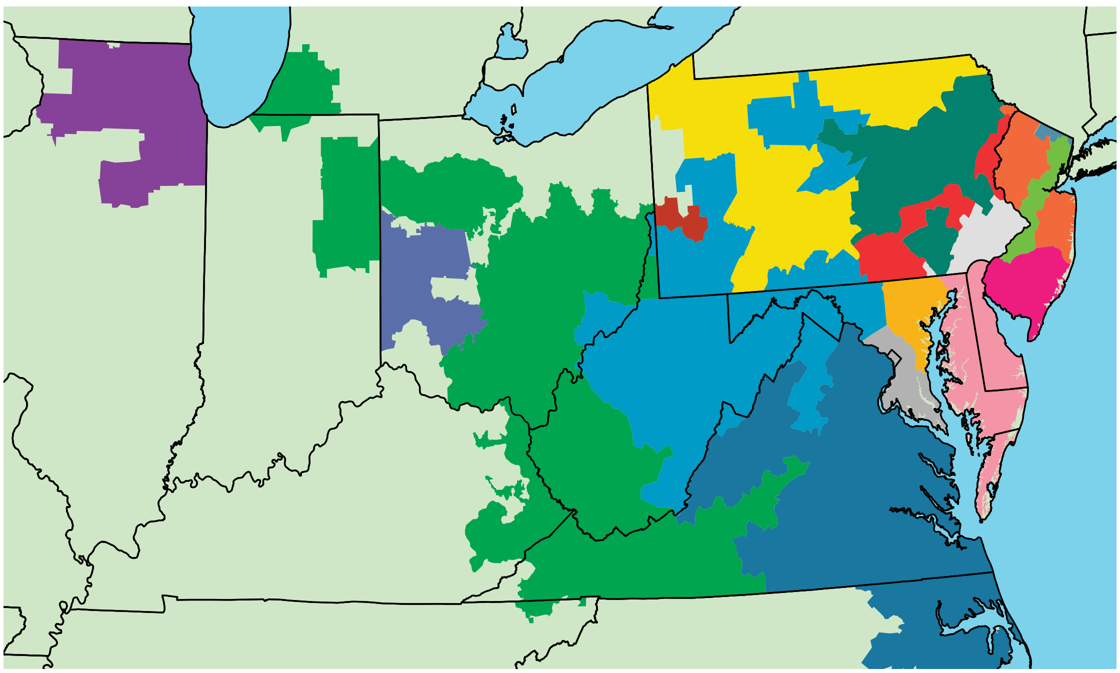
APPENDIX A – PJM GEOGRAPHY

During 2006, 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 zones



Legend

- Allegheny Power Company (AP)
- American Electric Power Co., Inc. (AEP)
- Atlantic Electric Company (AECO)
- Baltimore Gas and Electric Company (BGE)
- The Commonwealth Edison Company (ComEd)
- Dayton Power and Light Company (DAY)
- Delmarva Power and Light (DPL)
- Dominion
- Duquesne Light (DLCO)
- Jersey Central Power and Light Company (JCPL)
- Metropolitan Edison Company (Met-Ed)
- PECO Energy (PECO)
- PPL Electric Utilities (PPL)
- Pennsylvania Electric Company (PENELEC)
- Potomac Electric Power Company (PEPCO)
- Public Service Electric and Gas Company (PSEG)
- Rockland Electric Company (RECO)

Analysis of 2006 market results requires comparison to prior years. During calendar years 2004 and 2005, PJM integrated five new control zones. When making comparisons to 2004 and 2005, the 2006 State of the Market Report refers to three phases in calendar year 2004 and two phases in 2005 that correspond to those integrations.

During calendar years 2004 and 2005, PJM integrated five control zones. In the 2004 State of the Market Report the calendar year was divided into three phases, corresponding to market integration dates.[1] In the 2005 State of the Market Report the calendar year was divided into two phases, also corresponding to market integration dates:[2]

- **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,[3] and the Allegheny Power Company (AP) Control Zone.[4]

- **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 Commonwealth Edison Company Control Area (ComEd).[5]

- **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.

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

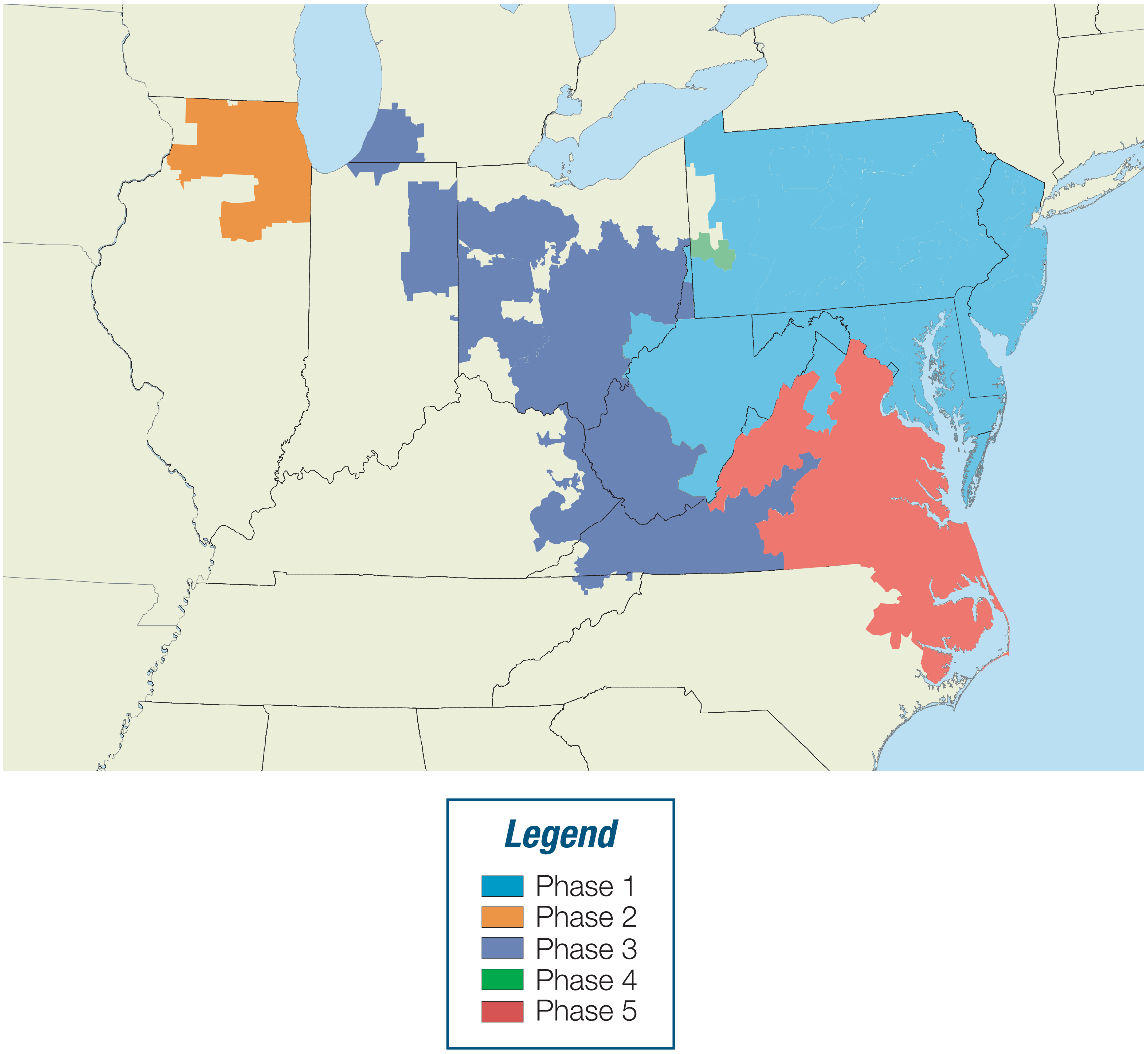
2 See the *2005 State of the Market Report* (March 8, 2006) for more detailed descriptions of Phases 4 and 5.

3 The Mid-Atlantic Region is comprised of the AECO, BGE, DPL, JCPL, Met-Ed, PECO, PENELEC, PEPCO, PPL, PSEG and RECO Control Zones.

4 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.

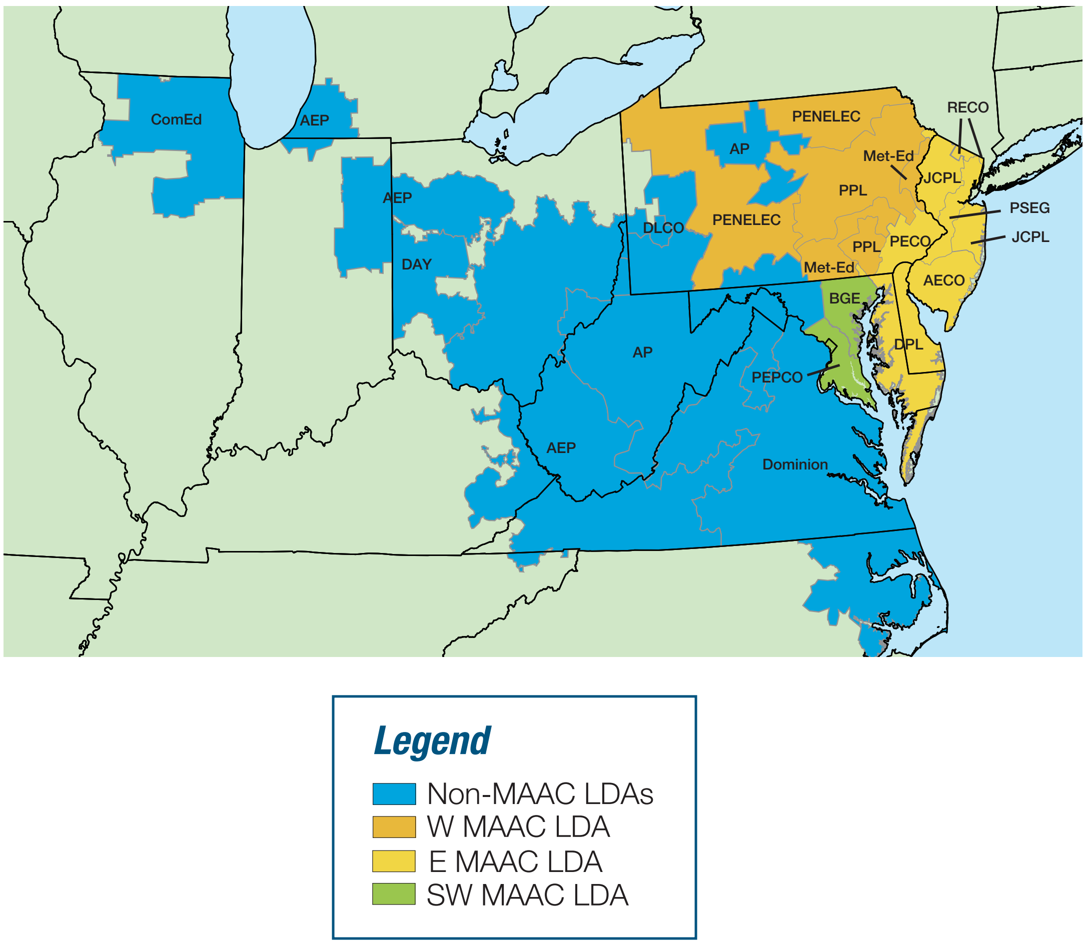
5 During the five-month period May 1, 2004, through September 30, 2004, the ComEd Control Zone (ComEd) was called the Northern Illinois Control Area (NICA).

Figure A-2 PJM integration phases



A locational deliverability area (LDA) is a geographic area within the PJM Control Area that has limited transmission capability to import capacity to satisfy such area's reliability requirements, as determined by PJM in connection with its preparation of the Regional Transmission Expansion Plan (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



6 See PJM Open Access Transmission Tariff (OATT), "Attachment DD: Definition 2.38" (Issued September 29, 2006, with an effective date of June 1, 2007).

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

APPENDIX C – ENERGY MARKET

Load

Frequency Distribution of Load

Table C-1 provides the frequency distributions of PJM load by hour, for the calendar years 2002 to 2006. The table shows the number of hours (frequency) and the cumulative percent of hours (cumulative percent) when the load was between 0 MW and 20,000 MW and then within a given 5,000-MW load interval, or for the cumulative column, within the interval plus all the lower load intervals. The integrations of the AP Control Zone during 2002, the ComEd, AEP and DAY Control Zones during 2004 and the DLCO and Dominion Control Zones during 2005 mean that annual comparisons of load frequency are significantly affected by PJM's geographic growth. [1]

For the year 2002, the most frequently occurring load interval was 30,000 MW to 35,000 MW at 26.5 percent of the hours, with the load interval 35,000 MW to 40,000 MW nearly as frequent at 25.1 percent of the hours. In 2003, the most frequently occurring load interval was 35,000 MW to 40,000 MW at 31.3 percent of the hours, while load was less than 35,000 MW for 36.3 percent of the hours.

The frequency distribution of load in 2004 reflects the integrations of the ComEd, AEP and DAY Control Zones. The most frequently occurring load interval was 35,000 MW to 40,000 MW at 15.8 percent of the hours. The next most frequently occurring interval was 40,000 MW to 45,000 MW at 14.9 percent of the hours. Load was less than 60,000 MW for 74.8 percent of the time, less than 70,000 MW for 92.8 percent of the time and less than 90,000 MW for all but nine hours.

The frequency distribution of load in 2005 reflects the phased integrations of the DLCO and Dominion Control Zones. The most frequently occurring load interval was 75,000 MW to 80,000 MW at 16.1 percent of the hours. The next most frequently occurring interval was 65,000 MW to 70,000 MW at 13.4 percent of the hours. Load was less than 85,000 MW for 72.9 percent of the time, less than 100,000 MW for 88.2 percent of the time and less than 130,000 MW for all but 22 hours.

For the year 2006, the most frequently occurring load interval was 75,000 MW to 80,000 MW at 17.1 percent of the hours. The next most frequently occurring interval was 80,000 MW to 85,000 MW at 15.3 percent of the hours. Load was less than 85,000 MW for 70.9 percent of the hours, less than 100,000 MW for 91.5 percent of the hours and less than 130,000 MW for all but 50 hours.

The peak demand for the year 2006 was 144,644 MW on August 2, 2006. It was 8.1 percent higher than the peak demand for the year 2005 of 133,763 MW on July 26, 2005. [2]

1 See *2006 State of the Market Report*, Volume II, Appendix A, "PJM Geography."

2 Peak-load data for 2006 are from PJM's eMTR data.

Table C-1 Frequency distribution of hourly PJM real-time load: Calendar years 2002 to 2006

	2002		2003		2004		2005		2006	
Load (1,000 MW)	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent
20 and Less	4	0.05%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
20 to 25	398	4.59%	100	1.14%	15	0.17%	0	0.00%	0	0.00%
25 to 30	1,749	24.55%	1,193	14.76%	280	3.36%	0	0.00%	0	0.00%
30 to 35	2,320	51.04%	1,887	36.30%	697	11.29%	0	0.00%	0	0.00%
35 to 40	2,199	76.14%	2,738	67.56%	1,387	27.08%	0	0.00%	0	0.00%
40 to 45	1,037	87.98%	1,666	86.58%	1,311	42.01%	0	0.00%	0	0.00%
45 to 50	508	93.78%	796	95.66%	1,150	55.10%	71	0.81%	2	0.02%
50 to 55	252	96.66%	284	98.90%	847	64.74%	286	4.08%	129	1.50%
55 to 60	198	98.92%	84	99.86%	885	74.82%	636	11.34%	504	7.25%
60 to 65	95	100.00%	12	100.00%	760	83.47%	843	20.96%	689	15.11%
65 to 70	0	100.00%	0	100.00%	821	92.82%	1,170	34.32%	967	26.15%
70 to 75	0	100.00%	0	100.00%	391	97.27%	1,089	46.75%	1,079	38.47%
75 to 80	0	100.00%	0	100.00%	157	99.06%	1,407	62.81%	1,501	55.61%
80 to 85	0	100.00%	0	100.00%	48	99.60%	887	72.93%	1,337	70.87%
85 to 90	0	100.00%	0	100.00%	26	99.90%	557	79.29%	943	81.63%
90 to 95	0	100.00%	0	100.00%	7	99.98%	453	84.46%	569	88.13%
95 to 100	0	100.00%	0	100.00%	2	100.00%	330	88.23%	295	91.50%
100 to 105	0	100.00%	0	100.00%	0	100.00%	308	91.75%	215	93.95%
105 to 110	0	100.00%	0	100.00%	0	100.00%	283	94.98%	161	95.79%
110 to 115	0	100.00%	0	100.00%	0	100.00%	169	96.91%	145	97.44%
115 to 120	0	100.00%	0	100.00%	0	100.00%	113	98.20%	102	98.61%
120 to 125	0	100.00%	0	100.00%	0	100.00%	93	99.26%	45	99.12%
125 to 130	0	100.00%	0	100.00%	0	100.00%	43	99.75%	27	99.43%
130 to 135	0	100.00%	0	100.00%	0	100.00%	22	100.00%	19	99.65%
135 to 140	0	100.00%	0	100.00%	0	100.00%	0	100.00%	19	99.86%
>140	0	100.00%	0	100.00%	0	100.00%	0	100.00%	12	100.00%

Off-Peak and On-Peak Load

Table C-2 presents summary load statistics for 1998 to 2006 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 about 23 percent higher than off-peak load in 2006. Average load during on-peak hours in 2006 was 1.3 percent higher than in 2005. Off-peak load in 2006 was 2.2 percent higher than in 2005. (See Table C-3.)

Table C-2 Off-peak and on-peak load (MW): Calendar years 1998 to 2006

	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	25,268	32,344	1.28	24,728	31,081	1.26	4,091	4,388	1.07
1999	26,453	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	31,817	40,362	1.27	30,654	38,378	1.25	6,060	7,419	1.22
2003	33,595	41,755	1.24	32,971	40,802	1.24	5,546	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

Table C-3 Multiyear change in load: Calendar years 1998 to 2006

	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%	(1.6%)	4.3%	2.8%	(1.6%)	20.9%	9.9%	(8.4%)
2000	1.8%	1.6%	0.0%	2.1%	2.5%	0.0%	(9.7%)	(13.3%)	(4.1%)
2001	(0.4%)	1.5%	1.6%	0.5%	1.0%	0.8%	(5.4%)	16.0%	22.3%
2002	18.7%	17.7%	(0.8%)	16.0%	16.0%	0.0%	43.4%	52.9%	6.1%
2003	5.6%	3.5%	(2.4%)	7.6%	6.3%	(0.8%)	(8.5%)	(26.9%)	(19.7%)
2004	32.9%	34.2%	1.6%	30.5%	38.7%	5.6%	95.5%	132.2%	18.4%
2005	57.5%	55.6%	(1.6%)	58.2%	45.8%	(7.6%)	17.4%	21.0%	3.4%
2006	2.2%	1.3%	(0.8%)	3.3%	3.2%	0.0%	(10.9%)	(16.9%)	(6.7%)

Locational Marginal Price (LMP)

In assessing changes in LMP over time, the PJM Market Monitoring Unit (MMU) examines three measures: nominal LMP, load-weighted LMP and fuel-cost-adjusted, load-weighted LMP. Nominal LMP measures the change in reported price. Load-weighted LMP measures the change in reported price weighted by the actual hourly MWh load to reflect what customers actually pay for energy. Fuel-cost-adjusted, load-weighted LMP measures the change in reported price actually paid by load after accounting for the change in price that reflects shifts in underlying fuel prices.

Real-Time LMP

Frequency Distribution of Real-Time LMP

Table C-4 provides frequency distributions of real-time LMP, by hour, for the calendar years 2002 to 2006. The table shows the number of hours (frequency) and the cumulative percent of hours (cumulative percent) when LMP was within a given price interval, or for the cumulative column, within the interval plus all the lower price intervals.

During the period 2002 to 2003, LMP was most frequently in the $10-per-MWh to $20-per-MWh interval. In 2004, however, LMP occurred in the $30-per-MWh to $40-per-MWh interval most frequently at 21.9 percent of the time and in the $20-per-MWh to $30-per-MWh interval nearly as frequently at 21.6 percent of the time. In 2005, LMP occurred in the $30-per-MWh to $40-per-MWh interval most frequently at 20.5 percent of the time and in the $20-per-MWh to $30-per-MWh interval at 14.7 percent of the time. In 2005, LMP was less than $60 per MWh for 63.2 percent of the hours and less than $100 per MWh for 87.4 percent of the hours. LMP was $200 per MWh or greater for 35 hours (0.4 percent of the hours) in 2005. In 2006, LMP was in the $20-per-MWh to $30-per-MWh interval most frequently (22.4 percent of the time) and in the $30-per-MWh to $40-per-MWh interval next most frequently (21.0 percent of the hours). In 2006, LMP was less than $60 per MWh for 75.1 percent of the hours and less than $100 per MWh for 94.7 percent of the hours. LMP was $200 per MWh or greater for 35 hours (0.4 percent of the hours) in 2006.

Table C-4 Frequency distribution by hours of PJM real-time energy market LMP (Dollars per MWh): Calendar years 2002 to 2006

	2002		2003		2004		2005		2006	
LMP	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent
$10 and Less	194	2.21%	241	2.75%	173	1.97%	142	1.62%	85	0.97%
$10 to $20	3,791	45.49%	2,083	26.53%	712	10.08%	259	4.58%	247	3.79%
$20 to $30	2,104	69.51%	1,957	48.87%	1,900	31.71%	1,290	19.30%	1,958	26.14%
$30 to $40	1,048	81.47%	1,102	61.45%	1,928	53.65%	1,793	39.77%	1,840	47.15%
$40 to $50	701	89.47%	1,043	73.36%	1,445	70.10%	1,172	53.15%	1,405	63.18%
$50 to $60	391	93.94%	812	82.63%	994	81.42%	877	63.16%	1,040	75.06%
$60 to $70	201	96.23%	532	88.70%	668	89.03%	730	71.50%	662	82.61%
$70 to $80	132	97.74%	380	93.04%	445	94.09%	568	77.98%	479	88.08%
$80 to $90	69	98.53%	255	95.95%	270	97.17%	453	83.15%	347	92.04%
$90 to $100	49	99.09%	152	97.68%	117	98.50%	374	87.42%	230	94.67%
$100 to $110	27	99.39%	75	98.54%	72	99.32%	297	90.81%	162	96.52%
$110 to $120	13	99.54%	52	99.13%	25	99.60%	208	93.18%	95	97.60%
$120 to $130	12	99.68%	28	99.45%	14	99.76%	159	95.00%	61	98.30%
$130 to $140	3	99.71%	23	99.71%	10	99.87%	110	96.26%	46	98.82%
$140 to $150	5	99.77%	14	99.87%	6	99.94%	94	97.33%	27	99.13%
$150 to $160	4	99.82%	5	99.93%	3	99.98%	53	97.93%	16	99.32%
$160 to $170	1	99.83%	1	99.94%	1	99.99%	57	98.58%	11	99.44%
$170 to $180	1	99.84%	1	99.95%	0	99.99%	51	99.17%	6	99.51%
$180 to $190	3	99.87%	2	99.98%	1	100.00%	22	99.42%	3	99.54%
$190 to $200	2	99.90%	1	99.99%	0	100.00%	16	99.60%	5	99.60%
$200 to $210	1	99.91%	0	99.99%	0	100.00%	12	99.74%	3	99.63%
$210 to $220	1	99.92%	1	100.00%	0	100.00%	10	99.85%	7	99.71%
$220 to $230	0	99.92%	0	100.00%	0	100.00%	5	99.91%	1	99.73%
$230 to $240	0	99.92%	0	100.00%	0	100.00%	1	99.92%	1	99.74%
$240 to $250	0	99.92%	0	100.00%	0	100.00%	1	99.93%	1	99.75%
$250 to $260	0	99.92%	0	100.00%	0	100.00%	3	99.97%	1	99.76%
$260 to $270	0	99.92%	0	100.00%	0	100.00%	2	99.99%	0	99.76%
$270 to $280	0	99.92%	0	100.00%	0	100.00%	0	99.99%	3	99.79%
$280 to $290	1	99.93%	0	100.00%	0	100.00%	1	100.00%	1	99.81%
$290 to $300	1	99.94%	0	100.00%	0	100.00%	0	100.00%	0	99.81%
$300 to $400	2	99.97%	0	100.00%	0	100.00%	0	100.00%	11	99.93%
$400 to $500	1	99.98%	0	100.00%	0	100.00%	0	100.00%	2	99.95%
$500 to $600	1	99.99%	0	100.00%	0	100.00%	0	100.00%	1	99.97%
$600 to $700	0	99.99%	0	100.00%	0	100.00%	0	100.00%	1	99.98%
> $700	1	100.00%	0	100.00%	0	100.00%	0	100.00%	2	100.00%

Off-Peak and On-Peak, Load-Weighted Real-Time LMP: 2005 to 2006

Table C-5 shows load-weighted, average LMP for 2005 and 2006 during off-peak and on-peak periods. In 2006, the on-peak, load-weighted LMP was 55 percent higher than the off-peak LMP, while in 2005, it was 64 percent greater. On-peak, load-weighted, average LMP in 2006 was 17.4 percent lower than in 2005. Off-peak, load-weighted LMP in 2006 was 12.9 percent lower than in 2005. The on-peak median LMP was lower in 2006 than in 2005 by 22.3 percent; off-peak median LMP was lower in 2006 than in 2005 by 9.4 percent. Dispersion in load-weighted LMP, as indicated by standard deviation, was 23.4 percent lower in 2006 than in 2005 during off-peak hours and was 17.1 percent higher during on-peak hours. Since the mean was above the median during on-peak and off-peak hours, both showed a positive skewness. The mean was, however, proportionately higher than the median in 2006 as compared to 2005 during both on-peak and off-peak periods (19.5 percent and 23.6 percent compared to 12.4 percent and 28.6 percent, respectively). The differences reflect larger positive skewness in the on-peak hours.

Table C-5 Off-peak and on-peak, load-weighted LMP (Dollars per MWh): Calendar years 2005 to 2006

	2005			2006			Difference 2005 to 2006		
	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	$47.69	$78.04	1.64	$41.53	$64.46	1.55	(12.9%)	(17.4%)	(5.5%)
Median	$37.07	$69.42	1.87	$33.59	$53.96	1.61	(9.4%)	(22.3%)	(13.9%)
Standard Deviation	$31.38	$37.95	1.21	$24.03	$44.45	1.85	(23.4%)	17.1%	52.9%

Off-Peak and On-Peak, Fuel-Cost-Adjusted, Load-Weighted Real-Time 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 from 80 percent to 90 percent of marginal cost, 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 will also increase.

The impact of fuel cost on LMP depends on the fuel burned by the marginal units. To account for differences in fuel cost between different time periods of interest, the fuel-cost-adjusted, load-weighted LMP is used to compare load-weighted LMPs on a common fuel-cost basis.

Table C-6 and Table C-7 show the load-weighted, average real-time LMP and the fuel-cost-adjusted, load-weighted, average real-time LMP for 2006 for on-peak and off-peak hours. During on-peak hours the fuel-cost-adjusted, load-weighted, real-time LMP in 2006 decreased by 7.3 percent over the load-weighted, real-time LMP in 2005. The fuel-cost-adjusted, load-weighted, real-time LMP in 2006 decreased by 3.4 percent in the off-peak hours compared to the load-weighted, real-time LMP in 2005.

Table C-6 On-peak PJM fuel-cost-adjusted, load-weighted LMP (Dollars per MWh): Year-over-year method

	2005	2006
Load-Weighted LMP	$78.04	$64.46
Fuel-Cost-Adjusted, Load-Weighted LMP	NA	$72.37
Year-over-Year Comparison	NA	(7.3%)

Table C-7 Off-peak PJM fuel-cost-adjusted, load-weighted LMP (Dollars per MWh): Year-over-year method

	2005	2006
Load-Weighted LMP	$47.69	$41.53
Fuel-Cost-Adjusted, Load-Weighted LMP	NA	$46.05
Year-over-Year Comparison	NA	(3.4%)

Load-Weighted, Real-Time LMP during Constrained Hours

Table C-8 shows that the load-weighted, average LMP during constrained hours was 12.9 percent lower in 2006 than it had been in 2005.[3] The median, load-weighted LMP during constrained hours was 13.0 percent lower in 2006 than in 2005 and the standard deviation was 3.6 percent higher in 2006 than in 2005.

Table C-8 Load-weighted, average LMP during constrained hours (Dollars per MWh): Calendar years 2005 to 2006

	2005	2006	Difference
Average	$66.18	$57.62	(12.9%)
Median	$55.56	$48.34	(13.0%)
Standard Deviation	$38.61	$40.01	3.6%

Table C-9 provides a comparison of load-weighted, average LMP during constrained and unconstrained hours for 2005 and 2006. In 2006, load-weighted, average LMP during constrained hours was 61.1 percent higher than load-weighted, average LMP during unconstrained hours. The comparable number for 2005 was 53.8 percent.

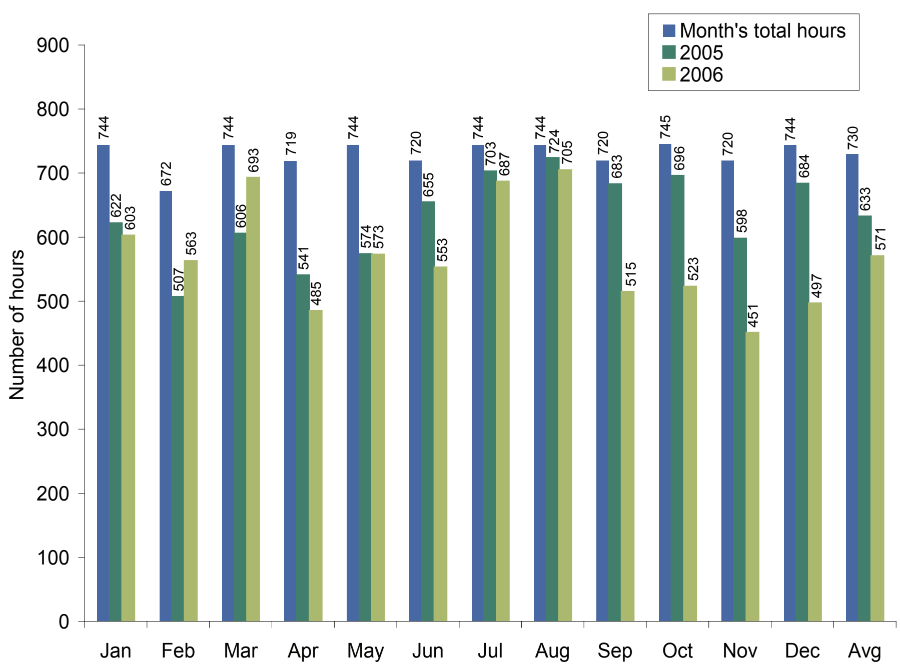
3 A constrained hour, or a constraint hour, is any hour during which one or more facilities are congested. In the *2006 State of the Market Report*, in order to have a consistent metric for real-time and day-ahead congestion frequency, real-time congestion frequency is measured using the convention that an hour is constrained if any of its component five-minute intervals is constrained. This is also consistent with the way in which PJM reports real-time congestion. In the *2005 State of the Market Report*, an hour was considered constrained if one or more facilities were constrained for four or more of the 12 five-minute intervals in that hour. In the *2004 State of the Market Report*, this appendix defined a congested hour as one in which the difference in LMP between at least two buses in that hour was greater than $1.00.

Table C-9 Load-weighted, average LMP during constrained and unconstrained hours (Dollars per MWh): Calendar years 2005 to 2006

	2005			2006		
	Unconstrained Hours	Constrained Hours	Difference	Unconstrained Hours	Constrained Hours	Difference
Average	$43.03	$66.18	53.8%	$35.76	$57.62	61.1%
Median	$36.30	$55.56	53.1%	$29.67	$48.34	62.9%
Standard Deviation	$26.13	$38.61	47.8%	$18.43	$40.01	117.1%

Figure C-1 shows the number of hours and the number of constrained hours during each month in 2005 and 2006. There were 7,593 constrained hours in 2005 and 6,848 in 2006, a decrease of approximately 9.8 percent. Figure C-1 also shows that the average number of constrained hours per month was slightly higher in 2005 than in 2006, with 633 per month in 2005 versus 571 per month in 2006.

Figure C-1 PJM real-time constrained hours: Calendar years 2005 to 2006



Day-Ahead and Real-Time LMP

On average, prices in the Real-Time Energy Market in 2006 were slightly higher than those in the Day-Ahead Energy Market and real-time prices showed greater dispersion. This pattern of average, system LMP distribution for 2006 can be seen in Table C-4 and Table C-10. Together they show the frequency distribution by hours for the two markets. In PJM's Real-Time Energy Market, the most frequently occurring price interval was the $20-per-MWh to $30-per-MWh interval with 22.4 percent of the hours in 2006. (See Table

C-4.) The most frequently occurring price interval in the PJM Day-Ahead Energy Market was the $40-per-MWh to $50-per-MWh interval with 21.6 percent of the hours in 2006. (See Table C-10.) In the Real-Time Energy Market, prices were above $200 per MWh for 35 hours (0.4 percent of the hours), reaching a high for the year of $763.80 per MWh on August 1, 2006, during the hour ending 1800 EPT. In the Day-Ahead Energy Market, prices were above $200 per MWh for 25 hours (0.3 percent of the hours) and reached a high for the year of $333.91 per MWh on August 3, 2006, during the hour ending 1700 EPT.

Table C-10 Frequency distribution by hours of PJM day-ahead LMP (Dollars per MWh): Calendar year 2002 to 2006

	2002		2003		2004		2005		2006	
LMP	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent
$10 and Less	128	1.46%	131	1.50%	59	0.67%	47	0.54%	11	0.13%
$10 to $20	3,177	37.73%	1,530	18.96%	715	8.81%	162	2.39%	147	1.80%
$20 to $30	2,564	67.00%	1,846	40.03%	1,684	27.98%	1,022	14.05%	1,610	20.18%
$30 to $40	1,470	83.78%	1,635	58.70%	1,848	49.02%	1,753	34.06%	1,747	40.13%
$40 to $50	690	91.66%	1,384	74.50%	1,946	71.17%	1,382	49.84%	1,890	61.70%
$50 to $60	329	95.41%	1,004	85.96%	1,357	86.62%	1,102	62.42%	1,364	77.27%
$60 to $70	146	97.08%	554	92.28%	728	94.91%	812	71.69%	905	87.60%
$70 to $80	92	98.13%	318	95.91%	278	98.08%	686	79.52%	524	93.58%
$80 to $90	50	98.70%	157	97.71%	110	99.33%	524	85.50%	237	96.29%
$90 to $100	29	99.03%	95	98.79%	42	99.81%	388	89.93%	145	97.95%
$100 to $110	24	99.30%	41	99.26%	11	99.93%	263	92.93%	65	98.69%
$110 to $120	16	99.49%	21	99.50%	4	99.98%	207	95.30%	38	99.12%
$120 to $130	7	99.57%	22	99.75%	2	100.00%	151	97.02%	11	99.25%
$130 to $140	11	99.69%	7	99.83%	0	100.00%	102	98.18%	8	99.34%
$140 to $150	7	99.77%	5	99.89%	0	100.00%	64	98.92%	8	99.43%
$150 to $160	8	99.86%	10	100.00%	0	100.00%	46	99.44%	7	99.51%
$160 to $170	1	99.87%	0	100.00%	0	100.00%	27	99.75%	6	99.58%
$170 to $180	2	99.90%	0	100.00%	0	100.00%	11	99.87%	6	99.65%
$180 to $190	4	99.94%	0	100.00%	0	100.00%	8	99.97%	3	99.68%
$190 to $200	0	99.94%	0	100.00%	0	100.00%	1	99.98%	3	99.71%
$200 to $210	4	99.99%	0	100.00%	0	100.00%	2	100.00%	3	99.75%
$210 to $220	1	100.00%	0	100.00%	0	100.00%	0	100.00%	3	99.78%
$220 to $230	0	100.00%	0	100.00%	0	100.00%	0	100.00%	1	99.79%
$230 to $240	0	100.00%	0	100.00%	0	100.00%	0	100.00%	3	99.83%
$240 to $250	0	100.00%	0	100.00%	0	100.00%	0	100.00%	2	99.85%
$250 to $260	0	100.00%	0	100.00%	0	100.00%	0	100.00%	1	99.86%
$260 to $270	0	100.00%	0	100.00%	0	100.00%	0	100.00%	2	99.89%
$270 to $280	0	100.00%	0	100.00%	0	100.00%	0	100.00%	1	99.90%
$280 to $290	0	100.00%	0	100.00%	0	100.00%	0	100.00%	1	99.91%
$290 to $300	0	100.00%	0	100.00%	0	100.00%	0	100.00%	1	99.92%
> $300	0	100.00%	0	100.00%	0	100.00%	0	100.00%	7	100.00%

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

Table C-11 shows average LMP during off-peak and on-peak periods for the Day-Ahead and Real-Time Energy Market during calendar year 2006. Day-ahead and real-time, on-peak average LMPs were 54 percent and 56 percent higher, respectively, than the corresponding off-peak average LMP. Since the mean was above the median in these markets, both showed a positive skewness. The mean was, however, proportionately higher than the median in the Real-Time Energy Market as compared to the Day-Ahead Energy Market during both on-peak and off-peak periods (17 percent and 23 percent compared to 9 percent and 12 percent, respectively). The differences reflect larger positive skewness in the Real-Time Energy Market.

Figure C-2 and Figure C-3 show the difference between real-time and day-ahead LMP during calendar year 2006 during the on-peak and off-peak hours, respectively. The difference between real-time and day-ahead average LMP during on-peak hours was $1.76 per MWh. (Day-ahead LMP was lower than real-time LMP.) During the off-peak hours, the difference between real-time and day-ahead average LMP was $0.67 per MWh. (Day-ahead LMP was lower than real-time LMP.)

Table C-11 Off-peak and on-peak hourly LMP (Dollars per MWh): Calendar year 2006

	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	$38.45	$59.25	1.54	$39.12	$61.01	1.56	1.7%	3.0%	1.3%
Median	$34.40	$54.41	1.58	$31.84	$52.28	1.64	(7.4%)	(3.9%)	3.8%
Standard Deviation	$16.06	$25.54	1.59	$22.58	$38.21	1.69	40.6%	49.6%	6.3%

Figure C-2 Hourly real-time LMP minus day-ahead LMP (On-peak hours): Calendar year 2006

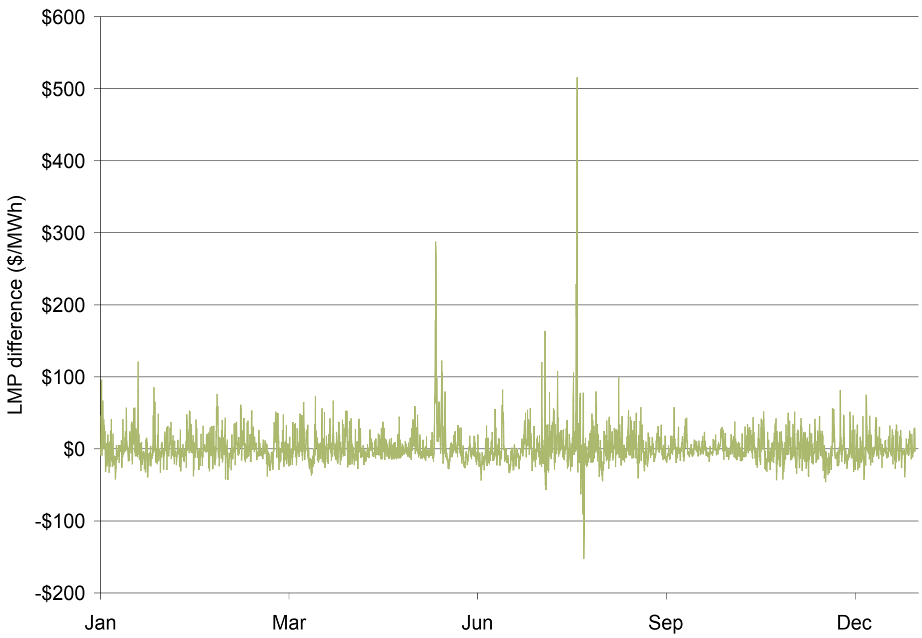
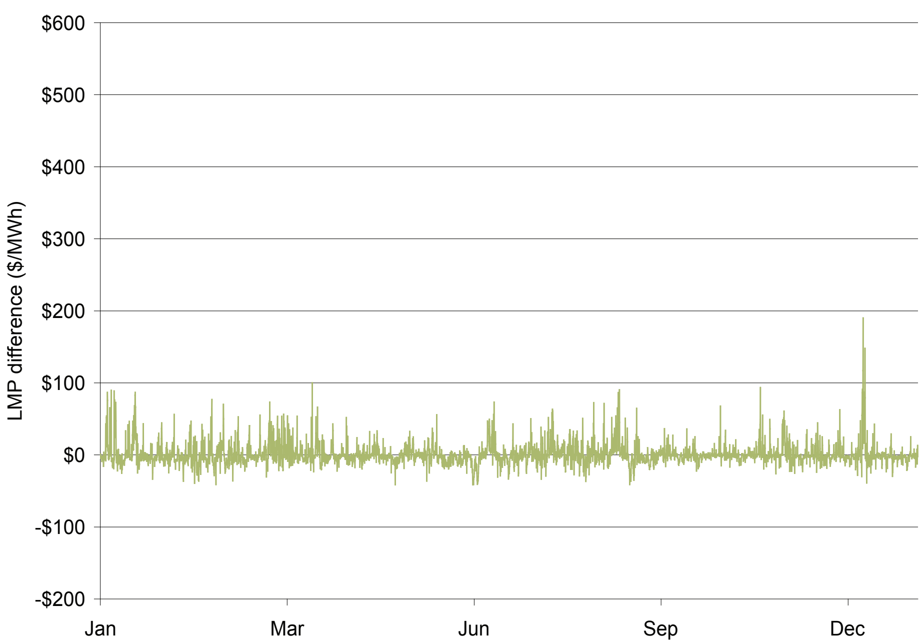


Figure C-3 Hourly real-time LMP minus day-ahead LMP (Off-peak hours): Calendar year 2006



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

Table C-12 and Table C-13 show the average on-peak and off-peak LMP for each zone in the Day-Ahead and Real-Time Energy Market during calendar year 2006. The zone with the maximum difference between real-time and day-ahead on-peak LMP was the PEPCO Control Zone with an on-peak, day-ahead zonal LMP $2.53 lower than its on-peak, real-time zonal LMP. DPL Control Zone had the smallest difference with its on-peak, real-time zonal LMP $0.10 lower than its on-peak, day-ahead zonal LMP. (See Table C-12.) The PEPCO and Dominion Control Zones had the largest difference between real-time and day-ahead off-peak zonal LMP, with day-ahead LMP $1.68 lower than real-time LMP. The zone with the smallest difference between real-time and day-ahead off-peak zonal LMP was DAY Control Zone with day-ahead LMP $0.10 lower than real-time LMP. (See Table C-13.)

Table C-12 Zonal on-peak hourly LMP (Dollars per MWh): Calendar year 2006

	Day Ahead	Real Time	Difference	Difference as Percent Real Time
AECO	$68.16	$69.42	($1.26)	(1.82%)
AEP	$51.91	$53.55	($1.64)	(3.06%)
AP	$58.32	$60.06	($1.74)	(2.90%)
BGE	$67.26	$69.58	($2.32)	(3.33%)
ComEd	$51.73	$53.17	($1.44)	(2.71%)
DAY	$50.85	$52.64	($1.79)	(3.40%)
DLCO	$48.72	$50.86	($2.14)	(4.21%)
Dominion	$64.95	$67.00	($2.05)	(3.06%)
DPL	$65.31	$65.21	$0.10	0.15%
JCPL	$63.44	$64.30	($0.86)	(1.34%)
Met-Ed	$65.31	$64.92	$0.39	0.60%
PECO	$64.60	$64.10	$0.50	0.78%
PENELEC	$56.77	$57.83	($1.06)	(1.83%)
PEPCO	$68.59	$71.12	($2.53)	(3.56%)
PPL	$63.54	$63.34	$0.20	0.32%
PSEG	$66.33	$68.09	($1.76)	(2.58%)
RECO	$66.14	$67.19	($1.05)	(1.56%)

Table C-13 Zonal off-peak hourly LMP (Dollars per MWh): Calendar year 2006

	Day Ahead	Real Time	Difference	Difference as Percent Real Time
AECO	$42.83	$43.51	($0.68)	(1.56%)
AEP	$32.29	$32.46	($0.17)	(0.52%)
AP	$37.82	$38.88	($1.06)	(2.73%)
BGE	$45.35	$46.87	($1.52)	(3.24%)
ComEd	$31.80	$31.43	$0.37	1.18%
DAY	$31.22	$31.32	($0.10)	(0.32%)
DLCO	$30.52	$29.37	$1.15	3.92%
Dominion	$45.62	$47.30	($1.68)	(3.55%)
DPL	$42.32	$42.61	($0.29)	(0.68%)
JCPL	$40.67	$40.97	($0.30)	(0.73%)
Met-Ed	$41.67	$42.05	($0.38)	(0.90%)
PECO	$41.96	$42.28	($0.32)	(0.76%)
PENELEC	$36.84	$36.95	($0.11)	(0.30%)
PEPCO	$46.55	$48.23	($1.68)	(3.48%)
PPL	$41.05	$41.29	($0.24)	(0.58%)
PSEG	$42.74	$42.88	($0.14)	(0.33%)
RECO	$42.81	$42.36	$0.45	1.06%

Day-Ahead and Real-Time LMP during Constrained Hours

Figure C-4 shows the number of constrained hours in each month for the Day-Ahead and Real-Time Energy Market, the total number of hours and the total number of constrained hours in each month for 2006. Overall, there were 6,848 constrained hours in the Real-Time Energy Market and 8,626 constrained hours in the Day-Ahead Energy Market. Figure C-4 shows that in every month of calendar year 2006 the number of constrained hours in the Day-Ahead Energy Market exceeded those in the Real-Time Energy Market. Over the year, the Day-Ahead Energy Market had 26.0 percent more constrained hours than the Real-Time Energy Market.

Figure C-4 Day-ahead and real-time, market-constrained hours: Calendar year 2006

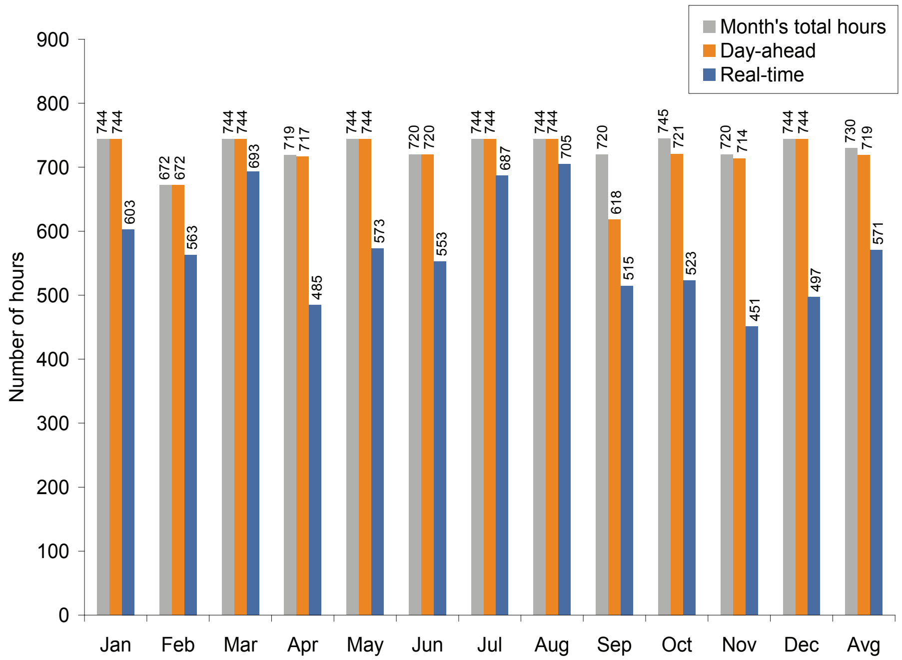


Table C-14 shows average LMP during constrained and unconstrained hours in the Day-Ahead and Real-Time Energy Market. In the Day-Ahead Energy Market, average LMP during constrained hours was 52.5 percent higher than average LMP during unconstrained hours. In the Real-Time Energy Market, average LMP during constrained hours was 57.1 percent higher than average LMP during unconstrained hours. Average LMP during constrained hours was 10.7 percent higher in the Real-Time Energy Market than in the Day-Ahead Energy Market and LMP during unconstrained hours was 7.4 percent higher in the Real-Time Market than in the Day-Ahead Market.

Table C-14 LMP during constrained and unconstrained hours (Dollars per MWh): Calendar year 2006

	Day Ahead			Real Time		
	Unconstrained Hours	Constrained Hours	Difference	Unconstrained Hours	Constrained Hours	Difference
Average	$31.70	$48.35	52.5%	$34.06	$53.52	57.1%
Median	$30.84	$44.50	44.3%	$27.99	$45.41	62.2%
Standard Deviation	$9.59	$23.48	144.8%	$17.81	$34.60	94.3%

Taken together, the data show that average LMP in the Day-Ahead Energy Market during constrained hours was 0.5 percent higher than the overall average LMP for the Day-Ahead Energy Market, while average LMP during unconstrained hours was 34.1 percent lower.[4] In the Real-Time Energy Market, average LMP during constrained hours was 8.6 percent higher than the overall average LMP for the Real-Time Energy Market, while average LMP during unconstrained hours was 30.9 percent lower.

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 Market.

PJM has clear rules limiting the exercise of local market power.[5] 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. The offer-capping rules exempt certain units from offer capping based on the date of their construction. Such exempt units can and do exercise market power, at times, that would not be permitted if the units were not exempt.

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. 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.

4 See *2006 State of the Market Report*, Volume II, Section 2, "Energy Market, Part 1" for a discussion of load and LMP.

5 See PJM Amended and Restated Operating Agreement (OA), Schedule 1, Section 6.4.2 (January 19, 2007).

Levels of offer capping have generally been low and stable over the last five years. Table C-15 through Table C-18 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 Market. [6]

Table C-15 Average day-ahead, offer-capped units: Calendar years 2002 to 2006

	2002		2003		2004		2005		2006	
	Avg. Units Capped	Percent	Avg. Units Capped	Percent	Avg. Units Capped	Percent	Avg. Units Capped	Percent	Avg. Units Capped	Percent
Jan	0.6	0.1%	0.5	0.1%	0.4	0.1%	0.4	0.0%	0.1	0.0%
Feb	0.4	0.1%	0.7	0.1%	0.2	0.0%	0.4	0.0%	0.2	0.0%
Mar	0.1	0.0%	0.1	0.0%	0.2	0.0%	0.6	0.1%	0.7	0.1%
Apr	0.7	0.1%	0.6	0.1%	0.3	0.0%	0.4	0.0%	0.2	0.0%
May	0.2	0.0%	0.3	0.0%	0.6	0.1%	0.2	0.0%	0.1	0.0%
Jun	1.4	0.3%	0.7	0.1%	1.1	0.2%	0.4	0.0%	0.7	0.1%
Jul	1.9	0.4%	1.4	0.3%	2.6	0.4%	0.9	0.1%	4.1	0.4%
Aug	4.5	0.8%	2.1	0.4%	3.0	0.4%	1.1	0.1%	4.7	0.5%
Sep	1.9	0.4%	1.1	0.2%	3.1	0.4%	0.2	0.0%	0.6	0.1%
Oct	0.4	0.1%	0.9	0.2%	0.6	0.1%	0.3	0.0%	0.3	0.0%
Nov	0.6	0.1%	0.2	0.0%	0.5	0.1%	0.2	0.0%	0.3	0.0%
Dec	0.8	0.1%	0.1	0.0%	0.5	0.1%	0.7	0.1%	0.7	0.0%

Table C-16 Average day-ahead, offer-capped MW: Calendar years 2002 to 2006

	2002		2003		2004		2005		2006	
	Avg. MW Capped	Percent	Avg. MW Capped	Percent	Avg. MW Capped	Percent	Avg. MW Capped	Percent	Avg. MW Capped	Percent
Jan	40	0.1%	37	0.1%	51	0.1%	87	0.1%	4	0.0%
Feb	30	0.1%	27	0.1%	68	0.1%	75	0.1%	6	0.0%
Mar	6	0.0%	4	0.0%	48	0.1%	58	0.1%	51	0.1%
Apr	48	0.1%	38	0.1%	41	0.1%	34	0.0%	31	0.0%
May	14	0.0%	52	0.1%	52	0.1%	14	0.0%	22	0.0%
Jun	48	0.1%	69	0.2%	49	0.1%	28	0.0%	164	0.0%
Jul	77	0.1%	132	0.3%	243	0.4%	52	0.0%	518	0.5%
Aug	106	0.2%	148	0.3%	348	0.5%	63	0.1%	398	0.4%
Sep	78	0.2%	139	0.3%	221	0.4%	13	0.0%	51	0.1%
Oct	57	0.1%	100	0.2%	34	0.0%	16	0.0%	27	0.0%
Nov	30	0.1%	21	0.1%	28	0.0%	26	0.0%	15	0.0%
Dec	25	0.1%	25	0.1%	35	0.0%	48	0.0%	40	0.0%

6 Data quality improvements have caused values in these tables to vary slightly from previously published results.

Table C-17 Average real-time, offer-capped units: Calendar years 2002 to 2006

	2002		2003		2004		2005		2006	
	Avg. Units Capped	Percent	Avg. Units Capped	Percent	Avg. Units Capped	Percent	Avg. Units Capped	Percent	Avg. Units Capped	Percent
Jan	1.6	0.3%	1.5	0.3%	2.7	0.4%	2.5	0.3%	1.9	0.2%
Feb	0.8	0.2%	1.5	0.3%	0.7	0.1%	1.3	0.1%	2.1	0.2%
Mar	0.4	0.1%	0.5	0.1%	0.8	0.1%	1.4	0.2%	2.3	0.2%
Apr	1.0	0.2%	0.8	0.1%	1.8	0.3%	1.2	0.1%	1.5	0.2%
May	1.2	0.2%	1.6	0.3%	5.9	0.8%	0.8	0.1%	3.4	0.3%
Jun	3.1	0.6%	2.9	0.5%	3.9	0.5%	10.0	1.0%	2.5	0.3%
Jul	8.6	1.6%	3.3	0.6%	4.7	0.7%	13.9	1.4%	8.6	0.9%
Aug	9.7	1.8%	6.3	1.1%	6.3	0.9%	13.7	1.4%	9.5	1.0%
Sep	4.1	0.8%	3.7	0.7%	4.2	0.6%	7.9	0.8%	1.8	0.2%
Oct	1.4	0.3%	1.8	0.3%	1.1	0.1%	7.9	0.8%	1.7	0.2%
Nov	1.2	0.2%	1.0	0.2%	1.1	0.1%	3.3	0.3%	1.1	0.1%
Dec	1.5	0.3%	0.8	0.1%	3.3	0.4%	4.4	0.4%	1.0	0.0%

Table C-18 Average real-time, offer-capped MW: Calendar years 2002 to 2006

	2002		2003		2004		2005		2006	
	Avg. MW Capped	Percent	Avg. MW Capped	Percent	Avg. MW Capped	Percent	Avg. MW Capped	Percent	Avg. MW Capped	Percent
Jan	89.5	0.3%	86.8	0.2%	175.0	0.4%	208.9	0.3%	42.1	0.1%
Feb	45.9	0.2%	74.2	0.2%	86.8	0.2%	144.9	0.2%	67.1	0.1%
Mar	24.1	0.1%	44.0	0.1%	76.2	0.2%	74.2	0.1%	87.6	0.1%
Apr	62.0	0.2%	28.8	0.1%	115.2	0.3%	58.8	0.1%	75.3	0.1%
May	63.0	0.2%	101.2	0.3%	257.1	0.5%	77.9	0.1%	135.6	0.2%
Jun	104.7	0.3%	110.0	0.3%	166.8	0.3%	652.1	0.7%	160.1	0.2%
Jul	218.1	0.6%	251.6	0.6%	331.9	0.6%	818.8	0.9%	505.8	0.5%
Aug	311.2	0.7%	293.9	0.7%	450.4	0.8%	908.4	1.0%	517.8	0.6%
Sep	176.8	0.5%	240.8	0.7%	268.5	0.5%	476.9	0.6%	68.7	0.1%
Oct	92.0	0.3%	96.0	0.3%	77.2	0.1%	337.5	0.5%	49.4	0.1%
Nov	55.3	0.2%	53.5	0.2%	110.4	0.2%	129.4	0.2%	30.5	0.0%
Dec	51.6	0.1%	44.0	0.1%	202.0	0.3%	155.5	0.2%	11.5	0.0%

In order to help understand the frequency of offer capping in more detail, Table C-19 through Table C-22 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 year indicated. For example, in 2005 19 units were offer capped for more than 80 percent of their run hours and had at least 500 offer-capped run hours. The count of units in each category includes units that also met more restrictive criteria. In this example, the 19 units that were offer capped during more than 80 percent of their run hours and had a total of at least 500 offer-capped run hours are also included in the 80 percent row for the 400 offer-capped, run-hour column as well as the 300 offer-capped, run-hour column and the one offer-capped, run-hour column. The one offer-capped, run-hour column shows the total number of units meeting each percentage threshold with any offer-capped hours for the year. Similarly in this example, the four units that were offer capped more than 80 percent of their run hours are also included in each of the subsequent rows corresponding to a specific column, as they were also offer capped during more than 75 percent, 60 percent, 50 percent, 25 percent and 10 percent of their run hours.

Table C-19 Offer-capped unit statistics: Calendar year 2002

Percentage of Offer-Capped Run Hours	2002 Minimum Offer-Capped Hours					
	500	400	300	200	100	1
90%	1	1	2	5	6	6
80%	4	4	8	15	20	20
75%	4	4	8	16	26	26
60%	4	4	10	19	32	39
50%	4	5	17	26	39	54
25%	6	7	19	28	51	122
10%	6	8	20	29	61	169

Table C-20 Offer-capped unit statistics: Calendar year 2003

Percentage of Offer-Capped Run Hours	2003 Minimum Offer-Capped Hours					
	500	400	300	200	100	1
90%	0	0	0	0	0	1
80%	0	1	1	1	2	10
75%	1	2	2	5	9	18
60%	1	2	2	8	16	39
50%	1	2	2	11	21	51
25%	5	9	11	20	33	97
10%	6	10	12	23	47	150

Table C-21 Offer-capped unit statistics: Calendar year 2004

Percentage of Offer-Capped Run Hours	2004 Minimum Offer-Capped Hours					
	500	400	300	200	100	1
90%	0	1	2	7	10	15
80%	3	4	5	15	24	38
75%	4	5	10	20	30	49
60%	5	8	13	23	34	70
50%	5	8	13	24	36	80
25%	6	10	16	30	48	128
10%	8	12	20	37	71	189

Table C-22 Offer-capped unit statistics: Calendar year 2005

Percentage of Offer-Capped Run Hours	2005 Minimum Offer-Capped Hours					
	500	400	300	200	100	1
90%	12	13	13	14	16	17
80%	19	26	26	33	41	53
75%	19	27	30	40	55	70
60%	20	28	35	49	75	102
50%	20	28	37	51	79	115
25%	22	39	49	66	104	194
10%	22	39	50	67	111	234

Locational Net Revenue – Perfect Dispatch

In order to show how net revenue varies by location, balancing energy market net revenues were calculated for each of the 17 current PJM control zones for the perfect dispatch scenarios. The perfect dispatch results are presented in Table C-23, Table C-24 and Table C-25 for new entry, combustion turbine (CT), combined-cycle (CC) and pulverized coal (CP) generators. Net revenues are shown for a transmission zone only if that zone was integrated into PJM for the entire calendar year. The tables show the balancing energy market net revenue using PJM average prices and the differential net revenues for each zone. For example, in Table C-23, the 2006 calendar year net revenues for a CT plant under perfect dispatch using the average PJM LMP is $22,031 per installed MW-year. The net revenue for the same plant located in the ComEd Control Zone is $7,813 per installed MW-year less than the PJM systemwide net revenue, or $14,218 per installed MW-year. The net revenue for the same plant located in the PEPCO Control Zone is $44,666 per installed MW-year more than the PJM systemwide net revenue, or $66,697 per installed MW-year.

Table C-23 Balancing energy market net revenues by control zone for a CT under perfect dispatch (Dollars per installed MW-year): Calendar years 1999 to 2006

Zone	1999	2000	2001	2002	2003	2004	2005	2006	Average
PJM	$62,065	$16,476	$39,269	$23,232	$12,154	$8,063	$15,741	$22,031	$24,879
AECO	$701	$4,687	$12,580	$6,460	$4,458	$12,311	$23,114	$22,095	$10,801
AEP	NA	NA	NA	NA	NA	NA	($10,023)	($12,115)	($11,069)
AP	NA	NA	NA	NA	($3,724)	($1,487)	$386	($1,170)	($1,499)
BGE	($952)	($2,101)	($8,269)	$7,201	$3,025	$4,511	$28,274	$36,001	$8,461
ComEd	NA	NA	NA	NA	NA	NA	($5,882)	($7,813)	($6,848)
DAY	NA	NA	NA	NA	NA	NA	($9,996)	($12,878)	($11,437)
Dominion	NA	NA	NA	NA	NA	NA	NA	$32,158	$32,158
DPL	$2,342	$5,936	$23,656	$9,533	$4,715	$5,959	$16,627	$12,863	$10,204
DLCO	NA	NA	NA	NA	NA	NA	($10,085)	($11,790)	($10,938)
JCPL	$408	$1,742	$7,837	($579)	$765	$23,333	$21,928	$9,964	$8,175
Met-Ed	($604)	($818)	$514	$3,279	$1,513	$3,387	$15,910	$12,289	$4,434
PECO	$1,038	$4,196	$8,271	$491	$3,403	$2,824	$17,854	$10,432	$6,064
PENELEC	($445)	($1,220)	($13,673)	$1,088	($1,531)	($181)	($2,921)	($8,369)	($3,407)
PEPCO	($1,208)	($2,324)	($13,673)	$9,209	$3,745	$6,581	$34,341	$44,666	$10,167
PPL	($266)	($1,000)	($4,046)	($2,396)	($95)	$227	$11,990	$6,575	$1,374
PSEG	$945	$2,807	$8,253	($891)	$3,302	$21,656	$24,017	$10,763	$8,856
RECO	NA	NA	NA	NA	$3,618	$7,759	$18,420	$8,086	$9,471

Table C-24 Balancing energy market net revenues by control zone for a CC under perfect dispatch (Dollars per installed MW-year): Calendar years 1999 to 2006

Zone	1999	2000	2001	2002	2003	2004	2005	2006	Average
PJM	$89,600	$42,647	$68,949	$51,639	$50,346	$49,600	$68,308	$70,828	$61,490
AECO	$369	$6,037	$15,136	$8,588	$8,818	$29,242	$52,839	$40,173	$20,150
AEP	NA	NA	NA	NA	NA	NA	($30,862)	($30,171)	($30,517)
AP	NA	NA	NA	NA	($10,543)	($8,220)	$2,646	($3,029)	($4,787)
BGE	($1,922)	($4,282)	($12,000)	$7,613	$4,565	$8,908	$53,397	$53,484	$13,721
ComEd	NA	NA	NA	NA	NA	NA	($19,646)	($21,879)	($20,763)
DAY	NA	NA	NA	NA	NA	NA	($32,534)	($32,786)	($32,660)
Dominion	NA	NA	NA	NA	NA	NA	NA	$49,777	$49,777
DPL	$3,224	$10,513	$27,928	$11,314	$8,195	$15,425	$36,869	$22,338	$16,976
DLCO	NA	NA	NA	NA	NA	NA	($33,810)	($34,095)	($33,953)
JCPL	$182	$1,848	$7,427	($1,241)	$469	$40,808	$45,033	$17,002	$13,941
Met-Ed	($1,029)	($2,294)	($1,100)	$3,042	$748	$5,560	$31,842	$20,632	$7,175
PECO	$763	$5,198	$7,722	$121	$5,321	$9,844	$36,711	$18,673	$10,544
PENELEC	($473)	($1,481)	($17,839)	$6,953	($4,619)	($6,547)	($7,640)	($17,668)	($6,164)
PEPCO	($2,253)	($4,652)	($17,839)	$9,218	$5,996	$12,226	$62,274	$63,985	$16,119
PPL	($652)	($2,651)	($6,506)	($4,155)	($1,604)	($1,417)	$24,933	$12,676	$2,578
PSEG	$2,403	$7,204	$10,855	($619)	$8,250	$40,430	$55,133	$25,820	$18,685
RECO	NA	NA	NA	NA	$9,106	$20,924	$43,340	$21,713	$23,771

Table C-25 Balancing energy market net revenues by control zone for a CP under perfect dispatch (Dollars per installed MW-year): Calendar years 1999 to 2006

Zone	1999	2000	2001	2002	2003	2004	2005	2006	Average
PJM	$101,011	$112,202	$106,866	$101,345	$166,540	$136,280	$232,351	$184,241	$142,605
AECO	($256)	$5,122	$15,153	$9,430	$9,665	$41,508	$77,363	$45,776	$25,470
AEP	NA	NA	NA	NA	NA	NA	($74,453)	($54,313)	($64,383)
AP	NA	NA	NA	NA	($19,807)	($11,498)	$1,774	($4,901)	($8,608)
BGE	($2,680)	($8,863)	($13,513)	$7,067	$3,350	$12,914	$72,679	$59,843	$16,350
ComEd	NA	NA	NA	NA	NA	NA	($80,567)	($59,069)	($69,818)
DAY	NA	NA	NA	NA	NA	NA	($84,755)	($62,175)	($73,465)
Dominion	NA	NA	NA	NA	NA	NA	NA	$51,982	$51,982
DPL	$3,359	$16,332	$34,181	$12,795	$9,375	$24,712	$56,735	$25,357	$22,856
DLCO	NA	NA	NA	NA	NA	NA	($91,771)	($70,030)	($80,900)
JCPL	($455)	($1,051)	$6,853	($2,037)	($1,885)	$51,590	$63,687	$18,146	$16,856
Met-Ed	($1,714)	($6,087)	($2,305)	$2,424	($1,933)	$9,143	$46,129	$23,134	$8,599
PECO	$137	$3,590	$7,229	($651)	$4,453	$18,297	$55,294	$20,703	$13,632
PENELEC	($966)	$794	($19,759)	$10,429	($5,796)	($11,158)	($13,447)	($24,558)	($8,058)
PEPCO	($3,012)	($9,180)	($19,759)	$8,413	$5,062	$16,512	$83,162	$70,889	$19,011
PPL	($1,319)	($7,108)	($7,976)	($6,393)	($5,585)	$1,040	$36,995	$14,246	$2,988
PSEG	$2,532	$12,789	$13,295	($321)	$14,169	$54,258	$84,691	$36,312	$27,216
RECO	NA	NA	NA	NA	$16,484	$32,902	$68,468	$31,036	$37,223

APPENDIX D – INTERCHANGE TRANSACTIONS

In competitive wholesale power markets, price signals guide purchase and sales decisions. If neighboring wholesale power markets incorporate security-constrained nodal pricing and are designed and managed well, the interface pricing points allow economic signals to guide efficient import and export decisions. When a competitive market shares a boundary with an area reliant on bilateral contracts and associated contract paths to manage transactions, however, the independent system operator (ISO) or regional transmission organization (RTO) needs to define its interface pricing points so that imports and exports, especially under conditions of congestion, face price signals that are consistent with the underlying reality of generation and transmission resources.

PJM has an established process for developing and implementing interface prices. PJM increased the sophistication of that process in 2002 by addressing the causes of loop flow. PJM further developed the application of interface pricing for the integration of the Commonwealth Edison Company (ComEd) Control Area on May 1, 2004,[1] and on October 1, 2004, with the Phase 3 integration of the American Electric Power Company (AEP) and The Dayton Power & Light Company (DAY) Control Zones.[2]

In 2005 the integrations of Phases 4 and 5 brought two new zones into the PJM system, the Duquesne Light Company (DLCO) and the Dominion Control Zones. As a result, both the PJM/DLCO and PJM/Dominion Virginia Power (VAP) interfaces were retired. In addition, the Midwest Independent Transmission System Operator, Inc. (Midwest ISO) started its market-based system on April 1, 2005. The startup required establishment of a new interface pricing point: MISO.

On October 1, 2006, the southeast and southwest pricing points were retired and replaced with a single south pricing point, the SOUTHIMP (import) and the SOUTHEXP (export) pricing points, in response to PJM's ongoing analysis of loop flow.

NYISO Issues

If interface prices were defined in a comparable manner by PJM and the New York Independent System Operator (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.

Institutional difference between PJM and NYISO markets partially explains observed differences in border prices.[3] The NYISO requires hourly bids or offer prices for each export or import transaction and clears its

1 Control zones and control areas are geographic areas that customarily bear the name of a large utility service provider working within their boundaries. The nomenclature applies to the geographic area, not to any single company. See *2006 State of the Market Report*, Volume II, Appendix A, "PJM Geography" for a description of the evolution of the PJM footprint during 2004 and 2005.

2 Control areas external to PJM are referred to as control areas not control zones. For example, the FirstEnergy control area is not referred to as the FirstEnergy control zone.

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

market each hour based on hourly bids.[4] Import transactions to NYISO are treated by NYISO as generator bids at the NYISO/PJM proxy bus. Export transactions are treated by NYISO as price-capped load offers. Competing bids and offers are evaluated along with the 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. It is a function of time lags built into the functioning 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 less 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 NYISO, the price the participants 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.

PJM operating practices provide that 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.[5] The duration of the requested transaction can vary from a single hour 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, only about 1 percent of all transactions submit an associated price. Transactions are accepted in order of submission based on whether PJM has the capability to import or export the requested MW. Since they receive the actual real-time price for their scheduled imports or exports, these transactions are price takers in the Real-Time Market. 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 lead-time is substantially shorter in the PJM market.

The NYISO rules provide that RTC results should be available 45 minutes before the operating hour. Thus winning bidders have 25 minutes from the time when RTC results indicate that their transaction will flow until the time when they must get their transaction cleared with PJM to meet the 20-minute requirement. To get a transaction cleared with PJM, the market participant must have a valid North American Electric Reliability Council (NERC) Tag, an Open Access Same-Time Information System (OASIS) reservation, a PJM schedule 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.

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

5 See PJM "Manual 11: Scheduling Operations" (August 11, 2006) (Accessed January 8, 2007) <http://www.pjm.com/contributions/pjm-manuals/pdf/m11.pdf > (823 KB).

Consolidated Edison Company (Con Edison) and Public Service Electric and Gas Company (PSE&G) Wheeling Contracts[6]

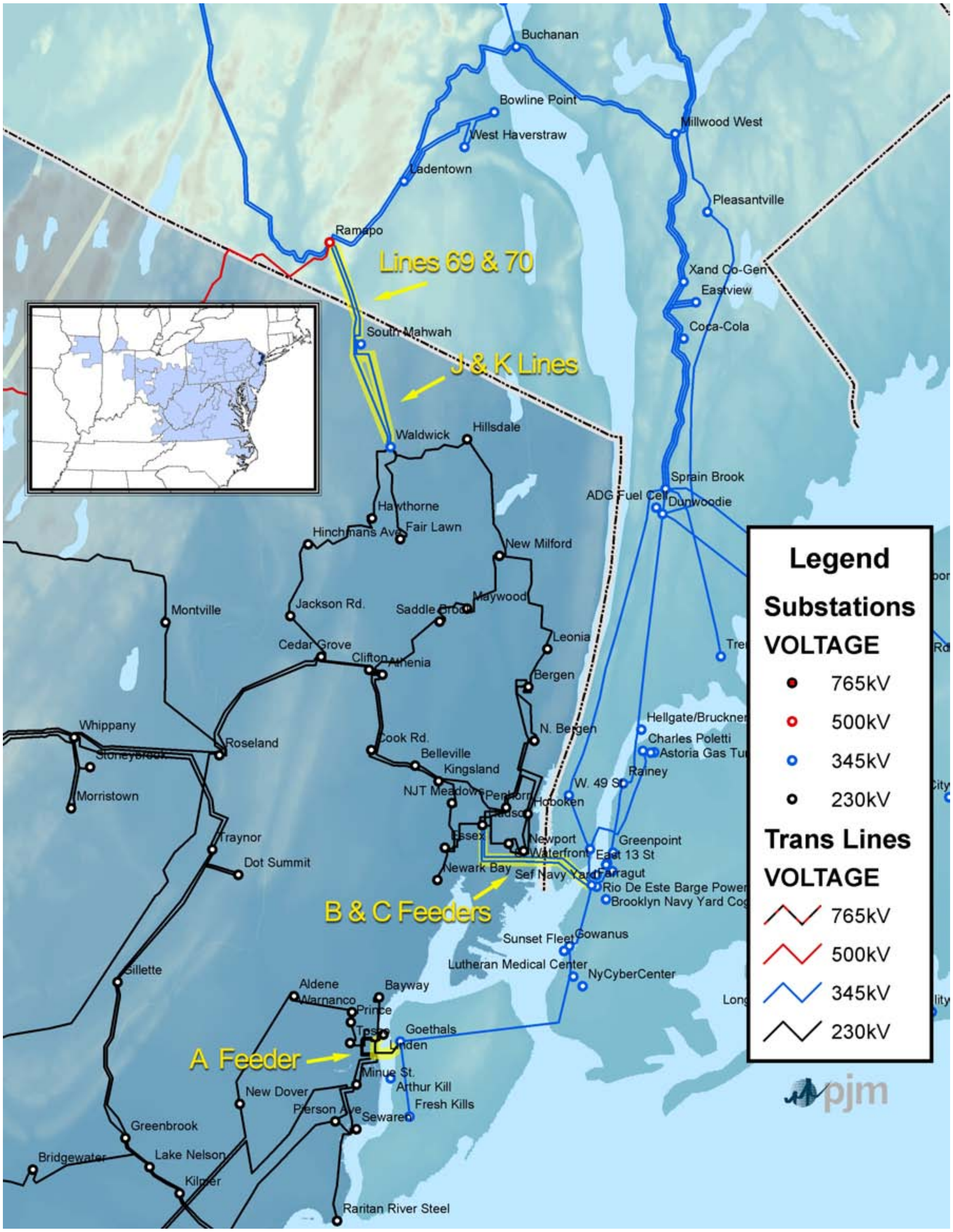
To help meet the demand for power in New York City, Con Edison uses electricity generated in upstate New York and wheeled through New York and New Jersey. A common path is through Westchester County using lines controlled by NYISO. Another path is through northern New Jersey using lines controlled by PJM. 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 United States Federal Energy Regulatory Commission (FERC) in 2001. In May 2005, the FERC issued an order setting out a protocol developed by the four parties.[7] In July 2005, the protocol was implemented.

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 then wheels the power across its system and delivers it back to Con Edison across lines connecting directly into the city. (See Figure D-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 New Milford Switching Station (New Jersey) via the J line and ultimately from Linden Switching Station (New Jersey) to Goethals Substation (New York) and from Hudson Generating Station (New Jersey) to 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 underdelivered on the agreements and asked the FERC to resolve the issue.

6 Prior state of the market reports indicated that this contract is an agreement between Con Edison and PSEG. The contract is between Con Edison and PSE&G, a wholly owned subsidiary of PSEG.

7 111 FERC ¶ 61,228 (2005).

Figure D-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.[8] The protocol was implemented in July 2005.

The Day-Ahead Energy Market Process

The protocol allows Con Edison to elect up to the contracted flow under 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 charges 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 Financial Transmission Rights (FTRs) associated with the 600 MW contract. The PSE&G FTRs are treated like all other FTRs. During 2006, the PSE&G FTR revenues were less than the associated congestion charges by $0.4 million ($2.1 million in 2005) because, for the entire PJM FTR Market, revenue was insufficient to fully fund FTRs. Under the FERC order, Con Edison receives credits on an hourly basis for up to the amount of its congestion charges associated with its elections under the 400 MW contract from a pool containing any excess congestion revenue after hourly FTRs are funded. During 2006, Con Edison's congestion credits were less than the associated congestion charges by $0.7 million ($8.2 million in 2005). (See Table D-1.)

8 111 FERC ¶ 61,228 (2005).

Table D-1 Con Edison and PSE&G wheel settlements data: Calendar year 2006

		Con Edison			PSE&G		
		Day Ahead	Balancing	Total	Day Ahead	Balancing	Total
Jan	Congestion Charge	$101,316.00		$101,316.00	$151,974.00		$151,974.00
	Congestion Credit			$183,232.00			$151,974.00
	Previous month(s) credit adj.						$112,720.07
	Net Charge			($81,916.00)			($112,720.07)
Feb	Congestion Charge	$122,168.00		$122,168.00	$183,252.00		$183,252.00
	Congestion Credit			$35,898.68			$171,986.43
	Previous month(s) credit adj.						$27,727.37
	Net Charge			$86,269.32			($16,461.80)
Mar	Congestion Charge	$246,730.93	($1,272.55)	$245,458.38	384,624.00		$384,624.00
	Congestion Credit			$46,772.29			$304,471.59
	Previous month(s) credit adj.						$44.34
	Net Charge			$198,686.09			$80,108.07
Apr	Congestion Charge	$628,037.55	($2,539.34)	$625,498.21	$961,902.00		$961,902.00
	Congestion Credit			$23,514.51			$581,564.88
	Previous month(s) credit adj.						$181.85
	Net Charge			$601,983.70			$380,155.27
May	Congestion Charge	$235,969.22	$14,947.12	$250,916.34	$368,940.00		$368,940.00
	Congestion Credit			$61,216.94			$337,563.65
	Previous month(s) credit adj.						$124.94
	Net Charge			$189,699.40			$31,251.41
Jun	Congestion Charge	$168,488.00		$168,488.00	$252,732.00		$252,732.00
	Congestion Credit			$79,365.65			$241,690.96
	Previous month(s) credit adj.						$6,993.82
	Net Charge			$89,122.35			$4,047.22
Jul	Congestion Charge	$248,572.00		$248,572.00	$372,858.00		$372,858.00
	Congestion Credit			$252,912.00			$372,858.00
	Previous month(s) credit adj.						$11,041.04
	Net Charge			($4,340.00)			($11,041.04)
Aug	Congestion Charge	$550,232.00		$550,232.00	$825,348.00		$825,348.00
	Congestion Credit			$553,096.00			$825,348.00
	Previous month(s) credit adj.						
	Net Charge			($2,864.00)			$0.00
Sep	Congestion Charge	$359,722.52	($737.90)	$358,984.62	$548,526.00		$548,526.00
	Congestion Credit			$368,622.52			$548,526.00
	Previous month(s) credit adj.						
	Net Charge			($9,637.90)			$0.00

Table D-1 Con Edison and PSE&G wheel settlements data: Calendar year 2006, continued

		Con Edison			PSE&G		
		Day Ahead	Balancing	Total	Day Ahead	Balancing	Total
Oct	Congestion Charge	$106,264.00		$106,264.00	$159,396.00		$159,396.00
	Congestion Credit			$200,864.00			$159,396.00
	Previous month(s) credit adj.						
	Net Charge			($94,600.00)			$0.00
Nov	Congestion Charge	($182,216.00)		($182,216.00)	($273,324.00)		($273,324.00)
	Congestion Credit			$43,868.00			($273,324.00)
	Previous month(s) credit adj.						
	Net Charge			($226,084.00)			$0.00
Dec	Congestion Charge	$111,736.66	($1,232.20)	$110,504.46	$223,032.00		$223,032.00
	Congestion Credit			$187,421.04			$223,032.00
	Previous month(s) credit adj.						
	Net Charge			($76,916.58)			$0.00
Total	Congestion Charge	$2,697,020.88	$9,165.13	$2,706,186.01	$4,159,260.00	$0.00	$4,159,260.00
	Congestion Credit			$2,036,783.63			$3,645,087.51
	Credit Adj.			$0.00			$158,833.43
	Net Charge			$669,402.38			$355,339.06

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. As a general matter, this has not occurred.

APPENDIX E – CAPACITY MARKET[1]

Background

PJM and its members have long relied on capacity obligations as one of the methods to ensure reliability. Before retail restructuring, the original PJM members had determined their loads and related capacity obligations annually. Combined with state regulatory requirements to build and incentives to maintain adequate capacity, this system created a reliable pool, where capacity and energy were adequate to meet customer needs and where capacity costs were borne equitably by members and their loads.

Capacity obligations continue to be critical to maintaining reliability and to contribute to the effective, competitive operation of the PJM Energy Market. Adequate capacity resources, equal to or greater than expected load plus a reserve margin, help to ensure that energy is available on even the highest load days.

On January 1, 1999, in response to retail restructuring requirements, PJM introduced a transparent, PJM-run market in capacity credits.[2] New retail market entrants needed a way to acquire capacity credits to meet obligations associated with competitively gained load. Existing utilities needed a way to sell excess capacity credits when load was lost to new competitors. The PJM Capacity Credit Market (CCM) provides a mechanism to balance supply and demand for capacity credits not met through the bilateral market or self-supply. The PJM CCM is designed to provide a transparent mechanism through which all competitors can buy and sell capacity based on need.

Under the Reliability Assurance Agreement (RAA) governing the Capacity Market operated by the PJM regional transmission organization (RTO), each load-serving entity (LSE) must own or purchase capacity resources greater than, or equal to, its capacity obligation. To cover this responsibility, LSEs may own or purchase capacity credits, unit-specific capacity or capacity imports.

Capacity Obligations

As shown in Equation E-1, in the PJM Capacity Market, load forecasts are used to determine a forecast peak load. These forecast peak-load values are further adjusted to establish capacity obligations. [3]

1 On June 1, 2005, the PJM Capacity Market became the sole capacity market for all control zones. It is referred to here as the PJM Capacity Market, the PJM Capacity Credit Market or simply PJM. The Commonwealth Edison Company (ComEd) capacity market was an interim market limited to that control zone. It began on June 1, 2004, and continued through May 31, 2005. Beginning on June 1, 2005, all control zones participated in a single PJM Capacity Market. The interim capacity market is referred to as the ComEd capacity market, the ComEd capacity credit market (CCM) or simply ComEd.

Control zones and control areas are geographic areas that customarily bear the name of a large utility service provider operating within their boundaries. The names apply to the geographic area, not to any single company. See *2006 State of the Market Report*, Volume II, Appendix A, "PJM Geography" for a description of the evolution of the PJM footprint during 2004 and 2005.

2 The first PJM Capacity Credit Markets (CCMs) were run in late 1998, with an effective date of January 1, 1999.

3 See PJM "Manual 17: Capacity Obligations," Revision 6 (June 1, 2005) <http://www.pjm.com/ contributions/pjm-manuals/pdf/m17v06.pdf> (105 KB).

The adjusted forecast peak-load value is multiplied by the forecast pool requirement (FPR) to determine the unforced capacity obligation for PJM.[4] The FPR is equal to one plus a reserve margin, multiplied by the PJM unforced outage factor. An LSE's unforced capacity obligation for a zone is based on its customers' aggregate share of the prior summer's weather-normalized zonal peak load multiplied by zonal scaling factors[5] and the FPR. The LSE's zonal obligation may be further adjusted for ALM credits. The FPR is set for each planning period which commences every June 1.

Equation E-1 Calculating PJM unforced capacity obligations

Unforced Capacity Obligation = [(Peak Load • Zonal Scaling Factor) – (ALM • ALM Factor)] • Forecast Pool Requirement

Meeting Capacity Obligations

In this Capacity Market, an LSE's load can change on a daily basis as customers switch suppliers. The unforced capacity position of every such LSE is calculated daily when its capacity resources are compared to its capacity obligation to determine if any LSE is short of capacity resources. Deficient entities must contract for capacity resources to satisfy their deficiency. Any LSE that remains deficient must pay an interval penalty equal to the capacity deficiency rate (CDR) times the number of days in an interval.[6] If an LSE is short because of a short-term load increase, it pays only the daily penalty until the end of the month. In no case is a deficient LSE charged more than the CDR multiplied by the number of days in the interval, multiplied by each MW of deficiency.

Capacity Resources

Capacity resources are defined as MW of net generating capacity meeting PJM-specific criteria. They may be located within or outside of PJM, but they must be committed to serving load within PJM. All capacity resources must pass tests regarding the capability of generation to serve load and to deliver energy. This latter criterion requires adequate transmission service.[7]

Capacity resources may be owned, or they may be bought in three different ways:

- **Bilateral, from an Internal PJM Source.** Internal, bilateral purchases may be in the form of a sale of all or part of a specific generating unit, or in the form of a capacity credit, measured in MW and defined in terms of unforced capacity.

- **Bilateral, from a Generating Unit External to PJM.** External, bilateral purchases (capacity imports) must meet PJM criteria, including that imports are from specific generating units and that sellers have firm transmission from the identified units to the metered boundaries of the RTO.

4 Adjusted for active load-management (ALM).

5 Zonal scaling factors are applied to historical peak loads to produce forecasted zonal peak loads.

6 The CDR is a function both of the annual carrying costs of a combustion turbine (CT) and the forced outage rate and thus may change annually. The CDR was changed to $170.09 per MW-day, effective June 1, 2004, to $171.18 per MW-day, effective January 1, 2005, and to $170.45 per MW-day, effective June 1, 2006.

7 See PJM "Reliability Assurance Agreement," Capacity Resources (May 17, 2004), p. 2.

- **Capacity Credit Market.** For the PJM Capacity Market, market purchases may be made from the Daily, Monthly or Multimonthly CCM Auctions. For the interim ComEd capacity market, market purchases could be made from the ComEd monthly or multimonthly capacity credit market auctions.

The sale of a generating unit as a capacity resource within the PJM Control Area entails obligations for the generation owner. The first four of these requirements, listed below, are essential to the definition of a capacity resource and contribute directly to system reliability.

- **Energy Recall Right.** PJM rules specify that when a generation owner sells capacity resources to the PJM Capacity Market from a unit, the seller is contractually obligated to allow PJM to recall the energy generated by that unit if the energy is sold outside of PJM. This right enables PJM to recall energy exports from capacity resources when it invokes emergency procedures.[8] The recall right establishes a link between capacity and actual delivery of energy when it is needed. Thus, PJM can call upon energy from all capacity resources to serve load within the Control Area. When PJM invokes the recall right, the energy supplier is paid the PJM real-time energy market price.

- **Day-Ahead Energy Market Offer Requirement.** Owners of PJM capacity resources are required to offer their output into PJM's Day-Ahead Energy Market. When LSEs purchase capacity, they ensure that resources are available to provide energy on a daily basis, not just in emergencies. Since day-ahead offers are financially binding, PJM capacity resource owners must provide the offered energy at the offered price if the offer is accepted in the Day-Ahead Energy Market. This energy can be provided by the specific unit offered, by a bilateral energy purchase, or by an energy purchase from the Real-Time Energy Market.

- **Deliverability.** To qualify as a PJM capacity resource, energy from the generating unit must be deliverable to load in the PJM Control Area. Capacity resources must be deliverable,[9] consistent with a loss of load expectation as specified by the reliability principles and standards, to the total system load, including portion(s) of the system that may have a capacity deficiency. In addition, for external capacity resources used to meet an accounted-for obligation within PJM, capacity and energy must be delivered to the metered boundaries of the RTO through firm transmission service.

- **Generator Outage Reporting Requirement.** Owners of PJM capacity resources are required to submit historical outage data to PJM pursuant to Schedule 12 of the RAA.[10]

Market Dynamics

RAA procedures determine the total capacity obligation for the PJM Capacity Market and thus the total demand for capacity in the market. The RAA includes rules for allocating total capacity obligation to individual LSEs in each market. An LSE's deficiency is equivalent to its allocated capacity obligation, net of bilateral contracts, self-supply and the active load management (ALM). LSEs bid this deficiency into the appropriate Capacity Credit Market Auctions.

8 See PJM "Manual 13: Emergency Operations," Revision 19 (October 1, 2004) <http://www.pjm.com/ contributions/pjm-manuals/pdf/m13v19.pdf> (461 KB).

9 Deliverable per PJM "Reliability Assurance Agreement," Schedule 10 (May 17, 2004), p. 52 <http: //www.pjm.com/documents/downloads/agreements/raa.pdf> (344 KB).

10 See PJM "Reliability Assurance Agreement," Schedule 12 (May 17, 2004), p. 57 <http: //www.pjm.com/documents/downloads/agreements/raa.pdf> (344 KB).

The short- and intermediate-term supply of capacity credits in the Capacity Credit Market is a function of: physical capacity in the Control Area; prices of energy and capacity in external markets; prices in the PJM Energy and Capacity Markets; capacity resource imports and exports; and transmission service availability and price. The long-term supply of capacity credits is a function of physical capacity in the Control Area which is in turn a function of incentives to build and maintain capacity.

While physical generating units in PJM are the primary source of capacity resources, capacity resources can be exported from PJM and imported into PJM, subject to transmission limitations. It is the ability to export and to import capacity resources that makes capacity supply in PJM a function of price in both internal and external capacity and energy markets.

In capacity markets, as in other markets, market power is the ability of a market participant to increase market price above the competitive level. The competitive market price is the marginal cost of producing the last unit of output, assuming no scarcity and including opportunity costs. For capacity, the opportunity cost of selling into a Capacity Market operated by the RTO is the additional revenue foregone by not selling into an external energy and/or capacity market.

Generation owners can be expected to sell capacity into the most profitable market. A competitive price in a capacity market is a function of the marginal cost of capacity. The marginal cost of capacity is, in turn, determined by the time period over which a choice is made as well as by the alternative opportunities available to the generation owner. If an owner is considering whether to sell a capacity resource for a year, marginal cost would include the incremental cost of maintaining the unit for that year (going forward cost) so that it can qualify as a capacity resource and any relevant opportunity cost. If an owner is considering whether to sell a capacity resource for a day, the only relevant cost is the opportunity cost. The opportunity cost associated with the sale of a capacity resource is a function of the expected probability that the energy will be recalled and the expected distribution of the difference between external and internal energy prices.

Generators can be expected to evaluate the opportunities to sell capacity on a continuing basis, over a variety of time frames, depending on the rules of the capacity markets. The existence of interval markets makes the generators' decisions more dependent on assessments of seasonal energy market price differentials and recall probabilities. With longer capacity obligations, the likelihood of the net external energy market price differential exceeding the capacity penalty for the period is lower and, therefore, the incentives to sell the system short are lower.

2005 Baseline Capacity Market Data

From June 2004 through May 2005, a separate ComEd capacity credit market operated under PJM rules, but with capacity obligations and capabilities measured in installed MW. On June 1, 2005, all ComEd capacity markets were fully integrated into the PJM capacity marketplace. To analyze PJM Capacity Market performance during 2006 as compared to 2005, the *2006 State of the Market Report* limits the relevant 2005 period to the one that started on June 1, 2005, and ended on December 31, 2005, when all capacity became measured by unforced MW. The report refers to it as the 2005 ComEd post capacity integration (PCI) period (i.e., the 2005 ComEd PCI period).

The following tables provide the baseline data for this 2005 ComEd PCI period, to which the 2006 Capacity Market results are compared.

Table E-1 PJM's ComEd PCI period capacity summary (MW): June to December 2005

	Mean	Standard Deviation	Minimum	Maximum
Installed Capacity	163,269	436	162,588	163,951
Unforced Capacity	152,780	680	151,868	153,746
Obligation	142,783	237	142,213	143,260
Sum of Excess	9,997	769	8,665	11,056
Sum of Deficiency	0	0	0	0
Net Excess	9,997	769	8,665	11,056
Imports	3,997	266	3,728	4,391
Exports	5,032	563	4,278	5,746
Net Exchange	(1,035)	394	(1,655)	(486)
Unit-Specific Transactions	18,354	457	17,803	19,064
Capacity Credit Transactions	138,017	1,685	135,666	140,859
Internal Bilateral Transactions	156,371	1,633	153,966	158,940
Daily Capacity Credits	1,605	379	1,025	2,455
Monthly Capacity Credits	1,221	271	699	1,539
Multimonthly Capacity Credits	4,179	264	3,744	4,497
All Capacity Credits	7,005	598	6,079	8,103
ALM Credits	2,042	5	2,035	2,065

Table E-2 PJM's ComEd PCI period capacity market load obligation served: June to December 2005

	Average Obligation (MW)							
	PJM EDCs	PJM EDC Generating Affiliates	PJM EDC Marketing Affiliates	Non-PJM EDC Generating Affiliates	Non-PJM EDC Marketing Affiliates	Non-EDC Generating Affiliates	Non-EDC Marketing Affiliates	Total
Jun	89,798	23,945	12,259	604	6,604	175	8,958	142,343
Jul	90,088	23,943	12,437	604	6,598	162	9,001	142,833
Aug	89,750	24,066	12,572	604	6,687	162	9,059	142,900
Sep	89,917	24,009	12,656	604	6,740	162	9,081	143,169
Oct	89,925	23,787	12,452	608	6,684	164	9,092	142,712
Nov	90,097	23,817	12,177	608	6,865	164	9,015	142,743
Dec	90,563	23,857	12,005	609	6,804	164	8,777	142,779
Average	90,021	23,918	12,365	606	6,711	165	8,997	142,783
Percent of Total Obligation	63.0%	16.8%	8.7%	0.4%	4.7%	0.1%	6.3%	100.0%

Table E-3 PJM's ComEd PCI period capacity market load obligation served by PJM EDCs and affiliates: June to December 2005

	PJM EDCs					PJM EDC Generating Affiliates					PJM EDC Marketing Affiliates				
	Self-Supply (MW)	CCM (MW)	Net Bilateral Contracts (MW)	Obligation (MW)	Net Excess (MW)	Self-Supply (MW)	CCM (MW)	Net Bilateral Contracts (MW)	Obligation (MW)	Net Excess (MW)	Self-Supply (MW)	CCM (MW)	Net Bilateral Contracts (MW)	Obligation (MW)	Net Excess (MW)
Jun	50,291	729	40,840	89,798	2,062	65,660	(1,650)	(37,717)	23,945	2,348	0	1,106	11,497	12,259	344
Jul	50,291	417	41,234	90,088	1,854	65,601	(2,067)	(37,491)	23,943	2,100	0	1,598	11,153	12,437	314
Aug	50,291	303	40,873	89,750	1,717	65,600	(1,775)	(37,725)	24,066	2,034	0	1,727	11,112	12,572	267
Sep	50,365	181	40,912	89,917	1,541	65,553	(1,807)	(37,943)	24,009	1,794	0	1,832	11,103	12,656	279
Oct	51,123	679	41,126	89,925	3,003	65,420	(1,486)	(38,562)	23,787	1,585	0	1,842	10,979	12,452	369
Nov	51,133	448	41,378	90,097	2,862	65,420	(1,481)	(38,793)	23,817	1,329	0	1,542	10,936	12,177	301
Dec	51,380	568	41,443	90,563	2,828	65,439	(1,767)	(38,910)	23,857	905	0	1,547	10,778	12,005	320
Average	50,698	475	41,116	90,021	2,268	65,527	(1,720)	(38,163)	23,918	1,726	0	1,601	11,078	12,365	314
Percent of Total Obligation	56.0%	0.5%	45.6%	102.1%	2.1%	273.4%	(7.6%)	(157.2%)	108.6%	8.6%	0.0%	12.6%	89.9%	102.5%	2.5%

Table E-4 PJM's ComEd PCI period capacity market load obligation served by non-PJM EDC affiliates: June to December 2005

	Non-PJM EDC Generating Affiliates					Non-PJM EDC Marketing Affiliates				
	Self-Supply (MW)	CCM (MW)	Net Bilateral Contracts (MW)	Obligation (MW)	Net Excess (MW)	Self-Supply (MW)	CCM (MW)	Net Bilateral Contracts (MW)	Obligation (MW)	Net Excess (MW)
Jun	13,665	24	(10,037)	604	3,048	0	617	6,690	6,604	703
Jul	13,668	(97)	(10,028)	604	2,939	0	706	6,467	6,598	575
Aug	13,668	(161)	(9,954)	604	2,949	0	545	6,526	6,687	384
Sep	13,668	(135)	(10,059)	604	2,870	0	573	6,655	6,740	488
Oct	13,555	(299)	(10,151)	608	2,497	0	532	7,121	6,684	969
Nov	13,553	(200)	(10,191)	608	2,554	0	505	7,313	6,865	953
Dec	13,553	(213)	(10,174)	609	2,557	0	662	7,305	6,804	1,163
Average	13,618	(155)	(10,085)	606	2,772	0	592	6,868	6,711	749
Percent of Total Obligation	2261.8%	(15.4%)	(1658.0%)	588.4%	488.4%	0.0%	9.2%	98.9%	108.1%	8.1%

Table E-5 PJM's ComEd PCI period capacity market load obligation served by non-EDC affiliates: June to December 2005

	Non-EDC Generating Affiliates					Non-EDC Marketing Affiliates				
	Self-Supply (MW)	CCM (MW)	Net Bilateral Contracts (MW)	Obligation (MW)	Net Excess (MW)	Self-Supply (MW)	CCM (MW)	Net Bilateral Contracts (MW)	Obligation (MW)	Net Excess (MW)
Jun	23,954	(1,135)	(21,783)	175	861	0	308	9,249	8,958	599
Jul	23,975	(922)	(21,539)	162	1,352	0	364	9,058	9,001	421
Aug	23,973	(534)	(21,860)	162	1,417	0	(105)	9,587	9,059	423
Sep	23,971	(1,072)	(21,358)	162	1,379	0	427	9,203	9,081	549
Oct	24,081	(1,299)	(20,457)	164	2,161	0	30	9,407	9,092	345
Nov	24,048	(830)	(20,395)	164	2,659	0	16	9,238	9,015	239
Dec	23,809	(857)	(20,196)	164	2,592	0	60	8,888	8,777	171
Average	23,973	(949)	(21,083)	165	1,776	0	156	9,233	8,997	392
Percent of Total Obligation	14486.8%	(551.6%)	(13077.3%)	857.9%	757.9%	0.0%	2.7%	102.8%	105.5%	5.5%

Table E-6 PJM's ComEd PCI period CCM HHI: June to December 2005

	Daily Market HHI	Monthly and Multimonthly Market HHI
Average	1711	2911
Minimum	1313	1484
Maximum	2219	10000
Highest Market Share (One Auction)	42.8%	100.0%
Highest Market Share (All Auctions)	31.4%	25.3%
# Auctions	214	35
# Auctions with HHI >1800	91	31
% Auctions with HHI >1800	42.5%	88.6%

Table E-7 PJM's ComEd PCI period CCM three pivotal supplier residual supply index (RSI): June to December 2005

	Daily Market RSI_3	Monthly and Multimonthly Market RSI_3
Average	0.48	0.18
Minimum	0.27	0.00
Maximum	0.85	1.16
# Auctions	214	34
# Auctions with = 1 Pivotal Supplier	153	33
% Auctions with = 1 Pivotal Supplier	71.5%	97.1%
# Auctions with <= 3 Pivotal Suppliers	214	34
% Auctions with <= 3 Pivotal Suppliers	100.0%	100.0%

Table E-8 PJM's ComEd PCI period CCM: June to December 2005

	Average Daily Capacity Credits (MW)			Weighted-Average Price ($ per MW-day)		
	Daily CCM	Monthly and Multimonthly CCM	Combined Markets	Daily CCM	Monthly and Multimonthly CCM	Combined Markets
Jun	1,112	5,053	6,165	$0.00	$9.47	$7.76
Jul	1,290	5,497	6,787	$0.05	$8.79	$7.13
Aug	1,476	5,216	6,692	$0.05	$7.29	$5.69
Sep	1,387	5,219	6,606	$0.05	$7.00	$5.54
Oct	1,787	5,282	7,069	$0.64	$5.32	$4.14
Nov	1,948	5,883	7,831	$0.62	$4.85	$3.80
Dec	2,225	5,648	7,873	$0.02	$5.08	$3.65
Average	1,605	5,400	7,005	$0.23	$6.77	$5.27

Generator Performance: NERC OMC Outage Cause Codes

Table E-9 includes a list of the North American Electric Reliability Council (NERC) GADS cause codes deemed outside management control (OMC). PJM does not automatically include cause codes 9200-9299 as outside management control for the purposes of calculating unforced capacity, with the exception of code 9250 under certain conditions.

Table E-9 NERC GADS cause codes deemed outside management control[11] (OMC)

Cause Code	Reason for Outage
3600	Switchyard transformers and associated cooling systems - external
3611	Switchyard circuit breakers - external
3612	Switchyard system protection devices - external
3619	Other switchyard equipment - external
3710	Transmission line (connected to powerhouse switchyard to 1st Substation)
3720	Transmission equipment at the 1st substation (see code 9300 if applicable)
3730	Transmission equipment beyond the 1st substation (see code 9300 if applicable)
9000	Flood
9010	Fire, not related to a specific component
9020	Lightning
9025	Geomagnetic disturbance
9030	Earthquake
9035	Hurricane
9036	Storms (ice, snow, etc)
9040	Other catastrophe
9130	Lack of fuel (water from rivers or lakes, coal mines, gas lines, etc) where the operator is not in control of contracts, supply lines, or delivery of fuels
9135	Lack of water (hydro)
9150	Labor strikes company-wide problems or strikes outside the company's jurisdiction such as manufacturers (delaying repairs) or transportation (fuel supply) problems.
9200	High ash content
9210	Low grindability
9220	High sulfur content
9230	High vanadium content
9240	High sodium content
9250	Low Btu coal
9260	Low Btu oil
9270	Wet coal
9280	Frozen coal
9290	Other fuel quality problems
9300	Transmission system problems other than catastrophes (do not include switchyard problems in this category; see codes 3600 to 3629, 3720 to 3730)
9320	Other miscellaneous external problems
9500	Regulatory (nuclear) proceedings and hearings - regulatory agency initiated
9502	Regulatory (nuclear) proceedings and hearings - intervener initiated
9504	Regulatory (environmental) proceedings and hearings - regulatory agency initiated
9506	Regulatory (environmental) proceedings and hearings - intervenor initiated
9510	Plant modifications strictly for compliance with new or changed regulatory requirements (scrubbers, cooling towers, etc.)
9590	Miscellaneous regulatory (this code is primarily intended for use with event contribution code 2 to indicate that a regulatory-related factor contributed to the primary cause of the event)

11 See NERC, "Generator Availability Data System Data Reporting Instructions," Appendix K <ftp://www.nerc.com/pub/sys/all_updl/gads/dri/Appendix-K-Outside-Plant-Management-Control.pdf> (161 KB).

APPENDIX F – ANCILLARY SERVICE MARKETS

This appendix covers two subject areas: 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 generation 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]

Generators wishing to participate in the Regulation Market must pass certification and submit to random testing. Certification requires that generators 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]

Control Performance Standard (CPS) and Balancing Authority ACE Limit (BAAL)

Two control performance standards are established by NERC for evaluating ACE control. One measure is a statistical measure of ACE variability and its relationship to frequency error. The purpose of the new 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.

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: Dispatching Operations," Revision 13 (May 26, 2006), Section 3, "System Control," p. 17.

2 Regulation Market business rules are defined in PJM "Manual 11: Scheduling Operations," Revision 29 (August 11, 2006), pp. 50-58.

3 See PJM "Manual 12: Dispatching Operations," Revision 13 (May 26, 2006), Section 4, p. 29.

- **CPS1.** NERC requires that the first measure of the CPS survey provide a measure of the control area's performance. The measure is intended to provide the control area with a frequency-sensitive evaluation of how well it met its demand requirements. A minimum passing score for CPS1 is 100 percent.[4]

- **CPS2/BAAL.** NERC also requires that the second measure of the CPS survey be designed to bound ACE 10-minute averages. CPS2 provides a control measure of excessive, unscheduled power flows that could result from large ACEs. CPS2 is measured by counting the number of 10-minute periods during a month when the 10-minute average of the PJM Control Area's ACE is within defined limits known as L_{10}. The specific, 10-minute periods of each hour are those ending at 10, 20, 30, 40, 50 and 60 minutes after the hour. A passing score for CPS2 is achieved when 90 percent of these 10-minute periods during a single month are within L_{10}. From January 1 through January 31, 2006, the PJM Control Area's L_{10} standard was 281.2 MW. From February 1 through February 28, PJM's L_{10} standard was 283.9 MW. From March 1 through December 31, PJM's L_{10} standard was 284.3 MW.

- **BAAL.** Since August 1, 2005, PJM has participated in the NERC "Balancing Standard Proof-of-Concept Field Test" which has established a new metric, balancing authority ACE limit (BAAL), as a possible substitute for CPS2. Participants in the field test have a waiver from meeting the CPS2 requirement for the duration of the field test. As a substitute, the field test participants are required to comply with BAAL limits, which have been established on a trial basis.[5] 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 98 percent.

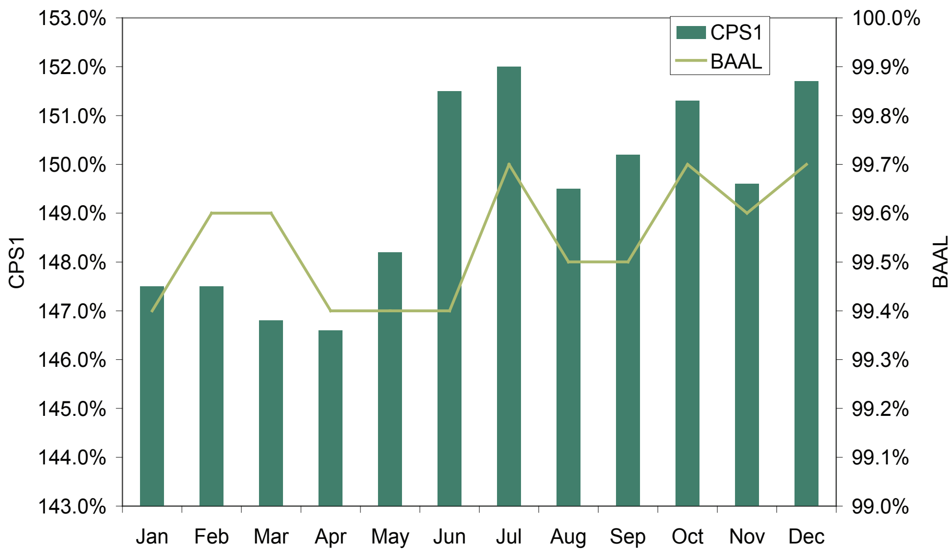
4 For more information about the definition and calculation of CPS, see PJM "Manual 12: "Dispatching Operations," Revision 13 (May 26, 2006), pp. 19-21. The formal definition of CPS1 can be found in NERC's "Performance Standards Reference Document," Version 2 (November 21, 2002), Section B.1.1.1. The formal definition of CPS2 can be found in NERC's "Performance Standards Reference Document," Version 2 (November 21, 2002), Section B.1.1.2.

5 See PJM "Manual 12: "Dispatching Operations," Revision 13 (May 26, 2006), pp. 19-21.

PJM's CPS/BAAL Performance

As Figure F-1 shows, PJM's performance relative to both the CPS1 and BAAL metrics was acceptable in calendar year 2006.

Figure F-1 PJM CPS1 and BAAL performance: Calendar year 2006



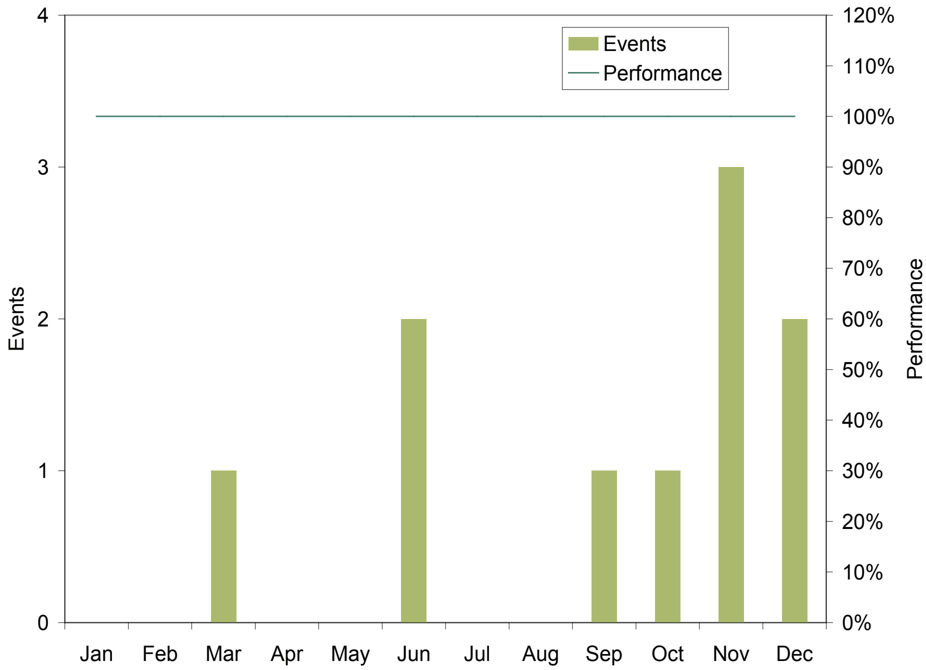
PJM dispatchers have to balance both ACE and frequency. Meeting the CPS1 standard requires balancing frequency on a monthly running-average basis. Meeting the BAAL standard requires PJM dispatchers maintaining interconnection frequency within a predefined frequency profile under all conditions (normal 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.

A dispatch performance metric that is directly related to synchronized reserve is the disturbance control standard (DCS).[6] DCS measures how well PJM dispatch recovers from a disturbance. A disturbance is defined as any ACE deviation over 800 MW. Compliance with the NERC DCS is recovery to zero or predisturbance level within 15 minutes.

PJM experienced 10 DCS events during calendar year 2006 and successfully recovered from all of them. All events were caused by a major unit's tripping. Recovery times ranged from six minutes to 11 minutes. Figure F-2 illustrates the event count and performance by month. All of the events resulted in low ACE. The solution for most of the events was to declare a 100 percent spinning event.

6 For more information on the NERC DCS, see "Standard BAL-002-0 — Disturbance Control Performance" (April 1, 2005) << ftp://www.nerc.com/pub/sys/all_updl/standards/rs/BAL-002-0.pdf>> (61 KB).

Figure F-2 DCS event count and PJM performance (By month): Calendar year 2006



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

Regulation market-clearing price (RMCP) is determined algorithmically by the PJM Market Operations Group by first creating a supply curve of available units and their associated regulation prices; then assigning regulation to units in increasing order of price until the regulation MW requirement is satisfied. The price of the most expensive unit required to satisfy the regulation requirement is the RMCP. Calculating the supply curve is complicated by the fact that the Synchronized Reserve Market is solved simultaneously. Regulation, synchronized reserve and the Energy Market are all co-optimized to achieve the lowest overall cost after first taking into account units that self-schedule. In the event it is not possible to satisfy both regulation and synchronized reserve, regulation has the higher priority.

The process by which available regulation is defined and assigned is complicated, but important to understanding regulation price and regulation market competitiveness.

- **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 become certified for regulation may then be decommissioned, fail regulation testing or be removed from the Regulation Market by their owners.

- **Regulation Offers.** All owners of generating units qualified to provide regulation may, but are not required to, offer their regulation capacity daily into the Regulation Market using the PJM market user interface. Regulating units may also self-schedule. Self-scheduled units have zero lost opportunity cost (LOC) and are the first to be assigned. Demand resources are eligible to offer regulation. Demand resources have an LOC of zero. 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 and 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. All regulation offers 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 it has self-scheduled regulation); c.) Units which are assigned synchronized reserve; and d.) Units for which regulation minimum is set equal to regulation maximum (unless the unit is a hydroelectric unit or it has self-scheduled regulation), or units that are offline (except combustion turbine units).

  Even after SPREGO has run and selected units for regulation, PJM dispatchers can deselect units from SPREGO for other 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 offer cost 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. 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 simultaneously and cooptimized 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, inter-area transfer limits, resource distribution factors, self-scheduled resources, limited fuel resources, bilateral transactions, hydrological constraints, generation requirements and reserve requirements.

- **Cleared Regulation.** Units that are 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.

APPENDIX G – FINANCIAL TRANSMISSION AND AUCTION REVENUE RIGHTS

Appendix G provides examples of topics related to Financial Transmission Rights (FTRs) and Auction Revenue Rights (ARRs):

- The sources of total congestion revenue and the determination of FTR target allocations and congestion receipts;
- The procedure for prorating ARRs when transmission capability limits the number of ARRs that can be allocated; and
- The establishment of ARR target allocations and credits through the Annual FTR Auction.

FTR Target Allocations and Congestion Revenue

Table G-1 shows an example of the sources of total congestion revenue and the determination of FTR target allocations and congestion receipts.

Table G-1 Congestion revenue, FTR target allocations and FTR congestion credits: Illustration

Day-Ahead Congestion Revenue						
Pricing Node	**Day-Ahead LMP**	**Day-Ahead Load**	**Load Payments**	**Day-Ahead Generation**	**Generation Credits**	**Transmission Congestion Charges**
A	$10	0	$0	100	$1,000	($1,000)
B	$15	50	$750	0	$0	$750
C	$20	50	$1,000	100	$2,000	($1,000)
D	$25	50	$1,250	0	$0	$1,250
E	$30	50	$1,500	0	$0	$1,500
Total		200	$4,500	200	$3,000	$1,500
Balancing Congestion Revenue						
Pricing Node	**Real-Time LMP**	**Load Deviation**	**Load Payments**	**Generation Deviation**	**Generation Credits**	**Transmission Congestion Charges**
A	$8	0	$0	0	$0	$0
B	$18	0	$0	0	$0	$0
C	$25	3	$75	5	$125	($50)
D	$20	(5)	($100)	0	$0	($100)
E	$40	7	$280	0	$0	$280
Total		5	$255	5	$125	$130
Transmission Congestion Charges Accounting						
Balancing Transmission Congestion Charges						$130
+Day-Ahead Transmission Congestion Charges						$1,500
=Total Transmission Congestion Charges						$1,630
FTR Target Allocations						
Path	**Day-Ahead Path Price**	**FTR MW**	**FTR Target Allocations**	**Positive FTR Target Allocations**	**Negative FTR Target Allocations**	
A-C	$10	50	$500	$500	$0	
A-D	$15	50	$750	$750	$0	
D-B	($10)	25	($250)	$0	($250)	
B-E	$15	50	$750	$750	$0	
Total		175	$1,750	$2,000	($250)	
Congestion Accounting						
Transmission Congestion Charges						$1,630
+Negative FTR Target Allocations						$250
=Total Congestion Charges						$1,880
Positive FTR Target Allocations				$2,000		
-FTR Congestion Credits				$1,880		
=Congestion Credit Deficiency				$120		
FTR Payout Ratio				0.94		

ARR Prorating Procedure

Table G-2 shows an example of the prorating procedure for ARRs. If line A-B has a 100 MW rating, but ARR requests from two customers together would impose 175 MW of flow on it, the service request would exceed its capability by 75 MW. The first customer's ARR request (ARR #1) is for a total of 300 MW with a 0.50 impact on the constrained line. It would thus impose 150 MW of flow on the line. The second customer's request (ARR #2) is for a total of 100 MW with a 0.25 impact and would impose an additional 25 MW on the constrained line.

Table G-2 ARR allocation prorating procedure: Illustration

Line A-B Rating = 100 MW						
ARR #	Path	Per MW Effect on Line A-B	Requested ARRs	Resulting Line A-B Flow	Prorated ARRs	Prorated Line A-B Flow
1	C-D	0.50	300	150	150	75
2	E-F	0.25	100	25	100	25
Total			400	175	250	100

Equation G-1 Calculation of prorated ARRs

Individual pro rata MW = (Line capability) • (Individual requested MW / Total requested MW) • (1 / per MW effect on line)

The equation would then be solved for each request as follows:

ARR #1 pro rata MW award = (100 MW) • (300 MW / 400 MW) • (1 / 0.50) = 150 MW

ARR #2 pro rata MW award = (100 MW) • (100 MW / 400 MW) • (1 / 0.25) = 100 MW

Together the prorated, awarded ARRs would impose a flow equal to line A-B's capability (150 MW • 0.50 + 100 MW • 0.25 = 100 MW).

ARR Credit

Table G-3 shows an example of how ARR target allocations are established, how FTR auction revenue is generated and how ARR credits are determined. The purchasers of FTRs pay and the holders of ARRs are paid based on cleared nodal prices from the Annual FTR Auction. If total revenue from the auction is greater than the sum of the ARR target allocations, then the surplus is used to offset any FTR congestion credit deficiencies occurring in the hourly Day-Ahead Energy Market.

Table G-3 ARR credits: Illustration

Path	Annual FTR Auction Path Price	ARR MW	ARR Target Allocation	FTR MW	FTR Auction Revenue	ARR Credits
A-C	$10	10	$100	10	$100	$100
A-D	$15	10	$150	5	$75	$150
B-D	$10	0	$0	20	$200	$0
B-E	$15	10	$150	5	$75	$150
Total		30	$400	40	$450	$400
ARR Payout Ratio = ARR Credits / ARR Target Allocations = $400 / $400 = 100%						
Surplus ARR Revenue = FTR Auction Revenue - ARR Credits = $450 - $400 = $50						

APPENDIX H – CALCULATING LOCATIONAL MARGINAL PRICE

In order to understand the relevance of various measures of locational marginal price (LMP), it is important to understand exactly how average LMPs are calculated across time and across buses. This Appendix explains how PJM calculates average LMP and load-weighted LMP for the system, for a zone and, by extension, for any aggregation of buses, for an hour, for a day and for a year.

Hourly Integrated LMP and Hourly Integrated Load

In PJM a real-time LMP is calculated at every bus in every five-minute interval.

The five-minute system LMP is the load-weighted, system average LMP for that five-minute interval, calculated using the five-minute LMP at each load bus and the corresponding five-minute load at each load bus in the system. The sum of the product of the five-minute LMP and five-minute load at each bus, divided by the sum of the five-minute loads across the buses equal the load-weighted, system LMP for that five-minute interval.

In PJM, the hourly LMP at a bus is equal to the simple average of the 12 five-minute interval LMPs in the hour at that bus. This is termed the hourly integrated LMP at the bus. The hourly load at a bus is also calculated as the simple average of the 12 five-minute interval loads in the hour at that bus. This is termed the hourly integrated load at the bus. The hourly values are the basis of PJM's settlement calculations.

Load-Weighted LMP

The load-weighted, system LMP for an hour is equal to the sum of the product of the hourly integrated bus LMP for each load bus and the hourly integrated load for each load bus, for the hour, divided by the sum of the hourly integrated bus loads for the hour.

The load-weighted, zonal LMP for an hour is equal to the sum of the product of the hourly integrated bus LMP for each load bus in the zone and the hourly integrated load for each load bus in the zone, divided by the sum of the hourly integrated loads for each load bus in the zone.

The daily load-weighted, system LMP is equal to the product of the hourly integrated LMP for each load bus and the hourly integrated load for each load bus, for each hour, summed over every hour of the day, divided by the sum of the hourly integrated bus loads for the system for the day.

The daily load-weighted, zonal LMP is equal to the product of each of the hourly integrated LMP for each load bus in the zone and the hourly integrated load for each load bus in the zone, for each hour, summed over every hour of the day, divided by the sum of the hourly integrated bus loads at each load bus in the zone for the day.

The load-weighted, system LMP for a year is equal to the product of the hourly integrated LMP and hourly integrated load for each load bus, summed across every hour of the year, divided by the sum of the hourly integrated bus loads at each load bus in the system for each hour in the year.

The load-weighted, zonal LMP for a year is equal to the product of each of the hourly integrated bus LMP and hourly integrated load for each load bus in the zone, summed across every hour of the year, divided by the sum of the hourly integrated bus loads at each load bus in the zone for each hour in the year.

Equation H-1 LMP calculations

		i = 5 minute interval	h = 12 intervals = hour i = 1..12	d = 24 hours = day h=1..24	y = 365 days = 8760 hours = year d = 1..365
Bus	Simple Average	LMP_{bi}	$LMP_{bh}=\frac{\sum_{i=1}^{12} LMP_{bi}}{12}$	$LMP_{bd}=\sum_{h=1}^{24}\frac{LMP_{bh}}{24}$	$LMP_{by}=\sum_{h=1}^{8760}\frac{LMP_{bh}}{8760}$
Bus	Load Weighted Average			$lwLMP_{bd}=\frac{\sum_{h=1}^{24}(LMP_{bh}\cdot Load_{bh})}{\sum_{h=1}^{24} Load_{bh}}$	$lwLMP_{by}=\frac{\sum_{h=1}^{8760}(LMP_{bh}\cdot Load_{bh})}{\sum_{h=1}^{8760} Load_{bh}}$
System	Simple Average	$LMP_{si}=\frac{\sum_{b=1}^{B} LMP_{bi}}{B}$	$LMP_{sh}=\frac{\sum_{b=1}^{B} LMP_{bh}}{B}$	$LMP_{sd}=\frac{\sum_{h=1}^{24}\frac{\sum_{b=1}^{B} LMP_{bh}\cdot Load_{bh}}{\sum_{b=1}^{B} Load_{bh}}}{24}$	$LMP_{sy}=\frac{\sum_{h=1}^{8760}\frac{\sum_{b=1}^{B} LMP_{bh}\cdot Load_{bh}}{\sum_{b=1}^{B} Load_{bh}}}{8760}$
System	Load Weighted Average	$lwLMP_{si}=\frac{\sum_{b=1}^{B}(LMP_{bi}\cdot Load_{bi})}{\sum_{b=1}^{B} Load_{bi}}$	$lwLMP_{sh}=\frac{\sum_{b=1}^{B}(LMP_{bh}\cdot Load_{bh})}{\sum_{b=1}^{B} Load_{bh}}$	$lwLMP_{sd}=\frac{\sum_{h=1}^{24}\sum_{b=1}^{B}(LMP_{bh}\cdot Load_{bh})}{\sum_{h=1}^{24}\sum_{b=1}^{B} Load_{bh}}$	$lwLMP_{sy}=\frac{\sum_{h=1}^{8760}\sum_{b=1}^{B}(LMP_{bh}\cdot Load_{bh})}{\sum_{h=1}^{8760}\sum_{b=1}^{B} Load_{bh}}$

APPENDIX I – GENERATOR SENSITIVITY FACTORS

Sensitivity factors define the impact of each marginal unit on locational marginal price (LMP) at every bus on the system.[1] The recent availability of sensitivity factor data permits the refinement of analyses in areas where the goal is to calculate the impact of unit characteristics or behavior on LMP.[2] This includes the impact on LMP of unit markups, frequently mitigated unit adders, unit markups by exempt units, the cost of various fuel types and the cost of emissions allowances.[3]

Generator sensitivity factors, or unit participation factors (UPFs), are calculated within the least-cost, security-constrained optimization program. For every five-minute system solution, UPFs describe the incremental amount of output that would have to be provided by each of the current set of marginal units to meet the next increment of load at a specified bus while maintaining total system energy balance. A UPF is calculated from each marginal unit to each load bus in an interval. In the absence of marginal losses, the sum of the UPFs associated with the set of marginal units in any given interval, for a particular load bus, will always sum to 1.0. UPFs can be either positive or negative. A negative UPF for a unit with respect to a specific load bus indicates that the unit would have to be backed down for the system to meet the incremental load at the load bus.

Within the context of a security-constrained, least-cost dispatch solution for an interval, where the LMP at the marginal unit's bus equals the marginal unit's offer, consistent with its output level, LMP at each load bus is equal to each marginal unit's UPF, relative to that load bus, multiplied by its offer price. The markup is defined as the difference between the price from the price-based offer curve and the cost from the cost-based offer curve. In some cases, the bus price for the marginal unit may not equal the calculated price based on the offer curve of the marginal unit. These differences are the result of unit dispatch constraints and transmission constraints and the interactions among them. Any difference between the price based on the offer curve and the actual bus price is defined as the "constrained off" component. In addition, final LMPs calculated using UPFs may differ slightly from PJM posted LMPs as a result of rounding and missing data. This differential is identified as "NA."

1 For another review of sensitivity factors, please refer to "PJM 101: The Basics" (September 14, 2006), p. 107 <http://www.pjm.com/ services/courses/downloads/the-basics-part-01.pdf> (6.41 MB).

2 The PJM Market Monitoring Unit (MMU) identified applications for sensitivity factors and began to save sensitivity factors in 2006.

3 In prior state of the market reports, the impact of each marginal unit on load and LMP was based on an engineering estimate when there were multiple marginal units.

Table I-1 below shows the relationship between marginal generator offers and the LMP at a specific load bus X in a given five-minute interval.

Table I-1 LMP at bus X

Generator	UPF Bus X	Offer	Generator Contribution to LMP at X	Generator percentage contribution to LMP at X
A	0.5	$200.00	$100.00	0.85
B	0.4	$40.00	$16.00	0.14
C	0.1	$10.00	$1.00	0.01
			LMP at X	
			$117.00	1.00

As shown in Table I-1, three marginal generators at three different buses (A, B and C) have an effect on the LMP at load bus X. Each generator's effect on LMP at X is measured by the UPF of that unit with respect to X. The UPF for generator A is 0.5 relative to load bus X. That means that 50 percent of marginal Unit A's offer price will contribute directly to the LMP at X. Since A has an offer price of $200, generator A contributes $100, or UPF times the offer, to the LMP at load bus X. The UPFs from all the marginal units to the load bus must sum to 1.0, so that the marginal units explain 100 percent of the load bus LMP. Generators B and C have UPFs of 0.4 and 0.1, respectively, and offer prices of $40 and $10, respectively, and therefore contribute $16 and $1, respectively, to the LMP at X. Together, the marginal units' offers multiplied by their UPFs with respect to load bus X explain the interval LMP at the load bus.

Hourly Integrated LMP Using UPF

The presentation above shows the relationship between LMP and UPFs for a five-minute interval. Since PJM charges loads and credits generators on the basis of hourly integrated LMP, the relationship among marginal unit offers, UPFs and the hourly integrated LMP must be specified.

The relevant variables and notation are defined as follows:

h = hour

i = five-minute interval

t = year, where t designates the current year and t-1 designates the previous year

b = a specified load bus, where b ranges from 1 to B.

g = a specified marginal generator, where g ranges from 1 to G.

L = interval-specific load

Equation I-1 Hourly integrated load at a bus

The hourly integrated load at a bus is the simple average of the 12 interval loads at a bus in a given hour:

$$\text{Load}_{bh} = \frac{\sum_{i=1}^{12} L_{bi}}{12}$$

Equation I-2 Load bus LMP

Load bus LMPs are determined on a five-minute basis and are a function of marginal unit offers and UPFs in that interval:

$$\text{LMP}_{bi} = \sum_{g=1}^{G} \left(\text{offer}_{gi} \bullet \text{UPF}_{gbi}\right)$$

Equation I-3 Hourly integrated LMP at a bus

The hourly integrated LMP at a bus is the simple average of the 12 interval LMPs at a bus in a given hour:

$$\text{LMP}_{bh} = \frac{\sum_{i=1}^{12} \text{LMP}_{bi}}{12}$$

Equation I-4 Hourly total system cost

Total cost (TC) of the system in the hour is equal to the product of the hourly integrated LMP and the hourly integrated load at each bus summed across all buses in the hour:

$$\text{TC}_{h} = \sum_{b=1}^{B} \left(\text{LMP}_{bh} \bullet \text{Load}_{bh}\right)$$

Equation I-5 Hourly load-weighted LMP

System, load-weighted LMP for the hour is equal to the total hourly system cost (TC) divided by the sum of the bus's simple 12 interval average loads in the hour.

$$LMPSYS_h = \frac{TC_h}{\sum_{b=1}^{B} Load_{bh}}$$

Equation I-6 System average annual load-weighted LMP

The load-weighted (LW), average system (S) LMP for the year:

$$Annual\_SLW\_LMP = \sum_{h=1}^{8760} \frac{TC_h}{\sum_{b=1}^{B} Load_{bh}}$$

Hourly Integrated Markup Effects Using UPFs

UPFs can be used to accurately calculate the markup component of LMP by individual marginal units at any individual load bus, on the LMP at any aggregation of load buses and thus on the system LMP. The markup component of LMP resulting from the markup behavior of marginal units on the system price is a measure of market power (market performance). The markup component of LMP is based on the markup of the actual marginal units and is not based on a redispatch of the system using cost-based offers.

To determine the effect of marginal unit markup on system LMP on an hourly integrated basis, the following steps are required.

Equation I-7 UPF based hourly total system cost

Total cost (TC) of the system in the hour is equal to the product of the simple average LMP and the simple average load at each bus summed across all buses in the hour which, using the definitions above, can be expressed in terms of marginal unit offers and UPFs:

$$TC_h = \sum_{b=1}^{B} LMP_{bh} \bullet Load_{bh} = \sum_{b=1}^{B} \left[Load_{bh} \bullet \frac{\left[\sum_{i=1}^{12} \sum_{g=1}^{G} \left(offer_{gi} \bullet UPF_{gbi} \right) \right]}{12} \right]$$

Equation I-8 System, load-weighted LMP

System, load-weighted LMP for the hour is equal to total hourly system cost divided by the sum of the bus's simple 12 interval average loads in the hour.

$$LMPSYS_h = \frac{TC_h}{\sum_{b=1}^{B} Load_{bh}} = \frac{\sum_{b=1}^{B}\left[Load_{bh} \bullet \frac{\sum_{i=1}^{12}\sum_{g=1}^{G}\left(offer_{gi} \bullet UPF_{gbi}\right)}{12}\right]}{\sum_{b=1}^{B} Load_{bh}}$$

Equation I-9 Cost-based offer system, hourly load-weighted LMP

Holding dispatch and marginal units constant, the system, hourly load-weighted LMP based on cost offers of the marginal units is found by substituting the marginal unit cost offers into the LMPSYS formula above:

$$LMPSYSCost_h = \frac{TC_h}{\sum_{b=1}^{B} Load_{bh}} = \frac{\sum_{b=1}^{B}\left[Load_{bh} \bullet \frac{\sum_{i=1}^{12}\sum_{g=1}^{G}\left(CostOffer_{gi} \bullet UPF_{gbi}\right)}{12}\right]}{\sum_{b=1}^{B} Load_{bh}}$$

Equation I-10 Impact of marginal unit markup on LMP

The marginal unit markups contribution to system LMP for the hour is:

$Mark\_Up = LMPSYS_h - LMPSYSCost_h$

UPF–Weighted, Marginal Unit Markup

Equation I-11 Price-cost markup index

The price-cost markup index for a marginal unit provides a generator conduct or behavior measure of market power:

$$MarkUp_{gi} = \frac{\left(Offer_{gi} - CostOffer_{gi}\right)}{Offer_{gi}}$$

Equation I-12 UPF load-weighted, marginal unit markup

The UPF load-weighted, marginal unit markup (measure of unit conduct) provides a measure of market power for a given hour. This measure reflects the weighted-average markup index for marginal units (conduct or behavior):

$$lwMarkUp_{sh} = \frac{\sum_{b=1}^{B}\left[\frac{\sum_{i=1}^{12}\sum_{g=1}^{G}\left(MarkUp_{gi} \bullet UPF_{gbi}\right)}{12} \bullet Load_{bh}\right]}{\sum_{b=1}^{B} Load_{bh}}$$

Hourly Integrated Load-Weighted, Historical, Cost-Adjusted LMP Using UPFs

UPFs can be used to calculate load-weighted, historical, cost-adjusted LMP for a specific time period. This method is used to disaggregate the various sources of LMP, including all the components of unit marginal cost and unit markup, and to calculate the contributions of each source to changes in system LMP.

The extent to which changes in fuel costs, emission allowance costs, variable operation and maintenance costs (VOM) and markup affect the offers of marginal units depends on the share of each component of the offers. Changes in cost between specified time periods affect only the portion of the unit's offer related to the specified cost. The percentage of a unit's offer that is based on each of the components is given as the following:

Fuel:	$\%Fuel_{gi}$
SO_2:	$\%SO_{2\,gi}$
NO_X:	$\%NO_{X\,gi}$
VOM:	$\%VOM_{gi}$
Markup:	$\%Mark\text{-}Up_{gi}$

Note that the proportion of specific components of unit offers are calculated on an interval and unit-specific basis.

Cost components are determined for each marginal unit for the relevant time periods:

Delivered fuel cost per MWh: FC_{gt}.

Sulfur dioxide emission-related cost per MWh: SO_{2gt}.

Nitrogen oxide emission-related cost per MWh: NO_{xgt}.

Fuel costs (FC) are specific to the unit's location, the unit's fuel type and the time period in question. For example:

FC_{gt}=Avg Fuel Cost in specified "Current Year's Period" (ex, April 1st of 2006)

FC_{gt-1}=Avg Fuel Cost in specified "Previous Year's Period" (ex, April 1st of 2005)

Fuel-Cost-Adjusted LMP

The portion of a marginal generator's offer that is related to fuel costs for a specified period is adjusted to reflect the previous period's fuel costs.

Equation I-13 Fuel-cost-adjusted offer

Subtracting the proportional fuel cost adjustment from the marginal generator's interval-specific offer provides the fuel-cost-adjusted offer (FCA):

$$FCAOffer_{gi} = Offer_{gi} \bullet \left[1 - \%Fuel_{gi} \bullet \frac{\left(FC_{gt} - FC_{gt-1}\right)}{FC_{gt}} \right]$$

Equation I-14 Fuel-cost-adjusted, load-weighted LMP

Using $FCAOffer_{gi}$ for all marginal units in place of the unadjusted offers ($offer_{gi}$) in Equation I-8 (the system, load-weighted LMP equation) results in the hourly fuel-cost-adjusted, load-weighted LMP:

$$LWFCAsysLMP_h = \frac{TCFCA_h}{\sum_{b=1}^{B} Load_{bh}} = \frac{\sum_{b=1}^{B} \left[Load_{bh} \bullet \frac{\sum_{i=1}^{12} \sum_{g=1}^{G} \left(FCAoffer_{gi} \bullet UPF_{gbi}\right)}{12} \right]}{\sum_{b=1}^{B} Load_{bh}}$$

Equation I-15 Annual systemwide, fuel-cost-adjusted, load-weighted LMP

The annual systemwide, fuel-cost-adjusted, load-weighted (SFCALW) LMP for the year is given by the following equation:

$$\text{Annual\_SFCALW\_LMP} = \sum_{h=1}^{8760} \frac{\text{TCFCA}_h}{\sum_{b=1}^{B} \text{Load}_{bh}}$$

Cost-Adjusted LMP

Equation I-16 Unit historical, cost-adjusted offer

Summing the unit's specific historic cost-adjusted component effects and subtracting that sum from the unit's unadjusted offer provides the historical, cost-adjusted offer of the unit (HCAOffer):

$$\text{HCAOffer}_{gi} = \text{Offer}_{gi} \bullet \left[1 - \%\text{Fuel}_{gi} \bullet \left(\frac{\text{FC}_{gt} - \text{FC}_{gt-1}}{\text{FC}_{gt}}\right) - \%\text{NOx}_{gi} \bullet \left(\frac{\text{NOx}_{gt} - \text{NOx}_{gt-1}}{\text{NOx}_{gt}}\right) - \%\text{SO2}_{gi} \bullet \left(\frac{\text{SO2}_{gt} - \text{SO2}_{gt-1}}{\text{SO2}_{gt}}\right)\right]$$

Equation I-17 Unit historical, cost-adjusted, load-weighted LMP

Using each unit's HCAOffer_{gi} in place of its unadjusted offers (offer_{gi}) in Equation I-8 (the system, load-weighted LMP equation) results in the following historical, cost-adjusted, load-weighted LMP for the hour in question:

$$\text{LWHCAsysLMP}_h = \frac{\text{TCHCA}_h}{\sum_{b=1}^{B} \text{Load}_{bh}} = \frac{\sum_{b=1}^{B} \left[\text{Load}_{bh} \bullet \frac{\sum_{i=1}^{12} \sum_{g=1}^{G} \left(\text{HCAOffer}_{gi} \bullet \text{UPF}_{gbi}\right)}{12}\right]}{\sum_{b=1}^{B} \text{Load}_{bh}}$$

Equation I-18 Systemwide, historical, cost-adjusted, load-weighted LMP

The annual systemwide, historical, cost-adjusted, load-weighted (annual SHCALW) LMP for the year is given by the following equation:

$$\text{Annual\_SHCALW\_LMP} = \sum_{h=1}^{8760} \frac{\text{TCHCA}_h}{\sum_{b=1}^{B} \text{Load}_{bh}}$$

APPENDIX J – THREE PIVOTAL SUPPLIER TEST

PJM markets are designed to promote competitive outcomes derived from the interaction of supply and demand in each of the PJM markets. Market design itself is the primary means of achieving and promoting competitive outcomes in the PJM markets. One of the Market Monitoring Unit's (MMU's) primary goals is to identify actual or potential market design flaws.[1] PJM's market power mitigation goals have focused on market designs that promote competition (a structural basis for competitive outcomes) and on limiting market power mitigation to instances where market structure is not competitive and thus where market design alone cannot mitigate market power. In the PJM Energy Market, this occurs only in the case of local market power. When a transmission constraint creates the potential for local market power, PJM applies a structural test to determine if the local market is competitive, applies a behavioral test to determine if generator offers exceed competitive levels and applies a market performance test to determine if such generator offers would affect the market price.

The structural test for suspending offer capping set forth in the PJM Amended and Restated Operating Agreement (OA) Schedule 1, Sections 6.4.1(e) and (f) is the three pivotal supplier test. The three pivotal supplier test is applied by PJM on an ongoing basis in order to determine whether offer capping is required for any constraint not exempt from offer capping. The three pivotal supplier test defined in the OA represents a significant evolution in accuracy because the current application of the test uses real-time data and tests constraints as they actually arise with all the actual system features that exist at the time including transmission constraints, load and generator availability.

As a result of PJM's implementation of the three pivotal supplier test in real time, the actual competitive conditions associated with each binding constraint are analyzed in real time as they arise. The three pivotal supplier test replaced the prior approach which was to offer cap all units required to resolve a binding constraint. The application of the three pivotal supplier test has meant a reduction in the application of offer capping to unit owners. As a result of the application of the three pivotal supplier test, offer capping is applied only at times when the local market structure is not competitive and only to those participants with structural market power.

Three Pivotal Supplier Test: Background

By order issued April 18, 2005, the United States Federal Energy Regulatory Commission (FERC) set for hearing, in Docket No. EL04-121-000, PJM's proposal: (a) to exempt the AP South Interface from PJM's offer-capping rules; and (b) to conduct annual competitive analyses to determine whether additional exemptions from offer capping are warranted.

By order issued July 5, 2005, the FERC also set for hearing, in Docket No. EL03-236-006, PJM's three pivotal supplier test. The Commission further set for hearing issues related to the appropriateness of implementing scarcity pricing in PJM. In the July order, the Commission consolidated Docket No. EL04-121-000 and Docket No. EL03-236-006.

1 PJM Open Access Transmission Tariff (OATT), "Attachment M: Market Monitoring Plan," Third Revised Sheet No. 452 (Effective July 17, 2006).

On November 16, 2005, PJM filed a "Settlement Agreement" resolving all issues set for hearing in the two section 206 proceedings established by the Commission to address certain aspects of PJM's market power mitigation rules, including the application of the three pivotal supplier test, provisions for scarcity pricing, offer caps for frequently mitigated units and competitive issues associated with certain of PJM's internal interfaces. On December 20, 2005, the presiding administrative law judge certified the "Settlement Agreement" to the Commission as uncontested. On January 27, 2006, in Docket Nos. EL03-236-006, EL04-121-000, 001 and 002, the Commission ordered that the "Settlement Agreement," including the amendments to the PJM Tariff and its OA, was in the public interest and was thereby approved and accepted for filing and made effective as set forth in the "Settlement Agreement."[2]

Market Structure Tests and Market Power Mitigation: Core Concepts

A test for local market power based on the number of pivotal suppliers has a solid basis in economics and is clear and unambiguous to apply in practice. There is no perfect test, but the three pivotal supplier test for local market power strikes a reasonable balance between the requirement to limit extreme structural market power and the goal of limiting intervention in markets where competitive forces are adequate. The three pivotal supplier test for local market power is a reasonable application of the logic contained in the Commission's market power tests.

The Commission adopted market power screens and tests in the AEP Order.[3] The AEP Order defined two indicative screens and the more dispositive delivered price test. The Commission's delivered price test for market power defines the relevant market as all suppliers who offer at or below the clearing price times 1.05 and using that definition, applies pivotal supplier, market share and market concentration analyses. These tests are failed if the supplier in question is pivotal, has a market share in excess of 20 percent or if the Herfindahl-Hirschman Index (HHI) in the relevant market exceeds 2500. A supplier is pivotal under the screen if it is pivotal in the relevant market as defined by the delivered price test. The Commission also recognized that there are interactions among the results of each screen under the delivered price test and that some interpretation is required and, in fact, is encouraged.[4]

The three pivotal supplier test, as implemented, is consistent with the Commission's market power tests, encompassed under the delivered price test. The three pivotal supplier test is an application of the delivered price test to both the Real-Time Market and hourly Day-Ahead Market. The three pivotal supplier test explicitly incorporates the impact of excess supply and implicitly accounts for the impact of the price elasticity of demand in the market power tests. The three pivotal supplier test includes more competitors in its definition of the relevant market than the delivered price test. While the delivered price test defines the relevant market to include all offers with costs less than or equal to 1.05 times the market price, the three pivotal supplier test includes all offers with costs less than or equal to 1.50 times the clearing price for the local market.

The goal of defining the relevant market is to determine those units that are actual competitors to the units that clear in a market. The Commission definition would indicate, if the marginal unit set the clearing price

2 114 FERC ¶ 61,076 (2006).

3 107 FERC ¶ 61,018 (2004) (AEP Order).

4 107 FERC ¶ 61,018 (2004).

based on an offer of $200 per MWh, that all units with costs less than or equal to $210 per MWh have a competitive effect on the offer of the marginal unit. These units are all defined to be meaningful competitors in the sense that it is assumed that their behavior constrains the behavior of the marginal and inframarginal units. The three pivotal supplier definition would indicate that, if the marginal unit set the clearing price based on an offer of $200 per MWh, that all units with costs less than or equal to $300 per MWh have a competitive effect on the offer of the marginal unit. These units are all defined to be meaningful competitors in the sense that it is assumed that their behavior constrains the behavior of the marginal and inframarginal units. Clearly, the three pivotal supplier test incorporates a definition of meaningful competitors that is at the high end of inclusive. It is certainly questionable whether a $300 offer meaningfully constrains the offer of a $200 unit. This broad market definition is combined with the recognition that multiple owners can be meaningfully jointly pivotal. The three pivotal supplier test includes three pivotal suppliers while the Commission test includes only one pivotal supplier.

The three pivotal supplier test is also consistent with the delivered price test in that it tests for the interaction between individual participant attributes and features of the relevant market structure. The three pivotal supplier test is an explicit test for the ability to exercise unilateral market power as well as market power via coordinated action, based on economic theory, which accounts simultaneously for market shares and the supply-demand balance in the market.

The results of the three pivotal supplier test can differ from the results of the HHI and market share tests. The three pivotal supplier test can show the existence of structural market power when the HHI is less than 2500 and the maximum market share is less than 20 percent. The three pivotal supplier test can also show the absence of market power when the HHI is greater than 2500 and the maximum market share is greater than 20 percent. The three pivotal supplier test is more accurate than the HHI and market share tests because it focuses on the relationship between demand and the most significant aspect of the ownership structure of supply available to meet it. A market share in excess of 20 percent does not matter if the holder of that market share is not jointly pivotal and is unlikely to be able to affect the market price. A market share less than 20 percent does not matter if the holder of that market share is jointly pivotal and is likely to be able to affect the market price. Similarly, an HHI in excess of 2500 does not matter if the relevant owners are not jointly pivotal and are unlikely to be able to affect the market price. An HHI less than 2500 does not matter if the relevant owners are jointly pivotal and are likely to be able to affect the market price.[5]

The three pivotal supplier test was designed in light of actual elasticity conditions in load pockets in wholesale power markets in PJM. The price elasticity of demand is probably the most critical variable in determining whether a particular market structure is likely to result in a competitive outcome. A market with a specific set of market structure features is likely to have a competitive outcome under one range of demand elasticity conditions and a noncompetitive outcome under another set of elasticity conditions. It is essential that market power tests account for actual elasticity conditions and that evaluation of market power tests neither ignore elasticity nor make counterfactual elasticity assumptions. As the Commission stated, “In markets with very little demand elasticity, a pivotal supplier could extract significant monopoly rents during peak periods because customers have few, if any, alternatives.”[6] The Commission also stated:

5 For detailed examples, see Joseph E. Bowring, PJM Market Monitor, “MMU Analysis of Combined Regulation Market,” PJM Market Implementation Committee Meeting (December 20, 2006).

6 107 FERC ¶ 61,018 (2004).

> In both of these models, the lower the demand elasticity, the higher the mark-up over marginal costs. It must be recognized that demand elasticity is extremely small in electricity markets; in other words, because electricity is considered an essential service, the demand for it is not very responsive to price increases. These models illustrate the need for a conservative approach in order to ensure competitive outcomes for customers because many customers lack one of the key protections against market power: demand response.[7]

The three pivotal supplier test is a reasonable application of the Commission's delivered price test to the case of load pockets that arise in a market based on security-constrained, economic dispatch with locational market pricing and extremely inelastic demand. The three pivotal supplier test also exists in the context of a local market power mitigation rule that relies on a structure test, a participant behavior test and a market impact test. The three pivotal supplier test explicitly incorporates the relationship between supply and demand in the definition of pivotal and it provides a clear test for whether excess supply is adequate to offset other structural features of the market and result in an adequately competitive market structure. The greater the supply relative to demand, the less likely that three suppliers will be jointly pivotal, all else equal.

The three pivotal supplier test represents a significant modification of the previously existing PJM local market power rule, which did not include an explicit market structure test. The goal of the applying a market structure test is to continue to limit the exercise of market power by generation owners in load pockets but to lift offer capping when the exercise of market power is unlikely. The goal of the three pivotal supplier test, proposed by PJM, was not to weaken the local market power rules but to make them more flexible by adding an explicit market structure test. As recognized by PJM when the local market power rule was proposed in 1997 and has continued to be the case, the local markets created by transmission constraints are generally not structurally competitive. Nonetheless, it is appropriate to have a clear test as to when a local market is adequately competitive to permit the relaxation of local market power mitigation. The three pivotal supplier test proposed by PJM is not a guarantee that suppliers will behave in a competitive manner in load pockets. The three pivotal supplier test is a structural test that is not a perfect predictor of actual behavior. The existence of this risk is the reason that the PJM Tariff language also includes the ability of the MMU to request that the Commission reinstate offer caps in cases where there is not a competitive outcome.

Three Pivotal Supplier Test: Mechanics

The three pivotal supplier test measures the degree to which the supply from three generation suppliers is required in order to meet the demand to relieve a constraint. Two key variables in the analysis are the demand and the supply. The demand consists of the incremental, effective MW required to relieve the constraint. Total supply consists of all effective MW of supply incrementally available to relieve the constraint at a distribution factor (DFAX) greater than or equal to the DFAX used by PJM in operations.[8] For purposes of the test, incremental effective MW are attributed to specific suppliers on the basis of their control of the

7 107 FERC ¶ 61,018 (2004).

8 A unit's contribution towards a supplier's effective, incrementally available supply is based on the DFAX of the unit relative to the constraint and the unit's incrementally available capacity over current load levels, to the extent that the capacity in question can be made available within an hour of the time the relief will be needed. Effective, incrementally available MW from an unloaded 100 MW 15-minute start combustion turbine (CT) with a DFAX of .05 to a constraint would be 5 MW relative to the constraint in question. Effective, incrementally available MW from a 200 MW steam unit, with 100 MW loaded, a 50 MW ramp rate and a DFAX of .5 to the constraint would be 25 MW.

assets in question. Generation capacity controlled directly or indirectly through affiliates or contracts with third parties are attributed to a single supplier.

The supply directly included as relevant to the market in the three pivotal supplier test consists of the incremental, effective MW of supply that are available at a price less than, or equal to, 1.5 times the clearing price (P_c) that would result from the intersection of demand (constraint relief required) and the incremental supply available to resolve the constraint. This measure of supply is termed the relevant effective supply (S) in the market for the relief of the constraint in question. In every case, incrementally available supply is measured as incremental effective MW of supply, as shown in Equation J-1, and the clearing price (P_c) is defined as shown in Equation J-2.

Equation J-1 Incremental effective MW of supply

$$MW \cdot DFAX$$

Equation J-2 Price of clearing offer

$$P_c = \frac{Offer_c - SMP}{DFAX_c}$$

To be relevant, the effective offer of incremental supplier i must be less than or equal to 1.5 times P_c:

Equation J-3 Relevant and effective offer

$$P_{ie} = \frac{Offer_i}{DFAX_i} \leq 1.5 \cdot P_c$$

Where the relevant, effective incremental supply of supplier i is a function of price:

Equation J-4 Relevant and effective supply of supplier i

$$S_i = MW\left(P_{ie}\right) \cdot DFAX_i$$

Where, S_i is the relevant effective supply (relevant, incremental and effective supply) of supplier i, total relevant effective supply (total relevant, incremental and effective supply) for suppliers i=1 to n is shown in Equation J-5.

Equation J-5 Total relevant, effective supply

$$S = \sum_{i=1}^{n} S_i$$

Each effective supplier, from 1 to n, is ranked, from largest to smallest relevant effective supply, relative to the constraint for which it is being tested. In the first iteration of the test, the two largest suppliers are combined with the third largest supplier, and this combined supply is subtracted from total relevant effective supply, described above. The resulting amount of net relevant effective supply is divided by the total relief required (D). Where j defines the supplier being tested in combination with the two largest suppliers (initially the third largest supplier with j=3), Equation J-6 shows the formula for the three pivotal supplier metric, the three pivotal residual supplier index (RSI3).

Equation J-6 Calculating the three pivotal supplier test

$$RSI3_j = \frac{\sum_{i=1}^{n}(S_i) - \sum_{i=1}^{2}(S_i) - S_j}{D}$$

Where j=3, if $RSI3_j$ is less than, or equal to, 1.0, the three largest suppliers in the market for the relief of the constraint fail the three pivotal supplier test. That is, the three largest suppliers are jointly pivotal for the local market created by the need to relieve the constraint using local, out of merit units. If $RSI3_j$ is greater than 1.0, the three largest potential suppliers of relief MW pass the test and the remaining suppliers (j=4..n) pass the test. In the event of a failure of the three largest suppliers, further iterations of the test are needed, with each subsequent iteration testing a subsequently smaller supplier (j=4..n) in combination with the two largest suppliers. In each iteration, when $RSI3_j$ is less than 1.0, it indicates that the tested supplier, in combination with the two largest suppliers, has failed the test. Iterations of the test continue until the combination of the two largest suppliers and a supplier j achieve a result of $RSI3_j$ greater than 1.0. When the result of this process is that $RSI3_j$ is greater than 1.0, the remaining suppliers will pass the test.

If a supplier fails the test for a constraint, units that are part of a supplier's relevant effective supply with respect to a constraint can have their offers capped at cost plus 10 percent, or cost plus relevant adders for frequently mitigated units and associated units. However, capping only occurs to the extent that the units of this supplier's relevant, effective supply are offered at greater than cost plus 10 percent and are actually dispatched to contribute to the relief of the constraint in question.

APPENDIX K – GLOSSARY

Active load management (ALM)	Retail customer load that can be interrupted at the request of PJM. Such a PJM request is considered an emergency action and is implemented prior to a voltage reduction. ALM derives an ALM credit in the accounted-for-obligation.
Aggregate	Combination of buses or bus prices.
Ancillary service	Those services necessary to support the transmission of capacity and energy from resources to loads while, in accordance with good utility practice, maintaining reliable operation of the transmission provider's transmission system.
Ancillary service area	A defined market service area for ancillary services including regulation and synchronized reserve.
Area control error (ACE)	Area control error (ACE) is a real-time metric used by PJM operators to measure the imbalance between load and generation. ACE is the instantaneous MW imbalance between generation and load plus net interchange.
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 unweighted LMP	An LMP calculated by averaging hourly LMP with equal hourly weights.
Balancing Energy Market	Energy that is generated and financially settled during real time.
Basic generation service (BGS)	The default electric generation service provided by the electric public utility to consumers who do not elect to buy electricity from a third-party supplier.

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 assistance from the transmission system.
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 credit	An entitlement to a specified number of MW of unforced capacity from a capacity resource for the purpose of satisfying capacity obligations imposed under the Reliability Assurance Agreement (RAA).
Capacity deficiency rate (CDR)	The capacity deficiency rate is based on the annual carrying charges for a new combustion turbine, installed and connected to the transmission system. To express the CDR in terms of unforced capacity, it must be further divided by the quantity 1 minus the EFORd.
Capacity Market	All markets where PJM members can trade capacity.
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)	A generating unit generally consisting of one or more gas-fired turbines and a heat recovery steam generator. Electricity is produced by a gas turbine whose exhaust is recovered to heat water, yielding steam for a steam turbine that produces still more electricity.
Combustion turbine (CT)	A generating unit in which a combustion turbine engine is the prime mover.
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)	Financial bid to purchase a defined MW level of energy up to a specified LMP, above which the bid is zero.

Dispatch rate	Control signal, expressed in dollars per MWh, calculated by PJM and transmitted continuously and dynamically to generating units to direct the output level of all generation resources dispatched by PJM.
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.
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 equivalent availability factor is the proportion of hours in a year that a unit is available to generate at full capacity.
Equivalent demand forced outage rate	The equivalent demand forced outage rate
(EFORd)	(EFORd) (generally referred to as the forced outage rate) is a measure of the probability that a generating unit will fail, either partially or totally, to perform when it is needed to operate.
Equivalent forced outage factor (EFOF)	The equivalent forced outage factor is the proportion of hours in a year that a unit is unavailable because of forced outages.
Equivalent maintenance outage factor	The equivalent maintenance outage factor is
(EMOF)	the proportion of hours in a year that a unit is unavailable because of maintenance outages.
Equivalent planned outage factor (EPOF)	The equivalent planned outage factor is the proportion of hours in a year that a unit is unavailable because of planned outages.
External resource	A resource located outside metered PJM boundaries.
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	Firm transmission service that is reserved and/or scheduled between specified points of receipt and delivery.

Firm transmission	Transmission service that is intended to be available at all times to the maximum extent practicable. Service availability is, however, subject to an emergency, an unanticipated failure of a facility or other event.
Fixed-demand bid	Bid to purchase a defined MW level of energy, regardless of LMP.
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 offers	Schedules of MW offered and the corresponding offer price.
Generator 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 deficiency	The sum of all companies' individual capacity deficiency, or the shortfall of unforced capacity below unforced capacity obligation. The term is also referred to as accounted-for deficiency.
Gross excess	The amount by which a load-serving entity's (LSE's) unforced capacity exceeds its accounted-for obligation. The term is referred to as "Accounted-for Excess" in "Manual 35: Definitions and Acronyms."
Gross export volume (energy)	The sum of all export transaction volume (MWh).
Gross import volume (energy)	The sum of all import transaction volume (MWh).
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 installed on combined-cycle generators.
Increment offers (INC)	Financial offers in the Day-Ahead Energy Market to supply specified amounts of MW at, or above, a given price.

Initial threshold	In the context of the PJM economic planning process, when the cumulative gross congestion cost of a constraint exceeds the applicable initial threshold, PJM begins determining the extent to which the load affected by that constraint is unhedgeable. Initial threshold values are specific to the transmission level voltage of the affected facility.
Installed capacity	Installed capacity is the as-tested maximum net dependable capability of the generator, measured in MW.
Interval Market	The Capacity Market rules provide for three Interval Markets, covering the months from January through May, June through September and October through December.
Load	Demand for electricity at a given time.
Load aggregator	An entity licensed to sell energy to retail customers located within the service territory of a local distribution company.
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.
Lost opportunity cost (LOC)	The difference in net compensation from the Energy Market between what a unit receives when providing regulation or synchronized reserve and what it would have received for providing energy output.
Marginal unit	The last 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 reasonable creditworthiness standards as established by PJM. Market buyers are otherwise able to make purchases and market sellers are otherwise able to make sales in the PJM Energy or Capacity Credit Markets.
Market threshold	In the context of the PJM economic planning process, each market threshold represents the level of unhedgeable congestion costs that triggers the start of a one-year "market window" for the development of market solutions to unhedgeable congestion. Market threshold values are specific to the transmission voltage of the affected facility.
Market user interface	A thin client application allowing generation marketers to provide and to view generation data, including bids, unit status and market results.

Market window	In the context of the PJM economic planning process, the period of time during which PJM allows for the development of market solutions to unhedgeable congestion associated with an affected facility.
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.
Merchant solution	In the context of the PJM economic planning process, a solution proposed to reduce or to eliminate unhedgeable congestion on an affected facility.
Min gen	An emergency declaration for periods of light load.[1]
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.
Non-economic generation	Units producing energy at an offer price greater than the LMP.
North American Electric Reliability Council	A voluntary organization of U.S. and Canadian utilities and power pools established to assure coordinated operation of the interconnected transmission systems.

1 See PJM "Manual 13: Emergency Operations," Section 2, pp. 43-48.

Obligation	The sum of all load-serving entities' unforced capacity obligations as determined by summing the weather-adjusted summer coincident peak demands for the prior summer, netting out ALM credits, adding a reserve margin and adjusting for the system average forced outage rate.
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.
Phase-in FTRs	FTRs directly allocated to eligible customers outside of the regularly scheduled FTR allocations when new control zones are integrated into PJM after the start of the current planning period. Phase-in FTRs remain in effect until the start of the next regularly scheduled FTR allocation.
PJM member	Any entity that has completed an application and satisfies the requirements of PJM 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.
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.
Regional Transmission Expansion	The process by which PJM recommends
Planning (RTEP) Protocol	specific transmission facility enhancements and expansions based on reliability and economic criteria.
Selective catalytic reduction (SCR)	NOx 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.
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.
Special protection scheme (SPS)	A load transfer relaying scheme intended to reduce the adverse post-contingency impact on a protected facility.
Spot Market	Transactions made in the Real-Time and Day-Ahead Energy Market at hourly LMP.
Standard deviation	A measure of data variability around the mean.
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.
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 or by reducing load on pumped storage hydroelectric facilities or by reducing the demand of demand 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 in the general range of 70 to 80, reflecting the outdoor atmospheric conditions of temperature and humidity as a measure of comfort (or discomfort) during warm weather. THI is defined as follows: THI = Td – (0.55 – 0.55RH) * (Td - 58) where Td is the dry-bulb temperature and RH is the percentage of relative humidity.
Unforced capacity	Installed capacity adjusted by forced outage rates.
Wheel-through	An energy transaction flowing through a transmission grid whose origination and destination are outside of the transmission grid.
Zone	See “Control zone” (above).

APPENDIX L – LIST OF ACRONYMS

ACE	Area control error
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
AP	Allegheny Power Company
ARR	Auction Revenue Right
ASA	Ancillary service area
ATC	Available transfer capability
AU	Associated unit
BAAL	Balancing authority ACE limit
BGE	Baltimore Gas and Electric Company
BGS	Basic generation service
BME	Balancing market evaluation
Btu	British thermal unit
CAISO	California Independent System Operator
C&I	Commercial and industrial customers
CC	Combined cycle
CCM	Capacity Credit Market

CDR	Capacity deficiency rate
CDTF	Cost Development Task Force
CF	Coordinated flowgate under the Joint Operating Agreement between PJM and the Midwest Independent Transmission System Operator, Inc.
CILCO	Central Illinois Light Company
CIN	Cinergy Corporation
CLMP	Congestion component of LMP
ComEd	The Commonwealth Edison Company
Con Edison	The Consolidated Edison Company
CP	Pulverized coal-fired generator
CPL	Carolina Power & Light Company
CPS	Control performance standard
CSP	Curtailment service provider
CT	Combustion turbine
DAY	The Dayton Power & Light Company
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

DSR	Demand-side response
DUK	Duke Energy Corp.
EAF	Equivalent availability factor
ECAR	East Central Area Reliability Council
EDC	Electricity distribution company
EDT	Eastern Daylight Time
EES	Enhanced Energy Scheduler
EFOF	Equivalent forced outage factor
EFORd	Equivalent demand forced outage rate
EHV	Extra-high-voltage
EKPC	East Kentucky Power Cooperative, Inc.
EMOF	Equivalent maintenance outage factor
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
FMU	Frequently mitigated unit
FPA	Federal Power Act
FPPL	Forecast period peak load
FPR	Forecast pool requirement

FTR	Financial Transmission Right
GCA	Generating control area
GE	General Electric Company
GWh	Gigawatt-hour
HHI	Herfindahl-Hirschman Index
HRSG	Heat recovery steam generator
HVDC	High-voltage direct current
Hz	Hertz
ICAP	Installed capacity
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
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.
LGIA	Large Generator Interconnection Agreement
LMP	Locational marginal price
LOC	Lost opportunity cost
LSE	Load-serving entity
LTE	Long-term emergency
MAAC	Mid-Atlantic Area Council
MACRS	Modified accelerated cost recovery schedule
MAIN	Mid-America Interconnected Network, Inc.
MAPP	Mid-Continent Area Power Pool
MC	The PJM Members Committee
MCP	Market-clearing price
MEC	MidAmerican Energy Company
MECS	Michigan Electric Coordinated System
Met-Ed	Metropolitan Edison Company
MEW	Western subarea of Metropolitan Edison Company
MICHFE	The pricing point for the Michigan Electric Coordinated System and FirstEnergy control areas
Midwest ISO	Midwest Independent Transmission System Operator, Inc.
MIL	Mandatory interruptible load
MMU	PJM Market Monitoring Unit
MP	Market participant
MUI	Market user interface

MW	Megawatt
MWh	Megawatt-hour
NERC	North American Electric Reliability Council
NICA	Northern Illinois Control Area
NIPSCO	Northern Indiana Public Service Company
NNL	Network and native load
NO_x	Nitrogen oxides
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
OPL	Obligation peak load
OVEC	Ohio Valley Electric Corporation
PAR	Phase angle regulator
PCS	Production cost study
PE	PECO zone
PEC	Progress Energy Carolinas, Inc.

PECO	PECO Energy Company
PENELEC	Pennsylvania Electric Company
PEPCO	Pepco (formerly Potomac Electric Power Company)
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
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/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/NIPS	The interface between PJM and the Northern Indiana Public Service Company's control area
PJM/NYIS	The interface between PJM and the New York Independent System Operator
PJM/Ontario IESO	PJM/Ontario IESO pricing point

PJM/OVEC	The interface between PJM and the Ohio Valley Electric Corporation's control area
PJM/TVA	The interface between PJM and the Tennessee Valley Authority's control area
PJM/VAP	The interface between PJM and the Dominion Virginia Power's control area
PJM/WEC	The interface between PJM and the Wisconsin Energy Corporation's control area
PLC	Peak load contributions
PNNE	PENELEC's northeastern subarea
PNNW	PENELEC's northwestern subarea
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
QIL	Qualified interruptible load
RAA	Reliability Assurance Agreement among Load-Serving Entities
RECO	Rockland Electric Company zone
RMCP	Regulation market-clearing price
RPM	Reliability Pricing Model
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
SCPA	Southcentral Pennsylvania subarea
SCR	Selective catalytic reduction
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)
SPS	Special protection scheme
SRMCP	Synchronized reserve market-clearing price
STD	Standard deviation
STE	Short-term emergency
SVC	Static Var compensator
TEAC	Transmission Expansion Advisory Committee
THI	Temperature-humidity index

TLR	Transmission loading relief
TPS	Three pivotal supplier
TVA	Tennessee Valley Authority
UDS	Unit dispatch system
UGI	UGI Utilities, Inc.
UPF	Unit participation factor
VACAR	Virginia and Carolinas Area
VAP	Dominion Virginia Power
VOM	Variable operation and maintenance expense
WEC	Wisconsin Energy Corporation

APPENDIX M – ERRATA

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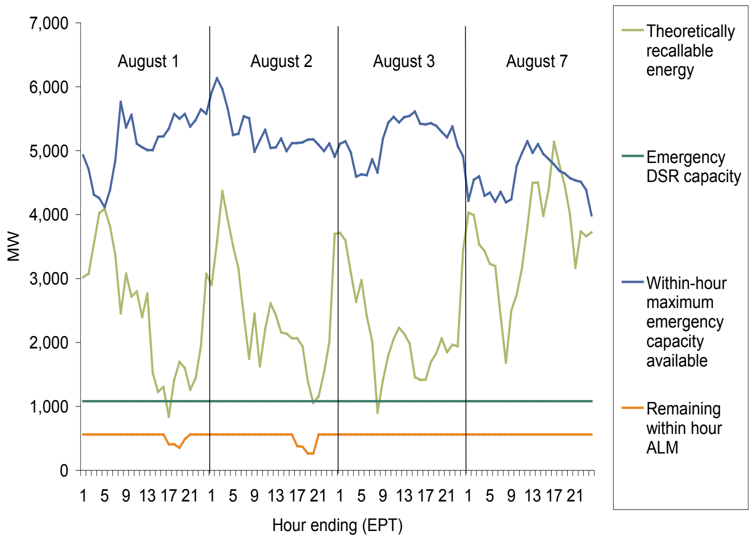
Figure 3-10 Within-hour emergency resources: August 1 to August 3, and August 7, 2006



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Operating Reserve Credits by Category

Figure 3-12 shows that the largest share of total operating reserve credits, 42.57 percent, was paid to resources in the Balancing Energy Market during 2006 and that 75.36 percent of total operating reserve credits were in the balancing category. Figure 3-12 also shows that 10.24 percent of total operating reserve credits were paid to resources in the Day-Ahead Energy Market and that 20.31 percent of total operating reserve credits were in the day-ahead category.[86]

Figure 3-12 Operating reserve credits: Calendar year 2006