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 $546.9 million or 28.3 percent, from $1,932.2 million in 2014 to $1,385.3 million in 2015.
- **Day-Ahead Congestion.** Day-ahead congestion costs decreased by $599.1 million or 26.9 percent, from $2,231.3 million in 2014 to $1,632.1 million in 2015.
- **Balancing Congestion.** Balancing congestion costs increased by $52.2 million or 17.5 percent, from -$299.1 million in 2014 to -$246.9 million in 2015.
- **Real-Time Congestion.** Real-time congestion costs decreased by $668.2 million or 30.7 percent, from

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 February 18, 2016, and are subject to change, based on continued PJM billing updates.

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$2,173.0 million in 2014 to $1,504.9 million in 2015.

- **Monthly Congestion.** In 2015, 31.0 percent ($429.8 million) of total congestion cost was incurred in February and 14.6 percent ($201.9 million) of total congestion cost was incurred in the months of January and March. Monthly total congestion costs in 2015 ranged from $58.4 million in August to $429.8 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 5004/5005 Interface, the Bedington - Black Oak Interface, the Bagley – Graceton Line, the Conastone – Northwest Line and the Cherry Valley Flowgate.

- **Congestion Frequency.** Congestion frequency continued to be significantly higher in the Day-Ahead Energy Market than in the Real-Time Energy Market in 2015. The number of congestion event hours in the Day-Ahead Energy Market was about six times higher than the number of congestion event hours in the Real-Time Energy Market.

  Day-ahead congestion frequency decreased by 49.2 percent from 363,463 congestion event hours 2014 to 184,713 congestion event hours in 2015. 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 1.0 percent from 28,802 congestion event hours in 2014 to 28,524 congestion event hours in 2015.

- **Congested Facilities.** Day-ahead, congestion-event hours decreased on all types of congestion facilities. Real-time, congestion-event hours increased on line and transformer facilities and decrease on flowgate and interface facilities.

  The Conastone – Northwest Line was the largest contributor to congestion costs in 2015. With $108.8 million in total congestion costs, it accounted for 7.9 percent of the total PJM congestion costs in 2015.

- **Zonal Congestion.** ComEd had the largest total congestion costs among all control zones in 2015. ComEd had $311.3 million in total congestion costs, comprised of -$688.9 million in total load congestion payments, -$1,029.4 million in total generation congestion credits and -$29.2 million in explicit congestion costs. The Cherry Valley Flowgate, the Oak Grove - Galesburg Flowgate, the Braidwood - East Frankfort Line, the Bunsonville - Eugene Flowgate and the Rising Flowgate contributed $150.4 million, or 48.3 percent of the total ComEd control zone congestion costs.

- **Ownership.** In 2015, 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 2015, financial entities received $133.1 million in congestion credits, a decrease of $93.6 million or 41.3 percent compared to the 2014. In 2015, physical entities paid $1,518.3 million in congestion charges, a decrease of $640.6 million or 29.7 percent compared to 2014. 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 2015, the total explicit cost is -$127.3 million and 122.4 percent of the total explicit cost is comprised of congestion cost by UTCs, which is -$155.9 million.

Marginal Loss Cost

- **Total Marginal Loss Costs.** Total marginal loss costs decreased by $497.4 million or 33.9 percent, from $1,466.1 million in 2014 to $968.7 million in 2015. Total marginal loss costs were higher in 2014 as a result of high load and outages caused by cold weather in January 2014. The loss MWh in PJM decreased 5.3 percent, from 17,150.0 GWh in 2014 to 16,241.3 GWh in 2015. The loss component of LMP remained constant, $0.02 in 2014 and $0.02 in 2015.

- **Monthly Total Marginal Loss Costs.** Monthly total marginal loss costs in 2015 ranged from $44.6 million in December to $220.3 million in February.

- **Day-Ahead Marginal Loss Costs.** Day-ahead marginal loss costs decreased by $558.8 million

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or 35.6 percent, from $1,571.4 million in 2014 to $1,012.6 million in 2015.

- **Balancing Marginal Loss Costs.** Balancing marginal loss costs increased by $61.4 million or 58.3 percent, from -$105.3 million in 2014 to -$43.9 million in 2015.
- **Total Marginal Loss Surplus.** The total marginal loss surplus decreased in 2015 by $145.8 million or 30.2 percent, from $482.1 million in 2014, to $336.3 million in 2015.

Energy Cost

- **Total Energy Costs.** Total energy costs increased by $350.3 million or 35.8 percent, from -$977.7 million in 2014 to -$627.4 million in 2015.
- **Day-Ahead Energy Costs.** Day-ahead energy costs increased by $585.8 million or 43.6 percent, from -$1,343.7 million in 2014 to -$757.9 million in 2015.
- **Balancing Energy Costs.** Balancing energy costs decreased by $242.4 million or 65.5 percent, from $370.2 million in 2014 to $127.8 million in 2015.
- **Monthly Total Energy Costs.** Monthly total energy costs in 2015 ranged from -$141.5 million in February to -$28.9 million in December.

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 59.8 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 seven months of the 2015 to 2016 planning period ARRs and self scheduled FTRs offset 85.8 percent of total congestion costs.

ARRs and FTRs served as an effective, but not total, offset to congestion. ARR and FTR revenues offset 88.3 percent of the total congestion costs including the Day-Ahead Energy Market and the balancing energy market in PJM for the 2014 to 2015 planning period. In the first seven months of the 2015 to 2016 planning period (June through December), total ARR and FTR revenues offset 88.7 percent of the 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

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>.

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.

Table 11-1 shows the PJM real-time, load-weighted average LMP components 2009 through 2015.[7]

The load-weighted average real-time LMP decreased $16.98 or 31.9 percent from $53.14 in 2014 to $36.16 in 2015. The load-weighted average congestion component increased $0.06 from -$0.02 in 2014 to $0.04 in 2015. The load-weighted average loss component did not change in 2015 from 2014. The load-weighted average energy component decreased $17.02 or 32.0 percent from $53.13 in 2014 to $36.11 in 2015.

Table 11-1 PJM real-time, load-weighted average LMP components (Dollars per MWh): 2009 through 2015[8]

	Real-Time LMP	Energy Component	Congestion Component	Loss Component
2009	$39.05	$38.97	$0.05	$0.03
2010	$48.35	$48.23	$0.08	$0.04
2011	$45.94	$45.87	$0.05	$0.02
2012	$35.23	$35.18	$0.04	$0.01
2013	$38.66	$38.64	$0.01	$0.02
2014	$53.14	$53.13	($0.02)	$0.02
2015	$36.16	$36.11	$0.04	$0.02

Table 11-2 shows the PJM day-ahead, load-weighted average LMP components for 2009 through 2015.[9]

The load-weighted average day-ahead LMP decreased $16.89 or 31.5 percent from $53.62 in 2014 to $36.73 in 2015. The load-weighted average congestion component decreased $0.02 or 7.6 percent from $0.26 in 2014 to $0.24 in 2015. The load-weighted average loss component decreased -$0.00 or 23.2 percent from -$0.02 in 2014 to -$0.01 in 2015. The load-weighted average energy component decreased $16.88 or 31.6 percent from $53.38 in 2014 to $36.51 in 2015.

Table 11-2 PJM day-ahead, load-weighted average LMP components (Dollars per MWh): 2009 through 2015

	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
2009	$38.82	$38.96	($0.04)	($0.09)
2010	$47.65	$47.67	$0.05	($0.07)
2011	$45.19	$45.40	($0.06)	($0.15)
2012	$34.55	$34.46	$0.11	($0.01)
2013	$38.93	$38.79	$0.13	$0.00
2014	$53.62	$53.38	$0.26	($0.02)
2015	$36.73	$36.51	$0.24	($0.01)

Zonal Components

The real-time components of LMP for each control zone are presented in Table 11-3 for 2014 and 2015. In 2015, BGE had the highest real-time congestion component of all control zones and ComEd had the lowest real-time congestion component.

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.

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.

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Table 11-3 Zonal and PJM real-time, load-weighted average LMP components (Dollars per MWh): 2014 and 2015

	2014				2015			
	Real-Time LMP	Energy Component	Congestion Component	Loss Component	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AECO	$55.77	$51.69	$2.11	$1.97	$35.85	$35.82	($1.16)	$1.19
AEP	$47.81	$53.32	($4.32)	($1.19)	$33.90	$36.05	($1.39)	($0.76)
AP	$52.94	$53.88	($1.01)	$0.07	$38.04	$36.44	$1.44	$0.17
ATSI	$48.60	$52.07	($4.04)	$0.57	$34.00	$35.60	($1.89)	$0.29
BGE	$67.78	$54.46	$10.86	$2.46	$47.22	$36.78	$8.69	$1.76
ComEd	$42.04	$51.56	($6.92)	($2.60)	$29.85	$35.28	($3.50)	($1.94)
DAY	$47.36	$53.07	($5.87)	$0.17	$34.20	$35.90	($1.86)	$0.17
DEOK	$45.00	$52.87	($5.42)	($2.44)	$33.28	$35.88	($1.17)	($1.42)
DLCO	$44.22	$52.00	($6.12)	($1.66)	$32.21	$35.64	($2.75)	($0.69)
Dominion	$62.99	$54.58	$7.93	$0.48	$41.42	$36.92	$3.98	$0.52
DPL	$65.03	$54.72	$7.24	$3.07	$42.27	$37.02	$3.38	$1.87
EKPC	$47.88	$56.97	($6.57)	($2.52)	$32.93	$37.54	($2.97)	($1.64)
JCPL	$56.07	$52.18	$1.85	$2.04	$35.65	$36.07	($1.53)	$1.11
Met-Ed	$56.08	$53.42	$1.55	$1.11	$35.79	$36.20	($1.07)	$0.67
PECO	$55.94	$52.73	$1.86	$1.35	$35.11	$36.03	($1.68)	$0.76
PENELEC	$51.90	$52.71	($1.31)	$0.50	$36.13	$35.78	($0.28)	$0.63
Pepco	$65.61	$53.92	$10.09	$1.60	$43.04	$36.56	$5.35	$1.12
PPL	$56.97	$54.02	$2.03	$0.91	$35.95	$36.40	($0.95)	$0.51
PSEG	$57.90	$51.43	$4.49	$1.99	$36.97	$35.47	$0.45	$1.04
RECO	$56.79	$51.34	$3.58	$1.87	$37.58	$35.68	$0.84	$1.06
PJM	$53.14	$53.13	($0.02)	$0.02	$36.16	$36.11	$0.04	$0.02

The day-ahead components of LMP for each control zone are presented in Table 11-4 for 2014 and 2015. In 2015, BGE had the highest day-ahead congestion component of all control zones and ComEd had the lowest day-ahead congestion component.

Table 11-4 Zonal and PJM day-ahead, load-weighted average LMP components (Dollars per MWh): 2014 and 2015

	2014				2015			
	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AECO	$57.24	$51.67	$4.04	$1.53	$36.86	$36.25	($0.13)	$0.75
AEP	$48.83	$54.40	($4.59)	($0.98)	$34.20	$36.56	($1.80)	($0.57)
AP	$52.60	$54.21	($1.36)	($0.26)	$37.95	$36.83	$1.16	($0.05)
ATSI	$49.52	$52.63	($3.58)	$0.47	$34.34	$35.99	($1.97)	$0.32
BGE	$68.52	$54.65	$11.97	$1.90	$47.92	$36.98	$9.61	$1.33
ComEd	$42.82	$52.38	($7.86)	($1.71)	$29.45	$35.76	($4.81)	($1.50)
DAY	$48.95	$53.95	($5.45)	$0.45	$34.39	$36.43	($2.35)	$0.31
DEOK	$46.19	$52.68	($4.71)	($1.77)	$33.90	$36.69	($1.67)	($1.12)
DLCO	$44.95	$52.32	($5.52)	($1.85)	$32.57	$36.07	($2.70)	($0.80)
Dominion	$60.43	$54.75	$5.64	$0.05	$43.09	$37.39	$5.20	$0.50
DPL	$66.60	$54.56	$9.51	$2.52	$42.28	$37.23	$3.62	$1.44
EKPC	$48.80	$57.51	($6.32)	($2.39)	$33.42	$38.22	($3.21)	($1.59)
JCPL	$59.42	$52.87	$4.67	$1.87	$36.86	$36.49	($0.47)	$0.85
Met-Ed	$57.42	$53.10	$3.71	$0.61	$35.82	$36.27	($0.64)	$0.19
PECO	$57.60	$52.75	$3.87	$0.99	$35.96	$36.23	($0.63)	$0.37
PENELEC	$51.32	$51.08	($0.21)	$0.44	$35.90	$36.09	($0.55)	$0.36
Pepco	$64.04	$53.04	$9.85	$1.14	$44.38	$36.72	$6.81	$0.85
PPL	$59.04	$54.13	$4.47	$0.44	$36.62	$36.68	($0.14)	$0.08
PSEG	$61.27	$52.09	$7.33	$1.84	$37.82	$36.07	$0.83	$0.93
RECO	$59.75	$51.71	$6.27	$1.76	$38.10	$36.28	$0.88	$0.94
PJM	$53.62	$53.38	$0.26	($0.02)	$36.73	$36.51	$0.24	($0.01)

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Hub Components

The real-time components of LMP for each hub are presented in Table 11-5 for 2014 and 2015.

Table 11-5 Hub real-time, load-weighted average LMP components (Dollars per MWh): 2014 and 2015

	2014				2015			
	Real-Time LMP	Energy Component	Congestion Component	Loss Component	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AEP Gen Hub	$43.51	$53.25	($6.46)	($3.28)	$32.44	$37.65	($3.08)	($2.13)
AEP-DAY Hub	$46.29	$53.41	($5.69)	($1.43)	$33.67	$36.90	($2.24)	($1.00)
ATSI Gen Hub	$47.22	$51.92	($4.47)	($0.23)	$33.04	$35.83	($2.43)	($0.36)
Chicago Gen Hub	$39.52	$50.46	($7.68)	($3.25)	$27.91	$34.41	($4.16)	($2.34)
Chicago Hub	$42.68	$52.35	($7.11)	($2.56)	$30.42	$36.13	($3.75)	($1.95)
Dominion Hub	$64.29	$56.55	$7.84	($0.10)	$41.12	$37.33	$3.63	$0.16
Eastern Hub	$61.27	$52.20	$6.29	$2.78	$40.03	$35.29	$3.03	$1.71
N Illinois Hub	$41.20	$51.02	($6.98)	($2.84)	$29.35	$34.83	($3.44)	($2.04)
New Jersey Hub	$56.21	$51.22	$3.05	$1.94	$36.09	$35.66	($0.62)	$1.06
Ohio Hub	$46.25	$53.32	($5.80)	($1.28)	$32.88	$36.08	($2.32)	($0.87)
West Interface Hub	$50.60	$51.86	($0.42)	($0.83)	$34.67	$36.00	($0.71)	($0.62)
Western Hub	$57.23	$55.07	$2.14	$0.02	$40.83	$38.59	$1.94	$0.30

The day-ahead components of LMP for each hub are presented in Table 11-6 for 2014 and 2015.

Table 11-6 Hub day-ahead, load-weighted average LMP components (Dollars per MWh): 2014 and 2015

	2014				2015			
	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AEP Gen Hub	$42.22	$48.97	($4.25)	($2.50)	$30.66	$33.21	($1.17)	($1.38)
AEP-DAY Hub	$46.64	$52.38	($4.83)	($0.91)	$32.77	$35.73	($2.32)	($0.64)
ATSI Gen Hub	$50.09	$52.42	($2.47)	$0.14	$29.05	$29.71	($0.60)	($0.05)
Chicago Gen Hub	$43.01	$55.95	($10.23)	($2.71)	$26.65	$32.83	($4.46)	($1.72)
Chicago Hub	$42.50	$51.94	($7.85)	($1.58)	$29.09	$34.97	($4.51)	($1.37)
Dominion Hub	$59.15	$54.48	$5.14	($0.47)	$42.57	$37.38	$4.96	$0.24
Eastern Hub	$64.43	$53.17	$8.65	$2.61	$42.19	$36.99	$3.71	$1.49
N Illinois Hub	$42.47	$52.94	($8.44)	($2.02)	$28.72	$34.91	($4.60)	($1.59)
New Jersey Hub	$59.41	$51.99	$5.66	$1.77	$37.29	$36.26	$0.18	$0.85
Ohio Hub	$46.59	$52.22	($4.97)	($0.66)	$32.60	$35.61	($2.46)	($0.55)
West Interface Hub	$49.78	$50.56	($0.05)	($0.72)	$35.10	$35.43	$0.05	($0.38)
Western Hub	$52.65	$50.52	$2.31	($0.18)	$38.34	$36.29	$2.11	($0.06)

Component Costs

Table 11-7 shows the total energy, loss and congestion component costs and the total PJM billing for 2009 through 2015. These totals are actually net energy, loss and congestion costs. Total congestion and marginal loss costs decreased in 2015 compared to 2014. Total congestion and marginal loss costs in 2014 were higher in 2014 as a result of high load and outages caused by cold weather in January 2014.

Table 11-7 Total PJM costs by component (Dollars (Millions)): 2009 through 2015[10,11]

	Component Costs (Millions)					
	Energy Costs	Loss Costs	Congestion Costs	Total Costs	Total PJM Billing	Total Costs Percent of PJM Billing
2009	($629)	$1,268	$719	$1,358	$26,550	5.1%
2010	($798)	$1,635	$1,423	$2,260	$34,771	6.5%
2011	($794)	$1,380	$999	$1,585	$35,887	4.4%
2012	($593)	$982	$529	$918	$29,181	3.1%
2013	($688)	$1,035	$677	$1,025	$33,862	3.0%
2014	($978)	$1,466	$1,932	$2,421	$50,030	4.8%
2015	($630)	$969	$1,385	$1,724	$42,630	4.0%

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.

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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.
- **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

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.

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

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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 2015 were $1,385.3 million, which was comprised of load congestion payments of $614.8 million, generation credits of -$897.8 million and explicit congestion of -$127.3 million. Total congestion costs in PJM in 2014 were $1,932.2 million, which was comprised of load congestion payments of $648.1 million, generation credits of -$1,453.0 million and explicit congestion of -$169.0 million. The decrease in total congestion cost from 2014 to 2015 is primarily a result of the decrease in generation credits.

Total Congestion

Table 11-8 shows total congestion for 2008 through 2015. 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)): 2008 through 2015

	Congestion Costs (Millions)			
	Congestion Cost	Percent Change	Total PJM Billing	Percent of PJM Billing
2008	$2,052	NA	$34,306	6.0%
2009	$719	(65.0%)	$26,550	2.7%
2010	$1,423	98.0%	$34,771	4.1%
2011	$999	(29.8%)	$35,887	2.8%
2012	$529	(47.0%)	$29,181	1.8%
2013	$677	28.0%	$33,862	2.0%
2014	$1,932	185.5%	$50,030	3.9%
2015	$1,385	(28.3%)	$42,630	3.2%

Table 11-9 shows the congestion costs by accounting category by market for 2015. In 2015, PJM total congestion costs were comprised of $614.8 million in load congestion payments, -$897.8 million in generation congestion credits, and -$127.3 million in explicit congestion costs.

Table 11-9 Total PJM congestion costs by accounting category by market (Dollars (Millions)): 2008 through 2015

	Congestion Costs (Millions)									
	Day Ahead				Balancing					
	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Inadvertent Charges	Grand Total
2008	$1,260.3	($1,133.1)	$203.0	$2,596.5	($225.9)	$79.2	($239.5)	($544.6)	$0.0	$2,051.8
2009	$292.3	($525.2)	$83.9	$901.4	($39.0)	$10.1	($133.4)	($182.4)	$0.0	$719.0
2010	$376.4	($1,239.8)	$96.9	$1,713.1	($37.5)	$72.8	($179.5)	($289.8)	($0.0)	$1,423.3
2011	$400.5	($777.6)	$66.9	$1,245.0	$53.5	$109.5	($190.0)	($246.0)	$0.0	$999.0
2012	$122.7	($525.3)	$131.9	$779.9	($7.6)	$57.9	($185.4)	($250.9)	$0.0	$529.0
2013	$281.2	($592.5)	$137.6	$1,011.3	$5.9	$131.3	($209.0)	($334.4)	$0.0	$676.9
2014	$595.5	($1,671.2)	($35.4)	$2,231.3	$52.7	$218.1	($133.6)	($299.1)	$0.0	$1,932.2
2015	$614.2	($967.6)	$50.3	$1,632.1	$0.6	$69.8	($177.6)	($246.9)	$0.0	$1,385.3

Table 11-10 and Table 11-11 show the total congestion costs for each transaction type in 2015 and 2014. The decrease in total congestion cost from 2014 to 2015 is

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.>

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>.

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mainly due to the decrease in negative generation credits incurred by generation in the Day-Ahead Energy Market. Congestion costs incurred by generation in the Day-Ahead Energy Market decreased by $664.0 million or 31.7 percent, from $2,094.0 million in 2014 to $1,429.9 million in 2015. Table 11-10 shows that in 2015 DECs paid $81.4 million in congestion cost in the day-ahead market were paid $97.6 million in congestion credits in the balancing energy market and received $16.2 million in net payment for congestion. In 2015, INCs were paid $24.2 million in congestion credits in the day-ahead market, paid $5.1 million in congestion cost in the balancing energy market and received $19.1 million in net payment for congestion. In 2015, up to congestion paid $25.0 million in congestion cost in the day-ahead market, were paid $180.8 million in congestion credits in balancing market and received $155.9 million in net payment for congestion.

Table 11-10 Total PJM congestion costs by transaction type by market (Dollars (Millions)): 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	$81.4	$0.0	$0.0	$81.4	($97.6)	$0.0	$0.0	($97.6)	$0.0	($16.2)
Demand	$109.5	$0.0	$0.0	$109.5	$69.2	$0.0	$0.0	$69.2	$0.0	$178.7
Demand Response	($0.2)	$0.0	$0.0	($0.2)	$0.2	$0.0	$0.0	$0.2	$0.0	($0.0)
Explicit Congestion Only	$0.0	$0.0	$4.9	$4.9	$0.0	$0.0	($0.0)	($0.0)	$0.0	$4.9
Export	($51.5)	$0.0	$0.7	($50.8)	($4.4)	$0.0	$1.9	($2.4)	$0.0	($53.3)
Generation	$0.0	($1,429.9)	$0.0	$1,429.9	$0.0	$113.7	$0.0	($113.7)	$0.0	$1,316.2
Grandfathered Overuse	$0.0	$0.0	($2.4)	($2.4)	$0.0	$0.0	$0.5	$0.5	$0.0	($1.9)
Import	$0.0	($37.1)	$1.4	$38.5	$0.0	($71.9)	$1.4	$73.3	$0.0	$111.8
INC	$0.0	$24.2	$0.0	($24.2)	$0.0	($5.1)	$0.0	$5.1	$0.0	($19.1)
Internal Bilateral	$449.4	$449.5	$0.1	$0.0	$33.7	$33.7	$0.0	($0.0)	$0.0	($0.0)
Up to Congestion	$0.0	$0.0	$25.0	$25.0	$0.0	$0.0	($180.8)	($180.8)	$0.0	($155.9)
Wheel In	$0.0	$25.6	$20.6	($5.0)	$0.0	($0.5)	($0.6)	($0.1)	$0.0	($5.1)
Wheel Out	$25.6	$0.0	$0.0	$25.6	($0.5)	$0.0	$0.0	($0.5)	$0.0	$25.1
Total	$614.2	($967.6)	$50.3	$1,632.1	$0.6	$69.8	($177.6)	($246.9)	$0.0	$1,385.3

Table 11-11 Total PJM congestion costs by transaction type by market (Dollars (Millions)): 2014

	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	$79.9	$0.0	$0.0	$79.9	($57.8)	$0.0	$0.0	($57.8)	$0.0	$22.1
Demand	$130.2	$0.0	$0.0	$130.2	$142.4	$0.0	$0.0	$142.4	$0.0	$272.6
Demand Response	($1.1)	$0.0	$0.0	($1.1)	$1.0	$0.0	$0.0	$1.0	$0.0	($0.1)
Explicit Congestion Only	$0.0	$0.0	$3.2	$3.2	$0.0	$0.0	$0.3	$0.3	$0.0	$3.5
Export	($95.0)	$0.0	($0.8)	($95.7)	($44.2)	$0.0	$6.3	($37.9)	$0.0	($133.6)
Generation	$0.0	($2,094.0)	$0.0	$2,094.0	$0.0	$296.4	$0.0	($296.4)	$0.0	$1,797.6
Grandfathered Overuse	$0.0	$0.0	($11.4)	($11.4)	$0.0	$0.0	$0.9	$0.9	$0.0	($10.5)
Import	$0.0	($46.7)	$8.6	$55.3	$0.0	($125.1)	$3.8	$128.9	$0.0	$184.3
INC	$0.0	($12.7)	$0.0	$12.7	$0.0	$35.7	$0.0	($35.7)	$0.0	($23.0)
Internal Bilateral	$418.1	$419.0	$0.9	($0.0)	$13.4	$13.4	$0.0	($0.0)	$0.0	($0.0)
Up to Congestion	$0.0	$0.0	($57.0)	($57.0)	$0.0	$0.0	($143.2)	($143.2)	$0.0	($200.2)
Wheel In	$0.0	$63.2	$21.2	($42.0)	$0.0	($2.2)	($1.7)	$0.5	$0.0	($41.6)
Wheel Out	$63.2	$0.0	$0.0	$63.2	($2.2)	$0.0	$0.0	($2.2)	$0.0	$61.1
Total	$595.5	($1,671.2)	($35.4)	$2,231.3	$52.7	$218.1	($133.6)	($299.1)	$0.0	$1,932.2

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Table 11-12 Total PJM congestion costs by transaction type by market: 2014 to 2015 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	$1.5	$0.0	$0.0	$1.5	($39.8)	$0.0	$0.0	($39.8)	$0.0	($38.3)
Demand	($20.7)	$0.0	$0.0	($20.7)	($73.2)	$0.0	$0.0	($73.2)	$0.0	($93.9)
Demand Response	$0.9	$0.0	$0.0	$0.9	($0.8)	$0.0	$0.0	($0.8)	$0.0	$0.1
Explicit Congestion Only	$0.0	$0.0	$1.7	$1.7	$0.0	$0.0	($0.3)	($0.3)	$0.0	$1.4
Export	$43.4	$0.0	$1.5	$44.9	$39.8	$0.0	($4.4)	$35.4	$0.0	$80.3
Generation	$0.0	$664.0	$0.0	($664.0)	$0.0	($182.7)	$0.0	$182.7	$0.0	($481.3)
Grandfathered Overuse	$0.0	$0.0	$8.9	$8.9	$0.0	$0.0	($0.4)	($0.4)	$0.0	$8.6
Import	$0.0	$9.7	($7.2)	($16.9)	$0.0	$53.2	($2.4)	($55.7)	$0.0	($72.5)
INC	$0.0	$36.9	$0.0	($36.9)	$0.0	($40.8)	$0.0	$40.8	$0.0	$3.9
Internal Bilateral	$31.3	$30.5	($0.8)	$0.0	$20.3	$20.3	$0.0	($0.0)	$0.0	($0.0)
Up to Congestion	$0.0	$0.0	$82.0	$82.0	$0.0	$0.0	($37.7)	($37.7)	$0.0	$44.3
Wheel In	$0.0	($37.6)	($0.5)	$37.1	$0.0	$1.7	$1.1	($0.6)	$0.0	$36.5
Wheel Out	($37.6)	$0.0	$0.0	($37.6)	$1.7	$0.0	$0.0	$1.7	$0.0	($35.9)
Total	$18.8	$703.5	$85.6	($599.1)	($52.1)	($148.3)	($44.0)	$52.2	$0.0	($546.9)

Monthly Congestion

Table 11-13 shows that monthly total congestion costs ranged from $58.4 million to $429.8 million in 2015. Table 11-13 shows that congestion costs in January of 2014 were substantially higher than congestion costs in January of 2015, due to weather related load and outages in January of 2014.

Table 11-13 Monthly PJM congestion costs by market (Dollars (Millions)): 2014 and 2015

	Congestion Costs (Millions)							
	2014				2015			
	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total
Jan	$922.5	($97.4)	$0.0	$825.1	$156.7	($24.4)	$0.0	$132.3
Feb	$203.5	($38.3)	$0.0	$165.2	$476.3	($46.4)	($0.0)	$429.8
Mar	$307.3	($61.5)	$0.0	$245.8	$140.9	($71.4)	$0.0	$69.5
Apr	$66.3	($12.0)	($0.0)	$54.3	$76.3	($4.9)	($0.0)	$71.4
May	$84.9	($21.9)	$0.0	$63.1	$128.9	($19.9)	$0.0	$109.0
Jun	$107.4	($18.6)	$0.0	$88.8	$114.0	($7.5)	($0.0)	$106.6
Jul	$118.1	($14.0)	$0.0	$104.1	$97.4	($8.5)	($0.0)	$89.0
Aug	$68.9	$0.0	$0.0	$68.9	$64.2	($5.8)	$0.0	$58.4
Sep	$85.8	$4.4	$0.0	$90.1	$92.3	($15.3)	($0.0)	$77.0
Oct	$87.1	($14.3)	($0.0)	$72.8	$103.2	($16.8)	($0.0)	$86.4
Nov	$105.3	($16.3)	$0.0	$89.0	$102.8	($10.8)	$0.0	$92.0
Dec	$74.3	($9.3)	($0.0)	$65.0	$79.1	($15.2)	$0.0	$63.9
Total	$2,231.3	($299.1)	$0.0	$1,932.2	$1,632.1	($246.9)	$0.0	$1,385.3

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Figure 11-1 shows PJM monthly total congestion cost for 2009 through 2015.

Figure 11-1 PJM monthly total congestion cost (Dollars (Millions)): 2009 through 2015

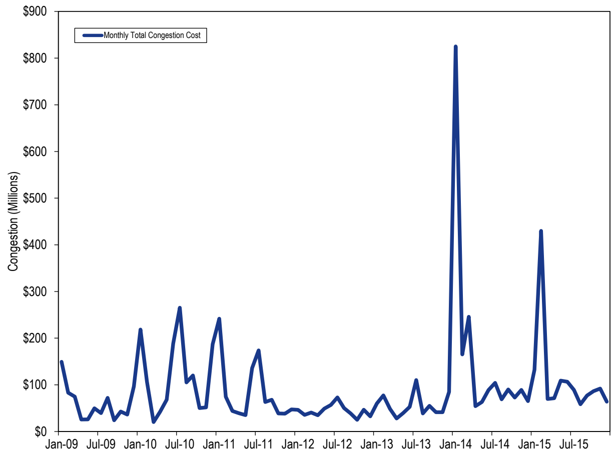

Table 11-14 Monthly PJM congestion costs by virtual transaction type and by market (Dollars (Millions)): 2015

	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)
Apr	$4.3	($2.5)	$5.3	$7.1	($5.8)	$3.7	($10.0)	($12.2)	($5.0)
May	$5.1	($3.7)	$5.9	$7.3	($4.8)	($2.1)	($21.7)	($28.6)	($21.3)
Jun	$9.0	($3.2)	$6.6	$12.4	($9.5)	$0.2	($6.9)	($16.2)	($3.8)
Jul	$7.0	($3.0)	$4.7	$8.7	($7.5)	$3.5	($12.3)	($16.4)	($7.7)
Aug	$4.2	($1.8)	$2.8	$5.2	($4.4)	$0.5	($6.6)	($10.5)	($5.3)
Sep	$4.3	$0.1	$4.6	$9.1	($6.4)	($4.1)	($10.5)	($21.0)	($11.9)
Oct	$6.7	($1.7)	$9.6	$14.6	($6.8)	($0.5)	($14.0)	($21.3)	($6.7)
Nov	$5.9	($3.3)	$7.7	$10.4	($5.0)	$2.1	($7.5)	($10.4)	($0.1)
Dec	$6.7	($1.9)	$6.2	$11.0	($7.0)	$0.9	($11.9)	($18.0)	($6.9)
Total	$81.4	($24.2)	$25.0	$82.2	($97.6)	$5.1	($180.8)	($273.3)	($191.1)

Table 11-14 shows the monthly total congestion costs for each virtual transaction type in 2015 and Table 11-15 shows the monthly total congestion costs for each virtual transaction type in 2014. 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 were paid both day-ahead congestion credits and balancing congestion credits in 2014 and in 2015 UTCs paid day-ahead congestion costs and were paid balancing congestion credits. Total day-ahead congestion payments to UTCs decreased by $82.0 million from 2014 to 2015, from $57.0 million in 2014 to -$25.0 million in 2015. Over the same period balancing congestion payments to UTCs increased from $143.2 million in 2014 to $180.8 million in 2015. Overall, total congestion payments to UTC decreased by 22.2 percent between 2014 and 2015. UTCs were paid $200.2 million in congestion in 2014 and $155.9 million in 2015. 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]

18 See 18 CFR § 385.213 (2014).

Table 11-15 Monthly PJM congestion costs by virtual transaction type and by market (Dollars (Millions)): 2014

	Congestion Costs (Millions)								
	Day-Ahead				Balancing				
	DEC	INC	Up to Congestion	Virtual Total	DEC	INC	Up to Congestion	Virtual Total	Virtual Grand Total
Jan	$51.0	$27.1	($109.4)	($31.4)	($31.8)	($26.7)	($23.5)	($82.0)	($113.3)
Feb	$7.4	$1.5	($5.8)	$3.1	($8.1)	($6.5)	($11.1)	($25.7)	($22.6)
Mar	$2.2	$4.9	$3.1	$10.2	($2.3)	($11.0)	($33.3)	($46.6)	($36.4)
Apr	($2.2)	($0.2)	$12.7	$10.3	$0.8	($0.3)	($9.5)	($9.0)	$1.3
May	$3.8	($1.6)	$10.7	$12.9	($3.5)	$0.4	($9.2)	($12.3)	$0.7
Jun	$2.7	($1.0)	$11.6	$13.2	($0.1)	($0.5)	($15.5)	($16.1)	($2.9)
Jul	$5.2	($0.1)	$13.4	$18.5	($4.3)	($1.2)	($13.7)	($19.2)	($0.7)
Aug	$1.4	($1.2)	$4.4	$4.6	($0.3)	$0.7	($1.1)	($0.7)	$3.9
Sep	$2.5	($2.6)	($1.1)	($1.2)	($0.6)	$1.0	$0.7	$1.0	($0.1)
Oct	$2.0	($6.2)	($0.1)	($4.3)	($1.5)	$5.3	($9.5)	($5.7)	($10.0)
Nov	$2.1	($5.3)	$1.0	($2.3)	($6.2)	$1.8	($10.8)	($15.1)	($17.4)
Dec	$1.9	($2.5)	$2.5	$1.9	$0.2	$1.3	($6.7)	($5.2)	($3.3)
Total	$79.9	$12.7	($57.0)	$35.6	($57.8)	($35.7)	($143.2)	($236.6)	($201.0)

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 2015, there were 184,713 day-ahead, congestion-event hours compared to 363,463 day-ahead congestion-event hours in 2014. In 2015, there were 28,524 real-time, congestion-event hours compared to 28,802 real-time, congestion-event hours in 2014.

During 2015, there were 14,968 real-time congestion-event hours, 8.1 percent of day-ahead energy congestion-event hours, when the same facilities also constrained in the Real-Time Energy Market. During 2015, there were 14,961 day-ahead congestion-event hours, 52.5 percent of real-time congestion-event hours, when the same facilities were also constrained in the Day-Ahead Energy Market.

The Conastone – Northwest Line was the largest contributor to total congestion costs in 2015. With $108.5 million in total congestion costs, it accounted for 7.9 percent of the total PJM congestion costs in 2015. The top five constraints in terms of congestion costs contributed $472.6 million, or 34.1 percent, of the total PJM congestion costs in 2015. The top five constraints were the 5004/5005 Interface, the Bedington - Black Oak Interface, the Bagley – Graceton Line, the Conastone – Northwest Line and the Cherry Valley Flowgate.

Congestion by Facility Type and Voltage

In 2015, day-ahead, congestion-event hours decreased on all types of congestion facilities. Real-time, congestion-event hours increased on line and transformer facilities and decreased on flowgate and interface facilities.

Day-ahead congestion costs decreased on all types of facilities except transmission lines in 2015 compared to 2014. Balancing congestion costs increased on all types of facilities except transmission lines in 2015 compared to 2014.

Table 11-16 provides congestion-event hour subtotals and congestion cost subtotals comparing 2015 results by facility type: line, transformer, interface, flowgate and unclassified facilities.[19,20] Table 11-17 presents this information for 2014.

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.

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Table 11-16 Congestion summary (By facility type): 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	$25.2	($276.6)	($22.9)	$278.9	$1.7	$2.7	($25.1)	($26.1)	$252.8	26,167	5,394
Interface	$74.8	($316.9)	($30.1)	$361.6	$10.7	$28.8	$2.9	($15.1)	$346.5	9,208	2,052
Line	$397.9	($234.2)	$96.9	$729.0	($17.1)	$24.1	($145.6)	($186.8)	$542.2	107,542	17,449
Other	($0.2)	($1.2)	$0.3	$1.2	$0.1	$0.1	($0.1)	($0.1)	$1.2	1,976	38
Transformer	$116.6	($137.4)	$5.8	$259.8	$4.9	$13.4	($20.6)	($29.0)	$230.7	39,820	3,591
Unclassified	$0.0	($1.4)	$0.3	$1.6	$0.3	$0.9	$10.8	$10.3	$11.9	NA	NA
Total	$614.2	($967.6)	$50.3	$1,632.1	$0.6	$69.8	($177.6)	($246.9)	$1,385.3	184,713	28,524

Table 11-17 Congestion summary (By facility type): 2014

	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	($100.8)	($423.8)	($16.8)	$306.2	$2.8	$13.7	($37.9)	($48.7)	$257.4	35,828	5,909
Interface	$367.4	($630.9)	($105.2)	$893.1	$62.7	$145.7	$16.6	($66.5)	$826.6	19,248	5,511
Line	$215.7	($470.6)	$39.9	$726.3	($25.8)	$41.9	($59.1)	($126.8)	$599.5	189,019	14,693
Other	$0.0	($2.5)	$1.0	$3.6	$0.0	$0.0	($0.0)	$0.0	$3.6	7,003	1
Transformer	$111.2	($131.4)	$32.3	$275.0	$5.3	$15.3	($62.2)	($72.2)	$202.8	112,365	2,688
Unclassified	$2.0	($11.8)	$13.4	$27.3	$7.6	$1.6	$9.0	$15.1	$42.4	NA	NA
Total	$595.5	($1,671.2)	($35.4)	$2,231.3	$52.7	$218.1	($133.6)	($299.1)	$1,932.2	363,463	28,802

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 2015, there were 184,713 congestion-event hours in the Day-Ahead Energy Market. Among those day-ahead congestion-event hours, only 14,968 (8.1 percent) were also constrained in the Real-Time Energy Market. In 2014, among the 363,463 day-ahead congestion-event hours, only 15,933 (4.4 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 2015, there were 28,524 congestion-event hours in the Real-Time Energy Market. Among these real-time congestion-event hours, 14,961 (52.5 percent) were also constrained in the Day-Ahead Energy Market. In 2014, among the 28,802 real-time congestion-event hours, 16,399 (56.9 percent) were also in the Day-Ahead Energy Market.

Table 11-18 Congestion event hours (Day-Ahead against Real-Time): 2014 and 2015

	Congestion Event Hours					
	2014			2015		
Type	Day-Ahead	Corresponding Real-Time	Percent	Day-Ahead	Corresponding Real-Time	Percent
Flowgate	35,828	3,265	9.1%	26,167	2,504	9.6%
Interface	19,248	3,982	20.7%	9,208	1,503	16.3%
Line	189,019	7,562	4.0%	107,542	9,706	9.0%
Other	7,003	0	0.0%	1,976	0	0.0%
Transformer	112,365	1,124	1.0%	39,820	1,255	3.2%
Total	363,463	15,933	4.4%	184,713	14,968	8.1%

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.

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Table 11-19 Congestion event hours (Real-Time against Day-Ahead): 2014 and 2015

	Congestion Event Hours					
	2014			2015		
Type	Real-Time	Corresponding Day-Ahead	Percent	Real-Time	Corresponding Day-Ahead	Percent
Flowgate	5,909	3,395	57.5%	5,394	2,518	46.7%
Interface	5,511	4,349	78.9%	2,052	1,539	75.0%
Line	14,693	7,575	51.6%	17,449	9,705	55.6%
Other	1	0	0.0%	38	0	0.0%
Transformer	2,688	1,080	40.2%	3,591	1,199	33.4%
Total	28,802	16,399	56.9%	28,524	14,961	52.5%

Table 11-20 shows congestion costs by facility voltage class for 2015. Congestion costs in 2015 decreased for facilities rated at 765kV, 500 kV, 345 kV, 161 kV and 69 kV compared to 2014 (Table 11-21).

Table 11-20 Congestion summary (By facility voltage): 2015

	Congestion Costs (Millions)										
	Day-Ahead				Balancing					Congestion 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	$19.2	($56.5)	($4.2)	$71.5	$3.4	$2.3	($1.7)	($0.5)	$71.0	2,816	144
500	$85.4	($327.5)	($28.3)	$384.6	$13.2	$28.8	($1.3)	($16.9)	$367.8	10,615	1,180
460	($0.0)	($3.6)	$0.3	$4.0	$0.0	$0.0	$0.0	$0.0	$4.0	1,360	0
345	($12.4)	($174.0)	$15.7	$177.4	$7.6	$7.4	($26.5)	($26.3)	$151.1	31,125	2,694
230	$362.1	($30.3)	$30.0	$422.4	($4.0)	($3.6)	($53.7)	($54.1)	$368.3	34,830	8,484
161	($19.5)	($55.9)	($7.8)	$28.5	($1.0)	$1.9	($2.9)	($5.7)	$22.8	4,279	1,533
138	$109.7	($290.4)	$36.7	$436.8	($10.0)	$35.0	($96.5)	($141.5)	$295.4	71,226	10,656
115	$26.2	($22.8)	$7.4	$56.4	$0.5	$0.5	($4.7)	($4.7)	$51.6	13,587	1,930
69	$43.3	($5.3)	$0.1	$48.6	($9.5)	($3.2)	($1.2)	($7.5)	$41.2	13,793	1,853
34	$0.1	$0.0	$0.2	$0.3	($0.0)	$0.0	$0.0	$0.0	$0.3	1,026	50
13	$0.0	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	55	0
12	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	1	0
Unclassified	$0.0	($1.4)	$0.3	$1.6	$0.3	$0.9	$10.8	$10.3	$11.9	NA	NA
Total	$614.2	($967.6)	$50.3	$1,632.1	$0.6	$69.8	($177.6)	($246.9)	$1,385.3	184,713	28,524

Table 11-21 Congestion summary (By facility voltage): 2014

	Congestion Costs (Millions)										
	Day-Ahead				Balancing					Congestion 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	$24.5	($53.9)	$3.7	$82.2	$1.6	$0.4	($4.7)	($3.4)	$78.8	12,662	657
500	$372.8	($639.6)	($98.6)	$913.8	$75.0	$161.8	$7.6	($79.2)	$834.6	21,954	2,467
460	($0.0)	($0.3)	$0.1	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	218	0
345	($74.3)	($370.2)	$2.7	$298.6	$4.1	$17.7	($31.6)	($45.2)	$253.4	69,866	3,133
230	$129.2	($242.8)	($19.6)	$352.4	$3.4	($0.2)	($1.9)	$1.7	$354.1	55,335	8,293
161	($28.5)	($62.9)	($2.5)	$31.9	($1.9)	$0.6	($1.6)	($4.1)	$27.8	7,042	1,178
138	$90.9	($284.9)	$59.5	$435.3	($7.4)	$43.1	($106.0)	($156.6)	$278.8	153,597	9,662
115	$3.3	($23.1)	$4.6	$30.9	($6.1)	$2.7	($3.4)	($12.2)	$18.8	19,474	1,299
69	$75.3	$18.3	$1.3	$58.2	($23.7)	($9.6)	($1.0)	($15.2)	$43.1	19,352	2,113
34	$0.0	($0.0)	$0.1	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	3,917	0
26	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	31	0
13	($0.0)	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	5	0
12	$0.0	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	10	0
Unclassified	$2.0	($11.8)	$13.4	$27.3	$7.6	$1.6	$9.0	$15.1	$42.4	NA	NA
Total	$595.5	($1,671.2)	($35.4)	$2,231.3	$52.7	$218.1	($133.6)	($299.1)	$1,932.2	363,463	28,802

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Constraint Duration

Table 11-22 lists the constraints in 2014 and 2015 that were most frequently binding and Table 11-23 shows the constraints which experienced the largest change in congestion-event hours from 2014 to 2015.

Table 11-22 Top 25 constraints with frequent occurrence: 2014 and 2015

			Congestion Event Hours						Percent of Annual Hours					
			Day-Ahead			Real-Time			Day-Ahead			Real-Time		
No.	Constraint	Type	2014	2015	Change	2014	2015	Change	2014	2015	Change	2014	2015	Change
1	Bagley - Graceton	Line	4,584	3,544	(1,040)	1,884	1,973	89	52%	40%	(12%)	22%	22%	1%
2	Oak Grove - Galesburg	Flowgate	6,905	3,356	(3,549)	1,059	1,306	247	79%	38%	(41%)	12%	15%	3%
3	Bunsonville - Eugene	Flowgate	2,244	3,762	1,518	675	748	73	26%	43%	17%	8%	9%	1%
4	Conastone - Northwest	Line	103	2,536	2,433	108	1,734	1,626	1%	29%	28%	1%	20%	19%
5	Maywood - Saddlebrook	Line	1,511	3,456	1,945	186	509	323	17%	39%	22%	2%	6%	4%
6	Tidd	Transformer	833	3,803	2,970	7	92	85	10%	43%	34%	0%	1%	1%
7	Bergen - New Milford	Line	4,745	2,970	(1,775)	331	795	464	54%	34%	(20%)	4%	9%	5%
8	Braidwood	Transformer	7,742	3,727	(4,015)	0	0	0	88%	42%	(46%)	0%	0%	0%
9	East Danville - Banister	Line	272	3,465	3,193	6	126	120	3%	39%	36%	0%	1%	1%
10	Monroe - Vineland	Line	1,348	3,121	1,773	24	197	173	15%	36%	20%	0%	2%	2%
11	Bedington - Black Oak	Interface	2,796	2,933	137	323	344	21	32%	33%	1%	4%	4%	0%
12	Easton	Transformer	1,758	3,099	1,341	0	0	0	20%	35%	15%	0%	0%	0%
13	Sayreville - Sayreville	Line	2,869	3,077	208	0	0	0	33%	35%	2%	0%	0%	0%
14	East Bend	Transformer	5,082	2,808	(2,274)	0	0	0	58%	32%	(26%)	0%	0%	0%
15	SENECA	Interface	3,562	938	(2,624)	3,227	1,182	(2,045)	41%	11%	(30%)	37%	13%	(23%)
16	Michigan City - Laporte	Flowgate	3,111	1,879	(1,232)	0	0	0	36%	21%	(14%)	0%	0%	0%
17	Tanners Creek	Transformer	8,096	1,838	(6,258)	0	0	0	92%	21%	(71%)	0%	0%	0%
18	Burnham - Munster	Flowgate	341	1,748	1,407	0	0	0	4%	20%	16%	0%	0%	0%
19	Miami Fort - Willey	Line	79	1,585	1,506	32	112	80	1%	18%	17%	0%	1%	1%
20	Cherry Valley	Transformer	2,762	789	(1,973)	324	885	561	32%	9%	(23%)	4%	10%	6%
21	49 Street - Hoboken	Line	394	1,643	1,249	0	0	0	4%	19%	14%	0%	0%	0%
22	Breed - Wheatland	Flowgate	3,758	1,358	(2,400)	602	149	(453)	43%	15%	(27%)	7%	2%	(5%)
23	Braidwood - East Frankfort	Line	1,245	1,449	204	25	58	33	14%	16%	2%	0%	1%	0%
24	Elwood - Elwood	Other	2,160	1,464	(696)	0	0	0	25%	17%	(8%)	0%	0%	0%
25	Bergen - Leonia	Line	2,128	1,456	(672)	0	0	0	24%	17%	(8%)	0%	0%	0%

Table 11-23 Top 25 constraints with largest year-to-year change in occurrence: 2014 and 2015

			Congestion Event Hours						Percent of Annual Hours					
			Day-Ahead			Real-Time			Day-Ahead			Real-Time		
No.	Constraint	Type	2014	2015	Change	2014	2015	Change	2014	2015	Change	2014	2015	Change
1	Miami Fort	Transformer	8,820	815	(8,005)	23	3	(20)	101%	9%	(91%)	0%	0%	(0%)
2	Tanners Creek	Transformer	8,096	1,838	(6,258)	0	0	0	92%	21%	(71%)	0%	0%	0%
3	Clinch River	Transformer	6,618	478	(6,140)	0	0	0	76%	5%	(70%)	0%	0%	0%
4	Kendall Co. Energy Ctr.	Transformer	5,488	121	(5,367)	0	0	0	63%	1%	(61%)	0%	0%	0%
5	Monticello - East Winamac	Flowgate	3,511	0	(3,511)	1,440	0	(1,440)	40%	0%	(40%)	16%	0%	(16%)
6	AP South	Interface	5,090	1,285	(3,805)	981	42	(939)	58%	15%	(43%)	11%	0%	(11%)
7	SENECA	Interface	3,562	938	(2,624)	3,227	1,182	(2,045)	41%	11%	(30%)	37%	13%	(23%)
8	Huntington Junction - Huntington	Line	4,508	26	(4,482)	0	0	0	51%	0%	(51%)	0%	0%	0%
9	Burlington - Croydon	Line	4,971	880	(4,091)	544	214	(330)	57%	10%	(47%)	6%	2%	(4%)
10	Wolf Creek	Transformer	5,102	710	(4,392)	131	171	40	58%	8%	(50%)	1%	2%	0%
11	Sunbury	Transformer	4,344	29	(4,315)	0	0	0	50%	0%	(49%)	0%	0%	0%
12	Conastone - Northwest	Line	103	2,536	2,433	108	1,734	1,626	1%	29%	28%	1%	20%	19%
13	Braidwood	Transformer	7,742	3,727	(4,015)	0	0	0	88%	42%	(46%)	0%	0%	0%
14	Nelson - Cordova	Line	4,107	414	(3,693)	279	69	(210)	47%	5%	(42%)	3%	1%	(2%)
15	Sporn	Transformer	3,560	36	(3,524)	0	0	0	41%	0%	(40%)	0%	0%	0%
16	East Danville - Banister	Line	272	3,465	3,193	6	126	120	3%	39%	36%	0%	1%	1%
17	Oak Grove - Galesburg	Flowgate	6,905	3,356	(3,549)	1,059	1,306	247	79%	38%	(41%)	12%	15%	3%
18	Mardela - Vienna	Line	4,627	1,365	(3,262)	76	86	10	53%	16%	(37%)	1%	1%	0%
19	Fort Robinson - Wolf Hills	Line	3,185	0	(3,185)	0	0	0	36%	0%	(36%)	0%	0%	0%
20	Keeney	Transformer	3,099	9	(3,090)	58	0	(58)	35%	0%	(35%)	1%	0%	(1%)
21	Tidd	Transformer	833	3,803	2,970	7	92	85	10%	43%	34%	0%	1%	1%
22	Gould Street - Westport	Line	3,867	789	(3,078)	0	23	23	44%	9%	(35%)	0%	0%	0%
23	Beckjord	Transformer	3,040	145	(2,895)	0	0	0	35%	2%	(33%)	0%	0%	0%
24	Benton Harbor - Palisades	Flowgate	3,025	283	(2,742)	137	0	(137)	35%	3%	(31%)	2%	0%	(2%)
25	Breed - Wheatland	Flowgate	3,758	1,358	(2,400)	602	149	(453)	43%	15%	(27%)	7%	2%	(5%)

Constraint Costs

Table 11-24 and Table 11-25 present the top constraints affecting congestion costs by facility for the periods 2015 and 2014.

Table 11-24 Top 25 constraints affecting PJM congestion costs (By facility): 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
1	Conastone - Northwest	Line	BGE	$100.9	($2.4)	$1.6	$105.0	($1.6)	($8.1)	($2.7)	$3.8	$108.8	7.9%
2	Bagley - Graceton	Line	BGE	$99.5	$5.6	$5.0	$98.9	($0.2)	($12.4)	($3.2)	$9.0	$107.9	7.8%
3	5004/5005 Interface	Interface	500	($23.0)	($134.8)	($9.2)	$102.6	$7.0	$22.5	$1.9	($13.6)	$89.0	6.4%
4	Bedington - Black Oak	Interface	500	$46.1	($45.2)	($7.2)	$84.1	$2.4	$2.2	$3.2	$3.5	$87.6	6.3%
5	Cherry Valley	Flowgate	MISO	($9.1)	($82.1)	$6.7	$79.6	$0.0	$0.0	$0.0	$0.0	$79.6	5.7%
6	AP South	Interface	500	$38.1	($22.8)	($5.5)	$55.4	$0.3	$0.2	$0.6	$0.7	$56.2	4.1%
7	AEP - DOM	Interface	500	$28.1	($28.0)	($1.1)	$55.0	$0.9	$1.6	($1.9)	($2.6)	$52.4	3.8%
8	Joshua Falls	Transformer	AEP	$9.7	($35.9)	($4.7)	$40.9	$0.7	($0.1)	$2.3	$3.1	$44.0	3.2%
9	Bergen - New Milford	Line	PSEG	$25.2	$18.4	$17.9	$24.7	($7.6)	$9.3	($51.2)	($68.1)	($43.5)	(3.1%)
10	Person - Halifax	Flowgate	MISO	$79.7	$29.2	($10.4)	$40.1	$0.0	($0.0)	($0.1)	($0.1)	$40.0	2.9%
11	Maywood - Saddlebrook	Line	PSEG	$8.9	$3.9	$7.5	$12.5	($4.7)	$9.0	($22.2)	($36.0)	($23.4)	(1.7%)
12	East	Interface	500	($13.0)	($37.6)	($2.1)	$22.4	($0.1)	$0.3	$0.5	$0.1	$22.6	1.6%
13	Easton	Transformer	DPL	$29.0	$6.6	($0.5)	$21.9	$0.0	$0.0	$0.0	$0.0	$21.9	1.6%
14	Glenarm - Windy Edge	Line	BGE	$3.3	($13.0)	$1.0	$17.3	$1.9	($1.9)	($0.7)	$3.2	$20.5	1.5%
15	Oak Grove - Galesburg	Flowgate	MISO	($16.1)	($44.8)	($6.3)	$22.4	$0.2	$1.1	($1.9)	($2.8)	$19.7	1.4%
16	Mahans Lane - Tidd	Line	AEP	$7.7	($13.3)	($1.6)	$19.4	$0.4	$1.1	$0.9	$0.2	$19.6	1.4%
17	East Danville - Banister	Line	AEP	$8.1	($7.6)	$2.0	$17.7	$0.5	($1.5)	($0.6)	$1.4	$19.1	1.4%
18	49th Street - Hoboken	Line	PSEG	$0.0	$0.0	$0.0	$0.0	($3.0)	$2.1	($13.7)	($18.8)	($18.8)	(1.4%)
19	BCPEP	Interface	Pepco	$15.3	($3.0)	$0.1	$18.4	$0.0	$0.0	$0.0	$0.0	$18.4	1.3%
20	Braidwood - East Frankfort	Line	ComEd	($2.3)	($21.0)	$0.6	$19.4	$0.3	$0.4	($1.2)	($1.3)	$18.1	1.3%
21	Valley	Transformer	Dominion	$17.4	($0.2)	$0.0	$17.7	$0.0	$0.0	$0.0	$0.0	$17.7	1.3%
22	Cloverdale	Transformer	AEP	$6.6	($9.8)	($1.4)	$15.0	$0.0	$0.0	$0.0	$0.0	$15.0	1.1%
23	Breed - Wheatland	Flowgate	MISO	($1.7)	($15.5)	$0.6	$14.4	$0.1	($0.6)	($0.7)	($0.0)	$14.4	1.0%
24	Miami Fort - Willey	Line	DEOK	($0.8)	($12.4)	$1.2	$12.8	$1.2	$0.7	($0.3)	$0.2	$13.0	0.9%
25	Central	Interface	500	($15.5)	($32.7)	($3.9)	$13.3	$0.1	$1.0	$0.3	($0.7)	$12.6	0.9%

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Table 11-25 Top 25 constraints affecting PJM congestion costs (By facility): 2014

				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	2014
1	AP South	Interface	500	$329.7	($201.4)	($11.2)	$520.0	$31.5	$73.5	$8.9	($33.1)	$486.8	25.2%
2	West	Interface	500	($21.3)	($297.0)	($79.1)	$196.5	$17.7	$49.7	$17.0	($15.0)	$181.6	9.4%
3	Bagley - Graceton	Line	BGE	$98.5	($9.5)	($1.7)	$106.3	$5.7	($4.0)	$4.5	$14.2	$120.5	6.2%
4	Bedington - Black Oak	Interface	500	$42.8	($43.9)	($0.2)	$86.5	$3.9	$3.4	($2.3)	($1.9)	$84.6	4.4%
5	Breed - Wheatland	Flowgate	MISO	($17.7)	($100.2)	($9.3)	$73.2	$2.4	$1.1	$5.6	$6.9	$80.1	4.1%
6	Benton Harbor - Palisades	Flowgate	MISO	($12.5)	($79.3)	($8.0)	$58.8	($0.2)	$0.7	($1.0)	($1.8)	$57.0	2.9%
7	Cloverdale	Transformer	AEP	$23.3	($27.3)	$0.2	$50.7	$0.0	$0.0	$0.0	$0.0	$50.7	2.6%
8	BCPEP	Interface	Pepco	$15.6	($15.2)	($1.6)	$29.3	($1.6)	($14.2)	$1.5	$14.1	$43.4	2.2%
9	Unclassified	Unclassified	Unclassified	$2.0	($11.8)	$13.4	$27.3	$7.6	$1.6	$9.0	$15.1	$42.4	2.2%
10	Monticello - East Winamac	Flowgate	MISO	($3.8)	($46.7)	$1.6	$44.6	$2.6	$4.3	($10.8)	($12.5)	$32.1	1.7%
11	Oak Grove - Galesburg	Flowgate	MISO	($28.4)	($62.2)	($2.3)	$31.5	($0.4)	$0.5	($0.3)	($1.3)	$30.3	1.6%
12	Cherry Valley	Transformer	ComEd	$21.9	($20.4)	$5.2	$47.5	($5.1)	$1.1	($11.3)	($17.5)	$30.0	1.6%
13	Cook - Palisades	Flowgate	MISO	($12.6)	($55.3)	($5.3)	$37.4	($1.5)	$1.6	($6.2)	($9.3)	$28.1	1.5%
14	Readington - Roseland	Line	PSEG	($8.9)	($46.1)	($12.2)	$25.1	$0.9	$5.4	$5.8	$1.3	$26.4	1.4%
15	Cloverdale	Transformer	AEP	$23.1	($4.8)	($2.3)	$25.7	$0.0	$0.0	$0.0	$0.0	$25.7	1.3%
16	Wolf Creek	Transformer	AEP	$4.6	$1.3	$4.7	$8.0	$3.6	$5.6	($29.3)	($31.3)	($23.3)	(1.2%)
17	Brambleton - Loudoun	Line	Dominion	($11.2)	($35.1)	($1.3)	$22.6	$0.6	$0.0	$0.1	$0.6	$23.2	1.2%
18	SENECA	Interface	PENELEC	$5.6	$9.9	($6.5)	($10.9)	($3.0)	$1.2	($6.1)	($10.4)	($21.3)	(1.1%)
19	Wescosville	Transformer	PPL	$17.6	($0.8)	$2.7	$21.1	($0.0)	$0.0	$0.0	($0.0)	$21.1	1.1%
20	East	Interface	500	($9.8)	($34.2)	($3.4)	$21.0	$0.3	$0.7	$0.5	$0.1	$21.1	1.1%
21	Nelson - Cordova	Line	ComEd	($24.7)	($47.1)	$4.2	$26.6	($0.7)	$1.1	($4.3)	($6.0)	$20.5	1.1%
22	Bridgewater - Middlesex	Line	PSEG	$0.2	($22.2)	($3.0)	$19.4	($1.5)	$0.1	$1.4	($0.2)	$19.2	1.0%
23	5004/5005 Interface	Interface	500	($0.7)	($23.6)	($3.3)	$19.5	$8.1	$17.5	$7.3	($2.1)	$17.4	0.9%
24	Atlantic - Larrabee	Line	JCPL	$2.0	($14.8)	($0.7)	$16.1	$0.0	$1.3	$1.2	($0.1)	$16.0	0.8%
25	Amos	Transformer	AEP	$1.6	($12.8)	($0.2)	$14.2	$1.2	($1.6)	($1.2)	$1.6	$15.8	0.8%

Figure 11-2 shows the locations of the top 10 constraints by PJM total congestion costs in2015. Figure 11-3 shows the locations of the top 10 constraints by PJM day-ahead congestion costs in 2015. Figure 11-4 shows the locations of the top 10 constraints by PJM balancing congestion costs in 2015.

Figure 11-2 Location of the top 10 constraints by PJM total congestion costs: 2015

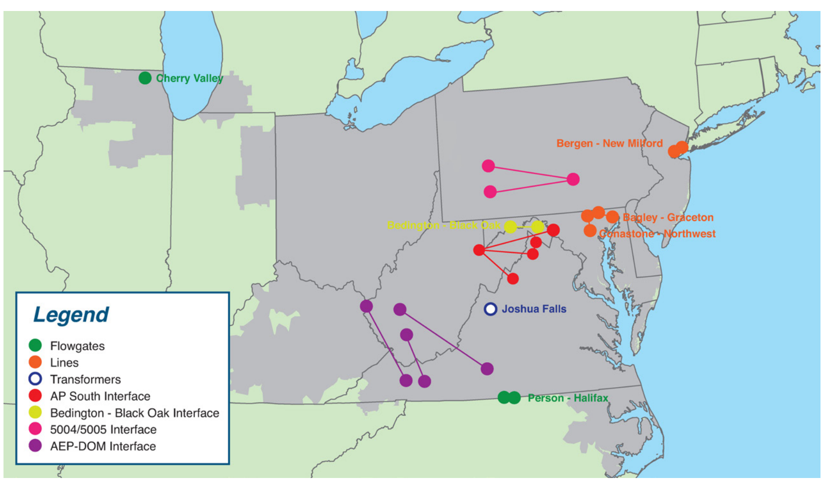


Figure 11-3 Location of the top 10 constraints by PJM day-ahead congestion costs: 2015

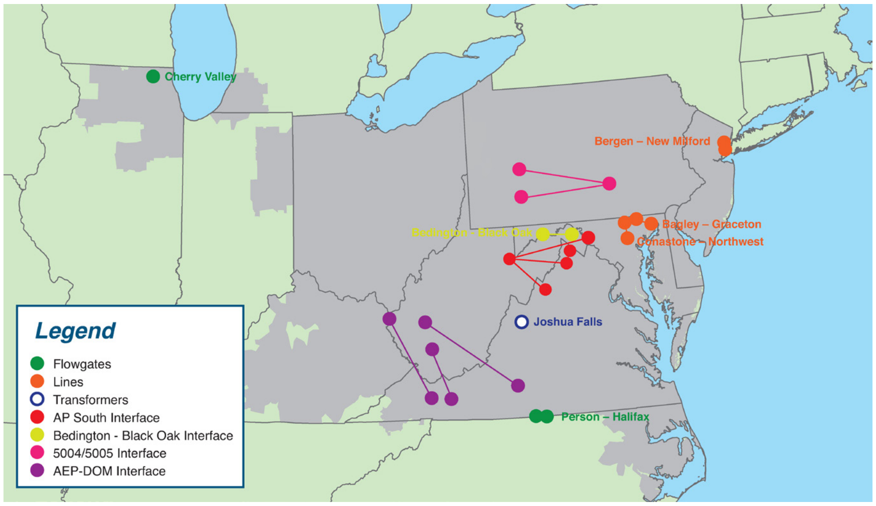
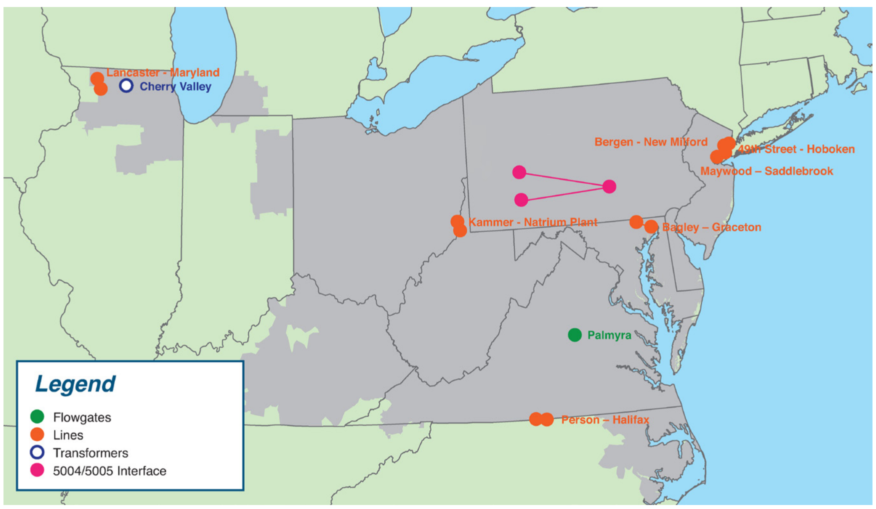


Figure 11-4 Location of the top 10 constraints by PJM balancing congestion costs: 2015



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 December 31, 2015, PJM had 130 flowgates eligible for M2M (Market to Market) coordination and MISO had 207 flowgates eligible for M2M coordination.

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>

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Table 11-26 and Table 11-27 show the MISO flowgates which PJM and/or MISO took dispatch action to control during 2015 and 2014, 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 2015, the Person - Halifax Flowgate made the most significant contribution to positive congestion while the Klondcin - Purdue 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): 2015

		Congestion Costs (Millions)									Congestion Event Hours	
		Day-Ahead				Balancing						
No.	Constraint	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day-Ahead	Real-Time
1	Cherry Valley	($9.1)	($82.1)	$6.7	$79.6	$0.0	$0.0	$0.0	$0.0	$79.6	1,348	0
2	Person - Halifax	$79.7	$29.2	($10.4)	$40.1	$0.0	($0.0)	($0.1)	($0.1)	$40.0	1,412	6
3	Oak Grove - Galesburg	($16.1)	($44.8)	($6.3)	$22.4	$0.2	$1.1	($1.9)	($2.8)	$19.7	3,356	1,306
4	Breed - Wheatland	($1.7)	($15.5)	$0.6	$14.4	$0.1	($0.6)	($0.7)	($0.0)	$14.4	1,358	149
5	Burnham - Munster	($0.0)	($10.7)	$1.1	$11.8	$0.0	$0.0	$0.0	$0.0	$11.8	1,748	0
6	Rising	$0.5	($11.8)	($6.6)	$5.7	$0.4	$0.0	$3.4	$3.7	$9.4	699	459
7	Bunsonville - Eugene	($3.1)	($17.8)	($7.6)	$7.2	$0.3	($0.2)	$1.5	$1.9	$9.1	3,762	748
8	Nelson	($2.9)	($11.3)	$0.8	$9.1	$0.0	$0.0	$0.0	$0.0	$9.1	708	0
9	Dixon - McGirr Rd	($3.1)	($11.0)	($0.0)	$7.9	$0.0	$0.0	$0.0	$0.0	$7.9	1,040	0
10	Michigan City - Laporte	$1.0	($6.9)	($0.4)	$7.5	$0.0	$0.0	$0.0	$0.0	$7.5	1,879	0
11	Monroe - Bayshore	($3.8)	($12.9)	($2.5)	$6.6	($0.1)	($0.8)	($0.1)	$0.5	$7.1	572	215
12	Crete - St Johns Tap	($0.2)	($5.7)	$1.0	$6.5	$0.0	$0.0	$0.0	$0.0	$6.5	724	0
13	Braidwood - East Frankfurt	($0.1)	($5.1)	($0.0)	$5.0	$0.0	$0.0	$0.0	$0.0	$5.0	54	0
14	Byron - Cherry Valley	($0.5)	($4.8)	$0.5	$4.9	$0.0	$0.0	$0.0	$0.0	$4.9	233	0
15	Mercer IP - Galesburg	($3.7)	($10.9)	($1.6)	$5.6	($0.0)	$0.5	($0.6)	($1.1)	$4.5	816	206
16	Marysville - Tangy	($0.4)	($5.1)	($0.2)	$4.5	$0.0	$0.0	$0.0	$0.0	$4.5	118	0
17	Cherry Valley - Silver Lake	($1.0)	($4.9)	$0.1	$4.1	$0.0	$0.0	$0.0	$0.0	$4.1	224	0
18	Benton Harbor - Palisades	($0.1)	($3.8)	($0.5)	$3.3	$0.0	$0.0	$0.0	$0.0	$3.3	283	0
19	Maryland	($2.3)	($4.6)	$0.8	$3.1	$0.0	$0.0	$0.0	$0.0	$3.1	434	0
20	Klondcin - Purdue	$0.0	($0.1)	$0.0	$0.1	$0.0	$0.4	($2.5)	($2.9)	($2.8)	40	53

Table 11-27 Top 20 congestion cost impacts from MISO flowgates affecting PJM dispatch (By facility): 2014

		Congestion Costs (Millions)									Congestion Event Hours	
		Day-Ahead				Balancing						
No.	Constraint	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day-Ahead	Real-Time
1	Breed - Wheatland	($17.7)	($100.2)	($9.3)	$73.2	$2.4	$1.1	$5.6	$6.9	$80.1	3,758	602
2	Benton Harbor - Palisades	($12.5)	($79.3)	($8.0)	$58.8	($0.2)	$0.7	($1.0)	($1.8)	$57.0	3,025	137
3	Monticello - East Winamac	($3.8)	($46.7)	$1.6	$44.6	$2.6	$4.3	($10.8)	($12.5)	$32.1	3,511	1,440
4	Oak Grove - Galesburg	($28.4)	($62.2)	($2.3)	$31.5	($0.4)	$0.5	($0.3)	($1.3)	$30.3	6,905	1,059
5	Cook - Palisades	($12.6)	($55.3)	($5.3)	$37.4	($1.5)	$1.6	($6.2)	($9.3)	$28.1	2,316	308
6	Michigan City - Laporte	($4.8)	($17.2)	$1.9	$14.4	$0.0	$0.0	$0.0	$0.0	$14.4	3,111	0
7	Rising	($5.1)	($3.8)	$1.4	$0.2	($3.9)	$1.2	($9.3)	($14.3)	($14.1)	386	115
8	Wake - Carso	$0.0	$0.0	$0.0	$0.0	$4.2	$2.7	($10.7)	($9.3)	($9.3)	0	115
9	Crete - St Johns Tap	($1.4)	($6.5)	$1.3	$6.4	$0.0	$0.0	$0.0	$0.0	$6.4	606	0
10	Cumberland - Bush	($0.2)	($3.2)	$0.5	$3.5	$0.0	$0.0	$0.0	$0.0	$3.5	470	0
11	Bunsonville - Eugene	($4.4)	($8.6)	($0.1)	$4.1	($0.1)	($0.2)	($0.9)	($0.7)	$3.4	2,244	675
12	Rantoul - Rantoul Jct	($2.7)	($5.5)	$0.3	$3.0	$0.0	$0.0	$0.0	$0.0	$3.0	1,088	0
13	Batesville - Hubble	($1.7)	($5.6)	($0.9)	$2.9	($0.0)	($0.0)	$0.1	$0.1	$3.0	438	16
14	Todd Hunter	($0.7)	($3.0)	$0.7	$2.9	$0.0	$0.0	$0.0	$0.0	$2.9	867	0
15	Byron - Cherry Valley	($0.6)	($3.4)	$0.1	$2.9	$0.0	$0.0	$0.0	$0.0	$2.9	42	0
16	Beaver Channel - Albany	$0.0	$0.0	$0.0	$0.0	($1.4)	$0.0	($1.0)	($2.5)	($2.5)	0	73
17	Paddock - Townline	$0.1	($2.4)	($0.3)	$2.2	$0.0	$0.0	$0.1	$0.1	$2.3	670	38
18	Edwards - Kewanee	($1.7)	($3.9)	$0.1	$2.3	$0.0	$0.0	$0.0	$0.0	$2.3	1,864	0
19	Nelson	($2.7)	($5.1)	($0.4)	$2.0	$0.0	$0.0	$0.0	$0.0	$2.0	169	19
20	Pana North	$0.1	($0.2)	$0.1	$0.4	$0.0	$0.3	($2.0)	($2.3)	($1.9)	162	275

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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 2015, and which had the greatest congestion cost impact on PJM.

Table 11-28 Top two congestion cost impacts from NYISO flowgates affecting PJM dispatch (By facility): 2015

				Congestion Costs (Millions)										
				Day-Ahead				Balancing					Congestion 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	$0.4	$1.1	($0.0)	($0.7)	($0.7)	0	419
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 11-29 Top two congestion cost impacts from NYISO flowgates affecting PJM dispatch (By facility): 2014

				Congestion Costs (Millions)										
				Day-Ahead				Balancing					Congestion 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	$0.5	$2.0	($0.1)	($1.6)	($1.6)	0	143
2	Dysinger East	Flowgate	NYISO	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	$0.0	$0.0	0	4

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 2015 and 2014. 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.

Table 11-30 Regional constraints summary (By facility): 2015

				Congestion Costs (Millions)										
				Day-Ahead				Balancing					Congestion 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	($23.0)	($134.8)	($9.2)	$102.6	$7.0	$22.5	$1.9	($13.6)	$89.0	678	321
2	Bedington - Black Oak	Interface	500	$46.1	($45.2)	($7.2)	$84.1	$2.4	$2.2	$3.2	$3.5	$87.6	2,933	344
3	AP South	Interface	500	$38.1	($22.8)	($5.5)	$55.4	$0.3	$0.2	$0.6	$0.7	$56.2	1,285	42
4	AEP - DOM	Interface	500	$28.1	($28.0)	($1.1)	$55.0	$0.9	$1.6	($1.9)	($2.6)	$52.4	1,328	44
5	East	Interface	500	($13.0)	($37.6)	($2.1)	$22.4	($0.1)	$0.3	$0.5	$0.1	$22.6	540	16
6	Central	Interface	500	($15.5)	($32.7)	($3.9)	$13.3	$0.1	$1.0	$0.3	($0.7)	$12.6	291	41
7	West	Interface	500	($1.8)	($15.6)	($0.9)	$12.9	$0.2	$1.0	$0.1	($0.6)	$12.3	319	49
8	Nagel - Phipps Bend	Line	500	($0.1)	($0.4)	$1.0	$1.3	$0.0	$0.0	$0.0	$0.0	$1.3	260	0
9	Juniata	Transformer	500	$0.2	($0.7)	$0.1	$1.0	$0.9	$0.7	$0.0	$0.2	$1.2	87	29

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>.

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Table 11-31 Regional constraints summary (By facility): 2014

				Congestion Costs (Millions)										
				Day-Ahead				Balancing					Congestion 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	AP South	Interface	500	$329.7	($201.4)	($11.2)	$520.0	$31.5	$73.5	$8.9	($33.1)	$486.8	5,090	981
2	West	Interface	500	($21.3)	($297.0)	($79.1)	$196.5	$17.7	$49.7	$17.0	($15.0)	$181.6	1,534	415
3	Bedington - Black Oak	Interface	500	$42.8	($43.9)	($0.2)	$86.5	$3.9	$3.4	($2.3)	($1.9)	$84.6	2,796	323
4	East	Interface	500	($9.8)	($34.2)	($3.4)	$21.0	$0.3	$0.7	$0.5	$0.1	$21.1	1,734	17
5	5004/5005 Interface	Interface	500	($0.7)	($23.6)	($3.3)	$19.5	$8.1	$17.5	$7.3	($2.1)	$17.4	554	336
6	AEP - DOM	Interface	500	$10.7	($11.4)	$3.9	$26.0	$5.3	$13.2	($9.6)	($17.5)	$8.5	2,511	66
7	Central	Interface	500	($5.2)	($13.9)	($3.8)	$4.8	$0.2	$0.5	$0.0	($0.3)	$4.6	334	10
8	Juniata	Transformer	500	$0.1	($0.2)	$0.1	$0.5	$0.1	($0.0)	($0.1)	$0.0	$0.5	253	9
9	Branchburg - Elroy	Line	500	($0.0)	($0.2)	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	43	0
10	Nagel - Phipps Bend	Line	500	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	53	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 2015, 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 2015, the total explicit cost was -$127.3 million (indicating net credits to participants), of which -$155.9 million (122.4 percent) was credited to UTCs. In 2014, the total explicit cost was -$169.0 million, of which -$200.2 million (118.5 percent) was credited to UTCs. In 2015, financial entities received $133.1 million in net congestion credits, a decrease of $93.6 million or 41.3 percent compared to 2014. In 2015, physical entities paid $1,518.3 million in congestion charges, a decrease of $640.6 million or 29.7 percent compared to 2014.

Table 11-32 Congestion cost by type of participant: 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	$82.3	$40.5	($2.7)	$39.0	($49.3)	($7.9)	($130.7)	($172.1)	$0.0	($133.1)
Physical	$531.9	($1,008.2)	$53.0	$1,593.1	$49.8	$77.7	($46.9)	($74.8)	$0.0	$1,518.3
Total	$614.2	($967.6)	$50.3	$1,632.1	$0.6	$69.8	($177.6)	($246.9)	$0.0	$1,385.3

Table 11-33 Congestion cost by type of participant: 2014

	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	$63.8	$75.7	($104.7)	($116.6)	($40.4)	($8.1)	($77.8)	($110.1)	$0.0	($226.7)
Physical	$531.6	($1,746.9)	$69.3	$2,347.9	$93.1	$226.2	($55.8)	($189.0)	$0.0	$2,158.9
Total	$595.5	($1,671.2)	($35.4)	$2,231.3	$52.7	$218.1	($133.6)	($299.1)	$0.0	$1,932.2

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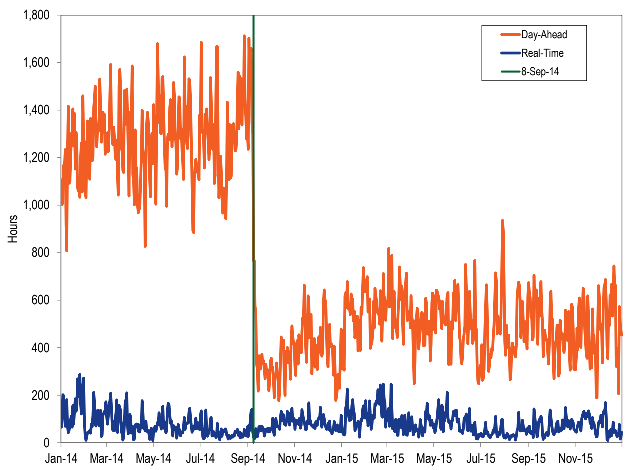
Congestion-Event Summary before and after September 8, 2014

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 2015.

Figure 11-5 Daily congestion event hours: 2014 through 2015



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 by 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.

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.

26 See 18 CFR § 385.213 (2014).

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

28 *Id.*

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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.

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 2015 was $968.7 million, which was comprised of load loss payments of -$37.1 million, generation loss credits of -$1,021.0 million, explicit loss costs of -$20.5 million and inadvertent loss charges of $0.0 million. Monthly marginal loss costs in 2015 ranged from $44.6 million

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

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

in December to $220.3 million in February. Total loss surplus decreased in 2015 by $148.2 million or 30.7 percent from 2014, from $482.1 million to $333.9 million.

Total Marginal Loss Costs

Table 11-34 shows the total marginal loss costs as a component of total energy related costs for 2009 through 2015.

Table 11-34 Total component costs (Dollars (Millions)): 2009 through 2015[31]

	Loss Costs	Percent Change	Total PJM Billing	Percent of PJM Billing
2009	$1,268	NA	$26,550	4.8%
2010	$1,635	29.0%	$34,771	4.7%
2011	$1,380	(15.6%)	$35,887	3.8%
2012	$982	(28.8%)	$29,181	3.4%
2013	$1,035	5.5%	$33,862	3.1%
2014	$1,466	41.6%	$50,030	2.9%
2015	$969	(33.9%)	$42,630	2.3%

Table 11-35 shows PJM total marginal loss costs by accounting category for 2009 through 2015. Table 11-36 shows PJM total marginal loss costs by accounting category by market for 2009 through 2015.

Table 11-35 Total PJM marginal loss costs by accounting category (Dollars (Millions)): 2009 through 2015

	Marginal Loss Costs (Millions)				
	Load Payments	Generation Credits	Explicit Costs	Inadvertent Charges	Total
2009	($78.5)	($1,314.3)	$32.0	($0.0)	$1,267.7
2010	($122.3)	($1,707.0)	$50.2	($0.0)	$1,634.8
2011	($174.0)	($1,551.9)	$1.6	$0.0	$1,379.5
2012	($11.1)	($1,036.8)	($44.0)	$0.0	$981.7
2013	($4.1)	($1,083.3)	($43.9)	($0.0)	$1,035.3
2014	($59.2)	($1,581.3)	($56.0)	$0.0	$1,466.1
2015	($31.7)	($1,021.0)	($20.5)	$0.0	$968.7

Table 11-36 Total PJM marginal loss costs by accounting category by market (Dollars (Millions)): 2009 through 2015

	Marginal Loss Costs (Millions)									
	Day-Ahead				Balancing					
	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Inadvertent Charges	Grand Total
2009	($84.7)	($1,311.7)	$65.4	$1,292.3	$6.2	($2.7)	($33.5)	($24.6)	($0.0)	$1,267.7
2010	($146.3)	($1,716.1)	$95.8	$1,665.6	$23.9	$9.1	($45.6)	($30.8)	($0.0)	$1,634.8
2011	($215.4)	($1,592.1)	$53.8	$1,430.5	$41.4	$40.2	($52.2)	($51.0)	$0.0	$1,379.5
2012	($43.0)	($1,060.3)	($13.4)	$1,003.8	$32.0	$23.4	($30.6)	($22.1)	$0.0	$981.7
2013	($37.1)	($1,112.4)	$62.4	$1,137.8	$33.0	$29.1	($106.4)	($102.5)	($0.0)	$1,035.3
2014	($113.9)	($1,618.8)	$66.6	$1,571.4	$54.7	$37.5	($122.5)	($105.3)	$0.0	$1,466.1
2015	($53.4)	($1,032.2)	$33.8	$1,012.6	$21.7	$11.3	($54.3)	($43.9)	$0.0	$968.7

Table 11-37 and Table 11-38 show the total loss costs for each transaction type in 2015 and 2014. In 2015, generation paid 97.1 percent of total loss cost and the loss cost paid by generation was $940.7 million. In 2014, generation paid 98.2 percent of total loss cost and the loss cost paid by generation was $1,439.1 million.

31 The loss costs include net inadvertent charges.

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Table 11-37 Total PJM loss costs by transaction type by market (Dollars (Millions)): 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	($1.3)	$0.0	$0.0	($1.3)	($4.0)	$0.0	$0.0	($4.0)	$0.0	($5.3)
Demand	($10.2)	$0.0	$0.0	($10.2)	$22.2	$0.0	$0.0	$22.2	$0.0	$12.0
Demand Response	($0.0)	$0.0	$0.0	($0.0)	$0.1	$0.0	$0.0	$0.1	$0.0	$0.0
Export	($17.8)	$0.0	$0.4	($17.4)	($2.5)	$0.0	$1.6	($1.0)	$0.0	($18.3)
Generation	$0.0	($980.0)	$0.0	$980.0	$0.0	$39.3	$0.0	($39.3)	$0.0	$940.7
Grandfathered Overuse	$0.0	$0.0	($1.5)	($1.5)	$0.0	$0.0	$0.0	$0.0	$0.0	($1.5)
Import	$0.0	($14.2)	$3.8	$18.0	$0.0	($48.2)	$1.6	$49.7	$0.0	$67.8
INC	$0.0	($13.9)	$0.0	$13.9	$0.0	$14.2	$0.0	($14.2)	$0.0	($0.2)
Internal Bilateral	($24.1)	($24.1)	$0.0	$0.0	$6.0	$6.0	$0.0	($0.0)	$0.0	($0.0)
Up to Congestion	$0.0	$0.0	$29.1	$29.1	$0.0	$0.0	($57.3)	($57.3)	$0.0	($28.2)
Wheel In	$0.0	$0.0	$1.9	$1.9	$0.0	$0.0	($0.1)	($0.1)	$0.0	$1.8
Total	($53.4)	($1,032.2)	$33.8	$1,012.6	$21.7	$11.3	($54.3)	($43.9)	$0.0	$968.7

Table 11-38 Total PJM loss costs by transaction type by market (Dollars (Millions)): 2014

	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	($4.3)	$0.0	$0.0	($4.3)	$3.4	$0.0	$0.0	$3.4	$0.0	($0.9)
Demand	($10.3)	$0.0	$0.0	($10.3)	$72.1	$0.0	$0.0	$72.1	$0.0	$61.8
Demand Response	($0.2)	$0.0	$0.0	($0.2)	$0.2	$0.0	$0.0	$0.2	$0.0	($0.0)
Export	($26.7)	$0.0	$0.2	($26.5)	($20.9)	$0.0	$2.4	($18.5)	$0.0	($44.9)
Generation	$0.0	($1,515.2)	$0.0	$1,515.2	$0.0	$76.1	$0.0	($76.1)	$0.0	$1,439.1
Grandfathered Overuse	$0.0	$0.0	($2.3)	($2.3)	$0.0	$0.0	$0.0	$0.0	$0.0	($2.3)
Import	$0.0	($10.8)	$15.6	$26.4	$0.0	($63.9)	$3.8	$67.8	$0.0	$94.2
INC	$0.0	($20.5)	$0.0	$20.5	$0.0	$25.4	$0.0	($25.4)	$0.0	($4.9)
Internal Bilateral	($72.4)	($72.3)	$0.1	($0.0)	($0.1)	($0.1)	$0.0	($0.0)	$0.0	($0.0)
Up to Congestion	$0.0	$0.0	$49.7	$49.7	$0.0	$0.0	($128.6)	($128.6)	$0.0	($79.0)
Wheel In	$0.0	$0.0	$3.3	$3.3	$0.0	$0.0	($0.2)	($0.2)	$0.0	$3.1
Total	($113.9)	($1,618.8)	$66.6	$1,571.4	$54.7	$37.5	($122.5)	($105.3)	$0.0	$1,466.1

Monthly Marginal Loss Costs

Table 11-39 shows a monthly summary of marginal loss costs by market type for 2014 and 2015. Total marginal loss costs decreased were higher in 2014 as a result of high load and outages caused by cold weather in the winter of 2014.

Table 11-39 Monthly marginal loss costs by market (Millions): 2014 and 2015

	Marginal Loss Costs (Millions)							
	2014				2015			
	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total
Jan	$431.1	($16.5)	$0.0	$414.6	$115.9	($4.2)	$0.0	$111.7
Feb	$202.1	($16.3)	$0.0	$185.8	$218.2	$2.0	$0.0	$220.3
Mar	$198.0	($22.6)	($0.0)	$175.4	$97.9	($4.7)	($0.0)	$93.2
Apr	$83.2	($11.8)	($0.0)	$71.4	$54.0	($2.0)	($0.0)	$52.0
May	$80.3	($11.5)	$0.0	$68.7	$66.2	($3.6)	$0.0	$62.6
Jun	$100.4	($10.2)	$0.0	$90.2	$73.2	($4.6)	($0.0)	$68.6
Jul	$102.1	($9.6)	$0.0	$92.5	$89.3	($5.7)	$0.0	$83.6
Aug	$80.5	($5.3)	$0.0	$75.2	$77.3	($4.4)	$0.0	$72.9
Sep	$70.3	($1.1)	$0.0	$69.2	$68.8	($3.8)	($0.0)	$65.0
Oct	$64.5	($0.1)	$0.0	$64.3	$53.8	($4.3)	($0.0)	$49.5
Nov	$82.9	$0.4	($0.0)	$83.3	$48.5	($3.6)	$0.0	$44.9
Dec	$76.2	($0.8)	($0.0)	$75.4	$49.6	($5.0)	($0.0)	$44.6
Total	$1,571.4	($105.3)	$0.0	$1,466.1	$1,012.6	($43.9)	$0.0	$968.7

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Figure 11-6 shows PJM monthly marginal loss costs for 2009 through 2015.

Figure 11-6 PJM monthly marginal loss costs (Dollars (Millions)): 2009 through 2015

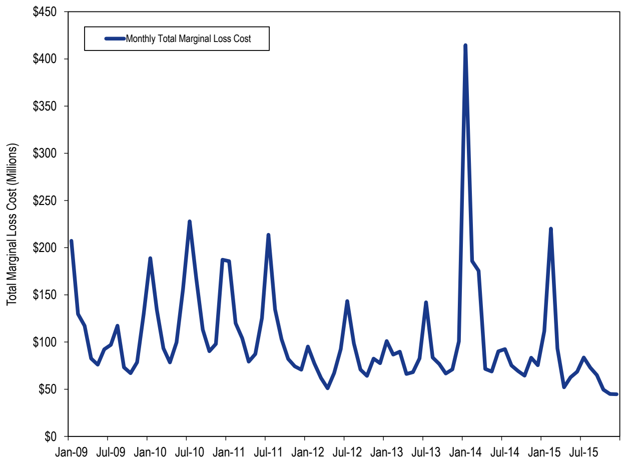

Table 11-40 and Table 11-41 show the monthly total loss costs for each virtual transaction type in 2014 and 2015. Virtual transaction loss costs, when positive, measure the total loss cost to the virtual transaction and when negative, measure the total loss credit to the virtual transaction. In 2015, DECs were paid $1.3 million in loss credits in the day-ahead market, were paid $4.0 million in congestion credits in the balancing energy market and received $5.3 million in net payment for loss. In 2015, INCs paid $13.9 million in loss credits in the day-ahead market, were paid $14.2 million in congestion cost in the balancing energy market and received $0.2 million in net payment for loss. In 2015, up to congestion paid $29.1 million in loss cost in the day-ahead market, were paid $57.3 million in loss credits in the balancing energy market and received $28.2 million in net payment for loss.

Table 11-40 Monthly PJM loss costs by virtual transaction type and by market (Dollars (Millions)): 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)
Apr	($0.3)	$0.9	$1.2	$1.7	($0.5)	($0.6)	($3.6)	($4.7)	($2.9)
May	($1.9)	$2.3	$1.2	$1.7	$0.4	($1.7)	($6.0)	($7.3)	($5.7)
Jun	($0.6)	$1.7	$4.3	$5.4	$0.2	($1.4)	($5.6)	($6.7)	($1.3)
Jul	$0.2	$1.1	$4.0	$5.3	($0.3)	($1.0)	($6.1)	($7.3)	($2.0)
Aug	$0.3	$0.9	$1.4	$2.6	($0.2)	($1.0)	($3.9)	($5.1)	($2.5)
Sep	$0.1	$1.0	$2.6	$3.7	($0.1)	($1.2)	($4.6)	($5.9)	($2.2)
Oct	$0.6	$0.5	$2.9	$4.0	($0.4)	($0.6)	($4.1)	($5.2)	($1.1)
Nov	($0.1)	$1.0	$2.4	$3.3	$0.2	($1.1)	($3.8)	($4.7)	($1.4)
Dec	$0.3	$0.7	$3.2	$4.3	($0.3)	($0.8)	($5.3)	($6.3)	($2.0)
Total	($1.3)	$13.9	$29.1	$41.8	($4.0)	($14.2)	($57.3)	($75.5)	($33.8)

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Table 11-41 Monthly PJM loss costs by virtual transaction type and by market (Dollars (Millions)): 2014

	Loss Costs (Millions)								
	Day-Ahead				Balancing				
	DEC	INC	Up to Congestion	Virtual Total	DEC	INC	Up to Congestion	Virtual Total	Virtual Grand Total
Jan	$5.6	$5.5	$1.8	$12.9	($4.3)	($8.2)	($19.7)	($32.3)	($19.4)
Feb	$0.0	$2.5	$7.5	$10.0	($0.8)	($3.4)	($15.9)	($20.1)	($10.1)
Mar	$1.2	$2.8	$12.9	$16.9	($0.5)	($3.8)	($23.3)	($27.6)	($10.6)
Apr	($1.1)	$0.9	$4.4	$4.2	$1.5	($0.8)	($11.9)	($11.2)	($7.0)
May	($1.6)	$1.6	$4.6	$4.5	$1.8	($1.6)	($12.8)	($12.6)	($8.1)
Jun	($1.0)	$1.3	$7.9	$8.2	$1.3	($1.7)	($13.8)	($14.3)	($6.1)
Jul	($0.5)	$1.2	$6.8	$7.5	$0.3	($1.5)	($12.1)	($13.2)	($5.8)
Aug	($1.2)	$1.1	$1.4	$1.3	$0.7	($0.9)	($7.5)	($7.7)	($6.3)
Sep	($1.0)	$0.8	$0.4	$0.2	$0.6	($0.9)	($3.7)	($4.0)	($3.8)
Oct	($1.8)	$0.8	$0.6	($0.5)	$1.6	($0.9)	($2.2)	($1.5)	($2.0)
Nov	($1.5)	$1.2	$1.0	$0.7	$0.9	($1.3)	($2.7)	($3.1)	($2.4)
Dec	($1.3)	$0.6	$0.5	($0.2)	$0.3	($0.4)	($3.0)	($3.1)	($3.3)
Total	($4.3)	$20.5	$49.7	$65.8	$3.4	($25.4)	($128.6)	($150.6)	($84.8)

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.

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 2009 through 2015. The total marginal loss credits decreased $145.8 million in 2015 from 2014.

Table 11-42 Marginal loss credits (Dollars (Millions)): 2009 through 2015[32]

	Loss Credit Accounting (Millions)			
	Total Energy Charges	Total Marginal Loss Charges	Adjustments	Total Loss Surplus
2009	($628.8)	$1,267.7	$0.8	$639.7
2010	($797.9)	$1,634.8	$0.0	$836.9
2011	($793.8)	$1,379.5	$0.9	$586.7
2012	($593.0)	$981.7	($2.0)	$386.7
2013	($687.6)	$1,035.3	($2.9)	$344.8
2014	($977.7)	$1,466.1	($6.3)	$482.1
2015	($627.4)	$968.7	($5.0)	$336.3

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.

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 2015 was -$627.4 million, which was comprised of load energy payments of $40,601.8 million, generation energy credits of $41,231.9 million, explicit energy costs of $0.0 million and inadvertent energy charges of $2.7 million. The monthly energy costs for 2015 ranged from -$141.5 million in February to -$28.9 million in December.

Table 11-43 shows total energy component costs and total PJM billing, for 2009 through 2015. The total energy component costs are net energy costs.

Table 11-43 Total PJM costs by energy component (Dollars (Millions)): 2009 through 2015[33]

	Energy Costs	Percent Change	Total PJM Billing	Percent of PJM Billing
2009	($629)	NA	$26,550	(2.4%)
2010	($798)	26.9%	$34,771	(2.3%)
2011	($794)	(0.5%)	$35,887	(2.2%)
2012	($593)	(25.3%)	$29,181	(2.0%)
2013	($688)	15.9%	$33,862	(2.0%)
2014	($978)	42.2%	$50,030	(2.0%)
2015	($627)	(35.8%)	$42,630	(1.5%)

Energy costs for 2009 through 2015 are shown in Table 11-44 and Table 11-45. Table 11-44 shows PJM energy costs by accounting category for 2009 through 2015 and Table 11-45 shows PJM energy costs by market category for 2009 through 2015.

Table 11-44 Total PJM energy costs by accounting category (Dollars (Millions)): 2009 through 2015

	Energy Costs (Millions)				
	Load Payments	Generation Credits	Explicit Costs	Inadvertent Charges	Total
2009	$42,535.2	$43,165.7	$0.0	$1.7	($628.8)
2010	$53,101.5	$53,886.9	$0.0	($12.6)	($797.9)
2011	$47,658.9	$48,481.0	$0.0	$28.3	($793.8)
2012	$37,471.3	$38,073.5	$0.0	$9.1	($593.0)
2013	$42,774.3	$43,454.6	$0.0	($7.4)	($687.6)
2014	$60,258.5	$61,232.0	$0.0	($4.2)	($977.7)
2015	$40,601.8	$41,231.9	$0.0	$2.7	($627.4)

33 The energy costs include net inadvertent charges.

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Table 11-45 Total PJM energy costs by market category (Dollars (Millions)): 2009 through 2015

	Energy Costs (Millions)									
	Day-Ahead				Balancing					
	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Inadvertent Charges	Grand Total
2009	$42,683.8	$43,351.2	$0.0	($667.4)	($148.5)	($185.5)	$0.0	$36.9	$1.7	($628.8)
2010	$53,164.9	$53,979.1	$0.0	($814.1)	($63.4)	($92.2)	$0.0	$28.8	($12.6)	($797.9)
2011	$48,144.9	$48,880.0	$0.0	($735.2)	($485.9)	($399.1)	$0.0	($86.9)	$28.3	($793.8)
2012	$37,641.2	$38,251.1	$0.0	($609.9)	($169.9)	($177.6)	$0.0	$7.7	$9.1	($593.0)
2013	$42,795.2	$43,628.9	$0.0	($833.7)	($20.9)	($174.4)	$0.0	$153.5	($7.4)	($687.6)
2014	$60,325.2	$61,668.9	$0.0	($1,343.7)	($66.7)	($436.9)	$0.0	$370.2	($4.2)	($977.7)
2015	$40,837.8	$41,595.7	$0.0	($757.9)	($236.0)	($363.8)	$0.0	$127.8	$2.7	($627.4)

Table 11-46 and Table 11-47 show the total energy costs for each virtual transaction type in 2015 and 2014. In 2015, generation were paid $28,339.7 million and demand paid $28,497.4 million in net energy payment. In 2014, generation were paid $42,531.8 million and demand paid $42,003.1 million in net energy payment.

Table 11-46 Total PJM energy costs by transaction type by market (Dollars (Millions)): 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	$1,303.1	$0.0	$0.0	$1,303.1	($1,297.8)	$0.0	$0.0	($1,297.8)	$5.3
Demand	$28,243.8	$0.0	$0.0	$28,243.8	$253.5	$0.0	$0.0	$253.5	$28,497.4
Demand Response	($1.9)	$0.0	$0.0	($1.9)	$1.8	$0.0	$0.0	$1.8	($0.1)
Export	$708.1	$0.0	$0.0	$708.1	$182.0	$0.0	$0.0	$182.0	$890.1
Generation	$0.0	$29,150.1	$0.0	($29,150.1)	$0.0	($810.4)	$0.0	$810.4	($28,339.7)
Import	$0.0	$451.9	$0.0	($451.9)	$0.0	$1,194.6	$0.0	($1,194.6)	($1,646.6)
INC	$0.0	$1,409.0	$0.0	($1,409.0)	$0.0	($1,372.5)	$0.0	$1,372.5	($36.5)
Internal Bilateral	$10,584.7	$10,584.7	$0.0	($0.0)	$624.5	$624.5	$0.0	$0.0	($0.0)
Total	$40,837.8	$41,595.7	$0.0	($757.9)	($236.0)	($363.8)	$0.0	$127.8	($630.1)

Table 11-47 Total PJM energy costs by transaction type by market (Dollars (Millions)): 2014

	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	$2,898.7	$0.0	$0.0	$2,898.7	($2,881.0)	$0.0	$0.0	($2,881.0)	$17.7
Demand	$40,504.8	$0.0	$0.0	$40,504.8	$1,498.3	$0.0	$0.0	$1,498.3	$42,003.1
Demand Response	($5.8)	$0.0	$0.0	($5.8)	$5.1	$0.0	$0.0	$5.1	($0.8)
Export	$1,188.3	$0.0	$0.0	$1,188.3	$619.2	$0.0	$0.0	$619.2	$1,807.5
Generation	$0.0	$43,777.0	$0.0	($43,777.0)	$0.0	($1,245.2)	$0.0	$1,245.2	($42,531.8)
Import	$0.0	$635.1	$0.0	($635.1)	$0.0	$1,593.7	$0.0	($1,593.7)	($2,228.8)
INC	$0.0	$1,517.1	$0.0	($1,517.1)	$0.0	($1,476.4)	$0.0	$1,476.4	($40.8)
Internal Bilateral	$15,739.6	$15,739.6	$0.0	($0.0)	$691.0	$691.0	$0.0	($0.0)	($0.0)
Total	$60,325.5	$61,668.9	$0.0	($1,343.4)	($67.4)	($436.9)	$0.0	$369.5	($973.9)

Monthly Energy Costs

Table 11-48 shows a monthly summary of energy costs by market type for 2014 and 2015. Marginal total energy costs in 2015 decreased from 2014. Monthly total energy costs in 2015 ranged from -$141.5 million in February to -$28.9 million in December.

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Table 11-48 Monthly energy costs by market type (Dollars (Millions)): 2014 and 2015

	Energy Costs (Millions)							
	2014				2015			
	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total
Jan	($339.8)	$68.1	($1.0)	($272.7)	($84.6)	$13.3	$0.9	($70.5)
Feb	($163.7)	$43.5	($2.8)	($123.0)	($150.5)	$6.2	$2.8	($141.5)
Mar	($167.3)	$50.8	($3.1)	($119.6)	($77.6)	$19.0	($1.0)	($59.6)
Apr	($90.4)	$36.7	($0.1)	($53.7)	($45.4)	$9.5	($0.1)	($36.0)
May	($92.4)	$44.0	$0.3	($48.1)	($57.1)	$12.2	$0.2	($44.7)
Jun	($94.7)	$33.4	$1.3	($59.9)	($53.8)	$8.7	($0.1)	($45.2)
Jul	($91.1)	$28.9	$0.7	($61.5)	($64.7)	$12.5	$0.1	($52.0)
Aug	($79.2)	$28.2	$0.5	($50.6)	($55.5)	$9.6	$0.1	($45.8)
Sep	($55.8)	$10.5	$0.7	($44.6)	($49.9)	$8.9	($0.0)	($41.1)
Oct	($47.5)	$8.3	$0.1	($39.1)	($41.8)	$9.1	($0.1)	($32.8)
Nov	($63.4)	$8.6	($0.4)	($55.2)	($37.0)	$7.7	$0.1	($29.1)
Dec	($58.3)	$9.0	($0.3)	($49.6)	($40.1)	$11.2	($0.0)	($28.9)
Total	($1,343.7)	$370.2	($4.2)	($977.7)	($757.9)	$127.8	$2.7	($627.4)

Figure 11-7 shows PJM monthly energy costs for 2009 through 2015.

Figure 11-7 PJM monthly energy costs (Millions): 2009 through 2015

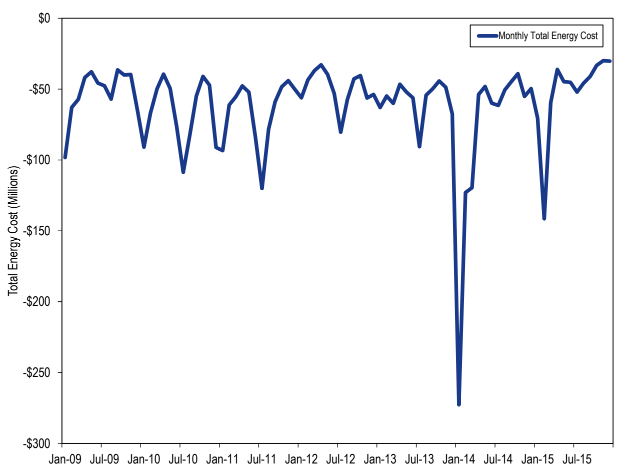

Table 11-49 and Table 11-50 show the monthly total energy costs for each virtual transaction type in 2015 and 2014. In 2015, DECs paid $1,303.1 million in energy credits in the day-ahead market, were paid $1,297.8 million in energy credits in the balancing energy market and paid $5.3 million in net payment for energy. In 2015, INCs were paid $1,409.0 million in energy credits in the day-ahead market, paid $1,372.5 million in energy cost in the balancing market and received $36.5 million in net payment for energy. In 2014, DECs paid $2,898.7 million in energy credits in the day-ahead market, were paid $2,881.0 million in energy credits in the balancing energy market and paid $17.7 million in net payment for energy. In 2014, INCs were paid $1,517.1 million in energy credits in the day-ahead market, paid $1,476.4 million in energy cost in the balancing energy market and received $40.8 million in net payment for energy.

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Table 11-49 Monthly PJM energy costs by virtual transaction type and by market (Dollars (Millions)): 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)
Apr	$78.8	($98.9)	($20.1)	($78.3)	$96.3	$18.0	($2.1)
May	$114.4	($128.4)	($14.0)	($108.5)	$119.8	$11.2	($2.8)
Jun	$98.2	($99.5)	($1.3)	($97.7)	$97.7	($0.0)	($1.4)
Jul	$88.8	($100.4)	($11.6)	($86.8)	$97.2	$10.4	($1.2)
Aug	$79.8	($95.8)	($16.0)	($76.7)	$92.2	$15.4	($0.6)
Sep	$99.1	($97.1)	$2.0	($107.4)	$102.0	($5.3)	($3.3)
Oct	$90.7	($98.1)	($7.4)	($85.6)	$92.7	$7.1	($0.3)
Nov	$74.2	($94.5)	($20.3)	($72.8)	$91.9	$19.2	($1.1)
Dec	$76.5	($89.9)	($13.4)	($77.9)	$89.9	$12.0	($1.4)
Total	$1,303.1	($1,409.0)	($105.9)	($1,297.8)	$1,372.5	$74.7	($31.1)

Table 11-50 Monthly PJM energy costs by virtual transaction type and by market (Dollars (Millions)): 2014

	Energy Costs (Millions)						
	Day-Ahead			Balancing			
	DEC	INC	Virtual Total	DEC	INC	Virtual Total	Virtual Grand Total
Jan	$568.1	($309.6)	$258.5	($525.2)	$271.0	($254.1)	$4.3
Feb	$288.0	($148.4)	$139.6	($283.6)	$144.8	($138.8)	$0.8
Mar	$331.5	($147.0)	$184.5	($364.2)	$159.1	($205.1)	($20.6)
Apr	$172.1	($86.0)	$86.1	($161.7)	$81.0	($80.6)	$5.5
May	$196.8	($126.8)	$70.0	($204.2)	$128.3	($75.9)	($5.9)
Jun	$204.3	($102.4)	$102.0	($211.8)	$104.7	($107.1)	($5.1)
Jul	$212.7	($109.3)	$103.4	($209.9)	$107.1	($102.9)	$0.5
Aug	$173.0	($88.8)	$84.1	($169.1)	$86.1	($83.1)	$1.1
Sep	$179.4	($85.3)	$94.2	($184.7)	$86.6	($98.1)	($4.0)
Oct	$182.0	($91.9)	$90.1	($189.2)	$94.6	($94.6)	($4.5)
Nov	$209.3	($122.9)	$86.4	($197.5)	$115.6	($81.8)	$4.5
Dec	$181.4	($98.7)	$82.7	($179.9)	$97.5	($82.4)	$0.2
Total	$2,898.7	($1,517.1)	$1,381.5	($2,881.0)	$1,476.4	($1,404.6)	($23.1)

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