	$61.49	$51.36	$9.45	$0.69	$24.20	$27.71	($3.54)	$0.03
PSEG	$65.62	$50.26	$12.95	$2.42	$25.19	$27.61	($2.82)	$0.40
RECO	$66.21	$50.11	$13.59	$2.51	$24.56	$27.56	($3.38)	$0.38
PJM	$52.02	$51.55	$0.48	($0.02)	$27.94	$27.80	$0.15	($0.00)

Hub Components

The real-time components of LMP for each hub are presented in Table 11-5 for the first three months of 2015 and the first three months of 2016.

Table 11-5 Hub real-time, load-weighted average LMP components (Dollars per MWh): January through March of 2015 and 2016

	2015 (Jan - Mar)				2016 (Jan - Mar)			
	Real-Time LMP	Energy Component	Congestion Component	Loss Component	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AEP Gen Hub	$37.40	$51.28	($9.95)	($3.93)	$25.34	$27.86	($1.25)	($1.27)
AEP-DAY Hub	$40.17	$50.90	($8.42)	($2.32)	$25.65	$27.27	($1.16)	($0.46)
ATSI Gen Hub	$41.58	$51.96	($9.08)	($1.30)	$25.96	$27.39	($1.30)	($0.14)
Chicago Gen Hub	$34.51	$48.58	($9.64)	($4.43)	$21.94	$26.36	($2.81)	($1.60)
Chicago Hub	$36.34	$49.67	($9.52)	($3.81)	$23.79	$26.62	($1.61)	($1.22)
Dominion Hub	$59.62	$53.81	$5.52	$0.29	$30.72	$27.10	$3.75	($0.13)
Eastern Hub	$64.78	$50.77	$9.99	$4.02	$28.94	$26.37	$1.64	$0.93
N Illinois Hub	$35.53	$48.66	($9.13)	($4.00)	$23.49	$26.48	($1.62)	($1.37)
New Jersey Hub	$62.68	$49.79	$9.94	$2.96	$24.09	$26.53	($2.85)	$0.41
Ohio Hub	$39.96	$50.54	($8.32)	($2.26)	$25.21	$26.69	($1.08)	($0.40)
West Interface Hub	$47.30	$55.05	($6.28)	($1.47)	$26.97	$26.69	$0.56	($0.28)
Western Hub	$55.82	$52.57	$2.54	$0.71	$29.48	$28.17	$1.13	$0.18

The day-ahead components of LMP for each hub are presented in Table 11-6 for the first three months of 2015 and 2016.

Table 11-6 Hub day-ahead, load-weighted average LMP components (Dollars per MWh): January through March of 2015 and 2016

	2015 (Jan - Mar)				2016 (Jan - Mar)			
	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AEP Gen Hub	$35.23	$48.22	($9.97)	($3.01)	$25.76	$27.68	($0.86)	($1.06)
AEP-DAY Hub	$39.65	$50.98	($9.83)	($1.50)	$26.31	$27.62	($0.94)	($0.37)
ATSI Gen Hub	$44.81	$54.21	($8.89)	($0.51)	$24.79	$25.18	($0.48)	$0.09
Chicago Gen Hub	$32.98	$47.98	($11.83)	($3.17)	$22.68	$27.66	($3.48)	($1.50)
Chicago Hub	$35.07	$49.58	($11.93)	($2.58)	$24.07	$27.35	($2.28)	($1.00)
Dominion Hub	$63.64	$53.23	$10.04	$0.38	$32.89	$28.28	$4.57	$0.04
Eastern Hub	$68.04	$51.87	$13.10	$3.07	$31.62	$27.86	$2.94	$0.82
N Illinois Hub	$34.39	$49.13	($11.86)	($2.88)	$24.09	$27.39	($2.09)	($1.20)
New Jersey Hub	$63.00	$50.09	$10.68	$2.23	$24.77	$27.56	($3.10)	$0.31
Ohio Hub	$39.70	$50.81	($9.78)	($1.33)	$26.10	$27.56	($1.10)	($0.35)
West Interface Hub	$45.34	$50.63	($4.49)	($0.80)	$28.36	$27.91	$0.69	($0.24)
Western Hub	$53.18	$50.59	$2.50	$0.09	$29.67	$28.00	$1.65	$0.03

Component Costs

Table 11-7 shows the total energy, loss and congestion component costs and the total PJM billing for January through March of 2009 through 2016. These totals are actually net energy, loss and congestion costs. Total congestion and marginal loss costs decreased in the first three months of 2016 compared to the first three months of 2015.

Table 11-7 Total PJM costs by component (Dollars (Millions)): January through March of 2009 through 2016[10 11]

	Component Costs (Millions)					
(Jan - Mar)	Energy Costs	Loss Costs	Congestion Costs	Total Costs	Total PJM Billing	Total Costs Percent of PJM Billing
2009	($218)	$454	$307	$543	$7,515	7.2%
2010	($208)	$417	$345	$554	$8,415	6.6%
2011	($210)	$410	$360	$560	$9,584	5.8%
2012	($136)	$234	$122	$220	$6,938	3.2%
2013	($178)	$278	$186	$286	$7,762	3.7%
2014	($515)	$776	$1,236	$1,497	$21,070	7.1%
2015	($272)	$425	$632	$785	$14,040	5.6%
2016	($114)	$170	$292	$349	$9,500	3.7%

Congestion

Congestion Accounting

Congestion occurs in the Day-Ahead and Real-Time Energy Markets.[12] Total congestion costs are equal to the net implicit congestion bill plus net explicit congestion costs plus net inadvertent congestion charges, incurred in both the Day-Ahead Energy Market and the balancing energy market.

In the analysis of total congestion costs, load congestion payments are netted against generation congestion credits on an hourly basis, by billing organization, and then summed for the given period.[13]

Load congestion payments and generation congestion credits are calculated for both the Day-Ahead and balancing energy markets.

- **Day-Ahead Load Congestion Payments.** Day-ahead load congestion payments are calculated for all cleared demand, decrement bids and day-ahead energy market sale transactions. Day-ahead load congestion payments 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 Generation Congestion Credits.** Day-ahead generation congestion credits are calculated for all cleared generation, increment offers and day-ahead energy market purchase transactions. Day-ahead generation congestion 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 Load Congestion Payments.** Balancing load congestion payments 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 load congestion payments are calculated using MW deviations and the real-time CLMP for each bus where a deviation exists.
- **Balancing Generation Congestion Credits.** Balancing generation congestion 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 generation congestion credits are calculated using MW deviations and the real-time CLMP for each bus where a deviation exists.
- **Explicit Congestion Costs.** Explicit congestion costs are the net congestion costs associated with point-to-point energy transactions. These costs equal the product of the transacted MW and CLMP differences between sources (origins) and sinks (destinations) in the Day-Ahead Energy Market. Balancing energy market explicit congestion costs 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.

10 The energy costs, loss costs and congestion costs include net inadvertent charges.
11 Total PJM billing is provided by PJM. The MMU is not able to verify the calculation.
12 When the term *congestion charge* is used in documents by PJM's Market Settlement Operations, it has the same meaning as the term *congestion costs* as used here.
13 This analysis does not treat affiliated billing organizations as a single organization. Thus, the generation congestion credits from one organization will not offset the load payments of its affiliate.

- 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.[14]

The congestion costs associated with specific constraints are the sum of the total day-ahead and balancing congestion costs associated with those constraints. The congestion costs in each zone are the sum of the congestion costs associated with each constraint that affects prices in the zone. The network nature of the transmission system means that congestion costs in a zone are frequently the result of constrained facilities located outside that zone.

Congestion costs can be both positive and negative and consequently load payments and generation credits can be both positive and negative. The CLMP is calculated with respect to the system reference bus LMP, 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 respective pricing node. The total CLMP at a pricing node is the sum of all constraint contributions to LMP and is equal to the difference between the actual LMP that results from transmission constraints, excluding losses, and the SMP. If an area experiences lower prices because of a constraint, the CLMP in that area is negative.[15]

The congestion metric requires careful review when considering the significance of congestion. The net congestion bill is calculated by subtracting generating congestion credits from load congestion payments. The logic is that congestion payments by load are offset by congestion revenues to generation, for the area analyzed. The net congestion bill is the source of payments to FTR holders. When load pays more for congestion in an area than generation receives, the positive difference is the source of payments to FTR holders as it is a measure of the value of transmission in bringing lower cost generation into the area.

Total congestion costs in PJM in the first three months of 2016 were $292.2 million, which was comprised of load congestion payments of $119.1 million, generation credits of -$181.6 million and explicit congestion of -$8.5 million. Total congestion costs in PJM in the first three months of 2015 were $631.7 million, which was comprised of load congestion payments of $332.5 million, generation credits of -$388.3 million and explicit congestion of -$89.1 million. The decrease in total congestion cost from the first three months of 2015 to the first three months of 2016 is primarily a result of the decrease in congestion costs incurred by generation.

14 OA. Schedule 1 (PJM Interchange Energy Market) §3.7.

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

Total Congestion

Table 11-8 shows total congestion for January through March of 2008 through 2016. Total congestion costs in Table 11-8 include congestion costs associated with PJM facilities and those associated with reciprocal, coordinated flowgates in the MISO and in the NYISO.[16] [17]

Table 11-8 Total PJM congestion (Dollars (Millions)): January through March of 2008 through 2016

	Congestion Costs (Millions)			
(Jan - Mar)	Congestion Cost	Percent Change	Total PJM Billing	Percent of PJM Billing
2008	$486	NA	$7,718	6.3%
2009	$307	(36.8%)	$7,515	4.1%
2010	$345	12.4%	$8,415	4.1%
2011	$360	4.3%	$9,584	3.8%
2012	$122	(66.0%)	$6,938	1.8%
2013	$186	51.9%	$7,762	2.4%
2014	$1,236	564.8%	$21,070	5.9%
2015	$632	(48.9%)	$14,040	4.5%
2016	$292	(53.7%)	$9,500	3.1%

Table 11-9 shows the congestion costs by accounting category by market for the first three months of 2016.

Table 11-9 Total PJM congestion costs by accounting category by market (Dollars (Millions)): January through March of 2008 through 2016

	Congestion Costs (Millions)									
	Day Ahead				Balancing					
(Jan - Mar)	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Inadvertent Charges	Grand Total
2008	$332.4	($220.0)	$39.9	$592.3	($46.0)	$29.5	($31.2)	($106.7)	$0.0	$485.6
2009	$120.2	($221.3)	$47.9	$389.5	($14.2)	($6.0)	($74.4)	($82.6)	($0.0)	$306.9
2010	$85.9	($293.1)	$12.9	$391.9	($5.7)	$12.1	($29.1)	($47.0)	($0.0)	$344.9
2011	$176.5	($226.7)	$4.1	$407.3	$21.6	$27.8	($41.2)	($47.4)	$0.0	$359.9
2012	$21.9	($131.4)	$27.5	$180.9	($5.1)	$11.3	($42.0)	($58.4)	$0.0	$122.4
2013	$85.0	($199.1)	$47.8	$331.9	($6.6)	$73.3	($66.0)	($145.9)	$0.0	$185.9
2014	$333.7	($1,193.9)	($94.3)	$1,433.3	$73.0	$208.9	($61.3)	($197.2)	$0.0	$1,236.1
2015	$327.0	($457.9)	($11.0)	$773.9	$5.4	$69.6	($78.0)	($142.2)	($0.0)	$631.7
2016	$120.2	($193.5)	$9.2	$322.9	($1.1)	$11.9	($17.7)	($30.8)	$0.0	$292.2

Table 11-10 and Table 11-11 show the total congestion costs for each transaction type in January through March of 2016 and 2015. Table 11-10 shows that in the first three months of 2016 DECs paid $17.9 million in congestion cost in the day-ahead market were paid $18.1 million in congestion credits in the balancing energy market, and received $0.2 million in net payment for congestion. In the first three months of 2016, INCs were paid $7.1 million in congestion credits in the day-ahead market, paid $1.8 million in congestion cost in the balancing energy market and received $5.4 million in net payment for congestion. In the first three months of 2016, up to congestion paid $6.1 million in congestion cost in the day-ahead market, were paid $19.1 million in congestion credits in balancing market and received $13.0 million in net payment for congestion.

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

17 See "Joint Operating Agreement Among and Between the New York Independent System Operator Inc. and PJM Interconnection, L.L.C.," (January 17, 2013) Section 35.12.1 <http://www.pjm.com/documents/agreements.aspx>.

Table 11-10 Total PJM congestion costs by transaction type by market (Dollars (Millions)): January through March of 2016

	Congestion Costs (Millions)									
	Day-Ahead				Balancing					
Transaction Type	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Inadvertent Charges	Grand Total
DEC	$17.9	$0.0	$0.0	$17.9	($18.1)	$0.0	$0.0	($18.1)	$0.0	($0.2)
Demand	$12.0	$0.0	$0.0	$12.0	$13.5	$0.0	$0.0	$13.5	$0.0	$25.5
Demand Response	($0.0)	$0.0	$0.0	($0.0)	($0.0)	$0.0	$0.0	($0.0)	$0.0	($0.0)
Export	$0.0	$0.0	$1.1	$1.1	$0.0	$0.0	($0.0)	($0.0)	$0.0	$1.1
Explicit Congestion Only	($19.2)	$0.0	($0.6)	($19.7)	($2.2)	$0.0	$0.7	($1.5)	$0.0	($21.3)
Generation	$0.0	($303.0)	$0.0	$303.0	$0.0	$20.8	$0.0	($20.8)	$0.0	$282.2
Grandfathered Overuse	$0.0	$0.0	$0.1	$0.1	$0.0	$0.0	$0.0	$0.0	$0.0	$0.1
Import	$0.0	($7.5)	$0.1	$7.6	$0.0	($12.7)	$0.6	$13.4	$0.0	$21.0
INC	$0.0	$7.1	$0.0	($7.1)	$0.0	($1.8)	$0.0	$1.8	$0.0	($5.4)
Internal Bilateral	$113.4	$113.7	$0.3	($0.0)	$5.7	$5.7	$0.0	($0.0)	$0.0	($0.0)
Up to Congestion	$0.0	$0.0	$6.1	$6.1	$0.0	$0.0	($19.1)	($19.1)	$0.0	($13.0)
Wheel In	$0.0	($3.9)	$2.1	$6.0	$0.0	($0.0)	$0.0	$0.0	$0.0	$6.0
Wheel Out	($3.9)	$0.0	$0.0	($3.9)	($0.0)	$0.0	$0.0	($0.0)	$0.0	($3.9)
Total	$120.2	($193.5)	$9.2	$322.9	($1.1)	$11.9	($17.7)	($30.7)	$0.0	$292.2

Table 11-11 Total PJM congestion costs by transaction type by market (Dollars (Millions)): January through March of 2015

	Congestion Costs (Millions)									
	Day-Ahead				Balancing					
Transaction Type	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Inadvertent Charges	Grand Total
DEC	$28.1	$0.0	$0.0	$28.1	($40.2)	$0.0	$0.0	($40.2)	$0.0	($12.1)
Demand	$78.2	$0.0	$0.0	$78.2	$32.1	$0.0	$0.0	$32.1	$0.0	$110.3
Demand Response	($0.2)	$0.0	$0.0	($0.2)	$0.1	$0.0	$0.0	$0.1	$0.0	($0.0)
Explicit Congestion Only	$0.0	$0.0	$1.0	$1.0	$0.0	$0.0	$0.0	$0.0	$0.0	$1.0
Export	$7.6	$0.0	$0.2	$7.8	$2.7	$0.0	$0.4	$3.1	$0.0	$10.9
Generation	$0.0	($640.8)	$0.0	$640.8	$0.0	$112.5	$0.0	($112.5)	$0.0	$528.3
Grandfathered Overuse	$0.0	$0.0	($2.2)	($2.2)	$0.0	$0.0	$0.4	$0.4	$0.0	($1.8)
Import	$0.0	($33.7)	$0.7	$34.4	$0.0	($52.7)	$1.1	$53.8	$0.0	$88.2
INC	$0.0	$3.3	$0.0	($3.3)	$0.0	($1.0)	$0.0	$1.0	$0.0	($2.3)
Internal Bilateral	$171.6	$171.6	$0.0	($0.0)	$11.3	$11.3	$0.0	($0.0)	$0.0	($0.0)
Up to Congestion	$0.0	$0.0	($28.5)	($28.5)	$0.0	$0.0	($79.4)	($79.4)	$0.0	($107.9)
Wheel In	$0.0	$41.6	$17.8	($23.8)	$0.0	($0.5)	($0.5)	($0.1)	$0.0	($23.9)
Wheel Out	$41.6	$0.0	$0.0	$41.6	($0.5)	$0.0	$0.0	($0.5)	$0.0	$41.1
Total	$327.0	($457.9)	($11.0)	$773.9	$5.4	$69.6	($78.0)	($142.2)	$0.0	$631.7

Table 11-12 shows the total congestion cost incurred by transaction type.

Table 11-12 Total PJM congestion costs by transaction type by market: January through March of 2015 to 2016 change (Dollars (Millions))

	Congestion Costs (Millions)									
	Day-Ahead				Balancing					
Transaction Type	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Inadvertent Charges	Grand Total
DEC	($10.3)	$0.0	$0.0	($10.3)	$22.2	$0.0	$0.0	$22.2	$0.0	$11.9
Demand	($66.3)	$0.0	$0.0	($66.3)	($17.9)	$0.0	$0.0	($17.9)	$0.0	($84.2)
Demand Response	$0.2	$0.0	$0.0	$0.2	($0.1)	$0.0	$0.0	($0.1)	$0.0	$0.0
Explicit Congestion Only	$0.0	$0.0	$0.1	$0.1	$0.0	$0.0	($0.0)	($0.0)	$0.0	$0.1
Export	($26.7)	$0.0	($0.8)	($27.6)	($4.9)	$0.0	$0.3	($4.6)	$0.0	($32.2)
Generation	$0.0	$337.8	$0.0	($337.8)	$0.0	($91.7)	$0.0	$91.7	$0.0	($246.1)
Grandfathered Overuse	$0.0	$0.0	$2.3	$2.3	$0.0	$0.0	($0.3)	($0.3)	$0.0	$1.9
Import	$0.0	$26.2	($0.5)	($26.8)	$0.0	$39.9	($0.5)	($40.4)	$0.0	($67.2)
INC	$0.0	$3.9	$0.0	($3.9)	$0.0	($0.8)	$0.0	$0.8	$0.0	($3.1)
Internal Bilateral	($58.3)	($58.0)	$0.3	($0.0)	($5.7)	($5.7)	$0.0	($0.0)	$0.0	($0.0)
Up to Congestion	$0.0	$0.0	$34.6	$34.6	$0.0	$0.0	$60.4	$60.4	$0.0	$95.0
Wheel In	$0.0	($45.5)	($15.7)	$29.8	$0.0	$0.5	$0.5	$0.1	$0.0	$29.9
Wheel Out	($45.5)	$0.0	$0.0	($45.5)	$0.5	$0.0	$0.0	$0.5	$0.0	($45.0)
Total	($206.8)	$264.5	$20.3	($451.0)	($6.0)	($57.7)	$60.3	$112.1	$0.0	($339.0)

Monthly Congestion

Table 11-13 shows that monthly total congestion costs ranged from $73.3 million to $111.3 million in the first three months of 2016.

Table 11-13 Monthly PJM congestion costs by market (Dollars (Millions)): January through March of 2015 and 2016

	Congestion Costs (Millions)							
	2015				2016			
	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total
Jan	$156.7	($24.4)	$0.0	$132.3	$123.5	($16.0)	$0.0	$107.6
Feb	$476.3	($46.4)	($0.0)	$429.8	$123.8	($12.5)	$0.0	$111.3
Mar	$140.9	($71.4)	$0.0	$69.5	$75.6	($2.2)	($0.0)	$73.3
Total	$773.9	($142.2)	($0.0)	$631.7	$322.9	($30.8)	$0.0	$292.2

Figure 11-1 shows PJM monthly total congestion cost for 2009 through March of 2016.

Figure 11-1 PJM monthly total congestion cost (Dollars (Millions)): 2009 through March of 2016

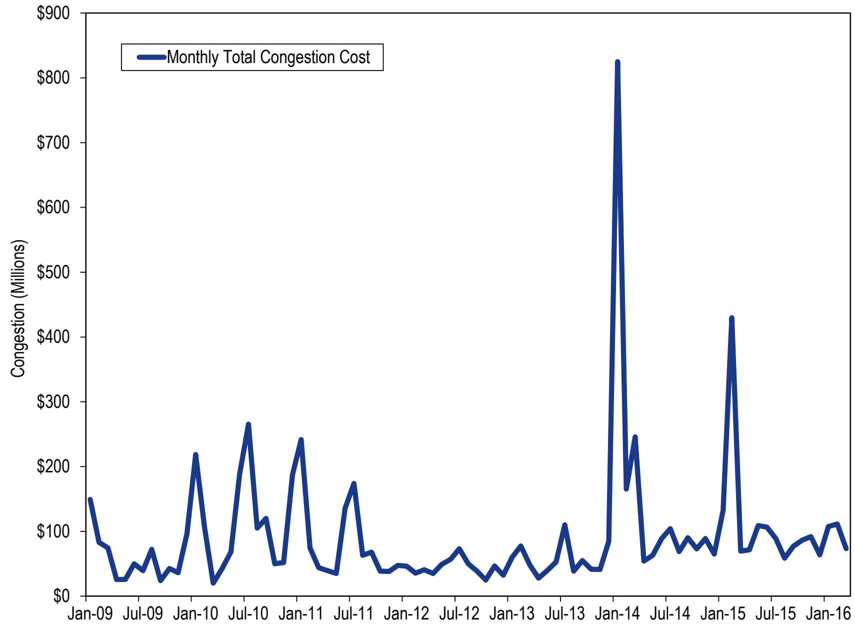


Table 11-14 shows the monthly total congestion costs for each virtual transaction type in the first three months of 2016 and Table 11-15 shows the monthly total congestion costs for each virtual transaction type in the first three months of 2015. Virtual transaction congestion costs, when positive, measure the total congestion cost to the virtual transaction and when negative, measure the total congestion credit to the virtual transaction. Table 11-14 and Table 11-15 shows that UTCs paid day-ahead congestion costs and were paid balancing congestion credits in the first three months of 2016 and in the first three months of 2015 UTCs were paid both day-ahead and balancing congestion credits. Total day-ahead congestion payments to UTCs decreased by $34.6 million from the first three months of 2015 to the first three months of 2016, from -$28.5 million in the first three months of 2015 to $6.1 million in the first three months of 2016. Over the same period balancing congestion payments to UTCs decreased from $79.4 million in the first three months of 2015 to $19.1 million in the first three months of 2016. Overall, total congestion payments to UTC decreased by 88.0 percent between January through March of 2015 and 2016. UTCs were paid $107.9 million in congestion in the first three months of 2015 and $13.0 million in the first three months of 2016. UTCs were paid $132.9 million in January 2014 alone, due to emergency conditions in that month. The significant reduction in UTC activity that started September 8, 2014, is reflected in the changes in day-ahead and balancing congestion related revenues attributed to UTCs between the two periods. The reduction in UTC activity was a result of FERC's UTC uplift refund notice, effective September 8, 2014.18

Table 11-14 Monthly PJM congestion costs by virtual transaction type and by market (Dollars (Millions)): January through March of 2016

	Congestion Costs (Millions)								
	Day-Ahead				Balancing				
	DEC	INC	Up to Congestion	Virtual Total	DEC	INC	Up to Congestion	Virtual Total	Virtual Grand Total
Jan	$6.8	($0.8)	$4.2	$10.1	($6.1)	($1.5)	($11.6)	($19.2)	($9.0)
Feb	$6.0	($1.0)	$1.2	$6.1	($8.1)	($0.5)	($6.3)	($14.9)	($8.8)
Mar	$5.1	($5.3)	$0.8	$0.5	($3.9)	$3.8	($1.2)	($1.3)	($0.8)
Total	$17.9	($7.1)	$6.1	$16.8	($18.1)	$1.8	($19.1)	($35.4)	($18.6)

Table 11-15 Monthly PJM congestion costs by virtual transaction type and by market (Dollars (Millions)): January through March of 2015

	Congestion Costs (Millions)								
	Day-Ahead				Balancing				
	DEC	INC	Up to Congestion	Virtual Total	DEC	INC	Up to Congestion	Virtual Total	Virtual Grand Total
Jan	$7.4	($3.2)	($3.4)	$0.8	($7.1)	$1.1	($11.3)	($17.4)	($16.6)
Feb	$11.1	$0.1	($37.6)	($26.4)	($15.4)	($0.6)	($13.0)	($29.0)	($55.4)
Mar	$9.6	($0.1)	$12.5	$22.0	($17.7)	$0.5	($55.1)	($72.3)	($50.3)
Total	$28.1	($3.3)	($28.5)	($3.7)	($40.2)	$1.0	($79.4)	($118.7)	($122.3)

18 See 18 CFR § 385.213 (2014).

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 the first three months of 2016, there were 66,373 day-ahead, congestion-event hours compared to 50,384 day-ahead congestion-event hours in the first three months of 2015. In the first three months of 2016, there were 6,763 real-time, congestion-event hours compared to 9,735 real-time, congestion-event hours in the first three months of 2015.

During the first three months of 2016, there were 3,985 congestion-event hours, 6.0 percent of day-ahead energy congestion-event hours, when the same facilities also constrained in the Real-Time Energy Market. During the first three months of 2016, there were 3,977 congestion-event hours, 58.8 percent of real-time congestion-event hours, when the same facilities were also constrained in the Day-Ahead Energy Market.

The Graceton Transformer was the largest contributor to total congestion costs in the first three months of 2016. With $29.8 million in total congestion costs, it accounted for 10.2 percent of the total PJM congestion costs in the first three months of 2016. The top five constraints in terms of congestion costs contributed $109.3 million, or 37.4 percent, of the total PJM congestion costs in the first three months of 2016. The top five constraints were the Graceton Transformer, the Bagley – Graceton Line, the Conastone – Northwest Line, the Milford – Steele Line and the Person - Halifax Flowgate.

Congestion by Facility Type and Voltage

In the first three months of 2016, day-ahead, congestion-event hours decreased on flowgates and interfaces and increased on lines and transformers. Real-time, congestion-event hours decreased on all types of facilities.

Day-ahead congestion costs decreased on all types of facilities in the first three months of 2016 compared to the first three months of 2015. Balancing congestion costs decreased on flowgates and transformers and increased on interfaces and transmission lines in the first three months of 2016 compared to the first three months of 2015.

Table 11-16 provides congestion-event hour subtotals and congestion cost subtotals comparing the first three months of 2016 results by facility type: line, transformer, interface, flowgate and unclassified facilities.[19] [20] Table 11-17 presents this information for the first three months of 2015.

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

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

Table 11-16 Congestion summary (By facility type): January through March of 2016

	Congestion Costs (Millions)										
	Day Ahead				Balancing					Event Hours	
Type	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day Ahead	Real Time
Flowgate	$17.6	($39.1)	($2.9)	$53.8	($0.9)	$3.9	($5.3)	($10.1)	$43.7	5,182	1,832
Interface	$15.1	($11.4)	($1.4)	$25.1	($0.1)	$0.3	$0.3	($0.0)	$25.0	1,746	86
Line	$62.8	($85.8)	$10.7	$159.2	$0.5	$5.4	($11.1)	($16.1)	$143.1	39,241	3,890
Other	($0.2)	($0.6)	$0.0	$0.4	$0.1	$0.0	$0.1	$0.1	$0.5	1,393	39
Transformer	$24.9	($56.6)	$2.7	$84.2	($1.8)	$2.0	($2.1)	($6.0)	$78.3	18,811	916
Unclassified	$0.0	($0.1)	$0.1	$0.2	$1.2	$0.3	$0.5	$1.4	$1.6	NA	NA
Total	$120.2	($193.5)	$9.2	$322.9	($1.1)	$11.9	($17.7)	($30.8)	$292.2	66,373	6,763

Table 11-17 Congestion summary (By facility type): January through March of 2015

	Congestion Costs (Millions)										
	Day Ahead				Balancing					Event Hours	
Type	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day Ahead	Real Time
Flowgate	$68.7	($35.8)	($21.9)	$82.7	$1.1	$0.3	($5.7)	($5.0)	$77.7	7,214	1,872
Interface	$44.1	($299.0)	($29.0)	$314.1	$10.7	$28.3	$4.4	($13.2)	$300.9	4,487	1,267
Line	$123.6	($62.9)	$45.5	$232.0	($7.9)	$36.0	($86.3)	($130.2)	$101.8	27,404	5,533
Other	$0.2	($0.0)	$0.2	$0.4	$0.0	$0.1	$0.1	$0.0	$0.4	568	26
Transformer	$90.5	($59.8)	($5.9)	$144.4	$2.2	$4.0	$3.0	$1.1	$145.5	10,711	1,037
Unclassified	($0.2)	($0.5)	$0.0	$0.3	($0.6)	$0.9	$6.5	$5.0	$5.4	NA	NA
Total	$327.0	($457.9)	($11.0)	$773.9	$5.4	$69.6	($78.0)	($142.2)	$631.7	50,384	9,735

Table 11-18 and Table 11-19 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 11-18. In January through March of 2016, there were 66,373 congestion-event hours in the Day-Ahead Energy Market. Among those day-ahead congestion-event hours, only 3,985 (6.0 percent) were also constrained in the Real-Time Energy Market. In January through March of 2015, among the 50,384 day-ahead congestion-event hours, only 5,606 (11.1 percent) were binding in the Real-Time Energy Market.[21]

Among the hours for which a facility is constrained in the Real-Time Energy Market, the number of hours during which the facility is also constrained in the Day-Ahead Energy Market are presented in Table 11-19. In January through March of 2016, there were 6,763 congestion-event hours in the Real-Time Energy Market. Among these real-time congestion-event hours, 3,977 (58.8 percent) were also constrained in the Day-Ahead Energy Market. In January through March of 2015, among the 9,735 real-time congestion-event hours, 5,582 (57.3 percent) were also in the Day-Ahead Energy Market.

21 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 11-18 Congestion event hours (Day-Ahead against Real-Time): January through March of 2015 and 2016

	Congestion Event Hours					
	2015 (Jan - Mar)			2016 (Jan - Mar)		
Type	Day Ahead Constrained	Corresponding Real Time Constrained	Percent	Day Ahead Constrained	Corresponding Real Time Constrained	Percent
Flowgate	7,214	1,112	15.4%	5,182	776	15.0%
Interface	4,487	958	21.4%	1,746	42	2.4%
Line	27,404	3,032	11.1%	39,241	2,600	6.6%
Other	568	0	0.0%	1,393	6	0.4%
Transformer	10,711	504	4.7%	18,811	561	3.0%
Total	50,384	5,606	11.1%	66,373	3,985	6.0%

Table 11-19 Congestion event hours (Real-Time against Day-Ahead): January through March of 2015 and 2016

	Congestion Event Hours					
	2015 (Jan - Mar)			2016 (Jan - Mar)		
Type	Real Time Constrained	Corresponding Day Ahead Constrained	Percent	Real Time Constrained	Corresponding Day Ahead Constrained	Percent
Flowgate	1,872	1,124	60.0%	1,832	778	42.5%
Interface	1,267	987	77.9%	86	44	51.2%
Line	5,533	3,014	54.5%	3,890	2,580	66.3%
Other	26	0	0.0%	39	6	15.4%
Transformer	1,037	457	44.1%	916	569	62.1%
Total	9,735	5,582	57.3%	6,763	3,977	58.8%

Table 11-20 shows congestion costs by facility voltage class for the first three months of 2016. Congestion costs in the first three months of 2016 decreased for facilities rated at 500 kV, 345 kV, 230 kV and 138 kV compared to the first three months of 2015 (Table 11-21).

Table 11-20 Congestion summary (By facility voltage): January through March of 2016

	Congestion Costs (Millions)										
	Day Ahead				Balancing					Event Hours	
Voltage (kV)	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day Ahead	Real Time
765	$0.2	($0.9)	$0.7	$1.8	$0.0	$0.0	$0.0	$0.0	$1.8	695	0
500	$21.4	($23.6)	($1.8)	$43.2	$1.9	$1.9	$1.1	$1.2	$44.4	2,364	372
345	($0.0)	($53.5)	$5.5	$58.9	$0.1	$6.6	($4.5)	($10.9)	$48.0	13,132	884
230	$81.4	($42.2)	($3.1)	$120.5	$4.5	$2.7	$1.8	$3.6	$124.1	13,359	2,115
161	($7.4)	($24.9)	($2.9)	$14.6	($2.1)	$2.6	($1.1)	($5.8)	$8.8	2,040	580
138	$16.7	($46.8)	$9.0	$72.6	($3.7)	$3.3	($13.9)	($20.9)	$51.7	23,959	1,652
115	$2.2	($2.2)	$0.5	$4.9	($1.3)	$0.6	($1.0)	($2.9)	$2.0	4,762	404
69	$5.7	$0.7	$1.1	$6.1	($1.7)	($6.0)	($0.7)	$3.6	$9.7	5,339	756
34	$0.0	$0.0	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	719	0
12	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	4	0
Unclassified	$0.0	($0.1)	$0.1	$0.2	$1.2	$0.3	$0.5	$1.4	$1.6	NA	NA
Total	$120.2	($193.5)	$9.2	$322.9	($1.1)	$11.9	($17.7)	($30.8)	$292.2	66,373	6,763

Table 11-21 Congestion summary (By facility voltage): January through March of 2015

	Congestion Costs (Millions)										
	Day Ahead				Balancing					Event Hours	
Voltage (kV)	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day Ahead	Real Time
765	$19.8	($46.4)	($6.3)	$59.8	$1.0	($0.1)	$1.8	$2.9	$62.7	1,298	133
500	$54.9	($302.1)	($28.3)	$328.7	$11.4	$28.3	$0.3	($16.7)	$312.0	4,504	827
460	($0.0)	($3.3)	$0.2	$3.6	$0.0	$0.0	$0.0	$0.0	$3.6	1,117	0
345	$3.6	($33.4)	$2.5	$39.5	$2.5	$1.7	($0.6)	$0.2	$39.7	4,958	659
230	$120.9	$8.7	$11.7	$123.9	($5.2)	$16.3	($33.0)	($54.6)	$69.3	10,587	2,273
161	($8.4)	($23.0)	($0.6)	$13.9	$0.3	$0.5	($1.4)	($1.6)	$12.3	1,789	747
138	$107.4	($55.3)	$8.1	$170.9	($3.7)	$20.4	($50.5)	($74.6)	$96.3	20,169	4,649
115	$1.5	($7.9)	$2.5	$11.8	$0.7	$1.3	($1.1)	($1.8)	$10.1	2,824	324
69	$27.6	$5.3	($1.0)	$21.4	($0.9)	$0.3	$0.0	($1.1)	$20.2	2,801	123
34	$0.0	($0.0)	$0.1	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	333	0
13	($0.0)	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	3	0
12	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	1	0
Unclassified	($0.2)	($0.5)	$0.0	$0.3	($0.6)	$0.9	$6.5	$5.0	$5.4	NA	NA
Total	$327.0	($457.9)	($11.0)	$773.9	$5.4	$69.6	($78.0)	($142.2)	$631.7	50,384	9,735

Constraint Duration

Table 11-22 lists the constraints in January through March of 2015 and 2016 that were most frequently binding and Table 11-23 shows the constraints which experienced the largest change in congestion-event hours from January through March of 2015 to 2016.

Table 11-22 Top 25 constraints with frequent occurrence: January through March of 2015 and 2016

			Event Hours						Percent of Annual Hours					
			Day Ahead			Real Time			Day Ahead			Real Time		
No.	Constraint	Type	2015	2016	Change	2015	2016	Change	2015	2016	Change	2015	2016	Change
1	Mercer IP - Galesburg	Flowgate	0	1,713	1,713	0	549	549	0%	20%	20%	0%	6%	6%
2	Monroe - Vineland	Line	359	1,917	1,558	0	252	252	4%	22%	18%	0%	3%	3%
3	Milford - Steele	Line	0	1,481	1,481	9	265	256	0%	17%	17%	0%	3%	3%
4	Miami Fort	Transformer	81	1,671	1,590	0	2	2	1%	19%	18%	0%	0%	0%
5	Graceton	Transformer	2	1,114	1,112	0	427	427	0%	13%	13%	0%	5%	5%
6	Bagley - Graceton	Line	499	1,051	552	146	433	287	6%	12%	6%	2%	5%	3%
7	Braidwood	Transformer	433	1,346	913	0	0	0	5%	15%	10%	0%	0%	0%
8	Cherry Valley	Transformer	98	1,026	928	14	141	127	1%	12%	11%	0%	2%	1%
9	Mardela - Vienna	Line	35	773	738	0	380	380	0%	9%	8%	0%	4%	4%
10	Kewanee - Hennepin Tap	Line	0	1,004	1,004	0	107	107	0%	11%	11%	0%	1%	1%
11	Tidd	Transformer	680	1,111	431	74	0	(74)	8%	13%	5%	1%	0%	(1%)
12	East Bend	Transformer	900	1,086	186	0	0	0	10%	12%	2%	0%	0%	0%
13	Conastone - Northwest	Line	0	607	607	0	432	432	0%	7%	7%	0%	5%	5%
14	Franklin - Vernon	Line	146	1,011	865	0	0	0	2%	12%	10%	0%	0%	0%
15	Clinch River	Transformer	231	1,003	772	0	0	0	3%	11%	9%	0%	0%	0%
16	East Danville - Banister	Line	1,577	1,001	(576)	126	0	(126)	18%	11%	(7%)	1%	0%	(1%)
17	Roxana - Praxair	Flowgate	0	662	662	0	335	335	0%	8%	8%	0%	4%	4%
18	Sayreville - Sayreville	Line	1,013	958	(55)	0	0	0	12%	11%	(1%)	0%	0%	0%
19	Everts Drive - South Troy	Line	70	864	794	0	49	49	1%	10%	9%	0%	1%	1%
20	Tanners Creek	Transformer	458	903	445	0	0	0	5%	10%	5%	0%	0%	0%
21	Cedar Grove - Roseland	Line	125	870	745	64	10	(54)	1%	10%	8%	1%	0%	(1%)
22	Bremo	Transformer	20	870	850	0	0	0	0%	10%	10%	0%	0%	0%
23	Cartanza	Transformer	10	824	814	0	0	0	0%	9%	9%	0%	0%	0%
24	E.K.P Hebron - Hebron	Line	0	817	817	0	0	0	0%	9%	9%	0%	0%	0%
25	La Salle - La Salle	Line	73	793	720	0	0	0	1%	9%	8%	0%	0%	0%

Table 11-23 Top 25 constraints with largest year-to-year change in occurrence: January through March of 2015 and 2016

			Event Hours						Percent of Annual Hours					
			Day Ahead			Real Time			Day Ahead			Real Time		
No.	Constraint	Type	2015	2016	Change	2015	2016	Change	2015	2016	Change	2015	2016	Change
1	Bergen - New Milford	Line	2,069	18	(2,051)	767	0	(767)	24%	0%	(23%)	9%	0%	(9%)
2	Oak Grove - Galesburg	Flowgate	1,789	0	(1,789)	747	3	(744)	20%	0%	(20%)	9%	0%	(8%)
3	Mercer IP - Galesburg	Flowgate	0	1,713	1,713	0	549	549	0%	20%	20%	0%	6%	6%
4	Maywood - Saddlebrook	Line	1,681	29	(1,652)	442	0	(442)	19%	0%	(19%)	5%	0%	(5%)
5	Easton	Transformer	2,005	91	(1,914)	0	0	0	23%	1%	(22%)	0%	0%	0%
6	Monroe - Vineland	Line	359	1,917	1,558	0	252	252	4%	22%	18%	0%	3%	3%
7	Milford - Steele	Line	0	1,481	1,481	9	265	256	0%	17%	17%	0%	3%	3%
8	Miami Fort	Transformer	81	1,671	1,590	0	2	2	1%	19%	18%	0%	0%	0%
9	Graceton	Transformer	2	1,114	1,112	0	427	427	0%	13%	13%	0%	5%	5%
10	Bunsonville - Eugene	Flowgate	1,148	0	(1,148)	272	0	(272)	13%	0%	(13%)	3%	0%	(3%)
11	Mahans Lane - Tidd	Line	978	0	(978)	394	0	(394)	11%	0%	(11%)	4%	0%	(4%)
12	Breed - Wheatland	Flowgate	1,235	0	(1,235)	90	0	(90)	14%	0%	(14%)	1%	0%	(1%)
13	Mardela - Vienna	Line	35	773	738	0	380	380	0%	9%	8%	0%	4%	4%
14	Brucea	Transformer	1,117	0	(1,117)	0	0	0	13%	0%	(13%)	0%	0%	0%
15	Kewanee - Hennepin Tap	Line	0	1,004	1,004	0	107	107	0%	11%	11%	0%	1%	1%
16	Cherry Valley	Transformer	98	1,026	928	14	141	127	1%	12%	11%	0%	2%	1%
17	Conastone - Northwest	Line	0	607	607	0	432	432	0%	7%	7%	0%	5%	5%
18	Roxana - Praxair	Flowgate	0	662	662	0	335	335	0%	8%	8%	0%	4%	4%
19	Bedington - Black Oak	Interface	1,320	542	(778)	255	52	(203)	15%	6%	(9%)	3%	1%	(2%)
20	SENECA	Interface	419	0	(419)	514	0	(514)	5%	0%	(5%)	6%	0%	(6%)
21	Braidwood	Transformer	433	1,346	913	0	0	0	5%	15%	10%	0%	0%	0%
22	Rising	Flowgate	611	0	(611)	295	3	(292)	7%	0%	(7%)	3%	0%	(3%)
23	Wolf Creek	Transformer	710	0	(710)	171	0	(171)	8%	0%	(8%)	2%	0%	(2%)
24	Franklin - Vernon	Line	146	1,011	865	0	0	0	2%	12%	10%	0%	0%	0%
25	Bremo	Transformer	20	870	850	0	0	0	0%	10%	10%	0%	0%	0%

Constraint Costs

Table 11-24 and Table 11-25 present the top constraints affecting congestion costs by facility for the periods January through March of 2016 and 2015.

Table 11-24 Top 25 constraints affecting PJM congestion costs (By facility): January through March of 2016

				Congestion Costs (Millions)								Percent of Total PJM Congestion Costs	
				Day Ahead				Balancing					
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	2016 (Jan - Mar)
1	Graceton	Transformer	BGE	$17.7	($11.5)	($1.8)	$27.4	($0.5)	($0.9)	$2.0	$2.4	$29.8	10.2%
2	Bagley - Graceton	Line	BGE	$21.5	($1.8)	($1.4)	$21.8	$0.6	($1.2)	$1.2	$3.0	$24.8	8.5%
3	Conastone - Northwest	Line	BGE	$20.1	($4.4)	($2.0)	$22.5	$0.5	$0.4	$2.2	$2.3	$24.8	8.5%
4	Milford - Steele	Line	DPL	($8.3)	($25.7)	$0.1	$17.5	$2.2	$1.4	($1.7)	($0.9)	$16.6	5.7%
5	Person - Halifax	Flowgate	MISO	$29.9	$16.1	($0.2)	$13.5	$0.0	$0.0	($0.2)	($0.2)	$13.3	4.5%
6	Kanawha River - Matt Funk	Line	AEP	$2.7	($17.1)	($1.1)	$18.8	($0.7)	$2.5	($3.3)	($6.6)	$12.2	4.2%
7	Loudoun	Transformer	500	$1.1	($9.8)	($0.3)	$10.6	$0.8	$0.7	$0.5	$0.6	$11.1	3.8%
8	AP South	Interface	500	$8.8	($3.2)	($1.2)	$10.7	$0.0	$0.0	$0.0	$0.0	$10.7	3.7%
9	Mercer IP - Galesburg	Flowgate	MISO	($7.3)	($23.2)	($2.8)	$13.1	($0.0)	$2.2	($0.8)	($3.0)	$10.1	3.4%
10	Conastone - Peach Bottom	Line	500	$5.8	($2.6)	($0.2)	$8.2	$0.7	$1.0	$0.4	$0.1	$8.3	2.8%
11	Cherry Valley	Transformer	ComEd	$7.3	($8.2)	$1.1	$16.5	($2.6)	$1.5	($4.2)	($8.3)	$8.2	2.8%
12	Bedington - Black Oak	Interface	500	$4.5	($4.2)	($0.7)	$8.0	$0.1	$0.1	$0.2	$0.2	$8.2	2.8%
13	Cherry Valley	Flowgate	MISO	($0.4)	($7.6)	$0.4	$7.7	$0.0	$0.0	$0.0	$0.0	$7.7	2.6%
14	Cherry Valley - Silver Lake	Flowgate	MISO	($1.3)	($7.2)	$0.7	$6.6	$0.0	$0.0	$0.0	$0.0	$6.6	2.3%
15	Kanawha	Transformer	AEP	$0.1	($5.7)	$0.3	$6.1	$0.0	$0.0	$0.0	$0.0	$6.1	2.1%
16	Mardela - Vienna	Line	DPL	($1.4)	($3.5)	($0.1)	$2.0	($0.6)	($4.1)	$0.5	$4.0	$6.0	2.1%
17	AEP - DOM	Interface	500	$1.4	($2.6)	$0.7	$4.7	$0.2	($0.0)	$0.1	$0.4	$5.1	1.7%
18	Meadow Brook - Strasburg	Line	AP	$8.0	$4.1	($0.2)	$3.6	($0.9)	($0.7)	$0.9	$0.6	$4.2	1.5%
19	Bremo	Transformer	Dominion	($1.4)	($5.1)	$0.3	$4.0	$0.0	$0.0	$0.0	$0.0	$4.0	1.4%
20	Braidwood - East Frankfurt	Flowgate	MISO	($0.0)	($3.2)	$0.4	$3.6	$0.0	$0.0	$0.0	$0.0	$3.6	1.2%
21	Kammer	Transformer	AEP	($1.3)	($5.5)	($0.2)	$4.0	$0.3	$0.6	($0.5)	($0.8)	$3.2	1.1%
22	Batesville - Hubble	Flowgate	MISO	($1.2)	($4.5)	($0.3)	$3.0	$0.2	($0.2)	($0.5)	($0.2)	$2.8	1.0%
23	Monroe - Vineland	Line	AECO	$6.4	$4.7	$1.7	$3.4	($1.0)	($1.6)	($1.3)	($0.6)	$2.7	0.9%
24	Richmond - Waneeta	Line	PECO	$0.5	($2.0)	$0.0	$2.5	$0.1	$0.6	$0.7	$0.2	$2.7	0.9%
25	Braidwood - East Frankfort	Line	ComEd	($0.1)	($2.6)	$0.1	$2.6	$0.0	$0.0	$0.0	$0.0	$2.6	0.9%

Table 11-25 Top 25 constraints affecting PJM congestion costs (By facility): January through March of 2015

				Congestion Costs (Millions)								Percent of Total PJM Congestion Costs	
				Day Ahead				Balancing					
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	2015 (Jan - Mar)
1	5004/5005 Interface	Interface	500	($22.8)	($132.5)	($9.1)	$100.6	$7.0	$22.4	$1.9	($13.5)	$87.1	13.8%
2	Bedington - Black Oak	Interface	500	$34.9	($40.2)	($7.4)	$67.7	$2.2	$1.8	$3.3	$3.7	$71.4	11.3%
3	AEP - DOM	Interface	500	$25.3	($26.7)	($1.0)	$51.0	$0.9	$1.6	($1.9)	($2.6)	$48.4	7.7%
4	AP South	Interface	500	$29.9	($20.8)	($4.5)	$46.2	$0.3	$0.2	$0.6	$0.7	$46.9	7.4%
5	Joshua Falls	Transformer	AEP	$9.5	($35.5)	($4.9)	$40.1	$0.7	($0.1)	$2.3	$3.1	$43.2	6.8%
6	Bergen - New Milford	Line	PSEG	$23.1	$17.1	$15.4	$21.4	($6.6)	$8.5	($47.0)	($62.1)	($40.7)	(6.4%)
7	Person - Halifax	Flowgate	MISO	$78.9	$28.5	($10.6)	$39.9	$0.0	($0.0)	($0.1)	($0.1)	$39.8	6.3%
8	Maywood - Saddlebrook	Line	PSEG	$7.9	$3.9	$6.1	$10.1	($4.8)	$8.6	($20.7)	($34.1)	($24.0)	(3.8%)
9	Easton	Transformer	DPL	$26.5	$6.1	($0.9)	$19.5	$0.0	$0.0	$0.0	$0.0	$19.5	3.1%
10	East	Interface	500	($10.0)	($31.2)	($1.9)	$19.2	($0.1)	$0.3	$0.5	$0.1	$19.4	3.1%
11	Mahans Lane - Tidd	Line	AEP	$7.7	($13.0)	($1.5)	$19.1	$0.4	$1.1	$0.9	$0.2	$19.3	3.1%
12	49th Street - Hoboken	Line	PSEG	$0.0	$0.0	$0.0	$0.0	($2.8)	$2.2	($13.1)	($18.1)	($18.1)	(2.9%)
13	East Danville - Banister	Line	AEP	$7.5	($5.8)	$1.3	$14.5	$0.5	($1.5)	($0.6)	$1.4	$15.9	2.5%
14	Breed - Wheatland	Flowgate	MISO	($1.6)	($14.5)	$0.6	$13.5	$0.0	($0.7)	$0.1	$0.8	$14.3	2.3%
15	Valley	Transformer	500	$13.8	($0.5)	($0.5)	$13.8	$0.0	$0.0	$0.0	$0.0	$13.8	2.2%
16	Cloverdale	Transformer	AEP	$5.9	($9.2)	($1.6)	$13.6	$0.0	$0.0	$0.0	$0.0	$13.6	2.1%
17	Central	Interface	500	($15.5)	($32.7)	($3.9)	$13.3	$0.1	$1.0	$0.3	($0.7)	$12.6	2.0%
18	Oak Grove - Galesburg	Flowgate	MISO	($8.4)	($23.0)	($0.6)	$13.9	$0.3	$0.5	($1.4)	($1.6)	$12.3	2.0%
19	Bagley - Graceton	Line	BGE	$8.2	($1.8)	$0.0	$10.1	($0.0)	($1.6)	$0.2	$1.8	$11.9	1.9%
20	West	Interface	500	($1.6)	($14.3)	($0.9)	$11.8	$0.2	$1.0	$0.1	($0.6)	$11.3	1.8%
21	Dravosburg - West Mifflin	Line	DLCO	$15.9	$3.4	($0.7)	$11.8	$0.4	$2.7	($0.1)	($2.3)	$9.5	1.5%
22	Rising	Flowgate	MISO	$0.5	($11.3)	($6.4)	$5.5	$0.2	($0.1)	$3.5	$3.8	$9.3	1.5%
23	49 Street - Hoboken	Line	PSEG	$1.2	($0.9)	$5.3	$7.4	$0.0	$0.0	$0.0	$0.0	$7.4	1.2%
24	Wescosville	Transformer	PPL	$10.1	$4.2	$1.3	$7.2	$0.1	($0.2)	($0.4)	($0.0)	$7.1	1.1%
25	Valley	Transformer	Dominion	$6.7	($0.9)	($0.1)	$7.4	$0.1	$0.5	($0.2)	($0.5)	$6.9	1.1%

Figure 11-2 shows the locations of the top 10 constraints by PJM total congestion costs in the first three months of 2016. Figure 11-3 shows the locations of the top 10 constraints by PJM day-ahead congestion costs in the first three months of 2016. Figure 11-4 shows the locations of the top 10 constraints by PJM balancing congestion costs in the first three months of 2016.

Figure 11-2 Location of the top 10 constraints by PJM total congestion costs: January through March of 2016

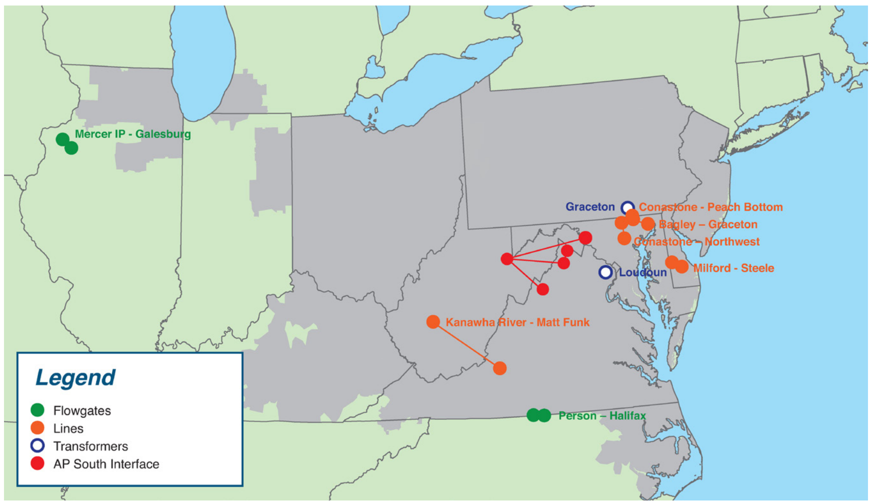


Figure 11-3 Location of the top 10 constraints by PJM day-ahead congestion costs: January through March of 2016

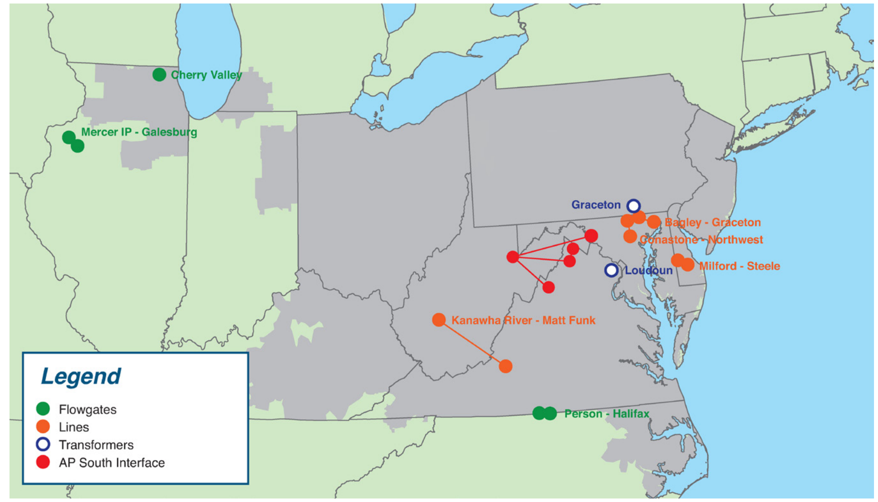
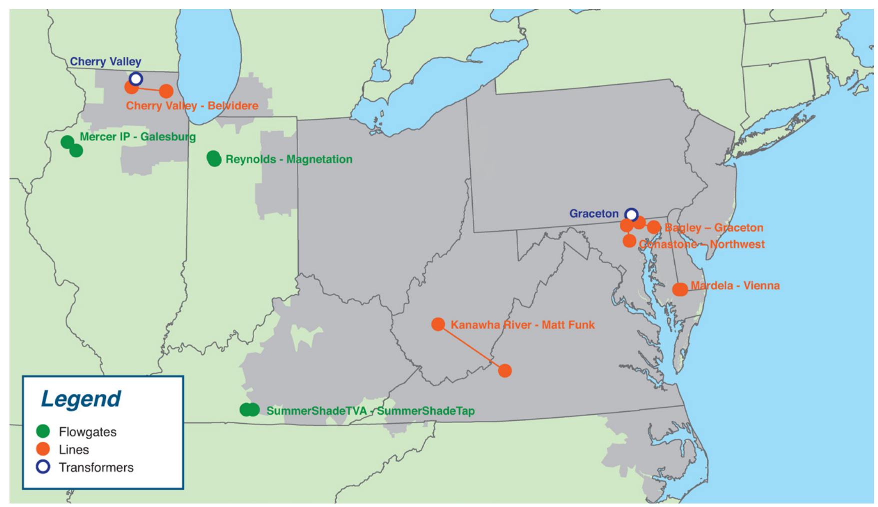


Figure 11-4 Location of the top 10 constraints by PJM balancing congestion costs: January through March of 2016



Congestion-Event Summary for MISO Flowgates

PJM and MISO have a joint operating agreement (JOA) which defines a coordinated methodology for congestion management. This agreement establishes reciprocal, coordinated flowgates in the combined footprint whose operating limits are respected by the operators of both organizations.[22] A flowgate is a facility or group of facilities that may act as constraint points on the regional system.[23] PJM models these coordinated flowgates and controls for them in its security-constrained, economic dispatch.

As of March 31, 2016, PJM had 133 flowgates eligible for M2M (Market to Market) coordination and MISO had 263 flowgates eligible for M2M coordination.

Table 11-26 and Table 11-27 show the MISO flowgates which PJM and/or MISO took dispatch action to control during the first three months of 2016 and the first three months of 2015, and which had the greatest congestion cost impact on PJM. Total congestion costs associated with a given constraint may be positive or negative in value. The top congestion cost impacts for MISO flowgates affecting PJM and MISO dispatch are presented by constraint, in descending order of the absolute value of total congestion costs. Among MISO flowgates in the first three months of 2016, the Person - Halifax Flowgate made the most significant contribution to positive congestion while the Summer Shade TVA – Summer Shade Tap Flowgate made the most significant contribution to negative congestion.

Table 11-26 Top 20 congestion cost impacts from MISO flowgates affecting PJM dispatch (By facility): January through March of 2016

		Congestion Costs (Millions)										
		Day Ahead				Balancing					Event Hours	
No.	Constraint	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day Ahead	Real Time
1	Person - Halifax	$29.9	$16.1	($0.2)	$13.5	$0.0	$0.0	($0.2)	($0.2)	$13.3	719	5
2	Mercer IP - Galesburg	($7.3)	($23.2)	($2.8)	$13.1	($0.0)	$2.2	($0.8)	($3.0)	$10.1	1,713	549
3	Cherry Valley	($0.4)	($7.6)	$0.4	$7.7	$0.0	$0.0	$0.0	$0.0	$7.7	293	0
4	Cherry Valley - Silver Lake	($1.3)	($7.2)	$0.7	$6.6	$0.0	$0.0	$0.0	$0.0	$6.6	365	0
5	Braidwood - East Frankfurt	($0.0)	($3.2)	$0.4	$3.6	$0.0	$0.0	$0.0	$0.0	$3.6	169	0
6	Batesville - Hubble	($1.2)	($4.5)	($0.3)	$3.0	$0.2	($0.2)	($0.5)	($0.2)	$2.8	284	58
7	SummerShadeTVA - SummerShadeTap	($0.2)	($1.4)	($0.1)	$1.1	($2.1)	$0.4	($0.3)	($2.8)	($1.7)	209	26
8	Roxana - Praxair	($0.9)	($2.3)	($1.0)	$0.4	$0.5	($0.3)	($2.4)	($1.6)	($1.2)	662	335
9	Reynolds - Magnetation	($0.5)	($3.2)	$0.3	$3.1	$0.0	$0.7	($1.3)	($2.0)	$1.1	334	205
10	Monroe - Bayshore	($0.2)	($0.8)	($0.1)	$0.5	($0.0)	($0.0)	($0.0)	($0.0)	$0.4	23	18
11	Rantoul - Rantoul Jct	($0.1)	($0.4)	($0.1)	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	61	0
12	Pleasant Valley - Belvidere	($0.0)	($0.3)	($0.0)	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	12	0
13	Dixon - McGirr Rd	($0.0)	($0.2)	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	48	0
14	Burnham - Munster	($0.0)	($0.1)	$0.1	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	44	0
15	West Dekalb - Glidden	($0.0)	($0.1)	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	59	0
16	Gary Ave	($0.1)	($0.3)	($0.1)	$0.2	$0.0	($0.0)	($0.1)	($0.1)	$0.1	56	12
17	North Champaign - Vermilion	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($0.1)	($0.1)	($0.1)	0	3
18	Vermilion - Tilton	($0.0)	($0.1)	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	56	0
19	Butler - Karns City	$0.1	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	9	0
20	Bunsonville	($0.0)	($0.1)	($0.0)	$0.0	($0.0)	$0.0	$0.0	($0.0)	$0.0	34	3

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

23 See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C.," (December 11, 2008), Section 2.2.24 <http://www.pjm.com/documents/agreements.aspx>.

Table 11-27 Top 20 congestion cost impacts from MISO flowgates affecting PJM dispatch (By facility): January through March of 2015

		Congestion Costs (Millions)										
		Day Ahead				Balancing					Event Hours	
No.	Constraint	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day Ahead	Real Time
1	Person - Halifax	$78.9	$28.5	($10.6)	$39.9	$0.0	($0.0)	($0.1)	($0.1)	$39.8	1,249	6
2	Breed - Wheatland	($1.6)	($14.5)	$0.6	$13.5	$0.0	($0.7)	$0.1	$0.8	$14.3	1,235	90
3	Oak Grove - Galesburg	($8.4)	($23.0)	($0.6)	$13.9	$0.3	$0.5	($1.4)	($1.6)	$12.3	1,789	747
4	Rising	$0.5	($11.3)	($6.4)	$5.5	$0.2	($0.1)	$3.5	$3.8	$9.3	611	295
5	Bunsonville - Eugene	($1.1)	($9.6)	($5.4)	$3.1	$0.0	($0.1)	$0.6	$0.8	$3.8	1,148	272
6	Klondcin - Purdue	$0.0	($0.1)	$0.0	$0.1	($0.0)	$0.4	($2.5)	($2.9)	($2.8)	40	48
7	Volunteer - Phipps Bend	$0.1	($1.3)	$0.1	$1.5	$0.0	($0.3)	($4.5)	($4.1)	($2.6)	43	49
8	Michigan City - Laporte	$0.6	($1.5)	$0.1	$2.1	$0.0	$0.0	$0.0	$0.0	$2.1	572	0
9	Pierce - Foster	($0.2)	($1.0)	$0.1	$0.9	$0.0	$0.0	$0.0	$0.0	$0.9	43	0
10	Burnham - Munster	$0.1	($0.5)	$0.1	$0.6	$0.0	$0.0	$0.0	$0.0	$0.6	85	0
11	Reynolds - Magnetation	$0.0	($1.0)	($0.0)	$1.0	$0.0	$0.2	($0.3)	($0.4)	$0.5	156	28
12	Reynold - Monticello	$0.0	($0.0)	$0.0	$0.0	($0.0)	$0.3	($0.2)	($0.5)	($0.5)	22	23
13	Wake - Carso	$0.0	$0.0	$0.0	$0.0	$0.4	$0.1	($0.0)	$0.2	$0.2	0	7
14	Monroe - Bayshore	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.4)	($0.1)	$0.2	$0.2	0	29
15	Byron - Cherry Valley	$0.0	($0.2)	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	27	0
16	Casey - Breed	($0.0)	($0.1)	($0.0)	$0.1	($0.0)	($0.0)	$0.0	$0.0	$0.1	89	1
17	Cherry Valley - Silver Lake	($0.0)	($0.1)	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	14	0
18	Hennepin	($0.0)	($0.1)	$0.0	$0.1	$0.0	($0.0)	($0.0)	($0.0)	$0.1	54	38
19	Powerton Jct - Lilly	($0.0)	($0.1)	$0.0	$0.1	($0.0)	($0.1)	($0.1)	($0.0)	$0.1	10	13
20	St John	$0.0	($0.0)	$0.0	$0.0	($0.0)	($0.0)	($0.1)	($0.1)	($0.0)	8	4

Congestion-Event Summary for NYISO Flowgates

PJM and NYISO have a joint operating agreement (JOA) which defines a coordinated methodology for congestion management. This agreement establishes a structure and framework for the reliable operation of the interconnected PJM and NYISO transmission systems and efficient market operation through M2M coordination.[24] Only a subset of all transmission constraints that exist in either market are eligible for coordinated congestion management. This subset of transmission constraints is identified as M2M flowgates. Flowgates eligible for the M2M coordination process are called M2M flowgates.[25]

Table 11-28 shows the NYISO flowgates which PJM and/or NYISO took dispatch action to control during the first three months of 2016, and which had the greatest congestion cost impact on PJM.

Congestion-Event Summary for the 500 kV System

Constraints on the 500 kV system generally have a regional impact. Table 11-30 and Table 11-31 show the 500 kV constraints affecting congestion costs in PJM for the first three months of 2016 and the first three months of 2015. Total congestion costs are the sum of the day-ahead and balancing congestion cost components. Total congestion costs associated with a given constraint may be positive or negative in value. The 500 kV constraints affecting congestion costs in PJM are presented by constraint, in descending order of the absolute value of total congestion costs.

24 See "Joint Operating Agreement Among and Between the New York Independent System Operator Inc. and PJM Interconnection, L.L.C.," (January 17, 2013) Section 35.3.1 <http://www.pjm.com/documents/agreements.aspx>.

25 See "Joint Operating Agreement Among and Between the New York Independent System Operator Inc. and PJM Interconnection, L.L.C.," (January 17, 2013) Section 35.23 <http://www.pjm.com/documents/agreements.aspx>.

Table 11-28 Top two congestion cost impacts from NYISO flowgates affecting PJM dispatch (By facility): January through March of 2016

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit Costs	Total	LoadPayments	Generation Credits	Explicit Costs	Total	Grand Total	Day Ahead	Real Time
1	Central East	Flowgate	NYISO	$0.0	$0.0	$0.0	$0.0	$0.4	$1.0	$0.2	($0.3)	($0.3)	0	516
2	Dysinger East	Flowgate	NYISO	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.0	0	2

Table 11-29 Top two congestion cost impacts from NYISO flowgates affecting PJM dispatch (By facility): January through March of 2015

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day Ahead	Real Time
1	Central East	Flowgate	NYISO	$0.0	$0.0	$0.0	$0.0	$0.0	$0.4	($0.1)	($0.5)	($0.5)	0	149
2	Dysinger East	Flowgate	NYISO	$0.0	$0.0	$0.0	$0.0	$0.0	($0.1)	$0.1	$0.2	$0.2	0	25

Table 11-30 Regional constraints summary (By facility): January through March of 2016

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day Ahead	Real Time
1	Loudoun	Transformer	500	$1.1	($9.8)	($0.3)	$10.6	$0.8	$0.7	$0.5	$0.6	$11.1	212	45
2	AP South	Interface	500	$8.8	($3.2)	($1.2)	$10.7	$0.0	$0.0	$0.0	$0.0	$10.7	416	0
3	Conastone - Peach Bottom	Line	500	$5.8	($2.6)	($0.2)	$8.2	$0.7	$1.0	$0.4	$0.1	$8.3	502	254
4	Bedington - Black Oak	Interface	500	$4.5	($4.2)	($0.7)	$8.0	$0.1	$0.1	$0.2	$0.2	$8.2	542	52
5	AEP - DOM	Interface	500	$1.4	($2.6)	$0.7	$4.7	$0.2	($0.0)	$0.1	$0.4	$5.1	592	4
6	West	Interface	500	($0.0)	($0.6)	($0.1)	$0.5	$0.0	$0.0	($0.0)	($0.0)	$0.5	38	2
7	5004/5005 Interface	Interface	500	($0.1)	($0.6)	($0.0)	$0.5	$0.0	$0.0	$0.0	$0.0	$0.5	29	0
8	Wylie Ridge	Transformer	500	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.1)	($0.1)	0	6
9	East	Interface	500	($0.0)	($0.1)	($0.0)	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	27	0

Table 11-31 Regional constraints summary (By facility): January through March of 2015

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day Ahead	Real Time
1	5004/5005 Interface	Interface	500	($22.8)	($132.5)	($9.1)	$100.6	$7.0	$22.4	$1.9	($13.5)	$87.1	536	318
2	Bedington - Black Oak	Interface	500	$34.9	($40.2)	($7.4)	$67.7	$2.2	$1.8	$3.3	$3.7	$71.4	1,320	255
3	AEP - DOM	Interface	500	$25.3	($26.7)	($1.0)	$51.0	$0.9	$1.6	($1.9)	($2.6)	$48.4	579	41
4	AP South	Interface	500	$29.9	($20.8)	($4.5)	$46.2	$0.3	$0.2	$0.6	$0.7	$46.9	547	30
5	East	Interface	500	($10.0)	($31.2)	($1.9)	$19.2	($0.1)	$0.3	$0.5	$0.1	$19.4	362	16
6	Valley	Transformer	500	$13.8	($0.5)	($0.5)	$13.8	$0.0	$0.0	$0.0	$0.0	$13.8	305	0
7	Central	Interface	500	($15.5)	($32.7)	($3.9)	$13.3	$0.1	$1.0	$0.3	($0.7)	$12.6	279	41
8	West	Interface	500	($1.6)	($14.3)	($0.9)	$11.8	$0.2	$1.0	$0.1	($0.6)	$11.3	236	49
9	Nagel - Phipps Bend	Line	500	($0.0)	($0.2)	$0.6	$0.9	$0.0	$0.0	$0.0	$0.0	$0.9	134	0

Congestion Costs by Physical and Financial Participants

In order to evaluate the recipients and payers of congestion, the MMU categorized all participants in PJM as either physical or financial. Physical entities include utilities and customers which primarily take physical positions in PJM markets. Financial entities include banks and hedge funds which primarily take financial positions in PJM markets. International market participants that primarily take financial positions in PJM markets are generally considered to be financial entities even if they are utilities in their own countries.

In the first three months of 2016, financial entities as a group were net recipients of congestion credits, and physical entities were net payers of congestion charges. Explicit costs are the primary source of congestion credits to financial entities. UTCs are in the explicit cost category and comprise most of that category. Total explicit cost is equal to day-ahead explicit cost plus balancing explicit cost. In the first three months of 2016, the total explicit cost was -\$8.5 million (indicating net credits to participants), of which -\$13.0 million (153.0 percent) was credited to UTCs. In the first three months of 2015, the total explicit cost was -\$89.1 million, of which -\$107.9 million (121.2 percent) was credited to UTCs. In the first three months of 2016, financial entities received \$16.7 million in net congestion credits, a decrease of \$52.5 million or 75.9 percent compared to the first three months of 2015. In the first three months of 2016, physical entities paid \$308.8 million in congestion charges, a decrease of \$392.0 million or 55.9 percent compared to the first three months of 2015.

Table 11-32 Congestion cost by type of participant: January through March of 2016

	Congestion Costs (Millions)									
	Day Ahead				Balancing					
Participant Type	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Inadvertent Charges	Grand Total
Financial	$2.4	($0.5)	($0.5)	$2.4	($10.6)	($2.5)	($11.0)	($19.1)	$0.0	($16.7)
Physical	$117.8	($193.0)	$9.7	$320.5	$9.5	$14.4	($6.7)	($11.7)	$0.0	$308.8
Total	$120.2	($193.5)	$9.2	$322.9	($1.1)	$11.9	($17.7)	($30.8)	$0.0	$292.2

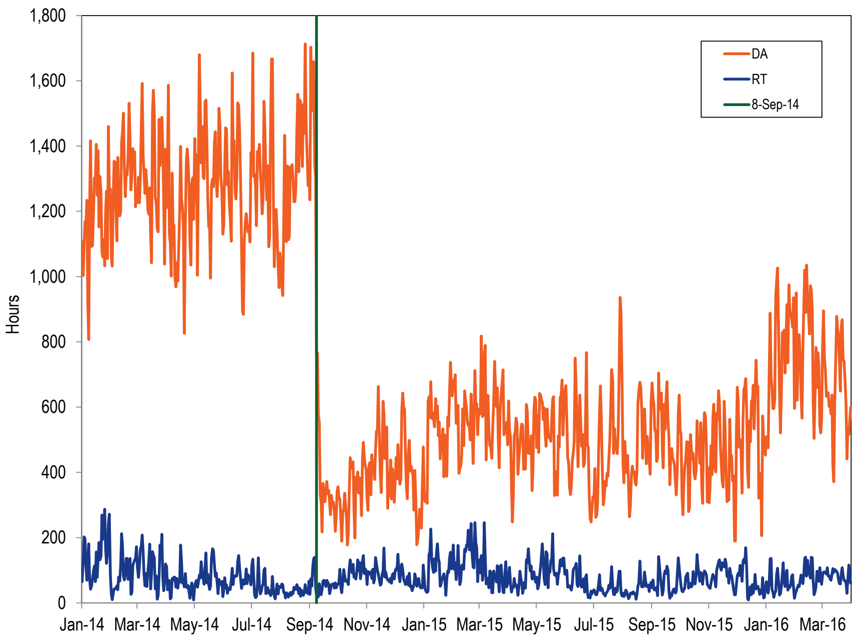
Table 11-33 Congestion cost by type of participant: January through March of 2015

	Congestion Costs (Millions)									
	Day Ahead				Balancing					
Participant Type	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Inadvertent Charges	Grand Total
Financial	$86.6	$45.7	($25.3)	$15.7	($20.5)	($2.6)	($66.8)	($84.8)	$0.0	($69.1)
Physical	$240.4	($503.6)	$14.2	$758.3	$26.0	$72.2	($11.2)	($57.4)	$0.0	$700.8
Total	$327.0	($457.9)	($11.0)	$773.9	$5.4	$69.6	($78.0)	($142.2)	$0.0	$631.7

Congestion-Event Summary before and after September 8, 2014

The day-ahead congestion event hours decreased significantly after September 8, 2014, when UTC activity declined significantly. The reduction in UTC activity was a result of FERC's UTC uplift refund notice, effective September 8, 2014.[26] Figure 11-5 shows the daily day-ahead and real-time congestion event hours for 2014 through March of 2016.

Figure 11-5 Daily congestion event hours: 2014 through March of 2016



26 See 18 CFR § 385.213 (2014).

Marginal Losses

Marginal Loss Accounting

Marginal losses occur in the Day-Ahead and Real-Time Energy Markets. The loss cost is based on the applicable day-ahead and real-time marginal loss component of LMP (MLMP). Total marginal loss costs, analogous to total congestion costs, are equal to the net of the load loss payments minus generation loss credits, plus explicit loss costs, 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 net implicit marginal loss costs plus net explicit marginal loss costs plus net inadvertent loss charges. Net implicit marginal loss costs equal load loss payments minus generation 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.[27] 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.[28] 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 load payments and generation credits can also be both positive and negative. 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.

27 OA. Schedule 1 (PJM Interchange Energy Market) §3.7.
28 *Id.*

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

The total loss surplus is the remaining loss amount from collection of marginal losses, after accounting for total 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.[29]

Marginal Loss Accounting

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 load loss payments minus generation loss credits, plus explicit loss costs, incurred in both the Day-Ahead Energy Market and the balancing energy market. Total marginal loss costs can by more accurately thought of as net marginal loss costs.

29 See PJM. "Manual 28: Operating Agreement Accounting," Revision 72 (December 17, 2015), p.65.

Marginal loss costs can be both positive and negative and consequently load payments and generation credits can also be both positive and negative. 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 Load Loss Payments.** Day-ahead load loss payments are calculated for all cleared demand, decrement bids and day-ahead energy market sale transactions. Day-ahead, load loss payments are calculated using MW and the load bus loss MLMP, the decrement bid MLMP or the MLMP at the source of the sale transaction.
- **Day-Ahead Generation Loss Credits.** Day-ahead generation loss credits are calculated for all cleared generation and increment offers and day-ahead energy market purchase transactions. Day-ahead, generation 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 Load Loss Payments.** Balancing load loss payments 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, load loss payments are calculated using MW deviations and the real-time MLMP for each bus where a deviation exists.
- **Balancing Generation Loss Credits.** Balancing generation 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, generation loss credits are calculated using MW deviations and the real-time MLMP for each bus where a deviation exists.
- **Explicit Loss Costs.** Explicit loss costs are the net loss costs associated with point to point energy transactions. 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 ratio basis.[30]

The total marginal loss cost in PJM for the first three months of 2016 was $170.1 million, which was comprised of load loss payments of -$8.0 million, generation loss credits of -$184.4 million, explicit loss costs of -$6.3 million and inadvertent loss charges of $0.0 million. Monthly marginal loss costs in the first three months of 2016 ranged from $40.6 million in March to $72.0 million in January. Total marginal loss surplus decreased in the first three months of 2016 by $94.3 million or 62.9 percent from the first three months of 2015, from $150.0 million to $55.7 million.

30 OA. Schedule 1 (PJM Interchange Energy Market) §3.7.

Total Marginal Loss Costs

Table 11-34 shows the total marginal loss costs as a component of total energy related costs for the first three months of 2009 through 2016.

Table 11-34 Total component costs (Dollars (Millions)): January through March of 2009 through 2016[31]

(Jan - Mar)	Loss Costs	Percent Change	Total PJM Billing	Percent of PJM Billing
2009	$454	NA	$7,515	6.0%
2010	$417	(8.2%)	$8,415	5.0%
2011	$410	(1.7%)	$9,584	4.3%
2012	$234	(42.8%)	$6,938	3.4%
2013	$278	18.5%	$7,762	3.6%
2014	$776	179.5%	$21,070	3.7%
2015	$425	(45.2%)	$14,040	3.0%
2016	$170	(60.0%)	$9,500	1.8%

Table 11-35 shows PJM total marginal loss costs by accounting category for the first three months of 2009 through 2016. Table 11-36 shows PJM total marginal loss costs by accounting category by market for the first three months of 2009 through 2016.

Table 11-35 Total PJM marginal loss costs by accounting category (Dollars (Millions)): January through March 2009 through 2016

	Marginal Loss Costs (Millions)				
(Jan - Mar)	Load Payments	Generation Credits	Explicit Costs	Inadvertent Charges	Total
2009	($21.3)	($460.6)	$14.7	$0.0	$454.0
2010	($3.8)	($414.1)	$6.3	($0.0)	$416.6
2011	($26.5)	($421.2)	$14.9	$0.0	$409.6
2012	($11.2)	($252.1)	($6.6)	$0.0	$234.3
2013	$8.0	($277.8)	($8.2)	($0.0)	$277.6
2014	($15.1)	($813.7)	($22.8)	$0.0	$775.9
2015	($4.0)	($434.0)	($4.9)	$0.0	$425.1
2016	($8.0)	($184.4)	($6.3)	$0.0	$170.1

31 The loss costs include net inadvertent charges.

Table 11-37 and Table 11-38 show the total loss costs for each transaction type in the first three months of 2016 and the first three months of 2015. In the first three months of 2016, generation paid 98.4 percent of total loss cost and the loss cost paid by generation was $167.4 million. In the first three months of 2015, generation paid 93.0 percent of total loss cost and the loss cost paid by generation was $395.4 million. Virtual transaction loss costs, when positive, measure the total loss cost to the virtual transaction and when negative, measure the total loss credit to the virtual transaction. In the first three months of 2016, DECs paid $0.4 million in loss costs in the day-ahead market, were paid $0.7 million in congestion credits in the balancing energy market and received $0.3 million in net payment for losses. In the first three months of 2016, INCs paid $3.1 million in loss costs in the day-ahead market, were paid $2.9 million in congestion credits in the balancing energy market and paid $0.2 million in net payment for losses. In the first three months of 2016, up to congestion paid $6.9 million in loss credits in the day-ahead market, were paid $14.5 million in loss credits in the balancing energy market and received $7.7 million in net payment for losses.

Table 11-36 Total PJM marginal loss costs by accounting category by market (Dollars (Millions)): January through March 2009 through 2016

	Marginal Loss Costs (Millions)									
	Day-Ahead				Balancing					
(Jan - Mar)	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Inadvertent Charges	Grand Total
2009	($23.3)	($457.6)	$30.9	$465.2	$2.1	($3.0)	($16.3)	($11.2)	$0.0	$454.0
2010	($8.5)	($413.5)	$12.8	$417.8	$4.7	($0.6)	($6.5)	($1.2)	($0.0)	$416.6
2011	($37.1)	($430.1)	$26.0	$419.1	$10.6	$8.9	($11.1)	($9.5)	$0.0	$409.6
2012	($16.7)	($256.8)	$8.0	$248.1	$5.6	$4.7	($14.6)	($13.8)	$0.0	$234.3
2013	($0.1)	($288.2)	$8.1	$296.2	$8.1	$10.4	($16.3)	($18.6)	($0.0)	$277.6
2014	($48.6)	($847.4)	$32.3	$831.1	$33.5	$33.7	($55.1)	($55.3)	$0.0	$775.9
2015	($17.4)	($441.6)	$7.8	$432.0	$13.5	$7.6	($12.8)	($6.9)	$0.0	$425.1
2016	($10.7)	($186.3)	$7.6	$183.3	$2.7	$1.9	($14.0)	($13.2)	$0.0	$170.1

Table 11-37 Total PJM loss costs by transaction type by market (Dollars (Millions)): January through March 2016

	Loss Costs (Millions)									
	Day-Ahead				Balancing					
Transaction Type	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Inadvertent Charges	Grand Total
DEC	$0.4	$0.0	$0.0	$0.4	($0.7)	$0.0	$0.0	($0.7)	$0.0	($0.3)
Demand	($1.0)	$0.0	$0.0	($1.0)	$2.6	$0.0	$0.0	$2.6	$0.0	$1.6
Demand Response	($0.0)	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Export	($3.6)	$0.0	$0.1	($3.6)	($0.1)	$0.0	$0.3	$0.2	$0.0	($3.4)
Generation	$0.0	($173.8)	$0.0	$173.8	$0.0	$6.5	$0.0	($6.5)	$0.0	$167.4
Grandfathered Overuse	$0.0	$0.0	($0.2)	($0.2)	$0.0	$0.0	($0.0)	($0.0)	$0.0	($0.2)
Import	$0.0	($3.0)	$0.5	$3.6	$0.0	($8.3)	$0.3	$8.6	$0.0	$12.2
INC	$0.0	($3.1)	$0.0	$3.1	$0.0	$2.9	$0.0	($2.9)	$0.0	$0.2
Internal Bilateral	($6.4)	($6.3)	$0.0	($0.0)	$0.8	$0.8	$0.0	($0.0)	$0.0	($0.0)
Up to Congestion	$0.0	$0.0	$6.9	$6.9	$0.0	$0.0	($14.5)	($14.5)	$0.0	($7.7)
Wheel In	$0.0	$0.0	$0.3	$0.3	$0.0	$0.0	$0.0	$0.0	$0.0	$0.4
Total	($10.7)	($186.3)	$7.6	$183.3	$2.7	$1.9	($14.0)	($13.2)	$0.0	$170.1

Table 11-38 Total PJM loss costs by transaction type by market (Dollars (Millions)): January through March 2015

	Loss Costs (Millions)									
	Day-Ahead				Balancing					
Transaction Type	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Inadvertent Charges	Grand Total
DEC	$0.1	$0.0	$0.0	$0.1	($3.0)	$0.0	$0.0	($3.0)	$0.0	($3.0)
Demand	($3.9)	$0.0	$0.0	($3.9)	$13.1	$0.0	$0.0	$13.1	$0.0	$9.1
Demand Response	($0.0)	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Export	($4.5)	$0.0	$0.2	($4.4)	($0.3)	$0.0	$0.7	$0.4	$0.0	($3.9)
Generation	$0.0	($421.1)	$0.0	$421.1	$0.0	$25.7	$0.0	($25.7)	$0.0	$395.4
Grandfathered Overuse	$0.0	$0.0	($0.7)	($0.7)	$0.0	$0.0	$0.1	$0.1	$0.0	($0.6)
Import	$0.0	($7.7)	$1.7	$9.4	$0.0	($26.7)	$0.8	$27.5	$0.0	$37.0
INC	$0.0	($3.8)	$0.0	$3.8	$0.0	$5.0	$0.0	($5.0)	$0.0	($1.2)
Internal Bilateral	($9.0)	($9.0)	$0.0	($0.0)	$3.7	$3.7	$0.0	($0.0)	$0.0	($0.0)
Up to Congestion	$0.0	$0.0	$5.9	$5.9	$0.0	$0.0	($14.3)	($14.3)	$0.0	($8.4)
Wheel In	$0.0	$0.0	$0.7	$0.7	$0.0	$0.0	($0.1)	($0.1)	$0.0	$0.6
Total	($17.4)	($441.6)	$7.8	$432.0	$13.5	$7.6	($12.8)	($6.9)	$0.0	$425.1

Monthly Marginal Loss Costs

Table 11-39 shows a monthly summary of marginal loss costs by market type for the first three months of 2015 and the first three months of 2016.

Table 11-39 Monthly marginal loss costs by market (Millions): January through March of 2015 and 2016

	Marginal Loss Costs (Millions)							
	2015				2016			
	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total
Jan	$115.9	($4.2)	$0.0	$111.7	$78.2	($6.2)	$0.0	$72.0
Feb	$218.2	$2.0	$0.0	$220.3	$61.3	($3.8)	$0.0	$57.5
Mar	$97.9	($4.7)	($0.0)	$93.2	$43.8	($3.2)	($0.0)	$40.6
Total	$432.0	($6.9)	$0.0	$425.1	$183.3	($13.2)	$0.0	$170.1

Figure 11-6 shows PJM monthly marginal loss costs for 2009 through March of 2016.

Figure 11-6 PJM monthly marginal loss costs (Dollars (Millions)): 2009 through March of 2016

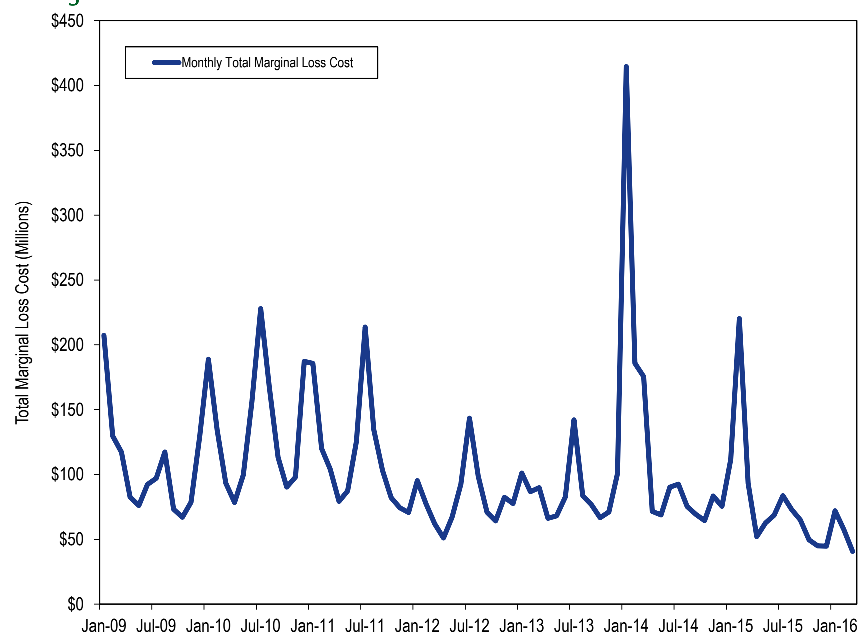


Table 11-40 and Table 11-41 show the monthly total loss costs for each virtual transaction type in the first three months of 2015 and the first three months of 2016. Virtual transaction loss costs, when positive, measure the total loss cost to the virtual transaction and when negative, measure the total loss credit to the virtual transaction. In the first three months of 2016, DECs paid $0.4 million in loss costs in the day-ahead market, were paid $0.7 million in congestion credits in the balancing energy market and received $0.3 million in net payment for loss. In the first three months of 2016, INCs paid $3.1 million in loss costs in the day-ahead market, were paid $2.9 million in congestion credits in the balancing energy market and paid $0.2 million in net payment for loss. In the first three months of 2016, up to congestion paid $6.9 million in loss credits in the day-ahead market, were paid $14.5 million in loss credits in the balancing energy market and received $7.7 million in net payment for loss.

Table 11-40 Monthly PJM loss costs by virtual transaction type and by market (Dollars (Millions)): January through March 2016

	Loss Costs (Millions)								
	Day-Ahead				Balancing				
	DEC	INC	Up to Congestion	Virtual Total	DEC	INC	Up to Congestion	Virtual Total	Virtual Grand Total
Jan	$0.3	$1.2	$3.7	$5.1	($0.6)	($1.1)	($6.8)	($8.5)	($3.3)
Feb	$0.1	$0.8	$1.9	$2.8	($0.0)	($0.8)	($4.3)	($5.2)	($2.4)
Mar	$0.0	$1.1	$1.3	$2.4	($0.1)	($0.9)	($3.4)	($4.5)	($2.0)
Total	$0.4	$3.1	$6.9	$10.3	($0.7)	($2.9)	($14.5)	($18.1)	($7.8)

Table 11-41 Monthly PJM loss costs by virtual transaction type and by market (Dollars (Millions)): January through March 2015

	Loss Costs (Millions)								
	Day-Ahead				Balancing				
	DEC	INC	Up to Congestion	Virtual Total	DEC	INC	Up to Congestion	Virtual Total	Virtual Grand Total
Jan	$0.2	$0.8	$2.9	$3.8	($1.1)	($0.7)	($4.9)	($6.7)	($2.9)
Feb	($0.6)	$1.8	($0.4)	$0.7	($0.8)	($2.0)	($3.4)	($6.2)	($5.5)
Mar	$0.5	$1.3	$3.5	$5.2	($1.1)	($2.3)	($6.0)	($9.4)	($4.2)
Total	$0.1	$3.8	$5.9	$9.8	($3.0)	($5.0)	($14.3)	($22.3)	($12.5)

Marginal Loss Costs and Loss Credits

Total loss surplus are calculated by adding the total energy costs, the total marginal loss costs and net residual market adjustments. The total energy costs are equal to the net implicit energy costs (load energy payments minus generation energy credits) plus net explicit energy costs plus net inadvertent energy charges. Total marginal loss costs are equal to the net implicit marginal loss costs (generation loss credits less load loss payments) plus net explicit loss costs 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 generation credits than load payments in every hour. Total energy costs plus total marginal loss costs plus net residual market adjustments equal marginal loss credits which are distributed to load and 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 11-42 shows the total energy costs, the total marginal loss costs collected, the net residual market adjustments and total marginal loss credits redistributed for the first three months of 2009 through 2016. The total marginal loss surplus decreased $94.3 million in the first three months of 2016 from the first three months of 2015.

Table 11-42 Marginal loss credits (Dollars (Millions)): January through March 2009 through 2016[32]

	Loss Credit Accounting (Millions)					
			Net Residual Market Adjustment			
(Jan - Mar)	Total Energy Charges	Total Marginal Loss Charges	Known Day-ahead Error	Day-ahead Loss MW Congestion	Balancing Loss MW Congestion	Total Loss Surplus
2009	($218.3)	$454.0	$0.0	($0.9)	($0.0)	$236.6
2010	($207.6)	$416.6	$0.0	$0.0	($0.0)	$208.9
2011	($209.9)	$409.6	($0.0)	($0.5)	$0.0	$200.1
2012	($136.4)	$234.3	$0.1	$0.3	$0.0	$97.7
2013	($177.9)	$277.6	$0.1	$0.3	($0.0)	$99.4
2014	($515.3)	$775.9	$0.0	$3.1	$0.2	$257.2
2015	($271.7)	$425.1	($0.5)	$2.9	($0.0)	$150.0
2016	($113.6)	$170.1	$0.0	$0.8	($0.0)	$55.7

Energy Costs

Energy Accounting

The energy component of LMP is the system reference bus LMP, also called the system marginal price (SMP). The energy cost is based on the day-ahead and real-time energy components of LMP. Total energy costs, analogous to total congestion costs or total loss costs, are equal to the load energy payments minus generation energy credits, plus explicit energy costs, incurred in both the Day-Ahead Energy Market and the balancing energy market, plus net inadvertent energy charges. Total energy costs can by more accurately thought of as net energy costs.

Total Energy Costs

The total energy cost for the first three months of 2016 was -$113.6 million, which was comprised of load energy payments of $7,764.7 million, generation energy credits of $7,879.3 million, explicit energy costs of $0.0 million and inadvertent energy charges of $1.0 million. The monthly energy costs for the first three months of 2016 ranged from -$47.7 million in January to -$27.4 million in March.

32 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.

Table 11-43 shows total energy component costs and total PJM billing, for the first three months of 2009 through 2016. The total energy component costs are net energy costs.

Table 11-43 Total PJM costs by energy component (Dollars (Millions)): January through March 2009 through 2016[33]

(Jan - Mar)	Energy Costs	Percent Change	Total PJM Billing	Percent of PJM Billing
2009	($218)	NA	$7,515	(2.9%)
2010	($208)	(4.9%)	$8,415	(2.5%)
2011	($210)	1.1%	$9,584	(2.2%)
2012	($136)	(35.0%)	$6,938	(2.0%)
2013	($178)	30.4%	$7,762	(2.3%)
2014	($515)	189.7%	$21,070	(2.4%)
2015	($272)	(47.3%)	$14,040	(1.9%)
2016	($114)	(58.2%)	$9,500	(1.2%)

Energy costs for the first three months of 2009 through 2016 are shown in Table 11-44 and Table 11-45. Table 11-44 shows PJM energy costs by accounting category for the first three months of 2009 through 2016 and Table 11-45 shows PJM energy costs by market category for the first three months of 2009 through 2016.

Table 11-44 Total PJM energy costs by accounting category (Dollars (Millions)): January through March 2009 through 2016

	Energy Costs (Millions)				
(Jan - Mar)	Load Payments	Generation Credits	Explicit Costs	Inadvertent Charges	Total
2009	$14,058.4	$14,277.4	$0.0	$0.7	($218.3)
2010	$13,424.4	$13,629.0	$0.0	($3.0)	($207.6)
2011	$11,943.9	$12,160.7	$0.0	$6.9	($209.9)
2012	$8,485.4	$8,628.7	$0.0	$6.8	($136.4)
2013	$10,357.2	$10,535.1	$0.0	($0.0)	($177.9)
2014	$28,506.2	$29,014.7	$0.0	($6.9)	($515.3)
2015	$15,702.1	$15,976.4	$0.0	$2.6	($271.7)
2016	$7,764.7	$7,879.3	$0.0	$1.0	($113.6)

33 The energy costs include net inadvertent charges.

Table 11-45 Total PJM energy costs by market category (Dollars (Millions)): January through March 2009 through 2016

	Energy Costs (Millions)									
	Day-Ahead				Balancing					
(Jan - Mar)	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Inadvertent Charges	Grand Total
2009	$14,129.6	$14,375.6	$0.0	($246.0)	($71.2)	($98.2)	$0.0	$27.0	$0.7	($218.3)
2010	$13,408.9	$13,619.2	$0.0	($210.2)	$15.5	$9.8	$0.0	$5.6	($3.0)	($207.6)
2011	$12,055.5	$12,259.3	$0.0	($203.9)	($111.6)	($98.6)	$0.0	($12.9)	$6.9	($209.9)
2012	$8,534.4	$8,649.0	$0.0	($114.6)	($49.0)	($20.4)	$0.0	($28.6)	$6.8	($136.4)
2013	$10,387.2	$10,580.9	$0.0	($193.7)	($29.9)	($45.8)	$0.0	$15.9	($0.0)	($177.9)
2014	$28,412.1	$29,082.9	$0.0	($670.9)	$94.2	($68.3)	$0.0	$162.4	($6.9)	($515.3)
2015	$15,764.8	$16,077.5	$0.0	($312.6)	($62.7)	($101.1)	$0.0	$38.4	$2.6	($271.7)
2016	$7,847.5	$7,997.9	$0.0	($150.4)	($82.8)	($118.6)	$0.0	$35.8	$1.0	($113.6)

Table 11-46 and Table 11-47 show the total energy costs for each virtual transaction type in the first three months of 2016 and the first three months of 2015. In the first three months of 2016, generation were paid $5,383.3 million and demand paid $5,441.3 million in net energy payment. In the first three months of 2015, generation were paid $10,882.7 million and demand paid $10,979.9 million in net energy payment.

Table 11-46 Total PJM energy costs by transaction type by market (Dollars (Millions)): January through March 2016

	Energy Costs (Millions)								
	Day-Ahead				Balancing				
Transaction Type	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total
DEC	$256.1	$0.0	$0.0	$256.1	($246.1)	$0.0	$0.0	($246.1)	$10.0
Demand	$5,436.9	$0.0	$0.0	$5,436.9	$4.4	$0.0	$0.0	$4.4	$5,441.3
Demand Response	($0.2)	$0.0	$0.0	($0.2)	$0.2	$0.0	$0.0	$0.2	($0.0)
Export	$114.9	$0.0	$0.0	$114.9	$31.6	$0.0	$0.0	$31.6	$146.4
Generation	$0.0	$5,559.1	$0.0	($5,559.1)	$0.0	($175.8)	$0.0	$175.8	($5,383.3)
Import	$0.0	$102.0	$0.0	($102.0)	$0.0	$213.5	$0.0	($213.5)	($315.5)
INC	$0.0	$296.9	$0.0	($296.9)	$0.0	($283.4)	$0.0	$283.4	($13.5)
Internal Bilateral	$2,039.9	$2,039.9	$0.0	$0.0	$127.1	$127.1	$0.0	($0.0)	($0.0)
Total	$7,847.5	$7,997.9	$0.0	($150.4)	($82.8)	($118.6)	$0.0	$35.8	($114.6)

Table 11-47 Total PJM energy costs by transaction type by market (Dollars (Millions)): January through March 2015

	Energy Costs (Millions)								
	Day-Ahead				Balancing				
Transaction Type	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total
DEC	$502.5	$0.0	$0.0	$502.5	($506.0)	$0.0	$0.0	($506.0)	($3.4)
Demand	$10,838.6	$0.0	$0.0	$10,838.6	$141.3	$0.0	$0.0	$141.3	$10,979.9
Demand Response	($0.8)	$0.0	$0.0	($0.8)	$0.8	$0.0	$0.0	$0.8	($0.0)
Export	$322.5	$0.0	$0.0	$322.5	$65.9	$0.0	$0.0	$65.9	$388.4
Generation	$0.0	$11,284.8	$0.0	($11,284.8)	$0.0	($402.1)	$0.0	$402.1	($10,882.7)
Import	$0.0	$184.3	$0.0	($184.3)	$0.0	$558.5	$0.0	($558.5)	($742.8)
INC	$0.0	$506.4	$0.0	($506.4)	$0.0	($492.8)	$0.0	$492.8	($13.5)
Internal Bilateral	$4,102.0	$4,102.0	$0.0	($0.0)	$235.3	$235.3	$0.0	($0.0)	($0.0)
Total	$15,764.8	$16,077.5	$0.0	($312.6)	($62.7)	($101.1)	$0.0	$38.4	($274.2)

Monthly Energy Costs

Table 11-48 shows a monthly summary of energy costs by market type for the first three months of 2015 and the first three months of 2016. Marginal total energy costs in the first three months of 2016 decreased from the first three months of 2015. Monthly total energy costs in the first three months of 2016 ranged from -$47.7 million in January to -$27.4 million in March.

Table 11-48 Monthly energy costs by market type (Dollars (Millions)): January through March 2015 and 2016

	Energy Costs (Millions)							
	2015				2016			
	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total
Jan	($84.6)	$13.3	$0.9	($70.5)	($63.8)	$15.4	$0.6	($47.7)
Feb	($150.5)	$6.2	$2.8	($141.5)	($50.0)	$11.1	$0.4	($38.5)
Mar	($77.6)	$19.0	($1.0)	($59.6)	($36.6)	$9.3	($0.1)	($27.4)
Total	($312.6)	$38.4	$2.6	($271.7)	($150.4)	$35.8	$1.0	($113.6)

Figure 11-7 shows PJM monthly energy costs for 2009 through March of 2016.

Figure 11-7 PJM monthly energy costs (Millions): 2009 through March of 2016

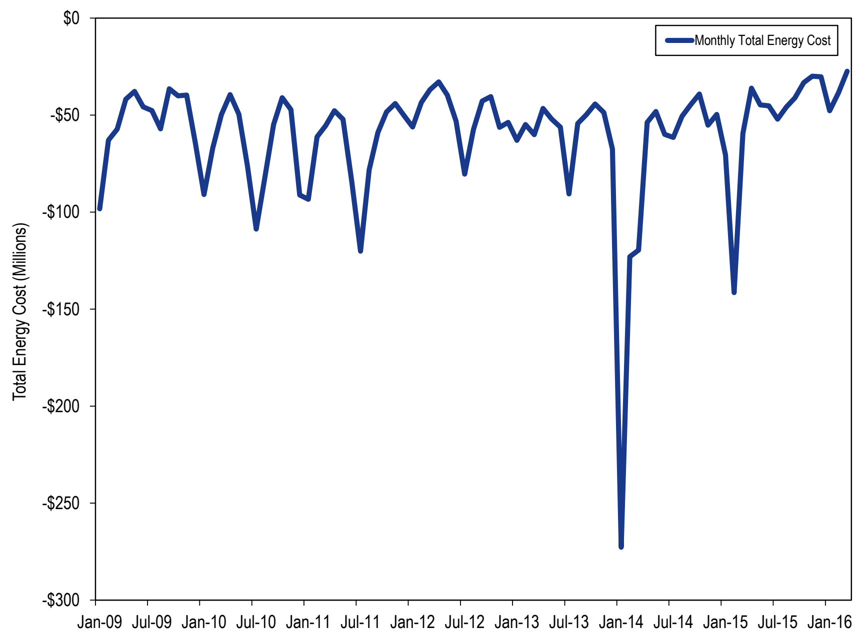


Table 11-49 and Table 11-50 show the monthly total energy costs for each virtual transaction type in the first three months of 2016 and the first three months of 2015. In the first three months of 2016, DECs paid $256.1 million in energy costs in the day-ahead market, were paid $246.1 million in energy credits in the balancing energy market and paid $10.0 million in net payment for energy. In the first three months of 2016, INCs were paid $296.9 million in energy credits in the day-ahead market, paid $283.4 million in energy cost in the balancing market and received $13.5 million in net payment for energy. In the first three months of 2015, DECs paid $502.5 million in energy costs in the day-ahead market, were paid $506.0 million in energy credits in the balancing energy market and were paid $3.4 million in net payment for energy. In the first three months of 2015, INCs were paid $506.4 million in energy credits in the day-ahead market, paid $492.8 million in energy cost in the balancing energy market and received $13.5 million in net payment for energy.

Table 11-49 Monthly PJM energy costs by virtual transaction type and by market (Dollars (Millions)): January through March 2016

	Energy Costs (Millions)						
	Day-Ahead			Balancing			
	DEC	INC	Virtual Total	DEC	INC	Virtual Total	Virtual Grand Total
Jan	$102.0	($109.3)	($7.2)	($101.0)	$106.1	$5.1	($2.1)
Feb	$85.5	($87.5)	($2.1)	($81.3)	$84.3	$3.0	$1.0
Mar	$68.6	($100.2)	($31.6)	($63.8)	$93.0	$29.2	($2.4)
Total	$256.1	($296.9)	($40.9)	($246.1)	$283.4	$37.3	($3.6)

Table 11-50 Monthly PJM energy costs by virtual transaction type and by market (Dollars (Millions)): January through March 2015

	Energy Costs (Millions)						
	Day-Ahead			Balancing			
	DEC	INC	Virtual Total	DEC	INC	Virtual Total	Virtual Grand Total
Jan	$152.0	($122.5)	$29.5	($152.0)	$120.6	($31.3)	($1.8)
Feb	$224.2	($243.8)	($19.5)	($217.0)	$223.6	$6.6	($13.0)
Mar	$126.3	($140.1)	($13.8)	($137.0)	$148.6	$11.6	($2.2)
Total	$502.5	($506.4)	($3.8)	($506.0)	$492.8	($13.1)	($17.0)