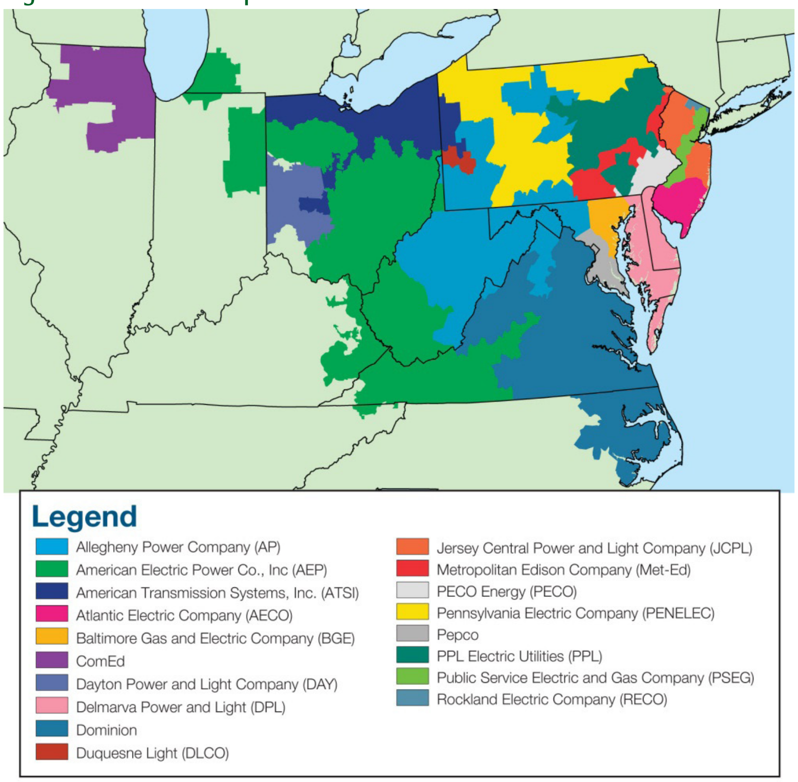
PJM Geography

During 2011, the PJM geographic footprint encompassed 18 control zones located in Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia.

Figure A-1 PJM's footprint and its 18 control zones[1,2]



Analysis of 2011 market results requires comparison to 2010 and certain other prior years. During calendar year 2011, PJM integrated the ATSI Control Zone. During calendar years 2006 through 2010 the PJM footprint was stable. During calendar years 2004 and 2005, PJM integrated five new control zones, three in 2004 and two in 2005. When making comparisons involving this period, the 2004, 2005 and 2006 state of the market reports referenced phases, each corresponding to market integration dates:[3]

- **Phase 1 (2004).** The four-month period from January 1, through April 30, 2004, during which PJM was comprised of the Mid-Atlantic Region, including its 11 zones,[4] and the Allegheny Power Company (AP) Control Zone.[5]
- **Phase 2 (2004).** The five-month period from May 1, through September 30, 2004, during which PJM was comprised of the Mid-Atlantic Region, including its 11 zones, the AP Control Zone and the ComEd Control Area.[6]
- **Phase 3 (2004).** The three-month period from October 1, through December 31, 2004, during which PJM was comprised of the Mid-Atlantic Region, including its 11 zones, the AP Control Zone and the ComEd Control Zone plus the American Electric Power Control Zone (AEP) and The Dayton Power & Light Company Control Zone (DAY). The ComEd Control Area became the ComEd Control Zone on October 1.
- **Phase 4 (2005).** The four-month period from January 1, through April 30, 2005, during which PJM was comprised of the Mid-Atlantic Region, including its 11 zones, the AP Control Zone, the ComEd Control Zone, the AEP Control Zone and the DAY Control Zone plus the Duquesne Light Company (DLCO) Control Zone which was integrated into PJM on January 1, 2005.
- **Phase 5 (2005 through 2011).** The period from May 1, 2005, through May 31, 2011, during which PJM was comprised of the Phase 4 elements plus the Dominion Control Zone which was integrated into PJM on May 1, 2005.
- **Phase 6 (2011).** The period from June 1, through December 31, 2011[7] during which PJM was comprised of the Phase 5 elements plus the ATSI

1 On June 1, 2011, the American Transmission Systems, Inc. (ATSI) Control Zone was integrated into PJM.

2 On January 1, 2012, the Duke Energy Ohio and Kentucky (DEOK) Control Zone was integrated into PJM. This report covers calendar year 2011, so this figure does not include results from the DEOK Control Zone.

3 See the *2004 State of the Market Report* (March 8, 2005) for more detailed descriptions of Phases 1, 2 and 3 and the *2005 State of the Market Report* (March 8, 2006) for more detailed descriptions of Phases 4 and 5.

4 The Mid-Atlantic Region is comprised of the AECO, BGE, DPL, JCPL, Met-Ed, PECO, PENELEC, Pepco, PPL, PSEG and RECO control zones.

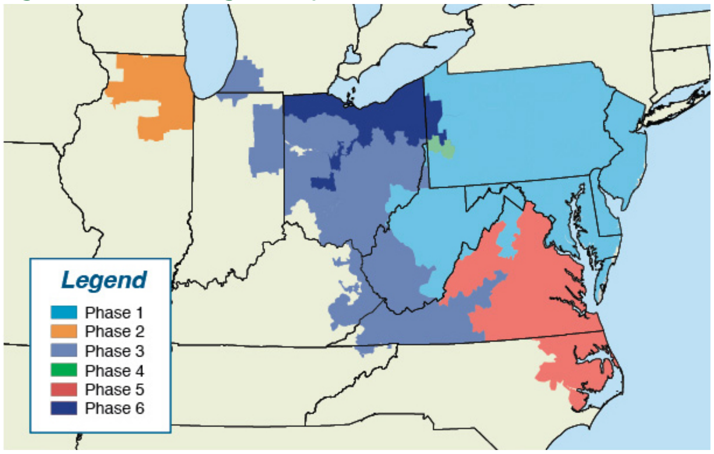
5 Zones, control zones and control areas are geographic areas that customarily bear the name of a large utility service provider operating within their boundaries. Names apply to the geographic area, not to any single company. The geographic areas did not change with the formalization of these concepts during PJM integrations. For simplicity, zones are referred to as control zones for all phases. The only exception is ComEd which is called the ComEd Control Area for Phase 2 only.

6 During the five-month period May 1, through September 30, 2004, the ComEd Control Zone (ComEd) was called the Northern Illinois Control Area (NICA).

7 On January 1, 2012, the Duke Energy Ohio and Kentucky (DEOK) Control Zone joined the PJM footprint. This report covers calendar year 2011, so it does not include results from the DEOK Control Zone.

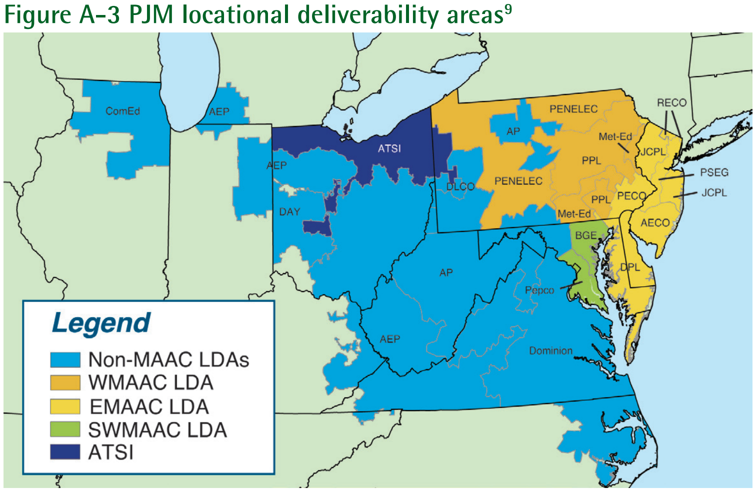
Control Zone which was integrated into PJM on June 1, 2011.

Figure A-2 PJM integration phases



A locational deliverability area (LDA)[8], defined as part of the RPM capacity market, is a Control Zone or part of a Control Zone within PJM with defined internal generation and defined transmission capability to import capacity in the RPM design.

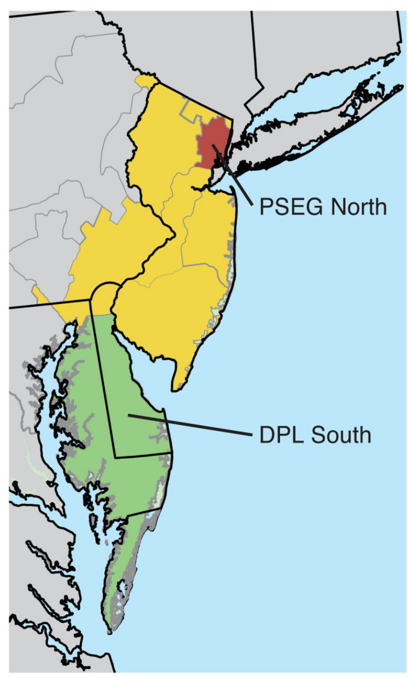
Figure A-3 PJM locational deliverability areas[9]



In PJM's Reliability Pricing Model (RPM) Auctions, an LDA becomes a separate market when it cannot meet its reliability requirements through a combination of economic merit order imports and internal generation without the purchase of out of merit capacity within the LDA. The regional transmission organization (RTO) market comprises the entire PJM footprint, unless an LDA is constrained. Each constrained LDA or group of LDAs is a separate market with a separate clearing price, and the RTO market is the balance of the footprint.

For the 2007/2008 and 2008/2009 Base Residual Auctions, the defined markets were RTO, EMAAC and SWMAAC. For the 2009/2010 Base Residual Auction, the defined markets were RTO, MAAC+APS and SWMAAC. The MAAC+APS LDA consists of the WMAAC, EMAAC, and SWMAAC LDAs, as shown in Figure A-3, plus the Allegheny Power System (APS or AP) Zone as shown in Figure A-1. For the 2010/2011 Base Residual Auction, the defined markets were RTO and DPL South. The DPL South LDA is shown in Figure A-4. For the 2011/2012 Base Residual Auction, the only defined market was RTO. For the 2012/2013 Base Residual Auction, the defined markets were RTO, MAAC, EMAAC, PSEG North, and DPL South. The PSEG North LDA is shown in Figure A-4. For the 2013/2014 Base Residual Auction, the defined markets were RTO, MAAC, EMAAC, and Pepco. For the 2014/2015 Base Residual Auction, the defined markets were RTO, MAAC, and PSEG North.

Figure A-4 PJM RPM EMAAC locational deliverability area, including PSEG North and DPL South



8 OATT Attachment DD § 2.38.
9 The ATSI Control Zone integration into PJM was effective beginning with the 2011/2012 delivery year. The ATSI Control Zone is considered a non-MAAC LDA.

PJM Market Milestones

Year	Month	Event
1996	April	FERC Order 888, "Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities"
1997	April	Energy Market with cost-based offers and market-clearing prices
	November	FERC approval of ISO status for PJM
1998	April	Cost-based Energy LMP Market
1999	January	Daily Capacity Market
	March	FERC approval of market-based rates for PJM
	March	Monthly and Multimonthly Capacity Market
	March	FERC approval of Market Monitoring Plan
	April	Offer-based Energy LMP Market
	April	FTR Market
2000	June	Regulation Market
	June	Day-Ahead Energy Market
	July	Customer Load-Reduction Pilot Program
2001	June	PJM Emergency and Economic Load-Response Programs
2002	April	Integration of AP Control Zone into PJM Western Region
	June	PJM Emergency and Economic Load-Response Programs
	December	Spinning Reserve Market
	December	FERC approval of RTO status for PJM
2003	May	Annual FTR Auction
2004	May	Integration of ComEd Control Area into PJM
	October	Integration of AEP Control Zone into PJM Western Region
	October	Integration of DAY Control Zone into PJM Western Region
2005	January	Integration of DLCO Control Zone into PJM
	May	Integration of Dominion Control Zone into PJM
2006	May	Balance of Planning Period FTR Auction
2007	April	First RPM Auction
	June	Marginal loss component in LMPs
2008	June	Day Ahead Scheduling Reserve (DASR) Market
	August	Independent, External MMU created as Monitoring Analytics, LLC
	October	Long Term FTR Auction
	December	Modified Operating Reserve Accounting Rules
	December	Three Pivotal Supplier Test in Regulation Market
2011	June	Integration of ATSI Control Zone into PJM

Energy Market

This appendix provides more detailed information about load, locational marginal prices (LMP) and offer-capped units.

Load

Frequency Distribution of Load

Table C-1 provides the frequency distributions of PJM accounting load by hour, for the calendar years 2007 to 2011.[1] The table shows the number of hours (frequency) and the percent of hours (cumulative percent) when the load was between 0 GWh and 20 GWh and then within a given 5-GWh load interval, or for the cumulative column, within the interval plus all the lower load intervals. The integrations of the AP Control Zone in 2002, the ComEd, AEP and DAY control zones in 2004, the DLCO and Dominion control zones in 2005 and the ATSI Control Zone in 2011 mean that annual comparisons of load frequency are significantly affected by PJM's geographic growth.[2]

Off-Peak and On-Peak Load

Table C-2 presents summary load statistics for 1998 to 2011 for the off-peak and on-peak hours, while Table C-3 shows the percent change in load on a year-to-year basis. The on-peak period is defined for each weekday (Monday to Friday) as the hour ending 0800 to the hour ending 2300 Eastern Prevailing Time (EPT), excluding North American Electric Reliability Council (NERC) holidays. Table C-2 shows that on-peak load was 22.2 percent higher than off-peak load in 2011. Average load during on-peak hours in 2011 was 3.8 percent higher than in 2010. Off-peak load in 2011 was 3.6 percent higher than in 2010 (Table C-3).

Locational Marginal Price (LMP)

In assessing changes in LMP over time, the Market Monitoring Unit (MMU) examines three measures: simple average LMP; load-weighted average LMP; and fuel-cost-adjusted, load-weighted average LMP. Differences in simple average LMP measure the change in reported price. (Simple average LMP will be referred to as average LMP.) Differences in load-weighted average LMP measure the change in reported price weighted by the actual hourly MWh load to reflect what customers actually pay for energy. Differences in fuel-cost-adjusted, load-weighted average LMP measure the change in reported price actually paid by load after accounting for the change in price that reflects changes in fuel prices.[3]

Any Load Serving Entity (LSE) may request to settle at a bus LMP or aggregate LMP per rules in PJM Manual 27. The zonal LMP includes every bus in the zone and is not affected by the choices of LSEs. The zonal LMP is defined by weighting each load bus LMP by its hourly individual load bus contribution to the total zonal load. The LMP for a defined aggregate is calculated by weighting each included load bus LMP by its hourly contribution to the total load of the defined aggregate.

In the Day-Ahead Energy Market buyers may submit bids at specific locations such as a transmission zone, aggregate or a single bus. Price sensitive demand bids specify price and MW quantities and a location for the bid. Market participants may submit increment offers or decrement bids at any hub, transmission zone, aggregate, single bus or eligible external interfaces. PJM provides the definitions of the transmission zones, aggregates, and single buses.[4]

Real-Time LMP

Frequency Distribution of Real-Time Average LMP

Table C-4 provides frequency distributions of PJM real-time hourly average LMP for the calendar years 2007 to 2011. The table shows the number of hours (frequency) and the percent of hours (cumulative percent) when the hourly PJM real-time LMP was within a given $10 per MWh price interval and lower than $300 per MWh, or within a given $100 per MWh price interval and higher than $300 per MWh, or for the cumulative column, within the interval plus all the lower price intervals.

1 The definitions of load are discussed in the *Technical Reference for PJM Markets*, Section 5, "Load Definitions."
2 See the *2011 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography."
3 See the *Technical Reference for PJM Markets*, Section 4, "Calculating Locational Marginal Price."
4 See PJM "Manual 11: Energy & Ancillary Services Market Operations," Revision 45 (June 23, 2010), Section 2, pp. 20.

Table C-1 Frequency distribution of PJM real-time, hourly load: Calendar years 2007 to 2011

	2007		2008		2009		2010		2011	
Load (GWh)	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent
0 to 20	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
20 to 25	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
25 to 30	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
30 to 35	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
35 to 40	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
40 to 45	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
45 to 50	0	0.00%	0	0.00%	15	0.17%	12	0.14%	5	0.06%
50 to 55	79	0.90%	127	1.45%	376	4.46%	272	3.24%	104	1.24%
55 to 60	433	5.84%	517	7.33%	738	12.89%	582	9.89%	325	4.95%
60 to 65	637	13.12%	667	14.92%	836	22.43%	699	17.87%	602	11.83%
65 to 70	890	23.28%	941	25.64%	915	32.88%	805	27.05%	859	21.63%
70 to 75	878	33.30%	1,048	37.57%	1,342	48.20%	1,323	42.16%	1,120	34.42%
75 to 80	1,227	47.31%	1,535	55.04%	1,488	65.18%	1,272	56.68%	1,177	47.85%
80 to 85	1,338	62.58%	1,208	68.80%	966	76.21%	948	67.50%	1,257	62.20%
85 to 90	981	73.78%	916	79.22%	742	84.68%	794	76.56%	1,024	73.89%
90 to 95	741	82.24%	655	86.68%	549	90.95%	659	84.09%	721	82.12%
95 to 100	577	88.82%	457	91.88%	388	95.38%	487	89.65%	493	87.75%
100 to 105	382	93.18%	292	95.21%	205	97.72%	318	93.28%	279	90.94%
105 to 110	223	95.73%	181	97.27%	121	99.10%	195	95.50%	194	93.15%
110 to 115	179	97.77%	133	98.78%	48	99.65%	151	97.23%	173	95.13%
115 to 120	106	98.98%	58	99.44%	26	99.94%	108	98.46%	149	96.83%
120 to 125	43	99.47%	35	99.84%	5	100.00%	84	99.42%	95	97.91%
125 to 130	31	99.83%	14	100.00%	0	100.00%	40	99.87%	68	98.69%
130 to 135	12	99.97%	0	100.00%	0	100.00%	11	100.00%	49	99.25%
135 to 140	3	100.00%	0	100.00%	0	100.00%	0	100.00%	35	99.65%
> 140	0	100.00%	0	100.00%	0	100.00%	0	100.00%	31	100.00%

Table C-2 Off-peak and on-peak load (MW): Calendar years 1998 to 2011

	Average			Median			Standard Deviation		
	Off Peak	On Peak	On Peak/ Off Peak	Off Peak	On Peak	On Peak/ Off Peak	Off Peak	On Peak	On Peak/ Off Peak
1998	25,269	32,344	1.28	24,729	31,081	1.26	4,091	4,388	1.07
1999	26,454	33,269	1.26	25,780	31,950	1.24	4,947	4,824	0.98
2000	26,917	33,797	1.26	26,313	32,757	1.24	4,466	4,181	0.94
2001	26,804	34,303	1.28	26,433	33,076	1.25	4,225	4,851	1.15
2002	31,734	40,314	1.27	30,590	38,365	1.25	6,111	7,464	1.22
2003	33,598	41,755	1.24	32,973	40,802	1.24	5,545	5,424	0.98
2004	44,631	56,020	1.26	43,028	56,578	1.31	10,845	12,595	1.16
2005	70,291	87,164	1.24	68,049	82,503	1.21	12,733	15,236	1.20
2006	71,810	88,323	1.23	70,300	84,810	1.21	11,348	12,662	1.12
2007	73,499	91,066	1.24	71,751	88,494	1.23	11,501	11,926	1.04
2008	72,175	87,915	1.22	70,516	85,431	1.21	11,378	11,205	0.98
2009	68,745	84,337	1.23	67,159	81,825	1.22	10,924	10,523	0.96
2010	72,186	88,066	1.22	70,318	85,435	1.21	12,942	13,753	1.06
2011	74,810	91,408	1.22	72,657	87,930	1.21	12,978	14,836	1.14

Table C-3 Multiyear change in load: Calendar years 1998 to 2011

	Average			Median			Standard Deviation		
	Off Peak	On Peak	On Peak/ Off Peak	Off Peak	On Peak	On Peak/ Off Peak	Off Peak	On Peak	On Peak/ Off Peak
1998	NA	NA	NA	NA	NA	NA	NA	NA	NA
1999	4.7%	2.9%	(1.7%)	4.3%	2.8%	(1.4%)	20.9%	9.9%	(9.1%)
2000	1.8%	1.6%	(0.2%)	2.1%	2.5%	0.5%	(9.7%)	(13.3%)	(4.0%)
2001	(0.4%)	1.5%	1.9%	0.5%	1.0%	0.5%	(5.4%)	16.0%	22.6%
2002	18.4%	17.5%	(0.7%)	15.7%	16.0%	0.2%	44.6%	53.9%	6.4%
2003	5.9%	3.6%	(2.2%)	7.8%	6.4%	(1.3%)	(9.3%)	(27.3%)	(19.9%)
2004	32.8%	34.2%	1.0%	30.5%	38.7%	6.3%	95.6%	132.2%	18.7%
2005	57.5%	55.6%	(1.2%)	58.2%	45.8%	(7.8%)	17.4%	21.0%	3.0%
2006	2.2%	1.3%	(0.8%)	3.3%	2.8%	(0.5%)	(10.9%)	(16.9%)	(6.8%)
2007	2.4%	3.1%	0.7%	2.1%	4.3%	2.2%	1.3%	(5.8%)	(7.1%)
2008	(1.8%)	(3.5%)	(1.7%)	(1.7%)	(3.5%)	(1.8%)	(1.1%)	(6.0%)	(5.0%)
2009	(4.8%)	(4.1%)	0.7%	(4.8%)	(4.2%)	0.6%	(4.0%)	(6.1%)	(2.2%)
2010	5.0%	4.4%	(0.6%)	4.7%	4.4%	(0.3%)	18.5%	30.7%	10.3%
2011	3.6%	3.8%	0.2%	3.3%	2.9%	(0.4%)	0.3%	7.9%	7.6%

Table C-4 Frequency distribution by hours of PJM Real-Time Energy Market LMP (Dollars per MWh): Calendar years 2007 to 2011

	2007		2008		2009		2010		2011	
LMP	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent
$10 and less	56	0.64%	94	1.07%	117	1.34%	65	0.74%	66	0.75%
$10 to $20	185	2.75%	129	2.54%	218	3.82%	127	2.19%	89	1.77%
$20 to $30	1,571	20.68%	490	8.12%	2,970	37.73%	1,810	22.85%	1,764	21.91%
$30 to $40	1,470	37.47%	1,443	24.54%	2,951	71.42%	3,150	58.81%	3,967	67.19%
$40 to $50	1,108	50.11%	1,533	42.00%	1,269	85.90%	1,462	75.50%	1,334	82.42%
$50 to $60	931	60.74%	1,212	55.79%	555	92.24%	766	84.25%	489	88.00%
$60 to $70	827	70.18%	845	65.41%	276	95.39%	427	89.12%	303	91.46%
$70 to $80	726	78.47%	709	73.49%	151	97.11%	274	92.25%	174	93.45%
$80 to $90	646	85.84%	502	79.20%	95	98.20%	165	94.13%	133	94.97%
$90 to $100	451	90.99%	385	83.58%	62	98.90%	134	95.66%	108	96.20%
$100 to $110	240	93.73%	352	87.59%	30	99.25%	82	96.60%	61	96.89%
$110 to $120	178	95.76%	265	90.61%	21	99.49%	71	97.41%	61	97.59%
$120 to $130	110	97.02%	199	92.87%	15	99.66%	61	98.11%	46	98.12%
$130 to $140	76	97.89%	144	94.51%	7	99.74%	44	98.61%	33	98.49%
$140 to $150	53	98.49%	111	95.78%	9	99.84%	29	98.94%	25	98.78%
$150 to $160	26	98.79%	102	96.94%	3	99.87%	22	99.19%	25	99.06%
$160 to $170	29	99.12%	68	97.71%	3	99.91%	11	99.32%	17	99.26%
$170 to $180	18	99.33%	52	98.30%	5	99.97%	13	99.46%	15	99.43%
$180 to $190	9	99.43%	45	98.82%	0	99.97%	12	99.60%	6	99.50%
$190 to $200	15	99.60%	29	99.15%	1	99.98%	9	99.70%	8	99.59%
$200 to $210	6	99.67%	20	99.37%	1	99.99%	7	99.78%	6	99.66%
$210 to $220	4	99.71%	11	99.50%	1	100.00%	4	99.83%	5	99.71%
$220 to $230	4	99.76%	14	99.66%	0	100.00%	3	99.86%	4	99.76%
$230 to $240	2	99.78%	10	99.77%	0	100.00%	5	99.92%	0	99.76%
$240 to $250	5	99.84%	2	99.80%	0	100.00%	3	99.95%	3	99.79%
$250 to $260	2	99.86%	5	99.85%	0	100.00%	1	99.97%	3	99.83%
$260 to $270	4	99.91%	4	99.90%	0	100.00%	0	99.97%	3	99.86%
$270 to $280	0	99.91%	1	99.91%	0	100.00%	0	99.97%	3	99.90%
$280 to $290	0	99.91%	1	99.92%	0	100.00%	1	99.98%	0	99.90%
$290 to $300	0	99.91%	0	99.92%	0	100.00%	0	99.98%	2	99.92%
$300 to $400	2	99.93%	6	99.99%	0	100.00%	2	100.00%	4	99.97%
$400 to $500	4	99.98%	1	100.00%	0	100.00%	0	100.00%	0	99.97%
$500 to $600	1	99.99%	0	100.00%	0	100.00%	0	100.00%	0	99.97%
$600 to $700	1	100.00%	0	100.00%	0	100.00%	0	100.00%	0	99.97%
> $700	0	100.00%	0	100.00%	0	100.00%	0	100.00%	3	100.00%

Off-Peak and On-Peak, PJM Real-Time, Load-Weighted Average LMP

Table C-5 shows load-weighted, average real-time LMP for 2010 and 2011 during off-peak and on-peak periods.

Off-Peak and On-Peak, Real-Time, Fuel-Cost-Adjusted, Load-Weighted, Average LMP

In a competitive market, changes in LMP result from changes in demand and changes in supply. Changes in LMP can result from changes in the marginal costs of marginal units, the units setting LMP. As competitive offers are equivalent to the marginal cost of generation and fuel costs make up between 80 percent and 90 percent of marginal cost on average, fuel cost is a key factor affecting supply and, therefore, the competitive clearing price. In a competitive market, if fuel costs increase and nothing else changes, the competitive price also increases.

The impact of fuel cost on marginal cost and on LMP depends on the fuel burned by marginal units and changes in fuel costs.[5] Changes in emission allowance costs are another contributor to changes in the marginal cost of marginal units. To account for the changes in fuel and allowance costs between 2010 and 2011, the load-weighted LMP for 2011 was adjusted to reflect the daily price of fuels and emission allowances used by marginal units from a base period, 2010. The fuel cost adjusted, load-weighted LMP for 2011 is compared to the load-weighted LMP for 2010.[6]

Table C-6 shows the real-time, load-weighted, average LMP for 2011 and the real-time, fuel-cost-adjusted, load-weighted, average LMP for 2011 for on-peak and off-peak hours. The fuel-cost adjusted load-weighted, average LMP for 2011 on-peak hours was 6.3 percent lower than the load-weighted, average LMP for 2010 on-peak hours. The fuel-cost adjusted load-weighted, average LMP for 2011 off-peak hours was 9.1 percent lower than the load-weighted, average LMP for 2010 off-peak hours. The mix of fuel types and costs in 2011 resulted in higher prices in 2011 than would have occurred if fuel prices had remained at their 2010 levels.

PJM Real-Time, Load-Weighted Average LMP during Constrained Hours

Table C-7 shows the PJM load-weighted, average LMP during constrained hours for 2010 and 2011.[7]

Table C-5 Off-peak and on-peak, PJM load-weighted, average LMP (Dollars per MWh): Calendar years 2010 to 2011

	2010			2011			Difference 2010 to 2011		
	Off Peak	On Peak	On Peak/ Off Peak	Off Peak	On Peak	On Peak/ Off Peak	Off Peak	On Peak	On Peak/ Off Peak
Average	$39.88	$56.25	1.41	$37.28	$54.07	1.45	(6.5%)	(3.9%)	2.8%
Median	$33.09	$45.28	1.37	$32.37	$41.26	1.27	(2.2%)	(8.9%)	(6.8%)
Standard deviation	$23.01	$31.48	1.37	$20.01	$40.74	2.04	(13.1%)	29.4%	48.8%

Table C-6 On-peak and off-peak real-time PJM fuel-cost-adjusted, load-weighted, average LMP (Dollars per MWh): Calendar year 2011

	2010 Load-Weighted LMP	2011 Fuel-Cost-Adjusted, Load-Weighted LMP	Change
On Peak	$56.25	$52.73	(6.3%)
Off Peak	$39.88	$36.25	(9.1%)

Table C-7 PJM real-time load-weighted, average LMP during constrained hours (Dollars per MWh): Calendar years 2010 to 2011

	2010	2011	Difference
Average	$49.56	$47.36	(4.4%)
Median	$39.85	$37.05	(7.0%)
Standard deviation	$29.83	$34.90	17.0%

5 See the *2011 State of the Market Report for PJM*, Volume II, Section 2,"Energy Market," at Table 2-15, "Type of fuel used (By marginal units): Calendar year 2011."

6 See the *Technical Reference for PJM Markets*, Section 7, "Calculation and Use of Generator Sensitivity/Unit Participation Factors."

7 A constrained hour, or a constraint hour, is any hour during which one or more facilities are congested. 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 consistent with the way in which PJM reports real-time congestion.

Table C-8 provides a comparison of PJM load-weighted, average LMP during constrained and unconstrained hours for 2010 and 2011.

Table C-8 PJM real-time load-weighted, average LMP during constrained and unconstrained hours (Dollars per MWh): Calendar years 2010 to 2011

	2010			2011		
	Unconstrained Hours	Constrained Hours	Difference	Unconstrained Hours	Constrained Hours	Difference
Average	$39.37	$49.56	25.9%	$35.14	$47.36	34.8%
Median	$35.34	$39.85	12.8%	$33.21	$37.05	11.6%
Standard deviation	$18.46	$29.83	61.6%	$15.69	$34.90	122.4%

Table C-9 shows the number of hours and the number of constrained hours in each month in 2010 and 2011.

Table C-9 PJM real-time constrained hours: Calendar years 2010 to 2011

	2010 Constrained Hours	2011 Constrained Hours	Total Hours
Jan	598	678	744
Feb	563	518	672
Mar	576	578	743
Apr	618	655	720
May	592	590	744
Jun	645	622	720
Jul	667	630	744
Aug	633	658	744
Sep	695	687	720
Oct	705	717	744
Nov	653	641	721
Dec	722	669	744
Avg	639	637	730

Day-Ahead and Real-Time LMP

On average, prices in the Real-Time Energy Market in 2011 were slightly higher than those in the Day-Ahead Energy Market and real-time prices showed greater dispersion. This pattern of system average LMP distribution for 2011 can be seen by comparing Table C-4 and Table C-10. Table C-10 shows frequency distributions of PJM day-ahead hourly LMP for the calendar years 2007 to 2011. Together the tables show the frequency distribution by hours for the two markets. In the Real-Time Energy Market, prices reached a high for the year of $770.58 per MWh on May 31, 2011, in the hour ending 1700 EPT. In the Day-Ahead Energy Market, prices reached a high for the year of $346.82 per MWh on June 8, 2011, in the hour ending 1700 EPT.

Off-Peak and On-Peak, Day-Ahead and Real-Time, Average LMP

Table C-11 shows PJM average LMP during off-peak and on-peak periods for the Day-Ahead and Real-Time Energy Markets in calendar year 2011. Figure C-1 and Figure C-2 show the difference between real-time and day-ahead LMP in calendar year 2011 during the on-peak and off-peak hours.

Figure C-1 Hourly real-time LMP minus day-ahead LMP (On-peak hours): Calendar year 2011

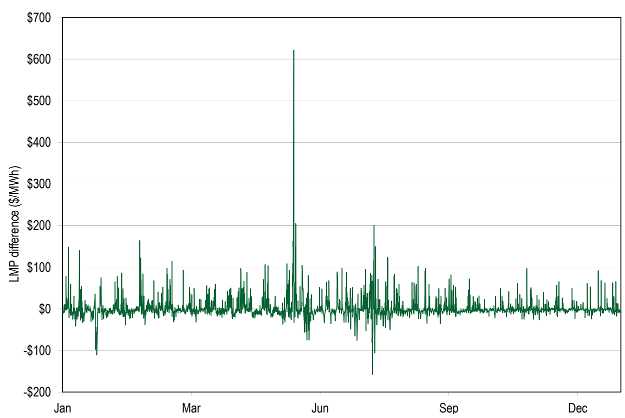


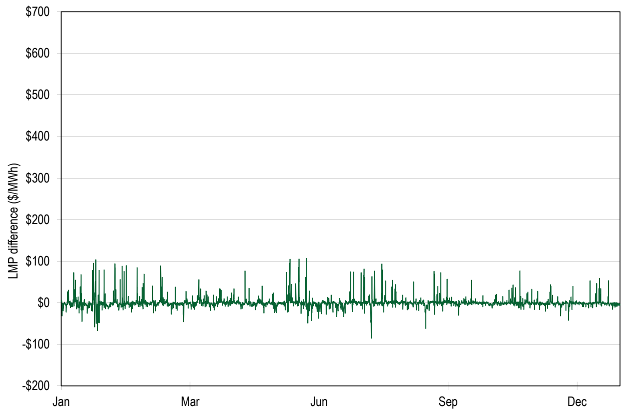
Table C-10 Frequency distribution by hours of PJM Day-Ahead Energy Market LMP (Dollars per MWh): Calendar years 2007 to 2011

	2007		2008		2009		2010		2011	
LMP	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent
$10 and less	3	0.03%	0	0.00%	23	0.26%	5	0.06%	0	0.00%
$10 to $20	88	1.04%	19	0.22%	343	4.18%	31	0.41%	33	0.38%
$20 to $30	1,291	15.78%	320	3.86%	2,380	31.35%	1,502	17.56%	1,595	18.58%
$30 to $40	1,495	32.84%	1,148	16.93%	3,221	68.12%	2,851	50.10%	3,359	56.93%
$40 to $50	1,221	46.78%	1,546	34.53%	1,717	87.72%	2,131	74.43%	2,024	80.03%
$50 to $60	1,266	61.23%	1,491	51.50%	557	94.08%	954	85.32%	872	89.99%
$60 to $70	1,301	76.08%	1,107	64.11%	253	96.96%	471	90.70%	406	94.62%
$70 to $80	939	86.80%	942	74.83%	138	98.54%	302	94.14%	174	96.61%
$80 to $90	504	92.56%	682	82.59%	68	99.32%	193	96.35%	87	97.60%
$90 to $100	264	95.57%	542	88.76%	33	99.69%	125	97.77%	61	98.30%
$100 to $110	155	97.34%	289	92.05%	19	99.91%	86	98.76%	29	98.63%
$110 to $120	104	98.53%	193	94.25%	6	99.98%	46	99.28%	30	98.97%
$120 to $130	59	99.20%	131	95.74%	2	100.00%	29	99.61%	16	99.16%
$130 to $140	33	99.58%	112	97.02%	0	100.00%	14	99.77%	21	99.39%
$140 to $150	13	99.73%	67	97.78%	0	100.00%	7	99.85%	17	99.59%
$150 to $160	8	99.82%	54	98.39%	0	100.00%	6	99.92%	7	99.67%
$160 to $170	7	99.90%	46	98.92%	0	100.00%	3	99.95%	3	99.70%
$170 to $180	3	99.93%	23	99.18%	0	100.00%	2	99.98%	2	99.73%
$180 to $190	4	99.98%	20	99.41%	0	100.00%	0	99.98%	2	99.75%
$190 to $200	1	99.99%	16	99.59%	0	100.00%	2	100.00%	2	99.77%
$200 to $210	1	100.00%	8	99.68%	0	100.00%	0	100.00%	1	99.78%
$210 to $220	0	100.00%	9	99.78%	0	100.00%	0	100.00%	0	99.78%
$220 to $230	0	100.00%	4	99.83%	0	100.00%	0	100.00%	2	99.81%
$230 to $240	0	100.00%	3	99.86%	0	100.00%	0	100.00%	1	99.82%
$240 to $250	0	100.00%	2	99.89%	0	100.00%	0	100.00%	0	99.82%
$250 to $260	0	100.00%	0	99.89%	0	100.00%	0	100.00%	2	99.84%
$260 to $270	0	100.00%	4	99.93%	0	100.00%	0	100.00%	2	99.86%
$270 to $280	0	100.00%	0	99.93%	0	100.00%	0	100.00%	0	99.86%
$280 to $290	0	100.00%	2	99.95%	0	100.00%	0	100.00%	0	99.86%
$290 to $300	0	100.00%	2	99.98%	0	100.00%	0	100.00%	4	99.91%
>$300	0	100.00%	2	100.00%	0	100.00%	0	100.00%	8	100.00%

Table C-11 Off-peak and on-peak, average day-ahead and real-time LMP (Dollars per MWh): Calendar year 2011

	Day Ahead			Real Time			Difference in Real Time Relative to Day Ahead		
	Off Peak	On Peak	On Peak/ Off Peak	Off Peak	On Peak	On Peak/ Off Peak	Off Peak	On Peak	On Peak/ Off Peak
Average	$35.61	$50.45	1.42	$35.56	$51.20	1.44	(0.1%)	1.5%	1.6%
Median	$32.43	$44.56	1.37	$31.58	$40.25	1.27	(2.6%)	(9.7%)	(7.2%)
Standard deviation	$12.44	$24.60	1.98	$18.07	$36.11	2.00	45.3%	46.8%	1.0%

Figure C-2 Hourly real-time average LMP minus day-ahead average LMP (Off-peak hours): Calendar year 2011



On-Peak and Off-Peak, Zonal, Day-Ahead and Real-Time, Average LMP

Table C-12 and Table C-13 show the on-peak and off-peak, average LMP for each zone in the Day-Ahead and Real-Time Energy Markets in calendar year 2011.

Table C-12 On-peak, zonal, average day-ahead and real-time LMP (Dollars per MWh): Calendar year 2011

	Day Ahead	Real Time	Difference	Difference as Percent Real Time
AECO	$57.01	$57.22	$0.21	0.37%
AEP	$45.90	$45.70	($0.20)	(0.45%)
AP	$50.60	$50.85	$0.24	0.48%
BGE	$46.98	$46.85	($0.14)	(0.29%)
ComEd	$58.02	$59.24	$1.22	2.06%
DAY	$41.48	$41.42	($0.06)	(0.14%)
DLCO	$56.88	$56.84	($0.04)	(0.06%)
Dominion	$45.93	$46.16	$0.23	0.50%
DPL	$53.87	$54.63	$0.76	1.39%
JCPL	$46.09	$46.50	$0.41	0.88%
Met-Ed	$56.40	$57.51	$1.12	1.94%
PECO	$54.32	$55.19	$0.87	1.58%
PENELEC	$56.30	$55.88	($0.42)	(0.75%)
Pepco	$50.44	$51.17	$0.73	1.43%
PPL	$56.45	$56.47	$0.02	0.03%
PSEG	$54.17	$55.48	$1.31	2.37%
RECO	$57.41	$58.27	$0.87	1.49%

Table C-13 Off-peak, zonal, average day-ahead and real-time LMP (Dollars per MWh): Calendar year 2011

	Day Ahead	Real Time	Difference	Difference as Percent Real Time
AECO	$39.88	$39.13	($0.76)	(1.93%)
AEP	$33.58	$33.23	($0.35)	(1.06%)
AP	$36.30	$35.99	($0.32)	(0.89%)
BGE	$32.71	$32.65	($0.06)	(0.19%)
ComEd	$40.51	$40.27	($0.23)	(0.58%)
DAY	$26.46	$26.22	($0.24)	(0.91%)
DLCO	$40.12	$39.04	($1.08)	(2.77%)
Dominion	$33.51	$33.17	($0.34)	(1.02%)
DPL	$39.14	$39.19	$0.05	0.13%
JCPL	$32.61	$32.43	($0.19)	(0.57%)
Met-Ed	$39.91	$39.05	($0.85)	(2.19%)
PECO	$38.40	$37.66	($0.75)	(1.98%)
PENELEC	$39.29	$38.44	($0.86)	(2.23%)
Pepco	$36.12	$35.79	($0.33)	(0.92%)
PPL	$39.85	$39.38	($0.48)	(1.21%)
PSEG	$38.28	$37.43	($0.85)	(2.26%)
RECO	$40.39	$39.36	($1.03)	(2.62%)

PJM Day-Ahead and Real-Time, Average LMP during Constrained Hours

Table C-14 shows the number of constrained hours for the Day-Ahead and Real-Time Energy Markets and the total number of hours in each month for 2011.

Table C-14 PJM day-ahead and real-time, market-constrained hours: Calendar year 2011

	DA Constrained Hours	RT Constrained Hours	Total Hours
Jan	744	678	744
Feb	672	518	672
Mar	743	578	743
Apr	720	655	720
May	744	590	744
Jun	720	622	720
Jul	744	630	744
Aug	744	658	744
Sep	720	687	720
Oct	744	717	744
Nov	721	641	721
Dec	744	669	744
Avg	730	637	730

Table C-15 shows PJM average LMP during constrained and unconstrained hours in the Day-Ahead and Real-Time Energy Markets.

Table C-15 PJM average LMP during constrained and unconstrained hours (Dollars per MWh): Calendar year 2011

	Day Ahead			Real Time		
	Unconstrained Hours	Constrained Hours	Difference	Unconstrained Hours	Constrained Hours	Difference
Average	$0.00	$42.52	NA	$33.88	$44.15	30.3%
Median	$0.00	$38.13	NA	$32.21	$35.85	11.3%
Standard deviation	$0.00	$20.48	NA	$15.03	$30.32	101.7%

LMP by Zone and by Jurisdiction

Zonal Real-Time, Average LMP

Table C-16 Zonal real-time, average LMP (Dollars per MWh): Calendar years 2010 and 2011 (See 2010 SOM, Table 2-35)

	2010	2011	Difference	Difference as Percent of 2010
AECO	$50.67	$47.56	($3.11)	(6.1%)
AEP	$38.36	$39.04	$0.67	1.8%
AP	$44.62	$42.91	($1.72)	(3.8%)
ATSI	NA	$39.24	NA	NA
BGE	$53.63	$49.11	($4.52)	(8.4%)
ComEd	$33.35	$33.30	($0.04)	(0.1%)
DAY	$38.11	$39.22	$1.11	2.9%
DLCO	$37.14	$38.98	$1.84	5.0%
Dominion	$50.94	$46.38	($4.56)	(8.9%)
DPL	$51.04	$47.33	($3.71)	(7.3%)
JCPL	$49.88	$47.65	($2.23)	(4.5%)
Met-Ed	$49.14	$45.82	($3.32)	(6.8%)
PECO	$49.11	$46.56	($2.55)	(5.2%)
PENELEC	$43.07	$42.95	($0.11)	(0.3%)
Pepco	$52.85	$47.34	($5.52)	(10.4%)
PPL	$47.75	$45.84	($1.91)	(4.0%)
PSEG	$50.97	$48.17	($2.81)	(5.5%)
RECO	$49.18	$44.28	($4.90)	(10.0%)
PJM	$44.83	$42.84	($1.99)	(4.4%)

Real-Time, Average LMP by Jurisdiction

Table C-17 Jurisdiction real-time, average LMP (Dollars per MWh): Calendar years 2010 and 2011 (See 2010 SOM, Table 2-36)

	2010	2011	Difference	Difference as Percent of 2010
Delaware	$50.10	$46.61	($3.49)	(7.0%)
Illinois	$33.35	$33.30	($0.04)	(0.1%)
Indiana	$37.45	$38.45	$1.00	2.7%
Kentucky	$38.49	$38.39	($0.10)	(0.3%)
Maryland	$53.18	$48.06	($5.11)	(9.6%)
Michigan	$37.88	$39.30	$1.42	3.8%
New Jersey	$50.60	$47.88	($2.72)	(5.4%)
North Carolina	$48.99	$45.23	($3.76)	(7.7%)
Ohio	$37.48	$39.38	$1.90	5.1%
Pennsylvania	$46.09	$44.48	($1.60)	(3.5%)
Tennessee	$39.27	$38.35	($0.92)	(2.3%)
Virginia	$49.46	$45.36	($4.10)	(8.3%)
West Virginia	$39.49	$39.72	$0.23	0.6%
District of Columbia	$53.03	$47.41	($5.62)	(10.6%)

Hub Real-Time, Average LMP

Table C-18 Hub real-time, average LMP (Dollars per MWh): Calendar years 2010 and 2011 (See 2010 SOM, Table 2-37)

	2010	2011	Difference	Difference as Percent of 2010
AEP Gen Hub	$35.56	$37.08	$1.52	4.3%
AEP-DAY Hub	$37.57	$38.55	$0.98	2.6%
ATSI Gen Hub	NA	$38.87	$38.87	NA
Chicago Gen Hub	$32.23	$32.25	$0.02	0.1%
Chicago Hub	$33.54	$33.48	-$0.06	(0.2%)
Dominion Hub	$49.43	$45.84	($3.58)	(7.2%)
Eastern Hub	$50.98	$47.71	($3.27)	(6.4%)
N Illinois Hub	$33.09	$33.07	-$0.02	(0.1%)
New Jersey Hub	$50.46	$47.88	-$2.57	(5.1%)
Ohio Hub	$37.64	$38.58	$0.94	2.5%
West Interface Hub	$40.50	$40.57	$0.07	0.2%
Western Hub	$45.93	$43.56	($2.37)	(5.2%)

Zonal Real-Time, Load-Weighted, Average LMP

Table C-19 Zonal real-time, load-weighted, average LMP (Dollars per MWh): Calendar years 2010 and 2011 (See 2010 SOM, Table 2-39)

	2010	2011	Difference	Difference as Percent of 2010
AECO	$57.02	$53.11	($3.91)	(6.9%)
AEP	$40.43	$40.92	$0.49	1.2%
AP	$47.63	$45.49	($2.14)	(4.5%)
ATSI	NA	$42.09	NA	NA
BGE	$59.19	$54.29	($4.91)	(8.3%)
ComEd	$36.21	$36.20	($0.00)	(0.0%)
DAY	$40.51	$41.78	$1.28	3.2%
DLCO	$39.41	$41.31	$1.90	4.8%
Dominion	$56.08	$50.59	($5.49)	(9.8%)
DPL	$56.51	$52.20	($4.31)	(7.6%)
JCPL	$56.00	$53.48	($2.53)	(4.5%)
Met-Ed	$53.47	$49.51	($3.96)	(7.4%)
PECO	$53.60	$50.83	($2.78)	(5.2%)
PENELEC	$45.17	$45.12	($0.05)	(0.1%)
Pepco	$58.16	$51.84	($6.31)	(10.9%)
PPL	$51.50	$49.31	($2.20)	(4.3%)
PSEG	$55.78	$52.68	($3.10)	(5.6%)
RECO	$54.85	$49.66	($5.19)	(9.5%)
PJM	$48.35	$45.94	($2.41)	(5.0%)

Real-Time, Load-Weighted, Average LMP by Jurisdiction

Table C-20 Jurisdiction real-time, load-weighted, average LMP (Dollars per MWh): Calendar years 2010 and 2011 (See 2010 SOM, Table 2-40)

	2010	2011	Difference	Difference as Percent of 2010
Delaware	$55.09	$51.13	($3.96)	(7.2%)
Illinois	$36.21	$36.20	($0.00)	(0.0%)
Indiana	$39.06	$40.12	$1.06	2.7%
Kentucky	$40.96	$40.41	($0.55)	(1.3%)
Maryland	$58.86	$52.99	($5.86)	(10.0%)
Michigan	$40.23	$41.60	$1.37	3.4%
New Jersey	$56.00	$52.91	($3.09)	(5.5%)
North Carolina	$53.80	$49.20	($4.60)	(8.6%)
Ohio	$39.47	$41.54	$2.07	5.3%
Pennsylvania	$49.49	$47.65	($1.84)	(3.7%)
Tennessee	$41.99	$40.27	($1.73)	(4.1%)
Virginia	$54.24	$49.22	($5.02)	(9.3%)
West Virginia	$41.72	$41.56	($0.15)	(0.4%)
District of Columbia	$57.36	$50.88	($6.47)	(11.3%)

Zonal Day-Ahead, Average LMP

Table C-21 Zonal day-ahead, average LMP (Dollars per MWh): Calendar years 2010 and 2011 (See 2010 SOM, Table 2-44)

	2010	2011	Difference	Difference as Percent of 2010
AECO	$50.44	$47.86	($2.58)	(5.1%)
AEP	$38.30	$39.32	$1.02	2.7%
AP	$44.42	$42.96	($1.46)	(3.3%)
ATSI	NA	$39.34	NA	NA
BGE	$53.24	$48.66	($4.58)	(8.6%)
ComEd	$33.37	$33.46	$0.09	0.3%
DAY	$37.97	$39.29	$1.32	3.5%
DLCO	$37.84	$38.89	$1.05	2.8%
Dominion	$51.16	$46.00	($5.16)	(10.1%)
DPL	$50.80	$47.93	($2.87)	(5.7%)
JCPL	$50.21	$47.59	($2.62)	(5.2%)
Met-Ed	$48.98	$45.82	($3.17)	(6.5%)
PECO	$49.58	$47.21	($2.37)	(4.8%)
PENELEC	$43.94	$42.79	($1.15)	(2.6%)
Pepco	$52.94	$47.58	($5.36)	(10.1%)
PPL	$47.67	$45.68	($1.99)	(4.2%)
PSEG	$50.89	$48.32	($2.57)	(5.1%)
RECO	$49.68	$45.80	($3.88)	(7.8%)
PJM	$44.57	$42.52	($2.05)	(4.6%)

Day-Ahead, Average LMP by Jurisdiction

Table C-22 Jurisdiction day-ahead, average LMP (Dollars per MWh): Calendar years 2010 and 2011 (See 2010 SOM, Table 2-45)

	2010	2011	Difference	Difference as Percent of 2010
Delaware	$49.74	$47.10	($2.64)	(5.3%)
Illinois	$33.37	$33.46	$0.09	0.3%
Indiana	$37.46	$38.51	$1.05	2.8%
Kentucky	$38.37	$38.50	$0.13	0.3%
Maryland	$53.10	$48.17	($4.93)	(9.3%)
Michigan	$37.97	$39.48	$1.51	4.0%
New Jersey	$50.63	$48.01	($2.62)	(5.2%)
North Carolina	$49.34	$44.86	($4.48)	(9.1%)
Ohio	$37.39	$39.36	$1.96	5.3%
Pennsylvania	$46.31	$44.64	($1.66)	(3.6%)
Tennessee	$39.26	$38.61	($0.66)	(1.7%)
Virginia	$49.83	$45.23	($4.60)	(9.2%)
West Virginia	$39.26	$40.27	$1.01	2.6%
District of Columbia	$53.02	$47.59	($5.42)	(10.2%)

Zonal Day-Ahead, Load-Weighted Average LMP

Table C-23 Zonal day-ahead, load-weighted, average LMP (Dollars per MWh): Calendar years 2010 and 2011 (See 2010 SOM, Table 2-47)

	2010	2011	Difference	Difference as Percent of 2010
AECO	$57.03	$53.09	($3.94)	(6.9%)
AEP	$40.35	$41.12	$0.77	1.9%
AP	$47.08	$45.10	($1.98)	(4.2%)
ATSI	NA	$41.89	NA	NA
BGE	$58.37	$53.21	($5.16)	(8.8%)
ComEd	$35.48	$35.72	$0.24	0.7%
DAY	$40.18	$41.54	$1.36	3.4%
DLCO	$40.03	$40.98	$0.95	2.4%
Dominion	$56.08	$49.78	($6.30)	(11.2%)
DPL	$55.76	$52.62	($3.14)	(5.6%)
JCPL	$55.07	$52.22	($2.85)	(5.2%)
Met-Ed	$52.78	$48.62	($4.15)	(7.9%)
PECO	$53.63	$51.11	($2.53)	(4.7%)
PENELEC	$45.52	$44.35	($1.18)	(2.6%)
Pepco	$56.41	$51.03	($5.38)	(9.5%)
PPL	$50.92	$48.69	($2.23)	(4.4%)
PSEG	$54.99	$52.23	($2.76)	(5.0%)
RECO	$55.56	$49.96	($5.60)	(10.1%)
PJM	$47.65	$45.19	($2.46)	(5.2%)

Day-Ahead, Load-Weighted, Average LMP by Jurisdiction

Table C-24 Jurisdiction day-ahead, load weighted LMP (Dollars per MWh): Calendar years 2010 and 2011 (See 2010 SOM, Table 2-48)

	2010	2011	Difference	Difference as Percent of 2010
Delaware	$54.23	$51.46	($2.77)	(5.1%)
Illinois	$35.48	$35.72	$0.24	0.7%
Indiana	$39.24	$40.15	$0.91	2.3%
Kentucky	$40.62	$40.41	($0.20)	(0.5%)
Maryland	$57.63	$52.23	($5.39)	(9.4%)
Michigan	$39.40	$41.37	$1.97	5.0%
New Jersey	$55.27	$52.29	($2.98)	(5.4%)
North Carolina	$54.05	$48.74	($5.31)	(9.8%)
Ohio	$39.31	$41.65	$2.34	6.0%
Pennsylvania	$49.13	$47.27	($1.86)	(3.8%)
Tennessee	$41.76	$40.58	($1.18)	(2.8%)
Virginia	$54.40	$48.65	($5.75)	(10.6%)
West Virginia	$41.58	$42.07	$0.49	1.2%
District of Columbia	$56.15	$50.57	($5.58)	(9.9%)

Zonal Price Differences

Table C-25 Zonal day-ahead and real-time average LMP (Dollars per MWh): Calendar year 2011 (See 2010 SOM, Table 2-68)

	Day Ahead	Real Time	Difference	Difference as Percent of Real Time
AECO	$47.86	$47.56	($0.30)	(0.6%)
AEP	$39.32	$39.04	($0.28)	(0.7%)
AP	$42.96	$42.91	($0.06)	(0.1%)
ATSI	$39.34	$39.24	($0.10)	(0.2%)
BGE	$48.66	$49.11	$0.44	0.9%
ComEd	$33.46	$33.30	($0.15)	(0.5%)
DAY	$39.29	$39.22	($0.07)	(0.2%)
DLCO	$38.89	$38.98	$0.09	0.2%
Dominion	$46.00	$46.38	$0.38	0.8%
DPL	$47.93	$47.33	($0.59)	(1.2%)
JCPL	$47.59	$47.65	$0.06	0.1%
Met-Ed	$45.82	$45.82	$0.01	0.0%
PECO	$47.21	$46.56	($0.65)	(1.4%)
PENELEC	$42.79	$42.95	$0.16	0.4%
Pepco	$47.58	$47.34	($0.25)	(0.5%)
PPL	$45.68	$45.84	$0.16	0.3%
PSEG	$48.32	$48.17	($0.15)	(0.3%)
RECO	$45.80	$44.28	($1.52)	(3.3%)
PJM	$42.52	$42.84	$0.32	0.7%

Jurisdictional Price Differences

Table C-26 Jurisdiction day-ahead and real-time average LMP (Dollars per MWh): Calendar year 2011 (See 2010 SOM, Table 2-69)

	Day Ahead	Real Time	Difference	Difference as Percent of Real Time
Delaware	$47.10	$46.61	($0.49)	(1.0%)
Illinois	$33.46	$33.30	($0.15)	(0.5%)
Indiana	$38.51	$38.45	($0.06)	(0.2%)
Kentucky	$38.50	$38.39	($0.11)	(0.3%)
Maryland	$48.17	$48.06	($0.10)	(0.2%)
Michigan	$39.48	$39.30	($0.18)	(0.5%)
New Jersey	$48.01	$47.88	($0.13)	(0.3%)
North Carolina	$44.86	$45.23	$0.37	0.8%
Ohio	$39.36	$39.38	$0.03	0.1%
Pennsylvania	$44.64	$44.48	($0.16)	(0.4%)
Tennessee	$38.61	$38.35	($0.25)	(0.7%)
Virginia	$45.23	$45.36	$0.13	0.3%
West Virginia	$40.27	$39.72	($0.55)	(1.4%)
District of Columbia	$47.59	$47.41	($0.18)	(0.4%)

Offer-Capped Units

PJM's market power mitigation goals have focused on market designs that promote competition and that limit market power mitigation to situations where market structure is not competitive and thus where market design alone cannot mitigate market power. In the PJM Energy Market, this situation occurs primarily in the case of local market power. Offer capping occurs only as a result of structurally noncompetitive local markets and noncompetitive offers in the Day-Ahead and Real-Time Energy Markets.

PJM has clear rules limiting the exercise of local market power.[8] The rules provide for offer capping when conditions on the transmission system create a structurally noncompetitive local market, when units in that local market have made noncompetitive offers and when such offers would set the price above the competitive level in the absence of mitigation. Offer caps are set at the level of a competitive offer. Offer-capped units receive the higher of the market price or their offer cap. Thus, if broader market conditions lead to a price greater than the offer cap, the unit receives the higher market price. The rules governing the exercise of local market power recognize that units in certain areas of the system would be in a position to extract monopoly profits, but for these rules.

8 See OA Schedule 1, § 6.4.2

Under existing rules, PJM suspends offer capping when structural market conditions, as determined by the three pivotal supplier test, indicate that suppliers are reasonably likely to behave in a competitive manner.[9] The goal is to apply a clear rule to limit the exercise of market power by generation owners in load pockets, but to apply the rule in a flexible manner in real time and to lift offer capping when the exercise of market power is unlikely based on the real-time application of the market structure screen.

Levels of offer capping have generally been low and stable over the last five years. Table C-27 through Table C-30 show offer capping by month, including the number of offer-capped units and the level of offer-capped MW in the Day-Ahead and Real-Time Energy Markets.

Table C-27 Average day-ahead, offer-capped units: Calendar years 2007 to 2011[10]

	2007		2008		2009		2010		2011	
	Avg. Units Capped	Percent	Avg. Units Capped	Percent	Avg. Units Capped	Percent	Avg. Units Capped	Percent	Avg. Units Capped	Percent
Jan	0.2	0.0%	0.5	0.0%	0.7	0.1%	0.6	0.1%	0.1	0.0%
Feb	0.8	0.1%	0.2	0.0%	0.3	0.0%	0.6	0.1%	0.0	0.0%
Mar	0.9	0.1%	0.0	0.0%	0.6	0.1%	0.3	0.0%	0.1	0.0%
Apr	0.2	0.0%	0.2	0.0%	0.0	0.0%	0.8	0.1%	0.3	0.0%
May	0.2	0.0%	0.6	0.1%	0.1	0.0%	1.2	0.1%	0.1	0.0%
Jun	0.8	0.1%	1.5	0.1%	0.3	0.0%	2.0	0.2%	0.0	0.0%
Jul	0.6	0.1%	1.7	0.2%	0.0	0.0%	2.8	0.3%	0.2	0.0%
Aug	1.0	0.1%	0.2	0.0%	0.4	0.0%	0.5	0.0%	0.3	0.0%
Sep	0.2	0.0%	0.4	0.0%	0.2	0.0%	0.5	0.0%	0.3	0.0%
Oct	0.8	0.1%	0.4	0.0%	0.1	0.0%	0.3	0.0%	0.0	0.0%
Nov	0.0	0.0%	0.5	0.0%	0.0	0.0%	0.3	0.0%	0.2	0.0%
Dec	0.1	0.0%	1.3	0.1%	0.3	0.0%	0.0	0.0%	0.0	0.0%

Table C-28 Average day-ahead, offer-capped MW: Calendar years 2007 to 2011[11]

	2007		2008		2009		2010		2011	
	Avg. MW Capped	Percent	Avg. MW Capped	Percent	Avg. MW Capped	Percent	Avg. MW Capped	Percent	Avg. MW Capped	Percent
Jan	23	0.0%	16	0.0%	98	0.1%	50	0.1%	9	0.0%
Feb	57	0.1%	11	0.0%	30	0.0%	29	0.0%	0	0.0%
Mar	86	0.1%	2	0.0%	47	0.1%	17	0.0%	13	0.0%
Apr	11	0.0%	31	0.0%	0	0.0%	98	0.1%	33	0.0%
May	38	0.0%	15	0.0%	9	0.0%	117	0.1%	14	0.0%
Jun	28	0.0%	91	0.1%	42	0.0%	129	0.1%	4	0.0%
Jul	45	0.0%	110	0.1%	0	0.0%	143	0.1%	20	0.0%
Aug	58	0.1%	35	0.0%	35	0.0%	61	0.1%	45	0.0%
Sep	14	0.0%	66	0.1%	10	0.0%	34	0.0%	38	0.0%
Oct	77	0.1%	39	0.0%	3	0.0%	26	0.0%	1	0.0%
Nov	4	0.0%	47	0.1%	0	0.0%	23	0.0%	23	0.0%
Dec	4	0.0%	187	0.2%	29	0.0%	0	0.0%	0	0.0%

9 See the *Technical Reference for PJM Markets*, Section 8, "Three Pivotal Supplier Test."
10 The version of this table in the *2010 State of the Market Report for PJM* incorrectly mapped the results to months for the years 2009 and 2010.
11 The version of this table in the *2010 State of the Market Report for PJM* incorrectly mapped the results to months for the years 2009 and 2010.

Table C-29 Average real-time, offer-capped units: Calendar years 2007 to 2011

	2007		2008		2009		2010		2011	
	Avg. Units Capped	Percent	Avg. Units Capped	Percent	Avg. Units Capped	Percent	Avg. Units Capped	Percent	Avg. Units Capped	Percent
Jan	1.2	0.1%	3.1	0.3%	2.4	0.2%	2.3	0.2%	2.8	0.3%
Feb	4.2	0.4%	2.6	0.3%	1.1	0.1%	1.9	0.2%	2.3	0.2%
Mar	1.9	0.2%	2.7	0.3%	1.8	0.2%	2.5	0.2%	1.6	0.1%
Apr	1.3	0.1%	3.1	0.3%	1.8	0.2%	3.2	0.3%	2.8	0.3%
May	1.9	0.2%	2.1	0.2%	1.0	0.1%	4.5	0.4%	2.8	0.3%
Jun	6.0	0.6%	8.7	0.8%	1.3	0.1%	7.1	0.7%	4.3	0.4%
Jul	4.4	0.4%	5.7	0.6%	1.1	0.1%	9.3	0.9%	8.0	0.7%
Aug	9.6	0.9%	2.0	0.2%	3.0	0.3%	5.8	0.5%	3.2	0.3%
Sep	5.5	0.5%	4.8	0.5%	1.6	0.1%	6.2	0.6%	6.4	0.6%
Oct	5.0	0.5%	2.5	0.2%	1.2	0.1%	3.5	0.3%	4.3	0.4%
Nov	2.9	0.3%	2.2	0.2%	0.6	0.1%	3.1	0.3%	4.1	0.4%
Dec	4.7	0.5%	2.5	0.2%	1.3	0.1%	6.3	0.6%	4.7	0.4%

Table C-30 Average real-time, offer-capped MW: Calendar years 2007 to 2011

	2007		2008		2009		2010		2011	
	Avg. MW Capped	Percent	Avg. MW Capped	Percent	Avg. MW Capped	Percent	Avg. MW Capped	Percent	Avg. MW Capped	Percent
Jan	50	0.1%	99	0.1%	158	0.2%	124	0.1%	197	0.2%
Feb	125	0.1%	92	0.1%	92	0.1%	117	0.1%	125	0.2%
Mar	142	0.2%	117	0.2%	147	0.2%	216	0.3%	167	0.2%
Apr	48	0.1%	125	0.2%	151	0.2%	251	0.4%	267	0.4%
May	68	0.1%	59	0.1%	64	0.1%	337	0.5%	291	0.4%
Jun	190	0.2%	415	0.5%	103	0.1%	382	0.4%	330	0.4%
Jul	160	0.2%	202	0.2%	74	0.1%	473	0.5%	436	0.4%
Aug	314	0.3%	99	0.1%	137	0.2%	253	0.3%	245	0.3%
Sep	218	0.3%	182	0.2%	95	0.1%	378	0.5%	436	0.5%
Oct	153	0.2%	177	0.3%	105	0.2%	345	0.5%	319	0.4%
Nov	104	0.1%	157	0.2%	60	0.1%	382	0.5%	324	0.4%
Dec	146	0.2%	211	0.3%	128	0.2%	538	0.6%	330	0.4%

In order to help understand the frequency of offer capping in more detail, Table C-31 through Table C-35 show the number of generating units that met the specified criteria for total offer-capped run hours and percentage of offer-capped run hours for the years 2007 through 2011.

Table C-31 Offer-capped unit statistics: Calendar year 2007

	2007 Offer-Capped Hours					
Run Hours Offer-Capped, Percent Greater Than Or Equal To:	Hours ≥ 500	Hours ≥ 400 and < 500	Hours ≥ 300 and < 400	Hours ≥ 200 and < 300	Hours ≥ 100 and < 200	Hours ≥ 1 and < 100
90%	2	1	3	2	6	0
80% and < 90%	15	3	0	14	13	6
75% and < 80%	0	0	0	0	2	4
70% and < 75%	0	0	2	0	1	3
60% and < 70%	0	0	0	1	3	24
50% and < 60%	1	0	0	0	0	21
25% and < 50%	0	0	0	0	0	51
10% and < 25%	0	0	0	3	12	37

Table C-32 Offer-capped unit statistics: Calendar year 2008

	2008 Offer-Capped Hours					
Run Hours Offer-Capped, Percent Greater Than Or Equal To:	Hours ≥ 500	Hours ≥ 400 and < 500	Hours ≥ 300 and < 400	Hours ≥ 200 and < 300	Hours ≥ 100 and < 200	Hours ≥ 1 and < 100
90%	0	0	0	1	1	4
80% and < 90%	0	0	1	0	4	10
75% and < 80%	0	0	5	4	4	11
70% and < 75%	1	0	1	2	4	9
60% and < 70%	1	0	0	4	4	30
50% and < 60%	0	0	2	3	3	20
25% and < 50%	0	5	10	11	10	57
10% and < 25%	1	0	1	0	6	48

Table C-33 Offer-capped unit statistics: Calendar year 2009

	2009 Offer-Capped Hours					
Run Hours Offer-Capped, Percent Greater Than Or Equal To:	Hours ≥ 500	Hours ≥ 400 and < 500	Hours ≥ 300 and < 400	Hours ≥ 200 and < 300	Hours ≥ 100 and < 200	Hours ≥ 1 and < 100
90%	0	0	0	0	1	6
80% and < 90%	0	0	0	1	2	13
75% and < 80%	0	0	0	1	0	6
70% and < 75%	0	0	0	1	1	9
60% and < 70%	0	0	0	0	1	21
50% and < 60%	0	0	0	0	1	19
25% and < 50%	0	1	1	2	3	56
10% and < 25%	1	0	0	0	6	53

Table C-34 Offer-capped unit statistics: Calendar year 2010

	2010 Offer-Capped Hours					
Run Hours Offer-Capped, Percent Greater Than Or Equal To:	Hours ≥ 500	Hours ≥ 400 and < 500	Hours ≥ 300 and < 400	Hours ≥ 200 and < 300	Hours ≥ 100 and < 200	Hours ≥ 1 and < 100
90%	2	0	0	0	1	13
80% and < 90%	0	2	1	7	8	13
75% and < 80%	0	0	0	0	3	7
70% and < 75%	3	0	0	0	4	13
60% and < 70%	0	1	1	1	0	34
50% and < 60%	1	0	0	5	0	22
25% and < 50%	4	2	4	9	17	41
10% and < 25%	2	0	0	4	2	37

Table C-35 Offer-capped unit statistics: Calendar year 2011

	2011 Offer-Capped Hours					
Run Hours Offer-Capped, Percent Greater Than Or Equal To:	Hours ≥ 500	Hours ≥ 400 and < 500	Hours ≥ 300 and < 400	Hours ≥ 200 and < 300	Hours ≥ 100 and < 200	Hours ≥ 1 and < 100
90%	0	0	0	6	9	4
80% and < 90%	0	0	1	2	5	9
75% and < 80%	0	0	0	0	3	3
70% and < 75%	0	0	0	0	0	10
60% and < 70%	0	1	0	1	1	20
50% and < 60%	0	0	0	2	13	23
25% and < 50%	2	0	0	5	19	70
10% and < 25%	9	2	0	0	2	49

Local Energy Market Structure: TPS Results

The three pivotal supplier test is applied by PJM on an ongoing basis in order to determine whether offer capping is required to prevent the exercise of local market power for any constraint.

The MMU analyzed the results of the three pivotal supplier tests conducted by PJM for the Real-Time Energy Market for the period January 1, 2011, through December 31, 2011. The three pivotal supplier test is applied every time the system solution indicates that out of merit resources are needed to relieve a transmission constraint. Only uncommitted resources, which would be started to relieve the transmission constraint, are subject to offer capping. Already committed units that can provide incremental relief cannot be offer capped. The results of the TPS test are shown for tests that could have resulted in offer capping and tests that resulted in offer capping.

Overall, the results confirm that the three pivotal supplier test results in offer capping when the local market is structurally noncompetitive and does not result in offer capping when that is not the case. Local markets are noncompetitive when the number of suppliers is relatively small. The results show that the percentage of tests where one or more suppliers pass the three pivotal supplier test increases as the number of suppliers increases and as the residual supply in the local market increases. The results also show that the percentage of tests where one or more suppliers fail the three pivotal supplier test increases as the number of suppliers decreases and the residual supply in the local market decreases.

This appendix provides data on the TPS tests that were applied in PJM control zones that had congestion from one or more constraints for 100 or more hours. In 2011, the AECO, AEP, AP, BGE, ComEd, DLCO, Dominion, Met-Ed, PECO and PSEG Control Zones experienced congestion resulting from one or more constraints binding for 100 or more hours. Using the three pivotal supplier results for calendar year 2011, actual competitive conditions associated with each of these frequently binding constraints were analyzed in real time.[1] The DAY, DPL, JCPL, PPL, PENELEC, Pepco and RECO Control Zones were not affected by constraints binding for 100 or more hours. Information is provided, by qualifying zone, for each constraint including the number of tests applied, the number of tests that could have resulted in offer capping, and the number of tests in which one or more owners passed and/or failed the three pivotal supplier test.[2] Additional information is provided for each constraint including the average MW required to relieve a constraint, the average supply available, the average number of owners included in each test and the average number of owners that passed or failed each test.

AECO Control Zone Results

In 2011, there was only one constraint in the AECO Control Zone that occurred for more than 100 hours. Table D-1 and Table D-2 show the results of the three pivotal supplier test applied to this constraint. Table D-1 provides the number of tests applied, the number and percentage of tests with one or more passing owners, and the number and percentage of tests with one or more failing owners. Table D-1 shows that all 2,977 on peak, and all 1,752 off peak tests resulted in one or more owners failing. Table D-2 shows the average constraint relief required on the constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market and the average number of owners passing and failing. Table D-2 shows that on an average, there was only one owner with available supply on peak and one owner off peak for the Shieldalloy - Vineland line. The three pivotal supplier test results reflect this, as all tests were failed.

1 See the Technical Reference for PJM Markets, Section 8,"Three Pivotal Supplier Test" for a more detailed explanation of the three pivotal supplier test.

2 The three pivotal supplier test in the Real-Time Energy Market is applied by PJM as necessary and may be applied multiple times within a single hour for a specific constraint. Each application of the test is done in a five-minute interval.

Table D-1 Three pivotal supplier results summary for constraints located in the AECO Control Zone: Calendar year 2011

Constraint	Period	Total Tests Applied	Tests with One or More Passing Owners	Percent Tests with One or More Passing Owners	Tests with One or More Failing Owners	Percent Tests with One or More Failing Owners
Shieldalloy - Vineland	Peak	2,977	0	0%	2,977	100%
	Off Peak	1,752	0	0%	1,752	100%

Table D-2 Three pivotal supplier test details for constraints located in the AECO Control Zone: Calendar year 2011[3]

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Shieldalloy - Vineland	Peak	11	12	1	0	1
	Off Peak	10	12	1	0	1

Table D-3 Summary of three pivotal supplier tests applied to uncommitted units for constraints located in the AECO Control Zone: Calendar year 2011

Constraint	Period	Total Tests Applied	Total Tests that Could Have Resulted in Offer Capping	Percent Total Tests that Could Have Resulted in Offer Capping	Total Tests Resulted in Offer Capping	Percent Total Tests Resulted in Offer Capping	Tests Resulted in Offer Capping as Percent of Tests that Could Have Resulted in Offer Capping
Shieldalloy - Vineland	Peak	2,977	6	0%	0	0%	0%
	Off Peak	1,752	6	0%	0	0%	0%

Table D-4 Three pivotal supplier results summary for constraints located in the AEP Control Zone: Calendar year 2011

Constraint	Period	Total Tests Applied	Tests with One or More Passing Owners	Percent Tests with One or More Passing Owners	Tests with One or More Failing Owners	Percent Tests with One or More Failing Owners
Brues - West Bellaire	Peak	12,484	0	0%	12,484	100%
	Off Peak	10,417	0	0%	10,417	100%
Carnegie - Tidd	Peak	5,553	0	0%	5,553	100%
	Off Peak	3,035	0	0%	3,035	100%
Cloverdale	Peak	1,736	134	8%	1,696	98%
	Off Peak	2,474	106	4%	2,443	99%
Dumont - Stillwell	Peak	1,972	229	12%	1,814	92%
	Off Peak	982	142	14%	908	92%
Kammer - Ormet	Peak	2,820	0	0%	2,820	100%
	Off Peak	964	0	0%	964	100%
Ruth - Turner	Peak	2,472	0	0%	2,472	100%
	Off Peak	2,401	0	0%	2,401	100%
Wolfcreek	Peak	2,470	0	0%	2,470	100%
	Off Peak	2,777	0	0%	2,777	100%

Table D-5 Three pivotal supplier test details for constraints located in the AEP Control Zone: Calendar year 2011[4]

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Brues - West Bellaire	Peak	23	29	1	0	1
	Off Peak	22	34	1	0	1
Carnegie - Tidd	Peak	14	40	1	0	1
	Off Peak	12	41	1	0	1
Cloverdale	Peak	225	318	10	0	10
	Off Peak	195	269	8	0	8
Dumont - Stillwell	Peak	194	250	13	1	12
	Off Peak	143	208	12	2	10
Kammer - Ormet	Peak	34	48	1	0	1
	Off Peak	18	34	1	0	1
Ruth - Turner	Peak	23	4	1	0	1
	Off Peak	20	4	1	0	1
Wolfcreek	Peak	30	17	2	0	2
	Off Peak	32	17	2	0	2

3 Average Effective Supply was incorrectly reported in prior State of the Market Reports.
4 Average Effective Supply was incorrectly reported in prior State of the Market Reports..

Table D-3 shows the subset of three pivotal supplier tests from Table D-1 that could have resulted in the offer capping of uncommitted units and those tests that did result in offer capping for the Shieldalloy - Vineland line in the AECO zone. Only six out of 2,977 tests applied to offline, uncommitted units that were eligible for offer capping on peak. Only six out of 1,752 tests were applied to offline, uncommitted units that were eligible for offer capping off peak. None of the tests resulted in offer capping. The results reflect the fact that units that are already running cannot be offer capped. Only uncommitted units, which would be started to provide constraint relief, are eligible to be offer capped.

AEP Control Zone Results

In 2011, there were seven constraints that occurred for more than 100 hours in the AEP Control Zone. Table D-4 and Table D-5 show the results of the three pivotal supplier tests applied to the constraints in the AEP Control Zone. Table D-4 provides the number of tests applied, the number and percentage of tests with one or more passing owners, and the number and percentage of tests with one or more failing owners. Table D-4 shows that most of the tests resulted in one or more owners failing. Table D-5 shows the average constraint relief required on the constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market and the average number of owner passing and failing. Table D-5 shows that for four of the seven constraints, the average number of owners with available supply was one.

Table D-6 shows the total tests applied for the eight constraints in the AEP zone, the subset of three pivotal supplier tests that could have resulted in offer capping and the portion of those tests that did result in offer capping. The results reflect the fact that units that are already running cannot be offer capped. Only uncommitted units, which would be started to provide constraint relief, are eligible to be offer capped. Table D-6 shows that four percent or fewer of the tests applied to the seven constraints in the AEP zone could have resulted in offer capping. For three of the seven constraints, none of the tests could have resulted in offer capping.

AP Control Zone Results

In 2011, there were four constraints that occurred for more than 100 hours in the AP Control Zone. Table D-7 and Table D-8 show the results of the three pivotal supplier tests applied to the constraints in the AP Control Zone. Table D-7 provides the number of tests applied, the number and percentage of tests with one or more passing owners, and the number and percentage of tests with one or more failing owners. Table D-7 shows that most of the tests resulted in one or more owners failing. Table D-8 shows the average constraint relief required on the constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market and the average number of owner passing and failing. Table D-8 shows that for two of the four constraints, the average number of owners with available supply was two or fewer.

Table D-6 Summary of three pivotal supplier tests applied to uncommitted units for constraints located in the AEP Control Zone: Calendar year 2011

Constraint	Period	Total Tests Applied	Total Tests that Could Have Resulted in Offer Capping	Percent Total Tests that Could Have Resulted in Offer Capping	Total Tests Resulted in Offer Capping	Percent Total Tests Resulted in Offer Capping	Tests Resulted in Offer Capping as Percent of Tests that Could Have Resulted in Offer Capping
Brues - West Bellaire	Peak	12,484	0	0%	0	0%	0%
	Off Peak	10,417	1	0%	0	0%	0%
Carnegie - Tidd	Peak	5,553	0	0%	0	0%	0%
	Off Peak	3,035	0	0%	0	0%	0%
Cloverdale	Peak	1,736	64	4%	37	2%	58%
	Off Peak	2,474	28	1%	8	0%	29%
Dumont - Stillwell	Peak	1,972	13	1%	1	0%	8%
	Off Peak	982	10	1%	1	0%	10%
Kammer - Ormet	Peak	2,820	0	0%	0	0%	0%
	Off Peak	964	0	0%	0	0%	0%
Ruth - Turner	Peak	2,472	0	0%	0	0%	0%
	Off Peak	2,401	0	0%	0	0%	0%
Wolfcreek	Peak	2,470	4	0%	1	0%	25%
	Off Peak	2,777	5	0%	0	0%	0%

Table D-7 Three pivotal supplier results summary for constraints located in the AP Control Zone: Calendar year 2011

Constraint	Period	Total Tests Applied	Tests with One or More Passing Owners	Percent Tests with One or More Passing Owners	Tests with One or More Failing Owners	Percent Tests with One or More Failing Owners
Bedington	Peak	3,624	0	0%	3,624	100%
	Off Peak	26	0	0%	26	100%
Belmont	Peak	5,642	0	0%	5,642	100%
	Off Peak	2,377	0	0%	2,377	100%
Mount Storm	Peak	3,316	454	14%	3,148	95%
	Off Peak	580	20	3%	576	99%
Wylie Ridge	Peak	5,909	824	14%	5,548	94%
	Off Peak	6,996	1000	14%	6,642	95%

Table D-8 Three pivotal supplier test details for constraints located in the AP Control Zone: Calendar year 2011[5]

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Bedington	Peak	36	27	2	0	2
	Off Peak	27	12	2	0	2
Belmont	Peak	28	16	1	0	1
	Off Peak	27	21	1	0	1
Mount Storm	Peak	322	478	13	1	11
	Off Peak	360	505	10	0	9
Wylie Ridge	Peak	132	126	14	1	12
	Off Peak	165	188	13	1	12

Table D-9 Summary of three pivotal supplier tests applied to uncommitted units for constraints located in the AP Control Zone: Calendar year 2011

Constraint	Period	Total Tests Applied	Total Tests that Could Have Resulted in Offer Capping	Percent Total Tests that Could Have Resulted in Offer Capping	Total Tests Resulted in Offer Capping	Percent Total Tests Resulted in Offer Capping	Tests Resulted in Offer Capping as Percent of Tests that Could Have Resulted in Offer Capping
Bedington	Peak	3,624	5	0%	0	0%	0%
	Off Peak	26	0	0%	0	0%	0%
Belmont	Peak	5,642	3	0%	0	0%	0%
	Off Peak	2,377	0	0%	0	0%	0%
Mount Storm	Peak	3,316	91	3%	37	1%	41%
	Off Peak	580	11	2%	2	0%	18%
Wylie Ridge	Peak	5,909	115	2%	47	1%	41%
	Off Peak	6,996	145	2%	51	1%	35%

Table D-10 Three pivotal supplier results summary for constraints located in the BGE Control Zone: Calendar year 2011

Constraint	Period	Total Tests Applied	Tests with One or More Passing Owners	Percent Tests with One or More Passing Owners	Tests with One or More Failing Owners	Percent Tests with One or More Failing Owners
Glenarm - Windy Edge	Peak	3,554	0	0%	3,554	100%
	Off Peak	1,137	0	0%	1,137	100%
Graceton - Raphael Road	Peak	5,869	2,256	38%	4,845	83%
	Off Peak	7,140	1,941	27%	6,393	90%
Northwest	Peak	2,746	430	16%	2,643	96%
	Off Peak	978	320	33%	872	89%
Riverside	Peak	2,336	0	0%	2,336	100%
	Off Peak	334	0	0%	334	100%

Table D-11 Three pivotal supplier test details for constraints located in the BGE Control Zone: Calendar year 2011[6]

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Glenarm - Windy Edge	Peak	23	11	1	0	1
	Off Peak	22	14	1	0	1
Graceton - Raphael Road	Peak	77	156	10	3	7
	Off Peak	83	156	9	2	7
Northwest	Peak	71	108	9	1	8
	Off Peak	69	128	9	2	7
Riverside	Peak	30	37	1	0	1
	Off Peak	64	60	1	0	1

5 Average Effective Supply was incorrectly reported in prior State of the Market Reports.
6 Average Effective Supply was incorrectly reported in prior State of the Market Reports.

Table D-9 shows the total tests applied for the ten constraints in the AP zone, the subset of three pivotal supplier tests that could have resulted in offer capping and the portion of those tests that did result in offer capping. The results reflect the fact that units that are already running cannot be offer capped. Only uncommitted units, which would be started to provide constraint relief, are eligible to be offer capped. Table D-9 shows that three percent or fewer of the tests applied to the four constraints in the AP zone could have resulted in offer capping. None of the constraints had more than one percent of its tests result in offer capping.

BGE Control Zone Results

In 2011, there were four constraints that occurred for more than 100 hours in the BGE Control Zone. Table D-10 and Table D-11 show the results of the three pivotal supplier tests applied to the constraints in the BGE Control Zone. Table D-10 provides the number of tests applied, the number and percentage of tests with one or more passing owners, and the number and percentage of tests with one or more failing owners. Table D-10 shows that for two of the four constraints, all of the tests resulted in one or more owners failing. Table D-11 shows the average constraint relief required on the constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market and the average number of owners passing and failing. Table D-11 shows that for two of the four constraints, there was only one owner, on average, with available supply to relieve the constraint, both on peak and off peak.

Table D-12 shows the total tests applied for the four constraints in the BGE zone, the subset of three pivotal supplier tests that could have resulted in offer capping and the portion of those tests that did result in offer capping. The results reflect the fact that units that are already running cannot be offer capped. Only uncommitted units, which would be started to provide constraint relief, are eligible to be offer capped. Table D-12 shows that two percent or fewer of the tests applied to the four constraints in the BGE zone could have resulted in offer capping and that one percent or fewer of their tests resulted in offer capping.

ComEd Control Zone Results

In 2011, there were five constraints that occurred for more than 100 hours in the ComEd Control Zone. Table D-13 and Table D-14 show the results of the three pivotal supplier tests applied to the constraints in the ComEd Control Zone. Table D-13 provides the number of tests

Table D-12 Summary of three pivotal supplier tests applied to uncommitted units for constraints located in the BGE Control Zone: Calendar year 2011

Constraint	Period	Total Tests Applied	Total Tests that Could Have Resulted in Offer Capping	Percent Total Tests that Could Have Resulted in Offer Capping	Total Tests Resulted in Offer Capping	Percent Total Tests Resulted in Offer Capping	Tests Resulted in Offer Capping as Percent of Tests that Could Have Resulted in Offer Capping
Glenarm - Windy Edge	Peak	3,554	3	0%	2	0%	67%
	Off Peak	1,137	4	0%	1	0%	25%
Graceton - Raphael Road	Peak	5,869	34	1%	7	0%	21%
	Off Peak	7,140	57	1%	10	0%	18%
Northwest	Peak	2,746	13	0%	8	0%	62%
	Off Peak	978	18	2%	7	1%	39%
Riverside	Peak	2,336	16	1%	14	1%	88%
	Off Peak	334	3	1%	3	1%	100%

Table D-13 Three pivotal supplier results summary for constraints located in the ComEd Control Zone: Calendar year 2011

Constraint	Period	Total Tests Applied	Tests with One or More Passing Owners	Percent Tests with One or More Passing Owners	Tests with One or More Failing Owners	Percent Tests with One or More Failing Owners
Burnham - Munster	Peak	2,979	270	9%	2,798	94%
	Off Peak	4,743	279	6%	4,643	98%
East Frankfort - Crete	Peak	3,005	12	0%	3,000	100%
	Off Peak	5,957	13	0%	5,952	100%
Electric Jct - Nelson	Peak	915	4	0%	912	100%
	Off Peak	1,085	4	0%	1,083	100%
Nelson - Cordova	Peak	547	5	1%	546	100%
	Off Peak	183	0	0%	183	100%
Pleasant Valley - Belvidere	Peak	461	0	0%	461	100%
	Off Peak	872	0	0%	872	100%

applied, the number and percentage of tests with one or more passing owners, and the number and percentage of tests with one or more failing owners. Table D-13 shows that most of the tests resulted in one or more owners failing for all five constraints. Table D-14 shows the average constraint relief required on the constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market and the average number of owner passing and failing. The average number of owners with available supply was three or less for three out of five constraints.

Table D-15 shows the total tests applied for the five constraints in the ComEd zone, the subset of three pivotal supplier tests that could have resulted in offer capping and the portion of those tests that did result in offer capping. The results reflect the fact that units that are already running cannot be offer capped. Only uncommitted units, which would be started to provide constraint relief, are eligible to be offer capped. Table D-15 shows that one percent or fewer of the tests applied to the seven constraints in the AEP zone could have resulted in offer capping.

Table D-14 Three pivotal supplier test details for constraints located in the ComEd Control Zone: Calendar year 2011[7]

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Burnham - Munster	Peak	156	210	10	1	9
	Off Peak	151	207	6	0	6
East Frankfort - Crete	Peak	132	155	3	0	3
	Off Peak	126	132	3	0	3
Electric Jct - Nelson	Peak	38	26	3	0	3
	Off Peak	28	24	3	0	3
Nelson - Cordova	Peak	32	32	4	0	4
	Off Peak	36	38	2	0	2
Pleasant Valley - Belvidere	Peak	10	7	1	0	1
	Off Peak	5	4	1	0	1

Table D-15 Summary of three pivotal supplier tests applied to uncommitted units for constraints located in the ComEd Control Zone: Calendar year 2011

Constraint	Period	Total Tests Applied	Total Tests that Could Have Resulted in Offer Capping	Percent Total Tests that Could Have Resulted in Offer Capping	Total Tests Resulted in Offer Capping	Percent Total Tests Resulted in Offer Capping	Tests Resulted in Offer Capping as Percent of Tests that Could Have Resulted in Offer Capping
Burnham - Munster	Peak	2,979	20	1%	14	0%	70%
	Off Peak	4,743	11	0%	2	0%	18%
East Frankfort - Crete	Peak	3,005	1	0%	0	0%	0%
	Off Peak	5,957	5	0%	0	0%	0%
Electric Jct - Nelson	Peak	915	3	0%	2	0%	67%
	Off Peak	1,085	0	0%	0	0%	0%
Nelson - Cordova	Peak	547	6	1%	2	0%	33%
	Off Peak	183	0	0%	0	0%	0%
Pleasant Valley - Belvidere	Peak	461	0	0%	0	0%	0%
	Off Peak	872	0	0%	0	0%	0%

Table D-16 Three pivotal supplier results summary for constraints located in the DLCO Control Zone: Calendar year 2011

Constraint	Period	Total Tests Applied	Tests with One or More Passing Owners	Percent Tests with One or More Passing Owners	Tests with One or More Failing Owners	Percent Tests with One or More Failing Owners
Crescent	Peak	2,872	0	0%	2,872	100%
	Off Peak	108	0	0%	108	100%

Table D-17 Three pivotal supplier test details for constraints located in the DLCO Control Zone: Calendar year 2011[8]

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Crescent	Peak	31	32	1	0	1
	Off Peak	26	30	2	0	2

7 Average Effective Supply was incorrectly reported in prior State of the Market Reports.
8 Average Effective Supply was incorrectly reported in prior State of the Market Reports.

DLCO Control Zone Results

In 2011, there was only one constraint that occurred for more than 100 hours in the DLCO Control Zone. Table D-16 and Table D-17 show the results of the three pivotal supplier tests applied to the constraint in the DLCO Control Zone. Table D-16 provides the number of tests applied, the number and percentage of tests with one or more passing owners, and the number and percentage of tests with one or more failing owners. Table D-16 shows that all tests resulted in one or more owners failing. Table D-17 shows the average constraint relief required on the constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market and the average number of owner passing and failing. The average number of owners with available supply was one on peak and two off peak for the Crescent constraint.

Table D-18 shows the total tests applied for the Crescent constraint in the DLCO zone, the subset of three pivotal supplier tests that could have resulted in offer capping and the portion of those tests that did result in offer capping. The results reflect the fact that units that are already running cannot be offer capped. Only uncommitted units, which would be started to provide constraint relief, are eligible to be offer capped. Table D-18 shows that only 3 of the 2,980 applied tests could have resulted in offer capping and none of those tests resulted in offer capping.

Dominion Control Zone Results

In 2011, there were five constraints that occurred for more than 100 hours in the Dominion Control Zone. Table D-19 and Table D-20 show the results of the three pivotal supplier tests applied to the constraints in the Dominion Control Zone. Table D-19 provides the number of tests applied, the number and percentage of tests with one or more passing owners, and the number and percentage of tests with one or more failing owners. Table D-19 shows that most of the tests resulted in one or more owners failing for all constraints. Table D-20 shows the average constraint relief required on the constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market and the average number of owner passing and failing. The average number of owners with available supply was less than five on peak and off peak for all five constraints.

Table D-18 Summary of three pivotal supplier tests applied to uncommitted units for constraints located in the DLCO Control Zone: Calendar year 2011

Constraint	Period	Total Tests Applied	Total Tests that Could Have Resulted in Offer Capping	Percent Total Tests that Could Have Resulted in Offer Capping	Total Tests Resulted in Offer Capping	Percent Total Tests Resulted in Offer Capping	Tests Resulted in Offer Capping as Percent of Tests that Could Have Resulted in Offer Capping
Crescent	Peak	2,872	3	0%	0	0%	0%
	Off Peak	108	0	0%	0	0%	0%

Table D-19 Three pivotal supplier results summary for constraints located in the Dominion Control Zone: Calendar year 2011

Constraint	Period	Total Tests Applied	Tests with One or More Passing Owners	Percent Tests with One or More Passing Owners	Tests with One or More Failing Owners	Percent Tests with One or More Failing Owners
Chaparral - Carson	Peak	3,296	92	3%	3,255	99%
	Off Peak	1,206	49	4%	1,183	98%
Clover	Peak	9,288	12	0%	9,284	100%
	Off Peak	3,919	1	0%	3,919	100%
Danville - East Danville	Peak	4,272	1	0%	4,272	100%
	Off Peak	5,124	0	0%	5,124	100%
Halifax - Mount Laurel	Peak	2,722	0	0%	2,722	100%
	Off Peak	1,404	0	0%	1,404	100%
Hollymead - Charlottesville	Peak	2,366	0	0%	2,366	100%
	Off Peak	2,052	0	0%	2,052	100%

Table D-21 shows the total tests applied for the five constraints in the Dominion zone, the subset of three pivotal supplier tests that could have resulted in offer capping and the portion of those tests that did result in offer capping. The results reflect the fact that units that are already running cannot be offer capped. Only uncommitted units, which would be started to provide constraint relief, are eligible to be offer capped. Table D-21 shows that one percent or fewer of the tests applied to the five constraints in the Dominion zone could have resulted in offer capping.

Met-Ed Control Zone Results

In 2011, there was only one constraint that occurred for more than 100 hours in the Met-Ed Control Zone. Table D-22 and Table D-23 show the results of the three pivotal supplier tests applied to the constraint in the Met-Ed Control Zone. Table D-22 provides the number of tests applied, the number and percentage of tests with one or more passing owners, and the number and percentage of tests with one or more failing owners. Table D-22 shows that all of tests resulted in one or more owners failing. Table D-23 shows the average constraint relief required on the constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market and the average number of owner passing and failing.

Table D-24 shows the total tests applied for the one constraint in the Met-Ed zone, the subset of three pivotal supplier tests that could have resulted in offer capping and the portion of those tests that did result in offer capping. The results reflect the fact that units that are already running cannot be offer capped. Only uncommitted units, which would be started to provide constraint relief, are eligible to be offer capped. Table D-24 shows that one percent or fewer of the tests applied to the one constraint in the Met-Ed zone could have resulted in offer capping. Only 18 out of 2,970 on peak tests could have resulted in offer capping. Only 14 out of 2,970 on peak tests resulted in offer capping. Only 11 out of 1,153 tests applied off peak could have resulted in offer capping. All 11 of those off peak tests resulted in offer capping.

Table D-20 Three pivotal supplier test details for constraints located in the Dominion Control Zone: Calendar year 2011[9]

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Chaparral - Carson	Peak	93	132	5	0	5
	Off Peak	71	106	4	0	4
Clover	Peak	103	145	3	0	3
	Off Peak	92	161	2	0	2
Danville - East Danville	Peak	50	38	2	0	2
	Off Peak	53	42	2	0	2
Halifax - Mount Laurel	Peak	10	15	1	0	1
	Off Peak	9	14	1	0	1
Hollymead - Charlottesville	Peak	57	49	2	0	2
	Off Peak	91	63	2	0	2

Table D-21 Summary of three pivotal supplier tests applied to uncommitted units for constraints located in the Dominion Control Zone: Calendar year 2011

Constraint	Period	Total Tests Applied	Total Tests that Could Have Resulted in Offer Capping	Percent Total Tests that Could Have Resulted in Offer Capping	Total Tests Resulted in Offer Capping	Percent Total Tests Resulted in Offer Capping	Tests Resulted in Offer Capping as Percent of Tests that Could Have Resulted in Offer Capping
Chaparral - Carson	Peak	3,296	4	0%	1	0%	25%
	Off Peak	1,206	7	1%	0	0%	0%
Clover	Peak	9,288	67	1%	19	0%	28%
	Off Peak	3,919	21	1%	6	0%	29%
Danville - East Danville	Peak	4,272	10	0%	7	0%	70%
	Off Peak	5,124	25	0%	3	0%	12%
Halifax - Mount Laurel	Peak	2,722	0	0%	0	0%	0%
	Off Peak	1,404	0	0%	0	0%	0%
Hollymead - Charlottesville	Peak	2,366	2	0%	0	0%	0%
	Off Peak	2,052	4	0%	3	0%	75%

9 Average Effective Supply was incorrectly reported in prior State of the Market Reports.

PECO Control Zone Results

In 2011, there were three constraints that occurred for more than 100 hours in the PECO Control Zone. Table D-25 and Table D-26 show the results of the three pivotal supplier tests applied to the constraints in the PECO Control Zone. Table D-25 provides the number of tests applied, the number and percentage of tests with one or more passing owners, and the number and percentage of tests with one or more failing owners. Table D-25 shows that most of tests resulted in one or more owners failing. Table D-26 shows the average constraint relief required on the constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market and the average number of owner passing and failing. For two of the three constraints, on an average, there was only one owner with available supply to relieve the constraint.

Table D-22 Three pivotal supplier results summary for constraints located in the Met-Ed Control Zone: Calendar year 2011

Constraint	Period	Total Tests Applied	Tests with One or More Passing Owners	Percent Tests with One or More Passing Owners	Tests with One or More Failing Owners	Percent Tests with One or More Failing Owners
Cly - Collins	Peak	2,970	0	0%	2,970	100%
	Off Peak	1,153	0	0%	1,153	100%

Table D-23 Three pivotal supplier test details for constraints located in the Met-Ed Control Zone: Calendar year 2011[10]

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Cly - Collins	Peak	22	12	1	0	1
	Off Peak	22	11	1	0	1

Table D-24 Summary of three pivotal supplier tests applied to uncommitted units for constraints located in the Met-Ed Control Zone: Calendar year 2011

Constraint	Period	Total Tests Applied	Total Tests that Could Have Resulted in Offer Capping	Percent Total Tests that Could Have Resulted in Offer Capping	Total Tests Resulted in Offer Capping	Percent Total Tests Resulted in Offer Capping	Tests Resulted in Offer Capping as Percent of Tests that Could Have Resulted in Offer Capping
Cly - Collins	Peak	2,970	18	1%	14	0%	78%
	Off Peak	1,153	11	1%	11	1%	100%

Table D-25 Three pivotal supplier results summary for constraints located in the PECO Control Zone: Calendar year 2011

Constraint	Period	Total Tests Applied	Tests with One or More Passing Owners	Percent Tests with One or More Passing Owners	Tests with One or More Failing Owners	Percent Tests with One or More Failing Owners
Cromby	Peak	1,823	0	0%	1,823	100%
	Off Peak	565	0	0%	565	100%
Eddington - Holmesburg	Peak	5,500	3	0%	5,500	100%
	Off Peak	2,001	3	0%	2,001	100%
Emilie	Peak	4,538	0	0%	4,538	100%
	Off Peak	2,875	0	0%	2,875	100%

Table D-26 Three pivotal supplier test details for constraints located in the PECO Control Zone: Calendar year 2011[11]

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Cromby	Peak	16	16	1	0	1
	Off Peak	18	19	1	0	1
Eddington - Holmesburg	Peak	63	110	2	0	2
	Off Peak	62	102	3	0	3
Emilie	Peak	45	108	1	0	1
	Off Peak	45	118	1	0	1

10 Average Effective Supply was incorrectly reported in prior State of the Market Reports.
11 Average Effective Supply was incorrectly reported in prior State of the Market Reports.

Table D-27 shows the total tests applied for the constraints in the PECO zone, the subset of three pivotal supplier tests that could have resulted in offer capping and the portion of those tests that did result in offer capping. The results reflect the fact that units that are already running cannot be offer capped. Only uncommitted units, which would be started to provide constraint relief, are eligible to be offer capped. Table D-27 shows that two percent or fewer of the tests applied to the constraints in the PECO zone could have resulted in offer capping. For two of the three constraints, none of the tests resulted in offer capping. For the third constraint, all 20 tests that could have resulted in offer capping did result in offer capping.

PSEG Control Zone Results

In 2011, there were two constraints that occurred for more than 100 hours in the PSEG Control Zone. Table D-28 and Table D-29 show the results of the three pivotal supplier tests applied to the constraints in the PSEG Control Zone. Table D-28 provides the number of tests applied, the number and percentage of tests with one or more passing owners, and the number and percentage of tests with one or more failing owners. Table D-28 shows that most of the tests resulted in one or more owners failing. Table D-29 shows the average constraint relief required on the constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market and the average number of owner passing and failing. For both of the constraints, the average number of owners with available supply was three or less.

Table D-30 shows the total tests applied for the two constraints in the PSEG zone, the subset of three pivotal supplier tests that could have resulted in offer capping and the portion of those tests that did result in offer capping. The results reflect the fact that units that are already running cannot be offer capped. Only uncommitted units, which would be started to provide constraint relief, are eligible to be offer capped. Table D-30 shows that one percent or fewer of the tests applied to the two constraints in the PSEG zone could have resulted in offer capping. The South Mahwah - Waldwick constraint had only 94 of its 13,812 applied tests that could have result in offer capping. Only 58 of the 13,812 applied tests did result in offer capping. The Sewaren - Woodbridge constraint had none of its 4,060 applied tests that could have resulted in offer capping.

Table D-27 Summary of three pivotal supplier tests applied to uncommitted units for constraints located in the PECO Control Zone: Calendar year 2011

Constraint	Period	Total Tests Applied	Total Tests that Could Have Resulted in Offer Capping	Percent Total Tests that Could Have Resulted in Offer Capping	Total Tests Resulted in Offer Capping	Percent Total Tests Resulted in Offer Capping	Tests Resulted in Offer Capping as Percent of Tests that Could Have Resulted in Offer Capping
Cromby	Peak	1,823	8	0%	8	0%	100%
	Off Peak	565	12	2%	12	2%	100%
Eddington - Holmesburg	Peak	5,500	1	0%	0	0%	0%
	Off Peak	2,001	1	0%	0	0%	0%
Emilie	Peak	4,538	0	0%	0	0%	0%
	Off Peak	2,875	0	0%	0	0%	0%

Table D-28 Three pivotal supplier results summary for constraints located in the PSEG Control Zone: Calendar year 2011

Constraint	Period	Total Tests Applied	Tests with One or More Passing Owners	Percent Tests with One or More Passing Owners	Tests with One or More Failing Owners	Percent Tests with One or More Failing Owners
Sewaren - Woodbridge	Peak	3,006	0	0%	3,006	100%
	Off Peak	1,054	0	0%	1,054	100%
South Mahwah - Waldwick	Peak	8,981	1	0%	8,981	100%
	Off Peak	4,831	5	0%	4,828	100%

Table D-29 Three pivotal supplier test details for constraints located in the PSEG Control Zone: Calendar year 2011[12]

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Sewaren - Woodbridge	Peak	10	40	1	0	1
	Off Peak	11	22	1	0	1
South Mahwah - Waldwick	Peak	70	65	3	0	3
	Off Peak	56	55	2	0	2

Table D-30 Summary of three pivotal supplier tests applied to uncommitted units for constraints located in the PSEG Control Zone: Calendar year 2011

Constraint	Period	Total Tests Applied	Total Tests that Could Have Resulted in Offer Capping	Percent Total Tests that Could Have Resulted in Offer Capping	Total Tests Resulted in Offer Capping	Percent Total Tests Resulted in Offer Capping	Tests Resulted in Offer Capping as Percent of Tests that Could Have Resulted in Offer Capping
Sewaren - Woodbridge	Peak	3,006	0	0%	0	0%	0%
	Off Peak	1,054	0	0%	0	0%	0%
South Mahwah - Waldwick	Peak	8,981	72	1%	42	0%	58%
	Off Peak	4,831	22	0%	16	0%	73%

12 Average Effective Supply was incorrectly reported in prior State of the Market Reports.

Interchange Transactions

Submitting Transactions into PJM

In competitive wholesale power markets, market participants' decisions to buy and sell power are based on actual and expected prices. If contiguous wholesale power markets incorporate security constrained nodal pricing, well designed interface pricing provides economic signals for import and export decisions by market participants, although those signals may be attenuated by a variety of institutional arrangements.

In order to understand the data on imports and exports, it is important to understand the institutional details of completing import and export transactions. These include the Open Access Same-Time Information System (OASIS), North American Electric Reliability Council (NERC) Tags, neighboring balancing authority check out processes, and transaction curtailment rules.[1]

Real-Time Market

Market participants that wish to transact energy into, out of, or through PJM in the Real-Time Energy Market are required to make their requests to PJM via the NERC Interchange Transaction Tag (NERC Tag). PJM's Enhanced Energy Scheduler (EES) software interfaces with NERC Tags to create an interface that both PJM market participants and PJM can use to evaluate and manage external transactions that affect the PJM RTO.

All PJM interchange transactions are required to be at least 45 minutes in duration. However, PJM system operators may make adjustments that cause a transaction or interval(s) of the transaction to violate this minimum duration.

Scheduling Requirements

External offers can be made either on the basis of an individual generator (resource specific offer) or an aggregate of generation supply (aggregate offer). Schedules are submitted to PJM by submitting a valid NERC Tag.

Specific timing requirements apply for the submission of schedules. Schedules can be submitted up to 20 minutes prior to the scheduled start time for hourly transactions. Schedules can be submitted up to 4 hours prior to the scheduled start time for transactions that are more than 24 hours in duration. For a schedule to be included in PJM's day-ahead checkout process, the NERC Tag must be approved by all entities who have approval rights, and be in a status of "Implemented", by 1400 (EPT) one day prior to start of schedule. Schedules utilizing the Real-Time with Price option, also known as dispatchable schedules, must be submitted prior to 1200 noon (EPT) the day prior to the scheduled start time. Schedules utilizing firm point-to-point transmission service must be submitted by 1000 (EPT) one day prior to start of schedule. Transactions utilizing firm point-to-point transmission submitted after 1000 (EPT) one day prior will be accommodated if practicable.

Acquiring Ramp

PJM allows market participants to reserve ramp while they complete their scheduling responsibilities. The ramp reservation is validated against the submitted NERC Tag to ensure the energy profile and path matches. Upon submission of a ramp reservation request, if PJM verifies ramp availability, the ramp reservation will move into a status of "Pending Tag" which means that it is a valid reservation that can be associated with a NERC Tag to complete the scheduling process.

Specific timing requirements apply for the submission of ramp reservations. Ramp reservations can be made up to 30 minutes prior to the scheduled start time for hourly transactions. Ramp reservations can be made up to 4 hours prior to start time for transactions that are more than 24 hours in duration. Ramp reservations utilizing the Real-Time with Price option must be made prior to 1200 noon (EPT) the day prior to the scheduled start time. Ramp reservations expire if they are not used.

Acquiring Transmission

All external transaction requests require a confirmed transmission reservation from the PJM OASIS.[2] Due to ramp limitations, PJM may require market participants to shift their transaction requests. If the market participant shifts the request up to one hour in either direction, they are not required to purchase additional transmission. If the market participant chooses to fix a ramp violation

1 The material in this section is based in part on PJM Manual M-41: Managing Interchange. See PJM. "M-41: Managing Interchange", Revision 03 (November 24, 2008).

2 For additional details see PJM. "*PJM Regional Practices document*" http://oasis.pjm.com.

by extending the duration of the transaction, they do not have to purchase additional transmission if the total MWh capacity of the transmission request is not exceeded, and the transaction does not extend beyond one hour prior to the start, or one hour past the end time of the transmission reservation.

Transmission Products

The OASIS products available for reservation include firm, network, non-firm and spot import service. The product type designated on the OASIS reservation determines when and how the transaction can be curtailed.

- **Firm.** Transmission service that is intended to be available at all times.
- **Network.** Transmission service that is for the sole purpose of serving network load. Network transmission service is only eligible to network customers.
- **Non-Firm.** Point-to-point transmission service under the PJM tariff that is reserved and scheduled on an as available basis and is subject to curtailment or interruption. Non-firm point-to-point transmission service is available for periods ranging from one hour to one month.
- **Spot Import.** The spot import service is an option for non-load serving entities to offer into the PJM spot market at the interface as price takers. Prior to April 2007, PJM did not limit spot import service. Effective April 2007, the availability of spot import service was limited by the Available Transmission Capacity (ATC) on the transmission path.

Source and Sink

For a real-time import energy transaction, when a market participant selects the Point of Receipt (POR) and Point of Delivery (POD) on their OASIS reservation, the source defaults to the associated interface price as defined by the POR/POD path. For example, if the selected POR is TVA and the POD is PJM, the source would initially default to TVA's Interface Pricing point (SouthIMP). At the time the energy is scheduled, if the Generation Control Area (GCA) on the NERC Tag represents physical flow entering PJM at an interface other than the SouthIMP Interface, the source would then default to that new interface. The sink bus is selected by the market participant at the time the OASIS reservation is made and can be any bus, hub or aggregate in the PJM footprint where LMP is calculated.

For a real-time export energy transaction, when a market participant selects the Point of Receipt (POR) and Point of Delivery (POD) on their OASIS reservation, the sink defaults to the associated interface price as defined by the POR/POD path. For example, if the selected POR is PJM and the POD is TVA, the sink would initially default to TVA's Interface Pricing point (SouthEXP). At the time the energy is scheduled, if the Load Control Area (LCA) on the NERC Tag represents physical flow leaving PJM at an interface other than the SouthEXP Interface, the sink would then default to that new interface. The source bus is selected by the market participant at the time the OASIS reservation is made and can be any bus, hub or aggregate in the PJM footprint where LMP is calculated.

For a real-time wheel through energy transaction, when a market participant selects the Point of Receipt (POR) and Point of Delivery (POD) on their OASIS reservation, both the source and sink default to the associated interface prices as defined by the POR/POD path. For example, if the selected POR is TVA and the POD is NYIS, the source would initially default to TVA's Interface Pricing point (SouthIMP), and the sink would initially default to NYIS's Interface Pricing point (NYIS). At the time the energy is scheduled, if the GCA on the NERC Tag represents physical flow entering PJM at an interface other than the SouthIMP Interface, the source would then default to that new interface. Similarly, if the LCA on the NERC Tag represents physical flow leaving PJM at an interface other than the NYIS Interface, the sink would then default to that new interface.

Real-Time Market Schedule Submission

Market participants enter schedules in PJM by submitting a valid NERC Tag. A NERC Tag can be submitted without a ramp reservation. When EES detects a NERC Tag that has been submitted without a ramp reservation, it will create a ramp reservation which will be evaluated against ramp, and approved or denied based on available ramp room at the time the NERC Tag is submitted.

Real-Time with Price Schedule Submission

Real-Time with Price schedules, also known as dispatchable schedules, differ from other schedules. To enter a Real-Time with Price schedule, the market participant must first make a ramp reservation in EES specifying "Real-Time with Price" and must enter a price associated with each energy block. Upon submission, the Real-Time with Price request will automatically move to the "Pending Tag" status, as Real-Time with Price schedules do not hold ramp. Once the information is entered in EES, a NERC Tag must be submitted with the ramp reservation associated on the NERC Tag. Upon implementation of the NERC Tag, PJM will curtail the tag to 0 MW. During the operating day, if the dispatchable transaction is to be loaded, PJM will then reload the tag. The process of issuing curtailments and reloading the tag continues through the operating day as the economics of the system dictate.

Dynamic Schedule Requirements

An entity that owns or controls a generating resource in the PJM Region may request that all or part of the generating resource's output be removed from the PJM Region, via dynamic scheduling of the output, to a load outside the PJM Region. An entity that owns or controls a generating resource outside of the PJM Region may request that all or part of the generating resource's output be added to the PJM Region, via dynamic scheduling of the output, to a load inside the PJM Region. Due to the complexity of these arrangements, requesting entities must coordinate with PJM and complete several steps before a dynamic schedule can be implemented. The requesting entity is responsible for submitting a dynamic NERC Tag to match the scheduled output of the generating resource.

Real-Time Evaluation and Checkout

PJM conducts an hourly checkout with each adjacent balancing authority using both the electronic approval of schedules and telephone calls. Once the tag has been approved by all parties with approval rights, the tag status moves to an "Implemented" status, and the schedule is ready for the adjacent balancing authority checkout.

PJM operators must verify all requested energy schedules with PJM's neighboring balancing authorities. Only if the neighboring balancing authority agrees with the expected interchange will the transaction flow. Both balancing authorities must enter the same values in their Energy Management Systems (EMS) to avoid inadvertent energy flows between balancing authorities. With the exception of the New York Independent System Operator (NYISO), all neighboring balancing authorities handle transaction requests in the same way as PJM. While the NYISO also requires NERC Tags, the NYISO utilizes their Market Information System (MIS) as their primary scheduling tool. The NYISO's real-time commitment (RTC) tool evaluates all bids and offers each hour, performs a least cost economic dispatch solution, and accepts or denies individual transactions in whole or in part based on this evaluation. Upon market clearing, the NYISO implements NERC Tag adjustments to match the output of the RTC. PJM and the NYISO can verify interchange transactions once the NYISO Tag adjustments are sent and approved. The results of the adjustments made by the NYISO affect PJM operations, as the adjustments often cause large swings in expected ramp for the next hour.

Real-Time with Price Evaluation and Checkout

Real-time with price schedules, also known as dispatchable schedules, are evaluated hourly to determine whether or not they will be loaded for the upcoming hour. Since real-time with price schedules do not hold ramp room, there may be times when the schedule is economic but will not be loaded because ramp is not available.

Curtailment of Transactions

Once a transaction has been implemented, energy flows between balancing authorities. Transactions can be curtailed based on economic and reliability considerations. There are three types of economic curtailments: curtailments of dispatchable schedules based on price; curtailments of transactions based on their OASIS designation as not willing to pay congestion; and self curtailments by market participant. Reliability curtailments are implemented by the balancing authorities and are termed TLRs or transmission loading relief.

Dispatchable transactions will be curtailed if the system operator does not believe that the transaction will be economic for the next hour. Not willing to pay congestion transactions will be curtailed if there is realized congestion between the designated source and sink. Transactions utilizing spot import service will be curtailed if the interface price where the transaction enters PJM reaches zero. All self curtailments must be requested on 15 minute intervals and will be approved only if there is available ramp.

Transmission Loading Relief (TLR)

TLRs are called to control flows on transmission facilities when economic redispatch cannot solve overloads on those facilities. TLRs are called to control flows related to external balancing authorities, as redispatch within an LMP market can generally resolve overloads on internal transmission facilities.

There are seven TLR levels and additional sublevels, determined by the severity of system conditions and whether the interchange transactions contributing to congestion on the impacted flowgates are using firm or non-firm transmission. Reliability coordinators are not required to implement TLRs in order. The TLR levels are described below.[3]

- **TLR Level 0 – TLR concluded:** A TLR Level 0 is initiated when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) violations are mitigated and the system is returned to a reliable state. Upon initiation of a TLR Level 0, transactions with the highest transmission priorities are reestablished first when possible. The purpose of a TLR Level 0 is to inform all affected parties that the TLR has been concluded.
- **TLR Level 1 – Potential SOL or IROL Violations:** A TLR Level 1 is initiated when the transmission system is still in a secure state but a reliability coordinator anticipates a transmission or generation contingency or other operating problem that could lead to a potential violation. No actions are required during a TLR Level 1. The purpose of a TLR Level 1 is to inform other reliability coordinators of a potential SOL or IROL.
- **TLR Level 2 – Hold transfers at present level to prevent SOL or IROL Violations:** A TLR Level 2 is initiated when the transmission system is still in a secure state but one or more transmission facilities are expected to approach, are approaching or have reached their SOL or IROL. The purpose of a TLR Level 2 is to prevent additional transactions that have an adverse affect on the identified transmission facility(ies) from starting.
- **TLR Level 3a – Reallocation of transmission service by curtailing interchange transactions using non-firm point-to-point transmission service to allow interchange transactions using higher priority transmission service:** A TLR Level 3a is initiated when the transmission system is secure but one or more transmission facilities are expected to approach, or are approaching their SOL or IROL, when there are transactions using non-firm point-to-point transmission service that have a greater than 5 percent effect on the facility and when there are transactions using a higher priority point-to-point transmission reservation that wish to begin. Curtailments to transactions in a TLR 3a begin on the top of the hour only. The purpose of TLR Level 3a is to curtail transactions using lower priority non-firm point-to-point transmission to allow transactions using higher priority transmission to flow.
- **TLR Level 3b – Curtail interchange transactions using non-firm transmission service arrangements to mitigate a SOL or IROL violation:** A TLR Level 3b is initiated when one or more transmission facilities is operating above their SOL or IROL; such operation is imminent and it is expected that facilities will exceed their reliability limits if corrective action is not taken; or one or more transmission facilities will exceed their SOL or IROL upon the removal from service of a generating unit or other transmission facility and transactions are flowing that are using non-firm point-to-point transmission service and have a greater than 5 percent impact on the facility. Curtailments of transactions in a TLR 3b can occur at any time within the operating hour. The purpose of a TLR Level 3b is to curtail transactions using non-firm point-to-point transmission service which impact the constraint by greater than 5 percent in order to mitigate a SOL or IROL.
- **TLR Level 4 – Reconfigure Transmission:** A TLR Level 4 is initiated when one or more transmission facilities are above their SOL or IROL limits or such operation is imminent and it is expected that facilities will exceed their reliability limits if corrective action is not taken. Upon issuance of a TLR Level 4, all transactions using non-firm point-to-point transmission service, in the current and next hour, with a greater than 5 percent impact on the facility, have been curtailed

3 Additional details regarding the TLR procedure can be found in NERC. "Standard IRO-006-4 – Reliability Coordination – Transmission Loading Relief" (October 23, 2007) (Accessed March 1, 2012) <http://www.nerc.com/files/IRO-006-4.pdf> (KB).

under the TLR 3b. The purpose of a TLR Level 4 is to request that the affected transmission operators reconfigure transmission on their system, or arrange for reconfiguration on other transmission systems, to mitigate the constraint if a SOL or IROL violation is imminent or occurring.

- **TLR Level 5a – Reallocation of transmission service by curtailing interchange transactions using firm point-to-point transmission service on a pro rata basis to allow additional interchange transactions using firm point-to-point transmission service:** A TLR Level 5a is initiated when one or more transmission facilities are at their SOL or IROL; all interchange transactions using non-firm point-to-point transmission service that affect the constraint by greater than 5 percent have been curtailed; no additional effective transmission configuration is available; and a transmission provider has been requested to begin an interchange transaction using previously arranged firm point-to-point transmission service. Curtailments to transactions in a TLR 5a begin on the top of the hour only. The purpose of a TLR Level 5a is to curtail existing interchange transactions, which are using firm point-to-point transmission service, on a pro rata basis to allow for the newly requested interchange transaction, also using firm point-to-point transmission service, to flow.

- **TLR Level 5b – Curtail transactions using firm point-to-point transmission service to mitigate an SOL or IROL violation:** A TLR Level 5b is initiated when one or more transmission facilities are operating above their SOL or IROL or such operation is imminent; one or more transmission facilities will exceed their SOL or IROL upon removal of a generating unit or another transmission facility; all interchange transactions using non-firm point-to-point transmission service that affect the constraint by greater than 5 percent have been curtailed; and no additional effective transmission configuration is available. Unlike a TLR 5a, curtailments to transactions in a TLR 5b can occur at any time within the operating hour. The purpose of a TLR Level 5b is to curtail transactions using firm point-to-point transmission service to mitigate a SOL or IROL.

- **TLR Level 6 – Emergency Procedures:** A TLR Level 6 is initiated when all interchange transactions using both non-firm and firm point-to-point transmission have been curtailed and one or more transmission facilities are above their SOL or IROL, or will exceed their SOL or IROL upon removal of a generating unit or other transmission facility. The purpose of a TLR Level 6 is to instruct balancing authorities and transmission providers to redispatch generation, reconfigure transmission or reduce load to mitigate the critical condition.

Table E-1 below shows the historic number of TLRs, by level, issued by reliability coordinators in the Eastern Interconnection since 2004.

Day-Ahead Market

For Day-Ahead Market scheduling, EES serves only as an interface to the eMarket application. Day-Ahead Market transactions are evaluated in the Day-Ahead Market, and the results sent to EES. No checkout is performed on Day-Ahead Market schedules as they are considered financially binding transactions and not physical schedules.

Submitting Day-Ahead Market Schedules

Market participants can submit Day-Ahead Market schedules to the eMarket application through EES. These schedules do not require a NERC Tag, as they are not physical schedules for actual flow. Day-Ahead Market schedules require an OASIS number to be associated upon submission.[4] The path is identified on the OASIS reservation. In addition to the selection of OASIS and pricing points, the market participant must enter their energy profile. ”Fixed” act as a price taker, “dispatchable” set a floor or ceiling price criteria for acceptance and “up-to” set the maximum amount of congestion the market participant is willing to pay.

NYISO Issues

If interface prices were defined in a comparable manner by PJM and the NYISO, if identical rules governed external transactions in PJM and the NYISO, if time lags were not built into the rules governing such transactions and if no risks were associated with such transactions, then prices at the interfaces would be expected to be very close and the level of transactions would be expected to be related to any price differentials. The fact that none of these conditions exists is important in explaining

4 On September 17, 2010, up-to congestion transactions no longer required a willing to pay congestion transmission reservation. Additional details can be found under the "Up-to Congestion" heading in *Section 8: Interchange Transactions* of this report.

Table E-1 TLRs by level and reliability coordinator: Calendar years 2004 through 2011

Year	Reliability Coordinator	3a	3b	4	5a	5b	6	Total
2004	EES	47	15	88	1	3	0	154
	FPL	0	1	0	0	0	0	1
	IMO	33	2	0	0	0	0	35
	MAIN	8	3	0	0	0	0	11
	MISO	650	210	409	9	3	0	1,281
	PJM	270	115	35	4	5	0	429
	SOCO	1	0	0	0	0	0	1
	SWPP	185	107	14	5	6	0	317
	TVA	56	17	0	0	1	0	74
	VACN	8	1	0	0	0	0	9
Total		1,258	471	546	19	18	0	2,312
2005	EES	49	10	101	6	3	1	170
	IMO	57	2	0	0	0	0	59
	MISO	776	296	200	5	14	0	1,291
	PJM	201	94	29	1	1	0	326
	SWPP	193	78	19	4	2	0	296
	TVA	172	61	12	2	3	0	250
	VACN	0	3	0	0	0	0	3
	VACS	2	2	0	1	0	0	5
Total		1,450	546	361	19	23	1	2,400
2006	EES	71	20	93	5	1	0	190
	ICTE	11	6	14	0	1	0	32
	IMO	1	0	0	0	0	0	1
	MISO	414	214	136	17	19	0	800
	ONT	27	3		0	0	0	30
	PJM	88	30	18	0	0	0	136
	SWPP	189	121	201	11	13	0	535
	TVA	90	52	31	1	2	0	176
	VACS	0	1	0	0	0	0	1
Total		891	447	493	34	36	0	1,901
2007	ICTE	95	42	139	19	10	0	305
	MISO	414	273	89	17	26	0	819
	ONT	47	4	1	0	0	0	52
	PJM	46	31	1	1	1	0	80
	SWPP	777	935	35	53	24	0	1,824
	TVA	45	40	25	2	2	0	114
	VACS	4	1	0	0	0	0	5
Total		1428	1326	290	92	63	0	3199

the observed relationship between interface prices and inter-ISO power flows, and those price differentials.[5]

There are institutional differences between PJM and the NYISO markets that are relevant to observed differences in border prices.[6] The NYISO requires hourly bids or offer prices for each export or import transaction and clears its market for each hour based on hourly bids.[7] Import transactions to the NYISO are treated by the NYISO as generator bids at the NYISO/PJM proxy bus. Export transactions are treated by the NYISO as price-capped load offers. Competing bids and offers are evaluated along with other NYISO resources and a proxy bus price is derived. Bidders are notified of the outcome. This process is repeated, with new bids and offers each hour. A significant lag exists between the time when offers and bids are submitted to the NYISO and the time when participants are notified that they have cleared. The lag is a result of the Real-Time Commitment (RTC) system and the fact that transactions can only be scheduled at the beginning of the hour.

As a result of the NYISO's RTC timing, market participants must submit bids or offers by no later than 75 minutes before the operating hour. The bid or offer includes the MW volume desired and, for imports into NYISO, the asking price or, for exports out of the NYISO, the price the participants are willing to pay. The required lead time means that participants make price and MW

5 See also the discussion of these issues in the *2005 State of the Market Report*, Section 4, "Interchange Transactions" (March 8, 2006).

6 See the *2005 State of the Market Report* (March 8, 2006), pp. 195-198.

7 See NYISO. "NYISO Transmission Services Manual," Version 2.0 (February 1, 2005) (Accessed March 1, 2012) <http://www.nyiso.com/public/webdocs/documents/manuals/operations/tran_ser_mnl.pdf> (463 KB).

Table E-1 TLRs by level and reliability coordinator: Calendar years 2004 through 2011 (continued)

2008	ICTE	132	41	112	43	25	0	353
	MISO	320	235	21	8	15	0	599
	ONT	153	7	1	0	0	0	161
	PJM	55	92	2	0	1	0	150
	SWPP	687	1,077	11	59	44	0	1,878
	TVA	48	72	29	5	4	0	158
Total		1,395	1,524	176	115	89	0	3,299
2009	ICTE	82	35	55	75	18	1	266
	MISO	199	140	2	15	25	0	381
	NYIS	101	8	0	0	0	0	109
	ONT	169	0	0	0	0	0	169
	PJM	61	68	0	0	0	0	129
	SWPP	383	1,466	33	77	24	0	1,983
	TVA	8	22	29	0	0	0	59
	VACS	0	1	0	0	0	0	1
Total		1,003	1,740	119	167	67	1	3,097
2010	ICTE	72	25	149	50	30	0	326
	MISO	123	93	0	15	18	0	249
	NYIS	104	0	0	0	0	0	104
	ONT	94	5	0	1	0	0	100
	PJM	65	45	0	0	0	0	110
	SWPP	244	1,049	19	63	32	0	1,407
	TVA	37	64	8	1	6	0	116
	VACS	1	1	0	0	0	0	2
Total		740	1,282	176	130	86	0	2,414
2011	ICTE	23	12	123	54	48	0	260
	MISO	92	30	1	9	9	0	141
	NYIS	161	0	0	0	0	0	161
	ONT	88	0	0	0	0	0	88
	PJM	34	28	0	0	0	0	62
	SWPP	292	298	1	25	22	0	638
	TVA	75	99	9	2	15	0	200
	VACS	9	3	0	0	0	0	12
Total		774	470	134	90	94	0	1,562

bids or offers based on expected prices. Transactions are accepted only for a single hour.

Under PJM operating practices, in the Real-Time Market, participants must make a request to import or export power at one of PJM's interfaces at least 20 minutes before the desired start which can be any quarter hour.[8] The duration of the requested transaction can vary from 45 minutes to an unlimited amount of time. Generally, PJM market participants provide only the MW, the duration and the direction of the real-time transaction. While bid prices for transactions are allowed in PJM, less than 1 percent of all transactions submit an associated price. Transactions are accepted, with virtually no lag, in order of submission, based on whether PJM has the capability to import or export the requested MW. If transactions do not submit a price, the transactions are priced at the real-time price for their scheduled imports or exports. As in the NYISO, the required lead time means that participants must make offers to buy or sell MW based on expected prices, but the required lead time is substantially shorter in the PJM market.

The NYISO rules provide that the RTC results should be available 45 minutes before the operating hour. Winning bidders then have 25 minutes from the time when the RTC results indicate that their transaction will flow to meet PJM's 20-minute notice requirement. To get a transaction cleared with PJM, the market participant must have a valid NERC Tag, an OASIS reservation and a PJM ramp reservation. Each of these requirements takes time to process.

The length of required lead times in both markets may be a contributor to the observed relationship between price differentials and flows. Market conditions can change significantly in a relatively short time. The resulting uncertainty could weaken the observed relationship between contemporaneous interface prices and flows.

8 See PJM. "Manual 41: Managing Interchange" (November 24, 2008) (Accessed March 1, 2012) <http://www.pjm.com/documents/~/media/documents/manuals/m41.ashx> (291 KB).

Consolidated Edison Company (Con Edison) and Public Service Electric and Gas Company (PSE&G) Wheeling Contracts

To help meet the demand for power in New York City, Con Edison uses electricity generated in upstate New York and wheeled through New York and New Jersey. A common path is through Westchester County using lines controlled by the NYISO. Another path is through northern New Jersey using lines controlled by PJM. This wheeled power creates loop flow across the PJM system. The Con Edison/PSE&G contracts governing the New Jersey path evolved during the 1970s and were the subject of a Con Edison complaint to the FERC in 2001. In May 2005, the FERC issued an order setting out a protocol developed by the two companies, PJM and the NYISO.[9] In July 2005, the protocol was implemented. Con Edison filed a protest with the FERC regarding the delivery performance in January 2006.[10] In August 2007, the FERC denied a rehearing request on Con Edison's complaints regarding protocol performance and refunds.[11] PJM continued to operate under the terms of the protocol through 2010.

The contracts provide for the delivery of up to 1,000 MW of power from Con Edison's Ramapo Substation in Rockland County, New York, to PSE&G at its Waldwick Switching Substation in Bergen County, New Jersey. PSE&G wheels the power across its system and delivers it to Con Edison across lines connecting directly into New York City (Figure E-1). Two separate contracts cover these wheeling arrangements. A 1975 agreement covers delivery of up to 400 MW through Ramapo (New York) to PSE&G's Waldwick Switching Station (New Jersey) then to the New Milford Switching Station (New Jersey) via the J line and ultimately from the Linden Switching Station (New Jersey) to the Goethals Substation (New York) and from the Hudson Generating Station (New Jersey) to the Farragut Switching Station (New York), via the A and B feeders, respectively. A 1978 agreement covers delivery of up to an additional 600 MW through Ramapo to Waldwick then to Fair Lawn, via the K line, and ultimately through a second Hudson-to-Farragut line, the C feeder. In 2001, Con Edison alleged that PSE&G had under delivered on the agreements and asked the FERC to resolve the issue.

Initial Implementation of the FERC Protocol

In May 2005, the FERC issued an order setting out a protocol developed by the four parties to address the issues raised by Con Edison.[12] The protocol was implemented in July 2005.

The Day-Ahead Energy Market Process

The protocol allows Con Edison to elect up to the flow specified in each contract through the PJM Day-Ahead Energy Market. These elections are transactions in the PJM Day-Ahead Energy Market. The 600 MW contract is for firm service and the 400 MW contract has a priority higher than non-firm service but less than firm service. These elections obligate PSE&G to pay congestion costs associated with the daily elected level of service under the 600 MW contract and obligate Con Edison to pay congestion costs associated with the daily elected level of service under the 400 MW contract. The interface prices for this transaction are not defined PJM interface prices, but are defined in the protocol based on the actual facilities governed by the protocol.

Under the FERC order, PSE&G is assigned FTRs associated with the 600 MW contract. The PSE&G FTRs are treated like all other FTRs. In 2011, PSE&G's revenues were greater than its congestion charges by $778,879 after adjustments (PSE&G's revenues were less than its congestion charges by $1,028,909 in 2010.) Under the FERC order, Con Edison receives credits on an hourly basis for its elections under the 400 MW contract from a pool containing any excess congestion revenue after hourly FTRs are funded. In 2011, Con Edison's congestion credits were $2,319,278 more than its day-ahead congestion charges (Credits had been $3,066,001 less than charges in 2010). Table E-2 shows the monthly details for both PSE&G and Con Edison.

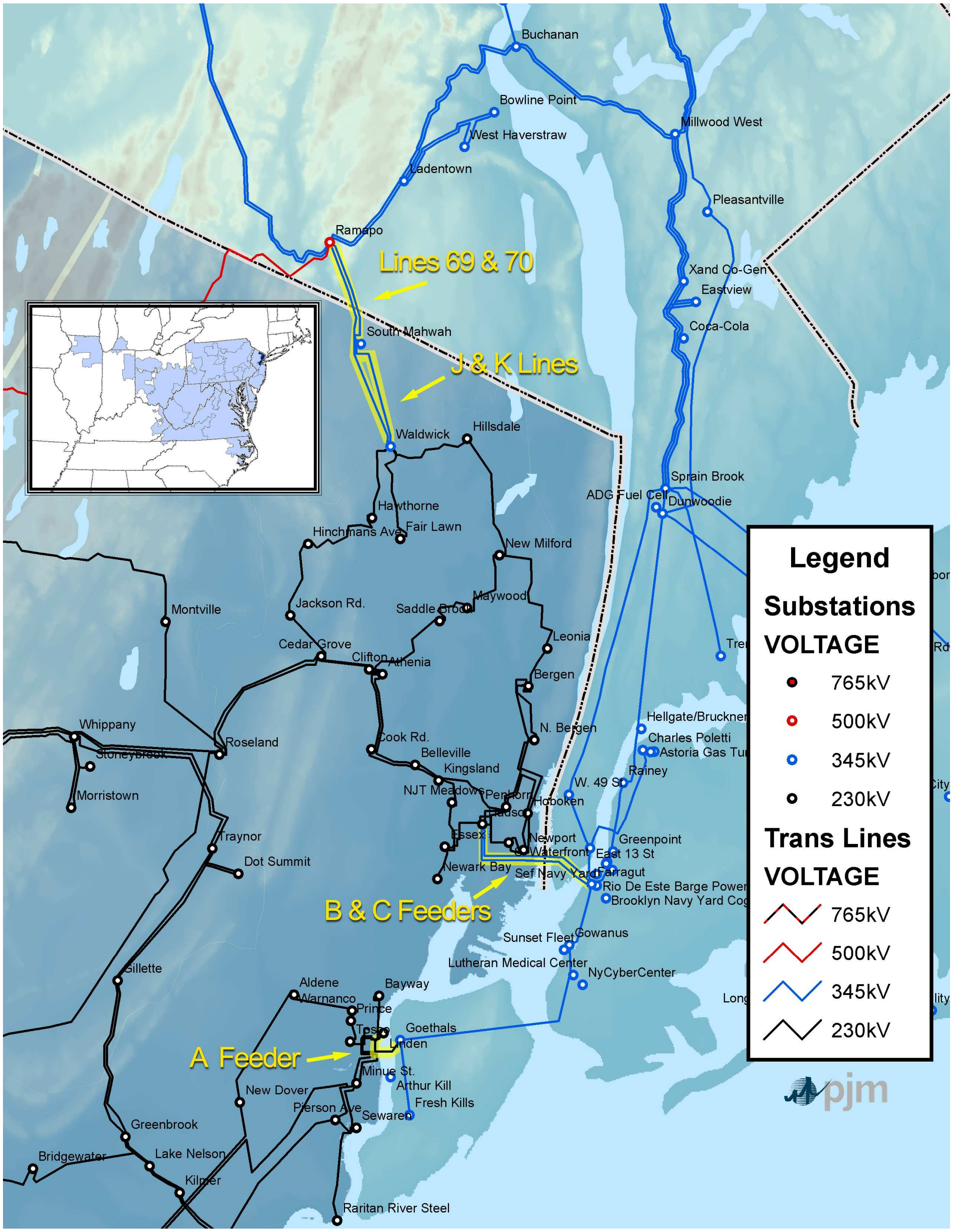
9 111 FERC ¶ 61,228 (2005).

10 "Protest of the Consolidated Edison Company of New York, Inc.", Protest, Docket No. EL02-23-000 (January 30, 2006).

11 120 FERC ¶ 61,161

12 111 FERC ¶ 61,228 (2005).

Figure E-1 Con Edison and PSE&G wheel



The protocol states:

> If there is congestion in PJM that affects the portion of the wheel that is associated with the 400 MW contract, PJM shall re-dispatch for the portion of the 400 MW contract for which ConEd specified it was willing to pay congestion, and ConEd shall pay for the re-dispatch. ConEd will be credited back for any congestion charges paid in the hour to the extent of any excess congestion revenues collected by PJM that remain after congestion credits are paid to all other firm transmission customers. Such credits to ConEd shall not exceed congestion payments owed or made by it.[13]

In effect, Con Edison has been given congestion credits that are the equivalent of a class of FTRs covering positive congestion with subordinated rights to revenue. However, Con Edison is not treated as having an FTR when congestion is negative. An FTR holder in that position would pay the negative congestion credits, but Con Edison does not. The protocol's provisions about congestion payments clearly cover congestion charges and offsetting congestion credits, but are not explicit on the treatment of Con Edison's negative congestion credits, which were -$2,715,707 in 2011. The parties should address this issue.

The Real-Time Energy Market Process

Under the terms of the protocol, Con Edison can make a real-time election of its desired flow for each hour in the Real-Time Energy Market. If this election differs from its day-ahead schedule, the company is subject to the resultant charges or credits. This occurred in 1.2 percent of the hours in 2011.

After years of litigation concerning whether or on what terms Con Edison's protocol would be renewed, PJM filed on February 23, 2009 a settlement on behalf of the parties to subsequent proceedings to resolve remaining issues with these contracts and their proposed rollover of the agreements under the PJM OATT.[14] By order issued September 16, 2010, the Commission approved this settlement,[15] which extends Con Edison's special protocol indefinitely. The Commission rejected objections raised first by NRG and FERC trial staff, and later by the MMU that this arrangement is discriminatory and inconsistent with the Commission's open access transmission policy.[16]

13 *PJM Interconnection, L.L.C.*, Operating Protocol for the Implementation of Commission Opinion No. 476, Docket No. EL02-23-000 (Phase II) (Effective: July 1, 2005), Original Sheet No. 6 <http://www.pjm.com/~/media/documents/agreements/20050701-attachment-iv-operating-protocol.ashx> (327 KB).

14 See Docket Nos. ER08-858-000, et al. The settling parties are the New York Independent System Operator, Inc. (NYISO), Con Ed, PSE&G, PSE&G Energy Resources & Trading LLC and the New Jersey Board of Public Utilities.

15 132 FERC ¶ 61,221.

16 *See, e.g.*, Motion to Intervene Out-of-Time and Comments of the Independent Market Monitor for PJM in Docket No. ER08-858-000, et al. (May 11, 2010).

Table E-2 Con Edison and PSE&G wheel settlements data: Calendar year 2011

		Con Edison			PSE&G		
		Day Ahead	Balancing	Total	Day Ahead	Balancing	Total
January	Congestion Charge	($63,871)	($35)	($63,906)	($1,666,133)	$0	($1,666,133)
	Congestion Credit			$1,415			($1,666,701)
	Adjustments			$15,121			$2,588
	Net Charge			($80,442)			($2,020)
February	Congestion Charge	($67,206)	$0	($67,206)	($1,753,211)	$0	($1,753,211)
	Congestion Credit			$67			($1,754,139)
	Adjustments			$0			($288)
	Net Charge			($67,273)			$1,216
March	Congestion Charge	($304,075)	($1)	($304,076)	($2,881,691)	$0	($2,881,691)
	Congestion Credit			$230			($2,869,877)
	Adjustments			$7			($1,005)
	Net Charge			($304,313)			($10,809)
April	Congestion Charge	($870,350)	$0	($870,350)	($4,211,372)	$0	($4,211,372)
	Congestion Credit			$132			($4,211,808)
	Adjustments			$0			($909)
	Net Charge			($870,483)			$1,345
May	Congestion Charge	$132,405	($23)	$132,382	($83)	$0	($83)
	Congestion Credit			$16,949			($146,647)
	Adjustments			($6)			$1,008,034
	Net Charge			$115,439			($861,471)
June	Congestion Charge	$108,202	$0	$108,202	$246,668	$0	$246,668
	Congestion Credit			$68,480			$215,208
	Adjustments			$0			($1,152)
	Net Charge			$39,722			$32,612
July	Congestion Charge	($569,345)	$0	($569,345)	($854,018)	$0	($854,018)
	Congestion Credit			$8,094			($854,687)
	Adjustments			($1)			($800)
	Net Charge			($577,438)			$1,469
August	Congestion Charge	($358,757)	($33)	($358,790)	($538,136)	$0	($538,136)
	Congestion Credit			$41,467			($543,794)
	Adjustments			$48			($1,028)
	Net Charge			($400,306)			$6,686
September	Congestion Charge	($122,265)	($870)	($123,135)	($395,803)		($395,803)
	Congestion Credit			$5,831			($414,487)
	Adjustments			$290			($803)
	Net Charge			($129,256)			$19,488
October	Congestion Charge	($37,616)	$0	($37,616)	($454,781)	$0	($454,781)
	Congestion Credit			$88			($460,193)
	Adjustments			$131			($752)
	Net Charge			($37,835)			$6,164
November	Congestion Charge	$955	($56)	$900	$10,537	$0	$10,537
	Congestion Credit			$228			$1,541
	Adjustments			$10			($769)
	Net Charge			$661			$9,765
December	Congestion Charge	($21,216)	($1,453)	($22,669)	($82,332)	$0	($82,332)
	Congestion Credit			$3,155			($98,217)
	Adjustments			$12			($791)
	Net Charge			($25,836)			$16,676
Total	Congestion Charge	($2,173,141)	($2,471)	($2,175,611)	($12,580,355)	$0	($12,580,355)
	Congestion Credit			$146,137			($12,803,800)
	Adjustments			$15,611			$1,002,325
	Net Charge			($2,337,360)			($778,879)

Ancillary Service Markets

This appendix covers two areas related to Ancillary Service Markets: area control error and the details of regulation availability and price determination.

Area Control Error (ACE)

Area control error (ACE) is a real-time metric used by PJM operators to measure the instantaneous MW imbalance between load plus net interchange and generation within PJM.[1] PJM dispatchers seek to ensure grid reliability by balancing ACE. A dispatcher's success in doing so is measured by control performance standard 1 (CPS1) and balancing authority ACE limit (BAAL) performance. These measurements are mandated by the North American Electric Reliability Council (NERC).

In the absence of a severe grid disturbance, the primary tool used by dispatchers to minimize ACE is regulation. Regulation is defined as a variable amount of energy under automatic control which is independent of economic cost signal and is obtainable within five minutes. Regulation contributes to maintaining the balance between load and generation by moving the output of selected generators up and down via an automatic generation control (AGC) signal.[2]

Resources wishing to participate in the Regulation Market must pass certification and submit to random testing. Certification requires that resources be capable of and responsive to AGC. After receiving certification, all participants in the Regulation Market are tested to ensure that regulation capacity is fully available at all times. Testing occurs at times of minimal load fluctuation. During testing, units must respond to a regulation test pattern for 40 minutes and must reach their offered regulation capacity levels, up and down, within five minutes. Units whose monitored response is less than their offered regulation capacity have their regulating capacity reduced by PJM.[3]

During 2008 an experimental battery-powered regulation unit was installed at the PJM facility. Observation of this unit reveals that new types of units will require that PJM's regulation unit certification testing procedure as administered by PJM's Performance Compliance group be modified, perhaps tailored to the specific unit types. The test as it is now designed measures the ability of the unit to respond to its regulation min/max within five minutes. This has always been the critical regulating metric for steam and CT units. But other types of units can meet this criterion easily yet still be inadequate for regulation because they lack the capacity to regulate for the entire hour in the event that regulation is almost completely above or below the regulation set point. Such units might include battery, pumped hydro, and inertial regulation units. During 2011, PJM modified its regulation rules to establish a minimum 0.1 MW capability for generating, storage and demand response units in order to qualify for regulation. PJM is currently studying significant modifications to the regulation market clearing procedure and regulation resource qualifying rules to promote new sources of regulation. Phase I implementation is expected in the late Spring of 2012. Among the changes will be implementation of real time performance evaluation designed to measure the accuracy and precision of regulation in response to the regulation signal. Another change will be the implementation of a dynamic (fast) regulation signal which regulation resources may choose to follow.

Control Performance Standard 1 (CPS1) and Balancing Authority ACE Limit (BAAL)

- Control Performance Standard 1 (CPS1) and Balancing Authority Ace Limit (BAAL) are standard metrics used to measure and report the effectiveness of ACE control. The purpose of the CPS1/BAAL standards is to maintain interconnection frequency within a predefined frequency profile under all conditions (normal and abnormal), to prevent frequency-related instability, unplanned tripping of load or generation, or uncontrolled separation or cascading outages that adversely impact the reliability of the interconnection.
- **CPS1.** CPS1 is a statistical measure of ACE variability and its relationship to frequency error. It is measured each minute. It is intended to provide

1 The PJM Manuals define ACE: "Area Control Error is a measure of the imbalance between sources of power and uses of power within the PJM RTO. This imbalance is calculated indirectly as the difference between scheduled and actual net interchange, plus the frequency bias contribution to yield ACE in megawatts. Two additional terms may be included in ACE under certain conditions--the time error bias term and PJM dispatcher adjustment term (manual add). These provide for automatic inadvertent interchange payback and error compensation, respectively." PJM. "Manual 12: Balancing Operations," Revision 23 (November 16, 2011), para. 3.1.1, "PJM Area Control Error" p. 11.

2 Regulation Market business rules are defined in PJM. "Manual 11: Energy & Ancillary Services Market Operations," Revision 49 (January 1, 2012), pp. 53-62.

3 See "Manual 12: Balancing Operations," Revision 23 (November 16, 2011), Section 4.5.5, pg. 49.

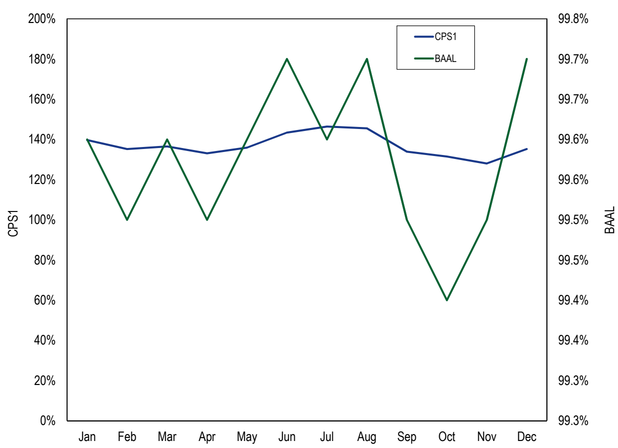
a frequency-sensitive evaluation of how well PJM meets its demand requirements with its supply resources. The maximum CPS1 score is 200 percent. This is achieved when either the frequency error is zero or the ACE is zero. The minimum passing score is 100 percent monthly.

- **BAAL.** Since August 1, 2005, PJM has participated in the NERC "Balancing Standard Proof-of-Concept Field Test" which establishes a new metric, balancing authority ACE limit (BAAL). PJM counts the total number of minutes that ACE complies with the BAAL limits (high and low) and divides it by the total number of minutes for a month, with a passing level for this goal being set at 99.0 percent for each month.

PJM's CPS/BAAL Performance

As Figure F-1 shows, PJM's performance for both CPS1 and BAAL metrics was acceptable in calendar year 2011.

Figure F-1 PJM CPS1/BAAL performance: Calendar year 2011



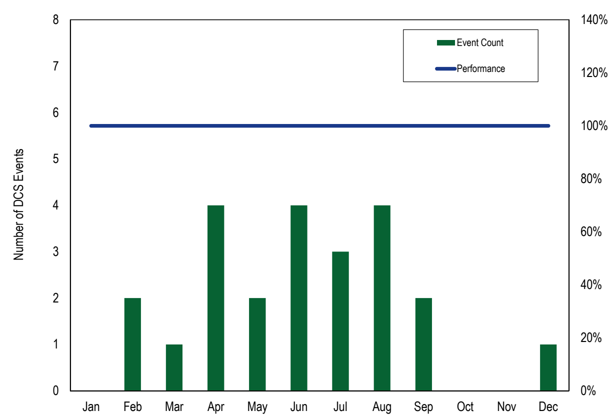
PJM dispatchers have to balance both ACE and frequency. Meeting the CPS1 and BAAL standards requires PJM dispatchers to maintain interconnection frequency within a predefined frequency profile under all conditions (normal and abnormal) to prevent frequency-related instability, unplanned tripping of load or generation, or uncontrolled separation or cascading outages that adversely impact the reliability of the interconnection.

PJM's DCS Performance

A dispatch performance metric that is directly related to synchronized reserve is the disturbance control standard (DCS).[4] DCS measures how well PJM dispatch recovers from a disturbance. A disturbance is defined as any ACE deviation greater than, or equal to, 80 percent of the magnitude of PJM's most severe single contingency loss. PJM currently interprets this to be any ACE deviation greater than 1,000 MW[5]. Compliance with the NERC DCS is recovery to zero or predisturbance level within 15 minutes.

PJM experienced 23 DCS events during calendar year 2011 and successfully recovered from all of them. Recovery times ranged from five minutes to 27 minutes. Figure F-2 illustrates the event count by month. All of the events resulted in low ACE. The solution in all 23 events was to declare a spinning event.

Figure F-2 DCS event count and PJM performance (By month): Calendar year 2011



Regulation Capacity, Daily Offers, Offered and Eligible, Hourly Assigned

The regulation market-clearing price (RMCP) is determined algorithmically by the PJM Market Operations Group. The market clearing software (SPREGO) creates a regulation supply curve as part of a two product, and two constraint optimized solution. The price of the

4 For more information on the NERC DCS, see "Standard BAL-002-0 – Disturbance Control Performance" (April 1, 2005) <www.nerc.com/files/BAL-002-0.pdf> (61 KB).

5 The *2010 State of the Market Report for PJM*, Volume II, Appendix F, p.659 "Ancillary Service Markets" indicated that the previous DCS threshold, 800 MW, applied for all of 2010. In fact, the threshold was changed to 1,000 MW on July 1 of 2010.

most expensive unit required to satisfy the regulation requirement is the RMCP. Calculating the supply curves for two products (regulation and synchronized reserve) with two constraints (energy and operating reserves) interactively is complicated, but necessary to achieve the lowest overall cost after first taking into account units that self schedule. In the event it is not possible to satisfy both regulation and synchronized reserve, regulation has the higher priority.

- **Regulation Capacity.** The sum of the regulation MW capability of all generating units which have qualified to participate in the Regulation Market is the theoretical maximum regulation capacity. This maximum regulation capacity varies over time because units that are certified for regulation may be decommissioned, fail regulation testing or be removed from the Regulation Market by their owners.
- **Regulation Offers.** All owners of generating units qualified to provide regulation may, but are not required to, offer their regulation capacity daily into the Regulation Market using the PJM market user interface. Regulating units may also self-schedule. Self-scheduled units have zero lost opportunity cost (LOC) and are the first to be assigned. Demand resources are eligible to offer regulation and did so for the first time in November of 2011. Demand resources have an LOC of zero. Under PJM rules, no more than 25 percent of the total regulation requirement may be supplied by demand resources. Total regulation offers are the sum of all regulation-capable units that offer regulation into the market for the day and that are not out of service or fully committed to provide energy. Owners of units that have entered offers into the PJM market user interface system have the ability to set unit status to "unavailable" for regulation for the day, or for a specific hour or set of hours. They also have the ability to change the amount of regulation MW offered in each hour. Unit owners do not have the ability to change their regulation offer price during a day. Starting in December, 2008, the PJM Market Users Interface allows regulation owners to enter cost data. For cost-based offers above $12 per MWh owners are required to enter cost data. All regulation offers that are not set to "Unavailable" for the day are summed to calculate the total daily regulation offered, a figure that changes each hour.
- **Regulation Offered and Eligible.** Sixty minutes before the market hour, PJM runs synchronized reserve and regulation market-clearing software (SPREGO) to determine the amount of Tier 2 synchronized reserve required, to develop regulation and synchronized reserve supply curves, to assign regulation and synchronized reserve to specific units and to determine the RMCP. All regulation resource units which have made offers in the daily Regulation Market are evaluated by SPREGO for regulation. SPREGO then excludes units according to the following ordered criteria: a) Daily or hourly unavailable units; b) Units for which the economic minimum is set equal to economic maximum (unless the unit is a hydroelectric unit or has self-scheduled regulation); c) Units which are assigned synchronized reserve; d) Units for which regulation minimum is set equal to regulation maximum (unless the unit is a hydroelectric unit or has self-scheduled regulation); e) Units that are offline (except combustion turbine units).

  Even after SPREGO has run and selected units for regulation, PJM dispatchers can dispatch units uneconomically for several reasons including: to control transmission constraints; to avoid overgeneration during periods of minimum generation alert; to remove a unit temporarily unable to regulate; or to remove a unit with a malfunctioning data link.

  For each offered and eligible unit in the regulation supply, the regulation total offer price is calculated using the sum of the unit's regulation cost-based offer and the opportunity cost based on the forecast LMP, unit economic minimum and economic maximum, regulation minimum and regulation maximum, startup costs and relevant offer schedule.[6] Based on this result, SPREGO determines if the period has three or fewer pivotal suppliers. If it does, all owners who are pivotal have their offers limited to the lesser of their cost or price offer. SPREGO uses price-based offers for those operators not offer capped and re-solves. This solution is final. The MW offered and the calculated regulation offered prices

6 See the *2011 State of the Market Report for PJM*, Volume II, Section 9, "Ancillary Services" for a full discussion of opportunity costs.

are used to create a regulation supply curve. The Regulation and Synchronized Reserve Markets are cleared interactively with the Energy Market and operating reserve requirements to minimize the cost of the combined products subject to reactive limits, resource constraints, unscheduled power flows, interarea transfer limits, resource distribution factors, self-scheduled resources, limited fuel resources, bilateral transactions, hydrological constraints, generation requirements and reserve requirements.

- **Cleared Regulation.** Regulation actually assigned by SPREGO is cleared regulation. The clearing price established by SPREGO becomes the final clearing price. In real time, units that have been assigned regulation and synchronized reserve are expected to provide regulation and synchronized reserve for the designated hour. At any time before or during the hour, PJM dispatchers can redispatch units for reliability reasons. Such redispatch leads to a disparity between cleared regulation and settled regulation.
- **Settled Regulation.** Units providing regulation are compensated at the clearing price times their actual MW provided (as opposed to cleared MW) plus any actual lost opportunity costs associated with providing regulation. The cost per MW of settled regulation can be higher than the regulation clearing price because there can be a difference between actual and cleared MW, as well as real-time versus forecast nodal prices.

Congestion and Marginal Losses

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

SMP, MLMP and CLMP are a product of the least cost, security constrained dispatch of system resources to meet system load. SMP is the incremental cost of energy, given the current dispatch, ignoring incremental considerations of losses and transmission constraints. Losses refer to energy lost to physical resistance in the transmission and distribution network as power is moved from generation to load. The greater the resistance of the system to flows of energy from generation to loads, the greater the losses of the system and the greater the generation of energy needed to meet a given level of load. Marginal losses are the incremental change in system power losses caused by changes in the system load and generation patterns.[1] Congestion results from physical limitations of elements of the transmission system to move power from point to point. Congestion costs reflect the incremental cost of relieving transmission constraints while maintaining system power balance. Congestion occurs when available, least-cost energy cannot be delivered to all loads 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.[2] 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.

LMP Components Real-Time and Day-Ahead

Table G-1 details the components of real-time LMP year over year basis from 2008 through 2011. Table G-2 compares 2010 real-time LMP components by zone to 2011 real-time LMP components by zone. Table G-3 compares 2010 real-time LMP components by hub to 2011 LMP components by hub. Table G-4 details the components of day-ahead LMP year over year basis from 2008 through 2011. Table G-5 compares 2010 day-ahead LMP components by zone to 2011 day-ahead LMP components by zone.

Table G-1 PJM real-time, simple average LMP components (Dollars per MWh): Calendar years 2010 and 2011

	Real-Time LMP	Energy Component	Congestion Component	Loss Component
2008	$66.40	$66.30	$0.06	$0.04
2009	$37.08	$37.01	$0.05	$0.03
2010	$44.83	$44.72	$0.07	$0.04
2011	$42.84	$42.77	$0.05	$0.02

Congestion Costs

Zonal Congestion Costs

Day-ahead and balancing congestion costs within zones for calendar years 2011 and 2010 are presented in Table G-6 and Table G-7.[3] 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 congestion costs. Load congestion payments, when positive, measure the congestion cost to load in an area. Load congestion payments, when negative, measure the 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 congestion credit to generation in an area. Generation congestion credits, when negative, measure the 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

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

2 This is referred to as dispatching units out of economic merit order. Economic merit order is the order of all generator offers from lowest to highest cost. Congestion occurs when loadings on transmission facilities mean the next unit in merit order cannot be used and a higher cost unit must be used in its place.

3 The total zonal congestion numbers were calculated as of March 2, 2012 and are, based on continued PJM billing updates, subject to change. As of March 2, 2012 the total zonal congestion related numbers presented here differed from the March 2, 2012 PJM totals by $0.72 Million, a discrepancy of 0.07 percent (.0007).

Table G-2 Zonal real-time, simple average LMP components (Dollars per MWh): Calendar years 2010 and 2011

	2010				2011			
	Real-Time LMP	Energy Component	Congestion Component	Loss Component	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AECO	$50.67	$44.72	$3.64	$2.31	$47.56	$42.77	$2.80	$1.99
AEP	$38.36	$44.72	($4.83)	($1.53)	$39.04	$42.77	($2.41)	($1.32)
AP	$44.62	$44.72	$0.12	($0.22)	$42.91	$42.77	$0.23	($0.09)
ATSI	NA	NA	NA	NA	$39.24	$41.20	($1.79)	($0.17)
BGE	$53.63	$44.72	$6.68	$2.23	$49.11	$42.77	$4.40	$1.93
ComEd	$33.35	$44.72	($8.58)	($2.80)	$33.30	$42.77	($6.92)	($2.55)
DAY	$38.11	$44.72	($5.69)	($0.91)	$39.22	$42.77	($2.81)	($0.74)
DLCO	$37.14	$44.72	($5.94)	($1.64)	$38.98	$42.77	($2.48)	($1.31)
Dominion	$51.04	$44.72	$3.82	$2.51	$47.33	$42.77	$2.32	$2.25
DPL	$50.94	$44.72	$5.35	$0.87	$46.38	$42.77	$3.02	$0.60
JCPL	$49.88	$44.72	$2.92	$2.23	$47.65	$42.77	$2.84	$2.04
Met-Ed	$49.14	$44.72	$3.47	$0.95	$45.82	$42.77	$2.34	$0.72
PECO	$49.11	$44.72	$2.84	$1.55	$46.56	$42.77	$2.37	$1.42
PENELEC	$43.07	$44.72	($1.42)	($0.24)	$42.95	$42.77	($0.19)	$0.37
Pepco	$47.75	$44.72	$2.34	$0.69	$45.84	$42.77	$2.42	$0.65
PPL	$50.97	$44.72	$3.99	$2.26	$48.17	$42.77	$3.30	$2.10
PSEG	$52.85	$44.72	$6.72	$1.41	$47.34	$42.77	$3.44	$1.13
RECO	$49.18	$44.72	$2.50	$1.95	$44.28	$42.77	($0.37)	$1.88

Table G-3 Hub real-time, simple average LMP components (Dollars per MWh): Calendar years 2010 and 2011

	2010				2011			
	Real-Time LMP	Energy Component	Congestion Component	Loss Component	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AEP Gen Hub	$35.56	$44.72	($6.15)	($3.01)	$37.08	$42.77	($3.00)	($2.69)
AEP-DAY Hub	$37.57	$44.72	($5.42)	($1.73)	$38.55	$42.77	($2.69)	($1.52)
ATSI Gen Hub	NA	NA	NA	NA	$38.87	$41.19	($1.77)	($0.55)
Chicago Gen Hub	$32.23	$44.72	($9.09)	($3.40)	$32.25	$42.77	($7.41)	($3.10)
Chicago Hub	$33.54	$44.72	($8.40)	($2.78)	$33.48	$42.77	($6.78)	($2.51)
Dominion Hub	$49.43	$44.72	$4.30	$0.40	$45.84	$42.77	$2.87	$0.20
Eastern Hub	$50.98	$44.72	$3.59	$2.66	$47.71	$42.77	$2.48	$2.47
N Illinois Hub	$33.08	$44.72	($8.61)	($3.02)	$33.07	$42.77	($6.95)	($2.76)
New Jersey Hub	$50.46	$44.72	$3.52	$2.21	$47.88	$42.77	$3.08	$2.03
Ohio Hub	$37.64	$44.72	($5.41)	($1.67)	$38.58	$42.77	($2.73)	($1.45)
West Interface Hub	$40.50	$44.72	($2.76)	($1.46)	$40.57	$42.77	($1.21)	($0.99)
Western Hub	$45.93	$44.72	$1.52	($0.31)	$43.56	$42.77	$0.88	($0.09)

Table G-4 PJM day-ahead, simple average LMP components (Dollars per MWh): Calendar years 2008 through 2011

	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
2008	$66.12	$66.43	($0.10)	($0.21)
2009	$37.00	$37.15	($0.06)	($0.09)
2010	$44.57	$44.61	$0.03	($0.06)
2011	$42.52	$42.72	($0.07)	($0.13)

Table G-5 Zonal day-ahead, simple average LMP components (Dollars per MWh): Calendar years 2010 and 2011

	2010				2011			
	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AECO	$50.44	$44.61	$2.96	$2.87	$47.86	$42.72	$2.84	$2.30
AEP	$38.30	$44.61	($4.05)	($2.26)	$39.32	$42.72	($1.93)	($1.47)
AP	$44.42	$44.61	$0.06	($0.25)	$42.96	$42.72	$0.29	($0.05)
ATSI	NA	NA	NA	NA	$39.34	$41.59	($1.37)	($0.88)
BGE	$53.24	$44.61	$5.75	$2.88	$48.66	$42.72	$3.69	$2.25
ComEd	$33.37	$44.61	($7.38)	($3.86)	$33.46	$42.72	($6.15)	($3.12)
DAY	$37.97	$44.61	($4.74)	($1.89)	$39.29	$42.72	($2.60)	($0.83)
DLCO	$37.84	$44.61	($4.75)	($2.02)	$38.89	$42.72	($2.52)	($1.31)
Dominion	$50.80	$44.61	$3.17	$3.02	$47.93	$42.72	$2.61	$2.59
DPL	$51.16	$44.61	$5.10	$1.45	$46.00	$42.72	$2.61	$0.66
JCPL	$50.21	$44.61	$2.59	$3.01	$47.59	$42.72	$2.48	$2.38
Met-Ed	$48.98	$44.61	$3.13	$1.24	$45.82	$42.72	$2.37	$0.72
PECO	$49.58	$44.61	$2.69	$2.28	$47.21	$42.72	$2.71	$1.78
PENELEC	$43.94	$44.61	($0.68)	$0.01	$42.79	$42.72	($0.17)	$0.24
Pepco	$47.67	$44.61	$2.20	$0.86	$45.68	$42.72	$2.37	$0.59
PPL	$50.89	$44.61	$3.04	$3.24	$48.32	$42.72	$3.06	$2.53
PSEG	$52.94	$44.61	$6.16	$2.18	$47.58	$42.72	$3.35	$1.51
RECO	$49.68	$44.61	$2.19	$2.88	$45.80	$42.72	$1.13	$1.95

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 ComEd Control Zone, AEP Control Zone and the AP Control Zone are examples of how a positive net congestion bill can result from very different combinations of load payments and generation credits. The ComEd Control Zone had the highest congestion charges, $239.0 million, of any control zone in 2011. 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.

The AEP Control Zone had the second highest congestion charges, $195.1 million of any control zone in 2011. The positive congestion costs in the AEP Control Zone were the result of negative load congestion payments offset by a bigger negative generation congestion credits. The AP Control Zone had the third highest congestion charges, $143.9 million, of any control zone in 2011. 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.

Table G-6 Congestion cost summary (By control zone): Calendar year 2011

	Congestion Costs (Millions)								
	Day Ahead				Balancing				
Control Zone	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total
AECO	$45.4	$15.7	$0.7	$30.5	($0.4)	$0.2	($1.0)	($1.6)	$28.9
AEP	($377.8)	($606.7)	$23.0	$251.8	$9.4	$37.2	($28.9)	($56.7)	$195.1
AP	$6.9	($143.7)	($2.6)	$148.1	$5.7	$8.0	($1.8)	($4.1)	$143.9
ATSI	($73.8)	($78.5)	$1.6	$6.3	$2.1	$8.0	($3.3)	($9.2)	($2.9)
BGE	$233.4	$180.3	$8.0	$61.0	$2.8	$1.8	($11.5)	($10.5)	$50.5
ComEd	($1,064.7)	($1,323.5)	($4.2)	$254.6	$57.4	$46.2	($26.7)	($15.5)	$239.0
DAY	($61.3)	($70.1)	$1.3	$10.1	$3.4	$6.1	($4.4)	($7.1)	$3.0
DLCO	($43.2)	($67.9)	$0.0	$24.7	($3.0)	$0.7	($0.7)	($4.4)	$20.4
DPL	$71.3	$28.6	$1.3	$44.0	$0.5	$3.9	($1.8)	($5.2)	$38.8
Dominion	$537.7	$375.1	$23.1	$185.7	($4.8)	$4.5	($37.7)	($47.0)	$138.7
External	($56.3)	($42.5)	($6.5)	($20.3)	($10.4)	($19.1)	($23.8)	($15.1)	($35.4)
JCPL	$78.8	$35.4	$1.0	$44.4	$3.9	$1.3	($1.5)	$1.1	$45.5
Met-Ed	$46.0	$48.1	$0.5	($1.7)	$1.7	$0.8	($0.7)	$0.2	($1.5)
PECO	$178.0	$163.2	$0.9	$15.7	($0.9)	$5.2	($1.1)	($7.2)	$8.5
PENELEC	($45.9)	($108.1)	$0.7	$62.9	$4.2	$7.2	($1.2)	($4.2)	$58.7
PPL	$137.2	$142.1	$5.0	$0.0	$6.7	$2.9	($3.3)	$0.5	$0.5
PSEG	$191.8	$154.3	$7.6	$45.1	$1.3	$17.7	($33.9)	($50.4)	($5.3)
Pepco	$230.7	$156.5	$5.4	$79.6	($3.6)	($1.8)	($6.6)	($8.4)	$71.1
RECO	$2.3	($0.1)	$0.1	$2.6	$0.0	$1.0	($0.2)	($1.1)	$1.5
Total	$36.3	($1,141.8)	$66.9	$1,245.0	$75.9	$131.9	($190.0)	($246.0)	$999.0

Table G-7 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	$43.6	$17.8	$0.3	$26.0	$0.4	($1.4)	($0.1)	$1.7	$27.7
AEP	($750.5)	($965.2)	$11.3	$225.9	($12.5)	$40.3	($19.0)	($71.7)	$154.2
AP	($5.9)	($313.4)	$0.8	$308.4	$11.7	$32.9	($5.2)	($26.4)	$282.0
BGE	$358.8	$285.7	$9.3	$82.4	$14.1	($6.0)	($11.4)	$8.7	$91.1
ComEd	($1,264.9)	($1,576.1)	($5.5)	$305.8	($15.0)	$16.2	($11.9)	($43.1)	$262.7
DAY	($108.9)	($120.2)	$5.6	$16.9	$3.4	$3.8	($6.9)	($7.3)	$9.6
DLCO	($151.5)	($196.0)	($0.7)	$43.7	($11.5)	$1.6	$0.2	($12.9)	$30.9
DPL	$82.2	$33.1	$1.3	$50.4	($0.8)	$0.9	($1.6)	($3.3)	$47.1
Dominion	$1,118.1	$825.6	$15.9	$308.4	$1.8	$6.7	($18.9)	($23.9)	$284.5
External	($196.9)	($211.5)	$17.4	$32.0	$0.4	($21.8)	($69.5)	($47.3)	($15.2)
JCPL	$84.3	$34.8	$0.5	$50.1	$0.2	($1.3)	($0.7)	$0.8	$50.9
Met-Ed	$62.9	$53.9	$1.3	$10.4	($0.9)	$0.1	($1.6)	($2.5)	$7.8
PECO	$275.7	$285.2	$0.3	($9.2)	($3.5)	$1.7	($0.9)	($6.0)	($15.2)
PENELEC	($124.0)	($221.9)	$1.0	$98.9	$17.1	$8.6	($0.7)	$7.8	$106.7
PPL	$119.0	$133.1	$3.6	($10.5)	$12.8	$9.5	($0.5)	$2.8	($7.7)
PSEG	$204.6	$175.3	$28.3	$57.6	($8.2)	$21.2	($23.6)	($53.0)	$4.6
Pepco	$501.2	$394.8	$6.1	$112.5	($10.9)	($3.0)	($6.9)	($14.9)	$97.7
RECO	$3.5	$0.2	$0.1	$3.4	$1.0	($0.0)	($0.2)	$0.9	$4.3
Total	$251.4	($1,364.8)	$96.9	$1,713.1	($0.2)	$110.1	($179.3)	($289.6)	$1,423.6

Details of Regional and Zonal Congestion

Constraints can affect prices and congestion across multiple 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 6 control zones (the AP, ATSI, ComEd, AEP, DLCO and DAY control zones); and the PJM Southern Region with one control zone (the Dominion Control Zone).

Table G-8 through Table G-42 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 2011 and 2010. In addition, day-ahead and real-time congestion-event hours are presented for each of the highlighted constraints. The 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. In 2011, the RECO control zone did not have any internal constraints, thus the RECO 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 G-8 AECO Control Zone top congestion cost impacts (By facility): Calendar Year 2011

				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	$9.7	$3.7	$0.1	$6.1	$0.0	($0.0)	($0.0)	$0.0	$6.1	1,734	40
2	5004/5005 Interface	Interface	500	$7.4	$3.3	$0.0	$4.2	$0.2	($0.4)	($0.1)	$0.5	$4.6	1,810	940
3	Sherman Avenue	Transformer	AECO	$4.6	$0.3	$0.1	$4.3	($0.2)	($0.1)	($0.0)	($0.1)	$4.2	1,196	60
4	East	Interface	500	$3.8	$1.4	$0.0	$2.4	($0.0)	($0.0)	($0.0)	($0.0)	$2.3	1,044	44
5	Wylie Ridge	Transformer	AP	$2.8	$1.1	$0.0	$1.7	$0.1	($0.1)	($0.0)	$0.2	$2.0	3,836	760
6	Graceton - Raphael Road	Line	BGE	($2.0)	($0.6)	($0.0)	($1.4)	($0.0)	$0.1	$0.0	($0.1)	($1.5)	2,314	830
7	Crete - St Johns Tap	Flowgate	MISO	$1.6	$0.4	$0.0	$1.1	$0.1	($0.0)	($0.0)	$0.1	$1.2	6,708	2,230
8	Shieldalloy - Vineland	Line	AECO	$3.9	$0.8	$0.2	$3.2	($1.4)	$0.5	($0.3)	($2.2)	$1.0	1,496	468
9	AP South	Interface	500	$1.5	$0.6	$0.1	$0.9	($0.0)	($0.1)	($0.1)	$0.0	$1.0	8,222	2,026
10	Dickerson - Quince Orchard	Line	Pepco	$1.4	$0.7	$0.0	$0.7	$0.0	($0.1)	($0.0)	$0.1	$0.8	284	152
11	South Mahwah - Waldwick	Line	PSEG	$0.9	$0.3	$0.1	$0.7	$0.0	($0.0)	($0.1)	$0.0	$0.7	10,538	988
12	East Frankfort - Crete	Line	ComEd	$0.6	$0.2	$0.0	$0.5	$0.0	($0.0)	($0.0)	$0.0	$0.5	3,092	658
13	Orchard - Orchard Tap	Line	AECO	$1.0	$0.5	$0.0	$0.5	$0.0	$0.0	$0.0	$0.0	$0.5	70	0
14	Plymouth Meeting - Whitpain	Line	PECO	$0.8	$0.4	$0.0	$0.5	$0.0	($0.0)	($0.0)	$0.0	$0.5	412	144
15	Burnham - Munster	Flowgate	MISO	$0.6	$0.2	$0.0	$0.5	$0.0	$0.0	$0.0	$0.0	$0.5	2,304	0
17	Orchard	Transformer	AECO	$0.7	$0.4	$0.0	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	48	0
19	Corson	Transformer	AECO	$0.1	($0.0)	$0.0	$0.1	$0.4	$0.1	($0.0)	$0.2	$0.3	62	52
26	Carlls Corner - Sherman Ave	Line	AECO	$0.1	$0.0	$0.0	$0.1	($0.2)	$0.2	($0.0)	($0.4)	($0.3)	188	88
44	Churchtown	Transformer	AECO	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.1	$0.0	($0.1)	($0.1)	0	66
58	Carnegie - Tidd	Line	AECO	$0.1	$0.0	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	1,704	0

Table G-9 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	$8.2	$3.7	$0.0	$4.5	$0.6	($0.7)	($0.0)	$1.2	$5.8	2,758	1,142
2	England - Middletap	Line	AECO	$4.0	$0.7	$0.0	$3.3	($0.4)	($0.4)	($0.0)	($0.0)	$3.2	672	138
3	West	Interface	500	$3.7	$1.8	$0.0	$1.9	$0.1	$0.0	$0.0	$0.1	$2.0	322	116
4	Monroe	Transformer	AECO	$1.7	$0.2	$0.0	$1.5	$0.1	($0.2)	($0.0)	$0.2	$1.8	464	96
5	Brandon Shores - Riverside	Line	BGE	$2.3	$1.1	$0.0	$1.3	$0.0	($0.2)	($0.0)	$0.2	$1.5	686	324
6	Absecon - Lewis	Line	AECO	$0.2	$0.0	$0.0	$0.2	($1.4)	$0.1	($0.1)	($1.6)	($1.4)	162	36
7	Graceton - Raphael Road	Line	BGE	($1.5)	($0.5)	($0.0)	($0.9)	($0.1)	$0.1	$0.0	($0.2)	($1.2)	682	468
8	AP South	Interface	500	$1.9	$0.9	$0.0	$1.0	$0.1	($0.0)	($0.0)	$0.1	$1.1	7,080	2,502
9	Shieldalloy - Vineland	Line	AECO	$3.2	$0.9	$0.1	$2.3	($1.2)	$0.1	($0.0)	($1.3)	$1.1	458	326
10	East Frankfort - Crete	Line	ComEd	$1.1	$0.3	$0.0	$0.9	$0.2	($0.0)	($0.0)	$0.2	$1.0	5,584	1,700
11	Tiltonsville - Windsor	Line	AP	$1.1	$0.4	$0.0	$0.7	$0.1	($0.1)	($0.0)	$0.2	$0.9	5,204	940
12	Branchburg - Readington	Line	PSEG	($1.3)	($0.5)	($0.0)	($0.8)	($0.1)	$0.0	$0.0	($0.1)	($0.8)	2,434	368
13	Bedington - Black Oak	Interface	500	$1.3	$0.6	$0.0	$0.8	$0.0	$0.0	($0.0)	$0.0	$0.8	3,704	222
14	Cloverdale - Lexington	Line	500	$0.8	$0.3	$0.0	$0.5	$0.2	$0.0	($0.0)	$0.2	$0.7	2,138	1,356
15	Brunner Island - Yorkana	Line	Met-Ed	($0.6)	($0.3)	($0.0)	($0.4)	($0.1)	$0.1	$0.0	($0.2)	($0.6)	474	360
24	Corson - Court	Line	AECO	$0.0	$0.0	$0.0	$0.0	($0.2)	$0.1	($0.0)	($0.3)	($0.3)	14	30
36	Corson - Union	Line	AECO	$0.0	$0.0	$0.0	$0.0	$0.2	($0.0)	$0.0	$0.2	$0.2	0	32
48	Sherman Avenue	Transformer	AECO	$0.2	($0.0)	$0.0	$0.2	($0.1)	$0.0	($0.0)	($0.1)	$0.1	62	38
78	Corson	Transformer	AECO	$0.0	$0.0	$0.0	$0.0	$0.1	$0.0	$0.0	$0.1	$0.1	0	34
88	Lewis - Motts - Cedar	Line	AECO	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	50	0

BGE Control Zone

Table G-10 BGE Control Zone top congestion cost impacts (By facility): Calendar Year 2011

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
				Load	Generation			Load	Generation			Grand	Day	Real
No.	Constraint	Type	Location	Payments	Credits	Explicit	Total	Payments	Credits	Explicit	Total	Total	Ahead	Time
1	West	Interface	500	$29.1	$21.1	$0.5	$8.5	$0.0	($0.1)	($0.0)	$0.1	$8.6	1,734	40
2	AP South	Interface	500	$58.6	$53.5	$1.7	$6.9	$1.4	($0.5)	($1.7)	$0.3	$7.1	8,222	2,026
3	Dickerson - Quince Orchard	Line	Pepco	$15.2	$11.0	$0.1	$4.3	$0.6	$0.4	($0.4)	($0.1)	$4.2	284	152
4	Wagner	Transformer	BGE	$4.2	$0.8	$0.1	$3.5	($0.1)	($0.6)	($0.3)	$0.2	$3.7	402	52
5	Riverside	Other	BGE	$0.5	$0.1	$0.0	$0.4	($0.1)	$2.8	($0.9)	($3.7)	($3.3)	40	262
6	Graceton - Raphael Road	Line	BGE	$14.6	$11.0	$0.6	$4.2	($0.1)	$0.4	($0.7)	($1.2)	$3.1	2,314	830
7	Pumphrey	Transformer	Pepco	$4.9	$2.1	$0.2	$3.0	$0.0	$0.0	$0.0	$0.0	$3.0	486	0
8	5004/5005 Interface	Interface	500	$10.9	$8.4	$0.1	$2.6	$0.1	($0.2)	($0.1)	$0.2	$2.8	1,810	940
9	Riverside - Riverside	Other	BGE	$2.3	($0.1)	$0.1	$2.5	$0.0	$0.0	$0.0	$0.0	$2.5	1,098	0
10	Wylie Ridge	Transformer	AP	$12.0	$10.3	$0.3	$2.0	$0.3	($0.1)	($0.2)	$0.2	$2.2	3,836	760
11	Conastone - Graceton	Line	BGE	$5.3	$3.6	$0.2	$1.9	$0.0	$0.0	$0.0	$0.0	$1.9	236	0
12	Crete - St Johns Tap	Flowgate	MISO	$7.9	$6.7	$0.2	$1.4	$0.3	$0.1	($0.2)	$0.0	$1.5	6,708	2,230
13	High Ridge - Howard	Line	BGE	$3.2	$1.0	$0.2	$2.3	($0.7)	($0.2)	($0.4)	($0.9)	$1.4	204	92
14	Glenarm - Windy Edge	Line	BGE	$5.3	$3.6	$0.3	$2.0	($0.0)	$0.3	($0.2)	($0.6)	$1.4	1,366	316
15	Brandon Shores - Riverside	Line	BGE	$0.9	($0.4)	$0.1	$1.3	($0.1)	($0.1)	($0.1)	($0.1)	$1.2	276	18
18	Erdman - Monument St.	Line	BGE	$1.0	$0.2	$0.0	$0.8	$0.0	$0.0	$0.0	$0.0	$0.8	14	0
20	Howard - Pumphrey	Line	BGE	$0.0	$0.0	$0.0	$0.0	($0.7)	($0.9)	($0.8)	($0.6)	($0.6)	0	120
28	Northwest	Other	BGE	$0.7	$0.5	$0.0	$0.3	($0.1)	$0.3	($0.2)	($0.6)	($0.4)	90	206
30	Chesaco Park - Gray Manor	Line	BGE	$0.3	($0.0)	$0.0	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	104	0
31	East Point - Riverside	Line	BGE	$0.3	($0.1)	$0.0	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	72	0

Table G-11 BGE Control Zone top congestion cost impacts (By facility): Calendar Year 2010

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
				Load	Generation			Load	Generation			Grand	Day	Real
No.	Constraint	Type	Location	Payments	Credits	Explicit	Total	Payments	Credits	Explicit	Total	Total	Ahead	Time
1	Brandon Shores - Riverside	Line	BGE	$17.0	($8.8)	$0.2	$26.0	($2.1)	$0.2	($0.3)	($2.5)	$23.5	686	324
2	AP South	Interface	500	$45.9	$35.1	$1.9	$12.6	$3.5	($1.4)	($1.6)	$3.4	$16.0	7,080	222
3	Doubs	Transformer	AP	$11.9	$7.1	$0.3	$5.1	$1.0	($1.2)	($0.5)	$1.8	$6.9	2,492	896
4	Bedington - Black Oak	Interface	500	$17.9	$13.2	$0.6	$5.3	$0.5	($0.3)	($0.4)	$0.4	$5.7	3,704	222
5	5004/5005 Interface	Interface	500	$7.3	$3.6	$0.3	$4.0	$0.5	($0.2)	($0.3)	$0.4	$4.5	2,758	1,142
6	West	Interface	500	$6.3	$3.1	$0.0	$3.2	$0.2	($0.0)	($0.0)	$0.2	$3.4	322	116
7	Graceton - Raphael Road	Line	BGE	$6.6	$4.3	$0.4	$2.8	$0.2	($0.5)	($0.5)	$0.1	$2.9	682	468
8	Mount Storm - Pruntytown	Line	500	$4.1	$3.5	$0.2	$0.8	$1.3	($0.6)	($0.6)	$1.4	$2.2	1,142	1,148
9	Brunner Island - Yorkana	Line	Met-Ed	$3.5	$2.0	$0.2	$1.7	$0.2	($0.0)	($0.2)	($0.1)	$1.6	474	360
10	Millville - Sleepy Hollow	Line	Dominion	$4.3	$3.3	$0.4	$1.4	$0.0	$0.0	$0.0	$0.0	$1.4	802	0
11	Cloverdale - Lexington	Line	500	$4.7	$4.4	$0.2	$0.5	$0.9	($0.3)	($0.3)	$0.9	$1.4	2,138	1,356
12	Tiltonsville - Windsor	Line	AP	$2.9	$2.0	$0.1	$1.0	$0.2	($0.1)	($0.1)	$0.2	$1.2	5,204	940
13	East Frankfort - Crete	Line	ComEd	$3.2	$2.5	$0.1	$0.8	$0.3	($0.1)	($0.0)	$0.4	$1.2	5,584	1,700
14	Pumphrey	Transformer	Pepco	$1.1	$0.3	$0.0	$0.9	$0.0	$0.0	$0.0	$0.0	$0.9	112	0
15	Five Forks - Rock Ridge	Line	Dominion	$0.0	$0.0	$0.0	$0.0	($0.3)	$0.5	($0.1)	($0.9)	($0.9)	0	76
27	Fullerton - Windyedge	Line	BGE	$0.4	($0.1)	$0.0	$0.5	$0.0	$0.0	$0.0	$0.0	$0.5	46	0
28	Graceton - Safe Harbor	Line	BGE	$0.9	$0.6	$0.1	$0.5	$0.2	$0.1	($0.2)	($0.0)	$0.4	208	140
30	Glenarm - Windy Edge	Line	BGE	$0.5	$0.2	$0.0	$0.3	$0.0	($0.1)	($0.0)	$0.1	$0.4	148	78
34	Green Street - Westport	Line	BGE	$0.3	($0.1)	$0.0	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	290	0
46	Five Forks - Rock Ridge	Line	BGE	$0.3	$0.1	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	78	0

DPL Control Zone

Table G-12 DPL Control Zone top congestion cost impacts (By facility): Calendar Year 2011

				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	$14.0	$5.0	$0.1	$9.1	$0.3	$0.8	($0.3)	($0.8)	$8.3	1,810	940
2	West	Interface	500	$16.2	$8.8	$0.2	$7.6	$0.0	$0.0	($0.0)	$0.0	$7.6	1,734	40
3	Wylie Ridge	Transformer	AP	$5.7	$1.6	$0.1	$4.1	$0.1	$0.2	($0.0)	($0.1)	$4.0	3,836	760
4	East	Interface	500	$7.0	$3.1	($0.0)	$3.8	($0.0)	$0.1	($0.0)	($0.1)	$3.8	1,044	44
5	AP South	Interface	500	$4.1	$1.5	$0.2	$2.9	$0.0	$0.3	($0.3)	($0.6)	$2.3	8,222	2,026
6	Crete - St Johns Tap	Flowgate	MISO	$3.0	$0.8	$0.0	$2.3	$0.1	$0.3	($0.0)	($0.2)	$2.0	6,708	2,230
7	Graceton - Raphael Road	Line	BGE	($3.9)	($1.4)	($0.3)	($2.8)	($0.1)	($0.6)	$0.2	$0.8	($2.0)	2,314	830
8	New Church - Piney Grove	Line	DPL	$2.1	$0.4	$0.1	$1.7	$0.0	$0.0	$0.0	$0.0	$1.7	980	0
9	Plymouth Meeting - Whitpain	Line	PECO	$2.3	$1.0	$0.0	$1.3	$0.1	$0.1	($0.1)	($0.0)	$1.3	412	144
10	Longwood - Wye Mills	Line	DPL	$1.5	$0.4	$0.1	$1.2	($0.0)	$0.0	($0.0)	($0.0)	$1.2	1,768	6
11	Burnham - Munster	Flowgate	MISO	$1.1	$0.4	$0.0	$0.7	$0.0	$0.0	$0.0	$0.0	$0.7	2,304	0
12	East Frankfort - Crete	Line	ComEd	$1.1	$0.3	$0.0	$0.8	$0.0	$0.1	$0.0	($0.1)	$0.7	3,092	658
13	Glenarm - Windy Edge	Line	BGE	($1.1)	($0.4)	($0.0)	($0.8)	($0.0)	($0.1)	$0.0	$0.1	($0.7)	1,366	316
14	Bedington - Black Oak	Interface	500	$0.9	$0.2	$0.0	$0.7	($0.0)	$0.0	($0.0)	($0.0)	$0.6	1,358	14
15	Dickerson - Quince Orchard	Line	Pepco	$2.5	$1.6	$0.0	$1.0	$0.1	$0.4	($0.0)	($0.4)	$0.6	284	152
22	Hallwood - Oak Hall	Line	DPL	$0.6	$0.2	$0.0	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	362	0
24	Mardela - Vienna	Line	DPL	$0.4	$0.1	$0.0	$0.4	($0.2)	$0.4	($0.1)	($0.8)	($0.4)	310	52
29	Easton - Trappe	Line	DPL	$0.4	$0.1	$0.0	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	248	0
47	Bellehaven - Tasley	Line	DPL	$0.2	($0.0)	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	1,220	0
53	Oak Hall	Transformer	DPL	$0.2	$0.0	($0.0)	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	10	0

Table G-13 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	$13.3	$5.7	$0.1	$7.7	$0.5	($0.0)	($0.2)	$0.3	$8.1	2,758	1,142
2	AP South	Interface	500	$5.0	$2.2	$0.1	$2.9	$0.2	$0.0	($0.0)	$0.1	$3.0	7,080	2,502
3	Oak Hall	Transformer	DPL	$2.7	$0.5	$0.0	$2.2	$0.0	$0.0	$0.0	$0.0	$2.2	1,218	0
4	West	Interface	500	$5.3	$3.4	$0.0	$1.9	$0.1	$0.1	($0.0)	$0.0	$1.9	322	116
5	East Frankfort - Crete	Line	ComEd	$2.1	$0.3	$0.0	$1.8	$0.0	$0.0	($0.0)	$0.0	$1.8	5,584	1,700
6	New Church - Piney Grove	Line	DPL	$1.9	$0.4	$0.0	$1.5	$0.0	$0.0	$0.0	$0.0	$1.5	600	0
7	Bedington - Black Oak	Interface	500	$2.7	$1.2	$0.0	$1.6	$0.0	$0.0	($0.0)	($0.1)	$1.5	3,704	222
8	Brandon Shores - Riverside	Line	BGE	$3.4	$2.0	$0.0	$1.5	$0.1	($0.0)	($0.0)	$0.1	$1.5	686	324
9	Graceton - Raphael Road	Line	BGE	($2.7)	($1.1)	($0.0)	($1.6)	($0.0)	($0.2)	$0.1	$0.2	($1.3)	682	468
10	Longwood - Wye Mills	Line	DPL	$1.6	$0.3	$0.0	$1.3	$0.0	$0.0	$0.0	$0.0	$1.3	520	0
11	Middletown - Mt Pleasant	Line	DPL	$1.7	$0.4	$0.0	$1.3	$0.0	$0.0	$0.0	$0.0	$1.3	326	0
12	Cloverdale - Lexington	Line	500	$1.4	$0.3	$0.0	$1.1	$0.2	$0.0	($0.1)	$0.1	$1.2	2,138	1,356
13	Tiltonsville - Windsor	Line	AP	$1.8	$0.8	$0.1	$1.1	$0.0	($0.0)	($0.1)	($0.0)	$1.1	5,204	940
14	Kenney - Stockton	Line	DPL	$1.0	$0.3	$0.0	$0.7	($1.6)	($0.0)	($0.1)	($1.7)	($1.0)	192	244
15	Branchburg - Readington	Line	PSEG	($1.9)	($0.9)	($0.1)	($1.0)	($0.0)	($0.0)	$0.0	$0.1	($1.0)	2,434	368
17	Indian River At20	Transformer	DPL	$0.0	$0.0	$0.0	$0.0	$0.3	($0.6)	($0.0)	$0.9	$0.9	0	16
20	Easton - Trappe	Line	DPL	$0.9	$0.2	$0.0	$0.7	$0.0	$0.0	$0.0	$0.0	$0.7	234	0
23	Dupont Seaford - Laurel	Line	DPL	$0.0	$0.0	$0.0	$0.0	($0.4)	$0.4	($0.0)	($0.7)	($0.7)	0	30
24	Keeney At5n	Transformer	DPL	$0.0	($0.0)	$0.0	$0.0	($0.1)	$0.6	($0.0)	($0.7)	($0.7)	52	26
25	Cecil - Colora	Line	DPL	$1.3	$0.4	$0.1	$1.0	($0.1)	$0.0	($0.1)	($0.3)	$0.7	258	78

JCPL Control Zone

Table G-14 JCPL Control Zone top congestion cost impacts (By facility): Calendar Year 2011

				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	$19.0	$8.6	$0.1	$10.5	$0.9	$0.2	($0.1)	$0.6	$11.0	1,810	940
2	West	Interface	500	$19.8	$11.4	$0.1	$8.6	($0.0)	($0.0)	($0.0)	($0.0)	$8.5	1,734	40
3	Redoak - Sayreville	Line	JCPL	($1.3)	($5.3)	($0.1)	$3.9	$0.0	$0.1	$0.0	($0.1)	$3.8	3,504	22
4	South Mahwah - Waldwick	Line	PSEG	$6.7	$3.0	$0.3	$4.1	($0.1)	($0.0)	($0.3)	($0.4)	$3.7	10,538	988
5	Wylie Ridge	Transformer	AP	$6.5	$3.0	$0.0	$3.5	$0.1	$0.1	($0.0)	($0.0)	$3.5	3,836	760
6	East	Interface	500	$6.7	$3.7	$0.0	$3.0	($0.1)	$0.0	($0.0)	($0.1)	$2.9	1,044	44
7	Bridgewater - Middlesex	Line	PSEG	$4.6	$1.8	$0.2	$3.0	($0.2)	$0.2	($0.5)	($0.9)	$2.1	1,108	126
8	Cedar Grove - Roseland	Line	PSEG	($3.1)	($1.2)	($0.1)	($2.1)	$0.0	$0.0	$0.0	$0.0	($2.0)	1,812	74
9	Crete - St Johns Tap	Flowgate	MISO	$3.6	$1.8	$0.0	$1.8	$0.1	$0.1	($0.0)	($0.0)	$1.8	6,708	2,230
10	Dickerson - Quince Orchard	Line	Pepco	$2.6	$1.6	$0.0	$1.0	$0.4	$0.1	($0.0)	$0.3	$1.3	284	152
11	Graceton - Raphael Road	Line	BGE	($4.1)	($2.7)	($0.1)	($1.5)	$0.4	$0.1	$0.1	$0.4	($1.2)	2,314	830
12	East Windsor - Smithburg	Line	JCPL	$0.0	$0.0	$0.0	$0.0	$0.9	($0.0)	$0.0	$0.9	$0.9	0	18
13	Susquehanna	Transformer	PPL	$1.2	$0.4	$0.0	$0.8	$0.0	$0.0	$0.0	$0.0	$0.8	240	0
14	East Frankfort - Crete	Line	ComEd	$1.4	$0.8	$0.0	$0.6	$0.0	($0.0)	($0.0)	$0.0	$0.6	3,092	658
15	Atlantic - Larrabee	Line	JCPL	$0.4	($0.2)	$0.0	$0.6	($0.0)	($0.0)	($0.0)	($0.0)	$0.6	168	2
42	Flanders - W. Wharton	Line	JCPL	$0.0	$0.0	$0.2	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	550	0
48	Kilmer - Sayreville	Line	JCPL	$0.3	$0.2	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	186	0
62	Deep Run - Englishtown	Line	JCPL	$0.0	$0.0	$0.0	$0.0	$0.1	$0.1	($0.1)	($0.1)	($0.1)	0	28
166	Lakewood - Larrabee	Line	JCPL	$0.0	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	10	0
179	Kittatiny - Newton	Line	JCPL	$0.0	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	16	0

Table G-15 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	$18.0	$8.0	$0.0	$10.0	$1.0	($0.2)	($0.1)	$1.1	$11.1	2,758	1,142
2	Branchburg - Readington	Line	PSEG	$6.8	$0.4	$0.1	$6.5	($0.5)	($0.3)	$0.1	($0.2)	$6.3	2,434	368
3	West	Interface	500	$7.5	$4.0	$0.0	$3.6	$0.0	($0.1)	($0.0)	$0.2	$3.7	322	116
4	Redoak - Sayreville	Line	JCPL	($2.0)	($5.8)	$0.0	$3.8	$0.1	$0.7	$0.0	($0.6)	$3.2	1,700	114
5	Athenia - Saddlebrook	Line	PSEG	($3.2)	($1.0)	($0.0)	($2.2)	($0.2)	$0.1	$0.0	($0.2)	($2.4)	5,918	662
6	Brandon Shores - Riverside	Line	BGE	$4.4	$2.3	$0.0	$2.1	$0.1	($0.1)	($0.0)	$0.1	$2.3	686	324
7	East Frankfort - Crete	Line	ComEd	$2.8	$1.4	($0.0)	$1.4	$0.0	($0.1)	$0.0	$0.1	$1.5	5,584	1,700
8	Tiltonsville - Windsor	Line	AP	$2.6	$1.4	$0.0	$1.2	($0.0)	($0.1)	($0.0)	$0.0	$1.3	5,204	940
9	Graceton - Raphael Road	Line	BGE	($3.2)	($1.8)	($0.0)	($1.4)	$0.3	$0.1	$0.0	$0.2	($1.2)	682	468
10	Cloverdale - Lexington	Line	500	$1.6	$0.7	$0.0	$0.9	$0.0	($0.1)	($0.0)	$0.1	$1.0	2,138	1,356
11	Atlantic - Larrabee	Line	JCPL	$0.9	$0.1	$0.0	$0.9	$0.0	($0.1)	($0.0)	$0.1	$0.9	246	24
12	Bedington - Black Oak	Interface	500	$1.5	$0.8	$0.1	$0.8	($0.0)	($0.0)	($0.0)	($0.0)	$0.8	3,704	222
13	Brunner Island - Yorkana	Line	Met-Ed	($2.0)	($1.2)	($0.0)	($0.9)	$0.3	$0.1	$0.0	$0.2	($0.7)	474	360
14	Wylie Ridge	Transformer	AP	$1.2	$0.6	$0.0	$0.6	($0.0)	($0.1)	($0.0)	$0.1	$0.6	1,010	752
15	Millville - Sleepy Hollow	Line	Dominion	$1.6	$0.9	$0.0	$0.6	$0.0	$0.0	$0.0	$0.0	$0.6	802	0
30	Sayreville - Werner	Line	JCPL	$0.0	$0.0	$0.0	$0.0	$0.1	($0.1)	$0.0	$0.3	$0.3	0	8
35	Franklin - West Wharton	Line	JCPL	$0.4	$0.2	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	122	0
41	Kilmer - Sayreville	Line	JCPL	$0.5	$0.3	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	234	0
203	Montville - Roseland	Line	JCPL	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	$0.0	($0.0)	($0.0)	0	10
237	Greystone - West Wharton	Line	JCPL	($0.0)	$0.0	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	($0.0)	8	0

Met-Ed Control Zone

Table G-16 Met-Ed Control Zone top congestion cost impacts (By facility): Calendar Year 2011

				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	$10.9	$15.5	$0.1	($4.6)	$0.0	$0.0	($0.0)	($0.0)	($4.6)	1,734	40
2	Cly - Collins	Line	Met-Ed	$1.9	($1.3)	$0.1	$3.3	($0.5)	$0.4	($0.0)	($0.9)	$2.3	710	324
3	Wylie Ridge	Transformer	AP	$4.4	$6.3	$0.1	($1.8)	$0.1	($0.0)	($0.0)	$0.1	($1.7)	3,836	760
4	Hunterstown	Transformer	Met-Ed	$1.6	$0.0	$0.0	$1.5	$0.0	$0.0	($0.0)	$0.0	$1.5	164	18
5	Middletown Jct - TMI	Line	Met-Ed	$0.4	($0.7)	$0.0	$1.1	$0.0	$0.0	$0.0	$0.0	$1.1	62	0
6	Crete - St Johns Tap	Flowgate	MISO	$2.4	$3.4	($0.0)	($1.0)	$0.1	($0.0)	($0.0)	$0.1	($0.9)	6,708	2,230
7	Graceton - Raphael Road	Line	BGE	($3.3)	($4.6)	($0.2)	$1.1	($0.1)	$0.2	$0.1	($0.2)	$0.9	2,314	830
8	East	Interface	500	$0.4	($0.2)	($0.1)	$0.5	$0.0	$0.0	$0.0	$0.0	$0.5	1,044	44
9	Carlisle Pike - Roxbury	Line	PENELEC	$0.6	$0.1	$0.0	$0.5	$0.0	$0.0	($0.0)	($0.0)	$0.5	268	8
10	Dickerson - Quince Orchard	Line	Pepco	$1.3	$1.9	$0.0	($0.5)	$0.2	$0.1	($0.0)	$0.1	($0.5)	284	152
11	East Frankfort - Crete	Line	ComEd	$0.9	$1.3	$0.0	($0.4)	$0.0	($0.0)	($0.0)	$0.0	($0.4)	3,092	658
12	Middletown Jctn. - Three Mile Island	Line	Met-Ed	$0.0	$0.0	$0.0	$0.0	($0.1)	$0.1	($0.1)	($0.4)	($0.4)	0	30
13	Burnham - Munster	Flowgate	MISO	$1.0	$1.4	($0.0)	($0.4)	$0.0	$0.0	$0.0	$0.0	($0.4)	2,304	0
14	Conastone - Graceton	Line	BGE	$0.1	($0.3)	($0.0)	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	236	0
15	Glenarm - Windy Edge	Line	BGE	($1.1)	($1.4)	($0.0)	$0.4	($0.0)	$0.0	$0.0	($0.0)	$0.3	1,366	316
22	Glendon - Hosensack	Line	Met-Ed	$0.1	($0.1)	($0.0)	$0.2	($0.0)	$0.0	$0.0	($0.0)	$0.2	140	2
29	Hunterstown - Lincoln	Line	Met-Ed	$0.1	$0.0	$0.0	$0.1	($0.0)	($0.0)	($0.0)	($0.0)	$0.1	220	16
31	Middletown Jct - Yorkhaven	Line	Met-Ed	$0.1	($0.0)	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	74	0
39	Cly - Newberry	Line	Met-Ed	$0.0	($0.0)	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	22	0
71	Manor - Safe Harbor	Line	Met-Ed	($0.1)	($0.1)	($0.0)	($0.0)	($0.0)	($0.0)	$0.0	$0.0	($0.0)	14	6

Table G-17 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	474	360
2	Hunterstown	Transformer	Met-Ed	$4.0	($0.7)	$0.1	$4.7	$0.0	$0.0	($0.0)	($0.0)	$4.7	622	52
3	West	Interface	500	$4.2	$5.4	$0.0	($1.1)	$0.0	($0.1)	($0.0)	$0.1	($1.1)	322	116
4	Doubs	Transformer	AP	$3.2	$2.1	$0.1	$1.2	($0.0)	($0.1)	($0.3)	($0.2)	$0.9	2,492	896
5	Graceton - Raphael Road	Line	BGE	($2.1)	($3.1)	($0.0)	$1.0	$0.2	$0.3	$0.1	($0.0)	$0.9	682	468
6	AP South	Interface	500	$4.9	$4.0	$0.1	$1.0	($0.1)	($0.0)	($0.2)	($0.2)	$0.8	7,080	2,502
7	Jackson - TMI	Line	Met-Ed	$0.5	($0.6)	$0.1	$1.2	($0.1)	$0.3	($0.0)	($0.4)	$0.8	74	108
8	5004/5005 Interface	Interface	500	$10.7	$10.3	$0.0	$0.5	($0.3)	($0.7)	($0.1)	$0.2	$0.7	2,758	1,142
9	Middletown Jct	Transformer	Met-Ed	$0.6	($0.1)	$0.0	$0.7	($0.1)	$0.1	$0.0	($0.1)	$0.6	22	24
10	Collins - Middletown Jct	Line	Met-Ed	$0.3	($0.3)	$0.0	$0.6	($0.0)	$0.1	($0.0)	($0.1)	$0.5	376	78
11	Middletown Jct - Yorkhaven	Line	Met-Ed	$0.6	$0.1	$0.0	$0.5	($0.0)	$0.0	$0.0	($0.0)	$0.5	380	24
12	Brandon Shores - Riverside	Line	BGE	$3.2	$3.8	$0.0	($0.5)	($0.0)	($0.1)	($0.0)	$0.0	($0.5)	686	324
13	Cloverdale - Lexington	Line	500	$1.3	$1.7	$0.0	($0.3)	$0.0	$0.1	($0.0)	($0.1)	($0.5)	2,138	1,356
14	Wylie Ridge	Transformer	AP	$0.8	$1.1	$0.0	($0.3)	($0.0)	$0.0	($0.0)	($0.1)	($0.4)	1,010	752
15	Tiltonsville - Windsor	Line	AP	$1.6	$2.0	$0.0	($0.4)	($0.1)	($0.1)	($0.1)	($0.0)	($0.4)	5,204	940
23	Jackson - North Hanover	Line	Met-Ed	$0.2	($0.0)	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	42	26
46	Cly - Collins	Line	Met-Ed	$0.0	($0.0)	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	38	0
67	Yorkana A	Transformer	Met-Ed	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	$0.0	0	10
68	Glendon - Hosensack	Line	Met-Ed	$0.0	($0.0)	$0.0	$0.0	($0.0)	$0.1	$0.0	($0.1)	($0.0)	62	78
75	Germantown - Straban	Line	Met-Ed	$0.1	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	22	0

PECO Control Zone

Table G-18 PECO Control Zone top congestion cost impacts (By facility): Calendar Year 2011

				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	$38.1	$45.9	$0.1	($7.6)	($0.0)	($0.0)	($0.0)	$0.0	($7.6)	1,734	40
2	Plymouth Meeting - Whitpain	Line	PECO	$11.1	$3.2	$0.0	$7.9	($0.3)	($0.0)	($0.1)	($0.4)	$7.6	412	144
3	East	Interface	500	$14.2	$8.9	$0.1	$5.4	($0.1)	$0.1	($0.0)	($0.2)	$5.2	1,044	44
4	Cromby	Transformer	PECO	$6.4	$0.6	$0.0	$5.8	($0.7)	$0.4	($0.0)	($1.1)	$4.7	756	304
5	Bryn Mawr - Plymouth Meeting	Line	PECO	$6.5	$2.0	$0.0	$4.4	($0.1)	($0.1)	$0.0	$0.0	$4.5	568	8
6	Graceton - Raphael Road	Line	BGE	($9.8)	($13.9)	($0.1)	$3.9	$0.5	$0.1	$0.1	$0.6	$4.5	2,314	830
7	AP South	Interface	500	$7.6	$11.8	$0.1	($4.0)	($0.2)	$0.1	($0.1)	($0.4)	($4.4)	8,222	2,026
8	5004/5005 Interface	Interface	500	$36.1	$38.8	$0.2	($2.5)	($0.6)	$1.0	($0.1)	($1.8)	($4.3)	1,810	940
9	Wylie Ridge	Transformer	AP	$14.0	$16.8	$0.1	($2.7)	($0.1)	$0.0	($0.1)	($0.1)	($2.8)	3,836	760
10	Bradford - Planebrook	Line	PECO	$2.4	($0.1)	$0.0	$2.5	$0.1	$0.3	$0.0	($0.2)	$2.3	242	86
11	Crete - St Johns Tap	Flowgate	MISO	$7.6	$9.5	$0.0	($1.9)	$0.0	$0.2	($0.0)	($0.2)	($2.1)	6,708	2,230
12	Dickerson - Quince Orchard	Line	Pepco	$5.9	$7.5	$0.0	($1.5)	$0.2	$0.5	($0.0)	($0.3)	($1.8)	284	152
13	Bala - Plymouth Meeting	Line	PECO	$2.6	$0.8	($0.0)	$1.8	$0.0	$0.0	$0.0	$0.0	$1.8	152	0
14	Conastone - Graceton	Line	BGE	($0.6)	($2.1)	($0.0)	$1.5	$0.0	$0.0	$0.0	$0.0	$1.5	236	0
15	Chichester	Transformer	PECO	$1.5	$0.1	$0.0	$1.5	($0.0)	$0.0	($0.0)	($0.1)	$1.4	118	8
16	Limerick	Transformer	PECO	$2.1	$0.7	($0.0)	$1.4	($0.0)	$0.0	($0.0)	($0.0)	$1.4	60	10
26	Eddystone - Saville	Line	PECO	$0.6	($0.0)	$0.0	$0.6	$0.0	$0.1	$0.0	($0.0)	$0.6	136	32
27	Emilie	Transformer	PECO	($0.2)	($0.8)	($0.0)	$0.7	$0.1	$0.3	$0.0	($0.2)	$0.5	630	306
32	Eddington - Holmesburg	Line	PECO	($0.0)	($0.4)	($0.0)	$0.4	($0.1)	$0.7	($0.0)	($0.8)	($0.4)	482	356
35	Blue Grass - Byberry	Line	PECO	$0.3	($0.1)	$0.0	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	116	0

Table G-19 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	$10.0	$16.5	$0.0	($6.5)	($0.5)	$1.4	($0.1)	($2.0)	($8.5)	2,758	1,142
2	Eddystone - Island Road	Line	PECO	$3.8	($4.4)	($0.0)	$8.1	($0.0)	$0.0	$0.0	($0.0)	$8.1	372	6
3	Limerick	Transformer	PECO	$3.0	$0.6	$0.0	$2.4	$0.1	($3.8)	($0.0)	$3.8	$6.3	106	36
4	AP South	Interface	500	$2.1	$6.8	$0.1	($4.5)	($0.1)	$0.2	($0.0)	($0.4)	($4.9)	7,080	2,502
5	West	Interface	500	$4.7	$7.1	$0.0	($2.3)	($0.0)	$0.0	($0.0)	($0.0)	($2.4)	322	116
6	Bedington - Black Oak	Interface	500	$1.6	$3.6	$0.0	($2.0)	($0.0)	$0.1	($0.0)	($0.1)	($2.1)	3,704	222
7	Graceton - Raphael Road	Line	BGE	($1.5)	($3.6)	($0.0)	$2.0	$0.4	$0.4	$0.0	($0.0)	$2.0	682	468
8	Peachbottom	Transformer	PECO	$0.0	$0.0	$0.0	$0.0	($0.7)	$0.1	($0.4)	($1.2)	($1.2)	0	28
9	Doubs	Transformer	AP	$0.9	$2.0	$0.0	($1.0)	($0.3)	($0.1)	($0.0)	($0.2)	($1.2)	2,492	896
10	East	Interface	500	$1.6	$0.4	($0.0)	$1.2	($0.0)	($0.0)	($0.0)	($0.0)	$1.2	370	16
11	Tiltonsville - Windsor	Line	AP	$1.5	$2.5	$0.0	($1.0)	($0.2)	($0.0)	($0.0)	($0.2)	($1.2)	5,204	940
12	East Frankfort - Crete	Line	ComEd	$1.9	$3.0	($0.0)	($1.1)	($0.1)	($0.1)	$0.0	$0.0	($1.1)	5,584	1,700
13	Plymouth Meeting - Whitpain	Line	PECO	$1.1	$0.2	$0.0	$0.9	($0.0)	($0.0)	$0.0	$0.0	$0.9	72	2
14	Keeney At5n	Transformer	DPL	$0.0	$0.0	$0.0	$0.0	($0.4)	$0.5	($0.0)	($0.8)	($0.8)	52	26
15	Brandon Shores - Riverside	Line	BGE	$3.6	$4.0	$0.0	($0.4)	($0.2)	$0.2	($0.0)	($0.4)	($0.7)	686	324
21	Burlington - Croydon	Line	PECO	($0.2)	($0.6)	($0.0)	$0.4	$0.0	($0.1)	($0.0)	$0.1	$0.4	2,162	66
25	Eddystone - Saville	Line	PECO	$0.3	($0.1)	$0.0	$0.4	$0.0	($0.0)	($0.0)	$0.0	$0.4	294	80
35	Jenkintown - Tabor	Line	PECO	$0.0	$0.0	$0.0	$0.0	($0.1)	$0.2	$0.0	($0.3)	($0.3)	0	20
55	Bradford - Planebrook	Line	PECO	$0.0	$0.0	$0.0	$0.0	$0.1	($0.1)	$0.0	$0.1	$0.1	0	2
57	Bryn Mawr - Plymouth Meeting	Line	PECO	$0.2	$0.0	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	28	0

PENELEC Control Zone

Table G-20 PENELEC Control Zone top congestion cost impacts (By facility): Calendar Year 2011

				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	($14.9)	($39.4)	($1.7)	$22.8	$1.7	$3.0	$2.5	$1.3	$24.1	1,810	940
2	AP South	Interface	500	($38.8)	($54.6)	($0.4)	$15.5	$2.7	$0.7	$0.9	$2.9	$18.4	8,222	2,026
3	West	Interface	500	($11.1)	($26.8)	($1.4)	$14.3	$0.0	$0.1	$0.1	$0.0	$14.3	1,734	40
4	Wylie Ridge	Transformer	AP	$8.1	$20.0	$0.8	($11.1)	($0.6)	($0.4)	($0.4)	($0.6)	($11.7)	3,836	760
5	Crete - St Johns Tap	Flowgate	MISO	$7.4	$10.0	$0.1	($2.5)	($0.3)	$0.2	($0.1)	($0.6)	($3.1)	6,708	2,230
6	Altoona - Bear Rock	Line	PENELEC	($2.8)	($5.5)	($0.1)	$2.6	$0.7	$0.6	$0.2	$0.2	$2.9	380	154
7	Johnstown - Seward	Line	PENELEC	$2.0	($0.6)	$0.0	$2.6	$0.0	$0.0	$0.0	$0.0	$2.6	102	0
8	Bedington - Black Oak	Interface	500	($5.1)	($7.5)	($0.1)	$2.2	$0.0	$0.0	$0.0	$0.0	$2.2	1,358	14
9	Butler - Karns City	Line	AP	$5.5	$3.9	$0.3	$2.0	($0.2)	$0.0	($0.1)	($0.3)	$1.7	772	116
10	Susquehanna	Transformer	PPL	$0.5	($1.3)	($0.1)	$1.6	$0.0	$0.0	$0.0	$0.0	$1.6	240	0
11	Yukon	Transformer	AP	$0.9	($0.9)	($0.0)	$1.8	($0.0)	$0.2	$0.0	($0.2)	$1.6	750	180
12	East	Interface	500	($2.4)	($4.2)	($0.3)	$1.5	$0.0	$0.1	$0.1	$0.0	$1.5	1,044	44
13	Graceton - Raphael Road	Line	BGE	($3.1)	($3.8)	($0.1)	$0.6	$0.2	$0.1	$0.1	$0.2	$0.8	2,314	830
14	East Frankfort - Crete	Line	ComEd	$2.9	$3.6	$0.1	($0.6)	$0.0	$0.1	($0.1)	($0.2)	($0.8)	3,092	658
15	Danville - East Danville	Line	AEP	$0.4	$1.2	($0.1)	($0.8)	$0.0	$0.0	$0.0	$0.0	($0.8)	9,216	0
17	Laurel Lake - Tiffany	Line	PENELEC	$0.7	$0.1	$0.1	$0.7	$0.0	$0.0	$0.0	$0.0	$0.7	154	0
23	Seward	Transformer	PENELEC	$0.4	$0.2	$0.0	$0.2	($0.2)	$0.5	($0.0)	($0.8)	($0.5)	42	44
26	East Towanda - S.Troy	Line	PENELEC	$0.2	$0.1	$0.3	$0.5	$0.0	$0.0	$0.0	$0.0	$0.5	1,440	0
28	Hooversville - Scalp Level	Line	PENELEC	$2.9	$2.1	$0.1	$0.8	($0.2)	$0.1	($0.1)	($0.4)	$0.5	434	110
35	Handsome Lake - Wayne	Line	PENELEC	$0.2	($0.2)	($0.0)	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	48	0

Table G-21 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	($45.2)	($68.7)	($0.0)	$23.5	$4.1	($1.1)	$0.1	$5.2	$28.7	7,080	2,502
2	5004/5005 Interface	Interface	500	($10.8)	($35.5)	($0.1)	$24.5	$3.9	$1.8	$0.1	$2.3	$26.8	2,758	1,142
3	Bedington - Black Oak	Interface	500	($15.6)	($23.6)	($0.0)	$8.0	$0.2	($0.1)	$0.0	$0.4	$8.3	3,704	222
4	West	Interface	500	($3.6)	($8.7)	$0.0	$5.1	$0.2	$0.1	$0.0	$0.1	$5.2	322	116
5	Mount Storm - Pruntytown	Line	500	($3.4)	($5.6)	$0.0	$2.2	$2.3	($0.3)	$0.1	$2.7	$4.8	1,142	1,148
6	Seward	Transformer	PENELEC	$12.0	$7.2	$0.0	$4.8	($0.2)	$0.6	($0.0)	($0.8)	$4.0	742	126
7	Wylie Ridge	Transformer	AP	$0.9	$3.3	$0.1	($2.3)	($0.3)	$0.4	($0.1)	($0.8)	($3.1)	1,010	752
8	Bear Rock - Johnstown	Line	PENELEC	($2.1)	($4.1)	($0.0)	$1.9	$1.1	$0.0	$0.0	$1.1	$3.0	394	114
9	Tiltonsville - Windsor	Line	AP	$4.0	$5.9	$0.1	($1.8)	($0.9)	$0.2	($0.0)	($1.1)	($2.9)	5,204	940
10	Altoona - Bear Rock	Line	PENELEC	($2.4)	($4.7)	($0.0)	$2.3	$0.5	($0.1)	$0.0	$0.5	$2.8	496	110
11	East Frankfort - Crete	Line	ComEd	$5.5	$7.6	$0.0	($2.1)	($0.4)	$0.3	($0.0)	($0.7)	($2.8)	5,584	1,700
12	AEP-DOM	Interface	500	($4.4)	($6.3)	($0.0)	$1.8	$0.2	($0.1)	$0.0	$0.3	$2.1	942	178
13	Johnstown - Seward	Line	PENELEC	$2.7	$0.7	$0.0	$2.0	$0.0	$0.0	$0.0	$0.0	$2.0	104	0
14	Doubs	Transformer	AP	($2.3)	($3.3)	$0.1	$1.1	$0.5	($0.1)	($0.0)	$0.6	$1.6	2,492	896
15	Hunterstown	Transformer	Met-Ed	($0.8)	($2.4)	($0.0)	$1.6	$0.0	$0.0	$0.0	$0.0	$1.6	622	52
18	Homer City - Seward	Line	PENELEC	$4.6	$3.3	$0.0	$1.4	$0.0	$0.0	$0.0	$0.0	$1.4	166	0
25	Keystone - Shelocta	Line	PENELEC	$3.0	$2.0	$0.0	$0.9	$0.0	$0.0	$0.0	$0.0	$0.9	78	0
28	Blairsville - Shelocta	Line	PENELEC	$1.7	$1.1	$0.0	$0.6	$0.0	$0.0	$0.0	$0.0	$0.6	48	0
30	Roxbury - Shade Gap	Line	PENELEC	($0.8)	($0.8)	($0.0)	($0.0)	$0.7	$1.3	$0.0	($0.6)	($0.6)	84	212
41	Clarks Summit - Eclipse	Line	PENELEC	$0.5	$0.1	$0.0	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	128	0

Pepco Control Zone

Table G-22 Pepco Control Zone top congestion cost impacts (By facility): Calendar Year 2011

				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	$79.8	$58.9	$1.4	$22.2	($2.2)	($1.5)	($1.3)	($2.0)	$20.1	8,222	2,026
2	Dickerson - Quince Orchard	Line	Pepco	$27.8	$12.2	$0.2	$15.9	$0.5	$1.8	($0.2)	($1.5)	$14.4	284	152
3	West	Interface	500	$19.3	$13.3	$0.3	$6.2	($0.0)	($0.0)	($0.0)	$0.0	$6.3	1,734	40
4	Graceton - Raphael Road	Line	BGE	$11.4	$7.8	$0.1	$3.8	($0.2)	$0.0	($0.1)	($0.4)	$3.4	2,314	830
5	Wylie Ridge	Transformer	AP	$11.7	$8.6	$0.3	$3.5	($0.3)	($0.2)	($0.1)	($0.1)	$3.4	3,836	760
6	Bedington - Black Oak	Interface	500	$11.4	$8.4	$0.2	$3.2	($0.0)	($0.0)	($0.0)	$0.0	$3.2	1,358	14
7	Crete - St Johns Tap	Flowgate	MISO	$8.3	$5.8	$0.1	$2.7	($0.2)	($0.0)	($0.1)	($0.3)	$2.4	6,708	2,230
8	Danville - East Danville	Line	AEP	$7.3	$5.1	($0.0)	$2.2	$0.0	$0.0	$0.0	$0.0	$2.2	9,216	0
9	AEP-DOM	Interface	500	$7.4	$5.6	$0.1	$2.0	($0.1)	($0.1)	$0.0	$0.0	$2.0	3,572	370
10	5004/5005 Interface	Interface	500	$5.8	$4.1	$0.1	$1.7	($0.0)	($0.1)	($0.1)	($0.1)	$1.6	1,810	940
11	East	Interface	500	($5.1)	($3.9)	($0.1)	($1.3)	$0.0	$0.1	$0.0	($0.1)	($1.4)	1,044	44
12	Gore - Hampshire	Line	AP	$4.3	$3.1	$0.0	$1.2	$0.0	$0.0	$0.0	$0.0	$1.2	1,654	0
13	East Frankfort - Crete	Line	ComEd	$3.4	$2.2	$0.1	$1.3	($0.0)	($0.0)	($0.1)	($0.1)	$1.2	3,092	658
14	Burnham - Munster	Flowgate	MISO	$3.3	$2.4	$0.0	$1.0	$0.0	$0.0	$0.0	$0.0	$1.0	2,304	0
15	Glenarm - Windy Edge	Line	BGE	$3.5	$2.5	$0.1	$1.1	($0.1)	($0.1)	($0.1)	($0.1)	$1.0	1,366	316
28	Pumphrey	Transformer	Pepco	($1.5)	($1.1)	($0.0)	($0.4)	$0.0	$0.0	$0.0	$0.0	($0.4)	486	0
56	Burches Hill	Transformer	Pepco	$0.8	$0.5	$0.1	$0.4	$0.1	$0.0	($0.2)	($0.2)	$0.2	136	88
76	Buzzard - Ritchie	Line	Pepco	$0.1	$0.0	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	148	0
93	Burtonsville - Sandy Springs	Line	Pepco	($0.2)	($0.1)	($0.0)	($0.1)	$0.0	$0.0	$0.0	$0.0	($0.1)	24	0
199	Dickerson - Pleasant View	Line	Pepco	$0.1	$0.0	$0.0	$0.0	($0.1)	($0.1)	($0.1)	($0.1)	($0.0)	26	20

Table G-23 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	$105.7	$78.2	$1.8	$29.3	($3.1)	($1.1)	($1.6)	($3.6)	$25.7	7,080	2,502
2	Bedington - Black Oak	Interface	500	$39.5	$27.7	$0.8	$12.5	($0.5)	($0.7)	($0.3)	($0.2)	$12.3	3,704	222
3	Doubs	Transformer	AP	$39.3	$24.9	$0.7	$15.1	($3.8)	$1.4	($1.7)	($6.8)	$8.2	2,492	896
4	Cloverdale - Lexington	Line	500	$10.6	$7.6	$0.1	$3.2	($0.9)	($0.9)	($0.3)	($0.3)	$2.9	2,138	1,356
5	Millville - Sleepy Hollow	Line	Dominion	$8.5	$6.1	$0.1	$2.5	$0.0	$0.0	$0.0	$0.0	$2.5	802	0
6	Graceton - Raphael Road	Line	BGE	$7.5	$4.9	$0.2	$2.7	($0.7)	($0.6)	($0.2)	($0.3)	$2.4	682	468
7	Brandon Shores - Riverside	Line	BGE	($13.4)	($10.1)	($0.2)	($3.4)	$1.1	$0.4	$0.3	$1.1	($2.4)	686	324
8	East Frankfort - Crete	Line	ComEd	$6.2	$3.8	$0.0	$2.4	($0.3)	($0.1)	($0.0)	($0.2)	$2.3	5,584	1,700
9	Reid - Ringgold	Line	AP	$5.1	$3.1	$0.2	$2.2	($0.1)	($0.1)	($0.0)	$0.0	$2.2	652	84
10	5004/5005 Interface	Interface	500	$6.8	$4.6	$0.2	$2.4	($0.3)	($0.1)	($0.1)	($0.3)	$2.0	2,758	1,142
11	Mount Storm - Pruntytown	Line	500	$9.3	$6.6	$0.1	$2.7	($1.6)	($1.2)	($0.4)	($0.9)	$1.9	1,142	1,148
12	West	Interface	500	$5.9	$3.9	$0.0	$2.0	($0.1)	($0.1)	($0.0)	($0.1)	$1.8	322	116
13	AEP-DOM	Interface	500	$8.0	$6.6	$0.1	$1.5	($0.1)	($0.2)	($0.1)	($0.0)	$1.5	942	178
14	Tiltonsville - Windsor	Line	AP	$5.3	$3.5	$0.1	$1.8	($0.4)	($0.1)	($0.1)	($0.4)	$1.5	5,204	940
15	Bowie	Line	Pepco	$2.3	$1.1	$0.1	$1.3	$0.0	$0.0	$0.0	$0.0	$1.3	88	0
16	Bowie - Lanham	Line	Pepco	$2.2	$0.9	$0.1	$1.4	($0.3)	($0.2)	($0.1)	($0.2)	$1.1	72	26
19	Dickerson - Pleasant View	Line	Pepco	($2.4)	($1.5)	($0.0)	($1.0)	$0.1	$0.2	$0.1	($0.0)	($1.0)	370	194
25	Benning - Ritchie	Line	Pepco	$0.8	$0.2	$0.1	$0.7	$0.0	$0.0	$0.0	$0.0	$0.7	156	0
33	Buzzard - Ritchie	Line	Pepco	$0.5	$0.0	$0.0	$0.5	($0.0)	($0.0)	($0.0)	($0.0)	$0.5	116	2
42	Bowie	Transformer	Pepco	$0.0	$0.0	$0.0	$0.0	$0.2	$0.4	($0.1)	($0.3)	($0.3)	0	18

PPL Control Zone

Table G-24 PPL Control Zone top congestion cost impacts (By facility): Calendar Year 2011

				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	$42.3	$53.4	$1.2	($10.0)	$1.8	$1.3	($0.8)	($0.2)	($10.2)	1,810	940
2	Susquehanna	Transformer	PPL	$16.5	$6.6	$0.2	$10.1	$0.0	$0.0	$0.0	$0.0	$10.1	240	0
3	West	Interface	500	$32.1	$38.0	$1.1	($4.8)	$0.0	($0.1)	($0.0)	$0.1	($4.7)	1,734	40
4	Harwood - Susquehanna	Line	PPL	$0.7	($3.0)	($0.1)	$3.7	($0.4)	$0.2	$0.1	($0.5)	$3.2	310	106
5	Graceton - Raphael Road	Line	BGE	($8.9)	($11.7)	($0.3)	$2.5	($0.1)	$0.1	$0.2	($0.0)	$2.5	2,314	830
6	Wylie Ridge	Transformer	AP	$14.0	$16.7	$0.4	($2.2)	$0.5	$0.1	($0.1)	$0.3	($1.9)	3,836	760
7	AP South	Interface	500	$0.4	($1.0)	$0.5	$1.8	$0.3	$0.1	($0.2)	$0.0	$1.9	8,222	2,026
8	Crete - St Johns Tap	Flowgate	MISO	$7.6	$9.5	$0.0	($1.9)	$0.4	$0.2	($0.0)	$0.2	($1.7)	6,708	2,230
9	Susquehanna	Transformer	PSEG	$0.0	$0.0	$0.0	$0.0	$0.1	($1.5)	($0.2)	$1.4	$1.4	0	104
10	Burnham - Munster	Flowgate	MISO	$3.0	$4.3	($0.0)	($1.3)	$0.0	$0.0	$0.0	$0.0	($1.3)	2,304	0
11	South Mahwah - Waldwick	Line	PSEG	$3.1	$3.9	$0.8	$0.0	$0.2	$0.3	($1.0)	($1.1)	($1.1)	10,538	988
12	Middletown Jctn. - Three Mile Island	Line	Met-Ed	$0.0	$0.0	$0.0	$0.0	$0.4	($0.7)	($0.0)	$1.1	$1.1	0	30
13	East	Interface	500	($0.2)	($1.4)	($0.2)	$1.0	$0.0	$0.0	$0.1	$0.1	$1.0	1,044	44
14	Wescosville	Transformer	PPL	$1.6	$0.9	$0.0	$0.7	$0.3	$0.0	($0.0)	$0.3	$1.0	88	80
15	East Frankfort - Crete	Line	ComEd	$2.7	$3.6	$0.0	($0.9)	$0.0	($0.0)	($0.0)	$0.1	($0.8)	3,092	658
51	Mountain	Transformer	PPL	$0.1	($0.2)	$0.0	$0.2	($0.2)	$0.1	($0.1)	($0.4)	($0.1)	134	90
52	Elroy	Transformer	PPL	$0.5	$0.6	$0.0	($0.1)	$0.0	$0.0	$0.0	$0.0	($0.1)	424	0
62	Juniata	Transformer	PPL	$0.8	$0.7	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	50	0
67	Dauphin - Juniata	Line	PPL	$0.2	$0.1	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	8	0
68	Quarry - Steel City	Line	PPL	($0.0)	($0.1)	($0.0)	$0.1	$0.0	($0.0)	$0.0	$0.0	$0.1	12	34

Table G-25 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	$32.8	$42.4	$0.9	($8.7)	$2.9	$1.4	($0.4)	$1.1	($7.6)	2,758	1,142
2	Brunner Island - Yorkana	Line	Met-Ed	($5.3)	($9.5)	($0.1)	$4.1	$0.3	$0.2	$0.1	$0.1	$4.2	474	360
3	West	Interface	500	$9.4	$12.2	$0.2	($2.7)	$0.1	$0.2	($0.1)	($0.2)	($2.8)	322	116
4	East Frankfort - Crete	Line	ComEd	$4.5	$6.8	($0.0)	($2.3)	$0.2	($0.2)	$0.0	$0.4	($1.8)	5,584	1,700
5	AP South	Interface	500	$2.8	$2.0	$0.5	$1.3	$0.3	($0.0)	($0.1)	$0.3	$1.6	7,080	2,502
6	Graceton - Raphael Road	Line	BGE	($4.7)	($6.6)	($0.1)	$1.8	($0.2)	$0.3	$0.0	($0.4)	$1.4	682	468
7	Harwood - Susquehanna	Line	PPL	$0.2	($1.4)	($0.0)	$1.6	$0.3	$0.5	($0.1)	($0.3)	$1.4	116	50
8	Millville - Sleepy Hollow	Line	Dominion	$2.4	$3.8	$0.1	($1.2)	$0.0	$0.0	$0.0	$0.0	($1.2)	802	0
9	Harwood - Siegfried	Line	PPL	($0.2)	($1.8)	$0.0	$1.5	($0.3)	$2.2	($0.1)	($2.6)	($1.1)	188	234
10	Juniata	Transformer	PENELEC	$0.0	$0.0	$0.1	$0.1	$0.7	$0.2	$0.4	$0.9	$1.0	92	54
11	Tiltonsville - Windsor	Line	AP	$3.7	$5.0	$0.1	($1.2)	$0.4	$0.2	($0.0)	$0.2	($1.0)	5,204	940
12	Eldred - Sunbury	Line	PPL	$0.6	($0.1)	$0.0	$0.7	$0.1	($0.1)	($0.0)	$0.1	$0.8	144	66
13	Crete - St Johns Tap	Flowgate	MISO	$1.9	$3.0	($0.0)	($1.1)	$0.1	($0.1)	$0.0	$0.2	($0.8)	1,782	622
14	Susquehanna	Transformer	PPL	$1.0	$0.3	$0.0	$0.7	$0.0	$0.0	$0.0	$0.0	$0.7	78	0
15	East Palmerton - Siegfried	Line	PPL	($0.1)	($0.7)	$0.0	$0.6	$0.0	$0.0	$0.0	$0.0	$0.6	140	0
19	East Palmerton - Harwood	Line	PPL	($0.0)	($0.5)	$0.0	$0.5	$0.0	$0.0	$0.0	$0.0	$0.5	102	0
27	Frackville - Siegfried	Line	PPL	($0.1)	($0.5)	($0.0)	$0.4	($0.0)	$0.0	($0.0)	($0.0)	$0.4	74	14
31	Eldred - Frackville	Line	PPL	$0.1	($0.2)	$0.0	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	40	0
35	Martins Creek - Siegfried	Line	PPL	($0.0)	($0.1)	$0.0	$0.1	($0.0)	$0.2	($0.1)	($0.3)	($0.3)	22	34
47	Juniata	Transformer	PPL	$0.5	$0.4	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	64	0

PSEG Control Zone

Table G-26 PSEG Control Zone top congestion cost impacts (By facility): Calendar Year 2011

				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	South Mahwah - Waldwick	Line	PSEG	$29.5	$14.6	($7.0)	$7.9	($1.9)	$3.9	($13.0)	($18.8)	($10.9)	10,538	988
2	Waldwick	Transformer	PSEG	$2.1	$1.1	$1.4	$2.4	($0.6)	$0.5	($7.6)	($8.7)	($6.4)	296	186
3	Cedar Grove - Roseland	Line	PSEG	$9.2	$3.9	$0.2	$5.5	($0.1)	$0.7	($0.2)	($0.9)	$4.6	1,812	74
4	AP South	Interface	500	($1.0)	$3.3	$1.5	($2.8)	$0.1	($0.2)	($1.6)	($1.2)	($4.0)	8,222	2,026
5	West	Interface	500	$36.3	$33.9	$1.4	$3.8	($0.1)	$0.1	($0.0)	($0.2)	$3.6	1,734	40
6	Bayway - Federal Square	Line	PSEG	$2.0	($0.6)	$0.2	$2.9	($0.0)	$0.0	($0.0)	($0.1)	$2.8	2,286	30
7	Branchburg - Readington	Line	PSEG	$3.6	$1.2	$0.3	$2.7	($0.1)	$0.4	($0.2)	($0.7)	$2.0	936	108
8	5004/5005 Interface	Interface	500	$33.3	$31.8	$1.5	$2.9	$1.4	$4.4	($1.7)	($4.7)	($1.8)	1,810	940
9	Susquehanna	Transformer	PPL	$1.5	$0.2	$0.0	$1.3	$0.0	$0.0	$0.0	$0.0	$1.3	240	0
10	Roseland - Whippany	Line	PSEG	$2.5	$1.1	$0.3	$1.6	($0.0)	$0.0	($0.4)	($0.5)	$1.2	684	112
11	Plymouth Meeting - Whitpain	Line	PECO	($0.7)	$0.6	$0.0	($1.2)	$0.1	($0.1)	($0.0)	$0.1	($1.1)	412	144
12	Redoak - Sayreville	Line	JCPL	$1.1	$0.1	$0.1	$1.1	($0.0)	$0.0	($0.0)	($0.0)	$1.1	3,504	22
13	Graceton - Raphael Road	Line	BGE	($8.6)	($8.9)	($0.5)	($0.2)	$0.2	($0.5)	$0.4	$1.2	$0.9	2,314	830
14	Wylie Ridge	Transformer	AP	$12.2	$12.4	$0.7	$0.5	$0.0	$1.0	($0.4)	($1.4)	($0.9)	3,836	760
15	Camden	Transformer	PSEG	$0.9	$0.2	$0.1	$0.8	$0.0	$0.0	$0.0	$0.0	$0.8	840	0
16	Bridgewater - Middlesex	Line	PSEG	$0.5	$0.3	$0.1	$0.3	$0.0	$0.7	($0.4)	($1.1)	($0.8)	1,108	126
17	Hawthorn - Waldwick	Line	PSEG	$0.2	$0.1	$0.6	$0.7	$0.0	$0.0	$0.0	$0.0	$0.7	1,318	0
18	Roseland - West Caldwell	Line	PSEG	$1.5	$0.5	$0.1	$1.1	($0.0)	$0.3	($0.2)	($0.4)	$0.7	264	58
23	Montville - Roseland	Line	PSEG	$1.1	$0.6	$0.0	$0.6	$0.0	$0.0	$0.0	$0.0	$0.6	126	0
24	Athenia - Saddlebrook	Line	PSEG	$0.9	$0.6	$0.3	$0.6	$0.0	$0.0	($0.0)	($0.0)	$0.6	2,796	8

Table G-27 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	$8.9	$1.2	$0.6	$8.3	$0.1	$1.0	($0.5)	($1.4)	$6.9	2,434	368
2	Hawthorn - Waldwick	Line	PSEG	$0.1	($0.0)	($0.0)	$0.0	($0.7)	$1.1	($1.7)	($3.4)	($3.4)	908	78
3	Athenia - Saddlebrook	Line	PSEG	$12.6	$2.5	$7.5	$17.6	($6.8)	$2.5	($5.0)	($14.3)	$3.3	5,918	662
4	AP South	Interface	500	$1.1	$5.4	$2.4	($1.9)	$0.2	($0.3)	($1.5)	($1.0)	($2.9)	7,080	2,502
5	Hillsdale - New Milford	Line	PSEG	$1.1	$0.5	$1.6	$2.2	$0.0	$0.0	($0.1)	($0.1)	$2.1	1,570	46
6	Eddystone - Island Road	Line	PECO	$1.0	($0.7)	$0.0	$1.7	$0.0	$0.0	($0.0)	$0.0	$1.7	372	6
7	5004/5005 Interface	Interface	500	$24.1	$23.1	$2.0	$3.0	$2.0	$1.6	($1.8)	($1.4)	$1.6	2,758	1,142
8	Hawthorn - Hinchmans Ave	Line	PSEG	($0.0)	($0.0)	($0.2)	($0.2)	($0.1)	$0.4	($0.9)	($1.4)	($1.6)	418	70
9	Redoak - Sayreville	Line	JCPL	$1.2	($0.3)	$0.1	$1.5	$0.0	($0.0)	($0.0)	$0.0	$1.5	1,700	114
10	North Ave - Pvsc	Line	PSEG	$0.2	($0.8)	$0.1	$1.0	$0.0	$0.0	$0.0	$0.0	$1.0	1,328	0
11	Bedington - Black Oak	Interface	500	$1.8	$3.6	$0.9	($0.9)	($0.0)	$0.0	($0.2)	($0.2)	($1.0)	3,704	222
12	Brandon Shores - Riverside	Line	BGE	$5.7	$5.0	$0.3	$1.0	$0.4	$0.1	($0.3)	$0.0	$1.0	686	324
13	Bayway - Federal Square	Line	PSEG	$0.6	($0.4)	$0.0	$1.0	($0.0)	$0.0	($0.0)	($0.0)	$1.0	1,088	16
14	Graceton - Raphael Road	Line	BGE	($4.5)	($4.6)	($0.2)	($0.2)	$0.2	($0.5)	$0.3	$1.0	$0.8	682	468
15	Doubs	Transformer	AP	$1.5	$1.4	$0.3	$0.4	($0.2)	$0.4	($0.6)	($1.3)	($0.8)	2,492	896
16	Bergen - Hoboken	Line	PSEG	$0.1	($0.2)	$0.4	$0.7	($0.2)	($0.1)	$0.1	$0.1	$0.8	1,004	58
19	Leonia - New Milford	Line	PSEG	$0.4	$0.3	$0.8	$0.9	($0.0)	$0.1	($0.0)	($0.2)	$0.7	2,172	12
21	Bayonne - PVSC	Line	PSEG	$0.0	($0.5)	$0.1	$0.6	$0.0	$0.0	$0.0	$0.0	$0.6	1,360	0
25	Hudson - Marion	Line	PSEG	$0.3	$0.1	$0.2	$0.5	$0.0	$0.0	$0.0	$0.0	$0.5	340	0
28	Fairlawn - Saddlebrook	Line	PSEG	$0.4	$0.2	$0.7	$0.9	($0.0)	$0.1	($0.4)	($0.5)	$0.4	996	34

RECO Control Zone

Table G-28 RECO Control Zone top congestion cost impacts (By facility): Calendar Year 2011

				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	South Mahwah - Waldwick	Line	PSEG	($1.5)	($0.6)	($0.0)	($0.9)	($0.0)	$1.0	$0.0	($1.0)	($1.9)	10,538	988
2	West	Interface	500	$1.0	$0.0	$0.0	$0.9	($0.0)	($0.0)	($0.0)	$0.0	$0.9	1,734	40
3	5004/5005 Interface	Interface	500	$0.9	$0.1	$0.0	$0.8	$0.0	($0.1)	($0.0)	$0.1	$0.9	1,810	940
4	Waldwick	Transformer	PSEG	($0.2)	($0.1)	($0.0)	($0.1)	($0.1)	$0.4	$0.0	($0.4)	($0.5)	296	186
5	East	Interface	500	$0.3	$0.0	$0.0	$0.3	($0.0)	($0.0)	$0.0	$0.0	$0.3	1,044	44
6	Wylie Ridge	Transformer	AP	$0.3	$0.1	$0.0	$0.3	$0.0	($0.0)	($0.0)	$0.0	$0.3	3,836	760
7	Cedar Grove - Roseland	Line	PSEG	$0.3	$0.1	$0.0	$0.3	($0.0)	($0.0)	($0.0)	$0.0	$0.3	1,812	74
8	Crete - St Johns Tap	Flowgate	MISO	$0.2	$0.0	$0.0	$0.2	$0.0	($0.0)	($0.0)	$0.0	$0.2	6,708	2,230
9	Graceton - Raphael Road	Line	BGE	($0.2)	($0.0)	($0.0)	($0.2)	$0.0	$0.0	$0.0	$0.0	($0.2)	2,314	830
10	Dickerson - Quince Orchard	Line	Pepco	$0.1	$0.0	$0.0	$0.1	$0.0	($0.0)	$0.0	$0.0	$0.2	284	152
11	AP South	Interface	500	($0.2)	($0.0)	$0.0	($0.1)	$0.0	$0.0	($0.0)	($0.0)	($0.2)	8,222	2,026
12	Branchburg - Readington	Line	PSEG	$0.1	$0.0	$0.0	$0.1	$0.0	($0.0)	$0.0	$0.0	$0.1	936	108
13	Burnham - Munster	Flowgate	MISO	$0.1	$0.0	($0.0)	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	2,304	0
14	Glenarm - Windy Edge	Line	BGE	($0.1)	($0.0)	($0.0)	($0.1)	$0.0	$0.0	$0.0	($0.0)	($0.1)	1,366	316
15	East Frankfort - Crete	Line	ComEd	$0.1	$0.0	$0.0	$0.1	($0.0)	($0.0)	($0.0)	($0.0)	$0.1	3,092	658

Table G-29 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	$0.9	$0.1	$0.0	$0.8	$0.2	($0.1)	($0.0)	$0.3	$1.1	2,758	1,142
2	Branchburg - Readington	Line	PSEG	$0.6	$0.0	$0.0	$0.5	$0.1	($0.0)	($0.0)	$0.1	$0.6	2,434	368
3	West	Interface	500	$0.4	$0.0	$0.0	$0.4	$0.0	($0.0)	$0.0	$0.0	$0.4	322	116
4	Brandon Shores - Riverside	Line	BGE	$0.2	$0.0	$0.0	$0.2	$0.0	($0.0)	$0.0	$0.0	$0.3	686	324
5	AP South	Interface	500	($0.2)	($0.0)	$0.0	($0.2)	($0.0)	$0.0	($0.0)	($0.1)	($0.2)	7,080	2,502
6	Athenia - Saddlebrook	Line	PSEG	$0.2	$0.0	($0.0)	$0.2	$0.0	($0.1)	$0.0	$0.1	$0.2	5,918	662
7	Graceton - Raphael Road	Line	BGE	($0.2)	($0.0)	($0.0)	($0.1)	($0.0)	$0.0	$0.0	($0.1)	($0.2)	682	468
8	Tiltonsville - Windsor	Line	AP	$0.2	$0.0	$0.0	$0.1	$0.0	($0.0)	($0.0)	$0.0	$0.2	5,204	940
9	East Frankfort - Crete	Line	ComEd	$0.1	$0.0	$0.0	$0.1	$0.0	($0.0)	($0.0)	$0.0	$0.2	5,584	1,700
10	Brunner Island - Yorkana	Line	Met-Ed	($0.1)	($0.0)	($0.0)	($0.1)	($0.0)	$0.0	$0.0	($0.0)	($0.1)	474	360
11	Hillsdale - New Milford	Line	PSEG	($0.1)	($0.0)	($0.0)	($0.1)	($0.0)	$0.0	$0.0	($0.0)	($0.1)	1,570	46
12	Hawthorn - Waldwick	Line	PSEG	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.1	$0.0	($0.1)	($0.1)	908	78
13	Hawthorn - Hinchmans Ave	Line	PSEG	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.1	$0.0	($0.1)	($0.1)	418	70
14	Millville - Sleepy Hollow	Line	Dominion	$0.1	$0.0	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	802	0
15	Doubs	Transformer	AP	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	$0.0	$0.1	2,470	896

Western Region Congestion-Event Summaries

AEP Control Zone

Table G-30 AEP Control Zone top congestion cost impacts (By facility): Calendar Year 2011

				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	($113.5)	($148.9)	($1.3)	$34.1	$3.7	$6.9	$2.3	($1.0)	$33.1	8,222	2,026
2	Belmont	Transformer	AP	$13.1	($15.0)	$4.9	$33.1	($2.0)	($0.3)	($3.9)	($5.6)	$27.5	8,742	998
3	AEP-DOM	Interface	500	($13.9)	($37.1)	$2.5	$25.7	$0.6	$1.5	($0.7)	($1.6)	$24.1	3,572	370
4	Brues - West Bellaire	Line	AEP	$21.7	$6.3	$1.9	$17.3	($2.1)	$1.7	($2.0)	($5.8)	$11.5	3,436	1,196
5	5004/5005 Interface	Interface	500	($65.3)	($76.4)	($0.8)	$10.3	$2.9	$3.9	$1.3	$0.3	$10.7	1,810	940
6	West	Interface	500	($56.9)	($68.0)	($0.6)	$10.4	$0.0	$0.1	$0.0	($0.0)	$10.4	1,734	40
7	Breed - Wheatland	Line	AEP	$1.2	($7.4)	($1.0)	$7.6	($0.0)	($0.0)	($0.0)	$0.0	$7.6	2,436	2
8	Danville - East Danville	Line	AEP	($30.1)	($29.9)	($5.4)	($5.6)	$0.0	$0.0	$0.0	$0.0	($5.6)	9,216	0
9	Michigan City - Laporte	Flowgate	MISO	$15.2	$8.9	$4.3	$10.6	($3.1)	($1.7)	($3.9)	($5.4)	$5.2	5,870	1,264
10	Kammer	Transformer	AEP	$5.5	($2.8)	$1.2	$9.4	($3.4)	($0.3)	($1.3)	($4.4)	$5.1	2,532	138
11	Wolfcreek	Transformer	AEP	($8.9)	($14.2)	$1.4	$6.7	($0.1)	$0.5	($1.2)	($1.9)	$4.8	5,094	452
12	Wylie Ridge	Transformer	AP	($42.9)	($49.0)	($1.3)	$4.8	$0.5	$1.3	$0.6	($0.2)	$4.6	3,836	760
13	Bedington - Black Oak	Interface	500	($16.5)	($20.8)	($0.1)	$4.2	$0.1	$0.0	$0.0	$0.0	$4.2	1,358	14
14	Cloverdale	Transformer	AEP	($4.5)	($8.8)	$0.4	$4.7	$0.2	$0.8	($0.0)	($0.7)	$4.1	1,402	250
15	Muskingum River	Transformer	AEP	($0.5)	($3.9)	$0.5	$3.9	$0.0	$0.0	$0.0	$0.0	$3.9	636	0
17	Marquis - Dept of Energy	Line	AEP	$0.1	($0.3)	$3.2	$3.6	$0.0	$0.0	$0.0	$0.0	$3.6	2,996	0
19	Muskingum River - East New Concord	Line	AEP	$0.7	($1.8)	$0.2	$2.7	$0.0	$0.0	$0.0	$0.0	$2.7	218	0
21	Jefferson - Clifty Creek	Line	AEP	($0.1)	($3.1)	($0.4)	$2.5	$0.0	$0.0	$0.0	$0.0	$2.5	538	0
23	Carbondale - Kanawha River	Line	AEP	($3.5)	($5.6)	$0.2	$2.3	$0.0	$0.0	$0.0	$0.0	$2.3	548	0
25	Muskingum River - Waterford	Line	AEP	($1.0)	($2.8)	$1.5	$3.3	$0.2	$0.8	($0.5)	($1.1)	$2.2	1,028	106

Table G-31 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	($32.6)	($81.3)	$0.4	$49.1	($3.4)	$2.5	$1.1	($4.9)	$44.2	7,080	2,502
2	AEP-DOM	Interface	500	$7.5	($20.1)	$1.0	$28.5	($0.2)	($0.3)	($0.3)	($0.1)	$28.4	942	178
3	Bedington - Black Oak	Interface	500	($12.3)	($26.5)	$0.1	$14.4	($0.1)	$0.1	$0.2	$0.0	$14.4	3,704	222
4	5004/5005 Interface	Interface	500	($17.8)	($27.1)	($0.4)	$8.9	($0.1)	$2.7	$0.6	($2.3)	$6.6	2,758	1,142
5	Baker - Broadford	Line	AEP	$0.1	($0.2)	$0.0	$0.3	($1.5)	$1.0	($3.5)	($5.9)	($5.6)	20	148
6	Belmont	Transformer	AP	$3.8	($0.8)	$0.7	$5.3	$0.2	($0.1)	($0.5)	($0.2)	$5.1	2,166	218
7	Kanawha River	Transformer	AEP	$2.7	($0.5)	$0.5	$3.7	$0.0	($0.0)	($0.0)	$0.0	$3.7	380	22
8	Brues - West Bellaire	Line	AEP	$0.0	$0.0	$0.0	$0.0	($2.1)	$0.9	($0.2)	($3.2)	($3.2)	0	156
9	Mahans Lane - Tidd	Line	AEP	($1.4)	($4.7)	($0.3)	$3.0	$0.2	$0.1	$0.0	$0.2	$3.2	1,292	414
10	Mount Storm - Pruntytown	Line	500	($2.9)	($8.0)	($0.1)	$5.0	($0.8)	$1.5	$0.5	($1.9)	$3.1	1,142	1,148
11	West	Interface	500	($5.6)	($9.0)	($0.1)	$3.3	($0.2)	$0.3	$0.1	($0.4)	$2.9	322	116
12	Kanawha - Kincaid	Line	AEP	$1.4	($0.7)	$0.2	$2.3	$0.0	$0.0	$0.0	$0.0	$2.3	440	0
13	Doubs	Transformer	AP	($10.8)	($13.8)	($0.2)	$2.8	$0.0	$0.9	$0.3	($0.6)	$2.2	2,492	896
14	Electric Jct - Nelson	Line	ComEd	$0.4	$0.6	$5.7	$5.5	($0.1)	($0.0)	($7.3)	($7.4)	($1.9)	2,908	482
15	Culloden - Wyoming	Line	AEP	$0.6	($0.8)	$0.5	$1.9	$0.0	$0.0	$0.0	$0.0	$1.9	92	0
18	Kammer - Natrium	Line	AEP	$1.5	($0.4)	$0.2	$2.0	($0.3)	$0.0	($0.1)	($0.4)	$1.6	614	96
20	Breed - Wheatland	Line	AEP	$0.0	($1.6)	($0.1)	$1.5	$0.0	$0.0	$0.0	$0.0	$1.5	300	2
22	Sullivan	Transformer	AEP	($0.0)	($1.4)	($0.0)	$1.3	$0.0	$0.0	$0.0	($0.0)	$1.3	370	94
23	Ruth - Turner	Line	AEP	$0.8	($0.4)	$0.1	$1.3	($0.0)	$0.0	($0.0)	($0.1)	$1.2	242	92
24	Cloverdale - Ivy Hill	Line	AEP	$0.0	$0.0	$0.0	$0.0	($1.1)	$0.1	$0.0	($1.2)	($1.2)	0	222

AP Control Zone

Table G-32 AP Control Zone top congestion cost impacts (By facility): Calendar Year 2011

				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	($26.3)	($91.6)	($7.8)	$57.6	$5.5	$5.7	$6.5	$6.3	$63.9	8,222	2,026
2	Belmont	Transformer	AP	$34.3	$7.2	$0.9	$28.0	($2.4)	($3.3)	($0.6)	$0.3	$28.3	8,742	998
3	5004/5005 Interface	Interface	500	($20.2)	($29.7)	($3.8)	$5.7	$1.4	$1.7	$4.4	$4.0	$9.7	1,810	940
4	Bedington - Black Oak	Interface	500	($3.1)	($11.6)	($1.9)	$6.5	$0.0	$0.1	$0.1	$0.1	$6.6	1,358	14
5	Yukon	Transformer	AP	$4.4	$0.0	$0.2	$4.6	$0.2	$0.4	($0.1)	($0.3)	$4.3	750	180
6	AEP-DOM	Interface	500	($1.3)	($4.7)	($0.0)	$3.3	$0.1	$0.1	$0.3	$0.4	$3.7	3,572	370
7	Bedington	Transformer	AP	$1.2	($2.7)	($0.2)	$3.6	($0.1)	$0.6	$0.3	($0.4)	$3.2	464	206
8	Wylie Ridge	Transformer	AP	$6.0	$9.7	$3.7	($0.0)	($0.1)	($0.3)	($3.1)	($2.9)	($2.9)	3,836	760
9	West	Interface	500	($18.5)	($24.4)	($3.2)	$2.6	$0.1	$0.0	$0.1	$0.1	$2.8	1,734	40
10	Wolfcreek	Transformer	AEP	$5.7	$8.2	$1.0	($1.5)	($0.5)	($0.6)	($1.0)	($0.9)	($2.4)	5,094	452
11	Tiltonsville - Windsor	Line	AP	$2.6	$0.7	$0.3	$2.1	($0.2)	($0.0)	($0.2)	($0.4)	$1.7	2,008	144
12	Dickerson - Quince Orchard	Line	Pepco	($6.8)	($5.2)	($0.9)	($2.5)	($0.8)	($0.2)	$1.3	$0.8	($1.7)	284	152
13	Mount Storm	Line	AP	($0.4)	($1.9)	$0.2	$1.6	$0.0	$0.0	$0.0	$0.0	$1.6	162	0
14	Danville - East Danville	Line	AEP	$0.3	($1.1)	$0.2	$1.5	$0.0	$0.0	$0.0	$0.0	$1.5	9,216	0
15	Valley	Transformer	Dominion	($0.8)	($2.0)	($0.0)	$1.2	$0.3	$0.2	$0.1	$0.2	$1.4	438	196
16	Gore - Hampshire	Line	AP	($2.1)	($3.8)	($0.4)	$1.3	$0.0	$0.0	$0.0	$0.0	$1.3	1,654	0
19	Mount Storm	Transformer	AP	$0.0	$0.0	$0.0	$0.0	$0.6	$1.1	($0.6)	($1.1)	($1.1)	0	218
21	Kingwood - Pruntytown	Line	AP	$0.8	($0.1)	$0.1	$0.9	($0.0)	($0.1)	($0.0)	($0.0)	$0.9	404	28
25	Hamilton - Weirton	Line	AP	$1.0	$0.3	$0.1	$0.8	$0.0	$0.0	($0.0)	($0.0)	$0.8	304	6
26	Halfway - Marlowe	Line	AP	$0.5	($0.2)	$0.0	$0.7	$0.0	$0.0	($0.0)	($0.0)	$0.7	158	18

Table G-33 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	($30.8)	($119.2)	($8.3)	$80.1	$5.3	$6.2	$7.4	$6.4	$86.5	7,080	2,502
2	Doubs	Transformer	AP	$13.6	($10.3)	($0.2)	$23.7	$3.4	$0.9	$0.1	$2.7	$26.3	2,492	896
3	Bedington - Black Oak	Interface	500	($10.2)	($38.1)	($1.8)	$26.0	$0.3	$1.9	$0.1	($1.5)	$24.6	3,704	222
4	Tiltonsville - Windsor	Line	AP	$17.1	$3.9	$1.5	$14.8	($2.6)	($0.7)	($1.7)	($3.6)	$11.2	5,204	940
5	Mount Storm - Pruntytown	Line	500	($2.8)	($11.1)	($0.4)	$7.9	$2.5	$1.7	$2.0	$2.8	$10.6	1,142	1,148
6	5004/5005 Interface	Interface	500	($17.1)	($26.2)	($1.4)	$7.7	$2.0	$2.9	$1.4	$0.6	$8.3	2,758	1,142
7	Belmont	Transformer	AP	$7.3	($0.7)	$0.2	$8.2	($0.2)	($0.3)	($0.2)	($0.1)	$8.1	2,166	218
8	AEP-DOM	Interface	500	($2.1)	($7.8)	$0.4	$6.0	$0.3	($0.2)	($0.1)	$0.4	$6.4	942	178
9	Kingwood - Pruntytown	Line	AP	$5.4	$1.4	$0.6	$4.6	$0.0	($0.1)	($0.2)	($0.0)	$4.6	996	98
10	Cloverdale - Lexington	Line	500	$1.4	($3.4)	$0.9	$5.7	($0.1)	$0.4	($1.8)	($2.3)	$3.4	2,138	1,356
11	Endless Caverns	Transformer	Dominion	$2.6	$0.0	$0.3	$2.9	$0.0	$0.0	($0.0)	($0.0)	$2.9	1,082	6
12	Nipetown - Reid	Line	AP	$0.0	($2.6)	($0.0)	$2.5	$0.1	$0.2	($0.0)	($0.1)	$2.5	642	126
13	Mahans Lane - Tidd	Line	AEP	$3.9	$1.4	$0.4	$2.9	($0.4)	($0.1)	($0.2)	($0.5)	$2.4	1,292	414
14	Fort Martin - Ronco	Line	AP	$0.2	$0.2	$0.1	$0.2	($0.2)	$0.9	($1.4)	($2.5)	($2.3)	62	84
15	Middlebourne - Willow	Line	AP	$2.0	($0.2)	$0.3	$2.5	($0.2)	($0.1)	($0.2)	($0.3)	$2.1	634	162
17	Wylie Ridge	Transformer	AP	$0.9	$1.5	$0.6	$0.0	($0.7)	($0.2)	($1.4)	($1.9)	($1.9)	1,010	752
18	Hamilton - Weirton	Line	AP	$2.7	$0.9	$0.2	$2.0	($0.1)	$0.1	($0.1)	($0.3)	$1.7	900	36
19	Yukon	Transformer	AP	$1.7	$0.1	$0.1	$1.7	$0.0	$0.1	$0.1	($0.0)	$1.7	224	34
20	Halfway - Marlowe	Line	AP	$0.6	($0.7)	($0.0)	$1.3	$0.2	($0.1)	$0.0	$0.2	$1.5	120	40
21	Bedington - Shepherdstown	Line	AP	($0.0)	($1.2)	$0.1	$1.3	$0.1	($0.1)	$0.0	$0.2	$1.5	1,100	90

ATSI Control Zone

Table G-34 ATSI Control Zone top congestion cost impacts (By facility): Calendar Year 2011

				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	($27.8)	($27.1)	($1.3)	($2.0)	($0.2)	$2.4	$1.8	($0.8)	($2.9)	8,222	2,026
2	Niles - Evergreen	Line	ATSI	$3.2	$0.8	$0.8	$3.2	($0.4)	$0.2	($0.6)	($1.2)	$1.9	892	54
3	Dickerson - Quince Orchard	Line	Pepco	($4.2)	($3.5)	$0.0	($0.7)	($0.2)	$0.4	($0.0)	($0.6)	($1.3)	284	152
4	West	Interface	500	($21.8)	($20.7)	($0.1)	($1.2)	($0.0)	$0.0	$0.0	($0.0)	($1.2)	1,734	40
5	Bayshore - Jeep	Line	ATSI	$0.8	($0.2)	$0.0	$1.0	$0.4	$0.2	$0.0	$0.2	$1.2	32	12
6	Clover	Transformer	Dominion	($2.8)	($2.3)	$0.4	($0.2)	$0.2	$0.4	($0.6)	($0.8)	($1.0)	2,476	938
7	Beaver - Sammis	Line	DLCO	($0.5)	($1.5)	($0.1)	$0.9	$0.0	$0.0	$0.0	$0.0	$0.9	442	22
8	Burnham - Munster	Flowgate	MISO	$4.5	$3.7	$0.1	$0.9	$0.0	$0.0	$0.0	$0.0	$0.9	2,304	0
9	South Canton - Torrey	Line	AEP	$1.4	$0.6	$0.0	$0.8	$0.0	$0.0	$0.0	$0.0	$0.8	82	16
10	Danville - East Danville	Line	AEP	($3.8)	($3.3)	($0.2)	($0.8)	$0.0	$0.0	$0.0	$0.0	($0.8)	9,216	0
11	5004/5005 Interface	Interface	500	($5.0)	($5.1)	($0.1)	($0.0)	$0.2	$1.2	$0.2	($0.7)	($0.8)	1,810	940
12	Muskingum River - Waterford	Line	AEP	$0.8	$0.7	$0.1	$0.1	$0.1	($0.1)	($1.0)	($0.7)	($0.6)	1,028	106
13	AEP-DOM	Interface	500	($4.4)	($3.8)	($0.1)	($0.8)	$0.0	$0.1	$0.2	$0.2	($0.6)	3,572	370
14	Benton Harbor - Palisades	Flowgate	MISO	$0.0	$0.0	$0.0	$0.0	($0.2)	($0.0)	($0.4)	($0.6)	($0.6)	134	264
15	Jeep - Dixie	Line	ATSI	$0.4	($0.1)	$0.0	$0.5	$0.0	$0.0	$0.0	$0.0	$0.5	28	0
20	Sammis - Wylie Ridge	Line	ATSI	($1.2)	($1.8)	($0.2)	$0.4	($0.0)	($0.0)	$0.0	$0.0	$0.4	484	8
29	Lakeview - Ottawa	Line	ATSI	$0.2	($0.0)	$0.0	$0.2	$0.0	$0.0	($0.0)	$0.0	$0.3	46	4
31	Galion – GM Mansfield	Line	ATSI	$0.3	$0.0	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	36	0
35	Galion - Leaside	Line	ATSI	$0.1	$0.1	$0.0	$0.1	$0.1	($0.0)	($0.0)	$0.1	$0.2	44	22
42	Brookside - Wellington	Line	ATSI	$0.1	$0.0	$0.1	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	224	0

ComEd Control Zone

Table G-35 ComEd Control Zone top congestion cost impacts (By facility): Calendar Year 2011

				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	Electric Jct - Nelson	Line	ComEd	($5.1)	($43.6)	$6.2	$44.8	$1.2	$4.0	($5.1)	($7.9)	$36.9	5,852	316
2	Crete - St Johns Tap	Flowgate	MISO	($156.4)	($190.6)	($16.6)	$17.6	$7.0	$5.6	$7.6	$8.9	$26.5	6,708	2,230
3	AP South	Interface	500	($122.0)	($134.5)	($0.9)	$11.6	$7.6	$2.5	$0.3	$5.5	$17.1	8,222	2,026
4	East Frankfort - Crete	Line	ComEd	($56.3)	($71.2)	($5.0)	$10.0	$1.5	$0.5	$2.1	$3.1	$13.1	3,092	658
5	Bunsonville - Eugene	Flowgate	MISO	($39.8)	($51.0)	($0.1)	$11.1	$0.0	$0.0	($0.0)	($0.0)	$11.1	4,888	22
6	Pleasant Valley - Belvidere	Line	ComEd	($5.3)	($17.4)	$1.2	$13.3	($0.3)	$2.2	($1.3)	($3.8)	$9.5	2,186	630
7	5004/5005 Interface	Interface	500	($62.7)	($69.3)	($0.4)	$6.2	$4.0	$2.0	$0.5	$2.5	$8.7	1,810	940
8	Wylie Ridge	Transformer	AP	($38.5)	($43.2)	($0.1)	$4.6	$1.6	$0.4	($0.1)	$1.1	$5.7	3,836	760
9	Michigan City - Laporte	Flowgate	MISO	($40.7)	($43.4)	$1.7	$4.3	$2.5	$0.5	($1.0)	$1.0	$5.4	5,870	1,264
10	Lakeview - Pleasant Prairie	Flowgate	MISO	$0.3	$0.2	$0.2	$0.3	($0.3)	($0.0)	($4.8)	($5.1)	($4.8)	48	604
11	Brokaw - Gibson	Flowgate	MISO	($15.1)	($19.7)	$0.5	$5.2	$0.2	$0.1	($0.6)	($0.5)	$4.7	1,418	190
12	Waukegan - Zion	Line	ComEd	$0.7	($1.2)	$2.9	$4.8	$0.0	$0.0	($0.3)	($0.3)	$4.5	3,468	14
13	Rantoul - Rantoul Jct	Flowgate	MISO	($14.3)	($18.3)	$0.0	$3.9	$0.3	$0.1	$0.1	$0.3	$4.2	1,106	376
14	Cherry Valley	Transformer	ComEd	$1.7	($1.8)	$0.5	$3.9	$0.1	$0.1	($0.2)	($0.2)	$3.7	1,406	164
15	West	Interface	500	($59.0)	($62.7)	($0.2)	$3.5	$0.1	$0.1	$0.0	$0.1	$3.6	1,734	40
16	Glidden - West Dekalb	Line	ComEd	($0.7)	($3.9)	$0.3	$3.5	$0.0	($0.0)	($0.0)	($0.0)	$3.5	2,236	2
19	Burnham - Munster	Line	ComEd	$0.0	$0.0	$0.0	$0.0	$1.2	($0.1)	$1.7	$3.0	$3.0	0	454
21	Wilton Center	Transformer	ComEd	($1.6)	($1.9)	$2.5	$2.8	$0.1	$0.1	$0.0	$0.0	$2.9	134	52
23	Belvidere - Woodstock	Line	ComEd	($0.1)	($3.0)	$0.3	$3.3	$0.0	$0.2	($0.2)	($0.5)	$2.8	378	86
25	Woodstock - 12205	Line	ComEd	($0.7)	($3.1)	$0.2	$2.6	$0.0	$0.0	$0.0	$0.0	$2.6	790	0

Table G-36 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	East Frankfort - Crete	Line	ComEd	($43.4)	($81.0)	($5.2)	$32.4	($3.7)	($1.1)	$1.2	($1.4)	$31.0	5,584	1,700
2	Electric Jct - Nelson	Line	ComEd	$1.1	($24.4)	$6.5	$32.1	$1.3	$3.7	($7.7)	($10.1)	$22.0	2,908	482
3	AP South	Interface	500	($73.8)	($99.1)	($0.7)	$24.6	($3.2)	($0.5)	($0.0)	($2.7)	$21.8	7,080	2,502
4	Crete - St Johns Tap	Flowgate	MISO	($22.3)	($36.7)	($1.7)	$12.8	($1.2)	($1.4)	$0.6	$0.8	$13.6	1,782	622
5	Pleasant Valley - Belvidere	Line	ComEd	($3.3)	($19.8)	$1.8	$18.3	$0.1	$2.7	($2.4)	($5.0)	$13.3	4,110	830
6	Nelson - Cordova	Line	ComEd	$8.1	($2.8)	$3.5	$14.3	$0.8	$1.7	($3.5)	($4.4)	$9.9	2,516	190
7	Bedington - Black Oak	Interface	500	($26.2)	($34.5)	($0.2)	$8.2	($0.7)	($0.2)	$0.0	($0.5)	$7.7	3,704	222
8	Waterman - West Dekalb	Line	ComEd	($1.6)	($7.4)	$0.8	$6.5	$0.4	$0.3	($0.2)	($0.0)	$6.5	5,216	576
9	5004/5005 Interface	Interface	500	($25.2)	($35.1)	($0.1)	$9.8	($4.3)	($0.7)	$0.2	($3.3)	$6.4	2,758	1,142
10	AEP-DOM	Interface	500	($10.3)	($16.3)	($0.4)	$5.6	($0.1)	($0.2)	$0.0	$0.1	$5.7	942	178
11	Rising	Flowgate	MISO	($2.2)	($6.9)	($0.0)	$4.7	($0.0)	$0.0	$0.0	($0.0)	$4.6	1,552	90
12	Cloverdale - Lexington	Line	500	($11.2)	($17.3)	($0.4)	$5.7	($1.7)	($0.2)	$0.4	($1.1)	$4.5	2,138	1,356
13	Glidden - West Dekalb	Line	ComEd	($0.2)	($3.8)	$0.4	$4.1	$0.0	$0.0	($0.0)	($0.0)	$4.1	1,520	4
14	Tiltonsville - Windsor	Line	AP	($10.9)	($14.7)	($0.3)	$3.6	($1.4)	($0.1)	$0.4	($0.9)	$2.7	5,204	940
15	Doubs	Transformer	AP	($15.2)	($19.1)	($0.1)	$3.8	($1.1)	$0.5	$0.1	($1.5)	$2.3	2,492	896
17	Cherry Valley	Transformer	ComEd	$0.9	($1.1)	$0.2	$2.1	$0.1	$0.1	($0.1)	($0.1)	$2.0	214	74
22	Electric Junction - Aurora	Line	ComEd	$1.3	$0.2	$0.0	$1.1	$0.0	$0.1	$0.1	$0.1	$1.2	272	70
23	Woodstock - 12205	Line	ComEd	($0.0)	($1.0)	$0.1	$1.2	$0.0	$0.0	$0.0	$0.0	$1.2	182	0
29	Belvidere - Woodstock	Line	ComEd	$0.3	($0.6)	$0.1	$0.9	$0.0	$0.1	($0.0)	($0.0)	$0.9	186	14
36	Burnham - Munster	Line	ComEd	($0.0)	($0.0)	($0.0)	$0.0	($0.1)	$0.6	($0.0)	($0.7)	($0.7)	2	164

DAY Control Zone

Table G-37 DAY Control Zone top congestion cost impacts (By facility): Calendar Year 2011

				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	Pierce - Foster	Flowgate	MISO	$0.0	$0.0	$0.0	$0.0	($0.1)	($0.2)	($1.7)	($1.6)	($1.6)	0	40
2	West	Interface	500	($7.3)	($8.7)	($0.0)	$1.4	$0.0	$0.0	$0.0	$0.0	$1.4	1,734	40
3	AP South	Interface	500	($16.1)	($17.7)	($0.4)	$1.2	$0.8	$1.5	$0.5	($0.2)	$1.0	8,222	2,026
4	AEP-DOM	Interface	500	($3.7)	($4.7)	($0.0)	$0.9	$0.1	$0.2	$0.1	$0.0	$0.9	3,572	370
5	Danville - East Danville	Line	AEP	($2.5)	($3.4)	($0.1)	$0.8	$0.0	$0.0	$0.0	$0.0	$0.8	9,216	0
6	Burnham - Munster	Flowgate	MISO	$1.1	$1.7	$0.1	($0.5)	$0.0	$0.0	$0.0	$0.0	($0.5)	2,304	0
7	Clover	Transformer	Dominion	($1.9)	($2.4)	$0.1	$0.6	$0.2	$0.2	($0.1)	($0.1)	$0.5	2,476	938
8	Crete - St Johns Tap	Flowgate	MISO	$2.8	$3.1	($0.1)	($0.4)	($0.1)	($0.1)	($0.2)	($0.1)	($0.5)	6,708	2,230
9	East Frankfort - Crete	Line	ComEd	$1.0	$1.4	$0.1	($0.3)	($0.0)	$0.0	($0.1)	($0.1)	($0.5)	3,092	658
10	Breed - Wheatland	Line	AEP	$0.5	$0.9	($0.0)	($0.4)	($0.0)	($0.0)	($0.0)	($0.0)	($0.4)	2,436	2
11	Wolfcreek	Transformer	AEP	($1.7)	($2.1)	($0.0)	$0.4	$0.1	$0.1	$0.0	($0.0)	$0.4	5,094	452
12	Bunsonville - Eugene	Flowgate	MISO	$1.7	$2.2	$0.1	($0.4)	$0.0	($0.0)	($0.0)	$0.0	($0.4)	4,888	22
13	Valley	Transformer	Dominion	($0.9)	($1.3)	($0.0)	$0.4	$0.1	$0.2	$0.0	($0.0)	$0.3	438	196
14	Belmont	Transformer	AP	($1.5)	($1.8)	$0.1	$0.4	$0.0	$0.1	($0.0)	($0.1)	$0.3	8,742	998
15	Brokaw - Gibson	Flowgate	MISO	$0.4	$0.8	$0.0	($0.3)	($0.0)	($0.0)	($0.0)	($0.0)	($0.3)	1,418	190
37	Trenton - Hutchings	Line	DAY	$0.2	$0.0	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	106	0
153	Foster2 - Pierce	Line	DAY	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	($0.0)	($0.0)	0	2

Table G-38 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	($1.4)	($2.5)	($0.2)	$0.9	$0.3	$0.0	$0.4	$0.7	$1.6	2,758	1,142
2	AP South	Interface	500	($4.5)	($6.2)	($0.9)	$0.8	$0.1	$0.5	$0.6	$0.2	$1.0	7,080	2,502
3	Cloverdale - Lexington	Line	500	($0.5)	($1.4)	($0.2)	$0.6	$0.1	($0.0)	$0.2	$0.3	$1.0	2,138	1,356
4	Pleasant Prairie - Zion	Flowgate	MISO	$0.0	($0.0)	$0.5	$0.5	($0.0)	$0.0	($1.4)	($1.4)	($0.9)	2,196	618
5	Mount Storm - Pruntytown	Line	500	($0.4)	($0.5)	($0.0)	$0.1	$0.2	$0.3	$0.7	$0.6	$0.7	1,142	1,148
6	AEP-DOM	Interface	500	($0.7)	($1.4)	($0.0)	$0.7	($0.0)	($0.0)	$0.0	$0.0	$0.7	942	178
7	Tiltonsville - Windsor	Line	AP	($0.7)	($1.0)	($0.3)	$0.1	$0.1	$0.0	$0.4	$0.5	$0.5	5,204	940
8	Harrison - Pruntytown	Line	500	($0.1)	($0.2)	($0.0)	$0.0	$0.1	$0.1	$0.4	$0.4	$0.5	462	446
9	Doubs	Transformer	AP	($0.9)	($1.3)	($0.1)	$0.3	$0.1	$0.1	$0.1	$0.1	$0.4	2,492	896
10	Branchburg - Flagtown	Line	PSEG	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($0.4)	($0.4)	($0.4)	0	0
11	Waterman - West Dekalb	Line	ComEd	$0.0	$0.0	$0.5	$0.5	$0.0	$0.0	($0.1)	($0.1)	$0.4	5,216	576
12	Pleasant Valley - Belvidere	Line	ComEd	$0.0	$0.0	$0.8	$0.8	($0.0)	$0.0	($1.2)	($1.2)	($0.4)	4,110	830
13	Bedington - Black Oak	Interface	500	($1.4)	($2.2)	($0.4)	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	3,704	222
14	Crete - St Johns Tap	Flowgate	MISO	$0.2	$0.4	($0.1)	($0.2)	($0.0)	$0.1	($0.0)	($0.1)	($0.3)	1,782	622
15	Clover	Transformer	Dominion	($0.2)	($0.5)	$0.1	$0.3	$0.0	($0.0)	($0.1)	$0.0	$0.3	1,004	516

DLCO Control Zone

Table G-39 DLCO Control Zone top congestion cost impacts (By facility): Calendar Year 2011

				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	$5.9	($0.4)	$0.1	$6.4	($0.1)	$0.1	($0.2)	($0.4)	$6.0	714	206
2	Wylie Ridge	Transformer	AP	($11.5)	($16.8)	($0.4)	$4.8	($0.4)	($0.1)	$0.2	($0.2)	$4.7	3,836	760
3	AP South	Interface	500	($18.6)	($23.3)	($0.5)	$4.1	($1.3)	$0.0	$0.4	($0.9)	$3.3	8,222	2,026
4	Collier - Elwyn	Line	DLCO	$1.8	($0.2)	$0.0	$2.0	$0.1	$0.1	($0.0)	($0.0)	$1.9	504	60
5	Brunot Island - Forbes	Line	DLCO	$0.7	($0.1)	$0.0	$0.8	($0.0)	($0.1)	($0.0)	$0.0	$0.8	172	72
6	Yukon	Transformer	AP	$2.0	$1.5	$0.1	$0.5	$0.3	($0.2)	($0.2)	$0.3	$0.8	750	180
7	AEP-DOM	Interface	500	($1.8)	($2.6)	$0.0	$0.8	($0.1)	($0.0)	$0.0	($0.0)	$0.7	3,572	370
8	Crete - St Johns Tap	Flowgate	MISO	$2.2	$2.9	$0.1	($0.7)	$0.1	$0.0	($0.0)	$0.1	($0.6)	6,708	2,230
9	5004/5005 Interface	Interface	500	($7.7)	($9.4)	($0.1)	$1.6	($0.6)	$0.5	$0.1	($1.0)	$0.6	1,810	940
10	Bedington - Black Oak	Interface	500	($2.2)	($2.7)	($0.0)	$0.6	($0.0)	$0.0	$0.0	($0.0)	$0.6	1,358	14
11	Beaver - Sammis	Line	DLCO	($0.6)	($1.4)	($0.0)	$0.7	($0.1)	$0.1	$0.0	($0.2)	$0.5	442	22
12	Arsenal - Highland	Line	DLCO	($0.0)	($0.1)	$0.0	$0.1	$0.0	($0.3)	$0.0	$0.4	$0.5	168	30
13	West	Interface	500	($6.8)	($7.2)	($0.1)	$0.4	($0.0)	$0.0	$0.0	($0.0)	$0.4	1,734	40
14	Burnham - Munster	Flowgate	MISO	$0.9	$1.2	$0.0	($0.4)	$0.0	$0.0	$0.0	$0.0	($0.4)	2,304	0
15	East Frankfort - Crete	Line	ComEd	$0.8	$1.2	$0.0	($0.3)	$0.0	$0.0	($0.0)	$0.0	($0.3)	3,092	658
18	Arsenal - Brunot Island	Line	DLCO	$0.2	$0.0	$0.0	$0.2	$0.0	($0.0)	($0.0)	$0.0	$0.2	100	18
20	Clinton - Findlay	Line	DLCO	$0.2	($0.0)	$0.0	$0.3	$0.0	$0.0	($0.0)	($0.0)	$0.2	48	24
23	St. Joe	Other	DLCO	$0.1	$0.0	$0.1	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	878	0
24	Beaver - Clinton	Line	DLCO	$0.1	($0.1)	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	68	0
33	Arsenal	Transformer	DLCO	$0.1	($0.0)	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	34	0

Table G-40 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	$12.2	($0.0)	$0.2	$12.4	$0.2	($0.5)	($0.3)	$0.4	$12.8	1,260	282
2	AP South	Interface	500	($36.5)	($43.0)	($0.2)	$6.4	($2.3)	($0.5)	$0.2	($1.5)	$4.8	7,080	2,502
3	Collier - Elwyn	Line	DLCO	$4.5	$0.3	$0.1	$4.4	($0.0)	($0.1)	($0.0)	$0.0	$4.4	920	222
4	Carson - Oakland	Line	DLCO	$2.6	$0.0	$0.0	$2.6	($0.0)	($0.0)	$0.0	($0.0)	$2.6	350	2
5	Bedington - Black Oak	Interface	500	($11.6)	($13.3)	($0.1)	$1.7	($0.2)	($0.0)	$0.0	($0.2)	$1.5	3,704	222
6	AEP-DOM	Interface	500	($4.3)	($5.7)	($0.0)	$1.4	($0.2)	($0.1)	$0.0	($0.1)	$1.3	942	178
7	Sammis - Wylie Ridge	Line	ATSI	($1.8)	($3.2)	($0.0)	$1.4	($0.1)	$0.2	$0.0	($0.2)	$1.2	1,042	120
8	Elrama - Mitchell	Line	AP	($2.5)	($1.9)	($0.1)	($0.7)	($0.1)	$0.0	$0.1	($0.0)	($0.7)	934	484
9	East Frankfort - Crete	Line	ComEd	$1.5	$2.3	($0.0)	($0.8)	$0.1	($0.1)	($0.0)	$0.2	($0.6)	5,584	1,700
10	5004/5005 Interface	Interface	500	($10.9)	($12.7)	($0.1)	$1.7	($1.3)	($0.1)	$0.1	($1.1)	$0.6	2,758	1,142
11	Cloverdale - Lexington	Line	500	($1.4)	($2.1)	$0.0	$0.7	($0.2)	($0.0)	($0.0)	($0.2)	$0.5	2,138	1,356
12	Arsenal - Highland	Line	DLCO	$0.5	($0.0)	$0.0	$0.5	($0.0)	$0.0	($0.0)	($0.0)	$0.5	96	14
13	Arsenal - Oakland	Line	DLCO	$0.1	($0.1)	$0.0	$0.3	($0.3)	$0.3	($0.0)	($0.6)	($0.4)	178	108
14	Collier	Transformer	DLCO	$0.3	$0.0	$0.0	$0.3	$0.0	($0.1)	($0.0)	$0.1	$0.4	16	16
15	Beaver - Mansfield	Line	DLCO	($0.1)	($0.4)	($0.0)	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	342	0
23	Crescent - Sewickly	Line	DLCO	$0.2	$0.0	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	24	0
25	Cheswick - Logan's Ferry	Line	DLCO	($0.0)	($0.1)	($0.0)	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	70	0
27	Beaver	Transformer	DLCO	$0.0	$0.0	$0.0	$0.0	($0.1)	$0.1	($0.0)	($0.1)	($0.1)	0	14
30	Arsenal	Transformer	DLCO	$0.1	$0.0	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	16	0
34	Collier - Woodville	Line	DLCO	$0.1	($0.1)	$0.0	$0.1	($0.0)	($0.0)	$0.0	($0.0)	$0.1	40	6

Southern Region Congestion-Event Summaries

Dominion Control Zone

Table G-41 Dominion Control Zone top congestion cost impacts (By facility): Calendar Year 2011

				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	$313.4	$233.9	$3.4	$82.9	($0.3)	$0.6	($4.1)	($5.0)	$77.9	8,222	2,026
2	Clover	Transformer	Dominion	$23.2	$7.9	$4.4	$19.8	($0.5)	$2.7	($8.2)	($11.4)	$8.4	2,476	938
3	AEP-DOM	Interface	500	$51.0	$46.9	$1.4	$5.6	($0.3)	($0.6)	($0.4)	($0.1)	$5.5	3,572	370
4	Danville - East Danville	Line	AEP	$60.1	$55.4	$0.7	$5.4	$0.0	$0.0	$0.0	$0.0	$5.4	9,216	0
5	Bedington - Black Oak	Interface	500	$32.0	$28.6	$0.6	$4.0	$0.0	($0.0)	($0.1)	$0.0	$4.0	1,358	14
6	Valley	Transformer	Dominion	$24.7	$20.0	$1.1	$5.8	($1.3)	($0.1)	($1.3)	($2.5)	$3.3	438	196
7	Chaparral - Carson	Line	Dominion	$5.1	$4.4	$0.5	$1.2	$0.2	$1.6	($3.0)	($4.5)	($3.3)	392	360
8	Dickerson - Quince Orchard	Line	Pepco	($32.1)	($29.0)	($0.9)	($4.1)	$0.4	$1.1	$1.5	$0.8	($3.3)	284	152
9	Graceton - Raphael Road	Line	BGE	$19.1	$16.5	$0.5	$3.1	($0.2)	($0.6)	($0.6)	($0.2)	$2.9	2,314	830
10	Crete - St Johns Tap	Flowgate	MISO	$25.7	$22.9	$0.1	$2.9	($0.3)	($0.4)	($0.2)	($0.0)	$2.9	6,708	2,230
11	Mount Storm	Transformer	AP	$0.0	$0.0	$0.0	$0.0	($1.0)	($1.6)	($3.4)	($2.9)	($2.9)	0	218
12	Cloverdale - Lexington	Line	500	$12.0	$8.7	$0.9	$4.2	($0.3)	($0.6)	($2.1)	($1.7)	$2.5	1,204	854
13	Cranes Corner - Fredericksburg	Line	Dominion	($3.3)	($6.0)	($0.2)	$2.5	$0.2	$0.4	$0.2	($0.0)	$2.5	250	46
14	Wylie Ridge	Transformer	AP	$19.6	$17.6	$0.8	$2.8	$0.1	($0.1)	($0.6)	($0.3)	$2.5	3,836	760
15	Hopewell - Chesterfield	Line	Dominion	$7.8	$4.6	$0.3	$3.5	($0.3)	($1.2)	($2.0)	($1.2)	$2.3	308	126
17	Halifax - Mount Laurel	Line	Dominion	$4.7	$1.8	$0.2	$3.1	($0.4)	$0.3	($0.2)	($0.9)	$2.3	1,456	294
19	Dooms	Transformer	Dominion	$18.2	$13.6	$1.1	$5.7	($5.0)	($1.1)	($3.7)	($7.6)	($1.9)	298	236
22	Bristers - Ox	Line	Dominion	($1.7)	($3.1)	$0.0	$1.5	$0.4	$0.5	($0.1)	($0.1)	$1.4	66	50
23	Powhatan - Bremo	Line	Dominion	$2.4	$1.3	$0.1	$1.2	$0.0	$0.0	$0.0	$0.0	$1.2	60	0
28	Crozet - Dooms	Line	Dominion	$3.2	$2.6	$0.2	$0.8	($0.0)	($0.0)	($0.0)	($0.0)	$0.8	236	4

Table G-42 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	$67.8	($42.5)	$0.8	$111.0	$2.7	$4.7	($0.6)	($2.5)	$108.5	7,080	2,502
2	Doubs	Transformer	AP	$0.1	($11.5)	($0.1)	$11.5	$1.5	$0.8	$0.4	$1.1	$12.6	2,492	896
3	Cloverdale - Lexington	Line	500	$17.5	$5.1	$2.0	$14.5	($1.8)	($2.5)	($2.7)	($2.0)	$12.5	2,138	1,356
4	Bedington - Black Oak	Interface	500	$20.8	$14.0	$3.0	$9.9	($0.2)	($0.1)	($0.9)	($1.0)	$8.8	3,704	222
5	Clover	Transformer	Dominion	$6.0	($2.6)	$1.6	$10.1	($0.3)	$0.3	($1.9)	($2.5)	$7.7	1,004	516
6	Pleasant View	Transformer	Dominion	$0.7	$0.0	$0.0	$0.7	($4.2)	$1.4	($0.6)	($6.2)	($5.5)	84	202
7	Millville - Sleepy Hollow	Line	Dominion	$1.1	($4.3)	($0.2)	$5.2	$0.0	$0.0	$0.0	$0.0	$5.2	802	0
8	Millville - Old Chapel	Line	AP	$0.3	($3.0)	($0.4)	$3.0	$0.7	$0.3	$1.3	$1.6	$4.6	420	278
9	Dooms	Transformer	Dominion	$3.3	($0.5)	($0.0)	$3.8	($0.6)	($0.7)	$0.1	$0.2	$4.0	162	62
10	Ox - Francona	Line	Dominion	$3.3	($0.6)	$0.0	$3.9	$0.0	$0.0	$0.0	$0.0	$3.9	132	0
11	AEP-DOM	Interface	500	$14.9	$12.1	$0.6	$3.4	($0.1)	($0.3)	($0.1)	$0.1	$3.5	942	178
12	Dickerson - Pleasant View	Line	Pepco	$3.9	$0.6	$0.1	$3.4	($0.1)	($0.3)	($0.2)	$0.0	$3.4	370	194
13	Ox - Glebe	Line	Dominion	$2.5	($0.7)	$0.0	$3.2	$0.0	$0.0	$0.0	$0.0	$3.2	60	0
14	East Frankfort - Crete	Line	ComEd	$4.8	$2.1	$0.2	$2.9	($0.2)	($0.5)	($0.2)	$0.1	$2.9	5,584	1,700
15	Chuckatuck - Benns Church	Line	Dominion	$2.5	($0.2)	$0.0	$2.7	$0.0	$0.0	$0.0	$0.0	$2.7	152	0
17	Endless Caverns	Transformer	Dominion	$0.8	($1.2)	$0.0	$2.0	($0.0)	($0.0)	$0.0	$0.0	$2.0	1,082	6
20	Greenwich - Elizabeth River	Line	Dominion	$1.6	($0.2)	$0.0	$1.8	$0.1	$0.0	($0.0)	$0.0	$1.8	64	44
21	Pleasant View	Line	Dominion	$1.8	$0.1	$0.1	$1.8	$0.0	$0.0	$0.0	$0.0	$1.8	64	0
22	Yadkin	Transformer	Dominion	$1.5	$0.1	$0.0	$1.5	$0.2	($0.1)	($0.1)	$0.3	$1.7	52	42
23	Danville - East Danville	Line	Dominion	$4.5	$2.7	($0.3)	$1.5	($0.2)	($0.4)	($0.0)	$0.3	$1.7	2,614	280

Marginal Losses

Zonal Marginal Loss Costs

Table G-43 Provides the marginal loss costs by control zone and type for the 2011 calendar year. Table G-44 provides the total marginal loss costs by control zone and month for the 2011 calendar year.

Table G-43 Marginal[4] loss costs by control zone and type (Dollars (Millions)): Calendar year 2011

	Marginal Loss Costs by Control Zone (Millions)									
	Day Ahead				Balancing					
	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Inadvertent Charges	Grand Total
AECO	$32.0	$6.9	$0.7	$25.8	$0.0	($0.6)	($0.5)	$0.1	$0.0	$26.0
AEP	($260.3)	($568.1)	$30.5	$338.3	$10.5	$13.9	($16.2)	($19.7)	$0.0	$318.6
AP	($6.2)	($103.7)	$7.2	$104.7	$3.0	$3.8	($1.9)	($2.7)	$0.0	$102.0
ATSI	($39.7)	($61.0)	$6.9	$28.3	$2.8	$2.4	($9.3)	($9.0)	$0.0	$19.3
BGE	$111.6	$54.2	$6.2	$63.5	$1.6	($1.0)	($4.9)	($2.3)	$0.0	$61.3
ComEd	($578.8)	($816.7)	$9.8	$247.7	$23.0	$9.3	($2.2)	$11.6	$0.0	$259.2
DAY	($18.0)	($84.3)	$6.1	$72.3	$0.5	$4.4	($2.4)	($6.2)	$0.0	$66.1
DLCO	($21.4)	($38.1)	$1.0	$17.7	($2.1)	$0.3	($0.8)	($3.1)	$0.0	$14.6
Dominion	$112.8	($13.3)	$10.1	$136.2	$6.9	$5.3	($9.1)	($7.5)	$0.0	$128.7
DPL	$68.0	$15.9	$2.0	$54.1	($3.7)	$0.1	($1.8)	($5.6)	$0.0	$48.5
External	($33.5)	($40.0)	($49.9)	($43.4)	($5.9)	($8.2)	$14.2	$16.5	$0.0	($26.9)
JCPL	$69.1	$31.8	$0.9	$38.1	$0.4	($0.4)	($1.1)	($0.3)	$0.0	$37.9
Met-Ed	$13.3	($5.2)	$0.0	$18.5	$0.7	($0.1)	($0.2)	$0.6	$0.0	$19.1
PECO	$105.5	$45.3	$0.7	$60.8	($0.8)	$0.2	($0.6)	($1.6)	$0.0	$59.2
PENELEC	($37.8)	($100.5)	($0.6)	$62.1	$2.2	$1.0	$0.2	$1.4	$0.0	$63.5
Pepco	$96.3	$46.5	$4.1	$53.9	($1.4)	($1.0)	($3.1)	($3.4)	$0.0	$50.5
PPL	$32.2	($22.4)	$1.6	$56.2	$3.0	$2.1	($0.3)	$0.7	$0.0	$56.9
PSEG	$136.4	$60.0	$16.3	$92.7	$0.4	$9.1	($12.2)	($20.9)	$0.0	$71.8
RECO	$3.3	$0.5	$0.1	$3.0	($0.0)	($0.4)	($0.1)	$0.3	$0.0	$3.2
Total	($215.4)	($1,592.1)	$53.8	$1,430.5	$41.3	$40.2	($52.2)	($51.0)	$0.0	$1,379.5

4 The "External" zone was labeled as "PJM" in previous State of the Market reports. The name was changed to "External" to clarify that this component of congestion is accrued on energy flows between external buses and PJM external interfaces.

Table G-44 Monthly marginal loss costs by control zone (Dollars (Millions)): Calendar year 2011

	Marginal Loss Costs by Control Zone (Millions)													
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Inadvertent Charge	Grand Total
AECO	$2.9	$2.0	$1.8	$1.5	$1.5	$3.2	$6.0	$3.2	$1.9	$0.8	$0.8	$0.3	$0.0	$26.0
AEP	$42.3	$25.8	$24.0	$19.4	$18.3	$30.6	$54.9	$34.5	$24.6	$15.4	$15.9	$12.9	$0.0	$318.6
AP	$14.3	$8.4	$7.7	$6.5	$6.6	$9.1	$16.1	$10.1	$7.4	$5.3	$5.3	$5.3	$0.0	$102.0
ATSI	$0.0	$0.0	$0.0	$0.0	$0.0	$1.5	$2.7	$2.2	$1.7	$5.2	$2.8	$3.2	$0.0	$19.3
BGE	$6.5	$5.0	$3.9	$3.2	$3.8	$6.3	$11.7	$6.6	$4.8	$3.3	$3.5	$2.9	$0.0	$61.3
ComEd	$32.3	$21.9	$23.1	$17.8	$15.3	$22.7	$30.1	$21.0	$21.1	$18.0	$18.6	$17.3	$0.0	$259.2
DAY	$5.2	$5.0	$4.5	$2.8	$4.1	$5.9	$10.3	$7.0	$6.7	$5.6	$4.8	$4.2	$0.0	$66.1
DLCO	$2.2	$1.6	$0.7	$0.8	$1.2	$1.2	$1.3	$1.1	$1.2	$1.3	$1.1	$0.9	$0.0	$14.6
Dominion	$19.8	$11.6	$9.7	$4.3	$8.2	$8.3	$24.0	$14.6	$10.2	$6.5	$6.0	$5.5	$0.0	$128.7
DPL	$7.7	$5.3	$3.6	$2.7	$2.6	$4.7	$7.9	$5.5	$3.8	$1.9	$1.7	$1.0	$0.0	$48.5
External	$6.4	$4.1	$0.0	($0.7)	($0.1)	($2.5)	($6.9)	($7.2)	($7.4)	($3.6)	($6.5)	($2.6)	$0.0	($26.9)
JCPL	$6.2	$4.1	$3.1	$2.5	$2.3	$3.6	$6.6	$3.3	$2.7	$1.4	$0.7	$1.3	$0.0	$37.9
Met-Ed	$2.1	$1.4	$1.4	$1.2	$1.5	$1.6	$2.4	$1.8	$1.4	$1.4	$1.5	$1.6	$0.0	$19.1
PECO	$6.6	$3.5	$3.5	$3.7	$4.9	$6.3	$10.0	$5.7	$3.7	$3.8	$3.7	$3.9	$0.0	$59.2
PENELEC	$8.9	$5.3	$3.6	$3.1	$5.0	$6.9	$10.3	$7.2	$4.7	$3.4	$3.2	$1.9	$0.0	$63.5
Pepco	$5.9	$3.7	$3.9	$3.1	$3.7	$5.1	$8.2	$5.2	$4.1	$2.8	$2.5	$2.3	$0.0	$50.5
PPL	$8.6	$4.7	$3.0	$2.6	$3.1	$4.4	$7.9	$6.1	$3.9	$4.2	$4.4	$4.0	$0.0	$56.9
PSEG	$7.3	$6.1	$6.3	$4.6	$5.2	$6.4	$9.7	$6.2	$6.0	$5.5	$4.0	$4.5	$0.0	$71.8
RECO	$0.5	$0.3	$0.3	$0.2	$0.2	$0.3	$0.5	$0.3	$0.3	$0.2	$0.1	$0.1	$0.0	$3.2
Total	$185.7	$119.9	$104.0	$79.2	$87.3	$125.4	$213.7	$134.5	$102.9	$82.0	$74.3	$70.6	$0.0	$1,379.5

FTR Volumes

Introduction

This Appendix presents the data used to create Figure 12-3 in the *2011 State of the Market Report for PJM*. Each table shows the FTR bid volume, cleared volume and net bid volume by planning period. The bid volume includes the buy, sell and self-scheduled offers. The cleared volume includes the buy, sell and self-scheduled offers that cleared. The net bid volume includes all bid and self-scheduled offers, excluding sell offers. The Long Term and Annual Auction volume is included in June of each planning period.

Table H-1 Long Term, Annual and Monthly FTR Auction bid and cleared volume: Planning period 2003 to 2004

Auction Date	Net Bid Volume (MW)	Cleared Volume (MW)	Bid Volume (MW)
Jun-03	2,679,072	89,840	2,690,737
Jul-03	295,753	8,642	300,808
Aug-03	215,206	9,978	220,241
Sep-03	226,994	9,068	234,315
Oct-03	127,739	10,522	135,885
Nov-03	114,211	8,247	122,362
Dec-03	131,180	8,352	139,221
Jan-04	128,086	10,947	136,657
Feb-04	128,303	12,187	137,790
Mar-04	144,617	13,827	156,543
Apr-04	141,437	17,358	157,776
May-04	168,480	44,641	178,973
Total	4,501,077	243,608	4,611,308

Table H-2 Long Term, Annual and Monthly FTR Auction bid and cleared volume: Planning period 2004 to 2005

Auction Date	Net Bid Volume (MW)	Cleared Volume (MW)	Bid Volume (MW)
Jun-04	939,214	125,044	1,019,868
Jul-04	160,472	21,761	190,198
Aug-04	144,402	22,650	176,642
Sep-04	155,837	13,999	194,229
Oct-04	180,542	49,816	226,156
Nov-04	213,036	23,912	247,780
Dec-04	226,271	18,384	260,964
Jan-05	212,061	22,549	236,135
Feb-05	276,385	20,700	305,613
Mar-05	306,472	25,712	348,416
Apr-05	307,297	36,914	330,088
May-05	280,690	32,545	300,966
Total	3,402,681	413,987	3,837,056

Table H-3 Long Term, Annual and Monthly FTR Auction bid and cleared volume: Planning period 2005 to 2006

Auction Date	Net Bid Volume (MW)	Cleared Volume (MW)	Bid Volume (MW)
Jun-05	1,011,821	159,049	1,120,404
Jul-05	300,153	23,929	340,891
Aug-05	233,493	17,966	276,936
Sep-05	222,404	22,133	266,577
Oct-05	147,493	18,906	189,458
Nov-05	183,750	20,525	227,432
Dec-05	200,886	19,422	244,608
Jan-06	234,473	21,431	275,081
Feb-06	250,308	26,463	293,774
Mar-06	272,662	31,968	317,705
Apr-06	431,398	36,603	472,732
May-06	384,767	38,977	424,962
Total	3,873,608	437,372	4,450,561

Table H-4 Long Term, Annual and Monthly FTR Auction bid and cleared volume: Planning period 2006 to 2007

Auction Date	Net Bid Volume (MW)	Cleared Volume (MW)	Bid Volume (MW)
Jun-06	2,274,846	198,380	2,533,660
Jul-06	719,494	31,662	934,424
Aug-06	738,375	26,392	932,469
Sep-06	630,072	37,351	841,698
Oct-06	710,045	51,193	888,011
Nov-06	765,177	40,110	890,318
Dec-06	757,683	42,848	919,549
Jan-07	778,266	59,813	905,249
Feb-07	884,953	68,179	969,447
Mar-07	661,938	69,754	799,130
Apr-07	455,411	30,963	551,601
May-07	432,783	37,207	480,219
Total	9,809,046	693,852	11,645,776

Table H-5 Long Term, Annual and Monthly FTR Auction bid and cleared volume: Planning period 2007 to 2008

Auction Date	Net Bid Volume (MW)	Cleared Volume (MW)	Bid Volume (MW)
Jun-07	2,961,754	323,632	3,462,015
Jul-07	794,490	51,248	1,068,961
Aug-07	944,015	63,392	1,224,668
Sep-07	901,284	66,611	1,200,730
Oct-07	973,936	112,427	1,245,797
Nov-07	841,326	61,592	1,059,631
Dec-07	1,276,687	49,825	1,461,068
Jan-08	501,642	27,377	655,581
Feb-08	583,749	37,288	676,847
Mar-08	437,241	31,941	590,524
Apr-08	326,050	34,805	427,105
May-08	280,005	22,837	331,327
Total	10,822,178	882,975	13,404,256

Table H-6 Long Term, Annual and Monthly FTR Auction bid and cleared volume: Planning period 2008 to 2009

Auction Date	Net Bid Volume (MW)	Cleared Volume (MW)	Bid Volume (MW)
Jun-08	3,511,130	339,654	3,832,169
Jul-08	968,615	53,843	1,211,784
Aug-08	961,694	40,027	1,224,054
Sep-08	925,250	64,901	1,127,274
Oct-08	802,966	52,768	965,756
Nov-08	607,441	45,707	738,336
Dec-08	550,352	37,633	748,485
Jan-09	488,102	43,739	673,525
Feb-09	492,216	40,439	639,274
Mar-09	391,938	42,722	581,075
Apr-09	299,908	35,685	440,629
May-09	222,092	21,016	295,198
Total	10,221,706	818,134	12,477,560

Table H-7 Long Term, Annual and Monthly FTR Auction bid and cleared volume: Planning period 2009 to 2010

Auction Date	Net Bid Volume (MW)	Cleared Volume (MW)	Bid Volume (MW)
Jun-09	2,652,340	307,584	3,156,826
Jul-09	488,748	41,389	849,742
Aug-09	414,151	55,261	708,452
Sep-09	427,221	56,998	718,246
Oct-09	538,476	64,328	797,069
Nov-09	559,750	65,577	745,333
Dec-09	447,221	68,470	672,986
Jan-10	529,887	64,435	728,765
Feb-10	490,391	62,153	670,272
Mar-10	389,934	73,069	615,690
Apr-10	345,301	66,017	489,638
May-10	291,537	52,036	375,812
Total	7,574,956	977,318	10,528,830

Table H-8 Long Term, Annual and Monthly FTR Auction bid and cleared volume: Planning period 2010 to 2011

Auction Date	Net Bid Volume (MW)	Cleared Volume (MW)	Bid Volume (MW)
Jun-10	3,177,131	428,603	3,894,566
Jul-10	720,172	102,883	1,145,991
Aug-10	859,260	93,226	1,202,137
Sep-10	1,079,947	144,423	1,510,812
Oct-10	1,041,425	120,281	1,427,494
Nov-10	922,444	111,442	1,261,969
Dec-10	1,005,436	157,609	1,359,582
Jan-11	902,052	132,866	1,207,101
Feb-11	931,164	160,750	1,184,383
Mar-11	952,963	182,340	1,250,283
Apr-11	660,480	138,230	913,583
May-11	620,691	169,610	762,538
Total	12,873,166	1,942,261	17,120,443

Table H-9 Long Term, Annual and Monthly FTR Auction bid and cleared volume: Planning period 2011 to 2012

Auction Date	Net Bid Volume (MW)	Cleared Volume (MW)	Bid Volume (MW)
Jun-11	6,233,773	847,183	7,437,352
Jul-11	1,602,795	241,288	2,233,307
Aug-11	1,385,040	204,442	1,981,888
Sep-11	969,184	112,746	1,581,241
Oct-11	1,424,062	134,653	1,908,956
Nov-11	1,098,133	117,705	1,562,764
Dec-11	811,035	93,492	1,318,347
Total	13,524,022	1,751,509	18,023,854

Glossary

Aggregate
Combination of buses or bus prices.

Ancillary Services
Those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the Transmission Provider's Transmission System in accordance with Good Utility Practice.

Area Control Error (ACE)
Area Control Error of the PJM RTO is the actual net interchange minus the biased scheduling net interchange, including time error. It is the sum of tie-in errors and frequency errors.

Associated unit (AU)
A unit that is located at the same site as a frequently mitigated unit (FMU) and which has identical electrical and economic impacts on the transmission system as an FMU but which does not qualify for FMU status.

Auction Revenue Right (ARR)
A financial instrument entitling its holder to auction revenue from Financial Transmission Rights (FTRs) based on locational marginal price (LMP) differences across a specific path in the Annual FTR Auction.

Automatic Generation Control (AGC)
An automatic control system comprised of hardware and software. Hardware is installed on generators allowing their output to be automatically adjusted and monitored by an external signal and software is installed facilitating that output adjustment.

Average hourly LMP
An LMP calculated by averaging hourly LMP with equal hourly weights; also referred to as a simple average hourly LMP.

Avoidable cost rate (ACR)
The costs that a generation owner would not incur if the generating unit did not operate for one year, in particular the delivery year. The ACR calculation is based on the categories of cost that are specified in Section 6.8 of Attachment DD of the PJM Tariff.

Avoidable Project Investment Recovery Rate (APIR)
A component of the avoidable cost rate (ACR) calculation. Project investment is the capital reasonably required to enable a capacity resource to continue operating or improve availability during peak-hour periods during the delivery year.

Balancing energy market
Energy that is generated and financially settled during real time.

Base Residual Auction (BRA)
Reliability Pricing Model (RPM) auction held in May three years prior to the start of the delivery year. Allows for the procurement of resource commitments to satisfy the region's unforced capacity obligation and allocates the cost of those commitments among the LSEs through the Locational Reliability Charge.

Bilateral agreement
An agreement between two parties for the sale and delivery of a service.

Black Start Unit
A generating unit with the ability to go from a shutdown condition to an operating condition and start delivering power without any outside assistance from the transmission system or interconnection.

Bottled generation
Economic generation that cannot be dispatched because of local operating constraints.

Burner tip fuel price
The cost of fuel delivered to the generator site equaling the fuel commodity price plus all transportation costs.

Bus
An interconnection point.

Capacity deficiency rate (CDR)

The CDR was designed to reflect the annual fixed costs of a new combustion turbine (CT) in PJM and the annual fixed costs of the associated transmission investment, including a return on investment, depreciation and fixed operation and maintenance expense, net of associated energy revenues. The CDR is used in applying penalties for capacity deficiencies. To express the CDR in terms of unforced capacity, it must be further divided by the quantity 1 minus the EFORd.

Capacity Emergency Transfer Limit (CETL)

The capability of the transmission system to support deliveries of electric energy to a given area experiencing a localized capacity emergency as determined in accordance with the PJM Manuals.

Capacity queue

A collection of Regional Transmission Expansion Planning (RTEP) capacity resource project requests received during a particular timeframe and designating an expected in-service date.

Combined Cycle (CC)

An electric generating technology in which electricity and process steam are produced from otherwise lost waste heat exiting from one or more combustion turbines. The exiting heat is routed to a conventional boiler or to a heat recovery steam generator for use by a conventional steam turbine in the production of electricity. This process increases the efficiency of the electric generating facility.

Combustion Turbine (CT)

A generating unit in which a combustion turbine engine is the prime mover for an electrical generator.

Congestion Management Process (CMP)

A process used between neighboring balancing authorities to coordinate the re-dispatch of resources to relieve transmission constraints.

Control Zone

An area within the PJM Control Area, as set forth in the PJM Open Access Transmission Tariff and the RAA. Schedule 16 of the RAA defines the distinct zones that comprise the PJM Control Area.

Decrement Bids (DEC)

An hourly bid, expressed in MWh, to purchase energy in the PJM Day-Ahead Energy Market if the Day-Ahead LMP is less than or equal to the specified bid price. This bid must specify hourly quantity, bid price and location (transmission zone, hub, aggregate or single bus).

Demand deviations

Hourly deviations in the demand category, equal to the difference between the sum of cleared decrement bids, day-ahead load, day-ahead sales, and day-ahead-exports, to the sum of real-time load, real-time sales, and real-time exports .

Demand Resource

A capacity resource with a demonstrated capability to provide a reduction in demand or otherwise control load. A Demand Resource may be an existing or planned resource.

Dispatch Rate

The control signal, expressed in dollars per MWh, calculated and transmitted continuously and dynamically to direct the output level of all generation resources dispatched by PJM in accordance with the Offer Data.

Disturbance Control Standard

A NERC-defined metric measuring the ability of a control area to return area control error (ACE) either to zero or to its predisturbance level after a disturbance such as a generator or transmission loss.

Eastern Prevailing Time (EPT)

Eastern Prevailing Time (EPT) is equivalent to Eastern Standard Time (EST) or Eastern Daylight Time (EDT) as is in effect from time to time.

Eastern Region

Defined region for purposes of allocating balancing operating reserve charges. Includes the BGE, Dominion, PENELEC, Pepco, Met-Ed, PPL, JCPL, PECO, DPL, PSEG, and RECO transmission zones.

Economic generation

Units producing energy at an offer price less than or equal to LMP.

End-use customer
Any customer purchasing electricity at retail.

Equivalent availability factor (EAF)
The proportion of hours in a year that a unit is available to generate at full capacity.

Equivalent demand forced outage rate (EFORd)
A measure of the probability that a generating unit will not be available due to forced outages or forced deratings when there is a demand on the unit to generate.

Equivalent forced outage factor (EFOF)
The proportion of hours in a year that a unit is unavailable because of forced outages.

Equivalent maintenance outage factor (EMOF)
The proportion of hours in a year that a unit is unavailable because of maintenance outages.

Equivalent planned outage factor (EPOF)
The proportion of hours in a year that a unit is unavailable because of planned outages.

External resource
A generation resource located outside metered boundaries of the PJM RTO.

Financial Transmission Right (FTR)
A financial instrument entitling the holder to receive revenues based on transmission congestion measured as hourly energy LMP differences in the PJM Day-Ahead Energy Market across a specific path.

Firm Point-to-Point Transmission Service
Transmission Service that is reserved and/or scheduled between specified Points of Receipt and Delivery.

Firm Transmission Service
Transmission service that is intended to be available at all times to the maximum extent practicable, subject to an emergency, and unanticipated failure of a facility, or other event beyond the control of the owner or operator of the facility, or the Office of the Interconnection.

Fixed Demand Bid
Bid to purchase a defined MW level of energy, regardless of LMP.

Fixed Resource Requirement (FRR)
An alternative method for a party to satisfy its obligation to provide Unforced Capacity. Allows an LSE to avoid direct participation in the RPM Auctions by meeting their fixed capacity resource requirement using internally owned capacity resources.

Flowgate
A transmission facility or group of facilities that consist of the total interface between control areas, a partial interface, or an interface within a control area.

Frequently mitigated unit (FMU)
A unit that was offer-capped for more than a defined proportion of its real-time run hours in the most recent 12-month period. FMU thresholds are 60 percent, 70 percent and 80 percent of run hours. Such units are permitted a defined adder to their cost-based offers in place of the usual 10 percent adder.

Generation Control Area (GCA) and Load Control Area (LCA)
Designations used on a NERC Tag to describe the balancing authority where the energy is generated (GCA) and the balancing authority where the load is served (LCA). Note: the terms “Control Area” in these acronyms are legacy terms for balancing authority, and are expected to be changed in the future.

Generator deviations
Hourly deviations in the generator category, equal to the difference between a unit’s cleared day-ahead generation, and a unit’s hourly, integrated real-time generation.

Generation Offers
Schedules of MW offered and the corresponding offer price.

Generation owner
A PJM member that owns or leases, with rights equivalent to ownership, facilities for generation of electric energy that are located within PJM.

Gross export volume (energy)
The sum of all export transaction volume (MWh).

Gross import volume (energy)
The sum of all import transaction volume (MWh).

Gigawatt (GW)
A unit of power equal to 1,000 megawatts.

Gigawatt-day
One GW of energy flow or capacity for one day.

Gigawatt-hour (GWh)
One GWh is a gigawatt produced or consumed for one hour.

Herfindahl-Hirschman Index (HHI)
HHI is calculated as the sum of the squares of the market share percentages of all firms in a market.

Hertz (Hz)
Electricity system frequency is measured in hertz.

HRSG
Heat recovery steam generator. An air-to-steam heat exchanger.

Increment offers (INC)
Financial offers in the Day-Ahead Energy Market to supply specified amounts of MW at, or above, a given price.

Incremental Auction
Reliability Pricing Model (RPM) auction to allow for an incremental procurement of resource commitments to satisfy an increase in the region's unforced capacity obligation due to a load forecast increase or a decrease in the amount of resource commitments due to a resource cancellation, delay, derating, EFORd increase, or decrease in the nominated value of a Planned Demand Resource.

Inframarginal unit
A unit that is operating, with an accepted offer that is less than the clearing price.

Installed capacity
Installed capacity is the as-tested maximum net dependable capability of the generator, measured in MW.

Load
Demand for electricity at a given time.

Load Management
Previously known as ALM (Active Load Management). ALM was a term that PJM used prior to the implementation of RPM where end use customer load could be reduced at the request of PJM. The ability to reduce metered load, either manually by the customer, after a request from the resource provider which holds the Load management rights or its agent (for Contractually Interruptible), or automatically in response to a communication signal from the resource provider which holds the Load management rights or its agent (for Direct Load Control).

Load-serving entity (LSE)
Load-serving entities provide electricity to retail customers. Load-serving entities include traditional distribution utilities and new entrants into the competitive power market.

Locational Deliverability Area (LDA)
Sub-regions used to evaluate locational constraints. LDAs include EDC zones, sub-zones, and combination of zones.

Marginal unit
The last, highest cost, generation unit to supply power under a merit order dispatch system.

Market-clearing price
The price that is paid by all load and paid to all suppliers.

Market participant
A PJM market participant can be a market supplier, a market buyer or both. Market buyers and market sellers are members that have met creditworthiness standards as established by the PJM Office of the Interconnection.

Market user interface
A thin client application allowing generation sellers to provide and to view generation data, including bids, unit status and market results.

Maximum daily starts
The maximum number of times a unit can start in a day. An operating parameter incorporated in a unit's schedule.

Maximum weekly starts
The maximum number of times a unit can start in a week. An operating parameter incorporated in a unit's schedule.

Mean
The arithmetic average.

Median
The midpoint of data values. Half the values are above and half below the median.

Megawatt (MW)
A unit of power equal to 1,000 kilowatts.

Megawatt-day
One MW of energy flow or capacity for one day.

Megawatt-hour (MWh)
One MWh is a megawatt produced or consumed for one hour.

Megawatt-year
One MW of energy flow or capacity for one calendar year.

Minimum down time
The minimum amount of time that a unit has to stay off, or "down," before starting again. An operating parameter incorporated in a unit's schedule.

Minimum run time
The minimum amount of time that a unit has to stay on before shutting down. An operating parameter incorporated in a unit's schedule.

Monthly CCM
The capacity credits cleared each month through the PJM Monthly Capacity Credit Market (CCM).

Multimonthly CCM
The capacity credits cleared through PJM Multimonthly Capacity Credit Market (CCM).

Net excess (capacity)
The net of gross excess and gross deficiency, therefore the total PJM capacity resources in excess of the sum of load-serving entities' obligations.

Net exchange (capacity)
Capacity imports less exports.

Net interchange (energy)
Gross import volume less gross export volume in MWh.

Network Transmission Service
Transmission service that is for the sole purpose of serving network load. Network transmission service is only available to network customers.

Noneconomic generation
Units producing energy at an offer price greater than the LMP.

Non-Firm Transmission Service
Point-to-point transmission service under the PJM tariff that is reserved and scheduled on an as available basis and is subject to curtailment or interruption. Non-firm point to point transmission service is available on a stand-alone basis for periods ranging from one hour to one month.

North American Electric Reliability Council (NERC)
A voluntary organization of U.S. and Canadian utilities and power pools established to assure coordinated operation of the interconnected transmission systems.

Off peak
For the PJM Energy Market, off-peak periods are all NERC holidays (i.e., New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, Christmas Day) and weekend hours plus weekdays from the hour ending at midnight until the hour ending at 0700.

On peak
For the PJM Energy Market, on-peak periods are weekdays, except NERC holidays (i.e., New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, Christmas Day) from the hour ending at 0800 until the hour ending at 2300.

Opportunity cost
In general, the value of the opportunity foregone when a specific action is taken. In the ancillary services markets, the difference in compensation from the Energy Market between what a unit receives when providing regulation or synchronized reserve and what it would have received had it provided energy instead.

Parameter-limited schedule
A schedule for a unit that has parameters that are used when the unit fails the three pivotal supplier test, or in a maximum generation emergency event. These parameters are pre-determined by the MMU based on unit class, unless an exception is otherwise granted.

PJM member
Any entity that has completed an application and satisfies the requirements of the PJM Board of Managers to conduct business with PJM, including transmission owners, generating entities, load-serving entities and marketers.

PJM planning year
The calendar period from June 1 through May 31.

Point of Receipt (POR) and Point of Delivery (POD)
Designations used on a transmission reservation. The designations, when combined, determine the transmission reservations' market path.

Pool-scheduled resource
A generating resource that the seller has turned over to PJM for scheduling and control.

Price duration curve
A graphic representation of the percent of hours that a system's price was at or below a given level during the year.

Price-sensitive bid
Purchases of a defined MW level of energy only up to a specified LMP. Above that LMP, the load bid is zero.

Primary operating interfaces
Primary operating interfaces are typically defined by a cross section of transmission paths or single facilities which affect a wide geographic area. These interfaces are modeled as constraints whose operating limits are respected in performing dispatch operations.

Ramp-limited desired (MW)
The achievable MW based on the UDS requested ramp rate.

Regional Transmission Expansion Planning (RTEP)
ProtocolThe process by which PJM recommends specific transmission facility enhancements and expansions based on reliability and economic criteria.

Reliability*First* Corporation
Reliability*First* Corporation (RFC) began operation January 1, 2006, as the successor to three other reliability organizations: the Mid-Atlantic Area Council (MAAC), the East Central Area Coordination Agreement (ECAR), and the Mid-American Interconnected Network (MAIN). PJM is registered with RFC to comply with its reliability standards for balancing authority (BA), planning coordinator (PC), reliability coordinator (RC), resource planner (RP), transmission operator (TOP), transmission planner (TP) and transmission service provider (TSP).

Reliability Pricing Model (RPM)
PJM's resource adequacy construct. The purpose of RPM is to develop a long term pricing signal for capacity resources and LSE obligations that is consistent with the PJM Regional Transmission Expansion Planning Process (RTEPP). RPM adds stability and a locational nature to the pricing signal for capacity.

Selective catalytic reduction (SCR)
NO_x reduction equipment usually installed on combined-cycle generators.

Self-scheduled generation

Units scheduled to run by their owners regardless of system dispatch signal. Self-scheduled units do not follow system dispatch signal and are not eligible to set LMP. Units can be submitted as a fixed block of MW that must be run, or as a minimum amount of MW that must run plus a dispatchable component above the minimum.

Shadow price

The constraint shadow price represents the incremental reduction in congestion cost achieved by relieving a constraint by 1 MW. The shadow price multiplied by the flow (in MW) on the constrained facility during each hour equals the hourly gross congestion cost for the constraint.

Short-Term Resource Procurement Target

The Short-Term Resource Procurement Target is equal to 2.5% of the PJM Region Reliability Requirement determined for such Base Residual Auction, 2% of the of the PJM Region Reliability Requirement as calculated at the time of the Base Residual Auction for purposes of the First Incremental Auction, and 1.5% of the of the PJM Region Reliability Requirement as calculated at the time of the Base Residual Auction for purposes of the Second Incremental Auction. The stated rationale for this administrative reduction in demand is to permit short lead time resource procurement in later auctions for the delivery year.

Sources and sinks

Sources are the origins or the injection end of a transmission transaction. Sinks are the destinations or the withdrawal end of a transaction.

Spot Import Transmission Service

Transmission service introduced as an option for non-load serving entities to offer into the PJM spot market at the border/interface as price takers.

Spot market

Transactions made in the Real-Time and Day-Ahead Energy Market at hourly LMP.

Static Var compensator

A static Var compensator (SVC) is an electrical device for providing fast-acting, reactive power compensation on high-voltage electricity transmission networks.

Summer Net Capability

The Summer Net Capability of each unit or station shall be based on summer conditions and on the power factor level normally expected for that unit or station at the time of the PJM summer peak load.

Summer conditions shall reflect the 50% probability of occurrence (approximated by the mean) of temperature and humidity conditions of the time of the PJM summer peak load. Conditions shall be based on local weather bureau records of the past 15 years, updated at 5 year intervals. When local weather records are not available, the values shall be estimated from the best data available.

For steam units, summer conditions shall mean, where applicable, the probable intake water temperature of once-through or open cooling systems experienced in June, July, and August at the time of the PJM peak each weekday.

For combustion turbine units, summer conditions shall mean, where applicable, the probable ambient air temperature and humidity condition experienced at the unit location at the time of the annual summer PJM peak.

The determination of the Summer Net Capability of hydro and pumped storage units shall be based on operational data or test results taken once each year at any time during the year. The same operational data or test results can be used for the determination of the Winter Net Capability.

For combined-cycle units, summer conditions shall mean where applicable, the probable intake water temperature of once-through or open cooling systems experienced in June, July, and August at the time of the PJM peak each weekday, and the probable ambient air temperature and humidity condition experienced at the unit location at the time of the annual summer PJM peak.

Supply deviations

Hourly deviations in the supply category, equal to the difference between the sum of cleared increment offers, day-ahead purchases, and day-ahead imports, to the sum of real-time purchases and real-time imports.

Synchronized reserve

Reserve capability which is required in order to enable an area to restore its tie lines to the pre-contingency state within 10 minutes of a contingency that causes an imbalance between load and generation. During normal operation, these reserves must be provided by increasing energy output on electrically synchronized equipment, by reducing load on pumped storage hydroelectric facilities or by reducing the demand by demand-side resources. During system restoration, customer load may be classified as synchronized reserve.

System installed capacity

System total installed capacity measures the sum of the installed capacity (in installed, not unforced, terms) from all internal and qualified external resources designated as PJM capacity resources.

System lambda

The cost to the PJM system of generating the next unit of output.

Temperature-humidity index (THI)

A temperature-humidity index (THI) gives a single, numerical value reflecting the outdoor atmospheric conditions of temperature and humidity as a measure of comfort (or discomfort) during warm weather. THI is defined as: THI = T_d – (0.55 – 0.55RH) * (T_d - 58) if T_d is > 58; else THI= T_d (where T_d is the dry-bulb temperature and RH is the percentage of relative humidity.)

Transmission Adequacy and Reliability Assessment (TARA)

An analysis tool that can calculate generation to load impacts. This tool is used to facilitate loop flow analysis across the Eastern Interconnection.

Turn down ratio

The ratio of dispatchable megawatts on a unit's schedule. Calculated by a unit's economic maximum MW divided by its economic minimum MW. An operating parameter of a unit's schedule.

Unforced capacity

Installed capacity adjusted by forced outage rates.

Western region

Defined region for purposes of allocating balancing operating reserve charges. Includes the AEP, AP, ComEd, DLCO, and DAY transmission zones.

Wheel-through

An energy transaction flowing through a transmission grid whose origination and destination are outside of the transmission grid.

Winter Weather Parameter (WWP)

WWP is wind speed adjusted temperature. WWP is defined as: WWP = Td - (0.5 * (WIND -10)) if WIND > 10 mph; WWP = Td if WIND <= 10 mph (where Td is the dry-bulb temperature and WIND is the wind speed.)

Zone

See "Control zone" (above).

List of Acronyms

AC2	Advanced Control Center
ACE	Area control error
ACR	Avoidable cost rate
AECI	Associated Electric Cooperative Inc.
AECO	Atlantic City Electric Company
AEG	Alliant Energy Corporation
AEP	American Electric Power Company, Inc.
AGC	Automatic generation control
ALM	Active load management
ALTE	Eastern Alliant Energy Corporation
ALTW	Western Alliant Energy Corporation
AMI	Advanced Metering Infrastructure
AMIL	Ameren - Illinois
AMRN	Ameren
AP	Allegheny Power Company
APIR	Avoidable Project Investment Recovery
ARR	Auction Revenue Right
ARS	Automatic reserve sharing
ATC	Available transfer capability
ATSI	American Transmission Systems, Inc.
AU	Associated unit
BA	Balancing authority
BAAL	Balancing authority ACE limit
BACT	Best Available Control Technology
BGE	Baltimore Gas and Electric Company
BGS	Basic generation service
BME	Balancing market evaluation
BOR	Balancing Operating Reserve
BRA	Base Residual Auction
BSSWG	Black Start Services Working Group
BTU	British thermal unit
C&I	Commercial and industrial customers
CAAA	Clean Air Act Amendments
CAIR	Clean Air Interstate Rule
CAISO	California Independent System Operator
CAMR	Clean Air Mercury Rule
CATR	Clean Air Transport Rule
CBL	Customer base line
CC	Combined cycle
CCM	Capacity Credit Market
CDR	Capacity deficiency rate
CDS	Cost Development Subcommittee
CDTF	Cost Development Task Force
CETL	Capacity emergency transfer limit
CETO	Capacity emergency transfer objective
CF	Coordinated flowgate under the Joint Operating Agreement between PJM and the Midwest Independent Transmission System Operator, Inc.
CILC	Central Illinois Light Company Interface
CILCO	Central Illinois Light Company
CIDS	Critical Infrastructure Protocol
CIN	Cinergy Corporation
CLMP	Congestion component of LMP
CMP	Congestion management process
CMR	Congestion Management Report
ComEd	The Commonwealth Edison Company
Con Edison	The Consolidated Edison Company
CONE	Cost of new entry
CP	Pulverized coal-fired generator

CPI	Consumer Price Index
CPL	Carolina Power & Light Company
CPS	Control performance standard
CRC	Central Repository for Curtailments
CRF	Capital Recovery Factor
CSAPR	Cross State Air Pollution Rule
CSP	Curtailment service provider
CT	Combustion turbine
CTR	Capacity transfer right
DASR	Day-Ahead Scheduling Reserve
DAY	Dayton Power & Light Company
DC	Direct current
DCS	Disturbance control standard
DEC	Decrement bid
DFAX	Distribution factor
DL	Diesel
DLC	Direct Load Control
DLCO	Duquesne Light Company
DPL	Delmarva Power & Light Company
DPLN	Delmarva Peninsula north
DPLS	Delmarva Peninsula south
DR	Demand response
DRS	Demand Response Subcommittee
DRSDTF	Demand Response Subzonal Dispatch Task Force
DSR	Demand-side response
DUK	Duke Energy Corporation
EAF	Equivalent availability factor
ECAR	East Central Area Reliability Council
EDC	Electricity distribution company
EDT	Eastern Daylight Time
EE	Energy Efficiency
EEA	Emergency energy alert
EES	Enhanced Energy Scheduler
EFOF	Equivalent forced outage factor
EFORd	Equivalent demand forced outage rate
EFORp	Equivalent forced outage rate during peak hours
EHV	Extra-high-voltage
EIS	Environmental Information Services
EKPC	East Kentucky Power Cooperative, Inc.
ELRP	Economic Load Response Program
EMAAC	Eastern Mid-Atlantic Area Council
EMOF	Equivalent maintenance outage factor
EMS	Energy management system
EPA	Environmental Protection Agency
EPOF	Equivalent planned outage factor
EPT	Eastern Prevailing Time
ESP	Electrostatic Precipitators (Baghouses)
EST	Eastern Standard Time
ExGen	Exelon Generation Company, L.L.C.
FE	FirstEnergy Corp.
FERC	The United States Federal Energy Regulatory Commission
FFE	Firm flow entitlement
FGD	Flue-gas desulfurization
FMU	Frequently mitigated unit
FPA	Federal Power Act
FPR	Forecast pool requirement
FRR	Fixed resource requirement
FSL	Firm Service Load
FTR	Financial Transmission Right
FTRTF	Financial Transmission Rights Task Force

GACT	Generally Available Control Technology
GCA	Generation control area
GE	General Electric Company
GHG	Greenhouse Gas
GLD	Guaranteed Load Drop
GW	Gigawatt
GWh	Gigawatt-hour
HAP	Hazardous Air Pollutants
HE	Hour Ending
HEDD	NJ High Energy Demand Day
HHI	Herfindahl-Hirschman Index
HRSG	Heat recovery steam generator
HVDC	High-voltage direct current
Hz	Hertz
IARR	Incremental ARRs
IA	RPM Incremental Auction
ICAP	Installed capacity
ICCP	Inter-Control Center Protocol
IDC	Interchange distribution calculator
IESO	Ontario Independent Electricity System Operator
ILR	Interruptible load for reliability
INC	Increment offer
IP	Illinois Power Company
IPL	Indianapolis Power & Light Company
IPP	Independent power producer
IRM	Installed reserve margin
IRR	Internal rate of return
ISA	Interconnection service agreement
ISO	Independent system operator
ITSCED	Intermediate Term Security Constrained Economic Dispatch
JCPL	Jersey Central Power & Light Company
JOA	Joint operating agreement
JOU	Jointly owned units
JRCA	Joint Reliability Coordination Agreement
KV	KiloVolt
KDAEV	Known Day-Ahead Error Value
LAER	Lowest Achievable Emissions Rate
LAS	PJM Load Analysis Subcommittee
LCA	Load control area
LDA	Locational deliverability area
LGEE	LG&E Energy, L.L.C.
LIND	Linden Variable Frequency Transformer (VFT)
LM	Load management
LMP	Locational marginal price
LMTF	Load Management Task Force
LOC	Lost opportunity cost
LSE	Load-serving entity
MAAC	Mid-Atlantic Area Council
MAAC+APS	Mid-Atlantic Area Council plus the Allegheny Power System
MACRS	Modified accelerated cost recovery schedule
MACT	Maximum Achievable Control Technology
MAIN	Mid-America Interconnected Network, Inc.
MAPP	Mid-Continent Area Power Pool
MATS	Mercury and Air Toxics Standards rule
MCP	Market-clearing price

MDS	Maximum daily starts
MDT	Minimum down time
MEC	MidAmerican Energy Company
MECS	Michigan Electric Coordinated System
Met-Ed	Metropolitan Edison Company
MIC	Market Implementation Committee
MICHFE	The pricing point for the Michigan Electric Coordinated System and FirstEnergy control areas
MIL	Mandatory interruptible load
MIS	Market information system
MISO	Midwest Independent Transmission System Operator, Inc.
MMU	PJM Market Monitoring Unit
Mon Power	Monongahela Power
MP	Market participant
MRC	Markets and reliability committee
MRT	Minimum run time
MUI	Market user interface
MW	Megawatt
MWh	Megawatt-hour
MWS	Maximum weekly starts
NAESB	North American Energy Standards Board
NCMPA	North Carolina Municipal Power Agency
NEPT	Neptune DC line
NERC	North American Electric Reliability Council
NESHAP	National Emission Standards for Hazardous Air Pollutants
NICA	Northern Illinois Control Area
NIPSCO	Northern Indiana Public Service Company
NJDEP	New Jersey Department of Environmental Protection
NNL	Network and native load
NOPR	Notice of Proposed Rulemaking
NO_x	Nitrogen oxides
NPS	National Park Service
NSPS	New Source Performance Standards
NSR	New Source Review
NUG	Non-utility generator
NYISO	New York Independent System Operator
OA	Amended and Restated Operating Agreement of PJM Interconnection, L.L.C.
OASIS	Open Access Same-Time Information System
OATI	Open Access Technology International, Inc.
OATT	PJM Open Access Transmission Tariff
ODEC	Old Dominion Electric Cooperative
OEM	Original equipment manufacturer
OI	PJM Office of the Interconnection
Ontario IESO	Ontario Independent Electricity System Operator
OPSI	Organization of PJM States, Inc.
OMC	Outside Management Control
OVEC	Ohio Valley Electric Corporation
ORS	NERC Operating Reliability Subcommittee
PAR	Phase angle regulator
PATH	Potomac – Appalachian Transmission Highline
PE	PECO zone
PEC	Progress Energy Carolinas, Inc.
PECO	PECO Energy Company

PENELEC	Pennsylvania Electric Company
Pepco	Formerly Potomac Electric Power Company or PEPCO
PHI	Pepco Holdings, Inc.
PJM	PJM Interconnection, L.L.C.
PJM/AEPNI	The interface between the American Electric Power Control Zone and Northern Illinois
PJM/AEPPJM	The interface between the American Electric Power Control Zone and PJM
PJM/AEPVP	The single interface pricing point formed in March 2003 from the combination of two previous interface pricing points: PJM/American Electric Power Company, Inc. and PJM/Dominion Resources, Inc.
PJM/AEPVPEXP	The export direction of the PJM/AEPVP interface pricing point
PJM/AEPVPIMP	The import direction of the PJM/AEPVP interface pricing point
PJM/ALTE	The interface between PJM and the eastern portion of the Alliant Energy Corporation's control area
PJM/ALTW	The interface between PJM and the western portion of the Alliant Energy Corporation's control area
PJM/AMRN	The interface between PJM and the Ameren Corporation's control area
PJM/CILC	The interface between PJM and the Central Illinois Light Company's control area
PJM/CIN	The interface between PJM and the Cinergy Corporation's control area
PJM/CPLE	The interface between PJM and the eastern portion of the Carolina Power & Light Company's control area
PJM/CPLW	The interface between PJM and the western portion of the Carolina Power & Light Company's control area
PJM/CWPL	The interface between PJM and the City Water, Light & Power's (City of Springfield, IL) control area
PJM/DLCO	The interface between PJM and the Duquesne Light Company's control area
PJM/DUK	The interface between PJM and the Duke Energy Corp.'s control area
PJM/EKPC	The interface between PJM and the Eastern Kentucky Power Corporation's control area
PJM/FE	The interface between PJM and the FirstEnergy Corp.'s control area
PJMICC	PJM Industrial Customer Coalition
PJM/IP	The interface between PJM and the Illinois Power Company's control area
PJM/IPL	The interface between PJM and the Indianapolis Power & Light Company's control area
PJM/LGEE	The interface between PJM and the Louisville Gas and Electric Company's control area
PJM/LIND	The interface between PJM and the New York System Operator over the Linden VFT line
PJM/MEC	The interface between PJM and MidAmerican Energy Company's control area
PJM/MECS	The interface between PJM and the Michigan Electric Coordinated System's control area
PJM/MISO	The interface between PJM and the Midwest Independent System Operator
PJM/NEPT	The interface between PJM and the New York Independent System Operator over the Neptune DC line
PJM/NIPS	The interface between PJM and the Northern Indiana Public Service Company's control area

PJM/NYIS	The interface between PJM and the New York Independent System Operator
PJM/Ontario IESO	PJM/Ontario IESO pricing point
PJM/OVEC	The interface between PJM and the Ohio Valley Electric Corporation's control area
PJM/TVA	The interface between PJM and the Tennessee Valley Authority's control area
PJM/VAP	The interface between PJM and the Dominion Virginia Power's control area
PJM/WEC	The interface between PJM and the Wisconsin Energy Corporation's control area
PLC	Peak Load Contribution
PLS	Parameter limited schedule
PMSS	Preliminary market structure screen
PNNE	PENELEC's northeastern subarea
PNNW	PENELEC's northwestern subarea
POD	Point of delivery
POR	Point of receipt
PPb	
PPL	PPL Electric Utilities Corporation
PSE&G	Public Service Electric and Gas Company (a wholly owned subsidiary of PSEG)
PSEG	Public Service Enterprise Group
PSD	Prevention of Significant Deterioration
PSN	PSEG north
PSNC	PSEG north central
RAA	Reliability Assurance Agreement among Load-Serving Entities
RCF	Reciprocal Coordinated Flowgate
RCIS	Reliability Coordinator Information System
REC	Renewable Energy Credit
RECO	Rockland Electric Company zone
RFC	Reliability*First* Corporation
RFP	Request for Proposal
RGGI	Regional Greenhouse Gas Initiative
RICE	Reciprocating Internal Combustion Engines
RLD (MW)	Ramp-limited desired (Megawatts)
RLR	Retail load responsibility
RMCP	Regulation market-clearing price
RMR	Reliability Must Run
RPM	Reliability Pricing Model
RPS	Renewable Portfolio Standard
RSI	Residual supply index
RSI_x	Residual supply index, using "x" pivotal suppliers
RTC	Real-time commitment
RTEP	Regional Transmission Expansion Plan
RTO	Regional transmission organization
SCE&G	South Carolina Energy and Gas
SCED	Security Constrained Economic Dispatch
SCPA	South central Pennsylvania subarea
SCR	Selective catalytic reduction
SEPA	Southeast Power Administration
SEPJM	Southeastern PJM subarea
SERC	SERC Reliability Corporation
SFT	Simultaneous feasibility test
SMECO	Southern Maryland Electric Cooperative

SMP	System marginal price
SNCR	Selective Non-Catalytic Reduction
SNJ	Southern New Jersey
SO_2	Sulfur dioxide
SOUTHEXP	South Export pricing point
SOUTHIMP	South Import pricing point
SPP	Southwest Power Pool, Inc.
SPREGO	Synchronized reserve and regulation optimizer (market-clearing software)
SRMCP	Synchronized reserve market-clearing price
STD	Standard deviation
STRPTAS	Short Term Resource Procurement Applicable Share
SVC	Static Var compensator
SWMAAC	Southwestern Mid-Atlantic Area Council
TARA	Transmission adequacy and reliability assessment
TDR	Turn down ratio
TEAC	Transmission Expansion Advisory Committee
THI	Temperature-humidity index
TISTF	Transactions Issues Senior Task Force
TLR	Transmission loading relief
TPS	Three pivotal supplier
TPSTF	Three Pivotal Supplier Task Force
TPY	Tons Per Year
TrAIL	Trans – Allegheny Interstate Line
TSIN	NERC Transmission System Information Network
TVA	Tennessee Valley Authority
UCAP	Unforced capacity
UDS	Unit dispatch system
UGI	UGI Utilities, Inc.
UPF	Unit participation factor
VACAR	Virginia and Carolinas Area
VAP	Dominion Virginia Power
VFT	Variable frequency transformer
VOCs	Volatile Organic Compounds
VOM expense	Variable operation and maintenance
VRR	Variable resource requirement
WEC	Wisconsin Energy Corporation
WLR	Wholesale load responsibility
WPC	Willing to pay congestion
WWP	Winter Weather Parameter
XEFORd	EFORd modified to exclude OMC outages