Congestion and Marginal Losses

The locational marginal price (LMP) is the incremental price of energy at a bus. The LMP at a bus is made up 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 is dependent on 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.

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 $523.6 million or 36.3 percent, from $1,442.3 million in the first six months of 2014 to $918.6 million in the first six months of 2015.
- **Day-Ahead Congestion.** Day-ahead congestion costs decreased by $598.7 million or 35.4 percent, from $1,691.9 million in the first six months of 2014 to $1,093.2 million in the first six months of 2015.

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 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 July 18, 2015, and are subject to change, based on continued PJM billing updates.

- **Balancing Congestion.** Balancing congestion costs increased by $75.1 million or 30.1 percent, from -$249.7 million in the first six months of 2014 to -$174.6 million in the first six months of 2015.
- **Real-Time Congestion.** Real-time congestion costs decreased by $716.8 million or 43.0 percent, from $1,668.4 million in the first six months of 2014 to $951.6 million in the first six months of 2015.
- **Monthly Congestion.** In 2015, 46.8 percent ($429.8 million) of total congestion cost was incurred in February and 22.0 percent ($201.9 million) of total congestion cost was incurred in the months of January and March. Monthly total congestion costs in the first six months of 2015 ranged from $69.5 million in March 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 AEP - DOM Interface, the AP South Interface, and the Bergen - New Milford line.
- **Congestion Frequency.** Congestion frequency continued to be significantly higher in the Day-Ahead Energy Market than in the Real-Time Energy Market in the first six months of 2015. The number of congestion event hours in the Day-Ahead Energy Market was about five times higher than the number of congestion event hours in the Real-Time Energy Market.

  Day-ahead congestion frequency decreased by 57.9 percent from 228,169 congestion event hours in the first six months of 2014 to 95,960 congestion event hours in the first six months of 2015. The day-ahead congestion event hours decreased significantly after September 8, 2014. The reduction was the result of the reduction in UTC activity which was a result of FERC's UTC uplift refund notice, retroactive to September 8, 2014.

  Real-time congestion frequency increased by 2.7 percent from 16,722 congestion event hours in the first six months of 2014 to 17,169 congestion event hours in the first six months of 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 5004/5005 Interface was the largest contributor to congestion costs in the first six months of 2015. With $88.8 million in total congestion costs, it accounted for 9.7 percent of the total PJM congestion costs in the first six months of 2015.
- **Zonal Congestion.** AEP had the largest total congestion costs among all control zones in the first six months of 2015. AEP had $248.8 million in total congestion costs, comprised of -$352.0 million in total load congestion payments, -$621.0 million in total generation congestion credits and -$20.2 million in explicit congestion costs. The AEP - DOM Interface, the Joshua Falls transformer, the 5004/5005 Interface, the Bedington - Black Oak Interface and the Mahans Lane – Tidd line contributed $119.7 million, or 48.1 percent of the total AEP control zone congestion costs.
- **Ownership.** In the first six months of 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 the first six months of 2015, financial entities received $98.8 million in congestion credits, a decrease of $92.3 million or 48.3 percent compared to the first six months of 2014. In the first six months of 2015, physical entities paid $1,017.5 million in congestion charges, a decrease of $615.9 million or 37.7 percent compared to the first six months of 2014. UTCs are in the explicit cost category and comprise most of that category. The total explicit cost is equal to day-ahead explicit cost plus balancing explicit cost. In the first six months of 2015, the total explicit cost is -$107.0 million and 120.3 percent of the total explicit cost is comprised of congestion cost by UTCs, which is -$128.6 million.

Marginal Loss Cost

- **Total Marginal Loss Costs.** Total marginal loss costs decreased by $397.9 million or 39.5 percent, from $1,006.2 million in the first six months of 2014 to $608.3 million in the first six months of 2015. Total marginal loss costs decreased because of the distribution of high load and outages caused by cold weather in January 2014. The loss MW in PJM decreased 17.6 percent, from 9,065.7 GWh in the first six months of 2014 to 7,470.2 GWh in the first six months of 2015. The loss component of LMP remained constant, $0.02 in the first six months of 2014 and $0.02 in the first six months of 2015.

- **Monthly Total Marginal Loss Costs.** Monthly total marginal loss costs in the first six months of 2015 ranged from $52.0 million in April to $220.3 million in February.
- **Day-Ahead Marginal Loss Costs.** Day-ahead marginal loss costs decreased by $469.6 million or 42.9 percent, from $1,095.0 million in the first six months of 2014 to $625.4 million in the first six months of 2015.
- **Balancing Marginal Loss Costs.** Balancing marginal loss costs increased by $71.7 million or 80.7 percent, from -$88.8 million in the first six months of 2014 to -$17.1 million in the first six months of 2015.
- **Marginal Loss Credits.** The marginal loss credits decreased in the first six months of 2015 by $118.3 million or 36.4 percent, from $325.0 million in the first six months of 2014, to $206.7 million in the first six months of 2015.

Energy Cost

- **Total Energy Costs.** Total energy costs increased by $279.5 million or 41.3 percent, from -$677.2 million in the first six months of 2014 to -$397.6 million in the first six months of 2015.
- **Day-Ahead Energy Costs.** Day-ahead energy costs increased by $479.4 million or 50.6 percent, from -$948.3 million in the first six months of 2014 to -$468.9 million in the first six months of 2015.
- **Balancing Energy Costs.** Balancing energy costs decreased by $207.8 million or 75.1 percent, from $276.6 million in the first six months of 2014 to $68.8 million in the first six months of 2015.
- **Monthly Total Energy Costs.** Monthly total energy costs in the first six months of 2015 ranged from -$141.5 million in February to -$36.0 million in April.

Conclusion

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.

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 2013 to 2014 planning period, total ARR and FTR revenues offset 98.2 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 are 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 made up of three components: the system marginal price (SMP), marginal loss component of LMP (MLMP), and congestion component of LMP (CLMP).

SMP, MLMP and CLMP are a product of the least cost, security constrained dispatch of system resources to meet system load. SMP is the incremental cost of energy, given the current dispatch and given the choice of reference bus. SMP is LMP net of losses and congestion. Losses refer to energy lost to physical resistance in the transmission and distribution network as power is moved from generation to load. The greater the resistance of the system to flows of energy from generation to loads, the greater the losses of the system and the greater the proportion of energy needed to meet a given level of load. Marginal losses are the incremental change in system power losses caused by changes in the system load and generation patterns.[5] The first derivative of total losses with respect to the power flow equals marginal losses. Congestion cost reflects the incremental cost of relieving transmission constraints while maintaining system power balance. Congestion occurs when available, least-cost energy cannot be delivered to all loads because transmission facilities are not adequate to deliver that energy. When the least-cost available energy cannot be delivered to load in a transmission-constrained area, higher cost units in the constrained area must be dispatched to meet that load.[6] The result is that the price of energy in the constrained area is higher than in the unconstrained area because of the combination of transmission limitations and the cost of local generation.

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

The load-weighted average real-time LMP decreased $27.62 or 39.5 percent from $69.92 in the first six months of 2014 to $42.30 in the first six months of 2015. The load-weighted average congestion component increased $0.09 or 161.3 percent from -$0.06 in the first six months of 2014 to $0.03 in the first six months of 2015. The load-weighted average loss component ($0.02) did not change in the first six months of 2015 from the first six months of 2014. The load-weighted average energy component decreased $27.71 or 39.6 percent from $69.95 in the first six months of 2014 to $42.24 in the first six months of 2015.

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

(Jan - Jun)	Real-Time LMP	Energy Component	Congestion Component	Loss Component
2009	$42.48	$42.40	$0.05	$0.03
2010	$45.75	$45.65	$0.06	$0.04
2011	$48.47	$48.40	$0.05	$0.03
2012	$31.21	$31.17	$0.04	$0.01
2013	$37.96	$37.92	$0.02	$0.02
2014	$69.92	$69.95	($0.06)	$0.02
2015	$42.30	$42.24	$0.03	$0.02

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

The load-weighted average day-ahead LMP decreased $27.40 or 38.8 percent from $70.66 in the first six months of 2014 to $43.26 in the first six months of 2015. The load-weighted average congestion component increased $0.04 or 12.3 percent from $0.30 in the first six months of 2014 to $0.33 in the first six months of 2015. The load-weighted average loss component decreased $0.01 or 80.8 percent from -$0.01 in the first six months of 2014 to -$0.02 in the first six months of 2015. The load-weighted average energy component decreased $27.43 or 39.0 percent from $70.37 in the first six months of 2014 to $42.95 in the first six months of 2015.

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

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

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.

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

(Jan - Jun)	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
2009	$42.21	$42.47	($0.14)	($0.12)
2010	$46.12	$46.04	$0.08	($0.00)
2011	$47.12	$47.32	($0.10)	($0.11)
2012	$31.84	$31.76	$0.10	($0.02)
2013	$38.23	$38.14	$0.09	$0.00
2014	$70.66	$70.37	$0.30	($0.01)
2015	$43.26	$42.95	$0.33	($0.02)

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

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

	2014 (Jan - Jun)				2015 (Jan - Jun)			
	Real-Time LMP	Energy Component	Congestion Component	Loss Component	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AECO	$76.31	$68.12	$5.29	$2.90	$45.10	$41.51	$1.81	$1.78
AEP	$59.99	$70.20	($8.35)	($1.86)	$37.76	$42.23	($3.24)	($1.24)
AP	$69.31	$71.06	($2.03)	$0.28	$44.73	$42.69	$1.73	$0.31
ATSI	$60.96	$67.95	($7.74)	$0.75	$37.75	$41.40	($3.85)	$0.20
BGE	$92.61	$72.13	$17.11	$3.37	$54.57	$43.15	$9.11	$2.30
ComEd	$50.82	$67.28	($12.64)	($3.82)	$31.54	$41.06	($6.72)	($2.80)
DAY	$58.75	$69.74	($10.82)	($0.17)	$37.79	$41.93	($3.86)	($0.29)
DEOK	$55.90	$69.54	($10.03)	($3.61)	$36.50	$41.91	($3.23)	($2.17)
DLCO	$53.86	$67.61	($11.52)	($2.22)	$34.87	$41.45	($5.67)	($0.91)
Dominion	$86.92	$72.63	$13.72	$0.57	$49.19	$43.51	$4.93	$0.75
DPL	$88.47	$72.89	$10.90	$4.68	$52.35	$43.55	$6.00	$2.80
EKPC	$60.73	$76.26	($11.83)	($3.70)	$36.36	$44.49	($5.76)	($2.37)
JCPL	$77.00	$68.45	$5.33	$3.21	$45.14	$41.82	$1.49	$1.82
Met-Ed	$77.14	$70.12	$5.20	$1.82	$45.80	$42.30	$2.31	$1.19
PECO	$77.01	$69.41	$5.35	$2.24	$44.65	$42.07	$1.19	$1.39
PENELEC	$67.58	$68.94	($2.16)	$0.80	$43.29	$41.79	$0.70	$0.80
Pepco	$90.86	$71.29	$17.29	$2.27	$50.34	$42.84	$5.98	$1.52
PPL	$78.54	$71.03	$5.96	$1.56	$46.08	$42.64	$2.42	$1.01
PSEG	$80.35	$67.47	$9.71	$3.17	$48.14	$41.29	$5.07	$1.78
RECO	$77.97	$67.10	$7.91	$2.96	$48.24	$41.03	$5.53	$1.69
PJM	$69.92	$69.95	($0.06)	$0.02	$42.30	$42.24	$0.03	$0.02

The day-ahead components of LMP for each control zone are presented in Table 11-4 for the first six months of 2014 and the first six months of 2015.

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

	2014 (Jan - Jun)				2015 (Jan - Jun)			
	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AECO	$79.81	$68.07	$9.20	$2.54	$46.67	$42.29	$3.31	$1.06
AEP	$61.61	$71.90	($8.59)	($1.71)	$38.25	$43.13	($4.03)	($0.84)
AP	$68.10	$71.32	($3.08)	($0.14)	$44.58	$43.38	$1.25	($0.04)
ATSI	$62.64	$68.79	($6.75)	$0.60	$38.48	$42.12	($3.99)	$0.35
BGE	$92.46	$72.27	$17.50	$2.70	$55.75	$43.59	$10.61	$1.54
ComEd	$53.08	$68.78	($13.09)	($2.62)	$31.09	$42.03	($9.02)	($1.92)
DAY	$61.59	$71.38	($9.85)	$0.06	$37.90	$42.87	($5.12)	$0.14
DEOK	$57.81	$69.49	($8.81)	($2.88)	$37.03	$43.09	($4.45)	($1.62)
DLCO	$55.14	$68.09	($10.46)	($2.49)	$35.40	$42.18	($5.65)	($1.14)
Dominion	$80.84	$72.75	$8.25	($0.16)	$52.25	$44.23	$7.33	$0.69
DPL	$91.52	$72.47	$15.05	$4.00	$53.99	$43.97	$8.04	$1.98
EKPC	$62.21	$76.90	($11.12)	($3.57)	$36.96	$45.59	($6.37)	($2.26)
JCPL	$83.74	$69.70	$10.74	$3.30	$47.29	$42.65	$3.36	$1.28
Met-Ed	$79.90	$69.62	$8.90	$1.37	$45.90	$42.52	$3.00	$0.37
PECO	$80.63	$69.47	$9.13	$2.03	$46.26	$42.53	$3.08	$0.65
PENELEC	$68.36	$67.74	($0.30)	$0.92	$42.42	$42.10	$0.01	$0.32
Pepco	$87.92	$70.61	$15.55	$1.76	$52.23	$43.03	$8.20	$1.00
PPL	$82.51	$71.14	$10.25	$1.12	$47.17	$43.17	$3.74	$0.26
PSEG	$87.36	$68.61	$15.50	$3.25	$48.87	$42.18	$5.32	$1.37
RECO	$83.55	$67.27	$13.24	$3.04	$48.71	$42.06	$5.27	$1.38
PJM	$70.66	$70.37	$0.30	($0.01)	$43.26	$42.95	$0.33	($0.02)

Hub Components

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

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

	2014 (Jan - Jun)				2015 (Jan - Jun)			
	Real-Time LMP	Energy Component	Congestion Component	Loss Component	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AEP Gen Hub	$51.71	$67.56	($11.32)	($4.53)	$34.98	$43.39	($5.58)	($2.83)
AEP-DAY Hub	$56.18	$68.67	($10.34)	($2.14)	$36.83	$42.75	($4.37)	($1.55)
ATSI Gen Hub	$60.06	$69.03	($8.62)	($0.34)	$37.06	$42.79	($5.02)	($0.71)
Chicago Gen Hub	$48.05	$66.39	($13.61)	($4.74)	$29.74	$39.97	($7.00)	($3.22)
Chicago Hub	$51.46	$67.86	($12.67)	($3.73)	$32.12	$41.81	($6.89)	($2.80)
Dominion Hub	$88.75	$75.51	$13.52	($0.29)	$49.31	$44.33	$4.71	$0.28
Eastern Hub	$81.17	$68.31	$8.73	$4.14	$49.77	$41.89	$5.25	$2.62
N Illinois Hub	$49.75	$66.93	($13.00)	($4.17)	$30.78	$40.16	($6.52)	($2.87)
New Jersey Hub	$77.85	$67.43	$7.34	$3.07	$46.14	$41.35	$3.05	$1.75
Ohio Hub	$56.55	$68.91	($10.38)	($1.98)	$36.16	$42.07	($4.45)	($1.45)
West Interface Hub	$64.40	$66.31	($0.84)	($1.07)	$40.54	$44.09	($2.63)	($0.93)
Western Hub	$74.44	$70.80	$3.54	$0.10	$46.79	$44.10	$2.26	$0.43

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

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

	2014 (Jan - Jun)				2015 (Jan - Jun)			
	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AEP Gen Hub	$47.47	$56.10	($5.64)	($2.98)	$33.94	$40.49	($4.57)	($1.98)
AEP-DAY Hub	$55.55	$64.73	($7.80)	($1.38)	$36.21	$42.21	($5.07)	($0.93)
ATSI Gen Hub	$56.03	$59.25	($3.39)	$0.17	$38.17	$41.52	($3.33)	($0.02)
Chicago Gen Hub	$49.04	$66.12	($13.66)	($3.42)	$28.51	$38.80	($8.13)	($2.16)
Chicago Hub	$49.45	$63.08	($11.46)	($2.18)	$30.95	$41.43	($8.68)	($1.80)
Dominion Hub	$78.56	$72.06	$7.49	($0.99)	$51.67	$44.14	$7.16	$0.37
Eastern Hub	$84.02	$68.10	$12.05	$3.87	$52.94	$43.50	$7.46	$1.98
N Illinois Hub	$49.88	$65.09	($12.45)	($2.76)	$30.24	$40.99	($8.73)	($2.02)
New Jersey Hub	$80.07	$65.88	$11.29	$2.90	$47.64	$42.24	$4.13	$1.27
Ohio Hub	$56.19	$65.53	($8.20)	($1.14)	$36.05	$42.00	($5.15)	($0.79)
West Interface Hub	$55.68	$56.82	($0.33)	($0.81)	$40.38	$42.03	($1.25)	($0.39)
Western Hub	$69.10	$65.84	$3.26	($0.00)	$44.39	$42.15	$2.45	($0.21)

Component Costs

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

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

	Component Costs (Millions)					
(Jan - Jun)	Energy Costs	Loss Costs	Congestion Costs	Total Costs	Total PJM Billing	Total Costs Percent of PJM Billing
2009	($344)	$705	$408	$769	$13,457	5.7%
2010	($373)	$751	$644	$1,022	$16,314	6.3%
2011	($394)	$701	$570	$878	$18,685	4.7%
2012	($262)	$445	$263	$446	$13,991	3.2%
2013	($333)	$494	$306	$468	$15,571	3.0%
2014	($677)	$1,006	$1,442	$1,771	$31,060	5.7%
2015	($398)	$608	$919	$1,129	$23,400	4.8%

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.

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.

Total congestion costs in PJM in the first six months of 2015 were $918.6 million, which was comprised of load congestion payments of $439.2 million, generation credits of -$586.4 million and explicit congestion of -$107.0 million. Total congestion costs in PJM in the first six months of 2014 were $1,422.3 million, which was comprised of load congestion payments of $456.9 million, generation credits of -$1,133.7 million and explicit congestion of -$148.3 million. The decrease in total congestion cost from the first six months of 2014 to the first six months of 2015 is primarily a result of the decrease in generation credits.

Total Congestion

Table 11-8 shows total congestion for the first six months of 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.[14,15]

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 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://pjm.com/documents/agreements/~/media/documents/agreements/joa-complete.ashx> (Accessed January 16, 2015).

15 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/~/media/documents/agreements/nyiso-pjm.ashx> (Accessed January 16, 2015).

Table 11-8 Total PJM congestion (Dollars (Millions)): January through June of 2008 through 2015

	Congestion Costs (Millions)			
(Jan - Jun)	Congestion Cost	Percent Change	Total PJM Billing	Percent of PJM Billing
2008	$1,166	NA	$16,549	7.0%
2009	$408	(65.0%)	$13,457	3.0%
2010	$644	57.8%	$16,314	3.9%
2011	$570	(11.5%)	$18,685	3.1%
2012	$263	(53.8%)	$13,991	1.9%
2013	$306	16.3%	$15,571	2.0%
2014	$1,442	371.3%	$31,060	4.6%
2015	$919	(36.3%)	$23,400	3.9%

Table 11-9 shows the congestion costs by accounting category by market for the first six months of 2015. In the first six months of 2015, PJM total congestion costs were comprised of $439.2 million in load congestion payments, -$586.4 million in generation congestion credits, and -$107.0 million in explicit congestion costs.

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

	Congestion Costs (Millions)									
	Day Ahead				Balancing					
(Jan - Jun)	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Inadvertent Charges	Grand Total
2008	$727.6	($589.4)	$86.7	$1,403.8	($102.4)	$68.2	($67.1)	($237.7)	$0.0	$1,166.1
2009	$159.3	($299.4)	$63.1	$521.7	($17.0)	($2.4)	($99.0)	($113.6)	$0.0	$408.2
2010	$151.5	($544.1)	$38.1	$733.8	($7.3)	$18.6	($63.9)	($89.8)	($0.0)	$644.0
2011	$256.0	($420.3)	$25.6	$701.9	$31.1	$56.0	($107.0)	($131.9)	$0.0	$570.0
2012	$56.8	($267.4)	$65.4	$389.6	($5.0)	$19.5	($101.8)	($126.4)	$0.0	$263.3
2013	$133.2	($306.1)	$87.8	$527.1	($8.4)	$90.4	($122.3)	($221.1)	($0.0)	$306.0
2014	$392.5	($1,353.6)	($54.1)	$1,691.9	$64.4	$219.9	($94.2)	($249.7)	$0.0	$1,442.3
2015	$428.5	($655.2)	$9.6	$1,093.2	$10.7	$68.8	($116.5)	($174.6)	$0.0	$918.6

Table 11-10 and Table 11-11 show that the decrease in total congestion cost from the first six months of 2014 to the first six months of 2015 is mainly due to the decrease in negative generation credits incurred by generation in Day-Ahead Market. Congestion costs incurred by generation in the Day-Ahead Market decreased by $673.5 million or 41.8 percent, from $1,612.0 million in the first six months of 2014 to $938.5 million in the first six months of 2015.

Table 11-10 Total PJM congestion costs by transaction type by market (Dollars (Millions)): January through June of 2015

	Congestion Costs (Millions)									
	Day Ahead				Balancing					
Transaction Type	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Inadvertent Charges	Grand Total
DEC	$46.6	$0.0	$0.0	$46.6	($60.5)	$0.0	$0.0	($60.5)	$0.0	($13.9)
Demand	$89.6	$0.0	$0.0	$89.6	$50.8	$0.0	$0.0	$50.8	($0.0)	$140.4
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	$2.3	$2.3	$0.0	$0.0	$0.0	$0.0	$0.0	$2.3
Export	($13.8)	$0.0	$0.6	($13.2)	($0.5)	$0.0	$1.1	$0.6	$0.0	($12.6)
Generation	$0.0	($938.5)	$0.0	$938.5	$0.0	$116.3	$0.0	($116.3)	$0.0	$822.2
Grandfathered Overuse	$0.0	$0.0	($2.7)	($2.7)	$0.0	$0.0	$0.5	$0.5	$0.0	($2.2)
Import	$0.0	($35.7)	$1.1	$36.8	$0.0	($65.4)	$0.3	$65.8	($0.0)	$102.5
INC	$0.0	$12.7	$0.0	($12.7)	$0.0	($2.8)	$0.0	$2.8	$0.0	($10.0)
Internal Bilateral	$270.0	$270.0	$0.0	$0.0	$21.2	$21.2	$0.0	($0.0)	$0.0	($0.0)
Up-to Congestion	$0.0	$0.0	($10.7)	($10.7)	$0.0	$0.0	($117.9)	($117.9)	$0.0	($128.6)
Wheel In	$0.0	$36.3	$19.1	($17.2)	$0.0	($0.5)	($0.6)	($0.0)	$0.0	($17.3)
Wheel Out	$36.3	$0.0	$0.0	$36.3	($0.5)	$0.0	$0.0	($0.5)	$0.0	$35.8
Total	$428.5	($655.2)	$9.6	$1,093.2	$10.7	$68.8	($116.5)	($174.6)	$0.0	$918.6

Table 11-11 Total PJM congestion costs by transaction type by market (Dollars (Millions)): January through June of 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	$64.9	$0.0	$0.0	$64.9	($45.1)	$0.0	$0.0	($45.1)	$0.0	$19.8
Demand	$58.2	$0.0	$0.0	$58.2	$141.0	$0.0	$0.0	$141.0	$0.0	$199.2
Demand Response	($1.0)	$0.0	$0.0	($1.0)	$1.0	$0.0	$0.0	$1.0	$0.0	($0.0)
Explicit Congestion Only	$0.0	$0.0	$1.2	$1.2	$0.0	$0.0	$0.3	$0.3	$0.0	$1.5
Export	($60.4)	$0.0	($1.2)	($61.6)	($38.8)	$0.0	$4.8	($34.0)	$0.0	($95.6)
Generation	$0.0	($1,612.0)	$0.0	$1,612.0	$0.0	$283.4	$0.0	($283.4)	$0.0	$1,328.6
Grandfathered Overuse	$0.0	$0.0	($4.1)	($4.1)	$0.0	$0.0	$0.3	$0.3	$0.0	($3.8)
Import	$0.0	($42.6)	$6.7	$49.3	$0.0	($114.4)	$4.0	$118.4	$0.0	$167.7
INC	$0.0	($30.6)	$0.0	$30.6	$0.0	$44.5	$0.0	($44.5)	$0.0	($13.9)
Internal Bilateral	$267.0	$267.8	$0.8	$0.0	$8.4	$8.4	$0.0	($0.0)	$0.0	$0.0
Up-to Congestion	$0.0	$0.0	($77.1)	($77.1)	$0.0	$0.0	($102.1)	($102.1)	$0.0	($179.2)
Wheel In	$0.0	$63.8	$19.6	($44.2)	$0.0	($2.1)	($1.5)	$0.6	$0.0	($43.6)
Wheel Out	$63.8	$0.0	$0.0	$63.8	($2.1)	$0.0	$0.0	($2.1)	$0.0	$61.7
Total	$392.5	($1,353.6)	($54.1)	$1,691.9	$64.4	$219.9	($94.2)	($249.7)	$0.0	$1,442.3

Monthly Congestion

Table 11-12 shows that monthly total congestion costs ranged from $69.5 million to $429.8 million in the first six months of 2015. Table 11-12 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 11-12 Monthly PJM congestion costs by market (Dollars (Millions)): January through June of 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	$114.1	($7.5)	($0.0)	$106.6
Total	$1,691.9	($249.7)	$0.0	$1,442.3	$1,093.2	($174.6)	$0.0	$918.6

Figure 11-1 shows PJM monthly total congestion cost for 2009 through the first six months of 2015.

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

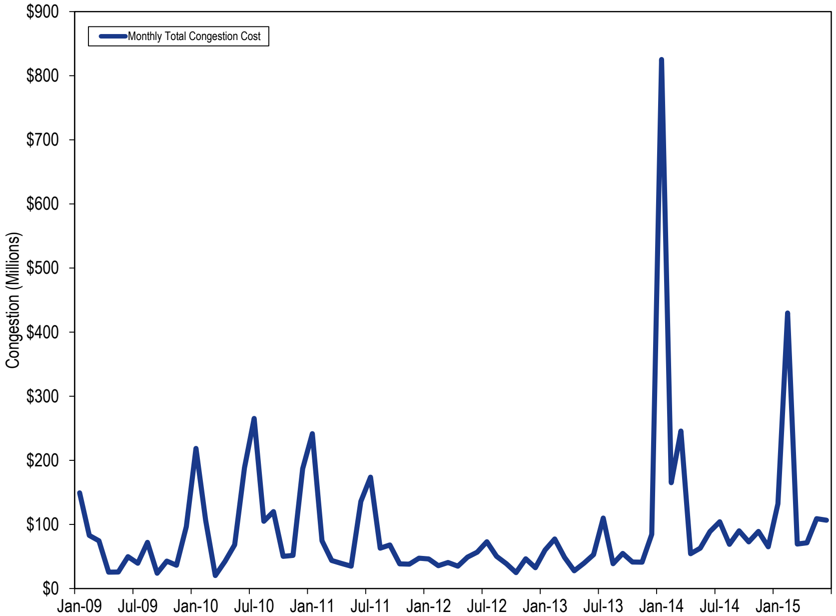


Table 11-13 shows the monthly total congestion costs for each virtual transaction type in the first six months of 2015 and Table 11-14 shows the monthly total congestion costs for each virtual transaction type in the first six months of 2014. Virtual transaction congestion costs, when positive, measure the total congestion cost to the virtual transaction and when negative, measure the total congestion credit to the virtual transaction. Table 11-13 and Table 11-14 shows that UTCs were paid both day-ahead congestion credits and balancing congestion credits in the first six months of 2014 and in the first six months of 2015. Total day-ahead congestion payments to UTCs decreased by $66.4 million from the first six months of 2014 to the first six months of 2015, from $77.1 million in the first six months of 2014 to $10.7 million in the first six months of 2015. Over the same period balancing congestion payments to UTCs increased from $102.1 million in the first six months of 2014 to $117.9 million in the first six months of 2015. Overall, total congestion payments to UTC decreased by 28.2 percent between the first six months of 2014 and the first six months of 2015. UTCs were paid $179.2 million in congestion in the first six months of 2014 and $128.6 million in the first six months of 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.[16]

Table 11-13 Monthly PJM congestion costs by virtual transaction type and by market (Dollars (Millions)): January through June of 2015

	Congestion Costs (Millions)								
	Day Ahead				Balancing				
	DEC	INC	Up-to Congestion	Virtual Total	DEC	INC	Up-to Congestion	Virtual Total	Virtual Grand Total
Jan	$7.4	($3.2)	($3.4)	$0.8	($7.1)	$1.1	($11.3)	($17.4)	($16.6)
Feb	$11.1	$0.1	($37.6)	($26.4)	($15.4)	($0.6)	($13.0)	($29.0)	($55.4)
Mar	$9.6	($0.1)	$12.5	$22.0	($17.7)	$0.5	($55.1)	($72.3)	($50.3)
Apr	$4.3	($2.5)	$5.3	$7.1	($5.8)	$3.7	($10.0)	($12.2)	($122.3)
May	$5.1	($3.7)	$5.9	$7.3	($4.8)	($2.1)	($21.7)	($28.6)	($228.1)
Jun	$9.0	($3.2)	$6.6	$12.4	($9.5)	$0.2	($6.9)	($16.2)	($400.8)
Total	$46.6	($12.7)	($10.7)	$23.1	($60.5)	$2.8	($117.9)	($175.6)	($751.2)

16 See 18 CFR § 385.213 (2014).

Table 11-14 Monthly PJM congestion costs by virtual transaction type and by market (Dollars (Millions)): January through June of 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)
Total	$64.9	$30.6	($77.1)	$18.3	($45.1)	($44.5)	($102.1)	($191.7)	($173.4)

Congested Facilities

A congestion event exists when a unit or units must be dispatched out of merit order to control for the potential impact of a contingency on a monitored facility or to control an actual overload. A congestion-event hour exists when a specific facility is constrained for one or more five-minute intervals within an hour. A congestion-event hour differs from a constrained hour, which is any hour during which one or more facilities are congested. Thus, if two facilities are constrained during an hour, the result is two congestion-event hours and one constrained hour. Constraints are often simultaneous, so the number of congestion-event hours usually exceeds the number of constrained hours and the number of congestion-event hours usually exceeds the number of hours in a year.

In order to have a consistent metric for real-time and day-ahead congestion frequency, real-time congestion frequency is measured using the convention that an hour is constrained if any of its component five-minute intervals is constrained. This is consistent with the way in which PJM reports real-time congestion. In the first six months of 2015, there were 95,960 day-ahead, congestion-event hours compared to 228,169 day-ahead congestion-event hours in the first six months of 2014. In the first six months of 2015, there were 17,169 real-time, congestion-event hours compared to 16,722 real-time, congestion-event hours in the first six months of 2014.

During the first six months of 2015, there were 9,295 real-time congestion-event hours, 9.7 percent of day-ahead energy congestion-event hours, when the same facilities also constrained in the Real-Time Energy Market. During the first six months of 2015, there were 9,286 day-ahead congestion-event hours, 54.1 percent of real-time congestion-event hours, when the same facilities were also constrained in the Day-Ahead Energy Market.

The 5004/5005 Interface was the largest contributor to total congestion costs in the first six months of 2015. With $88.8 million in total congestion costs, it accounted for 9.7 percent of the total PJM congestion costs in the first six months of 2015. The top five constraints in terms of congestion costs contributed $227.2 million, or 24.7 percent, of the total PJM congestion costs in the first six months of 2015. The top five constraints were the 5004/5005 Interface, the Bedington - Black Oak Interface, the AEP - DOM Interface, the AP South Interface, and the Bergen – New Milford line.

Congestion by Facility Type and Voltage

In the first six months of 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 decrease on flowgate and interface facilities.

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

Table 11-15 provides congestion-event hour subtotals and congestion cost subtotals comparing the first six months of 2015 results by facility type: line, transformer, interface, flowgate and unclassified facilities.[17,18] Table 11-16 presents this information for the first six months of 2014.

17 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.

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

Table 11-15 Congestion summary (By facility type): January through June of 2015

	Congestion Costs (Millions)										
	Day Ahead				Balancing					Event Hours	
Type	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day Ahead	Real Time
Flowgate	$54.6	($116.6)	($25.5)	$145.7	$2.2	($0.1)	($13.1)	($10.8)	$134.9	15,172	3,249
Interface	$59.1	($307.4)	($29.2)	$337.3	$10.6	$28.2	$2.9	($14.8)	$322.5	6,784	1,988
Line	$212.6	($144.3)	$65.4	$422.3	($7.2)	$28.0	($111.0)	($146.2)	$276.1	53,941	10,054
Other	$0.1	($0.4)	$0.3	$0.9	$0.0	$0.1	$0.1	$0.0	$0.9	974	26
Transformer	$102.1	($86.0)	($1.5)	$186.6	$5.8	$11.0	($2.3)	($7.5)	$179.0	19,089	1,852
Unclassified	($0.1)	($0.5)	$0.1	$0.4	($0.6)	$1.6	$7.0	$4.8	$5.2	NA	NA
Total	$428.5	($655.2)	$9.6	$1,093.2	$10.7	$68.8	($116.5)	($174.6)	$918.6	95,960	17,169

Table 11-16 Congestion summary (By facility type): January through June of 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	($81.9)	($332.4)	($14.0)	$236.5	$1.9	$13.3	($35.7)	($47.1)	$189.4	21,331	4,577
Interface	$322.7	($587.9)	($97.3)	$813.4	$61.9	$142.5	$21.4	($59.1)	$754.2	11,013	2,421
Line	$85.3	($347.0)	$24.7	$457.0	($13.3)	$47.1	($40.9)	($101.3)	$355.7	118,134	8,175
Other	$0.0	($1.0)	$0.6	$1.7	$0.0	$0.0	$0.0	$0.0	$1.7	4,543	0
Transformer	$65.1	($76.1)	$20.1	$161.3	$8.7	$15.7	($47.2)	($54.3)	$107.1	73,148	1,549
Unclassified	$1.1	($9.2)	$11.7	$22.1	$5.2	$1.3	$8.3	$12.2	$34.2	NA	NA
Total	$392.5	($1,353.6)	($54.1)	$1,691.9	$64.4	$219.9	($94.2)	($249.7)	$1,442.3	228,169	16,722

Table 11-17 and Table 11-18 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 11-17. In the first six months of 2015, there were 95,960 congestion-event hours in the Day-Ahead Energy Market. Among those day-ahead congestion-event hours, only 9,295 (9.7 percent) were also constrained in the Real-Time Energy Market. In the first six months of 2014, among the 228,169 day-ahead congestion-event hours, only 8,150 (3.6 percent) were binding in the Real-Time Energy Market.[19]

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 11-18. In the first six months of 2015, there were 17,169 congestion-event hours in the Real-Time Energy Market. Among these real-time congestion-event hours, 9,286 (54.1 percent) were also constrained in the Day-Ahead Energy Market. In the first six months of 2014, among the 16,722 real-time congestion-event hours, 8,607 (51.5 percent) were also in the Day-Ahead Energy Market.

19 Constraints are mapped to transmission facilities. In the Day-Ahead Energy Market, within a given hour, a single facility may be associated with multiple constraints. In such situations, the same facility accounts for more than one constraint-hour for a given hour in the Day-Ahead Energy Market. Similarly in the Real-Time Market a facility may account for more than one constraint-hour within a given hour.

Table 11-17 Congestion event hours (Day-Ahead against Real-Time): January through June of 2014 and 2015

	Congestion Event Hours					
	2014 (Jan - Jun)			2015 (Jan - Jun)		
Type	Day Ahead Constrained	Corresponding Real Time Constrained	Percent	Day Ahead Constrained	Corresponding Real Time Constrained	Percent
Flowgate	21,331	2,521	11.8%	15,172	1,741	11.5%
Interface	11,013	1,519	13.8%	6,784	1,467	21.6%
Line	118,134	3,641	3.1%	53,941	5,219	9.7%
Other	4,543	0	0.0%	974	0	0.0%
Transformer	73,148	469	0.6%	19,089	868	4.5%
Total	228,169	8,150	3.6%	95,960	9,295	9.7%

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

	Congestion Event Hours					
	2014 (Jan - Jun)			2015 (Jan - Jun)		
Type	Real Time Constrained	Corresponding Day Ahead Constrained	Percent	Real Time Constrained	Corresponding Day Ahead Constrained	Percent
Flowgate	4,577	2,647	57.8%	3,249	1,753	54.0%
Interface	2,421	1,852	76.5%	1,988	1,497	75.3%
Line	8,175	3,664	44.8%	10,054	5,216	51.9%
Other	0	0	0.0%	26	0	0.0%
Transformer	1,549	444	28.7%	1,852	820	44.3%
Total	16,722	8,607	51.5%	17,169	9,286	54.1%

Table 11-19 shows congestion costs by facility voltage class for the first six months of 2015. Congestion costs in the first six months of 2015 decreased for facilities rated at 500 kV, 345 kV, 230 kV and 138 kV compared to the first six months of 2014 (Table 11-20).

Table 11-19 Congestion summary (By facility voltage): January through June of 2015

	Congestion Costs (Millions)											
	Day Ahead				Balancing					Event Hours	
Voltage (kV)	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day Ahead	Real Time
765	$17.8	($54.0)	($5.2)	$66.6	$3.2	$4.3	$0.6	($0.5)	$66.1	1,569	136
500	$75.1	($317.2)	($27.8)	$364.5	$12.5	$28.5	($0.7)	($16.7)	$347.8	8,121	1,046
460	($0.0)	($3.6)	$0.3	$4.0	$0.0	$0.0	$0.0	$0.0	$4.0	1,360	0
345	($6.4)	($100.8)	$5.8	$100.2	$7.0	$5.4	($15.7)	($14.1)	$86.2	12,571	1,636
230	$197.6	($2.1)	$16.8	$216.6	($3.0)	$6.4	($41.1)	($50.5)	$166.1	16,815	4,450
161	($9.7)	($26.8)	($0.8)	$16.3	$0.3	$0.7	($2.0)	($2.5)	$13.8	2,005	873
138	$109.6	($126.9)	$15.5	$251.9	($5.9)	$22.8	($61.6)	($90.3)	$161.6	39,359	6,890
115	$14.3	($20.9)	$6.2	$41.4	$1.9	$0.8	($3.3)	($2.2)	$39.2	7,872	1,369
69	$30.3	($2.3)	($1.4)	$31.2	($4.7)	($1.8)	$0.3	($2.6)	$28.6	5,585	730
34	$0.0	$0.0	$0.1	$0.1	($0.0)	$0.0	$0.0	$0.0	$0.2	683	39
13	$0.0	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	19	0
12	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	1	0
Unclassified	($0.1)	($0.5)	$0.1	$0.4	($0.6)	$1.6	$7.0	$4.8	$5.2	NA	NA
Total	$428.5	($655.2)	$9.6	$1,093.2	$10.7	$68.8	($116.5)	($174.6)	$918.6	95,960	17,169

Table 11-20 Congestion summary (By facility voltage): January through June of 2014

	Congestion Costs (Millions)											
	Day Ahead				Balancing					Event Hours	
Voltage (kV)	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day Ahead	Real Time
765	$21.3	($35.4)	$2.1	$58.7	$0.3	$1.7	($2.7)	($4.1)	$54.6	7,723	223
500	$329.9	($584.7)	($97.1)	$817.4	$71.2	$158.6	$7.6	($79.8)	$737.6	14,504	2,119
345	($65.1)	($286.0)	($2.8)	$218.1	$3.7	$14.6	($23.8)	($34.7)	$183.4	44,669	2,157
230	$35.8	($202.8)	($15.2)	$223.4	$0.8	($0.7)	$1.5	$2.9	$226.3	34,885	3,057
161	($16.9)	($34.6)	($1.6)	$16.1	($1.9)	$0.0	($1.4)	($3.4)	$12.8	3,563	779
138	$48.2	($193.1)	$44.1	$285.4	($3.6)	$39.5	($80.0)	($123.1)	$162.2	97,054	6,879
115	($0.7)	($16.6)	$3.4	$19.3	($6.0)	$2.2	($2.6)	($10.7)	$8.6	12,708	1,003
69	$38.9	$8.8	$1.1	$31.3	($5.2)	$2.6	($1.1)	($8.9)	$22.3	10,372	505
34	$0.0	($0.0)	$0.1	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	2,669	0
26	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	13	0
12	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	9	0
Unclassified	$1.1	($9.2)	$11.7	$22.1	$5.2	$1.3	$8.3	$12.2	$34.2	NA	NA
Total	$392.5	($1,353.6)	($54.1)	$1,691.9	$64.4	$219.9	($94.2)	($249.7)	$1,442.3	228,169	16,722

Constraint Duration

Table 11-21 lists the constraints in the first six months of 2014 and the first six months of 2015 that were most frequently binding and Table 11-22 shows the constraints which experienced the largest change in congestion-event hours from the first six months of 2014 to the first six months of 2015.

Table 11-21 Top 25 constraints with frequent occurrence: January through June of 2014 and 2015

			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	Bergen - New Milford	Line	2,958	2,580	(378)	291	795	504	34%	29%	(4%)	3%	9%	6%
2	Oak Grove - Galesburg	Flowgate	3,563	2,005	(1,558)	690	872	182	41%	23%	(18%)	8%	10%	2%
3	East Danville - Banister	Line	0	2,704	2,704	3	126	123	0%	31%	31%	0%	1%	1%
4	Easton	Transformer	812	2,662	1,850	0	0	0	9%	30%	21%	0%	0%	0%
5	Bunsonville - Eugene	Flowgate	1,551	1,914	363	490	456	(34)	18%	22%	4%	6%	5%	(0%)
6	Maywood - Saddlebrook	Line	1,459	1,811	352	183	448	265	17%	21%	4%	2%	5%	3%
7	Bedington - Black Oak	Interface	1,613	1,911	298	253	282	29	18%	22%	3%	3%	3%	0%
8	SENECA	Interface	382	938	556	469	1,182	713	4%	11%	6%	5%	13%	8%
9	Bagley - Graceton	Line	1,717	1,352	(365)	457	621	164	20%	15%	(4%)	5%	7%	2%
10	Michigan City - Laporte	Flowgate	927	1,855	928	0	0	0	11%	21%	11%	0%	0%	0%
11	East Bend	Transformer	3,090	1,582	(1,508)	0	0	0	35%	18%	(17%)	0%	0%	0%
12	Breed - Wheatland	Flowgate	1,925	1,358	(567)	456	148	(308)	22%	15%	(7%)	5%	2%	(4%)
13	Tidd	Transformer	362	1,401	1,039	2	92	90	4%	16%	12%	0%	1%	1%
14	Mahans Lane - Tidd	Line	49	1,038	989	0	394	394	1%	12%	11%	0%	4%	4%
15	Person - Halifax	Flowgate	125	1,412	1,287	0	6	6	1%	16%	15%	0%	0%	0%
16	Brucea	Transformer	0	1,360	1,360	0	0	0	0%	15%	15%	0%	0%	0%
17	Sayreville - Sayreville	Line	1,891	1,281	(610)	0	0	0	22%	15%	(7%)	0%	0%	0%
18	Conastone - Northwest	Line	55	687	632	35	510	475	1%	8%	7%	0%	6%	5%
19	Glenarm - Windy Edge	Line	121	709	588	36	366	330	1%	8%	7%	0%	4%	4%
20	Burlington - Croydon	Line	2,972	859	(2,113)	386	214	(172)	34%	10%	(24%)	4%	2%	(2%)
21	Rising	Flowgate	386	652	266	105	372	267	4%	7%	3%	1%	4%	3%
22	5004/5005 Interface	Interface	362	661	299	313	321	8	4%	8%	3%	4%	4%	0%
23	AEP - DOM	Interface	1,514	939	(575)	55	42	(13)	17%	11%	(7%)	1%	0%	(0%)
24	Bergen - Leonia	Line	1,693	947	(746)	0	0	0	19%	11%	(9%)	0%	0%	0%
25	Belmont	Transformer	11	830	819	49	94	45	0%	9%	9%	1%	1%	1%

Table 11-22 Top 25 constraints with largest year-to-year change in occurrence: January through June of 2014 and 2015

			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	Tanners Creek	Transformer	6,020	676	(5,344)	0	0	0	69%	8%	(61%)	0%	0%	0%
2	Miami Fort	Transformer	5,413	215	(5,198)	21	3	(18)	62%	2%	(59%)	0%	0%	(0%)
3	Monticello - East Winamac	Flowgate	3,041	0	(3,041)	1,377	0	(1,377)	35%	0%	(35%)	16%	0%	(16%)
4	Braidwood	Transformer	5,253	915	(4,338)	0	0	0	60%	10%	(50%)	0%	0%	0%
5	Kendall Co. Energy Ctr.	Transformer	3,906	44	(3,862)	0	0	0	45%	1%	(44%)	0%	0%	0%
6	Sunbury	Transformer	3,839	29	(3,810)	0	0	0	44%	0%	(43%)	0%	0%	0%
7	AP South	Interface	3,703	846	(2,857)	879	42	(837)	42%	10%	(33%)	10%	0%	(10%)
8	Clinch River	Transformer	3,664	296	(3,368)	0	0	0	42%	3%	(38%)	0%	0%	0%
9	Keeney	Transformer	2,909	9	(2,900)	57	0	(57)	33%	0%	(33%)	1%	0%	(1%)
10	Mardela - Vienna	Line	3,141	312	(2,829)	44	1	(43)	36%	4%	(32%)	1%	0%	(0%)
11	East Danville - Banister	Line	0	2,704	2,704	3	126	123	0%	31%	31%	0%	1%	1%
12	Cook - Palisades	Flowgate	2,316	0	(2,316)	308	0	(308)	26%	0%	(26%)	4%	0%	(4%)
13	Nelson - Cordova	Line	2,814	414	(2,400)	227	45	(182)	32%	5%	(27%)	3%	1%	(2%)
14	Sporn	Transformer	2,530	34	(2,496)	0	0	0	29%	0%	(28%)	0%	0%	0%
15	Wolf Creek	Transformer	3,264	710	(2,554)	97	171	74	37%	8%	(29%)	1%	2%	1%
16	Beckjord	Transformer	2,492	52	(2,440)	0	0	0	28%	1%	(28%)	0%	0%	0%
17	Huntington Junction - Huntington	Line	2,394	25	(2,369)	0	0	0	27%	0%	(27%)	0%	0%	0%
18	Burlington - Croydon	Line	2,972	859	(2,113)	386	214	(172)	34%	10%	(24%)	4%	2%	(2%)
19	Fort Robinson - Wolf Hills	Line	2,101	0	(2,101)	0	0	0	24%	0%	(24%)	0%	0%	0%
20	Gould Street - Westport	Line	2,669	606	(2,063)	0	14	14	30%	7%	(24%)	0%	0%	0%
21	Argenta - Greenup	Line	2,047	90	(1,957)	0	0	0	23%	1%	(22%)	0%	0%	0%
22	Loretto - Cayuga	Line	1,954	0	(1,954)	0	0	0	22%	0%	(22%)	0%	0%	0%
23	West Moulton-City Of St. Marys	Line	2,105	189	(1,916)	0	0	0	24%	2%	(22%)	0%	0%	0%
24	Easton	Transformer	812	2,662	1,850	0	0	0	9%	30%	21%	0%	0%	0%
25	Tanners Creek	Transformer	1,679	95	(1,584)	0	0	0	19%	1%	(18%)	0%	0%	0%

Constraint Costs

Table 11-23 and Table 11-24 present the top constraints affecting congestion costs by facility for the periods the first six months of 2015 and the first six months of 2014.

Table 11-23 Top 25 constraints affecting PJM congestion costs (By facility): January through June of 2015

				Congestion Costs (Millions)									Percent of Total PJM Congestion Costs
				Day Ahead				Balancing					
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	2015 (Jan - Jun)
1	5004/5005 Interface	Interface	500	($22.9)	($134.6)	($9.2)	$102.4	$7.0	$22.5	$1.9	($13.6)	$88.8	9.7%
2	Bedington - Black Oak	Interface	500	$40.7	($42.0)	($7.1)	$75.5	$2.3	$1.7	$3.2	$3.8	$79.3	8.6%
3	AP South	Interface	500	$34.8	($21.4)	($5.1)	$51.1	$0.3	$0.2	$0.6	$0.7	$51.9	5.6%
4	AEP - DOM	Interface	500	$27.2	($27.6)	($1.0)	$53.8	$0.9	$1.6	($1.9)	($2.6)	$51.2	5.6%
5	Bergen - New Milford	Line	PSEG	$24.7	$18.1	$17.6	$24.2	($7.6)	$9.3	($51.2)	($68.1)	($44.0)	(4.8%)
6	Joshua Falls	Transformer	AEP	$9.6	($35.6)	($4.9)	$40.2	$0.7	($0.1)	$2.3	$3.1	$43.4	4.7%
7	Bagley - Graceton	Line	BGE	$36.8	$0.0	$1.3	$38.1	($0.3)	($5.7)	($0.7)	$4.7	$42.8	4.7%
8	Person - Halifax	Flowgate	MISO	$79.7	$29.2	($10.4)	$40.1	$0.0	($0.0)	($0.1)	($0.1)	$40.0	4.4%
9	Conastone - Northwest	Line	BGE	$27.7	($1.5)	$0.0	$29.2	$0.2	($1.9)	($1.1)	$1.0	$30.2	3.3%
10	Maywood - Saddlebrook	Line	PSEG	$7.9	$3.9	$6.3	$10.3	($4.8)	$8.7	($21.0)	($34.5)	($24.1)	(2.6%)
11	East	Interface	500	($12.1)	($35.5)	($1.9)	$21.5	($0.1)	$0.3	$0.5	$0.1	$21.6	2.4%
12	Easton	Transformer	DPL	$28.1	$6.4	($0.8)	$20.9	$0.0	$0.0	$0.0	$0.0	$20.9	2.3%
13	Mahans Lane - Tidd	Line	AEP	$7.7	($13.3)	($1.6)	$19.4	$0.4	$1.1	$0.9	$0.2	$19.6	2.1%
14	Glenarm - Windy Edge	Line	BGE	$2.8	($11.9)	$0.9	$15.7	$1.8	($1.7)	($0.5)	$3.1	$18.7	2.0%
15	East Danville - Banister	Line	AEP	$7.7	($7.4)	$1.8	$16.9	$0.5	($1.5)	($0.6)	$1.4	$18.3	2.0%
16	49th Street - Hoboken	Line	PSEG	$0.0	$0.0	$0.0	$0.0	($2.8)	$2.2	($13.1)	($18.1)	($18.1)	(2.0%)
17	Valley	Transformer	Dominion	$15.6	($0.5)	($0.0)	$16.1	$0.0	$0.0	$0.0	$0.0	$16.1	1.7%
18	Breed - Wheatland	Flowgate	MISO	($1.7)	($15.5)	$0.6	$14.4	$0.1	($0.6)	($0.7)	($0.0)	$14.4	1.6%
19	Oak Grove - Galesburg	Flowgate	MISO	($9.7)	($26.8)	($0.8)	$16.3	$0.3	$0.7	($2.0)	($2.5)	$13.8	1.5%
20	Cloverdale	Transformer	AEP	$5.9	($9.3)	($1.6)	$13.6	$0.0	$0.0	$0.0	$0.0	$13.6	1.5%
21	Central	Interface	500	($15.5)	($32.7)	($3.9)	$13.3	$0.1	$1.0	$0.3	($0.7)	$12.6	1.4%
22	West	Interface	500	($1.7)	($14.8)	($0.8)	$12.2	$0.2	$1.0	$0.1	($0.6)	$11.7	1.3%
23	BCPEP	Interface	Pepco	$8.0	($1.6)	$0.3	$9.9	$0.0	$0.0	$0.0	$0.0	$9.9	1.1%
24	Rising	Flowgate	MISO	$0.5	($11.7)	($6.6)	$5.6	$0.3	($0.1)	$3.7	$4.1	$9.7	1.1%
25	Dravosburg - West Mifflin	Line	DLCO	$15.9	$3.4	($0.7)	$11.8	$0.4	$2.7	($0.1)	($2.3)	$9.5	1.0%

Table 11-24 Top 25 constraints affecting PJM congestion costs (By facility): January through June of 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 (Jan - Jun)
1	AP South	Interface	500	$307.4	($190.7)	($9.9)	$488.3	$31.1	$73.2	$9.1	($32.9)	$455.4	31.6%
2	West	Interface	500	($19.9)	($284.5)	($78.1)	$186.5	$16.7	$47.7	$16.7	($14.3)	$172.2	11.9%
3	Breed - Wheatland	Flowgate	MISO	($14.4)	($80.8)	($8.8)	$57.7	$2.1	$1.2	$5.7	$6.6	$64.3	4.5%
4	Bedington - Black Oak	Interface	500	$25.3	($32.4)	($1.1)	$56.6	$2.9	$3.6	($1.7)	($2.4)	$54.2	3.8%
5	Cloverdale	Transformer	AEP	$22.0	($26.1)	($0.3)	$47.8	$0.0	$0.0	$0.0	$0.0	$47.8	3.3%
6	Benton Harbor - Palisades	Flowgate	MISO	($11.2)	($65.5)	($7.1)	$47.1	($0.2)	$0.6	($0.9)	($1.8)	$45.3	3.1%
7	BCPEP	Interface	Pepco	$11.2	($14.7)	($1.8)	$24.1	($1.7)	($14.1)	$1.4	$13.8	$37.8	2.6%
8	Bagley - Graceton	Line	BGE	$29.5	($1.8)	$2.8	$34.1	$1.4	$0.3	($0.3)	$0.8	$34.9	2.4%
9	Unclassified	Unclassified	Unclassified	$1.1	($9.2)	$11.7	$22.1	$5.2	$1.3	$8.3	$12.2	$34.2	2.4%
10	Cook - Palisades	Flowgate	MISO	($12.6)	($55.3)	($5.3)	$37.4	($1.5)	$1.6	($6.2)	($9.3)	$28.1	1.9%
11	Monticello - East Winamac	Flowgate	MISO	($3.3)	($41.9)	$0.9	$39.5	$2.5	$4.1	($9.8)	($11.5)	$28.1	1.9%
12	Readington - Roseland	Line	PSEG	($8.9)	($46.1)	($12.2)	$25.1	$0.9	$5.4	$5.8	$1.3	$26.4	1.8%
13	Wolf Creek	Transformer	AEP	$3.3	$0.4	$3.4	$6.2	$3.0	$5.9	($27.5)	($30.3)	($24.1)	(1.7%)
14	Brambleton - Loudoun	Line	Dominion	($11.2)	($35.1)	($1.3)	$22.6	$0.6	$0.0	$0.1	$0.6	$23.2	1.6%
15	Cloverdale	Transformer	AEP	$18.5	($5.0)	($2.4)	$21.1	$0.0	$0.0	$0.0	$0.0	$21.1	1.5%
16	Wescosville	Transformer	PPL	$17.5	($0.8)	$2.7	$21.0	($0.0)	$0.0	$0.0	($0.0)	$21.0	1.5%
17	Bridgewater - Middlesex	Line	PSEG	$0.1	($22.1)	($3.0)	$19.2	($1.5)	$0.1	$1.4	($0.2)	$19.0	1.3%
18	East	Interface	500	($6.5)	($25.9)	($3.1)	$16.3	$0.3	$0.7	$0.5	$0.1	$16.4	1.1%
19	Atlantic - Larrabee	Line	JCPL	$2.0	($14.8)	($0.7)	$16.1	$0.0	$1.3	$1.2	($0.1)	$16.0	1.1%
20	Nelson - Cordova	Line	ComEd	($21.1)	($39.6)	$2.6	$21.1	($0.7)	$0.9	($3.5)	($5.1)	$16.0	1.1%
21	Oak Grove - Galesburg	Flowgate	MISO	($16.9)	($34.6)	($1.6)	$16.1	($0.5)	($0.0)	($0.4)	($0.9)	$15.2	1.1%
22	Rising	Flowgate	MISO	($5.1)	($3.8)	$1.4	$0.2	($3.9)	$1.2	($9.3)	($14.3)	($14.1)	(1.0%)
23	Bergen - New Milford	Line	PSEG	$19.6	$11.2	$9.7	$18.1	($1.6)	$2.2	($0.7)	($4.5)	$13.6	0.9%
24	5004/5005 Interface	Interface	500	$0.5	($17.9)	($2.7)	$15.7	$7.7	$17.5	$7.1	($2.7)	$13.0	0.9%
25	Cloverdale	Transformer	AEP	$0.0	$0.0	$0.0	$0.0	$2.6	$4.6	($10.9)	($12.9)	($12.9)	(0.9%)

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

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

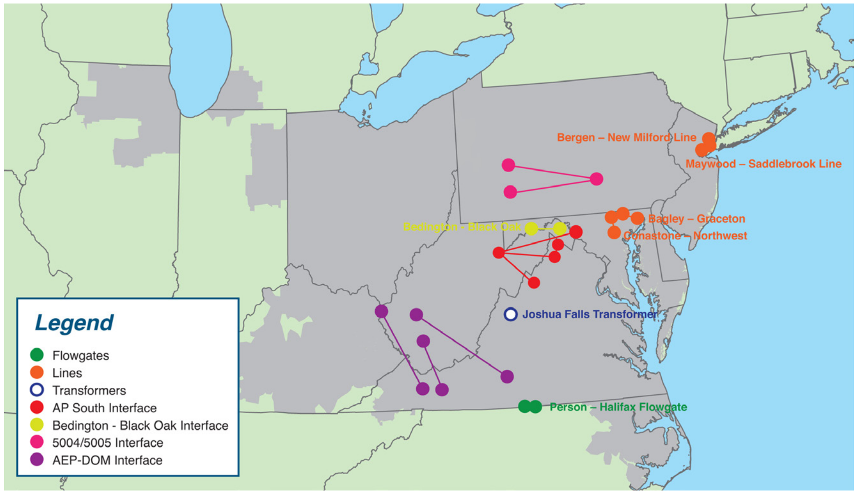


Figure 11-3 Location of the top 10 constraints by PJM day-ahead congestion costs: January through June of 2015

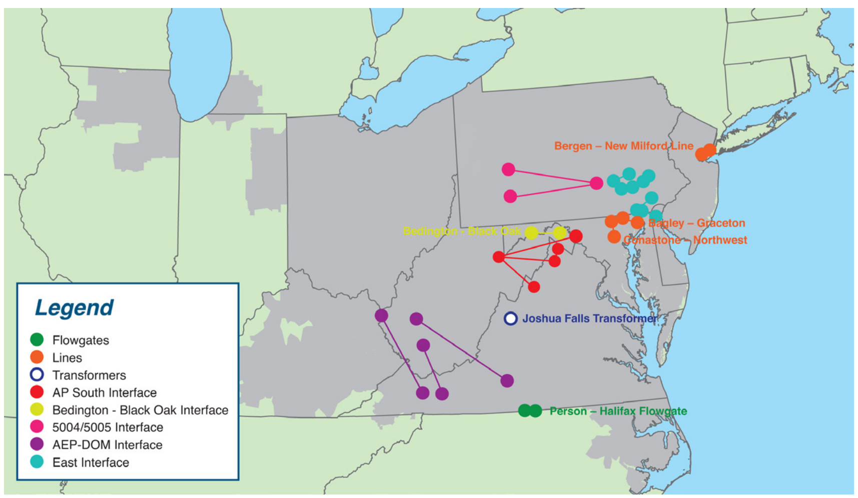
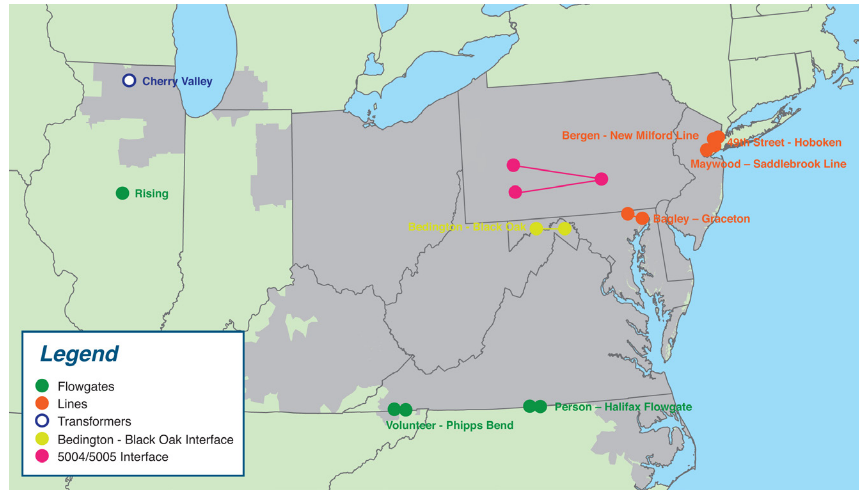


Figure 11-4 Location of the top 10 constraints by PJM balancing congestion costs: January through June of 2015



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.[20] A flowgate is a facility or group of facilities that may act as constraint points on the regional system.[21] PJM models these coordinated flowgates and controls for them in its security-constrained, economic dispatch.

As of June 30, 2015, PJM had 110 flowgates eligible for M2M (Market to Market) coordination and MISO had 268 flowgates eligible for M2M coordination.

Table 11-25 and Table 11-26 show the MISO flowgates which PJM and/or MISO took dispatch action to control during the first six months of 2015 and

20 See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C.," (September 17, 2010), Section 6.1 <http://pjm.com/documents/agreements/~/media/documents/agreements/joa-complete.ashx> (Accessed July 25, 2015).

21 See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C.," (February 26, 2014), Section 2.2.24 <http://pjm.com/documents/agreements/~/media/documents/agreements/joa-complete.ashx> (Accessed July 25, 2015).

the first six months of 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 the first six months of 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 11-25 Top 20 congestion cost impacts from MISO flowgates affecting PJM dispatch (By facility): January through June of 2015

		Congestion Costs (Millions)										
		Day Ahead				Balancing					Event Hours	
No.	Constraint	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day Ahead	Real Time
1	Person - Halifax	$79.7	$29.2	($10.4)	$40.1	$0.0	($0.0)	($0.1)	($0.1)	$40.0	1,412	6
2	Breed - Wheatland	($1.7)	($15.5)	$0.6	$14.4	$0.1	($0.6)	($0.7)	($0.0)	$14.4	1,358	148
3	Oak Grove - Galesburg	($9.7)	($26.8)	($0.8)	$16.3	$0.3	$0.7	($2.0)	($2.5)	$13.8	2,005	872
4	Rising	$0.5	($11.7)	($6.6)	$5.6	$0.3	($0.1)	$3.7	$4.1	$9.7	652	372
5	Michigan City - Laporte	$1.0	($6.8)	($0.4)	$7.3	$0.0	$0.0	$0.0	$0.0	$7.3	1,855	0
6	Monroe - Bayshore	($3.8)	($12.9)	($2.5)	$6.6	($0.1)	($0.8)	($0.1)	$0.6	$7.2	572	209
7	Burnham - Munster	$0.0	($5.8)	$0.3	$6.2	$0.0	$0.0	$0.0	$0.0	$6.2	786	0
8	Bunsonville - Eugene	($2.0)	($13.3)	($7.0)	$4.4	$0.1	($0.2)	$1.1	$1.4	$5.8	1,914	456
9	Nelson	($1.7)	($6.4)	$0.7	$5.3	$0.0	$0.0	$0.0	$0.0	$5.3	451	0
10	Braidwood - East Frankfurt	($0.1)	($5.1)	($0.0)	$5.0	$0.0	$0.0	$0.0	$0.0	$5.0	54	0
11	Marysville - Tangy	($0.4)	($5.1)	($0.2)	$4.5	$0.0	$0.0	$0.0	$0.0	$4.5	118	0
12	Cherry Valley - Silver Lake	($0.9)	($4.5)	$0.1	$3.7	$0.0	$0.0	$0.0	$0.0	$3.7	184	0
13	Dixon - McGirr Rd	($1.0)	($4.3)	($0.4)	$3.0	$0.0	$0.0	$0.0	$0.0	$3.0	273	0
14	Klondcin - Purdue	$0.0	($0.1)	$0.0	$0.1	$0.0	$0.4	($2.5)	($2.9)	($2.8)	40	53
15	Crete - St Johns Tap	($0.1)	($2.8)	$0.0	$2.7	$0.0	$0.0	$0.0	$0.0	$2.7	205	0
16	Volunteer - Phipps Bend	$0.1	($1.3)	$0.1	$1.5	$0.0	($0.3)	($4.5)	($4.1)	($2.6)	43	49
17	Byron - Cherry Valley	($0.2)	($2.5)	$0.4	$2.6	$0.0	$0.0	$0.0	$0.0	$2.6	157	0
18	Quad Cities	($1.1)	($2.2)	$0.8	$1.9	$0.0	$0.0	$0.0	$0.0	$1.9	278	0
19	Reynolds - Magnetation	($0.2)	($3.6)	$0.2	$3.7	$0.1	$0.2	($1.7)	($1.8)	$1.9	509	151
20	Powerton Jct - Lilly	($1.5)	($2.6)	$0.6	$1.6	$0.3	($0.3)	($0.4)	$0.2	$1.9	274	147

Table 11-26 Top 20 congestion cost impacts from MISO flowgates affecting PJM dispatch (By facility): January through June of 2014

		Congestion Costs (Millions)										
		Day Ahead				Balancing					Event Hours	
No.	Constraint	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day Ahead	Real Time
1	Breed - Wheatland	($14.4)	($80.8)	($8.8)	$57.7	$2.1	$1.2	$5.7	$6.6	$64.3	1,925	456
2	Benton Harbor - Palisades	($11.2)	($65.5)	($7.1)	$47.1	($0.2)	$0.6	($0.9)	($1.8)	$45.3	1,252	129
3	Cook - Palisades	($12.6)	($55.3)	($5.3)	$37.4	($1.5)	$1.6	($6.2)	($9.3)	$28.1	2,316	308
4	Monticello - East Winamac	($3.3)	($41.9)	$0.9	$39.5	$2.5	$4.1	($9.8)	($11.5)	$28.1	3,041	1,377
5	Oak Grove - Galesburg	($16.9)	($34.6)	($1.6)	$16.1	($0.5)	($0.0)	($0.4)	($0.9)	$15.2	3,563	690
6	Rising	($5.1)	($3.8)	$1.4	$0.2	($3.9)	$1.2	($9.3)	($14.3)	($14.1)	386	105
7	Wake - Carso	$0.0	$0.0	$0.0	$0.0	$4.2	$2.7	($10.7)	($9.3)	($9.3)	0	115
8	Michigan City - Laporte	($4.7)	($10.2)	$2.1	$7.6	$0.0	$0.0	$0.0	$0.0	$7.6	927	0
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	Todd Hunter	($0.7)	($3.0)	$0.7	$2.9	$0.0	$0.0	$0.0	$0.0	$2.9	867	0
12	Beaver Channel - Albany	$0.0	$0.0	$0.0	$0.0	($1.4)	$0.0	($1.0)	($2.5)	($2.5)	0	73
13	Paddock - Townline	$0.1	($2.4)	($0.3)	$2.2	$0.0	$0.0	$0.1	$0.1	$2.3	670	38
14	Nelson	($2.7)	($5.1)	($0.4)	$2.0	$0.0	$0.0	$0.0	$0.0	$2.0	165	0
15	Edwards - Kewanee	($1.6)	($3.4)	$0.0	$1.8	$0.0	$0.0	$0.0	$0.0	$1.8	1,448	0
16	Bunsonville - Eugene	($4.1)	($6.8)	$0.4	$3.0	($0.1)	($0.1)	($1.2)	($1.3)	$1.7	1,551	490
17	Magnetation - Monticello	($0.0)	($1.0)	$0.4	$1.3	$0.3	$0.3	$0.4	$0.4	$1.7	112	59
18	Pana North	$0.1	($0.1)	$0.1	$0.3	$0.0	$0.2	($1.8)	($1.9)	($1.6)	157	48
19	Batesville - Hubble	($0.7)	($2.3)	($0.5)	$1.1	($0.0)	($0.0)	$0.1	$0.1	$1.2	48	18
20	Rantoul - Rantoul Jct	($2.8)	($3.3)	$0.7	$1.1	$0.0	$0.0	$0.0	$0.0	$1.1	312	63

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.[22] 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.[23]

Table 11-27 shows the NYISO flowgates which PJM and/or NYISO took dispatch action to control during the first six months of 2015, and which had the greatest congestion cost impact on PJM.

22 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/~/media/documents/agreements/nyiso-pjm.ashx> (Accessed July 16, 2015).
23 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/~/media/documents/agreements/nyiso-pjm.ashx> (Accessed July 16, 2015).

Table 11-27 Top two congestion cost impacts from NYISO flowgates affecting PJM dispatch (By facility): January through June of 2015

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

Table 11-28 Top two congestion cost impacts from NYISO flowgates affecting PJM dispatch (By facility): January through June of 2014

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day Ahead	Real Time
1	Central East	Flowgate	NYISO	$0.0	$0.0	$0.0	$0.0	$0.5	$2.0	($0.1)	($1.6)	($1.6)	0	121
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 11-29 and Table 11-30 show the 500 kV constraints affecting congestion costs in PJM for the first six months of 2015 and the first six months of 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 11-29 Regional constraints summary (By facility): January through June of 2015

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day Ahead	Real Time
1	5004/5005 Interface	Interface	500	($22.9)	($134.6)	($9.2)	$102.4	$7.0	$22.5	$1.9	($13.6)	$88.8	661	321
2	Bedington - Black Oak	Interface	500	$40.7	($42.0)	($7.1)	$75.5	$2.3	$1.7	$3.2	$3.8	$79.3	1,911	282
3	AP South	Interface	500	$34.8	($21.4)	($5.1)	$51.1	$0.3	$0.2	$0.6	$0.7	$51.9	846	42
4	AEP - DOM	Interface	500	$27.2	($27.6)	($1.0)	$53.8	$0.9	$1.6	($1.9)	($2.6)	$51.2	939	42
5	East	Interface	500	($12.1)	($35.5)	($1.9)	$21.5	($0.1)	$0.3	$0.5	$0.1	$21.6	461	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	($1.7)	($14.8)	($0.8)	$12.2	$0.2	$1.0	$0.1	($0.6)	$11.7	273	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	$0.9	$0.4	$0.3	($0.1)	($0.0)	$0.9	62	21

Table 11-30 Regional constraints summary (By facility): January through June of 2014

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day Ahead	Real Time
1	AP South	Interface	500	$307.4	($190.7)	($9.9)	$488.3	$31.1	$73.2	$9.1	($32.9)	$455.4	3,703	879
2	West	Interface	500	($19.9)	($284.5)	($78.1)	$186.5	$16.7	$47.7	$16.7	($14.3)	$172.2	1,202	345
3	Bedington - Black Oak	Interface	500	$25.3	($32.4)	($1.1)	$56.6	$2.9	$3.6	($1.7)	($2.4)	$54.2	1,613	253
4	East	Interface	500	($6.5)	($25.9)	($3.1)	$16.3	$0.3	$0.7	$0.5	$0.1	$16.4	1,395	17
5	5004/5005 Interface	Interface	500	$0.5	($17.9)	($2.7)	$15.7	$7.7	$17.5	$7.1	($2.7)	$13.0	362	313
6	AEP - DOM	Interface	500	$8.6	($10.0)	$3.7	$22.3	$5.5	$13.3	($9.6)	($17.3)	$5.0	1,514	55
7	Central	Interface	500	($5.1)	($13.7)	($3.8)	$4.8	$0.2	$0.5	$0.0	($0.3)	$4.5	315	10
8	Branchburg - Elroy	Line	500	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	10	0
9	Juniata	Transformer	500	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	15	0
10	Conemaugh - Hunterstown	Line	500	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	0	1

Congestion Costs by Physical and Financial Participants

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

In the first six months of 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 the first six months of 2015, the total explicit cost was -$107.0 million (indicating net credits to participants), of which -$128.6 million (120.3 percent) was credited to UTCs. In the first six months of 2014, the total explicit cost was -$148.3 million, of which -$179.2 million (120.8 percent) was credited to UTCs. In the first six months of 2015, financial entities received $98.8 million in net congestion credits, a decrease of $92.3 million or 48.3 percent compared to the first six months of 2014. In the first six months of 2015, physical entities paid $1,017.5 million in congestion charges, a decrease of $615.9 million or 37.7 percent compared to the first six months of 2014.

Table 11-31 Congestion cost by type of participant: January through June of 2015

	Congestion Costs (Millions)									
	Day Ahead				Balancing					
Participant Type	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Inadvertent Charges	Grand Total
Financial	$83.6	$46.4	($20.4)	$16.8	($29.9)	($6.9)	($92.6)	($115.6)	$0.0	($98.8)
Physical	$344.9	($701.6)	$29.9	$1,076.4	$40.7	$75.7	($23.9)	($58.9)	$0.0	$1,017.5
Total	$428.5	($655.2)	$9.6	$1,093.2	$10.7	$68.8	($116.5)	($174.6)	$0.0	$918.6

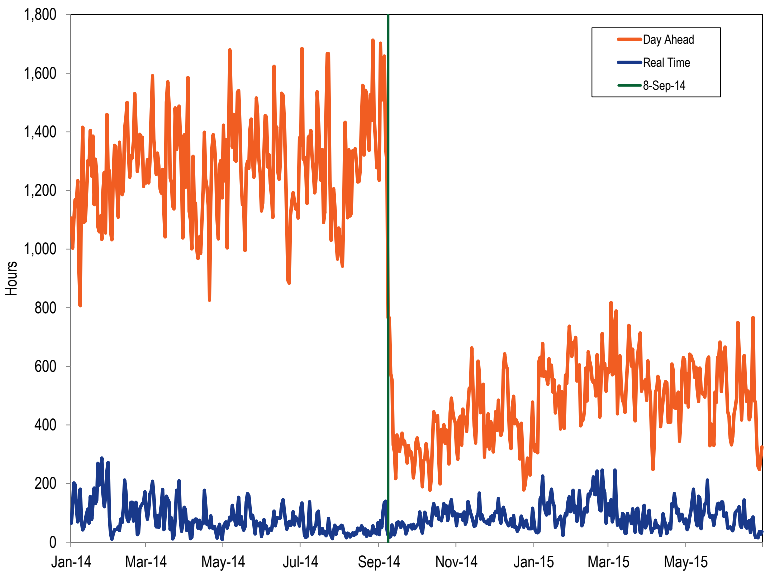
Table 11-32 Congestion cost by type of participant: January through June of 2014

	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	$65.9	$69.2	($103.1)	($106.5)	($26.5)	($0.3)	($58.4)	($84.6)	$0.0	($191.1)
Physical	$326.6	($1,422.8)	$49.0	$1,798.4	$90.9	$220.2	($35.7)	($165.0)	$0.0	$1,633.4
Total	$392.5	($1,353.6)	($54.1)	$1,691.9	$64.4	$219.9	($94.2)	($249.7)	$0.0	$1,442.3

Congestion-Event Summary before and after September 8, 2014

The day-ahead congestion event hours decreased significantly after September 8, 2014. The reduction in UTC activity was a result of FERC's UTC uplift refund notice, effective September 8, 2014.[24] Figure 11-5 shows the daily day-ahead and real-time congestion event hours for 2014 through June of 2015.

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



24 See 18 CFR § 385.213 (2014).

Marginal Losses

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.

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.[25] 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 load on a load ratio share basis. 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.

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

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.

Marginal loss credits or 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 paid back in full to load and exports on a load ratio basis. Payment to load is appropriate as load is the source of the surplus.

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.

The total marginal loss cost in PJM for the first six months of 2015 was $608.3 million, which was comprised of load loss payments of -$15.4 million, generation loss credits of -$635.5 million, explicit loss costs of -$11.9 million and inadvertent loss charges of $0.0 million. Monthly marginal loss costs in the first six months of 2015 ranged from $52.0 million in April to $220.3 million in February. Marginal loss credits decreased in the first six months of 2015 by $118.3 million or 36.4 percent from the first six months of 2014, from $325.0 million to $206.7 million.

Total Marginal Loss Costs

Table 11-33 shows the total marginal loss component costs for the first six months of 2009 through 2015.

Table 11-33 Total marginal loss component costs (Dollars (Millions)): January through June of 2009 through 2015[26]

(Jan - Jun)	Loss Costs	Percent Change	Total PJM Billing	Percent of PJM Billing
2009	$705	NA	$13,457	5.2%
2010	$751	6.5%	$16,314	4.6%
2011	$701	(6.6%)	$18,685	3.8%
2012	$445	(36.6%)	$13,991	3.2%
2013	$494	11.2%	$15,571	3.2%
2014	$1,006	103.5%	$31,060	3.2%
2015	$608	(39.5%)	$23,400	2.6%

26 The loss costs include net inadvertent charges.

Total marginal loss costs for the first six months of 2009 through 2015 are shown in Table 11-34 and Table 11-35. Table 11-34 shows PJM total marginal loss costs by accounting category for the first six months of 2009 through 2015. Table 11-35 shows PJM total marginal loss costs by accounting category by market for the first six months 2009 through 2015.

Table 11-34 Total PJM marginal loss costs by accounting category (Dollars (Millions)): January through June of 2009 through 2015

Marginal Loss Costs (Millions)					
(Jan - Jun)	Load Payments	Generation Credits	Explicit Costs	Inadvertent Charges	Total
2009	($42.2)	($726.4)	$20.7	$0.0	$704.8
2010	($15.7)	($750.5)	$16.2	($0.0)	$750.9
2011	($70.6)	($755.3)	$16.8	$0.0	$701.5
2012	($17.9)	($473.4)	($10.6)	$0.0	$444.9
2013	$8.6	($512.4)	($26.6)	($0.0)	$494.5
2014	($35.7)	($1,083.3)	($41.4)	$0.0	$1,006.2
2015	($15.4)	($635.5)	($11.9)	$0.0	$608.3

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

Marginal Loss Costs (Millions)										
	Day Ahead				Balancing					
(Jan - Jun)	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Inadvertent Charges	Grand Total
2009	($43.8)	($723.3)	$44.6	$724.1	$1.5	($3.1)	($23.9)	($19.3)	$0.0	$704.8
2010	($27.2)	($751.6)	$33.5	$757.9	$11.4	$1.2	($17.3)	($7.0)	($0.0)	$750.9
2011	($90.4)	($774.1)	$44.3	$728.1	$19.8	$18.8	($27.5)	($26.6)	$0.0	$701.5
2012	($30.4)	($481.4)	$15.5	$466.5	$12.5	$8.0	($26.1)	($21.6)	$0.0	$444.9
2013	($7.2)	($528.2)	$25.0	$546.0	$15.9	$15.8	($51.6)	($51.6)	($0.0)	$494.5
2014	($75.4)	($1,118.8)	$51.6	$1,095.0	$39.7	$35.6	($93.0)	($88.8)	$0.0	$1,006.2
2015	($33.2)	($643.0)	$15.6	$625.4	$17.8	$7.4	($27.5)	($17.1)	$0.0	$608.3

Monthly Marginal Loss Costs

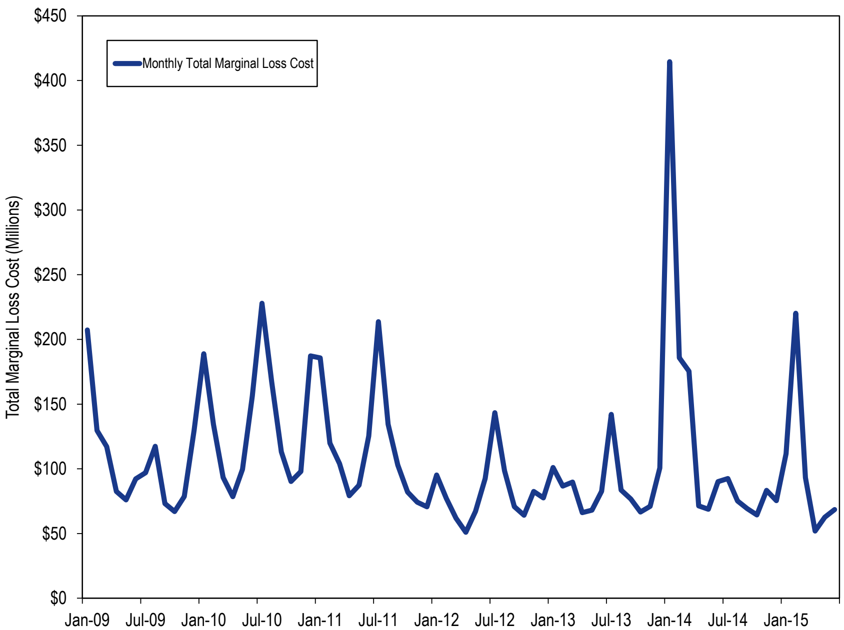
Table 11-36 shows a monthly summary of marginal loss costs by market type for the first six months of 2014 and the first six months of 2015. Total marginal loss costs decreased because of the distribution of high load and outages related to the cold weather in January, but marginal loss costs were also lower in March 2015 than in March 2014.

Table 11-36 Monthly marginal loss costs by market (Dollars (Millions)): January through June of 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
Total	$1,095.0	($88.8)	$0.0	$1,006.2	$625.4	($17.1)	$0.0	$608.3

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

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



Marginal Loss Costs and Loss Credits

Marginal loss credits (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 11-37 shows the total energy costs, the total marginal loss costs collected, the net residual market adjustments and total marginal loss credits redistributed for the first six months of 2009 through 2015. The total marginal loss credits decreased $118.3 million in the first six months of 2015 from the first six months of 2014.

Table 11-37 Marginal loss credits (Dollars (Millions)): January through June of 2009 through 2015[27]

	Loss Credit Accounting (Millions)			
(Jan - Jun)	Total Energy Charges	Total Marginal Loss Charges	Adjustments	Loss Credits
2009	($343.6)	$704.8	$1.3	$362.5
2010	($372.8)	$750.9	($0.6)	$377.5
2011	($393.9)	$701.5	$0.8	$308.4
2012	($262.0)	$444.9	($0.8)	$182.1
2013	($332.6)	$494.5	($0.7)	$161.3
2014	($677.2)	$1,006.2	($4.1)	$325.0
2015	($397.6)	$608.3	($3.9)	$206.7

Energy Costs

Energy Accounting

The energy component of LMP is the system reference bus LMP, also called the system marginal price (SMP). The energy cost is based on the day-ahead and real-time energy components of LMP. Total energy costs, analogous to total congestion costs, 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

27 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.

charges. Total energy costs can by more accurately thought of as net energy costs.

Ignoring interchange, total generation MWh must be greater than total load MWh in every hour in order to provide for losses. Since the hourly integrated energy component of LMP is the same for every bus in every hour, the net energy costs are negative (ignoring net interchange), with generation credits greater than load payments in every hour. These net energy costs plus net marginal loss costs plus net residual market adjustments, equal the marginal loss surplus which is distributed to load and exports.

Total Energy Costs

The total energy cost for the first six months of 2015 was -$397.6 million, which was comprised of load energy payments of $24,267.0 million, generation energy credits of $24,667.1 million, explicit energy costs of $0.0 million and inadvertent energy charges of $2.5 million. The monthly energy costs for the first six months of 2015 ranged from -$141.5 million in February to -$36.0 million in April.

Table 11-38 shows total energy component costs and total PJM billing, for the first six months of 2009 through 2015. The total energy component costs are net energy costs.

Table 11-38 Total PJM costs by energy component (Dollars (Millions)): January through June of 2009 through 2015[28]

(Jan - Jun)	Energy Costs	Percent Change	Total PJM Billing	Percent of PJM Billing
2009	($344)	NA	$13,457	(2.6%)
2010	($373)	8.5%	$16,314	(2.3%)
2011	($394)	5.7%	$18,685	(2.1%)
2012	($262)	(33.5%)	$13,991	(1.9%)
2013	($333)	26.9%	$15,571	(2.1%)
2014	($677)	103.6%	$31,060	(2.2%)
2015	($398)	(41.3%)	$23,400	(1.7%)

28 The energy costs include net inadvertent charges.

Energy costs for the first six months of 2009 through 2015 are shown in Table 11-39 and Table 11-40. Table 11-39 shows PJM energy costs by accounting category for the first six months of 2009 through 2015 and Table 11-40 shows PJM energy costs by market category for the first six months of 2009 through 2015. These energy costs are the actual total energy costs rather than the net energy costs in Table 11-38.

Table 11-39 Total PJM energy costs by accounting category (Dollars (Millions)): January through June of 2009 through 2015

	Energy Costs (Millions)				
(Jan - Jun)	Load Payments	Generation Credits	Explicit Costs	Inadvertent Charges	Total
2009	$22,815.7	$23,162.1	$0.0	$2.9	($343.6)
2010	$25,040.9	$25,406.7	$0.0	($7.1)	($372.8)
2011	$23,524.8	$23,932.1	$0.0	$13.3	($393.9)
2012	$16,823.4	$17,092.7	$0.0	$7.2	($262.0)
2013	$20,488.2	$20,819.3	$0.0	($1.5)	($332.6)
2014	$39,885.0	$40,556.7	$0.0	($5.4)	($677.2)
2015	$24,267.0	$24,667.1	$0.0	$2.5	($397.6)

Table 11-40 Total PJM energy costs by market category (Dollars (Millions)): January through June of 2009 through 2015

	Energy Costs (Millions)									
	Day Ahead				Balancing					
(Jan - Jun)	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Inadvertent Charges	Grand Total
2009	$22,893.0	$23,278.1	$0.0	($385.1)	($77.3)	($116.0)	$0.0	$38.7	$2.9	($343.6)
2010	$25,072.6	$25,450.1	$0.0	($377.5)	($31.6)	($43.4)	$0.0	$11.8	($7.1)	($372.8)
2011	$23,685.6	$24,076.3	$0.0	($390.6)	($160.8)	($144.1)	$0.0	($16.7)	$13.3	($393.9)
2012	$16,907.0	$17,148.9	$0.0	($241.9)	($83.6)	($56.2)	$0.0	($27.4)	$7.2	($262.0)
2013	$20,543.4	$20,895.6	$0.0	($352.2)	($55.1)	($76.3)	$0.0	$21.2	($1.5)	($332.6)
2014	$39,831.7	$40,780.0	$0.0	($948.3)	$53.3	($223.3)	$0.0	$276.6	($5.4)	($677.2)
2015	$24,389.1	$24,858.0	$0.0	($468.9)	($122.1)	($190.9)	$0.0	$68.8	$2.5	($397.6)

Monthly Energy Costs

Table 11-41 shows a monthly summary of energy costs by market type for the first six months of 2014 and the first six months of 2015. Marginal total energy costs in the first six months of 2015 decreased from 2014. Monthly total energy costs in the first six months of 2015 ranged from -$141.5 million in February to -$36.0 million in April.

Table 11-41 Monthly energy costs by market type (Dollars (Millions)): January through June of 2014 and 2015

	Energy Costs (Millions)							
	2014 (Jan - Jun)				2015 (Jan - Jun)			
	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)
Total	($948.3)	$276.6	($5.4)	($677.2)	($468.9)	$68.8	$2.5	($397.6)

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

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