APPENDIX C – ENERGY MARKET

Frequency Distribution of LMP

Figure C-1, Figure C-2, Figure C-3, Figure C-4, Figure C-5, Figure C-6, Figure C-7 and Figure C-8 provide frequency distributions of real-time locational marginal price (LMP), by hour, for the calendar years 1998 through 2005.[1] The figures show the number of hours (frequency), the cumulative number of hours (cumulative frequency), the percent of hours (percent) and the cumulative percent of hours (cumulative percent) that LMP was within a given, $10-price interval, or for the cumulative columns, within the interval plus all the lower price intervals.[2]

The first six figures show that during the period 1998 to 2003, LMP was most frequently in the $10-per-MWh to $20-per-MWh interval. In 2004, however, LMP occurred in the $30-per-MWh to $40-per-MWh interval most frequently at 22.0 percent of the time and in the $20-per-MWh to $30-per-MWh interval nearly as frequently at 21.6 percent of the time. In 2005, LMP occurred in the $30-per-MWh to $40-per-MWh interval most frequently at 20.5 percent of the time and in the $20-per-MWh to $30-per-MWh interval at 14.7 percent of the time. In 2005, LMP was less than $60 per MWh for 63.2 percent of the hours and less than $100 per MWh for 87.4 percent of the hours. LMP was $200 per MWh or greater for 35 hours (0.40 percent of the hours) in 2005.

Frequency Distribution of Load

Figure C-9, Figure C-10, Figure C-11, Figure C-12, Figure C-13, Figure C-14, Figure C-15 and Figure C-16 provide the frequency distributions of PJM load by hour, for the calendar years 1998 through 2005. The figures show the number of hours (frequency), the cumulative number of hours (cumulative frequency), the percent of hours (percent) and the cumulative percent of hours (cumulative percent) that the load was within a given, 5,000 MW load interval, or for the cumulative columns, within the interval plus all the lower load intervals. The integrations of the Allegheny Power Company (AP) Control Zone during 2002, of the Commonwealth Edison Company (ComEd), the American Electric Power Company (AEP) and The Dayton Power & Light Company (DAY) Control Zones during 2004 and of the Duquesne Light Company (DLCO) and Dominion Control Zones during 2005 mean that annual comparisons of load frequency are significantly affected by PJM's geographic growth.[3]

For the years 1998 and 1999, the most frequently occurring load interval was 25,000 MW to 30,000 MW at 35.0 percent and 33.6 percent of the hours, respectively. For the years 2000 and 2001, the most frequently occurring load interval was 30,000 MW to 35,000 MW at 33.9 percent and 34.6 percent of the hours, respectively. For the year 2002, the most frequently occurring load interval was 30,000 MW to 35,000 MW at 26.5 percent of the hours, with the load interval 35,000 MW to 40,000 MW nearly as frequent at 25.1 percent of the hours. In 2003, the most frequently occurring load interval was 35,000 MW to 40,000 MW at 31.3 percent of the hours, while load was less than 35,000 MW for 36.3 percent of the hours.

1 LMP was instituted in PJM in April 1998. Before then, there had been a single system price, the market-clearing price (MCP).

2 Only positive LMP intervals are included in these figures.

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. The names apply to the geographic area, not to any single company. The geographic areas did not change with the formalization of the control zone and control area concepts during PJM's Phase 3 integrations. For simplicity, zones are referred to as control zones for all five phases. The only exception is ComEd which is called the ComEd Control Area during Phase 2 of 2004 only.

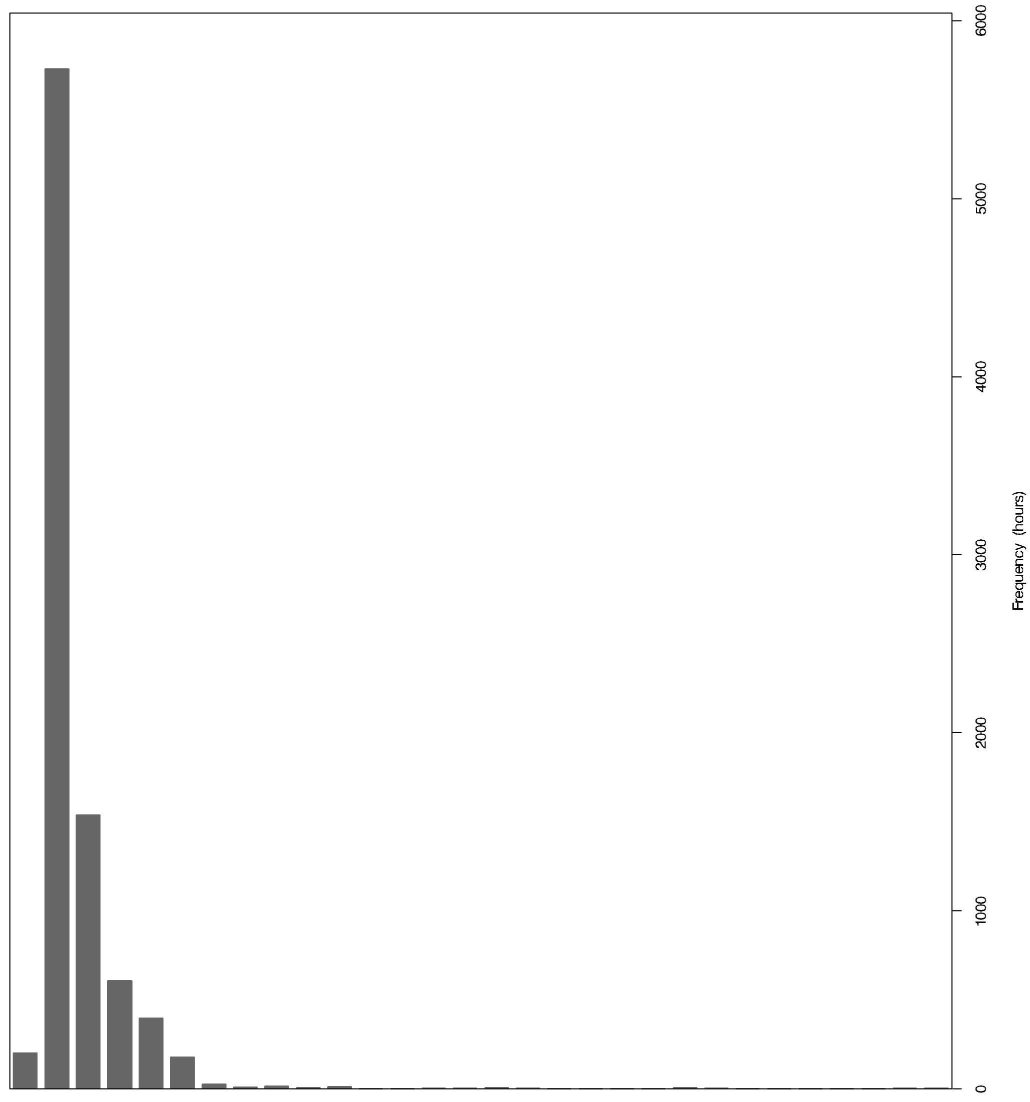
The frequency distribution of load in 2004 reflects the integrations of the ComEd, AEP and DAY Control Zones. The most frequently occurring load interval was 35,000 MW to 40,000 MW at 15.8 percent of the hours. The next most frequently occurring interval was 40,000 MW to 45,000 MW at 14.9 percent of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

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

The summer peak reflected both the Phase 4 integration of the DLCO Control Zone and the Phase 5 integration of the Dominion Control Zone. The peak demand for the year was 133,763 MW and occurred on July 26, 2005.

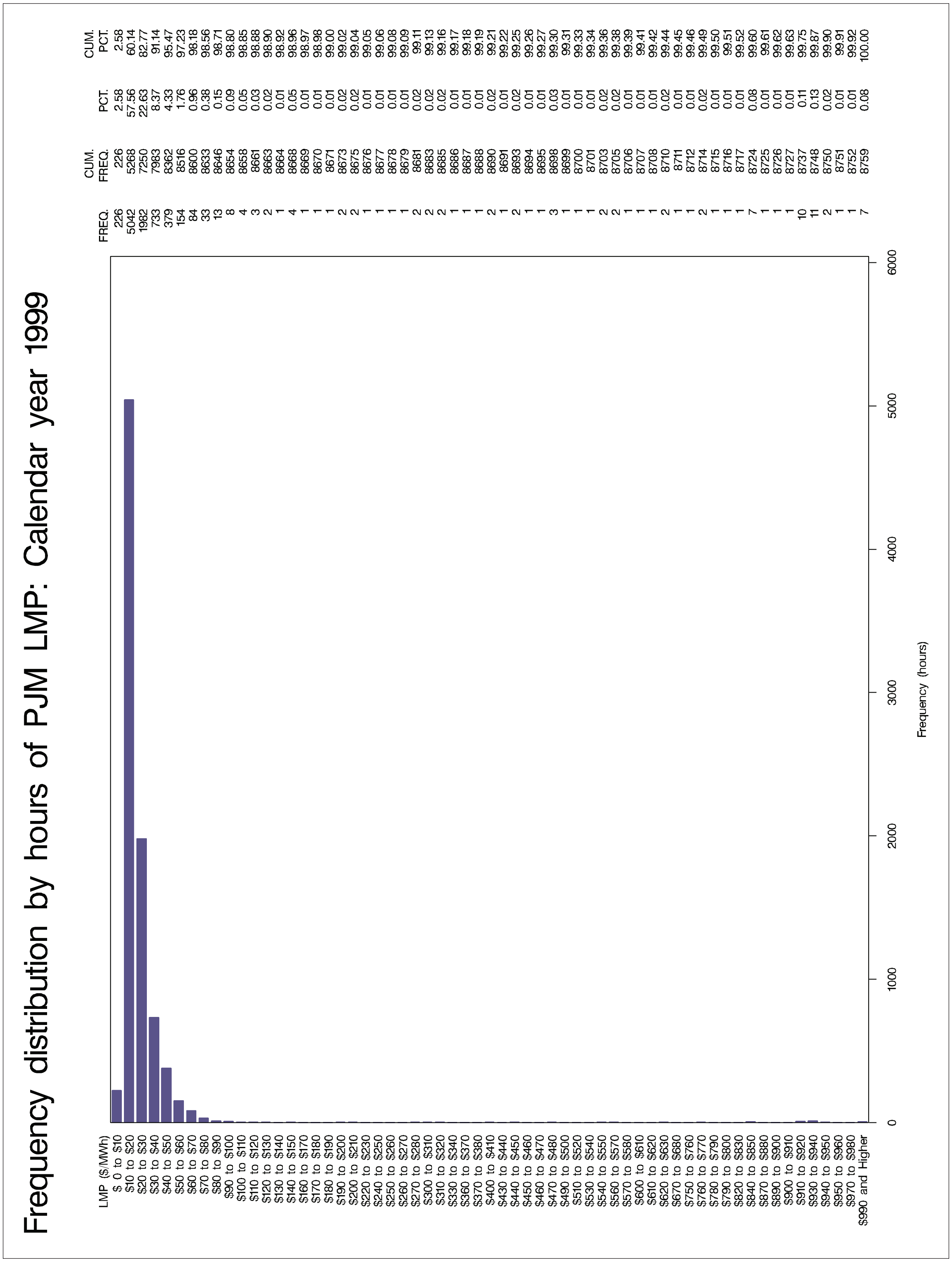
Figure C-1 - Frequency distribution by hours of PJM LMP: Calendar year 1998

Frequency distribution by hours of PJM LMP: Calendar year 1998



LMP ($/MWh)	FREQ.	CUM. FREQ.	PCT.	CUM. PCT.
$ 0 to $10	203	203	2.32	2.32
$10 to $20	5729	5932	65.41	67.72
$20 to $30	1539	7471	17.57	85.30
$30 to $40	607	8078	6.93	92.23
$40 to $50	396	8474	4.52	96.75
$50 to $60	178	8652	2.03	98.78
$60 to $70	27	8679	0.31	99.09
$70 to $80	10	8689	0.11	99.20
$80 to $90	15	8704	0.17	99.37
$90 to $100	6	8710	0.07	99.44
$100 to $110	11	8721	0.13	99.57
$110 to $120	1	8722	0.01	99.58
$120 to $130	1	8723	0.01	99.59
$130 to $140	4	8727	0.05	99.63
$140 to $150	3	8730	0.03	99.67
$150 to $160	6	8736	0.07	99.74
$180 to $190	2	8738	0.02	99.76
$190 to $200	1	8739	0.01	99.77
$200 to $210	1	8740	0.01	99.78
$220 to $230	1	8741	0.01	99.79
$240 to $250	1	8742	0.01	99.81
$300 to $310	5	8747	0.06	99.86
$460 to $470	2	8749	0.02	99.89
$500 to $510	1	8750	0.01	99.90
$510 to $520	1	8751	0.01	99.91
$680 to $690	1	8752	0.01	99.92
$700 to $710	1	8753	0.01	99.93
$850 to $860	1	8754	0.01	99.94
$890 to $900	3	8757	0.03	99.98
$990 and Higher	2	8759	0.02	100.00

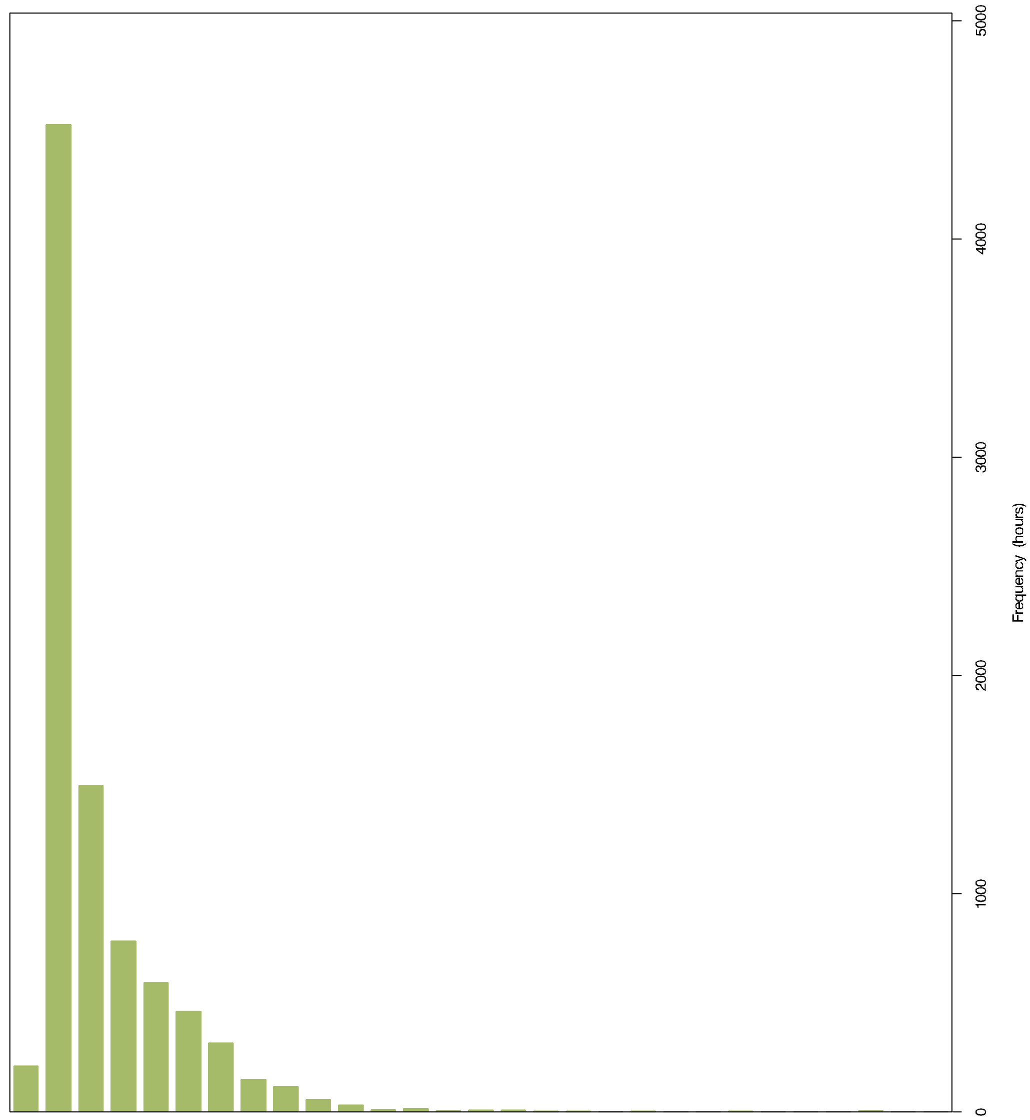
Figure C-2 - Frequency distribution by hours of PJM LMP: Calendar year 1999



LMP ($/MWh)	FREQ.	CUM. FREQ.	PCT.	CUM. PCT.
$ 0 to $10	226	226	2.58	2.58
$10 to $20	5042	5268	57.56	60.14
$20 to $30	1982	7250	22.63	82.77
$30 to $40	733	7983	8.37	91.14
$40 to $50	379	8362	4.33	95.47
$50 to $60	154	8516	1.76	97.23
$60 to $70	84	8600	0.96	98.18
$70 to $80	33	8633	0.38	98.56
$80 to $90	13	8646	0.15	98.71
$90 to $100	8	8654	0.09	98.80
$100 to $110	4	8658	0.05	98.85
$110 to $120	3	8661	0.03	98.88
$120 to $130	2	8663	0.02	98.90
$130 to $140	1	8664	0.01	98.92
$140 to $150	4	8668	0.05	98.96
$160 to $170	1	8669	0.01	98.97
$170 to $180	1	8670	0.01	98.98
$180 to $190	1	8671	0.01	99.00
$190 to $200	2	8673	0.02	99.02
$200 to $210	2	8675	0.02	99.04
$220 to $230	1	8676	0.01	99.05
$240 to $250	1	8677	0.01	99.06
$250 to $260	1	8678	0.01	99.08
$260 to $270	1	8679	0.01	99.09
$270 to $280	2	8681	0.02	99.11
$300 to $310	2	8683	0.02	99.13
$310 to $320	2	8685	0.02	99.16
$330 to $340	1	8686	0.01	99.17
$360 to $370	1	8687	0.01	99.18
$370 to $380	1	8688	0.01	99.19
$400 to $410	2	8690	0.02	99.21
$430 to $440	1	8691	0.01	99.22
$440 to $450	2	8693	0.02	99.25
$450 to $460	1	8694	0.01	99.26
$460 to $470	1	8695	0.01	99.27
$470 to $480	3	8698	0.03	99.30
$490 to $500	1	8699	0.01	99.31
$510 to $520	1	8700	0.01	99.33
$530 to $540	1	8701	0.01	99.34
$540 to $550	2	8703	0.02	99.36
$560 to $570	2	8705	0.02	99.38
$570 to $580	1	8706	0.01	99.39
$600 to $610	1	8707	0.01	99.41
$610 to $620	1	8708	0.01	99.42
$620 to $630	2	8710	0.02	99.44
$670 to $680	1	8711	0.01	99.45
$750 to $760	1	8712	0.01	99.46
$760 to $770	2	8714	0.02	99.49
$780 to $790	1	8715	0.01	99.50
$790 to $800	1	8716	0.01	99.51
$820 to $830	1	8717	0.01	99.52
$840 to $850	7	8724	0.08	99.60
$870 to $880	1	8725	0.01	99.61
$890 to $900	1	8726	0.01	99.62
$900 to $910	1	8727	0.01	99.63
$910 to $920	10	8737	0.11	99.75
$930 to $940	11	8748	0.13	99.87
$940 to $950	2	8750	0.02	99.90
$950 to $960	1	8751	0.01	99.91
$970 to $980	1	8752	0.01	99.92
$990 and Higher	7	8759	0.08	100.00

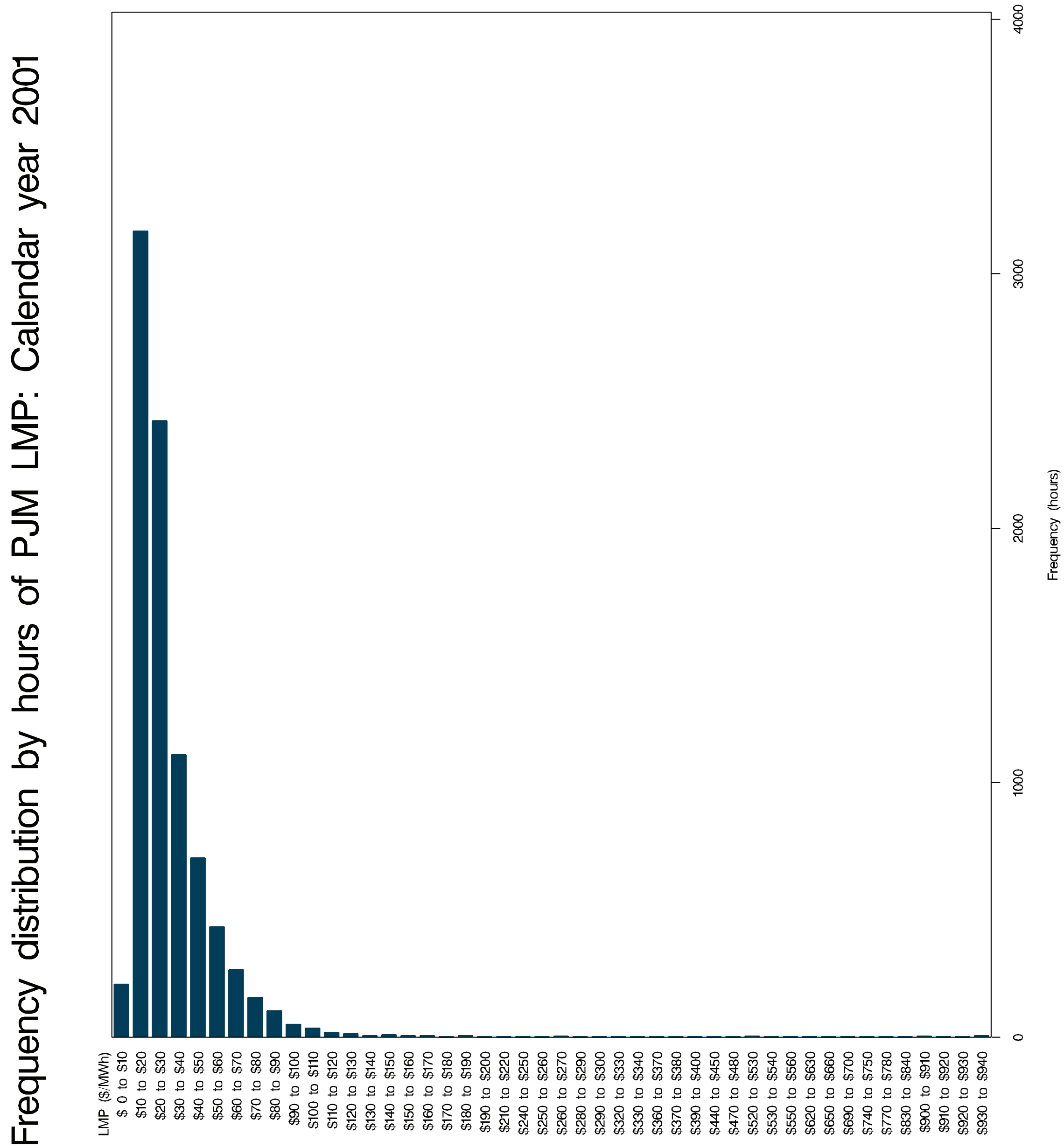
Figure C-3 - Frequency distribution by hours of PJM LMP: Calendar year 2000

Frequency distribution by hours of PJM LMP: Calendar year 2000



LMP ($/MWh)	FREQ.	CUM. FREQ.	PCT.	CUM. PCT.
$ 0 to $10	209	209	2.38	2.38
$10 to $20	4522	4731	51.49	53.87
$20 to $30	1494	6225	17.01	70.88
$30 to $40	782	7007	8.90	79.78
$40 to $50	591	7598	6.73	86.51
$50 to $60	459	8057	5.23	91.73
$60 to $70	315	8372	3.59	95.32
$70 to $80	147	8519	1.67	96.99
$80 to $90	115	8634	1.31	98.30
$90 to $100	56	8690	0.64	98.94
$100 to $110	31	8721	0.35	99.29
$110 to $120	9	8730	0.10	99.40
$120 to $130	13	8743	0.15	99.54
$130 to $140	5	8748	0.06	99.60
$140 to $150	8	8756	0.09	99.69
$150 to $160	6	8762	0.07	99.76
$160 to $170	3	8765	0.03	99.80
$170 to $180	2	8767	0.02	99.82
$180 to $190	1	8768	0.01	99.83
$190 to $200	2	8770	0.02	99.85
$210 to $220	1	8771	0.01	99.86
$220 to $230	1	8772	0.01	99.87
$260 to $270	2	8774	0.02	99.90
$280 to $290	1	8775	0.01	99.91
$290 to $300	1	8776	0.01	99.92
$360 to $370	1	8777	0.01	99.93
$480 to $490	4	8781	0.05	99.98
$590 to $600	1	8782	0.01	99.99
$800 to $810	1	8783	0.01	100.00

Figure C-4 - Frequency distribution by hours of PJM LMP: Calendar year 2001



LMP ($/MWh)	FREQ.	CUM. FREQ.	PCT.	CUM. PCT.
$ 0 to $10	209	209	2.39	2.39
$10 to $20	3167	3376	36.16	38.54
$20 to $30	2423	5799	27.66	66.21
$30 to $40	1109	6908	12.66	78.87
$40 to $50	704	7612	8.04	86.90
$50 to $60	433	8045	4.94	91.85
$60 to $70	264	8309	3.01	94.86
$70 to $80	155	8464	1.77	96.63
$80 to $90	104	8568	1.19	97.82
$90 to $100	50	8618	0.57	98.39
$100 to $110	36	8654	0.41	98.80
$110 to $120	18	8672	0.21	99.01
$120 to $130	13	8685	0.15	99.16
$130 to $140	5	8690	0.06	99.21
$140 to $150	9	8699	0.10	99.31
$150 to $160	6	8705	0.07	99.38
$160 to $170	6	8711	0.07	99.45
$170 to $180	2	8713	0.02	99.47
$180 to $190	5	8718	0.06	99.53
$190 to $200	1	8719	0.01	99.54
$210 to $220	1	8720	0.01	99.55
$240 to $250	1	8721	0.01	99.57
$250 to $260	1	8722	0.01	99.58
$260 to $270	3	8725	0.03	99.61
$280 to $290	1	8726	0.01	99.62
$290 to $300	1	8727	0.01	99.63
$320 to $330	1	8728	0.01	99.65
$330 to $340	2	8730	0.02	99.67
$360 to $370	1	8731	0.01	99.68
$370 to $380	2	8733	0.02	99.70
$390 to $400	1	8734	0.01	99.71
$440 to $450	1	8735	0.01	99.73
$470 to $480	1	8736	0.01	99.74
$520 to $530	3	8739	0.03	99.77
$530 to $540	1	8740	0.01	99.78
$550 to $560	2	8742	0.02	99.81
$620 to $630	1	8743	0.01	99.82
$650 to $660	2	8745	0.02	99.84
$690 to $700	1	8746	0.01	99.85
$740 to $750	1	8747	0.01	99.86
$770 to $780	1	8748	0.01	99.87
$830 to $840	1	8749	0.01	99.89
$900 to $910	3	8752	0.03	99.92
$910 to $920	1	8753	0.01	99.93
$920 to $930	1	8754	0.01	99.94
$930 to $940	5	8759	0.06	100.00

Figure C-5 - Frequency distribution by hours of PJM LMP: Calendar year 2002

Frequency distribution by hours of PJM LMP: Calendar year 2002

LMP ($/MWh)	FREQ.	CUM. FREQ.	PCT.	CUM. PCT.
$ 0 to $10	194	194	2.21	2.21
$10 to $20	3791	3985	43.28	45.49
$20 to $30	2104	6089	24.02	69.51
$30 to $40	1048	7137	11.96	81.47
$40 to $50	701	7838	8.00	89.47
$50 to $60	391	8229	4.46	93.94
$60 to $70	201	8430	2.29	96.23
$70 to $80	132	8562	1.51	97.74
$80 to $90	69	8631	0.79	98.53
$90 to $100	49	8680	0.56	99.09
$100 to $110	27	8707	0.31	99.39
$110 to $120	13	8720	0.15	99.54
$120 to $130	12	8732	0.14	99.68
$130 to $140	3	8735	0.03	99.71
$140 to $150	5	8740	0.06	99.77
$150 to $160	4	8744	0.05	99.82
$160 to $170	1	8745	0.01	99.83
$170 to $180	1	8746	0.01	99.84
$180 to $190	3	8749	0.03	99.87
$190 to $200	2	8751	0.02	99.90
$200 to $210	1	8752	0.01	99.91
$210 to $220	1	8753	0.01	99.92
$280 to $290	1	8754	0.01	99.93
$290 to $300	1	8755	0.01	99.94
$330 to $340	2	8757	0.02	99.97
$440 to $450	1	8758	0.01	99.98
$580 to $590	1	8759	0.01	99.99
$790 to $800	1	8760	0.01	100.00

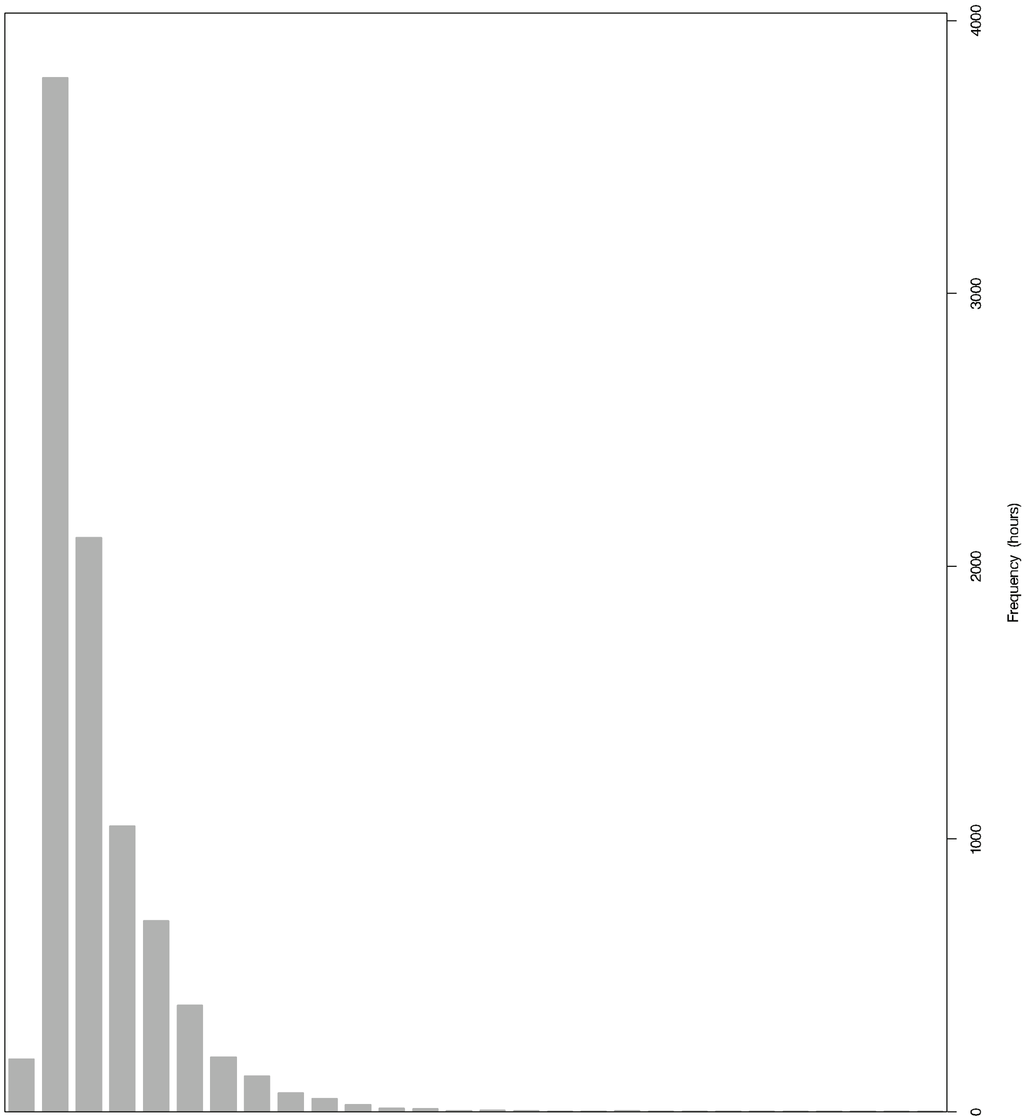
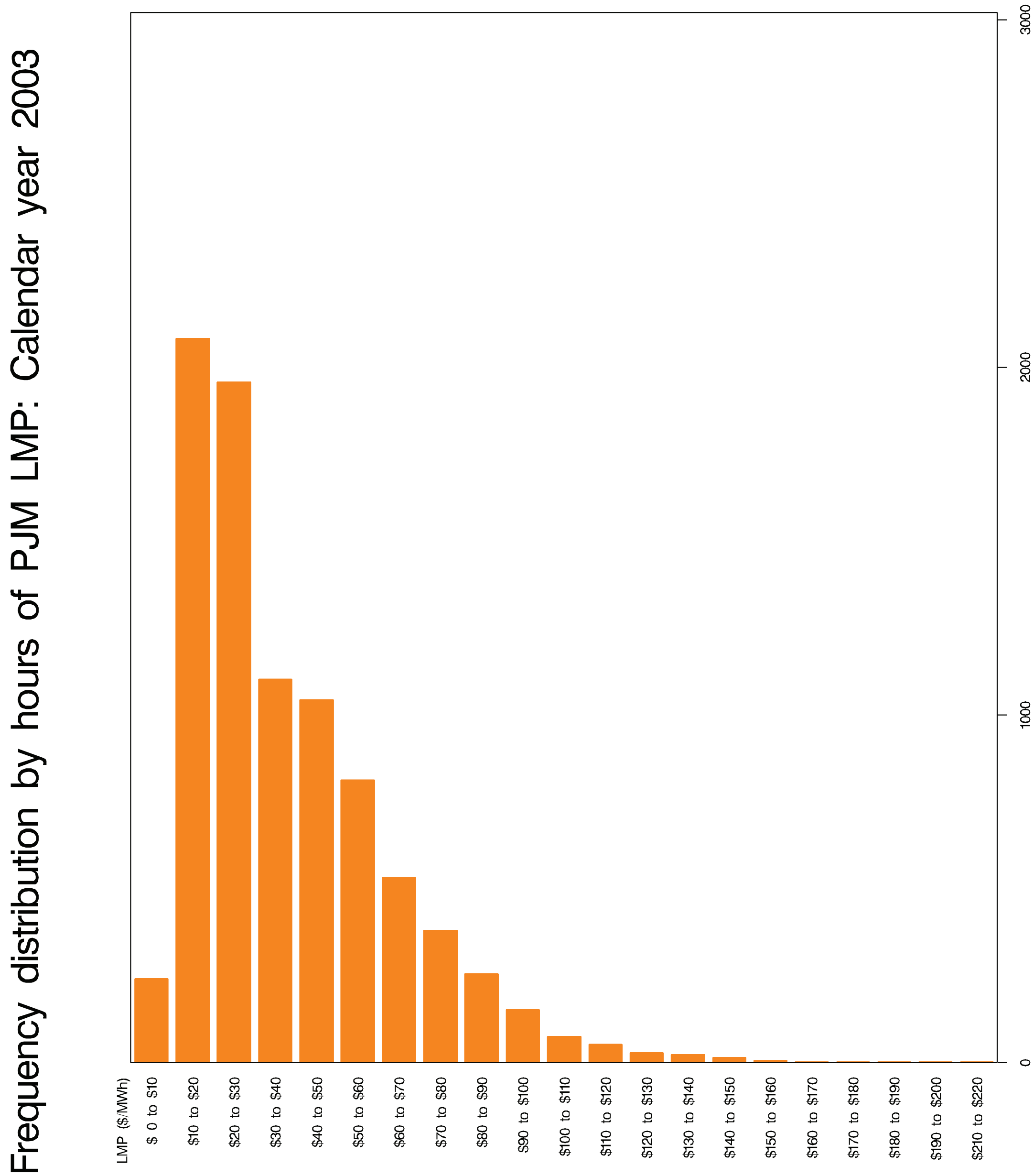


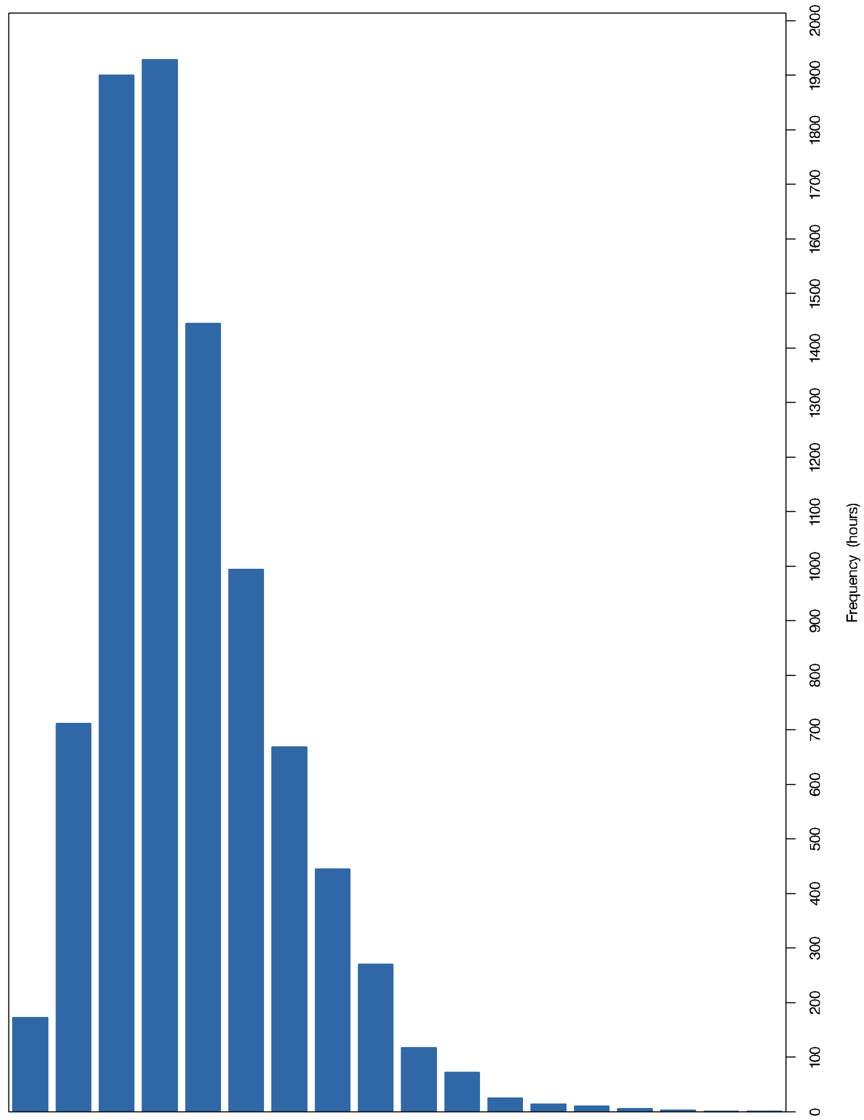
Figure C-6 - Frequency distribution by hours of PJM LMP: Calendar year 2003



LMP ($/MWh)	FREQ.	CUM. FREQ.	PCT.	CUM. PCT.
$ 0 to $10	241	241	2.75	2.75
$10 to $20	2083	2324	23.78	26.53
$20 to $30	1957	4281	22.34	48.87
$30 to $40	1102	5383	12.58	61.45
$40 to $50	1043	6426	11.91	73.36
$50 to $60	812	7238	9.27	82.63
$60 to $70	532	7770	6.07	88.70
$70 to $80	380	8150	4.34	93.04
$80 to $90	255	8405	2.91	95.95
$90 to $100	152	8557	1.74	97.68
$100 to $110	75	8632	0.86	98.54
$110 to $120	52	8684	0.59	99.13
$120 to $130	28	8712	0.32	99.45
$130 to $140	23	8735	0.26	99.71
$140 to $150	14	8749	0.16	99.87
$150 to $160	5	8754	0.06	99.93
$160 to $170	1	8755	0.01	99.94
$170 to $180	1	8756	0.01	99.95
$180 to $190	2	8758	0.02	99.98
$190 to $200	1	8759	0.01	99.99
$210 to $220	1	8760	0.01	100.00

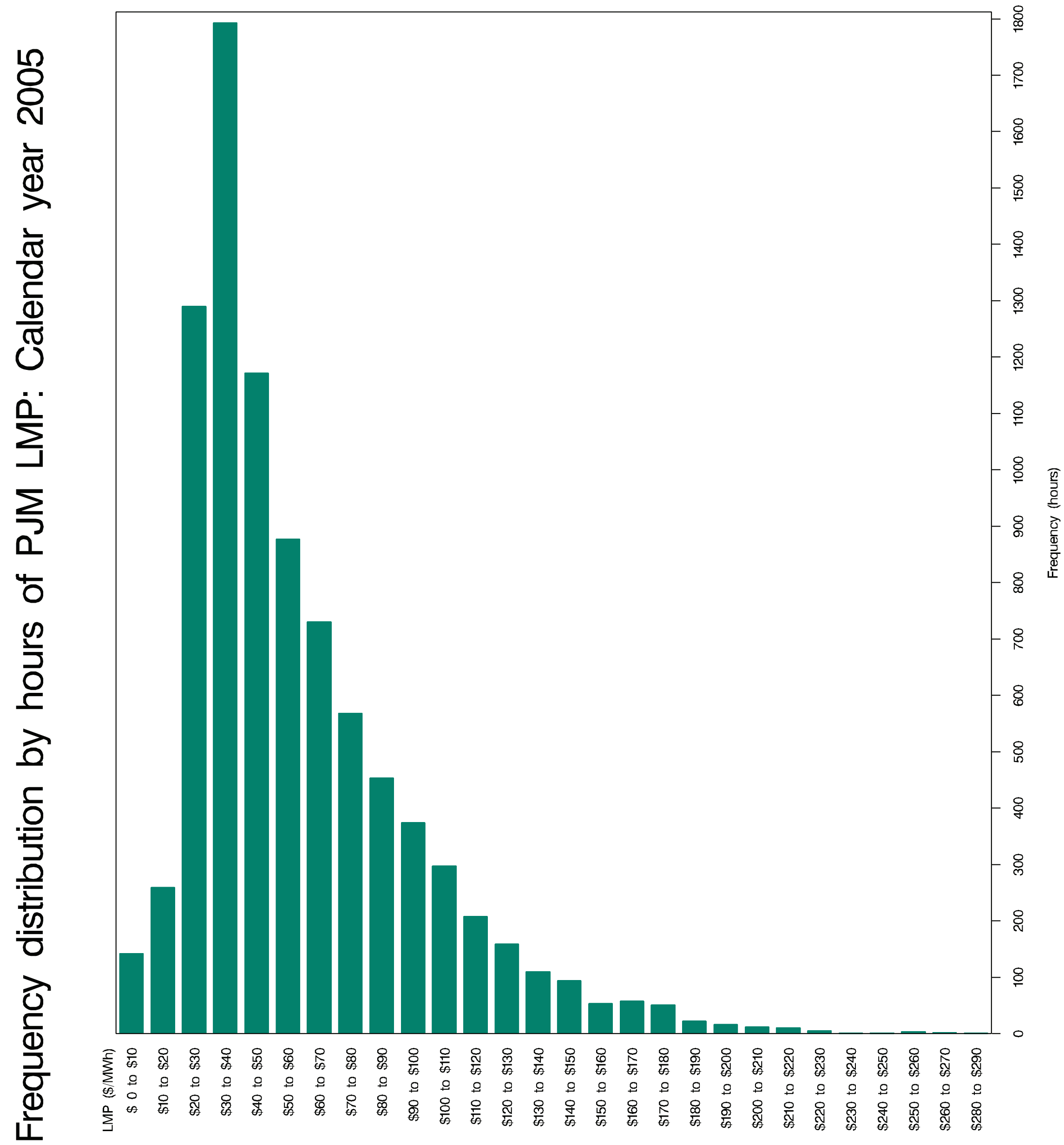
Figure C-7 - Frequency distribution by hours of PJM LMP: Calendar year 2004

Frequency distribution by hours of PJM LMP: Calendar year 2004



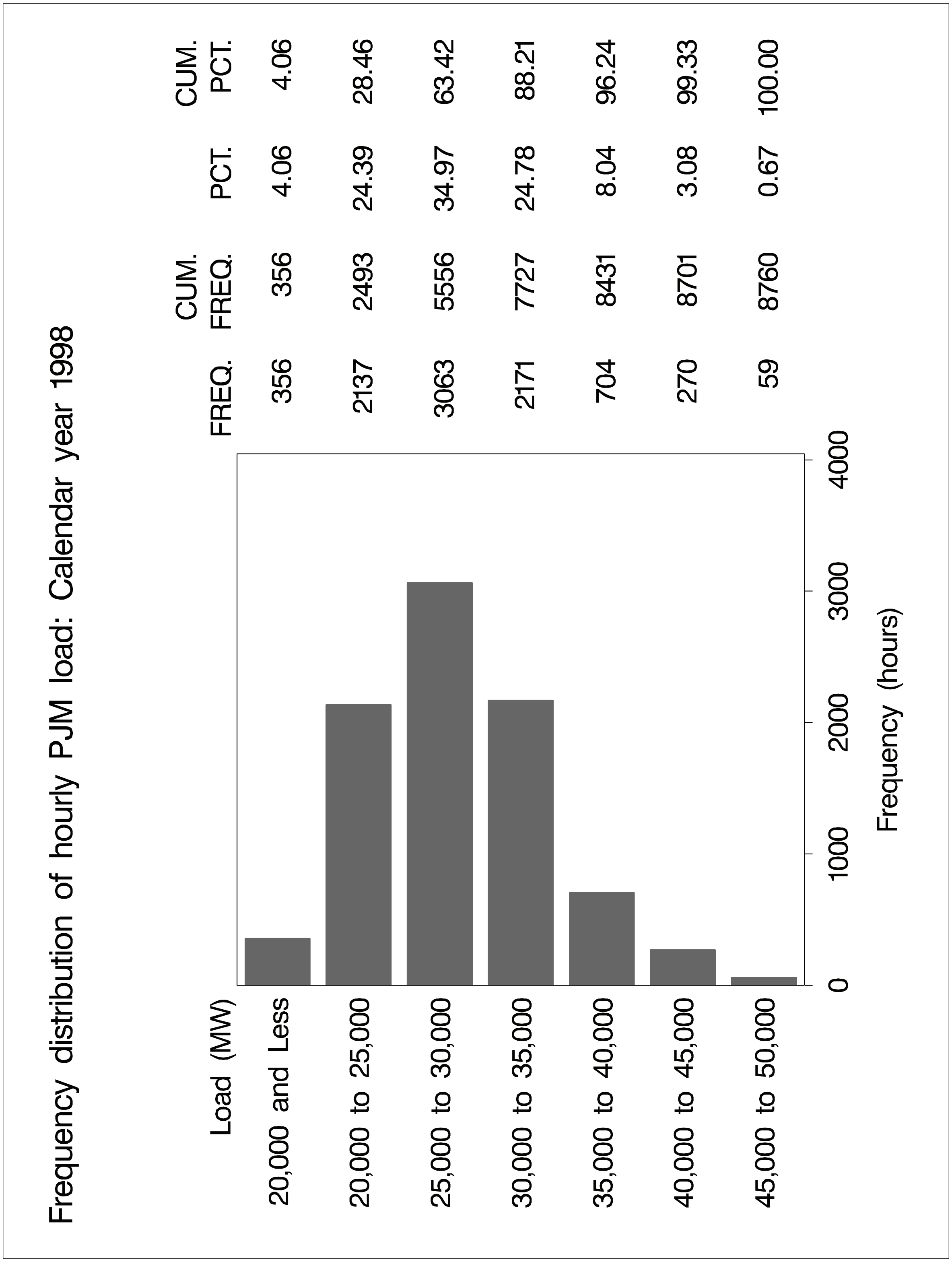
LMP ($/MWh)	FREQ.	CUM. FREQ.	PCT.	CUM. PCT.
$ 0 to $10	173	173	1.97	1.97
$10 to $20	712	885	8.11	10.08
$20 to $30	1900	2785	21.63	31.71
$30 to $40	1928	4713	21.95	53.65
$40 to $50	1445	6158	16.45	70.10
$50 to $60	994	7152	11.32	81.42
$60 to $70	668	7820	7.60	89.03
$70 to $80	445	8265	5.07	94.09
$80 to $90	270	8535	3.07	97.17
$90 to $100	117	8652	1.33	98.50
$100 to $110	72	8724	0.82	99.32
$110 to $120	25	8749	0.28	99.60
$120 to $130	14	8763	0.16	99.76
$130 to $140	10	8773	0.11	99.87
$140 to $150	6	8779	0.07	99.94
$150 to $160	3	8782	0.03	99.98
$160 to $170	1	8783	0.01	99.99
$180 to $190	1	8784	0.01	100.00

Figure C-8 - Frequency distribution by hours of PJM LMP: Calendar year 2005



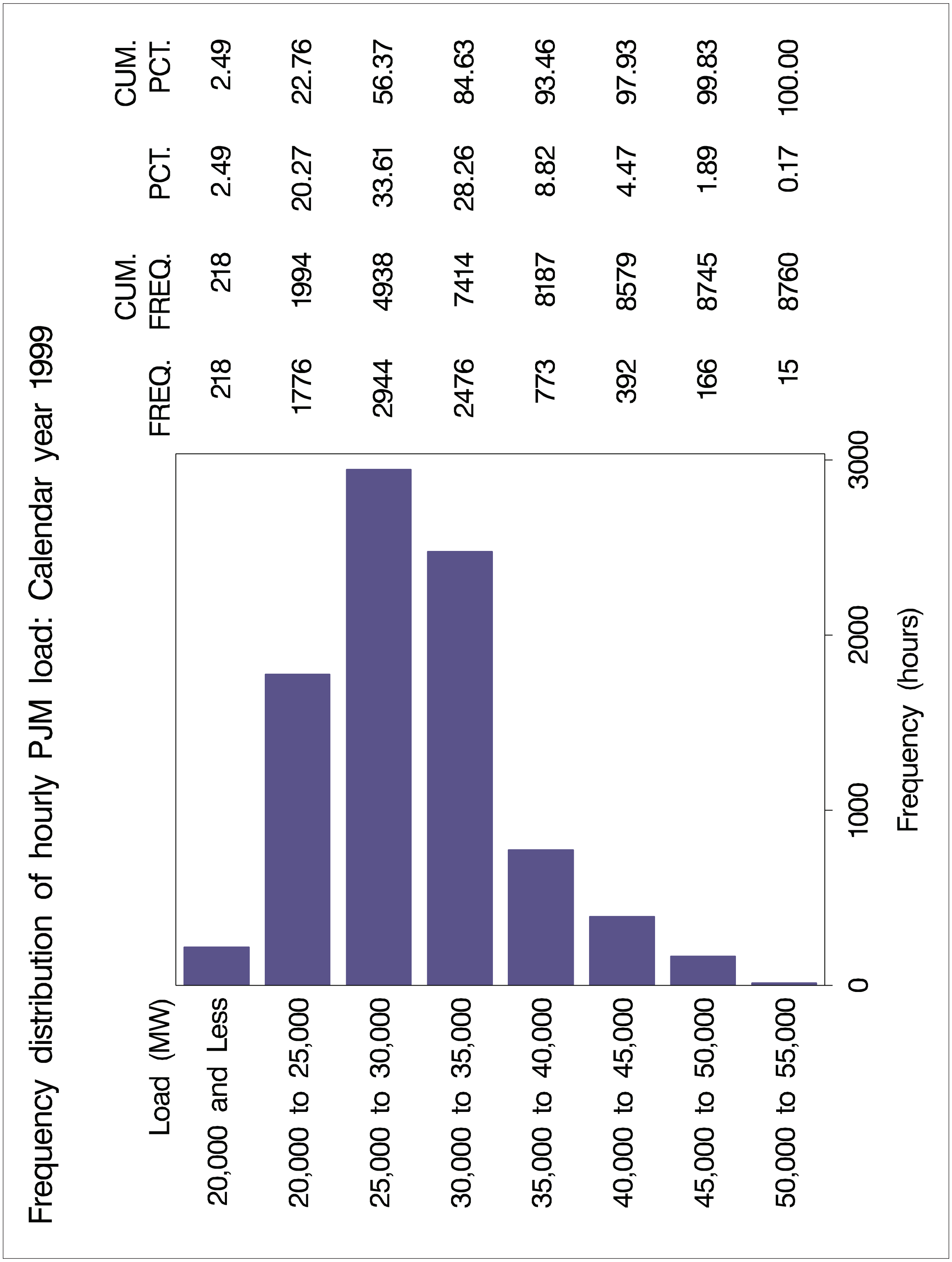
LMP ($/MWh)	FREQ.	CUM. FREQ.	PCT.	CUM. PCT.
$ 0 to $10	142	142	1.62	1.62
$10 to $20	259	401	2.96	4.58
$20 to $30	1290	1691	14.73	19.30
$30 to $40	1793	3484	20.47	39.77
$40 to $50	1172	4656	13.38	53.15
$50 to $60	877	5533	10.01	63.16
$60 to $70	730	6263	8.33	71.50
$70 to $80	568	6831	6.48	77.98
$80 to $90	453	7284	5.17	83.15
$90 to $100	374	7658	4.27	87.42
$100 to $110	297	7955	3.39	90.81
$110 to $120	208	8163	2.37	93.18
$120 to $130	159	8322	1.82	95.00
$130 to $140	110	8432	1.26	96.26
$140 to $150	94	8526	1.07	97.33
$150 to $160	53	8579	0.61	97.93
$160 to $170	57	8636	0.65	98.58
$170 to $180	51	8687	0.58	99.17
$180 to $190	22	8709	0.25	99.42
$190 to $200	16	8725	0.18	99.60
$200 to $210	12	8737	0.14	99.74
$210 to $220	10	8747	0.11	99.85
$220 to $230	5	8752	0.06	99.91
$230 to $240	1	8753	0.01	99.92
$240 to $250	1	8754	0.01	99.93
$250 to $260	3	8757	0.03	99.97
$260 to $270	2	8759	0.02	99.99
$280 to $290	1	8760	0.01	100.00

Figure C-9 - Frequency distribution of hourly PJM load: Calendar year 1998



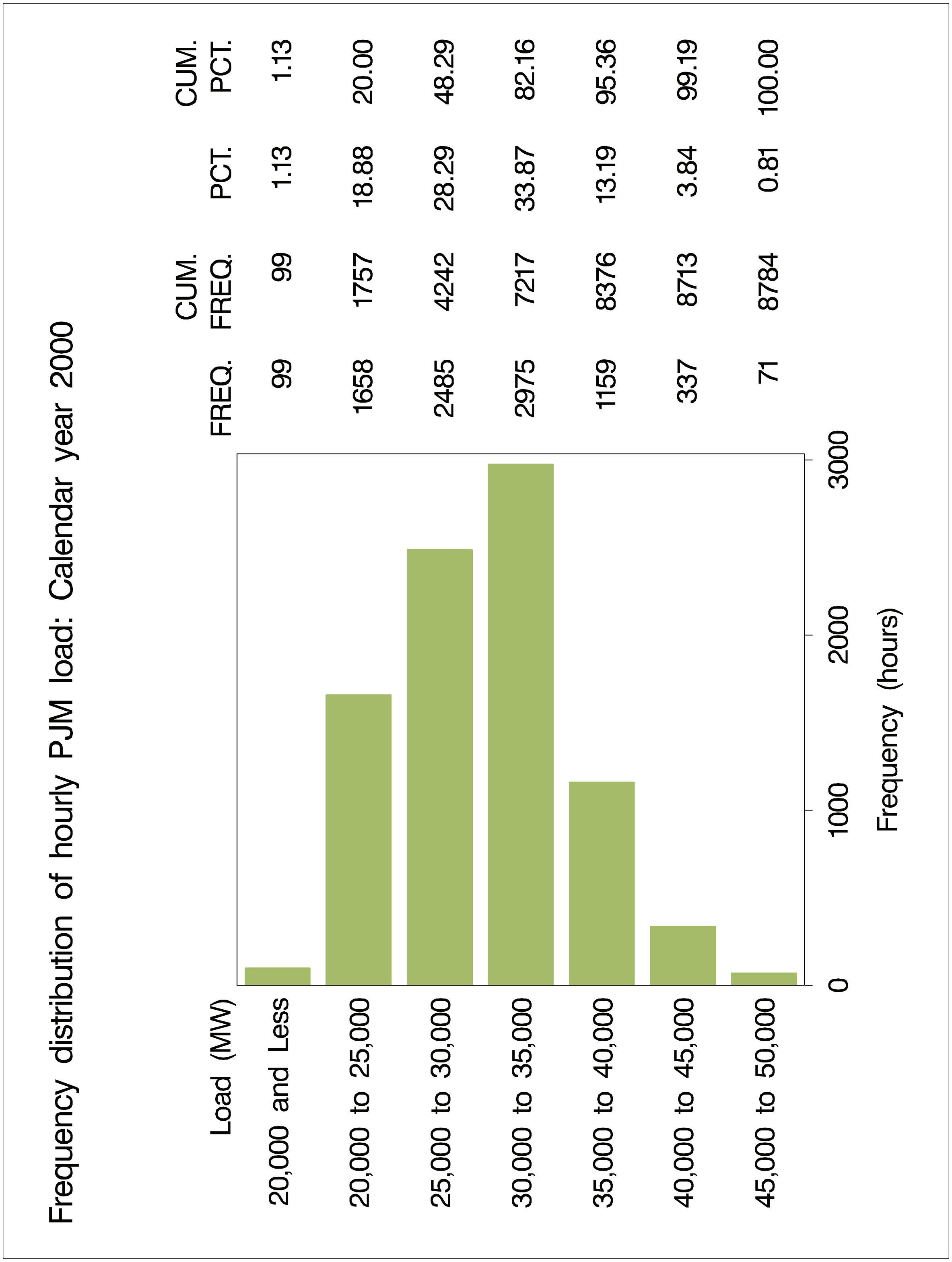
Load (MW)	FREQ.	CUM. FREQ.	PCT.	CUM. PCT.
20,000 and Less	356	356	4.06	4.06
20,000 to 25,000	2137	2493	24.39	28.46
25,000 to 30,000	3063	5556	34.97	63.42
30,000 to 35,000	2171	7727	24.78	88.21
35,000 to 40,000	704	8431	8.04	96.24
40,000 to 45,000	270	8701	3.08	99.33
45,000 to 50,000	59	8760	0.67	100.00

Figure C-10 - Frequency distribution of hourly PJM load: Calendar year 1999



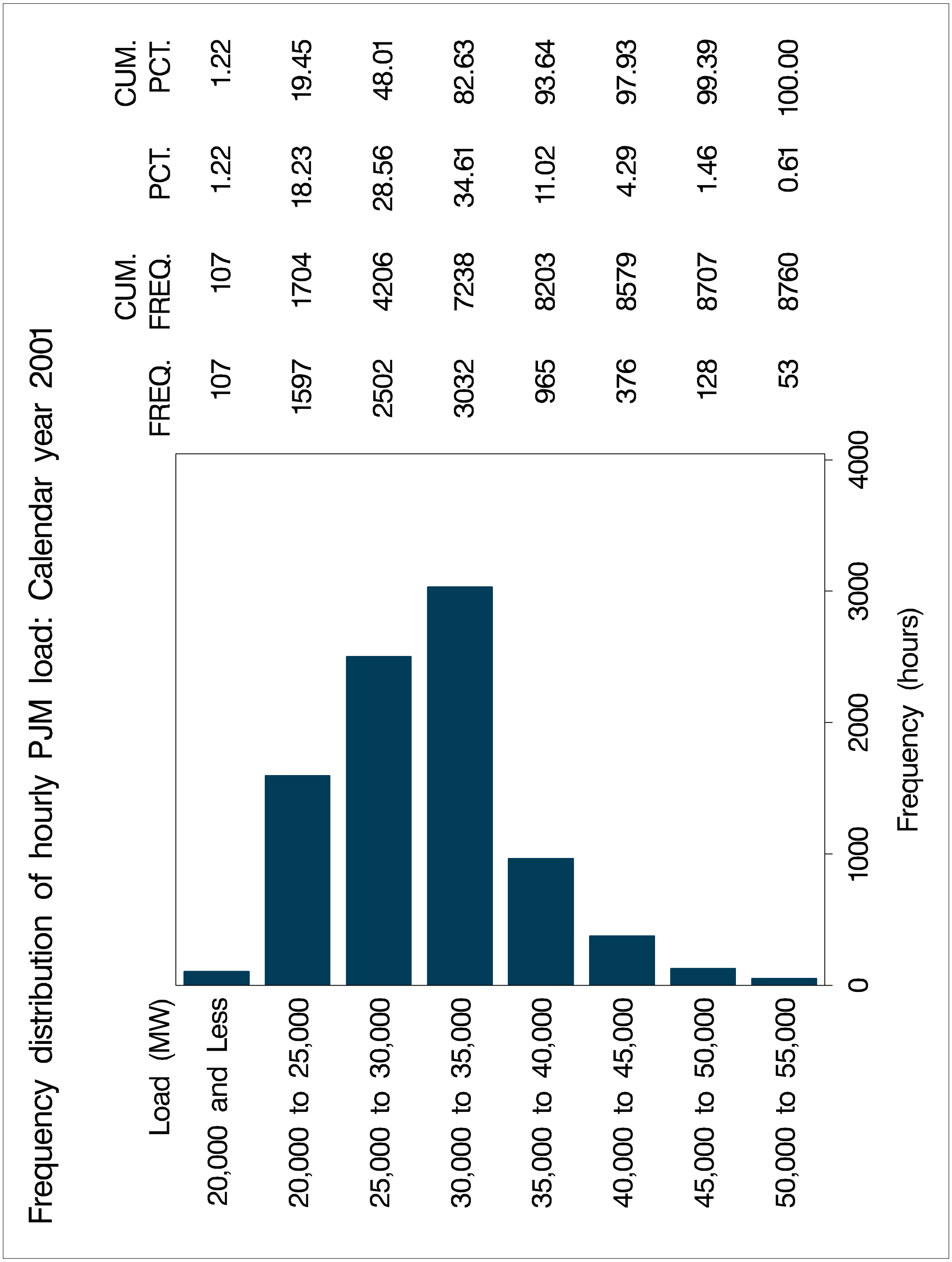
Load (MW)	FREQ.	CUM. FREQ.	PCT.	CUM. PCT.
20,000 and Less	218	218	2.49	2.49
20,000 to 25,000	1776	1994	20.27	22.76
25,000 to 30,000	2944	4938	33.61	56.37
30,000 to 35,000	2476	7414	28.26	84.63
35,000 to 40,000	773	8187	8.82	93.46
40,000 to 45,000	392	8579	4.47	97.93
45,000 to 50,000	166	8745	1.89	99.83
50,000 to 55,000	15	8760	0.17	100.00

Figure C-11 - Frequency distribution of hourly PJM load: Calendar year 2000



Load (MW)	FREQ.	CUM. FREQ.	PCT.	CUM. PCT.
20,000 and Less	99	99	1.13	1.13
20,000 to 25,000	1658	1757	18.88	20.00
25,000 to 30,000	2485	4242	28.29	48.29
30,000 to 35,000	2975	7217	33.87	82.16
35,000 to 40,000	1159	8376	13.19	95.36
40,000 to 45,000	337	8713	3.84	99.19
45,000 to 50,000	71	8784	0.81	100.00

Figure C-12 - Frequency distribution of hourly PJM load: Calendar year 2001



Load (MW)	FREQ.	CUM. FREQ.	PCT.	CUM. PCT.
20,000 and Less	107	107	1.22	1.22
20,000 to 25,000	1597	1704	18.23	19.45
25,000 to 30,000	2502	4206	28.56	48.01
30,000 to 35,000	3032	7238	34.61	82.63
35,000 to 40,000	965	8203	11.02	93.64
40,000 to 45,000	376	8579	4.29	97.93
45,000 to 50,000	128	8707	1.46	99.39
50,000 to 55,000	53	8760	0.61	100.00

Figure C-13 - Frequency distribution of hourly PJM load: Calendar year 2002

Frequency distribution of hourly PJM load: Calendar year 2002

Load (MW)	FREQ.	CUM. FREQ.	PCT.	CUM. PCT.
20,000 and Less	4	4	0.05	0.05
20,000 to 25,000	398	402	4.54	4.59
25,000 to 30,000	1749	2151	19.97	24.55
30,000 to 35,000	2320	4471	26.48	51.04
35,000 to 40,000	2199	6670	25.10	76.14
40,000 to 45,000	1037	7707	11.84	87.98
45,000 to 50,000	508	8215	5.80	93.78
50,000 to 55,000	252	8467	2.88	96.66
55,000 to 60,000	198	8665	2.26	98.92
60,000 to 65,000	95	8760	1.08	100.00

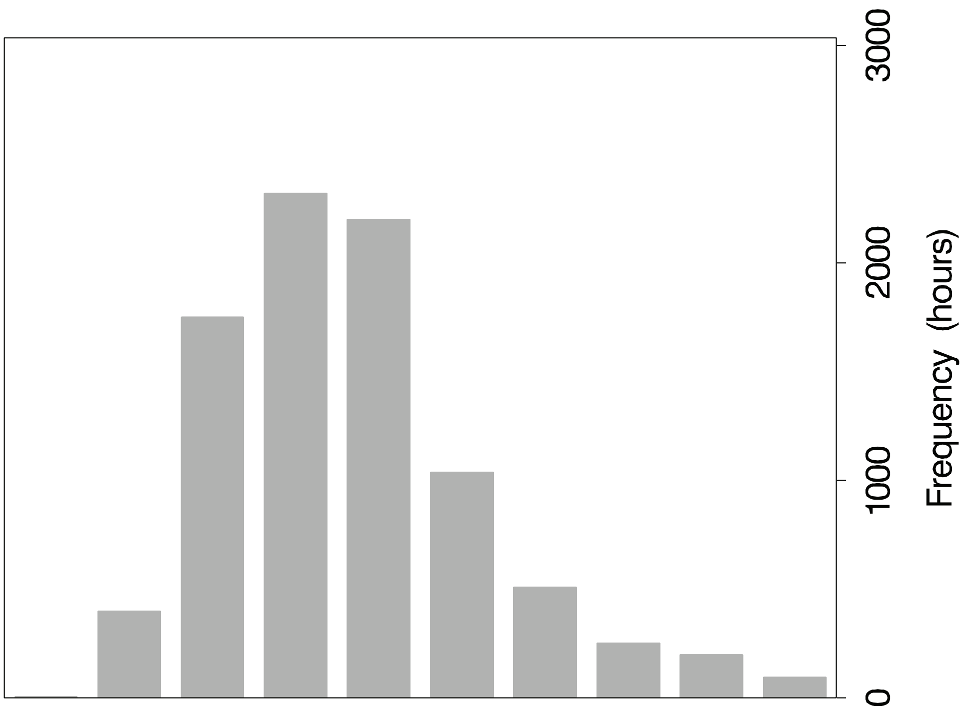
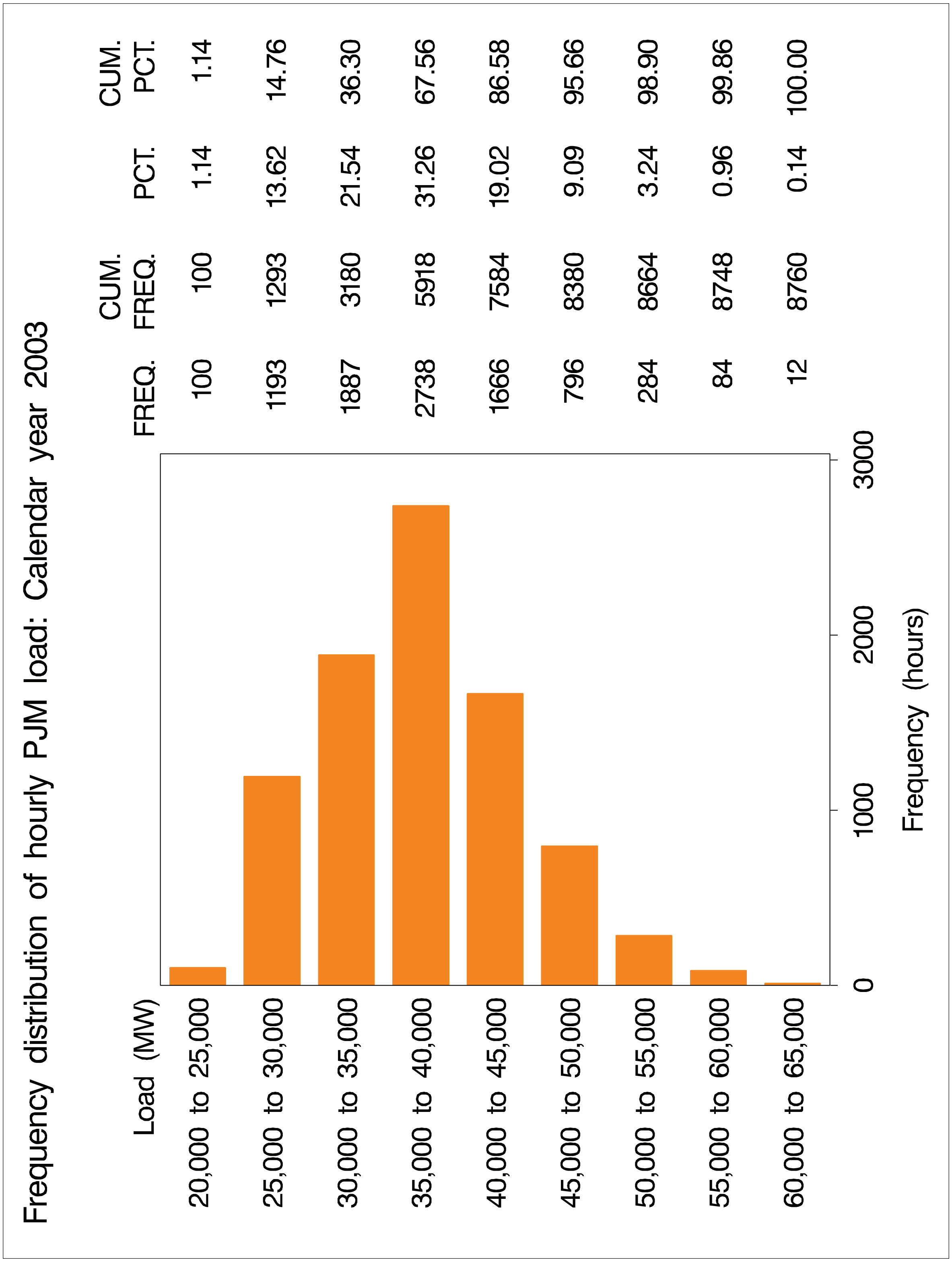


Figure C-14 - Frequency distribution of hourly PJM load: Calendar year 2003



Load (MW)	FREQ.	CUM. FREQ.	PCT.	CUM. PCT.
20,000 to 25,000	100	100	1.14	1.14
25,000 to 30,000	1193	1293	13.62	14.76
30,000 to 35,000	1887	3180	21.54	36.30
35,000 to 40,000	2738	5918	31.26	67.56
40,000 to 45,000	1666	7584	19.02	86.58
45,000 to 50,000	796	8380	9.09	95.66
50,000 to 55,000	284	8664	3.24	98.90
55,000 to 60,000	84	8748	0.96	99.86
60,000 to 65,000	12	8760	0.14	100.00

Figure C-15 - Frequency distribution of hourly PJM load: Calendar year 2004

Frequency distribution of hourly PJM load: Calendar year 2004

Load (MW)	FREQ.	CUM. FREQ.	PCT.	CUM. PCT.
20,000 to 25,000	15	15	0.17	0.17
25,000 to 30,000	280	295	3.19	3.36
30,000 to 35,000	697	992	7.93	11.29
35,000 to 40,000	1387	2379	15.79	27.08
40,000 to 45,000	1311	3690	14.92	42.01
45,000 to 50,000	1150	4840	13.09	55.10
50,000 to 55,000	847	5687	9.64	64.74
55,000 to 60,000	885	6572	10.08	74.82
60,000 to 65,000	760	7332	8.65	83.47
65,000 to 70,000	821	8153	9.35	92.82
70,000 to 75,000	391	8544	4.45	97.27
75,000 to 80,000	157	8701	1.79	99.06
80,000 to 85,000	48	8749	0.55	99.60
85,000 to 90,000	26	8775	0.30	99.90
90,000 to 95,000	7	8782	0.08	99.98
95,000 to 100,000	2	8784	0.02	100.00

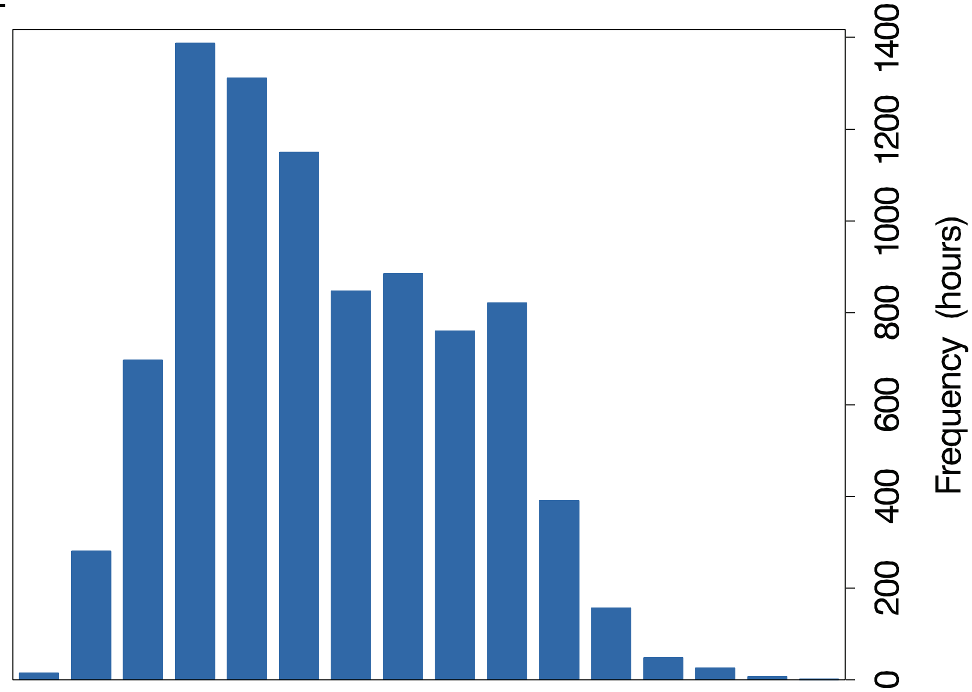
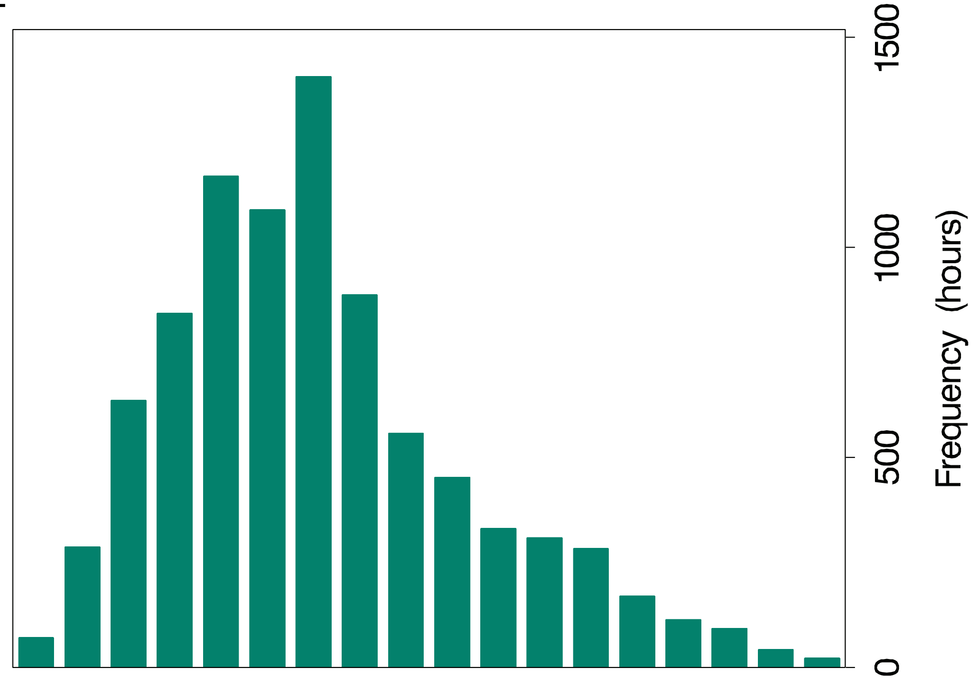


Figure C-16 - Frequency distribution of hourly PJM load: Calendar year 2005

Frequency distribution of hourly PJM load: Calendar year 2005

Load (MW)	FREQ.	CUM. FREQ.	PCT.	CUM. PCT.
45,000 to 50,000	71	71	0.81	0.81
50,000 to 55,000	286	357	3.26	4.08
55,000 to 60,000	636	993	7.26	11.34
60,000 to 65,000	843	1836	9.62	20.96
65,000 to 70,000	1170	3006	13.36	34.32
70,000 to 75,000	1089	4095	12.43	46.75
75,000 to 80,000	1407	5502	16.06	62.81
80,000 to 85,000	887	6389	10.13	72.93
85,000 to 90,000	557	6946	6.36	79.29
90,000 to 95,000	453	7399	5.17	84.46
95,000 to 100,000	330	7729	3.77	88.23
100,000 to 105,000	308	8037	3.52	91.75
105,000 to 110,000	283	8320	3.23	94.98
110,000 to 115,000	169	8489	1.93	96.91
115,000 to 120,000	113	8602	1.29	98.20
120,000 to 125,000	93	8695	1.06	99.26
125,000 to 130,000	43	8738	0.49	99.75
130,000 to 135,000	22	8760	0.25	100.00



Temperature and Humidity Index (THI)

Table C-1, Table C-2, Table C-3 and Table C-4 show the monthly average of the daily maximum THI values of four representative sites within the PJM footprint: Philadelphia, Pennsylvania; Chicago, Illinois; Columbus, Ohio; and Richmond, Virginia.[4] THI is defined as follows:

temperature - .55* (1-relative humidity/100) * (temperature – 58).[5]

As Table C-1, Table C-2, Table C-3 and Table C-4 show, the monthly averages of the daily maximum THI values for June, July and August within the PJM footprint were higher in 2005 than in 2004. Table C-1 shows the monthly average of the daily maximum THI values for Philadelphia, Pennsylvania, using temperature and humidity data as recorded at the Philadelphia International Airport. The 2005 daily maximum THI values for June, July and August were higher than those in 2004 by 3.23 percent, 2.66 percent and 3.20 percent, respectively. Table C-2 shows the monthly average of the daily maximum THI values for Chicago, Illinois, using temperature and humidity data as recorded at the O'Hare International Airport. The 2005 daily maximum THI values for June, July and August were higher than those in 2004 by 5.93 percent, 3.11 percent and 5.43 percent, respectively. Table C-3 shows the monthly average of the daily maximum THI values for Columbus, Ohio, using temperature and humidity data as recorded at the Port Columbus International Airport. The 2005 daily maximum THI values for June, July and August were higher than those in 2004 by 3.31 percent, 3.03 percent and 4.25 percent, respectively. Table C-4 shows the monthly average of the daily maximum THI values for Richmond, Virginia, using temperature and humidity data as recorded at the Richmond International Airport. The 2005 daily maximum THI values for June, July and August were higher than those in 2004 by 0.51 percent, 1.53 percent and 3.40 percent, respectively.

Table C-1 - Philadelphia average monthly maximum of temperature-humidity index (THI) comparison

	2004	2005	Difference
May	72.62	64.92	(10.60%)
Jun	73.42	75.79	3.23%
Jul	76.39	78.42	2.66%
Aug	75.86	78.29	3.20%
Sep	72.96	74.36	1.92%

Table C-2 - Chicago average monthly maximum of temperature-humidity index (THI) comparison

	2004	2005	Difference
May	67.79	63.98	(5.62%)
Jun	71.68	75.93	5.93%
Jul	74.29	76.60	3.11%
Aug	71.69	75.58	5.43%
Sep	71.55	72.60	1.47%

4 Temperature and relative humidity data that were used to calculate THI for Philadelphia, Chicago, Columbus and Richmond were obtained from Meteorlogix. See Appendix H, "Glossary," for more detail.

5 See PJM, "Load Data Systems Manual, Section M19," Revision 9 (January 1, 2006), Section 3, pp. 11-16.

Table C-3 - Columbus average monthly maximum of temperature-humidity index (THI) comparison

	2004	2005	Difference
May	71.53	64.95	(9.20%)
Jun	72.83	75.24	3.31%
Jul	75.17	77.45	3.03%
Aug	73.37	76.49	4.25%
Sep	71.86	72.99	1.57%

Table C-4 - Richmond average monthly maximum of temperature-humidity index (THI) comparison

	2004	2005	Difference
May	76.55	68.49	(10.53%)
Jun	76.85	77.24	0.51%
Jul	80.31	81.54	1.53%
Aug	77.85	80.50	3.40%
Sep	74.99	76.79	2.40%

Off-Peak and On-Peak Load

Table C-5 presents summary load statistics for 1998 to 2005 for the off-peak and on-peak hours, while Table C-6 shows the percent change in load on a year-to-year basis. 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-5 shows that on-peak load was about 24.0 percent higher than off-peak load in 2005. With the addition of the DLCO and Dominion Control Zones, average load during on-peak hours in 2005 was 55.6 percent higher than in 2004. Off-peak load in 2005 was 57.5 percent higher than in 2004. (See Table C-6.)

Table C-5 - Off-peak and on-peak load (MW): Calendar years 1998 through 2005

	Average Hourly Load			Median Hourly Load			Standard Deviation of Hourly Load		
	Off Peak	On Peak	On Peak/ Off Peak	Off Peak	On Peak	On Peak/ Off Peak	Off Peak	On Peak	On Peak/ Off Peak
1998	25,268	32,344	1.28	24,728	31,081	1.26	4,091	4,388	1.07
1999	26,453	33,269	1.26	25,780	31,950	1.24	4,947	4,824	0.98
2000	26,917	33,797	1.26	26,313	32,757	1.25	4,466	4,181	0.94
2001	26,804	34,303	1.28	26,433	33,076	1.25	4,225	4,851	1.15
2002	31,817	40,362	1.27	30,654	38,378	1.25	6,060	7,419	1.22
2003	33,595	41,755	1.24	32,971	40,802	1.24	5,546	5,424	0.98
2004	44,631	56,020	1.26	43,028	56,578	1.32	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

Table C-6 - Multiyear change in load: Calendar years 1998 through 2005

	Average Hourly Load		Median Hourly Load		Standard Deviation of Hourly Load	
	Off Peak	On Peak	Off Peak	On Peak	Off Peak	On Peak
1998	NA	NA	NA	NA	NA	NA
1999	4.7%	2.9%	4.3%	2.8%	20.9%	9.9%
2000	1.8%	1.6%	2.1%	2.5%	(9.7%)	(13.3%)
2001	(0.4%)	1.5%	0.5%	1.0%	(5.4%)	16.0%
2002	18.7%	17.7%	16.0%	16.0%	43.4%	52.9%
2003	5.6%	3.5%	7.6%	6.3%	(8.5%)	(26.9%)
2004	32.9%	34.2%	30.5%	38.7%	95.5%	132.2%
2005	57.5%	55.6%	58.2%	45.8%	17.4%	21.0%

Off-Peak and On-Peak, Load-Weighted LMP: 2004 and 2005

Table C-7 shows load-weighted, average LMP for 2004 and 2005 during off-peak and on-peak periods. In 2004, the on-peak, load-weighted LMP was 49 percent greater than the off-peak LMP, while in 2005, it was 64 percent greater. On-peak, load-weighted, average LMP in 2005 was 48.6 percent higher than in 2004. Off-peak, load-weighted LMP in 2005 was 35.2 percent higher than in 2004. Similarly, both on-peak and off-peak median LMPs were higher in 2005 than in 2004, by 43.5 percent and 21.9 percent, respectively. Dispersion in load-weighted LMP, as indicated by standard deviation, was 94.3 percent higher in 2005 than in 2004 during on-peak hours and was 62.5 percent higher during off-peak hours.

Table C-7 - Off-peak and on-peak, load-weighted LMP (Dollars per MWh): Calendar years 2004 and 2005

	2004			2005			Difference 2004 to 2005	
	Off Peak	On Peak	On Peak/ Off Peak	Off Peak	On Peak	On Peak/ Off Peak	Off Peak	On Peak
Average	$35.28	$52.53	1.49	$47.69	$78.04	1.64	35.2%	48.6%
Median	$30.42	$48.39	1.59	$37.08	$69.42	1.87	21.9%	43.5%
Standard Deviation	$19.31	$19.53	1.01	$31.38	$37.95	1.21	62.5%	94.3%

Fuel-Cost Adjustment

Fuel costs for 2004 and 2005 were taken from various published sources. Natural gas prices are the average of the daily cash price for Transco-Z6 (non-New York), Transco- Z5, Chicago Citygates and Texas Eastern-M3 and are adjusted for transportation to the burner tip. Light oil prices are the daily price for No. 2 distillate from the New York Harbor Spot Barge or the Chicago pipeline and are adjusted for transportation. Heavy oil prices are a daily average of the New York Harbor Spot Barge for 0.3 percent, 0.7 percent, 1.0 percent, 2.2 percent and 3.0 percent sulfur content. Coal prices are calculated based on unit-specific, cost-based offers.

In a competitive market, changes in LMP result from changes in demand and changes in supply. As competitive offers are equivalent to the marginal cost of generation and fuel costs make up from 80 percent to 90 percent of marginal cost, fuel cost is a key factor affecting supply and, therefore, the competitive clearing price. In a competitive market, if fuel costs increase and nothing else changes, the competitive price will also increase. In assessing changes in LMP over time, the PJM Market Monitoring Unit (MMU) examines three measures: nominal LMP, load-weighted LMP and fuel-cost-adjusted, load-weighted LMP. Nominal LMP measures the change in reported prices. Load-weighted LMP measures the change in reported prices weighted by the actual hourly MWh load to reflect what customers actually pay for energy. Fuel-cost-adjusted, load-weighted LMP measures the change in reported prices actually paid by load after accounting for the change in prices that reflects shifts in underlying fuel prices.

The impact of fuel cost on LMP depends on the fuel burned by the marginal units. To account for differences in fuel cost between different time periods of interest, the fuel-cost-adjusted, load-weighted LMP is used to compare load-weighted LMPs on a common fuel cost basis. The marginal unit fuel factors for the marginal units are one of the components needed to calculate the fuel-cost-adjusted, load-weighted LMP. The marginal unit fuel factors represent the percentage of system load affected by the marginal unit. The marginal unit fuel factors are aggregated by the marginal unit's fuel type and are used in the fuel-cost-adjusted, load-weighted LMP calculation to determine the quantity of load served by the marginal fuel.

The MMU applies an indexing method to adjust nominal LMPs for changes in fuel costs. The index has three components: a term that measures fuel prices in each period; a term that uses marginal unit fuel factors aggregated by fuel type; and a term that measures the MWh generated in each period. The MMU fuel cost index is calculated as a Fisher price index. The Fisher index is a chain-weighted index. A chain-weighted index permits both the MWh generated and fuel prices to change between periods rather than restricting the change to fuel prices only.

LMP during Constrained Hours: 2004 and 2005

Table C-8 presents summary statistics for load-weighted, average LMP during constrained hours in 2004 and 2005 and shows that by this measure price was 46.9 percent higher in 2005 than it had been in 2004. During constrained hours, the median, load-weighted LMP was 36.7 percent higher in 2005 than in 2004, and the dispersion of LMP, as shown by the standard deviation, was 87.8 percent higher in 2005 than in 2004.

Table C-8 - Load-weighted, average LMP during constrained hours (Dollars per MWh): Calendar years 2004 and 2005

	2004	2005	Difference
Average	$45.83	$67.33	46.9%
Median	$41.80	$57.13	36.7%
Standard Deviation	$20.67	$38.81	87.8%

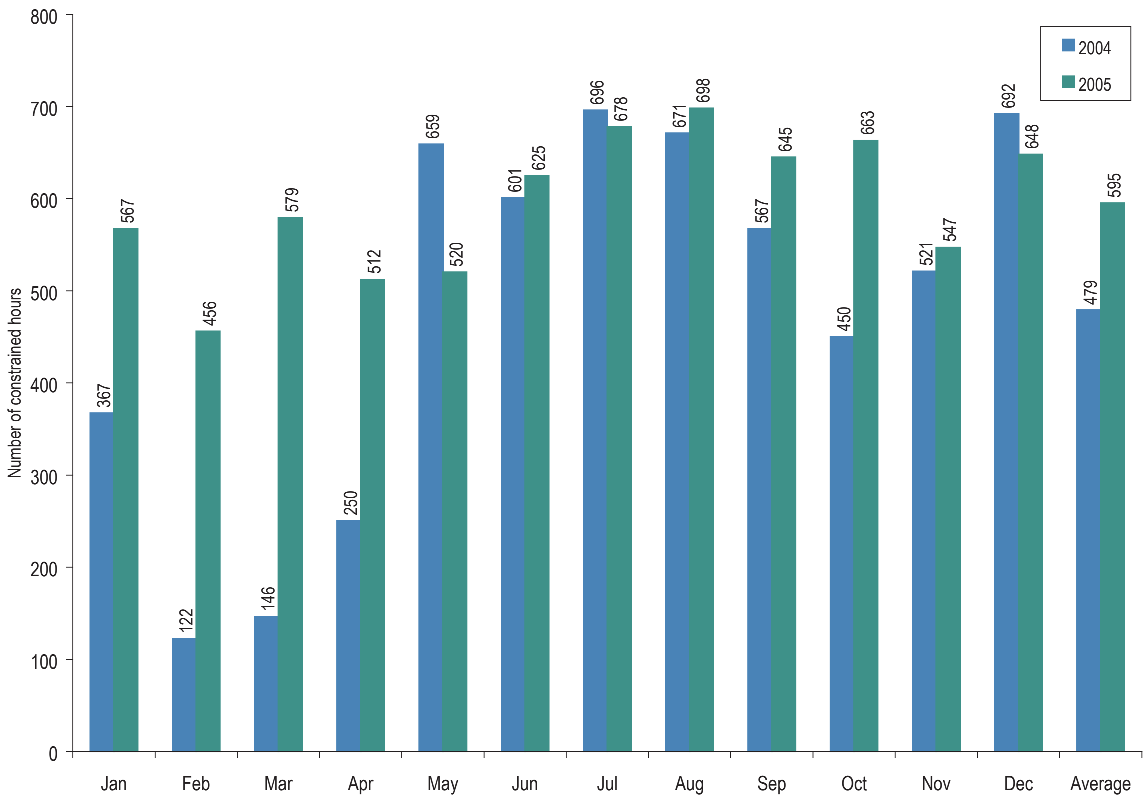
Table C-9 provides a comparison of load-weighted, average LMP during constrained and unconstrained hours for the two years. In 2005, load-weighted, average LMP during constrained hours was 53.0 percent higher than load-weighted, average LMP during unconstrained hours. The comparable number for 2004 was 12.4 percent.

Table C-9 - Load-weighted, average LMP during constrained and unconstrained hours (Dollars per MWh): Calendar years 2004 and 2005

	2004			2005		
	Unconstrained Hours	Constrained Hours	Difference	Unconstrained Hours	Constrained Hours	Difference
Average	$40.79	$45.83	12.4%	$44.00	$67.33	53.0%
Median	$36.62	$41.80	14.1%	$36.80	$57.13	55.3%
Standard Deviation	$22.17	$20.67	(6.8%)	$26.88	$38.81	44.4%

Figure C-17 shows the number of real-time constrained hours during each month in 2004 and 2005 and the average number of constrained hours per month for each year.[6] There were 5,742 constrained hours in 2004 and 7,138 in 2005, an increase of approximately 24.3 percent. Figure C-17 also shows that the average number of constrained hours per month was slightly higher in 2005 than in 2004, with 595 per month in 2005 versus 479 per month in 2004.

Figure C-17 - PJM real-time constrained hours: Calendar years 2004 through 2005

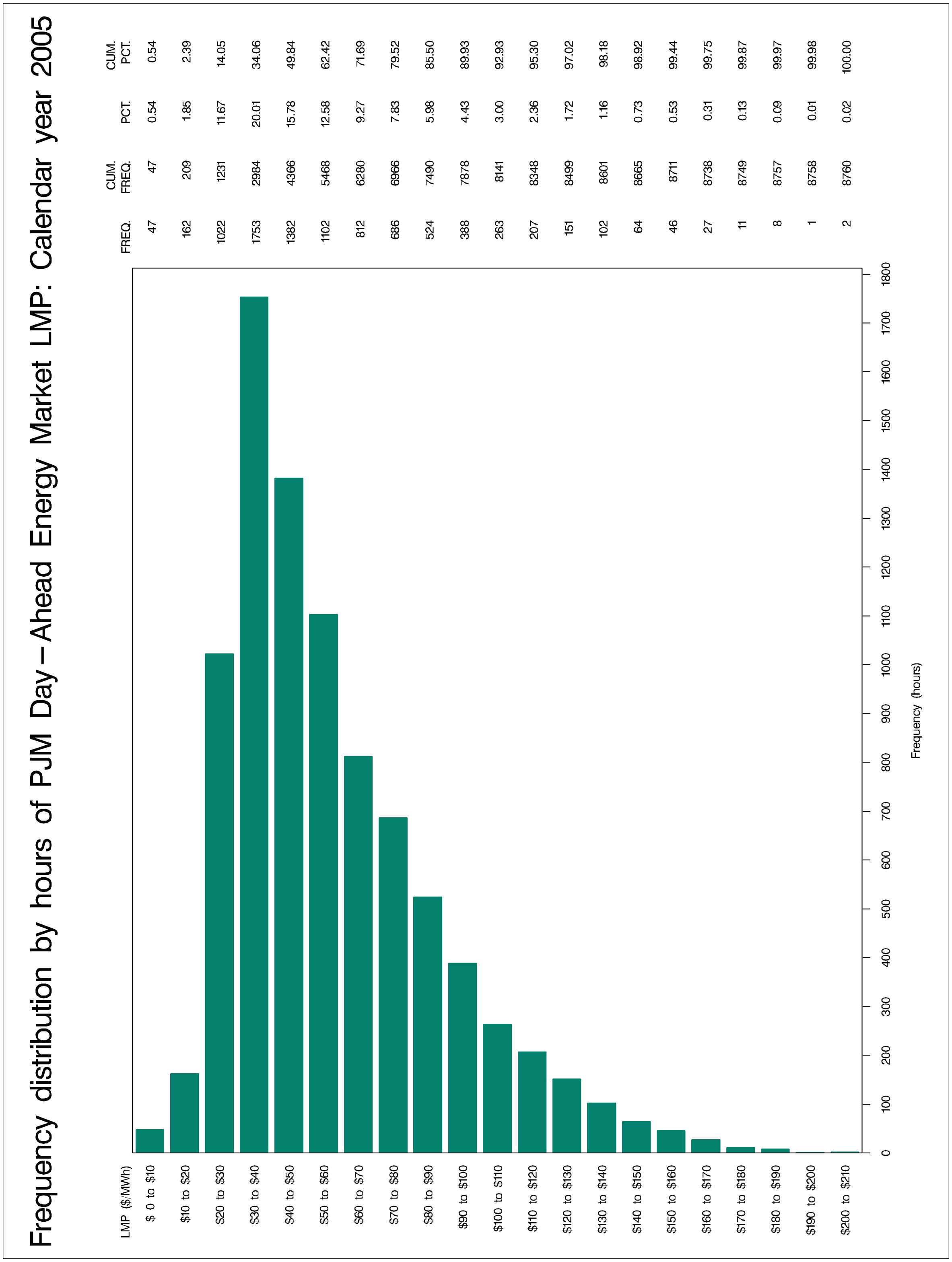


6 The constrained-hour data presented here use the convention that an hour is considered congested when the difference in LMP between at least two buses is greater than $0.00 and congestion occurs for 20 minutes or more within an hour. In prior years, this Appendix to state of the market reports defined a congested hour as one in which the difference in LMP between at least two buses in that hour was greater than $1.00.

Day-Ahead and Real-Time Prices

On average, prices in the Real-Time Energy Market are slightly higher than those in the Day-Ahead Energy Market and real-time prices show greater dispersion. This pattern of average, systemwide LMP price distribution for 2005 can be seen in Figure C-8 and Figure C-18. Together they show the frequency distribution by hours for the two markets. In PJM's Real-Time Energy Market, the $30-per-MWh to $40-per-MWh interval occurred during 20.5 percent of the hours. (See Figure C-8.) The most frequently occurring price interval in the PJM Day-Ahead Energy Market was the $30-per-MWh to $40-per-MWh interval with 20.0 percent of the hours. (See Figure C-18.) The $40-per-MWh to $50-per-MWh interval was the next most frequently occurring with 15.8 percent of the hours. The $60-per-MWh to $70-per-MWh interval occurred during 9.3 percent of the hours. In the Real-Time Energy Market, prices were less than $40 per MWh for 39.8 percent of the hours, while prices were less than $40 per MWh in the Day-Ahead Energy Market for 34.1 percent of the hours. Cumulatively, prices were less than $50 per MWh for 53.2 percent of the hours in the Real-Time Energy Market and 49.8 percent of the hours in the Day-Ahead Energy Market; less than $60 per MWh for 63.2 percent of the hours in the Real-Time Energy Market and 62.4 percent of the hours in the Day-Ahead Energy Market; less than $70 per MWh for 71.5 percent of the hours in the Real-Time Energy Market and 71.7 percent of the hours in the Day-Ahead Energy Market. In the Real-Time Energy Market, prices were above $200 per MWh for 35 hours (0.40 percent of the hours), reaching a high for the year of $286.86 per MWh on July 27 during the hour ending 1400 EPT. In the Day-Ahead Energy Market, prices were above $200 per MWh for two hours (0.02 percent of the hours) and reached a high for the year of $207.73 per MWh on August 4, 2005, during the hour ending 1600 EPT.

Figure C-18 - Frequency distribution by hours of PJM Day-Ahead Energy Market LMP: Calendar year 2005



Off-Peak and On-Peak LMP

Table C-10 shows average LMP during off-peak and on-peak periods for the Day-Ahead and Real-Time Energy Markets during calendar year 2005. Day-ahead and real-time, on-peak average LMPs were 66 percent and 68 percent higher, respectively, than the corresponding off-peak average LMP. The real-time, on-peak average LMP was 0.7 percent higher than the day-ahead, on-peak average LMP. Median LMPs during on-peak hours were 78 percent and 87 percent higher in the Day-Ahead and Real-Time Energy Markets, respectively, than median LMPs during off-peak hours. In contrast to average prices but consistent with historical experience, the real-time, on-peak median LMP was 1.6 percent lower than the day-ahead, on-peak median LMP. Since the mean was above the median in these markets, both showed a positive skewness. The mean was, however, proportionately higher than the median in the Real-Time Energy Market as compared to the Day-Ahead Energy Market during both on-peak and off-peak periods (14 percent and 27 percent compared to 11 percent and 19 percent, respectively). The differences reflect larger positive skewness in the Real-Time Energy Market. During on-peak hours, the standard deviation in the Real-Time Energy Market was about 20 percent higher than in the Day-Ahead Energy Market, while it was 32 percent higher during off-peak hours.

Table C-10, Figure C-19 and Figure C-20 show the difference between real-time and day-ahead LMP during calendar year 2005 during the on-peak and off-peak hours, respectively. The difference between real-time and day-ahead average LMP during on-peak hours was $0.53 per MWh. (Day-ahead LMP was lower than real-time LMP.) During the off-peak hours, the difference between real-time and day-ahead average LMP was $0.12 per MWh. (Day-ahead LMP was higher than real-time LMP.)

Table C-10 - Off-peak and on-peak hourly LMP (Dollars per MWh): Calendar year 2005

	Day Ahead			Real Time			Difference in Real Time Relative to Day Ahead	
	Off Peak	On Peak	On Peak/ Off Peak	Off Peak	On Peak	On Peak/ Off Peak	Off Peak	On Peak
Average	$44.26	$73.54	1.66	$44.14	$74.07	1.68	(0.3%)	0.7%
Median	$37.23	$66.22	1.78	$34.85	$65.14	1.87	(6.4%)	(1.6%)
Standard Deviation	$22.18	$30.25	1.36	$29.20	$36.23	1.24	31.7%	19.8%

Figure C-19 - Hourly real-time LMP minus day-ahead LMP (On-peak hours): Calendar year 2005

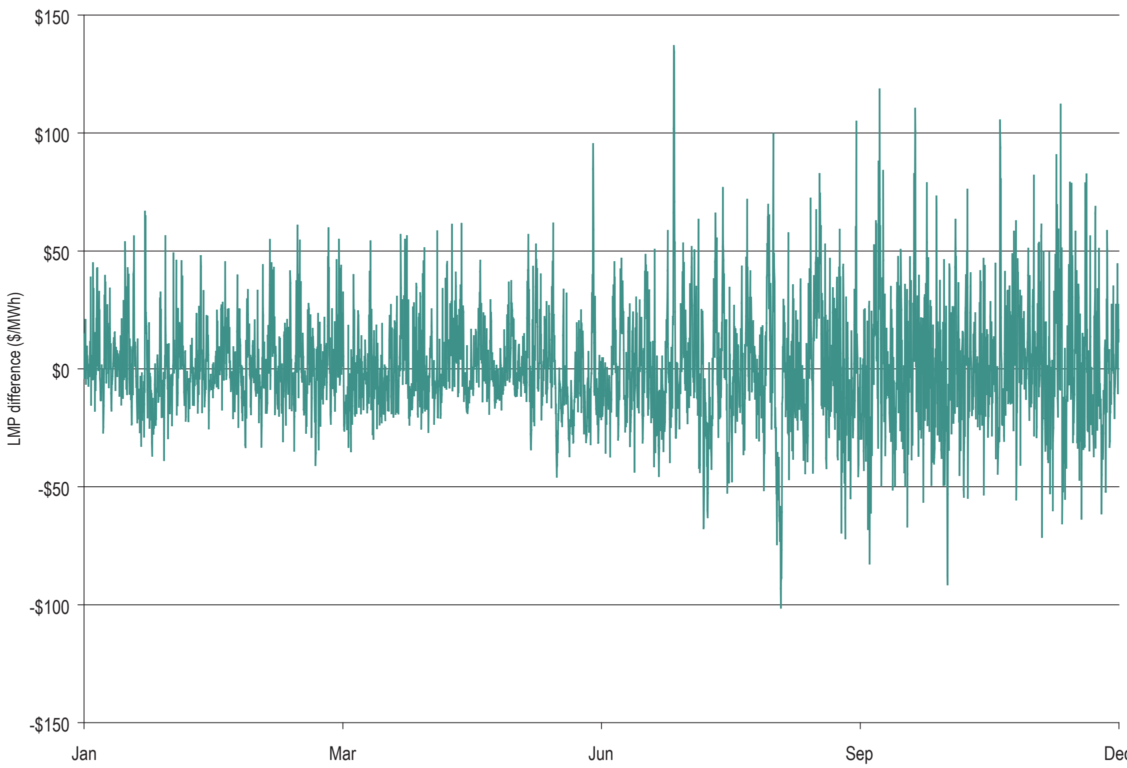
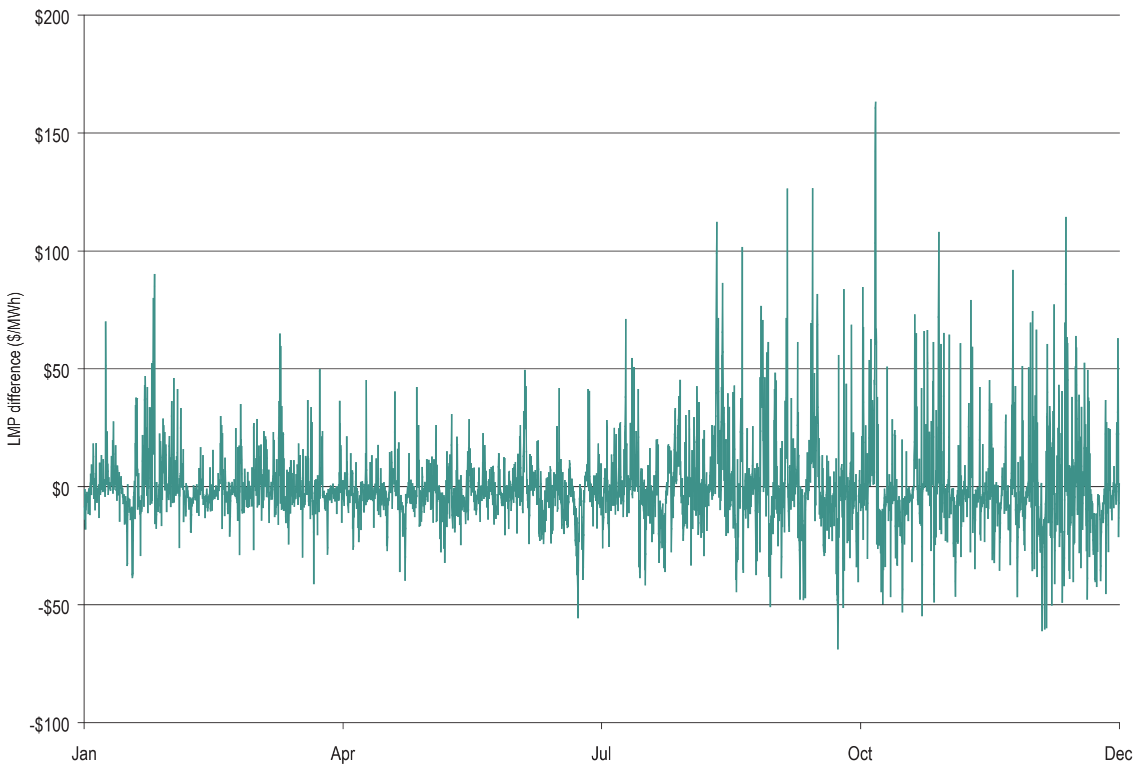


Figure C-20 - Hourly real-time LMP minus day-ahead LMP (Off-peak hours): Calendar year 2005



Off-Peak and On-Peak Zonal LMP

Table C-11 and Table C-12 show the average on-peak and off-peak LMP for each zone in the Day-Ahead and Real-Time Energy Markets during calendar year 2005. The difference between the Day-Ahead and Real-Time Energy Markets is displayed in both dollars per MWh and a percentage difference. The zone with the maximum difference between real-time and day-ahead LMP was the Delmarva Power & Light Control Zone (DPL) with an on-peak, real-time zonal LMP 3.40 percent lower than its on-peak, day-ahead zonal LMP. AEP had the smallest difference with its on-peak, real-time zonal LMP 0.13 percent lower than its on-peak, day-ahead zonal LMP. DLCO had the largest difference between off-peak zonal LMP, with day-ahead LMP 8.54 percent higher than real-time LMP. The zone with the smallest difference in off-peak zonal LMP was the Pennsylvania Electric Company Control Zone (PENELEC) with day-ahead LMP 0.05 percent higher than real-time LMP.

Table C-11 - Zonal on-peak hourly LMP (Dollars per MWh): Calendar year 2005

	Day Ahead	Real Time	Difference	Difference as Percent Real Time
AECO	$88.76	$86.88	$1.88	2.16%
AEP	$61.82	$61.74	$0.08	0.13%
AP	$73.35	$73.71	($0.36)	(0.49%)
BGE	$83.41	$85.25	($1.84)	(2.16%)
ComEd	$61.24	$61.40	($0.16)	(0.26%)
DAY	$60.51	$60.37	$0.14	0.23%
DLCO	$58.12	$57.92	$0.20	0.35%
Dominion	$90.75	$92.60	($1.85)	(2.00%)
DPL	$85.23	$82.43	$2.80	3.40%
JCPL	$84.34	$83.83	$0.51	0.61%
Met-Ed	$82.25	$81.11	$1.14	1.41%
PECO	$85.16	$82.89	$2.27	2.74%
PENELEC	$71.57	$71.20	$0.37	0.52%
PEPCO	$85.03	$86.55	($1.52)	(1.76%)
PPL	$81.31	$79.50	$1.81	2.28%
PSEG	$87.11	$88.39	($1.28)	(1.45%)
RECO	$83.57	$84.42	($0.85)	(1.01%)

Table C-12 - Zonal off-peak hourly LMP (Dollars per MWh): Calendar year 2005

	Day Ahead	Real Time	Difference	Difference as Percent Real Time
AECO	$51.67	$51.86	($0.19)	(0.37%)
AEP	$35.92	$34.82	$1.10	3.16%
AP	$44.87	$44.69	$0.18	0.40%
BGE	$52.47	$52.81	($0.34)	(0.64%)
ComEd	$34.48	$33.51	$0.97	2.89%
DAY	$34.91	$33.37	$1.54	4.62%
DLCO	$33.92	$31.25	$2.67	8.54%
Dominion	$54.73	$56.63	($1.90)	(3.36%)
DPL	$51.22	$51.00	$0.22	0.43%
JCPL	$49.61	$49.80	($0.19)	(0.38%)
Met-Ed	$49.78	$49.54	$0.24	0.48%
PECO	$50.75	$50.22	$0.53	1.06%
PENELEC	$43.81	$43.79	$0.02	0.05%
PEPCO	$53.60	$53.89	($0.29)	(0.54%)
PPL	$49.16	$48.71	$0.45	0.92%
PSEG	$52.39	$53.64	($1.25)	(2.33%)
RECO	$51.25	$52.96	($1.71)	(3.23%)

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

Table C-13 and Table C-14 show the average load-weighted LMP and the average load-weighted, fuel-cost-adjusted LMP for 1999 through 2005 for on-peak and off-peak hours. During on-peak hours the load-weighted, fuel-cost-adjusted LMP in 2005 increased by 5.8 percent over the load-weighted LMP in 2004. However, the load-weighted, fuel-cost-adjusted LMP in 2005 decreased by 3.2 percent in the off-peak hours compared to the load-weighted LMP in 2004.

Table C-13 - On-peak PJM load-weighted, fuel-cost-adjusted LMP (Dollars per MWh): Year-over-year method

	1999	2000	2001	2002	2003	2004	2005
Load-Weighted LMP	$45.31	$38.80	$48.36	$39.78	$49.97	$52.53	$78.04
Load-Weighted and Fuel-Cost-Adjusted LMP	NA	$25.92	$47.75	$42.81	$38.59	$46.92	$55.57
Year-over-Year Comparison	NA	(42.8%)	23.1%	(11.5%)	(3.0%)	(6.1%)	5.8%

Table C-14 - Off-peak PJM load-weighted, fuel-cost-adjusted LMP (Dollars per MWh): Year-over-year method

	1999	2000	2001	2002	2003	2004	2005
Load-Weighted LMP	$21.65	$21.93	$23.59	$22.51	$31.75	$35.28	$47.69
Load-Weighted and Fuel-Cost-Adjusted LMP	NA	$14.45	$23.34	$24.37	$24.26	$31.88	$34.14
Year-over-Year Comparison	NA	(33.3%)	6.4%	3.3%	7.8%	0.4%	(3.2%)

LMP during Constrained Hours: Day-Ahead and Real-Time Energy Markets

Figure C-21 shows the number of constrained hours in each month for the Day-Ahead and Real-Time Energy Markets and the average number of constrained hours for 2005. Overall, there were 7,138 constrained hours in the Real-Time Energy Market and 8,732 constrained hours in the Day-Ahead Energy Market. Figure C-21 shows that in every month of calendar year 2005 the number of constrained hours in the Day-Ahead Energy Market exceeded those in the Real-Time Energy Market. On average for the year, the Day-Ahead Energy Market had 22.4 percent more constrained hours than the Real-Time Energy Market.

Figure C-21 - Day-ahead and real-time, market-constrained hours: Calendar year 2005

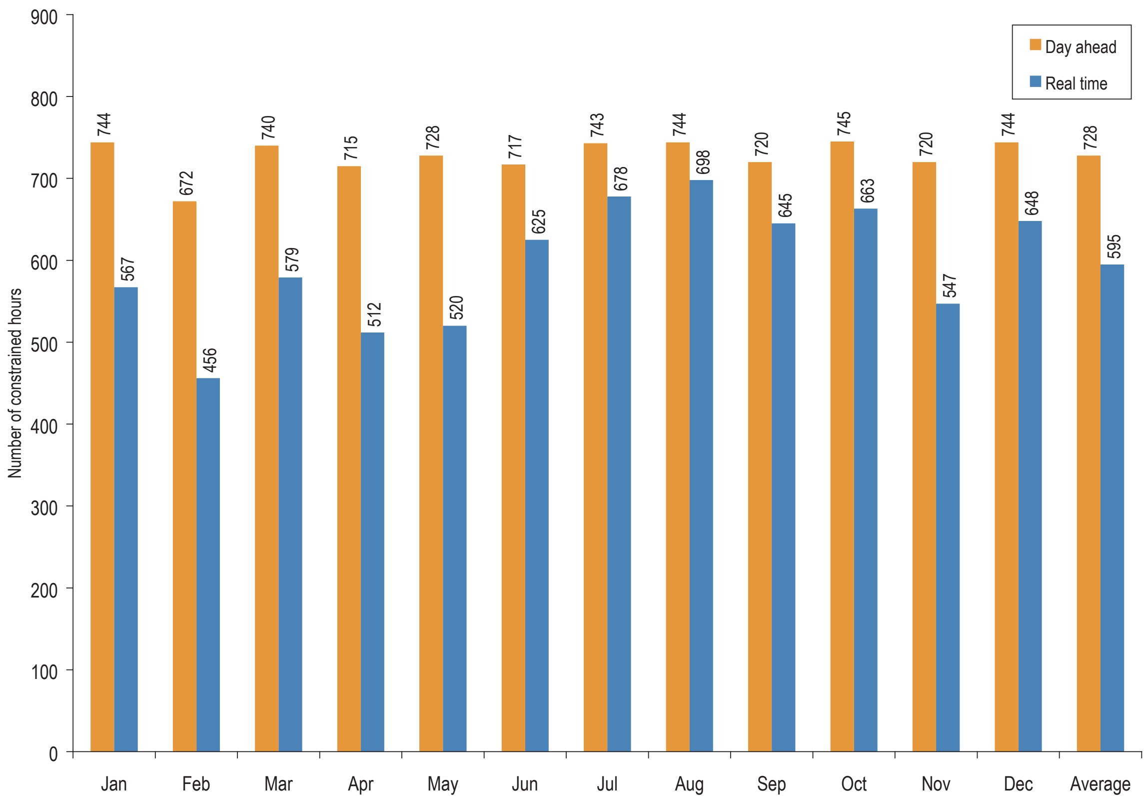


Table C-15 shows average LMP during constrained and unconstrained hours in the Day-Ahead and Real-Time Energy Markets. In the Day-Ahead Energy Market, average LMP during constrained hours was 104.8 percent higher than average LMP during unconstrained hours. In the Real-Time Energy Market, average LMP during constrained hours was 51.7 percent higher than average LMP during unconstrained hours. Average LMP during constrained hours was 6.9 percent higher in the Real-Time Energy Market than in the Day-Ahead Energy Market and LMP during unconstrained hours was 44.3 percent higher in the Real-Time Market than in the Day-Ahead Market.

Table C-15 - LMP during constrained and unconstrained hours (Dollars per MWh): Calendar year 2005

	Day Ahead			Real Time		
	Unconstrained Hours	Constrained Hours	Difference	Unconstrained Hours	Constrained Hours	Difference
Average	$28.32	$57.99	104.8%	$40.87	$61.99	51.7%
Median	$17.33	$50.17	189.5%	$34.29	$51.03	48.8%
Standard Deviation	$23.18	$30.01	29.5%	$25.75	$36.74	42.7%

Taken together, the data show that average LMP in the Day-Ahead Energy Market during constrained hours was 0.2 percent higher than the overall average LMP for the Day-Ahead Energy Market, while average LMP during unconstrained hours was 51.1 percent lower.[7] In the Real-Time Energy Market, average LMP during constrained hours was 6.7 percent higher than the overall average LMP for the Real-Time Energy Market, while average LMP during unconstrained hours was 29.6 percent lower.

7 See Section 2, "Energy Market, Part 1" for a discussion of load and LMP.

APPENDIX D – INTERCHANGE TRANSACTIONS

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

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

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

PJM Interface Pricing Point Definition – General Methodology[3]

PJM establishes prices for transactions with external control areas by assigning interface pricing points to external control areas. The interface pricing points are designed to reflect the way a transaction from or to an external area actually impacts PJM electrically. External control areas are either adjacent to PJM or not adjacent to PJM.

Transactions between PJM and external control areas need to be priced at the PJM border. A set of external pricing points is used to create such interface prices. The challenge is to create an interface price, composed of external pricing points, that accurately represents flows between PJM and an external control area and, therefore, to create price signals that embody the underlying economic and electrical system fundamentals. Transactions between adjacent control areas and PJM flow on one or more physical tie lines that constitute the interface between the two control areas.

1 Control zones and control areas are geographic areas that customarily bear the name of a large utility service provider working within their boundaries. The nomenclature applies to the geographic area, not to any single company.

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

3 This discussion of the PJM methodology for defining interface pricing points relies on the PJM analysis and associated white papers developed in conjunction with the 2004 integrations. See generally PJM, "AEP & DP&L Transmission and Market Integration White Paper, Version 1.4" (September 24, 2004); and PJM, "Draft ComEd Transmission and Market Integration White Paper, Version 2.3" (April 15, 2004).

Each adjacent control area either has a separate interface pricing point or, if distribution factor analysis shows that identified adjacent control areas have similar electrical effects on the tie lines connecting them to PJM, multiple adjacent control areas can use a common interface price definition. Thus an interface price definition may include external pricing points from one adjacent control area or a combination of adjacent control areas.

PJM analysis for the ComEd integration showed that transactions from specific, adjacent control areas had very similar electrical effects on PJM and were, therefore, given the same interface price definition. For example, MEC and Alliant Energy Corporation West (ALTW) are adjacent control areas with similar electrical effects on tie lines connecting them to PJM. As a result, the interface price is the same for both control areas and consists of a combination of external pricing points from both the adjacent control areas.

PJM analysis for the AEP and DAY Control Zone integrations showed a number of adjacent control areas with very similar effects on tie lines connecting them to PJM. As a result, single interface pricing points were created to define groups of adjacent control areas. As an example, a group of control areas with similar electrical effects on PJM was determined to include Central Illinois Light Company (CILCO), Illinois Power Company (IP), Indianapolis Power & Light Company (IPL), Ameren, Cinergy Corporation (CIN), East Kentucky Power Cooperative, Inc. (EKPC), LG&E Energy, L.L.C. (LGEE) and Tennessee Valley Authority (TVA). The Southwest pricing point was defined as the single interface price used to price transactions to or from any location within this group of adjacent control areas.

Transactions from external, non-adjacent control areas are also priced at interface prices. PJM, in its AEP and DAY transition white paper, describes how standard power flow analysis tools are used to simulate transactions with external, non-adjacent control areas to obtain distribution factor data. The distribution factor data are analyzed to determine through which adjacent control area the majority of power from the external, non-adjacent control area flows. By calculating the correlation coefficient between the external, non-adjacent control area distribution factor and the distribution factor for each of the adjacent control areas, PJM determines the association of an external control area with one of the adjacent control areas and assigns a corresponding interface price.

A more complex situation arises when a transaction from an external, non-adjacent control area results in similar flows on multiple interfaces with different interface price definitions. In that case, an additional interface price definition may be required to reflect the impact of transactions from the external, non-adjacent control area on multiple interface pricing points defined with adjacent control areas. As an example, flows between the Ontario Independent Electricity System Operator (Ontario IESO) and PJM tend to be split between adjacent control areas, primarily the New York Independent System Operator (NYIS) and the FirstEnergy Corp. (FE), each of which has a different interface price. Neither interface price was separately appropriate for transactions with the Ontario IESO. So PJM created the Ontario IESO interface price to include both interface prices so as to appropriately reflect the price for transactions with the Ontario IESO.

Phase 4 Integration of the DLCO Control Zone

With the integration of the DLCO Control Zone into PJM, the DLCO interface was retired. As a result, interface pricing points were reduced from nine to eight and the number of interfaces from 23 to 22. These pricing points are defined in Table D-1.

Table D-1 - DLCO integration interface pricing point definitions:[4] During Phase 4

	Included Control Areas
Northwest	Wisconsin Energy Corporation, Alliant Energy Corporation East, ALTW, MEC
Southwest	CILCO, IP, IPL, Ameren, CIN, EKPC, LGEE, TVA
OVEC	Ohio Valley Electric Corporation
NIPSCO	Northern Indiana Public Service Company
Southeast	Carolina Power & Light Company West, Carolina Power & Light Company East, Duke Power, Dominion Virginia Power
Ontario IESO	Ontario IESO
MICHFE	Michigan Electric Coordinated System, FE
NYIS	NYIS

Midwest ISO Begins Market-Based Operation

On April 1, 2005, the Midwest ISO began operation of its market-based system. This required PJM to establish a new pricing point at the border, increasing the number of pricing points from eight to nine. (See Table D-2.)

Table D-2 - Midwest ISO startup interface pricing point definitions:[5] From April 1, 2005, through December 31, 2005

	Included Control Areas
Northwest	Wisconsin Energy Corporation, Alliant Energy Corporation East, ALTW, MEC
Southwest	CILCO, IP, IPL, Ameren, CIN, EKPC, LGEE, TVA
OVEC	Ohio Valley Electric Corporation
NIPSCO	Northern Indiana Public Service Company
Southeast	Carolina Power & Light Company West, Carolina Power & Light Company East, Duke Power, Dominion Virginia Power
Ontario IESO	Ontario IESO
MICHFE	Michigan Electric Coordinated System, FE
NYIS	NYIS
MISO	Midwest ISO

Phase 5 Integration of the Dominion Control Zone

With the integration of the Dominion Control Zone into PJM on May 1, the Dominion interface was retired. Its elimination reduced interfaces from 22 to 21. The Southeast interface pricing point was modified to account for the integration.

4 See Section 4, "Interchange Transactions," for a discussion of the evolution of pricing points during 2005.
5 See Section 4, "Interchange Transactions," for a discussion of the evolution of pricing points during 2005.

APPENDIX E – CAPACITY MARKETS[1]

Background

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

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

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

With the Phase 2 integration of the Commonwealth Edison Company (ComEd) into PJM on May 1, 2004,[3] the "PJM-West Reliability Assurance Agreement Among Load-Serving Entities in the PJM-West Region" was amended by Schedule 17.[4] It specified capacity market rules that would be implemented only in the ComEd Capacity Market during an interim 13-month period that ended on May 31, 2005. The market rules were specified in terms of installed, rather than unforced, capacity and operated on a monthly basis. The ComEd Capacity Credit Market did not include the Daily Capacity Credit Market Auctions that are a feature of the Capacity Credit Market in the rest of PJM. Beginning on June 1, 2005, however, when the interim market ended, all ComEd Control Zone capacity transactions and obligations operated under the PJM Capacity Market rules then in effect.

1 On June 1, 2005, the PJM Capacity Market became the sole capacity market for all control zones. It is referred to here as the PJM Capacity Market, the PJM Capacity Credit Market or simply PJM. The Commonwealth Edison Company (ComEd) Capacity Market was an interim market limited to that control zone. It began on June 1, 2004, and continued through May 31, 2005. On June 1, 2005, all control zones participated in a single regional transmission organization (RTO) Capacity Market. Until then and for the purposes of the *2005 State of the Market Report*, the interim capacity market is referred to as the ComEd Capacity Market, the ComEd Capacity Credit Market or simply ComEd.

Zones, control zones and control areas are geographic areas that customarily bear the name of a large utility service provider operating within their boundaries. The names apply to the geographic area, not to any single company. The geographic areas did not change with the formalization of the control zone and control area concepts during the Phase 4 and Phase 5 integrations. For simplicity, zones are referred to as control zones for both phases. The only exception is ComEd which was called the ComEd Control Area for 2004 Phase 2 only.

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

3 Since the ComEd Control Area's Capacity Market did not open until June 1, 2004, throughout May 2004 the Commonwealth Edison Company covered all capacity obligations operating under the guidance of PJM. See "Schedule 17, Capacity Adequacy Standards and Procedures for the Commonwealth Edison Zone during the Interim Period." See also "PJM West Reliability Assurance Agreement Among Load-Serving Entities in the PJM West Region," Section L (December 20, 2004), pp. 48C – 48D.

4 "Schedule 17, Capacity Adequacy Standards and Procedures for the Commonwealth Edison Zone During the Interim Period." See also "PJM West Reliability Assurance Agreement Among Load-Serving Entities in the PJM West Region" (December 20, 2004), pp. 48A – 48D.

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

Capacity Obligations

For both the PJM Capacity Market and the interim ComEd Capacity Market, load forecasts are used to determine a forecast peak load. These forecast peak-load values are further adjusted to establish capacity obligations.

- **The PJM Capacity Market**. The adjusted forecast peak-load value[5] is multiplied by the forecast pool requirement (FPR) to determine the unforced capacity obligation for PJM. The FPR is equal to one plus a reserve margin, multiplied by the PJM unforced outage factor. An LSE's unforced capacity obligation for a zone is based on its customers' aggregate share of the prior summer's weather-normalized zonal peak load multiplied by zonal scaling factors[6] and the FPR. The LSE's zonal obligation may be further adjusted for ALM credits. The FPR is set for each planning period which commences every June 1.

- **The Interim ComEd Capacity Market.** The adjusted forecast peak-load value was multiplied by an installed reserve margin (IRM) to determine the capacity obligation. The IRM was to equal to one plus a reserve margin. The IRM was set for three consecutive intervals: a 1.15 IRM for the summer interval running from June 1, 2004, through September 30, 2004; a 1.4 IRM for the fall interval running from October 1, 2004, through December 31, 2004: and a 1.4 IRM for the winter interval running from January 1, 2005, through May 31, 2005.

  Each individual LSE's capacity obligation was based on its customers' aggregate share of the summer interval's forecasted peak load multiplied by the IRM. The amount was further adjusted for mandatory interruptible load (MIL). This allocation was also used to determine adjusted, peak-load values for the fall and winter intervals.

Meeting Capacity Obligations

- **The PJM Capacity Market.**[7] In this Capacity Market, an LSE's load can change on a daily basis as customers switch suppliers. The unforced capacity position of every such LSE is calculated daily when its capacity resources are compared to its capacity obligation to determine if any LSE is short of capacity resources. Deficient entities must contract for capacity resources to satisfy their deficiency. Any LSE that remains deficient must pay an interval penalty equal to the capacity deficiency rate (CDR) times the number of days in an interval.[8] If an LSE is short because of a short-term load increase, it pays only the daily penalty until the end of the month. In no case is a deficient LSE charged more than the CDR multiplied by the number of days in the interval, multiplied by each MW of deficiency.

5 Adjusted for active load-management (ALM).

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

7 See "PJM Manual 17, Capacity Obligations, Revision 06" (June 1, 2005) <http://www.pjm.com/contributions/pjm-manuals/pdf/m17vo6.pdf>(105 KB).

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

- **The Interim ComEd Capacity Market.** By contrast, in this Capacity Market, an LSE's load could only change monthly to reflect load shifts between LSEs as customers switch suppliers. In the ComEd Capacity Market, installed capacity rather than unforced capacity was used to meet capacity obligations. Deficient entities were required to contract for capacity resources to satisfy their deficiency. Any LSE that remained deficient had to pay a deficiency charge equal to the MW of deficiency times the daily deficiency rate,[9] times the number of days in the interval.

Capacity Resources

Capacity resources are defined as MW of net generating capacity meeting PJM-specific criteria. They may be located within or outside of PJM, but they must be committed to serving load within PJM. All capacity resources must pass tests regarding the capability of generation to serve load and to deliver energy. This latter criterion requires adequate transmission service.[10]

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

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

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

- **Capacity Credit Markets.** For the PJM Capacity Market, market purchases may be made from the Daily, Monthly or Multimonthly Capacity Credit Market Auctions. For the interim ComEd Capacity Market, market purchases could be made from the ComEd Monthly or Multimonthly Capacity Credit Market Auctions.

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

- **Energy Recall Right.** PJM rules specify that when a generation owner sells capacity resources from a unit, the seller is contractually obligated to allow PJM to recall the energy generated by that unit if the energy is sold outside of PJM. This right enables PJM to recall energy exports from capacity resources when it invokes emergency procedures.[11] The recall right establishes a link between capacity and actual delivery of energy when it is needed. Thus, PJM can call upon energy from all capacity resources to serve load within the Control Area. When PJM invokes the recall right, the energy supplier is paid the PJM Real-Time Energy Market price.

9 Effective June 1, 2004, the daily deficiency rate was $160.00 per MW-day.

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

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

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

- **Deliverability.** To qualify as a PJM capacity resource, energy from the generating unit must be deliverable to load in the PJM Control Area. Capacity resources must be deliverable,[12] consistent with a loss of load expectation as specified by the reliability principles and standards, to the total system load, including portion(s) of the system that may have a capacity deficiency. In addition, for external capacity resources used to meet an accounted-for obligation within PJM, capacity and energy must be delivered to the metered boundaries of the RTO through firm transmission service.

- **Generator Outage Reporting Requirement.** Owners of PJM capacity resources are required to submit historical outage data to PJM pursuant to Schedule 12 of the RAA.[13]

Market Dynamics

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

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

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

12 Deliverable per Schedule 10, PJM "Reliability Assurance Agreement" (May 17, 2004), p. 52 <http: //www.pjm.com/documents/downloads/agreements/raa.pdf> (344 KB).
13 See Schedule 12, PJM "Reliability Assurance Agreement" (May 17, 2004), p. 57 <http: //www.pjm.com/documents/downloads/agreements/raa.pdf> (344 KB).

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

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

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

APPENDIX F – ANCILLARY SERVICE MARKETS

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

Area Control Error (ACE)

Area control error (ACE) is a real-time metric used by PJM operators to measure the instantaneous MW imbalance between load plus net interchange, and generation. PJM dispatchers seek to ensure grid reliability by balancing ACE. A dispatcher's success in doing so is measured by control performance standards (CPS) that are mandated by the North American Electric Reliability Council (NERC).

In the absence of a severe grid disturbance, the primary tool used by dispatchers to minimize ACE is regulation. Regulation is defined as a variable amount of generation energy under automatic control which is independent of economic cost signal and is obtainable within five minutes. Regulation contributes to maintaining the balance between load and generation by moving the output of selected generators up and down via an automatic generation control (AGC) signal.[1]

Generators wishing to participate in the Regulation Market must pass certification and submit to random testing. Certification requires that generators be capable of and responsive to AGC. After receiving certification, all participants in the Regulation Market are tested to ensure that regulation capacity is fully available at all times. Testing occurs at times of minimal load fluctuation. During testing, units must respond to a regulation test pattern for 40 minutes and must reach their offered regulation capacity levels, up and down, within five minutes. Units whose monitored response is less than their offered regulation capacity have their regulating capacity reduced by PJM.[2]

Control Performance Standard (CPS)

Two control performance standards are established by NERC for evaluating ACE control. One measure is a statistical measure of ACE variability and its relationship to frequency error. The second measure is a statistical measure of unacceptably large net unscheduled power flows. These two measures define the NERC Control Performance Standard. The NERC Control Performance Standard is the measure against which all control areas are evaluated.

- **CPS1.** NERC requires that the first measure of the CPS survey provide a measure of the control area's performance. The measure is intended to provide the control area with a frequency-sensitive evaluation of how well it met its demand requirements. A minimum passing score for CPS1 is 100 percent.[3]

- **CPS2.** NERC also requires that the second measure of the CPS survey be designed to bound ACE 10-minute averages. CPS2 provides a control measure of excessive, unscheduled power flows that could result from large ACEs. CPS2 is measured by counting the number of 10-minute periods during

1 Regulation Market business rules are defined in "PJM Manual 11: Scheduling Operations," Revision 26 (November 9, 2005), pp. 48-56.

2 See "PJM Dispatching Operations Manual, M-12," Revision 12, Section 4 (August 16, 2005), p. 44.

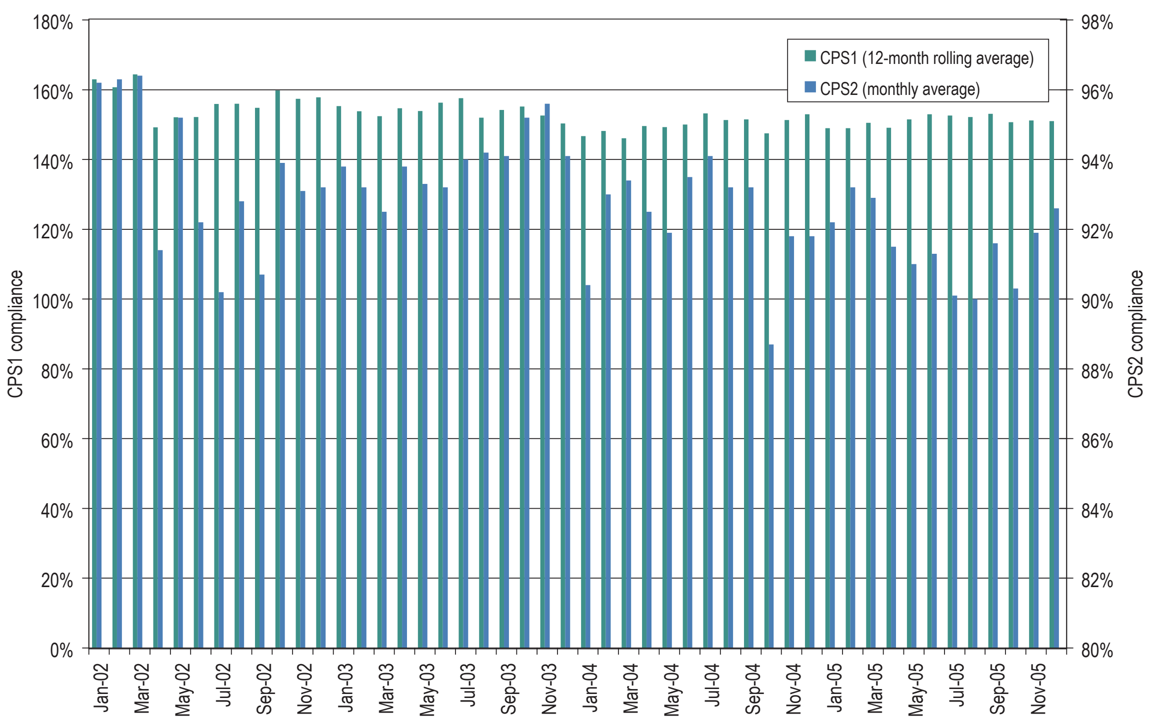
3 For more information about the definition and calculation of CPS, refer to "M12: Dispatching Operations," Revision 11 (January 1, 2005), pp. 19-21. The formal definition of CPS1 can be found in NERC's "Performance Standards Reference Document," version 2 (November 21, 2002), Section B.1.1.1. The formal definition of CPS2 can be found in NERC's "Performance Standards Reference Document," version 2 (November 21, 2002), Section B.1.1.2.

a month when the 10-minute average of the PJM Control Area's ACE is within defined limits known as L10. The specific, 10-minute periods of each hour are those ending at 10, 20, 30, 40, 50 and 60 minutes after the hour. A passing score for CPS2 is achieved when 90 percent of these 10-minute periods during a single month are within L10. From January 1 through January 31, 2005, the PJM Control Area's L10 standard was 258.5 MW. From February 1 through April 30, PJM's L10 standard was 261.9 MW. After the integration of Dominion (Phase 5), PJM's L10 standard was 281.2 MW.

PJM's CPS Performance

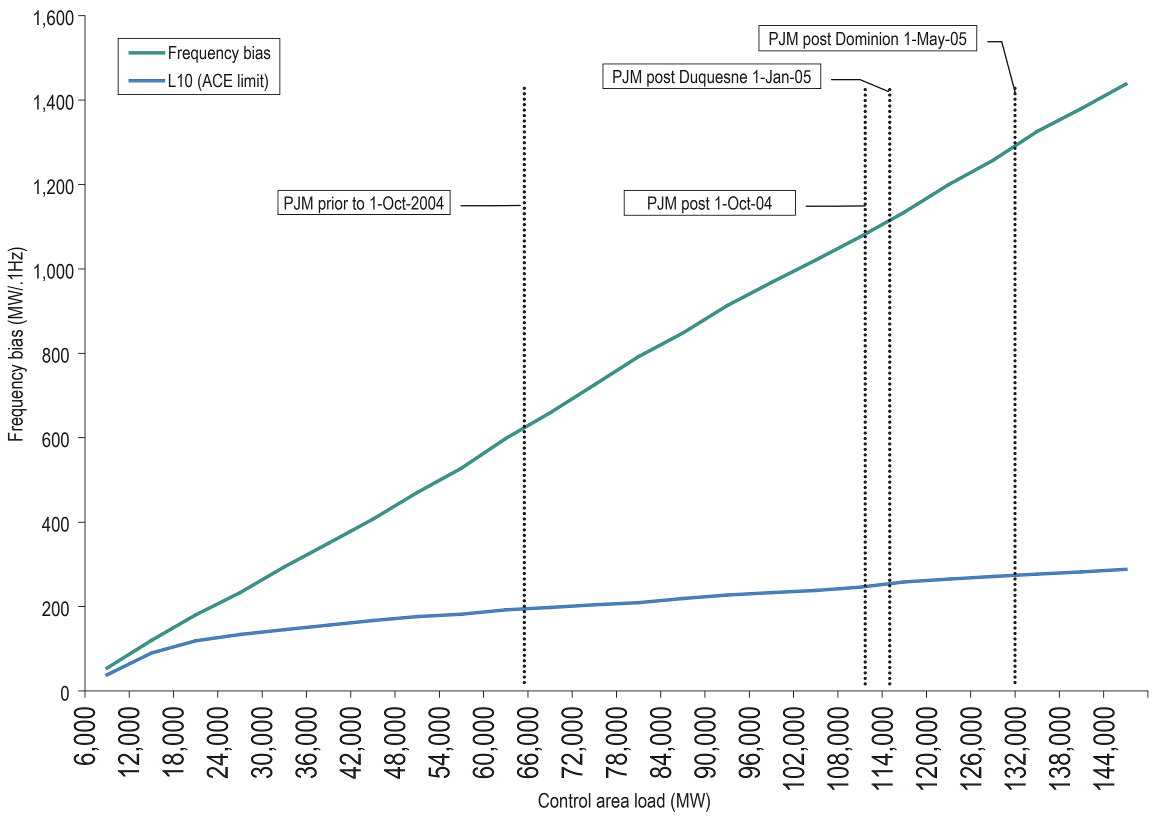
As Figure F-1 shows, PJM's performance relative to both the CPS1 and CPS2 metrics was acceptable in 2005. While PJM passed the CPS performance standard in 2005, PJM's performance with respect to these metrics remains an area of concern. Figure F-1 shows that CPS1 and CPS2 scores for 2005 are generally lower than they were in 2004 and generally lower since Dominion integration (Phase 5) on May 1, 2005. CPS1 and CPS2 standards are pass/fail so this decline is not a problem as long as PJM meets the CPS1 and CPS2 control standards.

Figure F-1 - PJM CPS1 and CPS2 performance: Calendar years 2002 to 2005



PJM dispatchers have to balance both ACE and frequency. Meeting the CPS1 standard requires balancing frequency on a monthly running-average basis. Meeting the CPS2 standard requires balancing ACE over 10-minute intervals throughout the day. As control area size (measured by load) grows, frequency bias grows linearly, while L10 (the CPS2 pass/fail standard) grows at an increasingly smaller rate. (See Figure F-2.) For this reason, the integration of external control areas into PJM requires PJM to balance ACE to a standard which grows tighter with control area growth. Furthermore the ACE control standard (CPS2) can sometimes be in conflict with the need to balance frequency over time.

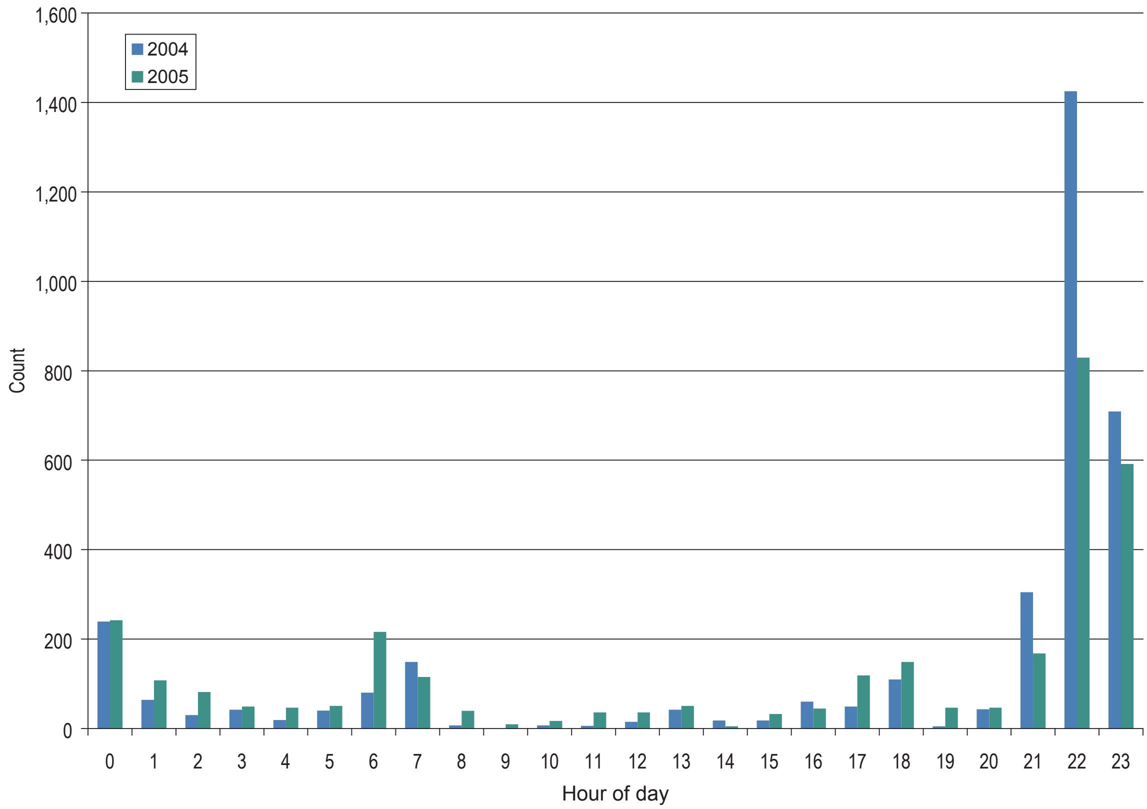
Figure F-2 - Frequency bias and CPS2 ACE limit (L10) as a function of control area size: Calendar years 2003 through 2005



These issues have made CPS2 less reflective of true grid reliability and more an issue of compliance. The CPS2 standard has been under discussion at NERC over the past two years. PJM is participating in discussions with NERC to solve these problems and to find a new measure that is better aligned with grid reliability.

Other metrics that directly measure frequency show improvement in 2005 over 2004. For example, the monthly average number of frequency excursions greater than 0.05 Hz above scheduled frequency was 290 in 2004 and 260 in 2005. The average duration of these frequency disturbances was 23 seconds in 2004 and 20 seconds in 2005. Figure F-3 illustrates that the number of high frequency excursions has gone down in 2005, and that those excursions have occurred primarily between 2100 EPT and 0000 EPT, and between 0600 EPT and 0700 EPT.

Figure F-3 - High frequency excursions above 0.05 Hz (By hour of day): Calendar years 2004 through 2005



ACE is controlled by PJM's regulation AGC signal, which is updated every four seconds. ACE is particularly difficult to control during times of rapid change in load. CPS2 scores were lower in 2005 than they were in 2004. Unlike 2004, however, in 2005 PJM did not have any monthly CPS2 violations (below 90 percent).

The majority of PJM's CPS2 violations in 2005 occurred between 0600 EPT and 0700 EPT and 2100 EPT and 0000 EPT. It is during these hours when many of the traditional dispatch problems occur. Among these problems are: many peak-hour energy contracts terminate at approximately the same time (2300 EPT) and start at 0600 EPT; load (demand) picks up sharply at 0600 EPT and falls off sharply at 2300 EPT; pumped storage units often switch from generation to load (pumping) at the top of hours 2100 EPT through 0000 EPT.

A particularly acute problem can occur when PJM's frequency deviates from its schedule and neighboring control areas also deviate in the same direction. In such a situation, the same AGC response corrects frequency and tie line error at different rates, making it hard to balance both. Such an event occurred on October 4, 2005, just after 2300 EPT. An unusually severe tie line mismatch between scheduled and actual values together with a low frequency excursion sent ACE to -1,700 MW. PJM dispatchers called a 100 percent spin event and ACE was recovered in approximately seven minutes. This event resulted in only one CPS2 violation. (There was, however, a second CPS2 violation 10 minutes later as a result of an over-correction.) October 4, 2005, was an unusually difficult day with 19 CPS2 violations and a CPS2 score of 86.7 percent (90 percent is passing).

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

Regulation market-clearing price (RMCP) is determined algorithmically by the PJM Market Operations Group by first creating a supply curve of available units and their associated regulation prices, then assigning regulation to units in increasing order of price until the regulation MW requirement is satisfied. The price of the most expensive unit required to satisfy the regulation requirement is the RMCP.

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

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

- **Regulation Offers.** All owners of generating units qualified to provide regulation may, but are not required to, offer their regulation capacity daily into the Regulation Market using the PJM Market User Interface. Total regulation offers are the sum of all regulation-capable units that offer regulation into the market and that are not out of service, committed or fully committed to provide energy. Owners of units that have entered offers into the PJM Market User Interface system have the right to set themselves to "unavailable" for regulation for the day, or for a specific hour or set of hours and also have the right to change the amount of regulation MW offered in each hour. Unit owners do not have the right to change their regulation offer price during a day. All regulation offers are summed to calculate the total daily regulation offered, a figure that changes each hour.

- **Regulation Offered and Eligible.** Sixty minutes before the market hour, PJM runs spinning and regulation market-clearing software (SPREGO) to determine the amount of Tier 2 spinning required, to develop regulation and spinning supply curves, to assign regulation and spinning to specific units and to determine the RMCP. All regulation resource units which have made offers in the daily Regulation Market are evaluated by SPREGO for regulation. SPREGO then excludes units according to the following ordered criteria:

  1. daily or hourly unavailable units;

  2. units for which the economic minimum is set equal to economic maximum (unless the unit is a hydroelectric unit or it has self-scheduled regulation);

  3. units which are self-scheduled or assigned spinning;

  4. units for which regulation minimum is set equal to regulation maximum (unless the unit is a hydroelectric unit or it has self-scheduled regulation), or units that are offline (except combustion turbine units);

  5. PJM dispatchers can deselect units from SPREGO to control transmission constraints, to avoid overgeneration during periods of minimum generation alert, to remove a unit temporarily unable to regulate, or to remove a unit with a malfunctioning data link.

  For each offered and eligible unit in the regulation supply, the regulation offer price is calculated using the sum of the unit's regulation offer cost and the opportunity cost based on the forecast LMP, unit economic minimum and economic maximum, regulation minimum and regulation maximum, startup costs and cost schedule. The MW offered and the calculated regulation offered prices are used to create a regulation supply curve. Units are assigned in order of price from the lowest price until the amount of required regulation has been assigned.

- **Regulation Assigned.** Units that are assigned regulation and spinning are expected to provide regulation and spinning for the designated hour. At any time before or during the hour, PJM dispatchers can redispatch units for reasons of reliability including to control transmission constraints, to avoid overgeneration during periods of minimum generation alert, to remove a unit temporarily unable to regulate or to remove a unit with a malfunctioning data link.

APPENDIX G – FINANCIAL TRANSMISSION AND AUCTION REVENUE RIGHTS

The procedure for prorating ARRs when transmission capability limits the amount of ARRs that can be allocated is illustrated here, as is the establishment of ARR target allocations and credits through the Annual FTR Auction.

ARR Prorating Procedure Illustration

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

Table G-1 - ARR allocation prorating procedure: Illustration

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

The equation would be solved for each request as follows:

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

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

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

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

ARR Credit Illustration

Table G-2 illustrates how ARR target allocations are established, how FTR auction revenue is generated and how ARR credits are determined. The purchasers of FTRs pay and the holders of ARRs are paid based on cleared nodal prices from the Annual FTR Auction. If total revenue from the auction is greater than the sum of ARR target allocations, then the surplus is used to offset any FTR congestion credit deficiencies that occur in the hourly Day-Ahead Energy Market.

Table G-2 - ARR credits: Illustration

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

APPENDIX H – GLOSSARY

Active load management (ALM)	Retail customer load that can be interrupted at the request of PJM. Such a PJM request is considered an emergency action and is implemented prior to a voltage reduction. ALM derives an ALM credit in the accounted-for-obligation.
Aggregate	Combination of buses or bus prices.
Ancillary service	Those services necessary to support the transmission of capacity and energy from resources to loads while, in accordance with good utility practice, maintaining reliable operation of the transmission provider's transmission system.
Ancillary service area	A defined market service area for ancillary services including regulation and spinning.
Area control error (ACE)	Area control error (ACE) is a real-time metric used by PJM operators to measure the imbalance between load and generation. ACE is the instantaneous MW imbalance between generation and load plus net interchange.
Associated unit (AU)	A unit that is located at the same site as a frequently mitigated unit (FMU) and which has identical electrical impacts on the transmission system as an FMU but which does not qualify for FMU status.
Auction Revenue Right (ARR)	A financial instrument entitling its holder to auction revenue from Financial Transmission Rights (FTRs) based on locational marginal price (LMP) differences across a specific path in the Annual FTR Auction.
Automatic generation control (AGC)	An automatic control system comprised of hardware and software. Hardware is installed on generators allowing their output to be automatically adjusted and monitored by an external signal and software is installed facilitating that output adjustment.
Average hourly unweighted LMP	An LMP calculated by averaging hourly LMP with equal hourly weights.
Basic generation service (BGS)	The default electric generation service provided by the electric public utility to consumers who do not elect to buy electricity from a third-party supplier.

Bilateral agreement	An agreement between two parties for the sale and delivery of a service.
Black start unit	A generating unit with the ability to go from a shutdown condition to an operating condition and start delivering power without assistance from the transmission system.
Bottled generation	Economic generation that cannot be dispatched because of local operating constraints.
Burner tip fuel price	The cost of fuel delivered to the generator site equaling the fuel commodity price plus all transportation costs.
Bus	An interconnection point.
Capacity credit	An entitlement to a specified number of MW of unforced capacity from a capacity resource for the purpose of satisfying capacity obligations imposed under the RAA.
Capacity deficiency rate (CDR)	The capacity deficiency rate is based on the annual carrying charges for a new combustion turbine, installed and connected to the transmission system. To express the CDR in terms of unforced capacity, it must be further divided by the quantity 1 minus the EFORd.
Capacity Markets	All markets where PJM members can trade capacity.
Capacity queue	A collection of RTEP process capacity resource project requests received during a particular timeframe and designating an expected in-service date.
Combined cycle (CC)	A generating unit generally consisting of one or more gas-fired turbines and a heat recovery steam generator. Electricity is produced by a gas turbine whose exhaust is recovered to heat water, yielding steam for a steam turbine that produces still more electricity.
Combustion turbine (CT)	A generating unit in which a combustion turbine engine is the prime mover.
Control zone	An area within the PJM Control Area, as set forth in the PJM Open Access Tariff and the Reliability Assurance Agreement (RAA). Schedule 16 of the RAA defines the distinct zones that comprise the PJM Control Area.

Decrement bids (DEC)	Financial offers to purchase specified amounts of MW in the Day-Ahead Energy Market at, or above, a given price.
Dispatch rate	Control signal, expressed in dollars per MWh, calculated by PJM and transmitted continuously and dynamically to generating units to direct the output level of all generation resources dispatched by the PJM Office of the Interconnection.
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.
End-use customer	Any customer purchasing electricity at retail.
Equivalent availability factor (EAF)	The equivalent availability factor is the proportion of hours in a year that a unit is available to generate at full capacity.
Equivalent demand forced outage rate (EFORd)	The equivalent demand forced outage rate (EFORd) (generally referred to as the forced outage rate) is a measure of the probability that a generating unit will fail, either partially or totally, to perform when it is needed to operate.
Equivalent forced outage factor (EFOF)	The equivalent forced outage factor is the proportion of hours in a year that a unit is unavailable due to forced outages.
Equivalent maintenance outage factor (EMOF)	The equivalent maintenance outage factor is the proportion of hours in a year that a unit is unavailable due to maintenance outages.
Equivalent planned outage factor (EPOF)	The equivalent planned outage factor is the proportion of hours in a year that a unit is unavailable due to planned outages.
External resource	A resource located outside metered PJM boundaries.
Financial Transmission Right (FTR)	A financial instrument entitling the holder to receive revenues based on transmission congestion measured as hourly energy LMP differences in the PJM Day-Ahead Energy Market across a specific path.

Firm point-to-point transmission	Firm transmission service that is reserved and/or scheduled between specified points of receipt and delivery.
Firm transmission	Transmission service that is intended to be available at all times to the maximum extent practicable. Service availability is, however, subject to an emergency, an unanticipated failure of a facility or other event.
Fixed-demand bid	Bid to purchase a defined MW level of energy, regardless of LMP.
Frequently mitigated unit (FMU)	A unit that was offer- capped for more than a defined proportion of its real-time run hours in the most recent 12-month period. FMU thresholds are 60 percent, 70 percent and 80 percent of run hours. Such units are permitted a defined adder to their cost-based offers in place of the usual 10 percent adder.
Generation offers	Schedules of MW offered and the corresponding offer price.
Generator owner	A PJM member that owns or leases, with rights equivalent to ownership, facilities for generation of electric energy that are located within PJM.
Gross deficiency	The sum of all companies' individual capacity deficiency, or the shortfall of unforced capacity below unforced capacity obligation. The term is also referred to as accounted-for deficiency.
Gross excess	The amount by which an LSE's unforced capacity exceeds its accounted-for obligation. The term is referred to as "Accounted-for Excess" in the "Definitions and Acronyms Manual" (Manual 35).
Gross export volume (energy)	The sum of all export transaction volume (MWh).
Gross import volume (energy)	The sum of all import transaction volume (MWh).
Herfindahl-Hirschman Index (HHI)	HHI is calculated as the sum of the squares of the market share percentages of all firms in a market.
Hertz (Hz)	Electricity system frequency is measured in hertz.
HRSG	Heat recovery steam generator. An air-to-steam heat exchanger installed on combined-cycle generators.

Increment offers (INC)	Financial offers in the Day-Ahead Energy Market to supply specified amounts of MW at, or above, a given price.
Initial threshold	In the context of the PJM economic planning process, when the cumulative gross congestion cost of a constraint exceeds the applicable initial threshold, PJM begins determining the extent to which the load affected by that constraint is unhedgeable. Initial threshold values are specific to the transmission level voltage of the affected facility.
Installed capacity	Installed capacity is the as-tested maximum net dependable capability of the generator, measured in MW.
Interval Market	The Capacity Market rules provide for three Interval Markets, covering the months from January through May, June through September and October through December.
Load	Demand for electricity at a given time.
Load aggregator	An entity licensed to sell energy to retail customers located within the service territory of a local distribution company.
Load-serving entity (LSE)	Load-serving entities provide electricity to retail customers. Load-serving entities include traditional distribution utilities and new entrants into the competitive power markets.
Lost opportunity cost (LOC)	The difference in net compensation from the Energy Market between what a unit receives when providing regulation or spinning reserve and what it would have received for providing energy output.
Mandatory interruptible load (MIL)	MIL is retail customer load in ComEd that can be interrupted at the request of PJM. PJM members commit to reduce load by a fixed MW amount or to a certain MW load or to initiate cycling of end-use equipment when called upon by PJM. The account of the LSE which nominated the customer's load drop is credited the MW amount committed. The credit can either be traded or used to meet the member's capacity obligation. Performance is measured, and penalties are charged for under compliance and payments are made for over compliance.
Marginal unit	The last generation unit to supply power under a merit order dispatch system.

Market-clearing price	The price that is paid by all load and paid to all suppliers.
Market participant	A PJM market participant can be a market supplier, a market buyer or both. Market buyers and market sellers are members that have met reasonable creditworthiness standards as established by the PJM Office of the Interconnection. Market buyers are otherwise able to make purchases and market sellers are otherwise able to make sales in the PJM Energy or Capacity Credit Markets.
Market threshold	In the context of the PJM economic planning process, each market threshold represents the level of unhedgeable congestion costs that triggers the start of a one-year "market window" for the development of market solutions to unhedgeable congestion. Market threshold values are specific to the transmission voltage of the affected facility.
Market user interface	A thin client application allowing generation marketers to provide and to view generation data, including bids, unit status and market results.
Market window	In the context of the PJM economic planning process, the period of time during which PJM allows for the development of market solutions to unhedgeable congestion associated with an affected facility.
Merchant solution	In the context of the PJM economic planning process, a solution proposed to reduce or to eliminate unhedgeable congestion on an affected facility.
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.

Min gen	An emergency declaration for periods of light load.[1]
Monthly CCMs	The capacity credits cleared each month through the PJM Monthly Capacity Credit Markets (CCMs).
Multimonthly CCMs	The capacity credits cleared through PJM Multimonthly Capacity Credit Markets (CCMs).
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.
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.
Obligation	The sum of all load-serving entities' unforced capacity obligations as determined by summing the weather-adjusted summer coincident peak demands for the prior summer, netting out ALM credits, adding a reserve margin and adjusting for the system average forced outage rate.
Off peak	For the PJM Energy Market, off-peak periods are all NERC holidays (i.e., New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, Christmas Day) and weekend hours plus weekdays from the hour ending at midnight until the hour ending at 0700.
On peak	For the PJM Energy Market, on-peak periods are weekdays, except NERC holidays (i.e., New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, Christmas Day) from the hour ending at 0800 until the hour ending at 2300.
Phase-in FTRs	FTRs directly allocated to eligible customers outside of the regularly scheduled FTR allocations when new control zones are integrated into PJM after the start of the current planning period. Phase-in FTRs remain in effect until the start of the next regularly scheduled FTR allocation.

1 See PJM Emergency Operations Manual, Section 13, Section 2, pp. 22-27.

PJM member	Any entity that has completed an application and satisfies the requirements of PJM to conduct business with the PJM Office of the Interconnection, including transmission owners, generating entities, load-serving entities and marketers.
PJM planning year	The calendar period from June 1 through May 31.
Price duration curve	A graphic representation of the percent of hours that a system's price was at or below a given level during the year.
Price-sensitive bid	Purchases of a defined MW level of energy only up to a specified LMP. Above that LMP, the load bid is zero.
Primary operating interfaces	Primary operating interfaces are typically defined by a cross section of transmission paths or single facilities which affect a wide geographic area. These interfaces are modeled as constraints whose operating limits are respected in performing dispatch operations.
Regional Transmission Expansion Planning (RTEP) Process	The process by which PJM recommends specific transmission facility enhancements and expansions based on reliability and economic criteria.
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.

Special protection scheme (SPS)	A load transfer relaying scheme intended to reduce the adverse post-contingency impact on a protected facility.
Spinning reserve	Reserve capability which is required in order to enable an area to restore its tie lines to the pre-contingency state within 10 minutes of a contingency that causes an imbalance between load and generation. During normal operation, these reserves must be provided by increasing energy output on electrically synchronized equipment or by reducing load on pumped storage hydroelectric facilities. During system restoration, customer load may be classified as spinning reserve.
Standard deviation	A measure of data variability around the mean.
Static Var compensator	A static Var compensator (SVC) is an electrical device for providing fast-acting, reactive power compensation on high-voltage electricity transmission networks.
System lambda	The cost to the PJM system of generating the next unit of output.
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.
Temperature-humidity index (THI)	A temperature-humidity index (THI) gives a single, numerical value in the general range of 70 to 80, reflecting the outdoor atmospheric conditions of temperature and humidity as a measure of comfort (or discomfort) during warm weather. THI is defined as follows: THI = T_d – (0.55 – 0.55RH) * (T_d - 58) where T_d is the dry-bulb temperature and RH is the percentage of relative humidity.
Unforced capacity	Installed capacity adjusted by forced outage rates.
Wheel-through	An energy transaction flowing through a transmission grid whose origination and destination are outside of the transmission grid.
Zone	See “Control zone” (above)

APPENDIX I – LIST OF ACRONYMS

ACE	Area control error
AECI	Associated Electric Cooperative Inc.
AECO	Atlantic City Electric Company
AEG	Alliant Energy Corporation
AEP	American Electric Power Company, Inc.
AGC	Automatic generation control
ALM	Active load management
AP	Allegheny Power Company
ARR	Auction Revenue Rights
ASA	Ancillary service area
ATC	Available transfer capability
AU	Associated unit
BGE	Baltimore Gas and Electric Company
BGS	Basic generation service
BME	Balancing market evaluation
Btu	British thermal unit
C&I	Commercial and industrial customers
CAISO	California Independent System Operator
CCM	Capacity Credit Market
CC	Combined cycle
CDR	Capacity deficiency rate

CDTF	Cost development task force
CF	Coordinated flowgate under the Joint Operating Agreement between PJM and the Midwest Independent Transmission System Operator, Inc.
CILCO	Central Illinois Light Company
CIN	Cinergy Corporation
ComEd	The Commonwealth Edison Company
CP	Pulverized coal-fired generator
CPL	Carolina Power & Light Company
CPS	Control performance standard
CT	Combustion turbine
DAY	The Dayton Power & Light Company
DCS	Disturbance control standard
DEC	Decrement bids
dfax	Distribution factor
DL	Diesel
DLCO	Duquesne Light Company
DPL	Delmarva Power & Light Company
DPLN	Delmarva Peninsula north
DPLS	Delmarva Peninsula south
DSR	Demand-side response
DUK	Duke Energy Corp.
EAF	Equivalent availability factor
ECAR	East Central Area Reliability Council

EDC	Electricity distribution company
EDT	Eastern Daylight Time
EES	Enhanced Energy Scheduler
EFOF	Equivalent forced outage factor
EFORd	Equivalent demand forced outage rate
EHV	Extra high voltage
EKPC	East Kentucky Power Cooperative, Inc.
EMOF	Equivalent maintenance outage factor
EPOF	Equivalent planned outage factor
EPT	Eastern Prevailing Time
EST	Eastern Standard Time
ExGen	Exelon Generation Company, L.L.C.
FE	FirstEnergy Corp.
FERC	The United States Federal Energy Regulatory Commission
FMU	Frequently mitigated unit
FPA	Federal Power Act
FPPL	Forecast period peak load
FPR	Forecast pool requirement
FTR	Financial Transmission Rights
GCA	Generating control area
GE	General Electric Company
GWh	Gigawatt-hour
HHI	Herfindahl-Hirschman Index

HRSG	Heat recovery steam generator
HVDC	High-voltage direct current
Hz	Hertz
ICAP	Installed capacity
INC	Increment offers
IP	Illinois Power Company
IPL	Indianapolis Power & Light Company
IPP	Independent power producer
IRM	Installed reserve margin
IRR	Internal rate of return
ISA	Interconnection Service Agreement
ISO	Independent system operator
JCPL	Jersey Central Power & Light Company
JOA	Joint Operating Agreement
JRCA	Joint Reliability Coordination Agreement
LAS	PJM Load Analysis Subcommittee
LCA	Load control area
LGEE	LG&E Energy, L.L.C.
LGIA	Large Generator Interconnection Agreement
LMP	Locational marginal price
LOC	Lost opportunity cost
LSE	Load-serving entity
LTE	Long-term emergency

MAIN	Mid-America Interconnected Network, Inc.
MAAC	Mid-Atlantic Area Council
MACRS	Modified accelerated cost recovery schedule
MAPP	Mid-Continent Area Power Pool
MC	The PJM Members Committee
MCP	Market-clearing price
MEC	MidAmerican Energy Company
MECS	Michigan Electric Coordinated System
Met-Ed	Metropolitan Edison Company
MEW	Western subarea of Metropolitan Edison Company
MICHFE	The pricing point for the Michigan Electric Coordinated System and FirstEnergy control areas.
Midwest ISO	Midwest Independent Transmission System Operator, Inc.
MIL	Mandatory interruptible load
MP	Market participant
MMU	PJM Market Monitoring Unit
MUI	Market user interface
MW	Megawatt
MWh	Megawatt-hour
NERC	North American Electric Reliability Council
NICA	Northern Illinois Control Area
NIPSCO	Northern Indiana Public Service Company
NNL	Network and native load

NO_x	Nitrogen oxides
NYISO	New York Independent System Operator
OA	PJM Operating Agreement
OASIS	Open Access Same-Time Information System
OATT	PJM Open Access Transmission Tariff
OC	Opportunity cost
ODEC	Old Dominion Electric Cooperative
OEM	Original equipment manufacturer
OI	PJM Office of the Interconnection
Ontario IESO	Ontario Independent Electricity System Operator
OPL	Obligation peak load
OVEC	Ohio Valley Electric Corporation
PE	PECO zone
PEC	Progress Energy Carolinas, Inc.
PECO	PECO Energy Company
PENELEC	Pennsylvania Electric Company
PEPCO	Pepco (formerly Potomac Electric Power Company)
PJM	PJM Interconnection, L.L.C.
PJM/AEPNI	The interface between the American Electric Power Control Zone and Northern Illinois
PJM/AEPPJM	The interface between the American Electric Power Control Zone and PJM

PJM/AEPVP	The single interface pricing point formed in March 2003 from the combination of two previous interface pricing points: PJM/American Electric Power Company, Inc. and PJM/Dominion Resources, Inc.
PJM/AEPVPEXP	The export direction of the PJM/AEPVP interface pricing point
PJM/AEPVPIMP	The import direction of the PJM/AEPVP interface pricing point
PJM/ALTE	The interface between PJM and the eastern portion of the Alliant Energy Corporation's control area
PJM/ALTW	The interface between PJM and the western portion of the Alliant Energy Corporation's control area
PJM/AMRN	The interface between PJM and the Ameren Corporation's control area
PJM/CILC	The interface between PJM and the Central Illinois Light Company's control area
PJM/CIN	The interface between PJM and the Cinergy Corporation's control area
PJM/CPLE	The interface between PJM and the eastern portion of the Carolina Power & Light Company's control area
PJM/CPLW	The interface between PJM and the western portion of the Carolina Power & Light Company's control area
PJM/DLCO	The interface between PJM and the Duquesne Light Company's control area
PJM/DUK	The interface between PJM and the Duke Energy Corp.'s control area
PJM/EKPC	The interface between PJM and the Eastern Kentucky Power Corporation's control area
PJM/FE	The interface between PJM and the FirstEnergy Corp.'s control area
PJM/IP	The interface between PJM and the Illinois Power Company's control area

PJM/IPL	The interface between PJM and the Indianapolis Power & Light Company's control area
PJM/MEC	The interface between PJM and MidAmerican Electric Company's control area
PJM/MECS	The interface between PJM and the Michigan Electric Coordinated System's control area
PJM/MISO	The interface between PJM and the Midwest Independent System Operator
PJM/NIPS	The interface between PJM and the Northern Indiana Public Service Company's control area
PJM/NYIS	The interface between PJM and the New York Independent System Operator
PJM/Ontario IESO	PJM/Ontario IESO pricing point
PJM/OVEC	The interface between PJM and the Ohio Valley Electric Corporation's control area
PJM/TVA	The interface between PJM and the Tennessee Valley Authority's control area
PJM/VAP	The interface between PJM and the Dominion Virginia Power's control area
PJM/WEC	The interface between PJM and the Wisconsin Energy Corporation's control area
PLC	Peak load contributions
PNNE	PENELEC's northeastern subarea
PNNW	PENELEC's northwestern subarea
PPL	PPL Electric Utilities Corporation
PSEG	Public Service Electric and Gas Company
PSN	PSEG north
PSNC	PSEG northcentral

QIL	Qualified interruptible load
RAA	Reliability Assurance Agreement among Load-Serving Entities in the PJM Control Area
RECO	Rockland Electric Company zone
RMCP	Regulation market-clearing price
RPM	Reliability Pricing Model
RSI	Residual supply index
RTC	Real-time commitment
RTEP	Regional Transmission Expansion Planning
RTO	Regional transmission organization
SCPA	Southcentral Pennsylvania subarea
SCR	Selective catalytic reduction
SEPJM	Southeastern PJM subarea
SERC	Southeastern Electric Reliability Council
SFT	Simultaneous feasibility test
SMECO	Southern Maryland Electric Cooperative
SNJ	Southern New Jersey
SO_2	Sulfur dioxide
SPP	Southwest Power Pool, Inc.
SPREGO	Spinning and regulation optimizer (market-clearing software)
SPS	Special protection scheme
SRMCP	Spinning reserve market-clearing price
STD	Standard deviation

STE	Short-term emergency
SVC	Static Var compensator
THI	Temperature-humidity index
TLR	Transmission loading relief
TVA	Tennessee Valley Authority
UGI	UGI Utilities, Inc.
VACAR	Virginia and Carolinas Area
VAP	Dominion Virginia Power
VOM	Variable operation and maintenance expense
WEC	Wisconsin Energy Corporation

ERRATA

If this sheet is bound with the report and not affixed to the errata page, then relevant changes are reflected in the Report. Otherwise, the corrections described below can be found in the online version currently available at http://www.pjm.com/markets/market-monitor/som.html.

Pages 29 and 116 - The third bullet in “Existing and Planned Generation” has been changed.

Page 136 - Figure 3-5 and associated text have been changed.

Page 137 - Table 3-16 has been changed.

Please address comments or questions to: bowrij@pjm.com.