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 a product of the least cost, security constrained dispatch of system resources to meet system load. SMP is the incremental cost of energy, given the current dispatch, ignoring losses and congestion. Losses refer to energy lost to physical resistance in the transmission network as power is moved from generation to load. 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.

1 On January 1, 2012, PJM integrated the Duke Energy Ohio/Kentucky (DEOK) 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.
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.

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 three months of 2013 decreased by $41.5 million or 30.4 percent from the first three months of 2012, from -$136.4 million to -$177.9 million. Day-ahead net energy costs in the first three months of 2013 decreased by $79.1 million or 69.0 percent from the first three months of 2012, from -$114.6 million to -$193.8 million. Balancing net energy costs in the first three months of 2013 increased by $44.5 million or 155.5 percent from the first three months of 2012, from -$28.6 million to $15.9 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 three months of 2013 ranged from -$63.0 million in January to -$54.8 million in February.

Marginal Loss Cost

- **Total Marginal Loss Costs.** Total marginal loss costs in the first three months of 2013 increased by $43.2 million or 18.5 percent from the first three months of 2012, from $234.3 million to $277.6 million. Day-ahead net marginal loss costs in the first three months of 2013 increased by $48.1 million or 19.4 percent from the first three months of 2012, from $248.1 million to $296.2 million. Balancing net marginal loss costs decreased in the first three months of 2013 by $4.8 million or 35.2 percent from the first three months of 2012, from -$13.8 million to -$18.6 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

3 The total marginal loss and congestion results were calculated as of April 15, 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* Section 10, "Congestion and Marginal Losses."

marginal loss costs in the first three months of 2013 ranged from $86.7 million in February 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 that is paid back in full to load and exports on a load ratio basis.[5] The marginal loss credits increased in the first three months of 2013 by $1.8 million or 1.8 percent from the first three months of 2012, from $97.7 million to $99.4 million.

Congestion Cost

- **Total Congestion.** Total congestion costs increased by $63.5 million or 51.9 percent, from $122.4 million in the first three months of 2012 to $185.9 million in the first three months of 2013.[6]
- **Day-Ahead Congestion.** Day-ahead congestion costs increased by $151.0 million or 83.5 percent, from $180.9 million in the first three months of 2012 to $331.9 million in the first three months of 2013.
- **Balancing Congestion.** Balancing congestion costs decreased by $87.5 million or 149.8 percent from -$58.4 million in the first three months of 2012 to -$145.9 million in the first three months of 2013.
- **Monthly Congestion.** Monthly congestion costs in the first three months of 2013 ranged from $48.5 million in March 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 line, the Clover and 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 three months of 2013. Day-ahead congestion frequency increased by 49.1 percent from 54,596 congestion event hours in the first three months of 2012 to 81,378 congestion event hours in the first three 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 45.1 percent from 4,129 congestion event hours in the first three months of 2012 to 5,914 congestion event hours in the first three months of 2013. Real-time, congestion-event hours increased on the flowgates, the interfaces, 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 three months of 2013, for only 3.1 percent of Day-Ahead Market facility constrained hours were the same facilities also constrained in the Real-Time Market. In the first three months of 2013, for 45.1 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 three months of 2013. With $81.8 million in total congestion costs, it accounted for 44.0 percent of the total PJM congestion costs in the first three months of 2013. The top five constraints in terms of congestion costs together contributed $72.8 million, or 39.2 percent, of the total PJM congestion costs in 2012. The top five constraints were the AP South and West interfaces, the Readington – Roseland transmission line, and Clover and Cloverdale transformers.
- **Zonal Congestion.** AP was the most congested zone in the first three months of 2013. AP had -$8.3 million in total load costs, -$44.8 million in total generation credits and -$1.6 million in explicit congestion, resulting in $34.9 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

5 See PJM. "Manual 28: Operating Agreement Accounting," Revision 56 (October 1, 2012). 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 April 16, 2013 and are, based on continued PJM billing updates, subject to change.

interface, the Bedington transformer, the Readington – Roseland and the Dickerson - Pleasant View line, and the 5004/5005 Interface contributed $29.0 million, or 83.0 percent of the total AP Control Zone congestion costs.

The ComEd Control Zone was the second most congested zone in PJM in the first three months of 2013, with $34.3 million. The Crete - St Johns Tap flowgate contributed $4.8 million or 13.9 percent of the total ComEd Control Zone congestion cost in first three months of 2013. The AEP Control Zone was the third most congested zone in PJM in the first three months of 2013, with a cost of $25.5 million.

- **Ownership.** In the first three 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 three months of 2013, financial companies received $28.3 million in net congestion credits, an increase of $8.1 million or 40.0 percent compared to the first three months of 2012. In the first three months of 2013, physical companies paid $214.2 million in net congestion charges, an increase of $71.6 million or 50.2 percent compared to the first three 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 three months of 2013 compared to the first three months of 2012. Total marginal loss costs increased in the first three months of 2013 by $43.2 million or 18.5 percent from the first three months of 2012, from $234.3 million to $277.6million.

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 first ten months of the 2012 to 2013 planning period, total ARR and FTR revenues offset 89.9 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 69.5 percent of the target allocation level for the first ten months of 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.

Locational Marginal Price (LMP)

Components

Table 10-1 shows the PJM real-time, load-weighted average LMP components for the first three months of 2009 to 2013. The load-weighted average real-time LMP increased $6.21 or 19.9 percent from $31.21 in the first three months of 2012 to $37.41 in the first three months of 2013. The load-weighted average congestion component did not change in the first three months of 2013 from the first three months of 2012, remaining at $0.02. The load-weighted average loss component increased $0.02 or 604.6 percent from $0.00 in the first three months of 2012 to $0.02 in the first three months of 2013. The load-weighted average energy component increased $6.19 or 19.9 percent from $31.18 in the first three months of 2012 to $37.37 in the first three months of 2013.

7 See the *2012 State of the Market Report for PJM* 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."

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

(Jan-Mar)	Real-Time LMP	Energy Component	Congestion Component	Loss Component
2009	$49.60	$49.51	$0.05	$0.04
2010	$45.92	$45.81	$0.06	$0.05
2011	$46.35	$46.30	$0.03	$0.03
2012	$31.21	$31.18	$0.02	$0.00
2013	$37.41	$37.37	$0.02	$0.02

Table 10-2 shows the PJM day-ahead, load-weighted average LMP components for the first three months of 2009 through 2013. The load-weighted average day-ahead LMP increased $5.75 or 18.3 percent from $31.51 in the first three months of 2012 to $37.26 in the first three months of 2013. The load-weighted average congestion component decreased $0.01 or 18.2 percent from $0.08 in the first three months of 2012 to $0.07 in the first three months of 2013. The load-weighted average loss component increased $0.03 or 133.7 percent from -$0.03 in the first three months of 2012 to $0.01 in the first three months of 2013. The load-weighted average energy component increased $5.74 or 18.2 percent from $31.45 in the first three months of 2012 to $37.19 in the first three months of 2013. In terms of proportion of day-ahead LMP, the energy and loss components both increased, while the energy and congestion components became a smaller proportion in the first three months of 2013.

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

(Jan-Mar)	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
2009	$49.44	$49.75	($0.18)	($0.13)
2010	$47.77	$47.74	$0.01	$0.02
2011	$47.14	$47.36	($0.11)	($0.11)
2012	$31.51	$31.45	$0.08	($0.03)
2013	$37.26	$37.19	$0.07	$0.01

Zonal Components

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

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

	2012 (Jan-Mar)				2013 (Jan-Mar)			
	Real-Time LMP	Energy Component	Congestion Component	Loss Component	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AECO	$31.86	$31.17	($0.34)	$1.03	$38.44	$37.27	($0.43)	$1.60
AEP	$29.96	$31.10	($0.39)	($0.75)	$35.34	$37.35	($1.09)	($0.92)
AP	$31.75	$31.21	$0.34	$0.19	$36.97	$37.43	($0.41)	($0.04)
ATSI	$30.37	$31.06	($0.83)	$0.13	$35.70	$37.21	($1.73)	$0.22
BGE	$36.38	$31.30	$3.30	$1.78	$42.02	$37.59	$2.52	$1.91
ComEd	$27.87	$31.01	($1.32)	($1.82)	$31.60	$37.04	($3.36)	($2.08)
DAY	$30.53	$31.15	($0.52)	($0.10)	$35.14	$37.38	($2.13)	($0.11)
DEOK	$29.14	$31.17	($0.44)	($1.59)	$33.20	$37.35	($2.23)	($1.92)
DLCO	$29.94	$31.01	($0.31)	($0.77)	$33.77	$37.19	($2.12)	($1.30)
Dominion	$33.01	$31.38	$1.19	$0.44	$40.68	$37.69	$2.54	$0.45
DPL	$35.06	$31.28	$2.23	$1.54	$39.53	$37.63	($0.39)	$2.28
JCPL	$32.13	$31.31	($0.36)	$1.18	$40.33	$37.43	$1.10	$1.80
Met-Ed	$31.39	$31.25	($0.35)	$0.49	$38.12	$37.46	($0.06)	$0.72
PECO	$31.53	$31.22	($0.42)	$0.73	$37.23	$37.35	($1.20)	$1.08
PENELEC	$31.04	$31.15	($0.63)	$0.53	$38.10	$37.29	$0.30	$0.52
Pepco	$35.23	$31.33	$2.69	$1.21	$42.05	$37.62	$3.05	$1.39
PPL	$31.19	$31.27	($0.53)	$0.44	$37.61	$37.46	($0.51)	$0.66
PSEG	$32.25	$31.15	($0.15)	$1.26	$47.59	$37.21	$8.88	$1.50
RECO	$32.00	$31.31	($0.43)	$1.12	$53.46	$37.33	$14.74	$1.39
PJM	$31.21	$31.18	$0.02	$0.00	$37.41	$37.37	$0.02	$0.02

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

	2012 (Jan-Mar)				2013 (Jan-Mar)			
	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AECO	$32.54	$31.48	$0.10	$0.96	$38.64	$37.26	($0.30)	$1.68
AEP	$30.33	$31.41	($0.24)	($0.83)	$34.99	$37.19	($1.27)	($0.92)
AP	$31.92	$31.53	$0.23	$0.16	$36.49	$37.24	($0.75)	$0.01
ATSI	$30.58	$31.33	($0.71)	($0.04)	$35.53	$37.14	($1.66)	$0.05
BGE	$36.54	$31.59	$3.04	$1.91	$41.70	$37.33	$2.52	$1.85
ComEd	$27.84	$31.32	($1.55)	($1.93)	$31.83	$37.00	($2.82)	($2.36)
DAY	$30.83	$31.46	($0.35)	($0.28)	$35.36	$37.28	($1.74)	($0.18)
DEOK	$29.17	$31.33	($0.18)	($1.99)	$33.41	$37.09	($1.91)	($1.77)
DLCO	$30.54	$31.33	$0.06	($0.85)	$33.48	$37.11	($2.34)	($1.28)
Dominion	$33.49	$31.66	$1.24	$0.59	$40.25	$37.48	$2.32	$0.45
DPL	$34.86	$31.56	$1.53	$1.77	$39.53	$37.28	($0.12)	$2.37
JCPL	$32.77	$31.59	$0.11	$1.07	$40.62	$37.28	$1.32	$2.02
Met-Ed	$31.55	$31.36	($0.21)	$0.40	$38.03	$37.06	$0.25	$0.72
PECO	$32.01	$31.49	($0.16)	$0.69	$37.56	$37.10	($0.68)	$1.14
PENELEC	$31.53	$31.35	($0.52)	$0.70	$38.25	$37.13	$0.30	$0.82
Pepco	$35.60	$31.52	$2.46	$1.62	$41.64	$37.22	$3.02	$1.39
PPL	$31.43	$31.49	($0.36)	$0.30	$37.66	$37.15	($0.09)	$0.60
PSEG	$32.90	$31.49	$0.15	$1.26	$46.55	$37.20	$7.51	$1.85
RECO	$32.38	$31.47	($0.23)	$1.13	$50.35	$37.27	$11.50	$1.58
PJM	$31.51	$31.45	$0.08	($0.03)	$37.26	$37.19	$0.07	$0.01

Component Costs

Table 10-5 shows the total energy, loss and congestion component costs and the total PJM billing for the first three 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 March of 2009 through 2013[8]

	Component Costs (Millions)					
(Jan-Mar)	Energy Costs	Loss Costs	Congestion Costs	Total Costs	Total PJM Billing	Total Costs Percent of PJM Billing
2009	($218)	$454	$307	$543	$7,515	7.2%
2010	($208)	$417	$345	$554	$8,415	6.6%
2011	($210)	$410	$360	$560	$9,584	5.8%
2012	($136)	$234	$122	$220	$6,938	3.2%
2013	($178)	$278	$186	$286	$7,762	3.7%

8 The Energy Costs, Loss Costs and Congestion Costs include net inadvertent charges.

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 (SMP). 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.[9]

The total energy cost for the first three months of 2013 was -$177.9 million, which was comprised of load energy payments of $10,357.2 million, generation energy credits of $10,535.1 million, explicit energy costs of $0.0 million and inadvertent energy charges of -$0.0 million. The monthly energy costs for the first three months of 2013 ranged from -$63.0 million in January to -$54.8 million in February.

Total Energy Costs

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

9 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 March of 2009 through 2013[10]

(Jan-Mar)	Energy Costs	Percent Change	Total PJM Billing	Percent of PJM Billing
2009	($218)	NA	$7,515	(2.9%)
2010	($208)	(4.9%)	$8,415	(2.5%)
2011	($210)	1.1%	$9,584	(2.2%)
2012	($136)	(35.0%)	$6,938	(2.0%)
2013	($178)	30.4%	$7,762	(2.3%)

Energy costs for the first three 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 three months of 2009 through 2013 and Table 10-8 shows PJM energy costs by market category for the first three 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 March of 2009 through 2013

	Energy Costs (Millions)				
(Jan-Mar)	Load Payments	Generation Credits	Explicit	Inadvertent Charges	Total
2009	$14,058.4	$14,277.4	$0.0	$0.7	($218.3)
2010	$13,424.4	$13,629.0	$0.0	($3.0)	($207.6)
2011	$11,943.9	$12,160.7	$0.0	$6.9	($209.9)
2012	$8,485.4	$8,628.7	$0.0	$6.8	($136.4)
2013	$10,357.2	$10,535.1	$0.0	($0.0)	($177.9)

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

	Energy Costs (Millions)									
	Day Ahead				Balancing					
(Jan-Mar)	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Inadvertent Charges	Grand Total
2009	$14,129.6	$14,375.6	$0.0	($246.0)	($71.2)	($98.2)	$0.0	$27.0	$0.7	($218.3)
2010	$13,408.9	$13,619.2	$0.0	($210.2)	$15.5	$9.8	$0.0	$5.6	($3.0)	($207.6)
2011	$12,055.5	$12,259.3	$0.0	($203.9)	($111.6)	($98.6)	$0.0	($12.9)	$6.9	($209.9)
2012	$8,534.4	$8,649.0	$0.0	($114.6)	($49.0)	($20.4)	$0.0	($28.6)	$6.8	($136.4)
2013	$10,387.2	$10,580.9	$0.0	($193.8)	($29.9)	($45.8)	$0.0	$15.9	($0.0)	($177.9)

10 The Energy Costs include net inadvertent charges.

Monthly Energy Costs

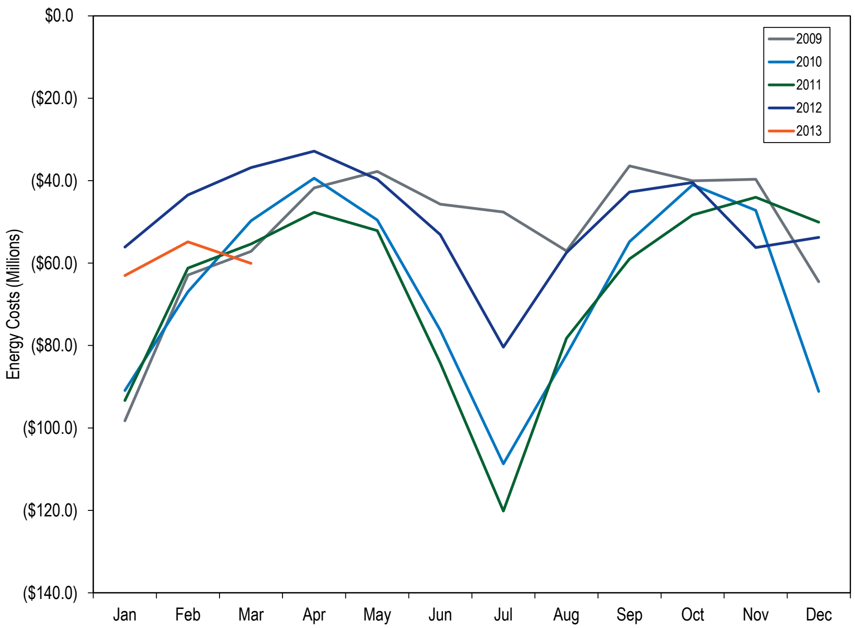
Table 10-9 shows a monthly summary of energy costs by type for the first three months of 2012 and 2013.

Table 10-9 Monthly energy costs by type (Dollars (Millions)): January through March of 2012 and 2013

	Energy Costs (Millions)							
	2012 (Jan-Mar)				2013 (Jan-Mar)			
	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)	($60.1)
Total	($114.6)	($28.6)	$6.8	($136.4)	($193.8)	$15.9	($0.0)	($177.9)

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

Figure 10-1 PJM monthly energy costs (Dollars (Millions)): January 2009 through March 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 three months of 2013 was $277.6 million, which was comprised of load loss payments of $8.0 million, generation loss credits of -$277.8 million, explicit loss costs of -$8.2 million and inadvertent loss charges of -$0.0 million. Monthly marginal loss costs in the first three months of 2013 ranged from $86.7 million in February to $101.1 million in January. Marginal loss credits increased in the first three months of 2013 by $1.8 million or 1.8 percent from the first three months of 2012, from $97.7 million to $99.4 million.

Total Marginal Loss Costs

Table 10-10 shows the total marginal loss component costs for the first three 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 March of 2009 through 2013[11,12]

(Jan-Mar)	Loss Costs	Percent Change	Total PJM Billing	Percent of PJM Billing
2009	$454	NA	$7,515	6.0%
2010	$417	(8.2%)	$8,415	5.0%
2011	$410	(1.7%)	$9,584	4.3%
2012	$234	(42.8%)	$6,938	3.4%
2013	$278	18.5%	$7,762	3.6%

11 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.
12 The Loss Costs include net inadvertent charges.

Total marginal loss costs for the first three 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 three months of 2009 through 2013. Table 10-12 shows PJM total marginal loss costs by market category for the first three months of 2009 through 2013.

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

	Marginal Loss Costs (Millions)				
(Jan-Mar)	Load Payments	Generation Credits	Explicit	Inadvertent Charges	Total
2009	($21.3)	($460.6)	$14.7	$0.0	$454.0
2010	($3.8)	($414.1)	$6.3	($0.0)	$416.6
2011	($26.5)	($421.2)	$14.9	$0.0	$409.6
2012	($11.2)	($252.1)	($6.6)	$0.0	$234.3
2013	$8.0	($277.8)	($8.2)	($0.0)	$277.6

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

	Marginal Loss Costs (Millions)									
	Day Ahead				Balancing					
(Jan-Mar)	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Inadvertent Charges	Grand Total
2009	($23.3)	($457.6)	$30.9	$465.2	$2.1	($3.0)	($16.3)	($11.2)	$0.0	$454.0
2010	($8.5)	($413.5)	$12.8	$417.8	$4.7	($0.6)	($6.5)	($1.2)	($0.0)	$416.6
2011	($37.1)	($430.1)	$26.0	$419.1	$10.6	$8.9	($11.1)	($9.5)	$0.0	$409.6
2012	($16.7)	($256.8)	$8.0	$248.1	$5.6	$4.7	($14.6)	($13.8)	$0.0	$234.3
2013	($0.1)	($288.2)	$8.1	$296.2	$8.1	$10.4	($16.3)	($18.6)	($0.0)	$277.6

Monthly Marginal Loss Costs

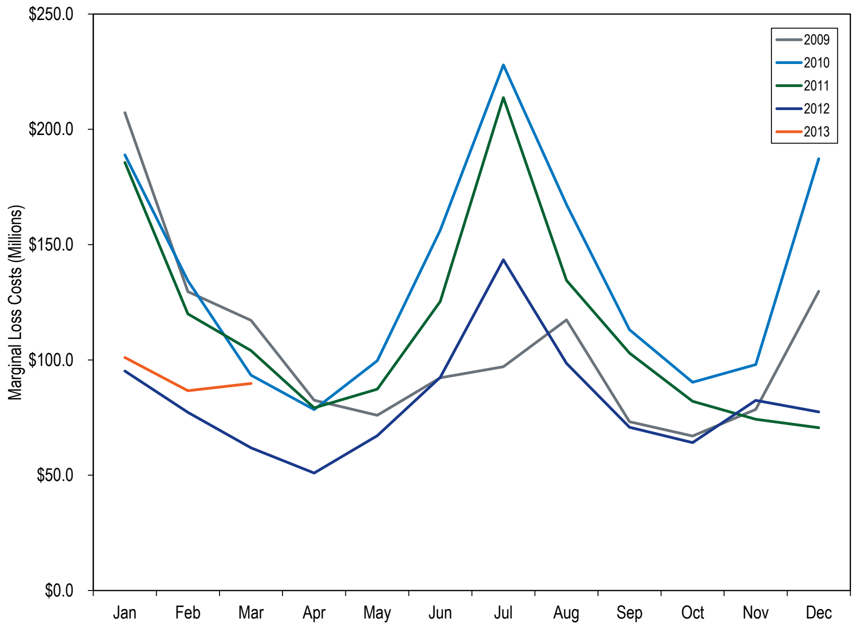
Table 10-13 shows a monthly summary of marginal loss costs by type for the first three months of 2012 and 2013.

Table 10-13 Monthly marginal loss costs by type (Dollars (Millions)): January through March of 2012 and 2013

	Marginal Loss Costs (Millions)							
	2012 (Jan-Mar)				2013 (Jan-Mar)			
	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
Total	$248.1	($13.8)	$0.0	$234.3	$296.2	($18.6)	($0.0)	$277.6

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

Figure 10-2 PJM monthly marginal loss costs (Dollars (Millions)): January 2009 through March 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 three months of 2009 through 2013.

Table 10-14 Marginal loss credits (Dollars (Millions)): January through March, 2009 through 2013[13]

	Loss Credit Accounting (Millions)			
(Jan-Mar)	Total Energy Charges	Total Marginal Loss Charges	Adjustments	Loss Credits
2009	($218.3)	$454.0	$0.9	$236.6
2010	($207.6)	$416.6	($0.0)	$208.9
2011	($209.9)	$409.6	$0.5	$200.1
2012	($136.4)	$234.3	($0.2)	$97.7
2013	($177.9)	$277.6	($0.3)	$99.4

Congestion

Congestion Accounting

Total congestion costs in PJM in the first three months of 2013 were $185.9 million, which was comprised of load congestion payments of $37.4 million, generation credits of -$166.7 million and explicit congestion of -$18.2 million (Table 10-16).

Total Congestion

Table 10-15 shows total congestion from January through March by year from 2008 through 2013.[14]

13 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.
14 Congestion charges for 2010 reflect an updated calculation compared to the results in the *2010 State of the Market Report for PJM*.

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

	Congestion Costs (Millions)			
(Jan - Mar)	Congestion Cost	Percent Change	Total PJM Billing	Percent of PJM Billing
2008	$485.6	NA	$7,718.0	6.3%
2009	$306.9	(36.8%)	$7,515.0	4.1%
2010	$344.9	12.4%	$8,415.0	4.1%
2011	$359.9	4.3%	$9,584.0	3.8%
2012	$122.4	(66.0%)	$6,938.0	1.8%
2013	$185.9	51.9%	$7,762.0	2.4%

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

	Congestion Costs (Millions)				
(Jan - Mar)	Load Payments	Generation Credits	Explicit Costs	Inadvertent Charges	Total
2008	$286.4	($190.5)	$8.7	$0.0	$485.6
2009	$106.0	($227.3)	($26.5)	$0.0	$306.9
2010	$80.1	($281.0)	($16.2)	$0.0	$344.9
2011	$198.1	($199.0)	($37.2)	$0.0	$359.9
2012	$16.8	($120.1)	($14.5)	$0.0	$122.4
2013	$37.4	($166.7)	($18.2)	$0.0	$185.9

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

	Congestion Costs (Millions)									
	Day Ahead				Balancing					
(Jan - Mar)	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Inadvertent Charges	Grand Total
2008	$332.4	($220.0)	$39.9	$592.3	($46.0)	$29.5	($31.2)	($106.7)	$0.0	$485.6
2009	$120.2	($221.3)	$47.9	$389.5	($14.2)	($6.0)	($74.4)	($82.6)	$0.0	$306.9
2010	$85.9	($293.1)	$12.9	$391.9	($5.7)	$12.1	($29.1)	($47.0)	$0.0	$344.9
2011	$176.5	($226.7)	$4.1	$407.3	$21.6	$27.8	($41.2)	($47.4)	$0.0	$359.9
2012	$21.9	($131.4)	$27.5	$180.9	($5.1)	$11.3	($42.0)	($58.4)	$0.0	$122.4
2013	$48.2	($235.8)	$47.8	$331.9	($10.8)	$69.1	($66.0)	($145.9)	$0.0	$185.9

Total congestion costs in Table 10-16 include congestion costs associated with PJM facilities and those associated with reciprocal, coordinated flowgates in the MISO[15] and those M2M flowgates in the NYISO.[16]

Table 10-16 shows the congestion costs by category for the first three months of 2013. The January through March 2013 PJM total congestion costs were comprised of $37.4 million in load congestion payments, -$166.7 million in generation congestion credits, and -$18.2 million in explicit congestion costs.

15 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).

16 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).

Monthly Congestion

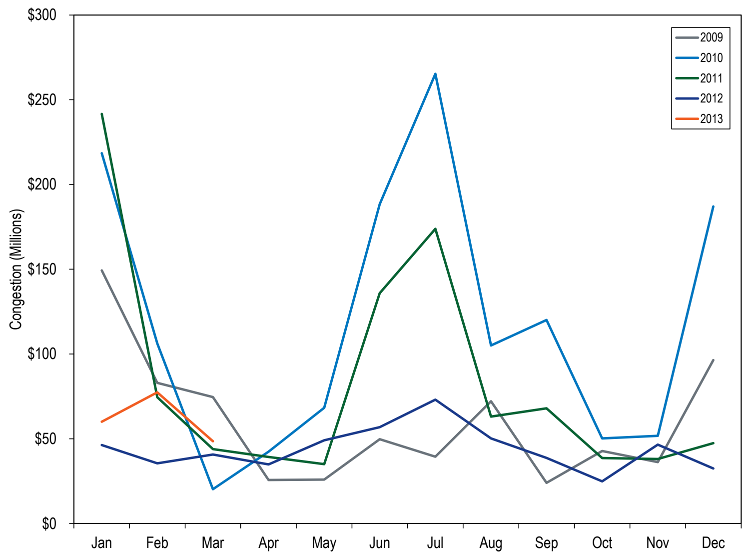
Table 10-18 shows that during the first three months of 2012 and 2013, monthly congestion costs ranged from $48.5 million to $77.4 million in 2013. Table 10-18 shows the monthly congestion costs in the first three months of 2013 were higher than in the first three months of 2012.

Table 10-18 Monthly PJM congestion costs by market type (Dollars (Millions)): January through March, 2012 to 2013

	Congestion Costs (Millions)							
	2012 (Jan-Mar)				2013 (Jan-Mar)			
	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
Total	$180.9	($58.4)	$0.0	$122.4	$331.9	($145.9)	$0.0	$185.9

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

Figure 10-3 PJM monthly congestion (Dollars (Millions)): January 2009 to March 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 months of 2013, there were 81,378 day-ahead, congestion-event hours compared to 54,596 day-ahead, congestion-event hours in the first three months of 2012. In the first three months of 2013, there were 5,914 real-time, congestion-event hours compared to 4,129 real-time, congestion-event hours in the first three months of 2012.

During the first three months of 2013, for only 3.1 percent of Day-Ahead Market facility constrained hours were the same facilities also constrained in the Real-Time Market. During the first three months of 2013, for 45.1 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 three months of 2013. With $81.8 million in total congestion costs, it accounted for 44.0 percent of the total PJM congestion costs in the first three months of 2013. The top five constraints in terms of congestion costs together contributed $72.8 million, or 39.2 percent, of the total PJM congestion costs in the first three months of 2013. The top five constraints were the AP South and West interfaces, the Readington – Roseland transmission line, and Clover and Cloverdale transformers.

Congestion by Facility Type and Voltage

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

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

Table 10-19 provides congestion-event hour subtotals and congestion cost subtotals comparing the first three months of 2013 results by facility type: line, transformer, interface, flowgate and unclassified facilities.[17,18] For comparison, this information is presented in Table 10-20 for the first three months of 2012.[19]

Table 10-19 Congestion summary (By facility type): January through March 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	($5.9)	($39.4)	$6.6	$40.1	$1.3	$7.1	($18.2)	($23.9)	$16.2	5,478	2,328
Interface	$69.4	($44.2)	($1.0)	$112.5	$7.0	$14.7	$1.8	($6.0)	$106.6	3,571	615
Line	$11.8	($93.6)	$24.4	$129.8	($12.1)	$44.6	($38.5)	($95.2)	$34.6	47,059	2,472
Other	$2.8	($1.8)	$5.1	$9.7	($0.0)	$0.0	$0.0	($0.0)	$9.7	4,443	5
Transformer	$6.9	($14.9)	$7.7	$29.5	($2.2)	$6.3	($10.3)	($18.8)	$10.7	20,827	494
Unclassified	$0.1	($5.2)	$5.0	$10.3	($0.6)	$0.6	($0.8)	($2.0)	$8.2	NA	NA
Total	$85.0	($199.1)	$47.8	$331.9	($6.6)	$73.3	($66.0)	($145.9)	$185.9	81,378	5,914

Table 10-20 Congestion summary (By facility type): January through March 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	($13.6)	($48.4)	$12.2	$47.0	$0.5	$2.6	($28.8)	($30.9)	$16.1	7,023	1,576
Interface	$12.2	($25.4)	($0.2)	$37.5	$2.3	$3.5	($2.2)	($3.5)	$34.0	1,649	179
Line	$21.3	($41.8)	$12.5	$75.6	($6.5)	$4.7	($10.3)	($21.4)	$54.1	32,682	1,932
Other	$1.0	($0.9)	($0.1)	$1.8	($0.7)	($0.0)	$0.2	($0.5)	$1.4	819	203
Transformer	$2.2	($13.2)	$2.7	$18.1	$0.1	$1.3	($0.7)	($1.8)	$16.2	12,423	239
Unclassified	$0.3	($0.2)	$0.4	$0.9	($0.1)	$0.1	($0.2)	($0.3)	$0.6	NA	NA
Total	$23.5	($129.9)	$27.5	$180.9	($4.3)	$12.1	($42.0)	($58.4)	$122.4	54,596	4,129

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 three months of 2013, there were 81,378 congestion event hours in the Day-Ahead Market. Among those, only 2,519 (3.1 percent) were also constrained in the Real-Time Market. In the first three months of 2012, among the 54,596 day-ahead congestion event hours, only 1,915 (3.5 percent) were binding in the Real-Time Market.[20]

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

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

19 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.

20 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.

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 three months of 2013, there were 5,861 congestion event hours in the Real-Time Market. Among these, 2,635 (45.0 percent) were also constrained in the Day-Ahead Market. In the first three months of 2012, among the 4,129 real-time congestion event hours, only 1,907 (46.2 percent) were binding in the day-ahead.

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

	Congestion Event Hours					
	2012 (Jan - Mar)			2013 (Jan - Mar)		
Type	Day Ahead Constrained	Corresponding Real Time Constrained	Percent	Day Ahead Constrained	Corresponding Real Time Constrained	Percent
Flowgate	7,023	721	10.3%	5,478	907	16.6%
Interface	1,649	77	4.7%	3,571	509	14.3%
Line	32,682	980	3.0%	47,059	895	1.9%
Other	819	47	5.7%	4,443	5	0.1%
Transformer	12,423	90	0.7%	20,827	203	1.0%
Total	54,596	1,915	3.5%	81,378	2,519	3.1%

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

	Congestion Event Hours					
	2012 (Jan - Mar)			2013 (Jan - Mar)		
Type	Real Time Constrained	Corresponding Day Ahead Constrained	Percent	Real Time Constrained	Corresponding Day Ahead Constrained	Percent
Flowgate	1,576	759	48.2%	2,328	1,041	44.7%
Interface	179	77	43.0%	615	525	85.4%
Line	1,932	934	48.3%	2,472	896	36.2%
Other	203	47	23.2%	5	5	100.0%
Transformer	239	90	37.7%	494	202	40.9%
Total	4,129	1,907	46.2%	5,914	2,669	45.1%

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

Table 10-23 Congestion summary (By facility voltage): January through March 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	$5.2	($2.9)	$3.7	$11.8	$0.0	$0.0	$0.0	$0.0	$11.8	2,027	0
500	$72.5	($49.3)	($0.5)	$121.3	$8.7	$15.1	($1.6)	($8.1)	$113.2	4,454	724
345	($4.1)	($27.8)	$6.7	$30.4	($1.3)	$8.7	($15.3)	($25.3)	$5.1	12,864	1,545
230	$11.9	($74.4)	$22.0	$108.2	($11.0)	$43.1	($30.9)	($85.0)	$23.2	15,851	1,330
161	($1.7)	($3.1)	($0.6)	$0.8	($0.4)	$0.2	($0.1)	($0.7)	$0.1	654	403
138	$0.6	($33.2)	$10.2	$44.1	($0.5)	$4.4	($16.4)	($21.4)	$22.7	34,864	1,668
115	($0.0)	($2.8)	$0.6	$3.3	($0.3)	$0.4	($0.1)	($0.8)	$2.5	3,366	185
69	$0.5	($0.3)	$0.7	$1.6	($1.2)	$0.7	($0.7)	($2.6)	($1.0)	4,394	59
34	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	2,893	0
12	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	11	0
Unclassified	$0.1	($5.2)	$5.0	$10.3	($0.6)	$0.6	($0.8)	($2.0)	$8.2	NA	NA
Total	$85.0	($199.1)	$47.8	$331.9	($6.6)	$73.3	($66.0)	($145.9)	$185.9	81,378	5,914

Table 10-24 Congestion summary (By facility voltage): January through March 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)	($1.6)	$1.2	$2.7	$0.1	($0.0)	($0.1)	($0.0)	$2.7	874	69
500	$13.0	($29.7)	$0.2	$42.9	$2.0	$4.7	($2.6)	($5.3)	$37.6	3,107	237
345	($8.7)	($32.4)	$5.1	$28.9	$0.8	$1.2	($12.8)	($13.2)	$15.6	8,368	684
230	$18.3	($13.2)	$0.1	$31.6	($1.2)	$1.4	$0.9	($1.7)	$29.9	8,794	1,010
161	($3.9)	($6.3)	$3.3	$5.7	($0.3)	$0.2	($4.4)	($4.9)	$0.8	1,342	344
138	($3.2)	($46.8)	$16.3	$60.0	($1.2)	$4.2	($22.0)	($27.4)	$32.6	26,513	1,554
115	$2.4	$0.1	$0.3	$2.6	($0.4)	$0.2	($0.0)	($0.7)	$2.0	3,203	89
69	$5.3	$0.3	$0.5	$5.5	($4.0)	$0.1	($0.9)	($5.0)	$0.5	2,391	142
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	4	0
Unclassified	$0.3	($0.2)	$0.4	$0.9	($0.1)	$0.1	($0.2)	($0.3)	$0.6	NA	NA
Total	$23.5	($129.9)	$27.5	$180.9	($4.3)	$12.1	($42.0)	($58.4)	$122.4	54,596	4,129

Constraint Duration

Table 10-25 lists constraints in the first three 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 three month of 2012 to the first three months of 2013.

Table 10-25 Top 25 constraints with frequent occurrence: January through March 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	2,257	3,174	917	0	0	0	26%	36%	10%	0%	0%	0%
2	Gould Street - Westport	Line	0	2,893	2,893	0	0	0	0%	33%	33%	0%	0%	0%
3	Readington - Roseland	Line	1	1,925	1,924	0	609	609	0%	22%	22%	0%	7%	7%
4	AP South	Interface	881	2,012	1,131	73	505	432	10%	23%	13%	1%	6%	5%
5	Devon - Skokie	Line	17	1,697	1,680	0	0	0	0%	19%	19%	0%	0%	0%
6	Howard - Shelby	Line	945	1,638	693	0	0	0	11%	19%	8%	0%	0%	0%
7	Prairie State - W Mt. Vernon	Flowgate	387	897	510	110	692	582	4%	10%	6%	1%	8%	7%
8	Haurd - Steward	Line	435	1,533	1,098	0	0	0	5%	17%	12%	0%	0%	0%
9	Tanners Creek	Transformer	0	1,458	1,458	0	0	0	0%	17%	17%	0%	0%	0%
10	Monticello - East Winamac	Flowgate	812	998	186	295	387	92	9%	11%	2%	3%	4%	1%
11	West Moulton-City Of St. Marys	Line	0	1,374	1,374	0	0	0	0%	16%	16%	0%	0%	0%
12	Zion	Line	1	1,326	1,325	0	0	0	0%	15%	15%	0%	0%	0%
13	Waldwick - Waldwick	Other	0	1,315	1,315	0	0	0	0%	15%	15%	0%	0%	0%
14	Bridgewater - Middlesex	Line	237	1,037	800	1	150	149	3%	12%	9%	0%	2%	2%
15	Braidwood	Transformer	0	1,168	1,168	0	0	0	0%	13%	13%	0%	0%	0%
16	Nelson - Cordova	Line	36	1,112	1,076	0	3	3	0%	13%	12%	0%	0%	0%
17	Oak Grove - Galesburg	Flowgate	1,342	654	(688)	344	362	18	15%	7%	(8%)	4%	4%	0%
18	Hudson	Other	0	971	971	0	0	0	0%	11%	11%	0%	0%	0%
19	Danville - East Danville	Line	200	943	743	0	0	0	2%	11%	8%	0%	0%	0%
20	Preston - Tanyard	Line	0	928	928	0	0	0	0%	11%	11%	0%	0%	0%
21	Rockport Works	Transformer	0	927	927	0	0	0	0%	11%	11%	0%	0%	0%
22	Loretto	Transformer	75	901	826	0	0	0	1%	10%	9%	0%	0%	0%
23	Huntingdon - Huntingdon1	Line	1,138	878	(260)	0	0	0	13%	10%	(3%)	0%	0%	0%
24	Breed - Wheatland	Flowgate	500	724	224	172	148	(24)	6%	8%	3%	2%	2%	(0%)
25	Linden - VFT	Line	913	840	(73)	0	0	0	10%	10%	(1%)	0%	0%	0%

Table 10-26 Top 25 constraints with largest year-to-year change in occurrence: January through March 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	2,893	2,893	0	0	0	0%	33%	33%	0%	0%	0%
2	Readington - Roseland	Line	1	1,925	1,924	0	609	609	0%	22%	22%	0%	7%	7%
3	Graceton - Raphael Road	Line	1,416	0	(1,416)	407	0	(407)	16%	0%	(16%)	5%	0%	(5%)
4	Devon - Skokie	Line	17	1,697	1,680	0	0	0	0%	19%	19%	0%	0%	0%
5	AP South	Interface	881	2,012	1,131	73	505	432	10%	23%	13%	1%	6%	5%
6	Tanners Creek	Transformer	0	1,458	1,458	0	0	0	0%	17%	17%	0%	0%	0%
7	West Moulton-City Of St. Marys	Line	0	1,374	1,374	0	0	0	0%	16%	16%	0%	0%	0%
8	Zion	Line	1	1,326	1,325	0	0	0	0%	15%	15%	0%	0%	0%
9	Belmont	Transformer	1,274	0	(1,274)	49	0	(49)	15%	0%	(15%)	1%	0%	(1%)
10	Waldwick - Waldwick	Other	0	1,315	1,315	0	0	0	0%	15%	15%	0%	0%	0%
11	Wolfcreek	Transformer	1,197	0	(1,197)	9	0	(9)	14%	0%	(14%)	0%	0%	(0%)
12	Braidwood	Transformer	0	1,168	1,168	0	0	0	0%	13%	13%	0%	0%	0%
13	Conesville	Transformer	1,113	0	(1,113)	0	0	0	13%	0%	(13%)	0%	0%	0%
14	Haurd - Steward	Line	435	1,533	1,098	0	0	0	5%	17%	12%	0%	0%	0%
15	Prairie State - W Mt. Vernon	Flowgate	387	897	510	110	692	582	4%	10%	6%	1%	8%	7%
16	Nelson - Cordova	Line	36	1,112	1,076	0	3	3	0%	13%	12%	0%	0%	0%
17	Rockwell - Crosby	Line	1,321	250	(1,071)	0	0	0	15%	3%	(12%)	0%	0%	0%
18	Hudson	Other	0	971	971	0	0	0	0%	11%	11%	0%	0%	0%
19	Bridgewater - Middlesex	Line	237	1,037	800	1	150	149	3%	12%	9%	0%	2%	2%
20	Preston - Tanyard	Line	0	928	928	0	0	0	0%	11%	11%	0%	0%	0%
21	Rockport Works	Transformer	0	927	927	0	0	0	0%	11%	11%	0%	0%	0%
22	Conesville	Transformer	1,060	137	(923)	0	0	0	12%	2%	(11%)	0%	0%	0%
23	Sporn	Transformer	2,257	3,174	917	0	0	0	26%	36%	10%	0%	0%	0%
24	Silver Lake - Pleasant Valley	Line	841	13	(828)	0	0	0	10%	0%	(9%)	0%	0%	0%
25	Loretto	Transformer	75	901	826	0	0	0	1%	10%	9%	0%	0%	0%

Constraint Costs

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

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

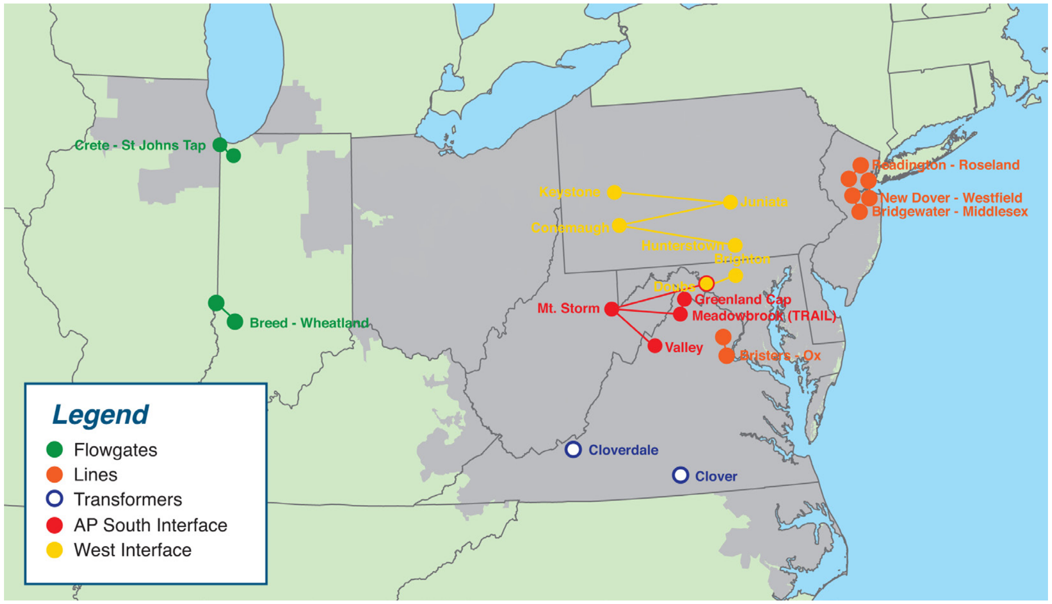
				Congestion Costs (Millions)									Percent of Total PJM Congestion Costs
				Day Ahead				Balancing					
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	2013 (Jan - Mar)
1	AP South	Interface	500	$62.2	($23.0)	$0.2	$85.4	$5.8	$10.8	$1.4	($3.6)	$81.8	44.0%
2	Readington - Roseland	Line	PSEG	$1.5	($41.1)	$8.5	$51.2	($10.7)	$37.0	($21.4)	($69.1)	($17.9)	(9.6%)
3	Clover	Transformer	Dominion	$0.0	$0.0	$0.0	$0.0	($0.1)	$5.2	($6.4)	($11.7)	($11.7)	(6.3%)
4	Cloverdale	Transformer	AEP	$5.2	($2.6)	$3.1	$10.9	$0.0	$0.0	$0.0	$0.0	$10.9	5.9%
5	West	Interface	500	$1.9	($8.4)	($0.6)	$9.8	$0.0	$0.0	($0.0)	($0.0)	$9.7	5.2%
6	Bridgewater - Middlesex	Line	PSEG	$0.0	($13.3)	$1.0	$14.3	($0.0)	$3.5	($1.2)	($4.7)	$9.6	5.1%
7	Unclassified	Unclassified	Unclassified	$0.1	($5.2)	$5.0	$10.3	($0.6)	$0.6	($0.8)	($2.0)	$8.2	4.4%
8	Crete - St Johns Tap	Flowgate	MISO	($0.4)	($5.8)	$2.2	$7.6	$0.0	$0.0	$0.0	$0.0	$7.6	4.1%
9	New Dover - Westfield	Line	PSEG	$0.6	($5.6)	$0.9	$7.0	$0.0	$0.0	$0.0	$0.0	$7.0	3.8%
10	Bristers - Ox	Line	Dominion	$2.4	($2.5)	$0.4	$5.4	$0.8	$0.3	($0.3)	$0.1	$5.5	3.0%
11	Breed - Wheatland	Flowgate	MISO	($0.6)	($5.6)	$1.4	$6.4	$0.0	($0.0)	($1.0)	($1.0)	$5.4	2.9%
12	5004/5005 Interface	Interface	500	$1.0	($6.7)	($0.3)	$7.3	$1.2	$3.9	$0.4	($2.3)	$5.0	2.7%
13	Bedington	Transformer	AP	$1.7	($2.9)	$0.1	$4.7	$0.1	$0.1	$0.0	$0.0	$4.8	2.6%
14	AEP - DOM	Interface	500	$3.0	($2.1)	($0.4)	$4.7	$0.0	$0.0	$0.0	$0.0	$4.7	2.5%
15	Dickerson - Pleasant View	Line	Pepco	$0.6	($3.1)	$1.2	$5.0	$0.4	$0.9	($1.1)	($1.6)	$3.4	1.8%
16	Amos	Transformer	AEP	$0.6	($2.6)	$1.1	$4.2	($2.5)	$1.1	($3.8)	($7.4)	($3.2)	(1.7%)
17	Prairie State - W Mt. Vernon	Flowgate	MISO	($1.7)	($4.3)	($0.2)	$2.3	$0.0	($0.2)	$0.6	$0.8	$3.1	1.7%
18	Waldwick - Waldwick	Other	PSEG	$0.0	($1.4)	$1.5	$3.0	$0.0	$0.0	$0.0	$0.0	$3.0	1.6%
19	Maywood - Saddlebrook	Line	PSEG	$0.0	($0.0)	$0.1	$0.2	($0.0)	$0.5	($2.6)	($3.1)	($3.0)	(1.6%)
20	Crete - St Johns	Line	ComEd	$0.0	$0.0	$0.0	$0.0	$0.1	$0.6	($2.5)	($2.9)	($2.9)	(1.6%)
21	Monticello - East Winamac	Flowgate	MISO	($0.8)	($15.0)	$2.6	$16.8	$0.3	$4.4	($9.8)	($13.9)	$2.9	1.5%
22	Bagley - Graceton	Line	BGE	$1.9	($0.7)	($0.0)	$2.6	($0.2)	($0.0)	$0.4	$0.3	$2.8	1.5%
23	Hudson	Other	PSEG	$2.1	$2.2	$3.0	$2.8	$0.0	$0.0	$0.0	$0.0	$2.8	1.5%
24	Huntingdon - Huntingdon1	Line	AP	($0.7)	($4.2)	($0.9)	$2.6	$0.0	$0.0	$0.0	$0.0	$2.6	1.4%
25	Essex - Essex	Other	PSEG	$0.4	($1.3)	$0.5	$2.2	$0.0	$0.0	$0.0	$0.0	$2.2	1.2%

Table 10-28 Top 25 constraints affecting PJM congestion costs (By facility): January through March 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 - Mar)
1	Graceton - Raphael Road	Line	BGE	$12.8	($8.9)	($2.4)	$19.2	$0.1	$0.1	$1.3	$1.3	$20.5	16.8%
2	AP South	Interface	500	$14.3	($7.6)	$0.1	$22.0	$1.3	$1.0	($2.2)	($2.0)	$20.1	16.4%
3	Woodstock	Flowgate	MISO	($2.3)	($13.0)	$1.3	$12.0	$0.0	$0.0	$0.0	$0.0	$12.0	9.8%
4	West	Interface	500	$0.4	($6.2)	($0.3)	$6.3	$0.0	$0.0	($0.0)	($0.0)	$6.3	5.1%
5	Breed - Wheatland	Flowgate	MISO	($0.7)	($4.0)	($0.0)	$3.4	$0.3	$0.3	($8.5)	($8.5)	($5.2)	(4.2%)
6	Crete - St Johns Tap	Flowgate	MISO	($2.7)	($9.7)	($0.4)	$6.5	$0.2	$0.5	($2.0)	($2.4)	$4.2	3.4%
7	Lancaster - Maryland	Line	ComEd	$0.2	($0.2)	$0.2	$0.6	($0.3)	$0.6	($3.5)	($4.4)	($3.8)	(3.1%)
8	East	Interface	500	($2.3)	($7.1)	($0.6)	$4.2	$0.1	$0.5	($0.1)	($0.5)	$3.7	3.0%
9	Silver Lake - Pleasant Valley	Line	ComEd	($2.2)	($4.8)	$1.0	$3.6	$0.0	$0.0	$0.0	$0.0	$3.6	3.0%
10	Belmont	Transformer	AP	$0.8	($4.2)	$0.4	$5.3	($0.3)	$1.1	($0.4)	($1.8)	$3.5	2.8%
11	Electric Jct - Nelson	Line	ComEd	($0.9)	($3.1)	$1.1	$3.3	$0.0	$0.0	($0.0)	($0.0)	$3.3	2.7%
12	5004/5005 Interface	Interface	500	$0.2	($3.0)	$0.4	$3.6	$0.7	$1.6	$0.1	($0.8)	$2.8	2.3%
13	Jefferson - Clifty Creek	Line	AEP	($0.1)	($1.9)	$0.8	$2.6	$0.0	$0.0	$0.0	$0.0	$2.6	2.2%
14	Kammer	Transformer	AEP	($0.8)	($3.2)	($0.3)	$2.1	$0.0	$0.0	$0.0	$0.0	$2.1	1.7%
15	Brues - West Bellaire	Line	AEP	$1.5	($0.6)	($0.3)	$1.9	($0.0)	$0.0	$0.0	($0.0)	$1.9	1.5%
16	Breed - Wheatland	Line	AEP	($0.9)	($2.6)	($0.0)	$1.6	$0.0	$0.0	$0.0	$0.0	$1.6	1.3%
17	Burnham - Munster	Line	ComEd	($0.1)	($0.3)	$0.1	$0.3	$0.0	$0.3	($1.6)	($1.9)	($1.6)	(1.3%)
18	Monticello - East Winamac	Flowgate	MISO	$0.0	($5.9)	$4.2	$10.1	$0.3	$1.2	($7.6)	($8.5)	$1.5	1.3%
19	Lake Nelson - Middlesex	Line	PSEG	$1.3	$0.2	$0.4	$1.5	$0.0	$0.0	$0.0	$0.0	$1.5	1.2%
20	Belvidere - Woodstock	Line	ComEd	($0.1)	($3.9)	$0.7	$4.5	($0.9)	$1.1	($4.0)	($6.0)	($1.5)	(1.2%)
21	Mazon - Mazon	Line	ComEd	($0.3)	($1.3)	$0.7	$1.8	($0.0)	($0.0)	($0.3)	($0.3)	$1.5	1.2%
22	Wolfcreek	Transformer	AEP	$0.1	($1.2)	$0.3	$1.5	($0.0)	($0.0)	($0.1)	($0.1)	$1.5	1.2%
23	Jefferson - Rockport	Line	AEP	($0.0)	($0.8)	$0.6	$1.5	$0.0	$0.0	$0.0	$0.0	$1.5	1.2%
24	Potomac River	Transformer	Pepco	$1.3	$0.0	$0.1	$1.4	$0.0	$0.0	$0.0	$0.0	$1.4	1.2%
25	Prairie State - W Mt. Vernon	Flowgate	MISO	($1.6)	($2.5)	$0.5	$1.4	($0.0)	($0.0)	($0.1)	($0.1)	$1.3	1.1%

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

Figure 10-4 Location of the top 10 constraints affecting PJM congestion costs: January through March 2013[21]



Congestion-Event Summary for MISO Flowgates

PJM and MISO have a joint operating agreement (JOA) which defines a coordinated methodology for congestion management. This agreement establishes reciprocal, coordinated flowgates in the combined footprint whose operating limits are respected by the operators of both organizations.[22] A flowgate is a facility or group of facilities that may act as constraint points on the regional system.[23] PJM models these coordinated flowgates and controls for them in its security-constrained, economic dispatch. Table 10-29 and Table 10-30 show the MISO flowgates which PJM and/or MISO took dispatch action to control during the first three months of 2013 and 2012 respectively, 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 three months of 2013, the Crete - St Johns Tap flowgate made the most significant contribution to positive congestion while the Volunteer - Phipps Bend flowgate made the most significant contribution to negative congestion.

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

22 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>.

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

Table 10-29 Top congestion cost impacts from MISO flowgates affecting PJM dispatch (By facility): January through March 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)	($5.8)	$2.2	$7.6	$0.0	$0.0	$0.0	$0.0	$7.6	773	0
2	Breed - Wheatland	($0.6)	($5.6)	$1.4	$6.4	$0.0	($0.0)	($1.0)	($1.0)	$5.4	724	148
3	Prairie State - W Mt. Vernon	($1.7)	($4.3)	($0.2)	$2.3	$0.0	($0.2)	$0.6	$0.8	$3.1	897	692
4	Monticello - East Winamac	($0.8)	($15.0)	$2.6	$16.8	$0.3	$4.4	($9.8)	($13.9)	$2.9	998	387
5	Volunteer - Phiipps Bend	$0.0	$0.0	$0.0	$0.0	$0.8	$0.0	($2.9)	($2.1)	($2.1)	0	63
6	Oak Grove - Galesburg	($1.7)	($3.1)	($0.6)	$0.8	($0.2)	$0.1	$0.3	$0.0	$0.8	654	362
7	Beaver Channel - Albany	$0.0	$0.0	$0.0	$0.0	($0.2)	$0.1	($0.4)	($0.7)	($0.7)	0	37
8	Lanesville	($0.1)	($0.5)	$0.2	$0.6	$0.0	($0.0)	($0.0)	$0.0	$0.6	290	14
9	Pana North	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	($0.5)	($0.6)	($0.6)	0	7
10	Rising	($0.4)	($1.5)	$0.6	$1.7	($0.1)	$0.1	($1.0)	($1.2)	$0.5	534	138
11	Rantoul - Rantoul Jct	($0.0)	($0.2)	$0.2	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	53	0
12	Cayuga	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($0.2)	($0.3)	($0.3)	0	13
13	Miami Fort - Hebron	($0.1)	($0.3)	($0.0)	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	64	0
14	Reynold-Monticello	($0.1)	($0.5)	$0.2	$0.7	$0.0	$0.0	($0.5)	($0.5)	$0.2	86	51
15	Bush - Lafayette	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($0.1)	($0.1)	($0.1)	0	5
16	Edwards - Kewanee	($0.0)	($0.1)	$0.1	$0.1	($0.0)	$0.0	$0.0	$0.0	$0.1	140	2
17	Bunsonville - Eugene	($0.1)	($0.2)	$0.0	$0.2	$0.0	($0.1)	($0.3)	($0.3)	($0.1)	24	91
18	Pawnee	$0.0	($0.0)	$0.1	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	39	0
19	Rantoul Jct - Sidney	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	($0.1)	($0.1)	($0.1)	0	33
20	Powerton - Lilly	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	$0.1	$0.1	0	23

Table 10-30 Top congestion cost impacts from MISO flowgates affecting PJM dispatch (By facility): January through March 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	($2.3)	($13.0)	$1.3	$12.0	$0.0	$0.0	$0.0	$0.0	$12.0	631	0
2	Breed - Wheatland	($0.7)	($4.0)	($0.0)	$3.4	$0.3	$0.3	($8.5)	($8.5)	($5.2)	500	172
3	Crete - St Johns Tap	($2.7)	($9.7)	($0.4)	$6.5	$0.2	$0.5	($2.0)	($2.4)	$4.2	1,189	155
4	Monticello - East Winamac	$0.0	($5.9)	$4.2	$10.1	$0.3	$1.2	($7.6)	($8.5)	$1.5	812	295
5	Prairie State - W Mt. Vernon	($1.6)	($2.5)	$0.5	$1.4	($0.0)	($0.0)	($0.1)	($0.1)	$1.3	387	110
6	Miami Fort - Hebron	($0.5)	($1.4)	$0.1	$1.1	($0.0)	($0.0)	($0.0)	($0.0)	$1.1	356	33
7	Oak Grove - Galesburg	($3.9)	($6.3)	$3.3	$5.7	($0.3)	$0.2	($4.4)	($4.9)	$0.8	1,342	344
8	Pana North	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.7)	($0.7)	($0.7)	0	11
9	Brokaw - Gibson	($0.5)	($0.9)	$0.2	$0.6	$0.0	$0.0	$0.0	$0.0	$0.6	160	0
10	Lanesville	$0.1	($0.1)	$0.4	$0.5	$0.0	$0.0	$0.0	$0.0	$0.5	236	0
11	Burnham - Munster	($0.3)	($0.6)	$0.1	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	223	0
12	Cumberland - Bush	($0.4)	($2.4)	$2.0	$4.0	$0.0	$0.5	($3.9)	($4.3)	($0.4)	646	119
13	Benton Harbor - Palisades	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.1	($0.3)	($0.4)	($0.4)	0	5
14	Bunsonville - Eugene	($0.3)	($0.5)	$0.1	$0.3	$0.0	($0.1)	($0.1)	($0.0)	$0.3	90	34
15	Baldwin-Mt Vernon	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.3)	($0.3)	($0.3)	0	137
16	Bloomton - Denoisck	($0.1)	($0.2)	$0.1	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	42	0
17	Dunes Acres - Michigan City	($0.2)	($0.3)	$0.1	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	172	0
18	Rising	($0.0)	($0.0)	$0.0	$0.0	($0.1)	$0.0	($0.1)	($0.2)	($0.2)	4	9
19	Gibson - Petersburg	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	$0.1	$0.1	$0.1	0	0
20	Rantoul - Rantoul Jct	($0.1)	($0.2)	$0.1	$0.2	($0.0)	($0.1)	($0.3)	($0.3)	($0.1)	56	0

Congestion-Event Summary for NYISO Flowgates

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

Table 10-31 shows the NYISO flowgates which PJM and/or NYISO took dispatch action to control during the first three 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 March 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	159
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

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 three months of 2013 and 2012 respectively. 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 March 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	$62.2	($23.0)	$0.2	$85.4	$5.8	$10.8	$1.4	($3.6)	$81.8	2,012	505
2	West	Interface	500	$1.9	($8.4)	($0.6)	$9.8	$0.0	$0.0	($0.0)	($0.0)	$9.7	341	1
3	5004/5005 Interface	Interface	500	$1.0	($6.7)	($0.3)	$7.3	$1.2	$3.9	$0.4	($2.3)	$5.0	151	96
4	AEP - DOM	Interface	500	$3.0	($2.1)	($0.4)	$4.7	$0.0	$0.0	$0.0	$0.0	$4.7	609	1
5	Central	Interface	500	($0.6)	($2.7)	($0.4)	$1.7	$0.0	$0.0	$0.0	$0.0	$1.7	116	0
6	Bedington - Black Oak	Interface	500	$0.9	($0.7)	$0.1	$1.7	$0.0	$0.0	($0.0)	($0.0)	$1.6	105	2
7	East	Interface	500	($0.1)	($0.3)	($0.0)	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	55	0
8	Conemaugh - Hunterstown	Line	500	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.2)	($0.2)	($0.2)	0	13
9	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
10	Cloverdale - Lexington	Interface	500	$0.0	$0.0	$0.0	$0.0	$0.0	($0.1)	($0.1)	$0.0	$0.0	0	6
11	EAST	Interface	500	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	($0.0)	($0.0)	($0.0)	0	4

24 See "Joint Operating Agreement Among and Between the New York Independent System Operator Inc and PJM Interconnection, L.L.C." (January 17, 2013) Section 35.3.1 <http://www.pjm.com/~/media/documents/agreements/nyiso-pjm.ashx> (Accessed April 17, 2013).
25 See "Joint Operating Agreement Among and Between the New York Independent System Operator Inc and PJM Interconnection, L.L.C." (January 17, 2013) Section 35.23 <http://www.pjm.com/~/media/documents/agreements/nyiso-pjm.ashx> (Accessed April 17, 2013).

Table 10-33 Regional constraints summary (By facility): January through March 2012

				Congestion Costs (Millions)									Event Hours	
				Day Ahead				Balancing						
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	$14.3	($7.6)	$0.1	$22.0	$1.3	$1.0	($2.2)	($2.0)	$20.1	881	73
2	West	Interface	500	$0.4	($6.2)	($0.3)	$6.3	$0.0	$0.0	($0.0)	($0.0)	$6.3	241	2
3	East	Interface	500	($2.3)	($7.1)	($0.6)	$4.2	$0.1	$0.5	($0.1)	($0.5)	$3.7	160	5
4	5004/5005 Interface	Interface	500	$0.2	($3.0)	$0.4	$3.6	$0.7	$1.6	$0.1	($0.8)	$2.8	131	64
5	Central	Interface	500	($0.6)	($1.2)	$0.1	$0.7	$0.0	$0.0	($0.0)	($0.0)	$0.7	170	2
6	AEP - DOM	Interface	500	$0.2	($0.3)	$0.1	$0.7	$0.3	$0.4	($0.1)	($0.2)	$0.5	66	31
7	Kammer	Transformer	500	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	$0.0	$0.0	0	19
8	Bedington - Black Oak	Interface	500	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	$0.0	$0.0	0	2

Congestion Costs by Physical and Financial Participants

In the first three months of 2013, financial companies as a group were net recipients of congestion credits, and physical companies were net payers of congestion charges.[26] In the first three months of 2013, financial companies received $28.3 million, an increase of $8.1 million or 40.0 percent compared to the first three months of 2012. In the first three months of 2013, physical companies paid $212.4 million in congestion charges, an increase of $71.6 million or 50.2 percent compared to the first three months of 2012.

Table 10-34 Congestion cost by the type of the participant: January through March 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	$29.4	$25.3	$30.0	$34.1	($12.4)	$1.2	($48.8)	($62.4)	$0.0	($28.3)
Physical	$55.6	($224.4)	$17.8	$297.7	$5.7	$72.0	($17.2)	($83.5)	$0.0	$214.2
Total	$85.0	($199.1)	$47.8	$331.9	($6.6)	$73.3	($66.0)	($145.9)	$0.0	$185.9

Table 10-35 Congestion cost by the type of the participant: January through March 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	($2.0)	($1.3)	$21.9	$21.2	($4.9)	$1.6	($35.0)	($41.4)	$0.0	($20.2)
Physical	$25.5	($128.6)	$5.6	$159.7	$0.5	$10.5	($7.0)	($17.0)	$0.0	$142.7
Total	$23.5	($129.9)	$27.5	$180.9	($4.3)	$12.1	($42.0)	($58.4)	$0.0	$122.4

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