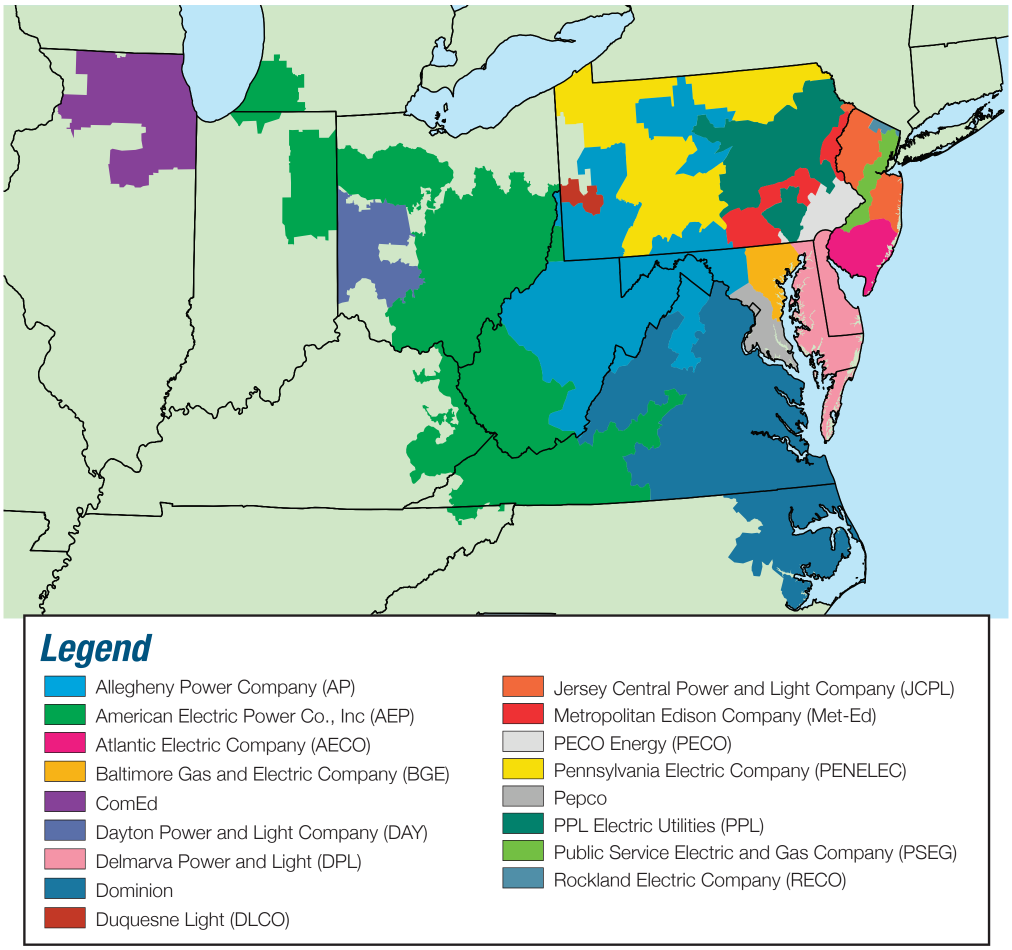
APPENDIX A – PJM GEOGRAPHY

During 2009, the PJM geographic footprint encompassed 17 control zones located in Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia.

Figure A-1 PJM's footprint and its 17 control zones



Analysis of 2009 market results requires comparison to 2008 and certain other prior years. During calendar years 2006 through 2009 the PJM footprint was stable. During calendar years 2004 and 2005, however, PJM integrated five new control zones, three in 2004 and two in 2005. When making comparisons involving this period, the 2004, 2005 and 2006 state of the market reports referenced phases, each corresponding to market integration dates:[1]

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

© 2010 Monitoring Analytics, LLC www.monitoringanalytics.com

- **Phase 1 (2004).** The four-month period from January 1, through April 30, 2004, during which PJM was comprised of the Mid-Atlantic Region, including its 11 zones,[2] and the Allegheny Power Company (AP) Control Zone.[3]

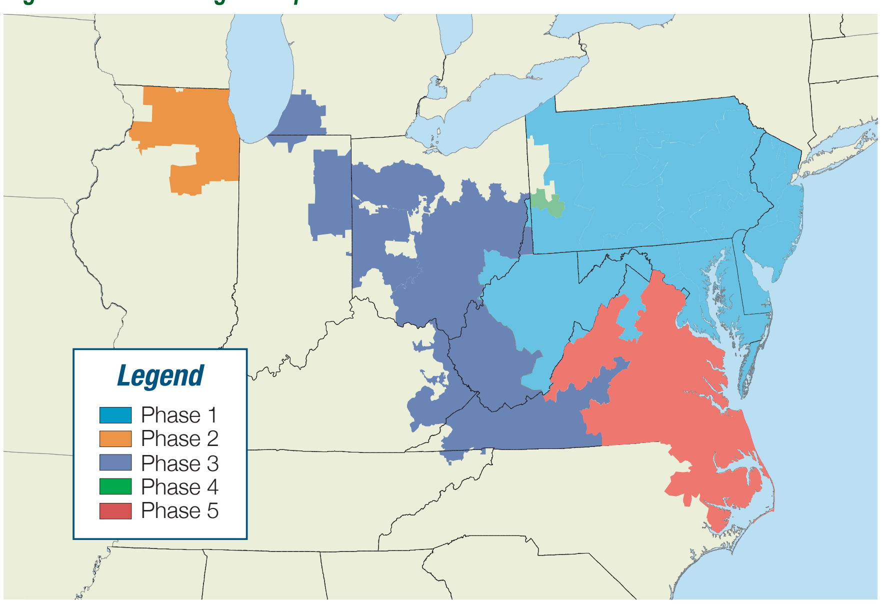
- **Phase 2 (2004).** The five-month period from May 1, through September 30, 2004, during which PJM was comprised of the Mid-Atlantic Region, including its 11 zones, the AP Control Zone and the ComEd Control Area.[4]

- **Phase 3 (2004).** The three-month period from October 1, through December 31, 2004, during which PJM was comprised of the Mid-Atlantic Region, including its 11 zones, the AP Control Zone and the ComEd Control Zone plus the American Electric Power Control Zone (AEP) and The Dayton Power & Light Company Control Zone (DAY). The ComEd Control Area became the ComEd Control Zone on October 1.

- **Phase 4 (2005).** The four-month period from January 1, through April 30, 2005, during which PJM was comprised of the Mid-Atlantic Region, including its 11 zones, the AP Control Zone, the ComEd Control Zone, the AEP Control Zone and the DAY Control Zone plus the Duquesne Light Company (DLCO) Control Zone which was integrated into PJM on January 1, 2005.

- **Phase 5 (2005).** The eight-month period from May 1, through December 31, 2005, during which PJM was comprised of the Phase 4 elements plus the Dominion Control Zone which was integrated into PJM on May 1, 2005.

Figure A-2 PJM integration phases



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

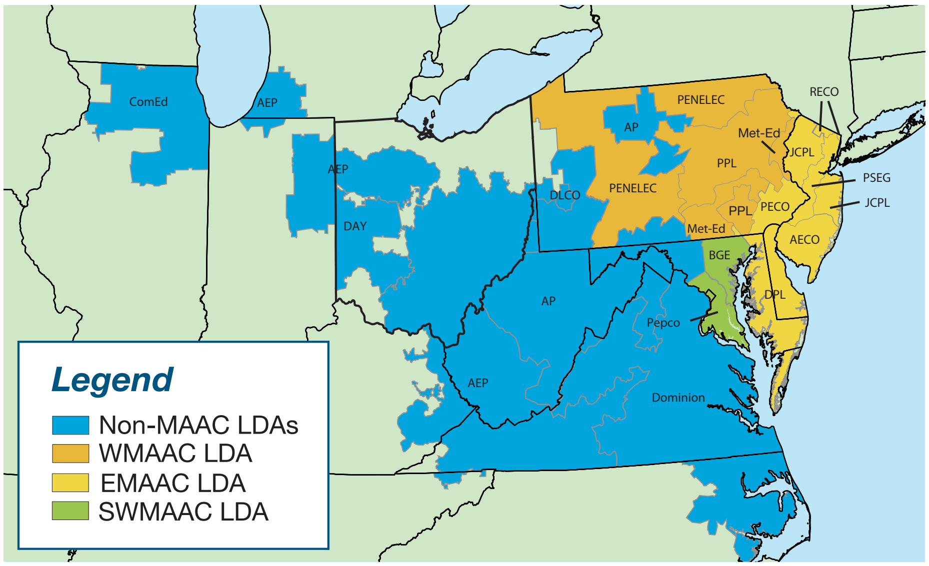
3 Zones, control zones and control areas are geographic areas that customarily bear the name of a large utility service provider operating within their boundaries. Names apply to the geographic area, not to any single company. The geographic areas did not change with the formalization of these concepts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

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

© 2010 Monitoring Analytics, LLC www.monitoringanalytics.com

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

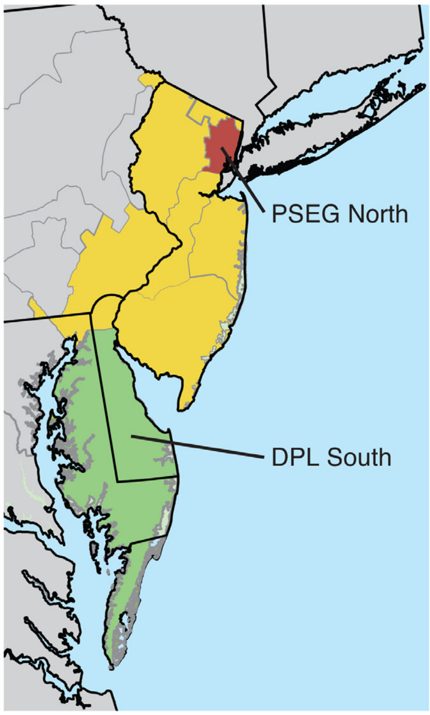
Figure A-3 PJM locational deliverability areas



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

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

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



© 2010 Monitoring Analytics, LLC www.monitoringanalytics.com

APPENDIX B – PJM MARKET MILESTONES

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

© 2010 Monitoring Analytics, LLC www.monitoringanalytics.com

APPENDIX C – ENERGY MARKET

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

Load

Frequency Distribution of Load

Table C-1 provides the frequency distributions of PJM accounting load by hour, for the calendar years 2005 to 2009.[1] The table shows the number of hours (frequency) and the cumulative percent of hours (cumulative percent) when the load was between 0 GWh and 20 GWh and then within a given 5-GWh load interval, or for the cumulative column, within the interval plus all the lower load intervals. The integrations of the AP Control Zone 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.[2]

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 GWh to 80 GWh at 16.1 percent of the hours. The next most frequently occurring interval was 65 GWh to 70 GWh at 13.4 percent of the hours. Load was less than 85 GWh for 72.9 percent of the time, less than 100 GWh for 88.2 percent of the time and less than 130 GWh for all but 22 hours.

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

During 2007, the most frequently occurring load interval was 80 GWh to 85 GWh at 15.3 percent of the hours. The next most frequently occurring interval was 75 GWh to 80 GWh at 14.0 percent of the hours. Load was less than 85 GWh for 62.6 percent of the hours, less than 100 GWh for 88.8 percent of the hours and less than 130 GWh for all but 15 hours.

During 2008, the most frequently occurring load interval was 75 GWh to 80 GWh at 17.5 percent of the hours. The next most frequently occurring interval was 80 GWh to 85 GWh at 13.8 percent of the hours. Load was less than 85 GWh for 68.8 percent of the hours, less than 100 GWh for 91.9 percent of the hours and less than 130 GWh for all hours.

During 2009, the most frequently occurring load interval was 75 GWh to 80 GWh at 17.0 percent of the hours. The next most frequently occurring interval was 70 GWh to 75 GWh at 15.3 percent of the hours. Load was less than 85 GWh for 76.2 percent of the hours, less than 100 GWh for 95.4 percent of the hours and less than 125 GWh for all hours.

1 The definitions of load are discussed in the *2009 State of the Market Report for PJM*, Volume II, Appendix I, "Load Definitions."

2 See the *2009 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography."

© 2010 Monitoring Analytics, LLC www.monitoringanalytics.com

Table C-1 Frequency distribution of PJM real-time, hourly load: Calendar years 2005 to 2009

	2005		2006		2007		2008		2009	
Load (GWh)	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent
0 to 20	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
20 to 25	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
25 to 30	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
30 to 35	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
35 to 40	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
40 to 45	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
45 to 50	71	0.81%	2	0.02%	0	0.00%	0	0.00%	15	0.17%
50 to 55	286	4.08%	129	1.50%	79	0.90%	127	1.45%	376	4.46%
55 to 60	636	11.34%	504	7.25%	433	5.84%	517	7.33%	738	12.89%
60 to 65	843	20.96%	689	15.11%	637	13.12%	667	14.92%	836	22.43%
65 to 70	1,170	34.32%	967	26.15%	890	23.28%	941	25.64%	915	32.88%
70 to 75	1,089	46.75%	1,079	38.47%	878	33.30%	1,048	37.57%	1,342	48.20%
75 to 80	1,407	62.81%	1,501	55.61%	1,227	47.31%	1,535	55.04%	1,488	65.18%
80 to 85	887	72.93%	1,337	70.87%	1,338	62.58%	1,208	68.80%	966	76.21%
85 to 90	557	79.29%	943	81.63%	981	73.78%	916	79.22%	742	84.68%
90 to 95	453	84.46%	569	88.13%	741	82.24%	655	86.68%	549	90.95%
95 to 100	330	88.23%	295	91.50%	577	88.82%	457	91.88%	388	95.38%
100 to 105	308	91.75%	215	93.95%	382	93.18%	292	95.21%	205	97.72%
105 to 110	283	94.98%	161	95.79%	223	95.73%	181	97.27%	121	99.10%
110 to 115	169	96.91%	145	97.44%	179	97.77%	133	98.78%	48	99.65%
115 to 120	113	98.20%	102	98.61%	106	98.98%	58	99.44%	26	99.94%
120 to 125	93	99.26%	45	99.12%	43	99.47%	35	99.84%	5	100.00%
125 to 130	43	99.75%	27	99.43%	31	99.83%	14	100.00%	0	0.00%
130 to 135	22	100.00%	19	99.65%	12	99.97%	0	0.00%	0	0.00%
135 to 140	0	0.00%	19	99.86%	3	100.00%	0	0.00%	0	0.00%
> 140	0	0.00%	12	100.00%	0	0.00%	0	0.00%	0	0.00%

Off-Peak and On-Peak Load

Table C-2 presents summary load statistics for 1998 to 2009 for the off-peak and on-peak hours, while Table C-3 shows the percent change in load on a year-to-year basis. The on-peak period is defined for each weekday (Monday to Friday) as the hour ending 0800 to the hour ending 2300 Eastern Prevailing Time (EPT), excluding North American Electric Reliability Council (NERC) holidays. Table C-2 shows that on-peak load was 22.7 percent higher than off-peak load in 2009. Average load during on-peak hours in 2009 was 4.1 percent lower than in 2008. Off-peak load in 2009 was 4.8 percent lower than in 2008.[3] (See Table C-3)

3 The increase in on-peak median load for 2006 was incorrectly reported as 3.2 percent in the *2006 State of the Market Report* rather than the 2.8 percent shown here.

© 2010 Monitoring Analytics, LLC www.monitoringanalytics.com

Table C-2 Off-peak and on-peak load (MW): Calendar years 1998 to 2009

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

Table C-3 Multiyear change in load: Calendar years 1998 to 2009

	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	18.4%	17.5%	(0.8%)	15.7%	16.0%	0.0%	44.6%	53.9%	6.1%
2003	5.9%	3.6%	(2.4%)	7.8%	6.4%	(0.8%)	(9.3%)	(27.3%)	(19.7%)
2004	32.8%	34.2%	1.6%	30.5%	38.7%	5.6%	95.6%	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%	2.8%	0.0%	(10.9%)	(16.9%)	(6.7%)
2007	2.4%	3.1%	0.8%	2.1%	4.3%	1.7%	1.3%	(5.8%)	(7.1%)
2008	(1.8%)	(3.5%)	(1.6%)	(1.7%)	(3.5%)	(1.6%)	(1.1%)	(6.0%)	(5.8%)
2009	(4.8%)	(4.1%)	0.8%	(4.8%)	(4.2%)	0.8%	(4.0%)	(6.1%)	(2.0%)

© 2010 Monitoring Analytics, LLC www.monitoringanalytics.com

Locational Marginal Price (LMP)

In assessing changes in LMP over time, the Market Monitoring Unit (MMU) examines three measures: simple LMP, load-weighted LMP and fuel-cost-adjusted, load-weighted LMP. Simple 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.[4]

Real-Time LMP

Frequency Distribution of Real-Time LMP

Table C-4 provides frequency distributions of PJM real-time hourly LMP for the calendar years 2005 to 2009. The table shows the number of hours (frequency) and the cumulative percent of hours (cumulative percent) when the hourly PJM LMP was within a given $10 per MWh price interval and lower than $300 per MWh, or within a given $100 per MWh price interval and higher than $300 per MWh, or for the cumulative column, within the interval plus all the lower price intervals.

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, less than $100 per MWh for 87.4 percent of the hours and LMP was $200 per MWh or greater for 35 hours (0.4 percent of the hours). 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 2007, LMP was in the $20 per MWh to $30 per MWh interval most frequently (17.9 percent of the time) and in the $30 per MWh to $40 per MWh interval next most frequently (16.8 percent of the hours). In 2007, LMP was $60 per MWh or less for 60.7 percent of the hours and was $100 per MWh or less for 91.0 percent of the hours. LMP was more than $200 per MWh for 35 hours (0.4 percent of the hours). In 2008, LMP was in the $40 per MWh to $50 per MWh interval most frequently (17.5 percent of the time) and in the $30 per MWh to $40 per MWh interval next most frequently (16.4 percent of the hours). In 2009, LMP was in the $20 per MWh to $30 per MWh interval most frequently (33.9 percent of the hours) and in the $30 per MWh to $40 per MWh interval next most frequently (33.7 percent of the hours).

4 See the *2009 State of the Market Report for PJM*, Volume II, Appendix H, "Calculating Locational Marginal Price."

© 2010 Monitoring Analytics, LLC www.monitoringanalytics.com

Table C-4 Frequency distribution by hours of PJM Real-Time Energy Market LMP (Dollars per MWh): Calendar years 2005 to 2009

	2005		2006		2007		2008		2009	
LMP	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent
$10 and less	142	1.62%	85	0.97%	56	0.64%	94	1.07%	117	1.34%
$10 to $20	259	4.58%	247	3.79%	185	2.75%	129	2.54%	218	3.82%
$20 to $30	1,290	19.30%	1,958	26.14%	1,571	20.68%	490	8.12%	2,970	37.73%
$30 to $40	1,793	39.77%	1,840	47.15%	1,470	37.47%	1,443	24.54%	2,951	71.42%
$40 to $50	1,172	53.15%	1,405	63.18%	1,108	50.11%	1,533	42.00%	1,269	85.90%
$50 to $60	877	63.16%	1,040	75.06%	931	60.74%	1,212	55.79%	555	92.24%
$60 to $70	730	71.50%	662	82.61%	827	70.18%	845	65.41%	276	95.39%
$70 to $80	568	77.98%	479	88.08%	726	78.47%	709	73.49%	151	97.11%
$80 to $90	453	83.15%	347	92.04%	646	85.84%	502	79.20%	95	98.20%
$90 to $100	374	87.42%	230	94.67%	451	90.99%	385	83.58%	62	98.90%
$100 to $110	297	90.81%	162	96.52%	240	93.73%	352	87.59%	30	99.25%
$110 to $120	208	93.18%	95	97.60%	178	95.76%	265	90.61%	21	99.49%
$120 to $130	159	95.00%	61	98.30%	110	97.02%	199	92.87%	15	99.66%
$130 to $140	110	96.26%	46	98.82%	76	97.89%	144	94.51%	7	99.74%
$140 to $150	94	97.33%	27	99.13%	53	98.49%	111	95.78%	9	99.84%
$150 to $160	53	97.93%	16	99.32%	26	98.79%	102	96.94%	3	99.87%
$160 to $170	57	98.58%	11	99.44%	29	99.12%	68	97.71%	3	99.91%
$170 to $180	51	99.17%	6	99.51%	18	99.33%	52	98.30%	5	99.97%
$180 to $190	22	99.42%	3	99.54%	9	99.43%	45	98.82%	0	99.97%
$190 to $200	16	99.60%	5	99.60%	15	99.60%	29	99.15%	1	99.98%
$200 to $210	12	99.74%	3	99.63%	6	99.67%	20	99.37%	1	99.99%
$210 to $220	10	99.85%	7	99.71%	4	99.71%	11	99.50%	1	100.00%
$220 to $230	5	99.91%	1	99.73%	4	99.76%	14	99.66%	0	0.00%
$230 to $240	1	99.92%	1	99.74%	2	99.78%	10	99.77%	0	0.00%
$240 to $250	1	99.93%	1	99.75%	5	99.84%	2	99.80%	0	0.00%
$250 to $260	3	99.97%	1	99.76%	2	99.86%	5	99.85%	0	0.00%
$260 to $270	2	99.99%	0	99.76%	4	99.91%	4	99.90%	0	0.00%
$270 to $280	0	99.99%	3	99.79%	0	99.91%	1	99.91%	0	0.00%
$280 to $290	1	100.00%	1	99.81%	0	99.91%	1	99.92%	0	0.00%
$290 to $300	0	0.00%	0	99.81%	0	99.91%	0	99.92%	0	0.00%
$300 to $400	0	0.00%	11	99.93%	2	99.93%	6	99.99%	0	0.00%
$400 to $500	0	0.00%	2	99.95%	4	99.98%	1	100.00%	0	0.00%
$500 to $600	0	0.00%	1	99.97%	1	99.99%	0	0.00%	0	0.00%
$600 to $700	0	0.00%	1	99.98%	1	100.00%	0	0.00%	0	0.00%
> $700	0	0.00%	2	100.00%	0	0.00%	0	0.00%	0	0.00%

© 2010 Monitoring Analytics, LLC www.monitoringanalytics.com

Off-Peak and On-Peak, PJM Real-Time, Load-Weighted LMP: 2008 to 2009

Table C-5 shows load-weighted, average LMP for 2008 and 2009 during off-peak and on-peak periods. In 2009, the on-peak, load-weighted LMP was 30.2 percent higher than the off-peak LMP, while in 2008, it was 45.8 percent higher. On-peak, load-weighted, average LMP in 2009 was 47.6 percent lower than in 2008. Off-peak, load-weighted LMP in 2009 was 41.3 percent lower than in 2008. The on-peak median LMP was lower in 2009 than in 2008 by 47.6 percent; off-peak median LMP was lower in 2009 than in 2008 by 35.4 percent. Dispersion in load-weighted LMP, as indicated by standard deviation, was 56.0 percent lower in 2009 than in 2008 during on-peak hours and was 53.6 percent lower during off-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 2009 as compared to 2008 during on-peak periods (14.3 percent in 2009 compared to 14.2 percent in 2008).

Table C-5 Off-peak and on-peak, PJM load-weighted, average LMP (Dollars per MWh): Calendar years 2008 to 2009

	2008			2009			Difference 2008 to 2009		
	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	$57.55	$83.90	1.46	$33.76	$43.95	1.30	(41.3%)	(47.6%)	(10.7%)
Median	$45.43	$73.47	1.62	$29.33	$38.46	1.31	(35.4%)	(47.6%)	(18.9%)
Standard deviation	$36.64	$40.72	1.11	$16.99	$17.93	1.06	(53.6%)	(56.0%)	(5.0%)

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

In a competitive market, changes in LMP result from changes in demand and changes in supply. As competitive offers are equivalent to the marginal cost of generation and fuel costs make up about 88 percent of marginal cost on average for marginal units, fuel cost is a key factor affecting supply and, therefore, the competitive clearing price. In a competitive market, if fuel costs increase and nothing else changes, the competitive price also increases.

The impact of fuel cost on LMP depends on the fuel burned by the marginal units. To account for differences in the impact of fuel costs on prices between different time periods, the fuel-cost-adjusted, load-weighted LMP is used to compare load-weighted LMPs using fuel costs from a base period.[5]

Table C-6 shows the real-time, load-weighted, average LMP for 2008 and the real-time, fuel-cost-adjusted, load-weighted, average LMP for 2009 for on-peak and off-peak hours. During on-peak hours, the real-time, fuel-cost-adjusted, load-weighted, average LMP in 2009 decreased by 13.3 percent over the real-time, load-weighted LMP in 2008. The real-time, fuel-cost-adjusted, load-weighted LMP in 2009 decreased by 6.3 percent in the off-peak hours compared to the real-time, load-weighted LMP in 2008.

5 See the *2009 State of the Market Report for PJM*, Volume II, Appendix K, "Calculation and Use of Generator Sensitivity/Unit Participation Factors."

© 2010 Monitoring Analytics, LLC www.monitoringanalytics.com

Table C-6 On-peak and off-peak real-time PJM fuel-cost-adjusted, load-weighted, average LMP (Dollars per MWh): Calendar year 2009

	2008 Load-Weighted LMP	2009 Fuel-Cost-Adjusted, Load-Weighted LMP	Change
On Peak	$83.90	$72.70	(13.3%)
Off Peak	$57.55	$53.92	(6.3%)

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

Table C-7 shows that the PJM load-weighted, average LMP during constrained hours was 43.9 percent lower in 2009 than it had been in 2008.[6] The load-weighted, median LMP during constrained hours was 40.9 percent lower in 2009 than in 2008 and the standard deviation was 54.6 percent lower in 2009 than in 2008.[7]

Table C-7 PJM real-time load-weighted, average LMP during constrained hours (Dollars per MWh): Calendar years 2008 to 2009

	2008	2009	Difference
Average	$72.90	$40.88	(43.9%)
Median	$60.53	$35.75	(40.9%)
Standard deviation	$41.92	$19.02	(54.6%)

Table C-8 provides a comparison of PJM load-weighted, average LMP during constrained and unconstrained hours for 2008 and 2009. In 2009, load-weighted, average LMP during constrained hours was 25.0 percent higher than load-weighted, average LMP during unconstrained hours. The comparable number for 2008 was 22.5 percent.[8]

Table C-8 PJM load-weighted, average LMP during constrained and unconstrained hours (Dollars per MWh): Calendar years 2008 to 2009

	2008			2009		
	Unconstrained Hours	Constrained Hours	Difference	Unconstrained Hours	Constrained Hours	Difference
Average	$59.49	$72.90	22.5%	$32.71	$40.88	25.0%
Median	$53.52	$60.53	13.1%	$29.95	$35.75	19.3%
Standard deviation	$31.68	$41.92	32.3%	$13.26	$19.02	43.4%

6 A constrained hour, or a constraint hour, is any hour during which one or more facilities are congested. Since the *2006 State of the Market Report for PJM,* in order to have a consistent metric for real-time and day-ahead congestion frequency, real-time congestion frequency has been 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 for PJM*, 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 for PJM*, 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.

7 The average real-time, load-weighted LMP in constrained hours for 2008 changed from $72.28 to $72.90, the median changed from $60.00 to $60.53, and the standard deviation changed from $41.58 to $41.92, compared to what was reported in the 2008 State of the Market Report for PJM due to an increase in the number of constrained hours. The change resulted from the correction of a data error.

8 The average real-time, load-weighted LMP on unconstrained hours in 2008 changed from $64.94 to $59.49, the median changed from $56.52 to $53.52, and the standard deviation changed from $36.89 to $31.68, compared to what was reported in the *2008 State of the Market Report for PJM* due to an increase in the number of constrained hours. The change resulted from the correction of a data error.

Table C-9 shows the number of hours and the number of constrained hours during each month in 2008 and 2009. There were 6,657 constrained hours in 2009 and 7,606 in 2008, an decrease of approximately 12.5 percent. Table C-9 also shows that the average number of constrained hours per month was lower in 2009 than in 2008, with 555 per month in 2009 versus 634 per month in 2008.[9]

Table C-9 PJM real-time constrained hours: Calendar years 2008 to 2009

	2008 Constrained Hours	2009 Constrained Hours	Total Hours
Jan	638	701	744
Feb	507	571	696
Mar	560	596	743
Apr	671	552	720
May	638	439	744
Jun	697	557	720
Jul	711	536	744
Aug	648	623	744
Sep	673	494	720
Oct	718	562	744
Nov	591	520	721
Dec	554	506	744
Avg	634	555	732

Day-Ahead and Real-Time LMP

On average, prices in the Real-Time Energy Market in 2009 were slightly higher than those in the Day-Ahead Energy Market and real-time prices showed greater dispersion. This pattern of system average LMP distribution for 2009 can be seen by comparing Table C-4 and Table C-10. Table C-10 shows frequency distributions of PJM day-ahead hourly LMP for the calendar years 2005 to 2009. Together the tables 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 with 33.9 percent of the hours in 2009. In the PJM Day-Ahead Energy Market, the most frequently occurring price interval was the \$30 per MWh to \$40 per MWh interval with 36.8 percent of the hours in 2009. The standard deviation of the simple average real-time LMP is higher than that of simple average day-ahead LMP (\$17.12 and \$13.39) and the standard deviation of the load-weighted real-time LMP is higher than that of load-weighted day-ahead LMP (\$18.21 and \$14.03). In the Real-Time Energy Market, prices were above \$100 per MWh for 96 hours (1.1 percent of the hours), reaching a high for the year of \$212.14 per MWh on January 16, 2009, during the hour ending 700 EPT. In the Day-Ahead Energy Market, prices were above \$100 per MWh for 27 hours (0.3 percent of the hours) and reached a high for the year of \$123.59 per MWh on March 3, 2009, during the hour ending 800 EPT.

9 The average number of constrained hours in July, 2008 changed from 513 to 711, compared to what was reported in the *2008 State of the Market Report for PJM*. The change resulted from the correction of a data error.

© 2010 Monitoring Analytics, LLC www.monitoringanalytics.com

Table C-10 Frequency distribution by hours of PJM Day-Ahead Energy Market LMP (Dollars per MWh): Calendar years 2005 to 2009

	2005		2006		2007		2008		2009	
LMP	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent
$10 and less	47	0.54%	11	0.13%	3	0.03%	0	0.00%	23	0.26%
$10 to $20	162	2.39%	147	1.80%	88	1.04%	19	0.22%	343	4.18%
$20 to $30	1,022	14.05%	1,610	20.18%	1,291	15.78%	320	3.86%	2,380	31.35%
$30 to $40	1,753	34.06%	1,747	40.13%	1,495	32.84%	1,148	16.93%	3,221	68.12%
$40 to $50	1,382	49.84%	1,890	61.70%	1,221	46.78%	1,546	34.53%	1,717	87.72%
$50 to $60	1,102	62.42%	1,364	77.27%	1,266	61.23%	1,491	51.50%	557	94.08%
$60 to $70	812	71.69%	905	87.60%	1,301	76.08%	1,107	64.11%	253	96.96%
$70 to $80	686	79.52%	524	93.58%	939	86.80%	942	74.83%	138	98.54%
$80 to $90	524	85.50%	237	96.29%	504	92.56%	682	82.59%	68	99.32%
$90 to $100	388	89.93%	145	97.95%	264	95.57%	542	88.76%	33	99.69%
$100 to $110	263	92.93%	65	98.69%	155	97.34%	289	92.05%	19	99.91%
$110 to $120	207	95.30%	38	99.12%	104	98.53%	193	94.25%	6	99.98%
$120 to $130	151	97.02%	11	99.25%	59	99.20%	131	95.74%	2	100.00%
$130 to $140	102	98.18%	8	99.34%	33	99.58%	112	97.02%	0	0.00%
$140 to $150	64	98.92%	8	99.43%	13	99.73%	67	97.78%	0	0.00%
$150 to $160	46	99.44%	7	99.51%	8	99.82%	54	98.39%	0	0.00%
$160 to $170	27	99.75%	6	99.58%	7	99.90%	46	98.92%	0	0.00%
$170 to $180	11	99.87%	6	99.65%	3	99.93%	23	99.18%	0	0.00%
$180 to $190	8	99.97%	3	99.68%	4	99.98%	20	99.41%	0	0.00%
$190 to $200	1	99.98%	3	99.71%	1	99.99%	16	99.59%	0	0.00%
$200 to $210	2	100.00%	3	99.75%	1	100.00%	8	99.68%	0	0.00%
$210 to $220	0	0.00%	3	99.78%	0	0.00%	9	99.78%	0	0.00%
$220 to $230	0	0.00%	1	99.79%	0	0.00%	4	99.83%	0	0.00%
$230 to $240	0	0.00%	3	99.83%	0	0.00%	3	99.86%	0	0.00%
$240 to $250	0	0.00%	2	99.85%	0	0.00%	2	99.89%	0	0.00%
$250 to $260	0	0.00%	1	99.86%	0	0.00%	0	99.89%	0	0.00%
$260 to $270	0	0.00%	2	99.89%	0	0.00%	4	99.93%	0	0.00%
$270 to $280	0	0.00%	1	99.90%	0	0.00%	0	99.93%	0	0.00%
$280 to $290	0	0.00%	1	99.91%	0	0.00%	2	99.95%	0	0.00%
$290 to $300	0	0.00%	1	99.92%	0	0.00%	2	99.98%	0	0.00%
>$300	0	0.00%	7	100.00%	0	0.00%	2	100.00%	0	0.00%

© 2010 Monitoring Analytics, LLC www.monitoringanalytics.com

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

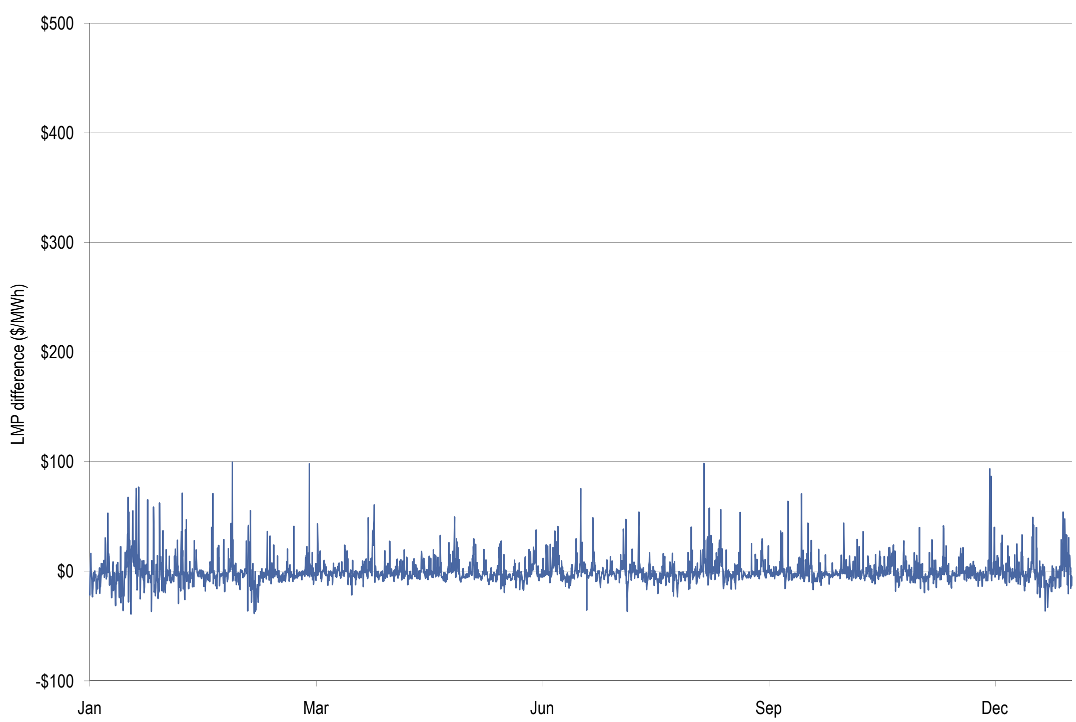
Table C-11 shows PJM simple average LMP during off-peak and on-peak periods for the Day-Ahead and Real-Time Energy Markets during calendar year 2009. On-peak, day-ahead and real-time, average LMPs were 34.9 percent and 33.2 percent higher, than the corresponding off-peak average LMPs. Since the mean 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 (13.8 percent and 12.6 percent compared to 7.9 percent and 9.6 percent). The differences reflect larger positive skewness in the Real-Time Energy Market.

Figure C-1 and Figure C-2 show the difference between real-time and day-ahead LMP during calendar year 2009 during the on-peak and off-peak hours. The difference between real-time and day-ahead average LMP during on-peak hours was $0.14 per MWh. (Day-ahead LMP was higher than real-time LMP.) During the off-peak hours, the difference between real-time and day-ahead average LMP was $0.28 per MWh. (Day-ahead LMP was lower than real-time LMP.)

Table C-11 Off-peak and on-peak, simple average LMP (Dollars per MWh): Calendar year 2009

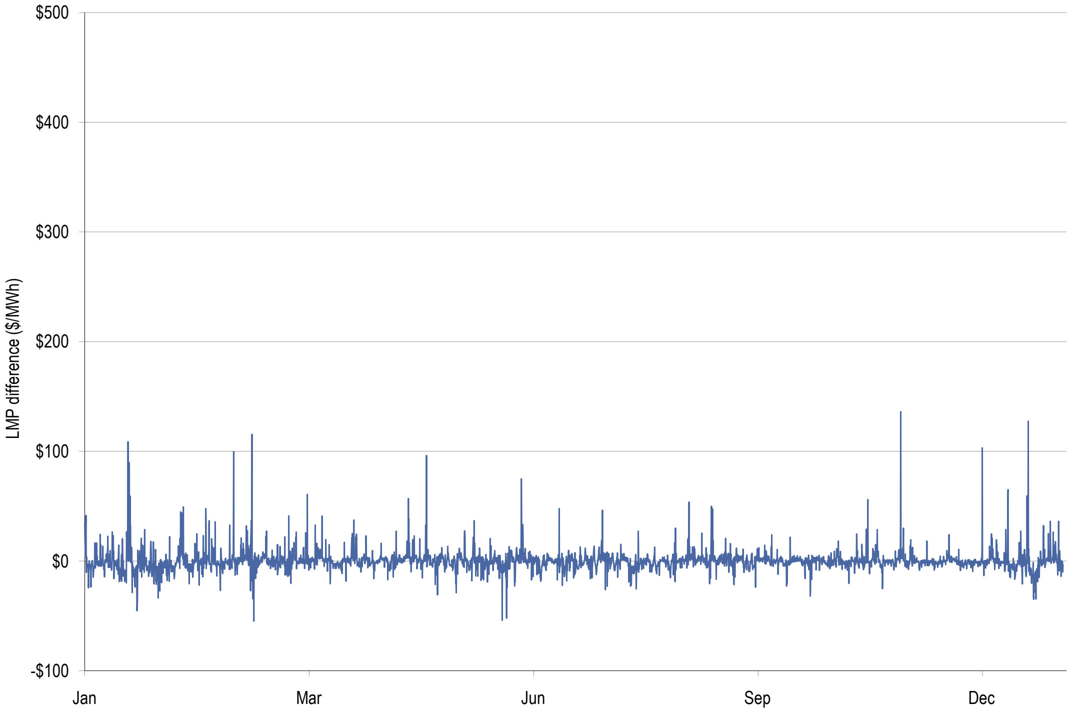
	Day Ahead			Real Time			Difference in Real Time Relative to Day Ahead		
	Off Peak	On Peak	On Peak/ Off Peak	Off Peak	On Peak	On Peak/ Off Peak	Off Peak	On Peak	On Peak/ Off Peak
Average	$31.81	$42.91	1.35	$32.10	$42.76	1.33	0.9%	(0.3%)	(1.2%)
Median	$29.02	$39.78	1.37	$28.49	$37.58	1.32	(1.8%)	(5.5%)	(3.8%)
Standard deviation	$11.82	$12.60	1.07	$15.63	$16.98	1.09	32.2%	34.7%	1.9%

Figure C-1 Hourly real-time LMP minus day-ahead LMP (On-peak hours): Calendar year 2009



© 2010 Monitoring Analytics, LLC www.monitoringanalytics.com

Figure C-2 Hourly real-time LMP minus day-ahead LMP (Off-peak hours): Calendar year 2009



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

Table C-12 and Table C-13 show the on-peak and off-peak, simple average LMPs for each zone in the Day-Ahead and Real-Time Energy Markets during calendar year 2009. The zone with the maximum difference between on-peak real-time and day-ahead LMP was the AECO Control Zone with a real-time, on-peak, zonal LMP that was $1.24 lower than its day-ahead, on-peak, zonal LMP. The AEP Control Zone had the smallest difference with its real-time, on-peak, zonal LMP $0.12 lower than its day-ahead, on-peak, zonal LMP. (See Table C-12) The DLCO Control Zone had the largest difference between off-peak zonal, real-time and day-ahead LMP, with real-time LMP that was $0.94 higher than day-ahead LMP. The zone with the smallest difference between off-peak, zonal, real-time and day-ahead LMP was the PENELEC Control Zone with a real-time LMP that was $0.02 higher than day-ahead LMP. (See Table C-13)

Table C-12 On-peak, zonal, simple average day-ahead and real-time LMP (Dollars per MWh): Calendar year 2009

	Day Ahead	Real Time	Difference	Difference as Percent Real Time
AECO	$47.98	$46.73	($1.24)	(2.66%)
AEP	$38.29	$38.17	($0.12)	(0.33%)
AP	$43.38	$43.97	$0.58	1.33%
BGE	$49.14	$48.03	($1.11)	(2.32%)
ComEd	$35.24	$35.39	$0.15	0.41%
DAY	$37.91	$38.30	$0.40	1.03%
DLCO	$37.59	$37.36	($0.23)	(0.62%)
Dominion	$46.25	$45.51	($0.74)	(1.62%)
DPL	$48.14	$47.40	($0.74)	(1.55%)
JCPL	$47.81	$47.19	($0.62)	(1.32%)
Met-Ed	$46.51	$46.00	($0.51)	(1.12%)
PECO	$46.96	$45.80	($1.16)	(2.53%)
PENELEC	$42.63	$42.09	($0.54)	(1.28%)
Pepco	$49.19	$48.65	($0.54)	(1.10%)
PPL	$46.08	$45.38	($0.70)	(1.55%)
PSEG	$48.42	$47.73	($0.70)	(1.46%)
RECO	$47.27	$46.88	($0.39)	(0.84%)

Table C-13 Off-peak, zonal, simple average LMP (Dollars per MWh): Calendar year 2009

	Day Ahead	Real Time	Difference	Difference as Percent Real Time
AECO	$35.71	$35.35	($0.35)	(1.00%)
AEP	$29.18	$29.64	$0.46	1.54%
AP	$32.90	$33.30	$0.40	1.21%
BGE	$36.79	$36.17	($0.63)	(1.74%)
ComEd	$23.41	$23.48	$0.07	0.28%
DAY	$28.57	$29.27	$0.70	2.39%
DLCO	$27.71	$28.65	$0.94	3.29%
Dominion	$35.60	$35.16	($0.44)	(1.26%)
DPL	$36.11	$35.81	($0.29)	(0.82%)
JCPL	$35.69	$35.42	($0.27)	(0.75%)
Met-Ed	$34.93	$34.61	($0.32)	(0.92%)
PECO	$35.38	$34.90	($0.48)	(1.38%)
PENELEC	$32.23	$32.25	$0.02	0.06%
Pepco	$36.70	$35.92	($0.77)	(2.15%)
PPL	$34.46	$34.22	($0.24)	(0.70%)
PSEG	$36.06	$35.60	($0.45)	(1.28%)
RECO	$35.34	$34.63	($0.71)	(2.06%)

© 2010 Monitoring Analytics, LLC www.monitoringanalytics.com

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

Table C-14 shows the number of constrained hours for the Day-Ahead and Real-Time Energy Markets and the total number of hours in each month for 2009. Overall, there were 6,657 constrained hours in the Real-Time Energy Market and 8,485 constrained hours in the Day-Ahead Energy Market. Table C-14 shows that in every month of calendar year 2009, excluding month of June, 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 27.5 percent more constrained hours than the Real-Time Energy Market.

Table C-14 PJM day-ahead and real-time, market-constrained hours: Calendar year 2009

	DA Constrained Hours	RT Constrained Hours	Total Hours
Jan	744	701	744
Feb	672	571	672
Mar	741	596	743
Apr	720	552	720
May	741	439	744
Jun	552	557	720
Jul	744	536	744
Aug	744	623	744
Sep	720	494	720
Oct	736	562	744
Nov	681	520	721
Dec	690	506	744
Avg	707	555	730

Table C-15 shows PJM simple average LMP during constrained and unconstrained hours in the Day-Ahead and Real-Time Energy Markets. In the Day-Ahead Energy Market, average LMP during constrained hours was 1.5 percent higher than average LMP during unconstrained hours.[10] In the Real-Time Energy Market, average LMP during constrained hours was 24.6 percent higher than average LMP during unconstrained hours. Average LMP during constrained hours was 5.2 percent higher in the Real-Time Energy Market than in the Day-Ahead Energy Market and LMP during unconstrained hours was 14.3 percent lower in the Real-Time Energy Market than in the Day-Ahead Energy Market.

10 This comparison is of limited usefulness as there were only 275 day-ahead unconstrained hours.

Table C-15 PJM simple average LMP during constrained and unconstrained hours (Dollars per MWh): Calendar year 2009

	Day Ahead			Real Time		
	Unconstrained Hours	Constrained Hours	Difference	Unconstrained Hours	Constrained Hours	Difference
Average	$36.47	$37.02	1.5%	$31.25	$38.93	24.6%
Median	$36.63	$35.13	(4.1%)	$29.14	$34.34	17.8%
Standard deviation	$12.21	$13.43	9.9%	$12.71	$17.90	40.9%

Taken together, the data show that simple average LMP in the Day-Ahead Energy Market during constrained hours was $0.02 (0.1 percent) higher than the overall simple average LMP for the Day-Ahead Energy Market, while simple average LMP during unconstrained hours was $0.53 (1.4 percent) lower although these comparisons are of limited usefulness as there were only 275 unconstrained hours in the Day-Ahead Energy Market.[11] In the Real-Time Energy Market, simple average LMP during constrained hours was $1.85 (5.0 percent) higher than the overall simple average LMP for the Real-Time Energy Market, while simple average LMP during unconstrained hours was $5.83 (15.7 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 Markets.

PJM has clear rules limiting the exercise of local market power.[12] The rules provide for offer capping when conditions on the transmission system create a structurally noncompetitive local market, when units in that local market have made noncompetitive offers and when such offers would set the price above the competitive level in the absence of mitigation. Offer caps are set at the level of a competitive offer. Offer-capped units receive the higher of the market price or their offer cap. Thus, if broader market conditions lead to a price greater than the offer cap, the unit receives the higher market price. The rules governing the exercise of local market power recognize that units in certain areas of the system would be in a position to extract monopoly profits, but for these rules.

Under existing rules, PJM suspends offer capping when structural market conditions, as determined by the three pivotal supplier test, indicate that suppliers are reasonably likely to behave in a competitive manner.[13] 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.

11 See the *2009 State of the Market Report for PJM*, Volume II, Section 2, "Energy Market, Part 1" for a discussion of load and LMP.
12 See PJM. "Amended and Restated Operating Agreement (OA)," Schedule 1, Section 6.4.2 (January 19, 2007).
13 See the *2009 State of the Market Report for PJM*, Volume II, Appendix L, "Three Pivotal Supplier Test."

© 2010 Monitoring Analytics, LLC www.monitoringanalytics.com

Levels of offer capping have generally been low and stable over the last five years. Table C-16 through Table C-19 show offer capping by month, including the number of offer-capped units and the level of offer-capped MW in the Day-Ahead and Real-Time Energy Markets.

Table C-16 Average day-ahead, offer-capped units: Calendar years 2005 to 2009

	2005		2006		2007		2008		2009	
	Avg. Units Capped	Percent	Avg. Units Capped	Percent	Avg. Units Capped	Percent	Avg. Units Capped	Percent	Avg. Units Capped	Percent
Jan	0.4	0.0%	0.1	0.0%	0.2	0.0%	0.5	0.0%	0.7	0.1%
Feb	0.4	0.0%	0.2	0.0%	0.8	0.1%	0.2	0.0%	0.3	0.0%
Mar	0.6	0.1%	0.7	0.1%	0.9	0.1%	0.0	0.0%	0.6	0.1%
Apr	0.4	0.0%	0.2	0.0%	0.2	0.0%	0.2	0.0%	0.0	0.0%
May	0.2	0.0%	0.1	0.0%	0.2	0.0%	0.6	0.1%	0.1	0.0%
Jun	0.4	0.0%	0.7	0.1%	0.8	0.1%	1.5	0.1%	0.3	0.0%
Jul	0.9	0.1%	4.1	0.4%	0.6	0.1%	1.7	0.2%	0.4	0.0%
Aug	1.1	0.1%	4.7	0.5%	1.0	0.1%	0.4	0.0%	0.2	0.0%
Sep	0.2	0.0%	0.6	0.1%	0.2	0.0%	0.4	0.0%	0.1	0.0%
Oct	0.3	0.0%	0.3	0.0%	0.8	0.1%	0.4	0.0%	0.3	0.0%
Nov	0.2	0.0%	0.3	0.0%	0.0	0.0%	0.5	0.1%	0.0	0.0%
Dec	0.7	0.1%	0.5	0.0%	0.1	0.0%	1.3	0.1%	0.0	0.0%

Table C-17 Average day-ahead, offer-capped MW: Calendar years 2005 to 2009

	2005		2006		2007		2008		2009	
	Avg. MW Capped	Percent	Avg. MW Capped	Percent	Avg. MW Capped	Percent	Avg. MW Capped	Percent	Avg. MW Capped	Percent
Jan	87	0.1%	4	0.0%	23	0.0%	16	0.0%	98	0.1%
Feb	75	0.1%	6	0.0%	57	0.1%	11	0.0%	30	0.0%
Mar	57	0.1%	51	0.1%	86	0.1%	2	0.0%	47	0.1%
Apr	34	0.0%	31	0.0%	11	0.0%	31	0.0%	0	0.0%
May	14	0.0%	22	0.0%	38	0.0%	15	0.0%	9	0.0%
Jun	28	0.0%	164	0.2%	28	0.0%	91	0.1%	42	0.0%
Jul	52	0.0%	518	0.5%	45	0.0%	110	0.1%	35	0.0%
Aug	63	0.1%	398	0.4%	58	0.1%	49	0.0%	10	0.0%
Sep	13	0.0%	51	0.1%	14	0.0%	70	0.1%	3	0.0%
Oct	16	0.0%	25	0.0%	77	0.1%	39	0.0%	29	0.0%
Nov	26	0.0%	15	0.0%	4	0.0%	53	0.1%	0	0.0%
Dec	48	0.0%	30	0.0%	4	0.0%	187	0.2%	0	0.0%

Table C-18 Average real-time, offer-capped units: Calendar years 2005 to 2009

	2005		2006		2007		2008		2009	
	Avg. Units Capped	Percent	Avg. Units Capped	Percent	Avg. Units Capped	Percent	Avg. Units Capped	Percent	Avg. Units Capped	Percent
Jan	2.5	0.3%	1.9	0.2%	1.2	0.1%	3.1	0.3%	2.4	0.2%
Feb	1.3	0.1%	2.1	0.2%	4.2	0.4%	2.6	0.3%	1.1	0.1%
Mar	1.4	0.2%	2.3	0.2%	1.9	0.2%	2.7	0.3%	1.8	0.2%
Apr	1.2	0.1%	1.5	0.2%	1.3	0.1%	3.1	0.3%	1.8	0.2%
May	0.8	0.1%	3.4	0.3%	1.9	0.2%	2.1	0.2%	1.0	0.1%
Jun	10.0	1.0%	2.5	0.3%	6.0	0.6%	8.7	0.8%	1.3	0.1%
Jul	13.9	1.4%	8.6	0.9%	4.4	0.4%	5.7	0.6%	1.1	0.1%
Aug	13.7	1.4%	9.5	1.0%	9.6	0.9%	2.1	0.2%	3.0	0.3%
Sep	7.9	0.8%	1.8	0.2%	5.5	0.5%	4.8	0.5%	1.6	0.1%
Oct	7.9	0.8%	1.7	0.2%	5.0	0.5%	2.5	0.2%	1.2	0.1%
Nov	3.3	0.3%	1.1	0.1%	2.9	0.3%	2.3	0.2%	0.6	0.1%
Dec	4.4	0.4%	1.0	0.0%	4.7	0.5%	2.4	0.2%	1.3	0.1%

Table C-19 Average real-time, offer-capped MW: Calendar years 2005 to 2009

	2005		2006		2007		2008		2009	
	Avg. MW Capped	Percent	Avg. MW Capped	Percent	Avg. MW Capped	Percent	Avg. MW Capped	Percent	Avg. MW Capped	Percent
Jan	209	0.3%	42	0.1%	50	0.1%	99	0.1%	158	0.2%
Feb	145	0.2%	67	0.1%	125	0.1%	92	0.1%	92	0.1%
Mar	74	0.1%	88	0.1%	142	0.2%	117	0.2%	147	0.2%
Apr	59	0.1%	75	0.1%	48	0.1%	125	0.2%	151	0.2%
May	78	0.1%	136	0.2%	68	0.1%	59	0.1%	64	0.1%
Jun	652	0.7%	160	0.2%	190	0.2%	415	0.5%	103	0.1%
Jul	819	0.9%	506	0.5%	160	0.2%	202	0.2%	74	0.1%
Aug	908	1.0%	518	0.6%	314	0.3%	114	0.1%	137	0.2%
Sep	477	0.6%	69	0.1%	218	0.3%	186	0.2%	95	0.1%
Oct	337	0.5%	49	0.1%	153	0.2%	177	0.3%	105	0.2%
Nov	129	0.2%	31	0.0%	104	0.1%	164	0.2%	60	0.1%
Dec	156	0.2%	12	0.0%	146	0.2%	200	0.2%	128	0.2%

In order to help understand the frequency of offer capping in more detail, Table C-20 through Table C-24 show the number of generating units that met the specified criteria for total offer-capped run hours and percentage of offer-capped run hours for the years 2005 through 2009.

© 2010 Monitoring Analytics, LLC www.monitoringanalytics.com

Table C-20 Offer-capped unit statistics: Calendar year 2005

Run Hours Offer-Capped, Percent Greater Than Or Equal To:	2005 Offer-Capped Hours					
	Hours ≥ 500	Hours ≥ 400 and < 500	Hours ≥ 300 and < 400	Hours ≥ 200 and < 300	Hours ≥ 100 and < 200	Hours ≥ 1 and < 100
90%	12	1	0	1	2	2
80% and < 90%	7	6	0	6	7	10
75% and < 80%	0	1	3	3	8	3
70% and < 75%	0	0	1	2	4	4
60% and < 70%	1	0	3	2	8	9
50% and < 60%	0	0	2	0	2	10
25% and < 50%	2	9	1	3	10	49
10% and < 25%	0	0	1	0	6	33

Table C-21 Offer-capped unit statistics: Calendar year 2006

Run Hours Offer-Capped, Percent Greater Than Or Equal To:	2006 Offer-Capped Hours					
	Hours ≥ 500	Hours ≥ 400 and < 500	Hours ≥ 300 and < 400	Hours ≥ 200 and < 300	Hours ≥ 100 and < 200	Hours ≥ 1 and < 100
90%	3	0	0	1	2	0
80% and < 90%	1	5	1	4	3	7
75% and < 80%	0	1	0	2	6	10
70% and < 75%	0	0	0	2	6	18
60% and < 70%	0	1	1	3	5	27
50% and < 60%	0	2	0	0	0	12
25% and < 50%	0	2	1	2	1	31
10% and < 25%	0	0	0	3	9	41

Table C-22 Offer-capped unit statistics: Calendar year 2007

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

Table C-23 Offer-capped unit statistics: Calendar year 2008

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

Table C-24 Offer-capped unit statistics: Calendar year 2009

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

© 2010 Monitoring Analytics, LLC www.monitoringanalytics.com

APPENDIX D – INTERCHANGE TRANSACTIONS

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

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

Transactions Background

OASIS Products

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

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

- **Network.** Transmission service that is for the sole purpose of serving network load. Network transmission service is only eligible to network customers.

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

- **Spot Import.** PJM introduced spot market imports with the introduction of the Energy Market on April 1, 1997 (Marginal Clearing Price). It was introduced as an option for non-load serving entities to offer into the PJM spot market at the border/interface as price takers, providing access to the PJM energy markets and reducing the cost of energy through increased competition. Prior to April 2007, PJM did not limit spot import service, preferring to let market prices ration the use of the service which is not physically limited. However, in 2007 PJM interpreted its Joint Operating Agreement (JOA) with the Midwest ISO (MISO) to require a limitation on spot import service in order to limit the impact of such transactions on selected external flowgates. In 2007, spot imports were added to the OASIS to account for the impacts of this network service on flowgates external to the PJM Transmission System. Effective April 2007, the availability of spot import service was limited by the Available Transmission Capacity (ATC) on the transmission path.

Source and Sink

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

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

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

NERC Tagging

A NERC Tag is required for all external energy transactions. A NERC Tag can be created only after a valid transmission reservation is acquired. If a ramp reservation has been made in advance, the market participant can enter the ramp reservation ID on the NERC Tag. If no ramp reservation has been created, upon submission of the NERC Tag, PJM will create a ramp reservation if there is available ramp. If there is no ramp available to match the tagged energy profile, the NERC Tag will be denied.

The NERC Tag requires that the complete path be specified from the GCA to the LCA. This complete path is utilized by PJM to determine the interface pricing point which PJM will associate with the

© 2010 Monitoring Analytics, LLC www.monitoringanalytics.com

transaction. The path specified in the OASIS reflects only the path of energy into or out of PJM to one neighboring balancing authority.

Neighboring Balancing Authority Checkout

PJM operators must verify all requested energy schedules with PJM's neighboring balancing authorities. Only if the neighboring balancing authority agrees with the expected interchange will the transaction flow. If there is a disagreement in the expected interchange for any 15 minute interval, the system operators must work to resolve the difference. It is important that both balancing authorities enter the same values in their Energy Management Systems (EMS) to avoid inadvertent energy from flowing between balancing authorities.

With the exception of the New York Independent System Operator (NYISO), all neighboring balancing authorities handle transaction requests in the same way as PJM (i.e. via the NERC Tag). This helps facilitate interchange transaction checkouts, as all balancing authorities are receiving the same information. While the NYISO also requires NERC Tags, the NYISO utilizes their Market Information System (MIS) as their primary scheduling tool. The NYISO's real-time commitment (RTC) tool evaluates all bids and offers each hour, and performs a least cost economic dispatch solution. The NYISO accepts or denies individual transactions in whole or in part based on this evaluation. Upon market clearing, the NYISO implements NERC Tag adjustments to match the output of the RTC. PJM and the NYISO can verify interchange transactions once the NYISO Tag adjustments are sent and approved. The results of the adjustments made by the NYISO affect PJM operations, as the adjustments often cause large swings in expected ramp for the next hour.

Curtailment of Transactions

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

A dispatchable external energy transaction (also known as "real-time with price") is one in which the market participant designates a floor or ceiling price on their external transaction. For example, an import dispatchable schedule specifies that the market participant only wishes to load the transaction if the LMP at the interface where the transaction is entering the PJM footprint reaches a specified limit (the minimum LMP at which they are willing to sell). An export dispatchable schedule specifies the maximum LMP at the interface where the market participant wishes to purchase the power from PJM.

PJM system operators evaluate dispatchable transactions 30 minutes prior to the start of every hour of the energy profile. If the system operator expects the floor (or ceiling) price to be realized over the next hour, they contact the market participant informing them that they are loading the transaction. Once loaded, the dispatchable transaction will run for the next hour. If at any time the system operator does not believe that the transaction will be economic for the next hour, they will

© 2010 Monitoring Analytics, LLC www.monitoringanalytics.com

elect to curtail the dispatchable transaction. Dispatchable schedules can be viewed as a generation offer, with a minimum run time of one hour. For import dispatchable schedules, if the transaction is loaded and then curtailed, or if the hourly integrated LMP falls below the price specified, the transaction will be made whole through payment of operating reserve credits.

Not willing to pay congestion transactions will be curtailed if there is realized congestion between the designated source and sink.

Transactions utilizing spot import service will be curtailed if the interface price where the transaction enters PJM reaches zero.

A market participant may curtail their own transactions. All self curtailments must be requested on 15 minute intervals. In order for PJM to approve a self curtailment request, there must be available ramp for the modification.

Transmission Loading Relief (TLR)

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

There are seven TLR levels and additional sublevels, determined by the severity of system conditions and whether the interchange transactions contributing to congestion on the impacted flowgates are using firm or non-firm transmission. Reliability coordinators are not required to implement TLRs in order. The TLR levels are described below.[1]

- **TLR Level 0 – TLR concluded:** A TLR Level 0 is initiated when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) violations are mitigated and the system is returned to a reliable state. Upon initiation of a TLR Level 0, transactions with the highest transmission priorities are reestablished first when possible. The purpose of a TLR Level 0 is to inform all affected parties that the TLR has been concluded.

- **TLR Level 1 – Potential SOL or IROL Violations:** A TLR Level 1 is initiated when the transmission system is still in a secure state but a reliability coordinator anticipates a transmission or generation contingency or other operating problem that could lead to a potential violation. No actions are required during a TLR Level 1. The purpose of a TLR Level 1 is to inform other reliability coordinators of a potential SOL or IROL.

- **TLR Level 2 – Hold transfers at present level to prevent SOL or IROL Violations:** A TLR Level 2 is initiated when the transmission system is still in a secure state but one or more transmission facilities are expected to approach, are approaching or have reached their SOL or

1 Additional details regarding the TLR procedure can be found in NERC. "Standard IRO-006-4 – Reliability Coordination – Transmission Loading Relief" (October 23, 2007) (Accessed January 26, 2010) <http://www.nerc.com/files/IRO-006-4.pdf> (KB).

© 2010 Monitoring Analytics, LLC www.monitoringanalytics.com

IROL. The purpose of a TLR Level 2 is to prevent additional transactions that have an adverse affect on the identified transmission facility(ies) from starting.

- **TLR Level 3a – Reallocation of transmission service by curtailing interchange transactions using non-firm point-to-point transmission service to allow interchange transactions using higher priority transmission service:** A TLR Level 3a is initiated when the transmission system is secure but one or more transmission facilities are expected to approach, or are approaching their SOL or IROL, when there are transactions using non-firm point-to-point transmission service that have a greater than 5 percent effect on the facility and when there are transactions using a higher priority point-to-point transmission reservation that wish to begin. Curtailments to transactions in a TLR 3a begin on the top of the hour only. The purpose of TLR Level 3a is to curtail transactions using lower priority non-firm point-to-point transmission to allow transactions using higher priority transmission to flow.

- **TLR Level 3b – Curtail interchange transactions using non-firm transmission service arrangements to mitigate a SOL or IROL violation:** A TLR Level 3b is initiated when one or more transmission facilities is operating above their SOL or IROL; such operation is imminent and it is expected that facilities will exceed their reliability limits if corrective action is not taken; or one or more transmission facilities will exceed their SOL or IROL upon the removal from service of a generating unit or other transmission facility and transactions are flowing that are using non-firm point-to-point transmission service and have a greater than 5 percent impact on the facility. Curtailments of transactions in a TLR 3b can occur at any time within the operating hour. The purpose of a TLR Level 3b is to curtail transactions using non-firm point-to-point transmission service which impact the constraint by greater than 5 percent in order to mitigate a SOL or IROL.

- **TLR Level 4 – Reconfigure Transmission:** A TLR Level 4 is initiated when one or more transmission facilities are above their SOL or IROL limits or such operation is imminent and it is expected that facilities will exceed their reliability limits if corrective action is not taken. Upon issuance of a TLR Level 4, all transactions using non-firm point-to-point transmission service, in the current and next hour, with a greater than 5 percent impact on the facility, have been curtailed under the TLR 3b. The purpose of a TLR Level 4 is to request that the affected transmission operators reconfigure transmission on their system, or arrange for reconfiguration on other transmission systems, to mitigate the constraint if a SOL or IROL violation is imminent or occurring.

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

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

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

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

© 2010 Monitoring Analytics, LLC www.monitoringanalytics.com

Table D-1 TLRs by level and reliability coordinator: Calendar years 2004 through 2009

Year	Reliability Coordinator	3a	3b	4	5a	5b	6	Total
2004	EES	47	15	88	1	3	0	154
	FPL	0	1	0	0	0	0	1
	IMO	33	2	0	0	0	0	35
	MAIN	8	3	0	0	0	0	11
	MISO	650	210	409	9	3	0	1,281
	PJM	270	115	35	4	5	0	429
	SOCO	1	0	0	0	0	0	1
	SWPP	185	107	14	5	6	0	317
	TVA	56	17	0	0	1	0	74
	VACN	8	1	0	0	0	0	9
Total		1,258	471	546	19	18	0	2,312
2005	EES	49	10	101	6	3	1	170
	IMO	57	2	0	0	0	0	59
	MISO	776	296	200	5	14	0	1,291
	PJM	201	94	29	1	1	0	326
	SWPP	193	78	19	4	2	0	296
	TVA	172	61	12	2	3	0	250
	VACN	0	3	0	0	0	0	3
	VACS	2	2	0	1	0	0	5
Total		1,450	546	361	19	23	1	2,400
2006	EES	71	20	93	5	1	0	190
	ICTE	11	6	14	0	1	0	32
	IMO	1	0	0	0	0	0	1
	MISO	414	214	136	17	19	0	800
	ONT	27	3		0	0	0	30
	PJM	88	30	18	0	0	0	136
	SWPP	189	121	201	11	13	0	535
	TVA	90	52	31	1	2	0	176
	VACS	0	1	0	0	0	0	1
Total		891	447	493	34	36	0	1,901
2007	ICTE	95	42	139	19	10	0	305
	MISO	414	273	89	17	26	0	819
	ONT	47	4	1	0	0	0	52
	PJM	46	31	1	1	1	0	80
	SWPP	777	935	35	53	24	0	1,824
	TVA	45	40	25	2	2	0	114
	VACS	4	1	0	0	0	0	5
Total		1428	1326	290	92	63	0	3199
2008	ICTE	132	41	112	43	25	0	353
	MISO	320	235	21	8	15	0	599
	ONT	153	7	1	0	0	0	161
	PJM	55	92	2	0	1	0	150
	SWPP	687	1,077	11	59	44	0	1,878
	TVA	48	72	29	5	4	0	158
Total		1,395	1,524	176	115	89	0	3,299
2009	ICTE	82	35	55	75	18	1	266
	MISO	199	140	2	15	25	0	381
	NYIS	101	8	0	0	0	0	109
	ONT	169	0	0	0	0	0	169
	PJM	61	68	0	0	0	0	129
	SWPP	383	1,466	33	77	24	0	1,983
	TVA	8	22	29	0	0	0	59
	VACS	0	1	0	0	0	0	1
Total		1,003	1,740	119	167	67	1	3,097

© 2010 Monitoring Analytics, LLC

NYISO Issues

If interface prices were defined in a comparable manner by PJM and the NYISO, if identical rules governed external transactions in PJM and the NYISO, if time lags were not built into the rules governing such transactions and if no risks were associated with such transactions, then prices at the interfaces would be expected to be very close and the level of transactions would be expected to be related to any price differentials. The fact that none of these conditions exists is important in explaining the observed relationship between interface prices and inter-ISO power flows, and those price differentials.[2]

There are institutional differences between PJM and the NYISO markets that are relevant to observed differences in border prices.[3] The NYISO requires hourly bids or offer prices for each export or import transaction and clears its market for each hour based on hourly bids.[4] Import transactions to the NYISO are treated by the NYISO as generator bids at the NYISO/PJM proxy bus. Export transactions are treated by the NYISO as price-capped load offers. Competing bids and offers are evaluated along with other NYISO resources and a proxy bus price is derived. Bidders are notified of the outcome. This process is repeated, with new bids and offers each hour. A significant lag exists between the time when offers and bids are submitted to the NYISO and the time when participants are notified that they have cleared. The lag is a result of the functioning of the RTC system and the fact that transactions can only be scheduled at the beginning of the hour.

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

Under PJM operating practices, in the Real-Time Market, participants must make a request to import or export power at one of PJM's interfaces at least 20 minutes before the desired start which can be any quarter hour.[5] The duration of the requested transaction can vary from 45 minutes to an unlimited amount of time. Generally, PJM market participants provide only the MW, the duration and the direction of the real-time transaction. While bid prices for transactions are allowed in PJM, less than 1 percent of all transactions submit an associated price. Transactions are accepted, with virtually no lag, in order of submission, based on whether PJM has the capability to import or export the requested MW. If transactions do not submit a price, the transactions are priced at the real-time price for their scheduled imports or exports. As in the NYISO, the required lead time means that participants must make offers to buy or sell MW based on expected prices, but the required lead time is substantially shorter in the PJM market.

The NYISO rules provide that the RTC results should be available 45 minutes before the operating hour. Winning bidders then have 25 minutes from the time when the RTC results indicate that their transaction will flow to meet PJM's 20-minute notice requirement. To get a transaction cleared with

2 See also the discussion of these issues in the *2005 State of the Market Report*, Section 4, "Interchange Transactions" (March 8, 2006).
3 See the *2005 State of the Market Report* (March 8, 2006), pp. 195-198.
4 See NYISO. "NYISO Transmission Services Manual," Version 2.0 (February 1, 2005) (Accessed January 26, 2010) <http://www.nyiso.com/public/webdocs/documents/manuals/operations/tran_ser_mnl.pdf> (463 KB).
5 See PJM. "Manual 41: Managing Interchange" (November 24, 2008) (Accessed January 26, 2010) <http://www.pjm.com/documents/~/media/documents/manuals/m41.ashx> (291 KB).

© 2010 Monitoring Analytics, LLC www.monitoringanalytics.com

PJM, the market participant must have a valid NERC Tag, an OASIS reservation and a PJM ramp reservation. Each of these requirements takes time to process.

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

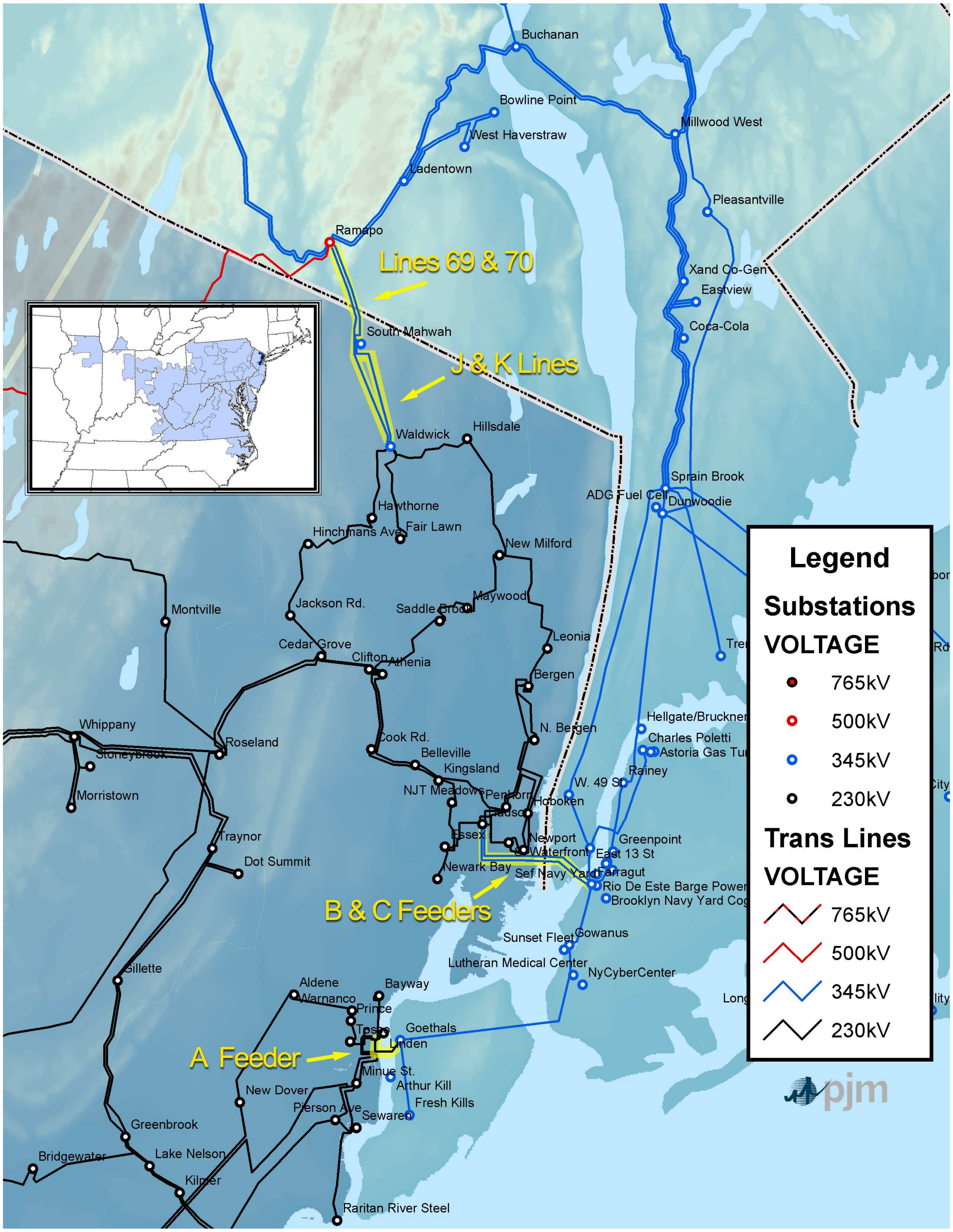
Consolidated Edison Company (Con Edison) and Public Service Electric and Gas Company (PSE&G) Wheeling Contracts

To help meet the demand for power in New York City, Con Edison uses electricity generated in upstate New York and wheeled through New York and New Jersey. A common path is through Westchester County using lines controlled by the NYISO. Another path is through northern New Jersey using lines controlled by PJM. This wheeled power creates loop flow across the PJM system. The Con Edison/PSE&G contracts governing the New Jersey path evolved during the 1970s and were the subject of a Con Edison complaint to the FERC in 2001. In May 2005, the FERC issued an order setting out a protocol developed by the two companies, PJM and the NYISO.[6] In July 2005, the protocol was implemented. Con Edison filed a protest with the FERC regarding the delivery performance in January 2006.[7]

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

6 111 FERC ¶ 61,228 (2005).
7 Protest of the Consolidated Edison Company of New York, Inc., Protest, Docket No. EL02-23 (January 30, 2006).

Figure D-1 Con Edison and PSE&G wheel



© 2010 Monitoring Analytics, LLC www.monitoringanalytics.com

Initial Implementation of the FERC Protocol

In May 2005, the FERC issued an order setting out a protocol developed by the four parties to address the issues raised by Con Edison.[8] The protocol was implemented in July 2005.

The Day-Ahead Energy Market Process

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

Under the FERC order, PSE&G is assigned FTRs associated with the 600 MW contract. The PSE&G FTRs are treated like all other FTRs. In 2009, PSE&G's revenues were less than its congestion charges by $5,417 after adjustments. (Revenues exceeded its charges by $13,768 in 2008.) Under the FERC order, Con Edison receives credits on an hourly basis for its elections under the 400 MW contract from a pool containing any excess congestion revenue after hourly FTRs are funded. In 2009, Con Edison's congestion credits were $232,744 less than its day-ahead congestion charges. Con Edison also had a day-ahead congestion credit. With appropriate adjustments accounted for, the result was that Con Edison's total charges exceeded its congestion credits by $251,102. (Credits had been $213,535 less than charges in 2008.) Table D-2 shows the monthly details for both PSE&G and Con Edison.

The protocol states:

> If there is congestion in PJM that affects the portion of the wheel that is associated with the 400 MW contract, PJM shall re-dispatch for the portion of the 400 MW contract for which ConEd specified it was willing to pay congestion, and ConEd shall pay for the re-dispatch. ConEd will be credited back for any congestion charges paid in the hour to the extent of any excess congestion revenues collected by PJM that remain after congestion credits are paid to all other firm transmission customers. Such credits to ConEd shall not exceed congestion payments owed or made by it.[9]

In effect, Con Edison has been given congestion credits that are the equivalent of a class of FTRs covering positive congestion with subordinated rights to revenue. However, Con Edison is not treated as having an FTR when congestion is negative. An FTR holder in that position would pay the negative congestion credits, but Con Edison does not. The protocol's provisions about congestion payments clearly cover congestion charges and offsetting congestion credits, but are not explicit on the treatment of Con Edison's negative congestion credits, which were -$251,102 in 2009. The parties should address this issue.

8 111 FERC ¶ 61,228 (2005).

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

The Real-Time Energy Market Process

Under the terms of the protocol, Con Edison can make a real-time election of its desired flow for each hour in the Real-Time Energy Market. If this election differs from its day-ahead schedule, the company is subject to the resultant charges or credits based on the difference between day-ahead and real-time prices. The real-time election differed from the day-ahead schedule in 2 percent of the hours in 2009.

Table D-2 Con Edison and PSE&G wheel settlements data: Calendar year 2009

		Con Edison			PSE&G		
		Day Ahead	Balancing	Total	Day Ahead	Balancing	Total
January	Congestion Charge	$279,940	($1,167)	$278,773	$841,794	$0	$841,794
	Congestion Credit			$280,235			$857,942
	Adjustments			$0			$1,013
	Net Charge			($1,462)			($17,161)
February	Congestion Charge	$0	$0	$0	$572,117	$0	$572,117
	Congestion Credit			$0			$572,117
	Adjustments			$0			($761)
	Net Charge			$0			$761
March	Congestion Charge	$123,847	($43)	$123,804	$328,334	$0	$328,334
	Congestion Credit			$65,759			$327,917
	Adjustments			($106,433)			($979)
	Net Charge			$164,478			$1,396
April	Congestion Charge	$269,027	($878)	$268,149	$426,910	$0	$426,910
	Congestion Credit			$269,259			$427,130
	Adjustments			$106,536			($728)
	Net Charge			($107,646)			$508
May	Congestion Charge	$162,299	$4,223	$166,522	$559,648	$0	$559,648
	Congestion Credit			$162,483			$559,648
	Adjustments			$485,456			$14,944
	Net Charge			($481,417)			($14,944)
June	Congestion Charge	$84,657	($235)	$84,422	$234,068	$0	$234,068
	Congestion Credit			$86,653			$234,068
	Adjustments			($1,377)			($1,610)
	Net Charge			($854)			$1,610

© 2010 Monitoring Analytics, LLC www.monitoringanalytics.com

		Con Edison			PSE&G		
		Day Ahead	Balancing	Total	Day Ahead	Balancing	Total
July	Congestion Charge	$151,152	$0	$151,152	$235,874	$0	$235,874
	Congestion Credit			$151,425			$235,874
	Adjustments			$0			$6,556
	Net Charge			($273)			($6,556)
August	Congestion Charge	$114,764	$0	$114,764	$180,342	$0	$180,342
	Congestion Credit			$64,770			$174,463
	Adjustments			$0			($2,591)
	Net Charge			$49,994			$8,470
September	Congestion Charge	$117,182	($68)	$117,115	$297,200	$0	$297,200
	Congestion Credit			$34,064			$262,288
	Adjustments			($7)			($1,281)
	Net Charge			$83,058			$36,194
October	Congestion Charge	$102,161	($485)	$101,676	$235,756	$0	$235,756
	Congestion Credit			$50,080			$209,886
	Adjustments			$357			($45)
	Net Charge			$51,239			$25,915
November	Congestion Charge	$33,790	$0	$33,790	$77,978	$0	$77,978
	Congestion Credit			$34,798			$79,076
	Adjustments			$209			($30)
	Net Charge			($1,217)			($1,067)
December	Congestion Charge	$49,561	($453)	$49,107	$129,195	$0	$129,195
	Congestion Credit			$56,109			$159,405
	Adjustments			$0			($501)
	Net Charge			($7,002)			($29,709)
Total	Congestion Charge	$1,488,379	$894	$1,489,274	$4,119,216	$0	$4,119,216
	Congestion Credit			$1,255,635			$4,099,812
	Adjustments			$484,741			$13,987
	Net Charge			($251,102)			$5,417

© 2010 Monitoring Analytics, LLC

© 2010 Monitoring Analytics, LLC www.monitoringanalytics.com

APPENDIX E – CAPACITY MARKET

Background

PJM and its members have long relied on capacity obligations as one of the methods to ensure reliability. 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.

On June 1, 2007, the Reliability Pricing Model (RPM) Capacity Market design was implemented in PJM, replacing the Capacity Credit Market (CCM) Capacity Market design. This appendix explains certain key features of the RPM design in more detail.[1]

Demand

VRR Curves

Under RPM, PJM establishes variable resource requirement (VRR) curves for the PJM RTO and for each constrained locational deliverability area (LDA). The VRR curve is a demand curve based on three price-quantity points. The demand curve quantities are based on negative and positive adjustments to the reliability requirement. The demand curve prices are based on multipliers applied to the net cost of new entry (CONE). Net CONE is CONE minus the energy and ancillary service revenue offset (E&AS).[2]

The PJM reliability requirement, measured as unforced capacity, is the RTO peak load forecast multiplied by the RTO forecast pool requirement (FPR) less the sum of any unforced capacity (UCAP) obligations served by fixed resource requirement (FRR) entities. The FPR is calculated as (1 + Installed Reserve Margin) times (1 - Pool Wide Average EFORd), where the Installed Reserve Margin (IRM) is the level of installed capacity needed to maintain an acceptable level of reliability. The PJM reliability requirement represents the target level of reserves required to meet PJM reliability standards.

Load Obligations

Participation by LSEs in the RPM for load served in PJM control zones is mandatory, except for those LSEs that have elected the FRR alternative.[3] Under RPM, each LSE that serves load in a PJM zone during the delivery year is responsible for paying a locational reliability charge equal to its daily unforced capacity obligation in the zone multiplied by the final zonal capacity price. LSEs may choose to hedge their locational reliability charge obligations by directly offering resources in

1 This section relies upon the cited PJM manuals where additional detail may be found.

2 See PJM. "Manual 18: PJM Capacity Market," Revision 8 (Effective January 1, 2010), p. 16 <http://www.pjm.com/~/media/documents/manuals/m18.ashx> (1.27 MB).

3 See "Reliability Assurance Agreement among Load-Serving Entities in the PJM Region," Substitute Original Sheet No. 40 (Effective June 1, 2007), Schedule 8.1.

© 2010 Monitoring Analytics, LLC

the Base Residual Auction (BRA) and Second Incremental Auction or by designating self-supplied resources (resources directly owned or resources contracted for through unit-specific bilateral purchases) as self-scheduled to cover their obligation in the Base Residual Auction.

Base UCAP Obligations

A base RTO UCAP obligation is determined after the clearing of the BRA and is posted with the BRA results. The base RTO UCAP obligation is equal to the sum of the UCAP obligation satisfied through the BRA plus the forecast RTO interruptible load for reliability (ILR) obligation, for delivery years prior to 2012/2013, or plus the RTO Short-Term Resource Procurement Target for the delivery years 2012/2013 and forward. Base zonal UCAP obligations are defined for each zone as an allocation of the RTO UCAP obligation based on zonal, peak-load forecasts and zonal ILR obligations, for delivery years prior to 2012/2013, or the zonal Short-Term Resource Procurement Target for the delivery years 2012/2013 and forward. The zonal UCAP obligation is equal to the zonal, weather-normalized summer peak for the summer four years prior to the delivery year multiplied by the base zonal RPM scaling factor and the FPR plus the forecast zonal ILR obligation, for delivery years prior to 2012/2013, or plus the zonal Short-Term Resource Procurement Target for the delivery years 2012/2013 and forward.

Final UCAP Obligation

Prior to the 2009/2010 delivery year, the final RTO UCAP obligation is determined after the clearing of the Second Incremental Auction (IA) and is posted with the second IA results.[4] For the 2009/2010 through 2011/2012 delivery years, the final RTO UCAP obligations are determined after the clearing of the Third IA. Effective with the 2012/2013 delivery year, the final RTO UCAP obligations are determined after the clearing of the final incremental auction. Prior to the 2012/2013 delivery year, the final RTO UCAP obligation is equal to the sum of the UCAP obligation satisfied through the BRA and the second IA plus the forecast RTO ILR obligation. Effective with the 2012/2013 delivery year, the final RTO UCAP obligation is equal to the total MW cleared in PJM Buy Bids in RPM Auctions, including cleared MW in the BRA, less the total MW cleared in PJM Sell Offers in RPM Auctions for the given delivery year. Prior to the 2009/2010 delivery year, the final zonal UCAP obligation is equal to the base zonal UCAP obligation plus the RTO UCAP obligation satisfied in the second IA multiplied by the zone's percentage allocation of the obligation satisfied in the second IA. For the 2009/2010 through 2011/2012 delivery years, the final zonal UCAP obligation is equal to the zonal allocation of the RTO UCAP obligation satisfied in the BRA and second IA plus the zonal forecast ILR obligation. The allocation of the RTO UCAP obligation satisfied in the BRA and second IA to zones is on a pro rata basis based on the final zonal peak load forecasts. For the 2012/2013 delivery year and beyond, the final zonal UCAP obligation is equal to the zonal allocation of the final RTO UCAP obligation. The allocation of the final RTO UCAP obligation to zones is on a pro rata basis based on the final RTO and zonal peak load forecasts for the delivery year.

LSE Daily UCAP Obligation

Obligation peak load is the peak load value on which LSEs' UCAP obligations are based. The obligation peak load allocation for a zone is constant and effective for the entire delivery year. The

4 See PJM. "Manual 18: PJM Capacity Market," Revision 8 (Effective January 1, 2010), p. 86 <http://www.pjm.com/~/media/documents/manuals/m18.ashx> (1.27 MB).

© 2010 Monitoring Analytics, LLC www.monitoringanalytics.com

daily UCAP obligation of an LSE in a zone/area equals the LSE's obligation peak load in the zone/area multiplied by the final zonal RPM scaling factor and the FPR.

Capacity Resources

Capacity resources may consist of generation resources, load management resources and qualifying transmission upgrades, all of which must meet specific criteria.[5] Generation resources may be located within or outside of PJM, but they must be committed to serving load within PJM and must pass tests regarding the capability of generation to serve load and to deliver energy.

Generation Resources

Generation resources may consist of existing generation, planned generation, and bilateral contracts for unit-specific capacity resources. Existing generation located within or outside PJM is eligible to be offered into RPM Auctions or traded bilaterally if it meets defined requirements.[6] Planned generation that is participating in PJM's Regional Transmission Expansion Planning (RTEP) Process is eligible to be offered into RPM Auctions if it meets defined requirements.

Load Management Resources

Load management is the ability to reduce metered load upon request.[7] A load management resource is eligible to be offered as a demand resource (DR) or, prior to the 2012/2013 delivery year, interruptible load for reliability (ILR). DR is a load resource that is offered into an RPM Auction as capacity and receives the relevant LDA or RTO resource clearing price. ILR is a load resource that is not offered into the RPM Auction, but receives the final zonal ILR price determined after the close of the second incremental auction. DR and ILR resources must meet defined requirements.

Energy Efficiency Resources

Existing or planned Energy Efficiency (EE) resources may be offered in an RPM auction starting with the 2012/2013 delivery year and receive the relevant LDA or RTO resource clearing price. An EE resource is a project, including installation of more efficient devices or equipment or implementation of more efficient processes or systems, exceeding then current building codes, appliance standards, or other relevant standards, designed to achieve a continuous (during peak periods) reduction in electric energy consumption that is not reflected in the peak load forecast prepared for the delivery year for which the Energy Efficiency Resource is proposed, and that is fully implemented at all times during such delivery year, without any requirement of notice, dispatch, or operator intervention.[8]

5 See PJM. "Manual 18: PJM Capacity Market," Revision 8 (Effective January 1, 2010), p. 29 <http://www.pjm.com/~/media/documents/manuals/m18.ashx> (1.27 MB).
6 See PJM. "Manual 18: PJM Capacity Market," Revision 8 (January 1, 2010), p. 22 <http://www.pjm.com/~/media/documents/manuals/m18.ashx> (1.27 MB).
7 See PJM. "Manual 18: PJM Capacity Market," Revision 8 (Effective January 1, 2010), p. 28 <http://www.pjm.com/~/media/documents/manuals/m18.ashx> (1.27 MB).
8 See PJM. "Reliability Assurance Agreement among Load-Serving Entities in the PJM Region," First Revised Sheet No. 35C (Effective March 27, 2009), Schedule 6, section M.

© 2010 Monitoring Analytics, LLC www.monitoringanalytics.com

Qualified Transmission Upgrades

A qualifying transmission upgrade may be offered into the BRA to increase import capability into a transmission-constrained LDA. Such transmission upgrades must meet the identified requirements.[9]

Obligations of Generation Capacity Resources

The sale of a generating unit as a capacity resource within PJM 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 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. 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. When PJM invokes the recall right, the energy supplier is paid the PJM Real-Time Energy Market price.

- **Day-Ahead Energy Market Offer Requirement.** Market sellers owning or controlling the output of a generation capacity resource that was committed in an FRR Capacity Plan, self-supplied, offered and cleared in any RPM auction, or designated as replacement capacity, and that is not unavailable due to an outage are required to offer into PJM's Day-Ahead Energy Market.[10] 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 PJM. Capacity resources must be deliverable, 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.[11] In addition, for external capacity resources used to meet an accounted for obligation within PJM, capacity and energy must be delivered to the metered, PJM boundaries 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.[12]

9 See PJM. "Manual 18: PJM Capacity Market," Revision 8 (Effective January 1, 2010), p. 38 <http://www.pjm.com/~/media/documents/manuals/m18.ashx> (1.27 MB).
10 See PJM. "Operating Agreement of PJM Interconnection, L.L.C.," Sixth Revised Sheet No. 93 (Effective June 1, 2008), Schedule 1, section 1.10.1A (d).
11 Deliverable per PJM. "Reliability Assurance Agreement among Load-Serving Entities in the PJM Region," Original Sheet No. 50 (Effective June 1, 2007), Schedule 10.
12 See PJM. "Reliability Assurance Agreement among Load-Serving Entities in the PJM Region," Original Sheet No. 53 (Effective June 1, 2007), Schedule 11.

© 2010 Monitoring Analytics, LLC www.monitoringanalytics.com

CETO/CETL

Since the ability to import energy and capacity into LDAs may be limited by the existing transmission capability, PJM conducts a load deliverability analysis for each LDA.[13,14] The first step in this process is to determine the transmission import requirement into an LDA, called the capacity emergency transfer objective (CETO). This value, expressed in MW, is the transmission import capability required for each LDA to meet the area reliability criterion of loss of load expectation due to insufficient import capability alone, of one occurrence in 25 years when the LDA is experiencing a localized capacity emergency.

The second step is to determine the transmission import limit for an LDA, called the capacity emergency transfer limit (CETL), which is also expressed in MW. The CETL is the ability of the transmission system to deliver energy into the LDA when it is experiencing the localized capacity emergency used in the CETO calculation.

If CETL is less than CETO, capacity-related transmission constraints may result in locational price differences in the RPM.[15] This will also trigger the planning of transmission upgrades under the RTEP Process. Prior to the 2012/2013 delivery year, only an LDA with CETL less than 1.05 times CETO was modeled as a constrained LDA in RPM. Effective with the 2012/2013 delivery year, an LDA with CETL less than 1.15 times CETO is modeled as a constrained LDA in RPM. Starting with the 2012/2013 delivery year, regardless of the CETO/CETL results, separate VRR curves will be established for any LDA with a locational price adder in one or more of the three immediately preceding BRAs, any LDA that PJM determines in a preliminary analysis is likely to have a locational price adder based on historic offer price levels, and EMAAC, SWMAAC, and MAAC LDAs.

Generator Performance: NERC OMC Outage Cause Codes

Table E-1 includes a list of the North American Electric Reliability Council (NERC) GADS cause codes that PJM deems 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.

13 See PJM. "Manual 14B: PJM Region Transmission Planning Process," Attachment C: PJM Deliverability Testing Methods," Revision 14 (Effective February 1, 2010), p. 45 <http://www.pjm.com/~/media/documents/manuals/m14b.ashx> (887.15 KB). PJM Manual 14B indicates that all "electrically cohesive load areas" are tested.

14 See PJM. "Manual 20: PJM Resource Adequacy Analysis," Revision 3 (Effective June 1, 2007), p. 32 <http://www.pjm.com/~/media/documents/manuals/m20.ashx> (662.90 KB).

15 See PJM. "Manual 18: PJM Capacity Market," Revision 8 (Effective January 1, 2010), p. 10, <http://www.pjm.com/~/media/documents/manuals/m18.ashx> (1.27 MB).

© 2010 Monitoring Analytics, LLC www.monitoringanalytics.com

Table E-1 NERC GADS cause codes that PJM deems outside management control[16] (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
9250	Low Btu coal
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)

16 See NERC. "Generator Availability Data System Data Reporting Instructions," Appendix K <http://www.nerc.com/files/Appendix_K_Outside_Plant_Management_Control.pdf> (149 KB).

© 2010 Monitoring Analytics, LLC www.monitoringanalytics.com

APPENDIX F – ANCILLARY SERVICE MARKETS

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

Area Control Error (ACE)

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

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

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

During 2008 an experimental battery-powered regulation unit was installed at the PJM facility. Observation of this unit reveals that new types of units will require that PJM's regulation unit certification testing procedure as administered by PJM's Performance Compliance group be modified, perhaps tailored to the specific unit types. The test as it is now designed measures the ability of the unit to respond to its regulation min/max within five minutes. This has always been the critical regulating metric for steam and CT units. But other types of units can meet this criterion easily yet still be inadequate for regulation because they lack the capacity to regulate for the entire hour in the event that regulation is almost completely above or below the regulation set point. Such units might include battery, pumped hydro, and inertial regulation units.

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

1 "Two additional terms may be included in ACE under certain conditions – time error bias and manual add (a PJM dispatcher term). These provide for automatic inadvertent interchange payback and error compensation, respectively." See PJM. "Manual 12: Balancing Operations," Revision 20 (October 5, 2009), Section 3, "System Control" p. 11.
2 Regulation Market business rules are defined in PJM. "Manual 11: Scheduling Operations," Revision 44 (January 1, 2010), pp. 38-44.
3 See PJM. "Manual 12: Balancing Operations," Revision 20 (October 5, 2009), Section 4, pp. 45-47.

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.

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

- **CPS2.** NERC also requires that the second CPS measure provide a measure of 10-minute ACE 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 PJM'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 December 31, 2009, PJM's L_{10} standard was 278.2 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: Balancing Operations," Revision 20 (October 5, 2009), pp. 80-90. 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.

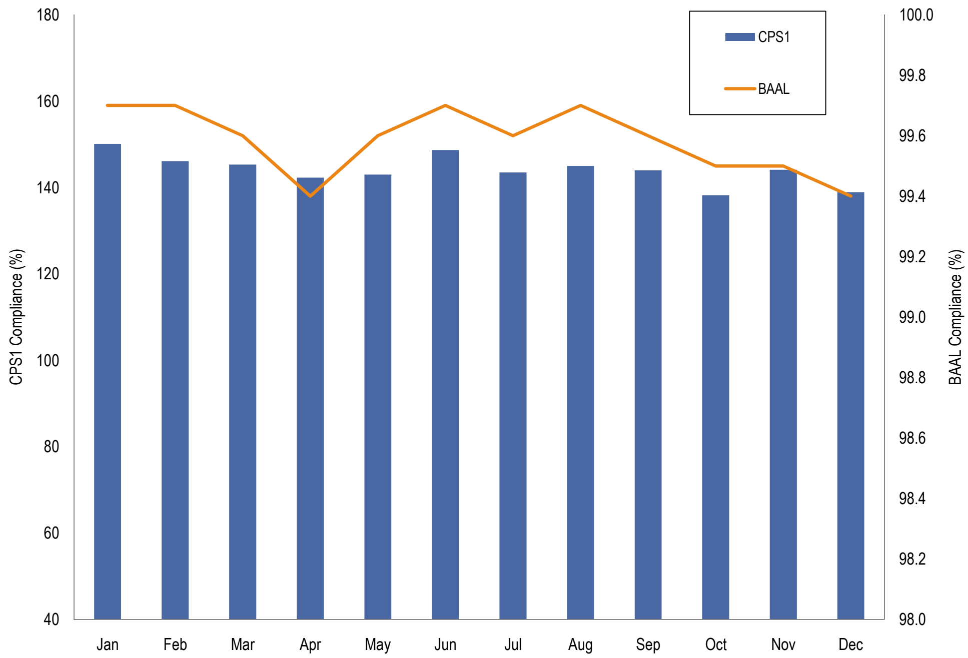
5 See PJM. "Manual 12: Balancing Operations," Revision 20 (October 5, 2009), pp. 80-90.

© 2010 Monitoring Analytics, LLC www.monitoringanalytics.com

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 2009.

Figure F-1 PJM CPS1 and BAAL performance: Calendar year 2009



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

PJM's DCS Performance

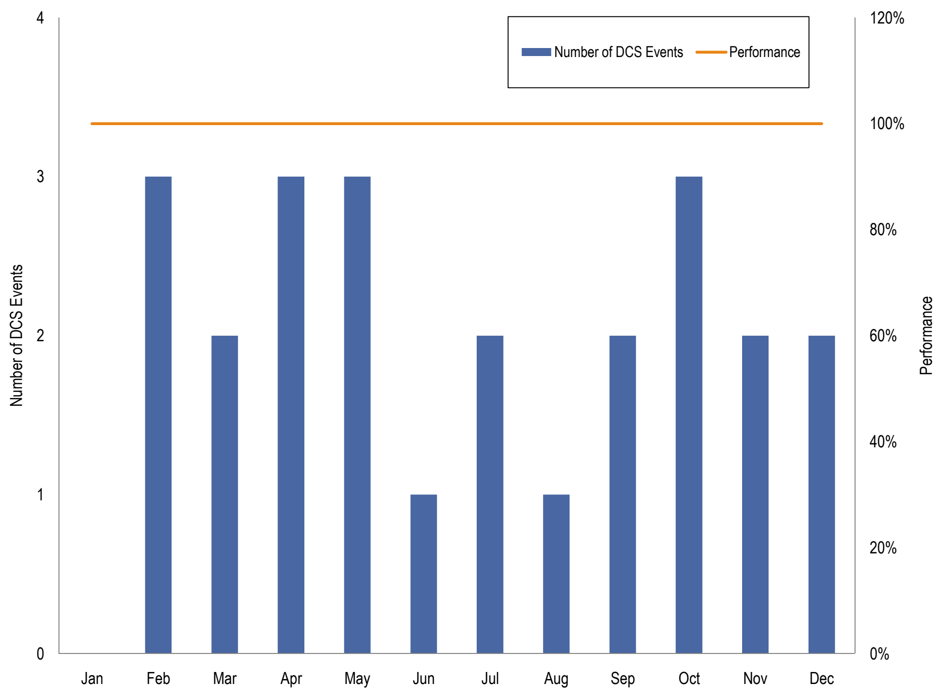
A dispatch performance metric that is directly related to synchronized reserve is the disturbance control standard (DCS).[6] DCS measures how well PJM dispatch recovers from a disturbance. A disturbance is defined as any ACE deviation greater than, or equal to, 80 percent of the magnitude of PJM's most severe single contingency loss. PJM currently interprets this to be any ACE deviation

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

greater than 800 MW. Compliance with the NERC DCS is recovery to zero or predisturbance level within 15 minutes.

PJM experienced 24 DCS events during calendar year 2009 and successfully recovered from all of them. All events were caused by the tripping of a major unit. Recovery times ranged from four minutes to 13 minutes. Figure F-2 illustrates the event count and performance by month. All of the events resulted in low ACE. The solution in 16 of the 24 events was to declare a 100 percent spinning event. The other events were addressed using redispatch or reserve sharing with NYISO.

Figure F-2 DCS event count and PJM performance (By month): Calendar year 2009



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

The regulation market-clearing price (RMCP) is determined algorithmically by the PJM Market Operations Group. The market clearing software (SPREGO) creates a regulation supply curve as part of a two product, and two constraint simultaneous solution. The price of the most expensive unit required to satisfy the regulation requirement is the RMCP. Calculating the supply curves for two products (regulation and synchronized reserve) with two constraints (energy and operating reserves) interactively is complicated, but necessary to achieve the lowest overall cost after first 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.

© 2010 Monitoring Analytics, LLC www.monitoringanalytics.com

- **Regulation Capacity.** The sum of the regulation MW capability of all generating units which have qualified to participate in the Regulation Market is the theoretical maximum regulation capacity. This maximum regulation capacity varies over time because units that are certified for regulation may be decommissioned, fail regulation testing or be removed from the Regulation Market by their owners.

- **Regulation Offers.** All owners of generating units qualified to provide regulation may, but are not required to, offer their regulation capacity daily into the Regulation Market using the PJM market user interface. Regulating units may also self-schedule. Self-scheduled units have zero lost opportunity cost (LOC) and are the first to be assigned. Demand resources were eligible to offer regulation although during 2009 none qualified to do so. Demand resources have an LOC of zero. Under PJM rules, no more than 25 percent of the total regulation requirement may be supplied by demand resources. Total regulation offers are the sum of all regulation-capable units that offer regulation into the market for the day and that are not out of service or fully committed to provide energy. Owners of units that have entered offers into the PJM market user interface system have the ability to set unit status to "unavailable" for regulation for the day, or for a specific hour or set of hours. They also have the ability to change the amount of regulation MW offered in each hour. Unit owners do not have the ability to change their regulation offer price during a day. Starting in December, 2008, the PJM Market Users Interface allows regulation owners to enter cost data. For cost-based offers above $12 per MWh owners are required to enter cost data. All regulation offers are summed to calculate the total daily regulation offered, a figure that changes each hour.

- **Regulation Offered and Eligible.** Sixty minutes before the market hour, PJM runs synchronized reserve and regulation market-clearing software (SPREGO) to determine the amount of Tier 2 synchronized reserve required, to develop regulation and synchronized reserve supply curves, to assign regulation and synchronized reserve to specific units and to determine the RMCP. All regulation resource units which have made offers in the daily Regulation Market are evaluated by SPREGO for regulation. SPREGO then excludes units according to the following ordered criteria: a) Daily or hourly unavailable units; b) Units for which the economic minimum is set equal to economic maximum (unless the unit is a hydroelectric unit or has self-scheduled regulation); c) Units which are assigned synchronized reserve; d) Units for which regulation minimum is set equal to regulation maximum (unless the unit is a hydroelectric unit or has self-scheduled regulation); e) Units that are offline (except combustion turbine units).

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

For each offered and eligible unit in the regulation supply, the regulation total offer price is calculated using the sum of the unit's regulation cost-based offer and the opportunity cost based on the forecast LMP, unit economic minimum and economic maximum, regulation minimum and regulation maximum, startup costs and relevant offer schedule.[7] Based on this result, SPREGO determines if the period has three or fewer pivotal suppliers. If it does, all owners who are pivotal have their offers limited to the lesser of their cost or price offer. SPREGO uses price-based offers for those operators not offer capped and re-solves. This solution is final. The MW offered and the calculated regulation offered prices are used to create a regulation supply curve. The Regulation and Synchronized Reserve Markets are cleared interactively with the Energy Market and operating reserve requirements to minimize the cost of the combined products subject to reactive limits, resource constraints, unscheduled power flows, interarea transfer limits, resource distribution factors, self-scheduled resources, limited fuel resources, bilateral transactions, hydrological constraints, generation requirements and reserve requirements.

- **Cleared Regulation.** Regulation actually assigned by SPREGO is cleared regulation. The clearing price established by SPREGO becomes the final clearing price. In real time, units that have been assigned regulation and synchronized reserve are expected to provide regulation and synchronized reserve for the designated hour. At any time before or during the hour, PJM dispatchers can redispatch units for reliability reasons. Such redispatch leads to a disparity between cleared regulation and settled regulation.

- **Settled Regulation.** Units providing regulation are compensated at the clearing price times their actual MW provided (as opposed to cleared MW) plus any actual lost opportunity costs associated with providing regulation. The cost per MW of settled regulation can be higher than the regulation clearing price because there can be a difference between actual and cleared MW, as well as real-time versus forecast nodal prices.

7 See the *2009 State of the Market Report for PJM*, Volume II, Section 6, "Ancillary Services" for a discussion of opportunity cost.

© 2010 Monitoring Analytics, LLC www.monitoringanalytics.com

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.

© 2010 Monitoring Analytics, LLC www.monitoringanalytics.com

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

Day-Ahead Congestion Revenue						
Pricing Node	Day-Ahead Congestion Price	Day-Ahead Load	Load Congestion Payments	Day-Ahead Generation	Generation Congestion 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 Congestion Price	Load Deviation	Load Congestion Payments	Generation Deviation	Generation Congestion 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	

© 2010 Monitoring Analytics, LLC www.monitoringanalytics.com

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 prorated 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 prorated MW award = (100 MW) • (300 MW / 400 MW) • (1 / 0.50) = 150 MW; and

ARR #2 prorated 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 Credits

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. For example, the FTR auction revenue is only $75 for the ARR on line A-D while the ARR target allocation is $150. The surplus FTR auction revenue from the other ARR paths is enough to cover the $75 deficiency and fulfill the ARR target allocation of $150.

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						

Self-Scheduled ARRs

Table G-4 shows an example of two ARR customers, one of which self schedules ARRs and one of which retains ARRs. During an Annual ARR Allocation, both ARR customers #1 and #2 are allocated 10 MW ARRs on line A-B. ARR customer #1 self schedules 10 MW ARRs on line A-B as FTRs during the subsequent Annual FTR Auction while ARR customer #2 retains 10 MW ARRs on line A-B. Based on cleared nodal prices from the Annual FTR Auction, ARRs on line A-B are valued at $10 per MW. Customer #2 will receive $100 in ARR credits. Customer #1 converts all of the 10 MW ARRs on line A-B to FTRs during the Annual FTR Auction and, as a result, this customer needs to pay $100 to purchase the associated self-scheduled FTRs although this cost will be fully offset by the same amount of ARR credits. Based on the difference in LMPs, FTRs on line A-B are valued at $15 per MW. Customer #1 will receive $150 in FTR credits. In summary, Customer #1 receives a net $150 in FTR credits as a result of self scheduling the 10 MW of allocated ARRs on line A-B as FTRs, while Customer #2 receives $100 in ARR credits as a result of retaining the 10 MW ARRs on line A-B.

Table G-4 Self-Scheduled ARR credits: Illustration

Customer #	Path	ARR MW	Annual FTR Auction Path Price	ARR Credits	Converted to FTRs?	Cost of Conversion to FTRs	Day-Ahead FTR Path Price	FTR Credits	Total Credits
1	A-B	10 MW	$10	$100	Yes	$100	$15	$150	$150
2	A-B	10 MW	$10	$100	No	$0	$15	$0	$100
Total credits = ARR credits - Cost of conversion to FTRs + FTR credits									

© 2010 Monitoring Analytics, LLC www.monitoringanalytics.com