SECTION 7 – CONGESTION

Congestion occurs when available, least-cost energy cannot be delivered to all loads for a period 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.[1] 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. Locational marginal prices (LMPs) reflect the price of the lowest-cost resources available to meet loads, taking into account actual delivery constraints imposed by the transmission system. Thus LMP is an efficient way to price energy when transmission constraints exist. Congestion reflects this efficient pricing.

Congestion reflects the underlying characteristics of the power system including the nature and capability of transmission facilities and the cost and geographical distribution of generation facilities. Congestion is neither good nor bad but is a direct measure of the extent to which there are differences in the cost of generation that cannot be equalized because of transmission constraints. A complete set of markets would require direct competition between investments in transmission and generation. The transmission system provides a physical hedge against congestion. The transmission system is paid for by firm load and, as a result, firm load receives the corollary financial hedge in the form of Auction Revenue Rights (ARRs) and/or Financial Transmission Rights (FTRs). While the transmission system and, therefore, ARRs/FTRs are not guaranteed to be a complete hedge against congestion, ARRs/FTRs do provide a substantial offset to the cost of congestion to firm load.[2]

The Market Monitoring Unit (MMU) analyzed congestion and its influence on PJM markets in 2010.

Highlights and New Analysis

- Congestion costs in 2010 increased by 99 percent over congestion costs in 2009 (Table 7-2). Despite the increase, total congestion in 2010 was lower than total congestion in every year from 2005, when PJM grew through a series of major integrations, through 2008.
- In 2010, Dominion was the most congested zone. Dominion accounted for nearly 20 percent of the total congestion cost (Table 7-17). In 2009, ComEd was the most congested zone, accounting for nearly 30 percent of the total congestion cost.
- Summer high-demand months (May through August) accounted for 45 percent of the total congestion cost in 2010. By contrast, the same period accounted for 26 percent of the total congestion cost in 2009 (Table 7-3).
- Review of the generation and transmission interconnection process. The generation and transmission interconnection process is complex and time consuming as a result of the nature of the required analyses.

1 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.

2 See the *2010 State of the Market Report for PJM*, Volume II, Section 8, “Financial Transmission and Auction Revenue Rights,” at “ARR and FTR Revenue and Congestion.”

- Review of backbone facilities. PJM backbone projects are a subset of significant baseline upgrades. The backbone upgrades are typically intended to resolve a wide range of reliability criteria violations and congestion issues and have substantial impacts on energy and capacity markets.

Recommendations

- The MMU recommends that PJM continue its efforts to find ways to modify the generation and transmission interconnection process to minimize the uncertainty for potential market entrants.

- The MMU recommends that PJM propose modifications to the transmission planning process that would limit significant changes in the status of major transmission projects after they have been approved, and thus limit the uncertainty imposed on markets by the use of evaluation criteria that are very sensitive to changes in forecasts of economic variables. These issues are currently being considered in the PJM stakeholder process.

- The MMU recommends continued efforts to incorporate transmission investments into competitive markets. Transmission investments have not been fully incorporated into competitive markets. The construction of new transmission facilities, and the lack of existing transmission, can have significant impacts on energy and capacity markets, but there is no market mechanism in place that would require direct competition between transmission and generation to meet loads in an area.

Overview

Congestion Cost

- **Total Congestion.** Total congestion costs increased by $709.1 million or 99 percent, from $719.0 million in 2009 to $1,428.1 million in 2010. Day-ahead congestion costs increased by $816.4 million or 91 percent, from $901.4 million in 2009 to $1,717.9 million in 2010. Balancing congestion costs decreased by $107.3 million or 59 percent, from -$182.4.0 million in 2009 to -$289.7 million in 2010. Despite the increase, total congestion in 2010 was lower than total congestion in every year from 2005, when PJM grew through a series of major integrations, through 2008. Total congestion costs have ranged from three percent to nine percent of PJM annual total billings since 2003. Congestion costs were four percent of total PJM billings in 2010, which is higher than the three percent share in 2009, but lower than the share of total billings from 2003 through 2008. Total PJM billings in 2010 were $34.771 billion.

- **Monthly Congestion.** Fluctuations in monthly congestion costs continued to be substantial. In 2010, these differences were driven by varying load and energy import levels, different patterns of generation, weather-induced changes in demand and variations in congestion frequency on constraints affecting large portions of PJM load. Monthly congestion costs in 2010 ranged from $20.4 million in March to $268.9 million in July.

Congestion Component of LMP and Facility or Zonal Congestion

- **Congestion Component of Locational Marginal Price (LMP).** To provide an indication of the geographic dispersion of congestion costs, the congestion component of LMP (CLMP) was calculated for control zones in PJM. Price separation between eastern, southern and western control zones in PJM was primarily a result of congestion on the AP South interface and other 500 kV constraints in the east. The AP South interface had the effect of increasing prices in eastern and southern control zones located on the constrained side of the affected facilities while reducing prices in the unconstrained western control zones.

- **Congested Facilities.** Congestion frequency continued to be significantly higher in the Day-Ahead Market than in the Real-Time Market in 2010.[3] Day-ahead congestion frequency increased from 2009 to 2010 by 21,998 congestion event hours or 28 percent. In 2010, there were 100,728 day-ahead, congestion-event hours compared to 78,530 day-ahead, congestion-event hours in 2009. Day-ahead, congestion-event hours increased on internal PJM interfaces, transformers and lines while congestion frequency decreased on the reciprocally coordinated flowgates between PJM and the Midwest Independent Transmission System Operator, Inc. (Midwest ISO). Real-time congestion frequency increased from 2009 to 2010 by 8,012 congestion event hours. In 2010, there were 23,459 real-time, congestion-event hours compared to 15,447 real-time, congestion-event hours in 2009. Real-time, congestion-event hours increased on the internal PJM interfaces transformers and lines, while congestion-event hours decreased on the reciprocally coordinated flowgates between PJM and the Midwest ISO. The AP South Interface was the largest contributor to congestion costs in 2010. With $421.6 million in total congestion costs, it accounted for 30 percent of the total PJM congestion costs in 2010. The top five constraints in terms of congestion costs together contributed $745.8 million, or 52 percent, of the total PJM congestion costs in 2010. The top five constraints were the AP South interface, the Bedington – Black Oak interface, the 5004/5005 interface, the Doubs transformer, and the AEP-DOM interface.

- **Zonal Congestion.** In 2010, the Dominion Control Zone experienced the highest congestion costs of the control zones in PJM with $285.5 million.[4] The AP South interface, the Cloverdale – Lexington line, the Doubs transformer, the Bedington – Black Oak interface, and the Clover transformer contributed $183.4 million, or 64 percent of the total Dominion Control Zone congestion costs (Table 7-53). The AP Control Zone had the second highest congestion cost in PJM in 2010. The $282.7 million in congestion costs in the AP Control Zone represented a 187 percent increase from the $95.3 million in congestion costs for the zone in 2009. The AP South interface contributed $110.3 million, or 39 percent of the total AP Control Zone congestion cost. Increases in day-ahead congestion frequency and congestion costs from the Bedington – Black Oak interface and the Doubs transformer also contributed to the increase in congestion cost in the AP Control Zone from 2009 to 2010. The Bedington – Black Oak interface contributed $32.5 million to the AP Control Zone congestion costs and the Doubs transformer contributed $27 million to the AP Control Zone congestion costs.

3 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.

4 See the *Report to the North Carolina Utilities Commission: Congestion in the Dominion Service Territory in North Carolina: May 1, 2008 through April 30, 2010*, <http://www.monitoringanalytics.com/reports/Reports/SR2010/State_Congestion_Report_NC_DOM_20100715.pdf >.

Generation and Transmission Interconnection Planning Process

Any entity (developer or applicant) that requests interconnection of a generating facility, including increases to the capacity of an existing generating unit, or requests interconnection of a merchant transmission facility, must follow the PJM interconnection process. The process is complex and time consuming as a result of the nature of the required analyses. Nonetheless, this process potentially creates barriers to entry by creating uncertainty for potential entrants about the cost and time associated with interconnecting to the grid. The MMU recommends that PJM continue its efforts to find ways to modify the generation and transmission interconnection process to minimize the uncertainty for potential market entrants.

Key Backbone Facilities

PJM baseline projects are implemented to resolve reliability criteria violations. PJM backbone projects are a subset of significant baseline upgrades. The backbone upgrades are typically intended to resolve a wide range of reliability criteria violations and congestion issues and have substantial impacts on energy and capacity markets. The current backbone projects are: Mount Storm – Doubs; Carson – Suffolk; Jacks Mountain; Mid-Atlantic Power Pathway (MAPP); Potomac – Appalachian Transmission Highline (PATH); Susquehanna – Roseland; and the Trans Allegheny Line (TrAIL) (Figure 7-1). The total planned costs for all of these projects are $6,048.4 million.

Economic Planning Process

- **Transmission and Markets.** As a general matter, transmission investments have not been fully incorporated into competitive markets. The construction of new transmission facilities can have significant impacts on energy and capacity markets, but there is no market mechanism in place that would require direct competition between transmission and generation to meet loads in an area. While the RPM construct does provide that qualifying transmission upgrades may be submitted as offers, there have been no such offers. More generally, network transmission is not built based directly on market signals because the owners of network transmission are compensated through a non market mechanism, typically under traditional regulation. PJM has taken a first step towards integrating transmission investments into the market through the use of economic evaluation metrics.[5] Economic evaluation metrics can be used to determine whether there are positive economic benefits associated with an investment in transmission that might warrant the investment even when it is not required for reliability. The goal of transmission planning should ultimately be the incorporation of transmission investment decisions into market driven processes as much as possible.

- **Restructuring Responsibility for Grid Development.** The FERC's recent decisions in the *Primary Power* and *Central Transmission* cases addressed significant issues about the ownership of transmission, the resultant incentives to build new transmission facilities and

5 *See* 126 FERC ¶ 61,152 (2009) (final approval for an approach with predefined formulas for determining whether a transmission investment passes the cost-benefit test including explicit accounting for changes in production costs, the costs of complying with environmental regulations, generation availability trends and demand-response trends), *order on reh'g*, 123 FERC ¶ 61,051 (2008).

the potential for competitive forces to reduce the cost of transmission.[6] On June 17, 2010, the FERC issued a Notice of Proposed Rulemaking (NOPR) including a proposal to "remove from Commission-approved tariffs or agreements a right of first refusal created by those documents that provides an incumbent transmission provider with an undue advantage over a nonincumbent transmission developer."[7] These cases and the proposed rule have the potential to significantly change the incentives to build transmission for both incumbents and potential entrants and therefore to have potentially significant impacts on the wholesale power markets.

Conclusion

Congestion reflects the underlying characteristics of the power system, including the nature and capability of transmission facilities, the cost and geographical distribution of generation facilities and the geographical distribution of load. Total congestion costs have ranged from three percent to nine percent of PJM annual total billings since 2003. Congestion costs were four percent of total PJM billings in 2010. Total PJM billings in 2010 were $34,771 million. Total congestion costs increased by $709.1 million or 99 percent, from $719.0 million in 2009 to $1,428.1 million in 2010. Day-ahead congestion costs increased by $816.4 million or 91 percent, from $901.4 million in 2009 to $1,717.9 million in 2010. Balancing congestion costs decreased by $107.3 million or 59 percent, from -$182.4 million in 2009 to -$289.7 million in 2010. 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. Day-ahead congestion frequency increased from 2009 to 2010 by 22,198 congestion event hours or 28 percent. In 2010, there were 100,728 day-ahead, congestion-event hours compared to 78,530 day-ahead, congestion-event hours in 2009. Real-time congestion frequency increased from 2009 to 2010 by 8,012 congestion event hours. In 2010, there were 23,459 real-time, congestion-event hours compared to 15,447 real-time, congestion-event hours in 2009.

ARRs and FTRs served as an effective, but not total, hedge against congestion. ARR and FTR revenues hedged 96.2 percent of the total congestion costs in the Day-Ahead Energy Market and the balancing energy market within PJM for the 2009 to 2010 planning period.[8] During the first seven months of the 2010 to 2011 planning period, total ARR and FTR revenues hedged 78.7 percent of the congestion costs within PJM. FTRs were paid at 96.9 percent of the target allocation level for the 12-month period of the 2009 to 2010 planning period, and at 85.2 percent of the target allocation level for the first seven months of the 2010 to 2011 planning period.[9] Revenue adequacy for a planning period is not final until the end of the period.

There are other ways to evaluate the effectiveness of ARRs and FTRs as a hedge. The value of ARRs and FTRs was 4.2 percent of total real-time energy charges to load for the calendar year 2010.[10]

6 131 FERC ¶ 61,015 (April 13, 2010); 131 FERC ¶ 61,243 (June 17, 2010).
7 See *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, FERC Docket No. RM10-23-000, 131 FERC ¶ 61,253.
8 See the *2010 State of the Market Report for PJM* Section 8, "Financial Transmission and Auction Revenue Rights," at Table 8-33, "ARR and FTR congestion hedging: Planning periods 2009 to 2010 and 2010 to 2011."
9 See the *2010 State of the Market Report for PJM* Section 8, "Financial Transmission and Auction Revenue Rights," at Table 8-21, "Monthly FTR accounting summary (Dollars (Millions)): Planning periods 2008 to 2009 and 2009 to 2010"
10 See the *2010 State of the Market Report for PJM* Section 8, "Financial Transmission and Auction Revenue Rights," at Table 8-34, "ARRs and FTRs as a hedge against energy charges by control zone: Calendar year 2010"

One constraint accounted for 30 percent of total congestion costs in 2010 and the top five constraints accounted for 52 percent of total congestion costs. The AP South Interface was the largest contributor to congestion costs in 2010.

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 increased congestion payments by load are offset by increased congestion revenues to generation, for the area analyzed. 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.[11] 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 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 in 2010 were $1,428.1 million, which was comprised of load congestion payments of $362.4 million, negative generation credits of $1,147.8 million and negative explicit congestion of $82.1 million (Table 7-2).

Congestion

Congestion Accounting

Transmission congestion can exist in PJM's Day-Ahead and Real-Time Energy Market. Transmission congestion charges in the Day-Ahead Energy Market can be directly hedged by FTRs. Balancing

11 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.

market congestion charges can be hedged by FTRs to the extent that a participant's energy flows in real time are consistent with those in the Day-Ahead Energy Market.[12]

Total congestion charges are equal to the net congestion bill plus explicit congestion charges, incurred in both the Day-Ahead Energy Market and the balancing energy market.

The net congestion bill is calculated by subtracting generating congestion credits from load congestion payments. The logic is that increased congestion payments by load are offset by increased 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.

In the 2010 analysis of total congestion costs, load congestion payments are netted against generation congestion credits on an hourly basis, by billing organization, and then summed for the given period.[13] A billing organization may offset load congestion payments with its generation portfolio or by purchasing supply from another entity via a bilateral transaction.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. (Decrement bids and energy sales can be thought of as scheduled load.) 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 and increment offers and Day-Ahead Energy Market purchase transactions. (Increment offers and energy purchases can be thought of as scheduled generation.) 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

12 The terms *congestion charges* and *congestion costs* are both used to refer to the costs associated with congestion. The term, *congestion charges*, is used in documents by PJM's Market Settlement Operations.

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

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 Charges.** Explicit congestion charges are the net congestion charges associated with point-to-point energy transactions. These charges 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 charges equal the product of the deviations between the real-time and day-ahead transacted MW and the differences between the real-time CLMP at the transactions' sources and sinks.

The congestion charges associated with specific constraints are the sum of the total day-ahead and balancing congestion costs associated with those constraints. The congestion charges in each zone are the sum of the congestion charges 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 also 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.[14]

14 For an example of the congestion accounting methods used in this section, see *Technical Reference for PJM Markets*, Section 3, "FTRs and ARRs."

Total Calendar Year Congestion

Congestion charges have ranged from 3 percent to 9 percent of annual total PJM billings since 2003.[15] Table 7-1 shows total congestion by year from 2003 through 2010. After unusually low congestion charges of $719 million in the year 2009, the congestion charges nearly doubled to $1,428 million in the year 2010.[16] Despite the increase, the net congestion charges collected in 2010 amount to only two-thirds of that collected in 2008.

Table 7-1 Total annual PJM congestion (Dollars (Millions)): Calendar years 2003 to 2010

	Congestion Charges	Percent Change	Total PJM Billing	Percent of PJM Billing
2003	$464	NA	$6,900	7%
2004	$750	62%	$8,700	9%
2005	$2,092	179%	$22,630	9%
2006	$1,603	(23%)	$20,945	8%
2007	$1,846	15%	$30,556	6%
2008	$2,117	15%	$34,306	6%
2009	$719	(66%)	$26,550	3%
2010	$1,428	99%	$34,771	4%
Total	$9,591		$185,358	5%

Total congestion charges in Table 7-1 include both congestion charges associated with PJM facilities and those associated with reciprocal, coordinated flowgates in the Midwest ISO whose operating limits are respected by PJM.[17]

Table 7-2 shows the 2010 PJM congestion costs by category. The 2010 PJM total congestion costs were comprised of $362.4 million in load congestion payments, $1,147 million in negative generation congestion credits, and negative $82.1 million in explicit congestion costs. Load payments for congestion increased by 43 percent while generation credits for congestion in absolute terms increased by 123 percent and explicit congestion in absolute terms also increased by 66 percent.

Table 7-2 Total annual PJM congestion costs by category (Dollars (Millions)): Calendar years 2009 and 2010

	Congestion Costs (Millions)			
Year	Load Payments	Generation Credits	Explicit	Total
2009	$253.3	($515.1)	($49.4)	$719.0
2010	$362.4	($1,147.8)	($82.1)	$1,428.1

15 Calculated values shown in Section 7, "Congestion," are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

16 PJM reports congestion in terms of revenue collected to fund FTR Target Allocations. This means that any hour that results in a net negative congestion cost (i.e. the sum of day-ahead and balancing congestion costs in a given hour is less than zero) is excluded from the total congestion cost calculation for a given period. Therefore, the total congestion costs reported here will be less than those reported by PJM, for the same period, because they include the net negative congestion costs.

17 See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C." (December 11, 2008) (Accessed January 23, 2011), Section 6.1 <http://www.pjm.com/documents/agreements/~/media/documents/agreements/joa-complete.ashx>.

Monthly Congestion

Table 7-3 shows that during calendar year 2010, monthly congestion charges ranged from a maximum of $268.9 million in July 2010 to a minimum of $20.4 million in March 2010. Nearly half of all calendar year 2010 congestion occurred in the months of June through September.

Table 7-3 Monthly PJM congestion charges (Dollars (Millions)): Calendar years 2009 to 2010

	2009	2010	Change	Percent Change
Jan	$149.3	$218.5	$69.2	46.3%
Feb	$83.0	$106.4	$23.4	28.3%
Mar	$74.6	$20.4	($54.2)	(72.7%)
Apr	$25.6	$42.6	$17.0	66.1%
May	$25.9	$68.5	$42.6	164.7%
Jun	$49.8	$188.5	$138.7	278.8%
Jul	$39.4	$268.9	$229.5	582.6%
Aug	$72.1	$105.1	$33.0	45.9%
Sep	$23.9	$119.9	$96.0	400.7%
Oct	$42.7	$50.3	$7.6	17.7%
Nov	$36.3	$52.0	$15.7	43.4%
Dec	$96.4	$187.1	$90.6	94.0%
Total	$719.0	$1,428.1	$709.1	98.6%

Congestion Component of LMP

The congestion component of LMP was calculated for each PJM control zone, to provide an indication of the geographic dispersion of congestion costs. The congestion component of LMP for control zones is presented in Table 7-4 for calendar years 2009 and 2010.

Table 7-4 shows overall congestion patterns in 2010. Price separation between eastern and western control zones in PJM was primarily a result of congestion on the AP South interface. This constraint generally had a positive congestion component of LMP in eastern and southern control zones located on the constrained side of the affected facilities while the unconstrained western zones had a negative congestion component of LMP.

Table 7-4 Annual average congestion component of LMP: Calendar years 2009 to 2010

	2009		2010	
Control Zone	Day Ahead	Real Time	Day Ahead	Real Time
AECO	$2.03	$1.83	$2.96	$3.64
AEP	($2.12)	($2.16)	($4.05)	($4.83)
AP	$0.62	$1.32	$0.06	$0.12
BGE	$3.33	$3.04	$5.75	$6.68
ComEd	($5.09)	($5.61)	($7.38)	($8.58)
DAY	($2.77)	($2.72)	($4.74)	($5.69)
DLCO	($3.37)	($3.02)	($4.75)	($5.94)
Dominion	$2.47	$2.37	$5.10	$5.35
DPL	$2.25	$2.32	$3.17	$3.82
JCPL	$1.82	$2.01	$2.59	$2.92
Met-Ed	$2.10	$2.03	$3.13	$3.47
PECO	$1.87	$1.71	$2.69	$2.84
PENELEC	($0.10)	($0.06)	($0.68)	($1.42)
Pepco	$3.75	$3.74	$6.16	$6.72
PPL	$1.88	$1.75	$2.20	$2.34
PSEG	$2.12	$2.27	$3.04	$3.99
RECO	$1.47	$1.55	$2.19	$2.50

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 2010, there were 100,728 day-ahead, congestion-event hours compared to 78,530 day-ahead, congestion-event hours in 2009. In 2010, there were 23,459 real-time, congestion-event hours compared to 15,447 real-time, congestion-event hours in 2009.

Congestion by Facility Type and Voltage

Day-ahead, congestion-event hours decreased on the reciprocally coordinated flowgates between PJM and the Midwest Independent Transmission System Operator, Inc. (Midwest ISO) while congestion frequency on internal PJM interfaces, transmission lines and transformers increased. Real-time, congestion-event hours decreased on the reciprocally coordinated flowgates between PJM and the Midwest ISO, while congestion frequency on interfaces, transmission lines and transformers increased.

Day-ahead congestion costs decreased on the reciprocally coordinated flowgates between PJM and the Midwest ISO and increased on PJM interfaces, transmission lines and transformers in 2010. Balancing congestion costs increased on the reciprocally coordinated flowgates between PJM and the Midwest ISO and transformers and decreased on PJM interfaces and transmission lines in 2010.

Table 7-5 provides congestion-event hour subtotals and congestion cost subtotals comparing 2010 calendar year results by facility type: line, transformer, interface, flowgate and unclassified facilities.[18,19] For comparison, this information is presented in Table 7-6 for calendar year 2009.[20]

Total congestion costs associated with the reciprocally coordinated flowgates between PJM and the Midwest ISO increased by $0.5 million from $11.4 million in 2009 to $11.9 million in 2010.[21] The day-ahead congestion cost and congestion event hours decreased in 2010 compared to 2009. Balancing congestion costs increased in 2010, while balancing congestion event hours decreased in comparison to 2009. Balancing congestion cost on the reciprocally coordinated flow gates were generally negative in 2009 and 2010. A decrease in congestion event-hours from 3,418 to 3,242 event hours was consistent with an increase in the congestion cost from -$80.8 million to -$60.1 million. The Crete – St Johns line flowgate accounted for $29.7 million in congestion costs and was the largest contributor to positive congestion costs among flowgates in 2010. The largest contribution to negative congestion costs among flowgates came from the Pleasant Prairie – Zion flowgate with -$10.9 million in 2010 congestion costs.

Total congestion costs associated with interfaces increased from $322.8 million in 2009 to $712.5 million in 2010. Interfaces typically include multiple transmission facilities and reflect power flows into or through a wider geographic area. Interface congestion constituted 50 percent of total PJM congestion costs in 2010. Among interfaces, the AP South, the Bedington – Black Oak and the 5004/5005 interfaces accounted for the largest contribution to positive congestion costs in 2010. The AP South interface, with $421.6 million in congestion, had the highest congestion cost of any facility in PJM, accounting for 30 percent of the total PJM congestion costs in 2010. The AP South, the Bedington – Black Oak and the 5004/5005 interfaces together accounted for $618.8 million or

18 Unclassified constraints appear in the Day-Ahead Market only and represent congestion costs incurred on market elements which are not posted by PJM. Congestion frequency associated with these unclassified constraints is not presented in order to be consistent with the posting of constrained facilities by PJM.

19 The term *flowgate* refers to Midwest ISO flowgates in this context.

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

21 The congestion costs reported here for the reciprocally coordinated flowgates between PJM and the Midwest ISO flowgates are calculated in the same manner as all other internal PJM constraints and use the congestion accounting methods defined in this section. For the payments to and from the Midwest ISO based on the market-to-market settlement calculations, defined in the "Joint Operating Agreement between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C.", see the *2010 State of the Market Report for PJM*, Volume II, Section 4, "Interchange Transactions," at "PJM and Midwest ISO Joint Operating Agreement."

87 percent of all interface congestion costs and were the largest contributors to positive congestion among interfaces in 2010.

Total congestion costs associated with transmission lines increased 74 percent from $282.9 million in 2009 to $493.1 million in 2010. Transmission line congestion accounted for 35 percent of the total PJM congestion costs for 2010. The East Frankfort – Crete and Cloverdale – Lexington lines together accounted for $68.9 million or 14 percent of all transmission line congestion costs and were the largest contributors to positive congestion among transmission lines in 2010.

Total congestion costs associated with transformers increased 29 percent from $103.6 million in 2009 to $184.4 million in 2010. Congestion on transformers accounted for 13 percent of the total PJM congestion costs in 2010. The Doubs and Belmont transformers together accounted for $91.3 million or 49 percent of all transformer congestion costs and were the largest contributors to positive congestion costs among transformers in 2010.

Table 7-5 Congestion summary (By facility type): Calendar year 2010

	Congestion Costs (Millions)										
	Day Ahead				Balancing					Event Hours	
Type	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
Flowgate	($9.5)	($76.1)	$5.5	$72.0	($3.1)	$3.8	($53.2)	($60.1)	$11.9	6,830	3,242
Interface	$84.6	($631.0)	$2.7	$718.2	$22.4	$24.0	($4.1)	($5.7)	$712.5	9,823	2,619
Line	$178.4	($433.9)	$68.9	$681.2	($44.3)	$42.5	($101.3)	($188.1)	$493.1	72,457	14,291
Transformer	$128.3	($81.5)	$10.4	$220.1	($10.9)	$4.7	($20.2)	($35.8)	$184.4	11,618	3,307
Unclassified	$16.6	($0.3)	$9.3	$26.2	$0.0	$0.0	$0.0	$0.0	$26.2	NA	NA
Total	$398.3	($1,222.9)	$96.7	$1,717.9	($35.9)	$75.0	($178.8)	($289.7)	$1,428.1	100,728	23,459

Table 7-6 Congestion summary (By facility type): Calendar year 2009

	Congestion Costs (Millions)										
	Day Ahead				Balancing					Event Hours	
Type	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
Flowgate	$18.0	($56.4)	$17.9	$92.3	($10.5)	$5.4	($65.0)	($80.8)	$11.4	9,434	3,418
Interface	$48.0	($263.5)	$2.1	$313.5	$4.0	($2.4)	$2.9	$9.3	$322.8	5,884	1,378
Line	$114.8	($195.7)	$41.0	$351.4	($18.7)	$11.5	($38.4)	($68.6)	$282.9	52,608	7,529
Transformer	$108.5	($14.6)	$22.9	$145.9	($13.8)	($4.4)	($32.9)	($42.3)	$103.6	10,604	3,122
Unclassified	$3.1	$4.9	$0.0	($1.7)	$0.0	$0.0	$0.0	$0.0	($1.7)	NA	NA
Total	$292.3	($525.2)	$83.9	$901.4	($39.0)	$10.1	($133.4)	($182.4)	$719.0	78,530	15,447

Table 7-7 Congestion Event Hours (Day Ahead against Real Time): Calendar Years 2009 to 2010

	Congestion Event Hours					
	2010			2009		
Type	Day Ahead Constrained	Corresponding Real Time Constrained	Percent	Day Ahead Constrained	Corresponding Real Time Constrained	Percent
Flowgate	6,830	1,023	15.0%	9,434	1,181	12.5%
Interface	9,823	1,881	19.1%	5,884	723	12.3%
Line	72,457	6,132	8.5%	52,608	3,752	7.1%
Transformer	11,618	1,529	13.2%	10,604	2,280	21.5%
Total	100,728	10,565	10.5%	78,530	7,936	10.1%

Table 7-8 Congestion Event Hours (Real Time against Day Ahead): Calendar Years 2009 to 2010

	Congestion Event Hours					
	2010			2009		
Type	Real Time Constrained	Corresponding Day Ahead Constrained	Percent	Real Time Constrained	Corresponding Day Ahead Constrained	Percent
Flowgate	3,242	1,042	32.1%	3,418	1,181	34.6%
Interface	2,619	1,881	71.8%	1,378	720	52.2%
Line	14,291	6,002	42.0%	7,529	3,711	49.3%
Transformer	3,307	1,496	45.2%	3,122	2,035	65.2%
Total	23,459	10,421	44.4%	15,447	7,647	49.5%

Table 7-7 and Table 7-8 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 7-7. In 2010, there were 100,728 congestion event hours in the day-ahead market. Among those, only 10,565 (10.5 percent) were also constrained in the real-time. In 2009, among the 78,530 day-ahead congestion event hours, only 7,936 (10.1 percent) were binding in the real-time.

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 7-8. In 2010, there were 23,459 congestion event hours in the real-time market. Among these, 10,421 (44.4 percent) were also constrained in the day-ahead market. In 2009, among the 15,447 real-time congestion event hours, only 7,647 (49.5 percent) were binding in the day-ahead.

Table 7-9 shows congestion costs by facility voltage class for 2010. In comparison to 2009 (shown in Table 7-10), congestion costs increased across 765 kV, 500 kV, 345 kV, 230 kV, 138 kV, 115 kV, 34 kV, 12 kV and unclassified facilities in 2010.

Congestion costs associated with 765 kV facilities increased from $0.1 million in 2009 to the $4.5 million experienced in 2010. Congestion on 765 kV facilities comprised less than 1 percent of total 2010 PJM congestion costs.

Congestion costs associated with 500 kV facilities increased 92 percent from $406.5 million in 2009, to $779.3 million in 2010. Congestion on 500 kV facilities comprised 55 percent of total 2010 PJM congestion costs. The AP South interface, the Bedington – Black Oak interface, the 5004/5005 interface and the AEP-DOM interface accounted for $745.8 million or 96 percent of all 500 kV congestion costs; they were the largest contributors to positive congestion among 500 kV facilities in 2010.

Congestion costs associated with 345 kV facilities increased by 25 percent from 58.1 million in 2009, to $72.3 million in 2010. Congestion on 345 kV facilities comprised five percent of total 2010 PJM congestion costs. The East Frankfurt – Crete line and the Crete – St. Johns line accounted for $69.4 million or 96 percent of all 345 kV congestion costs; they were the largest contributors to positive congestion among 345 kV facilities in 2010.

Congestion costs associated with 230 kV facilities increased 181 percent from $83.6 million in 2009 to $234.6 million in 2010. Congestion on 230 kV facilities comprised 16 percent of total 2010 PJM congestion costs. The Doubs transformer accounted for $64.7 million or 28 percent of all 230 kV congestion costs and was the largest contributor to positive congestion among 230 kV facilities in 2010.

Congestion costs associated with 138 kV facilities increased 67 percent from $158.3 million in 2009 to $264 million in 2010. Congestion on 138 kV facilities comprised 18 percent of total 2010 PJM congestion costs. The Belmont transformer and Tiltonsville – Windsor line together accounted for $46.0 million or 17 percent of all 138 kV congestion costs; they were the largest contributors to positive congestion among 138 kV facilities in 2010.

Congestion costs associated with 115 kV facilities decreased by 250 percent from $12.1 million in 2009, to $42.4 million in 2010. Congestion on 115 kV facilities comprised three percent of total 2009 PJM congestion costs. The Hunterstown and Erie West transformers together accounted for $15.6 million or 37 percent of all 115 kV congestion costs; they were the largest contributors to positive congestion among 115 kV facilities in 2010.

Congestion costs associated with 69 kV and below facilities increased by nearly 128 percent from $2.1 million in 2009, to $4.7 million in 2010. Congestion on 69 kV and below facilities comprised less than one percent of total 2010 PJM congestion costs. The Oak Hill transformer accounted for $2.5 million in congestion costs. It had the largest contribution to congestion costs among 69 kV and below facilities.

Table 7-9 Congestion summary (By facility voltage): Calendar year 2010

	Congestion Costs (Millions)										
	Day Ahead				Balancing					Event Hours	
Voltage (kV)	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
765	$1.1	($6.9)	$0.7	$8.7	($1.1)	($0.1)	($3.2)	($4.2)	$4.5	146	74
500	$108.3	($678.0)	$9.9	$796.1	$19.0	$15.0	($20.8)	($16.8)	$779.3	12,041	4,305
345	($9.8)	($168.7)	$28.9	$187.8	($10.3)	$10.3	($94.9)	($115.5)	$72.3	14,081	4,736
230	$74.4	($193.8)	$24.1	$292.3	($9.8)	$24.9	($23.0)	($57.7)	$234.6	20,187	4,252
138	$146.7	($172.7)	$22.5	$342.0	($24.3)	$19.3	($34.4)	($78.0)	$264.0	40,955	7,794
115	$45.5	($6.1)	$1.0	$52.6	($3.0)	$5.2	($2.0)	($10.2)	$42.4	6,387	1,593
69	$15.2	$3.5	$0.3	$12.0	($6.6)	$0.3	($0.5)	($7.4)	$4.6	6,639	686
34	($0.0)	($0.0)	$0.0	$0.0	$0.1	$0.0	$0.0	$0.1	$0.1	37	19
12	$0.3	$0.2	($0.0)	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	255	0
Unclassified	$16.6	($0.3)	$9.3	$26.2	$0.0	$0.0	$0.0	$0.0	$26.2	NA	NA
Total	$398.3	($1,222.9)	$96.7	$1,717.9	($35.9)	$75.0	($178.8)	($289.7)	$1,428.1	100,728	23,459

Table 7-10 Congestion summary (By facility voltage): Calendar year 2009

	Congestion Costs (Millions)										
	Day Ahead				Balancing					Event Hours	
Voltage (kV)	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
765	($0.0)	($0.0)	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	24	0
500	$114.9	($275.4)	$14.2	$404.4	($0.5)	($15.0)	($12.3)	$2.1	$406.5	11,643	3,301
345	$30.6	($61.4)	$34.8	$126.8	($5.3)	$7.1	($56.3)	($68.7)	$58.1	8,503	2,506
230	$56.4	($45.8)	$9.4	$111.7	($15.0)	$5.9	($7.2)	($28.0)	$83.6	15,103	2,095
138	$68.2	($147.7)	$24.9	$240.7	($14.8)	$10.4	($57.2)	($82.5)	$158.3	30,566	6,662
115	$11.6	($0.7)	$0.4	$12.6	$0.4	$0.6	($0.2)	($0.5)	$12.1	4,893	552
69	$7.3	$0.7	$0.2	$6.8	($3.8)	$0.9	($0.1)	($4.8)	$1.9	6,661	329
34	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	185	2
12	$0.4	$0.3	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	952	0
Unclassified	$3.1	$4.9	$0.0	($1.7)	$0.0	$0.0	$0.0	$0.0	($1.7)	NA	NA
Total	$292.3	($525.2)	$83.9	$901.4	($39.0)	$10.1	($133.4)	($182.4)	$719.0	78,530	15,447

Constraint Duration

Table 7-11 lists calendar year 2009 and 2010 constraints that were most frequently in effect and Table 7-12 shows the constraints which experienced the largest change in congestion-event hours from 2009 to 2010.[22]

The AP South interface, the East Frankfort – Crete line and the Athenia – Saddlebrook line were the most frequently occurring constraints in 2010. The Kammer transformer saw the largest decrease in congestion-event hours from 2009. The Athenia – Saddlebrook line saw the largest increase in congestion-event hours from 2009 to 2010, but still remained in the top 25 of the most frequently occurring transmission constraints. The Kammer transformer and the AP South interface were also among the top contributors to 2010 congestion costs (Table 7-13).

Table 7-11 Top 25 constraints with frequent occurrence: Calendar years 2009 to 2010

			Event Hours						Percent of Annual Hours					
			Day Ahead			Real Time			Day Ahead			Real Time		
No.	Constraint	Type	2009	2010	Change	2009	2010	Change	2009	2010	Change	2009	2010	Change
1	AP South	Interface	3,549	4,645	1,096	604	1,528	924	41%	53%	13%	7%	17%	11%
2	East Frankfort - Crete	Line	2,163	3,084	921	605	850	245	25%	35%	11%	7%	10%	3%
3	Athenia - Saddlebrook	Line	1,108	3,318	2,210	139	364	225	13%	38%	25%	2%	4%	3%
4	Waterman - West Dekalb	Line	1,499	3,002	1,503	57	343	286	17%	34%	17%	1%	4%	3%
5	Tiltonsville - Windsor	Line	2,070	2,723	653	311	506	195	24%	31%	7%	4%	6%	2%
6	Pleasant Valley - Belvidere	Line	3,648	2,553	(1,095)	405	467	62	42%	29%	(13%)	5%	5%	1%
7	Crete - St Johns Tap	Flowgate	1,571	2,066	495	306	823	517	18%	24%	6%	3%	9%	6%
8	Bedington - Black Oak	Interface	669	2,291	1,622	73	212	139	8%	26%	19%	1%	2%	2%
9	5004/5005 Interface	Interface	776	1,644	868	294	605	311	9%	19%	10%	3%	7%	4%
10	Belmont	Transformer	764	1,887	1,123	76	203	127	9%	22%	13%	1%	2%	1%
11	Cloverdale - Lexington	Line	1,019	1,127	108	434	684	250	12%	13%	1%	5%	8%	3%
12	Electric Jct - Nelson	Line	823	1,495	672	202	258	56	9%	17%	8%	2%	3%	1%
13	Pleasant Prairie - Zion	Flowgate	151	1,321	1,170	135	404	269	2%	15%	13%	2%	5%	3%
14	Nelson - Cordova	Line	0	1,546	1,546	22	95	73	0%	18%	18%	0%	1%	1%
15	Burlington - Croydon	Line	2,805	1,500	(1,305)	3	33	30	32%	17%	(15%)	0%	0%	0%
16	Pinehill - Stratford	Line	1,221	1,520	299	0	0	0	14%	17%	3%	0%	0%	0%
17	Carnegie - Tidd	Line	0	1,234	1,234	7	259	252	0%	14%	14%	0%	3%	3%
18	Danville - East Danville	Line	286	1,307	1,021	38	142	104	3%	15%	12%	0%	2%	1%
19	Branchburg - Readington	Line	37	1,235	1,198	13	185	172	0%	14%	14%	0%	2%	2%
20	Wylie Ridge	Transformer	354	728	374	335	683	348	4%	8%	4%	4%	8%	4%
21	Doubs	Transformer	429	909	480	246	500	254	5%	10%	5%	3%	6%	3%
22	Leonia - New Milford	Line	3,847	1,241	(2,606)	39	50	11	44%	14%	(30%)	0%	1%	0%
23	Lindenwold - Stratford	Line	681	1,272	591	0	0	0	8%	15%	7%	0%	0%	0%
24	Mount Storm - Pruntytown	Line	525	571	46	132	574	442	6%	7%	1%	2%	7%	5%
25	Glidden - West Dekalb	Line	1,166	1,090	(76)	21	21	0	13%	12%	(1%)	0%	0%	0%

22 Presented in descending order of absolute change between 2009 and 2010 day-ahead and real-time, congestion-event hours.

Table 7-12 Top 25 constraints with largest year-to-year change in occurrence: Calendar years 2009 to 2010

			Event Hours						Percent of Annual Hours					
			Day Ahead			Real Time			Day Ahead			Real Time		
No.	Constraint	Type	2009	2010	Change	2009	2010	Change	2009	2010	Change	2009	2010	Change
1	Kammer	Transformer	3,674	0	(3,674)	1,328	0	(1,328)	42%	0%	(42%)	15%	0%	(15%)
2	Dunes Acres - Michigan City	Flowgate	2,949	264	(2,685)	910	42	(868)	34%	3%	(31%)	10%	0%	(10%)
3	Leonia - New Milford	Line	3,847	1,241	(2,606)	39	50	11	44%	14%	(30%)	0%	1%	0%
4	Athenia - Saddlebrook	Line	1,108	3,318	2,210	139	364	225	13%	38%	25%	2%	4%	3%
5	AP South	Interface	3,549	4,645	1,096	604	1,528	924	41%	53%	13%	7%	17%	11%
6	Waterman - West Dekalb	Line	1,499	3,002	1,503	57	343	286	17%	34%	17%	1%	4%	3%
7	Bedington - Black Oak	Interface	669	2,291	1,622	73	212	139	8%	26%	19%	1%	2%	2%
8	Nelson - Cordova	Line	0	1,546	1,546	22	95	73	0%	18%	18%	0%	1%	1%
9	Carnegie - Tidd	Line	0	1,234	1,234	7	259	252	0%	14%	14%	0%	3%	3%
10	Pleasant Prairie - Zion	Flowgate	151	1,321	1,170	135	404	269	2%	15%	13%	2%	5%	3%
11	Branchburg - Readington	Line	37	1,235	1,198	13	185	172	0%	14%	14%	0%	2%	2%
12	Pana North	Flowgate	986	0	(986)	318	0	(318)	11%	0%	(11%)	4%	0%	(4%)
13	Burlington - Croydon	Line	2,805	1,500	(1,305)	3	33	30	32%	17%	(15%)	0%	0%	0%
14	Belmont	Transformer	764	1,887	1,123	76	203	127	9%	22%	13%	1%	2%	1%
15	5004/5005 Interface	Interface	776	1,644	868	294	605	311	9%	19%	10%	3%	7%	4%
16	East Frankfort - Crete	Line	2,163	3,084	921	605	850	245	25%	35%	11%	7%	10%	3%
17	Danville - East Danville	Line	286	1,307	1,021	38	142	104	3%	15%	12%	0%	2%	1%
18	State Line - Wolf Lake	Flowgate	1,284	376	(908)	183	7	(176)	15%	4%	(10%)	2%	0%	(2%)
19	Oak Grove - Galesburg	Flowgate	790	117	(673)	638	242	(396)	9%	1%	(8%)	7%	3%	(5%)
20	Kammer - Ormet	Line	552	0	(552)	509	3	(506)	6%	0%	(6%)	6%	0%	(6%)
21	Hillsdale - New Milford	Line	0	1,022	1,022	0	23	23	0%	12%	12%	0%	0%	0%
22	Pleasant Valley - Belvidere	Line	3,648	2,553	(1,095)	405	467	62	42%	29%	(13%)	5%	5%	1%
23	Cedar Grove - Clifton	Line	1,194	205	(989)	38	8	(30)	14%	2%	(11%)	0%	0%	(0%)
24	Crete - St Johns Tap	Flowgate	1,571	2,066	495	306	823	517	18%	24%	6%	3%	9%	6%
25	Pumphrey - Westport	Line	1,181	244	(937)	0	0	0	13%	3%	(11%)	0%	0%	0%

Constraint Costs

Table 7-13 and Table 7-14 present the top constraints affecting congestion costs by facility for calendar years 2010 and 2009.[23] The AP South interface was the largest contributor to congestion costs in 2010. With $421.6 million in total congestion costs, it accounted for 30 percent of the total PJM congestion costs in 2010. The top five constraints in terms of congestion costs together comprised 52 percent of the total PJM congestion costs in 2010.

23 Presented in descending order of annual total congestion costs.

Table 7-13 Top 25 constraints affecting annual PJM congestion costs (By facility): Calendar year 2010

				Congestion Costs (Millions)									Percent of Total PJM Congestion Costs
				Day Ahead				Balancing					
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	2010
1	AP South	Interface	500	($10.8)	($433.4)	($2.4)	$420.2	$11.2	$11.4	$1.6	$1.4	$421.6	30%
2	Bedington - Black Oak	Interface	500	$9.4	($96.0)	$2.7	$108.1	($0.1)	$1.1	($1.5)	($2.8)	$105.3	7%
3	5004/5005 Interface	Interface	500	$50.1	($42.0)	($0.1)	$92.1	$10.2	$9.0	($1.3)	($0.2)	$91.9	6%
4	Doubs	Transformer	AP	$39.7	($28.2)	$0.5	$68.4	$0.2	$1.1	($2.8)	($3.7)	$64.7	5%
5	AEP-DOM	Interface	500	$10.5	($52.8)	$2.5	$65.8	$0.3	$1.0	($2.8)	($3.5)	$62.3	4%
6	East Frankfort - Crete	Line	ComEd	$2.6	($43.0)	$6.1	$51.7	($4.5)	($0.4)	($7.6)	($11.8)	$39.9	3%
7	Crete - St Johns Tap	Flowgate	Midwest ISO	($9.0)	($51.4)	($5.1)	$37.3	$0.0	($1.1)	($8.9)	($7.8)	$29.5	2%
8	Cloverdale - Lexington	Line	AEP	$16.5	($14.4)	$3.0	$33.9	($3.0)	($3.6)	($5.5)	($4.9)	$28.9	2%
9	Belmont	Transformer	AP	$15.8	($15.0)	($0.6)	$30.2	($4.4)	($1.0)	($0.3)	($3.7)	$26.6	2%
10	Unclassified	Unclassified	Unclassified	$16.6	($0.3)	$9.3	$26.2	$0.0	$0.0	$0.0	$0.0	$26.2	2%
11	Brandon Shores - Riverside	Line	BGE	$16.7	($10.5)	($0.4)	$26.8	$0.8	$2.3	$0.4	($1.2)	$25.7	2%
12	Mount Storm - Pruntytown	Line	AP	$2.1	($20.5)	$2.1	$24.7	($0.1)	($5.1)	($4.8)	$0.2	$24.9	2%
13	West	Interface	500	$21.5	($1.6)	($0.2)	$22.9	$0.6	$1.3	$0.0	($0.7)	$22.2	2%
14	Tiltonsville - Windsor	Line	AP	$21.4	($2.2)	$1.4	$25.0	($4.5)	$0.2	($0.9)	($5.6)	$19.4	1%
15	Pleasant Valley - Belvidere	Line	ComEd	($9.0)	($29.2)	$3.5	$23.7	$0.1	$3.0	($4.9)	($7.8)	$15.9	1%
16	Graceton - Raphael Road	Line	BGE	($3.1)	($16.0)	$0.6	$13.6	$0.1	($1.6)	($0.2)	$1.5	$15.1	1%
17	Brunner Island - Yorkana	Line	Met-Ed	($2.5)	($15.2)	$0.4	$13.1	$0.8	($1.1)	($0.9)	$1.0	$14.1	1%
18	Crescent	Transformer	DLCO	$7.9	($5.2)	$0.8	$13.9	($0.0)	($0.6)	($1.0)	($0.4)	$13.5	1%
19	Clover	Transformer	Dominion	$3.2	($10.6)	$2.1	$15.9	($1.3)	($1.0)	($3.2)	($3.4)	$12.5	1%
20	Millville - Sleepy Hollow	Line	Dominion	$9.2	($2.8)	$0.3	$12.3	$0.0	$0.0	$0.0	$0.0	$12.3	1%
21	Millville - Old Chapel	Line	Dominion	$8.6	($2.6)	$1.0	$12.2	$0.0	$0.0	$0.0	$0.0	$12.2	1%
22	Branchburg - Readington	Line	PSEG	$5.7	($7.3)	$0.7	$13.7	($0.5)	$1.5	$0.1	($1.9)	$11.8	1%
23	Kanawha - Kincaid	Line	AEP	$8.9	($1.2)	$1.5	$11.6	$0.0	$0.0	$0.0	$0.0	$11.6	1%
24	Pleasant Prairie - Zion	Flowgate	Midwest ISO	($3.3)	($7.8)	$3.0	$7.5	($0.5)	$1.2	($16.7)	($18.4)	($10.9)	(1%)
25	Eddystone - Island Road	Line	PECO	$0.7	($7.7)	$1.1	$9.6	($0.0)	$0.0	$0.0	($0.0)	$9.5	1%

Table 7-14 Top 25 constraints affecting annual PJM congestion costs (By facility): Calendar year 2009

				Congestion Costs (Millions)									Percent of Total PJM Congestion Costs
				Day Ahead				Balancing					
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	2009
1	AP South	Interface	500	$12.0	($186.0)	($0.2)	$197.8	$2.9	($2.9)	$2.9	$8.7	$206.5	29%
2	West	Interface	500	$19.4	($22.9)	$0.7	$42.9	$0.4	($0.3)	$0.1	$0.8	$43.7	6%
3	5004/5005 Interface	Interface	500	$11.1	($31.0)	$0.3	$42.4	$1.3	$0.3	$0.2	$1.1	$43.6	6%
4	Pleasant Valley - Belvidere	Line	ComEd	($6.3)	($45.2)	$4.0	$42.9	($0.6)	$2.9	($5.3)	($8.8)	$34.2	5%
5	Kammer	Transformer	500	$50.8	$16.1	$9.0	$43.8	($4.9)	($6.7)	($11.6)	($9.8)	$34.0	5%
6	East Frankfort - Crete	Line	ComEd	$5.9	($19.1)	$8.6	$33.6	($1.0)	$1.3	($5.7)	($8.0)	$25.6	4%
7	Doubs	Transformer	AP	$17.6	($10.8)	$0.9	$29.3	($2.1)	$0.2	($1.8)	($4.2)	$25.1	3%
8	Mount Storm - Pruntytown	Line	AP	$1.8	($16.8)	$0.5	$19.1	$0.9	($1.7)	($1.1)	$1.5	$20.5	3%
9	Bedington - Black Oak	Interface	500	$3.8	($15.5)	$0.8	$20.1	($0.4)	($0.1)	$0.1	($0.2)	$19.8	3%
10	Dunes Acres - Michigan City	Flowgate	Midwest ISO	$13.5	($23.2)	$8.6	$45.4	($7.2)	($2.0)	($23.4)	($28.6)	$16.7	2%
11	Cloverdale - Lexington	Line	AEP	$8.1	($5.3)	$2.0	$15.3	($0.0)	($3.1)	($2.8)	$0.3	$15.6	2%
12	Crete - St Johns Tap	Flowgate	Midwest ISO	$3.2	($15.1)	$3.8	$22.0	($1.1)	$0.4	($6.1)	($7.7)	$14.4	2%
13	Tiltonsville - Windsor	Line	AP	$10.6	($0.9)	$0.3	$11.8	($0.4)	($0.6)	($0.7)	($0.6)	$11.2	2%
14	AEP-DOM	Interface	500	$1.4	($7.6)	$0.5	$9.5	($0.5)	($0.2)	($0.0)	($0.3)	$9.2	1%
15	Pana North	Flowgate	Midwest ISO	$0.1	($2.2)	$1.8	$4.2	($0.5)	$1.1	($11.5)	($13.0)	($8.9)	(1%)
16	Graceton - Raphael Road	Line	BGE	$1.5	($6.0)	$0.6	$8.1	$1.5	$0.1	($0.7)	$0.7	$8.8	1%
17	Ruth - Turner	Line	AEP	$2.5	($6.5)	$0.5	$9.5	($1.5)	($0.6)	($0.6)	($1.5)	$8.0	1%
18	Sammis - Wylie Ridge	Line	AP	$4.5	($3.5)	$3.5	$11.5	($1.1)	($0.2)	($2.8)	($3.7)	$7.8	1%
19	Kanawha River	Transformer	AEP	$2.0	($3.7)	$0.3	$6.0	$0.1	($0.5)	($0.1)	$0.5	$6.5	1%
20	Kammer - Ormet	Line	AEP	$4.3	($4.1)	($0.1)	$8.3	($1.6)	$0.5	($0.0)	($2.2)	$6.2	1%
21	Glidden - West Dekalb	Line	ComEd	($0.6)	($6.0)	$0.4	$5.9	$0.1	($0.0)	($0.0)	$0.1	$6.0	1%
22	Breed - Wheatland	Line	AEP	($0.2)	($5.2)	$0.6	$5.6	$0.0	($0.0)	($0.0)	($0.0)	$5.6	1%
23	Kanawha - Kincaid	Line	AEP	$1.9	($3.5)	$0.2	$5.6	$0.0	$0.0	$0.0	$0.0	$5.6	1%
24	Schahfer - Burr Oak	Flowgate	Midwest ISO	$0.4	($1.3)	$0.6	$2.3	($2.0)	$0.4	($5.4)	($7.8)	($5.6)	(1%)
25	Mount Storm	Transformer	AP	$0.9	($4.7)	($0.1)	$5.5	($0.2)	$0.1	$0.1	($0.2)	$5.3	1%

Congestion-Event Summary for Midwest ISO Flowgates

PJM and the Midwest ISO 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.[24] A flowgate is a facility or group of facilities that may act as constraint points on the regional system.[25] PJM models these coordinated flowgates and controls for them in its security-constrained, economic dispatch. Table 7-15 and Table 7-16 show the Midwest ISO flowgates which PJM took dispatch action to control during 2010 and 2009, 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 Midwest ISO flowgates affecting PJM dispatch are presented by constraint, in descending order of the absolute value of

24 See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C." (December 11, 2009) (Accessed February 19, 2010) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/joa-complete.ashx>.

25 See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C." (December 11, 2009) (Accessed February 19, 2010), Section 2.2.24 <http://www.pjm.com/documents/agreements/~/media/documents/agreements/joa-complete.ashx>.

total congestion costs. Among Midwest ISO flowgates in 2010, the Crete – St Johns flowgate made the most significant contribution to positive congestion while the Pleasant Prairie – Zion flowgate made the most significant contribution to negative congestion. Among Midwest ISO flowgates in 2009, the Dunes Acres – Michigan City flowgate made the most significant contribution to positive congestion, while the Pana North flowgate made the most significant negative contribution.

Table 7-15 Top congestion cost impacts from Midwest ISO flowgates affecting PJM dispatch (By facility): Calendar year 2010

		Congestion Costs (Millions)										
		Day Ahead				Balancing					Event Hours	
No.	Constraint	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	Crete - St Johns Tap	($9.0)	($51.4)	($5.1)	$37.3	$0.0	($1.1)	($8.9)	($7.8)	$29.5	2,066	823
2	Pleasant Prairie - Zion	($3.3)	($7.8)	$3.0	$7.5	($0.5)	$1.2	($16.7)	($18.4)	($10.9)	1,321	404
3	Benton Harbor - Palisades	$0.0	($0.0)	$0.0	$0.1	($0.0)	$0.7	($4.5)	($5.2)	($5.1)	11	114
4	Rising	$0.0	($5.1)	$0.9	$6.0	($0.2)	$0.4	($0.9)	($1.6)	$4.5	875	80
5	Oak Grove - Galesburg	($0.1)	($0.4)	$0.2	$0.4	($0.2)	$0.7	($3.0)	($3.9)	($3.4)	117	242
6	Dunes Acres - Michigan City	$0.5	($0.7)	$0.9	$2.1	($0.1)	($0.3)	$0.4	$0.6	$2.7	264	42
7	Palisades - Vergennes	$2.8	($0.6)	$0.5	$3.9	($0.1)	$0.4	($1.0)	($1.5)	$2.3	235	91
8	Breed - Wheatland	$0.0	$0.0	$0.0	$0.0	$0.0	$0.1	($2.0)	($2.1)	($2.1)	0	76
9	Burnham - Sheffield	($0.3)	($1.9)	$0.4	$2.0	$0.0	$0.0	$0.0	$0.0	$2.0	252	0
10	DC Cook - Palisades	$0.0	$0.0	$0.0	$0.0	($0.3)	$0.1	($1.5)	($1.9)	($1.9)	0	36
11	Paxton - Sidney	$0.0	$0.0	$0.0	$0.0	($0.1)	$0.1	($1.4)	($1.5)	($1.5)	0	29
12	Burr Oak	$0.2	($0.2)	$0.0	$0.4	$0.3	$0.3	($1.9)	($1.8)	($1.4)	140	210
13	State Line - Wolf Lake	$0.3	($0.7)	$0.6	$1.5	($0.1)	$0.0	($0.0)	($0.1)	$1.4	376	7
14	Eugene - Bunsonville	$0.0	$0.0	$0.0	$0.0	($0.1)	$0.0	($0.8)	($0.9)	($0.9)	0	51
15	Marktown - Inland Steel	$0.6	($1.0)	$0.7	$2.2	($0.9)	$0.7	($1.4)	($3.1)	($0.9)	424	344
16	Michigan City - Laporte	$0.1	($0.1)	$0.1	$0.3	($0.2)	($0.0)	($0.7)	($0.9)	($0.7)	50	67
17	Lanesville	$0.0	$0.0	$0.0	$0.0	$0.0	$0.1	($0.4)	($0.5)	($0.5)	0	48
18	Beaver Valley - Sammis	$0.0	$0.0	$0.0	$0.0	($0.1)	$0.1	($0.2)	($0.4)	($0.4)	0	8
19	Nucor - Whitestown	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($0.4)	($0.4)	($0.4)	0	23
20	Stillwell - Dumont	$0.0	($0.2)	$0.1	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	42	0

Table 7-16 Top congestion cost impacts from Midwest ISO flowgates affecting PJM dispatch (By facility): Calendar year 2009

		Congestion Costs (Millions)										
		Day Ahead				Balancing					Event Hours	
No.	Constraint	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	Dunes Acres - Michigan City	$13.5	($23.2)	$8.6	$45.4	($7.2)	($2.0)	($23.4)	($28.6)	$16.7	2,949	910
2	Crete - St Johns Tap	$3.2	($15.1)	$3.8	$22.0	($1.1)	$0.4	($6.1)	($7.7)	$14.4	1,571	306
3	Pana North	$0.1	($2.2)	$1.8	$4.2	($0.5)	$1.1	($11.5)	($13.0)	($8.9)	986	318
4	Schahfer - Burr Oak	$0.4	($1.3)	$0.6	$2.3	($2.0)	$0.4	($5.4)	($7.8)	($5.6)	62	81
5	Paddock - Townline	$0.5	($3.6)	$0.4	$4.6	$0.6	$0.3	($0.3)	($0.0)	$4.5	404	215
6	Breed - Wheatland	$0.0	$0.0	$0.0	$0.0	$0.1	$0.7	($3.2)	($3.8)	($3.8)	0	161
7	Pleasant Prairie - Zion	($0.0)	($0.4)	$0.2	$0.6	$0.2	$0.8	($3.6)	($4.2)	($3.6)	151	135
8	Rising	($0.1)	($2.7)	$0.5	$3.1	$0.0	$0.2	($0.8)	($1.0)	$2.1	572	150
9	Palisades - Argenta	$0.1	($0.1)	$0.1	$0.3	($0.3)	$0.6	($1.1)	($2.1)	($1.8)	49	58
10	State Line - Wolf Lake	$0.5	($2.6)	$1.1	$4.3	($0.5)	$0.6	($1.6)	($2.7)	$1.6	1,284	183
11	Eugene - Bunsonville	$0.0	$0.0	$0.0	$0.0	($0.1)	$0.1	($1.1)	($1.3)	($1.3)	0	44
12	Oak Grove - Galesburg	($0.6)	($4.3)	$0.1	$3.8	$0.8	$1.4	($4.2)	($4.8)	($1.0)	790	638
13	State Line - Roxana	$0.0	$0.0	$0.0	$0.0	($0.2)	$0.0	($0.4)	($0.6)	($0.6)	0	30
14	Pawnee	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	($0.4)	($0.4)	($0.4)	0	35
15	Lanesville	$0.3	($0.1)	$0.1	$0.5	$0.0	$0.1	($0.8)	($0.9)	($0.4)	104	32
16	Pierce - Foster	$0.0	$0.0	$0.0	$0.0	($0.1)	$0.3	($0.0)	($0.4)	($0.4)	0	5
17	Burr Oak	$0.1	($0.4)	$0.5	$0.9	($0.2)	$0.2	($0.8)	($1.3)	($0.3)	94	66
18	Krendale - Seneca	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.1	($0.1)	($0.2)	($0.2)	0	30
19	Bunsonville - Eugene	$0.0	($0.1)	$0.1	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	24	0
20	State Line	$0.0	($0.0)	($0.0)	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	385	0

Congestion-Event Summary for the 500 kV System

Constraints on the 500 kV system generally have a regional impact. Table 7-17 and Table 7-18 show the 500 kV constraints impacting congestion costs in 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 500 kV constraints impacting congestion costs in PJM are presented by constraint, in descending order of the absolute value of total congestion costs. In 2010, the AP South interface constraint contributed to positive congestion. There were no significant contributions to negative congestion from 500 kV constraints in 2010. In 2009, the AP South contributed to positive congestion. Also in 2009, there were no significant contributions to negative congestion.

Table 7-17 Regional constraints summary (By facility): Calendar year 2010

				Congestion Costs (Millions)									Event Hours	
				Day Ahead				Balancing						
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	AP South	Interface	500	($10.8)	($433.4)	($2.4)	$420.2	$11.2	$11.4	$1.6	$1.4	$421.6	4,645	1,528
2	Bedington - Black Oak	Interface	500	$9.4	($96.0)	$2.7	$108.1	($0.1)	$1.1	($1.5)	($2.8)	$105.3	2,291	212
3	5004/5005 Interface	Interface	500	$50.1	($42.0)	($0.1)	$92.1	$10.2	$9.0	($1.3)	($0.2)	$91.9	1,644	605
4	AEP-DOM	Interface	500	$10.5	($52.8)	$2.5	$65.8	$0.3	$1.0	($2.8)	($3.5)	$62.3	691	187
5	West	Interface	500	$21.5	($1.6)	($0.2)	$22.9	$0.6	$1.3	$0.0	($0.7)	$22.2	179	65
6	East	Interface	500	$2.7	($5.0)	$0.1	$7.8	$0.0	($0.0)	$0.0	$0.0	$7.8	256	8
7	Harrison - Pruntytown	Line	500	$1.9	($4.1)	$0.8	$6.9	($0.6)	($0.3)	($2.7)	($2.9)	$4.0	231	224
8	Central	Interface	500	$1.2	($0.2)	$0.1	$1.4	$0.1	$0.1	($0.1)	($0.0)	$1.3	117	13
9	Doubs - Mount Storm	Line	500	$0.0	$0.0	$0.0	$0.0	$0.5	$0.7	($0.1)	($0.3)	($0.3)	0	45
10	Conemaugh - Hunterstown	Line	500	$0.0	$0.0	$0.0	$0.0	($0.1)	$0.1	($0.1)	($0.3)	($0.3)	0	5
11	Harrison Tap - North Longview	Line	500	$0.1	($0.0)	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	6	0
12	Juniata - Keystone	Line	500	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	0	1

Table 7-18 Regional constraints summary (By facility): Calendar year 2009

				Congestion Costs (Millions)									Event Hours	
				Day Ahead				Balancing						
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	AP South	Interface	500	$12.0	($186.0)	($0.2)	$197.8	$2.9	($2.9)	$2.9	$8.7	$206.5	3,549	604
2	West	Interface	500	$19.4	($22.9)	$0.7	$42.9	$0.4	($0.3)	$0.1	$0.8	$43.7	504	87
3	5004/5005 Interface	Interface	500	$11.1	($31.0)	$0.3	$42.4	$1.3	$0.3	$0.2	$1.1	$43.6	776	294
4	Kammer	Transformer	500	$50.8	$16.1	$9.0	$43.8	($4.9)	($6.7)	($11.6)	($9.8)	$34.0	3,674	1,328
5	Bedington - Black Oak	Interface	500	$3.8	($15.5)	$0.8	$20.1	($0.4)	($0.1)	$0.1	($0.2)	$19.8	669	73
6	AEP-DOM	Interface	500	$1.4	($7.6)	$0.5	$9.5	($0.5)	($0.2)	($0.0)	($0.3)	$9.2	335	136
7	East	Interface	500	$0.3	($0.3)	($0.0)	$0.6	$0.0	$0.0	$0.0	$0.0	$0.6	32	0
8	Doubs - Mount Storm	Line	500	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.1)	$0.0	$0.1	$0.1	0	18
9	Harrison Tap - Kammer	Line	500	$0.0	($0.0)	$0.0	$0.0	$0.1	$0.0	$0.0	$0.1	$0.1	1	11
10	Central	Interface	500	$0.0	($0.1)	$0.0	$0.1	$0.0	$0.1	($0.0)	($0.1)	$0.1	19	8
11	Belmont - Harrison	Line	500	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	$0.0	5	2
12	Harrison - Pruntytown	Line	500	$0.0	($0.0)	$0.0	$0.0	($0.0)	($0.1)	($0.0)	($0.0)	$0.0	2	43
13	Conemaugh - Hunterstown	Line	500	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	$0.0	($0.0)	($0.0)	0	1
14	Harrison Tap - North Longview	Line	500	$0.0	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	2	0

Zonal Congestion

Summary

Day-ahead and balancing congestion costs within specific zones for calendar years 2010 and 2009 are presented in Table 7-19 and Table 7-20. 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 result when generation is on the lower priced side of a constraint or constraints. For example, congestion across the AP South interface 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).

PJM congestion accounting nets load congestion payments against generation congestion credits by billing organization. The net congestion bill for a zone or constraint may be either positive or negative, depending on the relative size and sign of load congestion payments and generation congestion credits. When summed across a zone, the net congestion bill shows the overall congestion charge or credit for an area, not including explicit congestion, but the net congestion bill is not a good measure of whether load is paying higher prices in the form of congestion.

The Dominion Control Zone, the AP Control Zone and the ComEd Control Zone are examples of how a positive net congestion bill can result from very different combinations of load payments and generation credits. The Dominion Control Zone had the highest congestion charges, $285.5 million, of any control zone in 2010. The large positive congestion costs in the Dominion Control Zone were the result of large positive load congestion payments plus negative generation congestion credits. This is an unusual combination because when load and generation are in the same area, higher load congestion payments will be at least partially offset by higher generation credits. In Dominion, negative generation credits were received by generators on the low side of the AP South constraint while most of the load was on the high side of the constraint and paid higher congestion costs. The AP Control Zone had the second highest congestion charges, $282.7 million, of any control zone in 2010. The positive congestion costs in the AP Control Zone were the result of relatively low positive load congestion payments and larger negative generation congestion credits, which added to the total congestion costs for AP rather than offsetting the positive load congestion payments. The ComEd Control Zone had the third highest congestion charges, $263.2 million, of any control zone in 2010. The positive congestion costs in the ComEd Control Zone were the result of large negative load congestion payments offset by even larger negative generation congestion credits. Thus, the lower prices in ComEd, which resulted from a lower congestion component of LMP, meant that load paid lower prices and lower congestion, and that generators received lower prices and a lower congestion component. The result was positive measured congestion costs. This somewhat counter intuitive result is the result of congestion accounting conventions.

Table 7-19 Congestion cost summary (By control zone): Calendar year 2010

Congestion Costs (Millions)									
	Day Ahead				Balancing				
Control Zone	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total
AECO	$40.9	$15.1	$0.3	$26.1	$0.5	($1.3)	($0.1)	$1.7	$27.7
AEP	($137.6)	($353.1)	$11.2	$226.7	($21.6)	$31.2	($18.9)	($71.7)	$155.0
AP	$14.8	($293.7)	$0.8	$309.3	$7.5	$28.8	($5.3)	($26.6)	$282.7
BGE	$198.2	$124.6	$9.3	$82.9	$15.2	($4.9)	($11.4)	$8.7	$91.6
ComEd	($483.2)	($795.1)	($5.5)	$306.4	($21.8)	$9.5	($11.9)	($43.2)	$263.2
DAY	($18.7)	($30.0)	$5.6	$16.9	$1.4	$1.8	($6.9)	($7.3)	$9.6
DLCO	($95.1)	($139.6)	($0.7)	$43.8	($11.9)	$1.1	$0.2	($12.9)	$30.9
DPL	$72.7	$23.5	$1.3	$50.5	$0.0	$1.7	($1.6)	($3.3)	$47.2
Dominion	$260.1	($33.3)	$15.9	$309.3	($5.6)	($0.6)	($18.8)	($23.9)	$285.5
External	($184.1)	($198.7)	$17.4	$32.0	$2.2	($20.0)	($69.1)	($46.9)	($14.9)
JCPL	$76.1	$26.5	$0.5	$50.2	$1.0	($0.5)	($0.7)	$0.8	$51.0
Met-Ed	$61.2	$52.0	$1.3	$10.5	($0.8)	$0.2	($1.5)	($2.6)	$8.0
PECO	$62.5	$72.1	$0.3	($9.3)	($2.9)	$2.3	($0.9)	($6.0)	($15.3)
PENELEC	($56.5)	($154.8)	$1.0	$99.2	$17.0	$8.4	($0.7)	$7.8	$107.0
PPL	$96.4	$110.4	$3.6	($10.4)	$12.4	$9.1	($0.5)	$2.7	($7.7)
PSEG	$129.5	$100.2	$28.3	$57.6	($9.6)	$20.2	($23.5)	($53.3)	$4.3
Pepco	$357.5	$250.9	$6.1	$112.8	($20.0)	($12.1)	($6.8)	($14.8)	$98.0
RECO	$3.5	$0.2	$0.1	$3.4	$1.0	($0.0)	($0.2)	$0.9	$4.3
Total	$398.3	($1,222.9)	$96.7	$1,717.9	($35.9)	$75.0	($178.8)	($289.7)	$1,428.1

Table 7-20 Congestion cost summary (By control zone): Calendar year 2009

	Congestion Costs (Millions)								
	Day Ahead				Balancing				
Control Zone	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total
AECO	$24.5	$9.2	$0.2	$15.6	($0.5)	$0.9	$0.4	($1.0)	$14.6
AEP	($60.2)	($160.5)	$9.0	$109.3	($7.2)	$8.4	($10.7)	($26.3)	$83.0
AP	$33.2	($80.7)	$12.9	$126.9	($4.5)	$5.0	($22.1)	($31.6)	$95.3
BGE	$97.6	$75.9	$2.4	$24.0	$6.9	($5.0)	($2.3)	$9.5	$33.5
ComEd	($255.3)	($493.1)	($4.1)	$233.7	($7.6)	$6.1	($0.4)	($14.0)	$219.7
DAY	($9.7)	($18.7)	($0.5)	$8.5	$0.9	$1.7	$0.1	($0.7)	$7.8
DLCO	($50.7)	($75.8)	($0.0)	$25.1	($4.0)	$5.3	($0.2)	($9.5)	$15.6
DPL	$49.7	$15.0	$0.4	$35.1	($1.9)	$1.6	($0.4)	($4.0)	$31.1
Dominion	$94.0	($15.4)	$7.5	$117.0	$1.1	($3.0)	($8.2)	($4.1)	$112.9
External	($22.2)	($56.7)	$37.3	$71.9	($1.3)	($7.6)	($79.1)	($72.8)	($1.0)
JCPL	$46.7	$18.9	$0.1	$27.9	$0.4	($2.7)	($0.2)	$2.9	$30.8
Met-Ed	$36.9	$36.8	$0.2	$0.4	$0.1	($1.0)	($0.3)	$0.8	$1.1
PECO	$19.0	$39.9	$0.1	($20.8)	($0.4)	$2.8	($0.1)	($3.3)	($24.1)
PENELEC	($6.8)	($38.9)	$0.3	$32.4	$1.3	$0.8	($0.1)	$0.4	$32.8
PPL	$14.6	$23.4	$2.7	($6.1)	($0.3)	($0.5)	$0.2	$0.4	($5.7)
PSEG	$74.8	$61.7	$11.7	$24.8	($0.7)	$6.9	($6.2)	($13.8)	$11.0
Pepco	$203.9	$133.9	$3.5	$73.5	($21.2)	($9.7)	($3.6)	($15.1)	$58.4
RECO	$2.2	$0.0	$0.1	$2.3	$0.0	($0.0)	($0.1)	($0.1)	$2.2
Total	$292.3	($525.2)	$83.9	$901.4	($39.0)	$10.1	($133.4)	($182.4)	$719.0

Details of Regional and Zonal Congestion

Constraints were examined by zone and categorized by their effect on regions. Zones correspond to regulated utility franchise areas. Regions generally comprise two or more zones. PJM is comprised of three regions: the PJM Mid-Atlantic Region with 11 control zones (the AECO, BGE, DPL, JCPL, Met-Ed, PECO, PENELEC, Pepco, PPL, PSEG and RECO control zones); the PJM Western Region with five control zones (the AP, ComEd, AEP, DLCO and DAY control zones); and the PJM Southern Region with one control zone (the Dominion Control Zone).

Table 7-21 through Table 7-54 present the top 15 constraints affecting each control zone's congestion costs, including the facility type and the location of the constrained facility for both 2010 and 2009. In addition, day-ahead and real-time congestion-event hours are presented for each of the highlighted constraints. Constraints can have wide-ranging effects, influencing prices and congestion across multiple zones. Many constraints that are physically located outside of a control zone can impact the congestion costs of that control zone. The following tables present the constraints in descending order of the absolute value of total congestion costs for each zone. In addition to the top 15 constraints, these tables show the top five local constraints for the control zone, which were not in the top 15 constraints, but are located inside the respective control zone. These constraints are shown to illustrate the effect local constraints have on the control zone in which they are located. In 2010, the RECO control zone did not have any constraints within their boundaries, thus the table shows only the top 15 constraints.

For each of the constraints presented in the following tables, the zonal cost impacts are decomposed into their Day-Ahead Energy Market and balancing market components. 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.

Mid-Atlantic Region Congestion-Event Summaries

AECO Control Zone

Table 7-21 AECO Control Zone top congestion cost impacts (By facility): Calendar year 2010

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	5004/5005 Interface	Interface	500	$9.7	$4.4	$0.0	$5.4	$0.7	($0.7)	($0.0)	$1.3	$6.7	1,644	605
2	England - Middletap	Line	AECO	$4.0	$0.7	$0.0	$3.3	($0.4)	($0.4)	($0.0)	($0.0)	$3.2	336	69
3	West	Interface	500	$3.8	$1.9	$0.0	$1.9	$0.1	$0.0	($0.0)	$0.1	$2.0	179	65
4	Monroe	Transformer	AECO	$1.7	$0.2	$0.0	$1.5	$0.1	($0.2)	($0.0)	$0.2	$1.8	232	48
5	Graceton - Raphael Road	Line	BGE	($2.1)	($0.7)	($0.0)	($1.4)	($0.2)	$0.1	$0.0	($0.3)	($1.7)	565	308
6	Brandon Shores - Riverside	Line	BGE	$2.4	$1.1	$0.0	$1.3	$0.0	($0.2)	($0.0)	$0.2	$1.5	344	162
7	Absecon - Lewis	Line	AECO	$0.2	$0.0	$0.0	$0.2	($1.5)	$0.1	($0.1)	($1.6)	($1.4)	81	18
8	Wylie Ridge	Transformer	AP	$1.1	$0.4	$0.0	$0.7	$0.5	($0.1)	($0.0)	$0.6	$1.3	728	683
9	Crete - St Johns Tap	Flowgate	Midwest ISO	$1.4	$0.4	($0.0)	$1.0	$0.2	($0.0)	($0.0)	$0.3	$1.3	2,066	823
10	AP South	Interface	500	$2.1	$1.0	$0.0	$1.1	$0.1	($0.1)	($0.0)	$0.1	$1.2	4,645	1,528
11	Shieldalloy - Vineland	Line	AECO	$3.3	$0.9	$0.1	$2.4	($1.2)	$0.1	($0.0)	($1.3)	$1.1	245	172
12	East Frankfort - Crete	Line	ComEd	$1.2	$0.3	$0.0	$0.9	$0.2	($0.0)	($0.0)	$0.2	$1.1	3,084	850
13	Tiltonsville - Windsor	Line	AP	$1.2	$0.5	$0.0	$0.7	$0.1	($0.1)	($0.0)	$0.2	$0.9	2,723	506
14	Bedington - Black Oak	Interface	500	$1.5	$0.6	$0.0	$0.9	$0.0	$0.0	($0.0)	$0.0	$0.9	2,291	212
15	Branchburg - Readington	Line	PSEG	($1.3)	($0.5)	($0.0)	($0.8)	($0.1)	$0.0	$0.0	($0.1)	($0.8)	1,235	185
26	Corson - Court	Line	AECO	$0.0	$0.0	$0.0	$0.0	($0.2)	$0.1	($0.0)	($0.3)	($0.3)	7	15
29	Sherman Avenue	Transformer	AECO	$0.4	$0.0	$0.0	$0.4	($0.1)	$0.0	($0.0)	($0.1)	$0.3	70	25
42	Corson - Union	Line	AECO	$0.0	$0.0	$0.0	$0.0	$0.2	($0.0)	$0.0	$0.2	$0.2	0	16
91	Corson	Transformer	AECO	$0.0	$0.0	$0.0	$0.0	$0.1	$0.0	$0.0	$0.1	$0.1	0	17
102	Lewis - Motts - Cedar	Line	AECO	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	25	0

Table 7-22 AECO Control Zone top congestion cost impacts (By facility): Calendar year 2009

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	Kammer	Transformer	500	$4.2	$1.3	$0.0	$2.9	$0.2	($0.0)	$0.0	$0.3	$3.1	3,674	1,328
2	West	Interface	500	$4.9	$2.3	$0.1	$2.6	$0.0	($0.0)	($0.0)	$0.0	$2.7	504	87
3	5004/5005 Interface	Interface	500	$4.4	$1.9	$0.0	$2.5	$0.1	$0.0	$0.0	$0.1	$2.7	776	294
4	Dunes Acres - Michigan City	Flowgate	Midwest ISO	$1.4	$0.3	$0.0	$1.1	$0.1	($0.0)	$0.0	$0.2	$1.3	2,949	910
5	Graceton - Raphael Road	Line	BGE	($1.5)	($0.5)	($0.0)	($1.1)	$0.2	$0.1	$0.0	$0.0	($1.1)	527	152
6	Wylie Ridge	Transformer	AP	$1.8	$0.9	$0.0	$0.9	($0.0)	$0.1	$0.1	($0.0)	$0.9	354	335
7	Absecon - Lewis	Line	AECO	$1.0	$0.1	$0.0	$1.0	($1.2)	$0.5	($0.0)	($1.7)	($0.8)	170	149
8	Atlantic - Larrabee	Line	JCPL	($0.5)	($0.1)	($0.0)	($0.4)	($0.2)	$0.1	$0.0	($0.3)	($0.7)	284	73
9	Doubs	Transformer	AP	$1.0	$0.4	$0.0	$0.6	$0.0	($0.0)	($0.0)	$0.0	$0.6	429	246
10	AP South	Interface	500	$1.0	$0.5	$0.0	$0.6	$0.0	$0.0	$0.1	$0.1	$0.6	3,549	604
11	Tiltonsville - Windsor	Line	AP	$0.7	$0.2	$0.0	$0.5	$0.0	($0.0)	($0.0)	$0.1	$0.5	2,070	311
12	East Frankfort - Crete	Line	ComEd	$0.7	$0.2	$0.0	$0.5	$0.0	($0.0)	$0.0	$0.0	$0.5	2,163	605
13	Monroe	Transformer	AECO	$0.5	$0.0	$0.0	$0.4	$0.1	($0.0)	$0.0	$0.1	$0.5	263	13
14	Shieldalloy - Vineland	Line	AECO	$1.1	$0.3	$0.0	$0.9	($0.3)	$0.1	($0.0)	($0.4)	$0.5	148	61
15	Sammis - Wylie Ridge	Line	AP	$0.7	$0.3	$0.0	$0.4	$0.0	($0.0)	($0.0)	$0.0	$0.5	806	157
16	Monroe - New Freedom	Line	AECO	$0.8	$0.4	$0.0	$0.5	$0.0	$0.0	$0.0	$0.0	$0.5	584	0
23	Lewis - Motts - Cedar	Line	AECO	$0.2	$0.0	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	108	0
34	Corson - Union	Line	AECO	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	$0.1	$0.1	0	3
84	Clayton - Williams	Line	AECO	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	3	0
118	Corson	Transformer	AECO	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	1	0

BGE Control Zone

Table 7-23 BGE Control Zone top congestion cost impacts (By facility): Calendar year 2010

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	Brandon Shores - Riverside	Line	BGE	$17.3	($8.9)	$0.2	$26.4	($2.1)	$0.2	($0.3)	($2.5)	$23.9	344	162
2	AP South	Interface	500	$55.3	$43.9	$2.3	$13.6	$4.4	($1.6)	($1.8)	$4.2	$17.8	4,645	1,528
3	Doubs	Transformer	AP	$13.3	$8.0	$0.4	$5.6	$1.1	($1.4)	($0.7)	$1.8	$7.5	920	525
4	Bedington - Black Oak	Interface	500	$22.3	$17.2	$0.9	$6.0	$0.6	($0.4)	($0.7)	$0.4	$6.3	2,291	212
5	5004/5005 Interface	Interface	500	$9.0	$4.6	$0.4	$4.8	$0.6	($0.2)	($0.3)	$0.4	$5.3	1,644	605
6	Graceton - Raphael Road	Line	BGE	$10.0	$6.7	$0.7	$4.0	$0.2	($0.7)	($0.7)	$0.2	$4.2	565	308
7	West	Interface	500	$6.5	$3.3	$0.1	$3.3	$0.2	($0.0)	($0.1)	$0.2	$3.5	179	65
8	Mount Storm - Pruntytown	Line	AP	$4.3	$3.6	$0.2	$0.8	$1.3	($0.6)	($0.6)	$1.4	$2.2	571	574
9	Brunner Island - Yorkana	Line	Met-Ed	$3.6	$2.1	$0.2	$1.7	$0.2	($0.0)	($0.2)	($0.1)	$1.6	237	180
10	Millville - Sleepy Hollow	Line	Dominion	$4.4	$3.4	$0.4	$1.4	$0.0	$0.0	$0.0	$0.0	$1.4	401	0
11	Cloverdale - Lexington	Line	AEP	$4.8	$4.5	$0.2	$0.5	$0.9	($0.3)	($0.3)	$0.9	$1.4	1,127	684
12	Wylie Ridge	Transformer	AP	$2.7	$2.0	$0.1	$0.9	$1.0	$0.1	($0.4)	$0.6	$1.4	728	683
13	Crete - St Johns Tap	Flowgate	Midwest ISO	$4.0	$3.0	$0.3	$1.3	$0.3	($0.0)	($0.2)	$0.1	$1.4	2,066	823
14	Millville - Old Chapel	Line	AP	$3.5	$2.9	$0.3	$0.9	$1.6	$0.1	($1.0)	$0.4	$1.3	210	303
15	Tiltonsville - Windsor	Line	AP	$3.1	$2.1	$0.1	$1.1	$0.2	($0.1)	($0.2)	$0.2	$1.3	2,723	506
32	Fullerton - Windyedge	Line	BGE	$0.4	($0.1)	$0.0	$0.5	$0.0	$0.0	$0.0	$0.0	$0.5	23	0
33	Graceton - Safe Harbor	Line	BGE	$0.9	$0.6	$0.1	$0.5	$0.2	$0.1	($0.2)	($0.0)	$0.4	104	70
34	Glenarm - Windy Edge	Line	BGE	$0.5	$0.2	$0.0	$0.3	$0.0	($0.1)	($0.0)	$0.1	$0.4	74	39
39	Green Street - Westport	Line	BGE	$0.3	($0.1)	$0.0	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	146	0
55	Five Forks - Rock Ridge	Line	BGE	$0.3	$0.1	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	39	0

Table 7-24 BGE Control Zone top congestion cost impacts (By facility): Calendar year 2009

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	AP South	Interface	500	$25.2	$23.7	$0.5	$2.0	$1.7	($1.2)	($0.5)	$2.5	$4.5	3,549	604
2	Kammer	Transformer	500	$11.9	$9.0	$0.2	$3.2	$1.0	($0.6)	($0.2)	$1.3	$4.5	3,674	1,328
3	Brandon Shores - Riverside	Line	BGE	$1.9	($1.0)	$0.0	$3.0	($0.1)	($0.0)	($0.0)	($0.1)	$2.9	134	13
4	Doubs	Transformer	AP	$6.4	$5.0	$0.4	$1.8	$0.5	($0.6)	($0.4)	$0.7	$2.5	429	246
5	Graceton - Raphael Road	Line	BGE	$6.6	$4.2	$0.1	$2.4	$0.0	$0.0	($0.1)	($0.1)	$2.3	527	152
6	5004/5005 Interface	Interface	500	$3.1	$1.7	$0.1	$1.5	$0.3	($0.2)	($0.1)	$0.4	$1.9	776	294
7	West	Interface	500	$8.9	$7.4	$0.2	$1.6	$0.1	($0.2)	($0.1)	$0.2	$1.9	504	87
8	Wylie Ridge	Transformer	AP	$3.6	$3.4	$0.1	$0.3	$0.6	($0.7)	($0.2)	$1.2	$1.5	354	335
9	Dunes Acres - Michigan City	Flowgate	Midwest ISO	$3.4	$2.8	$0.0	$0.6	$0.3	($0.0)	($0.0)	$0.4	$1.0	2,949	910
10	Bedington - Black Oak	Interface	500	$3.9	$3.3	$0.1	$0.8	$0.1	($0.0)	($0.0)	$0.1	$0.9	669	73
11	Mount Storm - Pruntytown	Line	AP	$3.2	$2.9	$0.0	$0.2	$0.5	($0.3)	($0.1)	$0.6	$0.9	525	132
12	Pumphrey - Westport	Line	Pepco	$0.5	($0.1)	$0.0	$0.7	$0.0	$0.0	$0.0	$0.0	$0.7	1,181	0
13	Fullerton - Windyedge	Line	BGE	$0.5	($0.1)	$0.0	$0.7	$0.0	$0.0	$0.0	$0.0	$0.7	31	0
14	Tiltonsville - Windsor	Line	AP	$1.5	$1.0	$0.0	$0.5	$0.1	($0.0)	($0.0)	$0.1	$0.6	2,070	311
15	Cloverdale - Lexington	Line	AEP	$2.6	$2.5	$0.0	$0.2	$0.4	($0.1)	($0.1)	$0.4	$0.6	1,019	434
16	Five Forks - Rock Ridge	Line	BGE	$0.7	$0.2	$0.0	$0.5	$0.0	$0.0	$0.0	$0.0	$0.5	136	0
21	Conastone	Transformer	BGE	$1.0	$0.6	($0.0)	$0.3	$0.0	($0.0)	($0.0)	$0.1	$0.4	75	12
24	Green Street - Westport	Line	BGE	$0.3	($0.0)	$0.0	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	365	0
27	Conastone - Otter	Line	BGE	$0.4	$0.2	$0.0	$0.2	$0.0	($0.0)	($0.0)	$0.0	$0.2	92	32
30	Waugh Chapel	Transformer	BGE	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.2)	$0.0	$0.2	$0.2	0	8

DPL Control Zone

Table 7-25 DPL Control Zone top congestion cost impacts (By facility): Calendar year 2010

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	5004/5005 Interface	Interface	500	$16.2	$6.2	$0.1	$10.1	$0.6	($0.0)	($0.2)	$0.5	$10.6	1,644	605
2	AP South	Interface	500	$5.6	$2.3	$0.1	$3.4	$0.3	$0.1	($0.1)	$0.0	$3.5	4,645	1,528
3	Oak Hall	Transformer	DPL	$3.0	$0.6	$0.0	$2.5	$0.0	$0.0	$0.0	$0.0	$2.5	668	0
4	Graceton - Raphael Road	Line	BGE	($3.9)	($1.2)	($0.0)	($2.7)	($0.1)	($0.2)	$0.1	$0.2	($2.5)	565	308
5	Crete - St Johns Tap	Flowgate	Midwest ISO	$2.6	$0.3	$0.0	$2.3	$0.2	$0.1	($0.1)	$0.0	$2.3	2,066	823
6	Wylie Ridge	Transformer	AP	$2.0	$0.3	$0.0	$1.7	$0.6	$0.2	($0.1)	$0.4	$2.0	728	683
7	West	Interface	500	$5.4	$3.4	$0.0	$2.0	$0.1	$0.1	($0.0)	$0.0	$2.0	179	65
8	East Frankfort - Crete	Line	ComEd	$2.3	$0.3	$0.0	$2.0	$0.0	$0.0	($0.0)	$0.0	$2.0	3,084	850
9	Bedington - Black Oak	Interface	500	$3.3	$1.3	$0.1	$2.0	$0.1	$0.1	($0.1)	($0.1)	$2.0	2,291	212
10	New Church - Piney Grove	Line	DPL	$2.1	$0.4	$0.0	$1.7	$0.0	$0.0	$0.0	$0.0	$1.7	334	0
11	East	Interface	500	$2.2	$0.6	$0.0	$1.6	($0.0)	$0.0	($0.0)	($0.0)	$1.5	256	8
12	Brandon Shores - Riverside	Line	BGE	$3.4	$2.0	$0.0	$1.5	$0.1	($0.0)	($0.0)	$0.1	$1.5	344	162
13	Longwood - Wye Mills	Line	DPL	$1.8	$0.3	$0.0	$1.5	$0.0	$0.0	$0.0	$0.0	$1.5	357	0
14	Middletown - Mt Pleasant	Line	DPL	$1.7	$0.4	$0.0	$1.3	$0.0	$0.0	$0.0	$0.0	$1.3	163	0
15	Cloverdale - Lexington	Line	AEP	$1.5	$0.3	$0.0	$1.2	$0.2	$0.0	($0.1)	$0.1	$1.2	1,127	684
17	Kenney - Stockton	Line	DPL	$1.0	$0.3	$0.0	$0.7	($1.6)	($0.0)	($0.1)	($1.7)	($1.0)	96	122
22	Indian River At20	Transformer	DPL	$0.0	$0.0	$0.0	$0.0	$0.3	($0.6)	($0.0)	$0.9	$0.9	0	8
24	Easton - Trappe	Line	DPL	$0.9	$0.2	$0.0	$0.7	$0.0	$0.0	$0.0	$0.0	$0.7	117	0
26	Dupont Seaford - Laurel	Line	DPL	$0.0	$0.0	$0.0	$0.0	($0.4)	$0.4	($0.0)	($0.7)	($0.7)	0	15
27	Keeney At5n	Transformer	DPL	$0.0	$0.0	$0.0	$0.0	($0.1)	$0.6	($0.0)	($0.7)	($0.7)	0	13

Table 7-26 DPL Control Zone top congestion cost impacts (By facility): Calendar year 2009

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	Kammer	Transformer	500	$7.5	$1.7	$0.0	$5.9	($0.1)	$0.3	($0.1)	($0.4)	$5.4	3,674	1,328
2	West	Interface	500	$9.2	$3.8	$0.0	$5.5	($0.0)	$0.1	($0.0)	($0.1)	$5.3	504	87
3	5004/5005 Interface	Interface	500	$7.3	$2.8	$0.1	$4.5	$0.1	$0.3	($0.1)	($0.3)	$4.2	776	294
4	Short - Laurel	Line	DPL	$0.0	$0.0	$0.0	$0.0	($2.1)	$0.2	($0.1)	($2.4)	($2.4)	0	27
5	Wylie Ridge	Transformer	AP	$3.4	$1.3	$0.0	$2.1	$0.2	$0.2	($0.0)	($0.0)	$2.1	354	335
6	Dunes Acres - Michigan City	Flowgate	Midwest ISO	$2.4	$0.3	($0.0)	$2.1	($0.1)	$0.0	$0.0	($0.1)	$2.0	2,949	910
7	AP South	Interface	500	$3.0	$0.9	$0.0	$2.1	$0.0	$0.1	($0.0)	($0.1)	$1.9	3,549	604
8	Graceton - Raphael Road	Line	BGE	($2.7)	($0.7)	($0.0)	($2.0)	$0.4	($0.2)	$0.0	$0.6	($1.4)	527	152
9	Middletown - Mt Pleasant	Line	DPL	$1.8	$0.3	$0.0	$1.5	($0.2)	$0.0	$0.0	($0.2)	$1.3	312	17
10	Sammis - Wylie Ridge	Line	AP	$1.5	$0.3	$0.0	$1.2	($0.0)	$0.0	($0.0)	($0.1)	$1.1	806	157
11	East Frankfort - Crete	Line	ComEd	$1.3	$0.3	$0.0	$1.0	$0.0	($0.0)	($0.0)	$0.1	$1.1	2,163	605
12	Tiltonsville - Windsor	Line	AP	$1.2	$0.3	$0.0	$0.9	($0.0)	$0.0	($0.0)	($0.1)	$0.8	2,070	311
13	North Seaford - Pine Street	Line	DPL	$1.0	$0.2	$0.0	$0.8	($0.0)	($0.0)	($0.0)	$0.0	$0.8	331	1
14	Cloverdale - Lexington	Line	AEP	$1.0	$0.2	$0.0	$0.8	$0.0	($0.0)	($0.0)	$0.0	$0.8	1,019	434
15	Doubs	Transformer	AP	$1.8	$1.1	$0.0	$0.8	$0.0	$0.1	($0.0)	($0.1)	$0.7	429	246
17	Easton - Trappe	Line	DPL	$0.7	$0.1	$0.0	$0.6	$0.0	$0.0	$0.0	$0.0	$0.6	212	0
18	Church - I.B. Corners	Line	DPL	$0.7	$0.1	$0.0	$0.6	($0.0)	$0.0	($0.0)	($0.0)	$0.6	66	5
20	Longwood - Wye Mills	Line	DPL	$0.6	$0.1	$0.0	$0.5	($0.0)	$0.0	$0.0	($0.0)	$0.5	250	3
22	Edgemoor - Harmony	Line	DPL	$0.8	$0.3	$0.0	$0.5	($0.1)	($0.0)	($0.0)	($0.1)	$0.4	28	7
23	Red Lion At20	Transformer	DPL	$0.4	$0.1	$0.0	$0.4	$0.0	($0.0)	$0.0	$0.0	$0.4	45	6

JCPL Control Zone

Table 7-27 JCPL Control Zone top congestion cost impacts (By facility): Calendar year 2010

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	5004/5005 Interface	Interface	500	$22.2	$9.4	$0.1	$12.9	$1.1	($0.3)	($0.1)	$1.2	$14.1	1,644	605
2	Branchburg - Readington	Line	PSEG	$6.8	$0.4	$0.1	$6.5	($0.5)	($0.3)	$0.1	($0.2)	$6.3	1,235	185
3	West	Interface	500	$7.7	$4.0	$0.0	$3.7	$0.0	($0.1)	($0.0)	$0.1	$3.8	179	65
4	Redoak - Sayreville	Line	JCPL	($2.1)	($6.1)	$0.0	$3.9	$0.1	$0.7	$0.0	($0.6)	$3.3	898	57
5	Athenia - Saddlebrook	Line	PSEG	($3.8)	($1.1)	($0.0)	($2.7)	($0.2)	$0.0	$0.0	($0.2)	($2.9)	3,318	364
6	Brandon Shores - Riverside	Line	BGE	$4.5	$2.4	$0.0	$2.2	$0.1	($0.1)	($0.0)	$0.1	$2.3	344	162
7	Crete - St Johns Tap	Flowgate	Midwest ISO	$3.6	$1.5	($0.0)	$2.1	$0.0	($0.0)	($0.0)	$0.1	$2.1	2,066	823
8	Graceton - Raphael Road	Line	BGE	($4.6)	($2.5)	($0.0)	($2.2)	$0.3	$0.1	$0.0	$0.2	($2.0)	565	308
9	Wylie Ridge	Transformer	AP	$2.7	$1.0	$0.0	$1.7	$0.1	($0.0)	($0.0)	$0.1	$1.8	728	683
10	Bridgewater - Middlesex	Line	PSEG	$4.4	$1.7	$0.1	$2.7	($1.2)	($0.4)	($0.2)	($1.0)	$1.7	372	91
11	East Frankfort - Crete	Line	ComEd	$3.0	$1.4	($0.0)	$1.5	$0.0	($0.1)	$0.0	$0.1	$1.7	3,084	850
12	Tiltonsville - Windsor	Line	AP	$2.8	$1.5	$0.0	$1.3	($0.0)	($0.1)	($0.0)	$0.0	$1.4	2,723	506
13	East	Interface	500	$2.3	$1.1	$0.0	$1.2	($0.0)	($0.0)	($0.0)	($0.0)	$1.2	256	8
14	Erie West	Transformer	PENELEC	$1.7	$0.5	($0.0)	$1.2	($0.0)	$0.1	$0.0	($0.0)	$1.2	680	175
15	Cloverdale - Lexington	Line	AEP	$1.6	$0.7	$0.0	$0.9	$0.1	($0.1)	($0.0)	$0.1	$1.0	1,127	684
16	Atlantic - Larrabee	Line	JCPL	$0.9	$0.1	$0.0	$0.9	$0.0	($0.1)	($0.0)	$0.1	$0.9	123	12
37	Sayreville - Werner	Line	JCPL	$0.0	$0.0	$0.0	$0.0	$0.1	($0.1)	$0.0	$0.3	$0.3	0	4
44	Franklin - West Wharton	Line	JCPL	$0.4	$0.2	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	61	0
46	Kilmer - Sayreville	Line	JCPL	$0.6	$0.3	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	130	0
197	Stoneybrook - W Wharton	Line	JCPL	($0.0)	$0.0	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	($0.0)	8	0

Table 7-28 JCPL Control Zone top congestion cost impacts (By facility): Calendar year 2009

				Congestion Costs (Millions)									Event Hours	
				Day Ahead				Balancing						
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	5004/5005 Interface	Interface	500	$9.5	$4.0	$0.0	$5.5	$0.2	($1.0)	($0.0)	$1.2	$6.6	776	294
2	West	Interface	500	$10.4	$4.3	$0.0	$6.1	$0.1	($0.2)	($0.0)	$0.2	$6.3	504	87
3	Kammer	Transformer	500	$8.2	$3.5	$0.0	$4.8	$0.1	($0.6)	($0.0)	$0.7	$5.4	3,674	1,328
4	Wylie Ridge	Transformer	AP	$3.9	$1.4	$0.0	$2.5	$0.1	($0.6)	($0.0)	$0.7	$3.2	354	335
5	Atlantic - Larrabee	Line	JCPL	$2.6	$0.4	$0.0	$2.2	($0.6)	($0.4)	($0.0)	($0.2)	$2.0	284	73
6	Dunes Acres - Michigan City	Flowgate	Midwest ISO	$3.0	$1.3	($0.1)	$1.6	($0.0)	($0.2)	$0.0	$0.2	$1.7	2,949	910
7	Sammis - Wylie Ridge	Line	AP	$1.7	$0.6	$0.0	$1.1	$0.0	($0.0)	($0.0)	$0.0	$1.2	806	157
8	Athenia - Saddlebrook	Line	PSEG	($1.3)	($0.3)	($0.0)	($1.0)	($0.0)	$0.1	$0.0	($0.1)	($1.1)	1,108	139
9	Graceton - Raphael Road	Line	BGE	($2.7)	($1.5)	($0.0)	($1.2)	$0.3	$0.2	$0.0	$0.1	($1.0)	527	152
10	East Frankfort - Crete	Line	ComEd	$1.6	$0.7	$0.0	$0.9	$0.0	($0.0)	($0.0)	$0.0	$1.0	2,163	605
11	Tiltonsville - Windsor	Line	AP	$1.5	$0.8	$0.0	$0.7	($0.0)	($0.1)	($0.0)	$0.0	$0.8	2,070	311
12	Cloverdale - Lexington	Line	AEP	$1.0	$0.4	$0.0	$0.6	$0.0	($0.0)	($0.0)	$0.1	$0.7	1,019	434
13	Crete - St Johns Tap	Flowgate	Midwest ISO	$1.1	$0.5	$0.0	$0.6	$0.0	($0.0)	($0.0)	$0.0	$0.7	1,571	306
14	Doubs	Transformer	AP	$1.7	$1.2	$0.0	$0.6	($0.0)	($0.1)	($0.0)	$0.1	$0.6	429	246
15	Krendale - Seneca	Line	AP	$0.9	$0.4	$0.0	$0.5	$0.0	$0.0	$0.0	$0.0	$0.5	353	0
29	Gilbert - Morris Park	Line	JCPL	$0.2	$0.0	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	38	0
46	Redoak - Sayreville	Line	JCPL	($0.0)	($0.1)	$0.0	$0.1	($0.0)	$0.0	$0.0	($0.0)	$0.1	59	7
80	Deep Run - Englishtown	Line	JCPL	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.0	0	2
86	Franklin - West Wharton	Line	JCPL	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	35	0
91	Kilmer - Sayreville	Line	JCPL	$0.4	$0.2	$0.0	$0.2	($0.0)	$0.2	$0.0	($0.2)	$0.0	23	16

Met-Ed Control Zone

Table 7-29 Met-Ed Control Zone top congestion cost impacts (By facility): Calendar year 2010

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	Brunner Island - Yorkana	Line	Met-Ed	$1.9	($4.1)	$0.1	$6.1	$0.0	$0.2	($0.0)	($0.2)	$6.0	237	180
2	Hunterstown	Transformer	Met-Ed	$4.2	($0.6)	$0.1	$4.9	$0.0	$0.0	($0.0)	($0.0)	$4.8	317	26
3	Graceton - Raphael Road	Line	BGE	($3.2)	($4.7)	($0.0)	$1.4	$0.2	$0.4	$0.1	($0.0)	$1.4	565	308
4	Wylie Ridge	Transformer	AP	$1.8	$2.9	$0.1	($1.1)	($0.1)	$0.0	($0.1)	($0.2)	($1.3)	728	683
5	Crete - St Johns Tap	Flowgate	Midwest ISO	$2.3	$3.5	$0.0	($1.1)	($0.1)	($0.0)	($0.0)	($0.1)	($1.2)	2,066	823
6	West	Interface	500	$4.3	$5.6	$0.0	($1.2)	$0.0	($0.1)	($0.1)	$0.1	($1.1)	179	65
7	Doubs	Transformer	AP	$3.6	$2.6	$0.1	$1.1	($0.1)	($0.2)	($0.3)	($0.2)	$0.9	920	525
8	AP South	Interface	500	$5.4	$4.6	$0.2	$1.0	($0.1)	($0.1)	($0.2)	($0.2)	$0.8	4,645	1,528
9	Jackson - TMI	Line	Met-Ed	$0.5	($0.6)	$0.1	$1.2	($0.1)	$0.3	($0.0)	($0.4)	$0.8	37	54
10	5004/5005 Interface	Interface	500	$13.4	$14.2	$0.0	($0.8)	($0.4)	($0.7)	($0.2)	$0.2	($0.6)	1,644	605
11	Erie West	Transformer	PENELEC	$0.9	$1.5	$0.0	($0.5)	($0.0)	($0.1)	($0.0)	($0.0)	($0.6)	680	175
12	Middletown Jct	Transformer	Met-Ed	$0.6	($0.1)	$0.0	$0.7	($0.1)	$0.1	$0.0	($0.1)	$0.6	11	12
13	Middletown Jct - Yorkhaven	Line	Met-Ed	$0.6	$0.1	$0.0	$0.6	($0.0)	$0.0	$0.0	($0.0)	$0.5	190	12
14	Collins - Middletown Jct	Line	Met-Ed	$0.3	($0.3)	$0.0	$0.6	($0.0)	$0.1	($0.0)	($0.1)	$0.5	191	42
15	Brandon Shores - Riverside	Line	BGE	$3.3	$3.8	$0.0	($0.5)	($0.0)	($0.1)	($0.0)	$0.0	($0.5)	344	162
26	Jackson - North Hanover	Line	Met-Ed	$0.2	($0.0)	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	21	13
33	Lincoln Jct. - Lincoln	Line	Met-Ed	$0.2	($0.0)	($0.0)	$0.2	($0.0)	$0.0	$0.0	($0.0)	$0.2	57	9
51	Cly - Collins	Line	Met-Ed	$0.0	($0.0)	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	19	0
77	Yorkana A	Transformer	Met-Ed	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	$0.0	0	5
79	Glendon - Hosensack	Line	Met-Ed	$0.0	($0.0)	$0.0	$0.0	($0.0)	$0.1	$0.0	($0.1)	($0.0)	31	39

Table 7-30 Met-Ed Control Zone top congestion cost impacts (By facility): Calendar year 2009

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	Kammer	Transformer	500	$6.0	$7.9	$0.1	($1.8)	($0.0)	($0.3)	($0.1)	$0.2	($1.6)	3,674	1,328
2	Brunner Island - Yorkana	Line	Met-Ed	$0.3	($0.7)	$0.0	$1.0	$0.0	$0.0	($0.0)	$0.0	$1.0	86	27
3	Graceton - Raphael Road	Line	BGE	($2.1)	($3.0)	($0.0)	$0.9	$0.1	$0.3	$0.0	($0.2)	$0.7	527	152
4	AP South	Interface	500	$2.5	$1.8	$0.0	$0.7	($0.0)	($0.0)	($0.0)	($0.0)	$0.7	3,549	604
5	Dunes Acres - Michigan City	Flowgate	Midwest ISO	$2.0	$2.5	$0.0	($0.5)	($0.0)	($0.0)	($0.0)	$0.0	($0.5)	2,949	910
6	5004/5005 Interface	Interface	500	$5.9	$6.6	$0.0	($0.6)	($0.1)	($0.3)	($0.0)	$0.2	($0.4)	776	294
7	Hunterstown	Transformer	Met-Ed	$0.3	($0.1)	($0.0)	$0.4	($0.0)	($0.0)	$0.0	($0.0)	$0.4	53	1
8	West	Interface	500	$7.4	$7.2	$0.0	$0.3	$0.0	($0.1)	($0.0)	$0.1	$0.3	504	87
9	Tiltonsville - Windsor	Line	AP	$1.0	$1.4	$0.0	($0.4)	$0.0	($0.1)	($0.0)	$0.1	($0.3)	2,070	311
10	Wylie Ridge	Transformer	AP	$3.1	$2.8	$0.0	$0.3	($0.1)	($0.2)	($0.0)	$0.0	$0.3	354	335
11	Middletown Jct - Yorkhaven	Line	Met-Ed	$0.2	$0.0	$0.0	$0.2	($0.0)	$0.0	$0.0	($0.0)	$0.2	32	2
12	Conastone	Transformer	BGE	($0.1)	($0.3)	($0.0)	$0.2	($0.0)	$0.0	($0.0)	($0.0)	$0.2	75	12
13	Hummelstown - Middletown Jct	Line	Met-Ed	$0.1	$0.3	$0.0	($0.2)	$0.0	($0.0)	($0.0)	$0.0	($0.2)	51	14
14	Middletown Jct	Transformer	Met-Ed	$0.3	($0.0)	$0.0	$0.3	($0.1)	$0.0	($0.0)	($0.1)	$0.2	62	12
15	East Frankfort - Crete	Line	ComEd	$1.1	$1.3	$0.0	($0.2)	$0.0	($0.0)	($0.0)	$0.0	($0.1)	2,163	605
32	Collins - Middletown Jct	Line	Met-Ed	$0.1	($0.1)	$0.0	$0.1	($0.0)	$0.0	$0.0	($0.1)	$0.1	103	16
36	Ironwood - South Lebanon	Line	Met-Ed	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	20	0
42	Cly - Newberry	Line	Met-Ed	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	13	0
67	Middletown Jct - S Lebanon	Line	Met-Ed	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	4	0
154	Germantown	Transformer	Met-Ed	($0.0)	($0.0)	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	($0.0)	10	0

PECO Control Zone

Table 7-31 PECO Control Zone top congestion cost impacts (By facility): Calendar year 2010

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	5004/5005 Interface	Interface	500	$15.1	$23.2	$0.0	($8.0)	($0.5)	$1.4	($0.1)	($2.0)	($10.0)	1,644	605
2	Eddystone - Island Road	Line	PECO	$3.8	($4.4)	($0.0)	$8.1	($0.0)	$0.0	$0.0	($0.0)	$8.1	186	3
3	Limerick	Transformer	PECO	$3.0	$0.6	$0.0	$2.4	$0.1	($3.8)	($0.0)	$3.8	$6.3	53	18
4	AP South	Interface	500	$2.7	$8.3	$0.1	($5.5)	($0.1)	$0.3	($0.0)	($0.5)	($5.9)	4,645	1,528
5	Graceton - Raphael Road	Line	BGE	($2.4)	($6.1)	($0.0)	$3.6	$0.4	$0.4	$0.0	$0.1	$3.7	565	308
6	Bedington - Black Oak	Interface	500	$2.1	$4.8	$0.0	($2.7)	($0.0)	$0.1	($0.0)	($0.1)	($2.8)	2,291	212
7	West	Interface	500	$4.9	$7.4	$0.0	($2.5)	($0.0)	($0.0)	($0.0)	($0.0)	($2.5)	179	65
8	Crete - St Johns Tap	Flowgate	Midwest ISO	$2.2	$4.2	($0.0)	($2.0)	($0.1)	($0.1)	$0.0	($0.0)	($2.0)	2,066	823
9	East	Interface	500	$2.9	$0.9	($0.0)	$1.9	($0.0)	($0.0)	($0.0)	($0.0)	$1.9	256	8
10	Wylie Ridge	Transformer	AP	$1.8	$2.7	$0.0	($0.9)	($0.3)	$0.5	($0.0)	($0.8)	($1.7)	728	683
11	Doubs	Transformer	AP	$1.3	$2.9	$0.0	($1.5)	($0.3)	($0.3)	($0.0)	($0.1)	($1.6)	920	525
12	Tiltonsville - Windsor	Line	AP	$1.7	$2.8	$0.0	($1.1)	($0.2)	($0.0)	($0.0)	($0.2)	($1.3)	2,723	506
13	Peachbottom	Transformer	PECO	$0.0	$0.0	$0.0	$0.0	($0.7)	$0.1	($0.4)	($1.2)	($1.2)	0	14
14	East Frankfort - Crete	Line	ComEd	$2.5	$3.7	($0.0)	($1.1)	($0.1)	($0.1)	$0.0	$0.0	($1.1)	3,084	850
15	Millville - Old Chapel	Line	AP	$1.1	$1.3	$0.0	($0.2)	($0.5)	$0.4	($0.1)	($0.9)	($1.1)	210	303
16	Plymouth Meeting - Whitpain	Line	PECO	$1.1	$0.2	$0.0	$0.9	($0.0)	($0.0)	$0.0	($0.0)	$0.9	36	3
21	Eddystone - Saville	Line	PECO	$0.5	($0.3)	$0.0	$0.7	$0.0	$0.0	($0.0)	$0.0	$0.7	206	40
26	Burlington - Croydon	Line	PECO	($0.3)	($0.8)	($0.0)	$0.5	$0.0	($0.1)	($0.0)	$0.1	$0.5	1,500	33
36	Buckingham - Pleasant Valley	Line	PECO	($0.7)	($0.4)	($0.0)	($0.4)	$0.0	($0.0)	$0.0	$0.0	($0.4)	139	11
45	Jenkintown - Tabor	Line	PECO	$0.0	$0.0	$0.0	$0.0	($0.1)	$0.2	$0.0	($0.3)	($0.3)	0	10

Table 7-32 PECO Control Zone top congestion cost impacts (By facility): Calendar year 2009

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	Kammer	Transformer	500	$3.7	$9.8	$0.0	($6.0)	($0.2)	($0.0)	$0.0	($0.2)	($6.2)	3,674	1,328
2	West	Interface	500	$3.3	$7.1	$0.0	($3.8)	($0.0)	($0.1)	($0.0)	$0.0	($3.7)	504	87
3	AP South	Interface	500	$0.5	$3.7	$0.0	($3.1)	($0.0)	$0.0	$0.0	($0.1)	($3.2)	3,549	604
4	5004/5005 Interface	Interface	500	$4.9	$7.9	$0.0	($3.0)	$0.0	($0.0)	$0.0	$0.1	($3.0)	776	294
5	Graceton - Raphael Road	Line	BGE	($1.4)	($4.4)	($0.0)	$2.9	$0.5	$0.5	($0.0)	($0.0)	$2.9	527	152
6	Doubs	Transformer	AP	$1.0	$3.3	$0.0	($2.3)	($0.2)	$0.2	$0.0	($0.3)	($2.6)	429	246
7	Dunes Acres - Michigan City	Flowgate	Midwest ISO	$1.5	$3.6	($0.0)	($2.0)	($0.1)	$0.1	($0.0)	($0.1)	($2.1)	2,949	910
8	East Frankfort - Crete	Line	ComEd	$0.7	$1.8	($0.0)	($1.1)	($0.0)	$0.0	($0.0)	($0.0)	($1.1)	2,163	605
9	Crete - St Johns Tap	Flowgate	Midwest ISO	$0.4	$1.4	($0.0)	($1.0)	($0.0)	$0.0	($0.0)	($0.1)	($1.1)	1,571	306
10	Tiltonsville - Windsor	Line	AP	$0.7	$1.8	$0.0	($1.1)	($0.0)	($0.0)	$0.0	$0.0	($1.1)	2,070	311
11	Wylie Ridge	Transformer	AP	$1.3	$2.3	$0.0	($0.9)	($0.1)	$0.0	($0.1)	($0.1)	($1.1)	354	335
12	Conastone	Transformer	BGE	($0.1)	($1.0)	$0.0	$1.0	$0.0	$0.0	$0.0	$0.0	$1.0	75	12
13	Sammis - Wylie Ridge	Line	AP	$0.6	$1.4	$0.0	($0.9)	($0.0)	$0.0	($0.0)	($0.1)	($0.9)	806	157
14	Cloverdale - Lexington	Line	AEP	$0.4	$1.2	$0.0	($0.7)	($0.0)	($0.0)	($0.0)	($0.0)	($0.8)	1,019	434
15	Holmesburg - Richmond	Line	PECO	($0.2)	($0.7)	($0.0)	$0.5	($0.0)	($0.1)	$0.0	$0.1	$0.6	428	40
19	Burlington - Croydon	Line	PECO	($0.3)	($0.7)	($0.0)	$0.4	($0.0)	($0.0)	$0.0	$0.0	$0.4	2,805	3
22	Emilie	Transformer	PECO	$0.3	($1.9)	($0.0)	$2.2	($0.2)	$1.7	$0.0	($1.9)	$0.3	281	247
27	Eddystone - Scott Paper	Line	PECO	$0.2	($0.0)	$0.0	$0.2	($0.0)	$0.0	$0.0	($0.0)	$0.2	30	2
39	Buckingham - Pleasant Valley	Line	PECO	($0.4)	($0.4)	($0.0)	($0.0)	($0.0)	$0.1	$0.0	($0.1)	($0.1)	131	60
42	Bryn Mawr - Plymouth Meeting	Line	PECO	$0.1	$0.0	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	5	0

PENELEC Control Zone

Table 7-33 PENELEC Control Zone top congestion cost impacts (By facility): Calendar year 2010

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	AP South	Interface	500	($55.2)	($84.6)	($0.1)	$29.3	$6.9	$1.4	$0.1	$5.6	$34.8	4,645	1,528
2	5004/5005 Interface	Interface	500	($13.0)	($44.0)	($0.4)	$30.7	$4.5	$2.3	$0.1	$2.3	$33.0	1,644	605
3	Bedington - Black Oak	Interface	500	($19.0)	($29.6)	($0.1)	$10.5	$0.6	$0.1	$0.1	$0.5	$11.1	2,291	212
4	Wylie Ridge	Transformer	AP	$2.4	$7.7	$0.3	($5.0)	($0.8)	($0.4)	($0.5)	($0.8)	($5.8)	728	683
5	West	Interface	500	($3.6)	($8.9)	($0.0)	$5.3	$0.3	$0.3	$0.0	$0.0	$5.3	179	65
6	Mount Storm - Pruntytown	Line	AP	($3.5)	($5.7)	$0.0	$2.2	$2.8	$0.2	$0.1	$2.7	$4.9	571	574
7	Crete - St Johns Tap	Flowgate	Midwest ISO	$6.5	$9.9	($0.0)	($3.4)	($0.4)	$0.3	($0.0)	($0.7)	($4.1)	2,066	823
8	Seward	Transformer	PENELEC	$11.9	$7.1	$0.0	$4.8	($0.2)	$0.5	($0.0)	($0.8)	$4.0	371	63
9	Erie West	Transformer	PENELEC	$17.2	$11.0	$0.6	$6.8	($2.7)	$0.1	($0.5)	($3.3)	$3.5	680	175
10	Altoona - Bear Rock	Line	PENELEC	($2.8)	($5.6)	($0.0)	$2.7	$0.5	($0.1)	$0.0	$0.5	$3.2	295	55
11	Tiltonsville - Windsor	Line	AP	$4.1	$6.3	$0.1	($2.1)	($1.0)	($0.0)	($0.1)	($1.1)	($3.2)	2,723	506
12	Bear Rock - Johnstown	Line	PENELEC	($2.2)	($4.2)	($0.0)	$2.0	$1.1	$0.0	$0.0	$1.1	$3.1	210	61
13	East Frankfort - Crete	Line	ComEd	$5.8	$8.1	$0.0	($2.3)	($0.7)	$0.1	($0.0)	($0.7)	($3.0)	3,084	850
14	AEP-DOM	Interface	500	($5.8)	($8.1)	($0.0)	$2.2	$0.2	($0.1)	($0.0)	$0.3	$2.5	691	187
15	Elrama - Mitchell	Line	AP	$1.3	$3.3	$0.0	($1.9)	($0.0)	($0.1)	($0.2)	($0.1)	($2.1)	581	357
16	Johnstown - Seward	Line	PENELEC	$2.7	$0.7	$0.0	$2.0	$0.0	$0.0	$0.0	$0.0	$2.0	52	0
21	Homer City - Seward	Line	PENELEC	$4.6	$3.3	$0.0	$1.4	$0.0	$0.0	$0.0	$0.0	$1.4	83	0
25	Keystone - Shelocta	Line	PENELEC	$1.1	($0.1)	($0.0)	$1.1	$0.0	$0.0	$0.0	$0.0	$1.1	86	0
36	Homer City - Shelocta	Line	PENELEC	($6.4)	($6.8)	($0.1)	$0.4	$0.2	$0.1	$0.1	$0.3	$0.6	339	76
37	Blairsville - Shelocta	Line	PENELEC	$1.7	$1.1	$0.0	$0.6	$0.0	$0.0	$0.0	$0.0	$0.6	24	0

Table 7-34 PENELEC Control Zone top congestion cost impacts (By facility): Calendar year 2009

				Congestion Costs (Millions)									Event Hours	
				Day Ahead				Balancing						
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	AP South	Interface	500	($17.8)	($35.0)	($0.1)	$17.1	$0.7	($0.2)	$0.1	$1.0	$18.2	3,549	604
2	West	Interface	500	($2.4)	($16.3)	($0.0)	$13.9	$0.0	$0.1	$0.0	($0.0)	$13.9	504	87
3	5004/5005 Interface	Interface	500	($3.5)	($18.7)	($0.0)	$15.2	$0.3	$1.6	$0.1	($1.3)	$13.9	776	294
4	Kammer	Transformer	500	$4.8	$15.9	$0.2	($10.8)	($0.5)	($0.9)	($0.1)	$0.2	($10.6)	3,674	1,328
5	Wylie Ridge	Transformer	AP	$1.5	$10.3	$0.1	($8.8)	($0.6)	($0.7)	($0.0)	$0.1	($8.7)	354	335
6	Seward	Transformer	PENELEC	$8.0	$4.6	($0.0)	$3.4	$0.0	$0.0	$0.0	$0.0	$3.4	283	0
7	Sammis - Wylie Ridge	Line	AP	$1.2	$4.5	$0.1	($3.3)	($0.1)	($0.1)	$0.0	($0.0)	($3.3)	806	157
8	Dunes Acres - Michigan City	Flowgate	Midwest ISO	$4.1	$7.6	($0.0)	($3.5)	$0.2	($0.5)	$0.0	$0.6	($2.9)	2,949	910
9	Mount Storm - Pruntytown	Line	AP	($2.4)	($4.6)	($0.0)	$2.2	$0.3	($0.1)	$0.0	$0.5	$2.7	525	132
10	Tiltonsville - Windsor	Line	AP	$1.3	$3.6	$0.0	($2.2)	$0.1	($0.0)	($0.0)	$0.1	($2.2)	2,070	311
11	Bedington - Black Oak	Interface	500	($2.3)	($4.4)	($0.0)	$2.2	($0.0)	($0.0)	$0.0	$0.0	$2.2	669	73
12	East Frankfort - Crete	Line	ComEd	$2.2	$3.8	$0.0	($1.6)	$0.0	($0.0)	($0.0)	$0.0	($1.6)	2,163	605
13	Homer City - Seward	Line	PENELEC	$2.9	$1.6	($0.0)	$1.3	$0.0	$0.0	$0.0	$0.0	$1.3	67	0
14	Homer City - Shelocta	Line	PENELEC	($3.9)	($5.5)	($0.1)	$1.6	($0.2)	$0.1	$0.0	($0.3)	$1.3	386	103
15	Krendale - Seneca	Line	AP	$1.4	$2.6	$0.0	($1.2)	$0.0	$0.0	$0.0	$0.0	($1.2)	353	0
16	Homer City	Transformer	PENELEC	$1.4	$0.2	($0.0)	$1.1	($0.0)	$0.0	$0.0	($0.0)	$1.1	260	2
18	Altoona - Bear Rock	Line	PENELEC	($1.9)	($3.0)	($0.0)	$1.1	($0.1)	($0.1)	$0.0	($0.1)	$1.1	176	32
26	Keystone - Shelocta	Line	PENELEC	($0.4)	($0.8)	($0.0)	$0.4	$0.1	$0.1	$0.0	($0.0)	$0.4	104	43
27	Altoona - Raystown	Line	PENELEC	($0.8)	($1.1)	($0.0)	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	55	0
34	Bear Rock - Johnstown	Line	PENELEC	($0.5)	($0.7)	($0.0)	$0.2	($0.1)	($0.1)	$0.0	($0.0)	$0.2	80	45

Pepco Control Zone

Table 7-35 Pepco Control Zone top congestion cost impacts (By facility): Calendar year 2010

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	AP South	Interface	500	$124.6	$92.3	$2.1	$34.4	($4.6)	($2.8)	($1.8)	($3.6)	$30.7	4,645	1,528
2	Bedington - Black Oak	Interface	500	$47.6	$33.8	$0.9	$14.8	($0.8)	($1.1)	($0.3)	$0.0	$14.8	2,291	212
3	Doubs	Transformer	AP	$41.9	$26.7	$0.8	$16.0	($4.1)	$0.7	($1.8)	($6.7)	$9.4	920	525
4	Graceton - Raphael Road	Line	BGE	$11.1	$7.1	$0.2	$4.2	($0.9)	($0.8)	($0.2)	($0.4)	$3.8	565	308
5	Cloverdale - Lexington	Line	AEP	$10.9	$7.8	$0.1	$3.3	($1.0)	($1.0)	($0.3)	($0.3)	$3.0	1,127	684
6	Millville - Sleepy Hollow	Line	Dominion	$8.6	$6.2	$0.1	$2.5	$0.0	$0.0	$0.0	$0.0	$2.5	401	0
7	Crete - St Johns Tap	Flowgate	Midwest ISO	$6.8	$4.5	$0.0	$2.3	($0.1)	($0.3)	($0.0)	$0.1	$2.5	2,066	823
8	5004/5005 Interface	Interface	500	$8.0	$5.4	$0.2	$2.8	($0.3)	($0.1)	($0.1)	($0.4)	$2.4	1,644	605
9	Brandon Shores - Riverside	Line	BGE	($13.6)	($10.2)	($0.2)	($3.5)	$1.2	$0.5	$0.3	$1.1	($2.4)	344	162
10	East Frankfort - Crete	Line	ComEd	$6.7	$4.2	$0.0	$2.5	($0.4)	($0.2)	($0.0)	($0.2)	$2.4	3,084	850
11	Reid - Ringgold	Line	AP	$5.3	$3.3	$0.2	$2.2	($0.1)	($0.1)	($0.0)	$0.0	$2.2	345	42
12	AEP-DOM	Interface	500	$10.7	$8.8	$0.1	$2.0	$0.0	($0.2)	($0.1)	$0.1	$2.1	691	187
13	West	Interface	500	$6.3	$4.2	$0.0	$2.1	($0.2)	($0.1)	($0.0)	($0.1)	$2.0	179	65
14	Mount Storm - Pruntytown	Line	AP	$9.4	$6.7	$0.1	$2.7	($2.0)	($1.6)	($0.4)	($0.9)	$1.9	571	574
15	Tiltonsville - Windsor	Line	AP	$5.6	$3.8	$0.1	$1.9	($0.4)	($0.2)	($0.1)	($0.4)	$1.5	2,723	506
18	Bowie	Line	Pepco	$2.3	$1.1	$0.1	$1.3	$0.0	$0.0	$0.0	$0.0	$1.3	44	0
20	Bowie - Lanham	Line	Pepco	$2.2	$0.9	$0.1	$1.4	($0.3)	($0.2)	($0.1)	($0.2)	$1.1	36	13
24	Dickerson - Pleasant View	Line	Pepco	($2.4)	($1.5)	($0.0)	($1.0)	$0.1	$0.2	$0.1	($0.0)	($1.0)	185	97
30	Benning - Ritchie	Line	Pepco	$0.8	$0.2	$0.1	$0.7	$0.0	$0.0	$0.0	$0.0	$0.7	78	0
37	Buzzard - Ritchie	Line	Pepco	$0.5	$0.0	$0.0	$0.5	($0.0)	($0.0)	($0.0)	($0.0)	$0.5	59	1

Table 7-36 Pepco Control Zone top congestion cost impacts (By facility): Calendar year 2009

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	AP South	Interface	500	$57.5	$42.6	$1.1	$16.0	($1.7)	($3.5)	($1.1)	$0.7	$16.7	3,549	604
2	Kammer	Transformer	500	$21.9	$15.1	$0.3	$7.1	($1.1)	($2.0)	($0.4)	$0.5	$7.6	3,674	1,328
3	Doubs	Transformer	AP	$16.2	$8.7	$0.3	$7.8	($1.7)	($0.2)	($0.3)	($1.7)	$6.0	429	246
4	Buzzard - Ritchie	Line	Pepco	$25.3	$3.2	$0.2	$22.3	($13.9)	$1.9	($0.6)	($16.4)	$5.9	421	149
5	Graceton - Raphael Road	Line	BGE	$6.7	$4.2	$0.2	$2.6	($0.7)	($1.0)	($0.2)	$0.2	$2.8	527	152
6	Bedington - Black Oak	Interface	500	$8.5	$6.0	$0.2	$2.6	($0.0)	($0.1)	($0.0)	$0.1	$2.7	669	73
7	West	Interface	500	$8.9	$6.5	$0.1	$2.4	($0.1)	($0.2)	($0.0)	$0.0	$2.5	504	87
8	Mount Storm - Pruntytown	Line	AP	$7.5	$5.8	$0.1	$1.9	($0.2)	($0.8)	($0.1)	$0.5	$2.4	525	132
9	Dunes Acres - Michigan City	Flowgate	Midwest ISO	$6.3	$4.2	($0.0)	$2.1	($0.2)	($0.5)	$0.0	$0.3	$2.4	2,949	910
10	Cloverdale - Lexington	Line	AEP	$6.0	$4.3	$0.1	$1.8	($0.2)	($0.5)	($0.1)	$0.2	$1.9	1,019	434
11	Wylie Ridge	Transformer	AP	$6.2	$4.9	$0.0	$1.3	($0.3)	($0.7)	($0.0)	$0.3	$1.7	354	335
12	East Frankfort - Crete	Line	ComEd	$3.1	$2.0	$0.0	$1.1	($0.1)	($0.1)	($0.0)	$0.1	$1.1	2,163	605
13	Sammis - Wylie Ridge	Line	AP	$3.1	$2.2	$0.1	$1.0	($0.1)	($0.2)	($0.0)	$0.0	$1.0	806	157
14	Tiltonsville - Windsor	Line	AP	$2.3	$1.5	$0.1	$0.9	($0.0)	($0.1)	($0.1)	($0.0)	$0.9	2,070	311
15	Mount Storm	Transformer	AP	$2.1	$1.5	$0.0	$0.7	$0.0	($0.3)	($0.1)	$0.2	$0.9	151	80
19	Alabama Ave. - Palmers Corner	Line	Pepco	$0.5	$0.0	$0.0	$0.5	$0.0	$0.0	$0.0	$0.0	$0.5	12	0
24	Brighton	Transformer	Pepco	$0.7	$0.4	$0.0	$0.3	$0.0	($0.0)	$0.0	$0.0	$0.3	43	1
28	Dickerson - Pleasant View	Line	Pepco	$0.8	$0.5	$0.0	$0.3	($0.3)	($0.2)	($0.1)	($0.1)	$0.2	54	30
36	Burtonsville - Oak Grove	Line	Pepco	($0.3)	($0.4)	($0.0)	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	29	0
47	Oak Grove - Ritchie	Line	Pepco	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.1)	($0.0)	$0.1	$0.1	0	6

PPL Control Zone

Table 7-37 PPL Control Zone top congestion cost impacts (By facility): Calendar year 2010

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	5004/5005 Interface	Interface	500	$40.8	$53.1	$1.0	($11.3)	$3.3	$1.3	($0.4)	$1.5	($9.8)	1,644	605
2	Brunner Island - Yorkana	Line	Met-Ed	($5.2)	($9.5)	($0.1)	$4.1	$0.3	$0.2	$0.1	$0.1	$4.2	237	180
3	West	Interface	500	$9.7	$12.6	$0.2	($2.8)	$0.1	$0.2	($0.0)	($0.1)	($2.9)	179	65
4	AP South	Interface	500	$2.5	$1.1	$0.6	$2.0	$0.4	($0.1)	($0.1)	$0.3	$2.4	4,645	1,528
5	Graceton - Raphael Road	Line	BGE	($7.1)	($10.3)	($0.1)	$3.1	($0.4)	$0.4	$0.1	($0.7)	$2.4	565	308
6	Crete - St Johns Tap	Flowgate	Midwest ISO	$5.8	$8.7	($0.1)	($3.0)	$0.4	($0.2)	$0.0	$0.6	($2.3)	2,066	823
7	East Frankfort - Crete	Line	ComEd	$4.9	$7.3	($0.0)	($2.4)	$0.2	($0.2)	$0.0	$0.4	($2.0)	3,084	850
8	Harwood - Susquehanna	Line	PPL	$0.2	($1.4)	($0.0)	$1.6	$0.3	$0.5	($0.1)	($0.2)	$1.4	58	30
9	Millville - Sleepy Hollow	Line	Dominion	$2.4	$3.8	$0.1	($1.2)	$0.0	$0.0	$0.0	$0.0	($1.2)	401	0
10	Harwood - Siegfried	Line	PPL	($0.2)	($1.8)	$0.0	$1.5	($0.3)	$2.2	($0.1)	($2.6)	($1.1)	94	118
11	Tiltonsville - Windsor	Line	AP	$3.9	$5.3	$0.1	($1.3)	$0.5	$0.2	($0.0)	$0.3	($1.0)	2,723	506
12	Juniata	Transformer	PENELEC	$0.0	$0.0	$0.0	$0.0	$0.7	$0.2	$0.4	$0.9	$0.9	0	27
13	Eldred - Sunbury	Line	PPL	$0.6	($0.1)	$0.0	$0.7	$0.1	($0.1)	($0.0)	$0.1	$0.8	72	33
14	Bedington - Black Oak	Interface	500	$2.6	$2.2	$0.3	$0.6	$0.1	($0.1)	($0.0)	$0.1	$0.8	2,291	212
15	East	Interface	500	($0.1)	($0.8)	$0.0	$0.7	$0.0	$0.0	$0.0	($0.0)	$0.7	256	8
16	Susquehanna	Transformer	PPL	$1.0	$0.3	$0.0	$0.7	$0.0	$0.0	$0.0	$0.0	$0.7	39	0
19	East Palmerton - Siegfried	Line	PPL	($0.1)	($0.7)	$0.0	$0.6	$0.0	$0.0	$0.0	$0.0	$0.6	70	0
21	East Palmerton - Harwood	Line	PPL	($0.0)	($0.5)	$0.0	$0.5	$0.0	$0.0	$0.0	$0.0	$0.5	51	0
26	Frackville - Siegfried	Line	PPL	($0.1)	($0.6)	$0.0	$0.4	($0.0)	$0.0	($0.0)	($0.0)	$0.4	48	7
35	Eldred - Frackville	Line	PPL	$0.1	($0.2)	$0.0	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	20	0

Table 7-38 PPL Control Zone top congestion cost impacts (By facility): Calendar year 2009

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	Kammer	Transformer	500	$1.7	$5.5	$0.6	($3.2)	($0.2)	($0.2)	($0.1)	($0.0)	($3.2)	3,674	1,328
2	5004/5005 Interface	Interface	500	$2.9	$7.0	$0.5	($3.5)	$0.0	($0.8)	($0.0)	$0.7	($2.8)	776	294
3	Dunes Acres - Michigan City	Flowgate	Midwest ISO	$0.6	$2.3	($0.1)	($1.8)	($0.2)	($0.2)	$0.0	$0.0	($1.8)	2,949	910
4	AP South	Interface	500	$0.5	($0.6)	$0.3	$1.4	$0.1	($0.1)	$0.1	$0.3	$1.7	3,549	604
5	Graceton - Raphael Road	Line	BGE	($0.9)	($2.3)	($0.1)	$1.3	$0.1	$0.1	$0.0	$0.1	$1.4	527	152
6	Hummelstown - Middletown Jct	Line	Met-Ed	$1.0	($0.0)	$0.0	$1.1	$0.0	($0.0)	($0.0)	$0.0	$1.1	51	14
7	West	Interface	500	$3.0	$4.6	$0.5	($1.1)	($0.0)	($0.2)	($0.0)	$0.1	($0.9)	504	87
8	Brunner Island - Yorkana	Line	Met-Ed	($0.0)	($0.9)	($0.0)	$0.8	$0.0	$0.1	($0.0)	($0.0)	$0.8	86	27
9	Sammis - Wylie Ridge	Line	AP	$0.2	$1.0	$0.1	($0.7)	$0.0	($0.0)	$0.0	$0.0	($0.7)	806	157
10	Harwood - Susquehanna	Line	PPL	$0.2	($0.5)	$0.0	$0.7	($0.0)	$0.0	$0.0	($0.1)	$0.7	31	10
11	East Frankfort - Crete	Line	ComEd	$0.4	$1.0	$0.0	($0.6)	($0.1)	($0.1)	$0.0	($0.0)	($0.6)	2,163	605
12	Crete - St Johns Tap	Flowgate	Midwest ISO	$0.4	$0.8	($0.0)	($0.4)	($0.1)	($0.1)	$0.0	($0.0)	($0.5)	1,571	306
13	Tiltonsville - Windsor	Line	AP	$0.5	$0.9	$0.1	($0.3)	($0.1)	($0.0)	$0.0	($0.1)	($0.4)	2,070	311
14	Atlantic - Larrabee	Line	JCPL	$0.1	$0.1	($0.0)	($0.0)	($0.1)	$0.1	$0.0	($0.3)	($0.3)	284	73
15	Wylie Ridge	Transformer	AP	$1.1	$1.8	$0.3	($0.4)	$0.2	$0.1	$0.0	$0.1	($0.3)	354	335
16	PL North	Interface	PPL	$0.0	$0.0	$0.0	$0.0	$0.4	$0.6	($0.0)	($0.3)	($0.3)	0	176
27	Jenkins - Susquehanna	Line	PPL	$0.1	($0.1)	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	12	0
45	Dauphin - Juniata	Line	PPL	$0.0	($0.0)	$0.0	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.0	6	4
55	Eldred - Sunbury	Line	PPL	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	4	0
57	Harwood	Transformer	PPL	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	$0.0	($0.0)	$0.0	15	1

PSEG Control Zone

Table 7-39 PSEG Control Zone top congestion cost impacts (By facility): Calendar year 2010

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	Branchburg - Readington	Line	PSEG	$9.0	$1.2	$0.6	$8.4	($0.0)	$0.9	($0.5)	($1.4)	$6.9	1,235	185
2	Leonia - New Milford	Line	PSEG	$1.2	$0.7	$1.7	$2.3	($3.6)	$1.9	($0.8)	($6.3)	($4.0)	1,241	50
3	AP South	Interface	500	$0.4	$6.0	$2.8	($2.8)	$0.2	($0.4)	($1.7)	($1.1)	($3.8)	4,645	1,528
4	Hawthorn - Waldwick	Line	PSEG	$0.1	($0.0)	$0.0	$0.1	($0.7)	$1.1	($1.7)	($3.4)	($3.3)	499	39
5	Hillsdale - New Milford	Line	PSEG	$1.4	$0.7	$2.2	$2.9	$0.0	$0.0	($0.1)	($0.1)	$2.8	1,022	23
6	5004/5005 Interface	Interface	500	$29.8	$28.1	$2.4	$4.1	$2.0	$2.2	($1.9)	($2.1)	$2.0	1,644	605
7	Wylie Ridge	Transformer	AP	$3.8	$3.9	$0.3	$0.2	$0.2	$1.6	($0.8)	($2.2)	($2.0)	728	683
8	Millville - Old Chapel	Line	AP	$1.0	$1.4	$0.1	($0.4)	$0.1	$1.0	($0.6)	($1.5)	($1.9)	210	303
9	Eddystone - Island Road	Line	PECO	$1.0	($0.7)	$0.0	$1.7	$0.0	$0.0	($0.0)	$0.0	$1.7	186	3
10	Hawthorn - Hinchmans Ave	Line	PSEG	($0.0)	($0.0)	($0.2)	($0.2)	($0.1)	$0.4	($1.0)	($1.5)	($1.7)	209	38
11	Redoak - Sayreville	Line	JCPL	$1.3	($0.3)	$0.1	$1.6	$0.0	($0.0)	($0.0)	($0.0)	$1.6	898	57
12	Bedington - Black Oak	Interface	500	$2.0	$4.3	$1.1	($1.2)	($0.0)	($0.0)	($0.3)	($0.3)	($1.5)	2,291	212
13	Buckingham - Pleasant Valley	Line	PECO	$1.8	$0.7	$0.1	$1.2	($0.0)	$0.0	($0.0)	($0.0)	$1.2	139	11
14	Bayway - Federal Square	Line	PSEG	$0.7	($0.4)	$0.0	$1.1	($0.0)	($0.0)	$0.0	$0.0	$1.2	613	9
15	Doubs	Transformer	AP	$2.3	$2.1	$0.3	$0.4	($0.3)	$0.5	($0.7)	($1.6)	($1.1)	920	525
16	North Ave - Pvsc	Line	PSEG	$0.2	($0.8)	$0.1	$1.0	$0.0	$0.0	$0.0	$0.0	$1.0	664	0
19	Athenia - Saddlebrook	Line	PSEG	$14.8	$3.4	$8.5	$20.0	($10.0)	$3.0	($6.1)	($19.0)	$1.0	3,318	364
21	Cedar Grove - Clifton	Line	PSEG	$1.0	$0.4	$0.5	$1.1	($0.1)	$0.2	($0.1)	($0.3)	$0.8	205	8
22	Bergen - Hoboken	Line	PSEG	$0.1	($0.2)	$0.4	$0.7	($0.2)	($0.1)	$0.1	$0.1	$0.8	508	29
23	Bayonne - PVSC	Line	PSEG	$0.1	($0.6)	$0.1	$0.8	$0.0	$0.0	$0.0	$0.0	$0.8	834	0

Table 7-40 PSEG Control Zone top congestion cost impacts (By facility): Calendar year 2009

				Congestion Costs (Millions)									Event Hours	
				Day Ahead				Balancing						
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	Leonia - New Milford	Line	PSEG	$2.1	$0.8	$3.1	$4.4	($0.0)	$0.0	($0.3)	($0.3)	$4.1	3,847	39
2	Athenia - Saddlebrook	Line	PSEG	$3.2	$0.6	$1.3	$4.0	($0.2)	$0.1	($0.5)	($0.8)	$3.2	1,108	139
3	Plainsboro - Trenton	Line	PSEG	$3.5	($0.1)	$0.1	$3.8	($0.3)	$0.4	($0.1)	($0.7)	$3.1	389	164
4	Cedar Grove - Clifton	Line	PSEG	$2.3	$0.5	$1.0	$2.8	($0.1)	$0.0	($0.1)	($0.2)	$2.6	1,194	38
5	AP South	Interface	500	$0.2	$3.5	$1.1	($2.2)	$0.1	($0.2)	($0.5)	($0.2)	($2.4)	3,549	604
6	Fairlawn - Saddlebrook	Line	PSEG	$1.1	$0.2	$0.6	$1.6	$0.0	$0.0	$0.0	$0.0	$1.6	946	0
7	West	Interface	500	$11.8	$13.8	$0.9	($1.1)	($0.1)	$0.1	($0.2)	($0.3)	($1.4)	504	87
8	Wylie Ridge	Transformer	AP	$4.3	$5.4	$0.5	($0.6)	$0.0	$0.1	($0.6)	($0.7)	($1.3)	354	335
9	Hillsdale - Waldwick	Line	PSEG	$0.0	$0.0	$0.0	$0.0	($0.1)	$0.4	($0.5)	($1.0)	($1.0)	0	59
10	Monroe - New Freedom	Line	AECO	($0.1)	($1.1)	($0.0)	$0.9	$0.0	$0.0	$0.0	$0.0	$0.9	584	0
11	Bayway - Federal Square	Line	PSEG	$0.5	($0.3)	$0.0	$0.8	($0.0)	($0.0)	($0.0)	$0.0	$0.8	220	11
12	Buckingham - Pleasant Valley	Line	PECO	$0.9	($0.1)	$0.0	$1.0	($0.0)	$0.2	($0.0)	($0.3)	$0.7	131	60
13	Atlantic - Larrabee	Line	JCPL	$0.6	($0.7)	$0.0	$1.3	($0.0)	$0.6	($0.1)	($0.7)	$0.7	284	73
14	Brunswick - Edison	Line	PSEG	$1.0	($0.0)	$0.0	$1.1	($0.1)	$0.2	($0.2)	($0.5)	$0.6	138	76
15	Cedar Grove - Roseland	Line	PSEG	$0.4	$0.0	$0.0	$0.4	($0.2)	$0.5	($0.2)	($0.9)	($0.5)	64	71
16	Bayonne - PVSC	Line	PSEG	$0.0	($0.4)	$0.0	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	686	0
17	Branchburg - Flagtown	Line	PSEG	$0.6	($0.0)	$0.1	$0.7	($0.0)	$0.1	($0.1)	($0.2)	$0.4	161	16
18	Athenia - Fairlawn	Line	PSEG	$0.4	$0.0	$0.0	$0.4	$0.0	$0.0	($0.0)	($0.0)	$0.4	165	6
22	East Windsor - Windsor	Line	PSEG	$0.1	($0.3)	$0.0	$0.3	($0.0)	($0.0)	($0.0)	$0.0	$0.4	107	3
24	Sewaren	Transformer	PSEG	$0.3	($0.0)	$0.0	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	89	0

RECO Control Zone

Table 7-41 RECO Control Zone top congestion cost impacts (By facility): Calendar year 2010

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	5004/5005 Interface	Interface	500	$1.1	$0.1	$0.0	$1.0	$0.2	($0.1)	($0.0)	$0.3	$1.3	1,644	605
2	Branchburg - Readington	Line	PSEG	$0.6	$0.0	$0.0	$0.5	$0.1	($0.0)	($0.0)	$0.1	$0.6	1,235	185
3	West	Interface	500	$0.4	$0.0	$0.0	$0.4	$0.0	($0.0)	($0.0)	$0.0	$0.4	179	65
4	Athenia - Saddlebrook	Line	PSEG	$0.2	$0.0	($0.0)	$0.2	$0.1	($0.1)	$0.0	$0.1	$0.3	3,318	364
5	AP South	Interface	500	($0.2)	($0.0)	$0.0	($0.2)	($0.0)	$0.0	($0.0)	($0.1)	($0.3)	4,645	1,528
6	Brandon Shores - Riverside	Line	BGE	$0.2	$0.0	$0.0	$0.2	$0.0	($0.0)	$0.0	$0.0	$0.3	344	162
7	Graceton - Raphael Road	Line	BGE	($0.2)	($0.0)	($0.0)	($0.2)	($0.1)	$0.0	$0.0	($0.1)	($0.3)	565	308
8	Crete - St Johns Tap	Flowgate	Midwest ISO	$0.2	$0.0	$0.0	$0.2	$0.1	($0.0)	($0.0)	$0.1	$0.2	2,066	823
9	Wylie Ridge	Transformer	AP	$0.1	$0.0	$0.0	$0.1	$0.1	($0.0)	($0.0)	$0.1	$0.2	728	683
10	Tiltonsville - Windsor	Line	AP	$0.2	$0.0	$0.0	$0.2	$0.0	($0.0)	($0.0)	$0.0	$0.2	2,723	506
11	East Frankfort - Crete	Line	ComEd	$0.1	$0.0	$0.0	$0.1	$0.0	($0.0)	($0.0)	$0.0	$0.2	3,084	850
12	Hillsdale - New Milford	Line	PSEG	($0.2)	($0.0)	($0.0)	($0.2)	($0.0)	$0.0	$0.0	($0.0)	($0.2)	1,022	23
13	Erie West	Transformer	PENELEC	$0.1	$0.0	($0.0)	$0.1	$0.1	($0.0)	($0.0)	$0.0	$0.1	680	175
14	Brunner Island - Yorkana	Line	Met-Ed	($0.1)	($0.0)	($0.0)	($0.1)	($0.0)	$0.0	$0.0	($0.0)	($0.1)	237	180
15	Doubs	Transformer	AP	$0.1	$0.0	$0.0	$0.1	$0.0	($0.0)	($0.0)	$0.1	$0.1	920	525

Table 7-42 RECO Control Zone top congestion cost impacts (By facility): Calendar year 2009

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	West	Interface	500	$0.5	$0.0	$0.0	$0.6	($0.0)	($0.0)	($0.0)	($0.0)	$0.5	504	87
2	5004/5005 Interface	Interface	500	$0.5	$0.0	$0.0	$0.5	($0.0)	($0.0)	($0.0)	($0.1)	$0.4	776	294
3	Kammer	Transformer	500	$0.4	$0.0	$0.0	$0.4	$0.0	($0.0)	($0.0)	$0.0	$0.4	3,674	1,328
4	Dunes Acres - Michigan City	Flowgate	Midwest ISO	$0.2	$0.0	($0.0)	$0.2	$0.0	($0.0)	($0.0)	$0.0	$0.2	2,949	910
5	Wylie Ridge	Transformer	AP	$0.2	$0.0	$0.0	$0.2	($0.0)	($0.0)	($0.0)	($0.0)	$0.2	354	335
6	Graceton - Raphael Road	Line	BGE	($0.2)	($0.0)	($0.0)	($0.2)	$0.0	$0.0	$0.0	$0.0	($0.2)	527	152
7	AP South	Interface	500	($0.1)	($0.0)	($0.0)	($0.1)	($0.0)	$0.0	$0.0	($0.0)	($0.1)	3,549	604
8	Athenia - Saddlebrook	Line	PSEG	$0.1	($0.0)	$0.0	$0.1	($0.0)	($0.0)	$0.0	($0.0)	$0.1	1,108	139
9	East Frankfort - Crete	Line	ComEd	$0.1	$0.0	$0.0	$0.1	$0.0	($0.0)	$0.0	$0.0	$0.1	2,163	605
10	Doubs	Transformer	AP	$0.1	$0.0	$0.0	$0.1	$0.0	($0.0)	$0.0	$0.0	$0.1	429	246
11	Sammis - Wylie Ridge	Line	AP	$0.1	$0.0	$0.0	$0.1	$0.0	($0.0)	($0.0)	($0.0)	$0.1	806	157
12	Tiltonsville - Windsor	Line	AP	$0.1	$0.0	$0.0	$0.1	($0.0)	($0.0)	($0.0)	$0.0	$0.1	2,070	311
13	Crete - St Johns Tap	Flowgate	Midwest ISO	$0.1	$0.0	($0.0)	$0.1	$0.0	($0.0)	$0.0	$0.0	$0.1	1,571	306
14	Fairlawn - Saddlebrook	Line	PSEG	($0.1)	($0.0)	($0.0)	($0.1)	$0.0	$0.0	$0.0	$0.0	($0.1)	946	0
15	Krendale - Seneca	Line	AP	$0.1	$0.0	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	353	0

Western Region Congestion-Event Summaries

AEP Control Zone

Table 7-43 AEP Control Zone top congestion cost impacts (By facility): Calendar year 2010

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	AP South	Interface	500	($41.2)	($98.5)	$0.3	$57.6	($3.8)	$4.4	$1.7	($6.5)	$51.0	4,645	1,528
2	AEP-DOM	Interface	500	$9.8	($27.6)	$1.8	$39.2	($1.1)	$1.5	($1.3)	($4.0)	$35.2	691	187
3	Bedington - Black Oak	Interface	500	($16.3)	($32.7)	($0.0)	$16.4	($0.1)	$0.6	$0.4	($0.4)	$16.0	2,291	212
4	Kanawha - Kincaid	Line	AEP	$9.6	$0.2	$1.0	$10.4	$0.0	$0.0	$0.0	$0.0	$10.4	534	0
5	Belmont	Transformer	AP	$7.8	($3.3)	$1.5	$12.6	($2.5)	($0.8)	($1.0)	($2.7)	$9.8	1,887	203
6	5004/5005 Interface	Interface	500	($22.9)	($33.6)	($0.5)	$10.2	($0.3)	$2.9	$0.6	($2.6)	$7.6	1,644	605
7	Kanawha River - Kincaid	Line	AEP	$0.0	$0.0	$0.0	$0.0	($5.0)	$1.1	($1.2)	($7.3)	($7.3)	0	200
8	Kanawha River	Transformer	AEP	$3.6	($0.8)	$0.6	$5.1	($0.2)	($0.4)	($0.1)	($0.0)	$5.0	327	18
9	Mount Storm - Pruntytown	Line	AP	($2.9)	($8.1)	($0.1)	$5.1	($0.7)	$1.5	$0.5	($1.8)	$3.3	571	574
10	Mahans Lane - Tidd	Line	AEP	($1.4)	($4.7)	($0.3)	$3.0	$0.3	$0.1	$0.0	$0.2	$3.2	646	207
11	Brues - West Bellaire	Line	AEP	$0.0	$0.0	$0.0	$0.0	($2.1)	$0.8	($0.2)	($3.2)	($3.2)	0	78
12	West	Interface	500	($5.8)	($9.2)	($0.1)	$3.3	($0.2)	$0.3	$0.1	($0.4)	$2.9	179	65
13	East Frankfort - Crete	Line	ComEd	$8.8	$7.8	$2.4	$3.4	$0.0	($0.0)	($1.4)	($1.4)	$2.1	3,084	850
14	Doubs	Transformer	AP	($11.6)	($14.7)	($0.2)	$2.8	($0.0)	$1.2	$0.4	($0.8)	$2.0	920	525
15	Electric Jct - Nelson	Line	ComEd	$0.4	$0.6	$5.7	$5.5	($0.1)	($0.0)	($7.3)	($7.4)	($1.9)	1,495	258
17	Culloden - Wyoming	Line	AEP	$0.6	($0.8)	$0.5	$1.9	$0.0	$0.0	$0.0	$0.0	$1.9	46	0
18	Cloverdale - Ivy Hill	Line	AEP	$0.0	$0.0	$0.0	$0.0	($1.4)	$0.2	($0.1)	($1.7)	($1.7)	0	142
20	Kammer - Natrium	Line	AEP	$1.5	($0.4)	$0.2	$2.0	($0.3)	$0.1	($0.1)	($0.4)	$1.6	308	48
24	Breed - Wheatland	Line	AEP	$0.0	($1.6)	($0.1)	$1.5	$0.0	$0.0	$0.0	($0.0)	$1.5	150	1
25	Ruth - Turner	Line	AEP	$1.5	($0.9)	$0.2	$2.6	($0.5)	$0.4	($0.2)	($1.2)	$1.4	234	113

Table 7-44 AEP Control Zone top congestion cost impacts (By facility): Calendar year 2009

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	AP South	Interface	500	($20.1)	($39.8)	$1.2	$20.9	($1.2)	$0.4	$0.5	($1.1)	$19.7	3,549	604
2	Kammer	Transformer	500	($20.6)	($34.6)	($0.6)	$13.4	($0.8)	$2.5	$0.4	($2.9)	$10.6	3,674	1,328
3	Dunes Acres - Michigan City	Flowgate	Midwest ISO	$17.5	$8.9	$1.1	$9.7	($2.6)	($1.1)	($2.4)	($3.9)	$5.8	2,949	910
4	Ruth - Turner	Line	AEP	$4.9	($1.6)	$0.5	$7.0	($1.4)	($0.4)	($0.1)	($1.2)	$5.8	704	313
5	Kanawha - Kincaid	Line	AEP	$2.8	($2.1)	$0.2	$5.1	$0.0	$0.0	$0.0	$0.0	$5.1	291	0
6	Kammer - Ormet	Line	AEP	$7.8	$1.1	$0.3	$6.9	($1.6)	$0.5	($0.1)	($2.2)	$4.7	552	509
7	AEP-DOM	Interface	500	$1.3	($3.7)	$0.4	$5.3	($0.2)	$0.5	($0.0)	($0.8)	$4.5	335	136
8	Kanawha River	Transformer	AEP	$3.3	($0.3)	$0.5	$4.1	$0.1	($0.3)	($0.1)	$0.4	$4.4	163	37
9	Kanawha River - Bradley	Line	AEP	$1.3	($2.2)	$0.2	$3.8	($0.0)	$0.1	$0.0	($0.1)	$3.7	24	15
10	Breed - Wheatland	Line	AEP	$0.1	($3.9)	($0.5)	$3.5	$0.0	$0.0	$0.0	$0.0	$3.5	591	2
11	5004/5005 Interface	Interface	500	($9.2)	($12.9)	$0.0	$3.7	$0.1	$0.6	$0.1	($0.3)	$3.4	776	294
12	Sammis - Wylie Ridge	Line	AP	($5.0)	($3.1)	($0.1)	($2.0)	($0.3)	$0.2	($0.0)	($0.5)	($2.6)	806	157
13	Bedington - Black Oak	Interface	500	($2.8)	($5.1)	$0.1	$2.4	($0.1)	($0.0)	$0.0	($0.0)	$2.3	669	73
14	Mount Storm - Pruntytown	Line	AP	($3.1)	($5.2)	$0.2	$2.3	$0.0	$0.2	$0.1	($0.1)	$2.2	525	132
15	East Frankfort - Crete	Line	ComEd	$4.6	$2.9	$1.5	$3.2	($0.0)	$0.1	($0.9)	($1.0)	$2.1	2,163	605
18	Cloverdale - Lexington	Line	AEP	($7.0)	($5.1)	($0.4)	($2.3)	$0.4	$0.2	$0.2	$0.4	($1.9)	1,019	434
21	Axton	Transformer	AEP	$0.3	($0.8)	$0.1	$1.2	($0.1)	$0.1	$0.0	($0.2)	$1.1	116	12
27	Poston - Postel Tap	Line	AEP	$0.4	($0.6)	$0.2	$1.2	$0.1	$0.5	($0.0)	($0.4)	$0.8	148	118
28	Marquis - Waverly	Line	AEP	$0.7	$0.0	$0.1	$0.7	($0.0)	$0.0	($0.0)	($0.0)	$0.7	74	14
31	Kanawha River - Kincaid	Line	AEP	$0.0	$0.0	$0.0	$0.0	$0.3	($0.1)	$0.1	$0.5	$0.5	0	105

AP Control Zone

Table 7-45 AP Control Zone top congestion cost impacts (By facility): Calendar year 2010

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	AP South	Interface	500	($36.1)	($148.5)	($11.0)	$101.4	$5.8	$6.1	$9.1	$8.9	$110.3	4,645	1,528
2	Bedington - Black Oak	Interface	500	($11.7)	($48.2)	($2.6)	$33.9	$0.8	$3.2	$1.0	($1.4)	$32.5	2,291	212
3	Doubs	Transformer	AP	$13.9	($10.9)	($0.2)	$24.6	$3.2	$1.1	$0.2	$2.4	$27.0	920	525
4	Belmont	Transformer	AP	$15.9	($2.1)	$0.7	$18.6	($1.7)	($0.0)	($0.6)	($2.2)	$16.4	1,887	203
5	Tiltonsville - Windsor	Line	AP	$18.1	$4.2	$1.6	$15.5	($2.7)	($0.7)	($1.9)	($3.9)	$11.7	2,723	506
6	Mount Storm - Pruntytown	Line	AP	($2.8)	($11.2)	($0.4)	$8.0	$2.4	$1.6	$2.0	$2.8	$10.7	571	574
7	5004/5005 Interface	Interface	500	($21.7)	($33.5)	($2.1)	$9.7	$2.0	$2.9	$1.7	$0.8	$10.5	1,644	605
8	AEP-DOM	Interface	500	($2.9)	($10.4)	$0.4	$7.9	$0.4	($0.2)	($0.1)	$0.5	$8.4	691	187
9	Millville - Old Chapel	Line	AP	($1.0)	($2.4)	($0.3)	$1.1	($1.7)	$5.8	$0.6	($7.0)	($5.9)	210	303
10	Millville - Old Chapel	Line	Dominion	$1.8	($2.7)	$0.2	$4.8	$0.0	$0.0	$0.0	$0.0	$4.8	269	0
11	Wylie Ridge	Transformer	AP	$2.5	$4.7	$1.8	($0.4)	($1.2)	($0.8)	($4.0)	($4.3)	($4.7)	728	683
12	Kingwood - Pruntytown	Line	AP	$5.4	$1.4	$0.6	$4.6	$0.0	($0.1)	($0.2)	($0.0)	$4.6	502	49
13	Halfway - Marlowe	Line	AP	$0.8	($3.8)	($0.7)	$3.8	$0.7	$1.4	$1.4	$0.8	$4.6	157	73
14	Cloverdale - Lexington	Line	AEP	$1.5	($3.4)	$0.9	$5.8	($0.1)	$0.4	($1.9)	($2.3)	$3.5	1,127	684
15	Yukon	Transformer	AP	$3.3	$0.2	$0.1	$3.3	$0.1	$0.2	$0.1	$0.0	$3.3	195	38
16	Albright - Mt. Zion	Line	AP	$1.7	($0.8)	$0.1	$2.6	$0.2	($0.6)	($0.5)	$0.3	$3.0	727	193
18	Nipetown - Reid	Line	AP	($0.1)	($3.1)	($0.1)	$2.9	$0.1	$0.2	($0.0)	($0.1)	$2.8	352	63
20	Fort Martin - Ronco	Line	AP	$0.2	$0.2	$0.1	$0.2	($0.2)	$0.9	($1.4)	($2.5)	($2.3)	31	42
21	Middlebourne - Willow	Line	AP	$2.0	($0.2)	$0.3	$2.5	($0.2)	($0.1)	($0.2)	($0.3)	$2.2	333	81
22	Hamilton - Weirton	Line	AP	$3.2	$1.1	$0.2	$2.4	($0.1)	$0.1	($0.1)	($0.3)	$2.1	533	18

Table 7-46 AP Control Zone top congestion cost impacts (By facility): Calendar year 2009

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	AP South	Interface	500	($17.3)	($65.9)	($4.6)	$44.0	$2.6	$2.6	$3.3	$3.4	$47.4	3,549	604
2	Kammer	Transformer	500	$17.8	$27.8	$6.8	($3.2)	($3.0)	($0.9)	($8.2)	($10.3)	($13.5)	3,674	1,328
3	Mount Storm - Pruntytown	Line	AP	($2.0)	($10.1)	($0.6)	$7.4	$0.8	$0.8	$0.5	$0.5	$7.9	525	132
4	Doubs	Transformer	AP	$1.9	($6.6)	($0.2)	$8.4	($0.2)	$1.2	$0.2	($1.1)	$7.3	429	246
5	Bedington - Black Oak	Interface	500	($1.9)	($8.5)	($0.2)	$6.3	($0.3)	$0.2	$0.4	($0.2)	$6.2	669	73
6	Tiltonsville - Windsor	Line	AP	$9.1	$2.5	$0.5	$7.1	($0.5)	($0.3)	($0.8)	($1.1)	$6.0	2,070	311
7	5004/5005 Interface	Interface	500	($9.9)	($13.9)	($1.3)	$2.7	$1.0	$0.9	$1.8	$1.9	$4.6	776	294
8	Wylie Ridge	Transformer	AP	$6.1	$7.4	$5.4	$4.1	($1.1)	($0.5)	($7.2)	($7.7)	($3.6)	354	335
9	Belmont	Transformer	AP	$3.5	$0.2	$0.6	$4.0	($0.2)	$0.5	($0.1)	($0.7)	$3.2	1,029	76
10	Bedington - Harmony	Line	AP	$2.1	($0.1)	$0.5	$2.8	$0.0	$0.0	($0.0)	($0.1)	$2.7	280	28
11	Cloverdale - Lexington	Line	AEP	$1.3	($1.5)	$0.8	$3.6	($0.1)	$0.0	($0.9)	($1.0)	$2.6	1,019	434
12	Carroll - Catoctin	Line	AP	$0.4	$0.0	($0.0)	$0.3	$0.7	($0.8)	$0.2	$1.6	$2.0	99	22
13	Yukon	Transformer	AP	$2.2	$0.4	$0.0	$1.9	$0.0	$0.2	$0.1	($0.1)	$1.7	149	39
14	Krendale - Seneca	Line	AP	$1.6	$0.1	$0.2	$1.7	$0.0	$0.0	$0.0	$0.0	$1.7	353	0
15	Mount Storm	Transformer	AP	($0.5)	($2.2)	($0.3)	$1.4	$0.2	$0.5	$0.3	($0.1)	$1.4	151	80
17	Sammis - Wylie Ridge	Line	AP	$3.9	$2.9	$1.6	$2.6	($0.3)	($0.1)	($1.2)	($1.4)	$1.2	806	157
18	Kingwood - Pruntytown	Line	AP	$1.0	($0.1)	($0.0)	$1.1	$0.0	($0.0)	($0.0)	$0.0	$1.2	161	10
19	Middlebourne - Willow	Line	AP	$1.3	$0.1	($0.1)	$1.1	($0.1)	($0.1)	($0.0)	$0.0	$1.1	348	45
20	Elrama - Mitchell	Line	AP	$2.5	$1.2	$0.1	$1.5	($0.2)	$0.0	($0.2)	($0.4)	$1.1	367	198
22	Bedington	Transformer	AP	$4.3	($0.8)	$0.1	$5.1	($3.7)	$0.0	($2.2)	($6.0)	($0.8)	354	149

ComEd Control Zone

Table 7-47 ComEd Control Zone top congestion cost impacts (By facility): Calendar year 2010

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	Crete - St Johns Tap	Flowgate	Midwest ISO	($68.4)	($106.2)	($12.0)	$25.8	$0.6	($3.6)	$6.6	$10.8	$36.6	2,066	823
2	East Frankfort - Crete	Line	ComEd	($48.6)	($88.9)	($6.2)	$34.1	($3.2)	($0.7)	$1.2	($1.4)	$32.7	3,084	850
3	AP South	Interface	500	($89.1)	($120.4)	($1.0)	$30.4	($2.6)	$0.2	($0.0)	($2.8)	$27.6	4,645	1,528
4	Electric Jct - Nelson	Line	ComEd	$1.1	($24.9)	$6.7	$32.7	$1.3	$4.3	($9.4)	($12.4)	$20.3	1,495	258
5	Pleasant Valley - Belvidere	Line	ComEd	($3.8)	($23.9)	$2.6	$22.7	$0.1	$2.9	($2.9)	($5.7)	$17.0	2,553	467
6	Nelson - Cordova	Line	ComEd	$8.7	($3.0)	$4.0	$15.8	$0.8	$1.7	($3.5)	($4.4)	$11.3	1,546	95
7	Bedington - Black Oak	Interface	500	($31.9)	($42.8)	($0.3)	$10.7	($0.5)	($0.2)	$0.1	($0.2)	$10.4	2,291	212
8	5004/5005 Interface	Interface	500	($32.1)	($44.3)	($0.1)	$12.1	($4.2)	($0.9)	$0.2	($3.1)	$9.0	1,644	605
9	Waterman - West Dekalb	Line	ComEd	($2.2)	($9.2)	$1.3	$8.3	$0.8	$0.6	($0.5)	($0.2)	$8.1	3,002	343
10	AEP-DOM	Interface	500	($14.8)	($22.3)	($0.6)	$7.0	($0.0)	($0.2)	$0.2	$0.4	$7.4	691	187
11	Cherry Valley	Transformer	ComEd	$2.4	($3.6)	$0.6	$6.6	$0.1	$0.1	($0.1)	($0.1)	$6.5	535	39
12	Glidden - West Dekalb	Line	ComEd	($0.2)	($5.3)	$0.7	$5.8	$0.1	$0.0	($0.5)	($0.4)	$5.4	1,090	21
13	Rising	Flowgate	Midwest ISO	($3.1)	($8.6)	($0.1)	$5.4	($0.1)	$0.5	$0.2	($0.4)	$4.9	875	80
14	Cloverdale - Lexington	Line	AEP	($11.6)	($17.9)	($0.4)	$5.9	($1.6)	($0.1)	$0.4	($1.1)	$4.8	1,127	684
15	Goose Creek - Rising	Flowgate	Midwest ISO	($7.0)	($12.5)	($1.0)	$4.5	($0.2)	$0.4	($0.1)	($0.6)	$3.9	439	200
31	Electric Junction - Aurora	Line	ComEd	$1.3	$0.2	$0.0	$1.1	$0.0	$0.1	$0.1	$0.1	$1.2	136	35
33	Woodstock - 12205	Line	ComEd	($0.0)	($1.0)	$0.1	$1.2	$0.0	$0.0	$0.0	$0.0	$1.2	91	0
40	Belvidere - Woodstock	Line	ComEd	$0.3	($0.6)	$0.1	$1.0	$0.0	$0.1	($0.0)	($0.1)	$0.9	100	11
46	Burnham - Munster	Line	ComEd	($0.0)	($0.0)	($0.0)	$0.0	($0.0)	$0.6	($0.0)	($0.7)	($0.7)	1	82
47	Burnham - Sheffield	Line	ComEd	($1.1)	($1.8)	($0.0)	$0.8	($0.6)	($0.3)	$0.1	($0.1)	$0.6	41	162

Table 7-48 ComEd Control Zone top congestion cost impacts (By facility): Calendar year 2009

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	Pleasant Valley - Belvidere	Line	ComEd	($4.7)	($42.8)	($0.0)	$38.1	($0.2)	$2.4	$0.1	($2.5)	$35.6	3,648	405
2	East Frankfort - Crete	Line	ComEd	($20.1)	($41.5)	($0.3)	$21.1	($0.7)	$0.5	$0.1	($1.1)	$19.9	2,163	605
3	Dunes Acres - Michigan City	Flowgate	Midwest ISO	($46.2)	($70.5)	($3.1)	$21.3	($3.4)	($1.1)	$0.9	($1.4)	$19.8	2,949	910
4	Kammer	Transformer	500	($30.8)	($49.7)	($0.1)	$18.7	($0.4)	($0.9)	($0.0)	$0.4	$19.1	3,674	1,328
5	AP South	Interface	500	($34.7)	($53.5)	($0.1)	$18.7	($1.1)	($0.1)	($0.1)	($1.0)	$17.6	3,549	604
6	Crete - St Johns Tap	Flowgate	Midwest ISO	($14.7)	($30.3)	($0.4)	$15.2	($0.4)	$0.1	$0.1	($0.4)	$14.8	1,571	306
7	Electric Jct - Nelson	Line	ComEd	$0.2	($7.9)	$0.1	$8.2	$2.1	$1.4	($0.1)	$0.6	$8.8	823	202
8	5004/5005 Interface	Interface	500	($12.4)	($17.6)	($0.0)	$5.1	($0.6)	($1.1)	($0.0)	$0.4	$5.6	776	294
9	Glidden - West Dekalb	Line	ComEd	($0.4)	($5.7)	$0.1	$5.4	$0.1	($0.0)	$0.0	$0.2	$5.6	1,166	21
10	Paddock - Townline	Flowgate	Midwest ISO	($0.8)	($5.0)	($0.1)	$4.0	$0.5	$0.2	$0.1	$0.4	$4.4	404	215
11	Sliver Lake - Cherry Valley	Line	ComEd	$0.1	($3.7)	$0.1	$3.9	$0.8	$0.2	($0.1)	$0.5	$4.3	340	41
12	West	Interface	500	($12.4)	($16.6)	($0.0)	$4.1	($0.1)	($0.1)	($0.0)	$0.0	$4.1	504	87
13	Wylie Ridge	Transformer	AP	($7.9)	($10.9)	($0.0)	$3.0	($0.8)	($1.5)	$0.0	$0.8	$3.8	354	335
14	Doubs	Transformer	AP	($7.5)	($11.8)	($0.0)	$4.3	($0.7)	$0.1	$0.0	($0.7)	$3.6	429	246
15	Cloverdale - Lexington	Line	AEP	($5.1)	($9.0)	($0.0)	$3.9	($0.5)	($0.1)	$0.0	($0.3)	$3.5	1,019	434
20	Cherry Valley	Transformer	ComEd	$0.4	($2.4)	$0.0	$2.8	$0.0	$0.0	$0.0	($0.0)	$2.8	25	6
23	Waterman - West Dekalb	Line	ComEd	($0.6)	($2.4)	$0.0	$1.9	$0.3	($0.1)	($0.0)	$0.3	$2.2	1,499	57
24	Wilton Center - Pontiac	Line	ComEd	$1.6	$0.4	$0.0	$1.3	$0.1	$0.7	$0.0	($0.6)	$0.7	205	55
29	Quad Cities - Cordova	Line	ComEd	$0.2	($1.0)	$0.0	$1.3	($0.0)	$0.1	$0.0	($0.1)	$1.2	115	15
30	Burnham - Munster	Line	ComEd	($2.1)	($3.4)	($0.0)	$1.3	($0.0)	$0.0	($0.0)	($0.1)	$1.2	140	15

DAY Control Zone

Table 7-49 DAY Control Zone top congestion cost impacts (By facility): Calendar year 2010

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	5004/5005 Interface	Interface	500	($1.7)	($3.2)	($0.2)	$1.2	$0.3	$0.1	$0.4	$0.6	$1.8	1,644	605
2	AP South	Interface	500	($5.5)	($7.6)	($1.0)	$1.0	$0.1	$0.3	$0.7	$0.5	$1.5	4,645	1,528
3	AEP-DOM	Interface	500	($1.0)	($2.0)	($0.0)	$1.0	$0.0	($0.1)	($0.0)	$0.2	$1.1	691	187
4	Crete - St Johns Tap	Flowgate	Midwest ISO	$0.6	$1.1	($0.5)	($1.0)	($0.1)	$0.1	$0.1	($0.0)	($1.1)	2,066	823
5	Cloverdale - Lexington	Line	AEP	($0.5)	($1.5)	($0.2)	$0.7	$0.1	($0.0)	$0.2	$0.3	$1.0	1,127	684
6	Pleasant Prairie - Zion	Flowgate	Midwest ISO	$0.0	($0.0)	$0.5	$0.5	($0.0)	$0.0	($1.4)	($1.4)	($0.9)	1,321	404
7	Mount Storm - Pruntytown	Line	AP	($0.4)	($0.5)	($0.0)	$0.1	$0.2	$0.3	$0.7	$0.6	$0.7	571	574
8	Branchburg - Flagtown	Line	PSEG	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.6)	($0.6)	($0.6)	0	0
9	Tiltonsville - Windsor	Line	AP	($0.7)	($1.1)	($0.3)	$0.1	$0.1	($0.0)	$0.4	$0.5	$0.6	2,723	506
10	Doubs	Transformer	AP	($0.9)	($1.4)	($0.1)	$0.4	$0.1	$0.1	$0.1	$0.1	$0.5	920	525
11	Bedington - Black Oak	Interface	500	($1.8)	($2.7)	($0.4)	$0.5	$0.0	$0.2	$0.1	($0.1)	$0.5	2,291	212
12	Harrison - Pruntytown	Line	500	($0.1)	($0.2)	($0.0)	$0.0	$0.1	$0.1	$0.4	$0.4	$0.5	231	224
13	Waterman - West Dekalb	Line	ComEd	$0.0	$0.0	$0.5	$0.5	$0.0	$0.0	($0.1)	($0.1)	$0.4	3,002	343
14	Pleasant Valley - Belvidere	Line	ComEd	$0.0	$0.0	$0.8	$0.8	($0.0)	$0.0	($1.2)	($1.2)	($0.4)	2,553	467
15	Clover	Transformer	Dominion	($0.2)	($0.5)	$0.1	$0.3	$0.0	($0.0)	($0.1)	$0.0	$0.3	514	259
162	Hutchings - Sugarcreek	Line	DAY	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	$0.0	($0.0)	($0.0)	0	1
621	Greene - Clark	Line	DAY	($0.0)	($0.0)	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	($0.0)	1	0

Table 7-50 DAY Control Zone top congestion cost impacts (By facility): Calendar year 2009

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	Kammer	Transformer	500	($1.9)	($4.5)	($0.1)	$2.6	$0.4	($0.1)	$0.0	$0.5	$3.1	3,674	1,328
2	AP South	Interface	500	($2.6)	($3.9)	($0.0)	$1.3	$0.0	$0.3	($0.0)	($0.3)	$1.0	3,549	604
3	Dunes Acres - Michigan City	Flowgate	Midwest ISO	$0.4	$1.0	($0.5)	($1.1)	($0.0)	($0.0)	$0.1	$0.2	($0.9)	2,949	910
4	Doubs	Transformer	AP	($0.4)	($1.3)	$0.0	$0.9	$0.0	$0.1	$0.0	($0.1)	$0.8	429	246
5	West	Interface	500	($0.9)	($1.5)	($0.0)	$0.7	$0.0	$0.0	$0.0	($0.0)	$0.7	504	87
6	Cloverdale - Lexington	Line	AEP	($0.3)	($0.9)	$0.0	$0.6	$0.0	$0.1	$0.0	($0.1)	$0.6	1,019	434
7	Wylie Ridge	Transformer	AP	($0.6)	($1.1)	($0.0)	$0.5	$0.2	$0.2	$0.0	($0.0)	$0.4	354	335
8	Tiltonsville - Windsor	Line	AP	($0.3)	($0.8)	($0.0)	$0.5	$0.0	$0.1	$0.0	($0.1)	$0.4	2,070	311
9	5004/5005 Interface	Interface	500	($0.8)	($1.2)	($0.0)	$0.4	$0.1	$0.1	$0.0	($0.0)	$0.4	776	294
10	East Frankfort - Crete	Line	ComEd	$0.2	$0.5	$0.0	($0.3)	($0.0)	($0.0)	($0.0)	$0.0	($0.3)	2,163	605
11	Marquis - Waverly	Line	AEP	$0.0	($0.3)	($0.0)	$0.3	($0.0)	$0.0	$0.0	($0.0)	$0.2	74	14
12	Elrama - Mitchell	Line	AP	($0.1)	($0.3)	($0.0)	$0.2	$0.1	$0.0	$0.0	$0.1	$0.2	367	198
13	Sammis - Wylie Ridge	Line	AP	($0.3)	($0.5)	($0.0)	$0.2	$0.0	$0.1	($0.0)	($0.0)	$0.2	806	157
14	AEP-DOM	Interface	500	($0.2)	($0.3)	$0.0	$0.2	$0.0	($0.0)	$0.0	$0.0	$0.2	335	136
15	Pierce - Foster	Flowgate	Midwest ISO	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.1	($0.0)	($0.2)	($0.2)	0	5

DLCO Control Zone

Table 7-51 DLCO Control Zone top congestion cost impacts (By facility): Calendar year 2010

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	Crescent	Transformer	DLCO	$13.1	($0.7)	$0.3	$14.1	($0.1)	($0.4)	($0.3)	$0.1	$14.2	740	174
2	AP South	Interface	500	($41.7)	($49.3)	($0.3)	$7.2	($2.6)	($0.3)	$0.3	($2.0)	$5.2	4,645	1,528
3	Collier - Elwyn	Line	DLCO	$4.8	$0.1	$0.1	$4.9	($0.2)	($0.0)	($0.0)	($0.2)	$4.7	510	127
4	Elrama - Mitchell	Line	AP	($4.2)	($3.0)	($0.3)	($1.5)	($0.7)	$1.4	$0.3	($1.8)	($3.4)	581	357
5	Carson - Oakland	Line	DLCO	$3.0	($0.0)	$0.0	$3.0	$0.0	($0.0)	($0.0)	$0.0	$3.1	218	10
6	Bedington - Black Oak	Interface	500	($13.6)	($15.4)	($0.1)	$1.7	($0.4)	($0.0)	$0.0	($0.3)	$1.5	2,291	212
7	AEP-DOM	Interface	500	($5.8)	($7.5)	$0.0	$1.7	($0.3)	($0.1)	($0.0)	($0.3)	$1.4	691	187
8	Sammis - Wylie Ridge	Line	AP	($1.8)	($3.2)	($0.0)	$1.4	($0.1)	$0.2	$0.0	($0.2)	$1.2	524	60
9	East Frankfort - Crete	Line	ComEd	$1.6	$2.5	($0.0)	($0.8)	$0.1	($0.1)	($0.0)	$0.2	($0.7)	3,084	850
10	5004/5005 Interface	Interface	500	($13.3)	($15.1)	($0.1)	$1.8	($1.3)	($0.1)	$0.1	($1.1)	$0.6	1,644	605
11	Crete - St Johns Tap	Flowgate	Midwest ISO	$2.1	$3.0	($0.0)	($0.9)	$0.3	($0.0)	$0.0	$0.3	($0.6)	2,066	823
12	Cloverdale - Lexington	Line	AEP	($1.4)	($2.1)	$0.0	$0.7	($0.2)	($0.0)	($0.0)	($0.2)	$0.5	1,127	684
13	Arsenal - Highland	Line	DLCO	$0.5	($0.0)	$0.0	$0.5	($0.0)	$0.0	($0.0)	($0.0)	$0.5	48	7
14	Yukon	Transformer	AP	$0.5	$0.2	$0.0	$0.3	$0.1	($0.1)	($0.0)	$0.1	$0.4	195	38
15	Erie West	Transformer	PENELEC	($2.3)	($3.0)	($0.1)	$0.6	($0.3)	($0.0)	$0.0	($0.2)	$0.4	680	175
16	Arsenal - Oakland	Line	DLCO	$0.1	($0.1)	$0.0	$0.3	($0.3)	$0.3	($0.0)	($0.6)	($0.4)	89	54
18	Collier	Transformer	DLCO	$0.3	$0.0	$0.0	$0.3	$0.0	($0.1)	($0.0)	$0.1	$0.4	8	8
19	Beaver - Mansfield	Line	DLCO	($0.1)	($0.4)	($0.0)	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	175	0
27	Crescent - Sewickly	Line	DLCO	$0.2	$0.0	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	12	0
29	Cheswick - Logan's Ferry	Line	DLCO	($0.0)	($0.1)	($0.0)	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	35	0

Table 7-52 DLCO Control Zone top congestion cost impacts (By facility): Calendar year 2009

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	AP South	Interface	500	($15.3)	($21.2)	($0.1)	$5.8	($0.8)	$0.4	$0.1	($1.1)	$4.7	3,549	604
2	Sammis - Wylie Ridge	Line	AP	($5.2)	($10.0)	($0.0)	$4.7	($0.2)	$0.6	$0.0	($0.7)	$4.0	806	157
3	Elrama - Mitchell	Line	AP	($3.1)	($2.0)	($0.0)	($1.1)	($0.2)	$0.9	$0.0	($1.1)	($2.2)	367	198
4	West	Interface	500	($4.3)	($6.0)	($0.0)	$1.8	($0.1)	$0.0	$0.0	($0.1)	$1.6	504	87
5	Logans Ferry - Universal	Line	DLCO	$0.2	($1.3)	$0.0	$1.5	$0.0	$0.1	($0.0)	($0.1)	$1.4	395	156
6	Collier	Transformer	DLCO	$1.4	$0.3	$0.0	$1.2	$0.0	$0.0	$0.0	$0.0	$1.2	46	0
7	Wylie Ridge	Transformer	AP	($8.5)	($12.9)	($0.0)	$4.4	($1.2)	$2.2	$0.0	($3.3)	$1.1	354	335
8	Kammer	Transformer	500	($3.6)	($4.8)	$0.0	$1.3	($0.4)	($0.1)	($0.0)	($0.4)	$0.9	3,674	1,328
9	Dunes Acres - Michigan City	Flowgate	Midwest ISO	$1.7	$2.6	($0.0)	($0.9)	$0.2	$0.1	($0.0)	$0.1	($0.8)	2,949	910
10	Krendale - Seneca	Line	AP	($1.7)	($2.3)	($0.0)	$0.7	$0.0	$0.0	$0.0	$0.0	$0.7	353	0
11	Doubs	Transformer	AP	($1.9)	($1.4)	($0.0)	($0.5)	($0.1)	$0.0	$0.0	($0.2)	($0.7)	429	246
12	Mount Storm - Pruntytown	Line	AP	($1.9)	($2.8)	($0.0)	$0.9	($0.2)	$0.1	$0.0	($0.3)	$0.6	525	132
13	Kammer - West Bellaire	Line	AP	$1.2	$1.0	$0.0	$0.3	$0.2	($0.1)	($0.0)	$0.3	$0.6	227	54
14	Bedington - Black Oak	Interface	500	($1.8)	($2.4)	($0.0)	$0.6	($0.0)	$0.0	$0.0	($0.1)	$0.5	669	73
15	5004/5005 Interface	Interface	500	($4.8)	($6.1)	($0.0)	$1.3	($0.4)	$0.5	$0.0	($0.9)	$0.4	776	294
19	Collier - Elwyn	Line	DLCO	$0.3	$0.0	$0.0	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	30	0
20	Beaver - Clinton	Line	DLCO	$0.1	($0.2)	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	20	0
25	Cheswick - Logans Ferry	Line	DLCO	$0.0	($0.1)	$0.0	$0.1	($0.0)	($0.0)	($0.0)	$0.0	$0.1	49	3
26	Crescent	Transformer	DLCO	$0.1	$0.0	$0.0	$0.1	$0.2	$0.1	($0.0)	$0.0	$0.1	18	23
29	Cheswick - Evergreen	Line	DLCO	$0.0	($0.1)	$0.0	$0.1	$0.0	$0.0	$0.0	($0.0)	$0.1	35	5

Southern Region Congestion-Event Summaries

Dominion Control Zone

Table 7-53 Dominion Control Zone top congestion cost impacts (By facility): Calendar year 2010

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	AP South	Interface	500	$94.4	($48.7)	($1.0)	$142.1	$3.6	$8.6	$0.6	($4.4)	$137.7	4,645	1,528
2	Cloverdale - Lexington	Line	AEP	$18.2	$5.2	$2.1	$15.2	($1.8)	($2.5)	($2.7)	($2.0)	$13.1	1,127	684
3	Doubs	Transformer	AP	($0.9)	($12.3)	($0.1)	$11.2	$1.4	$0.5	$0.7	$1.6	$12.8	920	525
4	Bedington - Black Oak	Interface	500	$30.0	$19.8	$4.0	$14.3	($0.7)	$0.0	($1.6)	($2.3)	$12.0	2,291	212
5	Clover	Transformer	Dominion	$6.2	($2.4)	$1.6	$10.3	($0.3)	$0.3	($1.8)	($2.5)	$7.7	514	259
6	Pleasant View	Transformer	Dominion	$0.3	$0.0	$0.0	$0.3	($4.2)	$1.4	($0.6)	($6.2)	($6.0)	31	101
7	AEP-DOM	Interface	500	$19.3	$14.6	$1.3	$6.0	($0.0)	$0.2	($0.2)	($0.4)	$5.5	691	187
8	Millville - Sleepy Hollow	Line	Dominion	$1.2	($4.1)	($0.2)	$5.2	$0.0	$0.0	$0.0	$0.0	$5.2	401	0
9	Pleasantville - Ashburn	Line	Dominion	$6.7	$0.1	($0.2)	$6.4	($1.0)	$0.2	($0.1)	($1.3)	$5.0	94	35
10	Dooms	Transformer	Dominion	$4.1	($0.6)	($0.0)	$4.7	($0.6)	($0.9)	$0.1	$0.4	$5.0	107	31
11	Ox - Francona	Line	Dominion	$3.3	($0.6)	$0.0	$3.9	$0.0	$0.0	$0.0	$0.0	$3.9	66	0
12	Dickerson - Pleasant View	Line	Pepco	$3.9	$0.6	$0.1	$3.4	($0.1)	($0.3)	($0.2)	$0.0	$3.4	185	97
13	Ox - Glebe	Line	Dominion	$2.5	($0.7)	$0.0	$3.2	$0.0	$0.0	$0.0	$0.0	$3.2	30	0
14	East Frankfort - Crete	Line	ComEd	$5.7	$2.8	$0.2	$3.1	($0.2)	($0.5)	($0.2)	$0.1	$3.2	3,084	850
15	Millville - Old Chapel	Line	AP	$0.3	($3.0)	($0.4)	$3.0	($0.2)	$1.5	$1.7	$0.1	$3.0	210	303
17	Chuckatuck - Benns Church	Line	Dominion	$2.5	($0.2)	$0.0	$2.7	$0.0	$0.0	$0.0	$0.0	$2.7	76	0
19	Millville - Old Chapel	Line	Dominion	($0.5)	($3.4)	($0.5)	$2.4	$0.0	$0.0	$0.0	$0.0	$2.4	269	0
21	Endless Caverns	Transformer	Dominion	$0.8	($1.2)	$0.0	$2.0	($0.0)	($0.0)	$0.0	$0.0	$2.0	541	3
22	Chesapeake - Reeves Ave.	Line	Dominion	$0.2	($1.8)	$0.0	$2.0	($0.0)	$0.0	$0.0	($0.0)	$2.0	178	49
25	Greenwich - Elizabeth River	Line	Dominion	$1.6	($0.2)	$0.0	$1.8	$0.1	$0.0	($0.0)	$0.0	$1.8	32	22

Table 7-54 Dominion Control Zone top congestion cost impacts (By facility): Calendar year 2009

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	AP South	Interface	500	$37.3	($31.2)	($0.3)	$68.2	$1.6	$1.2	$0.4	$0.8	$69.0	3,549	604
2	Doubs	Transformer	AP	$0.4	($5.5)	$0.0	$5.8	$0.3	$0.1	$0.1	$0.3	$6.1	429	246
3	Cloverdale - Lexington	Line	AEP	$7.0	$2.7	$1.1	$5.4	($0.0)	($1.8)	($1.4)	$0.4	$5.8	1,019	434
4	Kammer	Transformer	500	$10.3	$8.3	$2.1	$4.2	($0.0)	($0.8)	($2.0)	($1.2)	$3.0	3,674	1,328
5	Dunes Acres - Michigan City	Flowgate	Midwest ISO	$4.4	$2.1	$0.1	$2.4	($0.2)	($0.6)	($0.1)	$0.3	$2.7	2,949	910
6	Bedington - Black Oak	Interface	500	$4.3	$2.5	$0.7	$2.6	($0.1)	($0.1)	($0.2)	($0.1)	$2.4	669	73
7	Beechwood - Kerr Dam	Line	Dominion	$1.5	($0.8)	($0.1)	$2.3	($0.2)	$0.1	$0.1	($0.2)	$2.1	665	234
8	Bristers - Ox	Line	Dominion	($0.1)	($1.9)	$0.0	$1.8	$0.1	$0.4	$0.0	($0.2)	$1.6	63	42
9	Chuckatuck - Benns Church	Line	Dominion	$1.5	($0.0)	$0.0	$1.6	$0.0	$0.0	$0.0	$0.0	$1.6	45	0
10	AEP-DOM	Interface	500	$1.7	$1.1	$0.1	$0.7	($0.2)	($0.7)	($0.1)	$0.3	$1.1	335	136
11	East Frankfort - Crete	Line	ComEd	$1.9	$1.0	$0.1	$1.1	($0.1)	($0.2)	($0.1)	$0.0	$1.1	2,163	605
12	West	Interface	500	($2.6)	($3.6)	$0.0	$1.0	$0.1	$0.2	$0.1	$0.0	$1.0	504	87
13	Wylie Ridge	Transformer	AP	$2.5	$1.7	$0.4	$1.2	($0.1)	($0.2)	($0.4)	($0.2)	$1.0	354	335
14	Ox	Transformer	Dominion	$0.8	($0.1)	$0.0	$1.0	$0.0	$0.0	$0.0	$0.0	$1.0	8	0
15	Crete - St Johns Tap	Flowgate	Midwest ISO	$1.6	$0.8	$0.2	$0.9	($0.1)	($0.3)	($0.2)	$0.0	$0.9	1,571	306
17	Crozet - Dooms	Line	Dominion	$0.7	($0.3)	$0.0	$1.0	($0.3)	($0.2)	($0.0)	($0.1)	$0.9	55	37
20	Beaumeade - Ashburn	Line	Dominion	$0.8	$0.0	$0.0	$0.8	$0.0	$0.0	$0.0	$0.0	$0.8	25	0
21	Chickahominy - Lanexa	Line	Dominion	$0.5	($0.0)	$0.0	$0.6	($0.1)	($0.3)	$0.0	$0.1	$0.7	42	19
22	Clover - Farmville	Line	Dominion	($0.0)	($0.7)	$0.0	$0.7	$0.0	$0.0	$0.0	$0.0	$0.7	41	0
23	Crozet - Barracks Rd	Line	Dominion	$0.8	$0.3	($0.0)	$0.4	$0.1	($0.1)	$0.0	$0.2	$0.6	47	11

Generation and Transmission Interconnection Planning Process

Participation in the PJM Capacity Market requires procurement of capacity interconnection rights. These rights persist during the unit's lifetime, and expire one year after a unit is retired.

Any entity (developer or applicant) that requests interconnection of a generating facility, including increases to the capacity of an existing generating unit, or requests interconnection of a merchant transmission facility, must follow the PJM interconnection process.[26] With the assumption that a facilities study is not required, and accounting for the time required by PJM to complete the required studies, it takes approximately ten months from the initial request for interconnection to the point where the applicant can begin to negotiate an Interconnection Service Agreement. Upon execution of the Interconnection Service Agreement, the parties can then develop an Interconnection Construction Service Agreement, which is used to develop an agreed upon schedule of work for construction (Table 7-55).

26 The material in this section is based on PJM Manual M-14A: Generation and Transmission Interconnection Process. "M-14A: Generation and Transmission Interconnection Process", Revision 8 (May 1, 2009).

Table 7-55 Generation and transmission interconnection timeline

Process Step	Start on	Complete by	Days to complete	Days to decide whether to continue
Feasibility Study	January 31	April 30	90	30
	April 30	July 31		
	October 31	October 31		
	January 31	January 31		
System Impact Study	January 31	June 01	120	30
	April 30	September 01		
	July 31	December 01		
	October 31	March 01		
Facilities Study	Upon acceptance of the Facilities Study Agreement	Varies	Varies	60
Interconnection Service Agreement	Upon acceptance of an Interconnection Service Agreement	Varies	Varies	60
Interconnection Construction Service Agreement	Upon acceptance of Interconnection Construction Service Agreement	Varies	Varies	NA

Initiating the Planning Process

To initiate the interconnection planning process, a developer must submit a Feasibility Study Agreement to PJM for execution along with required information about the project and the appropriate fees.[27] The applicant is obligated to pay the actual costs of studies conducted by PJM on its behalf. The feasibility study fees depend on when the request is submitted and the size of the interconnection request but the initial deposit cannot exceed $100,000. Resources that are 20 MW or less, or qualify as small resources, can often use an expedited queue process, under which a small resource can receive interim Capacity Interconnection Rights if a queue project is ready to be put in service ahead of other queued projects.

Feasibility Study

A developer is required to elect capacity resource status or energy only resource status. Capacity resource status allows the generator to meet capacity obligations through RPM, while energy resource status allows the unit to participate in the energy market only. In order to qualify as a capacity resource, sufficient transmission capability must exist to ensure the deliverability of the generator output to network load and to satisfy the reliability requirements of the NERC region in which the generator is located.[28]

27 The Feasibility Study Agreements are identified as Attachment N of the PJM Open Access Transmission Tariff (OATT) for generation interconnection requests and Attachment S of the PJM OATT for merchant transmission interconnection requests.

28 The PJM footprint includes all or part of Reliability*First* and the SERC Reliability Corporation (SERC) NERC regions.

Feasibility studies are performed four times each year. The feasibility studies are performed by PJM staff, with input by the affected Transmission Owners (TO), who provide verification of PJM results. The TOs also provide preliminary cost estimates for the project. The feasibility study is limited to short-circuit studies and load-flow analysis of probable contingencies, and does not include a stability analysis. In general, the feasibility study will be completed within 90 days.

System Impact Study

If the developer decides to proceed with the System Impact Study, they must pay the transmission provider a deposit (Table 7-56).[29]

Table 7-56 Impact Study Agreement deposit requirements

Project Size	Non-Refundable Deposit	Non-Refundable Cost per MW	Refundable Cost per MW	Maximum Deposit
<= 2MW	$5,000	$0	$0	NA
> 2 MW, <= 20 MW	$10,000	$0	$0	NA
> 20 MW, <= 100 MW	$0	$500	$0	NA
> 100 MW	$50,000	$0	$300	$300,000

The System Impact Study is a comprehensive regional analysis of the impact of adding the new generation or transmission facility to the system including the impact on deliverability to PJM load in the region where the generator or transmission facility is located. The System Impact Study identifies the system constraints relating to the new project and the necessary attachment facilities, local upgrades and network upgrades required to maintain reliability and deliverability in the region. The System Impact Studies are performed by PJM staff, with input by the affected TOs, who provide verification of PJM results. The TOs also provide more comprehensive cost estimates for the project than provided with the feasibility studies. System Impact Studies are performed four times each year.

The System Impact Study considers relationships among the new generator or transmission facility, other planned generators in the queue, and the existing system. The System Impact Study includes projects that were in the queue ahead of the project being studied. The Study attempts to model each project in the queue to appropriately identify the dependencies among the projects.

Facilities Study

If the developer decides to proceed with a Facilities Study, the applicant must submit a required refundable deposit in the amount of $100,000 or the estimated amount of its Facilities Study cost responsibility for the first three months of work on the study, whichever is greater. If the developer requests a Facilities Study, the results of the System Impact Study are incorporated in the Regional Transmission Expansion Plan (RTEP) Process.

29 See PJM. "PJM Open Access Transmission Tariff", Third Revised Sheet No. 224N (Effective April 27, 2009) Section VI.204.3A.

The Facilities Study provides an estimate of the cost to the applicant for attachment facilities, local upgrades and network upgrades necessary to accommodate the project, and an estimate of the time required to complete the design and construction of the facilities and upgrades. The Facilities Studies are performed by the affected TOs. The TOs also provide more accurate cost estimates for the project than provided with feasibility studies and system impact studies. The time to complete a Facilities Study varies depending on the elements under study.

Interconnection Service Agreement

If the developer decides to proceed with an Interconnection Service Agreement, they must provide PJM with a letter of credit or other acceptable form of security in the amount equal to the estimated costs of new facilities or upgrades for which the applicant is responsible. The applicant must also demonstrate: completion of a fuel deliverability agreement and water agreement (if necessary); control of any necessary rights-of-way for fuel and water interconnections (if necessary); acquisition of any necessary local, county and state site permits; and a signed memorandum of understanding for the acquisition of major equipment. PJM may also request milestone dates for permitting, regulatory certifications, or third party financial arrangements.

Interconnection Construction Service Agreement

Once an Interconnection Service Agreement is executed, PJM is required to tender an Interconnection Construction Service Agreement among the applicant, PJM and the affected Interconnection Transmission Owner(s) within 45 days. The applicant then has 60 days to execute the Interconnection Construction Service Agreement. If the Transmission Owner and the developer cannot agree upon the terms of the Interconnection Construction Service Agreement, dispute resolution may be requested, and the customer has the option to design and install all or any portion of the Transmission Owner Interconnection Facilities under the "Option to Build" clause.[30]

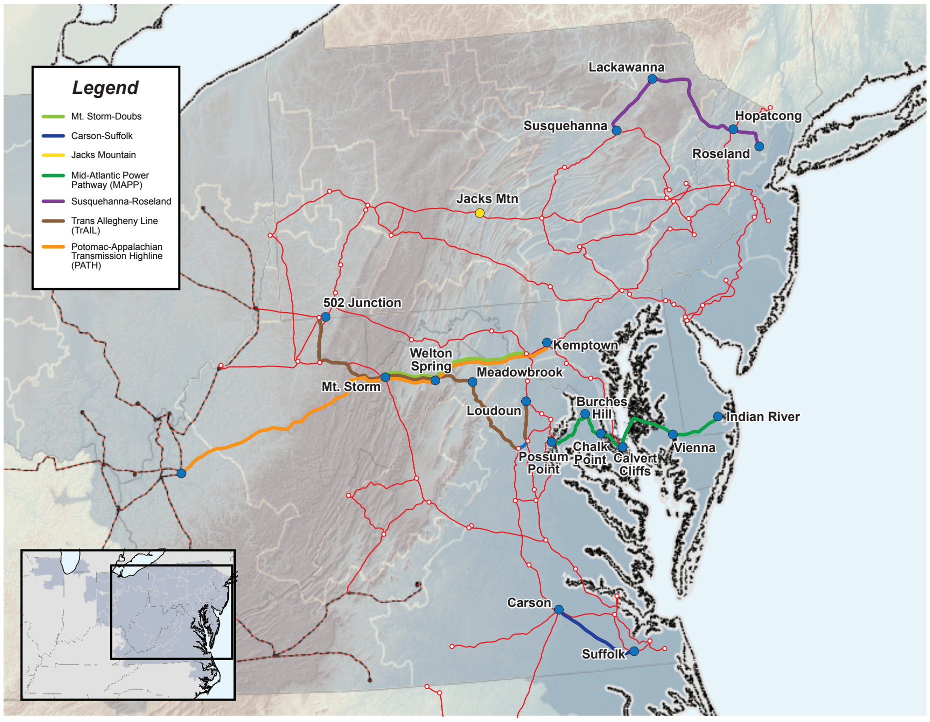
Key Backbone Facilities

PJM baseline projects are implemented to resolve reliability criteria violations. PJM backbone projects are a subset of significant baseline upgrades. The backbone upgrades are typically intended to resolve a wide range of reliability criteria violations and congestion issues and have substantial impacts on energy and capacity markets. The current backbone projects are: Mount Storm – Doubs; Carson – Suffolk; Jacks Mountain; Mid-Atlantic Power Pathway (MAPP); Potomac – Appalachian Transmission Highline (PATH); Susquehanna – Roseland; and the Trans Allegheny Line (TrAIL) (Figure 7-1). The total planned costs for all of these projects are $6,048.4 million.[31]

30 See PJM. "PJM Open Access Transmission Tariff", Sixth Revised Sheet No. 224CC (Effective March 1, 2007) Section VI.212.6.

31 Total estimated cost calculated from the backbone project cost estimates found in the "Construction Status Database" located at <http://www.pjm.com/planning/rtep-upgrades-status/backbone-status.aspx>.

Figure 7-1 Map of Backbone Projects[32]



Mount Storm – Doubs

The Mount Storm – Doubs transmission line includes 65.7 miles in West Virginia, 30.7 miles in Virginia and 2.8 miles in Maryland. Under this project, the existing transmission towers will be replaced, resulting in an increase in capacity of about 60 percent. The construction will occur within the existing right-of-way. The required in-service date for this project is June 2020. Engineering estimates are currently being developed.[33]

Carson – Suffolk

The Carson – Suffolk 500 kV project, located in southeastern Virginia, will result in the installation of a new 500/230 kV #2 transformer at Suffolk, and a new 230 kV line from Suffolk to the Thrasher substation. The required in-service date for this project is June 1, 2011. Nearly all of the right-of-way requirements have been acquired and all of the rights of entry have been secured. The line foundation design, the line structure and conductor design, and the substation designs at all the Carson, Suffolk and Thrasher buses have been completed. All contracts have been executed for line construction, tree trimming and materials. The Suffolk transformer delivery is scheduled for February 2011.[34]

32 Source: PJM © 2011. All rights reserved.
33 See pjm.com. <http://www.pjm.com/planning/rtep-upgrades-status/backbone-status/mount-storm-doubs.aspx>.
34 See pjm.com. <http://www.pjm.com/planning/rtep-upgrades-status/backbone-status/carson-suffolk.aspx>.

Jacks Mountain

The Jacks Mountain project includes a new 500 kV substation at Jacks Mountain and 1,000 MVARs of capacitors. The project requires the replacement of a wave trap (a device used to divert communication signals sent on the transmission line from the remote substation to the telecommunications/protection panel in the substation control room) and an upgrade of a section at the Keystone 500 kV bus, the replacement of two wave traps at the Juniata 500 kV bus as well as relay changes at the Juniata 500 kV substation. This project has been deemed necessary to resolve voltage problems for load deliverability reliability criteria violations starting on June 1, 2013, and is required to be in service by that date.

Currently, all land required for this project has been procured. The transmission line engineering design is in process, and the detailed substation engineering design is expected to be completed in the summer of 2011. The procurement of transmission line hardware and substation equipment has been delayed until the middle of 2011, for delivery in 2012. The 500 kV breakers have been ordered, and are scheduled for delivery in October 2012 and January 2013. The necessary 500 kV capacitor banks are also on order, with a scheduled delivery of January 2013. The 500 kV disconnect switches are on order, with a scheduled delivery of October 2012.[35]

Mid-Atlantic Power Pathway (MAPP)

The MAPP transmission project will serve the District of Columbia, Maryland and Delaware. This project will consist of approximately 69 miles of alternating current lines and 83 miles of direct current lines. The majority of this line will be built on, or adjacent to, existing transmission lines. The project requires a new 500 kV transmission line from the Possum Point to the Calvert Cliffs substations, and two 500 kV High Voltage Direct Current (HVDC) circuits from a new substation in Calvert Cliffs, MD, to a new substation in Wicomico County, MD and to a new substation in Sussex County, DE. Included in these circuits is a submarine cable crossing of the Chesapeake Bay.[36]

The Mid-Atlantic Power Pathway (MAPP) project is required to resolve reliability criteria violations starting June 1, 2014. While the current required in-service date is June 1, 2014, PJM is in the process of considering new information, including fuel cost estimates, emissions costs, future generation scenarios, load forecast updates and demand response projections, and will be reviewing the need date as part of the 2010 Regional Transmission Expansion Plan (RTEP). The results of this analysis will be presented to the PJM Transmission Expansion Advisory Committee (TEAC) and the PJM Board of Managers in the first quarter of 2011.

Currently, the majority of the necessary right-of-way is under contract. The Possum Point to Calvert Cliffs line will follow existing right-of-way as will the section from Vienna to Indian River. The engineering design for the Possum Point to Calvert Cliffs section is completed, and the design for the Calvert Cliffs to Indian River section is ongoing. Proposals for the direct current system have been received from bidders and are currently being evaluated.[37]

35 See pjm.com. <http://www.pjm.com/planning/rtep-upgrades-status/backbone-status/jacks-mountain.aspx>.

36 See webapps.powerpathways.com. “MAPP_Overview” (November 8, 2010) (Accessed February 27, 2011) <http://webapps.powerpathway.com/file_depot/0-10000000/0-10000/41/folder/66/MAPP_Overview.pdf>. (385 KB)

37 See pjm.com <http://www.pjm.com/planning/rtep-upgrades-status/backbone-status/mapp.aspx>.

Potomac – Appalachian Transmission Highline (PATH)

The Potomac - Appalachian Transmission Highline (PATH) project is required to resolve reliability criteria violations. The PATH project consists of a 765 kV transmission line extending approximately 275 miles from the Amos Substation, which is located in southwestern West Virginia, to the proposed Kemptown (765/500 kV) Substation, located in central Virginia. The project also includes a new Welton Spring (765/500 kV) Substation.

Currently, right-of-way issues are being discussed in West Virginia, Virginia and Maryland. The property for the Welton Spring and Kemptown substations has been acquired. The preliminary engineering design work, as well as the preliminary procurement activities, is in progress. Construction will be scheduled to begin following receipt of state commission approvals to construct. The required in-service date for the PATH line is June 1, 2015.[38]

Susquehanna – Roseland (S-R)

The Susquehanna - Roseland project is a new 500 kV transmission line from Susquehanna, located in central eastern Pennsylvania, to Roseland, located in north central New Jersey, which is required to resolve reliability criteria violations starting on June 1, 2012. The project will require an upgrade of seven 230 kV and one 500 kV substations, as well as three new 500 kV substations, two with a 500/230 kV transformers.

Currently, construction and right-of-way permit applications have been submitted with the National Park Service (NPS). A decision on the applications is not expected from the NPS until October of 2012. Additionally, the issuance of a New Jersey Department of Environmental Protection (NJDEP) Wetland and Flood Hazard Area Permit has also been delayed. While PJM has required an in-service date of June 1, 2012, construction of the project has been delayed as a result. The expected in-service date for the Roseland to Hopatcong portion is June 2014, with the remainder of the project to be completed by June 2015.[39]

Trans Allegheny Line (TrAIL)

The Trans Allegheny Line (TrAIL) project is necessary to meet growing demand in the Mid-Atlantic region and is required to resolve reliability criteria violations starting June 1, 2011. The project will include a new 500 kV transmission line extending from 502 Junction to Loudoun substation, and will include: a 76.8 mile segment from the 502 Junction bus to the Mt. Storm bus; a 60.1 mile segment from the Mt. Storm bus to the Meadowbrook bus; and an 80.8 mile segment from the Meadowbrook bus to the Loudoun bus.

The in-service dates for the three segments of the TrAIL project are: Meadowbrook to Loudoun on April 8, 2011; Meadowbrook to Mt. Storm on May 13, 2011 and Mt. Storm to 502 Junction on May 20, 2011. With the exception of a small portion of the new Mt. Storm to 502 Junction, all right-of-way

38 See pjm.com. <http://www.pjm.com/planning/rtep-upgrades-status/backbone-status/path.aspx>.
39 See pjm.com. <http://www.pjm.com/planning/rtep-upgrades-status/backbone-status/susquehanna-roseland.aspx>.

has been secured. The engineering and design of project is complete, with the exception of the on-going detailed protection and controls engineering designs. All equipment has been procured for transmission line work, and the substation materials are on order. Construction is in progress on all segments of the new transmission line.[40]

Economic Planning Process

Transmission system investments can be evaluated on a reliability basis or on an economic basis. The reliability evaluation examines whether a transmission upgrade is required in order to maintain reliability on the system in a particular area or areas, using specific planning and reliability criteria.[41] The economic evaluation examines whether a transmission upgrade, including reliability upgrades, results in positive economic benefits. The economic evaluation is more complex than a reliability evaluation because there is more judgment involved in the choice of relevant metrics for both benefits and costs. PJM's responsibility as an RTO requires PJM to constantly evaluate the need for transmission investments related to reliability and to help ensure the construction of needed facilities. As the operator and designer of markets, PJM also needs to consider the appropriate role for the economic evaluation of transmission system investments.

As a general matter, transmission investments have not been fully incorporated into competitive markets. The construction of new transmission facilities can have significant impacts on energy and capacity markets, but there is no market mechanism in place that would require competition between transmission and generation to meet loads in an area. While the RPM construct does provide that qualifying transmission upgrades may be submitted as offers, there have been no such offers. More generally, network transmission is not built based directly on market signals because the owners of network transmission are compensated through a non-market mechanism. Although the PJM Tariff does not yet comprehensively address the issue of competition between transmission and generation projects to solve congestion problems, PJM has taken a first step towards integrating transmission investments into the market through the use of economic evaluation metrics. Economic evaluation metrics can be used to determine whether there are positive economic benefits associated with an investment in transmission that might warrant the investment even when it is not required for reliability.

In 2009, FERC approved an approach to the economic evaluation of transmission projects using defined cost-benefit test metrics including changes in production costs, the costs of complying with environmental regulations, generation availability and demand-response availability.[42,43]

PJM performs a market efficiency analysis to compare the costs and benefits of (i) accelerating reliability-based enhancements or expansions already included in the regional transmission plan that, if accelerated, also could relieve one or more economic constraints; (ii) modifying reliability-based enhancements or expansions already included in the regional transmission plan that, as modified, would relieve one or more economic constraints; (iii) new enhancements or expansions that could relieve one or more economic constraints, but for which no reliability-based need has

40 See pjm.com. <http://www.pjm.com/planning/rtep-upgrades-status/backbone-status/trail.aspx>.
41 See PJM OA Schedule 6.
42 PJM initial filing, and first, second and third compliance filings submitted in Docket No. ER06-1474, respectively, on September 8, 2006, March 21, 2007, October 9, 2007 and June 16, 2008.
43 126 FERC ¶ 61,152.

been identified.[44] These economic constraints include, but are not limited to, constraints that cause significant historical gross congestion, significant historical unhedgeable congestion, pro-ration of Stage 1B ARR requests or significant congestion as forecasted in the market efficiency analysis. The market efficiency analysis uses the Benefit/Cost Ratio, defined as the present value of the total annual project benefit for each of the first 15 years divided by the present value of the project cost for the first 15 years of the project. To be included in the RTEP, the benefit/cost ratio must be greater than or equal to 1.25.

In the event that the annual review shows changes in the costs and benefits of particular projects, PJM reviews the changes with the TEAC and recommends to the PJM Board whether the project continues to provide measurable benefits and should remain in the RTEP. This yearly evaluation includes changes in cost estimates of the economic-based enhancement or expansion and changes in system conditions such as load forecasts, anticipated merchant transmission facilities, generation and demand response.

This annual review process has the potential to create substantial uncertainty for those building transmission facilities and for all market participants affected by the changes to the transmission system that would result from the completion of these facilities. Significant transmission projects, like the backbone facilities, have substantial impacts on energy and capacity markets and thus on the economics of both generation and load. The locational supply and demand of energy are affected and thus locational energy prices are affected. Changes in expected energy prices determine expected revenues from the energy market and expected payments to the energy market. The locational supply and demand of capacity are affected and thus locational capacity prices are affected. Changes in expected capacity prices determine expected revenues from the capacity market and expected payments to the capacity market. The uncertainty about transmission projects affects decisions about whether to invest in new generation and whether to continue to invest in existing generation. The uncertainty about transmission projects affects decisions about where to locate new load and decisions about whether to invest in demand side resources.

The MMU recommends that PJM propose modifications to the transmission planning process that would limit significant changes in the status of major transmission projects after they have been approved, and thus limit the uncertainty imposed on markets by the use of evaluation criteria that are very sensitive to changes in forecasts of economic variables.

44 The process is defined in Section 1. 5.7 of the PJM Tariff. See PJM. "PJM Open Access Transmission Tariff" (September 17, 2010) (Accessed February 1, 2011) <http://www.pjm.com/documents/~/media/documents/agreements/tariff.ashx> (32,881 KB). Each year, the assumptions to be used in performing the market efficiency analysis are presented to the PJM Transmission Expansion Advisory Committee (TEAC) for review and comment and the PJM Board approves the assumptions in June of each year.