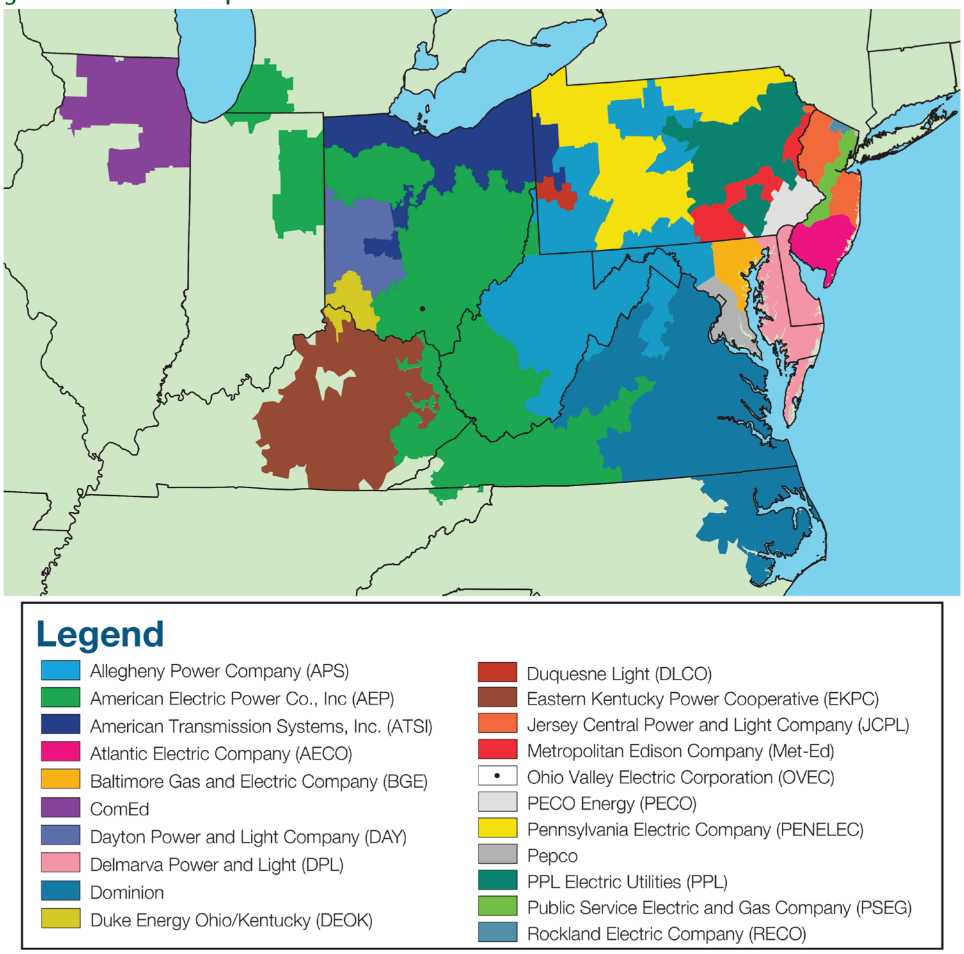
Appendix A PJM Geography

In 2017 and most of 2018, the PJM footprint included 20 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. On December 1, 2018, PJM integrated the Ohio Valley Electric Corporation (OVEC.) The OVEC Zone is represented by a single dot (Figure A-1) because, while OVEC owns a generating plant in Ohio and a generating plant in Indiana, and high voltage transmission lines, OVEC does not uniquely occupy a single geographic footprint like the other control zones.

Figure A-1 PJM's footprint and its 21 control zones

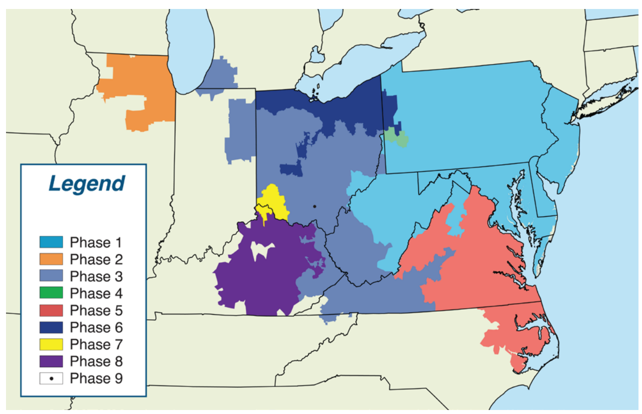


Analysis of 2018 market results includes comparisons to market results in prior years. In December 2018, PJM integrated the Ohio Valley Electric Corporation (OVEC.) In 2017, 2016, 2015 and 2014 no changes were made to the PJM footprint. In 2013, PJM integrated the Eastern Kentucky Power Cooperative (EKPC) Control Zone. In 2012, PJM integrated the Duke Energy Ohio and Kentucky (DEOK) Control Zone. In 2011, PJM integrated the ATSI Control Zone. In 2006 through 2010, the PJM footprint was stable. In 2004 and 2005, PJM integrated five new control zones, three in 2004 and two in 2005.

Figure A-2 shows the nine phases corresponding to market integration dates:[1]

- **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, and the Allegheny Power System (APS) Control Zone.[2 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 APS 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 APS 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 APS Control Zone, the ComEd Control Zone, the AEP Control Zone and the DAY Control Zone plus the Duquesne Light Company (DLCO) Control Zone which was integrated into PJM on January 1, 2005.
- **Phase 5 (2005 through 2011).** The period from May 1, 2005, through May 31, 2011, during which PJM was comprised of the Phase 4 elements plus the Dominion Control Zone which was integrated into PJM on May 1, 2005.
- **Phase 6 (2011).** The period from June 1, through December 31, 2011, during which PJM was comprised of the Phase 5 elements plus the ATSI Control Zone which was integrated into PJM on June 1, 2011.
- **Phase 7 (2012).** The period from January 1, 2012, through May 31, 2013, during which PJM was comprised of the Phase 6 elements plus the DEOK Control Zone which was integrated into PJM on January 1, 2012.
- **Phase 8 (2013 through November 2018).** The period from June 1, 2013, through November 30, 2018, during which PJM was comprised of the Phase 7 elements plus the EKPC Control Zone which was integrated into PJM on June 1, 2013.
- **Phase 9 (December 2018 through the present).** The period from December 1, 2018, through the present, during which PJM was comprised of the Phase 8 elements plus the OVEC Control Zone which was integrated into PJM on December 1, 2018.

Figure A-2 PJM integration phases



A locational deliverability area (LDA), defined in the RPM Capacity Market, is a Control Zone, part of a Control Zone, or a combination of Control Zones within PJM with defined internal generation and defined transmission capability to import capacity.[5]

Figure A-3 shows LDAs that are combinations of Control Zones. Figure A-4 and Figure A-5 show LDAs that are part of a Control Zone.

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.

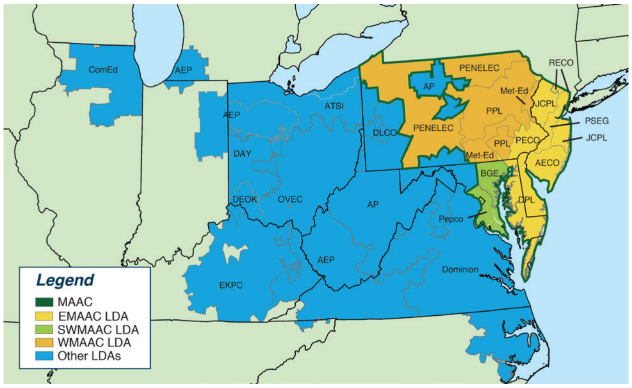
2 The Mid-Atlantic Region is comprised of the AECO, BGE, DPL, JCPL, Met-Ed, PECO, PENELEC, Pepco, PPL, PSEG and RECO control zones. The AP Control Zone was integrated in 2002. The RECO Control Zone was integrated in 2002.

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).

5 OATT Attachment DD § 2.38.

Figure A-3 PJM locational deliverability areas



In PJM's Reliability Pricing Model (RPM) Auctions, an LDA becomes a separate market when it cannot meet its reliability requirements through a combination of economic merit order imports and internal capacity without the purchase of out of merit capacity internal capacity. 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 Rest of RTO market is the balance of the footprint.

For the 2007/2008 and 2008/2009 Base Residual Auctions, the defined markets were RTO, EMAAC and SWMAAC. For the 2009/2010 Base Residual Auction, the defined markets were RTO, MAAC+APS and SWMAAC. The MAAC+APS LDA consists of the WMAAC, EMAAC, and SWMAAC LDAs, as shown in Figure A-3, plus the Allegheny Power System (APS) Zone as shown in Figure A-1. For the 2010/2011 Base Residual Auction, the defined markets were RTO and DPL South. The DPL South LDA is shown in Figure A-4. For the 2011/2012 Base Residual Auction, the only defined market was RTO. For the 2012/2013 Base Residual Auction, the defined markets were RTO, MAAC, EMAAC, PSEG North, and DPL South. The PSEG North LDA is shown in Figure A-4. For the 2013/2014 Base Residual Auction, the defined markets were RTO, MAAC, EMAAC, and Pepco. For the 2014/2015 Base Residual Auction, the defined markets were RTO, MAAC, and PSEG North. For the 2015/2016 Base Residual Auction, the defined markets were RTO, MAAC, and ATSI. For the 2016/2017 Base Residual Auction, the defined markets were RTO, MAAC, PSEG, and ATSI. For the 2017/2018 Base Residual Auction, the defined markets were RTO and PSEG. For the 2018/2019 Base Residual Auction, the defined markets were RTO, EMAAC, and ComEd. For the 2019/2020 Base Residual Auction, the defined markets were RTO, EMAAC, ComEd, and BGE. For the 2020/2021 Base Residual Auction, the defined markets were RTO, MAAC, EMAAC, ComEd, and DEOK.

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

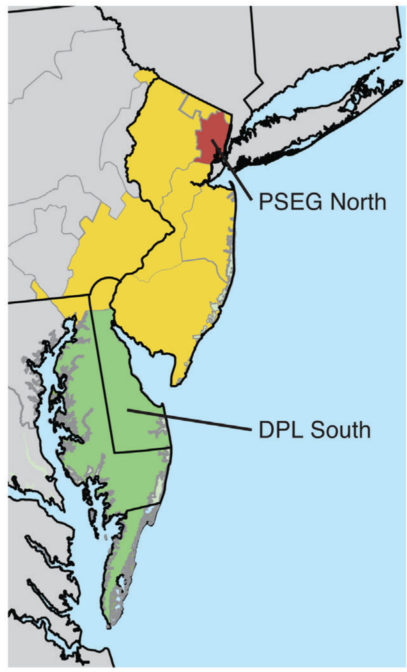
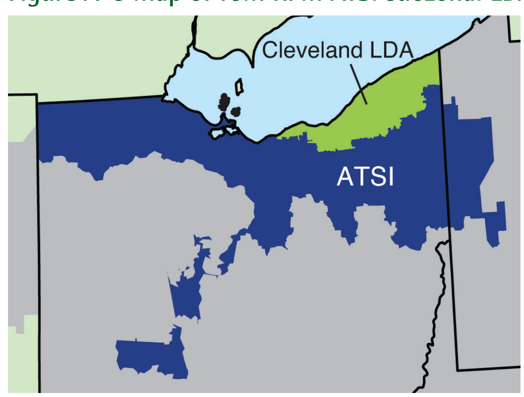


Figure A-5 Map of PJM RPM ATSI subzonal LDA



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
	June	Auction Revenue Rights (ARRs)
2004	May	Integration of ComEd Control Area into PJM
	October	Integration of AEP Control Zone into PJM Western Region
	October	Integration of DAY Control Zone into PJM Western Region
2005	January	Integration of DLCO Control Zone into PJM
	May	Integration of Dominion Control Zone into PJM
2006	May	Balance of Planning Period FTR Auction
2007	April	First RPM Auction
	June	Marginal loss component in LMPs
2008	June	Day-Ahead Scheduling Reserve (DASR) Market
	August	Independent, External MMU created as Monitoring Analytics, LLC
	October	Long Term FTR Auction
	December	Modified Operating Reserve accounting rules
	December	Three Pivotal Supplier Test in Regulation Market
2011	June	Integration of ATSI Control Zone into PJM
2012	January	Integration of DEOK Control Zone into PJM
	October	Regulation Market: Slow and fast frequency response
	October	Scarcity pricing in Energy Market
2013	June	Integration of Eastern Kentucky Power Cooperative (EKPC) into PJM
2015	August	First Capacity Performance Auction
2018	December	Integration of Ohio Valley Electric Corporation (OVEC) into PJM

Appendix C Energy Market

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

Load

Frequency Distribution of Load

Table C-1 provides the frequency distributions of PJM accounting load by hour, for 2007 through 2018.[1] The table shows the number of hours (frequency) and the percent of hours (cumulative percent) when the load was between zero GWh and 20 GWh and then by five GWh intervals. The integrations of the APS Control Zone in 2002, the ComEd, AEP and DAY control zones in 2004, the DLCO and Dominion control zones in 2005, the ATSI Control Zone in 2011, the DEOK Control Zone in 2012, the EKPC Control Zone in 2013, and the OVEC Control Zone in 2018 mean that annual comparisons of load frequency are significantly affected by PJM's growth.[2]

1 The definitions of load are discussed in the *Technical Reference for PJM Markets*, at "Load Definitions." <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

2 See the *2014 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography."

Table C-1 Frequency distribution of PJM real-time, hourly load: 2007 through 2018[3]

	2007		2008		2009		2010		2011		2012	
Load (GWh)	Frequency	Cumulative Percent	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%	0	0.00%
20 to 25	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
25 to 30	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
30 to 35	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
35 to 40	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
40 to 45	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
45 to 50	0	0.00%	0	0.00%	15	0.17%	12	0.14%	5	0.06%	0	0.00%
50 to 55	79	0.90%	127	1.45%	376	4.46%	272	3.24%	104	1.24%	0	0.00%
55 to 60	433	5.84%	517	7.33%	738	12.89%	582	9.89%	325	4.95%	104	1.18%
60 to 65	637	13.12%	667	14.92%	836	22.43%	699	17.87%	602	11.83%	471	6.55%
65 to 70	890	23.28%	941	25.64%	915	32.88%	805	27.05%	858	21.62%	629	13.71%
70 to 75	878	33.30%	1,048	37.57%	1,342	48.20%	1,323	42.16%	1,120	34.41%	785	22.64%
75 to 80	1,227	47.31%	1,535	55.04%	1,488	65.18%	1,272	56.68%	1,176	47.83%	1,010	34.14%
80 to 85	1,338	62.58%	1,208	68.80%	966	76.21%	948	67.50%	1,259	62.20%	1,390	49.97%
85 to 90	981	73.78%	916	79.22%	742	84.68%	794	76.56%	1,024	73.89%	1,233	64.00%
90 to 95	741	82.24%	655	86.68%	549	90.95%	659	84.09%	719	82.10%	973	75.08%
95 to 100	577	88.82%	457	91.88%	388	95.38%	487	89.65%	495	87.75%	691	82.95%
100 to 105	382	93.18%	292	95.21%	205	97.72%	318	93.28%	279	90.94%	436	87.91%
105 to 110	223	95.73%	181	97.27%	121	99.10%	195	95.50%	194	93.15%	289	91.20%
110 to 115	179	97.77%	133	98.78%	48	99.65%	151	97.23%	173	95.13%	185	93.31%
115 to 120	106	98.98%	58	99.44%	26	99.94%	108	98.46%	149	96.83%	152	95.04%
120 to 125	43	99.47%	35	99.84%	5	100.00%	84	99.42%	95	97.91%	135	96.57%
125 to 130	31	99.83%	14	100.00%	0	100.00%	40	99.87%	68	98.69%	121	97.95%
130 to 135	12	99.97%	0	100.00%	0	100.00%	11	100.00%	49	99.25%	77	98.83%
135 to 140	3	100.00%	0	100.00%	0	100.00%	0	100.00%	35	99.65%	46	99.35%
140 to 145	0	100.00%	0	100.00%	0	100.00%	0	100.00%	16	99.83%	39	99.80%
145 to 150	0	100.00%	0	100.00%	0	100.00%	0	100.00%	9	99.93%	16	99.98%
150 to 155	0	100.00%	0	100.00%	0	100.00%	0	100.00%	6	100.00%	2	100.00%
155 to 160	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%
> 160	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%

	2013		2014		2015		2016		2017		2018	
Load (GWh)	Frequency	Cumulative Percent	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%	0	0.00%
20 to 25	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
25 to 30	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
30 to 35	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
35 to 40	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
40 to 45	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
45 to 50	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
50 to 55	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
55 to 60	81	0.92%	78	0.89%	76	0.87%	74	0.84%	87	0.99%	15	0.17%
60 to 65	390	5.38%	379	5.22%	447	5.97%	443	5.89%	463	6.28%	216	2.64%
65 to 70	572	11.91%	573	11.76%	636	13.23%	601	12.73%	606	13.20%	486	8.18%
70 to 75	728	20.22%	726	20.05%	793	22.28%	811	21.96%	840	22.79%	672	15.86%
75 to 80	857	30.00%	800	29.18%	867	32.18%	905	32.26%	1,005	34.26%	958	26.79%
80 to 85	1,177	43.44%	1,170	42.53%	1,289	46.89%	1,500	49.34%	1,417	50.43%	1,274	41.34%
85 to 90	1,224	57.41%	1,241	56.70%	1,083	59.26%	1,049	61.28%	1,211	64.26%	1,271	55.84%
90 to 95	1,042	69.30%	860	66.52%	803	68.42%	722	69.50%	955	75.16%	974	66.96%
95 to 100	877	79.32%	785	75.48%	625	75.56%	642	76.81%	641	82.48%	788	75.96%
100 to 105	682	87.10%	685	83.30%	558	81.93%	520	82.73%	449	87.60%	591	82.71%
105 to 110	401	91.68%	550	89.58%	515	87.81%	395	87.23%	333	91.40%	457	87.92%
110 to 115	270	94.76%	357	93.65%	384	92.19%	367	91.40%	294	94.76%	339	91.79%
115 to 120	157	96.55%	225	96.22%	286	95.46%	231	94.03%	196	97.00%	229	94.41%
120 to 125	127	98.00%	156	98.00%	162	97.31%	152	95.77%	117	98.33%	184	96.51%
125 to 130	67	98.77%	100	99.14%	128	98.77%	160	97.59%	82	99.27%	126	97.95%
130 to 135	42	99.25%	63	99.86%	72	99.59%	111	98.85%	36	99.68%	84	98.90%
135 to 140	20	99.47%	12	100.00%	34	99.98%	75	99.70%	19	99.90%	55	99.53%
140 to 145	14	99.63%	0	100.00%	2	100.00%	17	99.90%	9	100.00%	36	99.94%
145 to 150	20	99.86%	0	100.00%	0	100.00%	9	100.00%	0	100.00%	5	100.00%
150 to 155	12	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%
155 to 160	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%
> 160	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%

3 Each range in the tables in this Appendix excludes the start value and includes the end value.

Off Peak and On Peak Load

Table C-2 shows summary load statistics for 1998 through 2018 for the off peak and on peak hours. Table C-3 shows the annual change in each statistic. The on peak period is defined for each weekday (Monday through Friday) as the hour ending 0800 to the hour ending 2300 Eastern Prevailing Time (EPT), excluding North American Electric Reliability Council (NERC) holidays.

Table C-2 Off peak and on peak load (MW): 1998 through 2018

	Average			Median			Standard Deviation		
	Off Peak	On Peak	On Peak/ Off Peak	Off Peak	On Peak	On Peak/ Off Peak	Off Peak	On Peak	On Peak/ Off Peak
1998	25,269	32,344	1.28	24,729	31,081	1.26	4,091	4,388	1.07
1999	26,454	33,269	1.26	25,780	31,950	1.24	4,947	4,824	0.98
2000	26,917	33,797	1.26	26,313	32,757	1.24	4,466	4,181	0.94
2001	26,804	34,303	1.28	26,433	33,076	1.25	4,225	4,851	1.15
2002	31,734	40,314	1.27	30,590	38,365	1.25	6,111	7,464	1.22
2003	33,598	41,755	1.24	32,973	40,802	1.24	5,545	5,424	0.98
2004	44,631	56,020	1.26	43,028	56,578	1.31	10,845	12,595	1.16
2005	70,291	87,164	1.24	68,049	82,503	1.21	12,733	15,236	1.20
2006	71,810	88,323	1.23	70,300	84,810	1.21	11,348	12,662	1.12
2007	73,499	91,066	1.24	71,751	88,494	1.23	11,501	11,926	1.04
2008	72,175	87,915	1.22	70,516	85,431	1.21	11,378	11,205	0.98
2009	68,765	84,375	1.23	67,198	81,842	1.22	10,916	10,519	0.96
2010	72,222	88,087	1.22	70,354	85,504	1.22	12,935	13,775	1.06
2011	74,815	91,413	1.22	72,661	87,938	1.21	12,978	14,835	1.14
2012	79,046	96,193	1.22	76,930	92,199	1.20	13,182	14,426	1.09
2013	80,232	97,624	1.22	78,751	95,465	1.21	12,588	13,105	1.04
2014	80,942	98,456	1.22	78,993	97,042	1.23	13,086	13,161	1.01
2015	80,669	97,620	1.21	77,648	94,316	1.21	14,288	14,387	1.01
2016	80,676	97,737	1.21	78,001	94,087	1.21	14,227	15,806	1.11
2017	79,237	95,148	1.20	77,160	91,910	1.19	12,664	13,230	1.04
2018	82,854	98,857	1.19	80,633	95,900	1.19	13,604	14,118	1.04

Table C-3 Changes in off peak and on peak load (MW): 1998 through 2018

	Average			Median			Standard Deviation		
	Off Peak	On Peak	On Peak/ Off Peak	Off Peak	On Peak	On Peak/ Off Peak	Off Peak	On Peak	On Peak/ Off Peak
1998	NA	NA	NA	NA	NA	NA	NA	NA	NA
1999	4.7%	2.9%	(1.7%)	4.3%	2.8%	(1.4%)	20.9%	9.9%	(9.1%)
2000	1.8%	1.6%	(0.2%)	2.1%	2.5%	0.5%	(9.7%)	(13.3%)	(4.0%)
2001	(0.4%)	1.5%	1.9%	0.5%	1.0%	0.5%	(5.4%)	16.0%	22.6%
2002	18.4%	17.5%	(0.7%)	15.7%	16.0%	0.2%	44.6%	53.9%	6.4%
2003	5.9%	3.6%	(2.2%)	7.8%	6.4%	(1.3%)	(9.3%)	(27.3%)	(19.9%)
2004	32.8%	34.2%	1.0%	30.5%	38.7%	6.3%	95.6%	132.2%	18.7%
2005	57.5%	55.6%	(1.2%)	58.2%	45.8%	(7.8%)	17.4%	21.0%	3.0%
2006	2.2%	1.3%	(0.8%)	3.3%	2.8%	(0.5%)	(10.9%)	(16.9%)	(6.8%)
2007	2.4%	3.1%	0.7%	2.1%	4.3%	2.2%	1.3%	(5.8%)	(7.1%)
2008	(1.8%)	(3.5%)	(1.7%)	(1.7%)	(3.5%)	(1.8%)	(1.1%)	(6.0%)	(5.0%)
2009	(4.7%)	(4.0%)	0.7%	(4.7%)	(4.2%)	0.5%	(4.1%)	(6.1%)	(2.1%)
2010	5.0%	4.4%	(0.6%)	4.7%	4.5%	(0.2%)	18.5%	30.9%	10.5%
2011	3.6%	3.8%	0.2%	3.3%	2.8%	(0.4%)	0.3%	7.7%	7.3%
2012	5.7%	5.2%	(0.4%)	5.9%	4.8%	(1.0%)	1.6%	(2.8%)	(4.3%)
2013	1.5%	1.5%	(0.0%)	2.4%	3.5%	1.1%	(4.5%)	(9.2%)	(4.9%)
2014	0.9%	0.9%	(0.0%)	0.3%	1.7%	1.3%	4.0%	0.4%	(3.4%)
2015	(0.3%)	(0.8%)	(0.5%)	(1.7%)	(2.8%)	(1.1%)	9.2%	9.3%	0.1%
2016	0.0%	0.1%	0.1%	0.5%	(0.2%)	(0.7%)	(0.4%)	9.9%	10.3%
2017	(1.8%)	(2.6%)	(0.9%)	(1.1%)	(2.3%)	(1.2%)	(11.0%)	(16.3%)	(6.0%)
2018	4.6%	3.9%	(0.6%)	4.5%	4.3%	(0.2%)	7.4%	6.7%	(0.7%)

Locational Marginal Price (LMP)

Three measures of LMP are calculated: average LMP; load-weighted average LMP; and fuel-cost-adjusted, load-weighted, average LMP. Differences in average LMP measure the change in reported price. Differences in load-weighted, average LMP measure the change in reported price weighted by the actual hourly MWh load to reflect what customers actually pay for energy. Differences in fuel-cost adjusted, load-weighted, average LMP measure what the change in reported price actually paid by load would have been if fuel costs in 2018 had been the same as in 2017, holding everything else constant.[4]

The zonal LMP includes every bus in the zone and is not affected by the choices of LSEs. The zonal LMP is defined by weighting each load bus LMP by its hourly contribution to total zonal load. The LMP for a defined aggregate is calculated by weighting each included load bus LMP by its hourly contribution to the total load of the defined aggregate.

During the settlement process, total load that is assigned to a load serving entity (LSE) in a zone is settled based on the LSE's choice to be charged either at the zonal price or at a different defined aggregate of nodal prices. Any LSE may request to settle at a different aggregate price instead of zonal LMP, but the change can only take effect on June 1 of each year.[5] If an LSE chooses to settle at a different aggregate, the load of the LSE is distributed to all of the buses in the aggregate.[6] If the LSE settles at

4 See the *Technical Reference for PJM Markets*, at "Calculating Locational Marginal Price."

5 See PJM "Manual 27: Open Access Transmission Tariff Accounting," Revision 90 (December 6, 2018),§ 5: Network Integration Transmission Service Accounting.

6 OATT. Common Service Provisions (Designation of Network Load) §31.7.

the zonal price, the load of the LSE will be distributed to all of the buses in the zone.[7]

Market rules related to the use of zonal pricing will change starting with the 2015/2016 planning period.[8] A residual zonal price will become the default price for load that has not elected to settle at nodal prices. When some load in a zone is nodally priced, the residual zonal price is the price of energy for the residual load, the load that is not priced nodally. The residual price is the average price at the nodes at which non-nodal load is served. The zonal LMP will continue to be used for virtual bidding, Financial Transmission Rights (FTRs), and bilateral energy transactions.

In the Day-Ahead Energy Market buyers may submit bids at specific locations such as a transmission zone, aggregate or a single bus. Price sensitive demand bids specify price and MW quantities and a location for the bid. Market participants may submit increment offers or decrement bids at any hub, transmission zone, aggregate, single bus or eligible external interfaces. PJM provides the definitions of the transmission zones, aggregates, and single buses.[9]

Real-Time LMP

Frequency Distribution of Real-Time Average LMP

Table C-4 provides frequency distributions of PJM real-time hourly average LMP for 2007 through 2018. The table shows the number of hours (frequency) and the percent of hours (cumulative percent) when the hourly PJM real-time LMP was, when negative, within a $100 per MWh price interval below $0 per MWh, or, when positive, 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. In the Real-Time Energy Market, prices reached a high for the year of $586.74 per MWh on January 7, 2018, in the hour ending 0800 EPT.

7 *Id*
8 *Id.*
9 See PJM "Manual 11: Energy & Ancillary Services Market Operations," Revision 106 (May 30, 2019), § 2: Overview of the PJM Energy Markets, p. 18.

Table C-4 Frequency distribution by hours of PJM Real-Time Energy Market LMP (Dollars per MWh): 2007 through 2018

	2007		2008		2009		2010		2011		2012		2013	
LMP	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent
-$200 to -$100	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	2	0.02%	0	0.00%
-$100 to $0	23	0.26%	45	0.51%	60	0.68%	34	0.39%	33	0.38%	50	0.59%	3	0.03%
$0 to $10	33	0.64%	49	1.07%	57	1.34%	31	0.74%	33	0.75%	79	1.49%	64	0.76%
$10 to $20	185	2.75%	129	2.54%	218	3.82%	127	2.19%	89	1.77%	510	7.30%	147	2.44%
$20 to $30	1,571	20.68%	490	8.12%	2,970	37.73%	1,810	22.85%	1,764	21.91%	4,002	52.86%	3,077	37.57%
$30 to $40	1,470	37.47%	1,443	24.54%	2,951	71.42%	3,150	58.81%	3,967	67.19%	2,801	84.74%	3,447	76.92%
$40 to $50	1,108	50.11%	1,533	42.00%	1,269	85.90%	1,462	75.50%	1,334	82.42%	668	92.35%	1,116	89.66%
$50 to $60	931	60.74%	1,212	55.79%	555	92.24%	766	84.25%	489	88.00%	244	95.13%	391	94.12%
$60 to $70	827	70.18%	845	65.41%	276	95.39%	427	89.12%	303	91.46%	136	96.68%	187	96.26%
$70 to $80	726	78.47%	709	73.49%	151	97.11%	274	92.25%	174	93.45%	75	97.53%	99	97.39%
$80 to $90	646	85.84%	502	79.20%	95	98.20%	165	94.13%	133	94.97%	51	98.11%	67	98.15%
$90 to $100	451	90.99%	385	83.58%	62	98.90%	134	95.66%	108	96.20%	38	98.54%	38	98.58%
$100 to $110	240	93.73%	352	87.59%	30	99.25%	82	96.60%	61	96.89%	32	98.91%	23	98.85%
$110 to $120	178	95.76%	265	90.61%	21	99.49%	71	97.41%	61	97.59%	20	99.13%	24	99.12%
$120 to $130	110	97.02%	199	92.87%	15	99.66%	61	98.11%	46	98.12%	15	99.31%	13	99.27%
$130 to $140	76	97.89%	144	94.51%	7	99.74%	44	98.61%	33	98.49%	10	99.42%	20	99.50%
$140 to $150	53	98.49%	111	95.78%	9	99.84%	29	98.94%	25	98.78%	7	99.50%	1	99.51%
$150 to $160	26	98.79%	102	96.94%	3	99.87%	22	99.19%	25	99.06%	8	99.59%	3	99.54%
$160 to $170	29	99.12%	68	97.71%	3	99.91%	11	99.32%	17	99.26%	5	99.65%	4	99.59%
$170 to $180	18	99.33%	52	98.30%	5	99.97%	13	99.46%	15	99.43%	1	99.66%	5	99.65%
$180 to $190	9	99.43%	45	98.82%	0	99.97%	12	99.60%	6	99.50%	2	99.68%	3	99.68%
$190 to $200	15	99.60%	29	99.15%	1	99.98%	9	99.70%	8	99.59%	3	99.72%	1	99.69%
$200 to $210	6	99.67%	20	99.37%	1	99.99%	7	99.78%	6	99.66%	2	99.74%	3	99.73%
$210 to $220	4	99.71%	11	99.50%	1	100.00%	4	99.83%	5	99.71%	1	99.75%	4	99.77%
$220 to $230	4	99.76%	14	99.66%	0	100.00%	3	99.86%	4	99.76%	0	99.75%	3	99.81%
$230 to $240	2	99.78%	10	99.77%	0	100.00%	5	99.92%	0	99.76%	4	99.80%	4	99.85%
$240 to $250	5	99.84%	2	99.80%	0	100.00%	3	99.95%	3	99.79%	5	99.85%	1	99.86%
$250 to $260	2	99.86%	5	99.85%	0	100.00%	1	99.97%	3	99.83%	5	99.91%	1	99.87%
$260 to $270	4	99.91%	4	99.90%	0	100.00%	0	99.97%	3	99.86%	0	99.91%	3	99.91%
$270 to $280	0	99.91%	1	99.91%	0	100.00%	0	99.97%	3	99.90%	1	99.92%	1	99.92%
$280 to $290	0	99.91%	1	99.92%	0	100.00%	1	99.98%	0	99.90%	1	99.93%	0	99.92%
$290 to $300	0	99.91%	0	99.92%	0	100.00%	0	99.98%	2	99.92%	0	99.93%	1	99.93%
$300 to $400	2	99.93%	6	99.99%	0	100.00%	2	100.00%	4	99.97%	6	100.00%	5	99.99%
$400 to $500	4	99.98%	1	100.00%	0	100.00%	0	100.00%	0	99.97%	0	100.00%	1	100.00%
$500 to $600	1	99.99%	0	100.00%	0	100.00%	0	100.00%	0	99.97%	0	100.00%	0	100.00%
$600 to $700	1	100.00%	0	100.00%	0	100.00%	0	100.00%	0	99.97%	0	100.00%	0	100.00%
$700 to $800	0	100.00%	0	100.00%	0	100.00%	0	100.00%	3	100.00%	0	100.00%	0	100.00%
$800 to $900	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%
$900 to $1000	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%
> $1,000	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%

	2014		2015		2016		2017		2018	
LMP	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent
-$200 to -$100	0	0.00%	5	0.06%	0	0.00%	0	0.00%	0	0.00%
-$100 to $0	15	0.17%	31	0.41%	18	0.20%	19	0.22%	4	0.05%
$0 to $10	40	0.63%	108	1.64%	67	0.97%	28	0.54%	13	0.19%
$10 to $20	224	3.18%	1,091	14.10%	1,690	20.21%	1,143	13.58%	996	11.56%
$20 to $30	2,662	33.57%	4,527	65.78%	4,931	76.34%	4,959	70.19%	3,954	56.70%
$30 to $40	2,782	65.33%	1,477	82.64%	1,217	90.20%	1,605	88.52%	2,020	79.76%
$40 to $50	1,161	78.58%	566	89.10%	382	94.55%	451	93.66%	746	88.28%
$50 to $60	619	85.65%	270	92.18%	156	96.32%	225	96.23%	333	92.08%
$60 to $70	287	88.93%	168	94.10%	116	97.64%	108	97.47%	173	94.05%
$70 to $80	206	91.28%	116	95.42%	79	98.54%	68	98.24%	112	95.33%
$80 to $90	142	92.90%	89	96.44%	49	99.10%	47	98.78%	76	96.20%
$90 to $100	102	94.06%	77	97.32%	17	99.29%	33	99.16%	49	96.76%
$100 to $110	71	94.87%	42	97.80%	22	99.54%	21	99.39%	57	97.41%
$110 to $120	55	95.50%	31	98.15%	11	99.67%	15	99.57%	38	97.84%
$120 to $130	50	96.07%	29	98.48%	7	99.75%	10	99.68%	29	98.17%
$130 to $140	42	96.55%	24	98.76%	4	99.80%	6	99.75%	25	98.46%
$140 to $150	21	96.79%	11	98.88%	4	99.84%	4	99.79%	11	98.58%
$150 to $160	22	97.04%	21	99.12%	3	99.87%	6	99.86%	16	98.77%
$160 to $170	22	97.29%	9	99.22%	2	99.90%	1	99.87%	18	98.97%
$170 to $180	21	97.53%	12	99.36%	5	99.95%	3	99.91%	14	99.13%
$180 to $190	24	97.81%	6	99.43%	0	99.95%	2	99.93%	12	99.27%
$190 to $200	18	98.01%	6	99.50%	3	99.99%	0	99.93%	17	99.46%
$200 to $210	17	98.21%	8	99.59%	0	99.99%	1	99.94%	4	99.51%
$210 to $220	14	98.37%	5	99.65%	0	99.99%	0	99.94%	8	99.60%
$220 to $230	11	98.49%	4	99.69%	1	100.00%	2	99.97%	0	99.60%
$230 to $240	10	98.61%	4	99.74%	0	100.00%	0	99.97%	0	99.60%
$240 to $250	8	98.70%	3	99.77%	0	100.00%	0	99.97%	4	99.65%
$250 to $260	6	98.77%	4	99.82%	0	100.00%	0	99.97%	2	99.67%
$260 to $270	5	98.82%	2	99.84%	0	100.00%	0	99.97%	3	99.70%
$270 to $280	9	98.93%	1	99.85%	0	100.00%	1	99.98%	5	99.76%
$280 to $290	10	99.04%	2	99.87%	0	100.00%	0	99.98%	4	99.81%
$290 to $300	7	99.12%	1	99.89%	0	100.00%	0	99.98%	2	99.83%
$300 to $400	35	99.52%	7	99.97%	0	100.00%	0	99.98%	12	99.97%
$400 to $500	22	99.77%	3	100.00%	0	100.00%	1	99.99%	2	99.99%
$500 to $600	6	99.84%	0	100.00%	0	100.00%	0	99.99%	1	100.00%
$600 to $700	1	99.85%	0	100.00%	0	100.00%	1	100.00%	0	100.00%
$700 to $800	2	99.87%	0	100.00%	0	100.00%	0	100.00%	0	100.00%
$800 to $900	4	99.92%	0	100.00%	0	100.00%	0	100.00%	0	100.00%
$900 to $1000	1	99.93%	0	100.00%	0	100.00%	0	100.00%	0	100.00%
> $1,000	6	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%

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

Table C-5 shows load-weighted, average real-time LMP for 2017 and 2018 during off peak and on peak periods.

Table C-5 Off peak and on peak, PJM load-weighted, average LMP (Dollars per MWh): 2017 and 2018

	2017			2018			Percent Change		
	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	$26.61	$35.20	1.32	$33.85	$42.46	1.25	27.2%	20.6%	(5.2%)
Median	$23.01	$29.83	1.30	$25.32	$33.81	1.33	10.1%	13.3%	2.9%
Standard deviation	$14.76	$22.07	1.50	$35.05	$30.08	0.86	137.5%	36.3%	(42.6%)

The real-time, load-weighted, average LMP for 2018 off peak hours increased by $7.24 or 27.2 percent from real-time load-weighted average LMP for 2017 off peak hours. The real-time load-weighted, average LMP for 2018 off peak hours was 8.5 percent higher than the real-time fuel-cost adjusted, load-weighted, average LMP for 2018 off peak hours. The real-time, fuel-cost adjusted, load-weighted, average LMP for 2018 off peak hours was 17.2 percent higher than the real-time load-weighted LMP for 2017 off peak hours. If fuel and emissions costs in 2018 off peak hours had been the same as in 2017 off peak hours, holding everything else constant, the real-time load-weighted LMP in 2018 off peak hours would have been lower, $31.20 per MWh, than the observed $33.85 per MWh. Only 36 percent of the increase in off peak hours LMP, $2.65 per MWh out of $7.24 per MWh, is directly attributable to fuel costs. Contributors to the other $4.59 per MWh are increased load, adjusted dispatch, and higher markups.

The real-time, load-weighted, average LMP for 2018 on peak hours increased by $7.26 or 20.6 percent from real-time load-weighted average LMP for 2017 on peak hours. The real-time load-weighted, average LMP for 2018 on peak hours was 6.2 percent higher than the real-time fuel-cost adjusted, load-weighted, average LMP for 2018 on peak hours. The real-time, fuel-cost adjusted, load-weighted, average LMP for 2018 on peak hours was 13.6 percent higher than the real-time load-weighted LMP for 2017 on peak hours. If fuel and emissions costs in 2018 on peak hours had been the same as in 2017 on peak hours, holding everything else constant, the real-time load-weighted LMP in 2018 on peak hours would have been lower, $39.98 per MWh, than the observed $42.46 per MWh. Only 34 percent of the increase in on peak hours LMP, $2.48 per MWh out of $7.26 per MWh, is directly attributable to fuel costs. Contributors to the other $4.78 per MWh are increased load, adjusted dispatch, and higher markups.

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

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

The impact of fuel cost on marginal cost and on LMP depends on the fuel burned by marginal units and changes in fuel costs.[10] Changes in emission allowance costs are another contributor to changes in the marginal cost of marginal units. To account for the changes in fuel and allowance costs between 2017 and 2018, the load-weighted, average LMP for 2018 was adjusted to reflect the daily price of fuels and emission allowances used by marginal units from a base period, 2017. The fuel cost adjusted, load-weighted, average LMP for 2018 is compared to the load-weighted, average LMP for 2017 and load-weighted, average LMP for 2018.[11]

Table C-6 shows the real-time, load-weighted, average LMP for 2018 and the real-time, fuel-cost adjusted, load-weighted, average LMP for 2018 for off peak and on peak hours.

10 See the *2018 State of the Market Report for PJM*, Volume II, Section 3,"Energy Market," at Table 3-7, "*Type of fuel used and technology (By real time marginal units):2014 through 2018.*"

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

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

	2018 Fuel-Cost Adjusted, Load-Weighted LMP	2018 Load-Weighted LMP	Change	Percent Change
Off Peak Average	$31.20	$33.85	$2.65	8.5%
On Peak Average	$39.98	$42.46	$2.48	6.2%
	2017 Load-Weighted LMP	2018 Fuel-Cost Adjusted, Load-Weighted LMP	Change	Percent Change
Off Peak Average	$26.61	$31.20	$4.59	17.2%
On Peak Average	$35.20	$39.98	$4.78	13.6%
	2017 Load-Weighted LMP	2018 Load-Weighted LMP	Change	Percent Change
Off Peak Average	$26.61	$33.85	$7.24	27.2%
On Peak Average	$35.20	$42.46	$7.26	20.6%

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

Table C-7 provides a comparison of PJM load-weighted, average LMP during constrained and unconstrained hours for 2017 and 2018.

Table C-7 PJM real-time load-weighted, average LMP during constrained and unconstrained hours (Dollars per MWh): 2017 and 2018

	2017		2018		Percent Change	
	Unconstrained Hours LMP	Constrained Hours LMP	Unconstrained Hours LMP	Constrained Hours LMP	Unconstrained Hours	Constrained Hours
Average	$24.42	$31.81	$24.71	$41.15	1.2%	29.3%
Median	$23.15	$26.99	$22.85	$31.55	(1.3%)	16.9%
Standard deviation	$7.06	$20.20	$7.97	$35.40	12.9%	75.2%

Table C-8 shows the number of hours and the number of constrained hours in each month in 2017 and 2018.

Table C-8 PJM real-time constrained hours: 2017 and 2018

	2017			2018		
	Constrained Hours	Total Hours	Percent of Total	Constrained Hours	Total Hours	Percent of Total
Jan	660	744	88.7%	564	744	75.8%
Feb	632	672	94.0%	517	672	76.9%
Mar	707	743	95.2%	724	743	97.4%
Apr	595	720	82.6%	681	720	94.6%
May	650	744	87.4%	725	744	97.4%
Jun	648	720	90.0%	511	720	71.0%
Jul	610	744	82.0%	431	744	57.9%
Aug	607	744	81.6%	464	744	62.4%
Sep	706	720	98.1%	599	720	83.2%
Oct	739	744	99.3%	624	744	83.9%
Nov	618	721	85.7%	651	721	90.3%
Dec	560	744	75.3%	603	744	81.0%
Avg	644	730	88.3%	591	730	81.0%

Day-Ahead LMP

Frequency Distribution of Day-Ahead Average LMP

Table C-9 provides frequency distributions of PJM day-ahead hourly average LMP for 2007 through 2018. The table shows the number of hours (frequency) and the percent of hours (cumulative percent) when the hourly PJM day-ahead LMP was, when negative, within a $100 per MWh price interval below $0 per MWh, or, when positive, within a $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.

In the Day-Ahead Energy Market, prices reached a high for the year of $296.49 per MWh on January 5, 2018, in the hour ending 1900 EPT.

Table C-9 Frequency distribution by hours of PJM Day-Ahead Energy Market LMP (Dollars per MWh): 2007 through 2018

	2007		2008		2009		2010		2011		2012		2013	
LMP	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent
-$200 to -$100	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
-$100 to $0	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
$0 to $10	3	0.03%	0	0.00%	23	0.26%	5	0.06%	0	0.00%	19	0.22%	1	0.01%
$10 to $20	88	1.04%	19	0.22%	343	4.18%	31	0.41%	33	0.38%	467	5.53%	76	0.88%
$20 to $30	1,291	15.78%	320	3.86%	2,380	31.35%	1,502	17.56%	1,595	18.58%	3,402	44.26%	2,364	27.87%
$30 to $40	1,495	32.84%	1,148	16.93%	3,221	68.12%	2,851	50.10%	3,359	56.93%	3,521	84.35%	3,794	71.18%
$40 to $50	1,221	46.78%	1,546	34.53%	1,717	87.72%	2,131	74.43%	2,024	80.03%	908	94.68%	1,761	91.28%
$50 to $60	1,266	61.23%	1,491	51.50%	557	94.08%	954	85.32%	872	89.99%	247	97.50%	421	96.08%
$60 to $70	1,301	76.08%	1,107	64.11%	253	96.96%	471	90.70%	406	94.62%	106	98.70%	169	98.01%
$70 to $80	939	86.80%	942	74.83%	138	98.54%	302	94.14%	174	96.61%	39	99.15%	64	98.74%
$80 to $90	504	92.56%	682	82.59%	68	99.32%	193	96.35%	87	97.60%	21	99.39%	35	99.14%
$90 to $100	264	95.57%	542	88.76%	33	99.69%	125	97.77%	61	98.30%	12	99.52%	22	99.39%
$100 to $110	155	97.34%	289	92.05%	19	99.91%	86	98.76%	29	98.63%	7	99.60%	12	99.53%
$110 to $120	104	98.53%	193	94.25%	6	99.98%	46	99.28%	30	98.97%	6	99.67%	4	99.58%
$120 to $130	59	99.20%	131	95.74%	2	100.00%	29	99.61%	16	99.16%	7	99.75%	3	99.61%
$130 to $140	33	99.58%	112	97.02%	0	100.00%	14	99.77%	21	99.39%	4	99.80%	2	99.63%
$140 to $150	13	99.73%	67	97.78%	0	100.00%	7	99.85%	17	99.59%	2	99.82%	2	99.66%
$150 to $160	8	99.82%	54	98.39%	0	100.00%	6	99.92%	7	99.67%	1	99.83%	2	99.68%
$160 to $170	7	99.90%	46	98.92%	0	100.00%	3	99.95%	3	99.70%	3	99.86%	5	99.74%
$170 to $180	3	99.93%	23	99.18%	0	100.00%	2	99.98%	2	99.73%	1	99.87%	3	99.77%
$180 to $190	4	99.98%	20	99.41%	0	100.00%	0	99.98%	2	99.75%	0	99.87%	2	99.79%
$190 to $200	1	99.99%	16	99.59%	0	100.00%	2	100.00%	2	99.77%	2	99.90%	2	99.82%
$200 to $210	1	100.00%	8	99.68%	0	100.00%	0	100.00%	1	99.78%	2	99.92%	3	99.85%
$210 to $220	0	100.00%	9	99.78%	0	100.00%	0	100.00%	0	99.78%	2	99.94%	2	99.87%
$220 to $230	0	100.00%	4	99.83%	0	100.00%	0	100.00%	2	99.81%	1	99.95%	4	99.92%
$230 to $240	0	100.00%	3	99.86%	0	100.00%	0	100.00%	1	99.82%	2	99.98%	0	99.92%
$240 to $250	0	100.00%	2	99.89%	0	100.00%	0	100.00%	0	99.82%	0	99.98%	1	99.93%
$250 to $260	0	100.00%	0	99.89%	0	100.00%	0	100.00%	2	99.84%	1	99.99%	1	99.94%
$260 to $270	0	100.00%	4	99.93%	0	100.00%	0	100.00%	2	99.86%	0	99.99%	0	99.94%
$270 to $280	0	100.00%	0	99.93%	0	100.00%	0	100.00%	0	99.86%	1	100.00%	1	99.95%
$280 to $290	0	100.00%	2	99.95%	0	100.00%	0	100.00%	0	99.86%	0	100.00%	0	99.95%
$290 to $300	0	100.00%	2	99.98%	0	100.00%	0	100.00%	4	99.91%	0	100.00%	2	99.98%
$300 to $400	0	100.00%	2	100.00%	0	100.00%	0	100.00%	8	100.00%	0	100.00%	2	100.00%
$400 to $500	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%
$500 to $600	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%
$600 to $700	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%
$700 to $800	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%
$800 to $900	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%
$900 to $1000	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%
> $1000	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%

	2014		2015		2016		2017		2018	
LMP	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent
-$200 to -$100	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
-$100 to $0	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
$0 to $10	12	0.14%	71	0.81%	35	0.40%	5	0.06%	0	0.00%
$10 to $20	112	1.42%	871	10.75%	1,462	17.04%	1,056	12.11%	796	9.09%
$20 to $30	2,106	25.46%	3,760	53.68%	4,509	68.37%	4,356	61.84%	3,312	46.89%
$30 to $40	2,648	55.68%	2,430	81.42%	1,837	89.29%	2,342	88.57%	2,597	76.54%
$40 to $50	1,866	76.99%	772	90.23%	592	96.03%	651	96.00%	1,153	89.70%
$50 to $60	827	86.43%	293	93.57%	204	98.35%	173	97.98%	386	94.11%
$60 to $70	346	90.38%	130	95.06%	73	99.18%	70	98.78%	120	95.48%
$70 to $80	191	92.56%	97	96.16%	34	99.57%	35	99.18%	84	96.44%
$80 to $90	108	93.79%	83	97.11%	21	99.81%	26	99.47%	62	97.15%
$90 to $100	77	94.67%	64	97.84%	7	99.89%	16	99.66%	48	97.69%
$100 to $110	51	95.25%	37	98.26%	6	99.95%	9	99.76%	28	98.01%
$110 to $120	33	95.63%	34	98.65%	4	100.00%	8	99.85%	27	98.32%
$120 to $130	26	95.92%	34	99.04%	0	100.00%	7	99.93%	33	98.70%
$130 to $140	34	96.31%	17	99.24%	0	100.00%	2	99.95%	17	98.89%
$140 to $150	18	96.52%	11	99.36%	0	100.00%	0	99.95%	19	99.11%
$150 to $160	31	96.87%	10	99.47%	0	100.00%	1	99.97%	16	99.29%
$160 to $170	22	97.12%	10	99.59%	0	100.00%	0	99.97%	7	99.37%
$170 to $180	26	97.42%	8	99.68%	0	100.00%	0	99.97%	19	99.59%
$180 to $190	29	97.75%	2	99.70%	0	100.00%	1	99.98%	8	99.68%
$190 to $200	24	98.03%	4	99.75%	0	100.00%	1	99.99%	7	99.76%
$200 to $210	14	98.18%	1	99.76%	0	100.00%	0	99.99%	2	99.78%
$210 to $220	13	98.33%	3	99.79%	0	100.00%	0	99.99%	6	99.85%
$220 to $230	15	98.50%	1	99.81%	0	100.00%	1	100.00%	1	99.86%
$230 to $240	8	98.60%	1	99.82%	0	100.00%	0	100.00%	0	99.86%
$240 to $250	10	98.71%	2	99.84%	0	100.00%	0	100.00%	2	99.89%
$250 to $260	6	98.78%	2	99.86%	0	100.00%	0	100.00%	5	99.94%
$260 to $270	9	98.88%	4	99.91%	0	100.00%	0	100.00%	2	99.97%
$270 to $280	15	99.05%	3	99.94%	0	100.00%	0	100.00%	0	99.97%
$280 to $290	7	99.13%	0	99.94%	0	100.00%	0	100.00%	1	99.98%
$290 to $300	6	99.20%	1	99.95%	0	100.00%	0	100.00%	2	100.00%
$300 to $400	31	99.55%	4	100.00%	0	100.00%	0	100.00%	0	100.00%
$400 to $500	15	99.73%	0	100.00%	0	100.00%	0	100.00%	0	100.00%
$500 to $600	12	99.86%	0	100.00%	0	100.00%	0	100.00%	0	100.00%
$600 to $700	6	99.93%	0	100.00%	0	100.00%	0	100.00%	0	100.00%
$700 to $800	1	99.94%	0	100.00%	0	100.00%	0	100.00%	0	100.00%
$800 to $900	1	99.95%	0	100.00%	0	100.00%	0	100.00%	0	100.00%
$900 to $1000	4	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%
> $1000	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%

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

Table C-10 shows PJM average LMP during off peak and on peak periods for the Day-Ahead and Real-Time Energy Markets in 2018. Figure C-1 and Figure C-2 show the difference between real-time and day-ahead LMP in 2018 during the on peak and off peak hours.

Table C-10 Off peak and on peak, average day ahead and real time LMP (Dollars per MWh): 2018

	Day Ahead		Real Time		Difference		Percent Change	
	Off Peak	On Peak	Off Peak	On Peak	Off Peak	On Peak	Off Peak	On Peak
Average	$30.70	$41.41	$31.33	$40.81	($0.62)	$0.60	2.0%	(1.4%)
Median	$25.43	$36.66	$24.41	$32.99	$1.03	$3.67	(4.0%)	(10.0%)
Standard deviation	$20.73	$22.71	$30.10	$28.01	($9.37)	($5.30)	45.2%	23.3%

Figure C-1 Hourly real-time LMP minus day-ahead LMP (On-peak hours): 2018

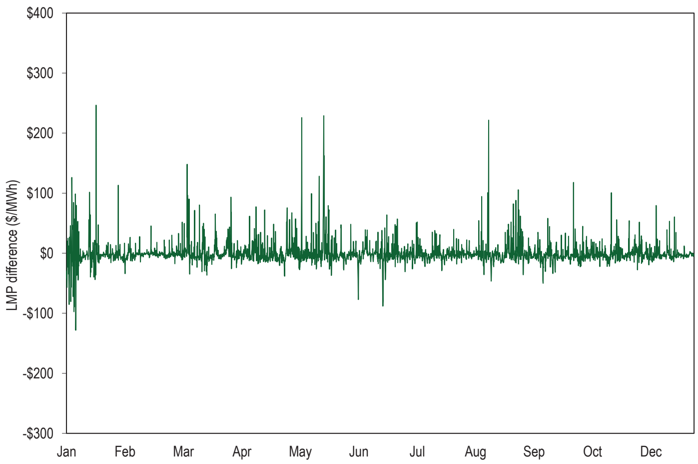
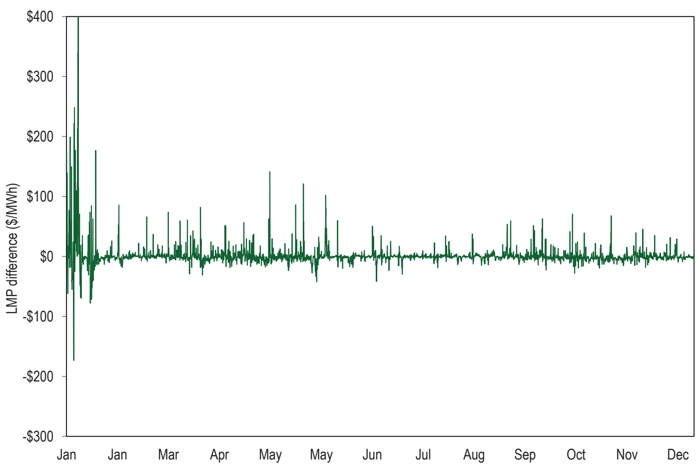


Figure C-2 Hourly real-time LMP minus day-ahead LMP (Off-peak hours): 2018



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

Table C-11 and Table C-12 show the on peak and off peak, average LMP for each zone in the Day-Ahead and Real-Time Energy Markets in 2017 and 2018.

Table C-11 On peak, zonal, average day-ahead and real-time LMP (Dollars per MWh): 2017 and 2018

	2017				2018			
	Day Ahead	Real Time	Difference	Percent of Real Time	Day Ahead	Real Time	Difference	Percent of Real Time
AECO	$31.91	$31.71	($0.19)	(0.6%)	$39.11	$38.59	($0.51)	(1.3%)
AEP	$34.19	$33.35	($0.84)	(2.5%)	$41.17	$40.59	($0.58)	(1.4%)
APS	$34.72	$34.32	($0.40)	(1.2%)	$42.68	$42.04	($0.64)	(1.5%)
ATSI	$35.25	$34.97	($0.27)	(0.8%)	$44.06	$44.93	$0.87	1.9%
BGE	$37.97	$37.15	($0.82)	(2.2%)	$46.50	$45.59	($0.91)	(2.0%)
ComEd	$32.45	$32.15	($0.31)	(1.0%)	$34.62	$33.70	($0.93)	(2.7%)
DAY	$35.10	$34.30	($0.80)	(2.3%)	$43.25	$42.55	($0.69)	(1.6%)
DEOK	$34.65	$33.78	($0.88)	(2.6%)	$44.33	$42.50	($1.84)	(4.3%)
DLCO	$34.55	$34.12	($0.43)	(1.3%)	$44.19	$44.99	$0.80	1.8%
Dominion	$36.75	$36.03	($0.72)	(2.0%)	$45.33	$43.98	($1.35)	(3.1%)
DPL	$34.58	$34.31	($0.27)	(0.8%)	$44.00	$44.75	$0.75	1.7%
EKPC	$32.99	$31.67	($1.32)	(4.2%)	$38.73	$37.81	($0.92)	(2.4%)
JCPL	$32.84	$32.80	($0.03)	(0.1%)	$38.80	$38.15	($0.64)	(1.7%)
Met-Ed	$34.11	$34.31	$0.19	0.6%	$39.52	$38.69	($0.83)	(2.1%)
OVEC	NA	NA	NA	NA	$35.15	$33.57	($1.58)	(4.7%)
PECO	$31.91	$31.96	$0.05	0.2%	$37.88	$37.27	($0.61)	(1.6%)
PENELEC	$33.58	$34.30	$0.72	2.1%	$41.10	$41.24	$0.13	0.3%
Pepco	$37.09	$36.16	($0.93)	(2.6%)	$45.10	$44.07	($1.03)	(2.3%)
PPL	$32.45	$32.53	$0.08	0.2%	$37.68	$36.87	($0.81)	(2.2%)
PSEG	$33.77	$33.93	$0.16	0.5%	$39.73	$38.66	($1.07)	(2.8%)
RECO	$33.88	$33.98	$0.11	0.3%	$40.33	$39.79	($0.54)	(1.3%)

Table C-12 Off peak, zonal, average day-ahead and real-time LMP (Dollars per MWh): 2017 and 2018

	2017				2018			
	Day Ahead	Real Time	Difference	Percent of Real Time	Day Ahead	Real Time	Difference	Percent of Real Time
AECO	$23.93	$24.44	$0.52	2.1%	$30.80	$31.51	$0.71	2.2%
AEP	$25.30	$25.25	($0.04)	(0.2%)	$30.41	$31.20	$0.78	2.5%
APS	$25.75	$25.91	$0.16	0.6%	$31.74	$32.49	$0.75	2.3%
ATSI	$25.58	$25.51	($0.07)	(0.3%)	$31.04	$31.68	$0.64	2.0%
BGE	$28.25	$28.51	$0.26	0.9%	$35.03	$35.55	$0.51	1.4%
ComEd	$22.17	$22.23	$0.06	0.3%	$23.45	$24.09	$0.65	2.7%
DAY	$25.74	$25.66	($0.08)	(0.3%)	$30.90	$31.32	$0.42	1.3%
DEOK	$25.15	$24.91	($0.24)	(1.0%)	$31.22	$31.26	$0.04	0.1%
DLCO	$25.14	$25.01	($0.13)	(0.5%)	$30.69	$31.07	$0.38	1.2%
Dominion	$27.31	$27.47	$0.16	0.6%	$34.20	$34.80	$0.59	1.7%
DPL	$25.91	$27.50	$1.58	5.8%	$33.14	$33.83	$0.69	2.0%
EKPC	$24.68	$24.61	($0.07)	(0.3%)	$28.75	$29.22	$0.46	1.6%
JCPL	$24.18	$24.58	$0.40	1.6%	$30.46	$30.97	$0.51	1.7%
Met-Ed	$24.25	$24.49	$0.24	1.0%	$29.89	$30.14	$0.25	0.8%
OVEC	NA	NA	NA	NA	$28.71	$28.70	($0.02)	(0.1%)
PECO	$23.91	$24.39	$0.48	2.0%	$30.12	$30.51	$0.39	1.3%
PENELEC	$24.77	$24.80	$0.03	0.1%	$30.45	$31.02	$0.57	1.8%
Pepco	$27.68	$27.85	$0.17	0.6%	$34.37	$34.84	$0.46	1.3%
PPL	$23.81	$24.10	$0.28	1.2%	$29.28	$29.52	$0.23	0.8%
PSEG	$24.66	$24.82	$0.17	0.7%	$30.64	$30.89	$0.25	0.8%
RECO	$24.73	$24.92	$0.19	0.8%	$30.62	$30.73	$0.11	0.4%

PJM Day-Ahead and Real-Time, 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 2018.

Table C-13 PJM day-ahead and real-time, market-constrained hours: 2018

	DA Constrained Hours	RT Constrained Hours	Total Hours
Jan	744	564	744
Feb	672	517	672
Mar	743	724	743
Apr	720	681	720
May	744	725	744
Jun	712	511	720
Jul	730	431	744
Aug	731	464	744
Sep	719	599	720
Oct	744	624	744
Nov	721	651	721
Dec	744	603	744
Avg	727	591	730

Table C-14 shows PJM average LMP during constrained and unconstrained hours in the Day-Ahead and Real-Time Energy Markets.

Table C-14 PJM average LMP during constrained and unconstrained hours (Dollars per MWh): 2018

	Day Ahead		Real Time		Difference		Percent Change	
	Unconstrained Hours LMP	Constrained Hours LMP	Unconstrained Hours LMP	Constrained Hours LMP	Unconstrained Hours LMP	Constrained Hours LMP	Unconstrained Hours LMP	Constrained Hours LMP
Average	$20.49	$44.02	$23.98	$38.51	$3.48	($5.51)	17.0%	(12.5%)
Median	$19.54	$34.88	$22.32	$30.18	$2.78	($4.70)	14.2%	(13.5%)
Standard deviation	$2.40	$32.42	$7.41	$31.99	$5.01	($0.43)	208.8%	(1.3%)

Price Convergence

Table C-15 provides frequency distributions of the differences between PJM real-time hourly LMP and PJM day-ahead hourly LMP for 2007 through 2018.

Table C-15 Frequency distribution by hours of PJM real-time LMP minus day-ahead LMP (Dollars per MWh): 2007 through 2017

	2007		2008		2009		2010		2011		2012		2013	
LMP	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent
< ($1,000)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
($1,000) to ($750)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
($750) to ($500)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
($500) to ($450)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
($450) to ($400)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
($400) to ($350)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
($350) to ($300)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
($300) to ($250)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
($250) to ($200)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	1	0.01%	1	0.01%
($200) to ($150)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	1	0.01%	4	0.06%	3	0.05%
($150) to ($100)	0	0.00%	1	0.01%	0	0.00%	0	0.00%	2	0.03%	6	0.13%	5	0.10%
($100) to ($50)	33	0.38%	88	1.01%	3	0.03%	13	0.15%	49	0.59%	17	0.32%	9	0.21%
($50) to $0	4,600	52.89%	5,120	59.30%	5,108	58.34%	5,543	63.42%	5,614	64.68%	5,576	63.80%	5,994	68.63%
$0 to $50	3,827	96.58%	3,247	96.27%	3,603	99.47%	3,004	97.72%	2,880	97.56%	3,061	98.65%	2,659	98.98%
$50 to $100	255	99.49%	284	99.50%	41	99.94%	164	99.59%	185	99.67%	82	99.58%	64	99.71%
$100 to $150	31	99.84%	37	99.92%	5	100.00%	25	99.87%	21	99.91%	17	99.77%	12	99.85%
$150 to $200	5	99.90%	4	99.97%	0	100.00%	9	99.98%	2	99.93%	12	99.91%	10	99.97%
$200 to $250	1	99.91%	2	99.99%	0	100.00%	2	100.00%	3	99.97%	5	99.97%	1	99.98%
$250 to $300	3	99.94%	0	99.99%	0	100.00%	0	100.00%	0	99.97%	1	99.98%	2	100.00%
$300 to $350	2	99.97%	1	100.00%	0	100.00%	0	100.00%	0	99.97%	2	100.00%	0	100.00%
$350 to $400	1	99.98%	0	100.00%	0	100.00%	0	100.00%	0	99.97%	0	100.00%	0	100.00%
$400 to $450	1	99.99%	0	100.00%	0	100.00%	0	100.00%	0	99.97%	0	100.00%	0	100.00%
$450 to $500	1	100.00%	0	100.00%	0	100.00%	0	100.00%	0	99.97%	0	100.00%	0	100.00%
$500 to $750	0	100.00%	0	100.00%	0	100.00%	0	100.00%	3	100.00%	0	100.00%	0	100.00%
$750 to $1,000	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%
$1,000 to $1,250	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%
>= $1,250	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%

	2014		2015		2016		2017		2018	
LMP	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent
< ($1,000)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
($1,000) to ($750)	2	0.02%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
($750) to ($500)	3	0.06%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
($500) to ($450)	1	0.07%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
($450) to ($400)	6	0.14%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
($400) to ($350)	5	0.19%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
($350) to ($300)	5	0.25%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
($300) to ($250)	6	0.32%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
($250) to ($200)	14	0.48%	1	0.01%	0	0.00%	0	0.00%	0	0.00%
($200) to ($150)	14	0.64%	4	0.06%	0	0.00%	0	0.00%	0	0.01%
($150) to ($100)	45	1.15%	17	0.25%	0	0.00%	2	0.02%	2	0.05%
($100) to ($50)	91	2.19%	65	0.99%	13	0.15%	9	0.13%	9	0.41%
($50) to $0	5,829	68.73%	6,034	69.87%	5,780	65.95%	5,460	62.45%	5,460	65.65%
$0 to $50	2,525	97.56%	2,467	98.04%	2,919	99.18%	3,231	99.34%	3,231	98.24%
$50 to $100	120	98.93%	126	99.47%	58	99.84%	45	99.85%	45	99.52%
$100 to $150	39	99.37%	34	99.86%	13	99.99%	8	99.94%	8	99.82%
$150 to $200	18	99.58%	7	99.94%	1	100.00%	3	99.98%	3	99.87%
$200 to $250	9	99.68%	3	99.98%	0	100.00%	0	99.98%	0	99.97%
$250 to $300	8	99.77%	1	99.99%	0	100.00%	0	99.98%	0	99.98%
$300 to $350	3	99.81%	1	100.00%	0	100.00%	0	99.98%	0	99.99%
$350 to $400	3	99.84%	0	100.00%	0	100.00%	0	99.98%	0	99.99%
$400 to $450	2	99.86%	0	100.00%	0	100.00%	1	99.99%	1	100.00%
$450 to $500	0	99.86%	0	100.00%	0	100.00%	0	99.99%	0	100.00%
$500 to $750	7	99.94%	0	100.00%	0	100.00%	1	100.00%	1	100.00%
$750 to $1,000	0	99.94%	0	100.00%	0	100.00%	0	100.00%	0	100.00%
$1,000 to $1,250	1	99.95%	0	100.00%	0	100.00%	0	100.00%	0	100.00%
>= $1,250	4	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%

LMP by Zone and by Jurisdiction

Jurisdiction Real-Time, Average LMP

Table C-16 Jurisdiction real-time, average LMP (Dollars per MWh): 2017 and 2018

	2017	2018	Difference	Percent Change
Delaware	$29.13	$36.30	$7.17	24.6%
Illinois	$26.83	$28.57	$1.74	6.5%
Indiana	$28.74	$33.43	$4.69	16.3%
Kentucky	$28.20	$33.97	$5.76	20.4%
Maryland	$32.07	$39.88	$7.81	24.4%
Michigan	$29.30	$33.36	$4.07	13.9%
New Jersey	$28.74	$34.56	$5.82	20.2%
North Carolina	$30.85	$38.75	$7.89	25.6%
Ohio	$29.45	$36.58	$7.13	24.2%
Pennsylvania	$28.60	$34.74	$6.14	21.5%
Tennessee	$28.35	$36.40	$8.05	28.4%
Virginia	$31.21	$39.11	$7.90	25.3%
West Virginia	$29.08	$35.69	$6.62	22.8%
District of Columbia	$31.82	$39.24	$7.42	23.3%

Hub Real-Time, Average LMP

Table C-17 Hub real-time, average LMP (Dollars per MWh): 2017 and 2018

	2017	2018	Difference	Percent Change
AEP Gen Hub	$27.92	$33.06	$5.15	18.4%
AEP-DAY Hub	$28.81	$34.48	$5.66	19.6%
ATSI Gen Hub	$29.29	$36.61	$7.31	25.0%
Chicago Gen Hub	$26.31	$28.16	$1.85	7.0%
Chicago Hub	$26.97	$28.68	$1.71	6.3%
Dominion Hub	$31.12	$38.89	$7.77	25.0%
Eastern Hub	$30.75	$38.47	$7.72	25.1%
N Illinois Hub	$26.69	$28.48	$1.79	6.7%
New Jersey Hub	$28.64	$34.44	$5.80	20.2%
Ohio Hub	$28.89	$34.32	$5.43	18.8%
West Interface Hub	$29.77	$37.62	$7.86	26.4%
Western Hub	$29.82	$36.57	$6.75	22.6%

Jurisdiction Real-Time, Load-Weighted, Average LMP

Table C-18 Jurisdiction real-time, load-weighted, average LMP (Dollars per MWh): 2017 and 2018

	2017	2018	Difference	Percent Change
Delaware	$31.45	$40.11	$8.66	27.5%
Illinois	$28.29	$30.05	$1.77	6.2%
Indiana	$29.65	$34.60	$4.95	16.7%
Kentucky	$29.45	$37.01	$7.56	25.7%
Maryland	$34.37	$43.99	$9.62	28.0%
Michigan	$30.50	$34.55	$4.05	13.3%
New Jersey	$30.75	$36.95	$6.20	20.2%
North Carolina	$32.42	$43.73	$11.31	34.9%
Ohio	$30.78	$38.81	$8.03	26.1%
Pennsylvania	$30.31	$37.33	$7.03	23.2%
Tennessee	$29.55	$42.08	$12.53	42.4%
Virginia	$33.20	$43.38	$10.18	30.7%
West Virginia	$30.23	$38.11	$7.88	26.1%
District of Columbia	$33.37	$41.68	$8.31	24.9%

Jurisdiction Day-Ahead, Average LMP

Table C-19 Jurisdiction day-ahead, average LMP (Dollars per MWh): 2017 and 2018

	2017	2018	Difference	Percent Change
Delaware	$28.51	$36.31	$7.79	27.3%
Illinois	$26.81	$28.53	$1.72	6.4%
Indiana	$28.64	$33.84	$5.20	18.1%
Kentucky	$28.86	$34.02	$5.15	17.9%
Maryland	$32.37	$40.08	$7.71	23.8%
Michigan	$29.60	$33.36	$3.76	12.7%
New Jersey	$28.50	$34.78	$6.28	22.0%
North Carolina	$30.93	$38.36	$7.43	24.0%
Ohio	$29.70	$36.23	$6.54	22.0%
Pennsylvania	$28.47	$34.61	$6.14	21.6%
Tennessee	$29.02	$35.62	$6.60	22.7%
Virginia	$31.62	$39.37	$7.75	24.5%
West Virginia	$29.41	$35.53	$6.13	20.8%
District of Columbia	$32.20	$39.56	$7.36	22.8%

Jurisdiction Day-Ahead, Load-Weighted, Average LMP

Table C-20 Jurisdiction day-ahead, load-weighted, average LMP (Dollars per MWh): 2017 and 2018

	2017	2018	Difference	Percent Change
Delaware	$30.57	$39.93	$9.36	30.6%
Illinois	$28.10	$30.00	$1.90	6.8%
Indiana	$29.38	$35.01	$5.63	19.1%
Kentucky	$30.24	$36.68	$6.44	21.3%
Maryland	$34.27	$43.78	$9.51	27.7%
Michigan	$30.60	$34.45	$3.85	12.6%
New Jersey	$30.11	$37.00	$6.89	22.9%
North Carolina	$32.67	$42.85	$10.17	31.1%
Ohio	$30.91	$38.23	$7.33	23.7%
Pennsylvania	$29.81	$36.79	$6.99	23.4%
Tennessee	$30.19	$39.30	$9.11	30.2%
Virginia	$33.40	$43.30	$9.89	29.6%
West Virginia	$30.67	$37.84	$7.18	23.4%
District of Columbia	$33.62	$41.81	$8.19	24.3%

Zonal Price Differences Between Day-Ahead and Real-Time

Table C-21 Zonal day-ahead and real-time average LMP (Dollars per MWh): 2018

	Day Ahead	Real Time	Difference	Percent of Real Time
AECO	$34.67	$34.81	($0.14)	(0.4%)
AEP	$35.42	$35.57	($0.15)	(0.4%)
APS	$36.84	$36.94	($0.10)	(0.3%)
ATSI	$37.10	$37.85	($0.75)	(2.0%)
BGE	$40.37	$40.22	$0.15	0.4%
ComEd	$28.65	$28.57	$0.09	0.3%
DAY	$36.65	$36.55	$0.10	0.3%
DEOK	$37.33	$36.49	$0.84	2.3%
DLCO	$36.98	$37.56	($0.57)	(1.5%)
Dominion	$39.38	$39.07	$0.31	0.8%
DPL	$38.20	$38.91	($0.72)	(1.8%)
EKPC	$33.40	$33.22	$0.18	0.5%
JCPL	$34.34	$34.32	$0.03	0.1%
Met-Ed	$34.38	$34.12	$0.26	0.7%
OVEC	$31.48	$30.79	$0.69	2.2%
PECO	$33.74	$33.66	$0.08	0.2%
PENELEC	$35.41	$35.78	($0.37)	(1.0%)
Pepco	$39.37	$39.14	$0.23	0.6%
PPL	$33.19	$32.94	$0.25	0.8%
PSEG	$34.87	$34.50	$0.37	1.1%
RECO	$35.14	$34.95	$0.19	0.5%

Jurisdictional Price Differences Between Day-Ahead and Real-Time

Table C-22 Jurisdiction day-ahead and real-time average LMP (Dollars per MWh): 2018

	Day Ahead	Real Time	Difference	Percent of Real Time
Delaware	$36.31	$36.30	$0.01	0.0%
Illinois	$28.53	$28.57	($0.03)	(0.1%)
Indiana	$33.84	$33.43	$0.41	1.2%
Kentucky	$34.02	$33.97	$0.05	0.1%
Maryland	$40.08	$39.88	$0.20	0.5%
Michigan	$33.36	$33.36	($0.00)	(0.0%)
New Jersey	$34.78	$34.56	$0.22	0.6%
North Carolina	$38.36	$38.75	($0.39)	(1.0%)
Ohio	$36.23	$36.58	($0.34)	(0.9%)
Pennsylvania	$34.61	$34.74	($0.13)	(0.4%)
Tennessee	$35.62	$36.40	($0.78)	(2.1%)
Virginia	$39.37	$39.11	$0.26	0.7%
West Virginia	$35.53	$35.69	($0.16)	(0.4%)
District of Columbia	$39.56	$39.24	$0.31	0.8%

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 as a result of structurally noncompetitive local markets and noncompetitive offers in the Day-Ahead and Real-Time Energy Markets. PJM also uses offer capping for units that are committed for reliability reasons, specifically for providing black start, reactive service and for units committed manually as part of conservative operations.

PJM 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.[12] The goal is to apply a clear rule to limit the exercise of market power by generation owners in load pockets, but to apply the rule in a flexible manner in real time and to lift offer capping when the exercise of market power is unlikely based on the real-time application of the market structure screen.

Levels of offer capping have generally been low and stable over the last five years. Table C-23 through Table C-26 show offer capping by month, including the average number of offer capped units, offer capped unit hours as a percentage of unit run hours, average offer capped MW, and offer capped MW as a percentage of total generation MW in the Day-Ahead and Real-Time Energy Markets. The statistics include units that are capped for failing the TPS test to provide constraint relief as well as units committed on their cost schedule for reliability reasons (reactive support, black start service and conservative operations).

12 See the *Technical Reference for PJM Markets*, Section 8, "Three Pivotal Supplier Test."

Table C-23 Average day-ahead, offer capped units: 2014 through 2018

	2014		2015		2016		2017		2018	
	Avg. Units Capped	Percent	Avg. Units Capped	Percent	Avg. Units Capped	Percent	Avg. Units Capped	Percent	Avg. Units Capped	Percent
Jan	6.3	1.3%	2.5	0.6%	0.8	0.2%	0.9	0.2%	1.0	0.2%
Feb	1.6	0.4%	2.3	0.5%	0.8	0.2%	1.6	0.4%	0.3	0.1%
Mar	2.3	0.5%	2.5	0.6%	0.8	0.2%	1.1	0.3%	0.5	0.1%
Apr	1.6	0.4%	4.3	1.1%	0.1	0.0%	0.4	0.1%	1.0	0.2%
May	1.9	0.5%	4.4	1.1%	0.6	0.1%	0.6	0.2%	1.1	0.2%
Jun	3.2	0.7%	5.4	1.2%	0.2	0.0%	0.0	0.0%	2.8	0.6%
Jul	1.3	0.3%	2.7	0.6%	0.2	0.0%	0.0	0.0%	1.5	0.3%
Aug	0.3	0.1%	2.2	0.5%	0.2	0.0%	0.1	0.0%	0.4	0.1%
Sep	0.7	0.2%	0.9	0.2%	1.2	0.3%	0.5	0.1%	1.1	0.2%
Oct	3.1	0.8%	1.0	0.3%	0.4	0.1%	0.6	0.1%	1.4	0.3%
Nov	4.4	1.1%	1.8	0.5%	1.2	0.3%	0.2	0.0%	0.7	0.1%
Dec	2.7	0.6%	0.7	0.2%	0.8	0.2%	0.2	0.1%	1.1	0.3%

Table C-24 Average day-ahead, offer capped MW: 2014 through 2018

	2014		2015		2016		2017		2018	
	Avg. MW Capped	Percent	Avg. MW Capped	Percent	Avg. MW Capped	Percent	Avg. MW Capped	Percent	Avg. MW Capped	Percent
Jan	905	0.8%	311	0.3%	144	0.1%	502	0.5%	120	0.1%
Feb	372	0.4%	355	0.3%	159	0.2%	525	0.6%	72	0.1%
Mar	609	0.6%	402	0.4%	91	0.1%	565	0.6%	153	0.2%
Apr	168	0.2%	1,164	1.5%	8	0.0%	243	0.3%	373	0.5%
May	179	0.2%	1,015	1.2%	25	0.0%	372	0.5%	416	0.5%
Jun	565	0.6%	1,587	1.7%	36	0.0%	0	0.0%	806	0.8%
Jul	320	0.3%	858	0.8%	25	0.0%	2	0.0%	563	0.5%
Aug	64	0.1%	787	0.8%	9	0.0%	33	0.0%	148	0.1%
Sep	79	0.1%	110	0.1%	95	0.1%	76	0.1%	354	0.4%
Oct	373	0.5%	243	0.3%	56	0.1%	50	0.1%	501	0.6%
Nov	454	0.5%	355	0.4%	464	0.6%	66	0.1%	213	0.2%
Dec	282	0.3%	49	0.1%	415	0.4%	48	0.1%	256	0.3%

Table C-25 Average real-time, offer capped units: 2014 through 2018

	2014		2015		2016		2017		2018	
	Avg. Units Capped	Percent	Avg. Units Capped	Percent	Avg. Units Capped	Percent	Avg. Units Capped	Percent	Avg. Units Capped	Percent
Jan	13.2	2.4%	3.7	0.8%	2.1	0.4%	2.0	0.4%	9.5	1.7%
Feb	4.3	0.8%	4.7	0.9%	1.5	0.3%	1.8	0.4%	4.2	0.8%
Mar	6.4	1.2%	3.9	0.8%	3.2	0.7%	1.6	0.3%	6.1	1.3%
Apr	1.7	0.4%	5.2	1.1%	1.3	0.3%	1.1	0.2%	5.8	1.1%
May	3.0	0.6%	5.5	1.1%	1.3	0.3%	1.7	0.3%	9.6	1.8%
Jun	4.6	0.9%	6.3	1.2%	1.6	0.3%	1.5	0.3%	7.2	1.3%
Jul	2.6	0.5%	3.5	0.6%	4.2	0.7%	2.1	0.4%	8.1	1.4%
Aug	0.8	0.2%	3.1	0.6%	3.3	0.5%	1.5	0.3%	6.9	1.1%
Sep	1.4	0.3%	2.3	0.5%	3.0	0.6%	4.2	0.8%	8.3	1.5%
Oct	3.8	0.9%	1.8	0.4%	2.5	0.5%	3.8	0.8%	9.4	1.8%
Nov	4.9	1.1%	2.5	0.6%	1.6	0.4%	1.8	0.4%	3.5	0.7%
Dec	3.2	0.7%	1.6	0.3%	1.4	0.3%	3.1	0.6%	4.5	0.9%

Table C-26 Average real-time, offer capped MW: 2014 through 2018

	2014		2015		2016		2017		2018	
	Avg. MW Capped	Percent	Avg. MW Capped	Percent	Avg. MW Capped	Percent	Avg. MW Capped	Percent	Avg. MW Capped	Percent
Jan	1,363	1.3%	351	0.4%	216	0.2%	557	0.6%	699	0.7%
Feb	452	0.5%	353	0.3%	145	0.2%	496	0.6%	210	0.2%
Mar	824	0.9%	487	0.5%	276	0.3%	624	0.7%	345	0.6%
Apr	192	0.2%	1,091	1.4%	90	0.1%	281	0.4%	644	0.8%
May	264	0.3%	1,003	1.2%	69	0.1%	433	0.6%	1,371	1.6%
Jun	649	0.7%	1,580	1.7%	197	0.2%	124	0.1%	1,192	1.2%
Jul	372	0.4%	957	1.0%	437	0.4%	204	0.2%	1,143	1.1%
Aug	90	0.1%	708	0.7%	311	0.3%	128	0.1%	808	0.7%
Sep	121	0.1%	207	0.2%	196	0.2%	271	0.3%	1,046	1.1%
Oct	431	0.6%	248	0.3%	222	0.3%	212	0.3%	1,821	2.0%
Nov	425	0.5%	368	0.5%	537	0.7%	294	0.4%	583	0.6%
Dec	298	0.3%	100	0.1%	454	0.5%	229	0.2%	891	0.9%

In order to help understand the frequency of offer capping in more detail, Table C-27 through Table C-31 show the number of generating units that met specified criteria for total offer capped run hours (constraint relief and reliability reasons) and percentage of offer capped run hours for the years 2014 through 2018 in the Real-Time Energy Market.

Table C-27 Offer capped unit statistics: 2014

	2014 Offer-Capped Hours					
Run Hours Offer-Capped, Percent Greater Than Or Equal To:	Hours ≥ 500	Hours ≥ 400 and < 500	Hours ≥ 300 and < 400	Hours ≥ 200 and < 300	Hours ≥ 100 and < 200	Hours ≥ 1 and < 100
90%	1	0	0	0	0	0
80% and < 90%	2	0	0	3	0	0
75% and < 80%	1	0	0	0	1	0
70% and < 75%	0	0	0	0	0	0
60% and < 70%	0	0	0	1	7	5
50% and < 60%	0	0	0	0	3	6
25% and < 50%	0	3	1	1	10	45
10% and < 25%	0	1	4	1	8	56

Table C-28 Offer-capped unit statistics: 2015

	2015 Offer-Capped Hours					
Run Hours Offer-Capped, Percent Greater Than Or Equal To:	Hours ≥ 500	Hours ≥ 400 and < 500	Hours ≥ 300 and < 400	Hours ≥ 200 and < 300	Hours ≥ 100 and < 200	Hours ≥ 1 and < 100
90%	2	0	0	0	1	4
80% and < 90%	0	1	1	0	0	6
75% and < 80%	0	0	0	0	0	3
70% and < 75%	0	0	0	0	0	4
60% and < 70%	0	0	0	1	0	9
50% and < 60%	0	0	0	0	1	9
25% and < 50%	0	0	0	0	1	26
10% and < 25%	0	0	5	2	5	34

Table C-29 Offer-capped unit statistics: 2016

	2016 Offer-Capped Hours					
Run Hours Offer-Capped, Percent Greater Than Or Equal To:	Hours ≥ 500	Hours ≥ 400 and < 500	Hours ≥ 300 and < 400	Hours ≥ 200 and < 300	Hours ≥ 100 and < 200	Hours ≥ 1 and < 100
90%	1	1	1	0	0	0
80% and < 90%	0	0	1	1	1	0
75% and < 80%	0	0	0	0	1	1
70% and < 75%	1	0	0	0	1	0
60% and < 70%	1	0	0	0	0	2
50% and < 60%	1	0	0	0	0	2
25% and < 50%	1	3	0	4	2	24
10% and < 25%	0	0	1	2	8	21

Table C-30 Offer-capped unit statistics: 2017

	2017 Offer-Capped Hours					
Run Hours Offer-Capped, Percent Greater Than Or Equal To:	Hours ≥ 500	Hours ≥ 400 and < 500	Hours ≥ 300 and < 400	Hours ≥ 200 and < 300	Hours ≥ 100 and < 200	Hours ≥ 1 and < 100
90%	0	0	1	1	1	1
80% and < 90%	0	0	1	2	0	1
75% and < 80%	0	0	0	1	1	0
70% and < 75%	1	0	0	0	0	1
60% and < 70%	0	0	0	0	1	1
50% and < 60%	0	0	0	1	0	1
25% and < 50%	1	0	1	1	6	31
10% and < 25%	0	0	1	1	14	36

Table C-31 Offer-capped unit statistics: 2018

	2018 Offer-Capped Hours					
Run Hours Offer-Capped, Percent Greater Than Or Equal To:	Hours ≥ 500	Hours ≥ 400 and < 500	Hours ≥ 300 and < 400	Hours ≥ 200 and < 300	Hours ≥ 100 and < 200	Hours ≥ 1 and < 100
90%	2	0	0	0	0	0
80% and < 90%	0	0	0	0	0	0
75% and < 80%	0	0	0	0	2	2
70% and < 75%	0	0	0	0	1	3
60% and < 70%	0	0	0	1	1	5
50% and < 60%	2	0	0	2	0	3
25% and < 50%	7	4	4	9	5	15
10% and < 25%	3	0	2	8	30	61

Energy Uplift

Credits and Charges to Generators

Table C-32 and Table C-33 compare the share of balancing operating reserve charges paid by generators and balancing operating reserve credits paid to generators in the Eastern Region and the Western Region. Generator charges are defined in these tables as the allocation of charges paid by generators due to generator deviations from day-ahead schedules or not following PJM dispatch.

Table C-32 shows that on average, 14.5 percent of the RTO and Eastern Region balancing generator charges, including lost opportunity cost and canceled resources charges, were paid by generators deviating in the Eastern Region while these generators received 47.7 percent of all balancing generator credits.

Table C-32 Monthly balancing operating reserve charges and credits to generators in the Eastern Region (Millions): 2018

	Generators RTO Deviation Charges	Generators Regional Deviation Charges	Generators LOC and Canceled Resources Charges	Total Charges	Balancing, LOC and Canceled Resources Credits
Jan	$2.4	$0.2	$3.6	$6.2	$33.2
Feb	$0.1	$0.0	$0.0	$0.1	$1.4
Mar	$0.2	$0.0	$0.3	$0.5	$3.4
Apr	$0.4	$0.1	$0.5	$0.9	$3.2
May	$0.4	$0.1	$1.3	$1.8	$4.9
Jun	$0.2	$0.1	$0.4	$0.7	$2.3
Jul	$0.6	$0.0	$0.2	$0.8	$3.2
Aug	$0.6	$0.0	$0.3	$0.9	$3.7
Sep	$0.5	$0.1	$0.4	$1.0	$4.7
Oct	$0.4	$0.1	$0.3	$0.8	$3.8
Nov	$0.4	$0.1	$0.1	$0.6	$2.7
Dec	$0.1	$0.1	$0.1	$0.3	$1.6
East Generators Total	$6.1	$0.9	$7.5	$14.5	$67.9
PJM Total	$45.9	$3.6	$52.6	$102.1	$142.5
Share	13.4%	23.6%	14.3%	14.2%	47.7%

Table C-33 shows that generators in the Western Region paid 11.1 percent of the RTO and Western Region balancing generator charges including lost opportunity cost and canceled resources charges while these generators received 50.7 percent of all balancing generator credits.

Table C-33 Monthly balancing operating reserve charges and credits to generators in the Western Region (Millions): 2018

	Generators RTO Deviation Charges	Generators Regional Deviation Charges	Generators LOC and Canceled Resources Charges	Total Charges	Balancing, LOC and Canceled Resources Credits
Jan	$1.9	$0.7	$2.3	$4.9	$20.9
Feb	$0.1	$0.0	$0.0	$0.1	$0.6
Mar	$0.2	$0.0	$0.4	$0.6	$3.0
Apr	$0.3	$0.0	$0.4	$0.8	$6.2
May	$0.3	$0.1	$1.1	$1.5	$9.2
Jun	$0.1	$0.0	$0.3	$0.5	$3.9
Jul	$0.5	$0.0	$0.2	$0.7	$6.2
Aug	$0.4	$0.0	$0.2	$0.6	$5.2
Sep	$0.4	$0.1	$0.3	$0.8	$7.4
Oct	$0.3	$0.0	$0.3	$0.5	$4.8
Nov	$0.3	$0.0	$0.1	$0.3	$4.2
Dec	$0.1	$0.0	$0.1	$0.2	$0.8
West Generators Total	$4.8	$1.1	$5.5	$11.4	$72.2
PJM Total	$45.9	$4.1	$52.6	$102.6	$142.5
Share	10.5%	25.7%	10.5%	11.1%	50.7%

Table C-34 shows that on average in 2018, energy uplift charges paid by generators were 13.0 percent of all energy uplift charges, 3.6 percentage point higher than the average in 2017. Generators received 99.6 percent of all energy uplift credits, while the remaining 0.4 percent of credits were paid to import transactions and demand resources.

Table C-34 Percentage of generators credits and charges of total credits and charges: 2017 and 2018

	2017		2018	
	Generators Share of Total Energy Uplift Charges	Generators Share of Total Energy Uplift Credits	Generators Share of Total Energy Uplift Charges	Generators Share of Total Energy Uplift Credits
Jan	9.4%	99.9%	17.8%	99.2%
Feb	2.5%	100.0%	3.3%	100.0%
Mar	9.0%	100.0%	8.5%	100.0%
Apr	8.3%	99.1%	12.8%	100.0%
May	9.8%	99.6%	12.8%	99.0%
Jun	9.3%	99.1%	6.1%	99.9%
Jul	8.5%	99.7%	12.5%	100.0%
Aug	7.3%	99.5%	15.3%	99.9%
Sep	7.5%	99.4%	11.2%	100.0%
Oct	8.6%	100.0%	13.0%	100.0%
Nov	9.5%	100.0%	11.3%	100.0%
Dec	9.4%	99.9%	13.0%	100.0%
Average	8.5%	99.7%	13.0%	99.6%

Energy Uplift Charges by Transaction/Resource Type

Table C-35 shows the energy uplift charges and applicable rates for each type of resource or transaction in PJM.

Table C-35 Energy uplift charge by transaction/resource type

		Transaction / Resource Type									
Charge	Rate	Load	Generation	Imports[1]	Exports[1]	Wheels	Economic DR	INCs	DECs	IBTs	UTCs
Day-Ahead Operating Reserve	Day-Ahead Operating Reserve Rate	X			X				X		
Balancing Operating Reserves for Reliability	RTO Reliability Rate	X			X						
	Regional (East or West) Reliability Rate	X			X						
Balancing Operating Reserves for Deviations[2]	RTO Deviation Rate	X	X	X	X		X	X	X	X	
	Regional (East or West) Deviation Rate	X	X	X	X		X	X	X	X	
	LOC Rate	X	X	X	X		X	X	X	X	
	Canceled Resources Rate	X	X	X	X		X	X	X	X	
Reactive Services	Implicit Rates	X									
Black Start Services	Implicit Rates	X[3]		X[4]	X[4]	X[4]					
Synchronous Condensing	Implicit Rate	X			X						

1 Dynamic scheduled transactions are exempt from operating reserve charges.
2 Participants only pay deviation charges if they incur deviations based on the rules specified in Manual 28.
3 Load is charged black start services based on their zonal peak load contribution.
4 Interchange transactions are charged black start services based on their point to point firm and non-firm reservations.

Appendix D Local Energy Market Structure: TPS Results

The three pivotal supplier test is applied by PJM on an ongoing basis in order to determine whether structural market power requires offer capping to prevent the potential exercise of local market power for binding constraints.

The MMU analyzed the results of the three pivotal supplier tests conducted by PJM for the Real-Time Energy Market for the period January 1, 2018, through December 31, 2018. The three pivotal supplier test is applied every time the system solution indicates that out of merit resources are needed to relieve a transmission constraint. Until November 1, 2017, only uncommitted resources, started to relieve the transmission constraint, were subject to offer capping. Resources that were committed economically, that were ramped up to provide incremental relief for a binding constraint, could not be switched from the schedule that they were operating on. Beginning November 1, 2017, under certain circumstances, online resources that are committed beyond their original commitment (day-ahead or real-time), to provide relief for a constraint, can be offer capped if the owner fails the TPS test, and the latest available cost-based offer is determined to be cheaper than the price-based offer. The results of the TPS test are shown for tests that could have resulted in offer capping and tests that did result in offer capping.

Overall, the results confirm that the three pivotal supplier test results in offer capping when the local market is structurally noncompetitive and does not result in offer capping when that is not the case. Local markets are noncompetitive when the number of suppliers is relatively small.

The three pivotal supplier test is calculated as part of the Intermediate Term Security Constrained Economic Dispatch (IT SCED) tool. IT SCED looks ahead at multiple intervals up to two hours ahead, and forecasts potential binding constraints and suggests unit commitment and dispatch changes to meet transmission limits. As a result of the remedial actions taken in advance in response to IT SCED forecasts, the set of constraints that appear to be potentially binding in IT SCED is not necessarily the same as the set of constraints that bind in the Real-Time SCED tool. This appendix provides data on the TPS tests that were applied in PJM control zones that had congestion from one or more constraints for 100 or more hours in real time. In 2018, the AECO, AEP, APS, ATSI, BGE, ComEd, Dominion, DPL, EKPC, Met-Ed, PECO, PENELEC, PPL, and PSEG control zones experienced congestion resulting from one or more constraints binding for 100 or more hours. Using the three pivotal supplier results for 2018, actual competitive conditions associated with each of these frequently binding constraints were analyzed for the Real-Time Energy Market. The DAY, DEOK, DLCO, JCPL, Pepco, and RECO control zones were not affected by constraints binding for 100 or more hours. Information is provided, by qualifying zone, for each constraint including the number of tests applied, the number of tests that could have resulted in offer capping and the number of tests that did result in offer capping. Information is also provided for binding constraints on the 500 kV transmission system that were binding for 100 or more hours. Additional information is provided for each constraint including the average MW required to relieve a constraint, the average supply available, the average number of owners included in each test and the average number of owners that passed or failed each test.

500 kV System Constraints

In 2018, there was one constraint that occurred for more than 100 hours on the 500 kV transmission system. Table D-1 shows the average constraint relief required on the constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market and the average number of owners passing and failing. Table D-1 shows that for the Conastone – Peach Bottom constraint, there were nineteen owners, on average, with available supply to relieve the constraint.

Table D-1 Three pivotal supplier test details for 500 kV system constraints: 2018

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Conastone - Peach Bottom	Peak	283	447	19	8	11
	Off Peak	332	497	19	9	11

Table D-2 shows the total tests applied for the 500 kV system constraint, the subset of three pivotal supplier tests that could have resulted in offer capping and the portion of those tests that did result in offer capping. Table D-2 shows that for the Conastone – Peach Bottom constraint, six percent of the total tests applied during peak hours resulted in offer capping, and nine percent of the total tests applied during off peak hours resulted in offer capping.

Table D-2 Summary of three pivotal supplier tests applied for 500 kV system constraints: 2018

Constraint	Period	Total Tests Applied	Total Tests that Could Have Resulted in Offer Capping	Percent Total Tests that Could Have Resulted in Offer Capping	Total Tests Resulted in Offer Capping	Percent Total Tests Resulted in Offer Capping	Tests Resulted in Offer Capping as Percent of Tests that Could Have Resulted in Offer Capping
Conastone - Peach Bottom	Peak	6,765	6,764	100%	381	6%	6%
	Off Peak	4,470	4,470	100%	380	9%	9%

AECO Control Zone Results

In 2018, there was one constraint that occurred for more than 100 hours in the AECO Control Zone. Table D-3 shows the average constraint relief required on the constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market and the average number of owners passing and failing. Table D-3 shows that for the Monroe - Vineland constraint in the AECO Zone, there was one owner, on average, with available supply to relieve the constraint.

Table D-3 Three pivotal supplier test details for constraints located in the AECO Control Zone: 2018

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Monroe - Vineland	Peak	26	27	1	0	1
	Off Peak	17	18	1	0	1

Table D-4 shows the total tests applied for the constraint in the AECO Zone, the subset of three pivotal supplier tests that could have resulted in offer capping and the portion of those tests that did result in offer capping. The results reflect the fact that units that are economically committed, that are ramped up to provide incremental relief during their original commitment, cannot be offer capped. Table D-4 shows that for the Monroe - Vineland constraint in the AECO Zone, zero percent of the total tests applied during peak hours resulted in offer capping, and one percent of the total tests applied during off peak hours resulted in offer capping.

Table D-4 Summary of three pivotal supplier tests for constraints located in the AECO Control Zone: 2018

Constraint	Period	Total Tests Applied	Total Tests that Could Have Resulted in Offer Capping	Percent Total Tests that Could Have Resulted in Offer Capping	Total Tests Resulted in Offer Capping	Percent Total Tests Resulted in Offer Capping	Tests Resulted in Offer Capping as Percent of Tests that Could Have Resulted in Offer Capping
Monroe - Vineland	Peak	2,746	1,431	52%	10	0%	1%
	Off Peak	1,066	755	71%	6	1%	1%

AEP Control Zone Results

In 2018, there were five constraints that occurred for more than 100 hours in the AEP Control Zone. Table D-5 shows the average constraint relief required on the constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market and the average number of owners passing and failing. Table D-5shows that for three of the five constraints in the AEP Zone, there was one owner, on average, with available supply to relieve the constraint.

Table D-5 Three pivotal supplier test details for constraints located in the AEP Control Zone: 2018

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Bosserman - Michigan City	Peak	26	17	3	0	3
	Off Peak	29	24	4	0	4
Delaware - Hogan	Peak	14	22	1	0	1
	Off Peak	10	21	1	0	1
Gable Switch Station - South Cadiz	Peak	11	11	1	0	1
	Off Peak	14	11	1	0	1
Lockwood - South Hicksville	Peak	32	7	1	0	1
	Off Peak	30	8	1	0	1
Tanners Creek - Miami Fort	Peak	141	150	4	0	4
	Off Peak	153	153	5	0	5

Table D-6 shows the total tests applied for the constraints in the AEP Zone, the subset of three pivotal supplier tests that could have resulted in offer capping and the portion of those tests that did result in offer capping. The results reflect the fact that units that are economically committed, that are ramped up to provide incremental relief during their original commitment, cannot be offer capped. Table D-6 shows that for the Tanners Creek – Miami Fort constraint in the AEP Zone, three percent of the total tests applied during peak hours resulted in offer capping, and two percent of the total tests applied during peak hours resulted in offer capping.

Table D-6 Summary of three pivotal supplier tests for constraints located in the AEP Control Zone: 2018

Constraint	Period	Total Tests Applied	Total Tests that Could Have Resulted in Offer Capping	Percent Total Tests that Could Have Resulted in Offer Capping	Total Tests Resulted in Offer Capping	Percent Total Tests Resulted in Offer Capping	Tests Resulted in Offer Capping as Percent of Tests that Could Have Resulted in Offer Capping
Bosserman - Michigan City	Peak	528	262	50%	2	0%	1%
	Off Peak	1,499	1,123	75%	0	0%	0%
Delaware - Hogan	Peak	4,338	897	21%	13	0%	1%
	Off Peak	1,428	179	13%	6	0%	3%
Gable Switch Station - South Cadiz	Peak	1,807	444	25%	0	0%	0%
	Off Peak	1,365	157	12%	0	0%	0%
Lockwood - South Hicksville	Peak	502	170	34%	0	0%	0%
	Off Peak	381	66	17%	0	0%	0%
Tanners Creek - Miami Fort	Peak	8,927	6,875	77%	273	3%	4%
	Off Peak	6,017	4,825	80%	104	2%	2%

APS Control Zone Results

In 2018, there were two constraints that occurred for more than 100 hours in the APS Control Zone. Table D-7 shows the average constraint relief required on the constraint, the average effective supply available to relieve the constraints, the average number of owners with available relief in the defined market and the average number of owners passing and failing. Table D-7 shows that for the Krendale - Shanor Manor constraint in the APS Zone, there were 10 owners on peak, and nine owners off peak, on average, with available supply to relieve the constraint.

Table D-7 Three pivotal supplier test details for constraints located in the APS Control Zone: 2018

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Krendale - Shanor Manor	Peak	73	67	10	1	10
	Off Peak	34	32	9	0	9
Meadow Brook - Strasburg	Peak	30	21	1	0	1
	Off Peak	16	7	1	0	1

Table D-8 shows the total tests applied for the constraint in the APS Zone, the subset of three pivotal supplier tests that could have resulted in offer capping and the portion of those tests that did result in offer capping. The results reflect the fact that units that are economically committed, that are ramped up to provide incremental relief during their original commitment, cannot be offer capped. Table D-8 shows that for both the constraints in the APS Zone, one percent or fewer of the total tests applied resulted in offer capping.

Table D-8 Summary of three pivotal supplier tests for constraints located in the APS Control Zone: 2018

Constraint	Period	Total Tests Applied	Total Tests that Could Have Resulted in Offer Capping	Percent Total Tests that Could Have Resulted in Offer Capping	Total Tests Resulted in Offer Capping	Percent Total Tests Resulted in Offer Capping	Tests Resulted in Offer Capping as Percent of Tests that Could Have Resulted in Offer Capping
Krendale - Shanor Manor	Peak	1,957	1,872	96%	4	0%	0%
	Off Peak	563	512	91%	0	0%	0%
Meadow Brook - Strasburg	Peak	617	412	67%	4	1%	1%
	Off Peak	1,181	820	69%	6	1%	1%

ATSI Control Zone Results

In 2018, there were five constraints in the ATSI Control Zone that occurred for more than 100 hours. Table D-9 shows the average constraint relief required on the constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market and the average number of owners passing and failing. Table D-9 shows that for the Lakeview – Greenfield constraint in the ATSI Zone, there were two owners, on average, with available supply to relieve the constraint.

Table D-9 Three pivotal supplier test details for constraints located in the ATSI Control Zone: 2018

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Cranberry - Hoytdale	Peak	70	72	11	1	10
	Off Peak	72	66	11	0	11
Lakeview - Greenfield	Peak	51	31	2	0	2
	Off Peak	42	19	2	0	2
Lallendorf - Monroe	Peak	66	58	6	0	6
	Off Peak	87	80	7	0	7
Maple - Jackson	Peak	40	34	7	1	6
	Off Peak	56	29	5	0	5
Nottingham	Peak	100	124	12	3	9
	Off Peak	72	92	9	2	8

Table D-10 shows the subset of three pivotal supplier tests that could have resulted in the offer capping of uncommitted units and those tests that did result in offer capping for constraints in the ATSI Zone. The results reflect the fact that units that are economically committed, that are ramped up to provide incremental relief during their original commitment, cannot be offer capped. Table D-10 shows that one percent or fewer of the tests applied resulted in offer capping for the five constraints.

Table D-10 Summary of three pivotal supplier tests for constraints located in the ATSI Control Zone: 2018

Constraint	Period	Total Tests Applied	Total Tests that Could Have Resulted in Offer Capping	Percent Total Tests that Could Have Resulted in Offer Capping	Total Tests Resulted in Offer Capping	Percent Total Tests Resulted in Offer Capping	Tests Resulted in Offer Capping as Percent of Tests that Could Have Resulted in Offer Capping
Cranberry - Hoytdale	Peak	2,770	2,648	96%	3	0%	0%
	Off Peak	3,073	2,952	96%	2	0%	0%
Lakeview - Greenfield	Peak	7,029	2,890	41%	14	0%	0%
	Off Peak	3,629	1,737	48%	0	0%	0%
Lallendorf - Monroe	Peak	2,031	1,080	53%	5	0%	0%
	Off Peak	2,478	1,905	77%	4	0%	0%
Maple - Jackson	Peak	2,369	2,110	89%	1	0%	0%
	Off Peak	1,007	822	82%	0	0%	0%
Nottingham	Peak	12,291	12,188	99%	124	1%	1%
	Off Peak	2,916	2,854	98%	10	0%	0%

BGE Control Zone Results

In 2018, there were three constraints that occurred for more than 100 hours in the BGE Control Zone. Table D-11 shows the average constraint relief required on the constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market and the average number of owner passing and failing. Table D-11 shows that for all three of the constraints in the BGE Zone, there were at least twelve owners, on average, with available supply to relieve the constraint.

Table D-11 Three pivotal supplier test details for constraints located in the BGE Control Zone: 2018

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Bagley - Graceton	Peak	133	180	14	6	8
	Off Peak	118	187	14	6	8
Conastone - Northwest	Peak	95	154	14	6	8
	Off Peak	106	139	13	4	9
Graceton - Safe Harbor	Peak	117	176	13	4	9
	Off Peak	100	160	12	4	8

Table D-12 shows the total tests applied for the three constraints in the BGE Zone, the subset of three pivotal supplier tests that could have resulted in offer capping and the portion of those tests that did result in offer capping. The results reflect the fact that units that are economically committed, that are ramped up to provide incremental relief during their original commitment, cannot be offer capped. Table D-12 shows that two percent or fewer of the tests applied to the constraints in the BGE Zone resulted in offer capping.

Table D-12 Summary of three pivotal supplier tests for constraints located in the BGE Control Zone: 2018

Constraint	Period	Total Tests Applied	Total Tests that Could Have Resulted in Offer Capping	Percent Total Tests that Could Have Resulted in Offer Capping	Total Tests Resulted in Offer Capping	Percent Total Tests Resulted in Offer Capping	Tests Resulted in Offer Capping as Percent of Tests that Could Have Resulted in Offer Capping
Bagley - Graceton	Peak	3,737	3,685	99%	59	2%	2%
	Off Peak	4,210	4,188	99%	33	1%	1%
Conastone - Northwest	Peak	6,590	6,513	99%	31	0%	0%
	Off Peak	2,602	2,596	100%	32	1%	1%
Graceton - Safe Harbor	Peak	31,002	30,779	99%	141	0%	0%
	Off Peak	42,735	42,516	99%	304	1%	1%

ComEd Control Zone Results

In 2018, there were five constraints that occurred for more than 100 hours in the ComEd Control Zone. Table D-13 shows the average constraint relief required on the constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market and the average number of owner passing and failing. Table D-13 shows that for all five constraints in the ComEd Zone, on average, the number of owners with available supply was less than or equal to six.

Table D-13 Three pivotal supplier test details for constraints located in the ComEd Control Zone: 2018

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Braidwood - East Frankfort	Peak	59	94	3	0	3
	Off Peak	36	73	3	0	3
Burnham - Munster	Peak	92	107	6	0	5
	Off Peak	76	97	5	0	5
Haumesser Road - Steward	Peak	14	61	2	0	2
	Off Peak	17	48	2	0	2
Olive	Peak	32	48	4	1	4
	Off Peak	38	54	4	0	4
Quad Cities - Cordova Energy	Peak	35	111	1	0	1
	Off Peak	37	95	1	0	1

Table D-14 shows the total tests applied for the five constraints in the ComEd Zone, the subset of three pivotal supplier tests that could have resulted in offer capping and the portion of those tests that did result in offer capping. The results reflect the fact that units that are economically committed, that are ramped up to provide incremental relief during their original commitment, cannot be offer capped. Table D-14 shows that for three of the five constraints, zero percent of the tests applied resulted in offer capping.

Table D-14 Summary of three pivotal supplier test for constraints located in the ComEd Control Zone: 2018

Constraint	Period	Total Tests Applied	Total Tests that Could Have Resulted in Offer Capping	Percent Total Tests that Could Have Resulted in Offer Capping	Total Tests Resulted in Offer Capping	Percent Total Tests Resulted in Offer Capping	Tests Resulted in Offer Capping as Percent of Tests that Could Have Resulted in Offer Capping
Braidwood - East Frankfort	Peak	2,472	1,345	54%	8	0%	1%
	Off Peak	2,897	1,654	57%	21	1%	1%
Burnham - Munster	Peak	1,011	742	73%	6	1%	1%
	Off Peak	2,507	1,366	54%	0	0%	0%
Haumesser Road - Steward	Peak	1,100	408	37%	0	0%	0%
	Off Peak	604	0	0%	0	0%	NA
Olive	Peak	1,186	826	70%	0	0%	0%
	Off Peak	2,853	1,492	52%	2	0%	0%
Quad Cities - Cordova Energy	Peak	2,372	588	25%	0	0%	0%
	Off Peak	4,383	1,045	24%	0	0%	0%

Dominion Control Zone Results

In 2018, there was one constraint that occurred for more than 100 hours in the Dominion Control Zone. Table D-15 shows the average constraint relief required on the constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market and the average number of owner passing and failing. Table D-15 shows that for both the constraints in the Dominion Zone, on average, there were four or more owners with available supply to relieve the constraint.

Table D-15 Three pivotal supplier test details for constraints located in the Dominion Control Zone: 2018

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Person - Sedge Hill	Peak	64	72	5	0	5
	Off Peak	53	83	4	0	4

Table D-16 shows the total tests applied for the constraint in the Dominion Zone, the subset of three pivotal supplier tests that could have resulted in offer capping and the portion of those tests that did result in offer capping. The results reflect the fact that units that are economically committed, that are ramped up to provide incremental relief during their original commitment, cannot be offer capped. Table D-16 shows that one percent or fewer of the tests applied to the constraints in the Dominion Zone resulted in offer capping.

Table D-16 Summary of three pivotal supplier tests for constraints located in the Dominion Control Zone: 2018

Constraint	Period	Total Tests Applied	Total Tests that Could Have Resulted in Offer Capping	Percent Total Tests that Could Have Resulted in Offer Capping	Total Tests Resulted in Offer Capping	Percent Total Tests Resulted in Offer Capping	Tests Resulted in Offer Capping as Percent of Tests that Could Have Resulted in Offer Capping
Person - Sedge Hill	Peak	1,913	1,739	91%	23	1%	1%
	Off Peak	2,156	2,113	98%	3	0%	0%

DPL Control Zone Results

In 2018, there were three constraints that occurred for more than 100 hours in the DPL Control Zone. Table D-17 shows the average constraint relief required, the average effective supply available to relieve the constraints, the average number of owners with available relief in the defined market and the average number of owners passing and failing. Table D-17 shows that, on average, the number of owners with available supply was two or less.

Table D-17 Three pivotal supplier test details for constraints located in the DPL Control Zone: 2018

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Dupnt Seaford - Laurel	Peak	35	36	2	0	2
	Off Peak	36	37	2	0	2
North Salisbury - Rockawalkin	Peak	19	19	2	0	2
	Off Peak	14	13	1	0	1
North Salisbury - Pemberton	Peak	13	14	1	0	1
	Off Peak	7	8	1	0	1

Table D-18 shows the total tests applied for the three constraints in the DPL Zone, the subset of three pivotal supplier tests that could have resulted in offer capping and the portion of those tests that did result in offer capping. The results reflect the fact that units that are economically committed, that are ramped up to provide incremental relief during their original commitment, cannot be offer capped. Table D-18 shows that one percent or fewer of the tests applied to the constraints in the DPL zone resulted in offer capping.

Table D-18 Summary of three pivotal supplier tests for constraints located in the DPL Control Zone: 2018

Constraint	Period	Total Tests Applied	Total Tests that Could Have Resulted in Offer Capping	Percent Total Tests that Could Have Resulted in Offer Capping	Total Tests Resulted in Offer Capping	Percent Total Tests Resulted in Offer Capping	Tests Resulted in Offer Capping as Percent of Tests that Could Have Resulted in Offer Capping
Dupnt Seaford - Laurel	Peak	2,473	1,513	61%	14	1%	1%
	Off Peak	1,175	909	77%	5	0%	1%
North Salisbury - Rockawalkin	Peak	20,203	12,396	61%	14	0%	0%
	Off Peak	8,600	6,525	76%	6	0%	0%
North Salisbury - Pemberton	Peak	1,550	1,325	85%	4	0%	0%
	Off Peak	1,375	1,287	94%	6	0%	0%

EKPC Control Zone Results

In 2018, there was one constraint that occurred for more than 100 hours in the EKPC Control Zone. Table D-19 shows the average constraint relief required on the constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market and the average number of owners passing and failing. Table D-19 shows that for the Kenton - Spurlock constraint in the EKPC Zone, there was one owner, on average, with available supply to relieve the constraint.

Table D-19 Three pivotal supplier test details for constraints located in the EKPC Control Zone: 2018

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Kenton - Spurlock	Peak	24	85	1	0	1
	Off Peak	16	70	1	0	1

Table D-20 shows the total tests applied for the constraint in the EKPC Zone, the subset of three pivotal supplier tests that could have resulted in offer capping and the portion of those tests that did result in offer capping. The results reflect the fact that units that are economically committed, that are ramped up to provide incremental relief during their original commitment, cannot be offer capped. Table D-20 shows that for the Kenton - Spurlock constraint in the EKPC Zone, zero percent of the total tests applied resulted in offer capping.

Table D-20 Summary of three pivotal supplier tests for constraints located in the EKPC Control Zone: 2018

Constraint	Period	Total Tests Applied	Total Tests that Could Have Resulted in Offer Capping	Percent Total Tests that Could Have Resulted in Offer Capping	Total Tests Resulted in Offer Capping	Percent Total Tests Resulted in Offer Capping	Tests Resulted in Offer Capping as Percent of Tests that Could Have Resulted in Offer Capping
Kenton - Spurlock	Peak	5,148	236	5%	0	0%	0%
	Off Peak	924	8	1%	0	0%	0%

MetEd Control Zone Results

In 2018, there were four constraints that occurred for more than 100 hours in the MetEd Control Zone. Table D-21 shows the average constraint relief required on each constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market and the average number of owner passing and failing. Table D-21 shows that for three out of the four constraints in the MetEd Zone, on average, the number of owners with available supply was one.

Table D-21 Three pivotal supplier test details for constraints located in the MetEd Control Zone: 2018

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Gardners - Texas East	Peak	23	16	2	0	2
	Off Peak	20	16	1	0	1
Hunterstown	Peak	138	263	1	0	1
	Off Peak	75	205	1	0	1
Ironwood - South Lebanon	Peak	50	103	1	0	1
	Off Peak	48	93	1	0	1
Middletown Jct	Peak	6	3	1	0	1
	Off Peak	7	2	1	0	1

Table D-22 shows the total tests applied for the constraints in the MetEd Zone, the subset of three pivotal supplier tests that could have resulted in offer capping and the portion of those tests that did result in offer capping. The results reflect the fact that units that are economically committed, that are ramped up to provide incremental relief during their original commitment, cannot be offer capped. Table D-22 shows that two percent or fewer of the tests applied to the constraints in the MetEd Zone resulted in offer capping.

Table D-22 Summary of three pivotal supplier tests for constraints located in the MetEd Control Zone: 2018

Constraint	Period	Total Tests Applied	Total Tests that Could Have Resulted in Offer Capping	Percent Total Tests that Could Have Resulted in Offer Capping	Total Tests Resulted in Offer Capping	Percent Total Tests Resulted in Offer Capping	Tests Resulted in Offer Capping as Percent of Tests that Could Have Resulted in Offer Capping
Gardners - Texas East	Peak	7,189	3,392	47%	33	0%	1%
	Off Peak	1,434	1,129	79%	34	2%	3%
Hunterstown	Peak	8,712	1,589	18%	0	0%	0%
	Off Peak	5,802	450	8%	0	0%	0%
Ironwood - South Lebanon	Peak	3,496	620	18%	1	0%	0%
	Off Peak	3,231	570	18%	1	0%	0%
Middletown Jct	Peak	1,282	757	59%	8	1%	1%
	Off Peak	20	20	100%	0	0%	0%

PECO Control Zone Results

In 2018, there was one constraint that occurred for more than 100 hours in the PECO Control Zone. Table D-23 shows the average constraint relief required on each constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market and the average number of owner passing and failing. Table D-23 shows that for the Emilie – Falls constraint in the PECO Zone, on average, the number of owners with available supply was two during peak hours and one during off peak hours.

Table D-23 Three pivotal supplier test details for constraints located in the PECO Control Zone: 2018

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Emilie - Falls	Peak	28	45	2	0	2
	Off Peak	36	64	1	0	1

Table D-24 shows the total tests applied for the constraint in the PECO Zone, the subset of three pivotal supplier tests that could have resulted in offer capping and the portion of those tests that did result in offer capping. The results reflect the fact that units that are economically committed, that are ramped up to provide incremental relief during their original commitment, cannot be offer capped. Table D-24 shows that zero percent of the tests applied to the constraint in the PECO Zone resulted in offer capping.

Table D-24 Summary of three pivotal supplier tests for constraints located in the PECO Control Zone: 2018

Constraint	Period	Total Tests Applied	Total Tests that Could Have Resulted in Offer Capping	Percent Total Tests that Could Have Resulted in Offer Capping	Total Tests Resulted in Offer Capping	Percent Total Tests Resulted in Offer Capping	Tests Resulted in Offer Capping as Percent of Tests that Could Have Resulted in Offer Capping
Emilie - Falls	Peak	5,954	3,197	54%	6	0%	0%
	Off Peak	2,690	1,179	44%	0	0%	0%

PENELEC Control Zone Results

In 2018, there were seven constraints that occurred for more than 100 hours in the PENELEC Control Zone. Table D-25 shows the average constraint relief required on each constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market and the average number of owner passing and failing. Table D-25 shows that for six out of the seven constraints in the PENELEC Zone, on average, the number of owners with available supply was two or less.

Table D-25 Three pivotal supplier test details for constraints located in the PENELEC Control Zone: 2018

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
East Sayre - East Towanda	Peak	19	26	2	0	2
	Off Peak	12	14	2	0	2
East Towanda - Hillside	Peak	29	117	2	0	2
	Off Peak	20	116	1	0	1
East Towanda - North Meshoppen	Peak	17	27	2	0	2
	Off Peak	21	22	2	0	2
Lenox - North Meshoppen	Peak	13	47	1	0	1
	Off Peak	11	48	1	0	1
Lincoln - Straban	Peak	29	6	2	0	2
	Off Peak	30	5	1	0	1
Niles Valley - Sabinsville	Peak	20	22	1	0	1
	Off Peak	21	23	1	0	1
North Meshoppen - Oxbow	Peak	53	73	5	0	5
	Off Peak	63	80	5	0	5

Table D-26 shows the total tests applied for the constraints in the PENELEC Zone, the subset of three pivotal supplier tests that could have resulted in offer capping and the portion of those tests that did result in offer capping. The results reflect the fact that units that are economically committed, that are ramped up to provide incremental relief during their original commitment, cannot be offer capped. Table D-26 shows that zero percent of the tests applied to the constraints in the PENELEC Zone resulted in offer capping.

Table D-26 Summary of three pivotal supplier tests for constraints located in the PENELEC Control Zone: 2018

Constraint	Period	Total Tests Applied	Total Tests that Could Have Resulted in Offer Capping	Percent Total Tests that Could Have Resulted in Offer Capping	Total Tests Resulted in Offer Capping	Percent Total Tests Resulted in Offer Capping	Tests Resulted in Offer Capping as Percent of Tests that Could Have Resulted in Offer Capping
East Sayre - East Towanda	Peak	2,634	1,347	51%	3	0%	0%
	Off Peak	1,021	609	60%	1	0%	0%
East Towanda - Hillside	Peak	2,403	1,489	62%	1	0%	0%
	Off Peak	1,382	444	32%	0	0%	0%
East Towanda - North Meshoppen	Peak	4,505	2,682	60%	4	0%	0%
	Off Peak	3,316	2,137	64%	7	0%	0%
Lenox - North Meshoppen	Peak	1,542	367	24%	0	0%	0%
	Off Peak	996	201	20%	0	0%	0%
Lincoln - Straban	Peak	3,324	915	28%	2	0%	0%
	Off Peak	1,694	239	14%	1	0%	0%
Niles Valley - Sabinsville	Peak	2,991	922	31%	0	0%	0%
	Off Peak	1,150	525	46%	0	0%	0%
North Meshoppen - Oxbow	Peak	1,999	1,312	66%	4	0%	0%
	Off Peak	2,227	1,202	54%	4	0%	0%

PPL Control Zone Results

In 2018, there were two constraints that occurred for more than 100 hours in the PPL Control Zone. Table D-27 shows the average constraint relief required on the constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market and the average number of owner passing and failing. Table D-27 shows that, on average, there were five or fewer owners with available supply to relieve the constraints.

Table D-27 Three pivotal supplier test details for constraints located in the PPL Control Zone: 2018

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Siegfried	Peak	55	79	5	0	5
	Off Peak	62	81	5	0	5
Wescosville	Peak	15	16	2	0	2
	Off Peak	16	14	2	0	2

Table D-28 shows the total tests applied for the two constraints in the PPL Zone, the subset of three pivotal supplier tests that could have resulted in offer capping and the portion of those tests that did result in offer capping. The results reflect the fact that units that are economically committed, that are ramped up to provide incremental relief during their original commitment, cannot be offer capped. Table D-28 shows that zero percent of the tests applied to the constraints in the PPL Zone resulted in offer capping.

Table D-28 Summary of three pivotal supplier tests for constraints located in the PPL Control Zone: 2018

Constraint	Period	Total Tests Applied	Total Tests that Could Have Resulted in Offer Capping	Percent Total Tests that Could Have Resulted in Offer Capping	Total Tests Resulted in Offer Capping	Percent Total Tests Resulted in Offer Capping	Tests Resulted in Offer Capping as Percent of Tests that Could Have Resulted in Offer Capping
Siegfried	Peak	5,371	3,477	65%	4	0%	0%
	Off Peak	4,771	3,311	69%	0	0%	0%
Wescosville	Peak	2,901	1,116	38%	2	0%	0%
	Off Peak	762	319	42%	1	0%	0%

PSEG Control Zone Results

In 2018, there was one constraint that occurred for more than 100 hours in the PSEG Control Zone. Table D-29 shows the average constraint relief required on the constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market and the average number of owner passing and failing. Table D-29 shows that for the Federal Square - Newark line, on average, there were two owners on peak and one owner off peak with available supply to relieve the constraint.

Table D-29 Three pivotal supplier test details for constraints located in the PSEG Control Zone: 2018

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Federal Square - Newark	Peak	48	137	2	0	2
	Off Peak	45	198	1	0	1

Table D-30 shows the total tests applied for the Federal Square - Newark constraint in the PSEG Zone, the subset of three pivotal supplier tests that could have resulted in offer capping and the portion of those tests that did result in offer capping. The results reflect the fact that units that are economically committed, that are ramped up to provide incremental relief during their original commitment, cannot be offer capped. Table D-30 shows that zero percent or fewer of the tests applied to the Federal Square - Newark constraint in the PSEG Zone resulted in offer capping.

Table D-30 Summary of three pivotal supplier tests for constraints located in the PSEG Control Zone: 2018

Constraint	Period	Total Tests Applied	Total Tests that Could Have Resulted in Offer Capping	Percent Total Tests that Could Have Resulted in Offer Capping	Total Tests Resulted in Offer Capping	Percent Total Tests Resulted in Offer Capping	Tests Resulted in Offer Capping as Percent of Tests that Could Have Resulted in Offer Capping
Federal Square - Newark	Peak	1,713	1,022	60%	2	0%	0%
	Off Peak	467	102	22%	0	0%	0%

Appendix E Interchange Transactions

Submitting Transactions into PJM

In competitive wholesale power markets, market participants' decisions to buy and sell power are based on actual and expected prices. If contiguous wholesale power markets incorporate security constrained nodal pricing, well designed interface pricing provides economic signals for import and export decisions by market participants, although those signals may be attenuated by a variety of institutional arrangements. Unfortunately, interface prices are not well designed and result in incentives to engage in transactions that are not efficient and would not occur if there were a single set of consistent LMPs across all interconnected markets.

The institutional details of completing import and export transactions include the Open Access Same-Time Information System (OASIS), North American Electric Reliability Council (NERC) Tags, neighboring balancing authority check out processes, and transaction curtailment rules.[1]

Real-Time Energy Market

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

Scheduling Requirements

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

Specific timing requirements apply for the submission of schedules. Schedules can be submitted up to 20 minutes prior to the scheduled start time for hourly transactions. Schedules can be submitted up to four hours prior to the scheduled start time for transactions that are more than 24 hours in duration.[2] Schedules utilizing the Real-Time with Price option, also known as dispatchable schedules, must be submitted prior to 1800 (EPT) the day prior to the scheduled start time. Schedules utilizing firm point to point transmission service must be submitted by 1000 (EPT) one day prior to start of schedule. Transactions utilizing firm point to point transmission submitted after 1000 (EPT) one day prior will be accommodated if practicable.

Acquiring Ramp

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

Specific timing requirements apply for the submission of ramp reservations. Ramp reservations can be made up to 30 minutes prior to the scheduled start time for hourly transactions. Ramp reservations can be made up to 4 hours prior to start time for transactions that are more than 24 hours in duration. Ramp reservations utilizing the Real-Time with Price option must be made prior to 1800 (EPT) the day prior to the scheduled start time. Ramp reservations expire if they are not used.

With the implementation of the coordinated transaction scheduling (CTS) product with the NYISO, PJM modified how ramp is handled at the PJM/NYISO Interface. Effective November 4, 2014, PJM no longer holds ramp room for any transactions submitted between PJM and the NYISO at the time of submission. Only after the NYISO completes its real-time market clearing process, and communicates the results to PJM, will PJM perform a ramp evaluation on transactions scheduled with the NYISO. If, in the event the NYISO market clearing process violates ramp, PJM makes additional adjustments on a

1 The material in this section is based in part on PJM's Regional Transmission and Energy Scheduling Practices Document. See PJM. "Regional Transmission and Energy Scheduling Practices," Version 7 (December 19, 2018). <http://www.pjm.com/~/media/etools/oasis/regional-practices-clean-pdf.ashx>.

2 PJM ended the requirement for a day-ahead checkout for real-time transactions. Previously, for a schedule to be included in PJM's day-ahead checkout process, the NERC Tag had to have been approved by all entities who had approval rights, and be in a status of "Implemented," by 1400 (EPT) one day prior to start of schedule.

last-in first-out basis as determined by the timestamp on the NERC Tag. This process prevents the transactions scheduled at the PJM/NYISO Interface from holding (or creating) ramp until they have completed their economic evaluation and are approved through the NYISO market clearing process. The MMU has not observed any adverse effects of the new process. The MMU will continue to monitor and evaluate the process.

Acquiring Transmission

All external transaction requests require a confirmed transmission reservation from the PJM OASIS.[3] Due to ramp limitations, PJM may require market participants to shift their transaction requests. If the market participant shifts the request up to one hour in either direction, they are not required to purchase additional transmission. If the market participant chooses to fix a ramp violation by extending the duration of the transaction, they do not have to purchase additional transmission if the total MWh capacity of the transmission request is not exceeded, and the transaction does not extend beyond one hour prior to the start, or one hour past the end time of the transmission reservation.

Transmission Products

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

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

Source and Sink

For real-time import and export energy transactions, when a market participant selects the Point of Receipt (POR) and Point of Delivery (POD) on their OASIS reservation, the source and sink defaults to the associated interface price as defined by the POR/POD path. For example, if the selected POR is TVA and the POD is PJM, the source and sink would initially default to TVA's Interface Pricing point (SouthIMP). At the time the energy is scheduled, if the Generation Control Area (GCA) or Load Control Area (LCA) on the NERC Tag represents physical flow entering or leaving PJM at an interface other than the default interface pricing point, the source or sink would be assigned the new interface pricing point reflecting the interface pricing point where the physical energy enters or leaves the PJM footprint.

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

Real-Time Market Schedule Submission

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

3 For additional details see PJM. "Regional Transmission and Energy Scheduling Practices," Version 7 (December 19, 2018). <http://www.pjm.com/~/media/etools/oasis/regional-practices-clean-pdf.ashx>.

Real-Time with Price Schedule Submission

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

Dynamic Transfers[4]

An entity that owns or controls a generating resource in the PJM Region may request that all or part of the generating resource’s output be electronically moved from the PJM Region (native BA) to another balancing authority (receiving BA). An entity that owns or controls a generating resource outside of the PJM Region may request that all or part of the generating resource’s output be electronically removed from its balancing authority to the PJM Region. This is referred to as a dynamic transfer. Dynamic transfers include dynamic schedules and pseudo ties.

Dynamic Schedule

A dynamic schedule is a time varying energy transfer that is updated in real time and included in scheduled net interchange in the same way as an interchange schedule in the Area Control Error (ACE) equation for both balancing authorities. A dynamically scheduled resource remains within its native balancing authority’s metered boundary while providing services to the receiving balancing authority. A dynamic schedule is modeled as an interchange schedule, and therefore is subject to NERC Tagging requirements.

4 The material in this section is based in part on PJM’s Manual 12: Balancing Operations. See PJM. “*PJM Manual 12: Balancing Operations*,” Rev. 38 (April 20, 2018) <http://www.pjm.com/~/media/documents/manuals/m12.ashx >.

Pseudo Tie

A pseudo tie is a time varying energy transfer that is updated in real-time and included in actual net interchange in the same way as a tie line in the ACE equation. A pseudo tie is accounted for as actual interchange. A pseudo tied resource is considered to be within the receiving BA’s metered boundary, and must therefore be modeled in the receiving BA’s Energy Management System (EMS). Pseudo ties are usually not subject to NERC Tagging because they are part of congestion management procedures, like the PJM/MISO Market to Market Congestion Management Agreement.

Pseudo ties must register with the North American Energy Standards Board (NAESB) to assist with interregional coordination management. Pseudo ties are subject to NERC Tagging requirements unless the pseudo-tie is included in congestion management procedures.

Real-Time Evaluation and Checkout

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

PJM operators must verify all requested energy schedules with PJM’s neighboring balancing authorities. Only if the neighboring balancing authority agrees with the expected interchange will the transaction flow. Both balancing authorities must enter the same values in their Energy Management Systems (EMS) to avoid inadvertent energy flows between balancing authorities.

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

Real-Time with Price Evaluation and Checkout

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

Curtailment of Transactions

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

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

Transmission Loading Relief (TLR)

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

There are seven TLR levels and additional sublevels, determined by the severity of system conditions and whether the interchange transactions contributing to congestion on the impacted flowgates are using firm or nonfirm transmission. Reliability coordinators are not required to implement TLRs in order. The TLR levels are described below.[5]

- **TLR Level 0 – TLR concluded:** A TLR Level 0 is initiated when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) violations are mitigated and the system is returned to a reliable state. Upon initiation of a TLR Level 0, transactions with the highest transmission priorities are reestablished first when possible. The purpose of a TLR Level 0 is to inform all affected parties that the TLR has been concluded.
- **TLR Level 1 – Potential SOL or IROL Violations:** A TLR Level 1 is initiated when the transmission system is still in a secure state but a reliability coordinator anticipates a transmission or generation contingency or other operating problem that could lead to a potential violation. No actions are required during a TLR Level 1. The purpose of a TLR Level 1 is to inform other reliability coordinators of a potential SOL or IROL.
- **TLR Level 2 – Hold transfers at present level to prevent SOL or IROL Violations:** A TLR Level 2 is initiated when the transmission system is still in a secure state but one or more transmission facilities are expected to approach, are approaching or have reached their SOL or IROL. The purpose of a TLR Level 2 is to prevent additional transactions that have an adverse impact on the identified transmission facility(ies) from starting.
- **TLR Level 3a – Reallocation of transmission service by curtailing interchange transactions using non-firm point-to-point transmission service to allow interchange transactions using higher priority transmission service:** A TLR Level 3a is initiated when the transmission system is secure but one or more transmission facilities are expected to approach, or are approaching their SOL or IROL, when there are transactions using nonfirm point to point transmission service that have a greater

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

than 5 percent effect on the facility and when there are transactions using a higher priority point to point transmission reservation that wish to begin. Curtailments to transactions in a TLR 3a begin on the top of the hour only. The purpose of TLR Level 3a is to curtail transactions using lower priority nonfirm point to point transmission to allow transactions using higher priority transmission to flow.

- **TLR Level 3b – Curtail interchange transactions using non-firm transmission service arrangements to mitigate a SOL or IROL violation:** A TLR Level 3b is initiated when one or more transmission facilities is operating above their SOL or IROL; such operation is imminent and it is expected that facilities will exceed their reliability limits if corrective action is not taken; or one or more transmission facilities will exceed their SOL or IROL upon the removal from service of a generating unit or other transmission facility and transactions are flowing that are using nonfirm point to point transmission service and have a greater than 5 percent impact on the facility. Curtailments of transactions in a TLR 3b can occur at any time within the operating hour. The purpose of a TLR Level 3b is to curtail transactions using nonfirm point to point transmission service which impact the constraint by greater than 5 percent in order to mitigate a SOL or IROL.
- **TLR Level 4 – Reconfigure Transmission:** A TLR Level 4 is initiated when one or more transmission facilities are above their SOL or IROL limits or such operation is imminent and it is expected that facilities will exceed their reliability limits if corrective action is not taken. Upon issuance of a TLR Level 4, all transactions using non firm point to point transmission service, in the current and next hour, with a greater than 5 percent impact on the facility, have been curtailed under the TLR 3b. The purpose of a TLR Level 4 is to request that the affected transmission operators reconfigure transmission on their system, or arrange for reconfiguration on other transmission systems, to mitigate the constraint if a SOL or IROL violation is imminent or occurring.
- **TLR Level 5a – Reallocation of transmission service by curtailing interchange transactions using firm point to point transmission service on a pro rata basis to allow additional interchange transactions using firm point to point transmission service:** A TLR Level 5a is initiated when one or more transmission facilities are at their SOL or IROL; all interchange transactions using nonfirm point to point transmission service that affect the constraint by greater than 5 percent have been curtailed; no additional effective transmission configuration is available; and a transmission provider has been requested to begin an interchange transaction using previously arranged firm point-to-point transmission service. Curtailments to transactions in a TLR 5a begin on the top of the hour only. The purpose of a TLR Level 5a is to curtail existing interchange transactions, which are using firm point-to-point transmission service, on a pro rata basis to allow for the newly requested interchange transaction, also using firm point to point transmission service, to flow.
- **TLR Level 5b – Curtail transactions using firm point to point transmission service to mitigate an SOL or IROL violation:** A TLR Level 5b is initiated when one or more transmission facilities are operating above their SOL or IROL or such operation is imminent; one or more transmission facilities will exceed their SOL or IROL upon removal of a generating unit or another transmission facility; all interchange transactions using nonfirm point to point transmission service that affect the constraint by greater than 5 percent have been curtailed; and no additional effective transmission configuration is available. Unlike a TLR 5a, curtailments to transactions in a TLR 5b can occur at any time within the operating hour. The purpose of a TLR Level 5b is to curtail transactions using firm point-to-point transmission service to mitigate a SOL or IROL.
- **TLR Level 6 – Emergency Procedures:** A TLR Level 6 is initiated when all interchange transactions using both nonfirm and firm point to point transmission have been curtailed and one or more transmission facilities are above their SOL or IROL, or will exceed their SOL or IROL upon removal of a generating unit or other transmission facility. The purpose of a TLR Level 6 is to instruct balancing authorities and transmission providers to redispatch generation, reconfigure transmission or reduce load to mitigate the critical condition.

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

Table E-1 TLRs by level and reliability coordinator: 2004 through 2018

Year	Reliability Coordinator	3a	3b	4	5a	5b	6	Total
2004	EES	47	15	88	1	3	0	154
	FPL	0	1	0	0	0	0	1
	IMO	33	2	0	0	0	0	35
	MAIN	8	3	0	0	0	0	11
	MISO	650	210	409	9	3	0	1,281
	PJM	270	115	35	4	5	0	429
	SOCO	1	0	0	0	0	0	1
	SWPP	185	107	14	5	6	0	317
	TVA	56	17	0	0	1	0	74
	VACN	8	1	0	0	0	0	9
Total		1,258	471	546	19	18	0	2,312
2005	EES	49	10	101	6	3	1	170
	IMO	57	2	0	0	0	0	59
	MISO	776	296	200	5	14	0	1,291
	PJM	201	94	29	1	1	0	326
	SWPP	193	78	19	4	2	0	296
	TVA	172	61	12	2	3	0	250
	VACN	0	3	0	0	0	0	3
	VACS	2	2	0	1	0	0	5
Total		1,450	546	361	19	23	1	2,400
2006	EES	71	20	93	5	1	0	190
	ICTE	11	6	14	0	1	0	32
	IMO	1	0	0	0	0	0	1
	MISO	414	214	136	17	19	0	800
	ONT	27	3		0	0	0	30
	PJM	88	30	18	0	0	0	136
	SWPP	189	121	201	11	13	0	535
	TVA	90	52	31	1	2	0	176
	VACS	0	1	0	0	0	0	1
Total		891	447	493	34	36	0	1,901
2007	ICTE	95	42	139	19	10	0	305
	MISO	414	273	89	17	26	0	819
	ONT	47	4	1	0	0	0	52
	PJM	46	31	1	1	1	0	80
	SWPP	777	935	35	53	24	0	1,824
	TVA	45	40	25	2	2	0	114
	VACS	4	1	0	0	0	0	5
Total		1428	1326	290	92	63	0	3,199
2008	ICTE	132	41	112	43	25	0	353
	MISO	320	235	21	8	15	0	599
	ONT	153	7	1	0	0	0	161
	PJM	55	92	2	0	1	0	150
	SWPP	687	1,077	11	59	44	0	1,878
	TVA	48	72	29	5	4	0	158
Total		1,395	1,524	176	115	89	0	3,299
2009	ICTE	82	35	55	75	18	1	266
	MISO	199	140	2	15	25	0	381
	NYIS	101	8	0	0	0	0	109
	ONT	169	0	0	0	0	0	169
	PJM	61	68	0	0	0	0	129
	SWPP	383	1,466	33	77	24	0	1,983
	TVA	8	22	29	0	0	0	59
	VACS	0	1	0	0	0	0	1
Total		1,003	1,740	119	167	67	1	3,097
2010	ICTE	72	25	149	50	30	0	326
	MISO	123	93	0	15	18	0	249
	NYIS	104	0	0	0	0	0	104
	ONT	94	5	0	1	0	0	100
	PJM	65	45	0	0	0	0	110
	SWPP	244	1,049	19	63	32	0	1,407
	TVA	37	64	8	1	6	0	116
	VACS	1	1	0	0	0	0	2
Total		740	1,282	176	130	86	0	2,414
2011	ICTE	23	12	123	54	48	0	260
	MISO	92	30	1	9	9	0	141
	NYIS	161	0	0	0	0	0	161
	ONT	88	0	0	0	0	0	88
	PJM	34	28	0	0	0	0	62
	SWPP	292	298	1	25	22	0	638
	TVA	75	99	9	2	15	0	200
	VACS	9	3	0	0	0	0	12
Total		774	470	134	90	94	0	1,562
2012	ICTE	25	7	11	63	40	0	146
	MISO	75	26	0	16	43	0	160
	NYIS	60	0	0	0	0	0	60
	ONT	47	1	0	0	0	0	48
	PJM	18	19	0	0	0	0	37
	SOCO	0	1	0	0	0	0	1
	SWPP	248	165	5	78	33	0	529
	TVA	55	32	9	7	5	0	108
	VACS	6	4	0	0	0	0	10
Total		534	255	25	164	121	0	1,099
2013	ICTE	0	0	0	0	0	0	0
	MISO	119	48	2	128	73	0	370
	NYIS	3	0	0	0	0	0	3
	ONT	7	0	0	0	0	0	7
	PJM	25	22	0	1	1	0	49
	SOCO	0	0	0	0	0	0	0
	SWPP	342	114	0	76	24	0	556
	TVA	29	26	2	5	5	0	67
	VACS	5	7	0	0	0	0	12
Total		530	217	4	210	103	0	1,064
2014	MISO	63	45	1	16	16	0	141
	NYIS	2	0	0	0	0	0	2
	ONT	3	0	0	0	0	0	3
	PJM	3	3	0	1	1	0	8
	SOCO	4	1	0	0	0	0	5
	SWPP	260	80	0	54	34	0	428
	TVA	31	40	2	25	34	0	132
	VACS	7	16	3	2	0	0	28
Total		373	185	6	98	85	0	747
2015	MISO	28	32	0	16	12	0	88
	NYIS	4	0	0	0	0	0	4
	ONT	3	1	0	0	0	0	4
	PJM	13	7	0	1	1	0	22
	SOCO	0	0	0	0	0	0	0
	SWPP	102	59	0	32	19	0	212
	TVA	36	64	0	24	36	0	160
	VACS	0	2	0	0	1	0	3
Total		186	165	0	73	69	0	493
2016	MISO	33	21	0	8	15	0	77
	NYIS	1	0	0	0	0	0	1
	ONT	10	0	0	0	0	0	10
	PJM	4	3	0	1	1	0	9
	SOCO	0	1	0	0	0	0	1
	SWPP	54	23	0	45	22	0	144
	TVA	41	65	0	4	18	0	128
	VACS	1	1	0	0	0	0	2
Total		144	114	0	58	56	0	372
2017	MISO	42	16	0	10	7	0	75
	NYIS	1	0	0	0	0	0	1
	ONT	6	0	0	0	0	0	6
	PJM	4	2	0	0	0	0	6
	SOCO	1	4	0	0	0	0	5
	SWPP	34	4	0	54	19	0	111
	TVA	13	11	0	2	5	0	31
	VACS	3	3	0	0	0	0	6
Total		104	40	0	66	31	0	241
2018	MISO	22	5	0	11	18	0	56
	NYIS	1	1	0	0	0	0	2
	ONT	10	0	0	0	0	0	10
	PJM	2	1	0	0	2	0	5
	SOCO	0	1	0	0	0	0	1
	SWPP	36	8	0	52	21	0	117
	TVA	10	34	0	9	6	0	59
	VACS	2	8	0	0	0	0	10
Total		83	58	0	72	47	0	260

Day-Ahead Energy Market

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

Submitting Day-Ahead Energy Market Schedules

Market participants can submit day-ahead market schedules to the eMKT application through ExSchedule. These schedules do not require a NERC Tag, as they are not physical schedules for actual flow. Day-ahead market schedules require an OASIS number to be associated upon submission.[6] The path is identified on the OASIS reservation. In addition to the selection of OASIS and pricing points, the market participant must enter their energy profile. "Fixed" act as a price taker, "dispatchable" set a floor or ceiling price criteria for acceptance and "up-to" set the maximum amount of congestion the market participant is willing to pay.

NYISO Issues

If interface prices were defined in a comparable manner by PJM and the NYISO, if identical rules governed external transactions in PJM and the NYISO, if time lags were not built into the rules governing such transactions and if no risks were associated with such transactions, then prices at the interfaces would be expected to be very close and the level of transactions would be expected to be related to any price differentials. The fact that none of these conditions exists is important in explaining the observed relationship between interface prices and inter-ISO power flows, and those price differentials.[7]

There are institutional differences between PJM and the NYISO markets that are relevant to observed differences in border prices.[8] The NYISO requires bids or offer prices for each export or import transaction and clears its market for each 15 minute interval based on bids.[9] Import transactions to the NYISO are treated by the NYISO as generator bids at the NYISO/PJM proxy bus. Export transactions are treated by the NYISO as price-capped load offers. Competing bids and offers are evaluated along with other NYISO resources and a proxy bus price is derived. Bidders are notified of the outcome. This process is repeated, with new bids and offers each 15 minute interval. A significant lag exists between the time when offers and bids are submitted to the NYISO and the time when participants are notified that they have cleared. The lag is a result of the Real-Time Commitment (RTC) system and the fact that transactions can only be scheduled at the beginning of the hour.

As a result of the NYISO's RTC timing, market participants must submit bids or offers by no later than 75 minutes before the operating hour. The bid or offer includes the MW volume desired and, for imports into NYISO, the asking price or, for exports out of the NYISO, the price the participants are willing to pay. The required lead time means that participants make price and MW bids or offers based on expected prices. Transactions are accepted only for a single 15 minute increment.

Under PJM operating practices, in the Real-Time Energy 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.[10] The duration of the requested transaction can vary from 15 minutes to an unlimited amount of time. Generally, PJM market participants provide only the MW, the duration and the direction of the real-time transaction. While bid prices for transactions are allowed in PJM, less than one percent of all transactions submit an associated price. Transactions are accepted, with virtually no lag, in order of submission, based on whether PJM has the capability to import or export the requested MW. If transactions do not submit a price, the transactions are priced at the real-time price for their scheduled imports or exports. As in the NYISO, the required lead time means that participants must make offers to buy or sell MW based on expected prices, but the required lead time is substantially shorter in the PJM market.

6 On September 17, 2010, up-to congestion transactions no longer required a willing to pay congestion transmission reservation. Additionally, effective May 15, 2012, up to congestion transactions were required to be submitted for the PJM day-ahead market evaluation in the eMarket application, and are no longer accepted through the EES application. Additional details can be found under the "Up to Congestion" heading in *Section 9: Interchange Transactions* of this report.

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

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

9 See NYISO. "*NYISO Transmission Services Manual*," Version 2.0 (February 1, 2005) <https://www.nyiso.com/documents/20142/2923301/tran_ser_mnl.pdf/a6baa5ca-29f0-1279-6618-042442dd4d9e>.

10 See PJM. "Regional Transmission and Energy Scheduling Practices," Version 7 (December 19, 2018). <http://www.pjm.com/~/media/etools/oasis/regional-practices-clean-pdf.ashx>.

The NYISO rules provide that the RTC results should be available 45 minutes before the operating 15 minute interval. Winning bidders then have 25 minutes from the time when the RTC results indicate that their transaction will flow to meet PJM's 20-minute notice requirement. To get a transaction cleared with PJM, the market participant must have a valid NERC Tag, an OASIS reservation and a PJM ramp reservation. Each of these requirements takes time to process.

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

Appendix F Ancillary Service Markets

This appendix covers five areas related to Ancillary Service Markets: area control error, Control Performance Standard 1 and Balancing Authority ACE Limit, Disturbance Control Standard (DCS), Primary Frequency Response, Regulation Market design changes, and the Synchronized Reserve Market clearing process.

Area Control Error (ACE)

Area control error (ACE) is a real-time measure of the instantaneous MW imbalance between load plus net interchange and generation within PJM.[1] PJM dispatchers seek to ensure grid reliability by balancing ACE. The metrics for success in balancing ACE are control performance standard 1 (CPS1) and balancing authority ACE limit (BAAL) performance. These measurements are mandated by the North American Electric Reliability Council (NERC).[2]

In the absence of a severe grid disturbance, the primary tool used by dispatchers to control 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.[3]

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

Control Performance Standard 1 (CPS1) and Balancing Authority ACE Limit (BAAL) are the NERC metrics for the effectiveness of power balance through ACE control. The goal of ACE control is to maintain power balance and interconnection frequency within predefined MW and frequency profiles under all conditions (normal and abnormal).

Frequency (as it applies to the electric power grid) is the rate at which alternating current cycles between minimum and maximum. Usually this is 60 Hz (one Hz is one cycle per second). PJM measures the instantaneous frequency every two seconds. Frequency changes when there is an imbalance between generation and load causing a mismatch between actual and scheduled tie-line flow. PJM dispatchers seek to minimize this deviation. If the mismatch persists, a time error can accumulate.

Frequency bias is a physical attribute of a control area. It is defined as the natural response in MW of that control area (at estimated yearly peak demand) to a change in frequency of 0.1Hz.[4] NERC requires each balancing authority to review and report its frequency bias by January 1 each year.

CPS1/BAAL are performance standards used to measure and report how well PJM accomplishes ACE and frequency balance. CPS1 and BAAL are defined according to NERC Standard BAL-001-2.[5]

NERC Standard BAL-001-2 Real Power Balancing Control Performance

NERC Standard BAL-001-2 mandates two requirements. Paragraph R1 requires that control performance standard 1 (CPS1) be maintained greater than or equal to 100 percent for each of twelve previous months evaluated monthly.[6] Meeting the CPS1 standard requires PJM dispatchers to maintain ACE within a fixed range around zero.

1 The PJM Manuals define ACE and the methodology for calculating it: "Area Control Error is a measure of the imbalance between sources of power and uses of power within the PJM RTO. This imbalance is calculated indirectly as the difference between scheduled and actual net interchange, plus the frequency bias contribution to yield ACE in megawatts. Two additional terms may be included in ACE under certain conditions–the time error bias term and PJM dispatcher adjustment term (manual add). These provide for automatic inadvertent interchange payback and error compensation, respectively,." "PJM Manual 12: Balancing Operations," Revision 39 (February 21, 2019), § 3.1.1.

2 NERC standard BAL-001-2 "Real Power Balancing Control Performance," <https://www.nerc.com/files/BAL-001-2.pdf>.

3 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Rev. 107 (Sep. 26, 2019) § 3.1.

4 See Frequency Response and Bias Standard BAL-003-0.1a <http://www.nerc.com/files/BAL-003-0_1a.pdf>.

5 NERC. BAL-001-2 – Real Power Balancing Control Performance Standard Background Document, Attachment 2 (Feb. 2013) <http://www.nerc.com/pa/Stand/Project%202010141%20%20Phase%201%20of%20Balancing%20Authority%20Re/BAL-001-2_Background_Document_Clean-20130301.pdf>.

6 See PJM. "Manual 12: Balancing Operations," Rev. 39 (Feb. 21, 2019), Section 3, "NERC Control Performance Standard" pg. 20.

CPS1

CPS1 is a statistical measure of ACE variability and its relationship to frequency error. It is measured each minute and averaged over a year. CPS1 is defined as:

> "the average of the clock-minute averages of a Balancing Area's ACE divided by minus 10 B (where B is Balancing Area frequency bias) times the corresponding clock-minute averages of the Interconnection's frequency error must be less than a specific limit. This limit, 'ε', is a constant derived from a targeted frequency bound (limit) that is reviewed and set, as necessary, by NERC."[7]

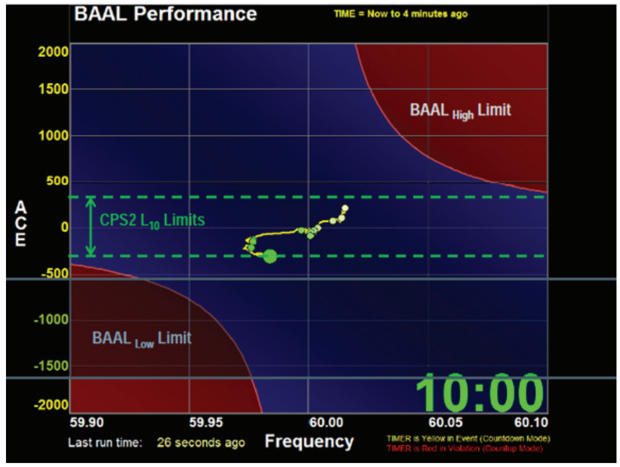
CPS1 is calculated as CPS1 = (2-CF)*100%. The frequency related compliance factor (CF) is a ratio of the accumulating clock-minute compliance parameters for the most recent twelve consecutive calendar months, divided by the square of the target frequency bound (ε1i). The ε1i value for the Eastern Interconnection is 0.018 Hz. It can be seen from this equation that if the yearly one-minute average deviations (CF) were zero the CPS1 score would be a perfect 200 percent. The maximum CPS1 score is 200 percent. This is achieved when either the frequency error is zero or the ACE is zero. The minimum passing score is 100 percent monthly.

The defined fixed range for the December 2018 through December 2019 operating year (+/- 257.1 MW/0.1Hz) is called L10. Compliance with the CPS1 standard requires that 90 percent of 10-minute periods have an average ACE value within the L10 range. The L10 was last changed on December 1, 2018. Previously it had been +/-258.2 MW/0.1Hz.

BAAL

The other NERC standard for maintaining power balance is the Balancing Authority ACE Limit (BAAL), which replaced the old CPS2. BAAL is a measure of the relationship between frequency and ACE such that both must remain within the blue area in Figure F-1. The $BAAL_{High}$ and $BAAL_{Low}$ limits are curves which are functions of measured frequency and scheduled frequency.

Figure F-1 Example set of BAAL measurements: Set of measurements is every two seconds for four minutes



PJM counts the total number of minutes that ACE complies with the BAAL limits (high and low) and divides it by the total number of minutes for a month, with a passing level for this goal being set at 99.0 percent for each month. BAAL high and low limits are defined dynamically.[8]

When actual frequency is less than Scheduled Frequency, $BAAL_{High}$ does not apply, and $BAAL_{Low}$ is calculated as:

$$BAAL_{Low} = \left(-10B_i \times (FTL_{Low} - F_S)\right) \times \frac{(FTL_{Low} - F_S)}{(F_A - F_S)}$$

When actual frequency is greater than Scheduled Frequency, $BAAL_{Low}$ does not apply and the $BAAL_{High}$ is calculated as:

$$BAAL_{High} = \left(-10B_i \times (FTL_{High} - F_S)\right) \times \frac{(FTL_{High} - F_S)}{(F_A - F_S)}$$

$BAAL_{Low}$ is the Low Balancing Authority ACE Limit (MW), $BAAL_{High}$ is the High Balancing Authority ACE Limit (MW), 10 is a constant to convert the Frequency Bias Setting from MW/0.1 Hz to MW/Hz, Bi is the Frequency Bias Setting for a Balancing Authority (expressed as MW/0.1 Hz), FA is the measured frequency in Hz, FS is the scheduled frequency in Hz, FTL_{Low} is the Low Frequency Trigger Limit (calculated as FS – 3ε1I Hz), and FTL_{High} is the High Frequency Trigger Limit (calculated as FS + 3ε1I Hz). The constant ε1I is derived from a targeted frequency bound for each Interconnection as follows: Eastern Interconnection

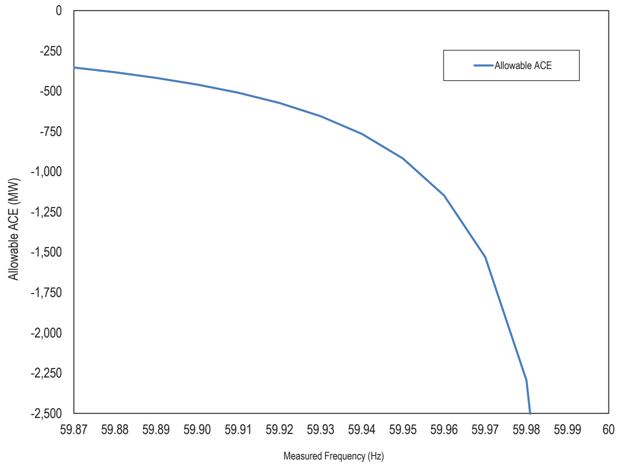
7 See PJM. "Manual 12: Balancing Operations," Rev. 39 (Feb. 21, 2019), Section 3, "System Control," pg. 21.

8 NERC BAL-001-2, Real Power Balancing Control Performance. Feb. 2013.

ε1I is 0.018 Hz, Western Interconnection ε1I is 0.0228 Hz, ERCOT Interconnection ε1I is 0.030 Hz, and Quebec Interconnection ε1I is 0.021 Hz.

Figure F-2 shows the relationship of measured frequency to allowable ACE deviation when measured frequency is less than scheduled frequency (defined by the $BAAL_{Low}$ equation, scheduled frequency = 60 Hz and negative ACE only). As the measured frequency approaches the scheduled frequency (typically 60 Hz), the allowable ACE increases in absolute value.

Figure F-2 Allowable ACE as a function of measured frequency

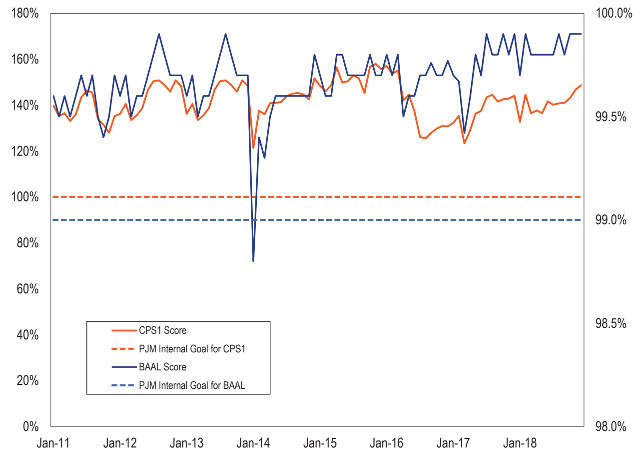


As an example consider a single 2-second measurement under the following scenario. The frequency bias is calculated by PJM each year. PJM's current frequency bias (for December 1, 2016, through November 30, 2017) is -1,015 MW/0.1Hz. PJM's frequency profile calls for a scheduled frequency of 60Hz (this can be changed by PJM dispatch under certain circumstances). Under this scenario, applying the formula for $BAAL_{Low}$ shows that ACE needs to be greater than -493.8975 MW at a real-time frequency of 59.92 Hz in order for this one measurement to be within acceptable BAAL limits. A complete scenario is provided by adding the ACE deviation for measured frequency greater than scheduled frequency $BAAL_{High}$ Figure F-1.

PJM's CPS/BAAL Performance

The BAAL standard set by NERC states that, "the clock-minute average of Reporting ACE does not exceed its clock-minute limit for more than 30 consecutive clock-minutes."[9] PJM has set an internal standard that measures the total number of minutes that ACE complies with the BAAL limits and divides it by the total number of minutes over the entire month, with a passing level set at 99.0 percent for each month. Figure F-3 shows PJM's CPS1 and BAAL performance from January 2011 through December 2018. PJM did not meet its internal goal for BAAL performance in January 2014, however PJM has remained in compliance with the applicable NERC standards since January 2011, for compliance for both CPS1 and BAAL metrics.

Figure F-3 PJM CPS1/BAAL performance: January 2011 through December 2018



PJM's DCS Performance

The NERC disturbance control standard (DCS) measures how well ACE recovers from a disturbance.[10] A disturbance is defined by NERC as any ACE deviation caused by sudden loss of generation greater than, or equal to, 80 percent of PJM's most severe single contingency loss. Disturbance control is measured and must be reported to NERC quarterly as percentage of recovery (Ri) as defined below.

9 See PJM. "Manual 12: Balancing Operations," Rev. 39 (Feb. 21, 2019), § 3.1.1.
10 For more information on the NERC DCS, see NERC "Standard BAL-002-0 — Disturbance Control Performance" (April 1, 2012) <www.nerc.com/files/BAL-002-0.pdf>.

If ACE was positive or zero just before the disturbance then ACE must be returned to zero within fifteen minutes. Full disturbance recovery within fifteen minutes represents 100 percent performance under this measure. Less than full recovery in fifteen minutes earns a score defined as:

$$R_i = \left(\frac{MW_{loss} - \max(0, ACE_a - ACE_m)}{MW_{loss}}\right) * 100\%$$

If ACE was negative just before the disturbance then ACE must be returned to its pre-disturbance value. Full disturbance recovery within fifteen minutes represents 100 percent performance under this measure. Less than full recovery in fifteen minutes earns a score as per:

$$R_i = \left(\frac{MW_{loss} - \max(0, -ACE_m)}{MW_{loss}}\right) * 100\%$$

Where MW_{loss} is the MW size of the disturbance from the beginning of the loss, ACE_a is the pre-disturbance ACE, ACE_m is the maximum algebraic value of the ACE measured within fifteen minutes following the disturbance.

PJM experienced 60 DCS events in 2015, 2016, 2017 and 2018. There were 15 DCS events in all of 2018. PJM DCS compliance has remained at 100% since 2011. (Table F-1).

Although PJM recovered from all DCS events by declaring a synchronized reserve event, not all synchronized reserve events are caused by DCS events. DCS events are "sudden unanticipated losses of supply-side resources."[11] Several significant synchronized reserve events in 2013 and 2014, most notably the 68 minute event of September 10, 2013, the 33 minute event of October 28, 2013, and the 34 minute event of January 7, 2014 were caused by low ACE and were therefore not reportable as DCS events. There were five low ACE events in 2017, including the 16 minute event on September 21, 2017. There was one low ACE event in 2018 on July 10. There have been 24 spinning events between January 2013 and December 2018 caused by Low ACE (Table F-1).[12] [13] [14] [15] [16] [17] [18]

11 Standard BAL-002-0 – Disturbance Control Performance," NERC (April 1, 2005) <www.nerc.com/files/BAL-002-0.pdf> (61 KB) para. 1.4, pag. 4.

12 Note that this information is publically available on PJM's website. Operating Committee (Feb. 6, 2018) "PJM Operations Summary," <https://pjm.com/-/media/committees-groups/committees/oc/20180206/20180206-item-04-january-2018-sos-summary.ashx>.

13 PJM. Operating Committee, "PJM Operations Summary," (May 1, 2018) <https://pjm.com/-/media/committees-groups/committees/oc/20180501/20180501-item-05-april-2018-sos-summary-partial.ashx>.

14 PJM. Operating Committee, "PJM Operations Summary," (July, 10, 2018).<https://pjm.com/-/media/committees-groups/committees/oc/20180710/20180710-item-07-june-2018-sos-summary.ashx>.

15 PJM. Operating Committee, "PJM Operations Summary," (Aug. 7, 2018) <https://pjm.com/-/media/committees-groups/committees/oc/20180807/20180807-item-05-sos-summary-july.ashx>.

16 PJM. Operating Committee, "PJM Operations Summary," (Sep. 11, 2018) <https://pjm.com/-/media/committees-groups/committees/oc/20180911/20180911-item-04-august-2018-sos-summary.ashx>.

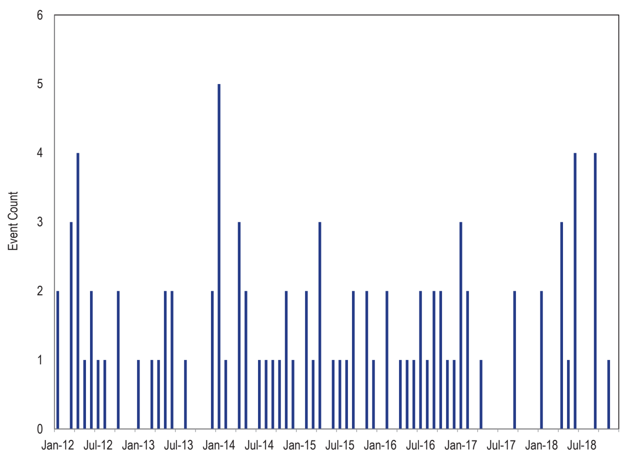
17 PJM. Operating Committee, "PJM Operations Summary," (Oct. 9, 2018) <https://pjm.com/-/media/committees-groups/committees/oc/20181009/20181009-item-04-september-2018-sos-summary.ashx>.

18 PJM. Operating Committee, PJM Operations Summary," (Nov. 6, 2018) <https://pjm.com/-/media/committees-groups/committees/oc/20181106/20181106-item-04-october-2018-sos-summary.ashx>.

Table F-1 Spinning Events and causes: 2018

Start Time	End Time	Duration (minutes)	Spin Cause	Operator Comment
1/1/18 7:41	1/1/18 7:48	6.7	Unit Trip	Spinning in PJM for Unit Trip, Virginia City #1 loaded at 694 MW. Also Amos #1 trip at 642 MW.
1/3/18 8:00	1/3/18 8:13	12.8	Unit Trip	Spinning in PJM for Unit Trip Gavin #1 1,350 MW
1/7/18 19:15	1/7/18 19:24	8.2	Unit Trip	Spinning in PJM for Unit Trip Killen #1 trip at 566 MW
4/12/18 17:27	4/12/18 17:38	10.1		
6/4/18 14:22	6/4/18 14:28	6.8	Unit Trip	Loss of Braidwood #1 @ 1,210 MW
6/29/18 19:20	6/29/18 19:30	9.8		
6/30/18 13:46	6/30/18 13:57	11.8		
7/4/18 14:56	7/4/18 15:03	7.0	Unit Trip	Spinning in PJM for Unit Trip Loss of St. Charles – Kelson Ridge.
7/10/18 19:45	7/10/18 19:58	12.6	Low ACE	Spinning in PJM for Low ACE
7/23/18 13:02	7/23/18 13:10	8.0	Unit Trip	Spinning in PJM for unit trip of Martins Creek #3 followed by the loss of Wildcat 5 minutes later
7/23/18 19:43	7/23/18 19:49	6.4	Unit Trip	Spinning in PJM for loss of Oregon Energy Center
7/24/18 20:17	7/24/18 20:24	6.5	Unit Trip	Spinning in PJM for loss of Wildcat CC, Sammis #2, and West Deptford - all within 5 minutes of each other. The trips and runbacks were unrelated.
8/12/18 15:06	8/12/18 15:17	10.3	Unit Trip	Unit Trip Keystone #2 - unit was loaded at 853 MW
9/13/18 13:47	9/13/18 13:54	7.3	Unit Trip	Gavin #2 tripped at approximately 1,300 MW.
9/14/18 17:24	9/14/18 17:31	6.6	Unit Trip	Loss of Salem #2.
9/27/18 0:08	9/27/18 0:16	7.6	Unit Trip	Quad Cities 1 tripped at approximately 925 MW.
9/30/18 15:29	9/30/18 15:40	10.6	Unit Trip	Peach Bottom #3 tripped, loaded at 1,300 MW
10/30/18 10:40	10/30/18 10:51	11.1		

Figure F-4 DCS event count (By month): January 2012 through December 2018



Primary Frequency Response

On November 17, 2016, FERC issued as Primary Frequency Response notice of proposed rulemaking (NOPR).[19] The NOPR proposed a regulation requiring all new generating facilities, both synchronous and nonsynchronous to install and enable primary frequency response capability as a condition of interconnection. Nuclear units are exempted from this NOPR. Existing units are exempted from this NOPR.

The NOPR proposed that all newly interconnecting generating facilities to install and enable primary frequency response capability that would allow a maximum five percent droop; a +/- 0.036 Hz deadband setting; and automated timely and sustained response to frequency deviations.[20]

The FERC standard is documented in NERC Reliability Standard BAL-003-2, Frequency Response and Frequency Bias Setting. PJM is currently conducting studies to define primary frequency events, compliance metrics, and requirement standards. A Markets and Reliability Task Force is conducting a study of NERC defined frequency excursion events. The study is expected to continue until December 2019.

19 157 FERC ¶ 61,122

20 Droop percentage is defined as ((generator speed at no load) – (generator speed at full load)) / (generator speed at no load). The NOPR requires that these parameters be based on nameplate capability.

Synchronized Reserve Market Clearing

PJM's market clearing engines consider resources capable of providing Tier 2 synchronized reserve to be either flexible or inflexible. CTs operating below their economically desired MW will sometimes be dispatched flexibly intra hour. Hydro resources are often a source of flexible T2. Inflexible units are scheduled by the hourly market solution sixty minutes before the operating hour, are committed to provide synchronized reserve for the entire hour, and are paid the higher of the SRMCP or their offer price plus LOC (demand response resources are paid SRMCP). Demand response resources are defined to be inflexible. Flexible units are identified and may be scheduled every time the market solution runs (hour ahead, intermediate term, and short term) and can be assigned to either synchronized reserve or to energy depending on the optimal economic solution. This flexibility allows for a less expensive hourly cost when intrahour events such as constraints binding, changes in imports or exports and performance problems occur.

The PJM Synchronized Reserve Market is recalculated and can be rescheduled both hourly and in all five minute intervals.

The market clearing engine first evaluates the most severe single contingency (MSSC). This becomes the synchronized reserve required MW.

One hour before the market hour, the ASO market clearing engine estimates the sum of the available Tier 1 synchronized reserve and the available transfer capacity from outside the RTO Zone. ASO subtracts this estimated sum from the synchronized reserve requirement to determine the amount of Tier 2 synchronized reserve needed to satisfy the requirement. If the synchronized reserve requirement is not filled from available Tier 1 and imports, then self scheduled Tier 2 synchronized reserve is assigned. If the required synchronized reserve is still not satisfied, ASO clears a market for inflexible synchronized reserve. Tier 2 synchronized reserve flexible resources can be changed throughout the hour by both the intermediate term and short term market clearing software.

Half an hour before the market hour, the intermediate term solution (IT SCED) performs the same functions as ASO up to the point of logging and committing individual resources, taking into account the amount of inflexible resources already committed by ASO. After IT SCED produces its solution, a PJM operator reviews the solution, calls the inflexible resources to commit them to provide Tier 2 synchronized reserve, and logs each resource separately. As with ASO, the amount of Tier 2 synchronized reserve provided by flexible resources is not logged and is not carried through to later steps in the clearing process.

Fifteen minutes before each 5-minute period in the market hour, real-time solution (RT SCED) estimates the amount of needed Tier 2 synchronized reserve, taking into account the amount of inflexible resources already committed by ASO and IT SCED. RT SCED considers only flexible resources due to the notification-time requirements of inflexible resources. Once RT SCED generates its solution, RT SCED commits the resources from its solution and logs these resources.

Every 5 minutes within the market hour, LPC calculates market clearing prices by incorporating resource offers and LOC based on real-time LMP and the cost of the marginal unit. LPC computes the clearing price of Tier 2 synchronized based on these factors and the committed resources and uses this price as the within-hour five-minute clearing price. When there is a simultaneous shortage of primary reserve and synchronized reserves the real-time prices for synchronized reserve will be the sum of the primary reserve and synchronized reserve penalty factors.[21]

Whereas the hourly price is the average of the five-minute prices within the hour, the hourly cost (per MW) is the sum of credits for cleared and self-scheduled synchronized reserve and credits for after market lost opportunity cost divided by the total MW of synchronized reserve cleared and self-scheduled. PJM guarantees resources to be made whole to their offer plus opportunity costs.

21 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Rev.107 (Sep. 26, 2019), p. 89.

Regulation Market Design Issues

On October 20, 2011, FERC issued Order No. 755 directing PJM and other RTOs/ISOs to modify their regulation market rules to include fast response in addition to traditional regulation resources."[22]

A rationale for the new market design was the assumption that new, fast response technologies could be used, in combination with traditional resources, to reduce the total amount of resources needed to meet regulation requirements and thereby reduce the cost of regulation. Order No. 755 required that the fast and slow resources be purchased in a single market, with compensation for both capacity (MW) and miles (ΔMW).[23] Regulation miles are calculated as the sum of the absolute value of a given regulation resource's movement (up and down) in response to a regulation signal.

To incorporate the new fast regulation, PJM developed a fast regulation signal (RegD) that responds faster to changes in ACE than the traditional slow regulation signal (RegA). Resources are free to choose which signal they will follow. A study by KEMA for PJM indicated that including a combination of RegA and RegD following resources in the Regulation Market would allow PJM to reduce its regulation requirement but still maintain CPS1 scores close to the historical average (significantly above the passing score of 100 percent).[24]

According to the study, the smaller the proportion of RegD MW and the greater the proportion of RegA, the greater the benefit to adding one more MW of RegD. The smaller the proportion of fast regulation used, the more slow regulation each MW of fast regulation can replace. Conversely, as the proportion of fast regulation increases, there is a decrease in the benefit of substituting fast capability for slow capability. This rate of substitution between fast and slow resources is the marginal benefit factor or MBF. The marginal benefit factor measures the equivalent MW of slow regulation that can be displaced by one MW of fast regulation. If one MW of fast regulation can replace two MW of slow regulation while maintaining the same overall regulation performance, the marginal benefit factor is 2.0. The marginal benefit factor decreases as the amount of fast resources increases. RegD MW additions are allowed (if economic) until the MBF is zero, at which point one MW of RegD does not reduce the amount of RegA needed to maintain the same overall regulation performance. Past this point, the addition of another MW of fast capability results in a MBF less than zero. An MBF less than zero means that adding another MW of fast regulation requires the addition of slow regulation in order to maintain a regulation performance target. At this point the rate of substitution is negative and the addition of fast resources makes it harder to maintain a regulation performance target.[25] It is possible for PJM to achieve a passing CPS1 score (100 percent) entirely with slow regulation resources as PJM has done since its inception, but PJM cannot achieve a passing CPS1 score using only fast regulation resources.

PJM administers the real-time regulation signal to resource owners on a two second scan rate using the RegA and RegD control signals. These signals are used to move regulating resources or fleets of resources within the total regulation capability (TRegA or TRegD) they can provide. PJM monitors compliance using the current regulation signals CRegA and CRegD. The CRegA signal tracks compliance with the RegA signal and the CRegD signal tracks compliance with the RegD signal. The current regulation signals CRegA and CRegD are calculated every two seconds as the response of a regulation resource (or the sum of resources' responses in the case of a fleet of resources) to the regulation signal they are receiving.[26] Figure F-5 shows a screenshot of a typical 10-minute time period of PJM's RegA signal and CRegA signal for all RegA resources. Figure F-6 shows a screenshot of typical 10-minute time period of PJM's RegD signal and CRegD signal for all RegD resources.

22 Order No. 755 at P 3. FERC ordered PJM "to compensate frequency regulation resources based on the actual service provided, including a capacity payment that includes the marginal unit's opportunity costs and a payment for performance that reflects the quantity of frequency regulation service provided by a resource when the resource is accurately following the dispatch signal."

23 Id. at PP 99, 131 & 177.

24 See KEMA. "KERMIT Study Report," (Dec. 13, 2011).

25 PJM calculates a marginal benefit factor using a function that is arbitrarily defined to have zero as its lower bound. The practical impact of this incorrect functional form is likely to be negligible in the near term because substantially more RegD resources would have to be added to result in a negative marginal benefit factor but the function should be corrected. See PJM. "Manual 11: Energy & Ancillary Services Markets Operations," Rev. 107 (Sep. 26, 2019), § 3.2.7.

26 See PJM. "Manual 12: Balancing Operations," Rev. 39 (Feb. 21, 2019), § 4.4.2.

Figure F-5 PJM RegA signal and CReg compliance signal. Example of typical 10-minute time period

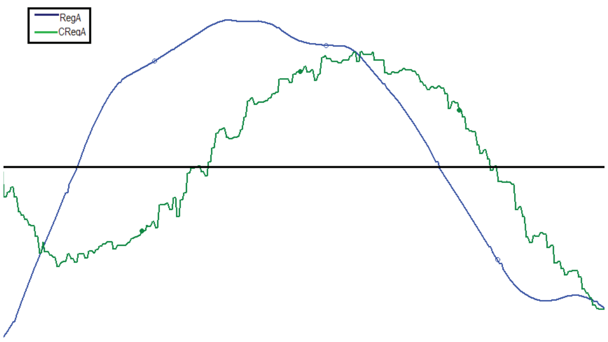
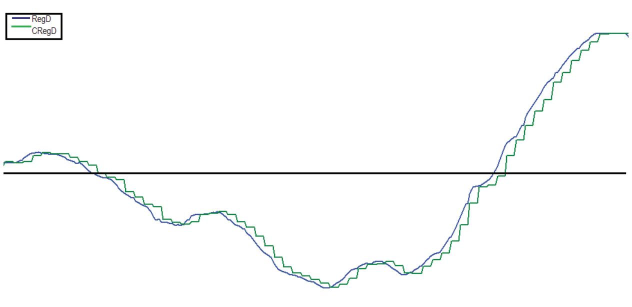


Figure F-6 PJM RegD signal and CRegD current regulation signal. Example of typical 10-minute time period



Regulation signals are designed for the purpose of moderating ACE, accounting for the characteristics of the expected response from the resources following the signal. The RegD signal is designed to contribute to the moderation of ACE given the attributes of fast regulation resources. The RegA signal is designed to contribute to the moderation of ACE given the attributes of traditional sources of regulation. Even a very fast regulating unit will need to have some capability to provide sustained MWh to help with ACE correction, and even a unit with a large MW capability must be able to react with some speed to help with ACE correction. The relationship between the two types of regulating resources is under constant review and the relationship between the two (the marginal benefit factor) is subject to change.

- **Regulation Offers.** All owners of generating and demand resources qualified to provide regulation may offer their regulation capability price in $/MW at cost plus up to $12 adder daily into the Regulation Market using the PJM market user interface. There is no must offer requirement for resources qualified to provide regulation. Users must also enter the signal type they want to follow (RegA or RegD), their regulation capability in MW, as well as cost validation parameters including fuel cost, heat rate at economic maximum, heat rate at regulation minimum, and the VOM rate. Regulating units may also self-schedule. Self-scheduled units have zero lost opportunity cost (LOC) and are the first to be assigned. Owners may also enter price based offers up to a maximum of $100/MW. Demand resources are eligible to offer regulation and did so for the first time in November 2011. Demand resources have an LOC of zero. Under current PJM rules, no more than 25 percent of the total regulation requirement may be supplied by demand resources.[27] 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. All regulation offers that are not set to unavailable for the day are summed to calculate the total daily regulation offered, a figure that changes each hour.
- **Regulation Offered and Eligible.** Sixty minutes before the market hour, PJM runs the Ancillary Services Optimizer software (ASO) to determine the amount of Tier 2 synchronized reserve/nonsynchronized reserve required, develop regulation and synchronized reserve supply curves, and assign regulation, synchronized reserve, and nonsynchronized reserve to specific units. All regulation resource units which have made offers in the daily Regulation Market are evaluated by ASO for regulation. ASO excludes units according to the following ordered criteria: daily or hourly unavailable status; units for which the economic minimum is set equal to economic maximum (unless the unit is a hydroelectric unit or has self-

27 See PJM. "Manual 11: Energy & Ancillary Services Markets Operations," Rev. 107 (Sep. 26, 2019), § 3.2.4.

scheduled regulation); units assigned synchronized reserve; units for which regulation minimum is set equal to regulation maximum (unless the unit is a hydroelectric unit or has self scheduled regulation); units that are offline (except combustion turbine units).[28]

- **Regulation Market Clearing and Dispatch.** The Regulation Market is cleared by the ASO 60 minutes before the operational hour. The specific units scheduled to regulate are selected at that time based on the lowest price set of units sufficient to fill the regulation requirement. The actual unit dispatch happens at the start of the operational hour and is under the control of unit operators. The final Regulation Market Clearing Price used to settle the regulation market is based on the costs and LMPs of the units that are actually dispatched. Differences between market clearing and market dispatch can cause unnecessary uplift payments or a final price paid to all units based on a less than optimal set of dispatched regulating units.

Even after ASO has run and selected units for regulation, PJM dispatchers can dispatch units uneconomically to provide regulation for several reasons including: to control transmission constraints; to avoid over-generation during periods of minimum generation alert; to remove a unit temporarily unable to regulate; or to remove a unit with a malfunctioning data link.[29]

For each offered and eligible unit in the regulation supply, the regulation total capability offer price is calculated using the sum of the unit's regulation cost-based offer (divided by the marginal benefit factor of the resource type and the historic performance score of the resource) plus 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, ASO 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. ASO uses price-based offers for those operators not offer capped and re-solves. Unit assignments based on this solution are final. The final clearing price is not determined at the time of unit assignment.

The Regulation, Synchronized Reserve, and Nonsynchronized Reserve Markets are cleared, prior to the hour, and supplementally within the hour, on a real-time basis. The Regulation, Synchronized Reserve, and Nonsynchronized Reserve Markets are cleared and priced interactively with the energy market and secondary reserve requirements to minimize the cost of the combined products subject to reactive limits, resource constraints, unscheduled power flows, inter area transfer limits, resource distribution factors, self-scheduled resources, limited fuel resources, bilateral transactions, hydrological constraints, generation requirements, reserve requirements and prior to the hour assignments for regulation and reserves.[30] The final clearing prices are calculated at five-minute intervals based on the real-time prices and LMPs of energy. These five-minute prices are averaged to arrive at the final hourly clearing price. This price is sent to Settlements and used and the basis for credits and charges.

- **Cleared Regulation.** Regulation actually assigned by ASO is cleared regulation. The capability and performance prices are calculated every five minutes by the Locational Pricing Calculator (LPC) with the final hourly clearing price averaged from the five minute prices. In real time, resources that have been assigned an ancillary service are expected to provide that ancillary service for the designated hour.
- **Settled Regulation.** Owners of regulation resources are compensated by RMCP (Regulation Market Clearing Price) credits and opportunity cost credits. RMCP credits are the sum of RMCCP (Regulation Market Capability Clearing Price) credits and RMPCP (Regulation Market Performance Clearing Price) credits. RMCCP credits are calculated as MW of regulation capability times the performance score times RMCCP. For RegA resources, RMPCP credits are calculated as MW of regulation capability times performance score times RMPCP. For RegD resources, RMPCP credits are calculated as MW of regulation capability times performance score times RegD to RegA mileage ratio times RMPCP. When calculating RMCCP and RMPCP credits, the MW of regulation capability are defined as the actual MW

28 See PJM. "Manual 11: Energy & Ancillary Services Markets Operations," Rev. 107 (Sep. 26, 2019), § 2.5.
29 See PJM. "Manual 11: Energy & Ancillary Services Markets Operations," Rev. 107 (Sep. 26, 2019), § 3.1.
30 See PJM. "Manual 11: Energy & Ancillary Services Markets Operations," Rev. 107 (Sep. 26, 2019), § 5.2.4.

provided (as opposed to cleared MW or effective MW). The owner of a regulation resource receives opportunity cost credits only if its RMCP credits are less than its offer plus opportunity cost (including lost opportunity cost during shoulder hours). The cost per actual MW of settled regulation can be higher than the regulation clearing price because actual MW and cleared MW may differ and RMCP credits may not completely cover lost opportunity costs.

Reactive Costs

Table F-2 through F-4 show reactive service charges, reactive capability revenue requirement charges and total charges by zone for 2013 through 2018. Reactive service charges are uplift charges to each zone for the reactive service provided. Reactive capability charges are charges to each zone for reactive capability. Table F-5 shows the total reactive charges, including reactive services charges and reactive capability charges for 2009 though 2018 by zone. Table F-6 shows the reactive services charges for 2009 though 2018 by zone. Table F-7 shows the reactive capability charges for 2009 though 2018 by zone. Table F-8 shows the total reactive service charges (energy uplift) for 2009 through 2018.

In 2011, some of the units needed for reactive power became uneconomic in the energy market. Rather than providing reactive power as a result of producing energy, the units were committed and dispatched by PJM out of merit solely in order to provide reactive power. As a further result, the incremental portion of the units' offers, net of energy market revenues, were categorized as reactive services charges because these costs were incurred in order to provide reactive power. The result was higher reactive services charges. The units were offer capped under PJM's market power mitigation rules. The frequency of offer capping resulted in the units becoming eligible for FMU adders. The FMU adders increased the cost-based offers which further increased the charges for reactive.

In 2012, the increased level of reactive services charges led to a change in the treatment of reactive services charges in the Day-Ahead Energy Market and to a change in the categorization of energy uplift credits paid to units needed for reactive power. Prior to September 2012, the start and no load components of the offers of these units were categorized as balancing operating reserve charges and the incremental portion of the offers were categorized as reactive services charges. In September 2012, PJM began to commit units for reactive in the Day-Ahead Energy Market in order to eliminate the differences between the day-ahead and real-time markets that resulted from the commitment of the units for reactive solely in the real-time market. In September, October and November 2012, all of the reactive service charges were categorized as day-ahead operating reserve charges, and allocated following that definition, and not as reactive services charges.

In December 2012, PJM filed proposed revisions to PJM's tariff and operating agreement with FERC to change the rules governing the categorization of reactive services charges, which were approved retroactive to December 2012.[31] Starting in December 2012 all the costs of the units committed for reactive (including start and no load costs), net of energy market revenues, were categorized as reactive service charges.

The significant increase in reactive services charges in 2013 was the combined result of the categorization of all reactive service charges as reactive, lower energy market offsets, an increase in uneconomic commitment for reactive in the day-ahead market, the inclusion of start and no load costs in reactive services charges, and the use of FMU adders in cost-based offers.

In 2014, reactive services charges declined to the pre 2013 levels as the combined result of a reduction in the FMU adders used for the units supplying reactive power, the November 2014, FERC approval of the effective elimination of FMU adders, PJM operations' increased reliance on combustion turbines and less on steam turbines, and transmission upgrades which reduced the need for reactive power.

31 See PJM Interconnection, L.L.C., Docket No. ER13-481-000 (Nov. 30, 2012).

Table F-2 Reactive service charges and reactive capability charges by zone: 2017 and 2018

	2017			2018		
Zone	Reactive Service Charges	Reactive Capability Charges	Total Charges	Reactive Service Charges	Reactive Capability Charges	Total Charges
AECO	$8,686	$4,247,222	$4,255,908	$145	$4,713,244	$4,713,390
AEP	$178,314	$39,234,081	$39,412,395	$775,231	$43,933,120	$44,708,351
APS	$135,676	$16,800,854	$16,936,530	$0	$16,229,147	$16,229,147
ATSI	$77,078	$21,342,021	$21,419,099	$0	$21,913,045	$21,913,045
BGE	$1,694,486	$8,205,331	$9,899,817	$30,956	$8,046,036	$8,076,993
ComEd	$13,242,447	$30,855,459	$44,097,906	$11,335,202	$39,133,222	$50,468,424
DAY	$15,845	$5,628,799	$5,644,643	$0	$4,557,604	$4,557,604
DEOK	$25,386	$8,057,110	$8,082,496	$0	$8,502,164	$8,502,164
Dominion	$120,722	$34,512,902	$34,633,624	$46,914	$38,115,437	$38,162,351
DPL	$1,308,524	$11,512,490	$12,821,014	$257,310	$11,525,471	$11,782,781
DLCO	$12,737	$779,263	$792,000	$0	$780,579	$780,579
EKPC	$20,528	$2,185,849	$2,206,377	$198,562	$2,189,542	$2,388,104
JCPL	$19,441	$8,973,314	$8,992,755	$0	$8,974,083	$8,974,083
Met-Ed	$68,170	$5,198,247	$5,266,417	$0	$4,831,397	$4,831,397
PECO	$103,510	$22,285,794	$22,389,303	$0	$23,244,991	$23,244,991
PENELEC	$1,675,853	$11,645,044	$13,320,897	$403,889	$11,993,445	$12,397,334
Pepco	$1,595,597	$8,301,363	$9,896,960	$0	$9,914,160	$9,914,160
PPL	$37,886	$24,416,798	$24,454,684	$90,643	$26,158,789	$26,249,432
PSEG	$37,255	$27,659,023	$27,696,277	$0	$28,164,482	$28,164,482
RECO	$1,239	$0	$1,239	$0	$0	$0
(Imp/Exp/Wheels)	$0	$19,435,328	$19,435,328	$0	$15,909,575	$15,909,575
Total	$20,379,379	$311,276,291	$331,655,670	$13,138,854	$328,829,532	$341,968,385

Table F-3 Reactive service charges and reactive capability charges by zone: 2015 and 2016

	2015			2016		
Zone	Reactive Service Charges	Reactive Capability Charges	Total Charges	Reactive Service Charges	Reactive Capability Charges	Total Charges
AECO	$17,555	$6,341,664	$6,359,219	$250	$5,097,197	$5,097,448
AEP	$458,265	$38,198,374	$38,656,639	$76,833	$37,638,226	$37,715,059
APS	$98,666	$16,666,745	$16,765,411	$1,440	$16,676,578	$16,678,018
ATSI	$3,844,142	$15,277,869	$19,122,011	$1,860	$21,809,408	$21,811,268
BGE	$63,849	$7,825,069	$7,888,919	$895	$7,592,963	$7,593,858
ComEd	$180,977	$25,334,050	$25,515,027	$1,025,426	$25,752,517	$26,777,944
DAY	$34,107	$8,487,449	$8,521,555	$501	$8,154,908	$8,155,409
DEOK	$53,426	$5,153,000	$5,206,427	$765	$6,096,321	$6,097,086
Dominion	$2,682,636	$29,848,959	$32,531,595	$19,204	$29,962,427	$29,981,631
DPL	$2,338,443	$11,172,936	$13,511,379	$786,662	$12,191,155	$12,977,817
DLCO	$25,334	$0	$25,334	$365	$130,487	$130,852
EKPC	$28,701	$2,154,987	$2,183,688	$162,131	$2,164,030	$2,326,162
JCPL	$39,781	$7,175,487	$7,215,268	$608	$9,065,146	$9,065,753
Met-Ed	$63,281	$7,730,837	$7,794,118	$15,525	$5,991,398	$6,006,923
PECO	$73,554	$17,744,319	$17,817,873	$1,113	$22,688,891	$22,690,004
PENELEC	$313,316	$7,303,956	$7,617,272	$250,696	$9,503,976	$9,754,672
Pepco	$69,105	$5,293,901	$5,363,006	$136,334	$6,070,782	$6,207,117
PPL	$81,863	$18,969,092	$19,050,955	$16,500	$20,235,159	$20,251,659
PSEG	$73,686	$28,662,896	$28,736,582	$1,133	$29,783,733	$29,784,865
RECO	$2,499	$0	$2,499	$37	$0	$37
(Imp/Exp/Wheels)	$0	$17,226,112	$17,226,112	$0	$17,853,808	$17,853,808
Total	$10,543,187	$276,567,702	$287,110,889	$2,498,279	$294,459,111	$296,957,390

Table F-4 Reactive service charges and reactive capability charges by zone: 2013 and 2014

	2013			2014		
Zone	Reactive Service Charges	Reactive Capability Charges	Total Charges	Reactive Service Charges	Reactive Capability Charges	Total Charges
AECO	$4,403,292	$5,132,698	$9,535,990	$106,829	$6,619,214	$6,726,043
AEP	$32,288,025	$40,300,353	$72,588,378	$864,219	$40,080,753	$40,944,971
APS	$9,279,229	$21,716,973	$30,996,202	$300,933	$18,526,432	$18,827,365
ATSI	$58,856,607	$15,741,842	$74,598,449	$12,057,257	$15,273,809	$27,331,066
BGE	$14,005,302	$7,771,212	$21,776,514	$55,746	$7,703,534	$7,759,280
ComEd	$19,358,913	$24,568,280	$43,927,193	$168,684	$24,890,361	$25,059,045
DAY	$3,264,499	$8,437,155	$11,701,654	$29,895	$8,356,294	$8,386,189
DEOK	$5,192,071	$5,758,934	$10,951,005	$29,300	$5,655,802	$5,685,102
Dominion	$20,219,951	$29,925,202	$50,145,153	$4,329,339	$29,664,589	$33,993,928
DPL	$49,034,124	$10,051,706	$59,085,829	$7,311,401	$10,767,117	$18,078,518
DLCO	$2,847,715	$0	$2,847,715	$15,641	$0	$15,641
EKPC	$2,008,773	$1,069,929	$3,078,702	$12,846	$2,121,517	$2,134,363
JCPL	$12,406,854	$6,257,533	$18,664,387	$39,367	$7,064,041	$7,103,408
Met-Ed	$3,258,954	$7,479,654	$10,738,607	$46,070	$7,529,560	$7,575,630
PECO	$9,041,403	$17,622,191	$26,663,594	$445,657	$17,468,722	$17,914,379
PENELEC	$35,775,549	$4,650,339	$40,425,887	$3,232,172	$6,386,846	$9,619,018
Pepco	$6,217,818	$5,257,465	$11,475,283	$51,280	$5,211,678	$5,262,958
PPL	$8,468,810	$18,872,215	$27,341,025	$44,987	$18,900,104	$18,945,091
PSEG	$16,415,012	$27,266,302	$43,681,314	$417,079	$27,028,845	$27,445,924
RECO	$298,052	$0	$298,052	$1,749	$0	$1,749
(Imp/Exp/Wheels)	$0	$19,038,717	$19,038,717	$0	$21,591,362	$21,591,362
Total	$312,640,950	$276,918,698	$589,559,649	$29,560,453	$280,840,576	$310,401,029

Table F-5 Total reactive service and reactive capability charges by zone: 2009 through 2018

Zone	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
AECO	$4,468,680	$4,670,504	$5,281,241	$6,058,739	$9,535,990	$6,726,043	$6,359,219	$5,097,448	$4,255,908	$4,713,390
AEP	$36,786,336	$40,256,622	$40,933,915	$43,342,930	$72,588,378	$40,944,971	$38,656,639	$37,715,059	$39,412,395	$44,708,351
APS	$19,118,180	$31,233,415	$20,310,685	$22,886,264	$30,996,202	$18,827,365	$16,765,411	$16,678,018	$16,936,530	$16,229,147
ATSI	$0	$0	$8,477,799	$30,426,223	$74,598,449	$27,331,066	$19,122,011	$21,811,268	$21,419,099	$21,913,045
BGE	$7,178,113	$7,652,993	$8,525,875	$11,856,108	$21,776,514	$7,759,280	$7,888,919	$7,593,858	$9,899,817	$8,076,993
ComEd	$20,521,747	$22,758,881	$25,726,883	$26,872,588	$43,927,193	$25,059,045	$25,515,027	$26,777,944	$44,097,906	$50,468,424
DAY	$7,651,501	$7,697,304	$8,280,466	$8,789,368	$11,701,654	$8,386,189	$8,521,555	$8,155,409	$5,644,643	$4,557,604
DEOK	$0	$0	$0	$6,265,412	$10,951,005	$5,685,102	$5,206,427	$6,097,086	$8,082,496	$8,502,164
Dominion	$28,031,746	$67,225,948	$31,336,152	$33,014,968	$50,145,153	$33,993,928	$32,531,595	$29,981,631	$34,633,624	$38,162,351
DPL	$8,871,883	$13,863,327	$22,790,883	$25,697,951	$59,085,829	$18,078,518	$13,511,379	$12,977,817	$12,821,014	$11,782,781
DLCO	$0	$0	$0	$297,882	$2,847,715	$15,641	$25,334	$130,852	$792,000	$780,579
EKPC	$0	$0	$0	$0	$3,078,702	$2,134,363	$2,183,688	$2,326,162	$2,206,377	$2,388,104
JCPL	$5,887,845	$5,880,280	$21,064,228	$9,662,807	$18,664,387	$7,103,408	$7,215,268	$9,065,753	$8,992,755	$8,974,083
Met-Ed	$6,913,516	$6,913,646	$7,528,865	$8,117,240	$10,738,607	$7,575,630	$7,794,118	$6,006,923	$5,266,417	$4,831,397
PECO	$15,273,666	$16,436,863	$20,359,432	$19,369,743	$26,663,594	$17,914,379	$17,817,873	$22,690,004	$22,389,303	$23,244,991
PENELEC	$3,043,946	$3,334,125	$5,759,500	$12,446,815	$40,425,887	$9,619,018	$7,617,272	$9,754,672	$13,320,897	$12,397,334
Pepco	$5,224,159	$8,170,035	$7,468,962	$8,522,491	$11,475,283	$5,262,958	$5,363,006	$6,207,117	$9,896,960	$9,914,160
PPL	$14,439,786	$15,497,270	$16,833,467	$21,456,809	$27,341,025	$18,945,091	$19,050,955	$20,251,659	$24,454,684	$26,249,432
PSEG	$25,239,745	$25,627,583	$29,645,403	$34,361,439	$43,681,314	$27,445,924	$28,736,582	$29,784,865	$27,696,277	$28,164,482
RECO	$0	$0	$5,594	$57,276	$298,052	$1,749	$2,499	$37	$1,239	$0
(Imp/Exp/Wheels)	$33,375,996	$34,090,011	$20,149,382	$19,462,321	$19,038,717	$21,591,362	$17,226,112	$17,853,808	$19,435,328	$15,909,575
Total	$242,026,843	$311,308,807	$300,478,731	$348,965,374	$589,559,649	$310,401,029	$287,110,889	$296,957,390	$331,655,670	$341,968,385

Table F-6 Reactive service charges by zone: 2009 through 2018

Zone	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
AECO	$67,285	$77,157	$204,412	$940,304	$4,403,292	$106,829	$17,555	$250	$8,686	$145
AEP	$55,497	$3,571,402	$1,600,992	$3,377,039	$32,288,025	$864,219	$458,265	$76,833	$178,314	$775,231
APS	$210,444	$12,349,162	$63,488	$1,098,407	$9,279,229	$300,933	$98,666	$1,440	$135,676	$0
ATSI	$0	$0	$2,195	$15,904,245	$58,856,607	$12,057,257	$3,844,142	$1,860	$77,078	$0
BGE	$0	$483,796	$839,251	$4,106,490	$14,005,302	$55,746	$63,849	$895	$1,694,486	$30,956
ComEd	$0	$1,482,811	$99,900	$1,993,905	$19,358,913	$168,684	$180,977	$1,025,426	$13,242,447	$11,335,202
DAY	$0	$55,306	$10,772	$375,657	$3,264,499	$29,895	$34,107	$501	$15,845	$0
DEOK	$0	$0	$0	$522,480	$5,192,071	$29,300	$53,426	$765	$25,386	$0
Dominion	$500,408	$39,618,969	$1,736,679	$3,172,919	$20,219,951	$4,329,339	$2,682,636	$19,204	$120,722	$46,914
DPL	$1,650,115	$5,439,801	$13,204,103	$16,032,605	$49,034,124	$7,311,401	$2,338,443	$786,662	$1,308,524	$257,310
DLCO	$0	$0	$0	$297,882	$2,847,715	$15,641	$25,334	$365	$12,737	$0
EKPC	$0	$0	$0	$0	$2,008,773	$12,846	$28,701	$162,131	$20,528	$198,562
JCPL	$107,887	$107,500	$14,874,806	$3,422,661	$12,406,854	$39,367	$39,781	$608	$19,441	$0
Met-Ed	$4,710	$13,420	$130,626	$658,370	$3,258,954	$46,070	$63,281	$15,525	$68,170	$0
PECO	$324,527	$1,506,292	$4,351,268	$2,035,443	$9,041,403	$445,657	$73,554	$1,113	$103,510	$0
PENELEC	$53,751	$347,644	$2,557,474	$7,809,399	$35,775,549	$3,232,172	$313,316	$250,696	$1,675,853	$403,889
Pepco	$0	$2,699,808	$1,603,928	$2,971,912	$6,217,818	$51,280	$69,105	$136,334	$1,595,597	$0
PPL	$12,380	$1,087,783	$607,296	$4,152,942	$8,468,810	$44,987	$81,863	$16,500	$37,886	$90,643
PSEG	$54,408	$473,526	$2,675,888	$7,170,902	$16,415,012	$417,079	$73,686	$1,133	$37,255	$0
RECO	$0	$0	$5,594	$57,276	$298,052	$1,749	$2,499	$37	$1,239	$0
(Imp/Exp/Wheels)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total	$3,041,411	$69,314,376	$44,568,672	$76,100,839	$312,640,950	$29,560,453	$10,543,187	$2,498,279	$20,379,379	$13,138,854

Table F-7 Reactive capability charges by zone: 2009 through 2018

Zone	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
AECO	$4,401,395	$4,593,347	$5,076,829	$5,118,435	$5,132,698	$6,619,214	$6,341,664	$5,097,197	$4,247,222	$4,713,244
AEP	$36,730,839	$36,685,220	$39,332,922	$39,965,891	$40,300,353	$40,080,753	$38,198,374	$37,638,226	$39,234,081	$43,933,120
APS	$18,907,736	$18,884,253	$20,247,197	$21,787,857	$21,716,973	$18,526,432	$16,666,745	$16,676,578	$16,800,854	$16,229,147
ATSI	$0	$0	$8,475,604	$14,521,977	$15,741,842	$15,273,809	$15,277,869	$21,809,408	$21,342,021	$21,913,045
BGE	$7,178,113	$7,169,197	$7,686,624	$7,749,618	$7,771,212	$7,703,534	$7,825,069	$7,592,963	$8,205,331	$8,046,036
ComEd	$20,521,747	$21,276,070	$25,626,984	$24,878,682	$24,568,280	$24,890,361	$25,334,050	$25,752,517	$30,855,459	$39,133,222
DAY	$7,651,501	$7,641,998	$8,269,694	$8,413,711	$8,437,155	$8,356,294	$8,487,449	$8,154,908	$5,628,799	$4,557,604
DEOK	$0	$0	$0	$5,742,932	$5,758,934	$5,655,802	$5,153,000	$6,096,321	$8,057,110	$8,502,164
Dominion	$27,531,337	$27,606,979	$29,599,473	$29,842,049	$29,925,202	$29,664,589	$29,848,959	$29,962,427	$34,512,902	$38,115,437
DPL	$7,221,768	$8,423,526	$9,586,780	$9,665,346	$10,051,706	$10,767,117	$11,172,936	$12,191,155	$11,512,490	$11,525,471
DLCO	$0	$0	$0	$0	$0	$0	$0	$130,487	$779,263	$780,579
EKPC	$0	$0	$0	$0	$1,069,929	$2,121,517	$2,154,987	$2,164,030	$2,185,849	$2,189,542
JCPL	$5,779,958	$5,772,779	$6,189,422	$6,240,146	$6,257,533	$7,064,041	$7,175,487	$9,065,146	$8,973,314	$8,974,083
Met-Ed	$6,908,806	$6,900,226	$7,398,239	$7,458,870	$7,479,654	$7,529,560	$7,730,837	$5,991,398	$5,198,247	$4,831,397
PECO	$14,949,138	$14,930,572	$16,008,164	$17,334,300	$17,622,191	$17,468,722	$17,744,319	$22,688,891	$22,285,794	$23,244,991
PENELEC	$2,990,195	$2,986,481	$3,202,026	$4,637,417	$4,650,339	$6,386,846	$7,303,956	$9,503,976	$11,645,044	$11,993,445
Pepco	$5,224,159	$5,470,228	$5,865,033	$5,550,578	$5,257,465	$5,211,678	$5,293,901	$6,070,782	$8,301,363	$9,914,160
PPL	$14,427,406	$14,409,487	$16,226,171	$17,303,867	$18,872,215	$18,900,104	$18,969,092	$20,235,159	$24,416,798	$26,158,789
PSEG	$25,185,337	$25,154,057	$26,969,515	$27,190,537	$27,266,302	$27,028,845	$28,662,896	$29,783,733	$27,659,023	$28,164,482
RECO	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(Imp/Exp/Wheels)	$33,375,996	$34,090,011	$20,149,382	$19,462,321	$19,038,717	$21,591,362	$17,226,112	$17,853,808	$19,435,328	$15,909,575
Total	$238,985,432	$241,994,431	$255,910,059	$272,864,535	$276,918,698	$280,840,576	$276,567,702	$294,459,111	$311,276,291	$328,829,532

Table F-8 Total reactive service and reactive capability charges: 2009 through 2018

	Reactive Service Charges	Reactive Capability Charges	Total Charges
2009	$3,041,411	$238,985,432	$242,026,843
2010	$69,314,376	$241,994,431	$311,308,807
2011	$44,568,672	$255,910,059	$300,478,731
2012	$76,100,839	$272,864,535	$348,965,374
2013	$312,640,950	$276,918,698	$589,559,649
2014	$29,560,453	$280,840,576	$310,401,029
2015	$10,543,187	$276,567,702	$287,110,889
2016	$2,498,279	$294,459,111	$296,957,390
2017	$20,379,379	$311,276,291	$331,655,670
2018	$13,138,854	$328,829,532	$341,968,385

Appendix G Congestion and Marginal Losses

The locational marginal price (LMP) is the incremental price of energy at a bus. The LMP at a bus is made up of three components: the system marginal price or energy component (SMP), the marginal loss component of LMP (MLMP), and the congestion component of LMP (CLMP).

SMP, MLMP and CLMP are products of the least cost, security constrained dispatch of system resources to meet system load.[1] SMP is the incremental cost of energy, given the current dispatch and given the choice of reference bus, or LMP net of losses and congestion. Losses refer to energy lost to physical resistance in the transmission network as power is moved from generation to load. Total losses refer to the total system wide transmission losses as a result of moving power from injections to withdrawals on the system. Total system wide transmission losses for 2018 were 15,620.4 GWh, a 4.7 percent increase compared to 2017. Marginal losses are the incremental change in system losses caused by changes in load and generation. Congestion occurs when available, least cost energy cannot be delivered to all load because transmission facilities are not adequate to deliver that energy and higher cost units in the constrained area must be dispatched to meet that load.[2] The result is that the price of energy in the constrained area is higher than in the unconstrained area.

Congestion is neither good nor bad, but is a direct measure of the extent to which there are multiple marginal generating units dispatched to serve load as a result of transmission constraints. Congestion is defined to be load payments in excess of generation revenues. Congestion revenues are the source of the funds to pay FTRs. In an LMP system, the only way to ensure that load receives the benefits associated with the use of the transmission system to deliver low cost energy is to use FTRs, or an equivalent mechanism, to pay back to load the difference between the total load payments and the total generation revenues.

1 For more information about LMP see the *Technical Reference for PJM Markets*, "Calculating Locational Marginal Price," <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

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

The energy, marginal losses and congestion metrics must be interpreted carefully. The term total congestion refers to what is actually net congestion, which is calculated as net implicit congestion costs plus net explicit congestion costs plus net inadvertent congestion charges. The net implicit congestion costs are the load congestion payments less generation congestion credits. This section refers to total energy costs and total marginal loss costs in the same way. As with congestion, total energy costs are more precisely termed net energy costs and total marginal loss costs are more precisely termed net marginal loss costs.

The components of LMP are the basis for calculating participant and location specific congestion and marginal losses.[3]

Congestion Costs

Zonal Congestion Costs

Positive or negative CLMPs caused by a specific constraint at a specific bus indicate whether that constraint is increasing or decreasing the LMP at that bus relative to the system marginal price. The total CLMP at a specific bus is the net sum of the positive and negative CLMPs caused by all binding constraints at that bus.

CLMPs are not congestion. CLMPs are a component of price paid by or to load and generation.

Area Based Congestion

Area based congestion is the sum of credits and charges for every bus within a specified aggregate of pricing nodes, typically a load zone. When summed across a zone, the net congestion bill shows the overall congestion charge or credit for the buses in that zone, not including explicit congestion. This is a less meaningful measure of local congestion than constraint based congestion.

Because the net congestion bill for a zone only includes charges or credits incurred in the zone, the congestion bill for the zone is not a good measure of the amount of congestion (the difference between what load pays and generation is paid) paid by the zonal load. Zonal congestion calculations do not, for example, account for the difference between what the zonal load is paying in

3 The total congestion and marginal losses were calculated as of January 24, 2019, and are subject to change, based on continued PJM billing updates.

congestion charges relative to what the generation is paid that serves that load if the zone is a net importer or a net exporter of generation. Zonal congestion calculated for a zone that is a net importer of generation will tend to have overstated congestion, as the calculation does not account for external generation credits from external generation used to serve that load. Zonal congestion calculated for a zone that is a net exporter of generation will tend to have overstated generation congestion credits, as the calculation does not account for only the generation used to meet the zone's internal load.

Constraint Based Congestion

The constraint based congestion calculation is the correct method of calculating local congestion. Constraint based congestion includes all energy charges or credits incurred to serve zonal load. Constraint based congestion is the congestion paid by the zonal load. Constraint based congestion calculations account for the total difference between what the zonal load pays in congestion charges and what the generation that serves that load is paid, regardless of whether the zone is a net importer or a net exporter of generation.

Constraint based congestion calculates congestion on a constraint by constraint basis. On a system wide basis, congestion results from transmission constraints that prevent the lowest cost generation from serving some load that must be served by higher cost generation. Transmission constraints cause differences in LMP, defined by the marginal cost of resolving the constraint given the need to meet power balance requirements, indicated by the shadow price of the constraint. The LMP at any point is equal to the system marginal price (SMP) plus the shadow price of the constraint times the DFAX of the binding constraint to the bus in question (the CLMP of the constraint at that bus), plus marginal losses (MLMP).

The total congestion caused by a constraint is equal to the product of the constraint shadow price times the net flow on the binding constraint. Total congestion caused by the constraint can also be calculated using the CLMPs caused by the constraint at every bus and the net MW injections or MW withdrawals at every affected bus. Congestion associated with a specific constraint is equal to load congestion charges (CLMP of that specific constraint at each bus times load MW at each bus) caused by that constraint in excess of generation congestion credits (CLMP of that specific constraint at each bus times generation MW at each bus) caused by that constraint.

In order to define the load that is actually paying congestion, constraint specific congestion is assigned to downstream (positive CLMP) load buses that paid the congestion caused by the constraint, in proportion to the congestion charges collected from that load due to that constraint. The congestion collected from each load bus due to a constraint is equal to the CLMP caused by that constraint times the MW of load at that load bus. This calculation is done for both day-ahead congestion and balancing congestion.

Constraint Specific Contribution to Area Based and Constraint Based Zonal Congestion

Constraints can affect prices and congestion across multiple zones. PJM is comprised of three regions: the PJM Mid-Atlantic Region with 11 control zones (the AECO, BGE, DPL, JCPL, Met-Ed, PECO, PENELEC, Pepco, PPL, PSEG and RECO control zones); the PJM West Region with nine control zones (the APS, ATSI, ComEd, AEP, DLCO, DEOK, DAY, EKPC and OVEC control zones); and the PJM South Region with one control zone (the Dominion Control Zone).[4]

Table G-1 through Table G-20 present the congestion costs of the top 20 constraints affecting each control zone using both area based calculations and constraint based calculations, including the facility type, the location of the constrained facility, day-ahead event hours and real-time event hours for 2017.[5] The tables present the top 20 constraints in descending order of the absolute value of congestion costs for each zone using constraint based calculations. In addition to the top 20 constraints, these tables show the congestion costs of all other constraints affecting the control zone.

4 See PJM Operating Agreement § 1.

5 For the same tables for 2018, see the *2018 State of the Market Report for PJM*, Volume II, Section 11, Congestion and Marginal Losses.

AECO Control Zone

Table G-1 AECO Control Zone top congestion cost impacts (By facility): 2017

				Congestion Costs (Millions)							
				Area Based			Constraint Based			Event Hours	
No.	Constraint	Type	Location	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Real-Time
1	Emilie - Falls	Line	PECO	$0.1	$0.1	$0.1	$1.1	($0.0)	$1.1	5,171	894
2	5004/5005 Interface	Interface	500	$1.2	($0.1)	$1.2	$0.5	($0.1)	$0.5	173	105
3	AP South	Interface	500	$0.1	($0.0)	$0.1	$0.3	($0.0)	$0.3	1,315	75
4	Graceton - Safe Harbor	Line	BGE	($1.4)	($0.2)	($1.5)	$0.3	$0.0	$0.3	3,118	1,151
5	Carson - Rawlings	Line	Dominion	$0.1	($0.0)	$0.1	$0.2	($0.0)	$0.2	720	231
6	Lakeview - Greenfield	Line	ATSI	$0.1	($0.0)	$0.1	$0.2	($0.0)	$0.2	1,593	164
7	Cedar Grove - Clifton	Line	PSEG	($0.2)	($0.1)	($0.2)	$0.2	($0.0)	$0.2	1,179	79
8	Monroe - Vineland	Line	AECO	$0.2	($0.0)	$0.1	$0.2	($0.0)	$0.2	343	13
9	Gardners - Texas East	Line	Met-Ed	($0.0)	($0.0)	($0.0)	$0.2	($0.0)	$0.2	1,317	116
10	East Townada - North Meshoppen	Line	PENELEC	$0.1	$0.0	$0.1	$0.2	$0.0	$0.2	1,802	0
11	Roxana - Praxair	Flowgate	MISO	$0.2	$0.0	$0.2	$0.2	($0.0)	$0.2	1,734	290
12	Chambers	Transformer	AECO	$0.2	$0.0	$0.2	$0.2	$0.0	$0.2	637	0
13	Westwood	Flowgate	MISO	($0.0)	($0.0)	($0.0)	$0.2	($0.0)	$0.1	3,399	198
14	North Meshoppen - Oxbow	Line	PENELEC	$0.2	($0.0)	$0.1	$0.1	$0.0	$0.1	1,098	178
15	Conastone - Peach Bottom	Line	500	($1.9)	($0.1)	($2.0)	$0.1	$0.0	$0.1	3,159	840
16	Conastone - Otter Creek	Line	PPL	($0.6)	($0.2)	($0.9)	$0.1	$0.0	$0.1	1,336	868
17	Churchtown	Transformer	AECO	$0.3	$0.0	$0.3	$0.1	$0.0	$0.1	220	0
18	Alpine - Belvidere	Flowgate	MISO	($0.0)	$0.0	($0.0)	$0.1	$0.0	$0.1	339	0
19	Bedington - Black Oak	Interface	500	$0.1	($0.0)	$0.1	$0.1	$0.0	$0.1	1,215	62
20	Chapelst - Harmony	Line	DPL	($0.0)	($0.0)	($0.0)	$0.1	$0.0	$0.1	581	4
	Top 20 Total			($1.3)	($0.6)	($1.9)	$4.6	($0.1)	$4.5	30,449	5,268
	All Other Constraints			($1.0)	($0.7)	($1.7)	$4.7	($0.6)	$4.2	121,590	16,875
	Total			($2.3)	($1.4)	($3.7)	$9.3	($0.6)	$8.7	152,039	22,143

BGE Control Zone

Table G-2 BGE Control Zone top congestion cost impacts (By facility): 2017

				Congestion Costs (Millions)							
				Area Based			Constraint Based			Event Hours	
No.	Constraint	Type	Location	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Real-Time
1	Conastone - Peach Bottom	Line	500	$4.2	($0.2)	$4.0	$2.1	$0.1	$2.2	3,159	840
2	Graceton - Safe Harbor	Line	BGE	$9.1	($1.3)	$7.8	$1.2	$0.0	$1.3	3,118	1,151
3	BCPEP	Interface	Pepco	$1.1	$0.0	$1.1	$1.2	$0.0	$1.2	557	0
4	5004/5005 Interface	Interface	500	$1.1	$0.6	$1.7	$1.3	($0.1)	$1.2	173	105
5	Conastone - Northwest	Line	BGE	$5.2	$0.4	$5.6	$1.1	$0.0	$1.2	975	228
6	AP South	Interface	500	$1.0	$0.0	$1.0	$1.2	($0.0)	$1.1	1,315	75
7	Carson - Rawlings	Line	Dominion	$0.6	($0.1)	$0.4	$0.9	($0.1)	$0.8	720	231
8	Conastone - Otter Creek	Line	PPL	$3.4	($0.9)	$2.4	$0.7	$0.0	$0.7	1,336	868
9	Three Mile Island	Transformer	500	$1.3	($0.5)	$0.8	$0.6	$0.1	$0.7	540	86
10	Cedar Grove - Clifton	Line	PSEG	($0.3)	$0.0	($0.3)	$0.7	($0.1)	$0.6	1,179	79
11	Bagley - Graceton	Line	BGE	$2.2	($0.2)	$1.9	$0.5	($0.0)	$0.5	554	127
12	Bedington - Black Oak	Interface	500	$0.9	($0.1)	$0.8	$0.5	$0.0	$0.5	1,215	62
13	Westwood	Flowgate	MISO	($0.1)	$0.0	($0.1)	$0.5	($0.0)	$0.5	3,399	198
14	Lakeview - Greenfield	Line	ATSI	$0.7	($0.1)	$0.6	$0.5	($0.0)	$0.5	1,593	164
15	Brunner Island - Yorkanna	Line	Met-Ed	$1.4	($0.0)	$1.4	$0.4	$0.0	$0.4	681	74
16	Alpine - Belvidere	Flowgate	MISO	($0.1)	$0.0	($0.1)	$0.4	$0.0	$0.4	339	0
17	Butler - Shanor Manor	Line	APS	($1.4)	$0.3	($1.2)	$0.4	($0.0)	$0.4	1,884	265
18	Gardners - Texas East	Line	Met-Ed	($0.4)	$0.2	($0.2)	$0.4	($0.0)	$0.4	1,317	116
19	Person - Sedge Hill	Line	Dominion	$0.5	($0.2)	$0.3	$0.6	($0.3)	$0.4	1,249	210
20	Roxana - Praxair	Flowgate	MISO	$0.6	($0.2)	$0.5	$0.4	($0.1)	$0.4	1,734	290
	Top 20 Total			$31.0	($2.5)	$28.5	$15.6	($0.4)	$15.3	27,037	5,169
	All Other Constraints			$11.4	$0.0	$11.4	$11.0	($1.5)	$9.4	134,014	17,026
	Total			$42.4	($2.5)	$39.9	$26.6	($1.9)	$24.7	161,051	22,195

DPL Control Zone

Table G-3 DPL Control Zone top congestion cost impacts (By facility): 2017

				Congestion Costs (Millions)							
				Area Based			Constraint Based			Event Hours	
No.	Constraint	Type	Location	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Real-Time
1	Loretto - Vienna	Line	DPL	$7.3	($0.3)	$6.9	$7.2	($0.2)	$7.0	3,950	60
2	Kent - Vaughn	Line	DPL	$3.4	$0.2	$3.7	$3.4	$0.0	$3.4	844	57
3	Emilie - Falls	Line	PECO	($2.4)	$0.2	($2.1)	$2.4	($0.0)	$2.4	5,171	894
4	Piney Grove	Transformer	DPL	($0.7)	$2.8	$2.1	($0.5)	$2.8	$2.2	352	328
5	Cedar Creek - Red Lion	Line	DPL	$3.4	($1.0)	$2.4	$2.0	($0.2)	$1.8	710	34
6	Kenney - Stockton	Line	DPL	($13.4)	$11.1	($2.3)	($13.4)	$11.7	($1.7)	327	347
7	Cedar Creek - Clayton	Line	DPL	$1.3	($0.0)	$1.3	$1.3	($0.0)	$1.3	335	5
8	5004/5005 Interface	Interface	500	$4.2	($1.1)	$3.2	$1.2	($0.1)	$1.1	173	105
9	Stockton - Kenney	Line	DPL	($0.9)	$0.0	($0.9)	($0.9)	$0.0	($0.9)	64	0
10	Church - New Meredith	Line	DPL	$0.9	$0.0	$0.9	$0.9	$0.0	$0.9	618	0
11	Chapelst - Harmony	Line	DPL	$1.0	$0.0	$1.0	$0.8	$0.0	$0.8	581	4
12	Preston - Tanyard	Line	DPL	$0.7	($0.0)	$0.7	$0.7	($0.0)	$0.7	556	1
13	AP South	Interface	500	$0.3	($0.0)	$0.2	$0.6	($0.0)	$0.6	1,315	75
14	Keeney - Steele	Line	DPL	$0.8	($0.0)	$0.8	$0.6	($0.0)	$0.5	198	4
15	Carson - Rawlings	Line	Dominion	$0.7	($0.1)	$0.6	$0.5	($0.0)	$0.5	720	231
16	Graceton - Safe Harbor	Line	BGE	($3.7)	$0.5	($3.2)	$0.5	$0.0	$0.5	3,118	1,151
17	Roxana - Praxair	Flowgate	MISO	$0.7	($0.1)	$0.6	$0.5	($0.0)	$0.5	1,734	290
18	Cheswold - Kent	Line	DPL	$0.4	($0.0)	$0.4	$0.4	($0.0)	$0.4	169	2
19	Sign Post - Stockton	Line	DPL	$0.1	$0.4	$0.4	$0.1	$0.4	$0.4	69	9
20	Mardela - Vienna	Line	DPL	$0.4	($0.0)	$0.4	$0.4	($0.0)	$0.4	577	5
	Top 20 Total			$4.4	$12.6	$17.0	$8.5	$14.2	$22.7	21,581	3,602
	All Other Constraints			($12.0)	$1.9	($10.1)	$13.7	($1.2)	$12.6	129,860	18,541
	Total			($7.6)	$14.5	$6.9	$22.2	$13.0	$35.2	151,441	22,143

JCPL Control Zone

Table G-4 JCPL Control Zone top congestion cost impacts (By facility): 2017

				Congestion Costs (Millions)							
				Area Based			Constraint Based			Event Hours	
No.	Constraint	Type	Location	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Real-Time
1	Emilie - Falls	Line	PECO	$1.2	$1.0	$2.2	$4.2	($0.0)	$4.2	5,171	894
2	5004/5005 Interface	Interface	500	$2.6	$1.1	$3.7	$1.2	($0.1)	$1.1	173	105
3	AP South	Interface	500	$0.1	$0.0	$0.1	$0.6	($0.0)	$0.6	1,315	75
4	Graceton - Safe Harbor	Line	BGE	($1.0)	($0.3)	($1.3)	$0.6	$0.0	$0.6	3,118	1,151
5	Carson - Rawlings	Line	Dominion	$0.2	$0.1	$0.3	$0.6	($0.0)	$0.5	720	231
6	Conastone - Peach Bottom	Line	500	$0.6	($0.2)	$0.4	$0.4	$0.0	$0.4	3,159	840
7	North Meshoppen - Oxbow	Line	PENELEC	$0.4	$0.1	$0.5	$0.4	$0.0	$0.4	1,098	178
8	Gardners - Texas East	Line	Met-Ed	($0.0)	($0.1)	($0.1)	$0.4	($0.0)	$0.4	1,317	116
9	East Townada - North Meshoppen	Line	PENELEC	$0.3	$0.0	$0.3	$0.4	$0.0	$0.4	1,802	0
10	Lakeview - Greenfield	Line	ATSI	$0.1	$0.1	$0.2	$0.4	($0.0)	$0.4	1,593	164
11	Cedar Grove - Clifton	Line	PSEG	($0.9)	($0.3)	($1.2)	$0.4	($0.1)	$0.4	1,179	79
12	Westwood	Flowgate	MISO	($0.0)	($0.0)	($0.0)	$0.4	($0.0)	$0.4	3,399	198
13	Conastone - Otter Creek	Line	PPL	($0.2)	($0.5)	($0.7)	$0.3	$0.0	$0.3	1,336	868
14	Alpine - Belvidere	Flowgate	MISO	$0.0	$0.0	$0.0	$0.3	$0.0	$0.3	339	0
15	Butler - Shanor Manor	Line	APS	($0.2)	($0.0)	($0.2)	$0.3	($0.0)	$0.3	1,884	265
16	Bedington - Black Oak	Interface	500	$0.1	$0.0	$0.1	$0.3	$0.0	$0.3	1,215	62
17	Jenkins - Susquehanna	Line	PPL	($0.0)	$0.0	($0.0)	$0.3	$0.0	$0.3	247	0
18	Three Mile Island	Transformer	500	$0.1	($0.0)	$0.1	$0.2	$0.0	$0.3	540	86
19	Person - Sedge Hill	Line	Dominion	$0.2	$0.1	$0.3	$0.4	($0.2)	$0.3	1,249	210
20	Pleasant View - Ashburn	Line	Dominion	$0.0	($0.1)	($0.1)	$0.3	($0.1)	$0.3	473	85
	Top 20 Total			$3.5	$1.1	$4.6	$12.3	($0.4)	$12.0	31,327	5,607
	All Other Constraints			$3.2	($0.3)	$3.0	$8.8	($1.1)	$7.7	122,236	16,536
	Total			$6.7	$0.8	$7.6	$21.2	($1.5)	$19.7	153,563	22,143

Met-Ed Control Zone

Table G-5 Met-Ed Control Zone top congestion cost impacts (By facility): 2017

				Congestion Costs (Millions)							
				Area Based			Constraint Based			Event Hours	
No.	Constraint	Type	Location	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Real-Time
1	Carlisle Pike - Roxbury	Line	PENELEC	$1.1	$0.4	$1.5	$1.1	$0.4	$1.5	398	116
2	Middletown Jct	Other	Met-Ed	$1.2	$0.3	$1.5	$0.8	$0.0	$0.8	945	72
3	Gardners - Texas East	Line	Met-Ed	$3.2	($0.5)	$2.7	$0.8	($0.0)	$0.8	1,317	116
4	5004/5005 Interface	Interface	500	($0.6)	($0.0)	($0.6)	$0.8	($0.1)	$0.8	173	105
5	Pequest River - Portland	Line	JCPL	$0.3	($1.0)	($0.7)	$0.3	($1.0)	($0.8)	76	94
6	Saxton - Three Springs	Line	PENELEC	$1.6	($0.1)	$1.5	$0.7	($0.0)	$0.7	888	151
7	Middletown Jct	Transformer	Met-Ed	$1.3	$0.0	$1.3	$0.7	$0.0	$0.7	1,034	0
8	Conastone - Peach Bottom	Line	500	$0.2	($0.2)	($0.0)	$0.5	$0.0	$0.5	3,159	840
9	Roxana - Praxair	Flowgate	MISO	($0.7)	($0.1)	($0.7)	($0.5)	($0.0)	($0.5)	1,734	290
10	Three Mile Island	Transformer	500	$0.4	$0.2	$0.6	$0.4	$0.0	$0.4	540	86
11	AP South	Interface	500	($0.0)	($0.0)	($0.0)	$0.4	($0.0)	$0.4	1,315	75
12	Newberry - Round Top	Line	Met-Ed	$0.6	($0.0)	$0.6	$0.4	$0.0	$0.4	474	32
13	Carson - Rawlings	Line	Dominion	($0.2)	($0.0)	($0.3)	$0.4	($0.0)	$0.4	720	231
14	Emilie - Falls	Line	PECO	$0.4	$0.0	$0.4	$0.4	($0.0)	$0.3	5,171	894
15	Graceton - Safe Harbor	Line	BGE	$0.9	$0.9	$1.8	$0.3	$0.0	$0.3	3,118	1,151
16	Cedar Grove - Clifton	Line	PSEG	($0.0)	$0.1	$0.0	$0.3	($0.1)	$0.3	1,179	79
17	Lakeview - Greenfield	Line	ATSI	($0.0)	($0.1)	($0.1)	$0.3	($0.0)	$0.3	1,593	164
18	Quarry - Steel City	Line	PPL	$0.0	($0.0)	$0.0	$0.2	$0.0	$0.2	1,508	300
19	Westwood	Flowgate	MISO	$0.0	$0.0	$0.0	$0.2	($0.0)	$0.2	3,399	198
20	Alpine - Belvidere	Flowgate	MISO	$0.0	$0.0	$0.0	$0.2	$0.0	$0.2	339	0
	Top 20 Total			$9.6	($0.1)	$9.5	$8.8	($0.8)	$8.1	29,080	4,994
	All Other Constraints			$8.5	$1.6	$10.1	$7.7	($0.8)	$6.9	129,820	17,201
	Total			$18.1	$1.5	$19.6	$16.5	($1.5)	$15.0	158,900	22,195

PECO Control Zone

Table G-6 PECO Control Zone top congestion cost impacts (By facility): 2017

				Congestion Costs (Millions)							
				Area Based			Constraint Based			Event Hours	
No.	Constraint	Type	Location	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Real-Time
1	Emilie - Falls	Line	PECO	$7.0	($1.6)	$5.3	$5.2	($0.0)	$5.2	5,171	894
2	5004/5005 Interface	Interface	500	($3.4)	$1.0	($2.4)	$2.2	($0.2)	$2.0	173	105
3	Limerick	Transformer	500	$1.3	$0.0	$1.3	$1.3	$0.0	$1.3	142	5
4	AP South	Interface	500	($0.7)	$0.1	($0.6)	$1.2	($0.0)	$1.1	1,315	75
5	Roxana - Praxair	Flowgate	MISO	($1.6)	$0.2	($1.4)	($1.1)	($0.0)	($1.1)	1,734	290
6	Graceton - Safe Harbor	Line	BGE	$11.3	($1.2)	$10.1	$1.0	$0.0	$1.0	3,118	1,151
7	Carson - Rawlings	Line	Dominion	($1.1)	$0.2	($0.9)	$1.0	($0.1)	$1.0	720	231
8	Phillips Island	Transformer	PECO	$0.8	$0.0	$0.8	$0.8	$0.0	$0.8	1,676	0
9	Gardners - Texas East	Line	Met-Ed	$0.9	($0.0)	$0.9	$0.8	($0.0)	$0.8	1,317	116
10	Cedar Grove - Clifton	Line	PSEG	$0.8	($0.1)	$0.7	$0.9	($0.1)	$0.7	1,179	79
11	Lakeview - Greenfield	Line	ATSI	($1.3)	$0.2	($1.1)	$0.7	($0.0)	$0.7	1,593	164
12	Cromby - Limerick	Line	PECO	$0.7	($0.0)	$0.7	$0.7	($0.0)	$0.7	412	13
13	Conastone - Peach Bottom	Line	500	$23.5	($0.4)	$23.2	$0.6	$0.0	$0.6	3,159	840
14	Westwood	Flowgate	MISO	$0.2	($0.0)	$0.2	$0.6	($0.0)	$0.6	3,399	198
15	East Townada - North Meshoppen	Line	PENELEC	($0.2)	$0.0	($0.2)	$0.6	$0.0	$0.6	1,802	0
16	Conastone - Otter Creek	Line	PPL	$8.0	($1.6)	$6.4	$0.5	$0.1	$0.6	1,336	868
17	Alpine - Belvidere	Flowgate	MISO	$0.1	$0.0	$0.1	$0.6	$0.0	$0.6	339	0
18	Bedington - Black Oak	Interface	500	($0.6)	$0.1	($0.5)	$0.5	$0.0	$0.5	1,215	62
19	Chapelst - Harmony	Line	DPL	$0.2	$0.0	$0.2	$0.5	$0.0	$0.5	581	4
20	Butler - Shanor Manor	Line	APS	$4.0	($0.1)	$3.9	$0.5	($0.0)	$0.5	1,884	265
	Top 20 Total			$50.1	($3.4)	$46.7	$19.2	($0.5)	$18.7	32,265	5,360
	All Other Constraints			$29.5	($1.0)	$28.4	$17.2	($2.2)	$15.0	121,864	16,788
	Total			$79.5	($4.4)	$75.2	$36.3	($2.7)	$33.7	154,129	22,148

PENELEC Control Zone

Table G-7 PENELEC Control Zone top congestion cost impacts (By facility): 2017

				Congestion Costs (Millions)							
				Area Based			Constraint Based			Event Hours	
No.	Constraint	Type	Location	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Real-Time
1	SENECA	Interface	PENELEC	($0.8)	($0.7)	($1.5)	($0.8)	($0.7)	($1.5)	114	155
2	Roxana - Praxair	Flowgate	MISO	($1.7)	$0.2	($1.5)	($1.2)	$0.0	($1.2)	1,734	290
3	Asylum	Transformer	PENELEC	$0.9	$0.0	$0.9	$0.9	$0.0	$0.9	859	0
4	Saxton - Three Springs	Line	PENELEC	$3.0	($0.8)	$2.2	$0.7	($0.0)	$0.7	888	151
5	Conastone - Peach Bottom	Line	500	$3.2	($0.6)	$2.6	$0.6	$0.0	$0.7	3,159	840
6	East Sayre - East Towanda	Line	PENELEC	$2.0	($1.0)	$1.0	$0.7	($0.0)	$0.7	821	261
7	Gardners - Texas East	Line	Met-Ed	$1.4	$0.6	$2.0	$0.6	($0.0)	$0.6	1,317	116
8	Seneca	Transformer	PENELEC	$0.6	$0.0	$0.6	$0.6	$0.0	$0.6	3,399	0
9	East Townada - North Meshoppen	Line	PENELEC	$4.8	$0.0	$4.8	$0.5	$0.0	$0.5	1,802	0
10	Graceton - Safe Harbor	Line	BGE	$3.6	($0.8)	$2.8	$0.4	$0.0	$0.5	3,118	1,151
11	Emilie - Falls	Line	PECO	($0.8)	$0.3	($0.5)	$0.5	($0.0)	$0.4	5,171	894
12	Carlisle Pike - Roxbury	Line	PENELEC	$0.4	$0.0	$0.4	$0.3	$0.1	$0.4	398	116
13	5004/5005 Interface	Interface	500	$7.1	$0.0	$7.1	$0.5	($0.0)	$0.4	173	105
14	AP South	Interface	500	$2.0	($0.0)	$2.0	$0.4	($0.0)	$0.4	1,315	75
15	Butler - Karns City	Line	APS	$0.9	$0.4	$1.3	$0.3	$0.0	$0.3	450	45
16	East Sayre	Transformer	PENELEC	$0.3	$0.0	$0.3	$0.3	$0.0	$0.3	1,286	0
17	Carson - Rawlings	Line	Dominion	($0.4)	$0.0	($0.4)	$0.3	($0.0)	$0.3	720	231
18	Lakeview - Greenfield	Line	ATSI	($1.8)	$0.2	($1.6)	$0.3	($0.0)	$0.3	1,593	164
19	Conastone - Otter Creek	Line	PPL	$1.7	($0.6)	$1.1	$0.2	$0.0	$0.3	1,336	868
20	Westwood	Flowgate	MISO	$0.3	($0.0)	$0.3	$0.3	($0.0)	$0.3	3,399	198
	Top 20 Total			$26.5	($2.7)	$23.9	$6.6	($0.6)	$5.9	33,052	5,660
	All Other Constraints			$31.2	($4.9)	$26.3	$9.7	($1.0)	$8.7	135,403	16,535
	Total			$57.8	($7.6)	$50.2	$16.2	($1.6)	$14.6	168,455	22,195

Pepco Control Zone

Table G-8 Pepco Control Zone top congestion cost impacts (By facility): 2017

				Congestion Costs (Millions)							
				Area Based			Constraint Based			Event Hours	
No.	Constraint	Type	Location	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Real-Time
1	Conastone - Peach Bottom	Line	500	$5.7	$1.1	$6.8	$2.1	$0.1	$2.2	3,159	840
2	AP South	Interface	500	$2.2	$0.1	$2.3	$1.2	($0.0)	$1.2	1,315	75
3	Graceton - Safe Harbor	Line	BGE	$6.0	$1.2	$7.2	$1.1	$0.0	$1.2	3,118	1,151
4	BCPEP	Interface	Pepco	$1.0	$0.0	$1.0	$1.2	$0.0	$1.2	557	0
5	5004/5005 Interface	Interface	500	$0.3	$0.2	$0.5	$1.1	($0.1)	$1.0	173	105
6	Conastone - Northwest	Line	BGE	$3.1	$0.8	$3.9	$0.9	$0.0	$0.9	975	228
7	Carson - Rawlings	Line	Dominion	$1.3	$0.3	$1.5	$0.8	($0.1)	$0.8	720	231
8	Roxana - Praxair	Flowgate	MISO	$1.1	$0.1	$1.1	$0.8	($0.0)	$0.8	1,734	290
9	Conastone - Otter Creek	Line	PPL	$3.3	$1.6	$4.8	$0.7	$0.0	$0.7	1,336	868
10	Three Mile Island	Transformer	500	$0.7	$0.5	$1.1	$0.6	$0.1	$0.7	540	86
11	Cedar Grove - Clifton	Line	PSEG	($0.3)	($0.1)	($0.4)	$0.7	($0.1)	$0.6	1,179	79
12	Bedington - Black Oak	Interface	500	$1.3	$0.1	$1.4	$0.5	$0.0	$0.5	1,215	62
13	Westwood	Flowgate	MISO	($0.1)	($0.0)	($0.1)	$0.5	($0.0)	$0.5	3,399	198
14	Butler - Shanor Manor	Line	APS	($0.6)	($0.2)	($0.7)	$0.4	($0.0)	$0.4	1,884	265
15	Brunner Island - Yorkanna	Line	Met-Ed	$1.1	$0.1	$1.2	$0.4	$0.0	$0.4	681	74
16	Alpine - Belvidere	Flowgate	MISO	($0.1)	$0.0	($0.1)	$0.4	$0.0	$0.4	339	0
17	Person - Sedge Hill	Line	Dominion	$1.3	$0.3	$1.6	$0.6	($0.2)	$0.4	1,249	210
18	AEP - DOM	Interface	500	$0.3	$0.1	$0.4	$0.4	$0.0	$0.4	948	32
19	Bagley - Graceton	Line	BGE	$0.9	$0.2	$1.2	$0.4	($0.0)	$0.4	554	127
20	Lake George - Aetna	Flowgate	MISO	($0.5)	($0.2)	($0.7)	$0.2	$0.1	$0.3	483	244
	Top 20 Total			$28.0	$6.0	$34.1	$14.9	($0.2)	$14.7	25,558	5,165
	All Other Constraints			$4.9	$0.1	$5.0	$9.3	($1.5)	$7.8	131,245	17,030
	Total			$32.9	$6.2	$39.1	$24.2	($1.7)	$22.5	156,803	22,195

PPL Control Zone

Table G-9 PPL Control Zone top congestion cost impacts (By facility): 2017

				Congestion Costs (Millions)							
				Area Based			Constraint Based			Event Hours	
No.	Constraint	Type	Location	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Real-Time
1	Quarry - Steel City	Line	PPL	$4.5	$0.3	$4.8	$4.3	$0.3	$4.5	1,508	300
2	Emilie - Falls	Line	PECO	($1.5)	$0.0	($1.5)	$3.0	($0.0)	$3.0	5,171	894
3	5004/5005 Interface	Interface	500	($2.8)	$0.5	($2.3)	$2.6	($0.2)	$2.3	173	105
4	AP South	Interface	500	$0.1	$0.1	$0.2	$1.2	($0.0)	$1.2	1,315	75
5	Conastone - Peach Bottom	Line	500	$7.2	$0.6	$7.8	$1.1	$0.1	$1.1	3,159	840
6	Carson - Rawlings	Line	Dominion	($0.4)	$0.0	($0.4)	$1.1	($0.1)	$1.1	720	231
7	Graceton - Safe Harbor	Line	BGE	$2.1	$0.1	$2.1	$0.8	$0.0	$0.8	3,118	1,151
8	Cedar Grove - Clifton	Line	PSEG	$0.6	($0.2)	$0.4	$0.9	($0.1)	$0.8	1,179	79
9	Gardners - Texas East	Line	Met-Ed	$0.3	($0.2)	$0.1	$0.8	($0.0)	$0.8	1,317	116
10	Three Mile Island	Transformer	500	$4.3	$0.7	$5.0	$0.7	$0.1	$0.8	540	86
11	East Townada - North Meshoppen	Line	PENELEC	($1.4)	$0.0	($1.4)	$0.7	$0.0	$0.7	1,802	0
12	Lakeview - Greenfield	Line	ATSI	($0.3)	$0.2	($0.1)	$0.8	($0.0)	$0.7	1,593	164
13	Saxton - Three Springs	Line	PENELEC	($0.0)	$0.1	$0.1	$0.7	($0.0)	$0.7	888	151
14	Elimsport - Sunbury	Line	PPL	$1.0	$0.0	$1.0	$0.7	$0.0	$0.7	154	93
15	Roxana - Praxair	Flowgate	MISO	($0.8)	($0.0)	($0.8)	($0.5)	($0.1)	($0.6)	1,734	290
16	Westwood	Flowgate	MISO	$0.1	($0.0)	$0.1	$0.6	($0.0)	$0.6	3,399	198
17	Alpine - Belvidere	Flowgate	MISO	$0.0	$0.0	$0.0	$0.6	$0.0	$0.6	339	0
18	Conastone - Otter Creek	Line	PPL	$3.8	$1.2	$5.0	$0.4	$0.1	$0.5	1,336	868
19	Person - Sedge Hill	Line	Dominion	($0.4)	$0.2	($0.2)	$0.8	($0.3)	$0.5	1,249	210
20	Bedington - Black Oak	Interface	500	$0.0	$0.0	$0.0	$0.5	$0.0	$0.5	1,215	62
	Top 20 Total			$16.5	$3.5	$20.0	$21.9	($0.4)	$21.5	31,909	5,913
	All Other Constraints			$12.3	$0.9	$13.2	$17.9	($1.8)	$16.1	125,067	16,230
	Total			$28.8	$4.4	$33.3	$39.8	($2.2)	$37.5	156,976	22,143

PSEG Control Zone

Table G-10 PSEG Control Zone top congestion cost impacts (By facility): 2017

				Congestion Costs (Millions)							
				Area Based			Constraint Based			Event Hours	
No.	Constraint	Type	Location	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Real-Time
1	Emilie - Falls	Line	PECO	$20.0	($1.7)	$18.3	$8.2	($0.0)	$8.2	5,171	894
2	5004/5005 Interface	Interface	500	$3.2	($3.6)	($0.3)	$2.3	($0.2)	$2.0	173	105
3	Cedar Grove - Clifton	Line	PSEG	$9.6	($3.4)	$6.2	$1.4	($0.2)	$1.2	1,179	79
4	AP South	Interface	500	($0.2)	($0.1)	($0.2)	$1.1	($0.0)	$1.1	1,315	75
5	Graceton - Safe Harbor	Line	BGE	($1.4)	$1.3	($0.1)	$1.1	$0.0	$1.1	3,118	1,151
6	Carson - Rawlings	Line	Dominion	$0.2	($0.2)	$0.1	$1.1	($0.1)	$1.0	720	231
7	East Towanda - Hillside	Line	PENELEC	$0.2	($0.0)	$0.2	$0.9	$0.0	$0.9	938	177
8	Conastone - Peach Bottom	Line	500	$3.9	$1.1	$5.0	$0.8	$0.0	$0.8	3,159	840
9	Gardners - Texas East	Line	Met-Ed	($0.1)	$0.2	$0.1	$0.7	($0.0)	$0.7	1,317	116
10	Westwood	Flowgate	MISO	($0.0)	$0.0	($0.0)	$0.7	($0.0)	$0.7	3,399	198
11	Lakeview - Greenfield	Line	ATSI	$0.2	($0.2)	$0.0	$0.6	($0.0)	$0.6	1,593	164
12	Conastone - Otter Creek	Line	PPL	$0.0	$0.6	$0.7	$0.5	$0.1	$0.6	1,336	868
13	Alpine - Belvidere	Flowgate	MISO	($0.0)	$0.0	($0.0)	$0.6	$0.0	$0.6	339	0
14	East Sayre - East Towanda	Line	PENELEC	$0.2	($0.2)	$0.0	$0.6	($0.1)	$0.6	821	261
15	East Townada - North Meshoppen	Line	PENELEC	$0.2	$0.0	$0.2	$0.6	$0.0	$0.6	1,802	0
16	Jenkins - Susquehanna	Line	PPL	$0.4	$0.0	$0.4	$0.6	$0.0	$0.6	247	0
17	Butler - Shanor Manor	Line	APS	($0.7)	$0.2	($0.5)	$0.6	($0.0)	$0.5	1,884	265
18	Bedington - Black Oak	Interface	500	($0.1)	($0.0)	($0.1)	$0.5	$0.0	$0.5	1,215	62
19	Three Mile Island	Transformer	500	$1.4	($0.0)	$1.4	$0.5	$0.0	$0.5	540	86
20	Pleasant View - Ashburn	Line	Dominion	($0.0)	($0.0)	($0.0)	$0.6	($0.1)	$0.5	473	85
	Top 20 Total			$37.0	($5.8)	$31.2	$23.8	($0.6)	$23.3	30,739	5,657
	All Other Constraints			$9.1	($3.6)	$5.5	$18.4	($1.9)	$16.5	134,063	16,486
	Total			$46.2	($9.5)	$36.7	$42.2	($2.5)	$39.8	164,802	22,143

RECO Control Zone

Table G-11 RECO Control Zone top congestion cost impacts (By facility): 2017

				Congestion Costs (Millions)							
				Area Based			Constraint Based			Event Hours	
No.	Constraint	Type	Location	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Real-Time
1	Emilie - Falls	Line	PECO	$0.4	$0.1	$0.6	$0.3	($0.0)	$0.3	5,171	894
2	East Sayre - East Towanda	Line	PENELEC	$0.0	$0.0	$0.0	$0.1	($0.0)	$0.1	821	261
3	5004/5005 Interface	Interface	500	$0.2	$0.0	$0.3	$0.1	($0.0)	$0.1	173	105
4	East Towanda - Hillside	Line	PENELEC	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	938	177
5	Roxana - Praxair	Flowgate	MISO	$0.0	$0.0	$0.1	$0.0	$0.0	$0.0	1,734	290
6	Graceton - Safe Harbor	Line	BGE	($0.4)	($0.0)	($0.5)	$0.0	$0.0	$0.0	3,118	1,151
7	Conastone - Peach Bottom	Line	500	($0.6)	($0.0)	($0.6)	$0.0	$0.0	$0.0	3,159	840
8	AP South	Interface	500	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	1,315	75
9	Carson - Rawlings	Line	Dominion	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	720	231
10	Cedar Grove - Clifton	Line	PSEG	$0.1	$0.1	$0.2	$0.0	($0.0)	$0.0	1,179	79
11	East Townada - North Meshoppen	Line	PENELEC	($0.0)	$0.0	($0.0)	$0.0	$0.0	$0.0	1,802	0
12	South Troy - Tennessee Gas Tap	Line	PENELEC	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	1,549	125
13	Westwood	Flowgate	MISO	($0.0)	($0.0)	($0.0)	$0.0	($0.0)	$0.0	3,399	198
14	Conastone - Otter Creek	Line	PPL	($0.2)	($0.1)	($0.3)	$0.0	$0.0	$0.0	1,336	868
15	Three Mile Island	Transformer	500	($0.2)	$0.0	($0.2)	$0.0	$0.0	$0.0	540	86
16	Butler - Shanor Manor	Line	APS	($0.2)	$0.0	($0.2)	$0.0	($0.0)	$0.0	1,884	265
17	Jenkins - Susquehanna	Line	PPL	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	247	0
18	Pleasant View - Ashburn	Line	Dominion	($0.1)	($0.0)	($0.1)	$0.0	($0.0)	$0.0	473	85
19	Alpine - Belvidere	Flowgate	MISO	($0.0)	$0.0	($0.0)	$0.0	$0.0	$0.0	339	0
20	Batesville - Hubble	Flowgate	MISO	($0.0)	$0.0	($0.0)	$0.0	($0.0)	$0.0	379	158
	Top 20 Total			($0.7)	$0.1	($0.6)	$0.9	($0.0)	$0.9	30,276	5,888
	All Other Constraints			($0.3)	$0.0	($0.3)	$0.6	($0.1)	$0.5	117,612	16,255
	Total			($1.1)	$0.1	($0.9)	$1.5	($0.1)	$1.4	147,888	22,143

West Region Congestion-Event Summaries

AEP Control Zone

Table G-12 AEP Control Zone top congestion cost impacts (By facility): 2017

				Congestion Costs (Millions)							
				Area Based			Constraint Based			Event Hours	
No.	Constraint	Type	Location	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Real-Time
1	Westwood	Flowgate	MISO	$15.1	$0.6	$15.7	$8.5	($0.0)	$8.5	3,399	198
2	Conastone - Peach Bottom	Line	500	($5.2)	$4.0	($1.2)	$7.1	$0.4	$7.5	3,159	840
3	Graceton - Safe Harbor	Line	BGE	($4.8)	$3.6	($1.3)	$4.1	$0.1	$4.2	3,118	1,151
4	Braidwood - East Frankfort	Line	ComEd	$0.0	($0.1)	($0.1)	$4.3	($0.3)	$4.0	4,171	301
5	Capitol Hill - Chemical	Line	AEP	$4.6	$0.0	$4.6	$3.7	$0.0	$3.7	735	0
6	AP South	Interface	500	$6.5	($0.8)	$5.7	$3.2	($0.1)	$3.1	1,315	75
7	Carson - Rawlings	Line	Dominion	$3.6	($1.7)	$1.9	$3.1	($0.2)	$2.9	720	231
8	Conastone - Otter Creek	Line	PPL	($2.9)	$3.6	$0.7	$2.6	$0.2	$2.8	1,336	868
9	Shadelnd - Lafaysouth	Flowgate	MISO	$2.8	$1.7	$4.5	$2.7	($0.0)	$2.7	1,055	669
10	Conastone - Northwest	Line	BGE	($1.0)	$0.7	($0.4)	$2.5	$0.1	$2.6	975	228
11	5004/5005 Interface	Interface	500	$7.6	($2.6)	$4.9	$2.8	($0.2)	$2.5	173	105
12	Three Mile Island	Transformer	500	($0.7)	$0.6	($0.1)	$2.1	$0.2	$2.4	540	86
13	Butler - Shanor Manor	Line	APS	($3.7)	$1.4	($2.3)	$2.3	($0.1)	$2.2	1,884	265
14	Alpine - Belvidere	Flowgate	MISO	$0.3	$0.0	$0.3	$1.8	$0.0	$1.8	339	0
15	Lakeview - Greenfield	Line	ATSI	($0.7)	$0.1	($0.6)	$1.8	($0.1)	$1.7	1,593	164
16	Iogtown - North Delphos	Line	AEP	$1.5	$0.0	$1.5	$1.6	$0.0	$1.6	1,876	0
17	Lake George - Aetna	Flowgate	MISO	$2.1	($1.3)	$0.8	$1.1	$0.4	$1.5	483	244
18	Bedington - Black Oak	Interface	500	$2.5	($0.3)	$2.2	$1.4	$0.0	$1.4	1,215	62
19	Batesville - Hubble	Flowgate	MISO	$2.9	($1.3)	$1.6	$1.5	($0.1)	$1.4	379	158
20	Person - Sedge Hill	Line	Dominion	$4.9	($3.3)	$1.6	$2.2	($0.8)	$1.4	1,249	210
	Top 20 Total			$35.5	$4.9	$40.3	$60.5	($0.4)	$60.1	29,714	5,855
	All Other Constraints			$56.0	($14.5)	$41.5	$56.0	($7.1)	$48.8	173,423	16,813
	Total			$91.5	($9.6)	$81.8	$116.4	($7.5)	$108.9	203,137	22,668

APS Control Zone

Table G-13 APS Control Zone top congestion cost impacts (By facility): 2017

				Congestion Costs (Millions)							
				Area Based			Constraint Based			Event Hours	
No.	Constraint	Type	Location	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Real-Time
1	Conastone - Peach Bottom	Line	500	$1.3	($1.5)	($0.3)	$2.5	$0.1	$2.7	3,159	840
2	Graceton - Safe Harbor	Line	BGE	$0.9	($0.7)	$0.2	$1.3	$0.0	$1.4	3,118	1,151
3	AP South	Interface	500	$5.7	$1.3	$7.0	$1.3	($0.0)	$1.2	1,315	75
4	5004/5005 Interface	Interface	500	$1.6	($0.9)	$0.8	$1.1	($0.1)	$1.0	173	105
5	Conastone - Northwest	Line	BGE	$0.4	($0.0)	$0.4	$0.9	$0.0	$1.0	975	228
6	Conastone - Otter Creek	Line	PPL	$0.3	($0.3)	($0.0)	$0.9	$0.1	$0.9	1,336	868
7	Three Mile Island	Transformer	500	$0.3	($0.2)	$0.1	$0.7	$0.1	$0.8	540	86
8	Carson - Rawlings	Line	Dominion	$1.3	$0.0	$1.4	$0.8	($0.1)	$0.7	720	231
9	Westwood	Flowgate	MISO	($0.1)	$0.0	($0.1)	$0.7	($0.0)	$0.7	3,399	198
10	Alpine - Belvidere	Flowgate	MISO	($0.1)	$0.0	($0.1)	$0.7	$0.0	$0.7	339	0
11	Lakeview - Greenfield	Line	ATSI	$1.1	($0.1)	$1.0	$0.7	($0.0)	$0.7	1,593	164
12	Person - Sedge Hill	Line	Dominion	$1.4	$0.2	$1.5	$1.0	($0.4)	$0.6	1,249	210
13	Saxton - Three Springs	Line	PENELEC	($0.4)	($0.3)	($0.7)	$0.6	($0.0)	$0.6	888	151
14	Bedington - Black Oak	Interface	500	$2.4	$0.7	$3.1	$0.6	$0.0	$0.6	1,215	62
15	Butler - Shanor Manor	Line	APS	($1.8)	$0.8	($1.1)	$0.6	($0.0)	$0.5	1,884	265
16	Lake George - Aetna	Flowgate	MISO	($0.2)	($0.1)	($0.2)	$0.4	$0.2	$0.5	483	244
17	Byron - Cherry Valley	Flowgate	MISO	($0.0)	$0.0	($0.0)	$0.5	$0.0	$0.5	347	0
18	Brokaw - Leroy	Flowgate	MISO	$0.2	($0.2)	($0.0)	$0.3	$0.2	$0.5	1,744	528
19	AEP - DOM	Interface	500	$0.5	$0.0	$0.6	$0.5	$0.0	$0.5	948	32
20	Batesville - Hubble	Flowgate	MISO	($0.0)	$0.0	($0.0)	$0.5	($0.0)	$0.5	379	158
	Top 20 Total			$14.8	($1.3)	$13.5	$16.6	$0.0	$16.6	25,804	5,596
	All Other Constraints			$5.9	$0.9	$6.8	$14.5	($3.3)	$11.2	142,093	16,602
	Total			$20.7	($0.4)	$20.3	$31.1	($3.3)	$27.8	167,897	22,198

ATSI Control Zone

Table G-14 ATSI Control Zone top congestion cost impacts (By facility): 2017

				Congestion Costs (Millions)							
				Area Based			Constraint Based			Event Hours	
No.	Constraint	Type	Location	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Real-Time
1	Conastone - Peach Bottom	Line	500	$3.0	($1.7)	$1.2	$3.5	$0.2	$3.7	3,159	840
2	Graceton - Safe Harbor	Line	BGE	$1.8	($1.0)	$0.8	$1.7	$0.1	$1.7	3,118	1,151
3	Roxana - Praxair	Flowgate	MISO	$2.9	($1.4)	$1.5	$2.1	($0.6)	$1.5	1,734	290
4	Carson - Rawlings	Line	Dominion	($1.0)	$0.3	($0.7)	$1.6	($0.1)	$1.5	720	231
5	Clinic Hospital - Inland	Line	ATSI	$1.6	$0.0	$1.6	$1.4	$0.0	$1.4	430	0
6	Conastone - Otter Creek	Line	PPL	$2.3	($1.5)	$0.7	$1.2	$0.1	$1.4	1,336	868
7	Butler - Shanor Manor	Line	APS	$7.4	($1.5)	$5.8	$1.3	($0.0)	$1.3	1,884	265
8	AP South	Interface	500	($3.0)	$0.4	($2.6)	$1.3	($0.0)	$1.3	1,315	75
9	Lakeview - Greenfield	Line	ATSI	$10.9	($2.1)	$8.7	$1.2	($0.0)	$1.2	1,593	164
10	Conastone - Northwest	Line	BGE	$0.2	($0.1)	$0.2	$1.1	$0.1	$1.1	975	228
11	5004/5005 Interface	Interface	500	($2.6)	$0.2	($2.5)	$1.1	($0.1)	$1.0	173	105
12	Westwood	Flowgate	MISO	($0.2)	($0.1)	($0.2)	$1.0	($0.0)	$1.0	3,399	198
13	Alpine - Belvidere	Flowgate	MISO	($0.1)	$0.0	($0.1)	$1.0	$0.0	$1.0	339	0
14	Lake George - Aetna	Flowgate	MISO	($0.9)	$0.7	($0.2)	$0.6	$0.2	$0.8	483	244
15	Person - Sedge Hill	Line	Dominion	($1.3)	$0.3	($1.0)	$1.2	($0.4)	$0.7	1,249	210
16	Byron - Cherry Valley	Flowgate	MISO	($0.1)	$0.0	($0.1)	$0.7	$0.0	$0.7	347	0
17	Batesville - Hubble	Flowgate	MISO	($0.0)	($0.0)	($0.0)	$0.7	($0.0)	$0.7	379	158
18	Bedington - Black Oak	Interface	500	($1.4)	$0.2	($1.2)	$0.7	$0.0	$0.7	1,215	62
19	Brokaw - Leroy	Flowgate	MISO	$1.1	($0.1)	$0.9	$0.4	$0.2	$0.6	1,744	528
20	Three Mile Island	Transformer	500	$0.3	($0.1)	$0.2	$0.5	$0.1	$0.6	540	86
	Top 20 Total			$20.6	($7.6)	$13.0	$24.2	($0.4)	$23.9	26,132	5,703
	All Other Constraints			$6.2	$0.4	$6.6	$19.5	($3.8)	$15.7	140,395	16,495
	Total			$26.8	($7.2)	$19.5	$43.7	($4.2)	$39.5	166,527	22,198

ComEd Control Zone

Table G-15 ComEd Control Zone top congestion cost impacts (By facility): 2017

				Congestion Costs (Millions)							
				Area Based			Constraint Based			Event Hours	
No.	Constraint	Type	Location	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Real-Time
1	Braidwood - East Frankfort	Line	ComEd	$45.4	($1.4)	$43.9	$36.0	($0.2)	$35.8	4,171	301
2	Cherry Valley	Transformer	ComEd	$21.0	($2.1)	$18.9	$21.0	($0.3)	$20.7	3,007	149
3	Conastone - Peach Bottom	Line	500	($3.3)	$1.0	($2.2)	$5.5	$0.3	$5.8	3,159	840
4	Quad Cities	Transformer	ComEd	$5.6	$0.0	$5.6	$5.6	$0.0	$5.6	9,457	0
5	Braidwood - Davis Creek	Line	ComEd	$4.5	$0.0	$4.5	$4.2	$0.0	$4.2	85	0
6	Graceton - Safe Harbor	Line	BGE	($2.6)	$0.9	($1.7)	$3.1	$0.1	$3.2	3,118	1,151
7	Westwood	Flowgate	MISO	$7.4	($0.5)	$6.8	$2.7	($0.0)	$2.6	3,399	198
8	Davis	Transformer	ComEd	$2.6	$0.0	$2.7	$2.5	$0.0	$2.5	406	17
9	Electric Junction - Lombard	Line	ComEd	$2.6	$0.3	$2.9	$2.1	$0.0	$2.2	327	13
10	Three Mile Island	Transformer	500	($0.5)	$0.0	($0.4)	$1.9	$0.2	$2.1	540	86
11	Conastone - Otter Creek	Line	PPL	($2.3)	($0.4)	($2.7)	$2.0	$0.1	$2.1	1,336	868
12	Carson - Rawlings	Line	Dominion	$3.2	$0.3	$3.4	$2.2	($0.2)	$2.0	720	231
13	AP South	Interface	500	$2.3	($0.7)	$1.6	$2.0	($0.0)	$2.0	1,315	75
14	Braidwood	Transformer	ComEd	$1.9	$0.0	$1.9	$1.9	$0.0	$1.9	2,086	0
15	Conastone - Northwest	Line	BGE	($1.2)	$0.3	($0.8)	$1.8	$0.1	$1.8	975	228
16	Belvidere - Woodstock	Line	ComEd	$1.9	($0.5)	$1.4	$1.9	($0.1)	$1.8	146	10
17	Butler - Shanor Manor	Line	APS	($1.8)	$0.2	($1.6)	$1.9	($0.0)	$1.8	1,884	265
18	5004/5005 Interface	Interface	500	$3.3	$1.3	$4.6	$1.9	($0.2)	$1.7	173	105
19	Lakeview - Greenfield	Line	ATSI	$4.0	$0.2	$4.2	$1.5	($0.0)	$1.5	1,593	164
20	Tanners Creek - Miami Fort	Line	AEP	$0.6	$0.2	$0.7	$1.3	$0.1	$1.5	1,213	63
	Top 20 Total			$94.6	($0.7)	$93.9	$103.0	($0.1)	$102.9	39,110	4,764
	All Other Constraints			$137.4	($3.0)	$134.3	$58.8	($4.8)	$54.0	160,929	17,476
	Total			$231.9	($3.7)	$228.2	$161.8	($4.9)	$156.9	200,039	22,240

DAY Control Zone

Table G-16 DAY Control Zone top congestion cost impacts (By facility): 2017

				Congestion Costs (Millions)							
				Area Based			Constraint Based			Event Hours	
No.	Constraint	Type	Location	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Real-Time
1	Conastone - Peach Bottom	Line	500	$0.5	($0.1)	$0.4	$1.0	$0.1	$1.0	3,159	840
2	Graceton - Safe Harbor	Line	BGE	$0.5	($0.1)	$0.4	$0.6	$0.0	$0.6	3,118	1,151
3	Carson - Rawlings	Line	Dominion	($0.4)	($0.1)	($0.6)	$0.4	($0.0)	$0.4	720	231
4	AP South	Interface	500	($0.6)	$0.4	($0.2)	$0.4	($0.0)	$0.4	1,315	75
5	Conastone - Otter Creek	Line	PPL	$0.2	($0.1)	$0.1	$0.4	$0.0	$0.4	1,336	868
6	Tanners Creek - Miami Fort	Line	AEP	$0.0	$0.3	$0.3	$0.3	$0.0	$0.4	1,213	63
7	Three Mile Island	Transformer	500	$0.0	($0.0)	$0.0	$0.3	$0.0	$0.4	540	86
8	Conastone - Northwest	Line	BGE	$0.2	($0.1)	$0.2	$0.3	$0.0	$0.3	975	228
9	5004/5005 Interface	Interface	500	($0.9)	$0.1	($0.8)	$0.4	($0.0)	$0.3	173	105
10	Butler - Shanor Manor	Line	APS	$0.6	$0.0	$0.6	$0.3	($0.0)	$0.3	1,884	265
11	Batesville - Hubble	Flowgate	MISO	$0.1	$0.8	$0.9	$0.3	($0.0)	$0.3	379	158
12	Lakeview - Greenfield	Line	ATSI	($1.1)	$0.2	($0.9)	$0.3	($0.0)	$0.3	1,593	164
13	Westwood	Flowgate	MISO	($0.0)	($0.0)	($0.0)	$0.3	($0.0)	$0.3	3,399	198
14	Alpine - Belvidere	Flowgate	MISO	($0.0)	$0.0	($0.0)	$0.2	$0.0	$0.2	339	0
15	Lake George - Aetna	Flowgate	MISO	($0.2)	$0.0	($0.2)	$0.1	$0.1	$0.2	483	244
16	Miami Fort	Transformer	DEOK	($0.0)	($0.0)	($0.0)	$0.2	$0.0	$0.2	2,176	1
17	Roxana - Praxair	Flowgate	MISO	$0.3	($0.1)	$0.2	$0.2	($0.0)	$0.2	1,734	290
18	Brunner Island - Yorkanna	Line	Met-Ed	$0.1	$0.0	$0.1	$0.2	$0.0	$0.2	681	74
19	Person - Sedge Hill	Line	Dominion	($0.5)	($0.1)	($0.5)	$0.3	($0.1)	$0.2	1,249	210
20	Bedington - Black Oak	Interface	500	($0.2)	$0.1	($0.1)	$0.2	$0.0	$0.2	1,215	62
	Top 20 Total			($1.3)	$1.2	($0.1)	$6.7	$0.0	$6.7	27,681	5,313
	All Other Constraints			($0.1)	$0.3	$0.2	$5.5	($0.9)	$4.6	168,991	16,885
	Total			($1.4)	$1.5	$0.1	$12.2	($0.9)	$11.3	196,672	22,198

DEOK Control Zone

Table G-17 DEOK Control Zone top congestion cost impacts (By facility): 2017

				Congestion Costs (Millions)							
				Area Based			Constraint Based			Event Hours	
No.	Constraint	Type	Location	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Real-Time
1	Conastone - Peach Bottom	Line	500	$0.0	$0.7	$0.7	$1.5	$0.1	$1.6	3,159	840
2	East Bend	Transformer	DEOK	$1.4	$0.0	$1.4	$1.4	$0.0	$1.4	4,464	0
3	Miami Fort	Transformer	DEOK	$2.1	$0.0	$2.1	$1.1	$0.0	$1.1	2,176	1
4	Graceton - Safe Harbor	Line	BGE	$0.1	$0.5	$0.6	$0.9	$0.0	$0.9	3,118	1,151
5	Tanners Creek - Miami Fort	Line	AEP	$1.6	$0.5	$2.1	$0.7	$0.1	$0.7	1,213	63
6	Batesville - Hubble	Flowgate	MISO	$8.2	($0.7)	$7.5	$0.7	($0.0)	$0.6	379	158
7	AP South	Interface	500	($0.5)	$0.1	($0.4)	$0.6	($0.0)	$0.6	1,315	75
8	Carson - Rawlings	Line	Dominion	($0.4)	$0.1	($0.4)	$0.6	($0.0)	$0.6	720	231
9	Conastone - Otter Creek	Line	PPL	($0.2)	$0.8	$0.6	$0.5	$0.0	$0.6	1,336	868
10	Conastone - Northwest	Line	BGE	$0.2	($0.0)	$0.1	$0.5	$0.0	$0.5	975	228
11	Three Mile Island	Transformer	500	$0.1	($0.1)	$0.0	$0.5	$0.0	$0.5	540	86
12	5004/5005 Interface	Interface	500	($0.8)	$0.5	($0.3)	$0.6	($0.1)	$0.5	173	105
13	Butler - Shanor Manor	Line	APS	$0.5	$0.1	$0.6	$0.5	($0.0)	$0.5	1,884	265
14	Lakeview - Greenfield	Line	ATSI	($0.5)	$0.2	($0.3)	$0.5	($0.0)	$0.4	1,593	164
15	Westwood	Flowgate	MISO	($0.1)	$0.0	($0.1)	$0.4	($0.0)	$0.4	3,399	198
16	Alpine - Belvidere	Flowgate	MISO	($0.0)	$0.0	($0.0)	$0.4	$0.0	$0.4	339	0
17	Lake George - Aetna	Flowgate	MISO	($0.3)	$0.0	($0.3)	$0.2	$0.1	$0.3	483	244
18	Brunner Island - Yorkanna	Line	Met-Ed	$0.1	$0.0	$0.1	$0.3	$0.0	$0.3	681	74
19	Bedington - Black Oak	Interface	500	($0.2)	($0.0)	($0.2)	$0.3	$0.0	$0.3	1,215	62
20	Person - Sedge Hill	Line	Dominion	($0.4)	$0.3	($0.0)	$0.4	($0.2)	$0.3	1,249	210
	Top 20 Total			$10.8	$3.0	$13.8	$12.5	$0.1	$12.6	30,411	5,023
	All Other Constraints			$3.1	$2.0	$5.1	$9.3	($1.2)	$8.1	136,213	17,176
	Total			$13.9	$5.1	$18.9	$21.8	($1.1)	$20.7	166,624	22,199

DLCO Control Zone

Table G-18 DLCO Control Zone top congestion cost impacts (By facility): 2017

				Congestion Costs (Millions)							
				Area Based			Constraint Based			Event Hours	
No.	Constraint	Type	Location	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Real-Time
1	Conastone - Peach Bottom	Line	500	($0.2)	($0.1)	($0.3)	$0.7	$0.0	$0.7	3,159	840
2	Graceton - Safe Harbor	Line	BGE	($0.1)	($0.0)	($0.1)	$0.4	$0.0	$0.4	3,118	1,151
3	Carson - Rawlings	Line	Dominion	$0.1	$0.0	$0.1	$0.3	($0.0)	$0.3	720	231
4	Conastone - Otter Creek	Line	PPL	($0.2)	($0.1)	($0.3)	$0.2	$0.0	$0.3	1,336	868
5	Butler - Shanor Manor	Line	APS	($0.8)	($0.0)	($0.8)	$0.3	($0.0)	$0.3	1,884	265
6	AP South	Interface	500	$0.3	($0.1)	$0.3	$0.3	($0.0)	$0.2	1,315	75
7	Lakeview - Greenfield	Line	ATSI	($0.5)	$0.1	($0.4)	$0.2	($0.0)	$0.2	1,593	164
8	Conastone - Northwest	Line	BGE	$0.0	$0.0	$0.0	$0.2	$0.0	$0.2	975	228
9	Westwood	Flowgate	MISO	$0.0	($0.0)	$0.0	$0.2	($0.0)	$0.2	3,399	198
10	5004/5005 Interface	Interface	500	$0.9	($0.6)	$0.3	$0.2	($0.0)	$0.2	173	105
11	Alpine - Belvidere	Flowgate	MISO	$0.0	$0.0	$0.0	$0.2	$0.0	$0.2	339	0
12	Ohio Central - West Coshocton	Line	AEP	($0.0)	($0.0)	($0.1)	$0.2	$0.0	$0.2	687	19
13	Lake George - Aetna	Flowgate	MISO	$0.0	$0.0	$0.0	$0.1	$0.0	$0.2	483	244
14	Person - Sedge Hill	Line	Dominion	$0.1	($0.0)	$0.1	$0.2	($0.1)	$0.1	1,249	210
15	Pleasant View - Ashburn	Line	Dominion	($0.0)	$0.0	($0.0)	$0.2	($0.0)	$0.1	473	85
16	Batesville - Hubble	Flowgate	MISO	$0.0	($0.0)	($0.0)	$0.2	($0.0)	$0.1	379	158
17	Roxana - Praxair	Flowgate	MISO	($0.2)	$0.0	($0.2)	($0.1)	$0.0	($0.1)	1,734	290
18	Byron - Cherry Valley	Flowgate	MISO	$0.0	$0.0	$0.0	$0.1	$0.0	$0.1	347	0
19	Bedington - Black Oak	Interface	500	$0.0	($0.0)	$0.0	$0.1	$0.0	$0.1	1,215	62
20	Brokaw - Leroy	Flowgate	MISO	($0.1)	($0.0)	($0.2)	$0.1	$0.0	$0.1	1,744	528
	Top 20 Total			($0.6)	($1.0)	($1.6)	$4.3	($0.0)	$4.2	26,322	5,721
	All Other Constraints			$1.3	($0.4)	$0.9	$3.3	($0.7)	$2.6	118,694	16,421
	Total			$0.8	($1.4)	($0.6)	$7.6	($0.7)	$6.9	145,016	22,142

EKPC Control Zone

Table G-19 EKPC Control Zone top congestion cost impacts (By facility): 2017

				Congestion Costs (Millions)							
				Area Based			Constraint Based			Event Hours	
No.	Constraint	Type	Location	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Real-Time
1	Conastone - Peach Bottom	Line	500	$1.0	($0.5)	$0.5	$0.7	$0.0	$0.8	3,159	840
2	Graceton - Safe Harbor	Line	BGE	$0.8	($0.4)	$0.4	$0.4	$0.0	$0.4	3,118	1,151
3	AP South	Interface	500	($0.4)	$0.2	($0.1)	$0.4	($0.0)	$0.4	1,315	75
4	Carson - Rawlings	Line	Dominion	($1.1)	$0.2	($0.9)	$0.3	($0.0)	$0.3	720	231
5	5004/5005 Interface	Interface	500	($0.7)	$0.1	($0.6)	$0.4	($0.0)	$0.3	173	105
6	Conastone - Northwest	Line	BGE	$0.3	($0.2)	$0.1	$0.3	$0.0	$0.3	975	228
7	Tanners Creek - Miami Fort	Line	AEP	$0.1	($0.0)	$0.0	$0.2	$0.0	$0.3	1,213	63
8	Conastone - Otter Creek	Line	PPL	$0.6	($0.4)	$0.2	$0.3	$0.0	$0.3	1,336	868
9	Three Mile Island	Transformer	500	$0.1	($0.1)	$0.1	$0.2	$0.0	$0.2	540	86
10	Westwood	Flowgate	MISO	($0.5)	$0.0	($0.4)	$0.2	($0.0)	$0.2	3,399	198
11	Lakeview - Greenfield	Line	ATSI	($0.5)	$0.3	($0.3)	$0.3	($0.0)	$0.2	1,593	164
12	Butler - Shanor Manor	Line	APS	$0.6	($0.3)	$0.3	$0.2	($0.0)	$0.2	1,884	265
13	Roxana - Praxair	Flowgate	MISO	$0.4	($0.1)	$0.3	$0.2	($0.0)	$0.2	1,734	290
14	Alpine - Belvidere	Flowgate	MISO	($0.0)	$0.0	($0.0)	$0.2	$0.0	$0.2	339	0
15	Bedington - Black Oak	Interface	500	($0.2)	$0.1	($0.1)	$0.2	$0.0	$0.2	1,215	62
16	Person - Sedge Hill	Line	Dominion	($1.2)	$0.3	($0.9)	$0.2	($0.1)	$0.2	1,249	210
17	Brunner Island - Yorkanna	Line	Met-Ed	$0.1	($0.0)	$0.1	$0.2	$0.0	$0.2	681	74
18	Lake George - Aetna	Flowgate	MISO	($0.2)	$0.1	($0.0)	$0.1	$0.0	$0.1	483	244
19	Batesville - Hubble	Flowgate	MISO	($3.7)	$1.3	($2.4)	$0.1	($0.0)	$0.1	379	158
20	Brokaw - Leroy	Flowgate	MISO	$0.4	($0.1)	$0.3	$0.1	$0.1	$0.1	1,744	528
	Top 20 Total			($4.2)	$0.6	($3.7)	$5.3	$0.0	$5.3	27,249	5,840
	All Other Constraints			($2.0)	$2.1	$0.1	$5.3	($0.7)	$4.6	133,704	16,359
	Total			($6.2)	$2.7	($3.6)	$10.6	($0.7)	$9.9	160,953	22,199

South Region Congestion-Event Summaries

Dominion Control Zone

Table G-20 Dominion Control Zone top congestion cost impacts (By facility): 2017

				Congestion Costs (Millions)							
				Area Based			Constraint Based			Event Hours	
No.	Constraint	Type	Location	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Real-Time
1	Conastone - Peach Bottom	Line	500	$1.7	($1.3)	$0.5	$6.1	$0.3	$6.5	3,159	840
2	AP South	Interface	500	$7.0	($1.3)	$5.7	$4.4	($0.1)	$4.3	1,315	75
3	Graceton - Safe Harbor	Line	BGE	$2.3	($1.4)	$0.9	$3.4	$0.1	$3.5	3,118	1,151
4	Carson - Rawlings	Line	Dominion	$10.9	($0.3)	$10.6	$2.9	($0.2)	$2.7	720	231
5	5004/5005 Interface	Interface	500	($0.0)	$0.5	$0.4	$3.0	($0.3)	$2.7	173	105
6	Conastone - Northwest	Line	BGE	$1.0	($0.4)	$0.6	$2.5	$0.1	$2.6	975	228
7	Conastone - Otter Creek	Line	PPL	$2.6	($0.8)	$1.8	$2.0	$0.1	$2.1	1,336	868
8	Pleasant View - Ashburn	Line	Dominion	$10.9	($2.3)	$8.6	$2.5	($0.5)	$2.0	473	85
9	Three Mile Island	Transformer	500	$0.2	($0.2)	($0.1)	$1.8	$0.2	$2.0	540	86
10	AEP - DOM	Interface	500	$1.2	($0.2)	$1.0	$1.7	$0.0	$1.7	948	32
11	Bedington - Black Oak	Interface	500	$2.4	($0.4)	$1.9	$1.6	$0.0	$1.6	1,215	62
12	Westwood	Flowgate	MISO	($0.0)	$0.0	($0.0)	$1.5	($0.0)	$1.5	3,399	198
13	Person - Sedge Hill	Line	Dominion	$4.0	($2.1)	$1.9	$2.3	($0.9)	$1.4	1,249	210
14	Cedar Grove - Clifton	Line	PSEG	($0.2)	$0.1	($0.1)	$1.7	($0.3)	$1.3	1,179	79
15	Alpine - Belvidere	Flowgate	MISO	($0.0)	$0.0	($0.0)	$1.3	$0.0	$1.3	339	0
16	Brunner Island - Yorkanna	Line	Met-Ed	$0.3	$0.0	$0.3	$1.2	$0.0	$1.2	681	74
17	Lake George - Aetna	Flowgate	MISO	($0.1)	$0.5	$0.4	$0.8	$0.4	$1.1	483	244
18	Bagley - Graceton	Line	BGE	$0.4	($0.2)	$0.2	$1.0	($0.0)	$1.0	554	127
19	Batesville - Hubble	Flowgate	MISO	$0.0	$0.2	$0.2	$1.1	($0.1)	$1.0	379	158
20	Brokaw - Leroy	Flowgate	MISO	$0.4	($0.1)	$0.3	$0.6	$0.3	$1.0	1,744	528
	Top 20 Total			$44.8	($9.7)	$35.1	$43.3	($0.8)	$42.5	23,979	5,381
	All Other Constraints			$18.8	($0.2)	$18.6	$30.3	($5.5)	$24.8	144,873	16,817
	Total			$63.7	($10.0)	$53.7	$73.7	($6.3)	$67.3	168,852	22,198

Marginal Losses Component of LMP

Zonal Marginal Loss Costs

Table G-21 provides marginal loss costs by control zone and type for 2018. Table G-22 provides total marginal loss costs by control zone and month for 2017 and 2018. The total marginal loss cost for the External category was $0.7 million in 2018.

Table G-21 Marginal loss costs by control zone and type (Dollars (Millions)): 2018

Marginal Loss Costs by Control Zone (Millions)										
	Day Ahead				Balancing					
	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Inadvertent Charges	Grand Total
AECO	$5.7	($1.7)	$0.1	$7.5	$0.2	($0.3)	($0.1)	$0.4	$0.0	$8.0
AEP	($68.5)	($291.6)	$2.6	$225.7	$3.3	$5.9	($4.2)	($6.8)	$0.0	$218.9
APS	$11.2	($44.4)	$1.6	$57.2	$0.3	($0.2)	($1.7)	($1.2)	$0.0	$56.0
ATSI	$35.1	($27.8)	$5.7	$68.6	($0.5)	$1.4	($7.7)	($9.6)	$0.0	$59.0
BGE	$49.1	$20.9	$3.1	$31.3	$0.5	($0.7)	($3.2)	($2.0)	$0.0	$29.3
ComEd	($231.8)	($408.5)	($5.9)	$170.9	$4.6	($4.4)	$4.6	$13.5	$0.0	$184.4
DAY	$14.4	($7.3)	$1.6	$23.3	($0.0)	($0.7)	($2.0)	($1.3)	$0.0	$22.0
DEOK	($18.9)	($30.3)	($1.3)	$10.1	$0.3	($1.4)	$2.6	$4.3	$0.0	$14.4
DLCO	$2.3	($6.9)	$0.4	$9.6	($0.1)	($0.1)	($0.4)	($0.4)	$0.0	$9.1
Dominion	$78.1	($13.1)	$1.1	$92.2	$1.8	($1.2)	($1.2)	$1.7	$0.0	$93.9
DPL	$24.8	$3.9	$2.0	$22.9	($1.0)	($1.5)	($2.6)	($2.1)	$0.0	$20.8
EKPC	($14.8)	($19.5)	$1.0	$5.7	$0.5	($0.1)	($1.1)	($0.6)	$0.0	$5.2
External	($16.7)	($20.4)	$25.4	$29.2	($6.1)	($8.4)	($30.7)	($28.4)	$0.0	$0.7
JCPL	$9.1	($0.5)	$1.3	$10.9	$0.6	($0.1)	($1.5)	($0.8)	$0.0	$10.1
Met-Ed	($0.2)	($20.7)	($0.1)	$20.5	$0.4	$0.6	($0.1)	($0.3)	$0.0	$20.1
OVEC	$0.0	($1.6)	$0.9	$2.5	($0.2)	($0.0)	($0.8)	($1.0)	($0.0)	$1.5
PECO	$2.7	($40.2)	$1.1	$44.0	$1.0	$1.0	($1.0)	($0.9)	$0.0	$43.1
PENELEC	($4.1)	($55.7)	($0.7)	$51.0	$0.0	($0.1)	($0.5)	($0.4)	$0.0	$50.6
Pepco	$46.0	$20.3	($0.3)	$25.4	($0.4)	($0.9)	$0.1	$0.6	$0.0	$26.0
PPL	($19.9)	($71.3)	$0.6	$52.1	$1.0	($1.3)	($0.6)	$1.7	$0.0	$53.8
PSEG	$19.0	($15.8)	$1.1	$35.8	($0.0)	$1.9	($1.2)	($3.1)	$0.0	$32.7
RECO	$0.6	$0.0	$0.3	$0.9	$0.0	($0.0)	($0.4)	($0.4)	$0.0	$0.5
Total	($76.7)	($1,032.2)	$41.7	$997.2	$6.1	($10.5)	($53.7)	($37.1)	$0.0	$960.1

Table G-22 Monthly marginal loss costs by control zone (Dollars (Millions)): 2017 and 2018

Marginal Loss Costs by Control Zone (Millions)														
2017														
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Inadvertent Charges	Grand Total
AECO	$0.5	$0.4	$0.5	$0.3	$0.1	$0.4	$0.9	$0.6	$0.3	$0.2	$0.1	$0.8	$0.0	$5.0
AEP	$15.2	$11.4	$15.0	$8.9	$11.9	$11.9	$15.6	$12.6	$9.6	$9.2	$9.1	$23.5	$0.0	$153.9
APS	$3.8	$2.7	$3.5	$2.5	$2.0	$2.6	$4.0	$3.4	$2.9	$2.6	$3.2	$5.3	$0.0	$38.5
ATSI	$3.0	$2.6	$4.7	$2.6	$3.4	$3.3	$3.9	$3.3	$3.1	$3.3	$3.7	$4.0	$0.0	$40.8
BGE	$2.6	$1.9	$2.5	$1.6	$1.1	$1.7	$2.6	$2.0	$1.5	$1.3	$1.1	$2.9	$0.0	$22.8
ComEd	$11.3	$8.4	$11.5	$10.0	$9.8	$9.8	$12.0	$9.4	$10.1	$9.9	$10.7	$17.8	$0.0	$130.8
DAY	$1.6	$0.9	$2.1	$2.0	$2.3	$2.3	$2.6	$2.3	$1.9	$1.9	$2.0	$2.1	$0.0	$24.1
DEOK	$1.0	$1.2	$1.2	$1.1	$1.0	$1.3	$1.0	$0.9	$1.3	$1.1	$1.2	$1.0	$0.0	$13.2
DLCO	$0.7	$0.5	$0.6	$0.4	$0.4	$0.6	$0.7	$0.6	$0.6	$0.5	$0.6	$0.9	$0.0	$7.0
Dominion	$6.3	$4.0	$5.2	$4.1	$5.4	$5.9	$8.7	$6.1	$5.7	$4.9	$4.5	$7.6	$0.0	$68.5
DPL	$0.7	$0.8	$1.0	$0.5	$0.4	$0.8	$1.6	$1.1	$0.6	$0.4	$0.4	$3.0	$0.0	$11.3
EKPC	$0.0	($0.1)	($0.1)	($0.2)	$0.2	$0.3	$0.4	$0.4	$0.5	$0.3	$0.1	($0.0)	$0.0	$1.7
External	$0.9	$0.5	$0.1	($1.6)	($1.5)	($0.7)	($1.4)	($1.1)	($1.1)	($0.9)	($0.4)	$2.1	$0.0	($5.0)
JCPL	$0.5	$0.4	$0.6	$0.5	$0.5	$0.5	$0.6	$0.5	$0.5	$0.3	$0.2	$1.6	$0.0	$6.6
Met-Ed	$1.4	$1.0	$1.1	$1.0	$1.6	$1.4	$1.7	$1.4	$1.3	$1.0	$1.7	$1.7	$0.0	$16.3
PECO	$2.2	$1.7	$2.6	$2.0	$2.8	$3.1	$3.3	$2.6	$3.0	$2.3	$2.9	$2.4	$0.0	$31.1
PENELEC	$3.8	$2.5	$4.3	$3.0	$4.0	$3.6	$4.9	$3.7	$3.3	$3.0	$3.3	$4.6	$0.0	$44.0
Pepco	$1.8	$1.5	$1.6	$1.2	$1.1	$1.4	$2.1	$1.7	$1.4	$1.3	$1.3	$2.5	$0.0	$18.8
PPL	$2.4	$2.1	$2.3	$2.4	$2.5	$2.4	$3.8	$3.0	$3.3	$3.1	$3.8	$4.5	$0.0	$35.6
PSEG	$2.7	$2.0	$2.4	$1.7	$1.2	$2.1	$2.5	$2.3	$2.3	$1.5	$1.8	$3.1	$0.0	$25.5
RECO	$0.1	$0.0	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.0	($0.0)	($0.0)	($0.0)	$0.1	$0.0	$0.3
Total	$62.3	$46.4	$62.8	$44.2	$50.1	$54.8	$71.6	$56.8	$52.0	$47.1	$51.3	$91.5	$0.0	$690.8

Marginal Loss Costs by Control Zone (Millions)														
2018														
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Inadvertent Charges	Grand Total
AECO	$2.5	$0.3	$0.2	$0.0	$0.3	$0.3	$1.0	$1.3	$0.5	$0.2	$0.8	$0.7	$0.0	$8.0
AEP	$58.8	$11.6	$15.5	$10.9	$13.4	$14.0	$17.8	$19.4	$14.5	$13.5	$15.7	$13.8	$0.0	$218.9
APS	$13.5	$3.0	$4.0	$3.2	$3.7	$3.4	$4.7	$4.7	$3.9	$3.2	$4.4	$4.3	$0.0	$56.0
ATSI	$7.7	$3.3	$4.7	$4.7	$4.8	$4.8	$5.6	$5.3	$5.5	$4.4	$4.4	$3.8	$0.0	$59.0
BGE	$6.8	$1.6	$1.9	$1.3	$1.6	$1.7	$3.1	$3.2	$2.2	$1.7	$2.2	$1.9	$0.0	$29.3
ComEd	$43.1	$9.3	$12.2	$10.8	$13.5	$10.8	$14.4	$14.8	$12.7	$12.6	$16.1	$14.1	$0.0	$184.4
DAY	$4.6	$1.4	$1.9	$2.2	$2.3	$1.9	$1.4	$1.0	$1.7	$1.2	$1.1	$1.3	$0.0	$22.0
DEOK	($1.4)	$0.7	$0.5	$1.0	$1.3	$1.7	$1.8	$1.6	$1.6	$2.3	$1.8	$1.7	$0.0	$14.4
DLCO	$2.0	$0.5	$0.8	$0.7	$0.8	$0.6	$0.6	$0.6	$0.6	$0.6	$0.7	$0.7	$0.0	$9.1
Dominion	$20.7	$4.0	$6.6	$4.5	$7.0	$6.9	$9.0	$8.8	$7.6	$6.3	$6.0	$6.3	$0.0	$93.9
DPL	$8.7	$1.2	$0.8	$0.8	$0.5	$0.6	$1.9	$2.0	$1.1	$0.7	$1.1	$1.4	$0.0	$20.8
EKPC	$1.8	$0.2	$0.1	$0.5	$0.2	$0.3	$0.2	$0.5	$0.4	$0.4	$0.1	$0.3	$0.0	$5.2
External	$7.1	$0.5	$1.1	$0.6	($1.0)	($1.1)	($0.4)	($0.6)	($1.0)	($1.5)	($1.3)	($1.5)	$0.0	$0.7
JCPL	$6.1	$0.4	$0.3	$0.5	$0.5	$0.2	$0.6	$0.7	$0.1	$0.0	$0.1	$0.5	$0.0	$10.1
Met-Ed	$3.2	$1.2	$1.6	$1.5	$1.3	$1.6	$1.7	$1.6	$1.7	$1.8	$1.2	$1.8	$0.0	$20.1
OVEC	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$1.5	($0.0)	$1.5
PECO	$4.6	$2.0	$3.7	$3.3	$3.7	$3.7	$3.8	$3.7	$3.9	$3.2	$4.4	$3.1	$0.0	$43.1
PENELEC	$8.6	$3.0	$4.5	$3.3	$3.1	$4.3	$5.0	$4.1	$3.0	$3.3	$3.7	$4.7	$0.0	$50.6
Pepco	$6.1	$1.3	$2.1	$1.3	$1.8	$1.5	$2.4	$2.5	$1.9	$1.4	$2.1	$1.5	$0.0	$26.0
PPL	$9.9	$2.0	$2.1	$2.3	$2.4	$4.3	$5.1	$5.3	$6.0	$4.7	$5.2	$4.4	$0.0	$53.8
PSEG	$7.9	$2.0	$2.6	$1.9	$2.3	$2.1	$2.4	$2.5	$2.3	$2.0	$2.2	$2.5	$0.0	$32.7
RECO	$0.4	$0.0	($0.0)	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.0	($0.1)	($0.0)	$0.0	$0.0	$0.5
Total	$222.8	$49.5	$67.2	$55.4	$63.4	$63.2	$82.2	$83.1	$70.2	$62.1	$72.2	$68.9	$0.0	$960.1

Energy Component of LMP

Zonal Energy Costs (SMP)

Table G-23 provides energy costs, defined by SMP, by control zone and type for 2018. Table G-24 provides total energy costs by control zone and month for 2017 and 2018. The total energy cost for the External category in 2018 was $295.0 million.

Table G-23 Energy costs by control zone and type (Dollars (Millions)): 2018

	Energy Costs by Control Zone (Millions)									
	Day Ahead				Balancing					
	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Inadvertent Charges	Grand Total
AECO	$427.1	$289.3	$0.0	$137.8	($0.2)	($27.5)	$0.0	$27.3	$0.1	$165.2
AEP	$6,177.3	$7,502.1	$0.0	($1,324.8)	($105.2)	($174.5)	$0.0	$69.3	$0.8	($1,254.8)
APS	$2,104.0	$1,997.1	$0.0	$106.8	$26.9	($8.1)	$0.0	$35.0	$0.3	$142.1
ATSI	$3,164.4	$2,164.5	$0.0	$999.9	($73.8)	($70.0)	$0.0	($3.8)	$0.4	$996.5
BGE	$2,036.5	$1,672.5	$0.0	$364.0	($6.8)	($30.8)	$0.0	$24.0	$0.2	$388.2
ComEd	$5,222.5	$6,310.6	$0.0	($1,088.1)	($79.2)	($11.8)	$0.0	($67.3)	$0.5	($1,155.0)
DAY	$835.5	$382.2	$0.0	$453.3	($4.3)	($4.3)	$0.0	($0.0)	$0.1	$453.4
DEOK	$1,173.5	$792.1	$0.0	$381.3	($17.2)	$13.2	$0.0	($30.4)	$0.2	$351.1
DLCO	$579.4	$661.5	$0.0	($82.1)	($5.4)	($19.0)	$0.0	$13.6	$0.1	($68.5)
Dominion	$7,492.0	$7,326.6	$0.0	$165.4	$8.5	$44.3	$0.0	($35.7)	$0.6	$130.3
DPL	$809.8	$353.1	$0.0	$456.7	($18.7)	($11.8)	$0.0	($6.9)	$0.1	$449.9
EKPC	$534.6	$391.9	$0.0	$142.8	($7.1)	($6.8)	$0.0	($0.3)	$0.1	$142.6
External	$890.8	$605.2	$0.0	$285.6	$225.6	$216.3	$0.0	$9.4	$0.0	$295.0
JCPL	$934.6	$620.6	$0.0	$314.0	$4.6	($19.3)	$0.0	$23.9	$0.1	$338.1
Met-Ed	$690.8	$936.4	$0.0	($245.5)	$7.3	($21.0)	$0.0	$28.4	$0.1	($217.1)
OVEC	$0.0	$36.6	$0.0	($36.6)	$3.6	$0.3	$0.0	$3.3	($0.0)	($33.3)
PECO	$1,731.4	$2,624.2	$0.0	($892.8)	$8.3	$35.8	$0.0	($27.5)	$0.2	($920.1)
PENELEC	$2,647.7	$3,599.8	$0.0	($952.0)	($60.7)	($111.9)	$0.0	$51.2	$0.1	($900.8)
Pepco	$2,790.1	$2,148.5	$0.0	$641.6	($41.8)	($47.8)	$0.0	$6.1	$0.2	$647.9
PPL	$1,876.2	$2,453.3	$0.0	($577.1)	$4.1	($6.2)	$0.0	$10.4	$0.2	($566.5)
PSEG	$1,771.0	$1,787.4	$0.0	($16.4)	($11.5)	$49.7	$0.0	($61.1)	$0.2	($77.3)
RECO	$58.7	$3.5	$0.0	$55.2	($1.4)	($2.4)	$0.0	$1.0	$0.0	$56.3
Total	$43,947.9	$44,658.9	$0.0	($711.0)	($144.1)	($213.8)	$0.0	$69.7	$4.6	($636.7)

Table G-24 Monthly energy costs by control zone (Dollars (Millions)): 2017 and 2018

Energy Costs by Control Zone (Millions)														
2017														
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Inadvertent Charge	Grand Total
AECO	$6.1	$4.6	$3.3	$4.6	$13.3	$9.1	$17.1	$11.2	$6.8	$5.1	$4.6	$12.8	$0.1	$98.7
AEP	($89.9)	($73.6)	($88.7)	($39.5)	($84.1)	($88.7)	($107.2)	($84.6)	($33.7)	($26.3)	($20.0)	($156.5)	$1.1	($891.7)
APS	$7.4	$9.8	$14.5	$1.6	$20.0	$3.2	($6.9)	($7.4)	($12.5)	($9.5)	($7.1)	$18.3	$0.4	$31.8
ATSI	$82.1	$64.7	$93.9	$52.2	$53.3	$63.8	$65.4	$62.0	$51.4	$66.9	$48.6	$74.5	$0.6	$779.4
BGE	$32.9	$30.4	$37.4	$23.8	$15.4	$28.9	$34.8	$29.2	$18.2	$20.6	$17.3	$35.4	$0.3	$324.7
ComEd	($94.4)	($49.2)	($78.5)	($92.1)	($80.1)	($49.1)	($60.6)	($46.6)	($59.0)	($80.8)	($83.0)	($115.2)	$0.9	($887.8)
DAY	$23.1	$19.8	$11.1	$3.4	$7.0	$13.1	$14.3	$11.7	$12.6	$8.9	$11.6	$25.5	$0.2	$162.3
DEOK	$19.0	$2.4	$8.0	$6.0	$32.3	$17.4	$34.9	$21.2	$18.5	$12.3	$11.3	$23.7	$0.2	$207.1
DLCO	($8.0)	($8.6)	($11.1)	($4.6)	$6.2	($7.6)	($5.6)	($6.1)	($7.4)	($13.6)	($5.7)	($13.7)	$0.1	($85.8)
Dominion	$2.6	$6.0	($2.4)	$11.0	$12.7	($15.7)	($14.7)	($7.0)	($6.3)	$9.4	$5.5	$42.6	$0.9	$44.6
DPL	$39.3	$23.9	$26.3	$22.2	$14.9	$22.3	$26.8	$25.4	$21.2	$19.9	$28.8	$45.9	$0.2	$317.1
EKPC	$13.8	$10.8	$13.9	$14.2	$7.9	$7.7	$9.9	$6.5	$8.3	$11.0	$16.7	$20.0	$0.1	$140.8
External	$0.8	$11.7	$27.8	$57.6	$49.6	$49.3	$61.1	$48.9	$55.5	$36.5	$26.9	$38.5	$0.0	$464.1
JCPL	$13.8	$7.2	$8.9	$14.3	$4.5	$9.5	$17.5	$8.2	$1.1	$5.5	$12.6	$26.3	$0.2	$129.6
Met-Ed	($16.9)	($17.1)	($1.7)	($11.1)	($24.7)	($16.8)	($19.3)	($14.8)	($14.9)	($9.2)	($21.1)	($16.8)	$0.1	($184.2)
PECO	($69.6)	($59.0)	($80.1)	($60.5)	($50.8)	($58.2)	($58.2)	($55.5)	($56.1)	($50.6)	($57.6)	($58.8)	$0.4	($714.6)
PENELEC	($70.8)	($51.7)	($81.9)	($56.7)	($71.4)	($59.3)	($76.4)	($66.4)	($52.2)	($52.2)	($43.6)	($101.4)	$0.2	($783.9)
Pepco	$63.3	$45.4	$55.9	$46.1	$45.5	$53.4	$56.2	$54.0	$40.3	$46.9	$44.4	$59.7	$0.3	$611.5
PPL	($3.0)	($10.9)	$21.0	($15.0)	($15.9)	($21.9)	($43.9)	($38.6)	($34.2)	($42.1)	($37.1)	($26.4)	$0.3	($267.5)
PSEG	($1.8)	($1.1)	($23.3)	($12.0)	$7.2	($1.7)	$3.0	$4.5	($0.4)	$2.5	$8.1	($1.6)	$0.4	($16.2)
RECO	$3.7	$2.6	$3.5	$3.0	$3.5	$4.1	$5.2	$4.2	$4.1	$3.3	$3.2	$4.4	$0.0	$44.7
Total	($46.7)	($31.8)	($42.3)	($31.5)	($33.6)	($37.1)	($46.6)	($40.0)	($38.9)	($35.5)	($35.6)	($62.7)	$7.1	($475.2)
Energy Costs by Control Zone (Millions)														
2018														
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Inadvertent Charge	Grand Total
AECO	$28.1	$6.4	$8.2	$16.2	$6.8	$12.3	$17.5	$18.9	$19.1	$15.4	$6.9	$9.2	$0.1	$165.2
AEP	($292.2)	($78.8)	($78.4)	($38.3)	($70.8)	($95.8)	($133.1)	($159.2)	($85.2)	($91.3)	($84.1)	($48.3)	$0.8	($1,254.8)
APS	$57.7	$9.2	$10.2	$23.8	($4.1)	($5.8)	$1.0	$4.8	$10.2	$15.7	$8.8	$10.2	$0.3	$142.1
ATSI	$144.0	$62.6	$95.9	$70.0	$85.9	$79.0	$98.0	$92.7	$81.2	$72.5	$62.4	$51.9	$0.4	$996.5
BGE	$59.5	$28.2	$30.3	$16.5	$18.1	$27.6	$43.3	$43.9	$33.4	$27.5	$29.5	$30.1	$0.2	$388.2
ComEd	($264.3)	($56.5)	($84.6)	($66.6)	($85.9)	($61.7)	($79.5)	($75.2)	($86.2)	($94.3)	($107.5)	($93.1)	$0.5	($1,155.0)
DAY	$46.9	$19.2	$24.5	$9.4	$19.7	$43.0	$47.4	$49.7	$42.7	$46.3	$53.3	$51.1	$0.1	$453.4
DEOK	$92.4	$14.5	$39.1	$40.2	$48.4	$38.1	$24.0	$19.8	$18.5	$0.6	$6.3	$8.8	$0.2	$351.1
DLCO	($25.7)	($7.1)	($9.7)	($3.1)	($2.3)	($5.6)	$1.2	$2.3	($4.9)	$1.1	($2.4)	($12.4)	$0.1	($68.5)
Dominion	$55.5	$4.9	$20.2	$23.3	$18.1	($11.5)	($10.9)	($5.8)	($18.7)	$4.4	$32.7	$17.4	$0.6	$130.3
DPL	$90.2	$27.7	$33.1	$24.9	$29.4	$33.2	$38.7	$35.1	$29.5	$24.0	$40.4	$43.7	$0.1	$449.9
EKPC	$23.1	$10.2	$16.4	$11.6	$13.9	$4.3	$9.7	$3.8	$8.4	$9.9	$18.4	$12.6	$0.1	$142.6
External	($72.7)	$17.0	($17.4)	($18.3)	$8.4	$42.4	$45.2	$57.2	$66.6	$68.3	$36.2	$62.1	$0.0	$295.0
JCPL	$97.7	$11.2	$6.5	$1.7	$8.7	$17.9	$26.1	$31.2	$22.1	$35.7	$45.0	$34.0	$0.1	$338.1
Met-Ed	($21.3)	($16.5)	($12.9)	($20.1)	($14.4)	($19.2)	($18.7)	($17.0)	($21.4)	($23.8)	($10.4)	($21.3)	$0.1	($217.1)
OVEC	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($33.3)	($0.0)	($33.3)
PECO	($86.6)	($57.7)	($70.8)	($84.8)	($95.0)	($65.7)	($75.7)	($71.9)	($70.8)	($69.0)	($92.2)	($79.9)	$0.2	($920.1)
PENELEC	($195.7)	($55.7)	($72.6)	($66.3)	($59.4)	($71.9)	($84.7)	($65.5)	($42.1)	($45.3)	($66.5)	($75.4)	$0.1	($900.8)
Pepco	$125.0	$46.0	$38.4	$41.4	$38.3	$50.2	$63.0	$60.1	$42.8	$37.4	$51.0	$54.2	$0.2	$647.9
PPL	($49.4)	($15.3)	($8.8)	($12.9)	($17.1)	($51.9)	($65.7)	($81.6)	($83.5)	($62.1)	($63.3)	($55.0)	$0.2	($566.5)
PSEG	$23.1	($5.9)	($13.0)	($10.0)	$7.7	($3.3)	($7.0)	($4.3)	($11.6)	($19.6)	($16.0)	($17.5)	$0.2	($77.3)
RECO	$9.2	$2.8	$3.5	$3.5	$4.5	$4.5	$6.1	$5.9	$4.6	$3.9	$4.1	$3.8	$0.0	$56.3
Total	($155.5)	($33.8)	($42.1)	($37.8)	($41.1)	($39.8)	($54.0)	($54.9)	($45.4)	($42.7)	($47.5)	($46.9)	$4.6	($636.7)

Appendix H FTR Volumes

This Appendix presents the data used to create Figure 13-5 in the 2018 State of the Market Report for PJM. Each table shows the FTR bid volume, cleared volume and net bid volume by planning period. The bid volume includes the buy, sell and self-scheduled offers. The cleared volume includes the cleared buy, cleared sell and self-scheduled offers. The net bid volume includes all bid and self-scheduled offers, excluding sell offers. The Annual Auction volume is included in June of each planning period.

Table H-1 Annual and Monthly FTR Auction bid and cleared volume: Planning period 2003/2004

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

Table H-2 Annual and Monthly FTR Auction bid and cleared volume: Planning period 2004/2005

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

Table H-3 Annual and Monthly FTR Auction bid and cleared volume: Planning period 2005/2006

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

Table H-4 Annual and Monthly FTR Auction bid and cleared volume: Planning period 2006/2007

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

Table H-5 Annual and Monthly FTR Auction bid and cleared volume: Planning period 2007/2008

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

Table H-6 Annual and Monthly FTR Auction bid and cleared volume: Planning period 2008/2009

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

Table H-7 Annual and Monthly FTR Auction bid and cleared volume: Planning period 2009/2010

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

Table H-8 Annual and Monthly FTR Auction bid and cleared volume: Planning period 2010/2011

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

Table H-9 Annual and Monthly FTR Auction bid and cleared volume: Planning period 2011/2012

Auction Date	Net Bid Volume (MW)	Cleared Volume (MW)	Bid Volume (MW)
Jun-11	6,233,773	847,183	7,437,352
Jul-11	1,602,795	241,288	2,233,307
Aug-11	1,385,040	204,442	1,981,888
Sep-11	969,184	112,746	1,581,241
Oct-11	1,424,062	134,653	1,908,956
Nov-11	1,098,133	117,705	1,562,764
Dec-11	811,035	93,492	1,318,347
Jan-12	772,843	88,683	1,240,355
Feb-12	816,356	93,977	1,234,341
Mar-12	665,949	99,659	1,126,207
Apr-12	449,078	131,218	795,785
May-12	295,103	94,642	470,495
Total	16,523,352	2,259,688	22,891,036

Table H-10 Annual and Monthly FTR Auction bid and cleared volume: Planning period 2012/2013

Auction Date	Net Bid Volume (MW)	Cleared Volume (MW)	Bid Volume (MW)
Jun-12	6,407,647	710,169	7,598,008
Jul-12	2,177,990	182,695	2,735,269
Aug-12	909,111	151,693	1,418,249
Sep-12	1,877,747	146,352	2,446,553
Oct-12	788,486	118,052	1,310,859
Nov-12	1,765,875	98,494	2,142,231
Dec-12	1,757,292	115,322	2,230,391
Jan-13	696,121	121,357	1,067,354
Feb-13	805,330	118,298	1,129,794
Mar-13	854,219	132,779	1,196,032
Apr-13	525,505	97,353	790,360
May-13	477,217	87,001	595,463
Total	15,684,148	1,522,778	19,881,561

Table H-11 Annual and Monthly FTR Auction bid and cleared volume: Planning period 2013/2014

Auction Date	Net Bid Volume (MW)	Cleared Volume (MW)	Bid Volume (MW)
Jun-13	6,607,570	791,995	7,909,805
Jul-13	2,000,987	189,328	2,571,100
Aug-13	2,193,738	239,816	2,726,508
Sep-13	2,046,401	260,404	2,604,664
Oct-13	1,692,645	222,661	2,233,085
Nov-13	1,823,502	237,130	2,307,163
Dec-13	1,795,279	216,021	2,298,733
Jan-14	1,713,078	185,284	2,092,055
Feb-14	1,588,809	157,166	1,979,691
Mar-14	1,560,077	169,500	1,918,025
Apr-14	1,247,111	127,436	1,559,987
May-14	757,354	80,601	934,844
Total	25,026,550	2,877,341	31,135,659

Table H-12 Annual and Monthly FTR Auction bid and cleared volume: Planning period 2014/2015

Auction Date	Net Bid Volume (MW)	Cleared Volume (MW)	Bid Volume (MW)
Jun-14	8,631,333	744,482	9,600,316
Jul-14	2,365,262	123,067	2,689,241
Aug-14	2,191,719	154,391	2,513,616
Sep-14	2,232,435	167,077	2,636,101
Oct-14	1,935,928	153,735	2,289,409
Nov-14	2,006,939	175,554	2,339,892
Dec-14	1,831,645	116,545	2,138,480
Jan-15	1,586,530	81,368	1,849,891
Feb-15	1,446,978	110,669	1,701,821
Mar-15	1,395,961	97,219	1,684,143
Apr-15	1,194,256	78,599	1,429,386
May-15	699,951	42,698	817,152
Total	27,518,938	2,045,403	31,689,447

Table H-13 Annual and Monthly FTR Auction bid and cleared volume: Planning period 2015/2016

Auction Date	Net Bid Volume (MW)	Cleared Volume (MW)	Bid Volume (MW)
Jun-15	6,726,193	634,988	7,956,486
Jul-15	1,713,451	90,329	2,341,646
Aug-15	1,593,674	78,196	2,046,131
Sep-15	2,160,014	160,357	2,628,872
Oct-15	1,196,435	71,600	1,704,518
Nov-15	2,060,194	92,310	2,482,819
Dec-15	1,834,874	93,273	2,239,329
Jan-16	2,033,402	151,198	2,374,385
Feb-16	2,305,964	89,153	2,610,677
Mar-16	2,085,527	151,835	2,444,912
Apr-16	1,393,628	117,292	1,663,102
May-16	658,850	59,976	780,265
Total	25,762,206	1,790,507	31,273,141

Table H-14 Annual and Monthly FTR Auction bid and cleared volume: Planning period 2016/2017

Auction Date	Net Bid Volume (MW)	Cleared Volume (MW)	Bid Volume (MW)
Jun-16	6,208,065	701,086	7,476,215
Jul-16	2,219,166	161,129	2,751,687
Aug-16	2,130,193	166,317	2,611,601
Sep-16	1,876,699	151,538	2,379,705
Oct-16	1,522,572	149,106	1,920,453
Nov-16	1,191,214	106,349	1,542,444
Dec-16	995,951	66,497	1,341,292
Jan-17	1,042,674	60,087	1,305,937
Feb-17	998,397	76,384	1,233,142
Mar-17	846,294	105,822	1,141,063
Apr-17	653,571	70,885	897,780
May-17	463,486	59,067	595,694
Total	20,148,281	1,874,268	25,197,013

Table H-15 Annual and Monthly FTR Auction bid and cleared volume: Planning period 2017/2018 through May 2018

Auction Date	Net Bid Volume (MW)	Cleared Volume (MW)	Bid Volume (MW)
Jun-17	5,455,078	872,195	6,469,151
Jul-17	2,003,170	257,105	2,530,997
Aug-17	1,703,960	178,490	2,240,951
Sep-17	1,372,384	181,542	1,863,571
Oct-17	1,172,291	150,774	1,649,567
Nov-17	1,327,717	105,816	1,697,539
Dec-17	1,366,297	131,964	1,662,660
Jan-18	1,201,482	87,763	1,494,040
Feb-18	1,132,589	69,333	1,378,665
Mar-18	1,027,661	73,656	1,291,330
Apr-18	616,013	44,824	857,945
May-18	355,923	40,976	485,269
Total	18,734,565	2,194,438	23,621,686

Table H-16 Annual and Monthly FTR Auction bid and cleared volume: Planning period 2018/2019 through December 2018

Auction Date	Net Bid Volume (MW)	Cleared Volume (MW)	Bid Volume (MW)
Jun-18	5,862,680	1,023,834	7,042,598
Jul-18	1,760,345	154,341	2,243,378
Aug-18	1,123,055	(27,571)	2,359,882
Sep-18	1,750,157	153,418	2,757,631
Oct-18	758,670	138,587	1,599,115
Nov-18	908,639	172,444	1,592,686
Dec-18	608,941	112,617	1,469,596
Total	12,772,487	1,727,670	19,064,885

Figure H-1 summarizes the total revenue associated with all FTRs, regardless of source, to FTR sinks that produced the largest positive and negative revenue from the 2018/2021 Long Term FTR Auction. The top 10 positive revenue producing FTR sinks accounted for $88.4 million (42.4 percent of the total positive revenue from sinks) and 6.5 percent of all FTRs purchased in the auction. The top 10 negative revenue producing FTR sinks accounted for -$66.0 million (36.1 percent of total negative revenue from sinks) and constituted 5.1 percent of all FTRs bought in the auction.

Figure H-1 Ten largest positive and negative revenue producing FTR sinks purchased in the Long Term FTR Auction: Planning periods 2018/2021

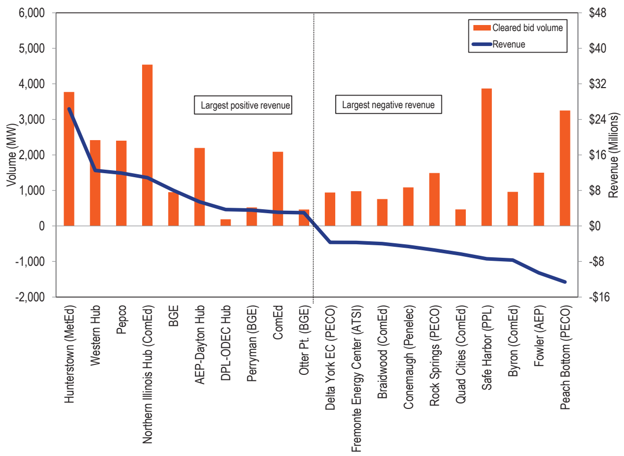


Figure H-2 summarizes the total revenue associated with all FTRs, regardless of sink, to FTR sources that produced the largest positive and negative revenue from the 2018/2021 Long Term FTR Auction. The top 10 positive revenue producing FTR sources accounted for $89.4 million (41.5 percent of the total positive revenue from sources) and 8.3 percent of all FTRs bought in the auction. The top 10 negative revenue producing FTR sources accounted for -$59.7 million (32.6 percent of total negative revenue from sources) and constituted 4.0 percent of all FTRs bought in the auction.

Figure H-2 Ten largest positive and negative revenue producing FTR sources purchased in the Long Term FTR Auction: Planning periods 2018/2021

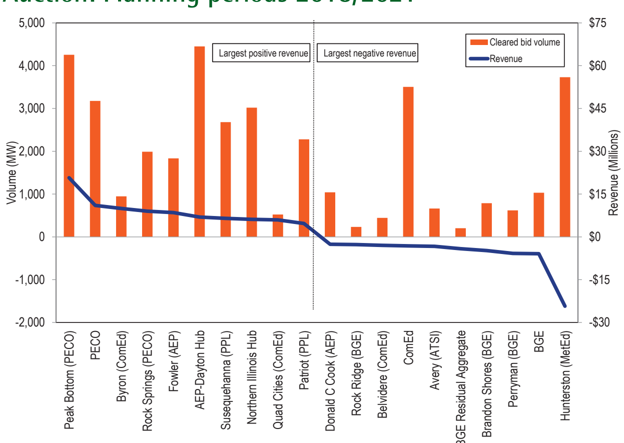


Figure H-3 summarizes the total revenue associated with all FTR sink points, regardless of source, that produced the largest positive and negative revenue in the Annual FTR Auction for the 2018/2019 planning period. The top 10 positive revenue sinks accounted for $450.7 million (46.1 percent of total positive revenue from sinks) and 12.4 percent of all FTRs purchased. The top 10 negative revenue sinks accounted for -$49.9 million (33.2 percent of total negative revenue from sinks) and 1.9 percent of all FTRs purchased.

Figure H-3 Ten largest positive and negative revenue producing FTR sinks purchased in the Annual FTR Auction: Planning period 2018/2019

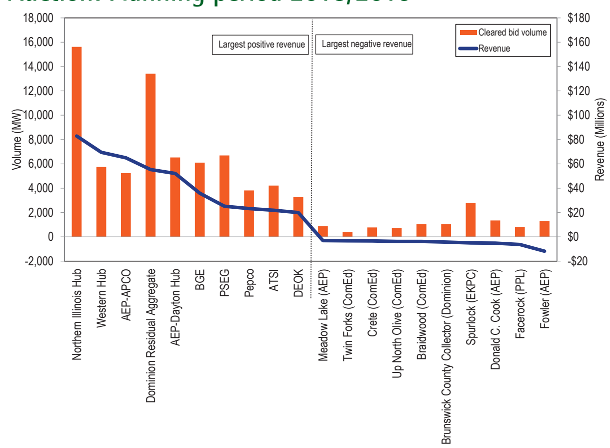


Figure H-4 summarizes total revenue associated with all FTR source points, regardless of sink, that produced the largest positive and negative revenue in the Annual FTR Auction for the 2018/2019 planning period. The top 10 positive revenue sources accounted for $320.6 million (33.3 percent of total positive revenue from sources) and 10.1 percent of all FTRs purchased. The top 10 negative revenue sources accounted for -$37.2 million (27.8 percent of total negative revenue from sources) and 4.5 percent of all FTRs purchased.

Figure H-4 Ten largest positive and negative revenue producing FTR sources purchased in the Annual FTR Auction: Planning period 2018/2019

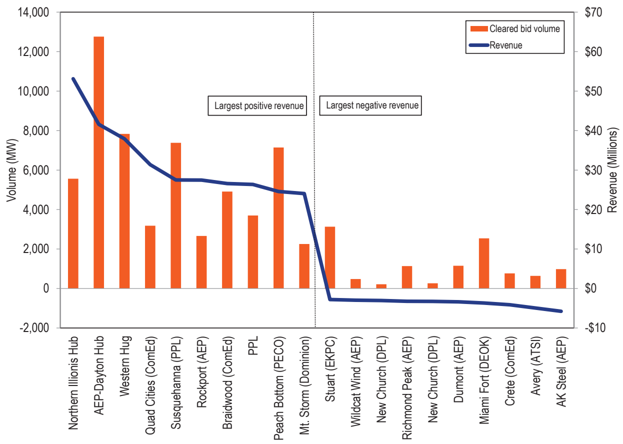


Figure H-5 summarizes total revenue associated with all FTRs, regardless of source, to the FTR sinks that produced the largest positive and negative revenue in the Monthly Balance of Planning Period FTR Auctions during the 2018/2019 planning period through December 2018. The top 10 positive revenue sinks accounted for $130.5 million (58.9 percent of total positive revenue from sinks) and 8.3 percent of all FTRs purchased. The top 10 negative revenue sinks accounted for -$36.6 million (20.7 percent of total negative revenue from sinks) and 0.4 percent of all FTRs purchased.

Figure H-5 Ten largest positive and negative revenue producing FTR sinks purchased in the Monthly Balance of Planning Period FTR Auctions: planning period 2018/2019 through December 31, 2018

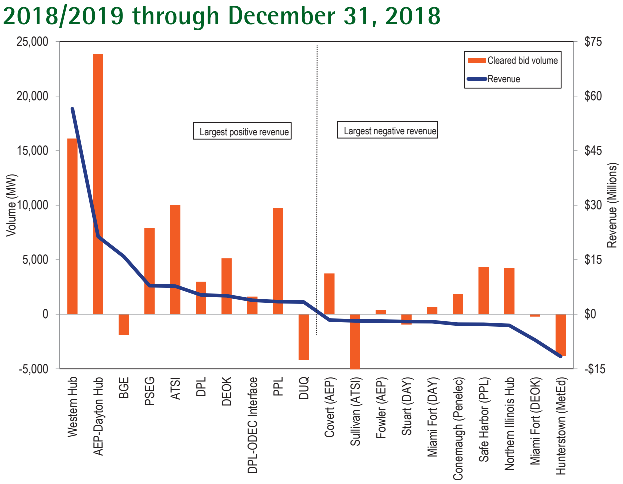
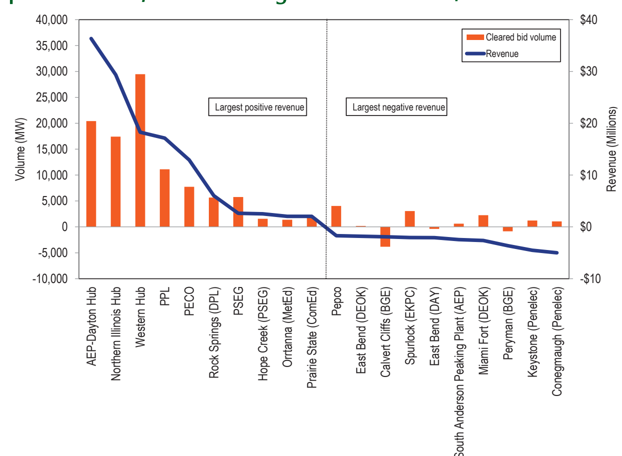


Figure H-6 summarizes the total revenue associated with all FTR source points, regardless of sink, that produced the largest positive and negative revenue in the Monthly Balance of Planning Period FTR Auctions during the 2018/2019 planning period. The top 10 positive revenue sources accounted for $129.3 million (61.8 percent of total positive revenue from sources) and 11.8 percent of all FTRs purchased. The top 10 negative revenue sources accounted for -$27.8 million (17.0 percent of total negative revenue from sources) and 0.8 percent of all FTRs purchased.

Figure H-6 Ten largest positive and negative revenue producing FTR sources purchased in the Monthly Balance of Planning Period FTR Auctions: planning period 2018/2019 through December 31, 2018



Appendix I Environmental and Renewable Energy Regulations

This appendix provides more detailed information about environmental and renewable energy regulations and the evolution of rules applicable within the PJM footprint.

Environmental and Renewable Energy Regulations

Environmental requirements and renewable energy mandates have a significant impact on PJM markets.

At the federal level, the Mercury and Air Toxics Standards Rule (MATS) requires significant investments for some fossil fuel fired power plants in the PJM footprint in order to reduce heavy metal emissions. The Environmental Protection Agency (EPA) has promulgated intrastate and interstate air quality standards and associated emissions limits for states. The Cross-State Air Pollution Rule (CSAPR) will require investments for some fossil fuel fired power plants in the PJM footprint in order to reduce SO_2 and NO_X emissions.

State regulations and multi-state agreements have an impact on PJM markets. New Jersey's high electric demand day (HEDD) rule limits NO_X emissions on peak energy demand days and requires investments for noncompliant units. CO_2 costs resulting from the Regional Greenhouse Gas Initiative (RGGI) affect some unit offers in the PJM energy market.

The investments required for environmental compliance have resulted in higher offers in the Capacity Market, and when units do not clear, in the retirement of units. Federal and state renewable energy mandates and associated incentives have resulted in the construction of substantial amounts of renewable capacity in the PJM footprint, especially wind and solar powered resources. Renewable energy credit (REC) markets created by state programs and federal tax credits have significant impacts on PJM wholesale markets.

Federal Environmental Regulation

The U.S. Environmental Protection Agency (EPA) administers the Clean Air Act (CAA). The CAA regulates air emissions by providing for the establishment of acceptable levels of emissions of hazardous air pollutants. The EPA issues technology based standards for major sources and area sources of emissions.[1] [2] The EPA's actions have and will continue to affect the cost to build and operate generating units in PJM, which in turn affects wholesale energy prices and capacity prices.

The EPA also administers the Clean Water Act (CWA), which regulates water pollution. The EPA implements the CWA through a permitting process, which regulates discharges from point sources that impact water quality and temperature in navigable waterways. In 2014, the EPA implemented new regulations for cooling water intakes under section 316(b) of the CWA.

Control of Mercury and Other Hazardous Air Pollutants

Section 112 of the CAA requires the EPA to promulgate emissions control standards, known as the National Emission Standards for Hazardous Air Pollutants (NESHAP), from both new and existing area and major sources.

On December 21, 2011, the U.S. Environmental Protection Agency (EPA) issued its Mercury and Air Toxics Standards rule (MATS), which applies the CAA maximum achievable control technology (MACT) requirement to new or modified sources of emissions of mercury and arsenic, acid gas, nickel, selenium and cyanide.[3] The rule established a compliance deadline of April 16, 2015.

In a related EPA rule, also issued on December 16, 2011, regarding utility New Source Performance Standards (NSPS), the EPA required new coal and oil fired electric utility generating units constructed after May 3, 2011, to

1 42 U.S.C. § 7401 et seq. (2000).

2 The EPA defines "major sources" as a stationary source or group of stationary sources that emit or have the potential to emit 10 tons per year or more of a hazardous air pollutant or 25 tons per year or more of a combination of hazardous air pollutants. An "area source" is any stationary source that is not a major source.

3 *National Emission Standards for Hazardous Air Pollutants From Coal and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil Fuel Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units*, EPA Docket No. EPA-HQ-OAR-2009-0234, 77 Fed. Reg. 9304 (February 16, 2012); *aff'd*, White Stallion Energy Center, LLC v EPA, No. 12-1100 (D.C. Cir. April 15, 2014).

comply with amended emission standards for SO_2, NO_X and filterable particulate matter (PM).[4]

The future of MATS is currently uncertain. On June 29, 2015, the U.S. Supreme Court remanded MATS to the U.S. Court of Appeals for the D.C. Circuit and ordered the EPA to consider cost earlier in the process when making the decision whether to regulate power plants under MATS.[5] The U.S. Supreme Court ruled in 2015 that "the EPA acted unreasonably when it deemed cost irrelevant to the decision to regulate power plants."[6] The remand did not stay MATS and had no effect on the implementation of MATS. The EPA performed a cost review and made the required determination on cost in a supplemental finding.[7] On April 14, 2016, the EPA issued the required finding that "a consideration of cost does not cause us to change our determination that regulation of hazardous air pollutant (HAP) emissions from coal- and oil-fired EGUs is appropriate and necessary."[8] The rule has been effective since April 14, 2016, and remains effective. In a case now pending before the U.S. Court of Appeals for the District of Columbia Circuit, the supplemental finding is under review.[9] On April 28, 2017, the Court granted the EPA's request to postpone scheduled oral argument "to allow the new Administration adequate time to review the Supplemental Finding to determine whether it will be reconsidered."[10]

Air Quality Standards: Control of NO_X, SO_2 and O_3 Emissions Allowances

The CAA requires each state to attain and maintain compliance with fine particulate matter and ozone national ambient air quality standards (NAAQS). Under NAAQS, the EPA establishes emission standards for six air pollutants, including NO_X, SO_2, O_3 at ground level, PM, CO, and Pb, and approves state plans to implement these standards, known as State Implementation Plans (SIPs).[11] Standards for each pollutant are set and periodically revised, most recently for SO_2 in 2010, and SIPS are filed, approved and revised accordingly.

On April 29, 2014, the U.S. Supreme Court upheld the EPA's Cross-State Air Pollution Rule (CSAPR) and on October 23, 2014, the U.S. Court of Appeals for the District of Columbia Circuit lifted the stay imposed on CSAPR, clearing the way for the EPA to implement this rule and to replace the Clean Air Interstate Rule (CAIR) then in effect. On November 21, 2014, the EPA issued a rule requiring compliance with CSAPR's Phase 1 emissions budgets effective January 1, 2015, and CSAPR's Phase 2 emissions effective January 1, 2017.[12] The ruling and the EPA rules eliminated CAIR and replaced it with CSAPR.

In January, 2015, the EPA began implementation of the Cross-State Air Pollution Rule (CSAPR) to address the CAA's requirement that each state prohibit emissions that significantly interfere with the ability of another state to meet NAAQS.[13] The CSAPR requires specific states in the eastern and central United States to reduce power plant emissions of SO_2 and NO_X that cross state lines and contribute to ozone and fine particle pollution in other states. The CSPAR requires reductions to levels consistent with the 1997 ozone and fine particle and 2006 fine particle NAAQS.[14] The CSAPR covers 28 states, including all of the PJM states except Delaware, and also excluding the District of Columbia.[15]

CSAPR establishes two groups of states with separate requirements standards. Group 1 includes a core region comprised of 21 states, including all of the PJM states except Delaware, and also excluding the District of Columbia.[16] Group 2 does not include any states in the PJM region.[17] Group 1 states must reduce both annual SO_2 and NO_X emissions to help downwind areas attain the 24-Hour and/or Annual Fine Particulate Matter[18]

4 NSPS are promulgated under CAA § 111.

5 Michigan et al. v. EPA, Slip Op. No. 14-46.

6 135 S. Ct. 2699, 2712 (2015).

7 *See Supplemental Finding That It Is Appropriate and Necessary to Regulate Hazardous Air Pollutants From Coal- and Oil-Fired Electric Utility Steam Generating Units*, EPA Docket No. EPA-HQ-OAR-2009-0234; *see also* White Stallion Energy Center, LLC v EPA, Slip Op. No. 12-1100 (D.C. Cir. 2015) (per curiam).

8 *Supplemental Finding that it is Appropriate and Necessary to Regulate Hazardous Air Pollutants from Coal- and Oil-Fired Electric Utility Steam Generating Units*, EPA Docket No. EPA-HQ-OAR-2009-0234; *see also* White Stallion Energy Center, LLC v EPA, Slip Op. No. 12-1100 (D.C. Cir. 2015) (per curiam).

9 *See* Case No. 16-1127, et al.

10 Respondent EPA's Motion to Continue Oral Argument, Case No. 16-1127, et al. (April 18, 2017) at 1.

11 Nitric Oxides (NO_X), Sulfur Dioxide (SO_2), Ozone (O_3), Particulate Matter (PM), Carbon Monoxide (CO) and Lead (Pb).

12 *Rulemaking to Amend Dates in Federal Implementation Plans Addressing Interstate Transport of Ozone and Fine Particulate Matter*, EPA-HQ-OAR-2009-0491.

13 CAA § 110(a)(2)(D)(i)(I).

14 *Federal Implementation Plans: Interstate Transport of Fine Particulate Matter and Ozone and Correction of SIP Approvals*, Final Rule, Docket No. EPA-HQ-OAR-2009-0491, 76 Fed. Reg. 48208 (August 8, 2011) ("CSAPR"); *Revisions to Federal Implementation Plans To Reduce Interstate Transport of Fine Particulate Matter and Ozone*, Final Rule, Docket No. EPA-HQ-2009-0491, 77 Fed. Reg. 10342 (February 21, 2012); *Revisions to Federal Implementation Plans To Reduce Interstate Transport of Fine Particulate Matter and Ozone*, Final Rule, Docket No. EPA-HQ-2009-0491, 77 Fed. Reg. 34830 (June 12, 2012).

15 *Id.*

16 Group 1 states include: New York, Pennsylvania, New Jersey, Maryland, Virginia, West Virginia, North Carolina, Tennessee, Kentucky, Ohio, Indiana, Illinois, Missouri, Iowa, Wisconsin, and Michigan.

17 Group 2 states include: Minnesota, Nebraska, Kansas, Texas, Alabama, Georgia and South Carolina.

18 The EPA defines Particulate Matter (PM) as "[a] complex mixture of extremely small particles and liquid droplets. It is made up of a number of components, including acids (such as nitrates and sulfates), organic chemicals, metals, and soil or dust particles." Fine PM ($PM_{2.5}$) measures less than 2.5 microns across.

NAAQS and to reduce ozone season NO_x emissions to help downwind areas attain the 2008 8-Hour Ozone NAAQS.

CSAPR requires reductions of emissions for each state below certain assurance levels, established separately for each emission type. Assurance levels are the state budget for each type of emission, determined by the sum of unit-level allowances assigned to each unit located in such state, plus a variability limit, which is meant to account for the inherent variability in the state's yearly baseline emissions. Because allowances are allocated only up to the state emissions budget, any level of emissions in a state above its budget must be covered by allowances obtained through trading for unused allowances allocated to units located in other states included in the same group.

The rule provides for implementation of a trading program for states in the CSAPR region. Sources in each state may achieve those limits as they prefer, including unlimited trading of emissions allowances among power plants within the same state and limited trading of emission allowances among power plants in different states in the same group.

If state emissions exceed the applicable assurance level, including the variability limit, a penalty is assessed and allocated to resources within the state in proportion to their responsibility for the excess. The penalty requires surrender of two additional allowances for each allowance needed to the cover the excess.

On September 7, 2016, the EPA issued a final rule updating the CSAPR ozone season NO_x emissions program to reflect the decrease to the ozone season NAAQS that occurred in 2008 (CSAPR Update).[19] The CSAPR had been finalized in 2011 based on the 1997 ozone season NAAQS. The 2008 ozone season NO_x emissions level was lowered to 0.075 ppm from 0.08 in 1997.[20] The CSAPR Update increases the reductions required from upwind states to assist downwind states' ability to meet the lower 2008 standard.

The CSAPR Update also finalizes Federal Implementation Plans (FIPs) for each of the PJM states covered by CSAPR.[21] The EPA approves a FIP for states that fail to timely submit and obtain approval of their own implementation plan (SIPs).

Starting May 1, 2017, the CSAPR Update requires reduced summertime NO_x from power plants in certain PJM states: Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, Ohio, Pennsylvania, Tennessee, Virginia and West Virginia.[22] The EPA has removed North Carolina from the ozone season NO_x trading program.[23]

Emission Standards for Reciprocating Internal Combustion Engines

On January 14, 2013, the EPA signed a final rule amending its rules regulating emissions from a wide variety of stationary reciprocating internal combustion engines (RICE).[24] RICE include certain types of electrical generation facilities like diesel engines typically used for backup, emergency or supplemental power, including facilities located behind the meter. These rules include: National Emission Standard for Hazardous Air Pollutants (NESHAP) for Reciprocating Internal Combustion Engines (RICE); New Source Performance Standards (NSPS) of Performance for Stationary Spark Ignition Internal Combustion Engines; and Standards of Performance for Stationary Compression Ignition Internal Combustion Engines (collectively RICE Rules).[25]

The RICE Rules apply to emissions such as formaldehyde, acrolein, acetaldehyde, methanol, CO, NO_x, volatile organic compounds (VOCs) and PM. The regulatory regime for RICE is complicated, and the applicable requirements turn on whether the engine is an "area source" or "major source," and the starter mechanism for the engine (compression ignition or spark ignition).[26]

19 *Cross-State Air Pollution Rule Update for the 2008 Ozone NAAQS*, EPA-HQ-OAR-2015-0500, 81 Fed. Reg. 74504 (Oct. 26, 2016) ("CSAPR Update").

20 *Federal Implementation Plans to Reduce Interstate Transport of Fine Particulate Matter and Ozone*, NOPR, EPA-HQ-OAR-2009-0491, 75 Fed. Reg. 45210, 45220 (Aug. 2, 2010).

21 CSAPR Update at 74506 & n.9. PJM states that did not submit SIPs include Illinois, Maryland, Michigan, New Jersey, North Carolina, Pennsylvania, Tennessee, Virginia, and West Virginia; PJM states submitting SIPs but not obtaining approval include Indiana, Kentucky and Ohio. *Id.*

22 *Id.* at 74554.

23 *Id.* at 74507 n.13.

24 *National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines; New Source Performance Standards for Stationary Internal Combustion Engines*, Final Rule, EPA Docket No. EPA-HQ-OAR-2008-0708, 78 Fed. Reg. 6674 (Jan. 30, 2013) ("2013 NESHAP RICE Rule"). In 2010, the EPA promulgated two rules with standards for hazardous air pollutant emissions from backup generators. The rules allowed backup generators to operate without emissions controls for fifteen hours each year as part of "demand response programs" during "emergency conditions that could lead to a potential electrical blackout." EPA Docket No. EPA-H-OAR-2009-0234 & -2011-0044, codified at 40 CFR Part 63, Subpart ZZZZ; EPA Dockets Nos. EPA-HQ-OAR-2005-0030 & EPA-HQ-OAR-2005-0029, -2010-0295, codified at 40 CFR Part 60 Subpart JJJJ ("2010 RICH NESHAP Rule").

25 *Id.*

26 CAA § 112(a) defines "major source" to mean "any stationary source or group of stationary sources located within a contiguous area and under common control that emits or has the potential to emit considering controls, in the aggregate, 10 tons per year or more of any hazardous air pollutant or 25 tons per year or more of any combination of hazardous air pollutants," and "area source" to mean, "any stationary source of hazardous air pollutants that is not a major source."

On May 22, 2012, the EPA proposed amendments to the 2010 RICE NESHAP Rule.[27] The proposed rule would have allowed owners and operators of emergency stationary internal combustion engines to operate them in emergency conditions, as defined in those regulations, as part of an emergency demand response program for 100 hours per year or the minimum hours required by an Independent System Operator's tariff, whichever is less. The rule would have increased the 2010 Rule's 15 hour per year run limit. The exempted emergency demand response programs included RPM demand resources.

On May 1, 2015, the U.S. Court of Appeals for the District of Columbia Circuit reversed the portion of the final rule exempting 100 hours of run time for certain stationary reciprocating internal combustion engines (RICE) participating in emergency demand response programs from the otherwise applicable emission standards.[28] As a result, the national emissions standards uniformly apply to all RICE.[29] The Court held that the "EPA acted arbitrarily and capriciously when it modified the National Emissions Standards and the Performance Standards to allow backup generators to operate without emissions controls for up to 100 hours per year as part of an emergency demand-response program."[30] Specifically, the Court found that the EPA failed to consider arguments concerning the rule's "impact on the efficiency and reliability of the energy grid," including arguments raised by the MMU.[31]

On April 15, 2016, the EPA issued a letter explaining how it would implement the vacatur order.[32] The EPA explained upon issuance of the Court's mandate, "an engine may not operate in circumstances described in the vacated [portions of the 2013 NESHAP RICE Rule] for any number of hours power per year."[33] The EPA explained that such engines could, however, continue to operate for specified emergency and nonemergency reasons.[34]

On May 3, 2016, the Court issued a mandate to implement its May 1, 2015, order. Issuance of the mandate triggered implementation of the policy.

The MMU verifies every delivery year that resource portfolios remain in compliance. The MMU contacts all CSPs with demand resources using diesel fuel, to ensure compliance is met among all PJM resources.

State Environmental Regulation

New Jersey High Electric Demand Day (HEDD) Rules

The EPA's transport rules apply to total annual and seasonal emissions. Units that run only during peak demand periods have relatively low annual emissions, and have less reason to make such investments under the EPA transport rules.

New Jersey addressed the issue of NO_X emissions on peak energy demand days with a rule that defines peak energy usage days, referred to as high electric demand days or HEDD, and imposes operational restrictions and emissions control requirements on units responsible for significant NO_X emissions on such high energy demand days.[35] New Jersey's HEDD rule, which became effective May 19, 2009, applies to HEDD units, which include units that have a NO_X emissions rate on HEDD equal to or exceeding 0.15 lbs/MMBtu and lack identified emission control technologies.[36] NO_X emissions limits for coal units became effective December 15, 2012.[37] NO_X emissions limits for other unit types became effective May 1, 2015.[38] As of December 31, 2017, two Cedar Station units, three Middle Street units, three Missouri units, one Sherman Ave unit, three Burlington units, three Edison units, four Essex units, three Kearny units, one Mercer unit, one National Park unit, one Sewaren unit, eight Glen Gardner units and four Werner units identified as NJ HEDD units have retired.[39] In total, 37

27 *National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines; New Source Performance Standards for Stationary Internal Combustion Engines*, Proposed Rule, EPA Docket No. EPA-HQ-OAR-2008-0708.

28 Delaware Department of Natural Resources and Environmental Control (DENREC) v. EPA, Slip Op. No. 13-1093; *National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines; New Source Performance Standards for Stationary Internal Combustion Engines*, Final Rule, EPA Docket No. EPA-HQ-OAR-2008-0708, 78 Fed. Reg. 9403 (Jan. 30, 2013).

29 *Id.*

30 DENREC v. EPA at 3, 20–21.

31 *Id.* at 22, citing Comments of the Independent Market Monitor for PJM, EPA Docket No. EPA-HQ-OAR-2008-0708 (Aug. 9, 2012) at 2.

32 EPA, Memorandum, Peter Tsirigotis Guidance on Vacatur of RICE NESHAP and NSPS Provisions for Emergency Engines (April 15, 2016).

33 See 40 CFR §§ 60.4211(f)(2)(ii)–(iii), 60.4243(d)(2)(ii)–(iii), and 63.6640(f)(2)(ii)–(iii) (Declared Energy Emergency Alert Level 2 or 5 percent voltage/frequency deviations).

34 See 40 CFR §§ 60.4211(f)(1), 60.4243(d)(1), and 63.6640(f)(1) ("There is no time limit on the use of emergency stationary ICE in emergency situations."); 40 §§ CFR 60.4211(f)(3), 60.4243(d)(3), 63.6640(f)(3)–(4).

35 N.J.A.C. § 7:27-19.

36 CTs must have either water injection or selective catalytic reduction (SCR) controls; steam units must have either an SCR or selective noncatalytic reduction (SNCR).

37 N.J.A.C. § 7:27-19.4.

38 N.J.A.C. § 7:27-19.5.

39 See Current New Jersey Turbines that are HEDD Units, <http://www.nj.gov/dep/workgroups/docs/apcrule_20110909turbinelist.pdf>.

NJ HEDD units have retired and the remaining 41 NJ HEDD units are still operating after taking actions to comply with the HEDD regulations.

Table 8-1 shows the HEDD emissions limits applicable to each unit type.

Table 8-1 HEDD maximum NO_X emission rates[40]

Fuel and Unit Type	NO_x Emission Limit (lbs/MWh)
Coal Steam Unit	1.50
Heavier than No. 2 Fuel Oil Steam Unit	2.00
Simple Cycle Gas CT	1.00
Simple Cycle Oil CT	1.60
Combined Cycle Gas CT	0.75
Combined Cycle Oil CT	1.20
Regenerative Cycle Gas CT	0.75
Regenerative Cycle Oil CT	1.20

Illinois Air Quality Standards (NO_X, SO_2 and Hg)

The State of Illinois has promulgated its own standards for NO_X, SO_2 and Hg (mercury) known as Multi-Pollutant Standards (MPS) and Combined Pollutants Standards (CPS).[41] MPS and CPS establish standards that are more stringent and take effect earlier than comparable Federal regulations, such as the EPA's MATS.

The Illinois Pollution Control Board has granted variances with conditions for compliance with MPS/CPS for Illinois units included in or potentially included in PJM markets.[42] In order to obtain variances, companies in PJM agreed to terms with the Illinois Pollution Control Board that resulted in investments in the installation of environmental pollution control equipment at units and deactivation of Illinois units that differ from what would have occurred had only Federal regulations applied.[43]

State Renewable Portfolio Standards

Nine PJM jurisdictions have enacted legislation that requires that a defined percentage of retail load be served by renewable resources, for which there are many standards and definitions. These are typically known as renewable portfolio standards, or RPS. In PJM jurisdictions that have adopted an RPS, load serving entities are often required by law to meet defined shares of load using specific renewable and/or alternative energy sources commonly called "eligible technologies." Load serving entities may generally fulfill these obligations in one of two ways: they may use their own generation resources classified as eligible technologies to produce power or they may purchase renewable energy credits (RECs) that represent a known quantity of power produced with eligible technologies by other market participants or in other geographical locations. Load serving entities that fail to meet the percent goals set in their jurisdiction's RPS by generating power from eligible technologies or purchasing RECs are penalized with alternative compliance payments. As of December 31, 2018, Delaware, Illinois, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, and Washington, D.C. had renewable portfolio standards that are mandatory and include penalties in the form of alternative compliance payments for underperformance.

Two PJM jurisdictions have enacted voluntary renewable portfolio standards. Load serving entities in states with voluntary standards are not bound by law to participate and face no alternative compliance payments. Instead, incentives are offered to load serving entities to develop renewable generation or, to a more limited extent, purchase RECs. As of December 31, 2018, Virginia and Indiana had renewable portfolio standards that are voluntary and do not include penalties in the form of alternative compliance payments for underperformance.

In this section, voluntary standards will not be directly compared to RPS with enforceable compliance payments. Indiana's voluntary standard illustrates the issue. Although a voluntary standard including target shares was enacted by the Indiana legislature in 2011, no load serving entities have volunteered to participate in the program.[44]

Three PJM states have no renewable portfolio standards. Kentucky and Tennessee have enacted no renewable portfolio standards. West Virginia had a voluntary standard, but the state legislature repealed their renewable portfolio standard on January 27, 2015, effective February 3, 2015.[45]

40 Regenerative cycle CTs are combustion turbines that recover heat from their exhaust gases and use that heat to preheat the inlet combustion air which is fed into the combustion turbine.

41 35 Ill. Admin. Code §§ 225.233 (Multi-Pollutant Standard (MPS)), 224.295 (Combined Pollutant Standard: Emissions Standards for NO_X and SO_2 (CPS)).

42 See, e.g., Midwest Generation, LLC, Opinion and Order of the Board, Docket No. PCB 13-24 (Variance-Air) (April 4, 2013); Midwest Generation, LLC, Opinion and Order of the Board, Docket No. PCB 12-121 (Variance-Air) (Aug. 23, 2012).

43 See *Id.*

44 See the Indiana Utility Regulatory Commission's "2018 Annual Report," at 35–36 <https://www.in.gov/iurc/files/IURC%20AR%202018%20WEB3.pdf>.

45 See Enr. Com. Sub. For H. B. No. 2001.

Appendix J Glossary

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

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

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

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

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

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

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

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

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

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

Behind the Meter
Behind The Meter Generation refers to a generation unit that delivers energy to load without using the Transmission System or any distribution facilities (unless the entity that owns or leases the distribution facilities has consented to such use of the distribution facilities and such consent has been demonstrated to the satisfaction of the Office of the Interconnection); provided, however, that Behind The Meter Generation does not include (i) at any time, any portion of such generating unit's capacity that is designated as a Generation Capacity Resource; or (ii) in an hour, any portion of the output of such generating unit[s] that is sold to another entity for consumption at another electrical location or into the PJM Interchange Energy Market. (OATT 1.3B)

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

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

Block Loaded
A resource offered to PJM in the energy or capacity market at a single MW output which is not dispatchable in the energy market and cannot be partially cleared in the capacity market.

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

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

Bus
An interconnection point.

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

Capacity Emergency Transfer Limit (CETL)
The capability of the transmission system to support deliveries of electric energy to a given area experiencing a localized capacity emergency as determined in accordance with the PJM Manuals.

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

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

Combustion Turbine (CT)
A generating unit in which a combustion turbine engine is the prime mover for an electrical generator.

Congestion Management Process (CMP)
A process used between neighboring balancing authorities to coordinate the re-dispatch of resources to relieve transmission constraints.

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

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

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

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

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

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

Eastern Prevailing Time (EPT)

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

Eastern Region

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

Economic generation

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

Effective MW

The MW of regulation provided by a regulating resource multiplied by that resource's marginal benefit factor and performance score.

End use customer

Any customer purchasing electricity at retail.

Equivalent availability factor (EAF)

The proportion of hours in a year that a unit is available to generate at full capacity.

Equivalent demand forced outage rate (EFORd)

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

Equivalent forced outage factor (EFOF)

The proportion of hours in a year that a unit is unavailable because of forced outages.

Equivalent maintenance outage factor (EMOF)

The proportion of hours in a year that a unit is unavailable because of maintenance outages.

Equivalent planned outage factor (EPOF)

The proportion of hours in a year that a unit is unavailable because of planned outages.

External resource

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

Financial Transmission Right (FTR)

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

Firm Point to Point Transmission Service

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

Firm Transmission Service

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

Fixed Demand Bid

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

Fixed Resource Requirement (FRR)

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

Flowgate

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

Frequently mitigated unit (FMU)

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

Fuel Diversity Index

Objective metric of fuel diversity, defined by FDI = $1 - \sum_{i=1}^{N} s_i^2$, where s_i is the share of fuel type i. The FDI is calculated separately for energy output and for installed capacity.

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

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

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

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

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

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

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

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

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

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

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

Hot/Cold Weather Alerts
A Hot Weather Alert is issued to prepare personnel and facilities for extreme hot and/or humid weather conditions that may cause unit unavailability to be higher than forecast for an extended period. It can be issued on a control zone basis and PJM communicates to members whether fuel limited resources are to be placed into Maximum Emergency category.

A Cold Weather Alert is issued to prepare personnel and facilities for extreme cold weather conditions. It can be initiated when actual temperatures in a zone fall near or below 10 degrees Fahrenheit or at higher temperatures if PJM projects a portion of gas fired capacity is unable to obtain spot market gas during load pick-up periods.

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

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

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

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

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

Load
Demand for electricity at a given time.

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

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

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

Marginal Benefit Factor
For RegD resources, this is the marginal rate of substitution between RegA and RegD resources.

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

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

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

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

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

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

Mean
The arithmetic average.

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

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

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

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

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

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

Minimum Offer Price Rule (MOPR)
The MOPR rule sets a floor offer price in the RPM Capacity Market, based on the average net cost of new entry (CONE) for certain classes of new or uprated generation capacity resources as defined in the OATT Attachment DD 5.13(h).

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

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

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

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

Net exchange (capacity)
Capacity imports less exports.

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

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

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

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

Nonsynchronized Reserve
Reserve MW available within 10 minutes, but not synchronized to the grid.

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

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

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

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

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

Performance Score
This is a measure of the quality of response of a regulating resource to its assigned regulation signal (RegA or RegD).

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

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

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

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

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

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

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

Qualified Replacement Resource
Generation resource used to replace retired resources that were historical Stage 1A source points for FTRs.

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

Reactive Service
Reactive Service, Reactive Supply and Voltage Control from Generation or Other Sources Service, is provided by generation and other sources (such as static VAR compensators and capacitor banks) of reactive power (measured in VAR). Reactive power helps maintain appropriate voltages on the transmission system and is essential to the flow of real power (measured in MW).

RegA
PJM's slow-oscillation regulation signal designed for resources with the ability to sustain energy output for long periods of time, but with limited ramp rates. PJM can satisfy the RTO-wide regulation requirement with only RegA resources.

RegD
PJM's fast-oscillation regulation signal designed for resources with the ability to quickly adjust energy output, but with limited ability to sustain energy output for long periods of time. PJM cannot satisfy the RTO-wide regulation requirement with only RegD resources.

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

Regulation
Regulation is an ancillary service that corrects short-term imbalances between generation and load and is provided by resources capable of responding to a PJM-generated signal.

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

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

Reserve
Energy available within a defined time for the purpose of correcting an imbalance between supply and demand.

Residual Metered Load
A Residual Metered Load aggregate represents all load buses in a fully metered EDC territory, minus all load that has been designated to be priced at specific non-zonal (or nodal) locations.

Seasonal Conditional Demand
An adjustment to the DASR requirement for summer and winter seasons. The SCD factor is calculated every year based on the top 10 peak load days from the prior year.

Selective catalytic reduction (SCR)

NO_x reduction equipment usually installed on combined-cycle generators.

Self-scheduled generation

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

Shadow price

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

Sources and sinks

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

Spot Import Transmission Service

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

Spot market

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

Static Var compensator

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

Summer Net Capability

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

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

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

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

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

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

Supply deviations

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

Synchronized reserve

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

System installed capacity

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

System lambda

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

Temperature-humidity index (THI)

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

Transmission Adequacy and Reliability Assessment (TARA)

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

Transmission Constraint Penalty Factor

In the PJM energy market optimization, the power flow on a transmission constraint is allowed to exceed its limit under some conditions. The violations incur a cost called a transmission penalty factor expressed in $/MWh. Following the principles of optimization, the shadow price or the marginal value of the transmission constraint can never exceed the transmission constraint penalty factor. For this reason, the transmission constraint penalty factor is also called marginal value limit.

Turn down ratio

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

Unforced capacity

Installed capacity adjusted by forced outage rates.

Western region

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

Wheel-through

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

Winter Weather Parameter (WWP)

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

Zone

See “Control zone” (above).

Appendix K List of Acronyms

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

Con Edison	The Consolidated Edison Company
CONE	Cost of new entry
CP	Pulverized coal-fired generator
CPI	Consumer Price Index
CPL	Carolina Power & Light Company
CPS	Control performance standard
CRC	Central Repository for Curtailments
CRF	Capital Recovery Factor
CSAPR	Cross State Air Pollution Rule
CSP	Curtailment service provider
CSTF	Capacity Senior Task Force
CT	Combustion turbine
CTO	Combustion Turbine Optimizer
CTR	Capacity transfer right
CWA	Clean Water Act
DAOR	Day – Ahead Operating Reserve
DASR	Day-Ahead Scheduling Reserve
DARRCA	Day – ahead reliability and reactive cost allocation
DAY	Dayton Power & Light Company
DC	Direct current
DCS	Disturbance control standard
DEC	Decrement bid
DFAX	Distribution factor
DGP	Degree of Generator Performance
DL	Diesel
DLC	Direct Load Control
DLCO	Duquesne Light Company
DPL	Delmarva Power & Light Company
DPLN	Delmarva Peninsula north
DPLS	Delmarva Peninsula south
DR	Demand response
DRS	Demand Response Subcommittee
DRSDTF	Demand Response Subzonal Dispatch Task Force
DSIRE	Database of State Incentives for Renewables & Efficiency
DSR	Demand side response
DUK	Duke Energy Corporation
EAC	Excess Availability Capacity
EAF	Equivalent availability factor
ECAR	East Central Area Reliability Council
EDC	Electricity distribution company
EDT	Eastern Daylight Time
EE	Energy efficiency
EEA	Emergency energy alert
EERS	Energy Efficiency Standards
EES	Enhanced energy scheduler
EFOF	Equivalent forced outage factor
EFORd	Equivalent demand forced outage rate
EFORp	Equivalent forced outage rate during peak hours
EGU	Electric Generating Units
EHV	Extra-high-voltage
EIS	Environmental Information Services
EKPC	East Kentucky Power Cooperative, Inc.
ELRP	Economic load response program
EMAAC	Eastern Mid-Atlantic Area Council
EMOF	Equivalent maintenance outage factor
EMS	Energy management system
EMUSTF	Energy Market Uplift Senior Task Force
EPA	Environmental Protection Agency
EPOF	Equivalent planned outage factor
EPT	Eastern Prevailing Time
ESP	Electrostatic precipitators (Baghouses)
EST	Eastern Standard Time
ExGen	Exelon Generation Company, L.L.C.
FE	FirstEnergy Corp.
FERC	The United States Federal Energy Regulatory Commission
FDIc	Fuel Diversity Index for capacity
FDIe	Fuel Diversity Index for energy generation
FFE	Firm flow entitlement

FGD	Flue-gas desulfurization
FMU	Frequently mitigated unit
FPA	Federal Power Act
FPR	Forecast pool requirement
FRR	Fixed resource requirement
FSL	Firm service load
FTR	Financial transmission right
GACT	Generally Available Control Technology
GCA	Generation control area
GE	General Electric Company
GHG	Greenhouse Gas
GLD	Guaranteed load drop
GSU	Generator Step-Up Transformers
GW	Gigawatt
GWh	Gigawatt-hour
HAP	Hazardous air pollutants
HE	Hour Ending
HEDD	NJ High Energy Demand Day
HHI	Herfindahl-Hirschman Index
HRSG	Heat recovery steam generator
HVDC	High-voltage direct current
Hz	Hertz
IARR	Incremental ARRs
IA	RPM Incremental Auction
IBTs	Internal Bilateral Transactions
ICAP	Installed capacity
ICCP	Inter-control center protocol
ICSA	Interconnection construction service agreement
IDC	Interchange distribution calculator
IESO	Ontario Independent Electricity System Operator
IGCC	Integrated Gasification Combined Cycle
ILR	Interruptible load for reliability
INC	Increment offer
IP	Illinois Power Company
IPL	Indianapolis Power & Light Company
IPP	Independent power producer
IPSTF	Interconnection Process Senior Task Force
IRM	Installed reserve margin
IROL	Interconnection Reliability Operating Limit
IRR	Internal rate of return
ISA	Interconnection service agreement
ISO	Independent system operator
ITSCED	Intermediate term security constrained economic dispatch
JCPL	Jersey Central Power & Light Company
JOA	Joint operating agreement
JOU	Jointly owned units
JRCA	Joint Reliability Coordination Agreement
KV	KiloVolt
KDAEV	Known Day-Ahead Error Value
LAER	Lowest Achievable Emissions Rate
LAS	PJM Load Analysis Subcommittee
LCA	Load control area
LDA	Locational deliverability area
LGEE	LG&E Energy, L.L.C.
LGIA	Large generator interconnection agreement
LGIP	Large generator interconnection procedure
LIND	Linden Variable Frequency Transformer (VFT)
LM	Load management
LMP	Locational marginal price
LMTF	Load Management Task Force
LOC	Lost opportunity cost
LPC	Locational Pricing Calculator
LSE	Load-serving entity
M2M	Market to market
MAAC	Mid-Atlantic Area Council

MAAC+APS	Mid-Atlantic Area Council plus the Allegheny Power System
MACRS	Modified accelerated cost recovery schedule
MACT	Maximum Achievable Control Technology
MAD	Mid-Atlantic Dominion subzone
MAIN	Mid-America Interconnected Network, Inc.
MAPP	Mid-Continent Area Power Pool
MATS	Mercury and Air Toxics Standards rule
MBF	Marginal Benefit Factor
MCP	Market-clearing price
MDS	Maximum daily starts
MDT	Minimum down time
MEC	MidAmerican Energy Company
MECS	Michigan Electric Coordinated System
Met-Ed	Metropolitan Edison Company
MIC	Market Implementation Committee
MICHFE	The pricing point for the Michigan Electric Coordinated System and FirstEnergy control areas
MIL	Mandatory interruptible load
MIS	Market information system
MISO	Midcontinent Independent Transmission System Operator, Inc.
MMU	PJM Market Monitoring Unit
Mon Power	Monongahela Power
MOPR	Minimum Offer Price Rule
MOPR-Ex	Minimum Offer Price Rule Extended
MP	Market participant
MP2	Monitored Priority 2
MRC	Markets and reliability committee
MRT	Minimum run time
MRTS	Marginal Rate of Technical Substitution
MTSL	Minimum Tank Suction Level
MUI	Market user interface
MW	Megawatt
MWh	Megawatt-hour
MWS	Maximum weekly starts
NAESB	North American Energy Standards Board
NAAQS	National Ambient Air Quality Standards
NBT	Net Benefits Test
NCMPA	North Carolina Municipal Power Agency
NEPT	Neptune DC Line
NERC	North American Electric Reliability Council
NESHAP	National Emission Standards for Hazardous Air Pollutants
NICA	Northern Illinois Control Area
NIPSCO	Northern Indiana Public Service Company
NJDEP	New Jersey Department of Environmental Protection
NNL	Network and native load
NOPR	Notice of Proposed Rulemaking
NO_x	Nitrogen oxides
NPDES	National Pollutant Discharge Elimination System
NPS	National Park Service
NSPS	New Source Performance Standards
NSR	New Source Review
NSRMCP	Nonsynchronized Reserve Market Clearing Price
NUG	Non-utility generator
NYISO	New York Independent System Operator
OA	Amended and Restated Operating Agreement of PJM Interconnection, L.L.C.
OASIS	Open Access Same-Time Information System
OATI	Open Access Technology International, Inc.

OATT	PJM Open Access Transmission Tariff
ODEC	Old Dominion Electric Cooperative
OEM	Original equipment manufacturer
OI	PJM Office of the Interconnection
Ontario IESO	Ontario Independent Electricity System Operator
OPSI	Organization of PJM States, Inc.
OMC	Outside Management Control
ORDC	Operating Reserve Demand Curve
ORS	NERC Operating Reliability Subcommittee
OVEC	Ohio Valley Electric Corporation
PAR	Phase angle regulator
PATH	Potomac – Appalachian Transmission Highline
PAI	Performance Assessment Interval
PCLLRW	Post Contingency Local Load Relief Warning
PE	PECO Zone
PEC	Progress Energy Carolinas, Inc.
PECO	PECO Energy Company
PENELEC	Pennsylvania Electric Company
Pepco	Formerly Potomac Electric Power Company or PEPCO
PHI	Pepco Holdings, Inc.
PJM	PJM Interconnection, L.L.C.
PJM/AEPNI	The interface between the American Electric Power Control Zone and Northern Illinois
PJM/AEPPJM	The interface between the American Electric Power Control Zone and PJM
PJM/AEPVP	The single interface pricing point formed in March 2003 from the combination of two previous interface pricing points: PJM/American Electric Power Company, Inc. and PJM/Dominion Resources, Inc.
PJM/AEPVPEXP	The export direction of the PJM/AEPVP interface pricing point
PJM/AEPVPIMP	The import direction of the PJM/AEPVP interface pricing point
PJM/ALTE	The interface between PJM and the eastern portion of the Alliant Energy Corporation's control area
PJM/ALTW	The interface between PJM and the western portion of the Alliant Energy Corporation's control area
PJM/AMRN	The interface between PJM and the Ameren Corporation's control area
PJM/CILC	The interface between PJM and the Central Illinois Light Company's control area
PJM/CIN	The interface between PJM and the Cinergy Corporation's control area
PJM/CPLE	The interface between PJM and the eastern portion of the Carolina Power & Light Company's control area
PJM/CPLW	The interface between PJM and the western portion of the Carolina Power & Light Company's control area
PJM/CWPL	The interface between PJM and the City Water, Light & Power's (City of Springfield, IL) control area
PJM/DLCO	The interface between PJM and the Duquesne Light Company's control area
PJM/DUK	The interface between PJM and the Duke Energy Corp.'s control area
PJM/EKPC	The interface between PJM and the Eastern Kentucky Power Corporation's control area
PJM/FE	The interface between PJM and the FirstEnergy Corp.'s control area
PJMICC	PJM Industrial Customer Coalition
PJM/IP	The interface between PJM and the Illinois Power Company's control area

PJM/IPL	The interface between PJM and the Indianapolis Power & Light Company's control area
PJM/LGEE	The interface between PJM and the Louisville Gas and Electric Company's control area
PJM/LIND	The interface between PJM and the New York System Operator over the Linden VFT line
PJM/MEC	The interface between PJM and MidAmerican Energy Company's control area
PJM/MECS	The interface between PJM and the Michigan Electric Coordinated System's control area
PJM/MISO	The interface between PJM and the Midwest Independent System Operator
PJM/NEPT	The interface between PJM and the New York Independent System Operator over the Neptune DC line
PJM/NIPS	The interface between PJM and the Northern Indiana Public Service Company's control area
PJM/NYIS	The interface between PJM and the New York Independent System Operator
PJM/Ontario IESO	PJM/Ontario IESO pricing point
PJM/OVEC	The interface between PJM and the Ohio Valley Electric Corporation's control area
PJM/TVA	The interface between PJM and the Tennessee Valley Authority's control area
PJM/VAP	The interface between PJM and the Dominion Virginia Power's control area
PJM/WEC	The interface between PJM and the Wisconsin Energy Corporation's control area
PLC	Peak Load Contribution
PLS	Parameter limited schedule
PMSS	Preliminary market structure screen
PNNE	PENELEC's northeastern subarea
PNNW	PENELEC's northwestern subarea
POD	Point of delivery
POR	Point of receipt
PPB	Parts per billion
PPL	PPL Electric Utilities Corporation
PSE&G	Public Service Electric and Gas Company (a wholly owned subsidiary of PSEG)
PSEG	Public Service Enterprise Group
PSD	Prevention of Significant Deterioration
PSN	PSEG north
PSNC	PSEG north central
QF	Qualifying Facility
QRR	Qualified Replacement Resource
RAA	Reliability Assurance Agreement among Load-Serving Entities
RAC	Reliability Assessment Commitment
RCF	Reciprocal Coordinated Flowgate
RCIS	Reliability Coordinator Information System
REC	Renewable Energy Credit
RECO	Rockland Electric Company zone
RERRA	Relevant Electric Retail Regulatory Authority
RFC	ReliabilityFirst Corporation
RFP	Request for Proposal
RGGI	Regional Greenhouse Gas Initiative
RICE	Reciprocating Internal Combustion Engines
RLD (MW)	Ramp-limited desired (Megawatts)
RLR	Retail load responsibility
RMCCP	Regulation market capability clearing price
RMCP	Regulation market-clearing price
RMPCP	Regulation market performance clearing price
RMR	Reliability Must Run
ROFR	Right of First Refusal
RPM	Reliability Pricing Model

RPS	Renewable Portfolio Standard
RRMSE	Relative Root Mean Squared Error
RSI	Residual supply index
RSIx	Residual supply index, using “x” pivotal suppliers
RTC	Real-time commitment
RTEP	Regional Transmission Expansion Plan
RTSCED	Real time security constrained economic dispatch
RTO	Regional transmission organization
SAA	Symmetrical Additive Adjustment
SCE&G	South Carolina Energy and Gas
SCD	Seasonal Conditional Demand
SCED	Security Constrained Economic Dispatch
SNCR	Selective noncatalytic reduction
SCPA	South central Pennsylvania subarea
SCR	Selective catalytic reduction
SEPA	Southeast Power Administration
SEPJM	Southeastern PJM subarea
SERC	SERC Reliability Corporation
SGIA	Small Generator Interconnection Agreement
SGIP	Small Generator Interconnection Procedures
SIPs	State Implementation Plan
SFT	Simultaneous feasibility test
SMECO	Southern Maryland Electric Cooperative
SMP	System marginal price
SMR	Sustainable market rule
SNCR	Selective Non-Catalytic Reduction
SNJ	Southern New Jersey
SO_2	Sulfur dioxide
SOUTHEXP	South Export pricing point
SOUTHIMP	South Import pricing point
SPP	Southwest Power Pool, Inc.
SPREGO	Synchronized reserve and regulation optimizer (market-clearing software)
SRMCP	Synchronized reserve market-clearing price
SRSTF	System Restoration Strategy Task Force
STD	Standard deviation
STRPTAS	Short Term Resource Procurement Applicable Share
SVC	Static Var compensator
SWMAAC	Southwestern Mid-Atlantic Area Council
TARA	Transmission adequacy and reliability assessment
TDR	Turn down ratio
TEAC	Transmission Expansion Advisory Committee
THI	Temperature-humidity index
TISTF	Transactions Issues Senior Task Force
TLR	Transmission loading relief
TMEP	Targeted market efficiency process
TPS	Three pivotal supplier
TPSTF	Three Pivotal Supplier Task Force
TPY	Tons Per Year
TrAIL	Trans – Allegheny Interstate Line
TSA	Thunderstorm Alert
TSIN	NERC Transmission System Information Network
TVA	Tennessee Valley Authority
UCAP	Unforced capacity
UCSA	Upgrade construction service agreement
UDS	Unit dispatch system
UGI	UGI Utilities, Inc.
ULSD	Ultra-Low Sulfur Diesel
UPF	Unit participation factor
VACAR	Virginia and Carolinas Area
VAP	Dominion Virginia Power
VFT	Variable frequency transformer
VOCs	Volatile Organic Compounds

VOM	Variable operation and maintenance expense
VRR	Variable resource requirement
WEC	Wisconsin Energy Corporation
WLR	Wholesale load responsibility
WPC	Willing to pay congestion
WWP	Winter Weather Parameter
XEFORd	EFORd modified to exclude OMC outages
ZEC	Zero Emissions Credit