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 six months of 2013 were 8,622 GWh, a 6.5 percent increase compared to the first six 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 six months of 2013 decreased by $70.6 million or 26.9 percent from the first six months of 2012, from -$262.0 million to -$332.6 million. Day-ahead net energy costs in the first six months of 2013 decreased by $110.4 million or 45.6 percent from the first six months of 2012, from -$241.9 million to -$352.2 million. Balancing net energy costs in the first six months of 2013 increased by $48.5 million or 177.2 percent from the first six months of 2012, from -$27.4 million to $21.1 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 six months of 2013 ranged from -$63.0 million in January to -$46.5 million in April.

Marginal Loss Cost

- **Total Marginal Loss Costs.** Total marginal loss costs in the first six months of 2013 increased by $49.6 million or 11.2 percent from the first six months of 2012, from $444.9 million to $494.5 million. Day-ahead net marginal loss costs in the first six months of 2013 increased by $79.5 million or 17.1 percent from the first six months of 2012, from $466.5

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 July 18, 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 $546.0 million. Balancing net marginal loss costs decreased in the first six months of 2013 by $29.9 million or 138.5 percent from the first six months of 2012, from -$21.6 million to -$51.5 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 six months of 2013 ranged from $66.2 million in April to $101.1 million in January.
- **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 six months of 2013 by $20.8 million or 11.4 percent from the first six months of 2012, from $182.1 million to $161.3 million.

Congestion Cost

- **Total Congestion.** Total congestion costs increased by $42.8 million or 16.3 percent, from $263.3 million in the first six months of 2012 to $306.1 million in the first six months of 2013.[6]
- **Day-Ahead Congestion.** Day-ahead congestion costs increased by $137.5 million or 35.3 percent, from $389.6 million in the first six months of 2012 to $527.1 million in the first six months of 2013.
- **Balancing Congestion.** Balancing congestion costs decreased by $94.7 million or 74.9 percent from -$126.4 million in the first six months of 2012 to -$221.1 million in the first six months of 2013.
- **Monthly Congestion.** Monthly congestion costs in the first six months of 2013 ranged from $27.8 million in April to $77.4 million in February.
- **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 Readington - Roseland and Laporte – Michigan line, the Cloverdale transformers, and the West Interface. (Table 10-27)
- **Congested Facilities.** Congestion frequency continued to be significantly higher in the Day-Ahead Market than in the Real-Time Market in the first six months of 2013. Day-ahead congestion frequency increased by 62.8 percent from 106,904 congestion event hours in the first six months of 2012 to 174,063 congestion event hours in the first six months of 2013. Day-ahead, congestion-event hours decreased on the flowgates while congestion frequency on internal PJM interfaces, transmission lines and transformers increased.

  Real-time congestion frequency increased by 7.8 percent from 9,260 congestion event hours in the first six months of 2012 to 9,984 congestion event hours in the first six months of 2013. Real-time, congestion-event hours increased on the flowgates, the interfaces, and the transformers, and the transmission lines.

  Facilities were constrained in the Day-Ahead Market more frequently than in the Real-Time Market. In the first six months of 2013, for only 2.1 percent of Day-Ahead Market facility constrained hours were the same facilities also constrained in the Real-Time Market. In the first six months of 2013, for 38.0 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 six months of 2013. With $104.3 million in total congestion costs, it accounted for 34.1 percent of the total PJM congestion costs in the first six months of 2013. The top five constraints in terms of congestion costs together contributed $132.2 million, or 43.2 percent, of the total PJM congestion costs in the first six months of 2013. The top five constraints

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 July 18, 2013, and are based on continued PJM billing updates, subject to change.

were the AP South and West interfaces, the Readington – Roseland and the Laporte – Michigan transmission lines, and the Cloverdale transformer.

- **Zonal Congestion.** ComEd was the most congested zone in the first six months of 2013. ComEd had -$201.9 million in total load costs, -$277.4 million in total generation credits and -$8.6 million in explicit congestion, resulting in $66.9 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 AP South interface, the Braidwood transformer, the Crete - St Johns Tap and Prairie State - W Mt. Vernon flowgates and the Braidwood - East Frankfort line contributed $25.6 million, or 38.3 percent of the total ComEd Control Zone congestion costs.

  The AP Control Zone was the second most congested zone in PJM in the first six months of 2013, with $50.2 million. The AP South interface contributed $33.4 million or 66.5 percent of the total AP Control Zone congestion cost in first six months of 2013. The Dominion Control Zone was the third most congested zone in PJM in the first six months of 2013, with a cost of $39.7 million.

- **Ownership.** In the first six 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 six months of 2013, financial companies received $54.3 million in net congestion credits, an increase of $11.5 million or 26.6 percent compared to the first six months of 2012. In the first six months of 2013, physical companies paid $360.7 million in net congestion charges, an increase of $54.3 million or 17.7 percent compared to the first six 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 six months of 2013 compared to the first six months of 2012. Total marginal loss costs increased in the first six months of 2013 by $49.6 million or 11.2 percent from the first six months of 2012, from $444.9 million to $494.5 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 88.8 percent of the total congestion costs in the Day-Ahead Energy Market and the balancing energy market within PJM for the 2011 to 2012 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 80.6 percent of the target allocation level for the 2011 to 2012 planning period, and at 67.8 percent of the target allocation level for the 2012 to 2013 planning period.[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 2011 to 2012 and 2012 to 2013."

Locational Marginal Price (LMP)

Components

Table 10-1 shows the PJM real-time, load-weighted average LMP components for the first six months of 2009 to 2013. The load-weighted average real-time LMP increased $6.75 or 21.9 percent from $31.21 in the first six months of 2012 to $37.96 in the first six months of 2013. The load-weighted average congestion component decreased $0.01 or 35.9 percent from $0.04 in the first six months of 2012 to $0.02 in the first six months of 2013. The load-weighted average loss component increased $0.01 or 145.8 percent from $0.01 in the first six months of 2012 to $0.02 in the first six months of 2013. The load-weighted average energy component increased $6.75 or 21.7 percent from $31.17 in the first six months of 2012 to $37.92 in the first six months of 2013.

Table 10-1 PJM real-time, load-weighted average LMP components (Dollars per MWh): January through June of 2009 through 2013

(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

Table 10-2 shows the PJM day-ahead, load-weighted average LMP components for the first six months of 2009 through 2013. The load-weighted average day-ahead LMP increased $6.40 or 20.1 percent from $31.83 in the first six months of 2012 to $38.23 in the first six months of 2013. The load-weighted average congestion component decreased $0.01 or 13.0 percent from $0.10 in the first six months of 2012 to $0.09 in the first six months of 2013. The load-weighted average loss component increased $0.03 or 113.0 percent from -$0.02 in the first six months of 2012 to $0.00 in the first six months of 2013. The load-weighted average energy component increased $6.39 or 20.1 percent from $31.76 in the first six months of 2012 to $38.14 in the first six months of 2013.

Table 10-2 PJM day-ahead, load-weighted average LMP components (Dollars per MWh): January through June of 2009 through 2013

(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	$31.83	$31.76	$0.10	($0.02)
2013	$38.23	$38.14	$0.09	$0.00

Zonal Components

The real-time components of LMP for each PJM control zone are presented in Table 10-3 for the first six months of 2012 and 2013. The day-ahead components of LMP for each control zone are presented in Table 10-4 for the first six months of 2012 and 2013.

Table 10-3 Zonal and PJM real-time, load-weighted average LMP components (Dollars per MWh): January through June of 2012 and 2013

	2012 (Jan-Jun)				2013 (Jan-Jun)			
	Real-Time LMP	Energy Component	Congestion Component	Loss Component	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AECO	$31.72	$31.37	($0.59)	$0.94	$39.42	$37.91	$0.04	$1.48
AEP	$29.98	$30.95	($0.33)	($0.64)	$35.98	$37.77	($0.96)	($0.84)
AP	$31.50	$31.10	$0.35	$0.05	$37.49	$37.87	($0.25)	($0.12)
ATSI	$30.32	$31.02	($0.79)	$0.09	$37.08	$37.78	($1.02)	$0.32
BGE	$36.38	$31.39	$3.48	$1.51	$43.07	$38.15	$3.14	$1.78
ComEd	$28.09	$31.05	($1.49)	($1.47)	$32.58	$37.72	($3.21)	($1.94)
DAY	$30.81	$31.12	($0.51)	$0.20	$36.33	$37.94	($1.62)	$0.00
DEOK	$29.41	$31.13	($0.43)	($1.29)	$34.56	$37.92	($1.60)	($1.75)
DLCO	$30.31	$31.02	$0.11	($0.83)	$34.89	$37.83	($1.62)	($1.32)
Dominion	$33.09	$31.42	$1.25	$0.42	$40.58	$38.20	$1.94	$0.44
DPL	$33.74	$31.35	$1.10	$1.28	$40.43	$38.10	$0.46	$1.87
EKPC	NA	NA	NA	NA	$34.68	$37.71	($1.12)	($1.91)
JCPL	$32.41	$31.63	($0.21)	$0.99	$40.84	$38.24	$0.98	$1.62
Met-Ed	$31.62	$31.20	$0.03	$0.39	$38.87	$37.96	$0.19	$0.72
PECO	$31.33	$31.26	($0.55)	$0.62	$38.42	$37.94	($0.45)	$0.93
PENELEC	$31.17	$30.89	($0.19)	$0.47	$38.30	$37.69	$0.10	$0.50
Pepco	$35.43	$31.42	$3.03	$0.97	$42.42	$38.21	$2.94	$1.27
PPL	$31.09	$31.14	($0.45)	$0.40	$38.50	$37.89	($0.04)	$0.65
PSEG	$32.14	$31.30	($0.24)	$1.08	$44.76	$37.93	$5.41	$1.42
RECO	$31.86	$31.79	($0.90)	$0.97	$47.44	$38.34	$7.79	$1.32
PJM	$31.21	$31.17	$0.04	$0.01	$37.96	$37.92	$0.02	$0.02

Table 10-4 Zonal and PJM day-ahead, load-weighted average LMP components (Dollars per MWh): January through June of 2012 and 2013

	2012 (Jan-Jun)				2013 (Jan-Jun)			
	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AECO	$33.09	$32.13	($0.04)	$1.01	$39.70	$38.26	($0.08)	$1.53
AEP	$30.56	$31.57	($0.28)	($0.74)	$36.19	$38.02	($1.00)	($0.84)
AP	$32.01	$31.68	$0.26	$0.08	$37.52	$38.09	($0.44)	($0.13)
ATSI	$30.75	$31.60	($0.75)	($0.09)	$37.05	$38.11	($1.18)	$0.13
BGE	$37.29	$32.07	$3.46	$1.76	$43.19	$38.34	$3.12	$1.72
ComEd	$28.11	$31.72	($1.74)	($1.87)	$33.25	$38.04	($2.83)	($1.96)
DAY	$31.43	$31.84	($0.46)	$0.05	$36.75	$38.22	($1.37)	($0.10)
DEOK	$29.90	$31.69	($0.26)	($1.53)	$35.11	$38.08	($1.38)	($1.59)
DLCO	$31.20	$31.71	$0.34	($0.85)	$35.24	$38.12	($1.55)	($1.33)
Dominion	$33.91	$32.06	$1.29	$0.56	$40.78	$38.50	$1.92	$0.35
DPL	$34.55	$32.07	$0.86	$1.62	$40.73	$38.24	$0.58	$1.92
EKPC	NA	NA	NA	NA	$35.28	$38.38	($1.16)	($1.93)
JCPL	$33.38	$32.22	$0.07	$1.09	$41.07	$38.42	$0.93	$1.71
Met-Ed	$32.25	$31.62	$0.20	$0.43	$38.94	$37.99	$0.29	$0.67
PECO	$32.34	$31.89	($0.25)	$0.70	$38.82	$38.11	($0.24)	$0.95
PENELEC	$31.97	$31.45	($0.09)	$0.61	$38.92	$37.95	$0.24	$0.73
Pepco	$36.10	$31.93	$2.85	$1.32	$42.49	$38.21	$3.04	$1.24
PPL	$31.65	$31.63	($0.30)	$0.32	$38.73	$38.01	$0.13	$0.58
PSEG	$33.46	$32.04	$0.12	$1.29	$44.93	$38.32	$4.98	$1.62
RECO	$32.87	$32.23	($0.42)	$1.06	$46.74	$38.39	$6.90	$1.44
PJM	$31.83	$31.76	$0.10	($0.02)	$38.23	$38.14	$0.09	$0.00

Component Costs

Table 10-5 shows the total energy, loss and congestion component costs and the total PJM billing for the first six months of 2009 through 2013. These totals are actually net energy, loss and congestion costs.

Table 10-5 Total PJM costs by component (Dollars (Millions)): January through June of 2009 through 2013[8, 9]

	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)	$495	$306	$468	$15,571	3.0%

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 six months of 2013 was -$332.6 million, which was comprised of load energy payments of $20,488.2 million, generation energy credits of $20,819.3 million, explicit energy costs of $0.0 million and inadvertent energy charges of -$1.5 million. The monthly energy costs for the first six months of 2013 ranged from -$63.0 million in January to -$46.5 million in April.

Total Energy Costs

Table 10-6 shows total energy component costs and total PJM billing, for the first six 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.

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.

Table 10-6 Total PJM costs by energy component (Dollars (Millions)): January through June of 2009 through 2013[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)	$495	$306	$468	$15,571	3.0%

Energy costs for the first six months of 2009 through 2013 are shown in Table 10-7 and Table 10-8. Table 10-7 shows PJM energy costs by category for the first six months of 2009 through 2013 and Table 10-8 shows PJM energy costs by market category for the first six months of 2009 through 2013. These energy costs are the actual total energy costs rather than the net energy costs in Table 10-6.

Table 10-7 Total PJM energy costs by category (Dollars (Millions)): January through June of 2009 through 2013

	Energy Costs (Millions)				
(Jan-Jun)	Load Payments	Generation Credits	Explicit	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)

11 The Energy Costs include net inadvertent charges.

Table 10-8 Total PJM energy costs by market category (Dollars (Millions)): January through June of 2009 through 2013

	Energy Costs (Millions)									
	Day Ahead				Balancing					
(Jan-Jun)	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	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	$21.1	($1.5)	($332.6)

Monthly Energy Costs

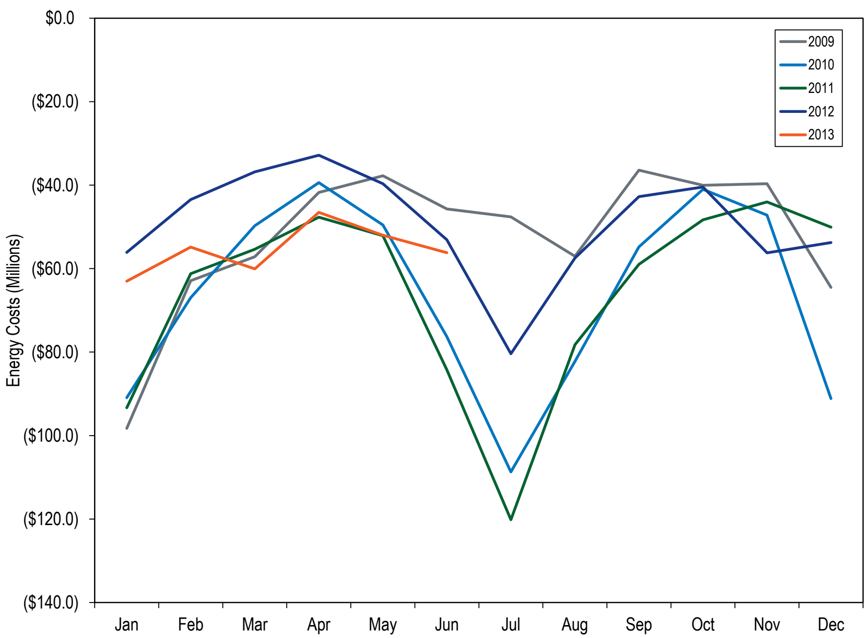
Table 10-9 shows a monthly summary of energy costs by type for the first six months of 2012 and 2013.

Table 10-9 Monthly energy costs by type (Dollars (Millions)): January through June 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)
Total	($241.9)	($27.4)	$7.2	($262.0)	($352.2)	$21.1	($1.5)	($332.6)

Figure 10-1 shows PJM monthly energy costs of January 2009 through June 2013.

Figure 10-1 PJM monthly energy costs (Dollars (Millions)): January 2009 through June 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 six months of 2013 was $494.5 million, which was comprised of load loss payments of $8.6 million, generation loss credits of -$512.4 million, explicit loss costs of -$26.5 million and inadvertent loss charges of -$0.0 million. Monthly marginal loss costs in the first six months of 2013 ranged from $66.2 million in April to $101.1 million in January. Marginal loss credits decreased in the first six months of 2013 by $20.8 million or 11.4 percent from the first six months of 2012, from $182.1 million to $161.3 million.

Total Marginal Loss Costs

Table 10-10 shows the total marginal loss component costs for the first six 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 10-10 Total PJM costs by loss component (Dollars (Millions)): January through June of 2009 through 2013[12, 13]

(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	$495	11.2%	$15,571	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 six months of 2009 through 2013 are shown in Table 10-11 and Table 10-12. Table 10-11 shows PJM total marginal loss costs by category for the first six months of 2009 through 2013. Table 10-12 shows PJM total marginal loss costs by market category for the first six months of 2009 through 2013.

Table 10-11 Total PJM marginal loss costs by category (Dollars (Millions)): January through June of 2009 through 2013

	Marginal Loss Costs (Millions)				
(Jan-Jun)	Load Payments	Generation Credits	Explicit	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

Table 10-12 Total PJM marginal loss costs by market category (Dollars (Millions)): January through June of 2009 through 2013

	Marginal Loss Costs (Millions)									
	Day Ahead				Balancing					
(Jan-Jun)	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	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)	($51.5)	($0.0)	$494.5

Monthly Marginal Loss Costs

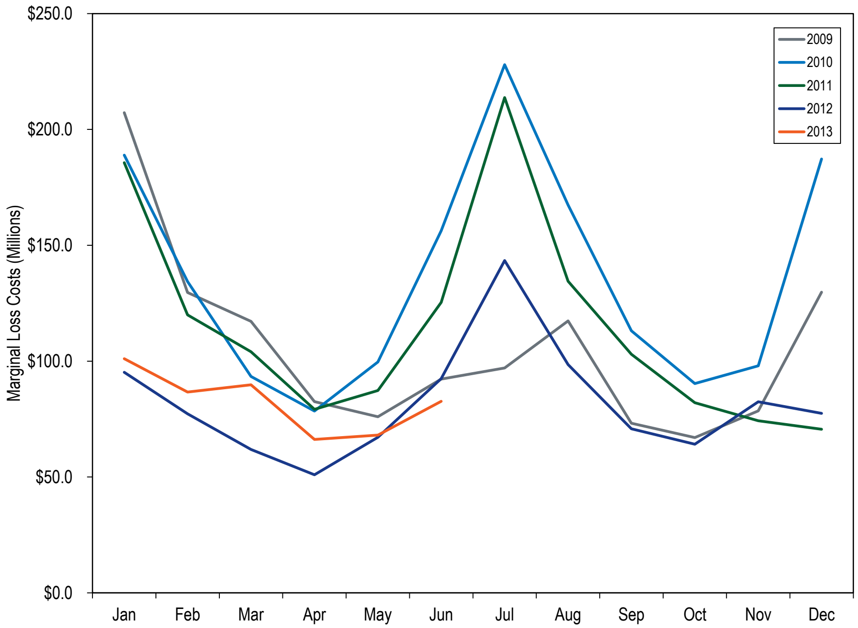
Table 10-13 shows a monthly summary of marginal loss costs by type for the first six months of 2012 and 2013.

Table 10-13 Monthly marginal loss costs by type (Dollars (Millions)): January through June 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
Total	$466.5	($21.6)	$0.0	$444.9	$546.0	($51.5)	($0.0)	$494.5

Figure 10-2 shows PJM monthly marginal loss costs of January 2009 through June 2013.

Figure 10-2 PJM monthly marginal loss costs (Dollars (Millions)): January 2009 through June 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 10-14 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 six months of 2009 through 2013. The total marginal loss credits decreased $20.8 million in the first six months of 2013 from the first six months of 2012.

Table 10-14 Marginal loss credits (Dollars (Millions)): January through June, 2009 through 2013[14]

	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

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.

Congestion

Congestion Accounting

Total congestion costs in PJM in the first six months of 2013 were $306.1 million, which was comprised of load congestion payments of $124.8 million, generation credits of -$215.7 million and explicit congestion of -$34.5 million (Table 10-16).

Total Congestion

Table 10-15 shows total congestion from January through June by year from 2008 through 2013.[15]

Table 10-15 Total PJM congestion (Dollars (Millions)): January through June, 2008 to 2013

	Congestion Costs (Millions)			
(Jan - Jun)	Congestion Cost	Percent Change	Total PJM Billing	Percent of PJM Billing
2008	$1,166.1	NA	$16,549	7.0%
2009	$408.2	(65.0%)	$13,457	3.0%
2010	$644.0	57.8%	$16,314	3.9%
2011	$570.0	(11.5%)	$18,685	3.1%
2012	$263.3	(53.8%)	$13,991	1.9%
2013	$306.1	16.3%	$15,571	2.0%

Total congestion costs in Table 10-16 include congestion costs associated with PJM facilities and those associated with reciprocal, coordinated flowgates in the MISO and in the NYISO.[16, 17]

Table 10-16 shows the congestion costs by category for the first six months of 2013. The January through June 2013 PJM total congestion costs were comprised of $124.8 million in load congestion payments, -$215.7 million in generation congestion credits, and -$34.5 million in explicit congestion costs.

Table 10-16 Total PJM congestion costs by category (Dollars (Millions)): January through June, 2008 to 2013

	Congestion Costs (Millions)				
(Jan - Jun)	Load Payments	GenerationCredits	Explicit Costs	Inadvertent Charges	Total
2008	$625.2	($521.3)	$19.6	$0.0	$1,166.1
2009	$142.3	($301.8)	($35.9)	$0.0	$408.2
2010	$144.2	($525.5)	($25.8)	($0.0)	$644.0
2011	$287.1	($364.3)	($81.4)	$0.0	$570.0
2012	$51.8	($247.9)	($36.4)	$0.0	$263.3
2013	$124.8	($215.7)	($34.5)	($0.0)	$306.1

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 10-17 Total PJM congestion costs by market category (Dollars (Millions)): January through June, 2008 to 2013

	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)	$306.1

Monthly Congestion

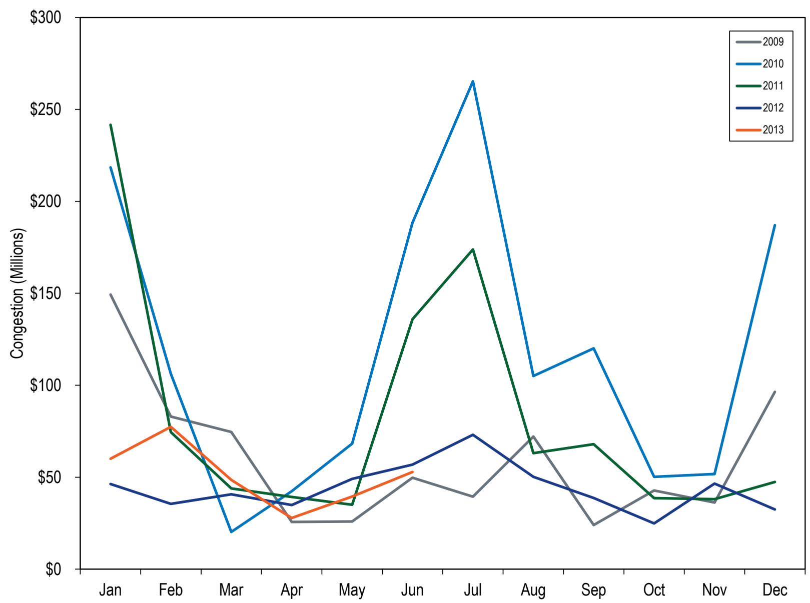
Table 10-18 shows that during the first six months of 2012 and 2013, monthly congestion costs ranged from $27.8 million to $77.4 million in 2013. Table 10-18 shows the monthly congestion costs in the first six months of 2013 were higher than in the first six months of 2012.

Table 10-18 Monthly PJM congestion costs by market type (Dollars (Millions)): January through June, 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	($19.1)	$0.0	$40.7	$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
Total	$389.6	($126.4)	$0.0	$263.3	$527.1	($221.1)	($0.0)	$306.1

Figure 10-3 shows PJM monthly congestion for January 2009 through June 2013.

Figure 10-3 PJM monthly congestion (Dollars (Millions)): January 2009 to June 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 six months of 2013, there were 174,063 day-ahead, congestion-event hours compared to 106,904 day-ahead, congestion-event hours in the first six months of 2012. In the first six months of 2013, there were 9,984 real-time, congestion-event hours compared to 9,260 real-time, congestion-event hours in the first six months of 2012.

During the first six months of 2013, for only 2.1 percent of Day-Ahead Market facility constrained hours were the same facilities also constrained in the Real-Time Market. During the first six months of 2013, for 38.0 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 six months of 2013. With $104.3 million in total congestion costs, it accounted for 34.1 percent of the total PJM congestion costs in the first six months of 2013. The top five constraints contributed $132.2 million, or 43.2 percent, of the total PJM congestion costs in the first six months of 2013. The top five constraints were the AP South and West interfaces, the Readington – Roseland and the Laporte – Michigan transmission line, and the Cloverdale transformer.

Congestion by Facility Type and Voltage

In the first six months of 2013, compared to the first six months of 2012, day-ahead, congestion-event hours decreased on the flowgates, while congestion frequency on internal PJM interfaces, transmission lines and transformers increased. Real-time, congestion-event hours increased on all types of facilities.

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

Table 10-19 provides congestion-event hour subtotals and congestion cost subtotals comparing the first six months of 2013 results by facility type: line, transformer, interface, flowgate and unclassified facilities.[18, 19] For comparison, this information is presented in Table 10-20 for the first six months of 2012.[20]

Table 10-19 Congestion summary (By facility type): January through June 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	Real Time
Flowgate	($17.7)	($72.3)	$13.1	$67.7	$0.6	$10.4	($32.0)	($41.8)	$25.9	11,963	3,553
Interface	$95.5	($56.8)	$6.5	$158.8	$8.8	$18.0	($2.9)	($12.1)	$146.7	6,744	830
Line	$32.2	($143.3)	$41.3	$216.8	($17.1)	$52.9	($72.6)	($142.7)	$74.2	99,748	4,715
Other	$3.8	($1.7)	$5.5	$11.0	($0.0)	$0.0	$0.0	($0.0)	$11.0	6,884	5
Transformer	$15.7	($28.6)	$14.5	$58.7	($0.7)	$7.9	($17.2)	($25.8)	$33.0	48,724	881
Unclassified	$3.7	($3.4)	$7.0	$14.1	($0.1)	$1.0	$2.4	$1.3	$15.3	NA	NA
Total	$133.2	($306.1)	$87.8	$527.1	($8.4)	$90.4	($122.3)	($221.1)	$306.1	174,063	9,984

Table 10-20 Congestion summary (By facility type): January through June 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	($28.2)	($99.0)	$29.6	$100.4	($0.5)	$6.7	($56.9)	($64.1)	$36.4	13,771	3,242
Interface	$20.5	($40.6)	($2.3)	$58.8	$6.5	$8.2	($1.7)	($3.4)	$55.5	2,740	254
Line	$45.1	($86.3)	$29.7	$161.0	($9.0)	$6.4	($39.0)	($54.5)	$106.6	63,777	4,598
Other	$8.0	($3.7)	$0.8	$12.5	($0.7)	($0.1)	($0.8)	($1.5)	$11.0	2,105	411
Transformer	$16.6	($30.8)	$6.1	$53.5	$2.0	$1.6	($3.2)	($2.8)	$50.7	24,511	755
Unclassified	$0.5	($1.4)	$1.4	$3.4	$0.1	$0.1	($0.2)	($0.2)	$3.1	NA	NA
Total	$62.5	($261.7)	$65.4	$389.6	($1.6)	$23.0	($101.8)	($126.4)	$263.3	106,904	9,260

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.

Table 10-21 and Table 10-22 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 10-21. In the first six months of 2013, there were 174,063 congestion event hours in the Day-Ahead Market. Among those, only 3,621 (2.1 percent) were also constrained in the Real-Time Market. In the first six months of 2012, among the 106,904 day-ahead congestion event hours, only 3,932 (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 10-22. In the first six months of 2013, there were 9,984 congestion event hours in the Real-Time Market. Among these, 3,798 (38.0 percent) were also constrained in the Day-Ahead Market. In the first six months of 2012, among the 9,260 real-time congestion event hours, only 3,873 (41.8 percent) were binding in the day-ahead.

Table 10-21 Congestion Event Hours (Day Ahead against Real Time): January through June 2012 to 2013

	Congestion Event Hours					
	2012 (Jan - Jun)			2013 (Jan - Jun)		
Type	Day Ahead Constrained	Corresponding Real Time Constrained	Percent	Day Ahead Constrained	Corresponding Real Time Constrained	Percent
Flowgate	13,771	1,464	10.6%	11,963	1,246	10.4%
Interface	2,740	105	3.8%	6,744	647	9.6%
Line	63,777	1,836	2.9%	99,748	1,452	1.5%
Other	2,105	258	12.3%	6,884	5	0.1%
Transformer	24,511	269	1.1%	48,724	271	0.6%
Total	106,904	3,932	3.7%	174,063	3,621	2.1%

Table 10-22 Congestion Event Hours (Real Time against Day Ahead): January through June 2012 to 2013

	Congestion Event Hours					
	2012 (Jan - Jun)			2013 (Jan - Jun)		
Type	Real Time Constrained	Corresponding Day Ahead Constrained	Percent	Real Time Constrained	Corresponding Day Ahead Constrained	Percent
Flowgate	3,242	1,518	46.8%	3,553	1,380	38.8%
Interface	254	103	40.6%	830	690	83.1%
Line	4,598	1,769	38.5%	4,715	1,455	30.9%
Other	411	222	54.0%	5	5	100.0%
Transformer	755	261	34.6%	881	268	30.4%
Total	9,260	3,873	41.8%	9,984	3,798	38.0%

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 10-23 shows congestion costs by facility voltage class for the first six months of 2013. In comparison to the first six months of 2012 (shown in Table 10-24), congestion costs decreased for facilities rated at 345 kV, 230 kV, 161 kV, 138 kV and 115kV in the first six months of 2013.

Table 10-23 Congestion summary (By facility voltage): January through June 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	$7.2	($4.4)	$5.9	$17.5	$0.0	$0.0	$0.0	$0.0	$17.5	5,426	0
500	$96.9	($66.5)	$7.4	$170.8	$12.3	$20.4	($12.2)	($20.3)	$150.5	9,088	1,063
345	($13.3)	($63.2)	$12.5	$62.3	($1.5)	$10.6	($34.3)	($46.4)	$16.0	29,296	2,205
230	$33.7	($91.2)	$29.6	$154.6	($8.7)	$45.0	($38.9)	($92.6)	$62.0	29,109	1,971
161	($2.1)	($4.0)	($0.4)	$1.5	($0.9)	$0.3	($2.9)	($4.1)	($2.6)	801	589
138	($3.5)	($71.0)	$24.8	$92.3	($5.9)	$10.0	($36.6)	($52.5)	$39.8	78,550	3,640
115	$2.0	($2.5)	$1.4	$5.9	($0.0)	$0.7	($0.7)	($1.5)	$4.4	7,864	296
69	$8.6	$0.2	($0.3)	$8.1	($3.7)	$2.2	$0.8	($5.0)	$3.0	9,537	220
34	($0.0)	($0.0)	$0.1	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	4,372	0
12	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	20	0
Unclassified	$3.7	($3.4)	$7.0	$14.1	($0.1)	$1.0	$2.4	$1.3	$15.3	NA	NA
Total	$133.2	($306.1)	$87.8	$527.1	($8.4)	$90.4	($122.3)	($221.1)	$306.1	174,063	9,984

Table 10-24 Congestion summary (By facility voltage): January through June 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	($0.2)	($2.4)	$2.2	$4.4	$0.1	($0.0)	($0.1)	($0.0)	$4.4	1,648	78
500	$24.0	($49.4)	($0.5)	$72.8	$6.9	$8.2	($3.5)	($4.8)	$68.0	5,463	434
345	($15.1)	($53.7)	$8.2	$46.9	$0.8	$2.9	($20.9)	($23.0)	$23.8	14,640	1,226
230	$45.3	($27.8)	$5.0	$78.1	$1.7	$2.9	($8.1)	($9.3)	$68.8	18,563	2,128
161	($6.0)	($9.7)	$5.6	$9.3	($0.6)	$0.9	($9.5)	($11.0)	($1.7)	1,948	720
138	($8.9)	($117.1)	$40.4	$148.6	($5.3)	$6.6	($57.7)	($69.5)	$79.1	52,116	3,932
115	$15.7	($0.5)	$2.1	$18.3	($0.4)	$0.7	($0.6)	($1.7)	$16.7	8,874	490
69	$7.2	$0.3	$1.0	$7.9	($4.9)	$0.8	($1.2)	($6.9)	$1.0	3,643	252
34	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	0	0
12	($0.0)	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	9	0
Unclassified	$0.5	($1.4)	$1.4	$3.4	$0.1	$0.1	($0.2)	($0.2)	$3.1	NA	NA
Total	$62.5	($261.7)	$65.4	$389.6	($1.6)	$23.0	($101.8)	($126.4)	$263.3	106,904	9,260

Constraint Duration

Table 10-25 lists constraints in the first six months of 2012 and 2013 that were most frequently in effect and Table 10-26 shows the constraints which experienced the largest change in congestion-event hours from the first six month of 2012 to the first six months of 2013.

Table 10-25 Top 25 constraints with frequent occurrence: January through June 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	5,062	6,015	953	0	0	0	58%	68%	11%	0%	0%	0%
2	Gould Street - Westport	Line	0	4,372	4,372	0	0	0	0%	50%	50%	0%	0%	0%
3	AP South	Interface	1,211	3,275	2,064	82	646	564	14%	37%	23%	1%	7%	6%
4	Braidwood	Transformer	0	3,914	3,914	0	0	0	0%	45%	45%	0%	0%	0%
5	Readington - Roseland	Line	340	3,128	2,788	0	713	713	4%	36%	32%	0%	8%	8%
6	Howard - Shelby	Line	1,450	3,248	1,798	0	0	0	17%	37%	20%	0%	0%	0%
7	Tanners Creek	Transformer	178	2,993	2,815	0	0	0	2%	34%	32%	0%	0%	0%
8	Sunbury	Transformer	0	2,865	2,865	0	0	0	0%	33%	33%	0%	0%	0%
9	Haurd - Steward	Line	794	2,669	1,875	1	0	(1)	9%	30%	21%	0%	0%	(0%)
10	West Moulton-City Of St. Marys	Line	0	2,406	2,406	0	0	0	0%	27%	27%	0%	0%	0%
11	Zion	Line	165	2,220	2,055	0	0	0	2%	25%	23%	0%	0%	0%
12	Monticello - East Winamac	Flowgate	1,683	1,598	(85)	541	449	(92)	19%	18%	(1%)	6%	5%	(1%)
13	Cloverdale	Transformer	3	1,979	1,976	9	0	(9)	0%	23%	22%	0%	0%	(0%)
14	Nelson - Cordova	Line	390	1,852	1,462	16	101	85	4%	21%	17%	0%	1%	1%
15	Rockport Works	Transformer	0	1,891	1,891	0	0	0	0%	22%	22%	0%	0%	0%
16	Prairie State - W Mt. Vernon	Flowgate	422	1,021	599	156	836	680	5%	12%	7%	2%	10%	8%
17	Bridgewater - Middlesex	Line	237	1,663	1,426	1	157	156	3%	19%	16%	0%	2%	2%
18	Danville - East Danville	Line	1,369	1,763	394	0	0	0	16%	20%	4%	0%	0%	0%
19	Hunlock Creek - A.G.A. Gas	Line	4	1,754	1,750	0	0	0	0%	20%	20%	0%	0%	0%
20	Devon - Skokie	Line	19	1,729	1,710	0	0	0	0%	20%	19%	0%	0%	0%
21	South Cadiz	Transformer	513	1,596	1,083	0	0	0	6%	18%	12%	0%	0%	0%
22	Loretto	Transformer	166	1,587	1,421	0	0	0	2%	18%	16%	0%	0%	0%
23	Miami Fort	Transformer	504	1,560	1,056	25	25	0	6%	18%	12%	0%	0%	(0%)
24	Huntingdon - Huntingdon1	Line	1,941	1,515	(426)	0	0	0	22%	17%	(5%)	0%	0%	0%
25	Electric Junction - Frontenac	Line	0	1,499	1,499	0	0	0	0%	17%	17%	0%	0%	0%

Table 10-26 Top 25 constraints with largest year-to-year change in occurrence: January through June 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	4,372	4,372	0	0	0	0%	50%	50%	0%	0%	0%
2	Braidwood	Transformer	0	3,914	3,914	0	0	0	0%	45%	45%	0%	0%	0%
3	Readington - Roseland	Line	340	3,128	2,788	0	713	713	4%	36%	32%	0%	8%	8%
4	Graceton - Raphael Road	Line	2,331	0	(2,331)	616	0	(616)	27%	0%	(27%)	7%	0%	(7%)
5	Sunbury	Transformer	0	2,865	2,865	0	0	0	0%	33%	33%	0%	0%	0%
6	Tanners Creek	Transformer	178	2,993	2,815	0	0	0	2%	34%	32%	0%	0%	0%
7	AP South	Interface	1,211	3,275	2,064	82	646	564	14%	37%	23%	1%	7%	6%
8	West Moulton-City Of St. Marys	Line	0	2,406	2,406	0	0	0	0%	27%	27%	0%	0%	0%
9	Zion	Line	165	2,220	2,055	0	0	0	2%	25%	23%	0%	0%	0%
10	Cloverdale	Transformer	3	1,979	1,976	9	0	(9)	0%	23%	22%	0%	0%	(0%)
11	Rockport Works	Transformer	0	1,891	1,891	0	0	0	0%	22%	22%	0%	0%	0%
12	Haurd - Steward	Line	794	2,669	1,875	1	0	(1)	9%	30%	21%	0%	0%	(0%)
13	Howard - Shelby	Line	1,450	3,248	1,798	0	0	0	17%	37%	20%	0%	0%	0%
14	Belmont	Transformer	1,723	0	(1,723)	60	0	(60)	20%	0%	(20%)	1%	0%	(1%)
15	Hunlock Creek - A.G.A. Gas	Line	4	1,754	1,750	0	0	0	0%	20%	20%	0%	0%	0%
16	Rockwell - Crosby	Line	2,050	329	(1,721)	0	0	0	23%	4%	(20%)	0%	0%	0%
17	Devon - Skokie	Line	19	1,729	1,710	0	0	0	0%	20%	19%	0%	0%	0%
18	Bridgewater - Middlesex	Line	237	1,663	1,426	1	157	156	3%	19%	16%	0%	2%	2%
19	Nelson - Cordova	Line	390	1,852	1,462	16	101	85	4%	21%	17%	0%	1%	1%
20	Electric Junction - Frontenac	Line	0	1,499	1,499	0	0	0	0%	17%	17%	0%	0%	0%
21	Wolf creek	Transformer	1,480	0	(1,480)	9	0	(9)	17%	0%	(17%)	0%	0%	(0%)
22	Conesville	Transformer	1,445	0	(1,445)	0	0	0	16%	0%	(16%)	0%	0%	0%
23	Marlowe	Transformer	0	1,427	1,427	0	0	0	0%	16%	16%	0%	0%	0%
24	Loretto	Transformer	166	1,587	1,421	0	0	0	2%	18%	16%	0%	0%	0%
25	Cumberland - Bush	Flowgate	1,667	402	(1,265)	283	152	(131)	19%	5%	(14%)	3%	2%	(2%)

Constraint Costs

Table 10-27 and Table 10-28 present the top constraints affecting congestion costs by facility for the periods January through June 2013 and 2012.

Table 10-27 Top 25 constraints affecting PJM congestion costs (By facility): January through June 2013

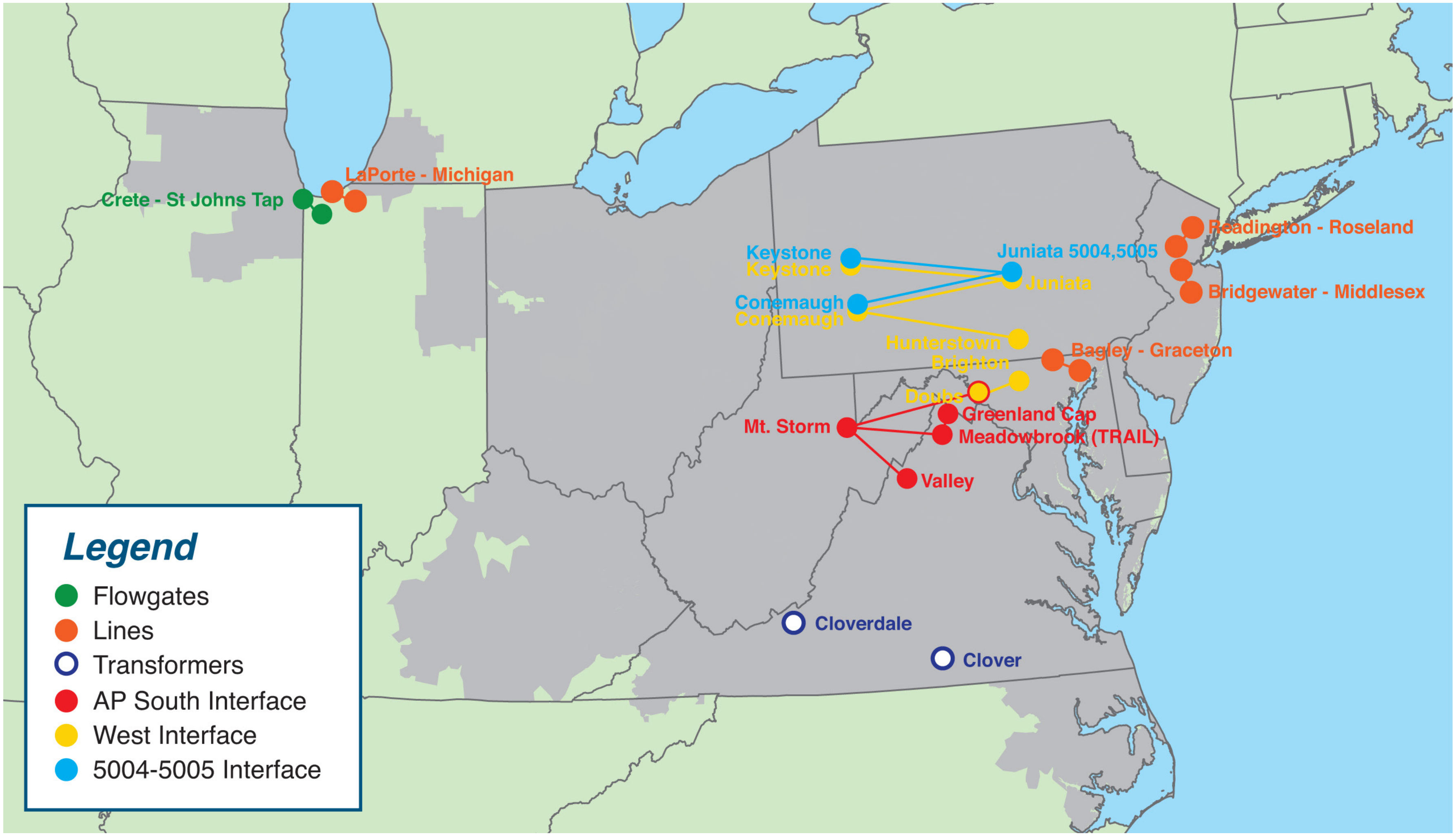
				Congestion Costs (Millions)									Percent of Total PJM Congestion Costs
				Day Ahead				Balancing					
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	2013 (Jan - Jun)
1	AP South	Interface	500	$81.4	($26.2)	$5.8	$113.3	$5.7	$12.3	($2.3)	($9.0)	$104.3	34.1%
2	Readington - Roseland	Line	PSEG	($1.7)	($49.4)	$5.2	$52.8	($10.5)	$38.1	($20.7)	($69.3)	($16.4)	(5.4%)
3	Unclassified	Unclassified	Unclassified	$3.7	($3.4)	$7.0	$14.1	($0.1)	$1.0	$2.4	$1.3	$15.3	5.0%
4	Cloverdale	Transformer	AEP	$7.4	($3.2)	$4.4	$15.1	$0.0	$0.0	$0.0	$0.0	$15.1	4.9%
5	West	Interface	500	$2.6	($13.0)	($0.4)	$15.2	$1.8	$2.4	($0.7)	($1.3)	$13.9	4.5%
6	Laporte - Michigan	Line	AEP	$0.0	$0.0	$0.0	$0.0	($6.5)	$1.3	($4.7)	($12.5)	($12.5)	(4.1%)
7	Bagley - Graceton	Line	BGE	$10.2	($0.5)	$1.8	$12.5	$0.1	($1.2)	($1.6)	($0.4)	$12.1	4.0%
8	Clover	Transformer	Dominion	$0.0	$0.0	$0.0	$0.0	($0.2)	$5.1	($6.8)	($12.1)	($12.1)	(4.0%)
9	Bridgewater - Middlesex	Line	PSEG	($0.2)	($14.9)	$1.3	$16.0	($0.0)	$3.5	($1.1)	($4.7)	$11.3	3.7%
10	Crete - St Johns Tap	Flowgate	MISO	($0.4)	($6.8)	$2.6	$9.0	$0.0	$0.0	$0.0	$0.0	$9.0	2.9%
11	5004/5005 Interface	Interface	500	$0.9	($10.5)	($0.3)	$11.1	$1.2	$3.9	$0.5	($2.2)	$8.9	2.9%
12	Bedington	Transformer	AP	$3.5	($5.1)	($0.0)	$8.6	$0.0	$0.4	$0.3	($0.1)	$8.5	2.8%
13	Bcpep	Interface	Pepco	$6.0	($0.2)	$1.6	$7.9	$0.0	$0.0	$0.0	$0.0	$7.9	2.6%
14	Monticello - East Winamac	Flowgate	MISO	($1.3)	($19.2)	$4.1	$22.0	$0.2	$4.6	($10.5)	($14.9)	$7.2	2.3%
15	New Dover - Westfield	Line	PSEG	$0.5	($5.7)	$0.9	$7.1	$0.0	$0.0	$0.0	$0.0	$7.1	2.3%
16	Braidwood	Transformer	ComEd	($0.1)	($6.2)	$0.9	$7.0	$0.0	$0.0	$0.0	$0.0	$7.0	2.3%
17	Conastone - Graceton	Line	BGE	$3.8	($0.9)	$1.4	$6.1	$0.1	($0.2)	($0.3)	($0.0)	$6.1	2.0%
18	Bristers - Ox	Line	Dominion	$2.5	($2.6)	$0.5	$5.5	$0.8	$0.3	($0.3)	$0.1	$5.5	1.8%
19	AEP - DOM	Interface	500	$3.3	($2.2)	($0.0)	$5.5	($0.1)	$0.1	($0.0)	($0.2)	$5.3	1.7%
20	Breed - Wheatland	Flowgate	MISO	($0.6)	($5.6)	$1.4	$6.4	$0.0	($0.0)	($1.1)	($1.0)	$5.3	1.7%
21	Michigan City - Laporte	Flowgate	MISO	($3.2)	($6.4)	$1.8	$5.0	$0.0	$0.0	$0.0	$0.0	$5.0	1.6%
22	Crete - St Johns	Line	ComEd	$0.0	$0.0	$0.0	$0.0	$0.2	$0.7	($3.7)	($4.3)	($4.3)	(1.4%)
23	Prairie State - W Mt. Vernon	Flowgate	MISO	($2.0)	($5.2)	($0.4)	$2.8	($0.0)	($0.1)	$0.7	$0.8	$3.6	1.2%
24	Dickerson - Pleasant View	Line	Pepco	$0.7	($3.2)	$1.2	$5.1	$0.4	$1.0	($1.2)	($1.8)	$3.3	1.1%
25	Lakeview - Greenfoe	Line	ATSI	($1.0)	($3.9)	$0.8	$3.7	$0.1	$0.2	($0.3)	($0.4)	$3.3	1.1%

Table 10-28 Top 25 constraints affecting PJM congestion costs (By facility): January through June 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 - Jun)
1	Graceton - Raphael Road	Line	BGE	$23.6	($7.8)	($1.8)	$29.5	($0.1)	($0.6)	$0.9	$1.3	$30.8	11.7%
2	Woodstock	Flowgate	MISO	($7.0)	($30.2)	$6.8	$30.0	$0.0	$0.0	$0.0	$0.0	$30.0	11.4%
3	AP South	Interface	500	$18.8	($8.3)	$0.1	$27.2	$3.3	$2.6	($2.6)	($1.9)	$25.4	9.6%
4	Belvidere - Woodstock	Line	ComEd	($0.2)	($4.6)	$1.0	$5.3	($2.4)	$3.2	($16.9)	($22.5)	($17.2)	(6.5%)
5	West	Interface	500	($0.6)	($16.6)	($2.3)	$13.7	$1.0	$1.1	$0.3	$0.1	$13.8	5.2%
6	Northwest	Other	BGE	$7.8	($2.4)	$0.4	$10.6	($0.7)	($0.1)	($0.8)	($1.5)	$9.1	3.5%
7	Pleasant Valley - Belvidere	Line	ComEd	($2.1)	($7.9)	$1.8	$7.5	$0.1	$0.1	($0.8)	($0.7)	$6.8	2.6%
8	Monticello - East Winamac	Flowgate	MISO	($0.1)	($13.7)	$9.3	$22.9	$0.4	$1.9	($15.1)	($16.6)	$6.3	2.4%
9	Kammer	Transformer	AEP	($2.3)	($8.5)	($1.0)	$5.2	($0.2)	$0.1	$0.2	($0.0)	$5.1	2.0%
10	Crescent	Transformer	DLCO	$0.9	($4.3)	($0.2)	$5.1	$0.2	$0.1	($0.1)	$0.0	$5.1	1.9%
11	Hunterstown	Transformer	Met-Ed	$1.4	($3.4)	$0.2	$5.0	$0.1	$0.0	($0.0)	$0.0	$5.0	1.9%
12	Belmont	Transformer	AP	$0.6	($5.4)	$0.5	$6.6	($0.4)	$0.8	($0.4)	($1.5)	$5.0	1.9%
13	Breed - Wheatland	Flowgate	MISO	($0.9)	($5.4)	$0.0	$4.5	$0.3	$0.3	($9.3)	($9.3)	($4.8)	(1.8%)
14	Electric Junction - Nelson	Line	ComEd	($1.3)	($4.2)	$1.7	$4.6	$0.0	$0.0	$0.0	$0.0	$4.6	1.8%
15	Silver Lake - Pleasant Valley	Line	ComEd	($2.8)	($6.0)	$1.3	$4.5	$0.0	$0.0	$0.0	$0.0	$4.5	1.7%
16	5004/5005 Interface	Interface	500	$0.1	($3.9)	$0.4	$4.5	$1.8	$2.3	$0.5	($0.0)	$4.5	1.7%
17	Loudoun - Gainsville	Line	Dominion	$0.0	($4.9)	($0.5)	$4.4	$0.4	$0.6	$0.2	($0.0)	$4.4	1.7%
18	East	Interface	500	($2.5)	($7.6)	($0.6)	$4.5	$0.1	$0.5	($0.1)	($0.5)	$4.0	1.5%
19	Bedington - Black Oak	Interface	500	$2.9	($1.4)	($0.2)	$4.0	$0.0	$0.0	($0.0)	($0.0)	$4.0	1.5%
20	Lancaster - Maryland	Line	ComEd	$0.2	($0.2)	$0.2	$0.6	($0.3)	$0.6	($3.5)	($4.4)	($3.8)	(1.4%)
21	Unclassified	Unclassified	Unclassified	$0.5	($1.4)	$1.4	$3.4	$0.1	$0.1	($0.2)	($0.2)	$3.1	1.2%
22	AEP - DOM	Interface	500	$2.6	($1.3)	$0.1	$4.1	$0.3	$1.6	$0.2	($1.0)	$3.1	1.2%
23	Hillsdale - New Milford	Line	PSEG	$0.2	($0.6)	$4.3	$5.1	$0.1	$1.1	($7.2)	($8.1)	($3.0)	(1.1%)
24	Three Mile Island	Transformer	Met-Ed	$1.3	($1.0)	$0.7	$2.9	$0.3	($1.0)	($1.3)	$0.1	$3.0	1.1%
25	Brues - West Bellaire	Line	AEP	$2.0	($1.4)	($0.5)	$2.9	($0.0)	$0.1	$0.1	($0.0)	$2.9	1.1%

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

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



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 10-29 and Table 10-30 show the MISO flowgates which PJM and/or MISO took dispatch action to control during the first six 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 six months of 2013, the Crete - St Johns Tap flowgate made the most significant contribution to positive congestion while the Beaver Channel - Albany flowgate made the most significant contribution to negative congestion.

Table 10-29 Top congestion cost impacts from MISO flowgates affecting PJM dispatch (By facility): January through June 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	Crete - St Johns Tap	($0.4)	($6.8)	$2.6	$9.0	$0.0	$0.0	$0.0	$0.0	$9.0	1,056	0
2	Monticello - East Winamac	($1.3)	($19.2)	$4.1	$22.0	$0.2	$4.6	($10.5)	($14.9)	$7.2	1,598	449
3	Breed - Wheatland	($0.6)	($5.6)	$1.4	$6.4	$0.0	($0.0)	($1.1)	($1.0)	$5.3	724	152
4	Michigan City - Laporte	($3.2)	($6.4)	$1.8	$5.0	$0.0	$0.0	$0.0	$0.0	$5.0	964	0
5	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
6	Beaver Channel - Albany	$0.0	$0.0	$0.0	$0.0	($0.6)	$0.1	($2.5)	($3.2)	($3.2)	0	80
7	Edwards - Kewanee	($2.0)	($3.5)	$1.6	$3.0	$0.0	$0.0	$0.0	$0.0	$3.0	1,201	12
8	Benton Harbor - Palisades	($0.7)	($4.3)	$1.5	$5.1	($0.0)	$0.7	($1.8)	($2.6)	$2.5	752	100
9	Volunteer - Phiipps Bend	$0.0	$0.0	$0.0	$0.0	$0.8	$0.0	($2.9)	($2.1)	($2.1)	0	63
10	Stillwell	$0.0	$0.0	$0.0	$0.0	($0.2)	$0.4	($1.4)	($1.9)	($1.9)	0	64
11	Cumberland - Bush	($0.1)	($2.0)	$0.6	$2.5	$0.4	$1.2	($3.5)	($4.3)	($1.8)	402	152
12	Miami Fort	($0.4)	($2.0)	$0.1	$1.7	$0.0	$0.0	$0.0	$0.0	$1.7	621	0
13	Hennepin	($0.2)	($0.5)	($0.1)	$0.1	($0.2)	$0.0	($1.4)	($1.6)	($1.5)	0	160
14	Rantoul Jct - Sidney	$0.0	$0.0	$0.0	$0.0	($0.3)	$0.5	($0.4)	($1.2)	($1.2)	0	116
15	Rantoul - Rantoul Jct	($0.9)	($1.3)	$0.5	$0.9	$0.0	$0.0	$0.0	$0.0	$0.9	340	0
16	Oak Grove - Galesburg	($2.1)	($4.0)	($0.4)	$1.5	($0.2)	$0.2	($0.4)	($0.8)	$0.6	801	504
17	Lanesville	($0.1)	($0.5)	$0.2	$0.6	$0.0	($0.0)	($0.0)	$0.0	$0.6	290	14
18	Beaver Channel - Albany	($0.6)	($1.2)	($0.0)	$0.6	$0.0	$0.0	$0.0	$0.0	$0.6	85	0
19	Pana North	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	($0.5)	($0.6)	($0.6)	0	7
20	Rising	($0.4)	($1.5)	$0.6	$1.7	($0.1)	$0.1	($1.0)	($1.2)	$0.5	534	138

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 10-30 Top congestion cost impacts from MISO flowgates affecting PJM dispatch (By facility): January through June 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	($0.1)	($13.7)	$9.3	$22.9	$0.4	$1.9	($15.1)	($16.6)	$6.3	1,683	541
3	Breed - Wheatland	($0.9)	($5.4)	$0.0	$4.5	$0.3	$0.3	($9.3)	($9.3)	($4.8)	693	224
4	Crete - St Johns Tap	($4.6)	($14.7)	($1.2)	$8.8	$0.3	$1.0	($5.4)	($6.1)	$2.7	1,766	268
5	Oak Grove - Galesburg	($6.0)	($9.7)	$5.6	$9.3	($0.6)	$0.9	($9.5)	($11.0)	($1.7)	1,948	720
6	Cumberland - Bush	($1.0)	($5.0)	$5.6	$9.5	$0.4	$1.2	($10.3)	($11.1)	($1.6)	1,667	283
7	Miami Fort - Hebron	($0.6)	($1.9)	$0.1	$1.4	($0.1)	($0.0)	$0.1	$0.0	$1.4	455	58
8	Prairie State - W Mt. Vernon	($1.6)	($2.6)	$0.5	$1.5	($0.0)	($0.0)	($0.2)	($0.2)	$1.3	422	156
9	Bunsonville - Eugene	($0.7)	($1.1)	$0.2	$0.7	$0.0	($0.1)	($0.1)	($0.0)	$0.7	236	37
10	Pana North	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.7)	($0.7)	($0.7)	0	11
11	Brokaw - Gibson	($0.5)	($0.9)	$0.2	$0.6	$0.0	$0.0	$0.0	$0.0	$0.6	160	4
12	Sheffield - Marktown	($1.1)	($2.1)	$0.2	$1.2	$0.2	$0.5	($0.3)	($0.7)	$0.5	1,055	66
13	Lanesville	$0.1	($0.0)	$0.6	$0.7	($0.0)	$0.0	($0.2)	($0.3)	$0.5	319	21
14	Edwards - Kewanee	($0.3)	($0.5)	$0.4	$0.7	$0.0	($0.0)	($0.2)	($0.2)	$0.5	127	36
15	Palisades - Roosevelt	($0.2)	($1.0)	($0.2)	$0.6	$0.0	($0.0)	($0.2)	($0.1)	$0.5	160	42
16	Beaver Channel - Albany	($1.6)	($5.1)	$0.8	$4.2	($1.3)	$0.6	($2.7)	($4.7)	($0.5)	360	111
17	Burnham - Munster	($0.3)	($0.6)	$0.1	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	226	0
18	Roxana - Praxair	($0.0)	($0.5)	($0.1)	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	135	0
19	Bush - Lafayette	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.1	($0.3)	($0.4)	($0.4)	0	0
20	Kenosha - Lakeview	($0.0)	($0.3)	$0.1	$0.4	($0.1)	$0.1	($0.6)	($0.7)	($0.3)	102	37

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]

Table 10-31 shows the NYISO flowgates which PJM and/or NYISO took dispatch action to control during the first six months of 2013, and which had the greatest congestion cost impact on PJM.

Table 10-31 Top congestion cost impacts from NYISO flowgates affecting PJM dispatch (By facility): January through June 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	($0.0)	$0.2	$0.0	($0.2)	($0.2)	0	9

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).

Congestion-Event Summary for the 500 kV System

Constraints on the 500 kV system generally have a regional impact. Table 10-32 and Table 10-33 show the 500 kV constraints impacting congestion costs in PJM for the first six 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 10-32 Regional constraints summary (By facility): January through June 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	$81.4	($26.2)	$5.8	$113.3	$5.7	$12.3	($2.3)	($9.0)	$104.3	3,275	646
2	West	Interface	500	$2.6	($13.0)	($0.4)	$15.2	$1.8	$2.4	($0.7)	($1.3)	$13.9	760	41
3	5004/5005 Interface	Interface	500	$0.9	($10.5)	($0.3)	$11.1	$1.2	$3.9	$0.5	($2.2)	$8.9	422	107
4	AEP - DOM	Interface	500	$3.3	($2.2)	($0.0)	$5.5	($0.1)	$0.1	($0.0)	($0.2)	$5.3	1,005	9
5	Bedington - Black Oak	Interface	500	$2.1	($1.2)	$0.2	$3.5	$0.1	($0.0)	($0.3)	($0.2)	$3.3	502	10
6	Central	Interface	500	($0.6)	($2.7)	($0.4)	$1.7	$0.0	$0.0	$0.0	$0.0	$1.7	128	0
7	Conemaugh - Hunterstown	Line	500	$0.1	($1.6)	$0.3	$2.0	$0.5	$0.7	($0.7)	($0.9)	$1.1	67	68
8	Cleveland	Interface	500	$0.0	$0.0	$0.0	$0.0	$0.1	($0.7)	$0.0	$0.8	$0.8	0	13
9	East	Interface	500	($0.2)	($0.8)	$0.0	$0.6	$0.0	$0.0	$0.0	$0.0	$0.6	151	0
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	0
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 10-33 Regional constraints summary (By facility): January through June 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	$18.8	($8.3)	$0.1	$27.2	$3.3	$2.6	($2.6)	($1.9)	$25.4	1,211	82
2	West	Interface	500	($0.6)	($16.6)	($2.3)	$13.7	$1.0	$1.1	$0.3	$0.1	$13.8	318	14
3	5004/5005 Interface	Interface	500	$0.1	($3.9)	$0.4	$4.5	$1.8	$2.3	$0.5	($0.0)	$4.5	152	83
4	East	Interface	500	($2.5)	($7.6)	($0.6)	$4.5	$0.1	$0.5	($0.1)	($0.5)	$4.0	177	5
5	Bedington - Black Oak	Interface	500	$2.9	($1.4)	($0.2)	$4.0	$0.0	$0.0	($0.0)	($0.0)	$4.0	136	16
6	AEP - DOM	Interface	500	$2.6	($1.3)	$0.1	$4.1	$0.3	$1.6	$0.2	($1.0)	$3.1	564	52
7	Central	Interface	500	($0.7)	($1.4)	$0.1	$0.8	$0.0	$0.0	($0.0)	($0.0)	$0.8	182	2
8	Kammer	Transformer	500	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	$0.0	$0.0	0	19
9	Burches Hill - Chalk Point	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 six 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 six months of 2013, financial companies received $54.7 million, an increase of $11.5 million or 26.6 percent compared to the first six months of 2012. In the first six months of 2013, physical companies paid $360.7 million in congestion charges, an increase of $54.3 million or 17.7 percent compared to the first six months of 2012.

Table 10-34 Congestion cost by the type of the participant: January through June 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	$35.9	$30.5	$55.2	$60.7	($21.6)	$2.8	($91.0)	($115.3)	$0.0	($54.7)
Physical	$97.3	($336.6)	$32.6	$466.5	$13.1	$87.6	($31.3)	($105.7)	$0.0	$360.7
Total	$133.2	($306.1)	$87.8	$527.1	($8.4)	$90.4	($122.3)	($221.1)	$0.0	$306.1

Table 10-35 Congestion cost by the type of the participant: January through June 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	($3.1)	($1.9)	$45.4	$44.1	($11.2)	($3.3)	($79.5)	($87.3)	$0.0	($43.2)
Physical	$65.6	($259.8)	$20.0	$345.5	$9.6	$26.3	($22.3)	($39.1)	$0.0	$306.4
Total	$62.5	($261.7)	$65.4	$389.6	($1.6)	$23.0	($101.8)	($126.4)	$0.0	$263.3

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