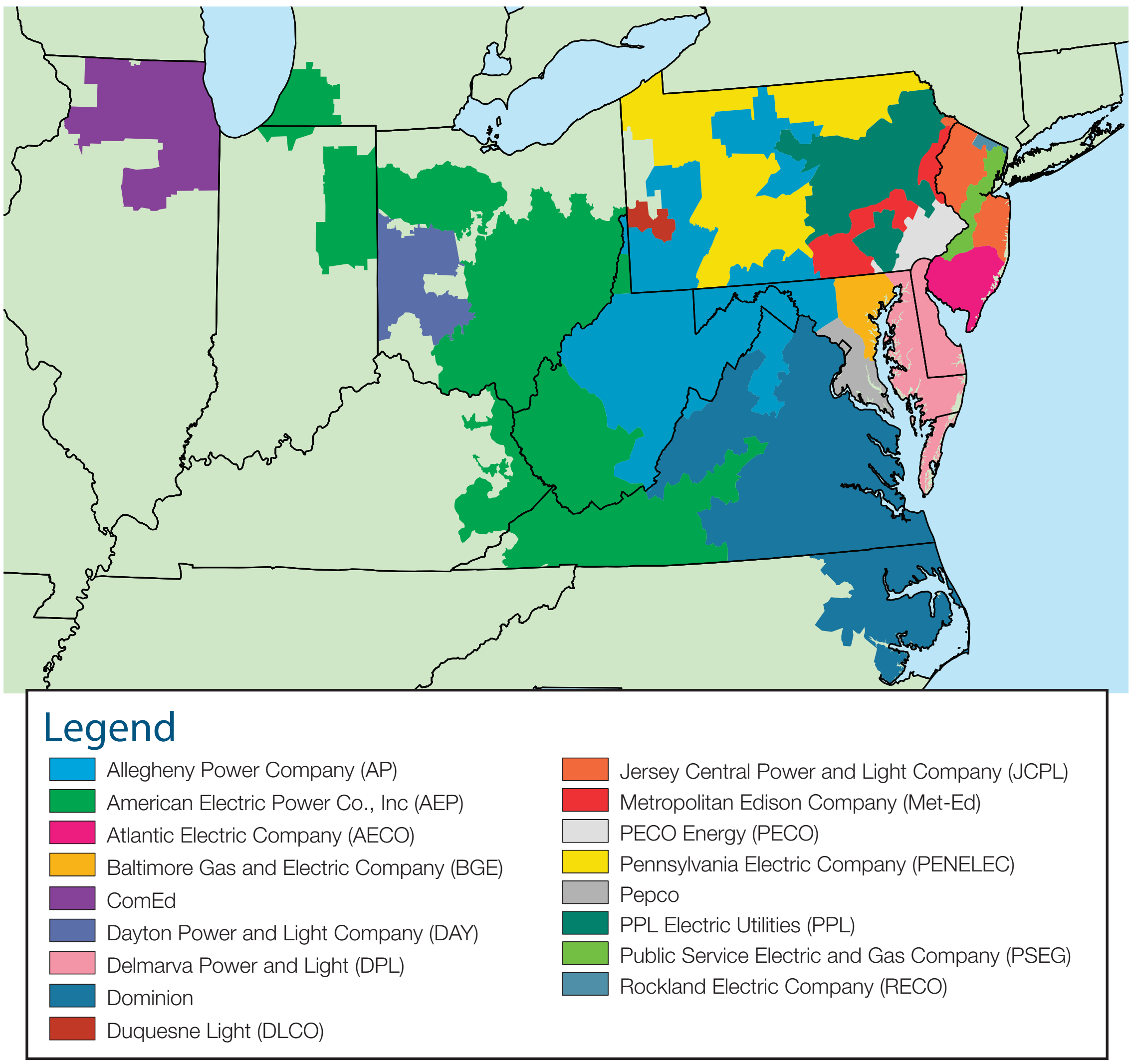
APPENDIX A – PJM GEOGRAPHY

During 2008, 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 2008 market results requires comparison to 2007 and certain other prior years. During 2006, 2007 and 2008 the PJM footprint was stable. During calendar years 2004 and 2005, however, PJM integrated five new control zones, three in 2004 and two in 2005. When making comparisons involving this period, the 2004, 2005 and 2006 state of the market reports referenced phases, each corresponding to market integration dates:[1]

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

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

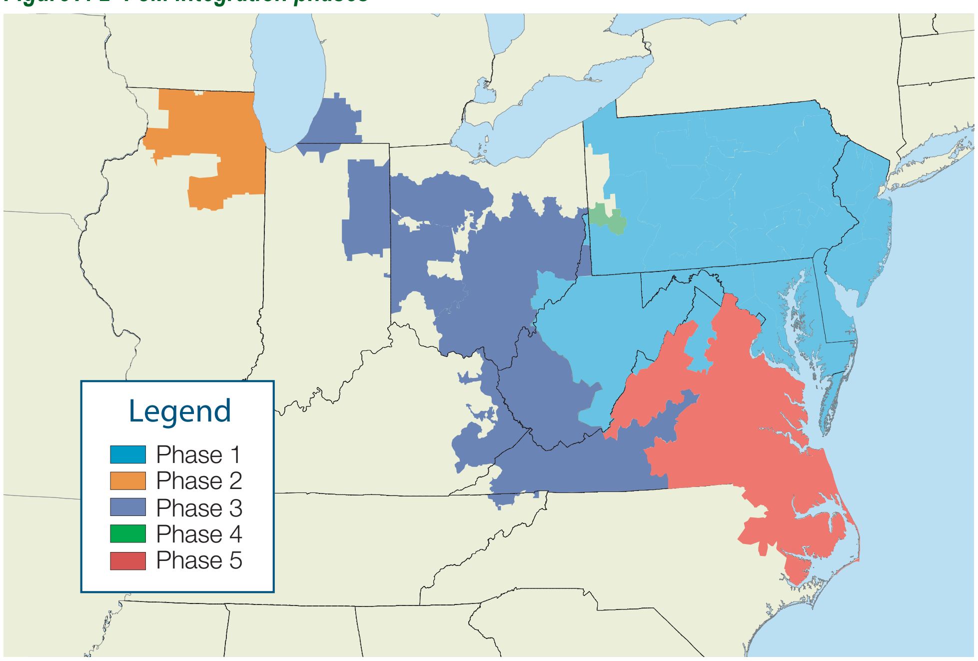
- **Phase 2 (2004).** The five-month period from May 1, through September 30, 2004, during which PJM was comprised of the Mid-Atlantic Region, including its 11 zones, the AP Control Zone and the ComEd Control Area.[4]

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

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

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

Figure A-2 PJM integration phases



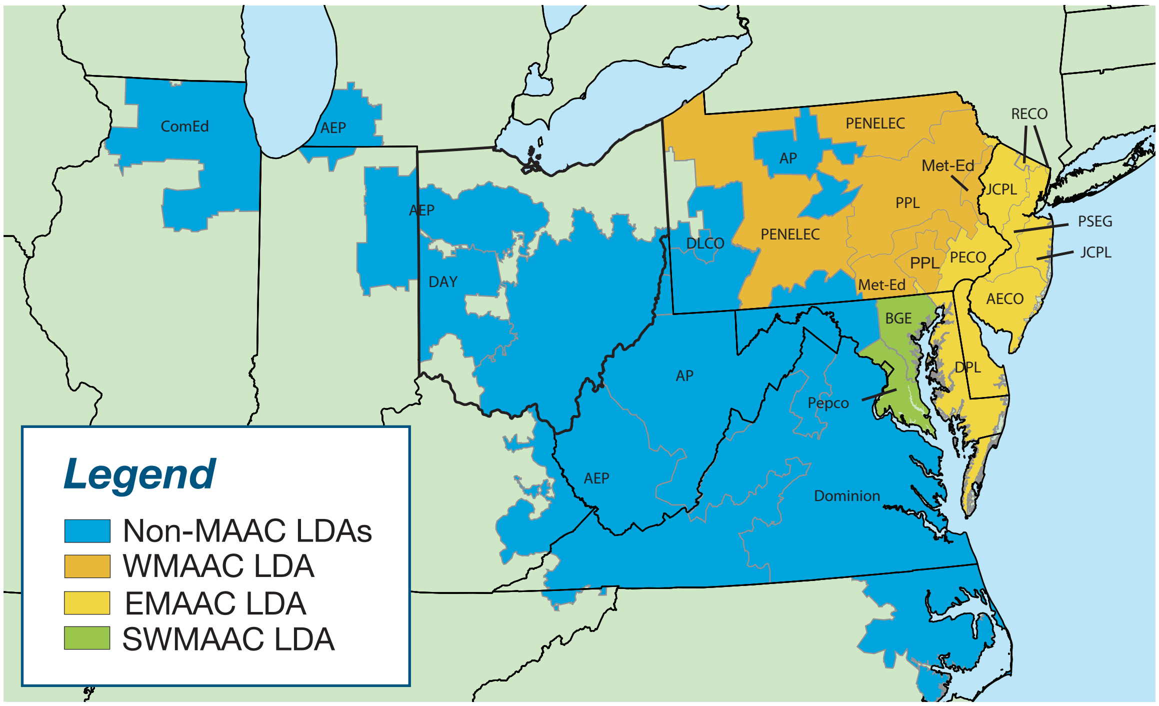
2 The Mid-Atlantic Region is comprised of the AECO, BGE, DPL, JCPL, Met-Ed, PECO, PENELEC, Pepco, PPL, PSEG and RECO control zones.

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

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

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

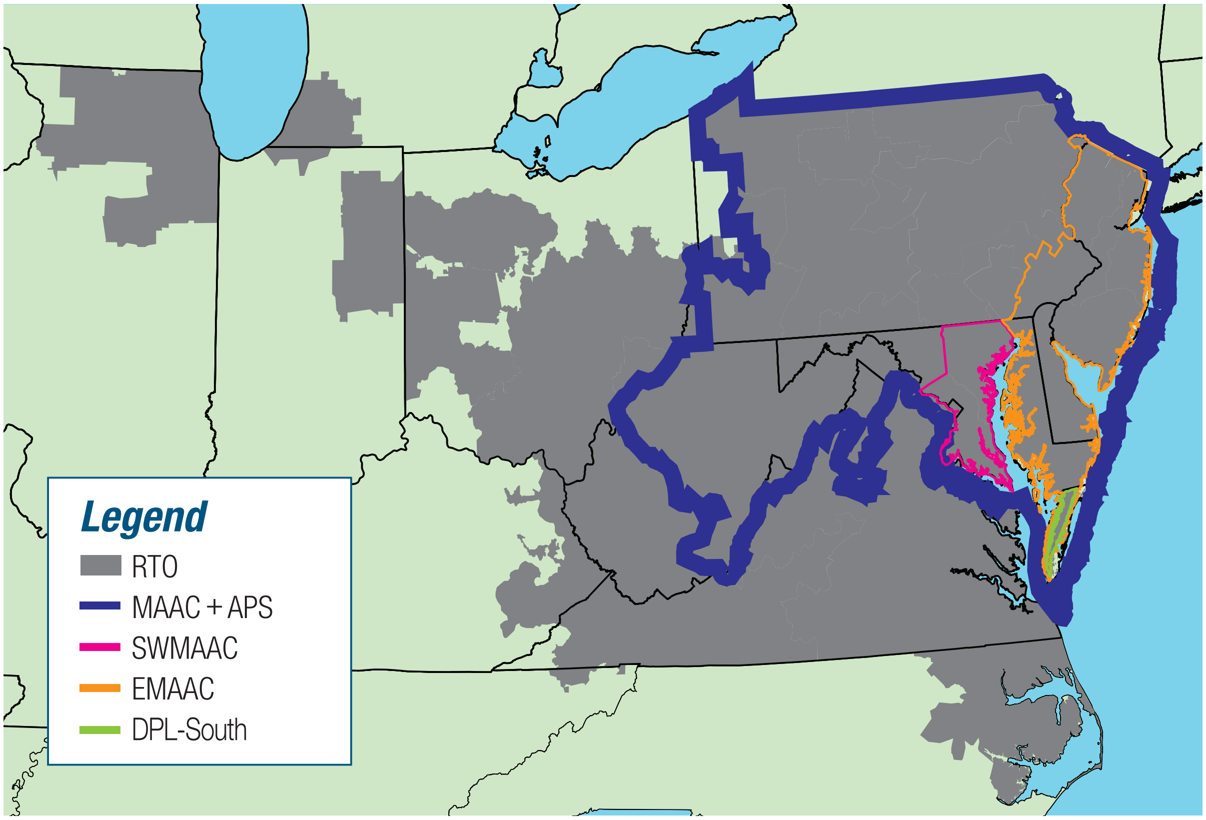


In PJM's Reliability Pricing Model (RPM) Auctions, markets are defined dynamically by LDA. The regional transmission organization (RTO) market comprises the entire PJM footprint, unless an LDA is constrained. Each constrained LDA or group of LDAs is a separate market with a separate clearing price and 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 (Allegheny Power System) and SWMAAC. For the 2010/2011 base residual auction, the defined markets were RTO and DPL-South, and for the 2011/2012 base residual auction, the only defined market was RTO. These RPM auction markets are shown in Figure A-4.

5 See PJM. "Open Access Transmission Tariff (OATT)," "Attachment DD: Definition 2.38" (Issued September 29, 2006, with an effective date of June 20, 2007).

Figure A-4 PJM RPM locational deliverability area markets



APPENDIX B – PJM MARKET MILESTONES

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

APPENDIX C – ENERGY MARKET

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

Load

Frequency Distribution of Load

Table C-1 provides the frequency distributions of PJM load by hour, for the calendar years 2004 to 2008.[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 2004 reflects the integrations of the ComEd, AEP and DAY control zones. The most frequently occurring load interval was 35 GWh to 40 GWh at 15.8 percent of the hours. The next most frequently occurring interval was 40 GWh to 45 GWh at 14.9 percent of the hours. Load was less than 60 GWh for 74.8 percent of the time, less than 70 GWh for 92.8 percent of the time and less than 90 GWh for all but nine hours.

The frequency distribution of load in 2005 reflects the phased integrations of the DLCO and Dominion control zones. The most frequently occurring load interval was 75 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

1 The definitions of load are discussed in the *2008 State of the Market Report*, Volume II, Appendix I, "Load Definitions."
2 See the *2008 State of the Market Report*, Volume II, Appendix A, "PJM Geography."

percent of the hours and less than 130 GWh for all hours.The peak demand for 2008 was 130,100 MW on June 9, 2008. It was 6.7 percent lower than the 2007 peak demand of 139,428 MW on August 8, 2007.[3]

Table C-1 Frequency distribution of PJM real-time, hourly load: Calendar years 2004 to 2008

	2004		2005		2006		2007		2008	
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	15	0.17%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
25 to 30	280	3.36%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
30 to 35	697	11.29%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
35 to 40	1,387	27.08%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
40 to 45	1,311	42.01%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
45 to 50	1,150	55.10%	71	0.81%	2	0.02%	0	0.00%	0	0.00%
50 to 55	847	64.74%	286	4.08%	129	1.50%	79	0.90%	127	1.45%
55 to 60	885	74.82%	636	11.34%	504	7.25%	433	5.84%	517	7.33%
60 to 65	760	83.47%	843	20.96%	689	15.11%	637	13.12%	667	14.92%
65 to 70	821	92.82%	1,170	34.32%	967	26.15%	890	23.28%	941	25.64%
70 to 75	391	97.27%	1,089	46.75%	1,079	38.47%	878	33.30%	1,048	37.57%
75 to 80	157	99.06%	1,407	62.81%	1,501	55.61%	1,227	47.31%	1,535	55.04%
80 to 85	48	99.60%	887	72.93%	1,337	70.87%	1,338	62.58%	1,208	68.80%
85 to 90	26	99.90%	557	79.29%	943	81.63%	981	73.78%	916	79.22%
90 to 95	7	99.98%	453	84.46%	569	88.13%	741	82.24%	655	86.68%
95 to 100	2	100.00%	330	88.23%	295	91.50%	577	88.82%	457	91.88%
100 to 105	0	0.00%	308	91.75%	215	93.95%	382	93.18%	292	95.21%
105 to 110	0	0.00%	283	94.98%	161	95.79%	223	95.73%	181	97.27%
110 to 115	0	0.00%	169	96.91%	145	97.44%	179	97.77%	133	98.78%
115 to 120	0	0.00%	113	98.20%	102	98.61%	106	98.98%	58	99.44%
120 to 125	0	0.00%	93	99.26%	45	99.12%	43	99.47%	35	99.84%
125 to 130	0	0.00%	43	99.75%	27	99.43%	31	99.83%	14	100.00%
130 to 135	0	0.00%	22	100.00%	19	99.65%	12	99.97%	0	0.00%
135 to 140	0	0.00%	0	0.00%	19	99.86%	3	100.00%	0	0.00%
> 140	0	0.00%	0	0.00%	12	100.00%	0	0.00%	0	0.00%

Off-Peak and On-Peak Load

Table C-2 presents summary load statistics for 1998 to 2008 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

3 Peak loads shown are eMTR load. See the *2008 State of the Market Report*, Volume II, Appendix I, "Load Definitions," for detailed definitions of load.

Eastern Prevailing Time (EPT), excluding North American Electric Reliability Council (NERC) holidays. Table C-2 shows that on-peak load was 21.8 percent higher than off-peak load in 2008. Average load during on-peak hours in 2008 was 3.5 percent lower than in 2007. Off-peak load in 2008 was 1.8 percent lower than in 2007.[4](See Table C-3.)

Table C-2 Real time Off-peak and on-peak load (MW): Calendar years 1998 to 2008

	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

Table C-3 Multiyear change in real time load: Calendar years 1998 to 2008

	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%)

4 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.

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.[5]

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 2004 to 2008. 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 2004, LMP occurred in the $30-per-MWh to $40-per-MWh interval most frequently at 21.9 percent of the time and in the $20-per-MWh to $30-per-MWh interval nearly as frequently at 21.6 percent of the time. In 2005, LMP occurred in the $30-per-MWh to $40-per-MWh interval most frequently at 20.5 percent of the time and in the $20-per-MWh to $30-per-MWh interval at 14.7 percent of the time. In 2005, LMP was less than $60 per MWh for 63.2 percent of the hours, 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).

5 See the *2008 State of the Market Report*, Volume II, Appendix H, "Calculating Locational Marginal Price."

Table C-4 Frequency distribution by hours of PJM Real-Time Energy Market LMP (Dollars per MWh): Calendar years 2004 to 2008

	2004		2005		2006		2007		2008	
LMP	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent
$10 and less	173	1.97%	142	1.62%	85	0.97%	56	0.64%	94	1.07%
$10 to $20	712	10.08%	259	4.58%	247	3.79%	185	2.75%	129	2.54%
$20 to $30	1,900	31.71%	1,290	19.30%	1,958	26.14%	1,571	20.68%	490	8.12%
$30 to $40	1,928	53.65%	1,793	39.77%	1,840	47.15%	1,470	37.47%	1,443	24.54%
$40 to $50	1,445	70.10%	1,172	53.15%	1,405	63.18%	1,108	50.11%	1,533	42.00%
$50 to $60	994	81.42%	877	63.16%	1,040	75.06%	931	60.74%	1,212	55.79%
$60 to $70	668	89.03%	730	71.50%	662	82.61%	827	70.18%	845	65.41%
$70 to $80	445	94.09%	568	77.98%	479	88.08%	726	78.47%	709	73.49%
$80 to $90	270	97.17%	453	83.15%	347	92.04%	646	85.84%	502	79.20%
$90 to $100	117	98.50%	374	87.42%	230	94.67%	451	90.99%	385	83.58%
$100 to $110	72	99.32%	297	90.81%	162	96.52%	240	93.73%	352	87.59%
$110 to $120	25	99.60%	208	93.18%	95	97.60%	178	95.76%	265	90.61%
$120 to $130	14	99.76%	159	95.00%	61	98.30%	110	97.02%	199	92.87%
$130 to $140	10	99.87%	110	96.26%	46	98.82%	76	97.89%	144	94.51%
$140 to $150	6	99.94%	94	97.33%	27	99.13%	53	98.49%	111	95.78%
$150 to $160	3	99.98%	53	97.93%	16	99.32%	26	98.79%	102	96.94%
$160 to $170	1	99.99%	57	98.58%	11	99.44%	29	99.12%	68	97.71%
$170 to $180	0	99.99%	51	99.17%	6	99.51%	18	99.33%	52	98.30%
$180 to $190	1	100.00%	22	99.42%	3	99.54%	9	99.43%	45	98.82%
$190 to $200	0	0.00%	16	99.60%	5	99.60%	15	99.60%	29	99.15%
$200 to $210	0	0.00%	12	99.74%	3	99.63%	6	99.67%	20	99.37%
$210 to $220	0	0.00%	10	99.85%	7	99.71%	4	99.71%	11	99.50%
$220 to $230	0	0.00%	5	99.91%	1	99.73%	4	99.76%	14	99.66%
$230 to $240	0	0.00%	1	99.92%	1	99.74%	2	99.78%	10	99.77%
$240 to $250	0	0.00%	1	99.93%	1	99.75%	5	99.84%	2	99.80%
$250 to $260	0	0.00%	3	99.97%	1	99.76%	2	99.86%	5	99.85%
$260 to $270	0	0.00%	2	99.99%	0	99.76%	4	99.91%	4	99.90%
$270 to $280	0	0.00%	0	99.99%	3	99.79%	0	99.91%	1	99.91%
$280 to $290	0	0.00%	1	100.00%	1	99.81%	0	99.91%	1	99.92%
$290 to $300	0	0.00%	0	0.00%	0	99.81%	0	99.91%	0	99.92%
$300 to $400	0	0.00%	0	0.00%	11	99.93%	2	99.93%	6	99.99%
$400 to $500	0	0.00%	0	0.00%	2	99.95%	4	99.98%	1	100.00%
$500 to $600	0	0.00%	0	0.00%	1	99.97%	1	99.99%	0	0.00%
$600 to $700	0	0.00%	0	0.00%	1	99.98%	1	100.00%	0	0.00%
> $700	0	0.00%	0	0.00%	2	100.00%	0	0.00%	0	0.00%

Off-Peak and On-Peak, PJM Real-Time, Load-Weighted LMP: 2007 to 2008

Table C-5 shows load-weighted, average LMP for 2007 and 2008 during off-peak and on-peak periods. In 2008, the on-peak, load-weighted LMP was 45.8 percent higher than the off-peak LMP, while in 2007, it was 52.6 percent higher. On-peak, load-weighted, average LMP in 2008 was 13.5 percent higher than in 2007. Off-peak, load-weighted LMP in 2008 was 18.8 percent higher than in 2007. The on-peak median LMP was higher in 2008 than in 2007 by 7.7 percent; off-peak median LMP was higher in 2008 than in 2007 by 19.9 percent. Dispersion in load-weighted LMP, as indicated by standard deviation, was 25.5 percent higher in 2008 than in 2007 during off-peak hours and was 4.2 percent higher during on-peak hours. Since the mean was above the median during on-peak and off-peak hours, both showed a positive skewness. The mean was, however, proportionately higher than the median in 2008 as compared to 2007 during on-peak periods (14.2 percent in 2008 compared to 8.3 percent in 2007). The differences reflect larger positive skewness in the on-peak hours.

Table C-5 Off-peak and on-peak, PJM load-weighted, average LMP (Dollars per MWh): Calendar years 2007 to 2008

	2007			2008			Difference 2007 to 2008		
	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	$48.43	$73.91	1.53	$57.55	$83.90	1.46	18.8%	13.5%	(4.6%)
Median	$37.89	$68.23	1.80	$45.43	$73.47	1.62	19.9%	7.7%	(10.0%)
Standard deviation	$29.20	$39.07	1.34	$36.64	$40.72	1.11	25.5%	4.2%	(17.2%)

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

Table C-6 shows that the PJM load-weighted, average LMP during constrained hours was 12.0 percent higher in 2008 than it had been in 2007.[6] The load-weighted, median LMP during constrained hours was 4.4 percent higher in 2008 than in 2007 and the standard deviation was 9.2 percent higher in 2008 than in 2007.

Table C-6 PJM load-weighted, average LMP during constrained hours (Dollars per MWh): Calendar years 2007 to 2008

	2007	2008	Difference
Average	$64.54	$72.28	12.0%
Median	$57.49	$60.00	4.4%
Standard deviation	$38.09	$41.58	9.2%

Table C-7 provides a comparison of PJM load-weighted, average LMP during constrained and unconstrained hours for 2007 and 2008. In 2008, load-weighted, average LMP during constrained

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,* 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*, an hour was considered constrained if one or more facilities were constrained for four or more of the 12 five-minute intervals in that hour. In the *2004 State of the Market Report*, this appendix defined a congested hour as one in which the difference in LMP between at least two buses in that hour was greater than $1.00.

hours was 11.3 percent higher than load-weighted, average LMP during unconstrained hours. The comparable number for 2007 was 35.0 percent.

Table C-7 PJM load-weighted, average LMP during constrained and unconstrained hours (Dollars per MWh): Calendar years 2007 to 2008

	2007			2008		
	Unconstrained Hours	Constrained Hours	Difference	Unconstrained Hours	Constrained Hours	Difference
Average	$47.82	$64.54	35.0%	$64.94	$72.28	11.3%
Median	$40.15	$57.49	43.2%	$56.52	$60.00	6.2%
Standard deviation	$26.78	$38.09	42.2%	$36.89	$41.58	12.7%

Table C-8 shows the number of hours and the number of constrained hours during each month in 2007 and 2008. There were 7,408 constrained hours in 2008 and 7,161 in 2007, an increase of approximately 3.4 percent. Table C-10 also shows that the average number of constrained hours per month was slightly higher in 2008 than in 2007, with 617 per month in 2008 versus 597 per month in 2007.

Table C-8 Table 0-10 PJM real-time constrained hours: Calendar years 2007 to 2008

	2007 Constrained Hours	2008 Constrained Hours	Total Hours
Jan	497	638	744
Feb	521	507	672
Mar	629	560	743
Apr	466	671	720
May	558	638	744
Jun	642	697	720
Jul	657	513	744
Aug	663	648	744
Sep	627	673	720
Oct	615	718	744
Nov	585	591	721
Dec	701	554	744
Avg	597	617	730

Day-Ahead and Real-Time LMP

On average, prices in the Real-Time Energy Market in 2008 were higher than those in the Day-Ahead Energy Market and real-time prices showed greater dispersion. This pattern of system average LMP distribution for 2008 can be seen by comparing Table C-4 and Table C-9. Table C-9 shows frequency distributions of PJM day-ahead hourly LMP for the calendar years 2004 to 2008. Together the tables show the frequency distribution by hours for the two markets. In PJM's Real-Time Energy Market and in the PJM Day-Ahead Energy Market, the most frequently occurring price interval was the $40-per-MWh to $50-per-MWh interval with 17.5 and 17.6 percent of the hours in 2008. The standard deviation of the simple average real-time LMP is higher than that of simple average day-ahead LMP ($38.62 and $30.87 respectively) and the standard deviation of the load-weighted real-time LMP is higher than that of load-weighted day-ahead LMP ($40.97 and $33.14 respectively). In the Real-Time Energy Market, prices were above $200 per MWh for 75 hours (0.9 percent of the hours), reaching a high for the year of $483.27 per MWh on June 12, 2008, during the hour ending 1600 EPT. In the Day-Ahead Energy Market, prices were above $200 per MWh for 36 hours (0.4 percent of the hours) and reached a high for the year of $312.12 per MWh on June 9, 2008, during the hour ending 1600 EPT.

Table C-9 Frequency distribution by hours of PJM Day-Ahead Energy Market LMP (Dollars per MWh): Calendar years 2004 to 2008

	2004		2005		2006		2007		2008	
LMP	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent
$10 and less	59	0.67%	47	0.54%	11	0.13%	3	0.03%	0	0.00%
$10 to $20	715	8.81%	162	2.39%	147	1.80%	88	1.04%	19	0.22%
$20 to $30	1,684	27.98%	1,022	14.05%	1,610	20.18%	1,291	15.78%	320	3.86%
$30 to $40	1,848	49.02%	1,753	34.06%	1,747	40.13%	1,495	32.84%	1,148	16.93%
$40 to $50	1,946	71.17%	1,382	49.84%	1,890	61.70%	1,221	46.78%	1,546	34.53%
$50 to $60	1,357	86.62%	1,102	62.42%	1,364	77.27%	1,266	61.23%	1,491	51.50%
$60 to $70	728	94.91%	812	71.69%	905	87.60%	1,301	76.08%	1,107	64.11%
$70 to $80	278	98.08%	686	79.52%	524	93.58%	939	86.80%	942	74.83%
$80 to $90	110	99.33%	524	85.50%	237	96.29%	504	92.56%	682	82.59%
$90 to $100	42	99.81%	388	89.93%	145	97.95%	264	95.57%	542	88.76%
$100 to $110	11	99.93%	263	92.93%	65	98.69%	155	97.34%	289	92.05%
$110 to $120	4	99.98%	207	95.30%	38	99.12%	104	98.53%	193	94.25%
$120 to $130	2	100.00%	151	97.02%	11	99.25%	59	99.20%	131	95.74%
$130 to $140	0	0.00%	102	98.18%	8	99.34%	33	99.58%	112	97.02%
$140 to $150	0	0.00%	64	98.92%	8	99.43%	13	99.73%	67	97.78%
$150 to $160	0	0.00%	46	99.44%	7	99.51%	8	99.82%	54	98.39%
$160 to $170	0	0.00%	27	99.75%	6	99.58%	7	99.90%	46	98.92%
$170 to $180	0	0.00%	11	99.87%	6	99.65%	3	99.93%	23	99.18%
$180 to $190	0	0.00%	8	99.97%	3	99.68%	4	99.98%	20	99.41%
$190 to $200	0	0.00%	1	99.98%	3	99.71%	1	99.99%	16	99.59%
$200 to $210	0	0.00%	2	100.00%	3	99.75%	1	100.00%	8	99.68%
$210 to $220	0	0.00%	0	0.00%	3	99.78%	0	0.00%	9	99.78%
$220 to $230	0	0.00%	0	0.00%	1	99.79%	0	0.00%	4	99.83%
$230 to $240	0	0.00%	0	0.00%	3	99.83%	0	0.00%	3	99.86%
$240 to $250	0	0.00%	0	0.00%	2	99.85%	0	0.00%	2	99.89%
$250 to $260	0	0.00%	0	0.00%	1	99.86%	0	0.00%	0	99.89%
$260 to $270	0	0.00%	0	0.00%	2	99.89%	0	0.00%	4	99.93%
$270 to $280	0	0.00%	0	0.00%	1	99.90%	0	0.00%	0	99.93%
$280 to $290	0	0.00%	0	0.00%	1	99.91%	0	0.00%	2	99.95%
$290 to $300	0	0.00%	0	0.00%	1	99.92%	0	0.00%	2	99.98%
>$300	0	0.00%	0	0.00%	7	100.00%	0	0.00%	2	100.00%

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

Table C-10 shows PJM simple average LMP during off-peak and on-peak periods for the Day-Ahead and Real-Time Energy Markets during calendar year 2008. On-peak, day-ahead and real-time, average LMPs were 52.5 percent and 50.4 percent higher, respectively, 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 (14.2 percent and 23.9 percent compared to 9.6 percent and 13.2 percent, respectively). 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 2008 during the on-peak and off-peak hours, respectively. The difference between real-time and day-ahead average LMP during on-peak hours was $0.13 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 $0.65 per MWh. (Day-ahead LMP was lower than real-time LMP.)

Table C-10 Off-peak and on-peak, simple average LMP (Dollars per MWh): Calendar year 2008

	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	$53.11	$81.00	1.53	$53.76	$80.87	1.50	1.2%	(0.2%)	(2.0%)
Median	$46.92	$73.92	1.58	$43.38	$70.81	1.63	(7.5%)	(4.2%)	3.2%
Standard deviation	$23.38	$31.68	1.36	$34.04	$38.48	1.13	45.6%	21.5%	(16.9%)

Figure C-1 Hourly real-time LMP minus day-ahead LMP (On-peak hours): Calendar year 2008

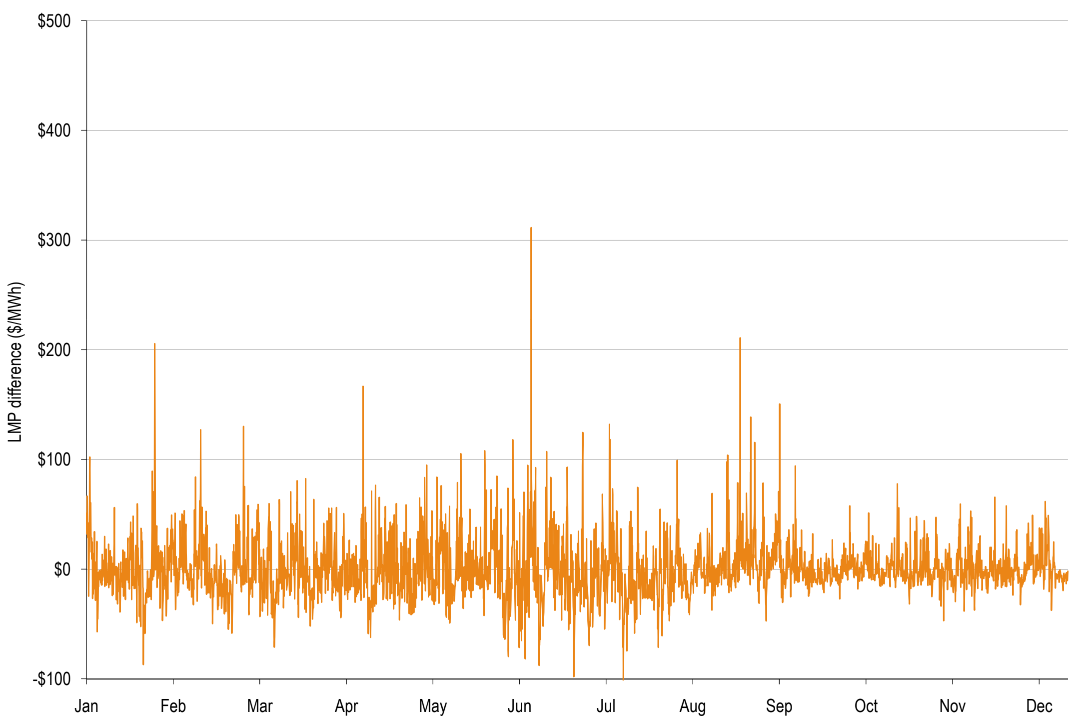


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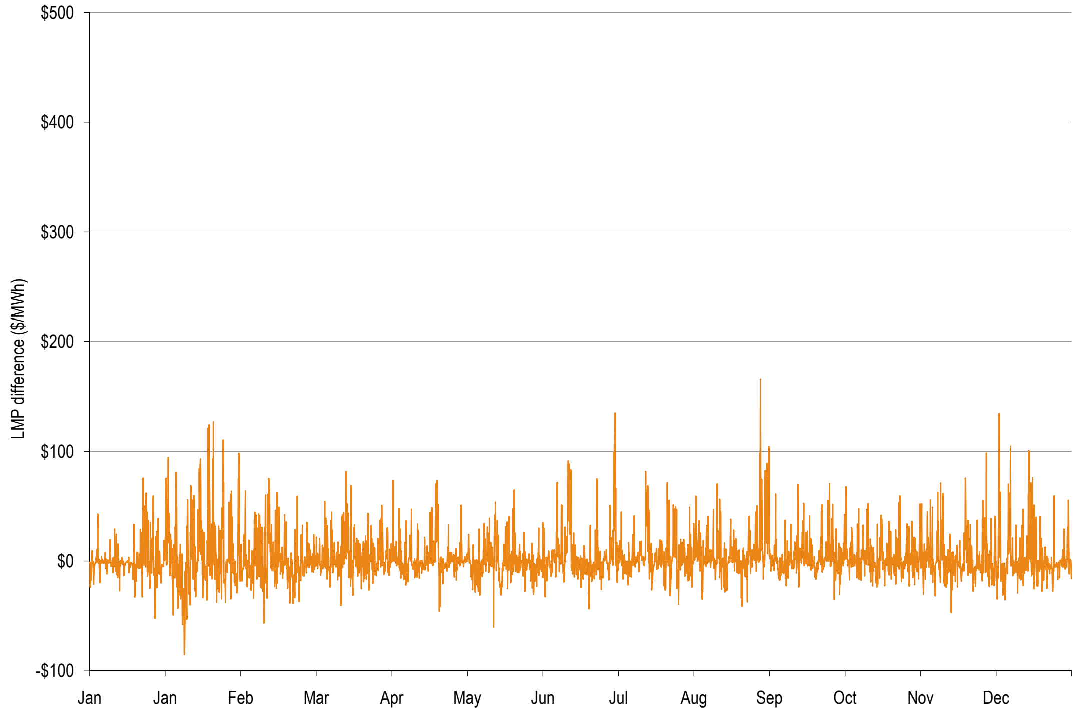
Figure C-2 Hourly real-time LMP minus day-ahead LMP (Off-peak hours): Calendar year 2008



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

Table C-11 and Table C-12 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 2008. 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 $2.96 higher than its day-ahead, on-peak, zonal LMP. The DAY Control Zone had the smallest difference with its real-time, on-peak, zonal LMP $0.23 higher than its day-ahead, on-peak, zonal LMP. (See Table C-13.) The DLCO Control Zone had the largest difference between off-peak zonal, real-time and day-ahead LMP, with real-time LMP that was $3.38 lower than day-ahead LMP. The zone with the smallest difference between off-peak, zonal, real-time and day-ahead LMP was the AEP Control Zone with a real-time LMP that was $0.03 higher than day-ahead LMP. (See Table C-14.)

Table C-11 On-peak, zonal, simple average LMP (Dollars per MWh): Calendar year 2008

	Day Ahead	Real Time	Difference	Difference as Percent Real Time
AECO	$95.93	$98.89	$2.96	2.99%
AEP	$68.10	$67.66	($0.44)	(0.65%)
AP	$78.85	$79.25	$0.40	0.50%
BGE	$96.34	$94.12	($2.22)	(2.36%)
ComEd	$66.63	$66.12	($0.51)	(0.77%)
DAY	$68.19	$68.42	$0.23	0.34%
DLCO	$65.22	$64.56	($0.66)	(1.02%)
Dominion	$88.73	$87.38	($1.35)	(1.54%)
DPL	$92.73	$91.37	($1.36)	(1.49%)
JCPL	$96.53	$95.49	($1.04)	(1.09%)
Met-Ed	$90.54	$89.13	($1.41)	(1.58%)
PECO	$90.60	$89.33	($1.27)	(1.42%)
PENELEC	$79.21	$77.21	($2.00)	(2.59%)
Pepco	$96.63	$94.20	($2.43)	(2.58%)
PPL	$89.17	$87.89	($1.28)	(1.46%)
PSEG	$95.83	$94.84	($0.99)	(1.04%)
RECO	$93.84	$92.72	($1.12)	(1.21%)

Table C-12 Off-peak, zonal, simple average LMP (Dollars per MWh): Calendar year 2008

	Day Ahead	Real Time	Difference	Difference as Percent Real Time
AECO	$64.19	$64.81	$0.62	0.96%
AEP	$40.94	$40.97	$0.03	0.07%
AP	$53.06	$54.14	$1.08	1.99%
BGE	$67.04	$67.75	$0.71	1.05%
ComEd	$36.40	$34.75	($1.65)	(4.75%)
DAY	$40.72	$40.81	$0.09	0.22%
DLCO	$38.43	$35.05	($3.38)	(9.64%)
Dominion	$64.13	$65.81	$1.68	2.55%
DPL	$65.03	$64.81	($0.22)	(0.34%)
JCPL	$65.07	$64.22	($0.85)	(1.32%)
Met-Ed	$62.44	$62.10	($0.34)	(0.55%)
PECO	$63.68	$62.61	($1.07)	(1.71%)
PENELEC	$52.79	$51.27	($1.52)	(2.96%)
Pepco	$67.82	$68.43	$0.61	0.89%
PPL	$61.21	$60.64	($0.57)	(0.94%)
PSEG	$65.74	$65.43	($0.31)	(0.47%)
RECO	$64.30	$64.12	($0.18)	(0.28%)

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

Table C-13 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 2008. Overall, there were 7,408 constrained hours in the Real-Time Energy Market and 8,711 constrained hours in the Day-Ahead Energy Market. Table C-13 shows that in every month of calendar year 2008 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 17.6 percent more constrained hours than the Real-Time Energy Market.

Table C-13 PJM day-ahead and real-time, market-constrained hours: Calendar year 2008

	DA Constrained Hours	RT Constrained Hours	Total Hours
Jan	744	638	744
Feb	696	507	696
Mar	740	560	743
Apr	696	671	720
May	720	638	744
Jun	720	697	720
Jul	744	513	744
Aug	739	648	744
Sep	720	673	720
Oct	744	718	744
Nov	720	591	721
Dec	728	554	744
Avg	726	617	732

Table C-14 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 2.2 percent higher than average LMP during unconstrained hours.[7] In the Real-Time Energy Market, average LMP during constrained hours was 11.3 percent higher than average LMP during unconstrained hours. Average LMP during constrained hours was 2.0 percent higher in the Real-Time Energy Market than in the Day-Ahead Energy Market and LMP during unconstrained hours was 6.4 percent lower in the Real-Time Energy Market than in the Day-Ahead Energy Market.

7 This comparison is of limited usefulness as there were only 73 day-ahead unconstrained hours.

Table C-14 PJM simple average LMP during constrained and unconstrained hours (Dollars per MWh): Calendar year 2008

	Day Ahead			Real Time		
	Unconstrained Hours	Constrained Hours	Difference	Unconstrained Hours	Constrained Hours	Difference
Average	$64.72	$66.13	2.2%	$60.61	$67.47	11.3%
Median	$66.37	$58.86	(11.3%)	$52.28	$56.10	7.3%
Standard deviation	$21.50	$30.94	43.9%	$35.72	$39.04	9.3%

Taken together, the data show that average LMP in the Day-Ahead Energy Market during constrained hours was $0.01 (0.0 percent) higher than the overall average LMP for the Day-Ahead Energy Market, while average LMP during unconstrained hours was $1.40 (2.1 percent) lower although these comparisons are of limited usefulness as there were only 73 unconstrained hours in the Day-Ahead Energy Market.[8] In the Real-Time Energy Market, average LMP during constrained hours was $1.07 (1.6 percent) higher than the overall average LMP for the Real-Time Energy Market, while average LMP during unconstrained hours was $5.79 (8.7 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.[9] 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.[10] 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.

8 See the *2008 State of the Market Report*, Volume II, Section 2, "Energy Market, Part 1" for a discussion of load and LMP.
9 See PJM. "Amended and Restated Operating Agreement (OA)," Schedule 1, Section 6.4.2 (January 19, 2007).
10 See the *2008 State of the Market Report*, Volume II, Appendix L, "Three Pivotal Supplier Test."

Levels of offer capping have generally been low and stable over the last five years. Table C-15 through Table C-18 show offer capping by month, including the number of offer-capped units and the level of offer-capped MW in the Day-Ahead and Real-Time Energy Markets.[11]

Table C-15 Average day-ahead, offer-capped units: Calendar years 2004 to 2008

	2004		2005		2006		2007		2008	
	Avg. Units Capped	Percent	Avg. Units Capped	Percent	Avg. Units Capped	Percent	Avg. Units Capped	Percent	Avg. Units Capped	Percent
Jan	0.4	0.1%	0.4	0.0%	0.1	0.0%	0.2	0.0%	0.5	0.0%
Feb	0.2	0.0%	0.4	0.0%	0.2	0.0%	0.8	0.1%	0.2	0.0%
Mar	0.1	0.0%	0.6	0.1%	0.7	0.1%	0.9	0.1%	0.0	0.0%
Apr	0.3	0.0%	0.4	0.0%	0.2	0.0%	0.2	0.0%	0.2	0.0%
May	0.6	0.1%	0.2	0.0%	0.1	0.0%	0.2	0.0%	0.6	0.1%
Jun	1.1	0.2%	0.4	0.0%	0.7	0.1%	0.8	0.1%	1.5	0.1%
Jul	2.6	0.4%	0.9	0.1%	4.1	0.4%	0.6	0.1%	1.7	0.2%
Aug	3.0	0.4%	1.1	0.1%	4.7	0.5%	1.0	0.1%	0.4	0.0%
Sep	3.0	0.4%	0.2	0.0%	0.6	0.1%	0.2	0.0%	0.4	0.0%
Oct	0.6	0.1%	0.3	0.0%	0.3	0.0%	0.8	0.1%	0.4	0.0%
Nov	0.5	0.1%	0.2	0.0%	0.3	0.0%	0.0	0.0%	0.5	0.1%
Dec	0.5	0.1%	0.7	0.1%	0.5	0.0%	0.1	0.0%	1.3	0.1%

Table C-16 Average day-ahead, offer-capped MW: Calendar years 2004 to 2008

	2004		2005		2006		2007		2008	
	Avg. MW Capped	Percent	Avg. MW Capped	Percent	Avg. MW Capped	Percent	Avg. MW Capped	Percent	Avg. MW Capped	Percent
Jan	51	0.1%	87	0.1%	4	0.0%	23	0.0%	16	0.0%
Feb	59	0.1%	75	0.1%	6	0.0%	57	0.1%	11	0.0%
Mar	32	0.1%	57	0.1%	51	0.1%	86	0.1%	2	0.0%
Apr	33	0.1%	34	0.0%	31	0.0%	11	0.0%	31	0.0%
May	52	0.1%	14	0.0%	22	0.0%	38	0.0%	15	0.0%
Jun	49	0.1%	28	0.0%	164	0.2%	28	0.0%	91	0.1%
Jul	243	0.4%	52	0.0%	518	0.5%	45	0.0%	110	0.1%
Aug	346	0.5%	63	0.1%	398	0.4%	58	0.1%	49	0.0%
Sep	218	0.3%	13	0.0%	51	0.1%	14	0.0%	70	0.1%
Oct	34	0.0%	16	0.0%	25	0.0%	77	0.1%	39	0.0%
Nov	28	0.0%	26	0.0%	15	0.0%	4	0.0%	53	0.1%
Dec	35	0.0%	48	0.0%	30	0.0%	4	0.0%	187	0.2%

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

Table C-17 Average real-time, offer-capped units: Calendar years 2004 to 2008

	2004		2005		2006		2007		2008	
	Avg. Units Capped	Percent	Avg. Units Capped	Percent	Avg. Units Capped	Percent	Avg. Units Capped	Percent	Avg. Units Capped	Percent
Jan	2.7	0.4%	2.5	0.3%	1.9	0.2%	1.2	0.1%	3.1	0.3%
Feb	0.7	0.1%	1.3	0.1%	2.1	0.2%	4.2	0.4%	2.6	0.3%
Mar	0.8	0.1%	1.4	0.2%	2.3	0.2%	1.9	0.2%	2.7	0.3%
Apr	1.8	0.3%	1.2	0.1%	1.5	0.2%	1.3	0.1%	3.1	0.3%
May	5.9	0.8%	0.8	0.1%	3.4	0.3%	1.9	0.2%	2.1	0.2%
Jun	3.9	0.5%	10.0	1.0%	2.5	0.3%	6.0	0.6%	8.7	0.8%
Jul	4.7	0.7%	13.9	1.4%	8.6	0.9%	4.4	0.4%	5.7	0.6%
Aug	6.3	0.9%	13.7	1.4%	9.5	1.0%	9.6	0.9%	2.1	0.2%
Sep	4.2	0.6%	7.9	0.8%	1.8	0.2%	5.5	0.5%	4.8	0.5%
Oct	1.1	0.1%	7.9	0.8%	1.7	0.2%	5.0	0.5%	2.5	0.2%
Nov	1.1	0.1%	3.3	0.3%	1.1	0.1%	2.9	0.3%	2.3	0.2%
Dec	3.3	0.4%	4.4	0.4%	1.0	0.0%	4.7	0.5%	2.4	0.2%

Table C-18 Average real-time, offer-capped MW: Calendar years 2004 to 2008

	2004		2005		2006		2007		2008	
	Avg. MW Capped	Percent	Avg. MW Capped	Percent	Avg. MW Capped	Percent	Avg. MW Capped	Percent	Avg. MW Capped	Percent
Jan	175	0.4%	209	0.3%	42	0.1%	50	0.1%	99	0.1%
Feb	87	0.2%	145	0.2%	67	0.1%	125	0.1%	92	0.1%
Mar	76	0.2%	74	0.1%	88	0.1%	142	0.2%	117	0.2%
Apr	115	0.3%	59	0.1%	75	0.1%	48	0.1%	125	0.2%
May	257	0.5%	78	0.1%	136	0.2%	68	0.1%	59	0.1%
Jun	167	0.3%	652	0.7%	160	0.2%	190	0.2%	415	0.5%
Jul	332	0.6%	819	0.9%	506	0.5%	160	0.2%	202	0.2%
Aug	450	0.8%	908	1.0%	518	0.6%	314	0.3%	114	0.1%
Sep	268	0.5%	477	0.6%	69	0.1%	218	0.3%	186	0.2%
Oct	77	0.1%	337	0.5%	49	0.1%	153	0.2%	177	0.3%
Nov	110	0.2%	129	0.2%	31	0.0%	104	0.1%	164	0.2%
Dec	202	0.3%	156	0.2%	12	0.0%	146	0.2%	200	0.2%

In order to help understand the frequency of offer capping in more detail, Table C-19 through Table C-23 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 2004 through 2008.

Table C-19 Offer-capped unit statistics: Calendar year 2004

Run Hours Offer-Capped, Percent Greater Than Or Equal To:	2004 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	1	1	5	3	5
80% and < 90%	3	0	0	5	6	10
75% and < 80%	1	0	4	0	1	7
70% and < 75%	0	1	0	0	1	7
60% and < 70%	1	1	0	0	0	7
50% and < 60%	0	0	0	1	1	13
25% and < 50%	1	1	1	3	6	32
10% and < 25%	2	0	2	3	16	38

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

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 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 the concept of spot market imports with the introduction of the PJM 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, therefore reducing the marginal cost of energy to load. In 2007, spot imports were added to the OASIS to add transparency and to properly account for the impacts of this network service on flowgates external to the PJM Transmission System. 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. PJM interpreted its Joint Operating Agreement (JOA) with the Midwest ISO to require a limitation on spot import service in order to limit the impact of such transactions on selected external flowgates.[1] The rule caused the availability of spot import service to be limited by the Available Transmission Capacity (ATC) on the transmission path.

1 See "WPC White Paper" (April 20, 2007) (Accessed December 29, 2008)<http://www.pjm.com/~/media/etools/oasis/wpc-white-paper.ashx>(97 KB).

Source and Sink

The source and sink of an OASIS reservation designate the buses on the PJM system for which settlement LMPs are calculated. For import external energy transactions, the source defaults to the external interface as determined by the selected Point of Receipt (POR) and Point of Delivery (POD). For external energy transactions, the sink defaults to the external interface as determined by the selected POR and POD. For wheel through transactions, both the source and sink default to the external interfaces as determined by the selected POR and POD (the source defaults to the POR interface and the sink defaults to the POD interface). The market participant can then select the source or sink that is not pre-determined by the selected path. This selection 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.

NERC Tagging

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

While the OASIS has a path component, this path only reflects the path of energy into or out of PJM to one neighboring balancing authority. The NERC Tag requires the complete path to be specified from the Generation Control Area (GCA) to the Load Control Area (LCA). This complete path is utilized by PJM to determine the interface pricing point which PJM will associate with the transaction.

Neighboring Balancing Authority Checkout

PJM operators must verify all requested energy schedules with its 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) so as 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 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, they utilize their Market Information System (MIS) as their primary scheduling tool. The MIS evaluates all bids and offers each hour, and performs a least cost economic dispatch solution. This evaluation accepts or denies individual transactions in whole or in part. Upon market clearing, the NYISO implements NERC Tag adjustments to match the output of the MIS. 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 under several conditions, including economic and reliability considerations. There are three types of economic curtailments: curtailments of dispatchable schedules; OASIS designation curtailments; and market participant self-curtailments. System reliability curtailments 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 from which they would like the energy to flow. For example, an import dispatchable schedule specifies that the market participant only wishes to load the transaction if the LMP at the interface from which the transaction is entering the PJM footprint reaches a specified limit (the minimum LMP they are willing to sell at). An export dispatchable schedule specifies the maximum LMP at the interface from which 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 feel that the transaction will be economic, they will elect to curtail the dispatchable transaction. Dispatchable schedules can be viewed as a generation offer, with a minimum run time of one hour. If prices are such that the transaction should not have been loaded, it will be made whole in the settlement process.

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

Spot import service is dispatchable at a price of zero, by definition. If the interface price reaches zero, PJM system operators will curtail all transactions using spot import service flowing over that interface.

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

NYISO Issues

If interface prices were defined in a comparable manner by PJM and NYISO, if identical rules governed external transactions in PJM and 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 NYISO markets that are relevant to observed differences in border prices.[3] 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 NYISO are treated by NYISO as generator bids at the NYISO/PJM proxy bus. Export transactions are treated by NYISO as price-capped load offers. Competing bids and offers are evaluated along with 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 NYISO and the time when participants are notified that they have cleared. The lag is a result of the functioning of the real-time commitment (RTC) system and the fact that transactions can only be scheduled at the beginning of the hour.

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

Under PJM operating practices, 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, only about 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. Since they receive the actual real-time price for their scheduled imports or exports, these transactions are price takers in the Real-Time Energy Market. As in 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.

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 15, 2009) <http://www.nyiso.com/public/webdocs/documents/manuals/operations/tran_ser_mnl.pdf> (463 KB).

5 See PJM. "Manual 41: Managing Interchange" (November 24, 20087) (Accessed January 15, 2009) < http://www.pjm.com/documents/~/media/documents/manuals/m41.ashx> (291 KB).

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

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

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

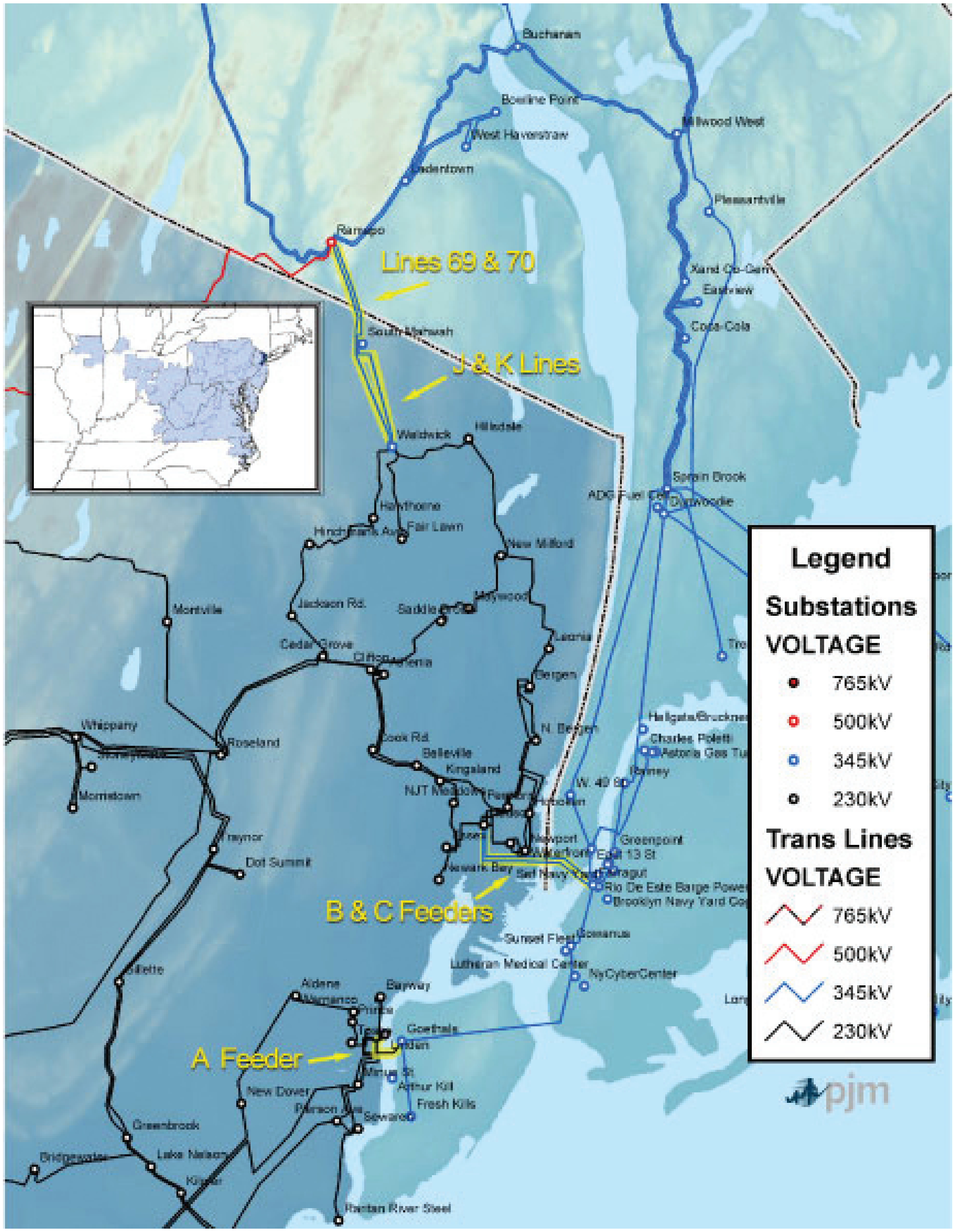
To help meet the demand for power in New York City, Con Edison uses electricity generated in upstate New York and wheeled through New York and New Jersey. A common path is through Westchester County using lines controlled by NYISO. Another path is through northern New Jersey using lines controlled by 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 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 then wheels the power across its system and delivers it back to Con Edison across lines connecting directly into the city. (See Figure D-1.) Two separate contracts cover these wheeling arrangements. A 1975 agreement covers delivery of up to 400 MW through Ramapo (New York) to PSE&G's Waldwick Switching Station (New Jersey) then to 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 underdelivered 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



Initial Implementation of the FERC Protocol

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

The Day-Ahead Energy Market Process

The protocol allows Con Edison to elect up to the 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 Financial Transmission Rights (FTRs) associated with the 600 MW contract. The PSE&G FTRs are treated like all other FTRs. In 2008, PSE&G's FTR revenues were less than its congestion charges by $26,250 after adjustments. (Revenues were approximately $14,250 less than charges in 2007.) 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 2008, Con Edison's congestion credits were $268,368 less than its day-ahead congestion charges. Con Edison also had negative day-ahead congestion charges, with the result that Con Edison's total credits exceeded its congestion charges by $213,535. (Credits had been approximately $1.7 million less than charges in 2007.) Table D-1 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 $213,535 in 2008. 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 5 percent of the hours in 2008.

Table D-1 Con Edison and PSE&G wheel settlements data: Calendar year 2008

		Con Edison			PSE&G		
		Day Ahead	Balancing	Total	Day Ahead	Balancing	Total
January	Congestion Charge	$164,163	($17,812)	$146,351	$287,369	$0	$287,369
	Congestion Credit			$190,400			$287,369
	Adjustment for defaults	($5,399)		($5,399)	($1,780)		($1,780)
	Net Charge			($38,650)			$1,780
February	Congestion Charge	$5,469	$10,333	$15,803	$20,770	$0	$20,770
	Congestion Credit			$81,674			$20,770
	Adjustment for defaults	($3,998)		($3,998)	($1,374)		($1,374)
	Net Charge			($61,874)			$1,374
March	Congestion Charge	$115,853	($1,839)	$114,014	$174,126	$0	$174,126
	Congestion Credit			$141,036			$174,126
	Adjustment for defaults	($2,376)		($2,376)	($670)		($670)
	Net Charge			($24,646)			$670
April	Congestion Charge	$303,483	$0	$303,483	$481,506	$0	$481,506
	Congestion Credit			$308,958			$481,506
	Adjustment for defaults	($682)		($682)	($147)		($147)
	Net Charge			($4,792)			$147
May	Congestion Charge	$752,197	($24,556)	$727,641	$1,140,758	$0	$1,140,758
	Congestion Credit			$752,944			$1,140,758
	Adjustment for defaults	($1,615)		($1,615)	($492)		($492)
	Net Charge			($23,688)			$492
June	Congestion Charge	$592,331	($7,259)	$585,072	$894,608	$0	$894,608
	Congestion Credit			$606,219			$894,608
	Adjustment for defaults	$997		$997	$374		$374
	Net Charge			($22,144)			($374)

		Con Edison			PSE&G		
		Day Ahead	Balancing	Total	Day Ahead	Balancing	Total
July	Congestion Charge	$1,056,304	$0	$1,056,304	$1,600,758	$0	$1,600,758
	Congestion Credit			$1,063,359			$1,600,758
	Adjustment for defaults	$0		$0	$0		$0
	Net Charge			($7,055)			$0
August	Congestion Charge	$146,243	($32,711)	$113,532	$219,364	($40,018)	$179,346
	Congestion Credit			$147,523			$219,364
	Adjustment for defaults	$0		$0	($682)		($682)
	Net Charge			($33,991)			($39,336)
September	Congestion Charge	$209,630	$2,125	$211,755	$366,394	$0	$366,394
	Congestion Credit			$85,305			$348,301
	Adjustment for defaults	$0		$0	($661)		($661)
	Net Charge			$126,450			$18,754
October	Congestion Charge	$170,129	$0	$170,129	$392,606	$0	$392,606
	Congestion Credit			$82,162			$386,591
	Adjustment for defaults	($4,037)		($4,037)	($652)		($652)
	Net Charge			$92,004			$6,666
November	Congestion Charge	$420,082	($218)	$419,864	$651,628	$0	$651,628
	Congestion Credit			$207,388			$633,053
	Adjustment for defaults	$0		$0	$0		$0
	Net Charge			$212,476			$18,575
December	Congestion Charge	$125,485	($8)	$125,477	$195,562	$0	$195,562
	Congestion Credit			$126,034			$218,077
	Adjustment for defaults	$0		$0	$0		$0
	Net Charge			($557)			($22,515)
Total	Congestion Charge	$4,061,370	($71,943)	$3,989,426	$6,425,449	($40,018)	$6,385,431
	Congestion Credit			$3,793,002			$6,405,281
	Adjustment for defaults			($17,110)			($6,082)
	Net Charge			$213,535			($13,768)

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 represents the target level of reserves required to meet PJM reliability standards. It 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, all measured in UCAP.

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 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.

1 This section relies upon the cited PJM manuals where additional detail may be found.
2 See PJM. "Manual 18: PJM Capacity Market," Revision 5 (Effective October 3, 2008), p. 25 <http://www.pjm.com/documents/~/media/documents/manuals/m18.ashx> (1.19 MB).
3 See PJM. "Manual 18: PJM Capacity Market," Revision 5 (Effective October 3, 2008), p. 12 <http://www.pjm.com/documents/~/media/documents/manuals/m18.ashx> (1.19 MB).

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. 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. 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.

Final UCAP Obligation

The final RTO UCAP obligation is determined after the clearing of the Second Incremental Auction (IA) and is posted with the second IA results. 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. 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.

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 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 PJM-specific criteria.[4] 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.[5] 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.

4 See PJM. "Manual 18: PJM Capacity Market," Revision 5 (Effective October 3, 2008), p. 28 <http://www.pjm.com/documents/~/media/documents/manuals/m18.ashx> (1.19 MB).
5 See PJM. "Manual 18: PJM Capacity Market," Revision 5 (October 3, 2008), p. 29 <http://www.pjm.com/documents/~/media/documents/manuals/m18.ashx> (1.19 MB).

Load Management Resources

Load management is the ability to reduce load upon request.[6] A load management resource is eligible to be offered as a demand resource (DR) or 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.

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.[7]

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

6 See PJM. "Manual 18: PJM Capacity Market," Revision 5 (Effective October 3, 2008), p. 33 <http://www.pjm.com/documents/~/media/documents/manuals/m18.ashx> (1.19 MB).
7 See PJM. "Manual 18: PJM Capacity Market," Revision 5 (Effective October 3, 2008), p. 41 <http://www.pjm.com/documents/~/media/documents/manuals/m18.ashx> (1.19 MB).

- **Deliverability.** To qualify as a PJM capacity resource, energy from the generating unit must be deliverable to PJM load. 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.[8] 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.[9]

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.[10] 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.[11] This will also trigger the planning of transmission upgrades under the RTEP Process.

Generator Performance: NERC OMC Outage Cause Codes

Table E-1 includes a list of the North American Electric Reliability Council (NERC) GADS cause codes deemed outside management control (OMC). PJM does not automatically include cause codes 9200-9299 as outside management control for the purposes of calculating unforced capacity, with the exception of code 9250 under certain conditions.

8 Deliverable per PJM. "Reliability Assurance Agreement," Schedule 10 (Effective June 1, 2007), Original Sheet No. 50 <http://www.pjm.com/documents/agreements/~/media/documents/agreements/raa.ashx> (1.92 MB).

9 See PJM. "Reliability Assurance Agreement," Schedule 12 (Effective June 1, 2007), Original Sheet No. 54 <http://www.pjm.com/documents/agreements/~/media/documents/agreements/raa.ashx> (1.92 MB).

10 See PJM. "Manual 14B: Generation and Transmission Interconnection Planning, Attachment E: PJM Deliverability Methods," Revision 12 (Effective August 8, 2008), p. 41 <http://www.pjm.com/documents/~/media/documents/manuals/m14b.ashx> (474 KB). PJM Manual 14B indicates that all "electrically cohesive load areas" are tested.

11 See PJM. "Manual 18: PJM Capacity Market," Revision 5 (Effective October 3, 2008), p. 18, <http://www.pjm.com/documents/~/media/documents/manuals/m18.ashx> (1.19 MB).

Table E-1 NERC GADS cause codes deemed outside management control[12]

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)

12 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).

APPENDIX F – ANCILLARY SERVICE MARKETS

This appendix covers two subject areas: area control error and the details of regulation availability and price determination.

Area Control Error (ACE)

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

In the absence of a severe grid disturbance, the primary tool used by dispatchers to minimize ACE is regulation. Regulation is defined as a variable amount of 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.

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 18 (July 2, 2008), Section 3, "System Control" p. 11.

2 Regulation Market business rules are defined in PJM. "Manual 11: Scheduling Operations," Revision 37 (November 24, 2008), pp. 33-39.

3 See PJM. "Manual 12: Balancing Operations," Revision 18 (July 2, 2008), pp. 43-45., Section 4, pp. 47-51.

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

Two control performance standards are established by NERC for evaluating ACE control. One measure is a statistical measure of ACE variability and its relationship to frequency error. The purpose of the new BAAL standard is to maintain interconnection frequency within a predefined frequency profile under all conditions (normal and abnormal), to prevent frequency-related instability, unplanned tripping of load or generation, or uncontrolled separation or cascading outages that adversely impact the reliability of the interconnection.

- **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, 2008, PJM's L_{10} standard was 291.6 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.

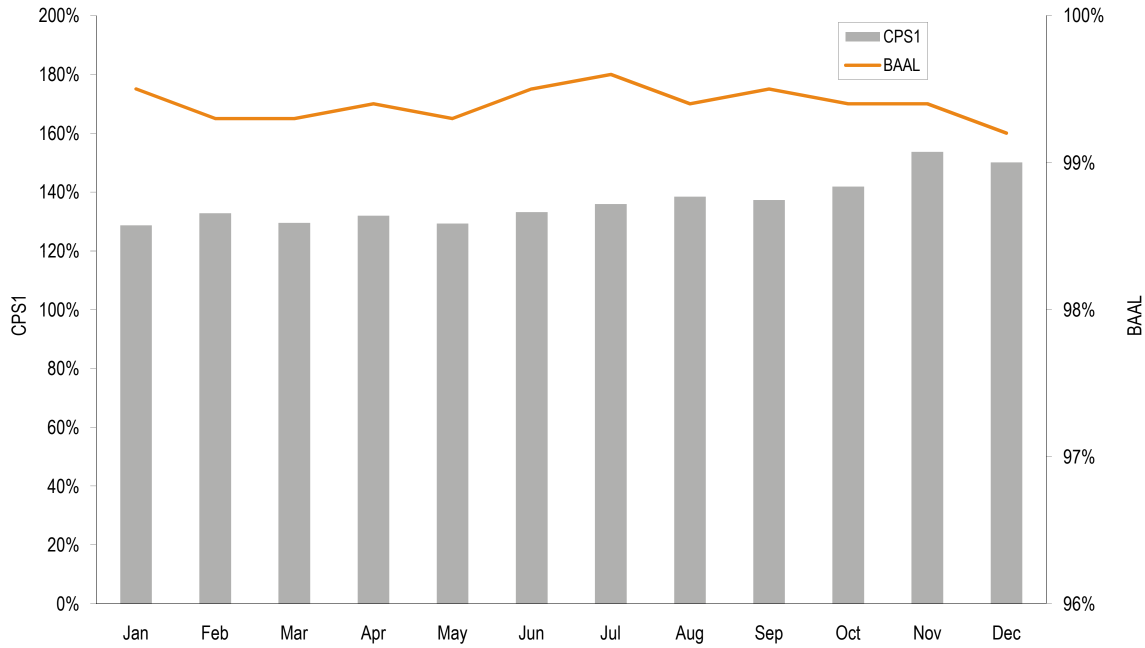
4 For more information about the definition and calculation of CPS, see PJM. "Manual 12: Balancing Operations," Revision 18 (July 2, 2008), pp. 76-77. The formal definition of CPS1 can be found in NERC's "Performance Standards Reference Document," Version 2 (November 21, 2002), Section B.1.1.1. The formal 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 18 (July 2, 2008), pp. 76-77.

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 2008.

Figure F-1 PJM CPS1 and BAAL performance: Calendar year 2008



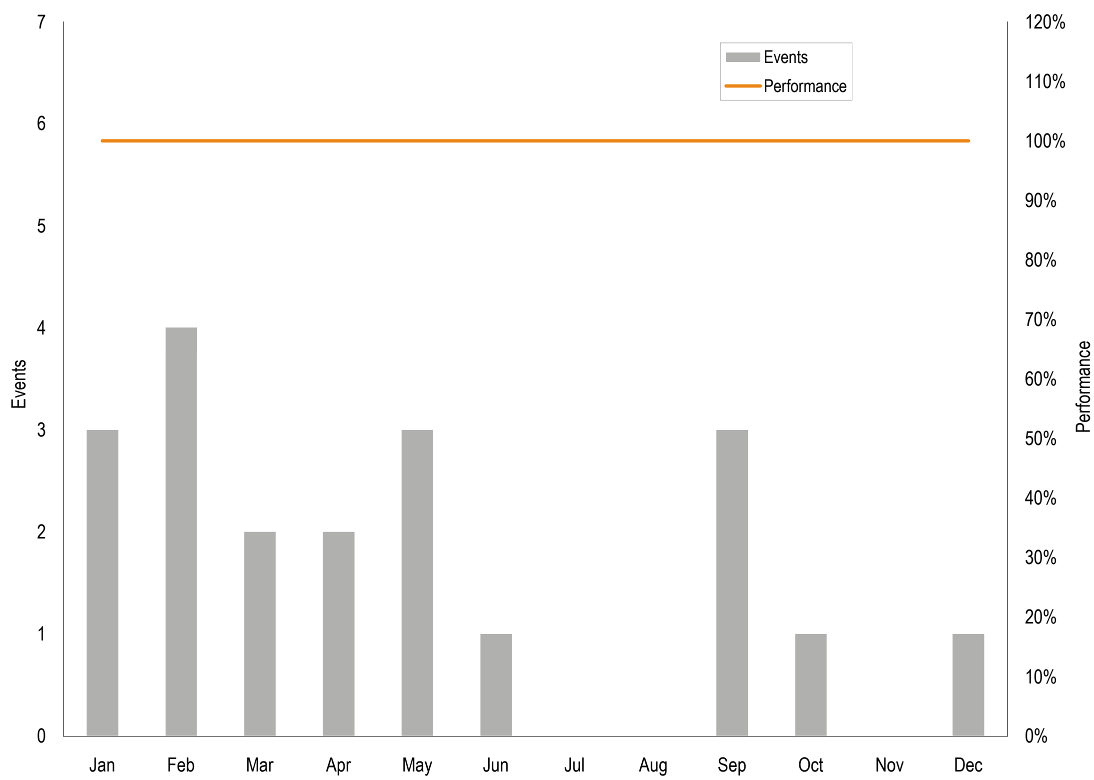
PJM dispatchers have to balance both ACE and frequency. Meeting the CPS1 standard requires balancing ACE and frequency on a monthly, running-average basis. Meeting the BAAL standard requires PJM dispatchers maintaining interconnection frequency within a predefined frequency profile under all conditions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

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

PJM experienced 20 DCS events during calendar year 2008 and successfully recovered from all of them. All events were caused by a major unit's tripping. 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 20 events was to declare a 100 percent spinning event.

Figure F-2 DCS event count and PJM performance (By month): Calendar year 2008



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).

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

The regulation market-clearing price (RMCP) is determined algorithmically by the PJM Market Operations Group. First, a theoretical, optimized energy dispatch is done based on current unit status and forecast LMP. Then the Market Operations Group creates a supply curve for regulation and for synchronized reserve of available units and their associated merit-order prices. The resulting supply curve is evaluated to see which if any of the owning companies are pivotal. Pivotal companies will have their resources offer capped at the lesser of their cost based or price based offer. The generating units of companies which are not pivotal will then have their offer reset to their price based offer and the market is cleared. Finally, the Market Operations Group assigns regulation and synchronized reserve to units in increasing order of price until the regulation MW and the synchronized reserve requirements are satisfied. The price of the most expensive unit required to satisfy the regulation requirement is the RMCP. Calculating the supply curves for three products (energy, regulation and synchronized reserve) interactively is complicated, but necessary to achieve the lowest overall cost after first taking into account units that self-schedule. In the event it is not possible to satisfy both regulation and synchronized reserve, regulation has the higher priority.

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

- **Regulation Offers.** All owners of generating units qualified to provide regulation may, but are not required to, offer their regulation capacity daily into the Regulation Market using the PJM market user interface. Regulating units may also self-schedule. Self-scheduled units have zero lost opportunity cost (LOC) and are the first to be assigned. Demand resources are eligible to offer regulation although during 2008 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. 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 cost-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.

APPENDIX G – FINANCIAL TRANSMISSION AND AUCTION REVENUE RIGHTS

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

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

FTR Target Allocations and Congestion Revenue

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

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

Day-Ahead Congestion Revenue

Pricing Node	Day-Ahead 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

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						