# 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.

The components of LMP are the basis for calculating participant and location specific congestion and marginal losses.[3]

## Overview

### Marginal Loss Cost

Before June 1, 2007, the PJM economic dispatch and LMP models did not include marginal losses. Losses were treated as a static component of load, and the physical nature and location of power system losses were ignored. The PJM Tariff required implementation of marginal losses when required technical systems became available. On June 1, 2007, PJM began including marginal losses in economic dispatch and LMP models.[4] The primary benefit of a marginal loss calculation is that it more accurately models the physical reality of power system losses, which permits increased efficiency and more optimal asset utilization. Marginal loss modeling creates a separate marginal loss price for every location on the power grid. This marginal loss price (MLMP) is a component of LMP that is charged to load and credited to generation.

Total marginal loss costs equal net implicit marginal loss costs plus net explicit marginal loss costs plus net inadvertent loss charges. Net implicit marginal loss costs equal load loss payments minus generation loss credits. Net explicit marginal loss costs are the net marginal loss costs associated with point-to-point energy transactions. Net inadvertent loss charges are the losses associated with the hourly difference between the net actual energy flow and the net scheduled energy flow into or out of the PJM control area.[5] Unlike the other categories of marginal loss accounting, inadvertent loss charges are common costs not directly attributable to specific participants. Inadvertent loss charges are distributed to load on a load ratio basis. Each of these categories of marginal loss costs is comprised of day-ahead and balancing marginal loss costs.

1 On January 1, 2012, PJM integrated the Duke Energy Ohio/Kentucky (DEOK) Control Zone. On June 1, 2011, PJM integrated the American Transmission Systems, Inc. (ATSI) 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. ATSI is treated as part of MISO for the period from January 2011 through May 31, 2011 and as part of PJM for the period from June 1, 2011 through December 31,2012.

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.

3 The total marginal loss and congestion results were calculated as of March 2, 2013, and are subject to change, based on continued PJM billing updates.

4 For additional information, see OATT Section 3.4.

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

Marginal loss costs can be positive or negative with respect to the reference bus. If an increase in load at a bus would decrease losses, the marginal loss component of LMP of that bus will be negative. If an increase in generation at a bus would result in an increase in losses, the marginal loss component of that bus will be negative. If an increase of load at a bus would increase losses, the marginal loss component of LMP at that bus will be positive. If an increase in generation at a bus results in a decrease of system losses, then the marginal loss component of LMP at that bus will be positive.

Day-ahead marginal loss costs are based on day-ahead MWh priced at the marginal loss price component of LMP. Balancing marginal loss costs are based on the load or generation deviations between the Day-Ahead and Real-Time Energy Markets priced at the marginal loss price component of LMP in the Real-Time Energy Market. If a participant has real-time generation or load that is greater than its day-ahead generation or load then the deviation will be positive. If there is a positive load deviation at a bus where the real-time LMP has a positive marginal loss component, positive balancing marginal loss costs will result. Similarly, if there is a positive load deviation at a bus where real-time LMP has a negative marginal loss component, negative balancing marginal loss costs will result. If a participant has real-time generation or load that is less than its day-ahead generation or load then the deviation will be negative. If there is a negative load deviation at a bus where real-time LMP has a positive marginal loss component, negative balancing marginal loss costs will result. Similarly, if there is a negative load deviation at a bus where real-time LMP has a negative marginal loss component, positive balancing marginal loss costs will result.

Marginal loss credits or loss surplus is the remaining loss amount from collection of marginal losses, after accounting for total energy costs and net residual market adjustments, that is paid back in full to load and exports on a load ratio basis.

- **Total Marginal Loss Costs.** Total marginal loss costs in 2012 decreased by $397.9 million or 28.8 percent from 2011, from $1,379.6 million to $981.7 million. Day-ahead net marginal loss costs in 2012 decreased by $426.8 million or 29.8 percent from 2011, from $1,430.5 million to $1,003.8 million. Balancing net marginal loss costs increased in 2012 by $28.9 million or 56.7 percent from 2011, from -$51.0 million to -$22.1 million.[6]
- **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 2012 ranged from $51.0 million in April to $143.4 million in July.
- **Marginal Loss Credits.** Marginal Loss Credits are calculated as total energy costs (net energy costs minus net energy credits plus net inadvertent energy charges) plus total marginal loss costs (net marginal loss costs minus net marginal loss credits plus net explicit loss costs plus net inadvertent loss charges) plus net residual market adjustments. Marginal loss credit or loss surplus is the remaining loss amount from overcollection of marginal losses, after accounting for total net energy costs and net residual market adjustments that is paid back in full to load and exports on a load ratio basis.[7,8] The marginal loss credits decreased in 2012 by $200.0 million or 34.1 percent from 2011, from $586.8 million to $386.7 million.
- **Zonal Total Marginal Loss Costs.** In 2012, zonal total marginal loss costs ranged from $2.1 million in RECO to $205.9 million in AEP. Compared to 2011, 2012 had a decrease in total marginal loss costs across the PJM control zones, except the ATSI control zone, which had an increase.[9]

## Congestion Cost

Total congestion costs equal net implicit congestion costs plus net explicit congestion costs plus net inadvertent congestion charges. Net implicit congestion costs equal load congestion payments minus generation

6 Total marginal loss costs in PJM in 2012 also changed due to the addition of the DEOK Control Zone, which accounted for $3.2 million or 0.3 percent of the total marginal loss costs. The ATSI Control Zone had an increase in total marginal loss cost in 2012 because it became part of PJM on June 1, 2011, which left the first five months of 2011 out of the 2011 total marginal loss cost for ATSI.

7 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.

8 Net residual market adjustments are common costs, not directly attributable to specific participants, that are deducted from total marginal loss credits before marginal loss credits are distributed on a load weighted ratio basis. Net residual market adjustments consist of the Known Day-Ahead Error Value (KDAEV), day-ahead loss MW congestion value and balancing loss MW congestion value. KDAEV are costs associated with MW imbalances created by discontinuities in, and adjustments to, the day-ahead market solution. The day-ahead and balancing loss congestion values are congestion costs associated with loss related MW.

9 See the *2012 State of the Market Report for PJM*, Volume II, Appendix G, "Congestion and Marginal Losses," at "Zonal Marginal Loss Costs."

congestion credits. Net explicit congestion costs are the net congestion costs associated with point-to-point energy transactions. Net inadvertent congestion charges are the congestion costs associated with hourly difference between the net actual energy flow and the net scheduled energy flow into or out of the PJM control area in that hour. Unlike the other categories of congestion cost accounting, inadvertent congestion charges are common costs not directly attributable to specific participants. Inadvertent congestion charges are distributed to load on a load ratio basis. Each of these categories of congestion costs is comprised of day-ahead and balancing congestion costs.

Congestion charges can be both positive and negative. When a constraint binds, the price effects of that constraint vary. The system marginal price (SMP) is uniform for all areas, while the congestion components of Locational Marginal Price (LMP) will either be positive or negative in a specific area, meaning that actual LMPs are above or below the SMP.[10]

Day-ahead congestion charges and credits are based on MWh and LMP in the Day-Ahead Energy Market. Balancing congestion charges and credits are based on load or generation deviations between the Day-Ahead and Real-Time Energy Markets and LMP in the Real-Time Energy Market. If a participant has real-time generation or load that is greater than its day-ahead generation or load then the deviation will be positive. If there is a positive load deviation at a bus where real-time LMP has a positive congestion component, positive balancing congestion costs will result. Similarly, if there is a positive load deviation at a bus where real-time LMP has a negative congestion component, negative balancing congestion costs will result. If a participant has real-time generation or load that is less than its day-ahead generation or load then the deviation will be negative. If there is a negative load deviation at a bus where real-time LMP has a positive congestion component, negative balancing congestion costs will result. Similarly, if there is a negative load deviation at a bus where real-time LMP has a positive congestion component, negative balancing congestion costs will result.

10 The SMP is the price at the distributed load reference bus.

- **Total Congestion.** Total congestion costs decreased by $470.0 million or 47.0 percent, from $999.0 million in 2011 to $529.0 million in 2012.[11] Day-ahead congestion costs decreased by $465.1 million or 37.4 percent, from $1,245.0 million in 2011 to $779.9 million in 2012. Balancing congestion costs decreased by $4.9 million or 2.0 percent from -$246.0 million in 2011 to -$250.9 million in 2012.
- **Monthly Congestion.** Significant monthly fluctuations in congestion costs were the result of changes in load and energy import levels, changes in the dispatch of generation and variations in congestion frequency on constraints affecting large portions of PJM load. Monthly congestion costs in 2012 ranged from $24.9 million in October to $73.1 million in July.
- **Geographic Differences in CLMP.** Differences in CPLM among eastern, southern and western control zones in PJM was primarily a result of congestion on the AP South interface, the Graceton – Raphael Road line, the Woodstock flowgate (reciprocally coordinated between PJM and MISO), West Interface, and the Bedington – Black Oak 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 2012.[12] Day-ahead congestion frequency increased by 60.3 percent from 155,670 congestion event hours in 2011 to 249,572 congestion event hours in 2012. Day-ahead, congestion-event hours decreased on internal PJM interfaces but increased on transmission lines, transformers and reciprocally coordinated flowgates between PJM and the MISO.

  Real-time congestion frequency decreased by 7.1 percent from 22,513 congestion event hours in 2011 to 20,917 congestion event hours in 2012. Real-time, congestion-event hours decreased on the internal PJM interfaces and transformers, but increased on transmission lines and reciprocally coordinated flowgates between PJM and MISO.

  Facilities were constrained in the Day-Ahead Market more frequently than in the Real-Time Market. In

11 The total zonal congestion numbers were calculated as of March 2, 2013 and are, based on continued PJM billing updates, subject to change.

12 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.

2012, for only 3.2 percent of Day-Ahead Market facility constrained hours were the same facilities also constrained in the Real-Time Market. In 2012, for 38.3 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 2012. With $68.5 million in total congestion costs, it accounted for 16.1 percent of the total PJM congestion costs in 2012. The top five constraints in terms of congestion costs together contributed $177.0 million, or 41.6 percent, of the total PJM congestion costs in 2012. The top five constraints were the AP South interface, the West interface, the Bedington - Black Oak interface, the Woodstock flowgate (a reciprocally coordinated flowgate between PJM and MISO) and the Graceton - Raphael Road line.

- **Zonal Congestion.**[13] ComEd was the most congested zone in 2012.[14] ComEd had -$334.2 million in total load costs, -$521.6 million in total generation credits and -$16.4 million in explicit congestion, resulting in $171.0 million in net congestion costs, reflecting significant local congestion between local generation and load, despite being on the upstream side of system wide congestion patterns. The Nelson - Cordova transmission line, Woodstock flowgate, Rantoul - Rantoul Jct flowgate, Oak Grove – Galesburg flowgate and the Prairie State - W Mt. Vernon flowgate contributed $81.0 million, or 47.4 percent of the total ComEd Control Zone congestion costs.

  The AEP Control Zone was the second most congested zone in PJM in 2012, with $104.2 million. The Monticello - East Winamac flowgate contributed $12.4 million or 11.9 percent of the total AEP Control Zone congestion cost in 2012. The Dominion Control Zone was the third most congested zone in PJM in 2012, with a cost of $63.3 million.

- **Ownership.** In 2012, financial companies as a group were net recipients of congestion credits, and physical companies were net payers of congestion charges. In 2012, financial companies received $83.1 million in net congestion credits, a decrease of $91.6 million or 52.4 percent compared to 2011. In 2012, physical companies paid $612.1 million in net congestion charges, a decrease of $561.5 million or 47.8 percent compared to 2011.

## Conclusion

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 have been decreasing since 2010, due to decreases in LMP and decreases in fuel costs. Total marginal loss costs decreased in 2012 by $397.9 million or 28.8 percent from 2011, from $1,379.6 million to $981.7 million.

Marginal loss credits are distributed to load and exports. Marginal loss credits decreased in 2012 by $200.0 million or 34.1 percent from 2011, from $586.8 million to $386.7 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. Total congestion costs decreased by $470.0 million or 47.0 percent, from $999.0 million in 2011 to $529.0 million in 2012. Congestion costs were significantly higher in the Day-Ahead Market than in the Real-Time Market. Congestion frequency was also significantly higher in the Day-Ahead Market than in the Real-Time Market.

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 seven months of the 2012 to 2013 planning period, total ARR and FTR revenues offset 82.1 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 74.9 percent of the target allocation level for the first seven months of the 2012 to 2013 planning

13 Tables reporting zonal congestion have been moved from this section of the report to Appendix G. See the *2012 State of the Market Report for PJM*, Volume II, Appendix G, "Congestion and Marginal Losses."

14 The total zonal congestion numbers were calculated as of March 2, 2013 and are, based on continued PJM billing updates, subject to change. As of March 2, 2013, the total zonal congestion related numbers presented here differed from the March 2, 2013 PJM totals by $0.10 Million, a discrepancy of 0.02 percent (.00019).

period.[15] 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

As of June 1, 2007, PJM changed from a single node reference bus to a distributed load reference bus. While there is no effect on the total LMP, the components of LMP change with a shift in the reference bus. With a distributed load reference bus, the energy component is now a load-weighted system price. There are no congestion or losses included in the load weighted reference bus price, unlike the case with a single node reference bus.

LMP at a bus reflects the incremental price of energy at that bus. LMP at any bus is made up of three components: the system marginal price (SMP), marginal loss component of LMP (MLMP), and congestion component of LMP (CLMP).

SMP, MLMP and CLMP are a product of the least cost, security constrained dispatch of system resources to meet system load. SMP is the incremental cost of energy, given the current dispatch, ignoring incremental considerations of losses and transmission constraints. Losses refer to energy lost to physical resistance in the transmission and distribution network as power is moved from generation to load. The greater the resistance of the system to flows of energy from generation to loads, the greater the losses of the system and the greater the proportion of energy needed to meet a given level of load. Marginal losses are the incremental change in system power losses caused by changes in the system load and generation patterns.[16] The first derivative of total losses with respect to the power flow equals marginal losses. Congestion cost reflects the incremental cost of relieving transmission constraints while maintaining system power balance. Congestion occurs when available, least-cost energy cannot be delivered to all loads because transmission facilities are not adequate to deliver that energy. When the least-cost available energy cannot be delivered to load in a transmission-constrained area, higher cost units in the constrained area must be dispatched to meet that load.[17] The result is that the price of energy in the constrained area is higher than in the unconstrained area because of the combination of transmission limitations and the cost of local generation.

Table 10-1 shows the PJM real-time, load-weighted average LMP components for the years 2009 to 2012. The load-weighted average real-time LMP decreased $10.71 or 23.3 percent from $45.94 in 2011 to $35.23 in 2012. The load-weighted average congestion component decreased $0.01 or 26.9 percent from $0.05 in 2011 to $0.04 in 2012. The load-weighted average loss component decreased $0.01 or 26.9 percent from $0.02 in 2011 to $0.01 in 2012. The load-weighted average energy component decreased $10.69 or 23.3 percent from $45.87 in 2011 to $35.18 in 2012.

**Table 10-1 PJM real-time, load-weighted average LMP components (Dollars per MWh): 2009 through 2012**

| Year | Real-Time LMP | Energy Component | Congestion Component | Loss Component |
|---|---|---|---|---|
| 2009 | $39.05 | $38.97 | $0.05 | $0.03 |
| 2010 | $48.35 | $48.23 | $0.08 | $0.04 |
| 2011 | $45.94 | $45.87 | $0.05 | $0.02 |
| 2012 | $35.23 | $35.18 | $0.04 | $0.01 |

In the Real-Time Energy Market, the distributed load reference bus is weighted by system estimates of the load in real time. At the time the LMP is determined in the Real-Time Energy Market, the energy component equals the system load-weighted price. However, real-time bus-specific loads are adjusted, after the fact, according to updated information from meters. This meter adjusted load is accounting load that is used in settlements and forms the basis of the reported PJM load weighted prices. This after the fact adjustment means that the Real-Time Energy Market energy component of LMP (SMP) and the PJM real-time load-weighted LMP are not equal. The difference between the real-time energy component of LMP and the PJM-wide real-time load-weighted LMP is due to the difference between estimated and meter corrected loads used to weight the load-weighted reference bus and the load-weighted LMP.

15 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"

16 For additional information, see the MMU Technical Reference for PJM Markets, at "Marginal Losses."

17 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.

Table 10-2 shows the PJM day-ahead, load-weighted average LMP components for 2009 through 2012. The load-weighted average day-ahead LMP decreased $10.64 or 23.5 percent from $45.19 in 2011 to $34.55 in 2012. The load-weighted average congestion component increased $0.17 or 276.8 percent from -$0.06 in 2011 to $0.11 in 2012. The load-weighted average loss component increased $0.14 or 90.7 percent from -$0.15 in 2011 to -$0.01 in 2012. The load-weighted average energy component decreased $10.94 or 24.1 percent from $45.40 in 2011 to $34.46 in 2012. In terms of proportion of day-ahead LMP, the congestion and loss components both increased, while the energy component became a smaller proportion in 2012.

**Table 10-2 PJM day-ahead, load-weighted average LMP components (Dollars per MWh): 2009 through 2012**

| Year | Day-Ahead LMP | Energy Component | Congestion Component | Loss Component |
|---|---|---|---|---|
| 2009 | $38.82 | $38.96 | ($0.04) | ($0.09) |
| 2010 | $47.65 | $47.67 | $0.05 | ($0.07) |
| 2011 | $45.19 | $45.40 | ($0.06) | ($0.15) |
| 2012 | $34.55 | $34.46 | $0.11 | ($0.01) |

In the Day-Ahead Energy Market, the distributed load reference bus is weighted by fixed-demand bids only and the day-ahead energy component is, therefore, a system fixed demand weighted price. The day-ahead weighted system price calculation uses all types of demand, including fixed, price-sensitive and decrement bids. In the Real-Time Energy Market, the energy component equals the system load-weighted price. However, in the Day-Ahead Energy Market the day-ahead energy component of LMP and the PJM day-ahead load-weighted LMP are not equal. The difference between the day-ahead energy component of LMP and the PJM day-ahead load-weighted LMP is due to the difference in the types of demand used to weight the load-weighted reference bus and the load-weighted LMP.

## Zonal Components

The real-time components of LMP for each PJM control zone are presented in Table 10-3 for 2011 and 2012. The day-ahead components of LMP for each control zone are presented in Table 10-4 for years 2011 and 2012.

### Table 10-3 Zonal and PJM real-time, load-weighted average LMP components (Dollars per MWh): 2011 and 2012

| | 2011 | | | | 2012 | | | |
|---|---|---|---|---|---|---|---|---|
| | Real-Time LMP | Energy Component | Congestion Component | Loss Component | Real-Time LMP | Energy Component | Congestion Component | Loss Component |
| AECO | $53.11 | $46.83 | $3.92 | $2.37 | $37.55 | $35.86 | $0.23 | $1.46 |
| AEP | $40.92 | $45.26 | ($2.91) | ($1.43) | $33.15 | $34.73 | ($0.75) | ($0.83) |
| AP | $45.49 | $45.56 | $0.06 | ($0.13) | $34.86 | $34.91 | $0.04 | ($0.09) |
| ATSI | $42.09 | $44.59 | ($2.32) | ($0.18) | $34.42 | $34.99 | ($0.78) | $0.21 |
| BGE | $54.27 | $46.40 | $5.74 | $2.14 | $40.03 | $35.44 | $2.99 | $1.59 |
| ComEd | $36.20 | $45.77 | ($6.93) | ($2.64) | $31.76 | $35.39 | ($2.05) | ($1.58) |
| DAY | $41.78 | $45.94 | ($3.40) | ($0.75) | $34.25 | $35.14 | ($0.95) | $0.05 |
| DEOK | NA | NA | NA | NA | $32.67 | $35.16 | ($0.87) | ($1.62) |
| DLCO | $41.31 | $45.73 | ($2.98) | ($1.45) | $33.53 | $35.05 | ($0.47) | ($1.05) |
| Dominion | $50.59 | $46.45 | $3.54 | $0.60 | $37.28 | $35.45 | $1.48 | $0.35 |
| DPL | $52.20 | $46.54 | $3.05 | $2.60 | $39.53 | $35.53 | $2.31 | $1.68 |
| JCPL | $53.48 | $47.22 | $3.88 | $2.37 | $37.34 | $35.92 | $0.09 | $1.33 |
| Met-Ed | $49.51 | $45.82 | $2.87 | $0.82 | $36.30 | $35.11 | $0.67 | $0.53 |
| PECO | $50.83 | $46.16 | $3.05 | $1.62 | $36.78 | $35.27 | $0.61 | $0.89 |
| PENELEC | $45.12 | $44.98 | ($0.25) | $0.38 | $35.10 | $34.66 | ($0.12) | $0.56 |
| Pepco | $51.84 | $46.47 | $4.17 | $1.20 | $39.08 | $35.47 | $2.68 | $0.93 |
| PPL | $49.31 | $45.57 | $2.99 | $0.75 | $35.44 | $34.92 | $0.00 | $0.52 |
| PSEG | $52.68 | $46.36 | $3.96 | $2.35 | $37.48 | $35.38 | $0.71 | $1.39 |
| RECO | $49.66 | $47.48 | $0.02 | $2.16 | $37.80 | $36.09 | $0.42 | $1.29 |
| PJM | $45.94 | $45.87 | $0.05 | $0.02 | $35.23 | $35.18 | $0.04 | $0.01 |

### Table 10-4 Zonal and PJM day-ahead, load-weighted average LMP components (Dollars per MWh): 2011 and 2012

| | 2011 | | | | 2012 | | | |
|---|---|---|---|---|---|---|---|---|
| | Day-Ahead LMP | Energy Component | Congestion Component | Loss Component | Day-Ahead LMP | Energy Component | Congestion Component | Loss Component |
| AECO | $53.09 | $46.58 | $3.78 | $2.74 | $37.36 | $35.08 | $0.66 | $1.62 |
| AEP | $41.12 | $45.12 | ($2.39) | ($1.61) | $32.71 | $34.19 | ($0.51) | ($0.97) |
| AP | $45.10 | $45.08 | $0.10 | ($0.09) | $34.29 | $34.26 | $0.09 | ($0.06) |
| ATSI | $41.89 | $44.76 | ($1.83) | ($1.04) | $33.55 | $34.32 | ($0.69) | ($0.08) |
| BGE | $53.21 | $46.11 | $4.57 | $2.53 | $39.55 | $34.85 | $2.76 | $1.93 |
| ComEd | $35.72 | $45.16 | ($6.17) | ($3.28) | $30.72 | $34.60 | ($1.98) | ($1.90) |
| DAY | $41.54 | $45.64 | ($3.21) | ($0.89) | $33.76 | $34.58 | ($0.65) | ($0.16) |
| DEOK | NA | NA | NA | NA | $32.18 | $34.45 | ($0.49) | ($1.79) |
| DLCO | $40.98 | $45.35 | ($2.94) | ($1.43) | $33.05 | $34.42 | ($0.30) | ($1.07) |
| Dominion | $49.78 | $46.13 | $2.97 | $0.68 | $36.56 | $34.76 | $1.31 | $0.48 |
| DPL | $52.62 | $46.24 | $3.40 | $2.97 | $38.91 | $34.94 | $1.86 | $2.11 |
| JCPL | $52.22 | $46.47 | $3.08 | $2.67 | $37.03 | $35.10 | $0.47 | $1.47 |
| Met-Ed | $48.62 | $45.08 | $2.74 | $0.80 | $35.44 | $34.29 | $0.50 | $0.65 |
| PECO | $51.11 | $45.66 | $3.43 | $2.01 | $36.40 | $34.62 | $0.72 | $1.06 |
| PENELEC | $44.35 | $44.35 | ($0.25) | $0.24 | $34.69 | $33.95 | $0.12 | $0.62 |
| Pepco | $51.03 | $45.49 | $3.90 | $1.64 | $38.26 | $34.58 | $2.39 | $1.29 |
| PPL | $48.69 | $45.23 | $2.79 | $0.67 | $34.82 | $34.22 | $0.12 | $0.48 |
| PSEG | $52.23 | $45.96 | $3.53 | $2.75 | $37.25 | $34.81 | $0.79 | $1.65 |
| RECO | $49.96 | $46.39 | $1.48 | $2.10 | $36.91 | $35.20 | $0.34 | $1.36 |
| PJM | $45.19 | $45.40 | ($0.06) | ($0.15) | $34.55 | $34.46 | $0.11 | ($0.01) |

# 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 net of the load energy payments minus generation energy credits, plus explicit energy costs, plus inadvertent energy charges, incurred in both the Day-Ahead Energy Market and the balancing energy market. 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.

- **Day-Ahead Load Energy Payments.** Day-ahead, load energy payments are calculated for all cleared demand, decrement bids and Day-Ahead Energy Market sale transactions. (Decrement bids and energy sales are equivalent to demand.) Day-ahead, load energy payments are calculated using MW and the load bus energy component of LMP (energy LMP), the decrement bid energy LMP or the energy LMP at the source of the sale transaction, as applicable.
- **Day-Ahead Generation Energy Credits.** Day-ahead, generation energy credits are calculated for all cleared generation and increment offers and Day-Ahead Energy Market purchase transactions. (Increment offers and energy purchases are equivalent to generation.) Day-ahead, generation energy credits are calculated using MW and the generator bus energy LMP, the increment offer energy LMP or the energy LMP at the sink of the purchase transaction, as applicable.
- **Balancing Load Energy Payments.** Balancing, load energy payments are calculated for all deviations between a PJM member's real-time load and energy sale transactions and their day-ahead cleared demand, decrement bids and energy sale transactions. Balancing, load energy payments are calculated using MW deviations and the real-time energy LMP for each bus where a deviation exists.
- **Balancing Generation Energy Credits.** Balancing, generation energy credits are calculated for all deviations between a PJM member's real-time generation and energy purchase transactions and the day-ahead cleared generation, increment offers and energy purchase transactions. Balancing, generation energy credits are calculated using MW deviations and the real-time energy LMP for each bus where a deviation exists.
- **Explicit Energy Costs.** Explicit energy costs are the net energy costs associated with point-to-point energy transactions. These costs equal the product of the transacted MW and energy LMP differences between sources (origins) and sinks (destinations) in the Day-Ahead Energy Market. Balancing energy market explicit energy costs equal the product of the differences between the real-time and day-ahead transacted MW and the differences between the real-time energy LMP at the transactions' sources and sinks. The explicit energy costs will sum to zero because the LMP (SMP) at the transactions' sources and sinks will be the same for each transaction.
- **Inadvertent Energy Charges.** Inadvertent energy charges are the net energy charges resulting from the differences between the net actual energy flow and the net scheduled energy flow into or out of the PJM control area each hour. This inadvertent interchange of energy may be positive or negative, where positive interchange typically results in a charge while negative interchange typically results in a credit. Inadvertent energy charges are common costs, not directly attributable to specific participants, which are distributed on a load ratio basis.[18]

## Total Energy Costs

Table 10-5 shows total energy, loss and congestion component costs and total PJM billing, for each year from 2009 through 2012. The total energy, loss and congestion component costs appear low compared to total PJM billing because these totals are actually net energy, loss and congestion costs.

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

### Table 10-5 Total PJM costs by component (Dollars (Millions)): 2009 through 2012[19]

| | Component Costs (Millions) | | | | | |
|---|---|---|---|---|---|---|
| | Energy Costs | Loss Costs | Congestion Costs | Total Costs | Total PJM Billing | Total Costs Percent of PJM Billing |
| 2009 | ($629) | $1,268 | $719 | $1,358 | $26,550 | 5.1% |
| 2010 | ($798) | $1,635 | $1,424 | $2,261 | $34,771 | 6.5% |
| 2011 | ($794) | $1,380 | $998 | $1,584 | $35,887 | 4.4% |
| 2012 | ($593) | $982 | $529 | $926 | $29,181 | 3.2% |

### Table 10-6 Total PJM energy costs by category (Dollars (Millions)): 2009 through 2012

| | Energy Costs (Millions) | | | | |
|---|---|---|---|---|---|
| | Load Payments | Generation Credits | Explicit Costs | Inadvertent Charges | Total |
| 2009 | $42,535.2 | $43,165.7 | $0.0 | $1.7 | ($628.8) |
| 2010 | $53,101.5 | $53,886.9 | $0.0 | ($12.6) | ($797.9) |
| 2011 | $47,658.9 | $48,480.9 | $0.0 | $28.3 | ($793.7) |
| 2012 | $37,471.4 | $38,073.5 | $0.0 | $9.1 | ($593.0) |

Energy costs for 2009 through 2012 are shown in Table 10-6 and Table 10-7. Table 10-6 shows PJM energy costs by category for 2009 through 2012 and Table 10-7 shows PJM energy costs by market category for 2009 through 2012. These energy costs are the actual total energy costs rather than the net energy costs in Table 10-5.

### Table 10-7 Total PJM energy costs by market category (Dollars (Millions)): 2009 through 2012

| | Energy Costs (Millions) | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Day Ahead | | | | Balancing | | | | | |
| | Load Payments | Generation Credits | Explicit Costs | Total | Load Payments | Generation Credits | Explicit Costs | Total | Inadvertent Charges | Grand Total |
| 2009 | $42,683.8 | $43,351.2 | $0.0 | ($667.4) | ($148.5) | ($185.5) | $0.0 | $36.9 | $1.7 | ($628.8) |
| 2010 | $53,164.9 | $53,979.1 | $0.0 | ($814.1) | ($63.4) | ($92.2) | $0.0 | $28.8 | ($12.6) | ($797.9) |
| 2011 | $48,144.9 | $48,880.0 | $0.0 | ($735.2) | ($485.9) | ($399.1) | $0.0 | ($86.8) | $28.3 | ($793.7) |
| 2012 | $37,641.2 | $38,251.1 | $0.0 | ($609.9) | ($169.8) | ($177.6) | $0.0 | $7.8 | $9.1 | ($593.0) |

## Monthly Energy Costs

Table 10-8 shows a monthly summary of energy costs by type for 2011 and 2012.

### Table 10-8 Monthly energy costs by type (Dollars (Millions)): 2011 and 2012

| | Energy Costs (Millions) | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | 2011 | | | | 2012 | | | |
| | Day-Ahead Total | Balancing Total | Inadvertent Charges | Grand Total | Day-Ahead Total | Balancing Total | Inadvertent Charges | Grand Total |
| Jan | ($90.3) | ($5.2) | $2.1 | ($93.3) | ($48.5) | ($10.1) | $2.5 | ($56.1) |
| Feb | ($61.1) | ($2.4) | $2.3 | ($61.2) | ($36.0) | ($9.9) | $2.4 | ($43.5) |
| Mar | ($52.4) | ($5.4) | $2.4 | ($55.4) | ($30.1) | ($8.6) | $1.9 | ($36.8) |
| Apr | ($49.9) | ($0.3) | $2.5 | ($47.7) | ($30.7) | ($2.8) | $0.7 | ($32.8) |
| May | ($54.8) | ($0.2) | $2.9 | ($52.1) | ($39.4) | $0.1 | ($0.3) | ($39.6) |
| Jun | ($82.1) | ($3.2) | $1.1 | ($84.2) | ($57.1) | $4.0 | $0.0 | ($53.1) |
| Jul | ($110.0) | ($16.8) | $6.7 | ($120.1) | ($84.0) | $3.0 | $0.6 | ($80.4) |
| Aug | ($66.9) | ($16.4) | $5.0 | ($78.2) | ($60.3) | $2.6 | $0.3 | ($57.4) |
| Sep | ($55.0) | ($5.5) | $1.5 | ($59.0) | ($43.6) | $1.1 | ($0.2) | ($42.8) |
| Oct | ($42.7) | ($5.9) | $0.3 | ($48.3) | ($42.2) | $1.6 | $0.2 | ($40.5) |
| Nov | ($30.2) | ($14.6) | $0.8 | ($44.0) | ($65.2) | $7.8 | $1.1 | ($56.2) |
| Dec | ($39.7) | ($11.0) | $0.6 | ($50.1) | ($72.7) | $19.0 | ($0.1) | ($53.8) |
| Total | ($735.2) | ($86.8) | $28.3 | ($793.7) | ($609.9) | $7.8 | $9.1 | ($593.0) |

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

# Marginal Losses

## Marginal Loss Accounting

PJM calculates marginal loss costs for each PJM member.

- **Day-Ahead Load Loss Payments.** Day-ahead, load loss payments are calculated for all cleared demand, decrement bids and Day-Ahead Energy Market sale transactions. Day-ahead, load loss payments are calculated using MW and the load bus loss component of LMP (MLMP), the decrement bid MLMP or the MLMP at the source of the sale transaction, as applicable.
- **Day-Ahead Generation Loss Credits.** Day-ahead, generation loss credits are calculated for all cleared generation and increment offers and Day-Ahead Energy Market purchase transactions. Day-ahead, generation loss credits are calculated using MW and the generator bus MLMP, the increment offer MLMP or the MLMP at the sink of the purchase transaction, as applicable.
- **Balancing Load Loss Payments.** Balancing, load loss payments are calculated for all deviations between a PJM member's real-time load and energy sale transactions and their day-ahead cleared demand, decrement bids and energy sale transactions. Balancing, load loss payments are calculated using MW deviations and the real-time MLMP for each bus where a deviation exists.
- **Balancing Generation Loss Credits.** Balancing, generation loss credits are calculated for all deviations between a PJM member's real-time generation and energy purchase transactions and the day-ahead cleared generation, increment offers and energy purchase transactions. Balancing, generation loss credits are calculated using MW deviations and the real-time MLMP for each bus where a deviation exists.
- **Explicit Loss Costs.** Explicit loss costs are the net loss costs associated with point-to-point energy transactions. These costs equal the product of the transacted MW and MLMP differences between sources (origins) and sinks (destinations) in the Day-Ahead Energy Market. Balancing energy market explicit loss costs equal the product of the differences between the real-time and day-ahead transacted MWs and the differences between the real-time MLMP at the transactions' sources and sinks.
- **Inadvertent Loss Charges.** Inadvertent loss charges are the net loss charges resulting from the differences between the net actual energy flow and the net scheduled energy flow into or out of the PJM control area each hour. This inadvertent interchange of energy may be positive or negative, where positive interchange typically results in a charge while negative interchange typically results in a credit. Inadvertent loss charges are common costs, not directly attributable to specific participants, that are distributed on a load ratio basis.[20]

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, plus inadvertent loss charges, 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.

Monthly marginal loss costs in 2012 ranged from $51.0 million in April to $143.4 million in July.

Marginal loss credits decreased in 2012 by $200.0 million or 34.1 percent from 2011, from $586.8 million to $386.7 million.

## Total Marginal Loss Costs

Table 10-9 shows the total marginal loss component costs for 2009 through 2012. The yearly total loss component costs appear low compared to total PJM billing because these totals are actually net loss costs.

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

### Table 10-9 Total PJM Marginal Loss Component Costs (Dollars (Millions)): 2009 through 2012[21]

| | Loss Costs | Percent Change | Total PJM Billing | Percent of PJM Billing |
|---|---|---|---|---|
| 2009 | $1,268 | NA | $26,550 | 4.8% |
| 2010 | $1,635 | 29.0% | $34,771 | 4.7% |
| 2011 | $1,380 | (15.6%) | $35,887 | 3.8% |
| 2012 | $982 | (28.8%) | $29,181 | 3.4% |

Total marginal loss costs for 2009 through 2012 are shown in Table 10-10 and Table 10-11. Table 10-10 shows PJM total marginal loss costs by category for 2009 through 2012. Table 10-11 shows PJM total marginal loss costs by market category for 2009 through 2012.

### Table 10-10 Total PJM marginal loss costs by category (Dollars (Millions)): 2009 through 2012

| | Marginal Loss Costs (Millions) | | | | |
|---|---|---|---|---|---|
| | Load Payments | Generation Credits | Explicit Costs | Inadvertent Charges | Total |
| 2009 | ($78.4) | ($1,314.2) | $32.0 | ($0.0) | $1,267.7 |
| 2010 | ($122.3) | ($1,707.0) | $50.2 | ($0.0) | $1,634.8 |
| 2011 | ($174.0) | ($1,551.9) | $1.6 | $0.0 | $1,379.6 |
| 2012 | ($11.1) | ($1,036.8) | ($44.0) | $0.0 | $981.7 |

### Table 10-11 Total PJM marginal loss costs by market category (Dollars (Millions)): 2009 through 2012

| | Marginal Loss Costs (Millions) | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Day Ahead | | | | Balancing | | | | | |
| | Load Payments | Generation Credits | Explicit Costs | Total | Load Payments | Generation Credits | Explicit Costs | Total | Inadvertent Charges | Grand Total |
| 2009 | ($84.7) | ($1,311.7) | $65.4 | $1,292.3 | $6.4 | ($2.5) | ($33.5) | ($24.6) | ($0.0) | $1,267.7 |
| 2010 | ($146.3) | ($1,716.1) | $95.8 | $1,665.6 | $23.9 | $9.1 | ($45.6) | ($30.8) | ($0.0) | $1,634.8 |
| 2011 | ($215.4) | ($1,592.1) | $53.8 | $1,430.5 | $41.4 | $40.2 | ($52.2) | ($51.0) | $0.0 | $1,379.6 |
| 2012 | ($43.0) | ($1,060.3) | ($13.4) | $1,003.8 | $32.0 | $23.4 | ($30.6) | ($22.1) | $0.0 | $981.7 |

### Table 10-12 Monthly marginal loss costs by type (Dollars (Millions)): 2011 and 2012

| | Marginal Loss Costs (Millions) | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | 2011 | | | | 2012 | | | |
| | Day-Ahead Total | Balancing Total | Inadvertent Charges | Grand Total | Day-Ahead Total | Balancing Total | Inadvertent Charges | Grand Total |
| Jan | $188.5 | ($2.9) | $0.0 | $185.7 | $100.6 | ($5.4) | $0.0 | $95.2 |
| Feb | $121.8 | ($1.8) | $0.0 | $119.9 | $80.4 | ($3.1) | $0.0 | $77.2 |
| Mar | $108.8 | ($4.8) | $0.0 | $104.0 | $67.1 | ($5.2) | $0.0 | $61.9 |
| Apr | $84.8 | ($5.6) | $0.0 | $79.2 | $55.4 | ($4.4) | $0.0 | $51.0 |
| May | $94.3 | ($7.0) | $0.0 | $87.3 | $69.6 | ($2.5) | ($0.0) | $67.1 |
| Jun | $129.9 | ($4.5) | $0.0 | $125.4 | $93.3 | ($0.8) | $0.0 | $92.5 |
| Jul | $217.4 | ($3.7) | $0.0 | $213.7 | $141.8 | $1.6 | $0.0 | $143.4 |
| Aug | $137.9 | ($3.5) | $0.0 | $134.5 | $96.1 | $2.4 | $0.0 | $98.5 |
| Sep | $107.7 | ($4.7) | $0.0 | $102.9 | $71.7 | ($0.9) | ($0.0) | $70.8 |
| Oct | $85.7 | ($3.6) | $0.0 | $82.0 | $65.9 | ($1.7) | $0.0 | $64.1 |
| Nov | $76.0 | ($1.7) | $0.0 | $74.3 | $83.0 | ($0.6) | $0.0 | $82.5 |
| Dec | $77.8 | ($7.1) | $0.0 | $70.6 | $78.8 | ($1.3) | $0.0 | $77.5 |
| Total | $1,430.5 | ($51.0) | $0.0 | $1,379.6 | $1,003.8 | ($22.1) | $0.0 | $981.7 |

## Monthly Marginal Loss Costs

Table 10-12 shows a monthly summary of marginal loss costs by type for 2011 and 2012.

## Marginal Loss Costs and Loss Credits

Marginal loss credits (loss surplus) are calculated by adding the total energy costs, the total marginal loss costs and net residual market adjustments. The total energy costs are equal to the net implicit energy costs (load energy payments less generation energy credits) plus net explicit energy costs plus net inadvertent energy charges. Total marginal loss costs are equal to the net implicit marginal loss costs (load loss payments less generation loss credits) plus net explicit loss costs plus net inadvertent loss charges.

21 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.

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 10-13 shows the total energy costs, the total marginal loss costs collected, the net residual market adjustments and total marginal loss credits redistributed for 2009 through 2012.

### Table 10-13 Marginal loss credits (Dollars (Millions)): 2009 through 2012[22]

| | Loss Credit Accounting (Millions) | | | |
|---|---|---|---|---|
| | Total Energy Costs | Total Marginal Loss Costs | Net Residual Adjustments | Loss Credits |
| 2009 | ($628.8) | $1,267.7 | $0.8 | $639.7 |
| 2010 | ($797.9) | $1,634.8 | ($0.5) | $836.4 |
| 2011 | ($793.7) | $1,379.6 | $0.9 | $586.8 |
| 2012 | ($593.0) | $981.7 | ($2.0) | $386.7 |

# Congestion

## Congestion Accounting

Transmission congestion occurs in the Day-Ahead and Real-Time Energy Market.[23] Total congestion costs are equal to the net implicit congestion costs plus net explicit congestion costs plus net inadvertent congestion charges, incurred in both the Day-Ahead Energy Market and the balancing energy market.

In the analysis of total congestion costs, load congestion payments are netted against generation congestion credits on an hourly basis, by billing organization, and then summed for the given period.[24]

Load Congestion Payments and Generation Congestion Credits are calculated for both the Day-Ahead and Balancing Energy Markets.

- **Day-Ahead Load Congestion Payments.** Day-ahead load congestion payments are calculated for all cleared demand, decrement bids and Day-Ahead Energy Market sale transactions. Day-ahead load congestion payments are calculated using MW and the load bus CLMP, the decrement bid CLMP or the CLMP at the source of the sale transaction, as applicable.
- **Day-Ahead Generation Congestion Credits.** Day-ahead generation congestion credits are calculated for all cleared generation, increment offers and Day-Ahead Energy Market purchase transactions. Day-ahead generation congestion credits are calculated using MW and the generator bus CLMP, the increment offer's CLMP or the CLMP at the sink of the purchase transaction, as applicable.
- **Balancing Load Congestion Payments.** Balancing load congestion payments are calculated for all deviations between a PJM member's real-time load and energy sale transactions and their day-ahead cleared demand, decrement bids and energy sale transactions. Balancing load congestion payments are calculated using MW deviations and the real-time CLMP for each bus where a deviation exists.
- **Balancing Generation Congestion Credits.** Balancing generation congestion credits are calculated for all deviations between a PJM member's real-time generation and energy purchase transactions and the day-ahead cleared generation, increment offers and energy purchase transactions. Balancing generation congestion credits are calculated using MW deviations and the real-time CLMP for each bus where a deviation exists.
- **Explicit Congestion Costs.** Explicit congestion costs are the net congestion costs associated with point-to-point energy transactions. These costs equal the product of the transacted MW and CLMP differences between sources (origins) and sinks (destinations) in the Day-Ahead Energy Market. Balancing energy market explicit congestion costs equal the product of the deviations between the real-time and day-ahead transacted MWs and the differences between the real- time CLMP at the transactions' sources and sinks.
- **Inadvertent Congestion Charges.** Inadvertent congestion charges are congestion charges resulting from the differences between the net actual energy

22 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.

23 When the term *congestion charges* is used in documents by PJM's Market Settlement Operations, it has the same meaning as the term *congestion costs* as used here.

24 This analysis does not treat affiliated billing organizations as a single organization. Thus, the generation congestion credits from one organization will not offset the load payments of its affiliate. This may overstate or understate the actual load payments or generation credits of an organization's parent company.

flow and the net scheduled energy flow into or out of the PJM control area each hour. This inadvertent interchange of energy may be positive or negative, where positive interchange typically results in a charge while negative interchange typically results in a credit. Inadvertent congestion charges are common costs, not directly attributable to specific participants, that are distributed on a load ratio basis.[25]

The congestion costs associated with specific constraints are the sum of the total day-ahead and balancing congestion costs associated with those constraints. The congestion costs in each zone are the sum of the congestion costs associated with each constraint that affects prices in the zone. The network nature of the transmission system means that congestion costs in a zone are frequently the result of constrained facilities located outside that zone.

Congestion costs can be both positive and negative and consequently load payments and generation credits can be both positive and negative. The CLMP is calculated with respect to the system reference bus LMP, also called the system marginal price (SMP). When a transmission constraint occurs, the resulting CLMP is positive on one side of the constraint and negative on the other side of the constraint and the corresponding congestion costs are positive or negative. For each transmission constraint, the CLMP reflects the cost of a constraint at a pricing node and is equal to the product of the constraint shadow price and the distribution factor at the respective pricing node. The total CLMP at a pricing node is the sum of all constraint contributions to LMP and is equal to the difference between the actual LMP that results from transmission constraints, excluding losses, and the SMP. If an area experiences lower prices because of a constraint, the CLMP in that area is negative.[26]

The congestion metric requires careful review when considering the significance of congestion. The net congestion bill is calculated by subtracting generating congestion credits from load congestion payments. The logic is that congestion payments by load are offset by congestion revenues to generation, for the area analyzed. Whether the net congestion bill is an appropriate measure of congestion for load depends on who pays the load congestion payments and who receives the generation congestion credits. The net congestion bill is an appropriate measure of congestion for a utility that charges load congestion payments to load and credits generation congestion credits to load. The net congestion bill is not an appropriate measure of congestion in situations where load pays the load congestion payments but does not receive the generation credits as an offset.

Net congestion, which includes both load congestion payments and generation congestion credits, is not a good measure of the congestion costs paid by load from the perspective of the wholesale market.[27] While total congestion costs represent the overall charge or credit to a zone, the components of congestion costs measure the extent to which load or generation bear total congestion costs. Load congestion payments, when positive, measure the total congestion cost to load in an area. Load congestion payments, when negative, measure the total congestion credit to load in an area. Negative load congestion payments result when load is on the lower priced side of a constraint or constraints. For example, congestion across the AP South interface means lower prices in western control zones and higher prices in eastern and southern control zones. Load in western control zones will benefit from lower prices and receive a congestion credit (negative load congestion payment). Load in the eastern and southern control zones will incur a congestion charge (positive load congestion payment). The reverse is true for generation congestion credits. Generation congestion credits, when positive, measure the total congestion credit to generation in an area. Generation congestion credits, when negative, measure the total congestion cost to generation in an area. Negative generation congestion credits are a cost in the sense that revenues to generators in the area are lower, by the amount of the congestion cost, than they would have been if they had been paid LMP without a congestion component, the total of system marginal price and the loss component. Negative generation congestion credits result when generation is on the lower priced side of a constraint or constraints. For example, congestion across the AP South interface

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

26 For an example of the congestion accounting methods used in this section, see *MMU Technical Reference for PJM Markets*, at "FTRs and ARRs."

27 The actual congestion payments by retail customers are a function of retail ratemaking policies and may or may not reflect an offset for congestion credits.

means lower prices in the western control zones and higher prices in the eastern and southern control zones. Generation in the western control zones will receive lower prices and incur a congestion charge (negative generation congestion credit). Generation in the eastern and southern control zones will receive higher prices and receive a congestion credit (positive generation congestion credit).

As an example, total congestion costs in PJM 2012 were $529.0 million, which was comprised of load congestion payments of $138.5 million, generation credits of -$444.0 million and explicit congestion of -$53.5 million (Table 10-15).

## Total Congestion

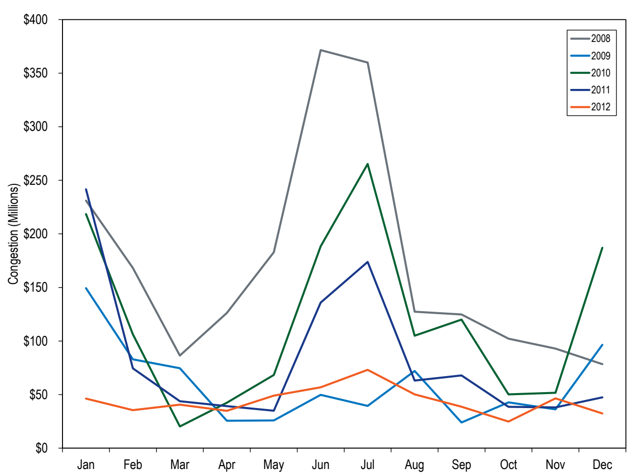
Table 10-14 shows total congestion for 2008 to 2012.[28]

### Table 10-14 Total PJM congestion (Dollars (Millions)): 2008 to 2012

| | Congestion Costs (Millions) | | | |
|---|---|---|---|---|
| | Congestion Cost | Percent Change | Total PJM Billing | Percent of PJM Billing |
| 2008 | $2,051.8 | NA | $34,306.0 | 6.0% |
| 2009 | $719.0 | (65.0%) | $26,550.0 | 2.7% |
| 2010 | $1,423.3 | 98.0% | $34,771.0 | 4.1% |
| 2011 | $999.0 | (29.8%) | $35,887.0 | 2.8% |
| 2012 | $529.0 | (47.0%) | $29,181.0 | 1.8% |

Figure 10-1 shows PJM monthly congestion for 2008 through 2012.

### Figure 10-1 PJM monthly congestion (Dollars (Millions)): 2008 to 2012




Total congestion costs in Table 10-15 include congestion costs associated with PJM facilities and those associated with reciprocal, coordinated flowgates in the MISO.[29]

Table 10-16 shows the 2012 congestion costs by category. The 2012 PJM total congestion costs were comprised of $138.5 million in load congestion payments, -$444.0 million in generation congestion credits, and -$53.5 million in explicit congestion costs.

### Table 10-15 Total PJM congestion costs by category (Dollars (Millions)): 2011 to 2012

| | Congestion Costs (Millions) | | | | |
|---|---|---|---|---|---|
| | Load Payments | Generation Credits | Explicit Costs | Inadvertent Charges | Total |
| 2011 | $112.2 | ($1,009.9) | ($123.1) | $0.0 | $999.0 |
| 2012 | $138.5 | ($444.0) | ($53.5) | $0.0 | $529.0 |

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

29 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 March 13, 2012).

### Table 10-16 Total PJM congestion costs by market category (Dollars (Millions)): 2011 to 2012

| | Congestion Costs (Millions) | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Day Ahead | | | | Balancing | | | | | |
| | Load Payments | Generation Credits | Explicit Costs | Total | Load Payments | Generation Credits | Explicit Costs | Total | Inadvertent Charges | Grand Total |
| 2011 | $36.2 | ($1,141.8) | $66.9 | $1,245.0 | $75.9 | $131.9 | ($190.0) | ($246.0) | $0.0 | $999.0 |
| 2012 | $135.5 | ($512.5) | $131.9 | $779.9 | $3.0 | $68.5 | ($185.4) | ($250.9) | $0.0 | $529.0 |

## Monthly Congestion

Table 10-17 shows that during 2012, monthly congestion costs ranged from $24.9 million to $73.1 million. Table 10-18 shows the congestion costs during 2011. Monthly congestion costs in 2012 were lower than in 2011.

### Table 10-17 Monthly PJM congestion costs (Dollars (Millions)): 2012

| | Congestion Costs (Millions) | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Day Ahead | | | | Balancing | | | | | |
| Month | Load Payments | Generation Credits | Explicit Costs | Total | Load Payments | Generation Credits | Explicit Costs | Total | Inadvertent Charges | Grand Total |
| Jan | $4.0 | ($53.1) | $9.3 | $66.3 | $1.0 | $5.7 | ($15.4) | ($20.0) | $0.0 | $46.3 |
| Feb | $9.1 | ($38.3) | $7.4 | $54.8 | ($3.7) | $2.7 | ($12.8) | ($19.2) | $0.0 | $35.5 |
| Mar | $10.4 | ($38.5) | $10.9 | $59.8 | ($1.6) | $3.7 | ($13.8) | ($19.1) | $0.0 | $40.7 |
| Apr | $11.7 | ($43.7) | $16.5 | $72.0 | ($3.2) | $5.2 | ($28.7) | ($37.1) | $0.0 | $34.9 |
| May | $13.4 | ($37.2) | $16.7 | $67.2 | $0.5 | ($2.6) | ($21.2) | ($18.2) | $0.0 | $49.1 |
| Jun | $14.0 | ($50.9) | $4.7 | $69.6 | $5.4 | $8.3 | ($9.8) | ($12.7) | $0.0 | $56.8 |
| Jul | $13.9 | ($67.6) | $9.5 | $91.0 | $3.3 | $7.3 | ($13.9) | ($17.9) | $0.0 | $73.1 |
| Aug | $23.9 | ($30.0) | $6.9 | $60.8 | $5.9 | $6.9 | ($9.6) | ($10.6) | $0.0 | $50.2 |
| Sep | $12.8 | ($44.0) | $4.9 | $61.8 | ($3.9) | $6.9 | ($12.3) | ($23.1) | $0.0 | $38.7 |
| Oct | $2.6 | ($38.1) | $13.7 | $54.4 | ($3.1) | $7.8 | ($18.7) | ($29.6) | $0.0 | $24.9 |
| Nov | $10.3 | ($40.5) | $15.7 | $66.4 | $2.1 | $9.3 | ($12.7) | ($19.9) | $0.0 | $46.5 |
| Dec | $9.5 | ($30.5) | $15.8 | $55.8 | $0.3 | $7.3 | ($16.4) | ($23.4) | $0.0 | $32.4 |
| Total | $135.5 | ($512.5) | $131.9 | $779.9 | $3.0 | $68.5 | ($185.4) | ($250.9) | $0.0 | $529.0 |

### Table 10-18 Monthly PJM congestion costs (Dollars (Millions)): 2011

| | Congestion Costs (Millions) | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Day Ahead | | | | Balancing | | | | | |
| Month | Load Payments | Generation Credits | Explicit Costs | Total | Load Payments | Generation Credits | Explicit Costs | Total | Inadvertent Charges | Grand Total |
| Jan | $27.0 | ($228.4) | $0.9 | $256.4 | $21.1 | $15.6 | ($20.3) | ($14.8) | $0.0 | $241.6 |
| Feb | $14.0 | ($77.5) | $1.0 | $92.5 | $5.6 | $12.8 | ($10.9) | ($18.0) | $0.0 | $74.5 |
| Mar | ($2.5) | ($58.8) | $2.2 | $58.4 | $0.2 | $4.7 | ($10.0) | ($14.6) | $0.0 | $43.9 |
| Apr | $5.0 | ($56.5) | $6.6 | $68.0 | $1.4 | $6.4 | ($23.7) | ($28.8) | $0.0 | $39.2 |
| May | $14.3 | ($41.5) | $8.6 | $64.3 | $3.0 | $7.4 | ($24.9) | ($29.3) | $0.0 | $35.0 |
| Jun | $1.8 | ($154.0) | $6.4 | $162.3 | $13.1 | $22.4 | ($17.1) | ($26.4) | $0.0 | $135.9 |
| Jul | $3.8 | ($184.1) | $6.5 | $194.4 | $21.2 | $21.6 | ($20.2) | ($20.6) | $0.0 | $173.8 |
| Aug | $4.7 | ($63.7) | $6.6 | $75.0 | ($0.4) | $1.8 | ($9.7) | ($11.9) | $0.0 | $63.1 |
| Sep | $0.0 | ($84.9) | $6.9 | $91.9 | $8.8 | $21.2 | ($11.5) | ($23.9) | $0.0 | $67.9 |
| Oct | ($8.7) | ($59.7) | $6.9 | $58.0 | $2.1 | $6.2 | ($15.2) | ($19.4) | $0.0 | $38.6 |
| Nov | ($12.6) | ($64.6) | $5.3 | $57.3 | ($0.6) | $6.8 | ($11.8) | ($19.2) | $0.0 | $38.1 |
| Dec | ($10.6) | ($68.1) | $9.0 | $66.5 | $0.5 | $5.0 | ($14.6) | ($19.1) | $0.0 | $47.4 |
| Total | $36.2 | ($1,141.8) | $66.9 | $1,245.0 | $75.9 | $131.9 | ($190.0) | ($246.0) | $0.0 | $999.0 |

# 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 2012, there were 249,572 day-ahead, congestion-event hours compared to 155,670 day-ahead, congestion-event hours in 2011. In 2012, there were 20,917 real-time, congestion-event hours compared to 22,513 real-time, congestion-event hours in 2011.

During 2012, for only 3.2 percent of Day-Ahead Market facility constrained hours were the same facilities also constrained in the Real-Time Market. During 2012, for 38.3 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 2012. With $68.5 million in total congestion costs, it accounted for 16.1 percent of the total PJM congestion costs in 2012. The top five constraints in terms of congestion costs together contributed $177.0 million, or 41.6 percent, of the total PJM congestion costs in 2012. The top five constraints were the AP South interface, Graceton – Raphael Road transmission line, Woodstock flowgate, Bedington - Black Oak interface and West interface.

## Congestion by Facility Type and Voltage

In 2012, compared to 2011, day-ahead, congestion-event hours increased on the reciprocally coordinated flowgates between PJM and MISO, transmission lines and transformers while congestion frequency on internal PJM interfaces decreased. Real-time, congestion-event hours increased on the reciprocally coordinated flowgates between PJM and the MISO and transmission lines, while congestion frequency on interfaces and transformers decreased.

Day-ahead congestion costs increased on the reciprocally coordinated flowgates between PJM and MISO in 2012 compared to 2011 and decreased on PJM interfaces, transmission lines and transformers in 2012 compared to 2011. Balancing congestion costs increased on the reciprocally coordinated flowgates between PJM and MISO and transformers and decreased on PJM interfaces and transmission lines in 2012 compared to 2011.

Table 10-19 provides congestion-event hour subtotals and congestion cost subtotals comparing the 2012 results by facility type: line, transformer, interface, flowgate and unclassified facilities.[30,31] For comparison, this information is presented in Table 10-20 for 2011.[32]

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 2012, there were 249,572 congestion event hours in the Day-Ahead Market. Among those, only 8,098 (3.2 percent) were also constrained in the Real-Time Market. In 2011, among the 155,670 day-ahead congestion event hours, only 8,976 (5.8 percent) were binding in the Real-Time Market.[33]

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 2012, there were 20,917 congestion event hours in the Real-Time Market. Among these, 8,011 (38.3 percent) were also constrained in the Day-Ahead Market. In 2011, among the 22,513 real-time congestion event hours, only 8,885 (39.5 percent) were binding in the day-ahead.

30 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.

31 The term flowgate refers to MISO flowgates in this section.

32 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.

33 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 10-19 Congestion summary (By facility type): 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 | ($60.3) | ($190.2) | $39.4 | $169.3 | ($5.9) | $10.5 | ($81.5) | ($97.9) | $71.4 | 29,500 | 7,772 |
| Interface | $70.8 | ($68.8) | $2.9 | $142.5 | $14.6 | $21.6 | ($3.6) | ($10.6) | $131.9 | 7,005 | 737 |
| Line | $78.0 | ($193.3) | $63.2 | $334.6 | ($9.0) | $31.4 | ($82.8) | ($123.2) | $211.3 | 144,670 | 10,151 |
| Other | $9.7 | ($4.3) | $2.0 | $16.0 | ($0.6) | $0.0 | ($0.9) | ($1.6) | $14.4 | 8,007 | 433 |
| Transformer | $31.1 | ($54.8) | $22.7 | $108.5 | $4.4 | $3.8 | ($15.5) | ($14.9) | $93.6 | 60,390 | 1,824 |
| Unclassified | $6.2 | ($1.2) | $1.7 | $9.1 | ($0.5) | $1.2 | ($1.2) | ($2.8) | $6.3 | NA | NA |
| Total | $135.5 | ($512.5) | $131.9 | $779.9 | $3.0 | $68.5 | ($185.4) | ($250.9) | $529.0 | 249,572 | 20,917 |

## Table 10-20 Congestion summary (By facility type): 2011

| | 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 | ($109.0) | ($212.8) | $11.0 | $114.8 | $8.4 | $22.9 | ($88.5) | ($103.0) | $11.8 | 23,179 | 7,423 |
| Interface | $64.0 | ($395.3) | ($10.7) | $448.7 | $37.7 | $38.3 | $7.1 | $6.4 | $455.1 | 9,013 | 1,803 |
| Line | $45.6 | ($346.3) | $39.5 | $431.3 | $23.2 | $51.2 | ($67.1) | ($95.1) | $336.2 | 89,956 | 9,259 |
| Other | ($0.5) | ($4.7) | $0.1 | $4.3 | $2.2 | $4.6 | ($0.4) | ($2.8) | $1.5 | 1,042 | 248 |
| Transformer | $35.1 | ($181.2) | $21.5 | $237.8 | $3.3 | $14.5 | ($39.7) | ($50.9) | $186.9 | 32,480 | 3,780 |
| Unclassified | $1.1 | ($1.5) | $5.4 | $8.0 | $1.2 | $0.3 | ($1.4) | ($0.5) | $7.5 | NA | NA |
| Total | $36.2 | ($1,141.8) | $66.9 | $1,245.0 | $75.9 | $131.9 | ($190.0) | ($246.0) | $999.0 | 155,670 | 22,513 |

## Table 10-21 Congestion Event Hours (Day Ahead against Real Time): Calendar years 2011 to 2012

| | Congestion Event Hours | | | | | |
|---|---|---|---|---|---|---|
| | 2012 | | | 2011 | | |
| Type | Day Ahead Constrained | Corresponding Real Time Constrained | Percent | Day Ahead Constrained | Corresponding Real Time Constrained | Percent |
| Flowgate | 29,500 | 3,239 | 11.0% | 23,179 | 2,917 | 12.6% |
| Interface | 7,005 | 369 | 5.3% | 9,013 | 1,144 | 12.7% |
| Line | 144,670 | 3,496 | 2.4% | 89,956 | 3,211 | 3.6% |
| Other | 8,007 | 265 | 3.3% | 1,042 | 67 | 6.4% |
| Transformer | 60,390 | 729 | 1.2% | 32,480 | 1,637 | 5.0% |
| Total | 249,572 | 8,098 | 3.2% | 155,670 | 8,976 | 5.8% |

## Table 10-22 Congestion Event Hours (Real Time against Day Ahead): 2011 to 2012

| | Congestion Event Hours | | | | | |
|---|---|---|---|---|---|---|
| | 2012 | | | 2011 | | |
| Type | Real Time Constrained | Corresponding Day Ahead Constrained | Percent | Real Time Constrained | Corresponding Day Ahead Constrained | Percent |
| Flowgate | 7,772 | 3,320 | 42.7% | 7,423 | 2,922 | 39.4% |
| Interface | 737 | 395 | 53.6% | 1,803 | 1,143 | 63.4% |
| Line | 10,151 | 3,382 | 33.3% | 9,259 | 3,150 | 34.0% |
| Other | 433 | 229 | 52.9% | 248 | 63 | 25.4% |
| Transformer | 1,824 | 685 | 37.6% | 3,780 | 1,607 | 42.5% |
| Total | 20,917 | 8,011 | 38.3% | 22,513 | 8,885 | 39.5% |

Table 10-23 shows congestion costs by facility voltage class for 2012. In comparison to 2011 (shown in Table 10-24), congestion costs decreased across 765kV, 500kV, 345kV and 230kV in 2012.

### Table 10-23 Congestion summary (By facility voltage): 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) | ($3.4) | $3.2 | $6.5 | $0.2 | ($0.1) | ($0.1) | $0.1 | $6.6 | 3,412 | 89 |
| 500 | $75.3 | ($79.3) | $5.2 | $159.9 | $19.7 | $25.8 | ($8.4) | ($14.6) | $145.3 | 12,025 | 1,129 |
| 345 | ($41.6) | ($135.1) | $23.7 | $117.2 | $1.6 | $7.8 | ($35.7) | ($41.9) | $75.3 | 34,050 | 3,623 |
| 230 | $67.2 | ($72.4) | $19.8 | $159.3 | $4.8 | $11.0 | ($38.7) | ($44.9) | $114.5 | 35,443 | 4,052 |
| 161 | ($14.3) | ($23.3) | $3.8 | $12.7 | ($1.5) | $1.9 | ($10.2) | ($13.6) | ($0.9) | 3,622 | 1,407 |
| 138 | ($9.1) | ($202.1) | $69.7 | $262.7 | ($9.0) | $15.5 | ($89.6) | ($114.1) | $148.7 | 130,390 | 8,661 |
| 115 | $24.1 | ($1.5) | $3.6 | $29.2 | ($0.5) | $2.1 | ($1.4) | ($4.0) | $25.2 | 18,614 | 901 |
| 69 | $28.0 | $5.9 | $1.1 | $23.1 | ($11.8) | $3.3 | ($0.1) | ($15.3) | $7.9 | 10,531 | 1,053 |
| 34 | $0.0 | ($0.0) | $0.0 | $0.1 | ($0.0) | $0.0 | $0.0 | $0.0 | $0.1 | 1,470 | 2 |
| 12 | ($0.0) | ($0.0) | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | 15 | 0 |
| Unclassified | $6.2 | ($1.2) | $1.7 | $9.1 | ($0.5) | $1.2 | ($1.2) | ($2.8) | $6.3 | NA | NA |
| Total | $135.5 | ($512.5) | $131.9 | $779.9 | $3.0 | $68.5 | ($185.4) | ($250.9) | $529.0 | 249,572 | 20,917 |

### Table 10-24 Congestion summary (By facility voltage): 2011

| | 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 | $0.8 | ($9.3) | $2.3 | $12.4 | $2.9 | $2.1 | ($2.6) | ($1.8) | $10.6 | 1,109 | 183 |
| 500 | $100.0 | ($466.5) | ($5.4) | $561.0 | $42.4 | $47.2 | ($11.1) | ($15.9) | $545.1 | 17,936 | 3,691 |
| 345 | ($98.5) | ($264.2) | $15.6 | $181.2 | $10.3 | $26.3 | ($69.4) | ($85.5) | $95.8 | 29,923 | 4,559 |
| 230 | $1.7 | ($175.8) | $12.5 | $190.1 | $18.3 | $21.4 | ($37.1) | ($40.2) | $149.9 | 23,752 | 3,540 |
| 161 | ($13.6) | ($22.0) | $6.3 | $14.6 | ($2.5) | $6.0 | ($20.8) | ($29.3) | ($14.7) | 1,760 | 1,152 |
| 138 | $21.2 | ($173.7) | $26.1 | $221.0 | $4.4 | $19.0 | ($46.1) | ($60.7) | $160.3 | 60,087 | 7,691 |
| 115 | $7.4 | ($27.8) | $4.2 | $39.5 | $1.1 | $7.3 | ($1.5) | ($7.7) | $31.8 | 12,193 | 1,109 |
| 69 | $16.1 | ($1.1) | ($0.1) | $17.1 | ($2.2) | $2.2 | $0.1 | ($4.4) | $12.7 | 8,872 | 583 |
| 35 | $0.1 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | 11 | 0 |
| 34 | $0.0 | ($0.0) | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | 2 | 5 |
| 14 | $0.0 | ($0.0) | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | 7 | 0 |
| 12 | ($0.0) | ($0.0) | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | 18 | 0 |
| Unclassified | $1.1 | ($1.5) | $5.4 | $8.0 | $1.2 | $0.3 | ($1.4) | ($0.5) | $7.5 | 9,999 | 9,999 |
| Total | $36.2 | ($1,141.8) | $66.9 | $1,245.0 | $75.9 | $131.9 | ($190.0) | ($246.0) | $999.0 | 155,670 | 22,513 |

## Constraint Duration

Table 10-25 lists constraints in 2011 to 2012 that were most frequently in effect and Table 10-26 shows the constraints which experienced the largest change in congestion-event hours from 2011 to 2012.

### Table 10-25 Top 25 constraints with frequent occurrence: 2011 to 2012

| | | | Event Hours | | | | | | Percent of Annual Hours | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | Day Ahead | | | Real Time | | | Day Ahead | | | Real Time | | |
| No. | Constraint | Type | 2011 | 2012 | Change | 2011 | 2012 | Change | 2011 | 2012 | Change | 2011 | 2012 | Change |
| 1 | Sporn | Transformer | 972 | 18,619 | 17,647 | 0 | 0 | 0 | 11% | 212% | 201% | 0% | 0% | 0% |
| 2 | Oak Grove - Galesburg | Flowgate | 1,760 | 3,622 | 1,862 | 1,145 | 1,359 | 214 | 20% | 41% | 21% | 13% | 15% | 2% |
| 3 | Linden - VFT | Line | 2,616 | 3,847 | 1,231 | 0 | 0 | 0 | 30% | 44% | 14% | 0% | 0% | 0% |
| 4 | Kammer | Transformer | 1,289 | 3,440 | 2,151 | 69 | 19 | (50) | 15% | 39% | 24% | 1% | 0% | (1%) |
| 5 | Huntingdon - Huntingdon1 | Line | 558 | 3,421 | 2,863 | 0 | 0 | 0 | 6% | 39% | 33% | 0% | 0% | 0% |
| 6 | Graceton - Raphael Road | Line | 1,162 | 2,664 | 1,502 | 415 | 723 | 308 | 13% | 30% | 17% | 5% | 8% | 3% |
| 7 | Monticello - East Winamac | Flowgate | 823 | 2,734 | 1,911 | 241 | 578 | 337 | 9% | 31% | 22% | 3% | 7% | 4% |
| 8 | Breed - Wheatland | Flowgate | 0 | 2,821 | 2,821 | 215 | 428 | 213 | 0% | 32% | 32% | 2% | 5% | 2% |
| 9 | Taylor - Grenshaw | Line | 0 | 3,088 | 3,088 | 0 | 0 | 0 | 0% | 35% | 35% | 0% | 0% | 0% |
| 10 | Bayway - Federal Square | Line | 1,146 | 3,034 | 1,888 | 15 | 48 | 33 | 13% | 35% | 21% | 0% | 1% | 0% |
| 11 | Big Sandy - Grangston | Line | 740 | 3,066 | 2,326 | 0 | 0 | 0 | 8% | 35% | 26% | 0% | 0% | 0% |
| 12 | AP South | Interface | 4,120 | 2,586 | (1,534) | 1,013 | 351 | (662) | 47% | 29% | (18%) | 12% | 4% | (8%) |
| 13 | Nelson - Cordova | Line | 606 | 2,643 | 2,037 | 105 | 288 | 183 | 7% | 30% | 23% | 1% | 3% | 2% |
| 14 | Crete - St Johns Tap | Flowgate | 3,378 | 2,377 | (1,001) | 1,120 | 277 | (843) | 39% | 27% | (12%) | 13% | 3% | (10%) |
| 15 | Devon - Skokie | Line | 0 | 2,627 | 2,627 | 0 | 0 | 0 | 0% | 30% | 30% | 0% | 0% | 0% |
| 16 | Bellefonte - Grangston | Line | 50 | 2,603 | 2,553 | 0 | 0 | 0 | 1% | 30% | 29% | 0% | 0% | 0% |
| 17 | Prairie State - W Mt. Vernon | Flowgate | 234 | 1,483 | 1,249 | 149 | 1,011 | 862 | 3% | 17% | 14% | 2% | 12% | 10% |
| 18 | Howard - Shelby | Line | 554 | 2,460 | 1,906 | 0 | 0 | 0 | 6% | 28% | 22% | 0% | 0% | 0% |
| 19 | Cumberland - Bush | Flowgate | 1,612 | 2,053 | 441 | 215 | 316 | 101 | 18% | 23% | 5% | 2% | 4% | 1% |
| 20 | Rantoul - Rantoul Jct | Flowgate | 553 | 2,036 | 1,483 | 188 | 315 | 127 | 6% | 23% | 17% | 2% | 4% | 1% |
| 21 | Danville - East Danville | Line | 4,632 | 2,234 | (2,398) | 323 | 14 | (309) | 53% | 25% | (27%) | 4% | 0% | (4%) |
| 22 | Rockwell - Crosby | Line | 571 | 2,212 | 1,641 | 0 | 0 | 0 | 7% | 25% | 19% | 0% | 0% | 0% |
| 23 | Conesville | Transformer | 1,250 | 2,195 | 945 | 0 | 0 | 0 | 14% | 25% | 11% | 0% | 0% | 0% |
| 24 | AEP - DOM | Interface | 1,789 | 2,095 | 306 | 185 | 61 | (124) | 20% | 24% | 3% | 2% | 1% | (1%) |
| 25 | Diversey - Clybourn | Line | 237 | 2,107 | 1,870 | 2 | 0 | (2) | 3% | 24% | 21% | 0% | 0% | (0%) |

### Table 10-26 Top 25 constraints with largest year-to-year change in occurrence: 2011 to 2012

| | | | Event Hours | | | | | | Percent of Annual Hours | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | Day Ahead | | | Real Time | | | Day Ahead | | | Real Time | | |
| No. | Constraint | Type | 2011 | 2012 | Change | 2011 | 2012 | Change | 2011 | 2012 | Change | 2011 | 2012 | Change |
| 1 | Sporn | Transformer | 972 | 18,619 | 17,647 | 0 | 0 | 0 | 11% | 212% | 201% | 0% | 0% | 0% |
| 2 | South Mahwah - Waldwick | Line | 5,269 | 210 | (5,059) | 494 | 0 | (494) | 60% | 2% | (58%) | 6% | 0% | (6%) |
| 3 | Taylor - Grenshaw | Line | 0 | 3,088 | 3,088 | 0 | 0 | 0 | 0% | 35% | 35% | 0% | 0% | 0% |
| 4 | Belmont | Transformer | 4,371 | 1,737 | (2,634) | 497 | 60 | (437) | 50% | 20% | (30%) | 6% | 1% | (5%) |
| 5 | Breed - Wheatland | Flowgate | 0 | 2,821 | 2,821 | 215 | 428 | 213 | 0% | 32% | 32% | 2% | 5% | 2% |
| 6 | Huntingdon - Huntingdon1 | Line | 558 | 3,421 | 2,863 | 0 | 0 | 0 | 6% | 39% | 33% | 0% | 0% | 0% |
| 7 | Danville - East Danville | Line | 4,632 | 2,234 | (2,398) | 323 | 14 | (309) | 53% | 25% | (27%) | 4% | 0% | (4%) |
| 8 | Michigan City - Laporte | Flowgate | 2,935 | 873 | (2,062) | 632 | 40 | (592) | 34% | 10% | (24%) | 7% | 0% | (7%) |
| 9 | Devon - Skokie | Line | 0 | 2,627 | 2,627 | 0 | 0 | 0 | 0% | 30% | 30% | 0% | 0% | 0% |
| 10 | Bellefonte - Grangston | Line | 50 | 2,603 | 2,553 | 0 | 0 | 0 | 1% | 30% | 29% | 0% | 0% | 0% |
| 11 | Electric Jct - Nelson | Line | 2,943 | 636 | (2,307) | 158 | 5 | (153) | 34% | 7% | (26%) | 2% | 0% | (2%) |
| 12 | Big Sandy - Grangston | Line | 740 | 3,066 | 2,326 | 0 | 0 | 0 | 8% | 35% | 26% | 0% | 0% | 0% |
| 13 | Fairview | Transformer | 2,288 | 0 | (2,288) | 0 | 0 | 0 | 26% | 0% | (26%) | 0% | 0% | 0% |
| 14 | Monticello - East Winamac | Flowgate | 823 | 2,734 | 1,911 | 241 | 578 | 337 | 9% | 31% | 22% | 3% | 7% | 4% |
| 15 | Nelson - Cordova | Line | 606 | 2,643 | 2,037 | 105 | 288 | 183 | 7% | 30% | 23% | 1% | 3% | 2% |
| 16 | AP South | Interface | 4,120 | 2,586 | (1,534) | 1,013 | 351 | (662) | 47% | 29% | (18%) | 12% | 4% | (8%) |
| 17 | Cox's Corner - Marlton | Line | 2,625 | 468 | (2,157) | 0 | 0 | 0 | 30% | 5% | (25%) | 0% | 0% | 0% |
| 18 | Prairie State - W Mt. Vernon | Flowgate | 234 | 1,483 | 1,249 | 149 | 1,011 | 862 | 3% | 17% | 14% | 2% | 12% | 10% |
| 19 | Kammer | Transformer | 1,289 | 3,440 | 2,151 | 69 | 19 | (50) | 15% | 39% | 24% | 1% | 0% | (1%) |
| 20 | Pinehill - Stratford | Line | 2,367 | 288 | (2,079) | 0 | 0 | 0 | 27% | 3% | (24%) | 0% | 0% | 0% |
| 21 | Oak Grove - Galesburg | Flowgate | 1,760 | 3,622 | 1,862 | 1,145 | 1,359 | 214 | 20% | 41% | 21% | 13% | 15% | 2% |
| 22 | Bunsonville - Eugene | Flowgate | 2,444 | 236 | (2,208) | 11 | 148 | 137 | 28% | 3% | (25%) | 0% | 2% | 2% |
| 23 | Emilie - Falls | Line | 2,938 | 902 | (2,036) | 11 | 1 | (10) | 34% | 10% | (23%) | 0% | 0% | (0%) |
| 24 | Bayway - Federal Square | Line | 1,146 | 3,034 | 1,888 | 15 | 48 | 33 | 13% | 35% | 21% | 0% | 1% | 0% |
| 25 | Tanners Creek | Transformer | 0 | 1,911 | 1,911 | 0 | 0 | 0 | 0% | 22% | 22% | 0% | 0% | 0% |

## Constraint Costs

Table 10-27 and Table 10-28 present the top constraints affecting congestion costs by facility for 2012 through 2011.

### Table 10-27 Top 25 constraints affecting PJM congestion costs (By facility): 2012

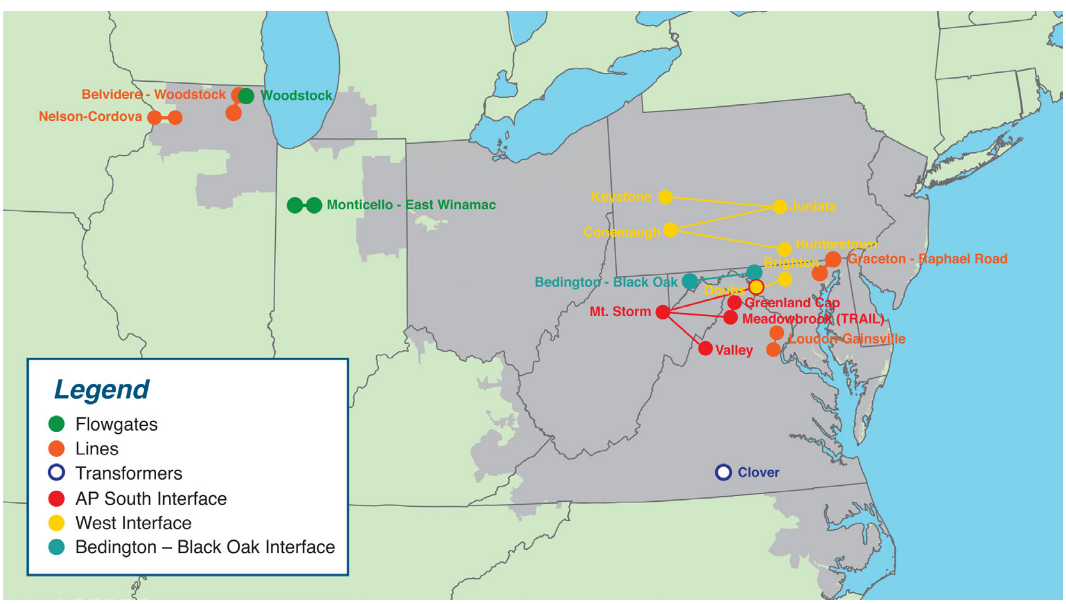
| | | | | Congestion Costs (Millions) | | | | | | | | | Percent of Total PJM Congestion Costs |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | Day Ahead | | | | Balancing | | | | | |
| No. | Constraint | Type | Location | Load Payments | Generation Credits | Explicit Costs | Total | Load Payments | Generation Credits | Explicit Costs | Total | Grand Total | 2012 |
| 1 | AP South | Interface | 500 | $48.3 | ($20.0) | $2.2 | $70.5 | $8.3 | $7.6 | ($2.7) | ($2.1) | $68.5 | 16.1% |
| 2 | Graceton - Raphael Road | Line | BGE | $26.5 | ($7.7) | ($1.1) | $33.1 | $1.0 | ($1.2) | ($0.3) | $1.9 | $35.0 | 8% |
| 3 | Woodstock | Flowgate | MISO | ($7.0) | ($30.2) | $6.8 | $30.0 | $0.0 | $0.0 | $0.0 | $0.0 | $30.0 | 7% |
| 4 | West | Interface | 500 | $2.5 | ($24.7) | ($0.5) | $26.7 | $1.6 | $4.0 | $0.1 | ($2.3) | $24.4 | 6% |
| 5 | Bedington - Black Oak | Interface | 500 | $13.6 | ($6.0) | $0.4 | $20.0 | $1.0 | $1.1 | ($0.7) | ($0.8) | $19.1 | 4% |
| 6 | Clover | Transformer | Dominion | $9.4 | ($7.5) | $6.7 | $23.6 | $0.9 | $0.8 | ($8.5) | ($8.3) | $15.2 | 4% |
| 7 | Belvidere - Woodstock | Line | ComEd | ($0.9) | ($8.5) | $0.2 | $7.7 | ($2.4) | $3.3 | ($16.3) | ($22.0) | ($14.3) | (3.4%) |
| 8 | Monticello - East Winamac | Flowgate | MISO | ($0.2) | ($19.6) | $11.5 | $31.0 | $0.4 | $1.9 | ($15.5) | ($17.0) | $14.0 | 3% |
| 9 | Nelson - Cordova | Line | ComEd | ($19.3) | ($34.3) | $6.9 | $21.9 | ($0.9) | $1.7 | ($7.9) | ($10.5) | $11.3 | 3% |
| 10 | Loudoun - Gainsville | Line | Dominion | $0.4 | ($11.0) | ($1.2) | $10.3 | $0.6 | $0.9 | $0.2 | ($0.1) | $10.2 | 2% |
| 11 | AEP - DOM | Interface | 500 | $8.3 | ($3.9) | $0.7 | $12.9 | $1.0 | $4.2 | ($0.4) | ($3.6) | $9.3 | 2% |
| 12 | Northwest | Other | BGE | $7.8 | ($2.4) | $0.4 | $10.6 | ($0.7) | ($0.1) | ($0.8) | ($1.5) | $9.1 | 2% |
| 13 | Rantoul - Rantoul Jct | Flowgate | MISO | ($7.3) | ($13.0) | $4.3 | $10.0 | ($0.2) | ($0.1) | ($1.7) | ($1.9) | $8.2 | 1.9% |
| 14 | Hunterstown | Transformer | Met-Ed | $3.4 | ($4.2) | $0.2 | $7.9 | $0.1 | $0.0 | ($0.0) | $0.0 | $7.9 | 2% |
| 15 | Crete - St Johns Tap | Flowgate | MISO | ($5.6) | ($19.2) | $0.1 | $13.8 | $0.3 | $0.9 | ($5.7) | ($6.3) | $7.5 | 2% |
| 16 | Pleasant Valley - Belvidere | Line | ComEd | ($2.3) | ($8.5) | $1.6 | $7.8 | $0.1 | $0.1 | ($0.8) | ($0.7) | $7.1 | 2% |
| 17 | Prairie State - W Mt. Vernon | Flowgate | MISO | ($4.8) | ($10.7) | $1.9 | $7.7 | ($0.0) | ($0.0) | ($0.7) | ($0.7) | $7.0 | 2% |
| 18 | Kammer | Transformer | AEP | ($3.0) | ($11.2) | ($1.2) | $7.0 | ($0.2) | $0.1 | $0.2 | ($0.0) | $7.0 | 2% |
| 19 | Sporn | Transformer | AEP | ($0.1) | ($0.6) | $6.0 | $6.5 | $0.0 | $0.0 | $0.0 | $0.0 | $6.5 | 1.5% |
| 20 | Harwood - Susquehanna | Line | PPL | $0.7 | ($5.4) | $0.3 | $6.4 | $0.1 | $0.1 | $0.1 | $0.1 | $6.5 | 2% |
| 21 | Unclassified | Unclassified | Unclassified | $6.2 | ($1.2) | $1.7 | $9.1 | ($0.5) | $1.2 | ($1.2) | ($2.8) | $6.3 | 1% |
| 22 | Leonia - New Milford | Line | PSEG | $1.5 | $1.8 | $2.7 | $2.4 | ($0.4) | $0.4 | ($7.2) | ($7.9) | ($5.6) | (1%) |
| 23 | Breed - Wheatland | Flowgate | MISO | ($2.8) | ($17.9) | $0.5 | $15.6 | $0.4 | $0.3 | ($10.1) | ($10.1) | $5.5 | 1% |
| 24 | Crescent | Transformer | DLCO | $0.9 | ($4.3) | ($0.2) | $5.1 | $0.2 | $0.2 | ($0.1) | $0.0 | $5.1 | 1% |
| 25 | Belmont | Transformer | AP | $0.6 | ($5.5) | $0.6 | $6.6 | ($0.4) | $0.8 | ($0.4) | ($1.5) | $5.0 | 1.2% |

### Table 10-28 Top 25 constraints affecting PJM congestion costs (By facility): 2011

| | | | | 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 | 2011 |
| 1 | AP South | Interface | 500 | $96.1 | ($140.1) | ($0.1) | $236.1 | $18.7 | $16.0 | $0.0 | $2.8 | $238.9 | 27% |
| 2 | 5004/5005 Interface | Interface | 500 | ($25.2) | ($101.5) | ($4.6) | $71.7 | $16.1 | $19.3 | $7.6 | $4.3 | $76.1 | 9% |
| 3 | West | Interface | 500 | ($19.3) | ($83.4) | ($5.0) | $59.1 | $0.2 | $0.1 | $0.1 | $0.3 | $59.3 | 7% |
| 4 | Belmont | Transformer | AP | $7.7 | ($49.9) | ($2.2) | $55.5 | ($3.5) | ($3.2) | ($1.6) | ($1.8) | $53.7 | 6% |
| 5 | AEP - DOM | Interface | 500 | $14.6 | ($21.5) | $2.1 | $38.2 | $2.0 | $1.5 | ($0.4) | $0.1 | $38.3 | 4% |
| 6 | Electric Jct - Nelson | Line | ComEd | ($10.8) | ($44.4) | $7.7 | $41.3 | $0.4 | $3.7 | ($7.7) | ($11.0) | $30.3 | 3% |
| 7 | Bedington - Black Oak | Interface | 500 | $10.9 | ($14.6) | ($2.0) | $23.5 | $0.2 | $0.1 | $0.0 | $0.1 | $23.7 | 3% |
| 8 | Crete - St Johns Tap | Flowgate | MISO | ($32.9) | ($66.4) | ($5.3) | $28.2 | $6.3 | $6.7 | ($4.5) | ($4.9) | $23.3 | 3% |
| 9 | Clover | Transformer | Dominion | $0.4 | ($21.4) | $4.6 | $26.4 | $2.8 | $3.4 | ($7.8) | ($8.5) | $17.9 | 2% |
| 10 | East | Interface | 500 | ($11.5) | ($31.5) | ($1.2) | $18.7 | $0.2 | $1.3 | $0.1 | ($1.0) | $17.8 | 2% |
| 11 | Dickerson - Quince Orchard | Line | Pepco | ($9.4) | ($28.8) | ($1.7) | $17.7 | $4.6 | $7.4 | $2.7 | ($0.2) | $17.5 | 2% |
| 12 | Oak Grove - Galesburg | Flowgate | MISO | ($13.6) | ($22.0) | $6.3 | $14.6 | ($2.5) | $6.0 | ($20.8) | ($29.3) | ($14.7) | (2%) |
| 13 | Susquehanna | Transformer | PPL | ($2.9) | ($17.4) | ($0.1) | $14.4 | $0.0 | $0.0 | $0.0 | $0.0 | $14.4 | 2% |
| 14 | Graceton - Raphael Road | Line | BGE | $10.9 | ($1.1) | ($0.8) | $11.2 | $0.7 | ($1.1) | $0.5 | $2.4 | $13.5 | 2% |
| 15 | Wylie Ridge | Transformer | AP | $15.3 | $3.6 | $1.8 | $13.6 | $2.2 | $1.2 | ($2.5) | ($1.5) | $12.1 | 1% |
| 16 | East Frankfort - Crete | Line | ComEd | ($10.0) | ($23.7) | ($1.3) | $12.4 | $0.6 | $0.6 | ($0.6) | ($0.6) | $11.8 | 1% |
| 17 | Brues - West Bellaire | Line | AEP | $19.8 | $4.5 | $0.7 | $16.1 | ($2.1) | $1.8 | ($1.5) | ($5.4) | $10.7 | 1% |
| 18 | Breed - Wheatland | Line | AEP | ($4.8) | ($13.2) | $2.0 | $10.5 | $0.0 | ($0.0) | ($0.1) | ($0.0) | $10.4 | 1% |
| 19 | Waldwick | Transformer | PSEG | ($0.5) | ($2.3) | $2.1 | $3.8 | $0.1 | $1.3 | ($12.5) | ($13.8) | ($9.9) | (1%) |
| 20 | Plymouth Meeting - Whitpain | Line | PECO | ($0.9) | ($10.8) | ($0.0) | $9.9 | $0.2 | $0.2 | ($0.1) | ($0.2) | $9.7 | 1% |
| 21 | Cloverdale | Transformer | AEP | $0.5 | ($7.6) | $1.6 | $9.7 | $0.7 | $0.6 | ($0.1) | ($0.0) | $9.7 | 1% |
| 22 | Bunsonville - Eugene | Flowgate | MISO | ($11.5) | ($19.0) | $2.1 | $9.6 | $0.0 | ($0.0) | ($0.0) | ($0.0) | $9.6 | 1% |
| 23 | Unclassified | Unclassified | Unclassified | $1.1 | ($1.5) | $5.4 | $8.0 | $1.2 | $0.3 | ($1.4) | ($0.5) | $7.5 | 1% |
| 24 | Pleasant Valley - Belvidere | Line | ComEd | ($6.6) | ($17.6) | $1.7 | $12.7 | ($0.6) | $2.1 | ($3.0) | ($5.7) | $7.0 | 1% |
| 25 | Cloverdale - Lexington | Line | 500 | $4.9 | ($2.9) | $1.3 | $9.1 | $3.3 | $2.1 | ($3.8) | ($2.7) | $6.4 | 1% |

Figure 10-2 shows the locations of the top 10 constraints affecting PJM congestion costs in 2012.

### Figure 10-2 Location of the top 10 constraints affecting PJM congestion costs: 2012[34]




34 The term flowgate refers to MISO reciprocal coordinated 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.[35] A flowgate is a facility or group of facilities that may act as constraint points on the regional system.[36] 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 2012 and 2011 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 2012, the Woodstock flowgate made the most significant contribution to positive congestion while the Rising flowgate made the most significant contribution to negative congestion.

### Table 10-29 Top congestion cost impacts from MISO flowgates affecting PJM dispatch (By facility): 2012

| | | Congestion Costs (Millions) | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Day Ahead | | | | Balancing | | | | | Event Hours | |
| No. | Constraint | Load Payments | Generation Credits | Explicit Costs | Total | Load Payments | Generation Credits | Explicit Costs | Total | Grand Total | Day Ahead | Real Time |
| 1 | Woodstock | ($7.0) | ($30.2) | $6.8 | $30.0 | $0.0 | $0.0 | $0.0 | $0.0 | $30.0 | 1,073 | 0 |
| 2 | Monticello - East Winamac | ($0.2) | ($19.6) | $11.5 | $31.0 | $0.4 | $1.9 | ($15.5) | ($17.0) | $14.0 | 2,734 | 578 |
| 3 | Rantoul - Rantoul Jct | ($7.3) | ($13.0) | $4.3 | $10.0 | ($0.2) | ($0.1) | ($1.7) | ($1.9) | $8.2 | 2,036 | 315 |
| 4 | Crete - St Johns Tap | ($5.6) | ($19.2) | $0.1 | $13.8 | $0.3 | $0.9 | ($5.7) | ($6.3) | $7.5 | 2,377 | 277 |
| 5 | Prairie State - W Mt. Vernon | ($4.8) | ($10.7) | $1.9 | $7.7 | ($0.0) | ($0.0) | ($0.7) | ($0.7) | $7.0 | 1,483 | 1,011 |
| 6 | Breed - Wheatland | ($2.8) | ($17.9) | $0.5 | $15.6 | $0.4 | $0.3 | ($10.1) | ($10.1) | $5.5 | 2,821 | 428 |
| 7 | Rising | ($3.1) | ($3.2) | $2.3 | $2.4 | ($1.2) | $0.8 | ($5.4) | ($7.4) | ($5.0) | 408 | 363 |
| 8 | Rantoul Jct - Sidney | $0.0 | $0.0 | $0.0 | $0.0 | $0.1 | $0.4 | ($4.0) | ($4.3) | ($4.3) | 0 | 331 |
| 9 | Benton Harbor - Palisades | ($0.6) | ($5.5) | ($0.8) | $4.1 | $0.1 | $0.3 | ($0.2) | ($0.4) | $3.8 | 840 | 71 |
| 10 | Miami Fort - Hebron | ($1.8) | ($5.7) | ($0.2) | $3.7 | ($0.1) | ($0.0) | $0.1 | $0.0 | $3.7 | 1,053 | 76 |
| 11 | Palisades - Roosevelt | ($0.9) | ($5.6) | ($0.6) | $4.1 | $0.1 | $0.3 | ($0.2) | ($0.4) | $3.7 | 855 | 209 |
| 12 | Cumberland - Bush | ($1.2) | ($5.5) | $6.2 | $10.5 | $0.4 | $1.2 | ($11.1) | ($11.8) | ($1.3) | 2,053 | 316 |
| 13 | Brokaw | $0.0 | $0.0 | $0.0 | $0.0 | ($0.0) | $0.1 | ($1.1) | ($1.2) | ($1.2) | 0 | 81 |
| 14 | Beaver Channel - Albany | $0.0 | $0.0 | $0.0 | $0.0 | ($0.7) | $0.2 | ($0.2) | ($1.1) | ($1.1) | 0 | 36 |
| 15 | Edwards - Kewanee | ($0.2) | ($0.9) | $0.5 | $1.2 | $0.0 | ($0.1) | ($0.3) | ($0.2) | $1.0 | 314 | 68 |
| 16 | Michigan City - Maple | ($1.0) | ($0.7) | $0.5 | $0.2 | ($0.4) | ($0.1) | ($0.8) | ($1.1) | ($0.9) | 73 | 51 |
| 17 | Beaver Channel - Albany | ($6.0) | ($17.0) | ($0.1) | $11.0 | ($4.8) | ($0.4) | ($5.7) | ($10.2) | $0.8 | 1,256 | 460 |
| 18 | Pana North | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | ($0.8) | ($0.8) | ($0.8) | 0 | 20 |
| 19 | Dunes Acres - Michigan City | ($0.2) | ($0.3) | $0.1 | $0.2 | ($0.2) | ($0.0) | ($0.7) | ($0.9) | ($0.7) | 180 | 23 |
| 20 | Bush - Lafayette | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.1 | ($0.6) | ($0.7) | ($0.7) | 0 | 296 |

35 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> (Accessed March 13, 2013).

36 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> (Accessed March 13, 2013).

### Table 10-30 Top congestion cost impacts from MISO flowgates affecting PJM dispatch (By facility): 2011

| | | 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 | ($32.9) | ($66.4) | ($5.3) | $28.2 | $6.3 | $6.7 | ($4.5) | ($4.9) | $23.3 | 3,378 | 1,120 |
| 2 | Oak Grove - Galesburg | ($13.6) | ($22.0) | $6.3 | $14.6 | ($2.5) | $6.0 | ($20.8) | ($29.3) | ($14.7) | 1,760 | 1,145 |
| 3 | Bunsonville - Eugene | ($11.5) | ($19.0) | $2.1 | $9.6 | $0.0 | ($0.0) | ($0.0) | ($0.0) | $9.6 | 2,444 | 11 |
| 4 | Pleasant Prairie - Zion | ($1.1) | ($1.6) | $0.7 | $1.2 | ($0.1) | ($0.5) | ($7.9) | ($7.5) | ($6.3) | 336 | 210 |
| 5 | Lakeview - Pleasant Prairie | ($0.1) | ($0.2) | $0.2 | $0.3 | ($0.3) | ($0.1) | ($5.7) | ($5.8) | ($5.6) | 24 | 302 |
| 6 | Burnham - Munster | ($10.9) | ($19.0) | ($3.0) | $5.1 | $0.0 | $0.0 | $0.0 | $0.0 | $5.1 | 1,152 | 0 |
| 7 | Stillwell | ($0.0) | ($0.4) | ($0.1) | $0.3 | ($0.3) | $1.3 | ($3.6) | ($5.2) | ($4.9) | 93 | 88 |
| 8 | Michigan City - Laporte | ($10.4) | ($16.4) | $3.0 | $9.0 | ($1.7) | ($1.3) | ($3.8) | ($4.2) | $4.8 | 2,935 | 632 |
| 9 | Breed - Wheatland | $0.0 | $0.0 | $0.0 | $0.0 | $0.4 | $0.3 | ($4.4) | ($4.2) | ($4.2) | 0 | 215 |
| 10 | Cook - Palisades | ($1.3) | ($5.2) | $0.3 | $4.1 | $0.0 | $0.0 | ($0.2) | ($0.2) | $3.9 | 481 | 9 |
| 11 | Rantoul - Rantoul Jct | ($3.2) | ($5.5) | $0.6 | $3.0 | $0.1 | $0.0 | ($0.5) | ($0.4) | $2.6 | 553 | 188 |
| 12 | Benton Harbor - Palisades | ($0.2) | ($1.0) | $0.2 | $1.0 | $0.8 | $1.2 | ($2.8) | ($3.2) | ($2.2) | 67 | 132 |
| 13 | St John - Liberty Park | ($1.8) | ($6.0) | $0.6 | $4.8 | $0.6 | $1.0 | ($2.2) | ($2.6) | $2.2 | 334 | 161 |
| 14 | Nucor - Whitestown | $0.0 | $0.0 | $0.0 | $0.0 | $0.2 | $0.5 | ($1.8) | ($2.1) | ($2.1) | 0 | 56 |
| 15 | Temporary Monticello - E Wiinamac | $0.0 | $0.0 | $0.0 | $0.0 | ($0.0) | $0.5 | ($1.2) | ($1.7) | ($1.7) | 0 | 69 |
| 16 | Eugene - Bunsonville | $0.0 | $0.0 | $0.0 | $0.0 | $0.1 | $0.1 | ($1.7) | ($1.6) | ($1.6) | 0 | 107 |
| 17 | Cumberland - Bush | ($1.0) | ($5.8) | $2.1 | $6.9 | $0.2 | $0.9 | ($4.6) | ($5.3) | $1.6 | 1,612 | 215 |
| 18 | Rising | ($5.2) | ($8.1) | ($0.1) | $2.8 | $0.0 | $1.1 | ($3.3) | ($4.4) | ($1.6) | 947 | 175 |
| 19 | Green Acres - St John | $0.0 | $0.0 | $0.0 | $0.0 | $0.6 | $1.4 | ($0.7) | ($1.5) | ($1.5) | 0 | 147 |
| 20 | Rantoul Jct - Sidney | ($1.0) | ($2.0) | $0.1 | $1.1 | $0.5 | $0.0 | ($0.2) | $0.3 | $1.3 | 62 | 113 |

## Congestion-Event Summary for the 500 kV System

Constraints on the 500 kV system generally have a regional impact. Table 10-31 and Table 10-32 show the 500 kV constraints impacting congestion costs in PJM for 2012 and 2011 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 10-31 Regional constraints summary (By facility): 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 | $48.3 | ($20.0) | $2.2 | $70.5 | $8.3 | $7.6 | ($2.7) | ($2.1) | $68.5 | 2,586 | 351 |
| 2 | West | Interface | 500 | $2.5 | ($24.7) | ($0.5) | $26.7 | $1.6 | $4.0 | $0.1 | ($2.3) | $24.4 | 841 | 130 |
| 3 | Bedington - Black Oak | Interface | 500 | $13.6 | ($6.0) | $0.4 | $20.0 | $1.0 | $1.1 | ($0.7) | ($0.8) | $19.1 | 780 | 54 |
| 4 | AEP - DOM | Interface | 500 | $8.3 | ($3.9) | $0.7 | $12.9 | $1.0 | $4.2 | ($0.4) | ($3.6) | $9.3 | 2,095 | 61 |
| 5 | East | Interface | 500 | ($2.6) | ($8.1) | ($0.6) | $4.8 | $0.1 | $0.5 | ($0.1) | ($0.5) | $4.4 | 209 | 5 |
| 6 | 5004/5005 Interface | Interface | 500 | $0.2 | ($4.1) | $0.5 | $4.8 | $2.5 | $3.5 | $0.3 | ($0.6) | $4.2 | 191 | 128 |
| 7 | Doubs - Mount Storm | Line | 500 | $1.3 | ($1.1) | $0.1 | $2.5 | $0.0 | $0.0 | $0.0 | $0.0 | $2.5 | 80 | 0 |
| 8 | Conemaugh - Hunterstown | Line | 500 | $0.4 | ($1.3) | $0.1 | $1.7 | $0.1 | $2.0 | ($1.9) | ($3.9) | ($2.1) | 38 | 117 |
| 9 | Central | Interface | 500 | ($0.9) | ($1.6) | $0.1 | $0.8 | $0.0 | $0.0 | ($0.0) | ($0.0) | $0.8 | 214 | 2 |
| 10 | Cloverdale - Lexington | Line | 500 | $0.0 | $0.0 | $0.0 | $0.0 | $0.1 | $0.1 | ($0.8) | ($0.8) | ($0.7) | 7 | 61 |
| 11 | Nagel | Line | 500 | $0.3 | ($0.0) | ($0.0) | $0.3 | $0.0 | $0.0 | $0.0 | $0.0 | $0.3 | 128 | 0 |
| 12 | Kammer | Transformer | 500 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | ($0.0) | ($0.0) | $0.0 | $0.1 | 12 | 19 |
| 13 | Mount Storm - Pruntytown | Line | 500 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | ($0.0) | $0.0 | $0.0 | $0.0 | 0 | 2 |
| 14 | Branchburg - Elroy | Line | 500 | ($0.0) | ($0.0) | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | 2 | 0 |
| 15 | 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 |

### Table 10-32 Regional constraints summary (By facility): 2011

| | | | | 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 | $96.1 | ($140.1) | ($0.1) | $236.1 | $18.7 | $16.0 | $0.0 | $2.8 | $238.9 | 4,120 | 1,013 |
| 2 | 5004/5005 Interface | Interface | 500 | ($25.2) | ($101.5) | ($4.6) | $71.7 | $16.1 | $19.3 | $7.6 | $4.3 | $76.1 | 905 | 470 |
| 3 | West | Interface | 500 | ($19.3) | ($83.4) | ($5.0) | $59.1 | $0.2 | $0.1 | $0.1 | $0.3 | $59.3 | 879 | 20 |
| 4 | AEP - DOM | Interface | 500 | $14.6 | ($21.5) | $2.1 | $38.2 | $2.0 | $1.5 | ($0.4) | $0.1 | $38.3 | 1,789 | 185 |
| 5 | Bedington - Black Oak | Interface | 500 | $10.9 | ($14.6) | ($2.0) | $23.5 | $0.2 | $0.1 | $0.0 | $0.1 | $23.7 | 679 | 7 |
| 6 | East | Interface | 500 | ($11.5) | ($31.5) | ($1.2) | $18.7 | $0.2 | $1.3 | $0.1 | ($1.0) | $17.8 | 523 | 22 |
| 7 | Cloverdale - Lexington | Line | 500 | $4.9 | ($2.9) | $1.3 | $9.1 | $3.3 | $2.1 | ($3.8) | ($2.7) | $6.4 | 602 | 427 |
| 8 | Central | Interface | 500 | ($1.5) | ($2.8) | ($0.0) | $1.3 | ($0.1) | ($0.1) | ($0.1) | ($0.1) | $1.2 | 118 | 8 |
| 9 | Mount Storm - Pruntytown | Line | 500 | $0.1 | ($0.2) | $0.0 | $0.3 | $0.2 | $0.0 | ($0.1) | $0.0 | $0.3 | 29 | 38 |
| 10 | Doubs - Mount Storm | Line | 500 | $0.0 | ($0.3) | ($0.0) | $0.3 | ($0.0) | $0.0 | ($0.0) | ($0.0) | $0.3 | 9 | 4 |
| 11 | Harrison - Pruntytown | Line | 500 | $0.0 | ($0.1) | $0.0 | $0.1 | ($0.0) | ($0.0) | $0.0 | $0.0 | $0.1 | 10 | 4 |
| 12 | Kammer | Transformer | 500 | ($0.0) | ($0.1) | ($0.0) | $0.1 | $0.0 | $0.0 | $0.0 | $0.0 | $0.1 | 13 | 0 |
| 13 | Dominion East | Interface | 500 | $0.0 | $0.0 | $0.0 | $0.0 | $0.3 | $0.1 | ($0.2) | $0.0 | $0.0 | 0 | 38 |
| 14 | Conemaugh - Hunterstown | Line | 500 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | ($0.0) | ($0.0) | 0 | 9 |

## Congestion Costs by Physical and Financial Participants

In order to evaluate the ownership of virtual bids, the MMU categorized all participants making virtual bids 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 2012, financial companies as a group were net recipients of congestion credits, whereas physical companies were net payers of congestion charges.[37] In 2012, financial companies received $83.1 million, a decrease of $91.6 million or 52.4 percent compared to 2011. In 2012, physical companies paid $612.1 million in congestion charges, a decrease of $561.5 million or 47.8 percent compared to 2011.

### Table 10-33 Congestion cost by the type of the participant: Calendar year 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 | ($0.2) | $11.1 | $90.1 | $78.8 | ($25.2) | ($1.3) | ($137.9) | ($161.9) | $0.0 | ($83.1) |
| Physical | $135.8 | ($523.6) | $41.8 | $701.1 | $28.3 | $69.8 | ($47.5) | ($89.0) | $0.0 | $612.1 |
| Total | $135.5 | ($512.5) | $131.9 | $779.9 | $3.0 | $68.5 | ($185.4) | ($250.9) | $0.0 | $529.0 |

### Table 10-34 Congestion cost by the type of the participant: Calendar year 2011

| | 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 | ($22.2) | $14.4 | $69.5 | $32.9 | ($26.8) | $9.1 | ($171.7) | ($207.5) | $0.0 | ($174.7) |
| Physical | $58.5 | ($1,156.2) | ($2.6) | $1,212.1 | $102.7 | $122.8 | ($18.4) | ($38.5) | $0.0 | $1,173.6 |
| Total | $36.2 | ($1,141.8) | $66.9 | $1,245.0 | $75.9 | $131.9 | ($190.0) | ($246.0) | $0.0 | $999.0 |

37 The total zonal congestion numbers were calculated as of March 2, 2013 and are, based on continued PJM billing updates, subject to change.