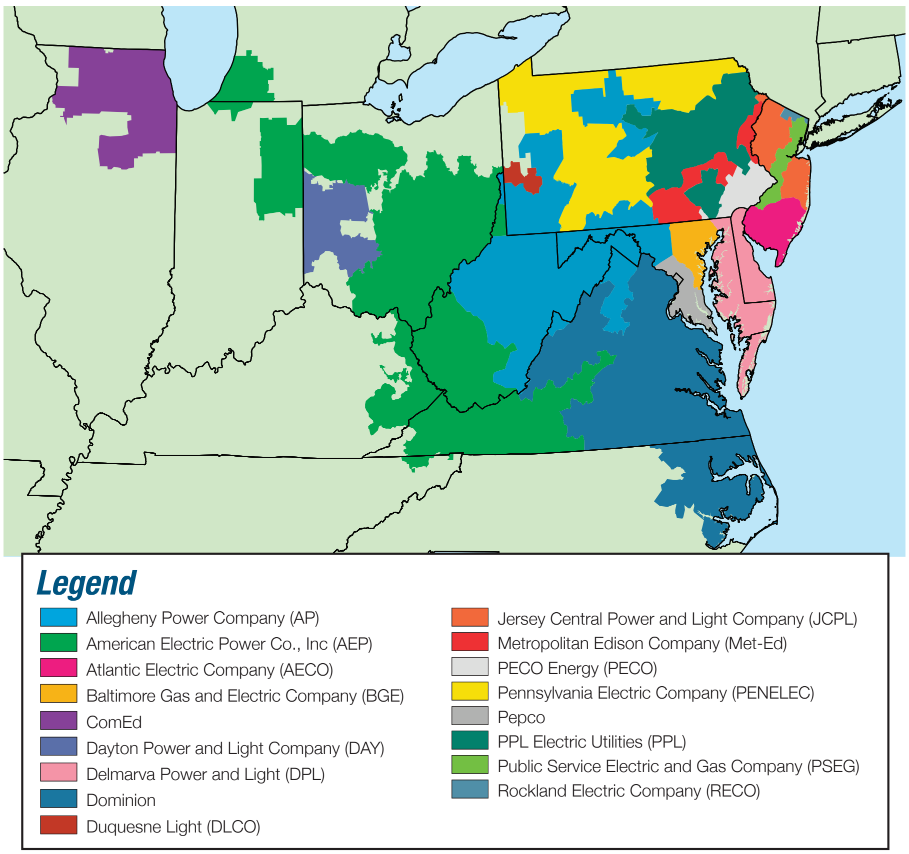
APPENDIX A – PJM GEOGRAPHY

During 2010, the PJM geographic footprint encompassed 17 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 17 control zones



Analysis of 2010 market results requires comparison to 2009 and certain other prior years. During calendar years 2006 through 2010 the PJM footprint was stable. During calendar years 2004 and 2005, however, 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:[1]

1 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.

- **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,[2] and the Allegheny Power Company (AP) Control Zone.[3]

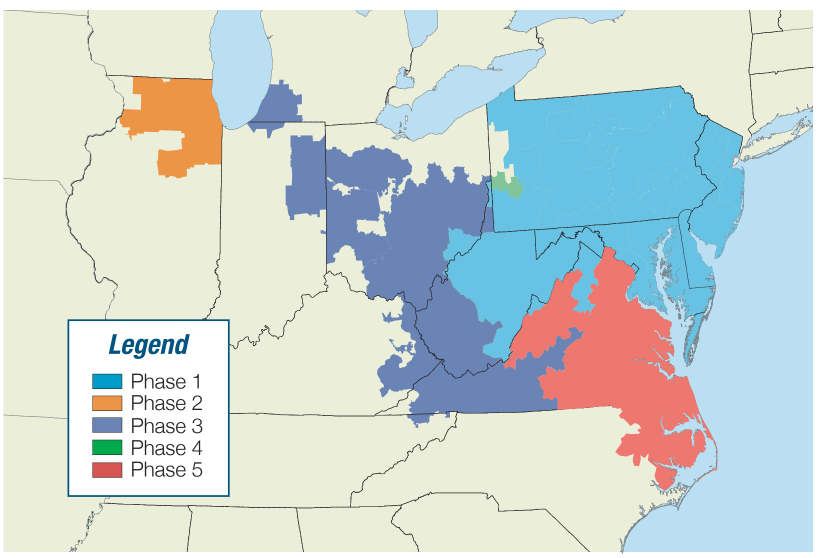
- **Phase 2 (2004).** The five-month period from May 1, through September 30, 2004, during which PJM was comprised of the Mid-Atlantic Region, including its 11 zones, the AP Control Zone and the ComEd Control Area.[4]

- **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).** The eight-month period from May 1, through December 31, 2005, during which PJM was comprised of the Phase 4 elements plus the Dominion Control Zone which was integrated into PJM on May 1, 2005.

Figure A-2 PJM integration phases



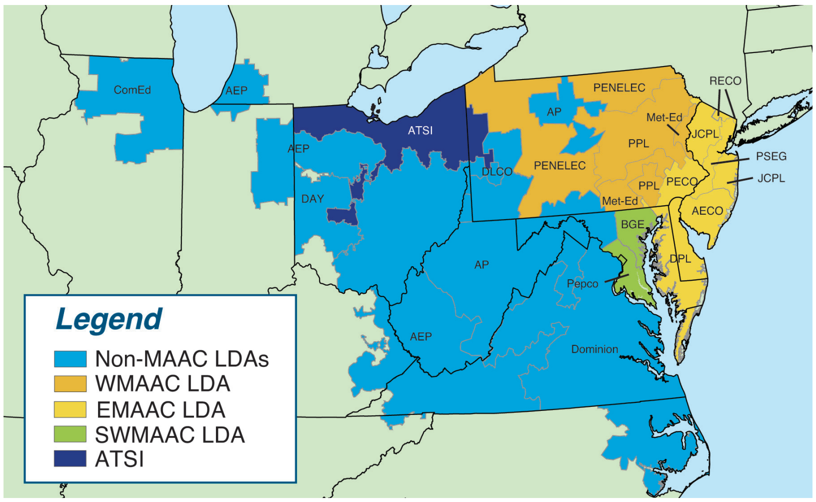
2 The Mid-Atlantic Region is comprised of the AECO, BGE, DPL, JCPL, Met-Ed, PECO, PENELEC, Pepco, PPL, PSEG and RECO control zones.

3 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.

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

A locational deliverability area (LDA) is a geographic area within PJM that has limited transmission capability to import capacity in the RPM design to satisfy its reliability requirements, as determined by PJM in connection with the preparation of the Regional Transmission Expansion Plan[5] (RTEP) and as specified in Schedule 10.1 of the PJM "Reliability Assurance Agreement with Load-Serving Entities."[6]

Figure A-3 PJM locational deliverability areas[7]

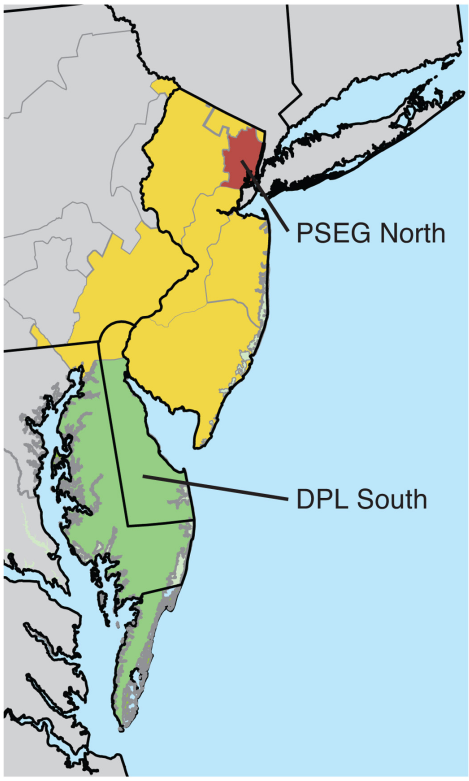


In PJM's Reliability Pricing Model (RPM) Auctions, markets are defined dynamically by LDA. The regional transmission organization (RTO) market comprises the entire PJM footprint, unless a modeled LDA is constrained. Each constrained LDA or group of LDAs is a separate market with a separate clearing price, 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.

5 See "Regional Transmission Expansion Plan Report," <http://www.pjm.com/documents/reports/rtep-report.aspx> (Accessed February 8, 2008).
6 See OATT Attachment DD: Reliability Pricing Model," § 2.59.
7 The ATSI zone integration into PJM is effective beginning with the 2011/2012 delivery year. The ATSI zone is considered a non-MAAC LDA.

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



APPENDIX B – 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

APPENDIX C - 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 2006 to 2010.[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 and the DLCO and Dominion control zones in 2005 mean that annual comparisons of load frequency are significantly affected by PJM's geographic growth.[2]

1 The definitions of load are discussed in the *Technical Reference for PJM Markets,* Section 5, "Load Definitions."
2 See the *2010 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography."

Table C-1 Frequency distribution of PJM real-time, hourly load: Calendar years 2006 to 2010

	2006		2007		2008		2009		2010	
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	2	0.02%	0	0.00%	0	0.00%	15	0.17%	12	0.14%
50 to 55	129	1.50%	79	0.90%	127	1.45%	376	4.46%	272	3.24%
55 to 60	504	7.25%	433	5.84%	517	7.33%	738	12.89%	582	9.89%
60 to 65	689	15.11%	637	13.12%	667	14.92%	836	22.43%	699	17.87%
65 to 70	967	26.15%	890	23.28%	941	25.64%	915	32.88%	805	27.05%
70 to 75	1,079	38.47%	878	33.30%	1,048	37.57%	1,342	48.20%	1,323	42.16%
75 to 80	1,501	55.61%	1,227	47.31%	1,535	55.04%	1,488	65.18%	1,272	56.68%
80 to 85	1,337	70.87%	1,338	62.58%	1,208	68.80%	966	76.21%	948	67.50%
85 to 90	943	81.63%	981	73.78%	916	79.22%	742	84.68%	794	76.56%
90 to 95	569	88.13%	741	82.24%	655	86.68%	549	90.95%	659	84.09%
95 to 100	295	91.50%	577	88.82%	457	91.88%	388	95.38%	487	89.65%
100 to 105	215	93.95%	382	93.18%	292	95.21%	205	97.72%	318	93.28%
105 to 110	161	95.79%	223	95.73%	181	97.27%	121	99.10%	195	95.50%
110 to 115	145	97.44%	179	97.77%	133	98.78%	48	99.65%	151	97.23%
115 to 120	102	98.61%	106	98.98%	58	99.44%	26	99.94%	108	98.46%
120 to 125	45	99.12%	43	99.47%	35	99.84%	5	100.00%	84	99.42%
125 to 130	27	99.43%	31	99.83%	14	100.00%	0	100.00%	40	99.87%
130 to 135	19	99.65%	12	99.97%	0	100.00%	0	100.00%	11	100.00%
135 to 140	19	99.86%	3	100.00%	0	100.00%	0	100.00%	0	100.00%
> 140	12	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%

Off-Peak and On-Peak Load

Table C-2 presents summary load statistics for 1998 to 2010 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 22.0 percent higher than off-peak load in 2010. Average load during on-peak hours in 2010 was 4.4 percent higher than in 2009. Off-peak load in 2010 was 5.0 percent higher than in 2009 (Table C-3).

Table C-2 Off-peak and on-peak load (MW): Calendar years 1998 to 2010

	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

Table C-3 Multiyear change in load: Calendar years 1998 to 2010

	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%

Locational Marginal Price (LMP)

In assessing changes in LMP over time, the Market Monitoring Unit (MMU) examines three measures: simple LMP; load-weighted LMP; and fuel-cost-adjusted, load-weighted LMP. Differences in simple LMP measure the change in reported price. Differences in load-weighted 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 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 LMP

Table C-4 provides frequency distributions of PJM real-time hourly LMP for the calendar years 2006 to 2010. 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.

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-4 Frequency distribution by hours of PJM Real-Time Energy Market LMP (Dollars per MWh): Calendar years 2006 to 2010

	2006		2007		2008		2009		2010	
LMP	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent
$10 and less	85	0.97%	56	0.64%	94	1.07%	117	1.34%	65	0.74%
$10 to $20	247	3.79%	185	2.75%	129	2.54%	218	3.82%	127	2.19%
$20 to $30	1,958	26.14%	1,571	20.68%	490	8.12%	2,970	37.73%	1,810	22.85%
$30 to $40	1,840	47.15%	1,470	37.47%	1,443	24.54%	2,951	71.42%	3,150	58.81%
$40 to $50	1,405	63.18%	1,108	50.11%	1,533	42.00%	1,269	85.90%	1,462	75.50%
$50 to $60	1,040	75.06%	931	60.74%	1,212	55.79%	555	92.24%	766	84.25%
$60 to $70	662	82.61%	827	70.18%	845	65.41%	276	95.39%	427	89.12%
$70 to $80	479	88.08%	726	78.47%	709	73.49%	151	97.11%	274	92.25%
$80 to $90	347	92.04%	646	85.84%	502	79.20%	95	98.20%	165	94.13%
$90 to $100	230	94.67%	451	90.99%	385	83.58%	62	98.90%	134	95.66%
$100 to $110	162	96.52%	240	93.73%	352	87.59%	30	99.25%	82	96.60%
$110 to $120	95	97.60%	178	95.76%	265	90.61%	21	99.49%	71	97.41%
$120 to $130	61	98.30%	110	97.02%	199	92.87%	15	99.66%	61	98.11%
$130 to $140	46	98.82%	76	97.89%	144	94.51%	7	99.74%	44	98.61%
$140 to $150	27	99.13%	53	98.49%	111	95.78%	9	99.84%	29	98.94%
$150 to $160	16	99.32%	26	98.79%	102	96.94%	3	99.87%	22	99.19%
$160 to $170	11	99.44%	29	99.12%	68	97.71%	3	99.91%	11	99.32%
$170 to $180	6	99.51%	18	99.33%	52	98.30%	5	99.97%	13	99.46%
$180 to $190	3	99.54%	9	99.43%	45	98.82%	0	99.97%	12	99.60%
$190 to $200	5	99.60%	15	99.60%	29	99.15%	1	99.98%	9	99.70%
$200 to $210	3	99.63%	6	99.67%	20	99.37%	1	99.99%	7	99.78%
$210 to $220	7	99.71%	4	99.71%	11	99.50%	1	100.00%	4	99.83%
$220 to $230	1	99.73%	4	99.76%	14	99.66%	0	100.00%	3	99.86%
$230 to $240	1	99.74%	2	99.78%	10	99.77%	0	100.00%	5	99.92%
$240 to $250	1	99.75%	5	99.84%	2	99.80%	0	100.00%	3	99.95%
$250 to $260	1	99.76%	2	99.86%	5	99.85%	0	100.00%	1	99.97%
$260 to $270	0	99.76%	4	99.91%	4	99.90%	0	100.00%	0	99.97%
$270 to $280	3	99.79%	0	99.91%	1	99.91%	0	100.00%	0	99.97%
$280 to $290	1	99.81%	0	99.91%	1	99.92%	0	100.00%	1	99.98%
$290 to $300	0	99.81%	0	99.91%	0	99.92%	0	100.00%	0	99.98%
$300 to $400	11	99.93%	2	99.93%	6	99.99%	0	100.00%	2	100.00%
$400 to $500	2	99.95%	4	99.98%	1	100.00%	0	100.00%	0	100.00%
$500 to $600	1	99.97%	1	99.99%	0	100.00%	0	100.00%	0	100.00%
$600 to $700	1	99.98%	1	100.00%	0	100.00%	0	100.00%	0	100.00%
> $700	2	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%

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

Table C-5 shows load-weighted, average real-time LMP for 2009 and 2010 during off-peak and on-peak periods.

Table C-5 Off-peak and on-peak, PJM load-weighted, average LMP (Dollars per MWh): Calendar years 2009 to 2010

	2009			2010			Difference 2009 to 2010		
	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	$33.76	$43.95	1.30	$39.88	$56.25	1.41	18.1%	28.0%	8.3%
Median	$29.33	$38.46	1.31	$33.09	$45.28	1.37	12.8%	17.7%	4.4%
Standard deviation	$16.99	$17.93	1.06	$23.01	$31.48	1.37	35.5%	75.6%	29.6%

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. As competitive offers are equivalent to the marginal cost of generation and fuel costs make up more than 80 percent of marginal cost on average for marginal units, 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 LMP depends on the fuel burned by the marginal units. To account for differences in the impact of fuel costs on prices between different time periods, the fuel-cost-adjusted, load-weighted LMP is used to compare load-weighted LMPs using fuel costs from a base period.[5]

Table C-6 shows the real-time, load-weighted, average LMP for 2009 and the real-time, fuel-cost-adjusted, load-weighted, average LMP for 2010 for on-peak and off-peak hours.

Table C-6 On-peak and off-peak real-time PJM fuel-cost-adjusted, load-weighted, average LMP (Dollars per MWh): Calendar year 2010

	2009 Load-Weighted LMP	2010 Fuel-Cost-Adjusted, Load-Weighted LMP	Change
On Peak	$43.95	$53.64	22.0%
Off Peak	$33.76	$39.27	16.3%

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

Table C-7 shows the PJM load-weighted, average LMP during constrained hours for 2009 and 2010.[6,7]

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

6 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.

7 The average real-time, load-weighted LMP in constrained hours for 2009 changed from $40.88 to $40.92 and the median changed from $35.75 to $35.81 compared to what was reported in the *2009 State of the Market Report for PJM*. The change resulted from the correction of a data error.

Table C-7 PJM real-time load-weighted, average LMP during constrained hours (Dollars per MWh): Calendar years 2009 to 2010

	2009	2010	Difference
Average	$40.92	$49.56	21.1%
Median	$35.81	$39.85	11.3%
Standard deviation	$19.02	$29.83	56.9%

Table C-8 provides a comparison of PJM load-weighted, average LMP during constrained and unconstrained hours for 2009 and 2010.[8]

Table C-8 PJM real-time load-weighted, average LMP during constrained and unconstrained hours (Dollars per MWh): Calendar years 2009 to 2010

	2009			2010		
	Unconstrained Hours	Constrained Hours	Difference	Unconstrained Hours	Constrained Hours	Difference
Average	$32.34	$40.92	26.5%	$39.37	$49.56	25.9%
Median	$29.80	$35.81	20.1%	$35.34	$39.85	12.8%
Standard deviation	$12.90	$19.02	47.4%	$18.46	$29.83	61.6%

Table C-9 shows the number of hours and the number of constrained hours in each month in 2009 and 2010.[9]

Table C-9 PJM real-time constrained hours: Calendar years 2009 to 2010

	2009 Constrained Hours	2010 Constrained Hours	Total Hours
Jan	725	598	744
Feb	571	563	672
Mar	596	576	743
Apr	552	618	720
May	457	592	744
Jun	557	645	720
Jul	537	667	744
Aug	623	633	744
Sep	498	695	720
Oct	562	705	744
Nov	521	653	721
Dec	511	722	744
Avg	559	639	730

8 The average real-time, load-weighted LMP in constrained hours and unconstrained hours for 2009 changed compared to what was reported in the *2009 State of the Market Report for PJM*. The change resulted from the correction of a data error. The average real-time, load-weighted LMP in unconstrained hours for 2009 changed from $32.71 to $32.34, the median changed from $29.95 to $29.80 and the standard deviation changed from 13.26 to 12.90. As a result, the difference between the average real-time, load-weighted LMP in constrained and unconstrained hours as percent changed from 25.0 percent to 26.5 percent, the difference between the median changed from 19.3 percent to 20.1 percent, and the difference between the standard deviation changed from 43.4 percent to 47.4 percent.

9 The average number of constrained hours in 2009 changed compared to what was reported in the *2009 State of the Market Report for PJM*. The change resulted from the correction of a data error. The constrained hours in January changed from 701 hours to 725 hours, the constrained hours in May changed from 439 hours to 457 hours, the constrained hours in July changed from 536 hours to 537 hours, the constrained hours in September changed from 494 hours to 498 hours, the constrained hours in November changed from 520 hours to 521 hours, and the constrained hours in December changed from 506 hours to 511 hours. As a result, the average constrained hours changed from 555 hours to 559 hours.

Day-Ahead and Real-Time LMP

On average, prices in the Real-Time Energy Market in 2010 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 2010 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 2006 to 2010. 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 $346.59 per MWh on August 11, 2010, in the hour ending 1600 EPT. In the Day-Ahead Energy Market, prices reached a high for the year of $199.82 per MWh on July 7, 2010, in the hour ending 1700 EPT.

Table C-10 Frequency distribution by hours of PJM Day-Ahead Energy Market LMP (Dollars per MWh): Calendar years 2006 to 2010

	2006		2007		2008		2009		2010	
LMP	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent
$10 and less	11	0.13%	3	0.03%	0	0.00%	23	0.26%	5	0.06%
$10 to $20	147	1.80%	88	1.04%	19	0.22%	343	4.18%	31	0.41%
$20 to $30	1,610	20.18%	1,291	15.78%	320	3.86%	2,380	31.35%	1,502	17.56%
$30 to $40	1,747	40.13%	1,495	32.84%	1,148	16.93%	3,221	68.12%	2,851	50.10%
$40 to $50	1,890	61.70%	1,221	46.78%	1,546	34.53%	1,717	87.72%	2,131	74.43%
$50 to $60	1,364	77.27%	1,266	61.23%	1,491	51.50%	557	94.08%	954	85.32%
$60 to $70	905	87.60%	1,301	76.08%	1,107	64.11%	253	96.96%	471	90.70%
$70 to $80	524	93.58%	939	86.80%	942	74.83%	138	98.54%	302	94.14%
$80 to $90	237	96.29%	504	92.56%	682	82.59%	68	99.32%	193	96.35%
$90 to $100	145	97.95%	264	95.57%	542	88.76%	33	99.69%	125	97.77%
$100 to $110	65	98.69%	155	97.34%	289	92.05%	19	99.91%	86	98.76%
$110 to $120	38	99.12%	104	98.53%	193	94.25%	6	99.98%	46	99.28%
$120 to $130	11	99.25%	59	99.20%	131	95.74%	2	100.00%	29	99.61%
$130 to $140	8	99.34%	33	99.58%	112	97.02%	0	100.00%	14	99.77%
$140 to $150	8	99.43%	13	99.73%	67	97.78%	0	100.00%	7	99.85%
$150 to $160	7	99.51%	8	99.82%	54	98.39%	0	100.00%	6	99.92%
$160 to $170	6	99.58%	7	99.90%	46	98.92%	0	100.00%	3	99.95%
$170 to $180	6	99.65%	3	99.93%	23	99.18%	0	100.00%	2	99.98%
$180 to $190	3	99.68%	4	99.98%	20	99.41%	0	100.00%	0	99.98%
$190 to $200	3	99.71%	1	99.99%	16	99.59%	0	100.00%	2	100.00%
$200 to $210	3	99.75%	1	100.00%	8	99.68%	0	100.00%	0	100.00%
$210 to $220	3	99.78%	0	100.00%	9	99.78%	0	100.00%	0	100.00%
$220 to $230	1	99.79%	0	100.00%	4	99.83%	0	100.00%	0	100.00%
$230 to $240	3	99.83%	0	100.00%	3	99.86%	0	100.00%	0	100.00%
$240 to $250	2	99.85%	0	100.00%	2	99.89%	0	100.00%	0	100.00%
$250 to $260	1	99.86%	0	100.00%	0	99.89%	0	100.00%	0	100.00%
$260 to $270	2	99.89%	0	100.00%	4	99.93%	0	100.00%	0	100.00%
$270 to $280	1	99.90%	0	100.00%	0	99.93%	0	100.00%	0	100.00%
$280 to $290	1	99.91%	0	100.00%	2	99.95%	0	100.00%	0	100.00%
$290 to $300	1	99.92%	0	100.00%	2	99.98%	0	100.00%	0	100.00%
>$300	7	100.00%	0	100.00%	2	100.00%	0	100.00%	0	100.00%

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

Table C-11 shows PJM simple average LMP during off-peak and on-peak periods for the Day-Ahead and Real-Time Energy Markets in calendar year 2010. Figure C-1 and Figure C-2 show the difference between real-time and day-ahead LMP in calendar year 2010 during the on-peak and off-peak hours.

Table C-11 Off-peak and on-peak, simple average day-ahead and real-time LMP (Dollars per MWh): Calendar year 2010

	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	$37.46	$52.67	1.41	$37.44	$53.25	1.42	(0.1%)	1.1%	1.2%
Median	$33.73	$45.48	1.35	$31.83	$43.20	1.36	(5.6%)	(5.0%)	0.6%
Standard deviation	$14.27	$20.07	1.41	$20.93	$28.93	1.38	46.7%	44.1%	(1.8%)

Figure C-1 Hourly real-time LMP minus day-ahead LMP (On-peak hours): Calendar year 2010

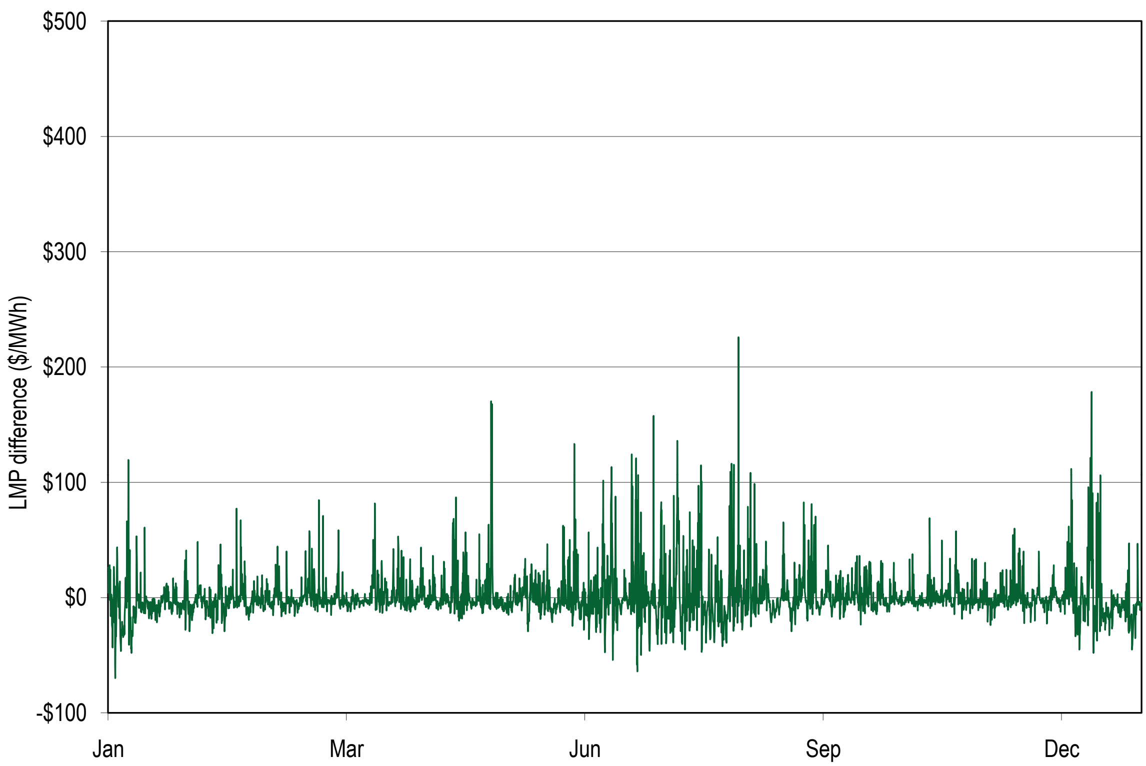
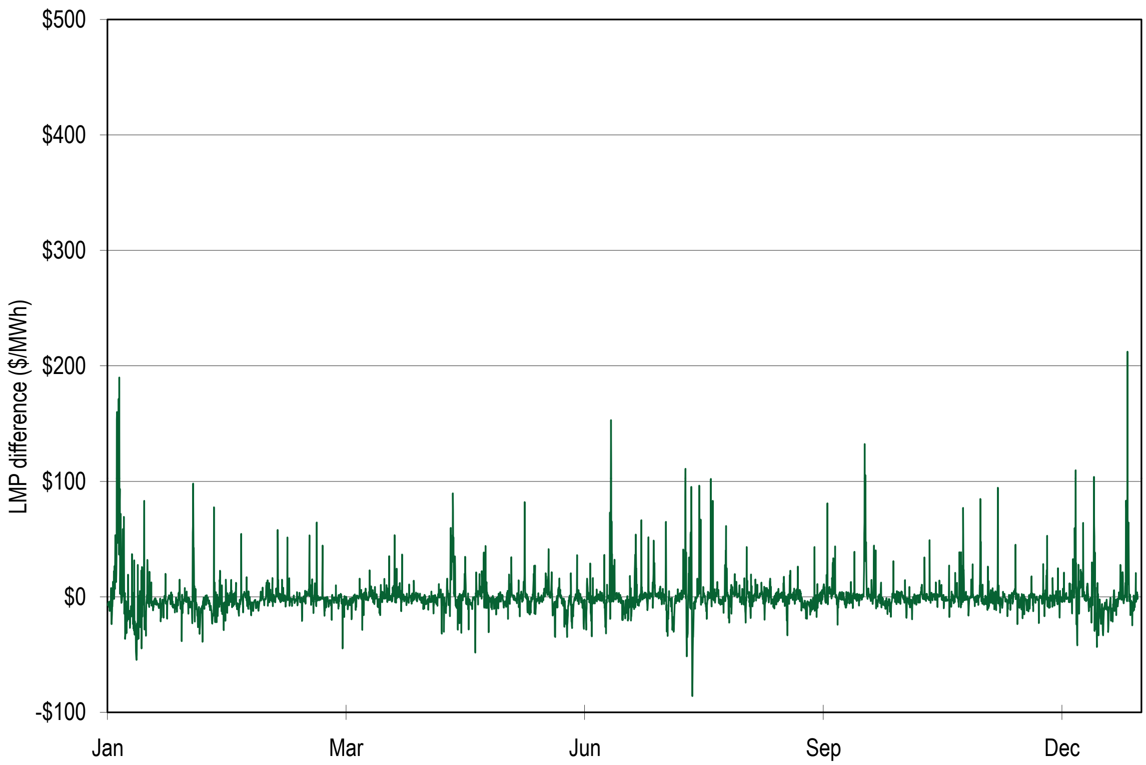


Figure C-2 Hourly real-time LMP minus day-ahead LMP (Off-peak hours): Calendar year 2010



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

Table C-12 and Table C-13 show the on-peak and off-peak, simple average LMPs for each zone in the Day-Ahead and Real-Time Energy Markets in calendar year 2010.

Table C-12 On-peak, zonal, simple average day-ahead and real-time LMP (Dollars per MWh): Calendar year 2010

	Day Ahead	Real Time	Difference	Difference as Percent Real Time
AECO	$59.71	$60.32	$0.62	1.02%
AEP	$44.49	$44.68	$0.18	0.41%
AP	$52.18	$52.35	$0.17	0.32%
BGE	$63.27	$64.36	$1.08	1.68%
ComEd	$41.37	$41.82	$0.45	1.08%
DAY	$44.39	$44.67	$0.28	0.62%
DLCO	$45.34	$45.81	$0.47	1.03%
Dominion	$59.34	$59.28	($0.06)	(0.11%)
DPL	$59.93	$60.36	$0.44	0.72%
JCPL	$59.42	$59.50	$0.09	0.15%
Met-Ed	$58.18	$58.95	$0.77	1.30%
PECO	$58.41	$58.23	($0.19)	(0.32%)
PENELEC	$51.32	$50.30	($1.02)	(2.02%)
Pepco	$62.57	$62.88	$0.32	0.50%
PPL	$56.28	$56.89	$0.61	1.07%
PSEG	$60.23	$60.93	$0.70	1.14%
RECO	$58.67	$58.36	($0.31)	(0.54%)

Table C-13 Off-peak, zonal, simple average day-ahead and real-time LMP (Dollars per MWh): Calendar year 2010

	Day Ahead	Real Time	Difference	Difference as Percent Real Time
AECO	$42.31	$42.18	($0.13)	(0.30%)
AEP	$32.86	$32.82	($0.05)	(0.14%)
AP	$37.61	$37.84	$0.23	0.61%
BGE	$44.42	$44.21	($0.21)	(0.48%)
ComEd	$26.34	$25.90	($0.44)	(1.68%)
DAY	$32.34	$32.36	$0.02	0.07%
DLCO	$31.26	$29.52	($1.73)	(5.87%)
Dominion	$43.97	$43.62	($0.35)	(0.81%)
DPL	$42.78	$42.86	$0.08	0.19%
JCPL	$42.12	$41.42	($0.70)	(1.69%)
Met-Ed	$40.90	$40.53	($0.37)	(0.92%)
PECO	$41.83	$41.10	($0.72)	(1.75%)
PENELEC	$37.46	$36.71	($0.74)	(2.03%)
Pepco	$44.49	$44.05	($0.45)	(1.02%)
PPL	$40.11	$39.73	($0.38)	(0.96%)
PSEG	$42.68	$42.24	($0.45)	(1.06%)
RECO	$41.79	$41.11	($0.68)	(1.66%)

PJM Day-Ahead and Real-Time, Simple 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 2010.

Table C-14 PJM day-ahead and real-time, market-constrained hours: Calendar year 2010

	DA Constrained Hours	RT Constrained Hours	Total Hours
Jan	741	598	744
Feb	168	563	672
Mar	670	576	743
Apr	719	618	720
May	744	592	744
Jun	720	645	720
Jul	720	667	744
Aug	744	633	744
Sep	720	695	720
Oct	744	705	744
Nov	721	653	721
Dec	720	722	744
Avg	678	639	730

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

Table C-15 PJM simple average LMP during constrained and unconstrained hours (Dollars per MWh): Calendar year 2010

	Day Ahead			Real Time		
	Unconstrained Hours	Constrained Hours	Difference	Unconstrained Hours	Constrained Hours	Difference
Average	$47.44	$44.35	(6.5%)	$37.27	$45.91	23.2%
Median	$44.13	$39.57	(10.3%)	$34.02	$37.39	9.9%
Standard deviation	$15.12	$19.07	26.1%	$17.45	$27.05	55.1%

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.[10] 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.

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.[11] 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-16 through Table C-19 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-16 Average day-ahead, offer-capped units: Calendar years 2006 to 2010

	2006		2007		2008		2009		2010	
	Avg. Units Capped	Percent	Avg. Units Capped	Percent	Avg. Units Capped	Percent	Avg. Units Capped	Percent	Avg. Units Capped	Percent
Jan	0.1	0.0%	0.2	0.0%	0.5	0.0%	0.7	0.1%	0.3	0.0%
Feb	0.2	0.0%	0.8	0.1%	0.2	0.0%	0.3	0.0%	0.8	0.1%
Mar	0.7	0.1%	0.9	0.1%	0.0	0.0%	0.6	0.1%	1.2	0.1%
Apr	0.2	0.0%	0.2	0.0%	0.2	0.0%	0.0	0.0%	2.0	0.2%
May	0.1	0.0%	0.2	0.0%	0.6	0.1%	0.1	0.0%	2.8	0.3%
Jun	0.7	0.1%	0.8	0.1%	1.5	0.1%	0.3	0.0%	0.5	0.0%
Jul	4.1	0.4%	0.6	0.1%	1.7	0.2%	0.4	0.0%	0.5	0.0%
Aug	4.7	0.5%	1.0	0.1%	0.2	0.0%	0.2	0.0%	0.3	0.0%
Sep	0.6	0.1%	0.2	0.0%	0.4	0.0%	0.1	0.0%	0.3	0.0%
Oct	0.3	0.0%	0.8	0.1%	0.4	0.0%	0.3	0.0%	0.0	0.0%
Nov	0.3	0.0%	0.0	0.0%	0.5	0.0%	0.6	0.1%	0.0	0.0%
Dec	0.7	0.0%	0.1	0.0%	1.3	0.1%	0.6	0.1%	0.0	0.0%

10 See OA Schedule 1, §6.4.2
11 See the *Technical Reference for PJM Markets*, Section 8, "Three Pivotal Supplier Test."

Table C-17 Average day-ahead, offer-capped MW: Calendar years 2006 to 2010

	2006		2007		2008		2009		2010	
	Avg. MW Capped	Percent	Avg. MW Capped	Percent	Avg. MW Capped	Percent	Avg. MW Capped	Percent	Avg. MW Capped	Percent
Jan	4	0.0%	23	0.0%	16	0.0%	98	0.1%	17	0.0%
Feb	6	0.0%	57	0.1%	11	0.0%	30	0.0%	98	0.1%
Mar	51	0.1%	86	0.1%	2	0.0%	47	0.1%	117	0.1%
Apr	31	0.0%	11	0.0%	31	0.0%	0	0.0%	129	0.1%
May	22	0.0%	38	0.0%	15	0.0%	9	0.0%	143	0.1%
Jun	164	0.2%	28	0.0%	91	0.1%	42	0.0%	61	0.1%
Jul	518	0.5%	45	0.0%	110	0.1%	35	0.0%	34	0.0%
Aug	398	0.4%	58	0.1%	35	0.0%	10	0.0%	26	0.0%
Sep	51	0.1%	14	0.0%	66	0.1%	3	0.0%	23	0.0%
Oct	27	0.0%	77	0.1%	39	0.0%	29	0.0%	0	0.0%
Nov	15	0.0%	4	0.0%	47	0.1%	50	0.1%	0	0.0%
Dec	40	0.0%	4	0.0%	187	0.2%	29	0.0%	0	0.0%

Table C-18 Average real-time, offer-capped units: Calendar years 2006 to 2010

	2006		2007		2008		2009		2010	
	Avg. Units Capped	Percent	Avg. Units Capped	Percent	Avg. Units Capped	Percent	Avg. Units Capped	Percent	Avg. Units Capped	Percent
Jan	1.9	0.2%	1.2	0.1%	3.1	0.3%	2.4	0.2%	2.3	0.2%
Feb	2.1	0.2%	4.2	0.4%	2.6	0.3%	1.1	0.1%	1.9	0.2%
Mar	2.3	0.2%	1.9	0.2%	2.7	0.3%	1.8	0.2%	2.5	0.2%
Apr	1.5	0.2%	1.3	0.1%	3.1	0.3%	1.8	0.2%	3.2	0.3%
May	3.4	0.3%	1.9	0.2%	2.1	0.2%	1.0	0.1%	4.5	0.4%
Jun	2.5	0.3%	6.0	0.6%	8.7	0.8%	1.3	0.1%	7.1	0.7%
Jul	8.6	0.9%	4.4	0.4%	5.7	0.6%	1.1	0.1%	9.3	0.9%
Aug	9.5	1.0%	9.6	0.9%	2.0	0.2%	3.0	0.3%	5.8	0.5%
Sep	1.8	0.2%	5.5	0.5%	4.8	0.5%	1.6	0.1%	6.2	0.6%
Oct	1.7	0.2%	5.0	0.5%	2.5	0.2%	1.2	0.1%	3.5	0.3%
Nov	1.1	0.1%	2.9	0.3%	2.2	0.2%	0.6	0.1%	3.1	0.3%
Dec	1.0	0.0%	4.7	0.5%	2.5	0.2%	1.3	0.1%	6.3	0.6%

Table C-19 Average real-time, offer-capped MW: Calendar years 2006 to 2010

	2006		2007		2008		2009		2010	
	Avg. MW Capped	Percent	Avg. MW Capped	Percent	Avg. MW Capped	Percent	Avg. MW Capped	Percent	Avg. MW Capped	Percent
Jan	42	0.1%	50	0.1%	99	0.1%	158	0.2%	124	0.1%
Feb	67	0.1%	125	0.1%	92	0.1%	92	0.1%	117	0.1%
Mar	88	0.1%	142	0.2%	117	0.2%	147	0.2%	216	0.3%
Apr	75	0.1%	48	0.1%	125	0.2%	151	0.2%	251	0.4%
May	136	0.2%	68	0.1%	59	0.1%	64	0.1%	337	0.5%
Jun	160	0.2%	190	0.2%	415	0.5%	103	0.1%	382	0.4%
Jul	506	0.5%	160	0.2%	202	0.2%	74	0.1%	473	0.5%
Aug	518	0.6%	314	0.3%	99	0.1%	137	0.2%	253	0.3%
Sep	69	0.1%	218	0.3%	182	0.2%	95	0.1%	378	0.5%
Oct	49	0.1%	153	0.2%	177	0.3%	105	0.2%	345	0.5%
Nov	31	0.0%	104	0.1%	157	0.2%	60	0.1%	382	0.5%
Dec	12	0.0%	146	0.2%	211	0.3%	128	0.2%	538	0.6%

In order to help understand the frequency of offer capping in more detail, Table C-20 through Table C-24 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 2006 through 2010.

Table C-20 Offer-capped unit statistics: Calendar year 2006

	2006 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%	3	0	0	1	2	0
80% and < 90%	1	5	1	4	3	7
75% and < 80%	0	1	0	2	6	10
70% and < 75%	0	0	0	2	6	18
60% and < 70%	0	1	1	3	5	27
50% and < 60%	0	2	0	0	0	12
25% and < 50%	0	2	1	2	1	31
10% and < 25%	0	0	0	3	9	41

Table C-21 Offer-capped unit statistics: Calendar year 2007

Run Hours Offer-Capped, Percent Greater Than Or Equal To:	2007 Offer-Capped Hours					
	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-22 Offer-capped unit statistics: Calendar year 2008

Run Hours Offer-Capped, Percent Greater Than Or Equal To:	2008 Offer-Capped Hours					
	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-23 Offer-capped unit statistics: Calendar year 2009

Run Hours Offer-Capped, Percent Greater Than Or Equal To:	2009 Offer-Capped Hours					
	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-24 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

APPENDIX D - 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.[1]

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, 2010, through December 31, 2010. 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 2010, the AECO, AEP, AP, BGE, ComEd, DLCO, Dominion, DPL, Met-Ed, PENELEC, PPL 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 2010, actual competitive conditions associated with each of these frequently binding constraints were analyzed in real time.[2] The DAY, JCPL, PECO, 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.[3] 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 2010, 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 1,913 on peak, and all 2,001 off peak tests resulted in one or more owners failing. Table D-2 shows the average constraint relief required on the constraint, the

1 The FERC eliminated the exemption of interfaces effective May 17, 2008. 123 FERC ¶ 61,169 (2008)

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

3 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.

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-2 shows that on average, there were two owners 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.

Table D-1 Three pivotal supplier results summary for constraints located in the AECO Control Zone: Calendar year 2010

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	1,913	0	0%	1,913	100%
	Off Peak	2,001	0	0%	2,001	100%

Table D-2 Three pivotal supplier test details for constraints located in the AECO Control Zone: Calendar year 2010

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	2	0	2
	Off Peak	9	11	1	0	1

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 two out of 1,913 tests applied to units that were eligible for offer capping on peak. Only six out of 2,001 tests were applied to units that were eligible for offer capping off peak. None of the tests resulted in offer capping.

Table D-3 Summary of three pivotal supplier tests applied to uncommitted units for constraints located in the AECO Control Zone: Calendar year 2010

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	1,913	2	0%	0	0%	0%
	Off Peak	2,001	6	0%	0	0%	0%

AEP Control Zone Results

In 2010, there were eight 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 five of the eight constraints, the average number of owners with available supply was one.

Table D-4 Three pivotal supplier results summary for constraints located in the AEP Control Zone: Calendar year 2010

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
Carnegie - Tidd	Peak	8,196	0	0%	8,196	100%
	Off Peak	3,060	0	0%	3,060	100%
Cloverdale	Peak	837	74	9%	820	98%
	Off Peak	2,798	75	3%	2,784	99%
Cloverdale - Ivy Hill	Peak	628	0	0%	628	100%
	Off Peak	633	0	0%	633	100%
Cloverdale - Lexington	Peak	2,797	433	15%	2,594	93%
	Off Peak	13,050	1,061	8%	12,764	98%
Dumont - Stillwell	Peak	168	19	11%	155	92%
	Off Peak	2,094	115	5%	2,008	96%
Kanawha River - Kincaid	Peak	2,866	0	0%	2,866	100%
	Off Peak	995	0	0%	995	100%
Mahans Lane - Tidd	Peak	2,801	0	0%	2,801	100%
	Off Peak	1,781	0	0%	1,781	100%
Ruth - Turner	Peak	2,101	0	0%	2,101	100%
	Off Peak	1,319	0	0%	1,319	100%

Table D-5 Three pivotal supplier test details for constraints located in the AEP Control Zone: Calendar year 2010

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Carnegie - Tidd	Peak	31	54	1	0	1
	Off Peak	32	50	1	0	1
Cloverdale	Peak	178	1,107	11	1	10
	Off Peak	188	1,231	8	0	8
Cloverdale - Ivy Hill	Peak	3	3	1	0	1
	Off Peak	4	3	1	0	1
Cloverdale - Lexington	Peak	217	1,807	16	2	14
	Off Peak	204	1,841	12	1	11
Dumont - Stillwell	Peak	257	2,021	21	2	19
	Off Peak	227	1,652	15	1	14
Kanawha River - Kincaid	Peak	7	6	1	0	1
	Off Peak	7	6	1	0	1
Mahans Lane - Tidd	Peak	16	21	1	0	1
	Off Peak	14	19	1	0	1
Ruth - Turner	Peak	16	9	1	0	1
	Off Peak	13	6	1	0	1

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 the offer capping of uncommitted units and the portion of those tests that did result in offer capping. Table D-6 shows that only a small fraction of the tests applied to the eight constraints in the AEP zone could have resulted in offer capping. For five of the eight constraints, none of the tests could have resulted in offer capping.

Table D-6 Summary of three pivotal supplier tests applied to uncommitted units for constraints located in the AEP Control Zone: Calendar year 2010

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
Carnegie - Tidd	Peak	8,196	0	0%	0	0%	0%
	Off Peak	3,060	0	0%	0	0%	0%
Cloverdale	Peak	837	69	8%	30	4%	43%
	Off Peak	2,798	35	1%	7	0%	20%
Cloverdale - Ivy Hill	Peak	628	0	0%	0	0%	0%
	Off Peak	633	0	0%	0	0%	0%
Cloverdale - Lexington	Peak	2,797	321	11%	140	5%	44%
	Off Peak	13,050	182	1%	47	0%	26%
Dumont - Stillwell	Peak	168	36	21%	17	10%	47%
	Off Peak	2,094	42	2%	9	0%	21%
Kanawha River - Kincaid	Peak	2,866	0	0%	0	0%	0%
	Off Peak	995	3	0%	0	0%	0%
Mahans Lane - Tidd	Peak	2,801	0	0%	0	0%	0%
	Off Peak	1,781	0	0%	0	0%	0%
Ruth - Turner	Peak	2,101	0	0%	0	0%	0%
	Off Peak	1,319	4	0%	0	0%	0%

AP Control Zone Results

In 2010, there were ten 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 owners passing and failing. Table D-8 shows that for six of the ten constraints, the average number of owners with available supply was two or fewer.

Table D-7 Three pivotal supplier results summary for constraints located in the AP Control Zone: Calendar year 2010

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
Albright - Mt. Zion	Peak	1,595	0	0%	1,595	100%
	Off Peak	1,283	0	0%	1,283	100%
Belmont	Peak	3,921	0	0%	3,921	100%
	Off Peak	769	0	0%	769	100%
Boonsboro - Marlowe	Peak	2,676	0	0%	2,676	100%
	Off Peak	726	0	0%	726	100%
Doubs	Peak	9,177	791	9%	8,700	95%
	Off Peak	1,552	119	8%	1,506	97%
Elrama - Mitchell	Peak	2,832	51	2%	2,800	99%
	Off Peak	9,225	65	1%	9,208	100%
Millvile - Sleepy Hollow	Peak	7,287	0	0%	7,287	100%
	Off Peak	2,001	0	0%	2,001	100%
Millville - Old Chapel	Peak	6,136	0	0%	6,136	100%
	Off Peak	3,157	0	0%	3,157	100%
Mount Storm - Pruntytown	Peak	9,092	1,034	11%	8,773	96%
	Off Peak	13,291	753	6%	13,089	98%
Tiltonsville - Windsor	Peak	5,859	0	0%	5,859	100%
	Off Peak	2,491	0	0%	2,491	100%
Wylie Ridge	Peak	9,846	1,113	11%	9,328	95%
	Off Peak	15,145	1,444	10%	14,445	95%

Table D-8 Three pivotal supplier test details for constraints located in the AP Control Zone: Calendar year 2010

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Albright - Mt. Zion	Peak	8	10	1	0	1
	Off Peak	13	9	1	0	1
Belmont	Peak	23	18	1	0	1
	Off Peak	15	11	1	0	1
Boonsboro - Marlowe	Peak	36	13	2	0	2
	Off Peak	34	8	2	0	2
Doubs	Peak	25	87	5	1	4
	Off Peak	24	96	5	0	4
Elrama - Mitchell	Peak	90	260	7	0	6
	Off Peak	98	199	5	0	5
Millvile - Sleepy Hollow	Peak	41	25	2	0	2
	Off Peak	24	12	1	0	1
Millville - Old Chapel	Peak	35	16	2	0	2
	Off Peak	34	10	1	0	1
Mount Storm - Pruntytown	Peak	318	1,369	10	1	9
	Off Peak	335	1,393	9	0	8
Tiltonsville - Windsor	Peak	22	11	2	0	2
	Off Peak	16	10	2	0	2
Wylie Ridge	Peak	198	1,099	16	1	15
	Off Peak	201	1,018	14	1	13

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 the offer capping of uncommitted units and the portion of those tests that did result in offer capping. Table D-9 shows that only a small fraction of the tests applied to the ten constraints in the AP zone could have resulted in offer capping. Nine of the constraints had less than two percent of peak or off peak tests that could have resulted in offer capping. The remaining constraint, Mount Storm – Pruntytown, had six percent of its peak and two percent of its off peak tests that could have resulted in offer capping. None of the constraints, including Mount Storm – Pruntytown had more than three percent of its tests result in offer capping.

Table D-9 Summary of three pivotal supplier tests applied to uncommitted units for constraints located in the AP Control Zone: Calendar year 2010

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
Albright - Mt. Zion	Peak	1,595	2	0%	0	0%	0%
	Off Peak	1,283	1	0%	1	0%	100%
Belmont	Peak	3,921	0	0%	0	0%	0%
	Off Peak	769	0	0%	0	0%	0%
Boonsboro - Marlowe	Peak	2,676	7	0%	7	0%	100%
	Off Peak	726	1	0%	1	0%	100%
Doubs	Peak	9,177	110	1%	63	1%	57%
	Off Peak	1,552	13	1%	10	1%	77%
Elrama - Mitchell	Peak	2,832	28	1%	14	0%	50%
	Off Peak	9,225	41	0%	13	0%	32%
Millvile - Sleepy Hollow	Peak	7,287	14	0%	14	0%	100%
	Off Peak	2,001	9	0%	9	0%	100%
Millville - Old Chapel	Peak	6,136	5	0%	5	0%	100%
	Off Peak	3,157	1	0%	1	0%	100%
Mount Storm - Pruntytown	Peak	9,092	542	6%	246	3%	45%
	Off Peak	13,291	267	2%	60	0%	22%
Tiltonsville - Windsor	Peak	5,859	12	0%	7	0%	58%
	Off Peak	2,491	7	0%	7	0%	100%
Wylie Ridge	Peak	9,846	236	2%	85	1%	36%
	Off Peak	15,145	231	2%	56	0%	24%

BGE Control Zone Results

In 2010, there were two 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 about 85 percent 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 owner passing and failing. Table D-11 shows that the average number of owners with available supply was 12 for the Brandon

Shores – Riverside line and the Graceton – Raphael Road line on peak. The average number of owners with available supply were 11 and 10 the Brandon Shores – Riverside line and the Graceton - Raphael Road line off peak.

Table D-10 Three pivotal supplier results summary for constraints located in the BGE Control Zone: Calendar year 2010

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
Brandon Shores - Riverside	Peak	2,901	744	26%	2,473	85%
	Off Peak	498	125	25%	418	84%
Graceton - Raphael Road	Peak	5,776	1,604	28%	5,029	87%
	Off Peak	3,650	1,142	31%	3,153	86%

Table D-11 Three pivotal supplier test details for constraints located in the BGE Control Zone: Calendar year 2010

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Brandon Shores - Riverside	Peak	53	316	12	3	9
	Off Peak	47	341	11	3	8
Graceton - Raphael Road	Peak	89	703	12	3	9
	Off Peak	93	644	10	3	8

Table D-12 shows the total tests applied for the two constraints in the BGE zone, the subset of three pivotal supplier tests that could have resulted in the offer capping of uncommitted units and the portion of those tests that did result in offer capping. Table D-12 shows that only a small fraction of the tests applied to the two constraints in the BGE zone could have resulted in offer capping. The two constraints in the BGE zone each had six percent or less of their tests that could have resulted in offer capping and each had two percent or less of their tests that resulted in offer capping.

Table D-12 Summary of three pivotal supplier tests applied to uncommitted units for constraints located in the BGE Control Zone: Calendar year 2010

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
Brandon Shores - Riverside	Peak	2,901	185	6%	69	2%	37%
	Off Peak	498	24	5%	2	0%	8%
Graceton - Raphael Road	Peak	5,776	96	2%	29	1%	30%
	Off Peak	3,650	93	3%	15	0%	16%

ComEd Control Zone Results

In 2010, there were six 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 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 constraints except for Wilton Center transformer during on-peak periods. 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 five out of six constraints. The average number of owners that passed is significant only for the Wilton Center transformer during on-peak periods.

Table D-13 Three pivotal supplier results summary for constraints located in the ComEd Control Zone: Calendar year 2010

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 - Sheffield	Peak	1,945	0	0%	1,945	100%
	Off Peak	3,625	2	0%	3,624	100%
East Frankfort - Crete	Peak	1,839	19	1%	1,829	99%
	Off Peak	11,080	195	2%	10,968	99%
Electric Jct - Nelson	Peak	1,622	3	0%	1,621	100%
	Off Peak	1,598	0	0%	1,598	100%
Pleasant Valley - Belvidere	Peak	1,784	0	0%	1,784	100%
	Off Peak	3,059	0	0%	3,059	100%
Waterman - West Dekalb	Peak	970	0	0%	970	100%
	Off Peak	1,293	0	0%	1,293	100%
Wilton Center	Peak	151	61	40%	100	66%
	Off Peak	1,162	96	8%	1,101	95%

Table D-14 Three pivotal supplier test details for constraints located in the ComEd Control Zone: Calendar year 2010

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Burnham - Sheffield	Peak	108	1,233	2	0	2
	Off Peak	108	812	2	0	2
East Frankfort - Crete	Peak	107	810	3	0	3
	Off Peak	90	681	3	0	3
Electric Jct - Nelson	Peak	38	43	2	0	2
	Off Peak	17	10	2	0	2
Pleasant Valley - Belvidere	Peak	10	4	1	0	1
	Off Peak	5	2	1	0	1
Waterman - West Dekalb	Peak	6	5	1	0	1
	Off Peak	7	17	1	0	1
Wilton Center	Peak	52	139	10	7	3
	Off Peak	111	258	6	1	5

Table D-15 shows the total tests applied for the six constraints in the ComEd zone, the subset of three pivotal supplier tests that could have resulted in the offer capping of uncommitted units and the portion of those tests that did result in offer capping. Table D-15 shows that only a small fraction of the tests applied to the six constraints in the ComEd zone could have resulted in offer capping. Three of the six constraints in the ComEd zone had no tests that could have resulted in offer capping. The other three constraints in the ComEd zone had seven percent or less of their tests that could have resulted in offer capping and each had one percent or less of their tests that resulted in offer capping.

Table D-15 Summary of three pivotal supplier tests applied to uncommitted units for constraints located in the ComEd Control Zone: Calendar year 2010

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 - Sheffield	Peak	1,945	0	0%	0	0%	0%
	Off Peak	3,625	0	0%	0	0%	0%
East Frankfort - Crete	Peak	1,839	11	1%	4	0%	36%
	Off Peak	11,080	16	0%	4	0%	25%
Electric Jct - Nelson	Peak	1,622	3	0%	1	0%	33%
	Off Peak	1,598	4	0%	0	0%	0%
Pleasant Valley - Belvidere	Peak	1,784	0	0%	0	0%	0%
	Off Peak	3,059	0	0%	0	0%	0%
Waterman - West Dekalb	Peak	970	0	0%	0	0%	0%
	Off Peak	1,293	0	0%	0	0%	0%
Wilton Center	Peak	151	10	7%	1	1%	10%
	Off Peak	1,162	9	1%	1	0%	11%

DLCO Control Zone Results

In 2010, there were two constraints 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 constraints 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 or two on peak and off peak for those two constraints.

Table D-16 Three pivotal supplier results summary for constraints located in the DLCO Control Zone: Calendar year 2010

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
Collier - Elwyn	Peak	1,412	0	0%	1,412	100%
	Off Peak	651	0	0%	651	100%
Crescent	Peak	3,704	0	0%	3,704	100%
	Off Peak	47	0	0%	47	100%

Table D-17 Three pivotal supplier test details for constraints located in the DLCO Control Zone: Calendar year 2010

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Collier - Elwyn	Peak	14	6	1	0	1
	Off Peak	17	14	1	0	1
Crescent	Peak	14	7	1	0	1
	Off Peak	10	11	2	0	2

Table D-18 shows the total tests applied for the two constraints in the DLCO zone, the subset of three pivotal supplier tests that could have resulted in the offer capping of uncommitted units and the portion of those tests that did result in offer capping. Table D-18 shows that only a small fraction of the tests applied to the two constraints in the DLCO zone could have resulted in offer capping. For the Collier – Elwyn constraint, only three of the 2,063 applied tests could have resulted in offer capping and two of those tests resulted in offer capping. For the Crescent constraint only 16 of the 3,751 applied tests could have resulted in offer capping and only 13 of those tests resulted in offer capping.

Table D-18 Summary of three pivotal supplier tests applied to uncommitted units for constraints located in the DLCO Control Zone: Calendar year 2010

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
Collier - Elwyn	Peak	1,412	2	0%	1	0%	50%
	Off Peak	651	1	0%	1	0%	100%
Crescent	Peak	3,704	16	0%	13	0%	81%
	Off Peak	47	0	0%	0	0%	0%

Dominion Control Zone Results

In 2010, 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 except for the Pleasant View transformer during on-peak periods. 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 four out of five constraints. The average number of owners that passed is significant only for the Pleasant View transformer during on-peak periods.

Table D-19 Three pivotal supplier results summary for constraints located in the Dominion Control Zone: Calendar year 2010

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
Beechwood - Kerr Dam	Peak	5,740	0	0%	5,740	100%
	Off Peak	1,444	0	0%	1,444	100%
Bremo - Kidds Store	Peak	1,376	0	0%	1,376	100%
	Off Peak	329	0	0%	329	100%
Clover	Peak	6,809	132	2%	6,753	99%
	Off Peak	1,030	4	0%	1,029	100%
Danville - East Danville	Peak	1,266	15	1%	1,262	100%
	Off Peak	2,275	6	0%	2,275	100%
Pleasant View	Peak	968	440	45%	605	63%
	Off Peak	662	5	1%	659	100%

Table D-20 Three pivotal supplier test details for constraints located in the Dominion Control Zone: Calendar year 2010

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Beechwood - Kerr Dam	Peak	9	36	1	0	1
	Off Peak	7	25	1	0	1
Bremo - Kidds Store	Peak	17	49	1	0	1
	Off Peak	11	47	1	0	1
Clover	Peak	83	249	4	0	3
	Off Peak	97	236	3	0	3
Danville - East Danville	Peak	44	46	3	0	3
	Off Peak	45	39	2	0	2
Pleasant View	Peak	62	125	14	9	5
	Off Peak	55	26	3	0	3

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 the offer capping of uncommitted units and the portion of those tests that did result in offer capping. Table D-21 shows that only a small fraction of the tests applied to the five constraints in the Dominion zone could have resulted in offer capping. Four of the five constraints in the Dominion zone had one percent or less of applied tests that could have resulted in offer capping. The remaining constraint, Pleasant View, had four percent or less of its applied peak period tests that could have resulted in offer capping.

Table D-21 Summary of three pivotal supplier tests applied to uncommitted units for constraints located in the Dominion Control Zone: Calendar year 2010

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
Beechwood - Kerr Dam	Peak	5,740	0	0%	0	0%	0%
	Off Peak	1,444	1	0%	0	0%	0%
Bremo - Kidds Store	Peak	1,376	0	0%	0	0%	0%
	Off Peak	329	0	0%	0	0%	0%
Clover	Peak	6,809	96	1%	25	0%	26%
	Off Peak	1,030	14	1%	1	0%	7%
Danville - East Danville	Peak	1,266	10	1%	0	0%	0%
	Off Peak	2,275	17	1%	1	0%	6%
Pleasant View	Peak	968	36	4%	7	1%	19%
	Off Peak	662	6	1%	3	0%	50%

DPL Control Zone Results

In 2010, there was only one constraint that occurred for more than 100 hours in the DPL Control Zone. Table D-22 and Table D-23 show the results of the three pivotal supplier tests applied to the constraints in the DPL 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 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. The average number of owners with available supply was one on peak and one off peak for this constraint.

Table D-22 Three pivotal supplier results summary for constraints located in the DPL Control Zone: Calendar year 2010

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
Kenney - Stockton	Peak	2,889	0	0%	2,889	100%
	Off Peak	418	0	0%	418	100%

Table D-23 Three pivotal supplier test details for constraints located in the DPL Control Zone: Calendar year 2010

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Kenney - Stockton	Peak	33	35	1	0	1
	Off Peak	12	12	1	0	1

Table D-24 shows the total tests applied for the one constraint in the DPL zone, the subset of three pivotal supplier tests that could have resulted in the offer capping of uncommitted units and the portion of those tests that did result in offer capping. Table D-24 shows that only a small fraction of the tests applied to the one constraint in the DPL zone could have resulted in offer capping. Only 14 out of 2,889 tests could have resulted in offer capping on peak and five of those tests resulted in offer capping. None of the tests applied in the off peak period could have resulted in offer capping.

Table D-24 Summary of three pivotal supplier tests applied to uncommitted units for constraints located in the DPL Control Zone: Calendar year 2010

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
Kenney - Stockton	Peak	2,889	14	0%	5	0%	36%
	Off Peak	418	0	0%	0	0%	0%

Met-Ed Control Zone Results

In 2010, there was only one constraint that occurred for more than 100 hours in the Met-Ed Control Zone. Table D-25 and Table D-26 show the result of the three pivotal supplier tests applied to the constraints in the Met-Ed 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.

Table D-25 Three pivotal supplier results summary for constraints located in the Met-Ed Control Zone: Calendar year 2010

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
Brunner Island - Yorkana	Peak	4,878	836	17%	4,499	92%
	Off Peak	1,378	20	1%	1,364	99%

Table D-26 Three pivotal supplier test details for constraints located in the Met-Ed Control Zone: Calendar year 2010

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Brunner Island - Yorkana	Peak	69	467	11	2	9
	Off Peak	68	417	6	0	6

Table D-27 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 the offer capping of uncommitted units and the portion of those tests that did result in offer capping. Table D-27 shows that only a small fraction of the tests applied to the one constraint in the Met-Ed zone could have resulted in offer capping. Only 94 out of 4,878 on peak tests could have resulted in offer capping. Only 36 out of 4,878 on peak tests resulted in offer capping. Only 19 out of 1,378 tests applied off peak could have resulted in offer capping. Only four of the off peak tests resulted in offer capping.

Table D-27 Summary of three pivotal supplier tests applied to uncommitted units for constraints located in the Met-Ed Control Zone: Calendar year 2010

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
Brunner Island - Yorkana	Peak	4,878	94	2%	36	1%	38%
	Off Peak	1,378	19	1%	4	0%	21%

PENELEC Control Zone Results

In 2010, there were two constraints that occurred for more than 100 hours in the PENELEC Control Zone. Table D-28 and Table D-29 show the results of the three pivotal supplier tests applied to the constraints in the PENELEC 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 all 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. The average number of owners with available supply was two for both constraints.

Table D-28 Three pivotal supplier results summary for constraints located in the PENELEC Control Zone: Calendar year 2010

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
Erie West	Peak	2,178	0	0%	2,178	100%
	Off Peak	1,814	0	0%	1,814	100%
Roxbury - Shade Gap	Peak	1,609	3	0%	1,608	100%
	Off Peak	1,278	0	0%	1,278	100%

Table D-29 Three pivotal supplier test details for constraints located in the PENELEC Control Zone: Calendar year 2010

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Erie West	Peak	34	13	2	0	2
	Off Peak	45	12	2	0	2
Roxbury - Shade Gap	Peak	12	13	2	0	2
	Off Peak	16	14	2	0	2

Table D-30 shows the total tests applied for the two constraints in the PENELEC zone, the subset of three pivotal supplier tests that could have resulted in the offer capping of uncommitted units and the portion of those tests that did result in offer capping. Table D-30 shows that only a small fraction of the tests applied to the two constraints in the PENELEC zone could have resulted in offer capping. For the Erie West constraint, only one out of 2,178 on peak tests could have and did result in offer capping. For the Roxbury – Shade Gap constraint, only six out of 1,609 on peak tests could have resulted in offer capping and only five of the tests did result in offer capping. None of the off peak tests for either constraint could have resulted in offer capping.

Table D-30 Summary of three pivotal supplier tests applied to uncommitted units for constraints located in the PENELEC Control Zone: Calendar year 2010

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
Erie West	Peak	2,178	1	0%	1	0%	100%
	Off Peak	1,814	0	0%	0	0%	0%
Roxbury - Shade Gap	Peak	1,609	6	0%	5	0%	83%
	Off Peak	1,278	0	0%	0	0%	0%

PPL Control Zone Results

In 2010, there was only one constraint that occurred for more than 100 hours in the PPL Control Zone. Table D-31 and Table D-32 how the results of the three pivotal supplier tests applied to the constraints in the PPL Control Zone. Table D-31 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-31 shows that most of tests resulted in one or more owners failing. Table D-32 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 six on peak and off peak for this constraint.

Table D-31 Three pivotal supplier results summary for constraints located in the PPL Control Zone: Calendar year 2010

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
Harwood - Siegfried	Peak	2,892	53	2%	2,873	99%
	Off Peak	2,054	6	0%	2,053	100%

Table D-32 Three pivotal supplier test details for constraints located in the PPL Control Zone: Calendar year 2010

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Harwood - Siegfried	Peak	86	532	6	0	6
	Off Peak	96	570	6	0	6

Table D-33 shows the total ests applied for the one constraint in the PPL zone, the subset of three pivotal supplier tests that could have resulted in the offer capping of uncommitted units and the portion of those tests that did result in offer capping. Table D-33 shows that only a small fraction of the tests applied to the one constraint in the PPL zone could have resulted in offer capping. Only nine out of 2,892 on peak tests could have resulted in offer capping. None of the on peak tests resulted in offer capping. Only six of the 2,054 off peak tests could have resulted in offer capping and only two of those tests did result in offer capping.

Table D-33 Summary of three pivotal supplier tests applied to uncommitted units for constraints located in the PPL Control Zone: Calendar year 2010

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
Harwood - Siegfried	Peak	2,892	9	0%	0	0%	0%
	Off Peak	2,054	6	0%	2	0%	33%

PSEG Control Zone Results

In 2010, there were two constraints that occurred for more than 100 hours in the PSEG Control Zone. Table D-34 and Table D-35 show the results of the three pivotal supplier tests applied to the constraints in the PSEG Control Zone. Table D-34 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-34 shows that all tests resulted in one or more owners failing. Table D-35 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-34 Three pivotal supplier results summary for constraints located in the PSEG Control Zone: Calendar year 2010

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
Athenia - Saddlebrook	Peak	2,233	2	0%	2,232	100%
	Off Peak	682	4	1%	681	100%
Branchburg - Readington	Peak	2,452	7	0%	2,449	100%
	Off Peak	922	0	0%	922	100%

Table D-35 Three pivotal supplier test details for constraints located in the PSEG Control Zone: Calendar year 2010

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Athenia - Saddlebrook	Peak	13	39	2	0	2
	Off Peak	29	66	2	0	2
Branchburg - Readington	Peak	39	65	3	0	3
	Off Peak	37	73	2	0	2

Table D-36 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 the offer capping of uncommitted units and the portion of those tests that did result in offer capping. Table D-36 shows that only a small fraction of the tests applied to the two constraints in the PSEG zone could have resulted in offer capping. The two constraints in the PSEG zone each had four percent or less of their tests that could have resulted in offer capping. The Athenia – Saddlebook constraint had only 107 of its 2,915 applied tests that could have result in offer capping. Only 77 of the 2,915 applied tests did result in offer capping. The Branchburg – Readington constraint had only 53 of its 3,374 applied tests that could have result in offer capping. Only 21 of the 3,374 applied tests did result in offer capping.

Table D-36 Summary of three pivotal supplier tests applied to uncommitted units for constraints located in the PSEG Control Zone: Calendar year 2010

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
Athenia - Saddlebrook	Peak	2,233	96	4%	70	3%	73%
	Off Peak	682	11	2%	7	1%	64%
Branchburg - Readington	Peak	2,452	39	2%	18	1%	46%
	Off Peak	922	14	2%	3	0%	21%

APPENDIX E - 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 Tag 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.

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).

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 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.

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

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 in the PJM footprint.

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 in the PJM footprint.

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

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 January 26, 2010) <http://www.nerc.com/files/IRO-006-4.pdf>.

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 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.

Table E-1 TLRs by level and reliability coordinator: Calendar years 2004 through 2010

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

Table E-1 continued next page

Year	Reliability Coordinator	3a	3b	4	5a	5b	6	Total
2006	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
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

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 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

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 4: Interchange Transactions* of this report.

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 January 26, 2010) <http://www.nyiso.com/public/webdocs/documents/manuals/operations/tran_ser_mnl.pdf> (463 KB).

are willing to pay. The required lead time means that participants make price and MW 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.

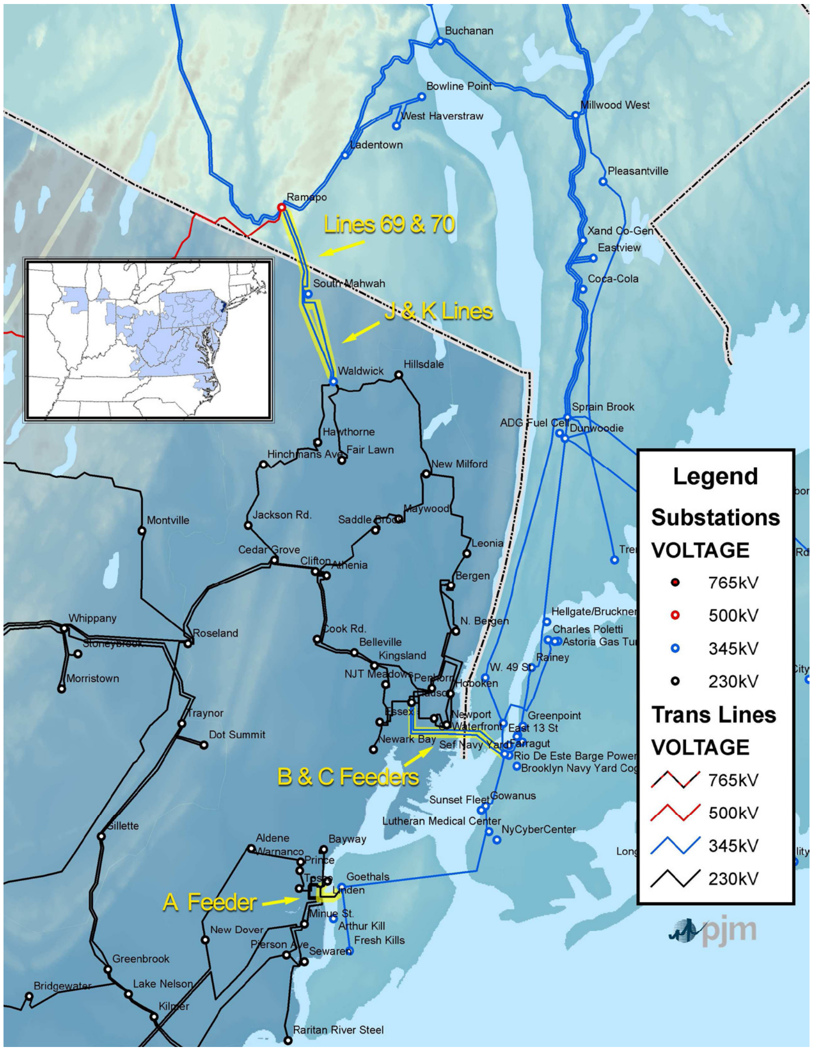
Consolidated Edison Company (Con Edison) and Public Service Electric and Gas Company (PSE&G) Wheeling Contracts

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.

8 See PJM. "Manual 41: Managing Interchange" (November 24, 2008) (Accessed January 26, 2010) <http://www.pjm.com/documents/~/media/documents/manuals/m41.ashx> (291 KB).
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

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.

Figure E-1 Con Edison and PSE&G wheel



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 2010, PSE&G's revenues were less than its congestion charges by $1,028,909 after adjustments ($5,417 in 2009.) 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 2010, Con Edison's congestion credits were $3,066,001 less than its day-ahead congestion charges (Credits had been $232,745 less than charges in 2009). Table E-2 shows the monthly details for both PSE&G and Con Edison.

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 -$178,749 in 2010. The parties should address this issue.

12 111 FERC ¶ 61,228 (2005).

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).

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 five percent of the hours in 2010.

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]

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 2010

		Con Edison			PSE&G		
		Day Ahead	Balancing	Total	Day Ahead	Balancing	Total
January	Congestion Charge	$480,875	($26,145)	$454,729	$721,312	$0	$721,312
	Congestion Credit			$481,563			$750,618
	Adjustments			$0			($831)
	Net Charge			($26,833)			($28,475)
February	Congestion Charge	$750,113	($301)	$749,813	$1,139,037	$0	$1,139,037
	Congestion Credit			$750,232			$1,141,484
	Adjustments			$0			$1,173
	Net Charge			($419)			($3,620)
March	Congestion Charge	$529,272	$0	$529,272	$803,998	$0	$803,998
	Congestion Credit			$101,432			$627,484
	Adjustments			$0			($1,313)
	Net Charge			$427,840			$177,827
April	Congestion Charge	$644,914	$5,079	$649,993	$1,321,568	$0	$1,321,568
	Congestion Credit			$74,000			$968,690
	Adjustments			$10,698			$2,426
	Net Charge			$565,295			$350,452
May	Congestion Charge	$224,672	$1,325	$225,996	$375,004	$0	$375,004
	Congestion Credit			$97,665			$372,773
	Adjustments			$888			$352,164
	Net Charge			$127,444			($349,933)
June	Congestion Charge	$174,627	($1,056)	$173,571	$293,644	$0	$293,644
	Congestion Credit			$64,239			$286,320
	Adjustments			$0			($1,060)
	Net Charge			$109,331			$8,385
July	Congestion Charge	$298,529	($15)	$298,514	$447,794	$0	$447,794
	Congestion Credit			$299,522			$450,663
	Adjustments			$4,473			$731
	Net Charge			($5,482)			($3,600)

Table E-2 continued next page

		Con Edison			PSE&G		
		Day Ahead	Balancing	Total	Day Ahead	Balancing	Total
August	Congestion Charge	$154,773	($524)	$154,249	$233,724	$0	$233,724
	Congestion Credit			$81,466			$222,829
	Adjustments			$0			($967)
	Net Charge			$72,783			$11,863
September	Congestion Charge	$463,799	($5,328)	$458,471	$695,698	$0	$695,698
	Congestion Credit			$92,515			$523,723
	Adjustments			$117			($935)
	Net Charge			$365,839			$172,910
October	Congestion Charge	$329,383	$2,975	$332,357	$494,074	$0	$494,074
	Congestion Credit			$34,078			$357,859
	Adjustments			$1,133			$132
	Net Charge			$297,146			$136,083
November	Congestion Charge	$247,756	$0	$247,756	$371,634	$0	$371,634
	Congestion Credit			$34,006			$237,347
	Adjustments			$67			($175)
	Net Charge			$213,684			$134,461
December	Congestion Charge	$1,067,775	$0	$1,067,775	$1,601,662	$0	$1,601,662
	Congestion Credit			$189,768			$1,179,190
	Adjustments			$675			($83)
	Net Charge			$877,332			$422,555
Total	Congestion Charge	$5,366,488	($23,991)	$5,342,497	$8,499,150	$0	$8,499,150
	Congestion Credit			$2,300,487			$7,118,980
	Adjustments			$18,050			$351,261
	Net Charge			$3,023,960			$1,028,909

APPENDIX F – 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 2010, PJM modified its regulation rules to establish a minimum 1 MW capability for generating and storage units in order to qualify for regulation. For demand response resources the minimum is 0.5 MW. PJM is currently studying significant modifications to the regulation market clearing procedure and regulation resource qualifying rules to promote new sources of regulation.

1 "Two additional terms may be included in ACE under certain conditions – time error bias and manual add (a PJM dispatcher term). These provide for automatic inadvertent interchange payback and error compensation, respectively." See PJM. "Manual 12: Balancing Operations," Revision 21 (October 1, 2010), para. 3.1.1, "System Control" p. 11.

2 Regulation Market business rules are defined in PJM. "Manual 11: Scheduling Operations," Revision 45 (June 23, 2010), pp. 54-62.

3 See "Manual 12: Balancing Operations," Revision 21 (October 1, 2010), Section 4.5, pg. 49.

Balancing Authority ACE Limit (BAAL)

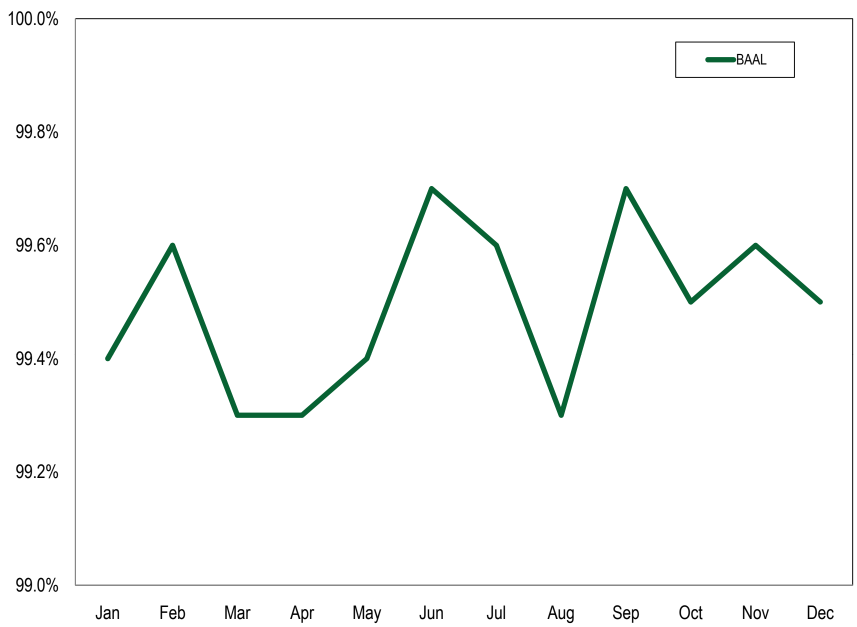
The purpose of the BAAL standard is to maintain interconnection frequency within a predefined frequency profile under all conditions (normal and abnormal), to prevent frequency-related instability, unplanned tripping of load or generation, or uncontrolled separation or cascading outages that adversely impact the reliability of the interconnection.

- **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), as a substitute for CPS2. PJM measures the total number of minutes the BAAL limit is exceeded (high or low) compared to the total number of minutes for a month, with a passing level for this goal being set at 99 percent for each month.

PJM's CPS/BAAL Performance

As Figure F-1 shows, PJM's performance for BAAL metrics was acceptable in calendar year 2010.

Figure F-1 PJM BAAL performance: Calendar year 2010



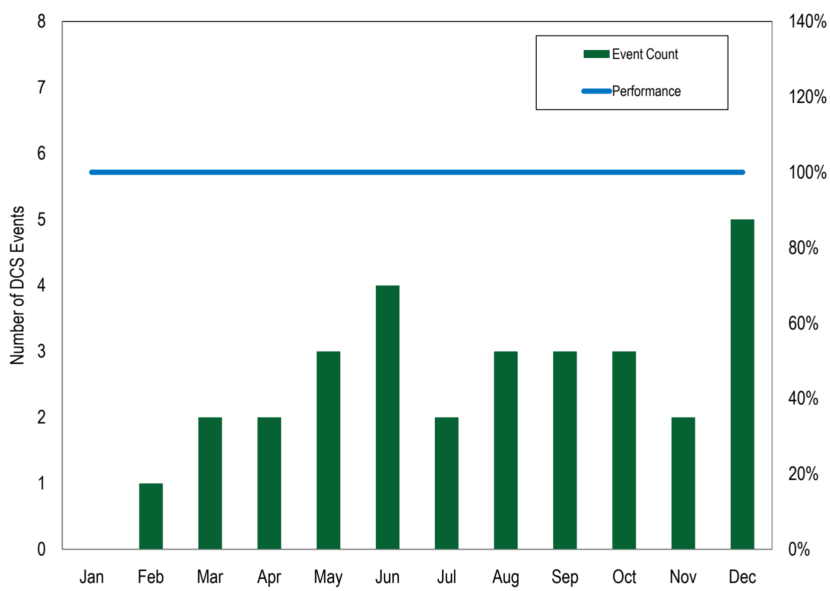
PJM dispatchers have to balance both ACE and frequency. Meeting the BAAL standard requires PJM dispatchers to maintain interconnection frequency within a predefined frequency profile under all conditions (normal and abnormal) to prevent frequency-related instability, unplanned tripping of load or generation, 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 800 MW. Compliance with the NERC DCS is recovery to zero or predisturbance level within 15 minutes.

PJM experienced 30 DCS events during calendar year 2010 and successfully recovered from all of them. All events were caused by the tripping of a major unit. Recovery times ranged from five minutes to 34 minutes. Figure F-2 illustrates the event count and performance by month. All of the events resulted in low ACE. The solution in all 30 events was to declare a spinning event.

Figure F-2 DCS event count and PJM performance (By month): Calendar year 2010



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 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

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).

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 were eligible to offer regulation although during 2010 none qualified to do so. 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.[5] 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 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.

5 See the *2010 State of the Market Report for PJM*, Volume II, Section 6, "Ancillary Services" for a full discussion of opportunity costs.

APPENDIX G – 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) deratings	A measure of the probability that a generating unit will not be available due to forced outages or forced 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) transmission	Designations used on a transmission reservation. The designations, when combined, determine the 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) Protocol	The 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 = T_d - (0.5 * (WIND -10) if WIND > 10 mph; WWP = T_d if WIND <= 10 mph (where T_d is the dry-bulb temperature and WIND is the wind speed.)
Zone	See “Control zone” (above).

APPENDIX H – LIST OF ACRONYMS

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
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
BRA	Base Residual Auction
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
CATR	Clean Air Transport Rule
CBL	Customer base line
CC	Combined cycle
CCM	Capacity Credit Market
CDR	Capacity deficiency rate
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
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
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
DLCO	Duquesne Light Company
DPL	Delmarva Power & Light Company
DPLN	Delmarva Peninsula north
DPLS	Delmarva Peninsula south
DR	Demand response
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
EKPC	East Kentucky Power Cooperative, Inc.
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
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
FTR	Financial Transmission Right
GACT	Generally Available Control Technology
GCA	Generation control area
GE	General Electric Company
GHG	Greenhouse Gas
GW	Gigawatt
GWh	Gigawatt-hour
HAP	Hazardous Air Pollutants
HHI	Herfindahl-Hirschman Index
HRSG	Heat recovery steam generator
HVDC	High-voltage direct current
Hz	Hertz
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
JCPL	Jersey Central Power & Light Company
JOA	Joint operating agreement
JOU	Jointly owned units
JRCA	Joint Reliability Coordination Agreement
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
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
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 Inc.	Midwest Independent Transmission System Operator,
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
NNL	Network and native load
NO_x	Nitrogen oxides
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
OMC	Outside Management Control
OVEC	Ohio Valley Electric Corporation
ORS	NERC Operating Reliability Subcommittee
PAR	Phase angle regulator
PE	PECO zone
PEC	Progress Energy Carolinas, Inc.

PECO	PECO Energy Company
PENELEC	Pennsylvania Electric Company
Pepco	Formerly Potomac Electric Power Company or PEPCO
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
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
PPL	PPL Electric Utilities Corporation
PSE&G	Public Service Electric and Gas Company (a wholly owned subsidiary of PSEG)
PSEG	Public Service Enterprise Group
PSN	PSEG north
PSNC	PSEG northcentral
RAA	Reliability Assurance Agreement among Load-Serving Entities
RCIS	Reliability Coordinator Information System
REC	Renewable Energy Credit
RECO	Rockland Electric Company zone
RFC	Reliability*First* Corporation
RGGI	Regional Greenhouse Gas Initiative
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	Southcentral Pennsylvania subarea
SCR	Selective catalytic reduction
SEPA	Southeast Power Administration
SEPJM	Southeastern PJM subarea
SERC	Southeastern Electric Reliability Council
SFT	Simultaneous feasibility test
SMECO	Southern Maryland Electric Cooperative
SMP	System marginal price
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
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
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
VOM	Variable operation and maintenance expense

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