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 or energy component (SMP), the marginal loss component of LMP (MLMP), and the congestion component of LMP (CLMP).[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 cost of energy, given the current dispatch, ignoring losses and congestion. 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. Total system-wide transmission losses for the first nine months of 2013 were 13,218 GWh, a 3.4 percent increase compared to the first nine months of 2012. Marginal losses are the incremental change in system losses caused by changes in load and generation. Congestion occurs when available, least-cost energy cannot be delivered to all load because transmission facilities are not adequate to deliver that energy and higher cost units in the constrained area must be dispatched to meet that load.[2] The result is that the price of energy in the constrained area is higher than in the unconstrained area.

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.

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 and marginal losses.[3,4]

Overview

Energy Cost

- **Total Energy Costs.** Total energy costs in the first nine months of 2013 decreased by $85 million or 19.2 percent from the first nine months of 2012, from -$442.6 million to -$527.6 million. Day-ahead net energy costs in the first nine months of 2013 decreased by $171.9 million or 40.0 percent from the first nine months of 2012, from -$429.8 million to -$601.6 million. Balancing net energy costs in the first nine months of 2013 increased by $98.9 million or 478.0 percent from the first nine months of 2012, from -$20.7 million to $78.2 million.
- **Monthly Total Energy Costs.** Significant monthly fluctuations in total energy costs were the result of load and energy import levels, and changes in dispatch of generation. Monthly total energy costs in the first nine months of 2013 ranged from -$90.8 million in July to -$46.5 million in April.

Marginal Loss Cost

- **Total Marginal Loss Costs.** Total marginal loss costs in the first nine months of 2013 increased by $39.4 million or 5.2 percent from the first nine months of 2012, from $757.6 million to $796.9 million. Day-ahead net marginal loss costs in the first nine months of 2013 increased by $95.5 million or 12.3 percent from the first nine months of 2012, from $776.0

1 On January 1, 2012, PJM integrated the Duke Energy Ohio/Kentucky (DEOK) Control Zone. On June 1, 2013, PJM integrated the East Kentucky Power Cooperative (EKPC) Control Zone. The metrics reported in this section treat DEOK as part of MISO for the first hour of January 2012 and as part of PJM for the second hour of January through December 2012. 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 June 2013.

2 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.

3 The total marginal loss and congestion results were calculated as of October 14, 2013, and are subject to change, based on continued PJM billing updates.

4 For more details on the concepts in this section, see the *2012 State of the Market Report for PJM, Volume II:* Section 10, "Congestion and Marginal Losses."

million to $871.5 million. Balancing net marginal loss costs decreased in the first nine months of 2013 by $56.1 million or 303.8 percent from the first nine months of 2012, from -$18.5 million to -$74.6 million.

- **Monthly Total Marginal Loss Costs.** Significant monthly fluctuations in total marginal loss costs were the result of changes in load and energy import levels, and changes in the dispatch of generation. Monthly total marginal loss costs in the first nine months of 2013 ranged from $66.2 million in April to $142.1 million in July.
- **Marginal Loss Credits.** Marginal Loss Credits are calculated as total energy costs (net energy costs minus net energy credits plus net inadvertent energy charges) plus total marginal loss costs (net marginal loss costs minus net marginal loss credits plus net explicit loss costs plus net inadvertent loss charges) plus net residual market adjustments. Marginal loss credit or loss surplus is the remaining loss amount from overcollection of marginal losses, after accounting for total net energy costs and net residual market adjustments, which is paid back in full to load and exports on a load ratio basis.[5] The marginal loss credits decreased in the first nine months of 2013 by $46.0 million or 14.7 percent from the first nine months of 2012, from $313.3 million to $267.3 million.

Congestion Cost

- **Total Congestion.** Total congestion costs increased by $83.5 million or 19.6 percent, from $425.2 million in the first nine months of 2012 to $508.7 million in the first nine months of 2013.[6]
- **Day-Ahead Congestion.** Day-ahead congestion costs increased by $197.3 million or 32.7 percent, from $603.2 million in the first nine months of 2012 to $800.5 million in the first nine months of 2013.
- **Balancing Congestion.** Balancing congestion costs decreased by $113.8 million or 63.9 percent from -$178.0 million in the first nine months of 2012 to -$291.8 million in the first nine months of 2013.
- **Monthly Congestion.** Monthly total congestion costs in the first nine months of 2013 ranged from $27.8 million in March to $109.2 million in July.
- **Geographic Differences in CLMP.** Differences in CLMP among eastern, southern and western control zones in PJM was primarily a result of congestion on the AP South interface, the West interface, the ATSI interface, the Bridgewater - Middlesex line, the Cloverdale transformer. (Table 11-27)
- **Congested Facilities.** Congestion frequency continued to be significantly higher in the Day-Ahead Market than in the Real-Time Market in the first nine months of 2013. Day-ahead congestion frequency increased by 54.1 percent from 168,509 congestion event hours in the first nine months of 2012 to 259,605 congestion event hours in the first nine months of 2013. Day-ahead, congestion-event hours increased on all types of congestion facilities.

  Real-time congestion frequency decreased by 6.0 percent from 15,153 congestion event hours in the first nine months of 2012 to 14,249 congestion event hours in the first nine months of 2013. Real-time, congestion-event hours increased on the interfaces and the flowgates, while congestion on the transformers, and the transmission lines decreased.

  Facilities were constrained in the Day-Ahead Market more frequently than in the Real-Time Market. In the first nine months of 2013, for only 2.0 percent of Day-Ahead Market facility constrained hours were the same facilities also constrained in the Real-Time Market. In the first nine months of 2013, for 37.9 percent of Real-Time Market facility constrained hours, the same facilities were also constrained in the Day-Ahead Market.

  The AP South Interface was the largest contributor to congestion costs in the first nine months of 2013. With $144.1 million in total congestion costs, it accounted for 28.3 percent of the total PJM congestion costs in the first nine months of 2013. The top five constraints in terms of congestion costs together contributed $183.8 million, or 36.1 percent, of the total PJM congestion costs in the first nine months of 2013. The

5 See PJM. "Manual 28: Operating Agreement Accounting," Revision 60 (June 1, 2013). Note that the over collection is not calculated by subtracting the prior calculation of average losses from the calculated total marginal losses.

6 The total zonal congestion numbers were calculated as of October 14, 2013, and are based on continued PJM billing updates, subject to change.

top five constraints were the AP South interface, the West interface, the ATSI interface, the Bridgewater – Middlesex line, and the Cloverdale transformer.

- **Zonal Congestion.** ComEd was the most congested zone in the first nine months of 2013. ComEd had -$337.8 million in total load costs, -$472.5 million in total generation credits and -$14.1 million in explicit congestion, resulting in $120.5 million in net congestion costs, reflecting significant local congestion between local generation and load, despite being on the upstream side of system wide congestion patterns. The Nelson – Cordova line, the Byron - Cherry Valle flowgate, the AP South interface, the Braidwood transformer, and the Crete - St Johns Tap flowgate contributed $44.1 million, or 36.6 percent of the total ComEd Control Zone congestion costs.

  The AEP Control Zone was the second most congested zone in PJM in the first nine months of 2013, with $76.5 million. The AP South interface contributed $21.0 million or 27.4 percent of the total AP Control Zone congestion cost in first nine months of 2013. The AP Control Zone was the third most congested zone in PJM in the first nine months of 2013, with a cost of $74.3 million.

- **Ownership.** In the first nine months of 2013, financial companies as a group were net recipients of congestion credits, and physical companies were net payers of congestion charges. In the first nine months of 2013, financial companies received $84.1 million in net congestion credits, an increase of $16.8 million or 25.0 percent compared to the first nine months of 2012. In the first nine months of 2013, physical companies paid $592.8 million in net congestion charges, an increase of $100.3 million or 20.4 percent compared to the first nine months of 2012.

Conclusion

Energy costs are the incremental costs to the system, which are the same at every bus for each hour, without taking losses and congestion into account.

Marginal losses are the costs of incremental power losses which result from the geographic distribution of generation and load and the physical characteristics of the transmission system interconnecting generation and load. When calculating marginal losses, load is charged and generation is credited for the power losses to the system. Marginal loss costs had been decreasing since 2010, due to decreases in LMP and fuel costs. However, increases in the LMP and fuel costs have led to higher marginal loss costs in the first nine months of 2013 compared to the first nine months of 2012. Total marginal loss costs increased in the first nine months of 2013 by $39.4 million or 5.2 percent from the first nine months of 2012, from $757.6 million to $796.9 million.

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 and the geographic distribution of load.

ARRs and FTRs served as an effective, but not total, offset against congestion. ARR and FTR revenues offset 85.5 percent of the total congestion costs in the Day-Ahead Energy Market and the balancing energy market within PJM for the 2013 to 2014 planning period. In the 2012 to 2013 planning period, total ARR and FTR revenues offset 92.6 percent of the congestion costs. FTRs were paid at 67.8 percent of the target allocation level for the 2012 to 2013 planning period, and at 77.3 percent of the target allocation level for the 2013 to 2014 planning period through September 30, 2013.[7] Revenue adequacy, measured relative to target allocations for a planning period is not final until the end of the period.

7 See the *2012 State of the Market Report for PJM, Volume II:* Section 12, "Financial Transmission and Auction Revenue Rights," at Table 12-23, "Monthly FTR accounting summary (Dollars (Millions)): Planning periods 2012 to 2013 and 2013 to 2014."

Locational Marginal Price (LMP)

Components

Table 11-1 shows the PJM real-time, load-weighted average LMP components for the first nine months of 2009 to 2013. The load-weighted average real-time LMP increased $4.72 or 13.5 percent from $35.02 in the first nine months of 2012 to $39.75 in the first nine months of 2013. The load-weighted average congestion component decreased $0.03 or 74.4 percent from $0.04 in the first nine months of 2012 to $0.01 in the first nine months of 2013. The load-weighted average loss component increased $0.01 or 61.7 percent from $0.01 in the first nine months of 2012 to $0.02 in the first nine months of 2013. The load-weighted average energy component increased $4.74 or 13.6 percent from $34.97 in the first nine months of 2012 to $39.72 in the first nine months of 2013.

Table 11-1 PJM real-time, load-weighted average LMP components (Dollars per MWh): January through September of 2009 through 2013

(Jan-Sep)	Real-Time LMP	Energy Component	Congestion Component	Loss Component
2009	$39.57	$39.49	$0.04	$0.03
2010	$49.91	$49.81	$0.06	$0.04
2011	$49.48	$49.40	$0.05	$0.03
2012	$35.02	$34.97	$0.04	$0.01
2013	$39.75	$39.72	$0.01	$0.02

Table 11-2 shows the PJM day-ahead, load-weighted average LMP components for the first nine months of 2009 through 2013. The load-weighted average day-ahead LMP increased $5.20 or 15.1 percent from $34.29 in the first nine months of 2012 to $39.49 in the first nine months of 2013. The load-weighted average congestion component increased $0.02 or 15.0 percent from $0.12 in the first nine months of 2012 to $0.14 in the first nine months of 2013. The load-weighted average loss component increased $0.02 or 99.3 percent from -$0.02 in the first nine months of 2012 to -$0.00 in the first nine months of 2013. The load-weighted average energy component increased $5.16 or 15.1 percent from $34.19 in the first nine months of 2012 to $39.35 in the first nine months of 2013.

Table 11-2 PJM day-ahead, load-weighted average LMP components (Dollars per MWh): January through September of 2009 through 2013

(Jan-Sep)	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
2009	$39.95	$39.50	($0.05)	($0.10)
2010	$49.12	$49.05	$0.11	($0.03)
2011	$48.34	$48.55	($0.05)	($0.16)
2012	$34.29	$34.19	$0.12	($0.02)
2013	$39.49	$39.35	$0.14	($0.00)

Zonal Components

The real-time components of LMP for each PJM control zone are presented in Table 11-3 for the first nine months of 2012 and 2013. The day-ahead components of LMP for each control zone are presented in Table 11-4 for the first nine months of 2012 and 2013.

Table 11-3 Zonal and PJM real-time, load-weighted average LMP components (Dollars per MWh): January through September of 2012 and 2013

	2012 (Jan-Sep)				2013 (Jan-Sep)			
	Real-Time LMP	Energy Component	Congestion Component	Loss Component	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AECO	$37.23	$35.88	($0.01)	$1.37	$42.09	$40.26	$0.03	$1.80
AEP	$32.81	$34.39	($0.82)	($0.77)	$36.31	$39.25	($1.98)	($0.96)
AP	$34.63	$34.61	$0.12	($0.10)	$38.52	$39.43	($0.73)	($0.18)
ATSI	$33.98	$34.71	($0.91)	$0.18	$44.63	$39.50	$4.67	$0.46
BGE	$40.16	$35.29	$3.28	$1.58	$44.55	$40.05	$2.70	$1.80
ComEd	$32.35	$35.27	($1.51)	($1.41)	$34.01	$39.78	($3.83)	($1.94)
DAY	$33.97	$34.88	($1.08)	$0.17	$36.91	$39.70	($2.69)	($0.10)
DEOK	$32.41	$34.95	($1.03)	($1.52)	$35.02	$39.62	($2.65)	($1.95)
DLCO	$33.44	$34.81	($0.37)	($1.01)	$36.44	$39.58	($1.85)	($1.29)
Dominion	$37.21	$35.29	$1.62	$0.31	$41.77	$39.92	$1.56	$0.29
DPL	$39.43	$35.40	$2.41	$1.62	$43.13	$40.03	$1.10	$2.00
EKPC	NA	NA	NA	NA	$35.06	$41.33	($3.93)	($2.35)
JCPL	$36.95	$36.02	($0.25)	$1.17	$44.45	$40.77	$1.79	$1.89
Met-Ed	$35.56	$34.85	$0.31	$0.40	$40.70	$39.68	$0.24	$0.78
PECO	$36.34	$35.07	$0.46	$0.81	$40.44	$39.84	($0.48)	$1.09
PENELEC	$34.40	$34.22	($0.25)	$0.44	$39.51	$39.15	($0.24)	$0.59
Pepco	$39.18	$35.31	$2.95	$0.92	$43.72	$40.06	$2.47	$1.19
PPL	$34.57	$34.59	($0.37)	$0.35	$40.19	$39.46	$0.05	$0.68
PSEG	$36.64	$35.31	$0.09	$1.24	$45.47	$40.04	$3.73	$1.70
RECO	$36.88	$36.17	($0.43)	$1.15	$47.74	$40.89	$5.20	$1.65
PJM	$35.02	$34.97	$0.04	$0.01	$39.75	$39.72	$0.01	$0.02

Table 11-4 Zonal and PJM day-ahead, load-weighted average LMP components (Dollars per MWh): January through September of 2012 and 2013

	2012 (Jan-Sep)				2013 (Jan-Sep)			
	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AECO	$37.05	$34.99	$0.51	$1.54	$42.18	$39.88	$0.54	$1.75
AEP	$32.36	$33.84	($0.56)	($0.92)	$36.92	$39.09	($1.26)	($0.91)
AP	$34.01	$33.92	$0.16	($0.07)	$38.47	$39.09	($0.40)	($0.23)
ATSI	$33.09	$34.00	($0.78)	($0.13)	$38.50	$39.24	($0.98)	$0.24
BGE	$39.53	$34.62	$3.00	$1.90	$44.82	$39.72	$3.39	$1.71
ComEd	$31.08	$34.41	($1.56)	($1.77)	$34.84	$39.53	($2.93)	($1.76)
DAY	$33.46	$34.30	($0.75)	($0.09)	$37.65	$39.48	($1.65)	($0.18)
DEOK	$31.87	$34.20	($0.59)	($1.73)	$35.94	$39.24	($1.60)	($1.70)
DLCO	$32.92	$34.13	($0.16)	($1.05)	$36.67	$39.33	($1.37)	($1.29)
Dominion	$36.40	$34.56	$1.35	$0.49	$42.02	$39.71	$2.15	$0.16
DPL	$38.72	$34.80	$1.85	$2.07	$43.19	$39.65	$1.57	$1.97
EKPC	NA	NA	NA	NA	$36.83	$41.03	($1.92)	($2.28)
JCPL	$36.58	$35.01	$0.24	$1.33	$43.63	$40.13	$1.71	$1.78
Met-Ed	$34.73	$33.96	$0.26	$0.51	$40.57	$39.12	$0.82	$0.63
PECO	$35.96	$34.38	$0.60	$0.98	$40.71	$39.41	$0.28	$1.02
PENELEC	$33.97	$33.46	($0.00)	$0.51	$39.56	$38.57	$0.27	$0.72
Pepco	$38.14	$34.28	$2.58	$1.28	$43.51	$39.20	$3.17	$1.13
PPL	$34.00	$33.86	($0.19)	$0.33	$40.12	$39.04	$0.56	$0.52
PSEG	$36.66	$34.62	$0.53	$1.51	$45.51	$39.79	$3.98	$1.75
RECO	$36.36	$35.10	$0.02	$1.24	$46.59	$40.03	$4.92	$1.64
PJM	$34.29	$34.19	$0.12	($0.02)	$39.49	$39.35	$0.14	($0.00)

Component Costs

Table 11-5 shows the total energy, loss and congestion component costs and the total PJM billing for the first nine months of 2009 through 2013. These totals are actually net energy, loss and congestion costs.

Table 11-5 Total PJM costs by component (Dollars (Millions)): January through September of 2009 through 2013[8,9]

	Component Costs (Millions)					
(Jan-Sep)	Energy Costs	Loss Costs	Congestion Costs	Total Costs	Total PJM Billing	Total Costs Percent of PJM Billing
2009	($485)	$992	$544	$1,051	$19,927	5.3%
2010	($619)	$1,259	$1,134	$1,775	$26,249	6.8%
2011	($651)	$1,153	$875	$1,376	$28,836	4.8%
2012	($443)	$758	$425	$740	$22,119	3.3%
2013	($528)	$797	$509	$778	$25,153	3.1%

8 The Energy Costs, Loss Costs and Congestion Costs include net inadvertent charges.
9 Total PJM Billing is provided by PJM, and the MMU is not able to reproduce and verify the calculation.

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 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.[10]

The total energy cost for the first nine months of 2013 was -$527.6 million, which was comprised of load energy payments of $32,756.4 million, generation energy credits of $33,279.8 million, explicit energy costs of $0.0 million and inadvertent energy charges of -$4.2 million. The monthly energy costs for the first nine months of 2013 ranged from -$90.8 million in July to -$46.5 million in April.

Total Energy Costs

Table 11-6 shows total energy component costs and total PJM billing, for the first nine months of 2009 through 2013. The total energy component costs appear low compared to total PJM billing because these totals are actually net energy costs.

Table 11-6 Total PJM costs by energy component (Dollars (Millions)): January through September of 2009 through 2013[11]

(Jan-Sep)	Energy Costs	Percent Change	Total PJM Billing	Percent of PJM Billing
2009	($485)	NA	$19,927	(2.4%)
2010	($619)	27.6%	$26,249	(2.4%)
2011	($651)	5.3%	$28,836	(2.3%)
2012	($443)	(32.0%)	$22,119	(2.0%)
2013	($528)	19.2%	$25,153	(2.1%)

Energy costs for the first nine months of 2009 through 2013 are shown in Table 11-7 and Table 11-8. Table 11-7 shows PJM energy costs by category for the first nine months of 2009 through 2013 and Table 11-8 shows PJM energy costs by market category for the first nine months of 2009 through 2013. These energy costs are the actual total energy costs rather than the net energy costs in Table 11-6.

Table 11-7 Total PJM energy costs by category (Dollars (Millions)): January through September of 2009 through 2013

	Energy Costs (Millions)				
(Jan-Sep)	Load Payments	Generation Credits	Explicit	Inadvertent Charges	Total
2009	$32,472.4	$32,960.8	$0.0	$3.8	($484.6)
2010	$41,562.3	$42,169.5	$0.0	($11.4)	($618.6)
2011	$38,515.2	$39,193.0	$0.0	$26.5	($651.3)
2012	$28,303.5	$28,754.0	$0.0	$7.9	($442.6)
2013	$32,756.4	$33,279.8	$0.0	($4.2)	($527.6)

10 Net residual adjustments 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.

11 The Energy Costs include net inadvertent charges.

Table 11-8 Total PJM energy costs by market category (Dollars (Millions)): January through September of 2009 through 2013

	Energy Costs (Millions)									
	Day Ahead				Balancing					
(Jan-Sep)	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Inadvertent Charges	Grand Total
2009	$32,628.0	$33,162.4	$0.0	($534.4)	($155.6)	($201.6)	$0.0	$45.9	$3.8	($484.6)
2010	$41,665.6	$42,289.1	$0.0	($623.5)	($103.4)	($119.7)	$0.0	$16.3	($11.4)	($618.6)
2011	$38,908.1	$39,530.7	$0.0	($622.6)	($392.9)	($337.7)	$0.0	($55.3)	$26.5	($651.3)
2012	$28,423.3	$28,853.1	$0.0	($429.8)	($119.9)	($99.2)	$0.0	($20.7)	$7.9	($442.6)
2013	$32,796.6	$33,398.2	$0.0	($601.6)	($40.2)	($118.4)	$0.0	$78.2	($4.2)	($527.6)

Monthly Energy Costs

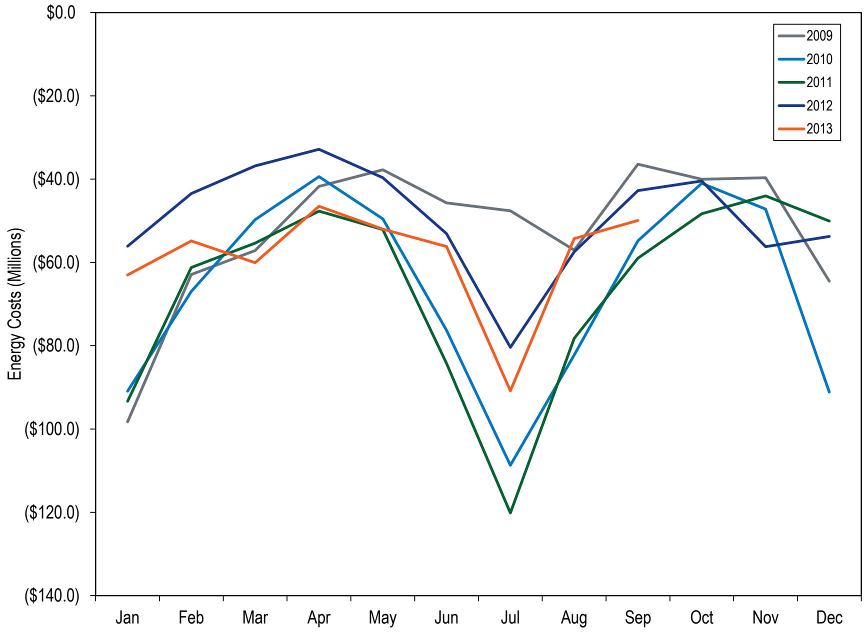
Table 11-9 shows a monthly summary of energy costs by type for the first nine months of 2012 and 2013.

Table 11-9 Monthly energy costs by type (Dollars (Millions)): January through September of 2012 and 2013

	Energy Costs (Millions)							
	2012				2013			
	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total
Jan	($48.5)	($10.1)	$2.5	($56.1)	($69.2)	$5.8	$0.5	($63.0)
Feb	($36.0)	($9.9)	$2.4	($43.5)	($60.6)	$5.9	($0.1)	($54.8)
Mar	($30.1)	($8.6)	$1.9	($36.8)	($63.9)	$4.2	($0.3)	($60.0)
Apr	($30.7)	($2.8)	$0.7	($32.8)	($46.8)	$0.9	($0.6)	($46.5)
May	($39.4)	$0.0	($0.3)	($39.7)	($48.3)	($3.4)	($0.3)	($52.0)
Jun	($57.1)	$4.0	$0.0	($53.1)	($63.4)	$7.8	($0.6)	($56.2)
Jul	($84.0)	$3.0	$0.6	($80.4)	($111.1)	$21.4	($1.1)	($90.8)
Aug	($60.3)	$2.6	$0.3	($57.4)	($71.0)	$17.4	($0.7)	($54.3)
Sep	($43.6)	$1.1	($0.2)	($42.8)	($67.3)	$18.3	($0.9)	($49.9)
Total	($429.8)	($20.7)	$7.9	($442.6)	($601.6)	$78.2	($4.2)	($527.6)

Figure 11-1 shows PJM monthly energy costs of January 2009 through September 2013.

Figure 11-1 PJM monthly energy costs (Dollars (Millions)): January 2009 through September 2013



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 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 nine months of 2013 was $796.9 million, which was comprised of load loss payments of -$3.3 million, generation loss credits of -$834.4 million, explicit loss costs of -$34.1 million and inadvertent loss charges of -$0.0 million. Monthly marginal loss costs in the first nine months of 2013 ranged from $66.2 million in April to $142.1 million in July. Marginal loss credits decreased in the first nine months of 2013 by $46.0 million or 14.7 percent from the first nine months of 2012, from $313.3 million to $267.3 million.

Total Marginal Loss Costs

Table 11-10 shows the total marginal loss component costs for the first nine months of 2009 through 2013. The yearly total loss component costs appear low compared to total PJM billing because these totals are actually net loss costs.

Table 11-10 Total PJM costs by loss component (Dollars (Millions)): January through September of 2009 through 2013[12,13]

(Jan-Sep)	Loss Costs	Percent Change	Total PJM Billing	Percent of PJM Billing
2009	$992	NA	$19,927	5.0%
2010	$1,259	26.9%	$26,249	4.8%
2011	$1,153	(8.5%)	$28,836	4.0%
2012	$758	(34.3%)	$22,119	3.4%
2013	$797	5.2%	$25,153	3.2%

12 Calculated values shown in Section 10, "Congestion and Marginal Losses," are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.
13 The Loss Costs include net inadvertent charges.

Total marginal loss costs for the first nine months of 2009 through 2013 are shown in Table 11-11 and Table 11-12. Table 11-11 shows PJM total marginal loss costs by category for the first nine months of 2009 through 2013. Table 11-12 shows PJM total marginal loss costs by market category for the first nine months of 2009 through 2013.

Table 11-11 Total PJM marginal loss costs by category (Dollars (Millions)): January through September of 2009 through 2013

	Marginal Loss Costs (Millions)				
(Jan-Sep)	Load Payments	Generation Credits	Explicit	InadvertentCharges	Total
2009	($62.5)	($1,028.9)	$26.1	$0.0	$992.4
2010	($71.8)	($1,299.6)	$31.5	($0.0)	$1,259.3
2011	($138.8)	($1,277.7)	$13.7	$0.0	$1,152.6
2012	($17.3)	($790.0)	($15.1)	$0.0	$757.6
2013	($3.3)	($834.4)	($34.1)	($0.0)	$796.9

Table 11-12 Total PJM marginal loss costs by market category (Dollars (Millions)): January through September of 2009 through 2013

	Marginal Loss Costs (Millions)									
	Day Ahead				Balancing					
(Jan-Sep)	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Inadvertent Charges	Grand Total
2009	($65.9)	($1,025.7)	$53.2	$1,013.0	$3.4	($3.1)	($27.1)	($20.6)	$0.0	$992.4
2010	($94.4)	($1,307.1)	$61.5	$1,274.2	$22.6	$7.5	($30.0)	($14.9)	($0.0)	$1,259.3
2011	($174.3)	($1,313.6)	$51.7	$1,191.1	$35.5	$36.0	($38.0)	($38.5)	$0.0	$1,152.6
2012	($42.2)	($805.6)	$12.7	$776.0	$24.9	$15.6	($27.8)	($18.5)	$0.0	$757.6
2013	($30.3)	($857.9)	$44.0	$871.5	$27.0	$23.5	($78.1)	($74.6)	($0.0)	$796.9

Monthly Marginal Loss Costs

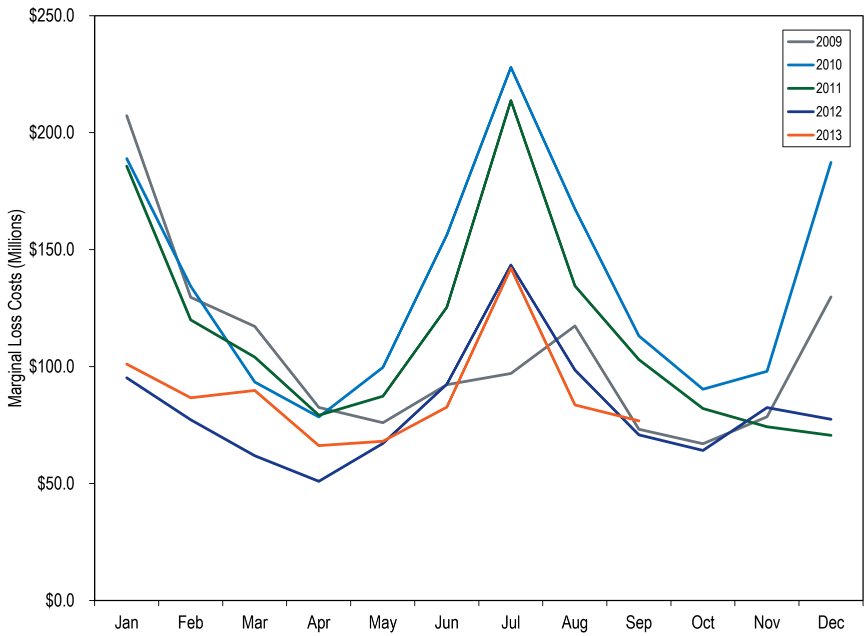
Table 11-13 shows a monthly summary of marginal loss costs by type for the first nine months of 2012 and 2013.

Table 11-13 Monthly marginal loss costs by type (Dollars (Millions)): January through September of 2012 and 2013

	Marginal Loss Costs (Millions)							
	2012				2013			
	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total
Jan	$100.6	($5.4)	$0.0	$95.2	$105.8	($4.7)	$0.0	$101.1
Feb	$80.4	($3.1)	$0.0	$77.2	$93.2	($6.5)	($0.0)	$86.7
Mar	$67.1	($5.2)	$0.0	$61.9	$97.2	($7.4)	($0.0)	$89.8
Apr	$55.4	($4.4)	$0.0	$51.0	$77.7	($11.5)	($0.0)	$66.2
May	$69.6	($2.5)	($0.0)	$67.1	$80.5	($12.4)	($0.0)	$68.1
Jun	$93.3	($0.8)	$0.0	$92.5	$91.7	($9.0)	($0.0)	$82.7
Jul	$141.8	$1.6	$0.0	$143.4	$149.2	($7.1)	($0.0)	$142.1
Aug	$96.1	$2.4	$0.0	$98.5	$91.3	($7.7)	($0.0)	$83.6
Sep	$71.7	($0.9)	($0.0)	$70.8	$85.0	($8.2)	($0.0)	$76.8
Total	$776.0	($18.5)	$0.0	$757.6	$871.5	($74.6)	($0.0)	$796.9

Figure 11-2 shows PJM monthly marginal loss costs of January 2009 through September 2013.

Figure 11-2 PJM monthly marginal loss costs (Dollars (Millions)): January 2009 through September of 2013



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 (generation energy credits less load energy payments) 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 11-14 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 nine months of 2009 through 2013. The total marginal loss credits decreased $46.0 million in the first nine months of 2013 from the first nine months of 2012.

Table 11-14 Marginal loss credits (Dollars (Millions)): January through September, 2009 through 2013[14]

	Loss Credit Accounting (Millions)			
(Jan-Sep)	Total Energy Charges	Total Marginal Loss Charges	Adjustments	Loss Credits
2009	($484.6)	$992.4	$0.7	$508.5
2010	($618.6)	$1,259.3	($1.2)	$639.6
2011	($651.3)	$1,152.6	$0.7	$502.1
2012	($442.6)	$757.6	($1.7)	$313.3
2013	($527.6)	$796.9	($2.1)	$267.3

Congestion

Congestion Accounting

Total congestion costs in PJM in the first nine months of 2013 were $508.7 million, which was comprised of load congestion payments of $233.1 million, generation credits of -$340.5 million and explicit congestion of -$64.8 million (Table 11-16).

14 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.

Total Congestion

Table 11-15 shows total congestion from January through September by year from 2008 through 2013.[15]

Table 11-15 Total PJM congestion (Dollars (Millions)): January through September, 2008 to 2013

	Congestion Costs (Millions)			
(Jan - Sep)	Congestion Cost	Percent Change	Total PJM Billing	Percent of PJM Billing
2008	$1,778.2	NA	$26,979	6.6%
2009	$543.6	(69.4%)	$19,927	2.7%
2010	$1,134.3	108.7%	$26,249	4.3%
2011	$874.9	(22.9%)	$28,836	3.0%
2012	$425.2	(51.4%)	$22,119	1.9%
2013	$508.7	19.6%	$25,153	2.0%

Total congestion costs in Table 11-16 include congestion costs associated with PJM facilities and those associated with reciprocal, coordinated flowgates in the MISO and in the NYISO.[16,17]

Table 11-16 shows the congestion costs by category for the first nine months of 2013. The January through September 2013 PJM total congestion costs were comprised of $233.1 million in load congestion payments, -$340.5 million in generation congestion credits, and -$64.8 million in explicit congestion costs.

Table 11-16 Total PJM congestion costs by category (Dollars (Millions)): January through September, 2008 to 2013

	Congestion Costs (Millions)				
(Jan - Sep)	Load Payments	Generation Credits	Explicit Costs	Inadvertent Charges	Total
2008	$921.9	($880.7)	($24.5)	$0.0	$1,778.2
2009	$210.6	($380.9)	($48.0)	$0.0	$543.6
2010	$290.2	($893.3)	($49.2)	($0.0)	$1,134.3
2011	$442.0	($535.7)	($102.8)	$0.0	$874.9
2012	$103.3	($372.7)	($50.9)	$0.0	$425.2
2013	$233.1	($340.5)	($64.8)	$0.0	$508.7

15 Congestion charges for 2010 reflect an updated calculation compared to the results in the *2010 State of the Market Report for PJM.*
16 See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C." (December 11, 2008) Section 6.1 <http://pjm.com/documents/agreements/~/media/documents/agreements/joa-complete.ashx> (Accessed April 17, 2013).
17 See "Joint Operating Agreement Among and Between the New York Independent System Operator Inc and PJM Interconnection, L.L.C." (January 17, 2013) Section 35.2.1 <http://www.pjm.com/~/media/documents/agreements/nyiso-pjm.ashx> (Accessed April 17, 2013).

Table 11-17 Total PJM congestion costs by market category (Dollars (Millions)): January through September, 2008 to 2013

	Congestion Costs (Millions)									
	Day Ahead				Balancing					
(Jan - Sep)	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Inadvertent Charges	Grand Total
2008	$1,126.9	($971.2)	$152.8	$2,250.9	($204.9)	$90.5	($177.3)	($472.7)	$0.0	$1,778.2
2009	$245.7	($385.0)	$73.8	$704.6	($35.1)	$4.1	($121.9)	($161.0)	$0.0	$543.6
2010	$301.7	($932.7)	$69.5	$1,303.9	($11.5)	$39.3	($118.7)	($169.6)	($0.0)	$1,134.3
2011	$389.3	($628.2)	$45.6	$1,063.2	$52.7	$92.6	($148.4)	($188.3)	$0.0	$874.9
2012	$106.6	($409.8)	$86.7	$603.2	($3.3)	$37.1	($137.6)	($178.0)	$0.0	$425.2
2013	$226.3	($452.6)	$121.6	$800.5	$6.8	$112.2	($186.4)	($291.8)	$0.0	$508.7

Monthly Congestion

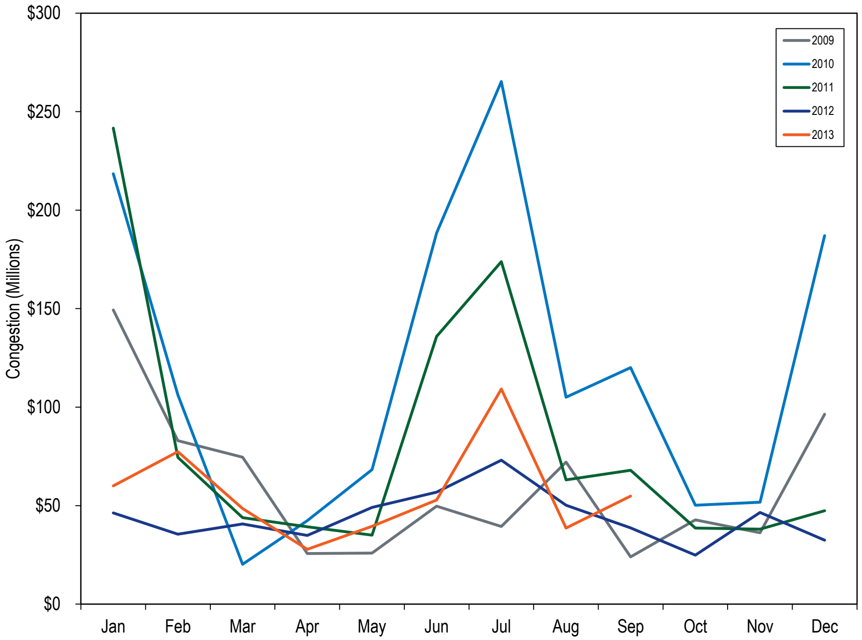
Table 11-18 shows that during the first nine months of 2012 and 2013, monthly total congestion costs ranged from $27.8 million to $109.2 million in 2013. Table 11-18 shows the monthly congestion costs in the first nine months of 2013 were higher than in the first nine months of 2012.

Table 11-18 Monthly PJM congestion costs by market type (Dollars (Millions)): January through September, 2012 to 2013

	Congestion Costs (Millions)							
	2012				2013			
	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total
Jan	$66.3	($20.0)	$0.0	$46.3	$136.8	($76.8)	$0.0	$60.0
Feb	$54.8	($19.2)	$0.0	$35.5	$125.1	($47.7)	$0.0	$77.4
Mar	$59.8	($19.2)	$0.0	$40.6	$69.9	($21.4)	($0.0)	$48.5
Apr	$72.0	($37.1)	$0.0	$34.9	$37.7	($9.9)	$0.0	$27.8
May	$67.2	($18.2)	($0.0)	$49.1	$75.3	($35.8)	($0.0)	$39.5
Jun	$69.6	($12.7)	($0.0)	$56.8	$82.2	($29.4)	($0.0)	$52.8
Jul	$91.0	($17.9)	$0.0	$73.1	$130.5	($21.3)	$0.0	$109.2
Aug	$60.8	($10.6)	$0.0	$50.2	$46.0	($7.4)	$0.0	$38.6
Sep	$61.8	($23.1)	($0.0)	$38.7	$97.0	($42.1)	$0.0	$54.9
Total	$603.2	($178.0)	$0.0	$425.2	$800.5	($291.8)	$0.0	$508.7

Figure 11-3 shows PJM monthly total congestion cost for January 2009 through September 2013.

Figure 11-3 PJM monthly total congestion cost (Dollars (Millions)): January 2009 to September 2013



Congested Facilities

A congestion event exists when a unit or units must be dispatched out of merit order to control the 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 likely exceeds the number of constrained hours and the number of congestion-event hours likely exceeds the number of hours within 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 also consistent with the way in which PJM reports real-time congestion. In the first nine months of 2013, there were 259,605 day-ahead, congestion-event hours compared to 168,509 day-ahead, congestion-event hours in the first nine months of 2012. In the first nine months of 2013, there were 14,249 real-time, congestion-event hours compared to 15,153 real-time, congestion-event hours in the first nine months of 2012.

During the first nine months of 2013, for only 2.0 percent of Day-Ahead Market facility constrained hours were the same facilities also constrained in the Real-Time Market. During the first nine months of 2013, for 37.9 percent of Real-Time Market facility constrained hours, the same facilities were also constrained in the Day-Ahead Market.

The AP South Interface was the largest contributor to congestion costs in the first nine months of 2013. With $144.1 million in total congestion costs, it accounted for 28.3 percent of the total PJM congestion costs in the first nine months of 2013. The top five constraints in terms of congestion costs together contributed $183.8 million, or 36.1 percent, of the total PJM congestion costs in the first nine months of 2013. The top five constraints were the AP South interface, the West interface, the ATSI interface, and the Bridgewater – Middlesex line, and the Cloverdale transformer.

Congestion by Facility Type and Voltage

In the first nine months of 2013, compared to the first nine months of 2012, day-ahead, congestion-event hours increased on all types of facilities. Real-time, congestion-event hours decreased on all types of facilities except internal PJM interfaces.

Day-ahead congestion costs decreased on the flowgates in the first nine months of 2013 compared to the first nine months of 2012 and increased on PJM interfaces, transmission lines and transformers in the first nine months of 2013 compared to the first nine months of 2012. Balancing congestion costs increased on flowgates and decreased on transformers, transmission lines and interfaces in the first nine months of 2013 compared to the first nine months of 2012.

Table 11-19 provides congestion-event hour subtotals and congestion cost subtotals comparing the first nine months of 2013 results by facility type: line, transformer, interface, flowgate and unclassified facilities.[18,19] For comparison, this information is presented in Table 11-20 for the first nine months of 2012.[20]

Table 11-21 and Table 11-22 compare day-ahead and real-time congestion event hours. Among the hours for which a facility is constrained in the Day-Ahead Market, the number of hours during which the facility is also constrained in the Real-Time Market are presented in Table 11-21. In the first nine months of 2013, there were 259,605 congestion event hours in the Day-Ahead Market. Among those, only 5,244 (2.0 percent) were also constrained in the Real-Time Market. In the first nine months of 2012, among the 168,509 day-ahead congestion event hours, only 6,238 (3.7 percent) were binding in the Real-Time Market.[21]

Among the hours for which a facility is constrained in the Real-Time Market, the number of hours during which the facility is also constrained in the Day-Ahead Market are presented in Table 11-22. In the first nine months of 2013, there were 14,249 congestion event hours in the Real-Time Market. Among these, 5,395 (37.9 percent) were also constrained in the Day-Ahead Market. In the first nine months of 2012, among the 15,153 real-time congestion event hours, only 6,123 (40.4 percent) were binding in the Day-Ahead Market.

Table 11-19 Congestion summary (By facility type): January through September 2013

	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	RealTime
Flowgate	($32.6)	($131.1)	$18.7	$117.2	$0.4	$11.8	($36.0)	($47.4)	$69.8	22,653	4,320
Interface	$141.3	($77.8)	$15.1	$234.2	$22.3	$29.1	($35.2)	($42.0)	$192.2	10,748	1,229
Line	$62.4	($204.5)	$54.0	$320.9	($17.5)	$59.4	($93.7)	($170.6)	$150.3	144,886	7,278
Other	$7.2	($2.4)	$6.4	$16.0	($0.4)	$0.1	($3.0)	($3.5)	$12.5	8,880	120
Transformer	$22.2	($56.0)	$21.2	$99.4	$1.6	$9.6	($19.8)	($27.8)	$71.6	72,438	1,302
Unclassified	$25.9	$19.2	$6.2	$12.8	$0.4	$2.1	$1.3	($0.4)	$12.4	NA	NA
Total	$226.3	($452.6)	$121.6	$800.5	$6.8	$112.2	($186.4)	($291.8)	$508.7	259,605	14,249

18 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.

19 The term flowgate refers to MISO flowgates and NYISO flowgates in this section.

20 For 2008 and 2009, the load congestion payments and generation congestion credits represent the net load congestion payments and net generation congestion credits for an organization, as this shows the extent to which each organization's load or generation was exposed to congestion costs.

21 Constraints are mapped to transmission facilities. In the Day-Ahead 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 Market. Similarly in the Real-Time Market a facility may account for more than one constraint-hour within a given hour.

Table 11-20 Congestion summary (By facility type): January through September 2012

	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	($42.4)	($144.3)	$28.4	$130.4	($4.4)	$7.5	($66.6)	($78.5)	$51.9	21,675	5,319
Interface	$48.5	($51.1)	$0.0	$99.6	$12.8	$15.5	($3.3)	($6.1)	$93.6	4,460	421
Line	$65.6	($157.1)	$41.0	$263.7	($8.4)	$18.2	($54.9)	($81.5)	$182.2	101,732	7,708
Other	$9.5	($3.9)	$1.4	$14.8	($0.6)	$0.0	($0.9)	($1.6)	$13.2	5,087	428
Transformer	$29.2	($45.4)	$14.3	$88.9	$4.1	$2.7	($11.6)	($10.1)	$78.8	35,555	1,277
Unclassified	$2.8	($1.4)	$1.6	$5.8	$0.2	$0.2	($0.2)	($0.3)	$5.5	NA	NA
Total	$113.1	($403.3)	$86.7	$603.2	$3.7	$44.1	($137.6)	($178.0)	$425.2	168,509	15,153

Table 11-21 Congestion Event Hours (Day Ahead against Real Time): January through September 2012 to 2013

	Congestion Event Hours					
	2012 (Jan - Sep)			2013 (Jan - Sep)		
Type	Day Ahead Constrained	Corresponding Real Time Constrained	Percent	Day Ahead Constrained	Corresponding Real Time Constrained	Percent
Flowgate	21,675	2,510	11.6%	22,653	1,603	7.1%
Interface	4,460	167	3.7%	10,748	870	8.1%
Line	101,732	2,731	2.7%	144,886	2,217	1.5%
Other	5,087	265	5.2%	8,880	161	1.8%
Transformer	35,555	565	1.6%	72,438	393	0.5%
Total	168,509	6,238	3.7%	259,605	5,244	2.0%

Table 11-22 Congestion Event Hours (Real Time against Day Ahead): January through September 2012 to 2013

	Congestion Event Hours					
	2012 (Jan - Sep)			2013 (Jan - Sep)		
Type	Real Time Constrained	Corresponding Day Ahead Constrained	Percent	Real Time Constrained	Corresponding Day Ahead Constrained	Percent
Flowgate	5,319	2,586	48.6%	4,320	1,739	40.3%
Interface	421	165	39.2%	1,229	952	77.5%
Line	7,708	2,603	33.8%	7,278	2,219	30.5%
Other	428	229	53.5%	120	99	82.5%
Transformer	1,277	540	42.3%	1,302	386	29.6%
Total	15,153	6,123	40.4%	14,249	5,395	37.9%

Table 11-23 shows congestion costs by facility voltage class for the first nine months of 2013. In comparison to the first nine months of 2012 (shown in Table 11-24), congestion costs decreased for facilities rated at 345 kV, 138 kV, and 115 kV in the first nine months of 2013.

Table 11-23 Congestion summary (By facility voltage): January through September 2013

	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	$4.5	($15.7)	$7.6	$27.9	($0.2)	$0.5	$0.8	$0.1	$28.0	7,783	15
500	$141.6	($89.8)	$17.9	$249.2	$27.8	$34.0	($47.1)	($53.2)	$196.0	14,345	1,630
345	($32.4)	($128.2)	$16.1	$111.9	($0.9)	$14.2	($45.4)	($60.5)	$51.4	45,323	3,069
230	$64.4	($113.9)	$38.3	$216.5	($4.5)	$45.5	($48.2)	($98.2)	$118.4	42,397	2,639
161	($4.5)	($9.1)	($0.9)	$3.7	($1.1)	$0.4	($3.0)	($4.5)	($0.8)	1,036	682
138	($13.4)	($119.6)	$33.4	$139.6	($6.2)	$12.4	($41.5)	($60.0)	$79.6	114,898	4,698
123	$5.5	$2.2	$0.8	$4.0	$0.0	$0.0	$0.0	$0.0	$4.0	526	0
115	$13.3	($0.1)	$3.1	$16.5	($2.9)	($0.7)	($4.0)	($6.2)	$10.3	13,597	908
69	$21.5	$2.4	($0.9)	$18.2	($5.8)	$3.7	$0.7	($8.8)	$9.4	13,661	579
34	($0.0)	($0.1)	$0.1	$0.2	$0.0	$0.0	($0.0)	($0.0)	$0.2	6,007	29
12	$0.0	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	32	0
Unclassified	$25.9	$19.2	$6.2	$12.8	$0.4	$2.1	$1.3	($0.4)	$12.4	NA	NA
Total	$226.3	($452.6)	$121.6	$800.5	$6.8	$112.2	($186.4)	($291.8)	$508.7	259,605	14,249

Table 11-24 Congestion summary (By facility voltage): January through September 2012

	Congestion Costs (Millions)										
	Day Ahead				Balancing					Event Hours	
Voltage (kV)	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day Ahead	Real Time
765	($0.1)	($2.8)	$2.6	$5.3	$0.2	($0.1)	($0.1)	$0.1	$5.4	2,256	89
500	$51.6	($59.8)	$1.9	$113.3	$14.1	$15.2	($5.8)	($6.9)	$106.4	7,757	648
345	($33.5)	($103.2)	$14.1	$83.7	$1.0	$6.1	($30.1)	($35.2)	$48.6	22,950	2,254
230	$62.8	($61.0)	$12.4	$136.2	$5.6	$5.9	($22.0)	($22.2)	$113.9	25,427	3,280
161	($11.4)	($17.9)	$4.5	$11.1	($0.8)	$1.5	($9.7)	($11.9)	($0.8)	3,021	1,189
138	($2.2)	($159.5)	$46.6	$203.8	($6.8)	$11.5	($69.1)	($87.3)	$116.5	86,601	6,177
115	$21.1	($2.2)	$2.6	$25.9	($0.4)	$1.5	($1.1)	($3.0)	$22.9	13,155	738
69	$22.0	$4.5	$0.6	$18.2	($9.5)	$2.3	$0.5	($11.3)	$6.8	7,330	776
34	($0.0)	($0.0)	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	0	2
12	($0.0)	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	12	0
Unclassified	$2.8	($1.4)	$1.6	$5.8	$0.2	$0.2	($0.2)	($0.3)	$5.5	NA	NA
Total	$113.1	($403.3)	$86.7	$603.2	$3.7	$44.1	($137.6)	($178.0)	$425.2	168,509	15,153

Constraint Duration

Table 11-25 lists constraints in the first nine months of 2012 and 2013 that were most frequently in effect and Table 11-26 shows the constraints which experienced the largest change in congestion-event hours from the first nine month of 2012 to the first nine months of 2013.

Table 11-25 Top 25 constraints with frequent occurrence: January through September 2012 and 2013

			Event Hours						Percent of Annual Hours					
			Day Ahead			Real Time			Day Ahead			Real Time		
No.	Constraint	Type	2012	2013	Change	2012	2013	Change	2012	2013	Change	2012	2013	Change
1	Sporn	Transformer	11,194	7,742	(3,452)	0	0	0	128%	88%	(40%)	0%	0%	0%
2	Gould Street - Westport	Line	0	6,007	6,007	2	21	19	0%	68%	68%	0%	0%	0%
3	Braidwood	Transformer	0	5,710	5,710	0	0	0	0%	65%	65%	0%	0%	0%
4	AP South	Interface	1,725	4,757	3,032	157	915	758	20%	54%	34%	2%	10%	9%
5	Sunbury	Transformer	0	4,915	4,915	0	0	0	0%	56%	56%	0%	0%	0%
6	Tanners Creek	Transformer	460	4,901	4,441	0	0	0	5%	56%	51%	0%	0%	0%
7	Howard - Shelby	Line	1,992	4,415	2,423	0	0	0	23%	50%	28%	0%	0%	0%
8	Nelson - Cordova	Line	1,587	3,919	2,332	253	238	(15)	18%	45%	26%	3%	3%	(0%)
9	Readington - Roseland	Line	340	3,206	2,866	20	713	693	4%	36%	33%	0%	8%	8%
10	Haurd - Steward	Line	1,213	3,366	2,153	1	0	(1)	14%	38%	24%	0%	0%	(0%)
11	West Moulton-City Of St. Marys	Line	0	3,315	3,315	0	0	0	0%	38%	38%	0%	0%	0%
12	Rockport Works	Transformer	0	2,844	2,844	0	0	0	0%	32%	32%	0%	0%	0%
13	Bridgewater - Middlesex	Line	237	2,395	2,158	1	230	229	3%	27%	25%	0%	3%	3%
14	Zion	Line	211	2,565	2,354	0	0	0	2%	29%	27%	0%	0%	0%
15	Monticello - East Winamac	Flowgate	2,556	1,926	(630)	567	542	(25)	29%	22%	(7%)	6%	6%	(0%)
16	South Cadiz	Transformer	842	2,455	1,613	0	0	0	10%	28%	18%	0%	0%	0%
17	Cloverdale	Transformer	133	2,409	2,276	20	0	(20)	2%	27%	26%	0%	0%	(0%)
18	Mardela - Vienna	Line	206	2,142	1,936	126	199	73	2%	24%	22%	1%	2%	1%
19	Michigan City - Laporte	Flowgate	873	2,304	1,431	40	0	(40)	10%	26%	16%	0%	0%	(0%)
20	Danville - East Danville	Line	1,573	2,267	694	6	3	(3)	18%	26%	8%	0%	0%	(0%)
21	Clinch River	Transformer	0	2,236	2,236	0	0	0	0%	25%	25%	0%	0%	0%
22	Hunlock Creek - A.G.A. Gas	Line	15	2,215	2,200	0	0	0	0%	25%	25%	0%	0%	0%
23	Halifax - Halifax 115	Line	1,195	2,213	1,018	0	0	0	14%	25%	12%	0%	0%	0%
24	Huntingdon - Huntingdon1	Line	2,786	2,202	(584)	0	0	0	32%	25%	(7%)	0%	0%	0%
25	Beckjord	Transformer	0	2,184	2,184	0	0	0	0%	25%	25%	0%	0%	0%

Table 11-26 Top 25 constraints with largest year-to-year change in occurrence: January through September 2012 and 2013

			Event Hours						Percent of Annual Hours					
			Day Ahead			Real Time			Day Ahead			Real Time		
No.	Constraint	Type	2012	2013	Change	2012	2013	Change	2012	2013	Change	2012	2013	Change
1	Gould Street - Westport	Line	0	6,007	6,007	2	21	19	0%	68%	68%	0%	0%	0%
2	Braidwood	Transformer	0	5,710	5,710	0	0	0	0%	65%	65%	0%	0%	0%
3	Sunbury	Transformer	0	4,915	4,915	0	0	0	0%	56%	56%	0%	0%	0%
4	Tanners Creek	Transformer	460	4,901	4,441	0	0	0	5%	56%	51%	0%	0%	0%
5	AP South	Interface	1,725	4,757	3,032	157	915	758	20%	54%	34%	2%	10%	9%
6	Readington - Roseland	Line	340	3,206	2,866	20	713	693	4%	36%	33%	0%	8%	8%
7	Sporn	Transformer	11,194	7,742	(3,452)	0	0	0	128%	88%	(40%)	0%	0%	0%
8	West Moulton-City Of St. Marys	Line	0	3,315	3,315	0	0	0	0%	38%	38%	0%	0%	0%
9	Graceton - Raphael Road	Line	2,494	0	(2,494)	697	0	(697)	28%	0%	(28%)	8%	0%	(8%)
10	Rockport Works	Transformer	0	2,844	2,844	0	0	0	0%	32%	32%	0%	0%	0%
11	Oak Grove - Galesburg	Flowgate	3,021	1,009	(2,012)	1,182	594	(588)	34%	11%	(23%)	13%	7%	(7%)
12	Howard - Shelby	Line	1,992	4,415	2,423	0	0	0	23%	50%	28%	0%	0%	0%
13	Bridgewater - Middlesex	Line	237	2,395	2,158	1	230	229	3%	27%	25%	0%	3%	3%
14	Zion	Line	211	2,565	2,354	0	0	0	2%	29%	27%	0%	0%	0%
15	Nelson - Cordova	Line	1,587	3,919	2,332	253	238	(15)	18%	45%	26%	3%	3%	(0%)
16	Cloverdale	Transformer	133	2,409	2,276	20	0	(20)	2%	27%	26%	0%	0%	(0%)
17	Clinch River	Transformer	0	2,236	2,236	0	0	0	0%	25%	25%	0%	0%	0%
18	Hunlock Creek - A.G.A. Gas	Line	15	2,215	2,200	0	0	0	0%	25%	25%	0%	0%	0%
19	Beckjord	Transformer	0	2,184	2,184	0	0	0	0%	25%	25%	0%	0%	0%
20	Haurd - Steward	Line	1,213	3,366	2,153	1	0	(1)	14%	38%	24%	0%	0%	(0%)
21	Mardela - Vienna	Line	206	2,142	1,936	126	199	73	2%	24%	22%	1%	2%	1%
22	Clover	Transformer	1,564	30	(1,534)	441	36	(405)	18%	0%	(18%)	5%	0%	(5%)
23	Electric Junction - Frontenac	Line	0	1,901	1,901	0	0	0	0%	22%	22%	0%	0%	0%
24	Westvaco - Cross School	Line	87	1,957	1,870	0	0	0	1%	22%	21%	0%	0%	0%
25	Loretto	Transformer	170	2,030	1,860	0	0	0	2%	23%	21%	0%	0%	0%

Constraint Costs

Table 11-27 and Table 11-28 present the top constraints affecting congestion costs by facility for the periods January through September 2013 and 2012.

Table 11-27 Top 25 constraints affecting PJM congestion costs (By facility): January through September 2013

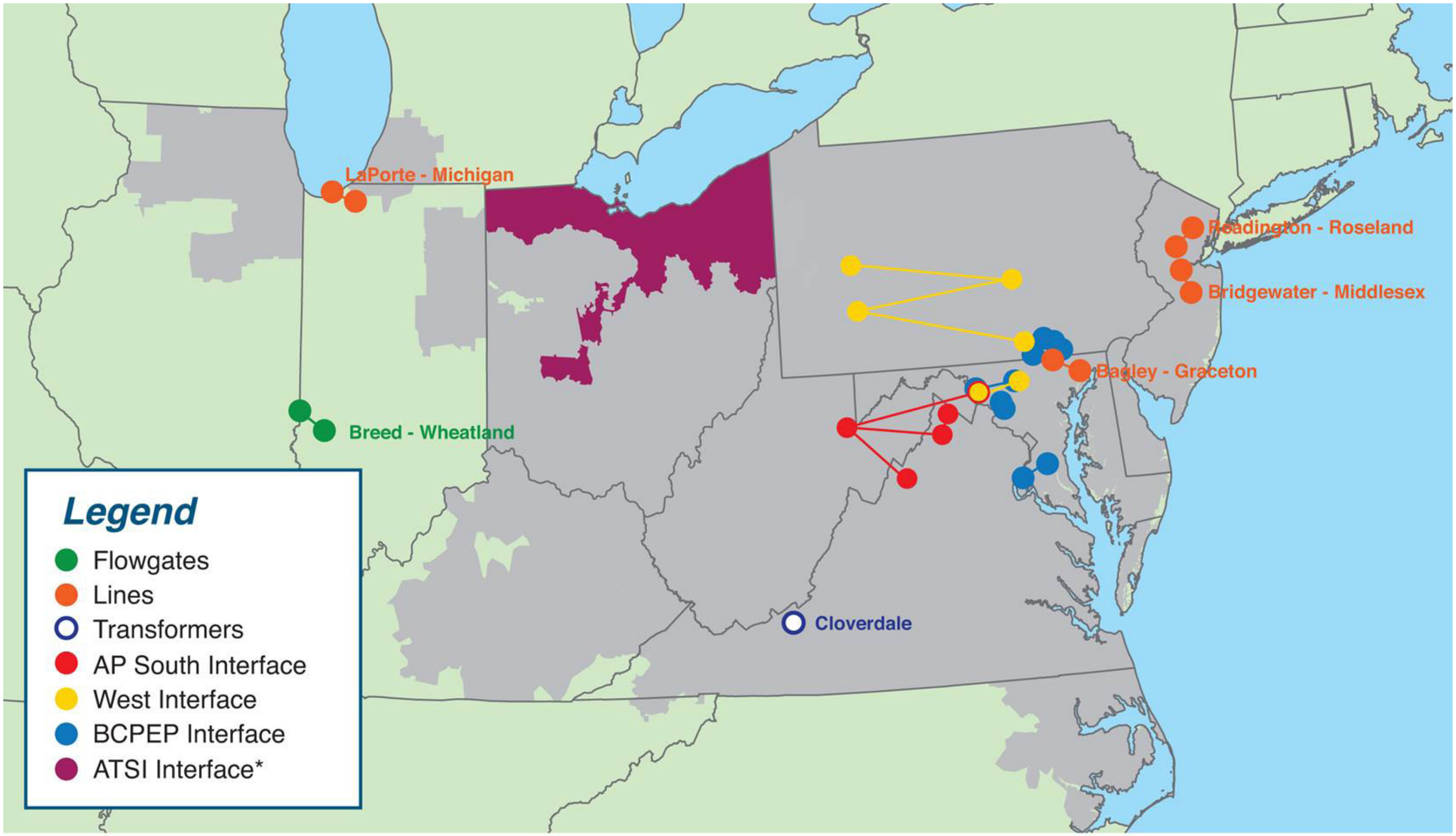
				Congestion Costs (Millions)								Percent of Total PJM Congestion Costs	
				Day Ahead				Balancing					
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	2013 (Jan - Sep)
1	AP South	Interface	500	$116.8	($29.5)	$12.9	$159.2	$7.5	$13.3	($9.2)	($15.1)	$144.1	28.3%
2	West	Interface	500	$3.2	($24.1)	$0.1	$27.4	$2.9	$3.1	($1.1)	($1.2)	$26.2	5.2%
3	ATSI	Interface	ATSI	$0.0	$0.0	$0.0	$0.0	$10.2	$9.0	($24.7)	($23.5)	($23.5)	(4.6%)
4	Bridgewater - Middlesex	Line	PSEG	($0.1)	($23.0)	$1.9	$24.8	$1.8	$4.5	($1.8)	($4.4)	$20.4	4.0%
5	Cloverdale	Transformer	AEP	$8.0	($3.6)	$4.9	$16.5	$0.0	$0.0	$0.0	$0.0	$16.5	3.3%
6	Readington - Roseland	Line	PSEG	($1.8)	($49.5)	$5.2	$52.9	($10.5)	$38.1	($20.7)	($69.3)	($16.3)	(3.2%)
7	BCPEP	Interface	Pepco	$11.8	($1.8)	$1.9	$15.6	$0.0	$0.0	$0.0	$0.0	$15.6	3.1%
8	Breed - Wheatland	Flowgate	MISO	($2.8)	($16.0)	$1.8	$15.0	$0.1	($0.1)	($1.3)	($1.1)	$13.9	2.7%
9	Bagley - Graceton	Line	BGE	$11.1	($0.7)	$1.8	$13.7	$0.3	($1.0)	($1.9)	($0.6)	$13.1	2.6%
10	Laporte - Michigan City	Line	AEP	$0.0	$0.0	$0.0	$0.0	($6.7)	$1.3	($4.9)	($12.9)	($12.9)	(2.5%)
11	Unclassified	Unclassified	Unclassified	$25.9	$19.2	$6.2	$12.8	$0.4	$2.1	$1.3	($0.4)	$12.4	2.4%
12	Clover	Transformer	Dominion	$0.0	$0.0	$0.0	$0.0	($0.2)	$5.1	($6.8)	($12.1)	($12.1)	(2.4%)
13	Monticello - East Winamac	Flowgate	MISO	($2.3)	($26.8)	$4.0	$28.5	$0.2	$5.4	($11.3)	($16.5)	$12.0	2.4%
14	Byron - Cherry Valley	Flowgate	MISO	($3.9)	($14.0)	$0.1	$10.2	$0.0	$0.0	$0.0	$0.0	$10.2	2.0%
15	5004/5005 Interface	Interface	500	$0.8	($11.7)	($0.4)	$12.2	$1.4	$3.9	$0.3	($2.2)	$10.0	2.0%
16	Bedington - Black Oak	Interface	500	$6.1	($3.1)	$0.8	$9.9	$0.1	($0.0)	($0.3)	($0.2)	$9.7	1.9%
17	Crete - St Johns Tap	Flowgate	MISO	($0.5)	($7.1)	$2.7	$9.3	$0.0	$0.0	$0.0	$0.0	$9.3	1.8%
18	South Canton	Transformer	AEP	($3.3)	($11.1)	$1.1	$8.9	($0.2)	$0.5	$0.8	$0.1	$8.9	1.8%
19	Conastone - Graceton	Line	BGE	$5.4	($2.0)	$1.6	$9.0	($0.0)	($0.1)	($0.2)	($0.2)	$8.8	1.7%
20	Byron - Cherry Valley	Line	ComEd	($0.0)	($0.1)	$0.0	$0.1	($1.2)	$2.5	($5.0)	($8.7)	($8.6)	(1.7%)
21	Bedington	Transformer	AP	$3.5	($5.1)	($0.0)	$8.6	$0.0	$0.4	$0.3	($0.1)	$8.5	1.7%
22	Braidwood	Transformer	ComEd	($0.2)	($7.4)	$1.2	$8.4	$0.0	$0.0	$0.0	$0.0	$8.4	1.7%
23	Michigan City - Laporte	Flowgate	MISO	($5.9)	($10.6)	$2.5	$7.2	$0.0	$0.0	$0.0	$0.0	$7.2	1.4%
24	New Dover - Westfield	Line	PSEG	$0.5	($5.8)	$0.9	$7.1	$0.0	$0.0	$0.0	$0.0	$7.1	1.4%
25	AEP - DOM	Interface	500	$4.0	($2.5)	$0.3	$6.8	($0.1)	$0.1	($0.0)	($0.2)	$6.6	1.3%

Table 11-28 Top 25 constraints affecting PJM congestion costs (By facility): January through September 2012

				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	2012 (Jan - Sep)
1	AP South	Interface	500	$36.0	($14.0)	$1.3	$51.3	$7.1	$4.6	($2.9)	($0.4)	$50.9	12.0%
2	Graceton - Raphael Road	Line	BGE	$25.1	($7.8)	($1.6)	$31.3	$0.8	($1.1)	$0.2	$2.1	$33.4	7.9%
3	Woodstock	Flowgate	MISO	($7.0)	($30.2)	$6.8	$30.0	$0.0	$0.0	$0.0	$0.0	$30.0	7.0%
4	Belvidere - Woodstock	Line	ComEd	($0.2)	($4.7)	$0.9	$5.4	($2.4)	$3.2	($16.8)	($22.5)	($17.1)	(4.0%)
5	Clover	Transformer	Dominion	$9.4	($7.5)	$6.7	$23.6	$0.9	$0.7	($8.4)	($8.2)	$15.3	3.6%
6	West	Interface	500	($0.6)	($17.4)	($2.2)	$14.5	$1.2	$1.2	$0.5	$0.4	$15.0	3.5%
7	Monticello - East Winamac	Flowgate	MISO	($0.2)	($18.9)	$11.1	$29.8	$0.4	$2.0	($15.4)	($16.9)	$12.9	3.0%
8	Bedington - Black Oak	Interface	500	$9.0	($4.0)	($0.0)	$13.0	$1.0	$1.1	($0.7)	($0.8)	$12.1	2.9%
9	Loudoun - Gainsville	Line	Dominion	$0.4	($11.0)	($1.2)	$10.2	$0.6	$0.9	$0.2	($0.1)	$10.0	2.4%
10	Northwest	Other	BGE	$7.8	($2.4)	$0.4	$10.6	($0.7)	($0.1)	($0.8)	($1.5)	$9.1	2.1%
11	Nelson - Cordova	Line	ComEd	($16.6)	($29.5)	$5.8	$18.7	($0.9)	$1.6	($7.5)	($10.0)	$8.7	2.0%
12	Hunterstown	Transformer	Met-Ed	$3.4	($4.2)	$0.2	$7.8	$0.1	$0.0	($0.0)	$0.0	$7.8	1.8%
13	Pleasant Valley - Belvidere	Line	ComEd	($2.2)	($8.0)	$1.8	$7.6	$0.1	$0.1	($0.8)	($0.7)	$6.9	1.6%
14	Kammer	Transformer	AEP	($3.0)	($11.2)	($1.3)	$6.9	($0.2)	$0.1	$0.2	($0.0)	$6.9	1.6%
15	Unclassified	Unclassified	Unclassified	$2.8	($1.4)	$1.6	$5.8	$0.2	$0.2	($0.2)	($0.3)	$5.5	1.3%
16	AEP - DOM	Interface	500	$6.0	($2.1)	$0.9	$9.0	$1.0	$4.2	($0.5)	($3.7)	$5.3	1.2%
17	Crescent	Transformer	DLCO	$0.9	($4.3)	($0.2)	$5.1	$0.2	$0.2	($0.1)	$0.0	$5.1	1.2%
18	Belmont	Transformer	AP	$0.6	($5.5)	$0.6	$6.6	($0.4)	$0.8	($0.4)	($1.5)	$5.0	1.2%
19	Plymouth Meeting - Whitpain	Line	PECO	$0.8	($3.9)	($0.1)	$4.6	$0.3	$0.7	$0.5	$0.0	$4.7	1.1%
20	Electric Junction - Nelson	Line	ComEd	($1.3)	($4.2)	$1.7	$4.6	$0.0	$0.0	($0.0)	($0.0)	$4.6	1.1%
21	Silver Lake - Pleasant Valley	Line	ComEd	($2.8)	($6.0)	$1.3	$4.5	$0.0	$0.0	$0.0	$0.0	$4.5	1.1%
22	Buxmont - Whitpain	Line	PECO	($1.1)	($7.0)	($1.5)	$4.3	$0.0	$0.0	$0.0	$0.0	$4.3	1.0%
23	East	Interface	500	($2.6)	($7.9)	($0.6)	$4.7	$0.1	$0.5	($0.1)	($0.5)	$4.2	1.0%
24	5004/5005 Interface	Interface	500	$0.1	($4.0)	$0.4	$4.5	$2.4	$3.2	$0.5	($0.4)	$4.2	1.0%
25	Kenova - Tri State	Line	AEP	$0.4	($3.4)	($0.1)	$3.8	($0.0)	$0.1	$0.1	$0.0	$3.8	0.9%

Figure 11-4 shows the locations of the top 10 constraints affecting PJM congestion costs in the first nine months of 2013.

Figure 11-4 Location of the top 10 constraints affecting PJM congestion costs: January through September 2013[22]



* ATSI is comprised of all tie lines into the ATSI transmission zone.

22 The term flowgate refers to MISO reciprocal coordinated flowgates and NYISO M2M flowgates in this section.

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.[23] A flowgate is a facility or group of facilities that may act as constraint points on the regional system.24 PJM models these coordinated flowgates and controls for them in its security-constrained, economic dispatch. Table 11-29 and Table 11-30 show the MISO flowgates which PJM and/or MISO took dispatch action to control during the first nine months of 2013 and 2012, and which had the greatest congestion cost impact on PJM. 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 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 nine months of 2013, the Breed - Wheatland flowgate made the most significant contribution to positive congestion while the Beaver Channel - Albany flowgate made the most significant contribution to negative congestion.

Table 11-29 Top congestion cost impacts from MISO flowgates affecting PJM dispatch (By facility): January through September 2013

		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	($2.8)	($16.0)	$1.8	$15.0	$0.1	($0.1)	($1.3)	($1.1)	$13.9	1,714	293
2	Monticello - East Winamac	($2.3)	($26.8)	$4.0	$28.5	$0.2	$5.4	($11.3)	($16.5)	$12.0	1,926	542
3	Byron - Cherry Valle	($3.9)	($14.0)	$0.1	$10.2	$0.0	$0.0	$0.0	$0.0	$10.2	72	0
4	Crete - St Johns Tap	($0.5)	($7.1)	$2.7	$9.3	$0.0	$0.0	$0.0	$0.0	$9.3	1,165	0
5	Michigan City - Laporte	($5.9)	($10.6)	$2.5	$7.2	$0.0	$0.0	$0.0	$0.0	$7.2	2,304	0
6	Benton Harbor - Palisades	($1.4)	($7.5)	$2.5	$8.6	($0.1)	$0.8	($2.0)	($2.8)	$5.8	1,700	114
7	Rocky - Battlebo	$5.5	$2.2	$0.8	$4.0	$0.0	$0.0	$0.0	$0.0	$4.0	526	0
8	Rantoul - Rantoul Jct	($3.7)	($5.8)	$1.6	$3.8	$0.0	$0.0	$0.0	$0.0	$3.8	1,673	0
9	Edwards - Kewanee	($2.5)	($4.1)	$2.0	$3.6	$0.0	$0.0	$0.0	$0.0	$3.6	2,095	12
10	Prairie State - W Mt. Vernon	($2.0)	($5.2)	($0.4)	$2.8	($0.0)	($0.1)	$0.7	$0.8	$3.6	1,021	836
11	Beaver Channel - Albany	$0.0	$0.0	$0.0	$0.0	($0.7)	$0.1	($2.6)	($3.4)	($3.4)	0	83
12	Miami Fort	($0.9)	($3.7)	($0.0)	$2.8	$0.0	$0.0	$0.0	$0.0	$2.8	1,098	0
13	Oak Grove - Galesburg	($0.8)	($2.7)	$0.9	$2.8	($0.0)	($0.0)	($0.5)	($0.5)	$2.3	1,278	76
14	Volunteer - Phiipps Bend	$0.0	$0.0	$0.0	$0.0	$0.8	$0.0	($2.9)	($2.1)	($2.1)	0	63
15	Stillwell	$0.0	$0.0	$0.0	$0.0	($0.2)	$0.4	($1.4)	($1.9)	($1.9)	0	64
16	Rantoul Jct - Sidney	$0.0	$0.0	$0.0	$0.0	($0.5)	$0.7	($0.5)	($1.7)	($1.7)	0	193
17	Hennepin	($0.2)	($0.5)	($0.1)	$0.1	($0.2)	$0.0	($1.4)	($1.6)	($1.5)	82	161
18	Pleasant Prairie - Zion	($0.5)	($1.6)	$0.7	$1.8	($0.0)	($0.0)	($0.5)	($0.5)	$1.3	855	76
19	Miami Fort - Hebron	($0.3)	($1.1)	$0.1	$1.0	$0.0	$0.0	$0.0	$0.0	$1.0	423	0
20	Roxana - Praxair	($2.3)	($2.6)	$0.4	$0.7	$0.3	$0.4	($1.4)	($1.4)	($0.7)	648	92

23 See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C." (December 11, 2008) <http://pjm.com/documents/agreements/~/media/documents/agreements/joa-complete.ashx>.

24 See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C." (December 11, 2008), Section 2.2.24 <http://pjm.com/documents/agreements/~/media/documents/agreements/joa-complete.ashx>.

Table 11-30 Top congestion cost impacts from MISO flowgates affecting PJM dispatch (By facility): January through September 2012

		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	Woodstock	($7.0)	($30.2)	$6.8	$30.0	$0.0	$0.0	$0.0	$0.0	$30.0	1,073	0
2	Monticello - East Winamac	($0.2)	($18.9)	$11.1	$29.8	$0.4	$2.0	($15.4)	($16.9)	$12.9	2,556	567
3	Palisades - Roosevelt	($0.8)	($5.1)	($0.6)	$3.7	$0.1	$0.3	($0.2)	($0.4)	$3.3	747	209
4	Crete - St Johns Tap	($4.9)	($15.5)	($1.3)	$9.3	$0.3	$0.9	($5.7)	($6.3)	$3.0	1,916	277
5	Breed - Wheatland	($1.3)	($8.2)	($0.1)	$6.9	$0.3	$0.3	($9.6)	($9.6)	($2.8)	1,269	276
6	Miami Fort - Hebron	($1.4)	($4.2)	($0.2)	$2.6	($0.1)	($0.0)	$0.1	$0.0	$2.6	690	76
7	Benton Harbor - Palisades	($0.4)	($3.5)	($0.8)	$2.4	$0.1	$0.3	($0.2)	($0.4)	$2.0	512	71
8	Rising	($0.3)	($0.3)	$0.0	$0.1	($0.4)	$0.2	($1.1)	($1.6)	($1.5)	48	114
9	Prairie State - W Mt. Vernon	($1.8)	($2.8)	$0.5	$1.5	($0.0)	$0.0	($0.2)	($0.2)	$1.3	511	190
10	Cumberland - Bush	($1.2)	($5.5)	$6.2	$10.5	$0.4	$1.2	($10.9)	($11.7)	($1.2)	2,053	313
11	Edwards - Kewanee	($0.2)	($0.9)	$0.5	$1.1	$0.0	($0.1)	($0.2)	($0.1)	$1.0	224	59
12	Rantoul - Rantoul Jct	($2.3)	($4.8)	$0.3	$2.8	($0.2)	($0.1)	($1.7)	($1.9)	$0.9	1,075	315
13	Oak Grove - Galesburg	($11.4)	($17.9)	$4.5	$11.1	($0.8)	$1.5	($9.6)	($11.8)	($0.7)	3,021	1,182
14	Pana North	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($0.7)	($0.7)	($0.7)	0	12
15	Bunsonville - Eugene	($0.7)	($1.1)	$0.2	$0.7	$0.0	($0.1)	($0.1)	($0.0)	$0.7	236	42
16	Dunes Acres - Michigan City	($0.2)	($0.3)	$0.1	$0.2	($0.2)	($0.0)	($0.7)	($0.9)	($0.7)	180	11
17	Bush - Lafayette	$0.0	$0.0	$0.0	$0.0	$0.0	$0.1	($0.6)	($0.7)	($0.7)	0	23
18	Michigan City - Laporte	($0.8)	($2.3)	($0.3)	$1.1	($0.3)	($0.1)	($0.3)	($0.5)	$0.6	873	40
19	Brokaw - Gibson	($0.5)	($0.9)	$0.2	$0.6	$0.0	$0.0	$0.0	$0.0	$0.6	160	0
20	Sheffield - Marktown	($1.1)	($2.1)	$0.2	$1.2	$0.2	$0.5	($0.3)	($0.7)	$0.5	1,055	10

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.[25] 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.[26]

25 See "Joint Operating Agreement Among and Between the New York Independent System Operator Inc. and PJM Interconnection, L.L.C." (January 17, 2013) Section 35.3.1 <http://www.pjm.com/~/media/documents/agreements/nyiso-pjm.ashx> (Accessed April 17, 2013).

26 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 April 17, 2013).

Table 11-31 shows the NYISO flowgates which PJM and/or NYISO took dispatch action to control during the first nine months of 2013, and which had the greatest congestion cost impact on PJM.

Table 11-31 Top congestion cost impacts from NYISO flowgates affecting PJM dispatch (By facility): January through September 2013

				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	$0.3	($1.2)	($0.2)	$1.3	$0.6	$2.1	($1.4)	($2.9)	($1.6)	48	167
2	Dysinger East	Flowgate	NYISO	$0.0	$0.0	$0.0	$0.0	$0.1	$0.1	($0.1)	($0.2)	($0.2)	0	21

Congestion-Event Summary for the 500 kV System

Constraints on the 500 kV system generally have a regional impact. Table 11-32 and Table 11-33 show the 500 kV constraints impacting congestion costs in PJM for the first nine months of 2013 and 2012. 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 impacting congestion costs in PJM are presented by constraint, in descending order of the absolute value of total congestion costs.

Table 11-32 Regional constraints summary (By facility): January through September 2013

				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	$116.8	($29.5)	$12.9	$159.2	$7.5	$13.3	($9.2)	($15.1)	$144.1	4,757	915
2	West	Interface	500	$3.2	($24.1)	$0.1	$27.4	$2.9	$3.1	($1.1)	($1.2)	$26.2	1,387	79
3	5004/5005 Interface	Interface	500	$0.8	($11.7)	($0.4)	$12.2	$1.4	$3.9	$0.3	($2.2)	$10.0	505	150
4	Bedington - Black Oak	Interface	500	$6.1	($3.1)	$0.8	$9.9	$0.1	($0.0)	($0.3)	($0.2)	$9.7	1,172	16
5	AEP - DOM	Interface	500	$4.0	($2.5)	$0.3	$6.8	($0.1)	$0.1	($0.0)	($0.2)	$6.6	1,317	10
6	Conemaugh - Hunterstown	Line	500	$0.4	($2.6)	$0.3	$3.4	$0.5	$0.7	($0.7)	($0.9)	$2.5	153	68
7	Central	Interface	500	($0.9)	($3.3)	($0.4)	$2.0	$0.0	$0.0	$0.0	$0.0	$2.0	167	0
8	East	Interface	500	($0.5)	($1.7)	($0.0)	$1.2	$0.0	$0.0	$0.0	$0.0	$1.2	254	0
9	Juniata	Transformer	500	$0.2	($0.3)	$0.2	$0.7	$0.4	$0.1	($0.4)	($0.1)	$0.6	0	4
10	Nagel - Phipps Bend	Line	500	$0.0	($0.0)	$0.1	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	22	0
11	Cloverdale - Lexington	Line	500	$0.0	$0.0	$0.0	$0.0	$0.0	($0.1)	($0.1)	$0.0	$0.0	0	6
12	EAST	Interface	500	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	($0.0)	($0.0)	($0.0)	0	4

Table 11-33 Regional constraints summary (By facility): January through September 2012

				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	$36.0	($14.0)	$1.3	$51.3	$7.1	$4.6	($2.9)	($0.4)	$50.9	1,725	157
2	West	Interface	500	($0.6)	($17.4)	($2.2)	$14.5	$1.2	$1.2	$0.5	$0.4	$15.0	369	17
3	Bedington - Black Oak	Interface	500	$9.0	($4.0)	($0.0)	$13.0	$1.0	$1.1	($0.7)	($0.8)	$12.1	421	54
4	AEP - DOM	Interface	500	$6.0	($2.1)	$0.9	$9.0	$1.0	$4.2	($0.5)	($3.7)	$5.3	1,340	59
5	East	Interface	500	($2.6)	($7.9)	($0.6)	$4.7	$0.1	$0.5	($0.1)	($0.5)	$4.2	190	5
6	5004/5005 Interface	Interface	500	$0.1	($4.0)	$0.4	$4.5	$2.4	$3.2	$0.5	($0.4)	$4.2	160	121
7	Juniata	Transformer	500	$0.4	($0.6)	$0.3	$1.3	$0.2	$0.0	($0.2)	($0.1)	$1.2	0	0
8	Central	Interface	500	($0.8)	($1.4)	$0.1	$0.8	$0.0	$0.0	($0.0)	($0.0)	$0.8	184	2
9	Cloverdale - Lexington	Line	500	$0.0	$0.0	$0.0	$0.0	$0.1	$0.1	($0.8)	($0.8)	($0.7)	7	61
10	Nagel	Line	500	$0.1	($0.0)	($0.0)	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	30	0
11	Kammer	Transformer	500	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	$0.0	$0.0	0	19
12	Branchburg - Elroy	Line	500	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	2	0

Congestion Costs by Physical and Financial Participants

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

In the first nine months of 2013, financial companies as a group were net recipients of congestion credits, and physical companies were net payers of congestion charges.[27] In the first nine months of 2013, financial companies received $84.1 million, an increase of $16.8 million or 25.0 percent compared to the first nine months of 2012. In the first nine months of 2013, physical companies paid $592.8 million in congestion charges, an increase of $100.3 million or 20.4 percent compared to the first nine months of 2012.

Table 11-34 Congestion cost by type of the participant: January through September 2013

	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	$41.6	$35.7	$77.3	$83.2	($28.3)	$0.9	($138.1)	($167.3)	$0.0	($84.1)
Physical	$184.7	($488.4)	$44.3	$717.3	$35.1	$111.3	($48.4)	($124.5)	$0.0	$592.8
Total	$226.3	($452.6)	$121.6	$800.5	$6.8	$112.2	($186.4)	($291.8)	$0.0	$508.7

Table 11-35 Congestion cost by type of the participant: January through September 2012

	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	($1.7)	$3.2	$54.5	$49.5	($19.8)	($5.5)	($102.5)	($116.8)	$0.0	($67.3)
Physical	$114.8	($406.6)	$32.2	$553.6	$23.5	$49.6	($35.1)	($61.2)	$0.0	$492.5
Total	$113.1	($403.3)	$86.7	$603.2	$3.7	$44.1	($137.6)	($178.0)	$0.0	$425.2

27 The total zonal congestion numbers were calculated as of April 15, 2013 and are, based on continued PJM billing updates, subject to change.