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BEFORE THE PUBLIC UTILITIES COMMISSION OF OHIO

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In the Matter of the Application of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company for Authority to Establish a Standard Service Offer Pursuant to RC §4928.143 in the Form of an Electric Security Plan. : Case No. 08-935-EL-SSO

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PROCEEDINGS

before Ms. Christine Pirik and Mr. Gregory Price, Attorney Examiners, at the Public Utilities Commission of Ohio, 180 East Broad Street, Room 11-C, Columbus, Ohio, called at 9:00 a.m. on Thursday, October 23, 2008.

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VOLUME VI

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11/6/08
Transcript docketed electronically

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PUBLIC UTILITIES COMMISSION OF OHIO CASE NO. 08-935-EL-SSO

Update of Table 2, Page 14 of Baron Direct Testimony to reflect Cinergy Hub and PJM West Forward Prices of October 10, 2008.

Table 2 - Updated
Average of Cinergy Hub and PJM West Forward Prices

Month	July 15, 2008	Sept. 19, 2008	Oct 10, 2008
Jan-09	366,491,657	301,744,112	265,706,909
Feb-09	322,780,327	265,802,942	233,954,477
Mar-09	279,537,902	239,778,174	213,283,427
Apr-09	282,923,809	244,497,973	214,979,554
Jan-Apr Avg.	1,251,733,695	1,051,823,202	927,924,366
Capacity Cost Rate ($/mW/day)	69.17	69.17	69.17
Peak Load + Reserves	13,327	13,327	13,327
Capacity Cost (@ 120 Days)	$110,619,431	$110,619,431	$110,619,431
Total Cost	$1,362,353,125	$1,162,442,633	$1,038,543,797
MWH Sales	18,794,716	18,794,716	18,794,716
$/mWh	$72.49	$61.85	$55.26

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EXHIBIT__(LK-6A)

OEG Ex
2A

Update of Graves Exhibit 3 PJM West Forward Prices for October 10, 2008 NYMEX Settled Prices

Exhibit 3: Constructed Cost Method (Using PJM West Forward) - Estimated Energy, Nits & AS Cost (2009-2011)

	PJM West Forward		Congestion Adjustment		Load Shape Adjustment		Ancillary &	Adjusted Forward (w/ AS)		FE Load		Energy, Nits & AS Costs		
Month	Peak	Off Peak	Peak	Off Peak	Peak	Off Peak	Nits Adder	Peak	Off Peak	Peak	Off Peak	Peak	Off Peak	Total
Jan-09	$70.07	$56.58	-13.44%	-37.21%	0.70%	1.23%	$7.64	$68.78	$43.86	2,697,570	2,610,245	185,547,179	114,491,913	300,039,092
Feb-09	$70.07	$56.58	-18.12%	-40.46%	0.70%	1.09%	$7.64	$65.50	$41.94	2,528,625	2,219,048	165,634,561	93,076,757	258,711,318
Mar-09	$65.80	$53.39	-19.32%	-56.28%	0.50%	1.45%	$7.64	$61.06	$31.76	2,609,758	2,368,464	159,342,411	75,213,566	234,555,976
Apr-09	$65.17	$48.39	-11.15%	-35.80%	0.77%	1.48%	$7.64	$66.05	$39.42	2,513,141	2,085,273	165,981,287	82,206,783	248,188,070
May-09	$64.63	$40.42	-5.31%	-27.25%	2.04%	3.13%	$7.64	$70.16	$38.31	2,341,560	2,350,454	164,275,886	90,047,529	254,323,415
Jun-09	$73.53	$49.00	-17.03%	-40.33%	2.06%	4.69%	$7.64	$70.16	$39.18	2,836,095	2,263,373	198,987,683	88,670,806	287,658,489
Jul-09	$87.85	$56.42	-18.17%	-40.01%	6.55%	9.06%	$7.64	$85.28	$46.60	3,045,387	2,403,178	259,716,176	111,983,312	371,699,489
Aug-09	$87.85	$56.42	-23.27%	-47.45%	5.76%	6.27%	$7.64	$80.11	$40.83	2,719,770	2,562,314	217,873,880	104,609,657	322,483,537
Sep-09	$68.67	$50.00	-18.02%	-45.99%	0.72%	1.45%	$7.64	$64.43	$35.37	2,487,275	2,187,866	160,255,352	77,384,820	237,640,173
Oct-09	$65.43	$49.25	-16.26%	-27.25%	0.55%	1.21%	$7.64	$62.79	$44.07	2,525,102	2,226,320	158,553,546	98,103,459	256,657,005
Nov-09	$62.18	$48.25	-19.56%	-41.75%	1.38%	2.28%	$7.64	$58.52	$36.85	2,327,925	2,332,993	136,220,105	85,960,819	222,180,924
Dec-09	$64.68	$55.50	-15.68%	-29.67%	3.15%	3.70%	$7.64	$64.22	$48.73	2,660,248	2,448,398	170,829,411	119,302,232	290,131,643
	$70.49	$51.68						$68.09	$40.58	31,292,454	28,057,926	2,143,217,477	1,141,051,653	3,284,269,129
	JM	JP												
Jan-10	$76.50	$58.78	-13.44%	-37.21%	0.70%	1.23%	$7.64	$74.39	$45.27	2,592,001	2,735,483	192,829,063	123,832,301	316,661,364
Feb-10	$76.50	$58.78	-18.12%	-40.46%	0.70%	1.09%	$7.64	$70.81	$43.28	2,552,146	2,246,512	180,726,901	97,220,873	277,947,775
Mar-10	$68.00	$55.46	-19.32%	-56.28%	0.50%	1.45%	$7.64	$62.84	$32.69	2,751,694	2,304,092	172,923,055	75,326,771	248,249,826
Apr-10	$68.00	$50.27	-11.15%	-35.80%	0.77%	1.48%	$7.64	$68.58	$40.66	2,532,483	2,104,099	173,681,736	85,545,400	259,227,137
May-10	$66.50	$41.99	-5.31%	-27.25%	2.04%	3.13%	$7.64	$71.97	$39.50	2,304,480	2,386,357	165,842,940	94,264,734	260,107,674
Jun-10	$78.00	$50.90	-17.03%	-40.33%	2.06%	4.69%	$7.64	$73.96	$40.40	2,891,131	2,265,664	213,837,879	91,534,724	305,372,603
Jul-10	$94.50	$58.61	-18.17%	-40.01%	6.55%	9.06%	$7.64	$91.16	$48.11	2,844,660	2,601,907	259,316,645	125,179,309	384,495,955
Aug-10	$94.50	$58.61	-23.27%	-47.45%	5.76%	6.27%	$7.64	$85.59	$42.11	2,866,934	2,499,286	245,389,625	105,257,199	350,646,825
Sep-10	$70.50	$51.94	-18.02%	-45.99%	0.72%	1.45%	$7.64	$65.94	$36.45	2,510,772	2,211,363	165,569,093	80,596,774	246,165,867
Oct-10	$65.25	$51.16	-16.26%	-27.25%	0.55%	1.21%	$7.64	$62.64	$45.48	2,423,289	2,336,398	151,792,945	106,258,342	258,051,287
Nov-10	$65.25	$50.12	-19.56%	-41.75%	1.38%	2.28%	$7.64	$61.03	$37.98	2,474,883	2,262,929	151,036,046	85,945,301	236,981,347
Dec-10	$65.25	$57.65	-15.68%	-29.67%	3.15%	3.70%	$7.64	$64.71	$50.32	2,820,890	2,364,049	182,551,569	118,963,409	301,514,978
	$74.06	$53.69						$71.14	$41.85	31,565,363	28,318,149	2,255,497,498	1,189,925,136	3,445,422,637
Jan-11	$73.86	$59.12	-13.44%	-37.21%	0.70%	1.23%	$7.64	$72.09	$45.49	2,533,247	2,864,566	182,628,726	130,298,116	312,926,842
Feb-11	$73.86	$59.12	-18.12%	-40.46%	0.70%	1.09%	$7.64	$68.64	$43.48	2,491,579	2,323,669	171,011,918	101,038,067	272,049,985
Mar-11	$69.36	$55.78	-19.32%	-56.28%	0.50%	1.45%	$7.64	$63.95	$32.84	2,690,690	2,375,456	172,076,657	78,003,458	250,080,114
Apr-11	$68.70	$50.56	-11.15%	-35.80%	0.77%	1.48%	$7.64	$69.21	$40.85	2,464,040	2,200,415	170,528,379	89,880,750	260,409,129
May-11	$68.13	$42.23	-5.31%	-27.25%	2.04%	3.13%	$7.64	$73.54	$39.69	2,219,680	2,581,600	163,236,618	102,452,053	265,688,671
Jun-11	$77.51	$51.20	-17.03%	-40.33%	2.06%	4.69%	$7.64	$73.55	$40.59	2,817,410	2,354,900	207,211,746	95,585,380	302,797,127
Jul-11	$92.61	$58.95	-18.17%	-40.01%	6.55%	9.06%	$7.64	$89.48	$48.34	2,765,486	2,716,887	247,468,311	131,345,928	378,814,239
Aug-11	$92.61	$58.95	-23.27%	-47.45%	5.76%	6.27%	$7.64	$84.03	$42.31	2,766,139	2,646,738	232,438,971	111,993,523	344,432,494
Sep-11	$72.39	$52.24	-18.02%	-45.99%	0.72%	1.45%	$7.64	$67.50	$36.61	2,418,137	2,364,316	163,234,222	86,564,646	249,798,868
Oct-11	$68.97	$51.46	-16.26%	-27.25%	0.55%	1.21%	$7.64	$65.78	$45.70	2,332,489	2,437,069	153,422,392	111,369,269	264,791,661
Nov-11	$65.55	$50.41	-19.56%	-41.75%	1.38%	2.28%	$7.64	$61.27	$38.15	2,422,685	2,398,623	148,436,856	91,519,100	239,955,956
Dec-11	$68.18	$57.99	-15.68%	-29.67%	3.15%	3.70%	$7.64	$67.28	$50.57	2,770,658	2,471,055	186,404,385	124,957,120	311,361,505
	$74.31	$54.00						$71.36	$42.05	30,692,440	29,736,294	2,198,099,181	1,255,007,411	3,453,106,591

Same as Exh 3a using Oct 10, 2008 data, using Graves calculation methodology
Using PJM on peak and off Peak NYMEX hub data (PJM West)

Update of Graves Exhibit 4 PJM West Forward Prices for October 10, 2008 NYMEX Settled Prices

Exhibit 4: Constructed Cost Method (Using PJM West Forward)
Calculation of Generation Service price (2009-2011)

	2009	2010	2011
Energy, NITS and Ancillary Costs ($)	3,284,269,129	3,445,422,637	3,453,106,591
Capacity Cost ($/MW-day)	69.17	82.5	95.45
Peak Capacity Plus Reserve Margin (MW)	13,327	13,530	13,736
Total Capacity Cost ($)	$336,468,544	$407,414,231	$478,542,931
Total Procurement Costs ($)	$3,620,737,673	$3,852,836,868	$3,931,649,522
Total Projected Load (MWh)	56,818,797	57,321,168	57,833,934
Total Procument Costs ($/MWh)	$63.72	$67.21	$67.98
Less: NITS and Ancillary Services	$7.98	$7.98	$7.98
Generation Market Price Excl NITS and Ancillary Svcs	$55.74	$59.23	$60.00
Estimated 50th Percentil Risk Premium (%)	15.96%	15.96%	15.96%
Projected Median Market Price ($/MWh)	$64.64	$68.69	$69.58

EXHIBIT__(LK-7A)

Update of Graves Exhibit 5 MISO Forward Prices for October 10, 2008 NYMEX Settled Prices

Exhibit 5: Constructed Cost Method (Using Cinergy Forward) - Estimated Energy, Nits & AS Cost (2009-2011)

Month	Cinergy Forward Peak	Cinergy Forward Off Peak	Congestion Adjustment Peak	Congestion Adjustment Off Peak	Load Shape Adjustment Peak	Load Shape Adjustment Off Peak	Ancillary & Nits Adder	Adjusted Forward (w/ AS) Peak	Adjusted Forward (w/ AS) Off Peak	FE Load Peak	FE Load Off Peak	Energy, Nits & AS Costs Peak	Energy, Nits & AS Costs Off Peak	Total
Jan-09	$58.44	$40.75	2.97%	0.77%	0.70%	1.23%	$7.64	$68.22	$49.21	2,697,570	2,610,245	184,041,033	128,437,105	312,478,139
Feb-09	$58.44	$40.75	2.36%	1.95%	0.70%	1.09%	$7.64	$67.87	$49.63	2,528,625	2,219,048	171,613,389	110,128,689	281,742,078
Mar-09	$55.38	$38.75	-0.47%	-8.32%	0.50%	1.45%	$7.64	$63.04	$43.73	2,609,756	2,368,464	164,510,182	103,567,898	268,078,079
Apr-09	$55.38	$38.75	-1.20%	-4.55%	0.77%	1.49%	$7.64	$62.78	$45.20	2,513,141	2,085,273	157,779,682	94,255,122	252,034,803
May-09	$52.31	$30.75	-3.22%	-3.48%	2.04%	3.13%	$7.64	$59.33	$38.28	2,341,560	2,350,454	138,931,175	89,980,961	228,912,137
Jun-09	$58.94	$32.75	-3.81%	-3.73%	2.06%	4.69%	$7.64	$65.55	$40.70	2,836,095	2,263,373	185,901,915	92,129,240	278,031,155
Jul-09	$72.81	$37.63	5.27%	-0.87%	6.55%	9.06%	$7.64	$89.06	$48.35	3,045,387	2,403,178	271,210,417	116,198,215	387,408,632
Aug-09	$72.81	$37.63	-1.74%	-5.17%	5.76%	6.27%	$7.64	$83.38	$45.68	2,719,770	2,562,314	226,766,160	117,056,573	343,822,733
Sep-09	$54.50	$30.75	-0.05%	-4.25%	0.72%	1.45%	$7.64	$62.51	$37.53	2,487,275	2,187,866	155,467,497	82,108,423	237,575,920
Oct-09	$51.50	$31.25	-1.21%	-0.94%	0.55%	1.21%	$7.64	$58.80	$38.97	2,525,102	2,226,320	148,476,250	86,769,431	235,245,681
Nov-09	$51.50	$31.25	-4.71%	-2.85%	1.38%	2.28%	$7.64	$57.43	$38.71	2,327,925	2,332,993	133,681,210	90,314,533	223,995,743
Dec-09	$51.50	$31.25	1.23%	1.79%	3.15%	3.70%	$7.64	$61.40	$40.61	2,660,248	2,448,398	163,327,788	99,418,731	262,746,519
	$57.79	$35.19						$66.61	$43.05	31,292,454	28,057,928	2,101,706,698	1,210,364,922	3,312,071,620
	EM [redacted]													
Jan-10	$63.50	$42.27	2.97%	0.77%	0.70%	1.23%	$7.64	$73.47	$50.75	2,592,001	2,735,483	190,435,480	138,837,691	329,273,171
Feb-10	$63.50	$42.27	2.36%	1.95%	0.70%	1.09%	$7.64	$73.08	$51.19	2,552,146	2,246,512	186,518,741	115,007,841	301,526,583
Mar-10	$57.75	$40.19	-0.47%	-8.32%	0.50%	1.45%	$7.64	$65.41	$45.07	2,751,694	2,304,092	179,980,944	103,852,506	283,833,450
Apr-10	$57.75	$40.19	-1.20%	-4.55%	0.77%	1.48%	$7.64	$65.14	$46.60	2,532,483	2,104,099	164,970,185	98,051,983	263,022,168
May-10	$55.00	$31.90	-3.22%	-3.48%	2.04%	3.13%	$7.64	$61.99	$39.42	2,304,480	2,386,357	142,857,020	94,081,142	236,938,162
Jun-10	$63.25	$33.97	-3.81%	-3.73%	2.06%	4.69%	$7.64	$69.78	$41.94	2,891,131	2,265,664	201,752,156	95,014,915	296,767,071
Jul-10	$79.25	$39.03	5.27%	-0.87%	6.56%	9.06%	$7.64	$96.26	$49.87	2,844,660	2,601,907	273,819,433	129,755,692	403,575,125
Aug-10	$79.25	$39.03	-1.74%	-5.17%	5.76%	6.27%	$7.64	$90.08	$47.10	2,866,934	2,499,296	258,241,517	117,721,942	375,963,459
Sep-10	$56.75	$31.90	-0.05%	-4.25%	0.72%	1.45%	$7.64	$64.77	$38.64	2,510,772	2,211,363	162,623,267	85,453,990	248,077,257
Oct-10	$51.75	$32.41	-1.21%	-0.94%	0.55%	1.21%	$7.64	$59.05	$40.14	2,423,269	2,336,398	143,091,459	93,788,583	236,880,043
Nov-10	$51.75	$32.41	-4.71%	-2.85%	1.38%	2.28%	$7.64	$57.67	$39.87	2,474,883	2,262,929	142,718,397	90,223,201	232,941,599
Dec-10	$51.75	$32.41	1.23%	1.79%	3.15%	3.70%	$7.64	$61.66	$41.83	2,820,890	2,364,049	173,926,627	98,898,663	272,825,291
	$60.94	$36.50						$69.86	$44.37	31,565,363	28,318,149	2,220,935,227	1,260,688,151	3,481,623,377
Jan-11	$63.50	$45.89	2.97%	0.77%	0.70%	1.23%	$7.64	$73.47	$54.45	2,533,247	2,864,566	186,128,280	155,980,101	342,108,362
Feb-11	$63.50	$45.89	2.36%	1.95%	0.70%	1.09%	$7.64	$73.09	$54.93	2,491,579	2,323,669	182,101,570	127,636,488	309,738,058
Mar-11	$60.18	$43.64	-0.47%	-8.32%	0.50%	1.45%	$7.64	$67.84	$48.28	2,690,890	2,375,456	182,540,612	114,694,348	297,234,960
Apr-11	$60.18	$43.64	-1.20%	-4.55%	0.77%	1.48%	$7.64	$67.56	$49.94	2,464,040	2,200,415	166,469,800	109,891,924	276,361,724
May-11	$56.84	$34.63	-3.22%	-3.48%	2.04%	3.13%	$7.64	$63.81	$42.15	2,219,680	2,581,600	141,641,601	108,815,022	250,456,624
Jun-11	$64.05	$36.88	-3.81%	-3.73%	2.06%	4.69%	$7.64	$70.57	$44.88	2,817,410	2,354,900	198,813,651	105,683,136	304,496,787
Jul-11	$79.12	$42.38	5.27%	-0.87%	6.55%	9.06%	$7.64	$96.11	$53.49	2,765,486	2,716,887	265,792,354	145,328,401	411,120,756
Aug-11	$79.12	$42.38	-1.74%	-5.17%	5.76%	6.27%	$7.64	$89.94	$50.49	2,766,139	2,646,738	248,784,554	133,623,336	382,407,890
Sep-11	$59.22	$34.63	-0.05%	-4.25%	0.72%	1.45%	$7.64	$67.28	$41.30	2,418,137	2,364,316	162,641,492	97,650,401	260,291,893
Oct-11	$55.98	$35.19	-1.21%	-0.94%	0.55%	1.21%	$7.64	$63.23	$42.93	2,332,469	2,437,069	147,490,109	104,622,333	252,112,442
Nov-11	$55.98	$35.19	-4.71%	-2.85%	1.38%	2.28%	$7.64	$61.74	$42.63	2,422,885	2,398,623	149,573,507	102,262,748	251,836,255
Dec-11	$55.98	$35.19	1.23%	1.79%	3.15%	3.70%	$7.64	$66.05	$44.77	2,770,658	2,471,055	183,011,455	110,621,050	293,632,505
	$62.60	$39.63						$71.72	$47.52	30,692,440	29,735,294	2,214,988,965	1,416,809,289	3,631,798,254

Same as Exh 5a using Oct10, 2008 data using Graves method.

Update of Graves Exhibit 6 MISO Forward Prices for October 10, 2008 NYMEX Settled Prices

Exhibit 6: Constructed Cost Method (Using MISO Forward)
Calculation of Generation Service price (2009-2011)

	2009	2010	2011
Energy, NITS and Ancillary Costs ($)	3,312,071,620	3,481,623,377	3,631,798,254
Capacity Cost ($/MW-day)	69.17	82.5	95.45
Peak Capacity Plus Reserve Margin (MW)	13,327	13,530	13,736
Total Capacity Cost ($)	$336,468,544	$407,414,231	$478,542,931
Total Procurement Costs ($)	$3,648,540,164	$3,889,037,608	$4,110,341,185
Total Projected Load (MWh)	56,818,797	57,321,168	57,833,934
Total Procument Costs ($/MWh)	$64.21	$67.85	$71.07
Less: NITS and Ancillary Services	$7.98	$7.98	$7.98
Generation Market Price Excl NITS and Ancillary Svcs	$56.23	$59.87	$63.09
Estimated 50th Percentil Risk Premium (%)	15.96%	15.96%	15.96%
Projected Median Market Price ($/MWh)	$65.21	$69.42	$73.16

EXHIBIT___(LK-8A)

Update of Jones Exhibits 8, 9, 10
Using MISO Forward Prices for October 10, 2008 NYMEX Settled Prices

Analysis of Market-Rate Offer Prices
Revised to MISO Forward Prices on October 10, 2008

	2009	2010	2011
Forecast Load (MWh)	57,202,562	57,712,876	58,233,804
Direct Costs ($/MWh)			
Round the Clock Energy Price	$45.95	$48.14	$50.66
Locational Adjustment	$0.70	$0.70	$0.70
Load Shaping	$3.49	$3.65	$3.84
Capacity Price	$5.89	$5.93	$5.96
Transmission and Ancillary Services	$7.50	$7.50	$7.50
Distribution Losses	$2.84	$2.95	$3.07
Total Direct Cost per MWh	$66.37	$68.86	$71.73
Less: Transmission Adjusted for Line Losses	7.84	7.84	7.84
Total Wholesale Generation Cost per MWh	$58.53	$61.02	$63.89
Margin	17%	29%	40%
Total Price per MWh	$68.48	$78.54	$89.37
Total Cost	$3,917,186,529	$4,532,997,648	$5,204,476,397

Update of Blank Attachment 1 for Jones and Graves Market Prices Using Oct 10, 2008 NYMEX Settlement Prices
Reflects Correction of Blank Error on Removal of Transmission Component of Market Prices

SUMMARY - TOTAL OHIO

Model Assumptions	
2008 Sales (MWH)	56,471,000
Sales Growth Rate	0.92%
Discount Rate	8.48%
2009 Market Rate Average ($/MWH)	66.70
2010 Market Rate Average ($/MWH)	73.80
2011 Market Rate Average ($/MWH)	80.37

Consultant Market Rates at Wholesale

Jones		Graves
$68.48	2009	$64.93
$78.54	2010	$69.06
$89.37	2011	$71.37

Year		2009		2010		2011		2012		2013		2014-2035	
Sales (MWH)		57,202,000		57,705,000		58,211,000		58,744,000		59,284,445		1,451,558,323	
ESP		Rate	Revenue	Rate	Revenue	Rate	Revenue	Rate	Revenue	Rate	Revenue	Rate	Revenue
Distribution Rates			$137.0		$150.0		$151.0						
Distribution Improvement Rider		2	$114.4	2	$115.4	2	$116.4						
ESP Generation Rate		67.50		71.50		75.50							
Generation Incraese over 2008 Rate of 68.18		-0.68	-$39.1	3.32	$191.4	7.32	$425.9						
Economic Development Rider			$0.0		$0.0		$0.0		$0.0		$0.0		$0.0
AMI Study			-$1.0		$0.0		$0.0		$0.0		$0.0		$0.0
Energy Efficiency and DSM			-$10.0		-$10.0		-$10.0		-$10.0		-$10.0		
Environmental remediation & Reclamation			-$15.0		-$15.0		-$15.0		$0.0		$0.0		$0.0
CEI RTC - Net of Residential Credits			-$316.0		-$275.0		$0.0		$0.0		$0.0		$0.0
Deferral Recovery - Generation Phase-In (10 Yr)		0.00	$0.0	0.00	$0.0	2.01	$117.0	2.01	$118.1	3.25	$192.7		$1,558.4
Deferral Recovery - CEI Distribution ($25M)		0.00	$0.0	0.00	$0.0	0.03	$1.7	0.03	$1.8	0.03	$1.8		$42.2
Total Revenues Per year			-$129.7		$156.8		$787.1		$109.8		$184.5		$1,600.6
NPV of Total Revenues Per Year	$1,577.1												

Consultant Market Rates		2009 Rate	2009 Revenue	2010 Rate	2010 Revenue	2011 Rate	2011 Revenue
Distribution Rates			$137.0		$150.0		$151.0
Generation rate		66.70		73.80		80.37	
Generation Increases over 2008 Rate of 68.18		-1.48	-$84.7	5.61	$324.0	12.18	$709.2
Total Revenues Per Year			$52.3		$474.0		$860.2
NPV of Total Revenues Per Year	$1,124.9						

NPV: Ohio Summary	Total Ohio
NPV: ESP	$1,577.1
NPV: Market Rates	$1,124.9
Benefits to Customers (Market - ESP)	-$452.2

EXHIBIT___(LK-10A)

Update of Blank Attachment 1 for Jones and Graves Market Prices Using Oct 10, 2008 NYMEX Settlement Prices
Reflects Correction of Blank Error on Removal of Transmission Component of Market Prices
Reflects No Retail Market Risk Premium in Jones and Graves Market Prices

SUMMARY - TOTAL OHIO

Model Assumptions	
2008 Sales (MWH)	58,471,000
Sales Growth Rate	0.92%
Discount Rate	8.48%
2009 Market Rate Average ($/MWH)	57.26
2010 Market Rate Average ($/MWH)	60.29
2011 Market Rate Average ($/MWH)	62.72

Consultant Market Rates at Wholesale

Jones		Graves
$58.53	2009	$55.99
$61.02	2010	$59.55
$63.89	2011	$61.55

Year		2009		2010		2011		2012		2013		2014-2035	
Sales (MWH)		57,202,000		57,705,000		58,211,000		58,744,000		59,284,445		1,451,558,323	
ESP		Rate	Revenue	Rate	Revenue	Rate	Revenue	Rate	Revenue	Rate	Revenue	Rate	Revenue
Distribution Rates			$137.0		$150.0		$151.0						
Distribution Improvement Rider		2	$114.4	2	$115.4	2	$116.4						
ESP Generation Rate		67.50		71.50		75.50							
Generation Incraese over 2008 Rate of 68.18		-0.68	-$39.1	3.32	$191.4	7.32	$425.9						
Economic Development Rider			$0.0		$0.0		$0.0		$0.0		$0.0		$0.0
AMI Study			-$1.0		$0.0		$0.0		$0.0		$0.0		$0.0
Energy Efficiency and DSM			-$10.0		-$10.0		-$10.0		-$10.0		-$10.0		
Environmental remediation & Reclamation			-$15.0		-$15.0		-$15.0		$0.0		$0.0		$0.0
CEI RTC - Net of Residential Credits			-$316.0		-$275.0		$0.0		$0.0		$0.0		$0.0
Deferral Recovery - Generation Phase-In (10 Yr)		0.00	$0.0	0.00	$0.0	2.01	$117.0	2.01	$118.1	3.25	$192.7		$1,558.4
Deferral Recovery - CEI Distribution ($25M)		0.00	$0.0	0.00	$0.0	0.03	$1.7	0.03	$1.8	0.03	$1.8		$42.2
Total Revenues Per year			-$129.7		$156.8		$787.1		$109.8		$184.5		$1,600.6
NPV of Total Revenues Per Year	$1,577.1												

Consultant Market Rates							
Distribution Rates			$137.0		$150.0		$151.0
Generation rate		57.26		60.29		62.72	
Generation Increases over 2008 Rate of 68.18		-10.93	-$625.0	-7.90	-$455.8	-5.47	-$318.3
Total Revenues Per Year			-$488.0		-$305.8		-$167.3
NPV of Total Revenues Per Year	-$840.7						

NPV: Ohio Summary	Total Ohio
NPV: ESP	$1,577.1
NPV: Market Rates	-$840.7
Benefits to Customers (Market - ESP)	-$2,417.8

RESTRUCTURING REVISITED

What we can learn from retail-rate increases in restructured and non-restructured states.

By J.P. Pfeifenberger, G.N. Basheda, and A.C. Schumacher

Company 9
13

After significant rate increases in many retail-access states, regulators and policy-makers are asking two critical questions: (1) Do the sharp increases in rates mean that customer choice and electric utility restructuring have failed? and (2) What can be done about these rate increases? The concerns about restructuring and retail access in the electric utility industry today are quite a change from 10 years ago, when it was widely anticipated that customer choice and competition would lead to lower rates, enhanced services, improved efficiency, and environmental benefits.[1]

To be sure, restructuring always was a controversial issue in terms of implementation. However, back in the mid- to late 1990s few questioned the prospect of significant economic benefits that competition and customer choice would provide. For many today, that "conventional wisdom" seemingly has shifted almost 180 degrees. Much of that shift in sentiment is triggered by the rate shocks experienced in many retail access states as market prices increased and restructuring-related rate freezes expired.

In 2006, for example, Baltimore Gas & Electric's retail rates increased 72 percent, which provoked a political uproar that almost resulted in the dismissal of the state's five public utility commissioners by the governor. Similarly, after heated and politically charged debates, United Illuminating is phasing in a 50-percent rate increase for its Connecticut customers, and Delmarva is phasing in a 59-percent rate increase in Delaware. Most recently, after a decade of reduced and frozen retail rates in Illinois, a move to market-based retail pricing of customers' generation service in January 2007 increased residential retail rates by an average of 21 percent for Commonwealth Edison and between 36 and 53 percent for the three Ameren distribution utilities. The fact that some of Ameren's electric-heating customers, who enjoyed frozen rates as low as 2.5 cents per kilowatt-hour, saw their monthly bills double or even triple only added to the political upheaval that has spurred legislative efforts to roll back Illinois retail rates to their previously frozen level. This proposed extension of the 10-year rate freeze now threatens to bankrupt the Illinois utilities and already has forced their credit ratings below investment grade. To some observers these developments are a sure sign that retail restructuring has failed and that re-regulation of the industry may be the only way out.

Retail Rates Put Into Perspective

Just how unusual are these increases in retail rates? Based on a nationwide analysis of retail-rate trends in restructured and non-restructured states, we find that the large rate hikes primarily are a function of expiring retail-rate freezes at a time of significantly higher fuel and wholesale power prices. As part of the negotiated transition from regulated to restructured markets, retail rates often were reduced and then frozen at those levels for a number of years. In several states, the recent expiration of these rate freezes coincided with significantly higher fuel costs and wholesale power prices. Hence, once the rate freezes expired, rates increased considerably to reflect the higher costs and new market fundamentals. However, despite these significant increases from frozen-rate levels, some of the new rates still compare favorably to regulated rates prior to restructuring. For example, despite the recent increase, 2007 residential rates for Commonwealth Edison are still 3 percent below their 1997 level (*i.e.*, in actual dollar terms, without even accounting for inflation).

Fig. 1 shows average retail rates in the now restructured and non-restructured states since 1985.[2] The figure shows that rates in restructured states on average are approximately 35 percent higher than in non-restructured states. However, the chart also shows that this discrepancy already existed in the mid-1990s, several years before restructuring was implemented. Thus, while it is correct that rates in restructured states are much higher than in non-restructured states, this difference already existed prior to restructuring. In fact, these rate trends show that significant rate increases in restructured states relative to non-restructured states happened between 1988 and 1993, when the gap in rates approximately doubled. These pre-restructuring rate trends helped cement support for restructuring efforts. Since then, as also shown in Fig. 1, rates in both types of states have trended very similarly.

Fig. 2 compares retail rates relative to their 1997 level—the last year before any state had implemented customer choice. The chart shows that from 1997 through 2006, average rates in both restructured and non-restructured states increased by 31 percent. This compares to a 26-percent increase in the consumer price index, a 34-percent increase in wages, a 93-percent increase in the average retail price of natural gas, and a 108-percent increase in gasoline prices.

Fig. 2 also shows that until 2006, rate increases in restructured states for the most part lagged those in non-restructured states. This "lag" may have been largely a function of restructuring-related rate freezes under which rates could not reflect the underlying cost trends. Nevertheless, such lagged rate increases in restructured states also mean there may have been significant savings for customers (albeit possibly only temporary). From 1998 through 2006, electricity sales totaled $1.3 trillion in the restructured states, which means the approximately 2-percent gap between the rate trends of restructured states (blue line) and non-restructured states (purple line) cumulatively amounts to $24 billion. In other words, had rates in restructured states trended exactly like rates in non-restructured states (*i.e.*, had the blue line in Fig. 2 moved in lockstep with the purple line), customers in restructured states would have paid $24 billion more. While this number does not represent an estimate of restructuring-related savings to date, it does suggest that the temporary restructuring-related rate reductions and rate freezes likely benefited customers—at least while they lasted.

Simply based on press coverage, one would have expected that the rate increases in restructured states far exceeded rate increases in traditionally regulated states. But that is not the case. The rate increases in traditionally regulated states may have happened more gradually (*e.g.*, through fuel-cost adjustment clauses), with similarly large overall increases but less public outcry and fewer political repercussions. For example, since 1997, average rates in Hawaii increased 68 percent, 57 percent in Wisconsin, 53 percent in Washington, 45 percent in Florida, and 42 percent in Louisiana.

Yet the public uproar and political repercussions over such rate increases in non-restructured states tend to pale in comparison. Even the very significant recent rate increases caused by the 2005 spikes in fuel and power costs appear to have attracted less public and political attention in restructured states, such as New Jersey and Massachusetts, where utilities already had supplied customers at market-based rates for a number of years. States in which these sharp recent increases coincided with the expiration of transition-related rate freezes—such as Maryland, Delaware, Connecticut, and now Illinois—seem to have experienced much more substantial political fallout.

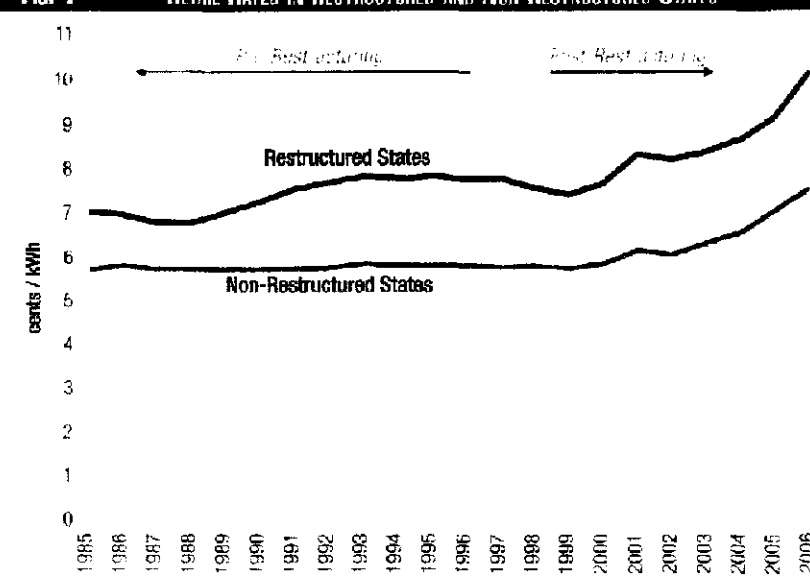
How will the 2006 decline in fuel and power prices affect retail rates in restructured and non-restructured states going forward? Considering that the 2001 spike in natural-gas prices affected rates in restructured states more strongly (*i.e.*, with larger increases and subsequent decreases), it will be interesting to see if that pattern repeats itself with respect to the 2005-2006 spike in natural gas, coal, and power prices. Just as fuel-adjustment clauses should lead to rate reductions in non-restructured states, lower wholesale power prices should lower rates in restructured states. Recent procurement results in some of the restructured states suggest that this may in fact be happening. For example, with the decline in wholesale market prices in New Hampshire, rates for Unitil's commercial and industrial customers dropped by about one-third in 2006 while rates for residential customers dropped by 10 percent earlier this year.

Are There Any Restructuring Benefits?

Although this rate comparison does not offer conclusive proof as to either the benefits or harms associated with restructuring, it does provide an important indication of how consumers in restructured states have fared relative to those in non-restructured states. Assuming costs increased similarly, it would appear restructuring did about as well as traditional regulation. If restructuring truly was a failure, one would have expected to see larger average rate increases in restructured states than in non-restructured states. This is not the case. In fact, utilities in restructured states on average not only face costs that tend to be higher than in non-restructured states, but these costs have also been increasing faster.

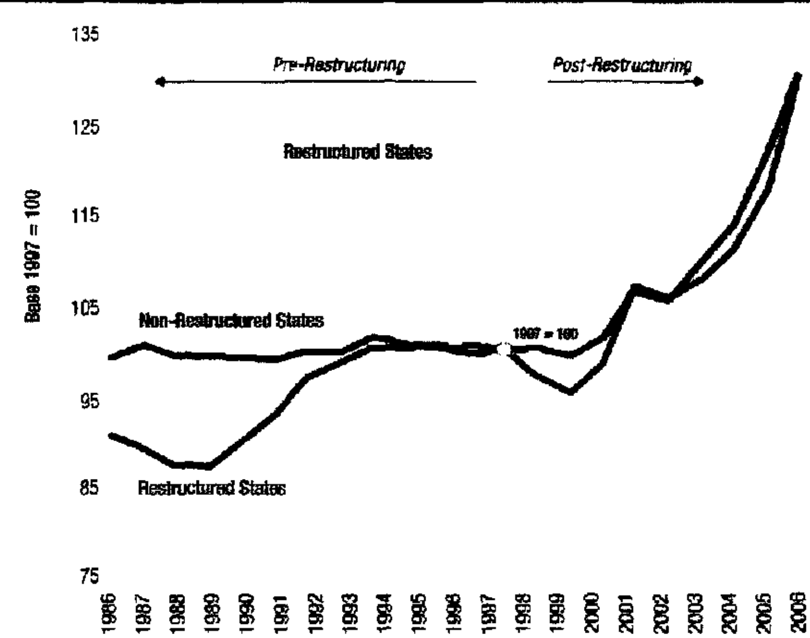
For example, since 1997 wages in restructured states are up 35 percent compared with 33 percent in non-restructured states. The differential is even larger for fuel. Considering the average 1997-2005 fuel mix in restructured and non-restructured states, our preliminary analysis indicates that the 2005 average cost of fuel delivered to generators (*i.e.*, the weighted average costs of coal, natural gas, petroleum, and nuclear fuels on a $/MMBtu basis) increased approximately 90 percent in

FIG. 1 RETAIL RATES IN RESTRUCTURED AND NON-RESTRUCTURED STATES



the more natural-gas-dependent restructured states, compared with "only" 62 percent in non-restructured states. (By 2006, the differential in fuel-cost increases appears to have narrowed to approximately 80 and 70 percent, but not all 2006 fuel-cost data is available and 2006 fuel costs probably are not reflected fully in 2006 electricity rates due to regulatory and procurement-related lags).[3] Given these higher cost increases in restructured states, the similar trend in average retail rates suggests potentially significant restructuring-related benefits that go beyond any temporary saving enjoyed while rates were frozen.

FIG. 2 RATE TRENDS IN RESTRUCTURED AND NON-RESTRUCTURED STATES



The extent to which restructuring might or might not have benefited customers has been analyzed more closely by more than a dozen studies over the last few years.[4] Some of these studies specifically evaluate the impact of retail choice, some assess only the benefits of centralized wholesale markets, and others attempt to quantify the combined benefits of wholesale and retail restructuring. The majority of these studies found that restructuring—either retail competition, centralized wholesale power markets, or the combination of retail and wholesale restructuring—have produced significant benefits for consumers. However, some reviewers of these studies contend that due to poor study designs, the quantified benefits cannot be relied upon. Only a few studies find that the impact of restructuring is either unclear or may have resulted in more quickly increasing customer rates.

To be sure, it is inherently difficult to quantify the benefits associated with restructuring because one must compare actual rates or industry efficiency to the hypothetical rates or industry efficiency that would have existed but for restructuring. With respect to retail competition, the analysis is complicated further by the fact that most customers have become exposed to market-based retail rates only very recently when transition-related rate freezes expired. Given this very limited experience with market-based retail pricing, it likely is too early to quantify reliably the benefits or harms from retail restructuring. But it is clear that restructuring has failed to produce the massive hoped-for benefits, the basis on which restructuring was sold politically.

Time to Re-Regulate?

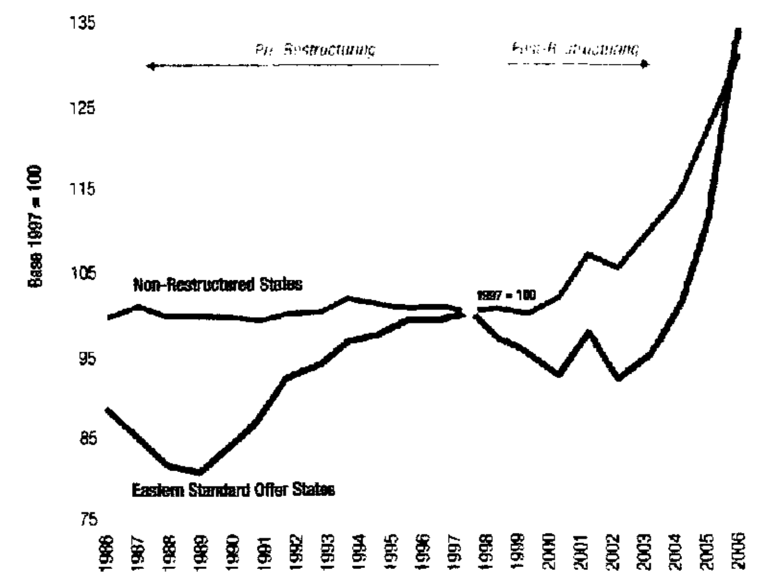
The large price adjustments coming out of rate freezes have triggered legislative calls for suspension of retail access (in particular for small customers) and the re-regulation of the utility industry in several states, including Virginia, Michigan, Connecticut, and Montana. However, despite the failure to meet high expectations and the rate hikes triggered by abruptly ending rate freezes, the available facts do not support a conclusion that customers in restructured states actually would have been better off under traditional cost-of-service regulation. It is even less clear that re-regulation would provide net benefits. Thus, despite the superficial appeal of re-regulation as a means of addressing the sharp recent rate increases, such initiatives must be viewed with significant caution and skepticism. After all, one must recall that the gap in rates between restructured and non-restructured states increased sharply under the regulated industry structure of the mid-1980s to the mid-1990s but, despite more rapidly increasing fuel costs, has not increased further since the onset of restructuring efforts.

Because those "good old regulated days" perhaps weren't as good as some of us may remember them, we ought to be careful about what we are asking for. Re-regulation would be a risky and potentially costly undertaking.

This concern is shared by others. For example, although Standard and Poor's notes that it "does not consider the prospects for significant re-regulation to be broad based, and therefore we consider threats to utility credit quality—at this time—to be fairly muted," and that thoughtful re-regulation efforts could be "beneficial for credit quality," the agency also stresses that "especially in a political environment that is certain to be highly contentious" re-regulation "is a risky proposition that could threaten utility balance sheets, destroy value, and impair credit ratings."[5] In fact, in its April 3 statement, S&P goes on to note further that:

> "It is not definitively clear whether liberalization has succeeded or failed. ... Would a return to traditional regulation lower electricity prices? Absent liberalization, would electricity prices have been lower, all else being equal? Forecasting what might have been is always difficult. And, of course, all else is rarely equal, such as the rapid rise in fuel prices and more recently a surge in capital costs. Nevertheless, the introduction of competition into generation resulted in greater efficiencies, lower heat rates, greater reliability, lower nonfuel operating costs, and in general, more widely adopted best practices. Consider how nuclear power plant operations have improved dramatically in competition's short tenure. Would a reversion to regulation preserve these gains? Absent the pressure of competition, it is hard to believe so, given cost-of-service regulation's history."

Fig. 3 Rate Trends in Non-Restructured and Eastern Standard Offer States



Source: The Brattle Group, based on EIA Data

Rate Trends in Eastern Retail Access States

Significant concerns over the outcome of restructuring have been raised in several Eastern U.S. retail-access states in which distribution utilities have begun to use auctions or auction-like RFP processes to procure generation supply for their remaining regulated "standard offer" or "basic generation service" customers. By the end of 2006, these Eastern "standard offer" states included Maine, New Jersey, Massachusetts, Maryland, D.C., Delaware, and Connecticut. During the mid-1990s, average rates in these states were approximately 60% above the average for non-restructured states. By 2003, that gap in rate levels had dropped to 39%, but it has since widened again to 47% in 2005 and 65% in 2006. This sharp recent increase, in part due to the transition from frozen to market-based rates, has caused particular political uproar in Maryland, Delaware, and Connecticut.

As shown in Fig. 3, the trend of average retail rates for this set of Eastern states differs from the trend for all restructured states shown in Fig. 2. Fig. 3 shows that following implementation of retail access, average rates first declined significantly relative to non-restructured states until 2002, only to "catch up" more quickly through significant rate hikes. Surprisingly, however, over the entire post-restructuring period rate the average increase in these Eastern states is 34% since 1997, which is, again, almost identical to the 31% rate increase in non-restructured states. These similar increases in retail rates also point to potentially significant restructuring-related benefits considering that, since 1997, the average cost of fuel delivered to generators in these states (on a $/MMBtu basis, weighted at the 1997-2005 average fuel mix) increased by approximately 120% through 2005 and 110% through 2006. This compares to increases in weighted average delivered fuel costs of 62% and approximately 70% in non-restructured states. And while the lagged rate increases resulted in steeper increases during the most recent years, the delay would appear to have benefited customers additionally: With total electricity sales of $218 billion from 1998 through 2006, the price gap between these restructured Eastern states (thin blue line) and non-restructured states (purple line) accumulates to $18 billion.

What Can Be Done?

Concerns about re-regulation do not mean that the recent rate hikes should not be addressed or that nothing can be done to mitigate rate hikes and reduce rate pressures going forward.[6] Available options include:

- Phase out the remaining rate freezes over a multi-year period, rather than ending them abruptly;
- Defer (and if possible securitize) portions of transition-related rate increases over a multi-year period;

■ Improve and expand low-income assistance and energy-efficiency programs to mitigate impacts for the most vulnerable customers;

■ Educate customers and facilitate municipal aggregation and entry of alternative retail suppliers to provide even small customers with a choice of service and pricing options;

■ Establish overlapping supply contracts and more frequent procurements of generation supply to avoid rate shocks resulting from disproportional impacts of individual procurement efforts;

■ Improve supply contracts and procurement processes to reduce the risk premium required by suppliers to serve the utilities' residual regulated load;

■ Adopt rate structures that better reflect market prices and more broadly implement demand-response, efficiency, and dynamic-pricing programs to reduce peak loads, enhance competition, and lower standard-offer procurement costs;

■ Improve wholesale-power markets by reducing seams, rate pancaking, and other market-related barriers to efficient trade and plant dispatch; and

■ Improve fuel and fuel-transportation markets to avoid or mitigate the effects of fuel-price shocks that drive up power prices (such as the 2005 hurricane-related disruption of natural-gas supply and coal-transportation-related spikes of coal prices).

The Bottom Line

Since restructuring started in 1997, average retail rates in both restructured and non-restructured states have increased by approximately 31 percent. This is surprising for two reasons. First, based on the public outcry over the sharp recent increases in retail-access states, one would have expected higher overall rate increases in restructured states. As it turns out, the sharp recent increases are mostly an artifact of abruptly ending restructuring-related rate freezes. Second, the fact that rates in restructured states have increased approximately the same as rates in non-restructured states appears to be good news, considering the more pronounced increases in average fuel and labor costs. While it is correct that average rates in restructured states significantly are above the rates in non-restructured states, that was already the case in the mid-1990s, before these states were restructured—which helped cement support for restructuring efforts.

Although retail restructuring has failed to live up to its high expectations, the available facts do not support a conclusion that customers in restructured states would have been better off under traditional cost-of-service regulation, nor that customers would likely benefit from re-regulation. But our skepticism about the effectiveness of re-regulation options does not mean that the recent rate hikes should not be addressed, as our suggestions on mitigating rate hikes and reducing rate pressures going forward indicate. Rather, despite the superficial appeal of re-regulation in light of the sharp recent rate increases, we are concerned that such initiatives carry a substantial risk of being ineffective and more costly in the long-run. ■

Johannes Pfeifenberger is a principal, Greg Basheda a senior consultant, and Adam Schumacher an associate of The Brattle Group, an economic and energy consulting firm. Opinions expressed in this article, as well as any errors or omissions, are the authors' alone. They can be reached at www.brattle.com.

Thanks to Philip Hanser, Ahmad Faruqui, Paul Carpenter, Peter Fox-Penner, Frank Graves, Joe Wharton, and Naunihal Gumer for valuable discussions and comments. This article is based in part on presentations by the authors at the May 2006 AESP conference in Chicago and the November 2006 National Association of State Utility Consumer Advocates conference in Miami.

Endnotes:

1. Our discussion focuses only on average retail rates as the bellweather in many of the currently ongoing discussions about the success or failure of retail access. We are not specifically addressing the other hoped-for benefits of retail access, nor the extent to which restructuring of transmission access and wholesale generation markets affected market efficiency, plant availability, transmission utilization, infrastructure investment, and reliability.
2. Average rates are calculated as the ratio of total retail revenues in restructured and non-restructured states to total kWh retail sales as reported by the Energy Information Administration. We define "restructured states" as the 20 states plus D.C. that implemented retail access for some or all customers, including Connecticut, D.C., Delaware, Illinois, Massachusetts, Maryland, Maine, Michigan, New Hampshire, New Jersey, New York, Ohio, Pennsylvania, Rhode Island, Texas, and Virginia as well as Arizona, California, Montana, Nevada, and O regon (the five states that have already limited, suspended, or reversed some of their restructuring effort). For an overview of restructuring and resource procurement in these states, see Pfeifenberger, Schumacher and Wharton, "Keeping Up with Retail Access? Developments in U.S. Restructuring and Resource Procurement for Regulated Retail Service," *The Electricity Journal*, December 2004, pp. 50-64.
3. Note again that these cost increases are based on a fixed 1997-2005 fuel mix. If the actual fuel mix for 1997 and 2005 is used, the 1997-2005/06 average percentage cost increases are quite similar due to a significant increase in nuclear output in restructured states, but also due to increasing reliance on natural gas in non-restructured states.
4. Some of these recent studies are listed and summarized in Appendix C of the Electric Energy Market Competition Task Force's *Report to Congress on Competition in Wholesale and Retail Markets for Electric Energy*, April 6, 2007 (posted at *http://www.usdoj.gov/atr/public/taskforces/eemtaskforce.htm*).
5. Standard & Poor's "The Credit Implications of U.S. Electric Utility Re-Regulation," April 12, 2007 and "Re-Regulation of U.S. Electric Utilities: The Toothpaste Challenge," April 3, 2007.
6. See also Graves, Hanser, and Basheda, *Rate Shock Mitigation*, prepared on behalf of the Edison Electric Institute (forthcoming).

Company Ex. 14

platts

Methodology and Specifications Guide

North American Electricity

LATEST UPDATE: OCTOBER 2007

The McGraw-Hill Companies

INTRODUCTION

This statement of methodology for Platts' North American electricity price surveys incorporates price reporting standards that went into effect July 1, 2003. The statement also takes into consideration standards for price reporting stated in the Federal Energy Regulatory Commission's July 24, 2003, policy statement on U.S. electricity and gas markets (PL03-3). The most recent revisions to this methodology reflect that Platts now incorporates forward electricity trading activity from IntercontinentalExchange in formulating its daily forward assessments for electricity.

While this methodology reflects core principles that long have provided the foundation for Platts' price reporting in North American electricity markets, it will continue to evolve as those markets change.

If you have questions concerning reporting to Platts or our statement of methodology, or would like to discuss any price reporting issues, please call or e-mail one of our editors: Mike Wilczek, senior editor for market development, 202-383-2246 (mike_wilczek@platts.com); Lisa Lawson, senior market editor, 713-658-3267 (lisa_lawson@platts.com); and Brian Jordan, editorial director for North American electricity and gas markets, 202-383-2181 (brian_jordan@platts.com).

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Platts discloses publicly the days of publication of its price assessments and indices, and the times during each trading day in which Platts considers transactions in determining its assessments and index levels. The dates of publication and the assessment periods are subject to change in the event of outside circumstances that affect Platts' ability to adhere to its normal publication schedule. Such circumstances include network outages, power failures, acts of terrorism and other situations that result in an interruption in Platts' operations at one or more of its worldwide offices. In the event that any such circumstance occurs, Platts will endeavor, whenever feasible, to communicate publicly any changes to its publication schedule and assessment periods, with as much advance notice as possible.

HOW THIS METHODOLOGY STATEMENT IS ORGANIZED

This description of methodology for electricity indexes and assessments in North America is divided into six major parts (I-VI) that parallel the entire process of producing the benchmarks.

- Part I describes what goes into Platts electricity benchmarks, including details on what market participants are expected to submit and the process for submitting data as well as the components of published data.
- Part II describes the security and confidentiality practices that Platts uses in handling and treating data, including the separation between Platts price reporting/index creation and its newsgathering and reporting.
- Part III is a detailed account of what Platts does with the data to formulate its electricity indexes and assessments, and includes descriptions of the statistical and editorial tools Platts uses to convert raw data into indexes and assessments. This section describes the process for screening outliers and the criteria for determining which daily benchmarks are indexes based on volume-weighted averages and which are assessments based on reported transactions and other market information. Part III also describes how Platts creates indexes and assessments for various products other than next-day electricity trades.
- Part IV lays out the verification and correction process for revising published prices and the criteria Platts uses to determine when it publishes a correction.
- Part V explains the process for verifying that published prices comply with Platts' standards.
- Part VI is a list of detailed definitions of the trading locations for which Platts publishes daily indexes or assessments.

PART I: DATA QUALITY AND DATA SUBMISSION

Platts' standards for data quality are at the heart of its process to produce reliable indexes and assessments and are designed to ensure that market participants provide complete and accurate information.

To that end, Platts requires formalized reporting relationships with market participants in which data is submitted from a central point in the mid- or back-office. If the reporting entity chooses, Platts will sign a standard confidentiality agreement protecting the submitted data. A copy of the standard agreement is available upon request. The data provider must certify that it is making a good-faith effort to report completely and accurately, and will have staff assigned to respond to questions concerning data submittals. In addition, reporting entities, in cases of error or omission, have an obligation to make reasonable efforts to inform Platts and, as necessary, modify their internal processes to eliminate or minimize the likelihood of future errors or omissions in their data submissions.

Data submitted to Platts must be detailed, transaction-level data. Below is a summary of what should be reported. (A separate Data Submission Guide that explains what to report for Platts electricity and natural gas price surveys is also available; to receive a copy e-mail electricityprice@platts.com.)

WHAT TO REPORT

- Report each business day all fixed-price physical and financial deals for delivery in North America.

- Report the price at which the two parties agreed to transact. Do not add estimated transmission cost to make the transaction fit one of Platts' delivery location definitions.

- Label deals for delivery at locations not defined or reported by Platts using the name of the control area, tie point or congestion management zone. Examples would include power for delivery to ISO New England's Connecticut zone and the Mona tie point in Utah. Although Platts may not currently assess those locations, if sufficient trading develops at a location and is sustained, Platts would be able to add that pricing point to its daily indexes. (Definitions for the locations for which indexes and assessments are currently published are in Part VI of this methodology statement.) In addition, information on deals at those points adds to Platts' understanding of the market and aids Platts in assessing thinly traded points in that geographic area.

- List all transactions individually and with the following information: location, trade date, start flow date, end flow date, shape (peak or off-peak), deal type (physical or financial), firm or non-firm, price ($/MWh), volume (MW), side of transaction (buy or sell), counterparty name, and intermediary name (broker or trading platform).

- Market participants remain divided on the question of counterparties, and Platts for now will accept data that does not include counterparty information. Platts firmly believes that counterparty information is the best single way to verify transactions. Platts encourages market participants that are not already doing so to initiate changes to agreements that currently prevent them from reporting counterparties. Some companies already provide this information, and Platts will continue to press for it.

- Deals should be reported only for transactions done that day. The cutoff for all transactions, including forward packages, is 2:30 pm EST/EDT. The cutoff time applies to the time a trade was transacted, not the time the trade is entered into the company's system. Do not include "early" daily deals done after the cutoff on the previous day. Platts considers these transactions to be non-standard deals done before the opening of the market. There is no formal close to the over-the-counter electricity markets, so we have selected 2:30 pm EST/EDT. We use that time as a close for assessing the value of forward power markets because it allows us to provide assessments that are comparable to New York Mercantile Exchange daily settlement prices for natural gas. The 2:30 closing time for transactions that are included in a daily report ensures that all deals are captured and reported; the end of daily trading in the marketplace in practice is earlier than 2:30 EST/EDT because of scheduling deadlines and the expiration of daily options. For New York over-the-counter markets, which are financial swaps, the cutoff is the release of the independent system operator's day-ahead market-clearing prices.

- Platts will, for the foreseeable future, include deals done after options expiration in its daily indexes and assessments, as long as those deals are priced within the range of the bulk of the day's trading. Platts in the past has attempted to exclude all deals done after options expiration because of the low level of trading activity and liquidity in most markets after options expiration, and the concern that such low liquidity would mean trades done after expiration were transacted under distressed conditions that could result in non-comparable prices. However, the lack of time stamps that would identify after-options trades makes it difficult to identify such trades in a straightforward and consistent manner. Platts believes that it would be preferable to exclude post-options trading, but until time-stamp information is available, Platts will eliminate the impact of such potentially "distressed" deals through its procedure for eliminating outliers. That process is described in detail in Part III.

- Platts will continue to push for time stamps to allow our editors to identify deals that were done after daily options expiration, as well as match up transaction information we receive from various market participants. In addition, time stamps also would provide Platts with a clearer picture of the movement of prices through the trading period and provide another tool for evaluating the quality of the data. Platts understands that many market participants are currently unable to provide time stamps because deals are entered into trading systems in bulk after trading is completed rather than as each transaction occurs.

HOW TO REPORT

- Reports of each day's deals should be compiled and sent to Platts by a non-commercial department of the company. Generally the reporting function is the responsibility of the mid- or back-office. Even in the case of small entities, FERC's standards state that prices should be provided by individuals "separate from trading activities" such as accounting or bookkeeping staff. Platts values the participation in its surveys of smaller market participants that may not have formal back-office or risk-management groups and will discuss with them ways to meet Platts and FERC standards for assuring the quality of data provided to Platts.

- Platts should be provided at least two contacts (with phone numbers and e-mail addresses for both) who are responsible for submissions and can answer questions about transactions reported to Platts.

- Individuals compiling reports in the mid- or back-office should make certain that all transactions done by the trading desk have been entered into the system before the report is submitted to Platts.

- *Reports should be sent electronically in either Excel or CSV* (comma separated values) format. Platts can provide reporting entities with a sample Excel sheet showing the preferred format and the information needed for each transaction.

- Reports should be sent to electricityprice@platts.com each day by 4:30 pm EST/EDT.

- Reporting entities should be prepared in the rare cases of e-mail malfunctions to fax submissions to Platts. Our fax numbers are 713-658-3240 for our Houston market reporting team and 202-383-2023 for our Washington market reporting group.

- If a reporting entity is unable to compile the needed information by the deadline set by Platts on a given day, it should notify Platts editors of the delay and the length of the delay by either e-mail or phone. This will help Platts editors decide whether to wait for the submission.

PART II: SECURITY AND CONFIDENTIALITY

Platts has a long history of keeping price data secure and confidential. There are two key aspects to ensuring the security and confidentiality of data: the security of the information technology systems and policies on access to data. Following is a description of Platts' processes.

- Price data is e-mailed to a specific Platts e-mail address, electricityprice@platts.com. E-mails to that address enter a secure network protected by firewalls and are accessible only by market editors. Encryption is available upon request of the reporting company.

- A senior market editor does an initial screening of data submissions and then distributes the relevant data to market editors who specialize in specific regions and market hubs.

- The data is then entered into a proprietary software system designed specifically to store and analyze trade data.

- Data is stored in a secure network, and under internal procedures audited and enforced by a Platts compliance officer, is kept for a period of at least three years.

- The compliance audit checks for adherence to the parameters set forth in the Platts Compliance Plan, which seeks to ensure that accurate records are kept, in order to document a market reporter's research. All U.S. electricity market reporters undergo audits at least twice a year.

- Data is protected under formal confidentiality agreements signed by data providers and Platts.

- Price data is used only for constructing indexes and assessments. Platts has a strict internal policy, reflected in its confidentiality agreements, of never using individual price data for news reporting purposes. Nor do Platts news reporters have access to individual entities' transaction reports. Data aggregated from all reporting sources — *e.g.*, changes in prices and trading volumes over time — may be used as the basis for news stories.

PART III: CALCULATING INDEXES AND MAKING ASSESSMENTS

Platts editors produce indexes and assessments of the next-day trading market. In addition, Platts produces daily assessments of forward electricity markets.

For daily trading hubs where there is sufficient liquidity, market editors use volume-weighted averages to calculate an index value.

For each daily index, Platts publishes the index price, the change from the previous day, the low, the high, the volume, the number of transactions the index is based on, and the running average for the index price for the month. Index prices, lows, and highs are expressed in $/MWh. The daily change is expressed in dollars. The volume in expressed in megawatts (MW) across the on-peak or off-peak period, rather than in megawatt hours. For instance, if ten 50-MW on-peak deals are reported, the volume would be expressed as 500 MW, rather than the equivalent value of 8,000 MWh (ten 50-MW deals multiplied by 16 hours).

Prior to calculating a volume-weighted average, Platts editors go through the critical process of analyzing the transactional data for potential mistakes made by data providers as well as for outliers. Editors have a number of statistical and journalistic tools available to them in scrubbing the raw data for errors and outliers.

In the beginning of the process the editor weeds out non-standard-size deals. Standard-size packages are multiples of 25 MW.

Non-standard-size deals are automatically excluded, regardless of where they fall in the range of trading. There often are special considerations attached to odd-sized deals that can affect price.

Platts uses customized spreadsheets for data analysis that display the distribution of the deals and flag deals more than two standard deviations from the mean. In addition, deals submitted that are outside what the editor has seen as the range of trading are flagged as questionable.

Transactions at prices more than two standard deviations from the mean are not necessarily deals done out of market or inaccurately reported deals. Platts often handles sets of data that are not normally distributed around the mean. This so-called "skew" of the normal distribution reflects normal market activity on a given day and means that some deals outside two standard deviations from the mean should be included in calculating the volume-weighted average to determine the index value.

After the initial flagging of outliers, Platts uses a number of tests to determine if a deal should be eliminated. If the deal fails these tests, it will be excluded from the calculation used to determine the final index.

On page 6 are two examples of how Platts editors determined whether to eliminate a deal when calculating an index based on a volume-weighted average. As the examples demonstrate, among the considerations or tests used to make that determination are:

- The direction and magnitude of the skew for the set of data, compared with how far out of the range of two standard deviations the deal is.
- An explanation based on market fundamentals for the "outlier" nature of the deal; the explanation must hold for deals other than the potential outlier. For example, a run-up in prices during the latter part of daily trading caused by an unplanned generation outage would provide an explanation based on market fundamentals for deals near the high end of the distribution, including those just inside two standard deviations from the mean and those just outside.
- Information that would demonstrate the deal was distressed, such as credit issues for either counterparty, or the fact that the deal was done after the expiration of daily options.
- The completeness of the set of transaction-specific information reported with the deal, including buy/sell and counterparty name.
- Information from another reporting party that verifies the deal; for example, the reporting of the deal by a named counterparty.

The following examples are hypothetical and do not include actual data provided by Platts sources. However, each example reflects characteristics of data sets commonly seen by Platts electricity market editors.

One other factor that Platts takes into consideration when deciding whether to exclude an outlier is the record of the data-submitting entity concerning data quality. Deals from reporting entities that consistently report fully and accurately are given greater credence.

The most credible market participants are those that:

- Report electronically from a non-commercial department of the company, such as the back office or risk group.
- Submit full reports of all deals in North America, for both the Eastern and Western interconnections, as well as both physical and financial transactions.
- Report all deals at the transaction level and provide all necessary descriptive information including buy/sell indicator and counterparty name.
- Make sure that the contacts designated to answer inquiries on data submissions are easily accessible and responsive to inquiries by Platts editors.
- Report every day and on time, and when problems arise that prevent reporting on time, notify Platts of the delay in a timely fashion.
- Rarely make errors in data submissions and follow up quickly when errors are made.
- Submit reports that include few outliers, and provide explanations for any outliers at the time when the outliers are reported.

LOW-LIQUIDITY DAILY MARKETS

For trading locations with very limited liquidity, Platts strongly believes it is better to publish an assessment rather than allow one or two market players to set the index based on very limited dealmaking. For that reason, Platts assesses such illiquid points using transactions, differentials to other locations, physical bid/ask spreads, derivatives trading and other information.

Platts clearly indicates when it assesses a daily electricity market rather than calculating an index based on a volume-weighted average. Assessments are indicated by an "NA" (not applicable) in the volume column.

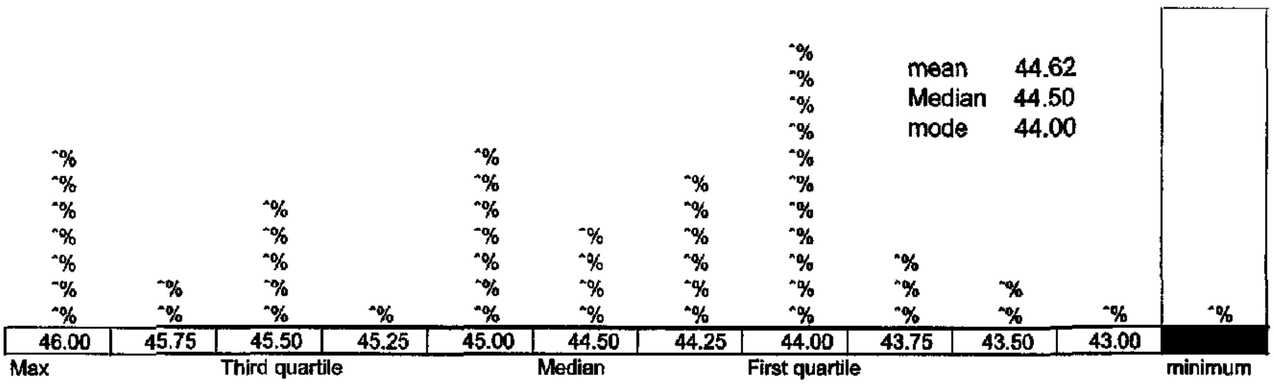
Platts believes such assessments for low-liquidity markets allow editors to provide a value that is more representative and reflective of the market than a volume-weighted average determined by a very limited number of market participants. Platts editors assess daily markets when either of two conditions applies:

(1) There are fewer than five individual transactions reported for a given location.

(2) The number of reporting entities providing transaction-level data is fewer than three.

A trading location must meet both of these thresholds before an index determined by the volume-weighted average will be calculated. These are the minimum thresholds, and Platts editors may decide on a case-by-case basis to assess a market even when these minimum standards are met if there is concern that a large, dominant market participant can effectively set a volume-weighted average. Platts will not allow one or two market

Example 1: 50 transactions, outlier discarded

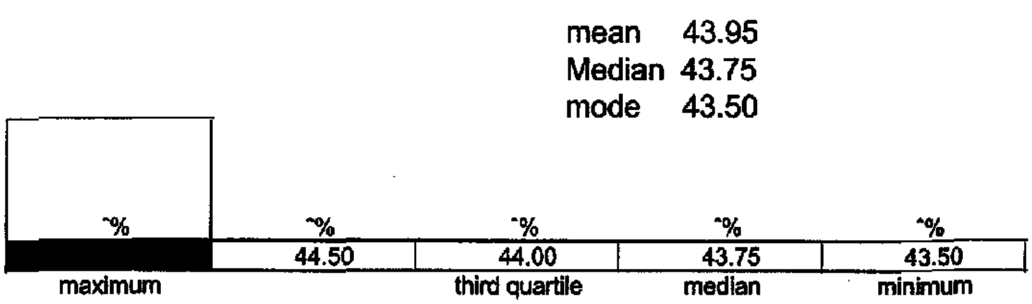


In this example the editor has a set of 50 next-day deals with a range of $5.25, and one outlier beyond two standard deviations from the mean. That single outlier is $2.25 lower than the next-lowest deal.

Using the list of "tests" or considerations applied to outliers (see above), there are several that weigh on the side of including the deal. It is a standard-volume transaction. There is considerable deal-making on the outlier's side of the mean. The data set also has a negative skew which causes low deals to be further from the mean. This causes our use of two standard deviations from the mean to identify outliers to give more room on the high side and less room on the low side. In addition, the source is in good standing.

However, there are other considerations that weigh toward discarding the deal. When the reporter calls to check the deal, the source verifies that the deal was done after options. The reporter was already aware that deals were done at that lower level after the expiration of daily options. The status of the deal as an after-options transaction and the great disparity between it and the other deals in our sample strongly indicate this could be a distressed deal—market conditions were substantially different after options on this day in this market. Those reasons would lead Platts to discard the deal. The decision to cut the deal would raise the volume-weighted index by 7 cents to $44.77/MWh.

Example 2: 10 transactions, outlier included



In this example the editor has a smaller data set of 10 transactions. The first consideration here is that Platts is handling a limited set of data. It fulfills the requirement of at least five deals, and they are all standard-size packages, but the number of transactions is relatively small. For smaller samples, statistical measures like the standard deviation are less meaningful, and therefore are not given as much weight by editors relative to when they are handling larger samples (like example 1). The magnitude of a deal's outlier nature logically carries less weight in a small sample.

A second consideration: The outlier is the minimum-size standard package for its market. A larger package size would increase the impact of the single transaction on the volume-weighted index.

The gap between the outlier and the next-highest-priced deal is limited to $1.00. In addition, the next-highest deal is reported by a different source, providing corroboration of trading activity on the high side of the data set.

The editor has no information that the deal was done after the expiration of daily options, and a call to the source confirms that the deal was not done after options. Although there is no matching price from another source, and there is no counter-party information, the other considerations weigh toward retaining the deal as part of the data set. The deal appears to have been accurately reported, and the list of tests weighs toward including the transaction. It is retained, and the inclusion of the deal leaves us a volume-weighted average at $43.78/MWh, 17 cents higher than it would have been if the deal had been discarded.

participants to set an index value.

Below is an example of how Platts editors determine an assessment in a low-liquidity market. Like the earlier examples, this example is hypothetical and does not include actual data provided by Platts sources. However, it reflects the general characteristics of data sets commonly seen by Platts electricity market editors in cases in which they assess daily markets.

ASSESSMENTS FOR WEEKEND-DELIVERY POWER

Indexes and assessments are also formulated for weekends for standard packages in various regions. In the East and Central regions, except in the Electric Reliability Council of Texas (ERCOT), on-peak indexes and assessments for standard non-holiday weekends are formulated based on 2x16 packages traded Friday for delivery during on-peak hours Saturday and Sunday. Off-peak indexes and assessments are based on 2x8 packages traded Friday for off-peak hours Saturday and Sunday. Single-day packages may be used to assess the value of these packages in the absence of reported transactions for two-day packages. However, final assessments will be the same for both Saturday and Sunday. Single-day deals will not be included with two-day packages in a volume-weighted index. Mixing single-day packages with two-day packages is avoided for the same reason Platts does not mix on-peak and around-the-clock packages in a day-ahead assessment.

In ERCOT, for standard non-holiday weekends, Platts formulates its off-peak assessments and indexes for the weekend based on transactions traded Friday for delivery during off-peak hours Saturday through Monday, known as 3x8 packages. On-peak assessments for standard weekends in ERCOT, as in other Eastern and Central markets, are based on 2x16 packages.

In the West, Saturday is normally part of a Friday and Saturday package. Single-day deals are not included in the volume-weighted index of either day, and assessments for the two days are the same. Sunday power is traded in the West for delivery around-the-clock as a package with the Monday off-peak deals. The price for Sunday will be equal to that of the Monday off-peak. Again, no single-day deals will be included in these calculations.

In all regions, these standard weekend packages are changed to accommodate holidays. (In the West, weekend packages are also changed to prevent splitting a package between two months.) When weekend packages are altered because of holidays, indexes and assessments are based on the standard holiday packages and single-day packages are not included in the volume-weighted indexes.

NEAR-TERMS

Platts changed its methodology for standard near-term packages (balance-of-the-week, balance-of-the-month and next-week) effective Dec. 1, 2005 to make its coverage more complete and consistent. Platts publishes an assessed range (low-high assessment) for those standard packages based on reported transactions. If there is only one transaction reported, the assessed range will be created by adding a minimum 50-cent range around the transaction. If no transactions are reported, Platts may elect to publish an assessed range based on bid/offer information, locational spreads, and other market information.

Example 3: 5 transactions and only two sources, determining an assessment

mean 42.60
median 41.00
mode 46.50

46.50	41.00	40.00	39.00
third quartile maximum	median	first quartile	minimum

In this example the editor has a data set that falls to meet one of the three thresholds for using a volume-weighted average to calculate an index. There are five transactions totaling 300 MW (which meets the thresholds of five deals and 250 MW) but only two sources of data (compared with the threshold minimum of three), so Platts will assess this market based on the deals reported as well as other market information.

This other information includes, but is not limited to, bids and offers gathered through discussions with traders and other sources and recent locational spreads between this market and a more-liquid adjacent market.

In this example there is no congestion between this location and the most liquid adjacent market. The daily market being assessed has been pricing about $2 above the more liquid adjacent market, which has a volume-weighted average of $39.80/MW.

The mid-market level from bids and offers is slightly above the $41.80 assessment based strictly on the spread to the more-liquid adjacent market.

In this example the volume-weighted average, based only on the deals reported by the two sources, would have been $42/MWh. One of the deals is a 100-MW deal at $39/MWh; the others were all 50-MW packages done at higher prices.

The editor assesses this market at $41.75/MWh based on three factors: the spread to the more-liquid adjacent market, the mid-market of the bids and offers, and the volume-weighted average of the limited amount of reported transactions.

DAILY FORWARD ASSESSMENTS

Platts produces daily market-on-close assessments of the value of standard over-the-counter forward packages each business day. Platts uses 2:30 pm Eastern prevailing time in the absence of a formal close for the OTC market. This is the close for open-outcry trading for the NYMEX Henry Hub gas contract and allows our daily forward power assessments to be compared with NYMEX gas settlement prices.

The assessments are formulated by editors based on forward transactions (including spread trades), differentials to other trading locations, differentials between time periods, physical bid/ask spreads, derivatives trading and other market information, including market fundamentals. Bids and offers made and transactions done nearer the close receive greater weight in the assessment process than those from early in the day.

Assessments across the curve should be in agreement. For example, the average for two months reported individually should be the price reported for the two-month package.

Daily forward assessments are for both standard on-peak and off-peak forward products.

Standard on-peak packages in Eastern and Central markets are 5x16 packages, which include power delivered during on-peak hours on weekdays and exclude weekends and holidays defined by the North American Electric Reliability Council (NERC).

Standard on-peak forward packages in Western markets are 6x16 packages, which include power delivered during the 16 on-peak hours each day Monday through Saturday and exclude Sundays and NERC holidays.

Standard off-peak packages vary among markets. In the New England, New York, Ontario, PJM and MISO markets, the standard off-peak package is a 5x8 package, which includes power delivered during the eight off-peak hours each day Monday through Friday and excludes weekends.

In the ERCOT, Into Entergy, Into Southern and Into TVA markets, the standard off-peak package is a 5x8 plus a 2x24 package, known as a wrap, which includes power for delivery during the eight off-peak hours each weekday, plus all 24 hours (around-the-clock) on weekends.

In Western markets, the standard off-peak package is a 6x8 plus a 1x24 package, also known as a wrap, which includes power for delivery during the eight off-peak hours Monday through Saturday plus all 24 hours (around the clock) on Sunday.

Platts gathers information on the forward market through the non-commercial departments of companies as well as in discussions with traders active in the market. In addition, Platts incorporates electricity forward trading activity from IntercontinentalExchange, including transactions and bids and offers.

The curve is a subjective assessment of market activity and assessments are made when there is no trading for a given market on that day.

PART IV: CORRECTIONS

Platts makes every effort to verify the accuracy of prices based on the information it has when it makes final determinations of indexes and assessments at the end of the day. As described in Part III, Platts editors routinely contact data providers about transactions that appear questionable and may request supporting information, such as counterparty, to verify the deal.

In cases where editors cannot obtain a satisfactory answer to their questions about an individual or series of transactions, or where they see indications of a possible pattern of questionable deals, they may choose to take their concerns to the entity's chief risk officer or comparable senior official. If editors still cannot resolve their concerns, they may opt to exclude the entity from participating in Platts' price surveys until senior company management provides sufficient reassurance that the entity is responsibly reporting accurate data.

Platts is committed to promptly correcting any material errors in published prices that result from human or computational mistakes. When corrections are made because of such errors, they are limited to corrections to data that was available when the index or assessment was calculated.

Because it is extremely important that Platts' indexes and assessments provide certainty, Platts' policy long has been not to revise prices after the fact for reasons other than human or computational errors. In particular, Platts cannot revise indexes or assessments in cases where market participants submit new, as opposed to corrected, information that they want included in the published prices. Allowing such revisions could open Platts to a never-ending revision process as market participants continually come forward with more data.

Errors found in a data submission should be brought to the attention of the appropriate Platts editor as soon as possible.

If Platts is notified of an error in a submission after a price is calculated and published, editors will determine the nature of the error, whether the erroneous data was used in calculating an index or making an assessment, the impact of the erroneous data if it was used, and whether Platts had in hand other data corroborating that the data should not have been included.

The impact of the error also will be considered. If the removal of the data fails to make a material change in the index or assessment, no correction will be made.

In defining what constitutes a material change, in cases of computational and human errors on the part of Platts or data providers, Platts will consider three primary factors: the percentage change in the index or assessment; the number of business days since the price in question was published; and the liquidity of the trading point as reflected in the volumes reported to Platts.

For example, an error resulting in a change of greater than 2% that is discovered within five business days of publication of a price for a high-liquidity point would be deemed material; an error resulting in a change of less than 0.5% that is discovered more than 15 days after publication of a price for a low-liquidity point would be deemed immaterial.

In addition to the three principal factors used to determine materiality, Platts will also consider other measures of the magnitude of the error, including: the absolute change in the price; the change in the range (low trade and high trade); the change in an index as a percentage of the range; the number of sources represented in the published price; the volume represented in the published price and the volume affected by the error; and the number of deals represented in the published price and the number of deals affected by the error.

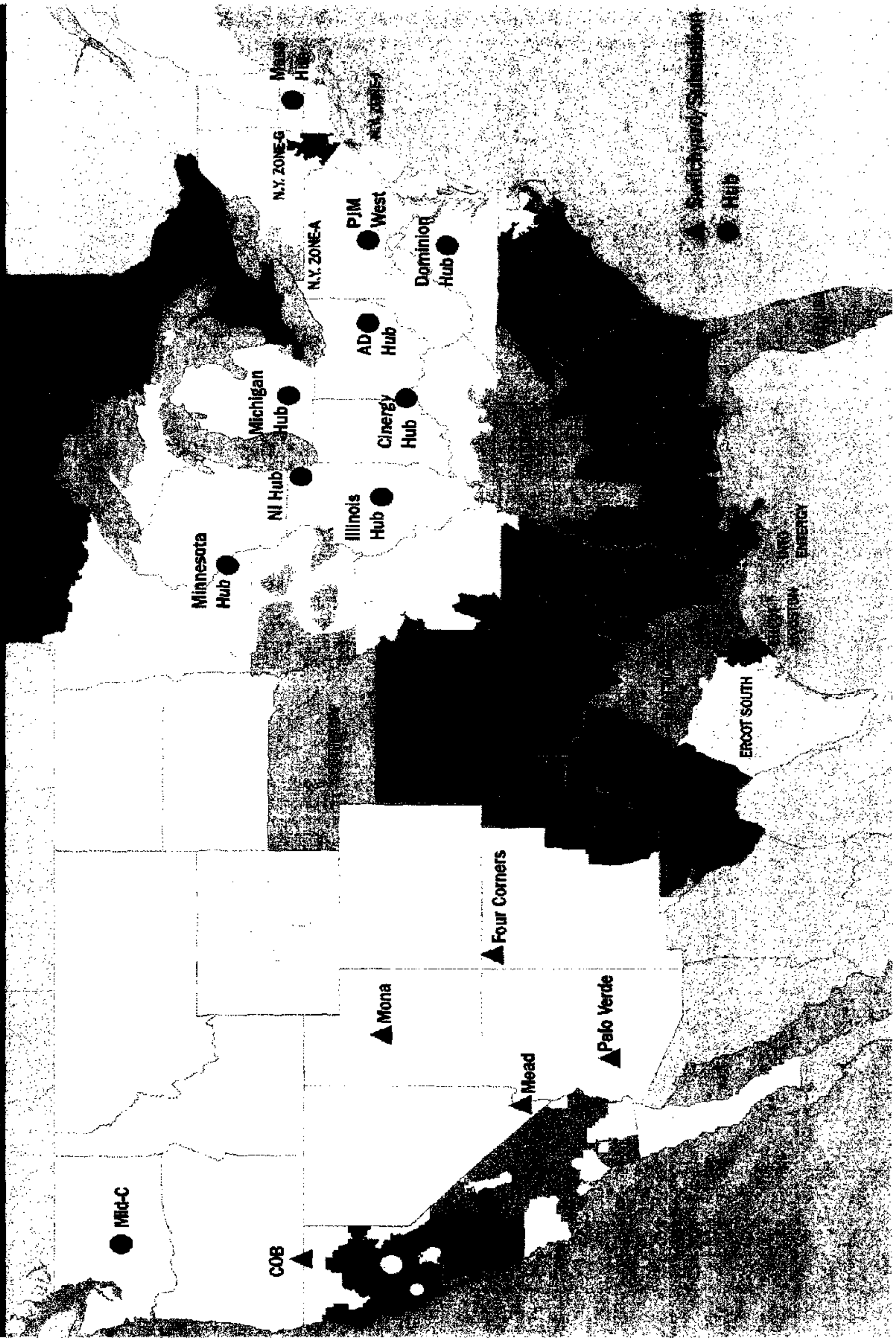
PART V: PLATTS EDITORIAL STANDARDS

Platts has in place a Code of Ethics with which all of its employees, including its editorial staff, must comply. Components of the code specifically address standards for market reporting.

In addition, all Platts employees must adhere to The McGraw-Hill Companies' Code of Business Ethics. Editors must re-sign each code annually. Company policies, among other things, prohibit editorial personnel and their spouses from trading in commodities or stocks, bonds or options of companies in the industry covered by their publication(s) and from dealing with outside parties in a manner that creates even an appearance of a conflict of interest. The McGraw-Hill Companies' Code of Business Ethics reflects McGraw-Hill's commitment to integrity, honesty and acting in good faith in all its dealings. The Platts Code of Ethics is designed to ensure that Platts information is the product of honest, fair and open reporting.

Platts has an independent compliance staff whose function is to ensure that Platts' market editors follow the stated methodology, records retention policy and code of ethics. In addition, The McGraw-Hill Companies' internal auditor, an independent group that reports directly to the parent company's board of directors, reviews the Platts compliance program.

Locations for which Platts publishes daily indexes or assessments



PART VI: DEFINITIONS OF THE TRADING LOCATIONS FOR WHICH PLATTS PUBLISHES DAILY INDEXES OR ASSESSMENTS

EASTERN MARKETS

Mass Hub

AKA: Massachusetts Hub, ISO New England Internal Hub

Description: The ISO New England's Internal hub comprises 36 nodes in central Massachusetts and is the most commonly used location in the six-state region for bilateral trading.

Market type: LMP

Grid operator: ISO New England

On-peak hours: Hour-ending 8 through 23

Off-peak hours: Hour-ending 1 through 7 and 24

Product assessed: Physical power, energy only (no capacity), firm with liquidated damages

Start date: Mar 2003

Predecessor/start date: New England (seller's choice)/May 1995

Platts day-ahead flow date code on-peak: AAMWY20

Platts day-ahead flow date code off-peak: AAMWX20

N.Y. Zone-G

AKA: Hudson Valley

Description: The New York ISO's Zone-G, for delivery to the Hudson Valley, comprises four sub-zone in eastern New York.

Market type: LMP

Grid operator: New York ISO

On-peak hours: Hour-ending 8 through 23

Off-peak hours: Hour-ending 1 through 7 and 24

Product assessed: Financial swap settled against the New York ISO day-ahead market clearing price

Start date: Nov 1999

Predecessor/start date: New York East/Mar 1997

Platts day-ahead flow date code on-peak: WEADV20

N.Y. Zone-J

AKA: New York City

Description: The New York ISO's Zone-J, for delivery to New York City, comprises one sub-zone covering New York City.

Market type: LMP

Grid operator: New York ISO

On-peak hours: Hour-ending 8 through 23

Off-peak hours: Hour-ending 1 through 7 and 24

Product assessed: Financial swap settled against the New York ISO day-ahead market clearing price

Start date: Sep 2000

Predecessor/start date: None

Platts day-ahead flow date code on-peak: AAFYS20

N.Y. Zone-A

AKA: West New York

Description: The New York ISO's Zone-A, for delivery to West New York, comprises two sub-zones in Western New York.

Market type: LMP

Grid operator: New York ISO

On-peak hours: Hour-ending 8 through 23

Off-peak hours: Hour-ending 1 through 7 and 24

Product assessed: Financial swap settled against the New York ISO day-ahead market clearing price

Start date: Nov 1999

Predecessor/start date: New York West/Mar 1997

Platts day-ahead flow date code on-peak: WEADW20

Ontario

AKA: none

Description: The Ontario market and pricing area comprises the grid controlled by Ontario's independent system operator, the Independent Electricity System Operator. The grid operator was originally named the Independent Market Operator.

Market type: LMP

Grid operator: Ontario's Independent Electricity System Operator

On-peak hours: Hour-ending 8 through 23

Off-peak hours: Hour-ending 1 through 7 and 24

Product assessed: Financial swap settled against the Ontario Independent Electric System Operator hourly market clearing price

Start date: Jun 2002

Predecessor/start date: none

Platts day-ahead flow date code on-peak: WEBER20

PJM West

AKA: PJM Western Hub

Description: The PJM Interconnection's Western Hub comprises a group of 110 nodes in a large, crescent-shaped subregion of the PJM Interconnection that stretches along the southern boundary of PJM, from southern Maryland north to Washington D.C. and northwest to central and western Pennsylvania.

Market type: LMP

Grid operator: The PJM Interconnection

On-peak hours: Hour-ending 8 through 23

Off-peak hours: Hour-ending 1 through 7 and 24

Product assessed: Physical power, energy only (no capacity), firm with liquidated damages

Start date: April 1, 1998

Predecessor/start date: PJM (seller's choice)/Oct 1994

Platts day-ahead flow date code on-peak: WEBDA20

Platts day-ahead flow date code off-peak: WEACH20

Dominion Hub

AKA: Virginia Power Company and PJM South

Description: The PJM Interconnection's Dominion hub comprises a group of approximately 644 nodes in Virginia within Dominion's Virginia Power control area. The Dominion control area is also referred to PJM South; the hub is a defined subset of nodes within PJM South. Transactions for delivery in the Dominion's Virginia Power control area were formerly used in the VACAR assessment.

Market type: LMP

Grid operator: The PJM Interconnection

On-peak hours: Hour-ending 8 through 23

Off-peak hours: Hour-ending 1 through 7 and 24

Product assessed: Physical power, energy only (no capacity), firm with liquidated damages

Start date: May 2005

Predecessor/start date: Formerly included in the VACAR index/Jan 2002; SERC/Oct 1994

Platts day-ahead flow date code on-peak: ABMCI20

Platts day-ahead flow date code off-peak: ABMCB20

VACAR

AKA: none

Description: VACAR comprises the control areas in the Virginia and Carolinas subregion of the Southeastern Electric Reliability Council, including: Progress Energy's Carolina Power and Light east and west, Duke, South Carolina Electric and Gas, Santee Cooper, Southeastern Power Administration and APGI Yadkin Division. Dominion's Virginia Power control area has been excluded since it joined the PJM interconnection on May 1, 2005.

Market type: no formal market design

Grid operator: individual utilities

On-peak hours: Hour-ending 7 through 22

Off-peak hours: Hour-ending 1 through 6 and 23 through 24

Product assessed: Physical power, energy only (no capacity), firm with liquidated damages

Start date: Jan 2002

Predecessor/start date: Formerly included in the SERC index/Oct 1994

Platts day-ahead flow date code on-peak: AAMCI20

Platts day-ahead flow date code off-peak: AAMCB20

Into Southern

AKA: Into SoCo

Description: Into Southern comprises power delivered to an interface with or a delivery point within the Southern Company control area, which spans a swath of SERC from Georgia to Mississippi including a portion of the Florida pan handle.

Market type: no formal market design

Grid operator: Southern Company

On-peak hours: Hour-ending 7 through 22

Off-peak hours: Hour-ending 1 through 6 and 23 through 24

Product assessed: Physical power, energy only (no capacity), firm with liquidated damages

Start date: Jan 2002

Predecessor/start date: Formerly included in the SERC index/Oct 1994

Platts day-ahead flow date code on-peak: AAMBJ20

Platts day-ahead flow date code off-peak: AAMBC20

Florida

AKA: Florida instate

Description: The Florida instate pricing area comprises control areas within the State of Florida or the Florida Reliability Coordination Council (FRPCC), excluding Gulf Power, which is part of the Southern Company control area. Florida control areas include: Progress Energy Florida, Florida Power & Light Company, Tampa Electric Company, Florida Municipal Power Agency, Gainesville Regional Utilities, JEA, City of Lakeland, Orlando Utilities Commission, City of Tallahassee and Seminole Electric Cooperative.

Market type: no formal market design

Grid operator: Individual utilities

On-peak hours: Hour-ending 7 through 22

Off-peak hours: Hour-ending 1 through 6 and 23 through 24

Product assessed: Physical power, energy only (no capacity), firm with liquidated damages

Start date: Jan 2002

Predecessor/start date: Florida-Georgia Border/Apr 1997

Platts day-ahead flow date code on-peak: AAMAV20

Platts day-ahead flow date code off-peak: AAMAO20

Into TVA

AKA: none

Description: Into TVA comprises power delivered to an interface with or a delivery point within the control area of the Tennessee Valley Authority, which includes Tennessee and the northern portion of Alabama.

Market type: no formal market design

Grid operator: Tennessee Valley Authority

On-peak hours: Hour-ending 7 through 22

Off-peak hours: Hour-ending 1 through 6 and 23 through 24

Product assessed: Physical power, energy only (no capacity), firm with liquidated damages

Start date: May 1997

Predecessor/start date: N.A.

Platts day-ahead flow date code on-peak: WEBAB20

Platts day-ahead flow date code off-peak: AAJER20

CENTRAL MARKETS

AD Hub

AKA: AEP-Dayton Hub

Description: The PJM Interconnection's AEP-Dayton Hub comprises a group of 1181 nodes located in the AEP and Dayton Power and Light's control areas in Ohio and Michigan.

Market type: LMP

Grid operator: The PJM Interconnection

On-peak hours: Hour-ending 8 through 23

Off-peak hours: Hour-ending 1 through 7 and 24

Product assessed: Physical power, energy only (no capacity), firm with liquidated damages

Start date: May 1997

Predecessor/start date: Into AEP/Feb 2004; Northern ECAR/May 1999; ECAR/Oct 1994

Platts day-ahead flow date code on-peak: WEBYO20

Platts day-ahead flow date code off-peak: AALDW20

NI Hub

AKA: Northern Illinois Hub

Description: The PJM Interconnection's Northern Illinois Hub comprises a group of 234 nodes located in the Commonwealth Edison control area in Northern Illinois.

Market type: LMP

Grid operator: The PJM Interconnection

On-peak hours: Hour-ending 8 through 23

Off-peak hours: Hour-ending 1 through 7 and 24

Product assessed: Physical power, energy only (no capacity), firm with liquidated damages

Start date: May 2004

Predecessor/start date: Into ComEd/May 1997

Platts day-ahead flow date code on-peak: WEBAC20

Platts day-ahead flow date code off-peak: AAJED20

South MAPP

AKA: none

Description: South MAPP comprises control areas in the southern portion of the Mid-Continent Area Power Pool (MAPP) region, mainly in Nebraska and Iowa, that are not part of the Midwest Independent Transmission System Operator. Those control areas include: Corn Belt Power Cooperative, MidAmerican Energy Company, Lincoln Electric System, Nebraska Public Power District and Omaha Public Power District.

Market type: no formal market design

Grid operator: individual utilities

On-peak hours: Hour-ending 7 through 22

Off-peak hours: Hour-ending 1 through 6 and 23 through 24

Product assessed: Physical power, energy only (no capacity), firm with liquidated damages

Start date: Sep 2000

Predecessor/start date: MAPP/Jan 1996

Platts day-ahead flow date code on-peak: AAFYP20

Platts day-ahead flow date code off-peak: AAJGZ20

North SPP

AKA: Southwest Power Pool

Description: North SPP comprises control areas in the Southwest Power Pool (SPP) in Kansas, Oklahoma, Arkansas, Louisiana and Texas. This pricing area was identified as North SPP after Entergy was broken out of the SPP index in February 1997. Control areas include: American Electric Power's Public Service Company of Oklahoma and Southwestern Electric Power Company, Aquila's Missouri Public Service and WestPlains Energy, Cleco Power, Kansas City Power & Light, OG&E Electric Services, Southwestern Public Service Company, Empire District Electric Company, Westar Energy's Kansas Gas and Electric Company, Sunflower Electric Power Corporation, Western Farmers Electric Cooperative, City of Lafayette Louisiana, City Power & Light Independence Missouri, The Board of Public Utilities Kansas City Kansas, Grand River Dam Authority and Louisiana Energy & Power Authority

Market type: no formal market design (SPP run balancing market planned for Oct 2006)

Grid operator: individual utilities; SPP can order redispatch of generation if necessary

On-peak hours: Hour-ending 7 through 22

Off-peak hours: Hour-ending 1 through 6 and 23 through 24

Product assessed: Physical power, energy only (no capacity), firm with liquidated damages

Start date: Feb 1997

Predecessor/start date: SPP/May 1995

Platts day-ahead flow date code on-peak: WEBCQ20

Platts day-ahead flow date code off-peak: WEBCS20

Michigan Hub

AKA: none

Description: The Midwest Independent Transmission System Operator's (MISO) Michigan hub comprises approximately 260 nodes covering a large portion of the lower peninsula of Michigan. The Michigan hub replaced the North ECAR trading area, which included the northern potion of the ECAR NERC region, excluding the AEP and Dayton Power and Light control areas.

Market type: LMP

Grid operator: Midwest Independent Transmission System Operator

On-peak hours: Hour-ending 8 through 23

Off-peak hours: Hour-ending 1 through 7 and 24

Product assessed: Physical power, energy only (no capacity), firm with liquidated damages

Start date: April 1, 2005

Predecessor/start date: Northern ECAR/May 1999; ECAR/Oct 1994

Platts day-ahead flow date code on-peak: ADMCI20

Platts day-ahead flow date code off-peak: ADMCB20

FirstEnergy Hub

AKA: none

Description: The Midwest Independent Transmission System Operator's FirstEnergy Hub comprises a group of 276 nodes in the traditional control area of FirstEnergy in northern Ohio.

Market type: LMP

Grid operator: Midwest Independent Transmission System Operator

On-peak hours: Hour-ending 8 through 23

Off-peak hours: Hour-ending 1 through 7 and 24

Product assessed: Physical power, energy only (no capacity), firm with liquidated damages

Start date: April 1, 2007

Predecessor/start date: None

Platts day-ahead flow date code on-peak: WECY020

Platts day-ahead flow date code off-peak: ADJDW20

Cinergy Hub

AKA: none

Description: The Midwest Independent Transmission System Operator's (MISO) Cinergy hub comprises approximately 330 nodes on that portion of the electric grid within the Midwest ISO footprint covering parts of southwestern Ohio, northern Kentucky, and Indiana. Cinergy Hub replaced the Into Cinergy trading point, which was based on the Cinergy utility control area.

Market type: LMP

Grid operator: Midwest Independent Transmission System Operator

On-peak hours: Hour-ending 8 through 23

Off-peak hours: Hour-ending 1 through 7 and 24

Product assessed: Physical power, energy only (no capacity), firm with liquidated damages

Start date: April 1, 2005

Predecessor/start date: Into Cinergy/Jan 1997; ECAR/Oct 1994

Platts day-ahead flow date code on-peak: WEAYO20

Platts day-ahead flow date code off-peak: AAJDW20

Illinois Hub

AKA: none

Description: The Midwest Independent Transmission System Operator's (MISO) Illinois Hub comprises approximately 150 nodes located mainly in central, south, and southwest Illinois. The Illinois hub replaced the South MAIN (Mid-America Interconnected Network) index, which included the portion of the MAIN NERC region south of the Commonwealth Edison's control area.

Market type: LMP

Grid operator: Midwest Independent Transmission System Operator

On-peak hours: Hour-ending 8 through 23

Off-peak hours: Hour-ending 1 through 7 and 24

Product assessed: Physical power, energy only (no capacity), firm with liquidated damages

Start date: April 1, 2005

Predecessor/start date: South MAIN/May 1999

Platts day-ahead flow date code on-peak: ACMCI20

Platts day-ahead flow date code off-peak: ACMCB20

Minnesota Hub

AKA: none

Description: The Midwest Independent Transmission System Operator's (MISO) Minnesota hub comprises approximately 170 nodes in and around the cities of Minneapolis and St. Paul, Minn. The Minnesota hub replaced the North MAIN and North MAPP trading areas, which encompassed the northern portions of the MAIN and MAPP NERC regions.

Market type: LMP

Grid operator: Midwest Independent Transmission System Operator

On-peak hours: Hour-ending 8 through 23

Off-peak hours: Hour-ending 1 through 7 and 24

Product assessed: Physical power, energy only (no capacity), firm with liquidated damages

Start date: April 1, 2005

Predecessor/start date: North MAIN/May 1999 and North MAPP/Sep 2000; MAPP/Jan 1996

Platts day-ahead flow date code on-peak: AEMCI20

Platts day-ahead flow date code off-peak: AEMCB20

Into Entergy

AKA: none

Description: Into Entergy comprises power delivered to an interface with or a delivery point within the Entergy control area, which spans portions of Arkansas, Mississippi, Louisiana and Texas. (The portion of Entergy's control area in Texas is not part of ERCOT.)

Market type: no formal market design

Grid operator: Entergy

On-peak hours: Hour-ending 7 through 23

Off-peak hours: Hour-ending 1 through 6 and 23 through 24

Product assessed: Physical power, energy only (no capacity), firm with liquidated damages

Start date: Feb 1997

Predecessor/start date: SPP/May 1995

Platts day-ahead flow date code on-peak: WEAZO20

Platts day-ahead flow date code off-peak: AAJEK20

ERCOT

AKA: ERCOT seller's choice

Description: The Electric Reliability Council of Texas operates much of the grid in Texas, with the ERCOT control area covering approximately 75% of the land area in Texas. ERCOT does not include the El Paso region, the northern panhandle, a small area around Texarkana, and a small portion of the region around Beaumont. ERCOT seller's choice includes contracts for power that can be delivered to any of the five zones that ERCOT is divided into: North, South, West, Northeast and Houston. ERCOT seller's choice product is often valued closely with the South zone, which has surplus generation.

Market type: Zonal

Grid operator: Electric Reliability Council of Texas

On-peak hours: Hour-ending 7 through 22

Off-peak hours: Hour-ending 1 through 6 and 23 through 24

Product assessed: Physical power, energy only (no capacity), firm with liquidated damages

Start date: Jan 1996

Predecessor/start date: none

Platts day-ahead flow date code on-peak: WEADO20

Platts day-ahead flow date code off-peak: WEADH20

ERCOT Houston

AKA: none

Description: ERCOT's Houston zone.

Market type: Zonal

Grid operator: Electric Reliability Council of Texas

On-peak hours: Hour-ending 7 through 22

Off-peak hours: Hour-ending 1 through 6 and 23 through 24

Product assessed: Physical power, energy only (no capacity), firm with liquidated damages

Start date: Mar 2002

Predecessor/start date: ERCOT/Jan 1996

Platts day-ahead flow date code on-peak: WEAFJ20

Platts day-ahead flow date code off-peak: WEAFI20

ERCOT North

AKA: none

Description: ERCOT's North zone, which does not include ERCOT's Northeast zone.

Market type: Zonal

Grid operator: Electric Reliability Council of Texas

On-peak hours: Hour-ending 7 through 22

Off-peak hours: Hour-ending 1 through 6 and 23 through 24

Product assessed: Physical power, energy only (no capacity), firm with liquidated damages

Start date: Mar 2002

Predecessor/start date: ERCOT/Jan 1996

Platts day-ahead flow date code on-peak: WEADY20

Platts day-ahead flow date code off-peak: WEADX20

ERCOT West

AKA: none

Description: ERCOT's West zone.

Market type: Zonal

Grid operator: Electric Reliability Council of Texas

On-peak hours: Hour-ending 7 through 22

Off-peak hours: Hour-ending 1 through 6 and 23 through 24

Product assessed: Physical power, energy only (no capacity), firm with liquidated damages

Start date: Mar 2002

Predecessor/start date: ERCOT Jan 1996

Platts day-ahead flow date code on-peak: WEAFY20

Platts day-ahead flow date code off-peak: WEAFX20

ERCOT South

AKA: none

Description: ERCOT's South zone.

Market type: Zonal

Grid operator: Electric Reliability Council of Texas

On-peak hours: Hour-ending 7 through 22

Off-peak hours: Hour-ending 1 through 6 and 23 through 24

Product assessed: Physical power, energy only (no capacity), firm with liquidated damages

Start date: Mar 2002

Predecessor/start date: ERCOT Jan 1996

Platts day-ahead flow date code on-peak: WEAEY20

Platts day-ahead flow date code off-peak: WEAEQ20

WESTERN MARKETS

Mid-C

AKA: Mid-Columbia

Description: Mid-C is a power trading hub for the Northwest U.S. comprising the control areas of three public utility districts in Washington that run hydro electric projects on the Columbia River. The three PUDs are Grant, Douglas and Chelan. Hydro projects include Wells, Rocky Reach, Rock Island, Wanapum and Priest Rapids dams.

Market type: no formal market design

Grid operator: individual utilities

On-peak hours: Hour-ending 7 through 22

Off-peak hours: Hour-ending 1 through 6 and 23 through 24

Product assessed: Physical power, energy only (no capacity), firm with liquidated damages

Start date: Oct 1994

Predecessor/start date: N.A.

Platts day-ahead flow date code on-peak: WEABF20

Platts day-ahead flow date code off-peak: WEACL20

COB

AKA: California-Oregon Border

Description: COB comprises the Captain Jack and Malin substations on the AC transmission system between Oregon and California.

Market type: no formal market design

Grid operator: individual utilities

On-peak hours: Hour-ending 7 through 22

Off-peak hours: Hour-ending 1 through 6 and 23 through 24

Product assessed: Physical power, energy only (no capacity), firm with liquidated damages

Start date: Oct 1994

Predecessor/start date: N.A.

Platts day-ahead flow date code on-peak: WEABE20

Platts day-ahead flow date code off-peak: WEACJ20

Palo Verde

AKA: PV or Palo

Description: Palo Verde comprises the switchyard at the Palo Verde nuclear power station west of Phoenix, Arizona.

Market type: no formal market design

Grid operator: individual utilities

On-peak hours: Hour-ending 7 through 22

Off-peak hours: Hour-ending 1 through 6 and 23 through 24

Product assessed: Physical power, energy only (no capacity), firm with liquidated damages

Start date: Oct 1994

Predecessor/start date: N.A.

Platts day-ahead flow date code on-peak: WEACC20

Platts day-ahead flow date code off-peak: WEACT20

Mead

AKA: none

Description: Mead comprises the switchyard at the Hoover Dam on the Colorado River, forming Lake Mead near Las Vegas, Nevada.

Market type: no formal market design

Grid operator: individual utilities

On-peak hours: Hour-ending 7 through 22

Off-peak hours: Hour-ending 1 through 6 and 23 through 24

Product assessed: Physical power, energy only (no capacity), firm with liquidated damages

Start date: Feb 2004

Predecessor/start date: Mead May 1995-Sep 1996.

Platts day-ahead flow date code on-peak: AAMBW20

Platts day-ahead flow date code off-peak: AAMBQ20

Mona

AKA: none

Description: Mona comprises the Mona substation in central Utah, directly south of Salt Lake City and linked to major generating units in the region, such as the Intermountain Power Project.

Market type: no formal market design

Grid operator: individual utilities

On-peak hours: Hour-ending 7 through 22

Off-peak hours: Hour-ending 1 through 6 and 23 through 24

Product assessed: Physical power, energy only (no capacity), firm with liquidated damages

Start date: Aug 2005

Predecessor/start date: N.A.

Platts day-ahead flow date code on-peak: AARLQ20

Platts day-ahead flow date code off-peak: AARLO20

Four Corners

AKA: none

Description: Four Corners comprises the switchyard of the coal-fired Four Corners power plant in Fruitland, New Mexico, located in the Northwestern corner of the state where Arizona, Colorado, New Mexico and Utah meet.

Market type: no formal market design

Grid operator: individual utilities

On-peak hours: Hour-ending 7 through 22

Off-peak hours: Hour-ending 1 through 6 and 23 through 24

Product assessed: Physical power, energy only (no capacity), firm with liquidated damages

Start date: May 1995

Predecessor/start date: N.A.

Platts day-ahead flow date code on-peak: WEABI20

Platts day-ahead flow date code off-peak: WEACR20

NP15

AKA: North-of-Path 15 or North Path

Description: NP15 comprises the California Independent System Operator's northern congestion zone. The zone is north of the main north-south AC transmission pathway, California Path 15.

Market type: Zonal with plans to move to a nodal system in 2007

Grid operator: California Independent System Operator

On-peak hours: Hour-ending 7 through 22

Off-peak hours: Hour-ending 1 through 6 and 23 through 24

Product assessed: Physical power, energy only (no capacity), firm with liquidated damages

Start date: Mar 1999

Predecessor/start date: Midway/May 1995

Platts day-ahead flow date code on-peak: AABDA20

Platts day-ahead flow date code off-peak: AABCZ20

SP15

AKA: South-of-Path 15 or South Path

Description: SP15 comprises the California Independent System Operator's southern congestion zone. The zone is south of the main north-south AC transmission pathway, California Path 15.

Market type: Zonal with plans to move to a nodal system in 2007

Grid operator: California Independent System Operator

On-peak hours: Hour-ending 7 through 22

Off-peak hours: Hour-ending 1 through 6 and 23 through 24

Product assessed: Physical power, energy only (no capacity), firm with liquidated damages

Start date: Mar 1999

Predecessor/start date: Midway/May 1995

Platts day-ahead flow date code on-peak: AABDF20

Platts day-ahead flow date code off-peak: AABDG20