2008 State of the Market Report for PJM

Monitoring Analytics, LLC

Independent Market Monitor for PJM

Members' Committee
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Market Monitor

Monitoring Analytics

State of the Market Conclusions - 2008

- Energy Market results were competitive
- Capacity Market results were competitive
- Regulation Market results cannot be determined to have been competitive or to have been noncompetitive
- Synchronized Reserve Markets' results were competitive
- Day Ahead Scheduling Reserve Market results were competitive
- FTR Market results were competitive

State of the Market Recommendations – Continued Action

- Retention and application of the improved local market power mitigation rules
- Retention and application of the improved market power mitigation rules in the regulation market
- Retention of the $1,000 per MWh offer cap in the PJM Energy Market and other rules that limit incentives to exercise market power
- Retention of the rules included in PJM's Reliability Pricing Model (RPM) Tariff

State of the Market Recommendations – Continued Action

- Retention and application of enhancements to PJM's rules governing operating reserve credits
- Modification of rules governing demand-side programs to ensure accurate measurement, verification and payment.
- Provision of data for external control areas to PJM to enable improved analysis of loop flows in order to enhance the efficiency of PJM markets.
- Continued enhancement of mechanisms used to manage prices and flows at interfaces with external areas.

State of the Market Recommendations – New Action

- Enhancements to PJM’s scarcity pricing rules
- Implementation of rules governing the definition of final prices to ensure certainty for market participants
- Implementation of improved cost-based data submission to permit better monitoring and better analysis of markets

Significant changes in 2008

- **FERC ended the exemption from market power mitigation for individual units and for interfaces, effective May 17, 2008.**
- **Three pivotal supplier test for structural market power implemented in Regulation Market, effective December 1, 2008.**
- **New rules for the payment of operating reserves credits, effective December 1, 2008.**
  - **Market power mitigation rules limiting use of inflexible operating parameters**
  - **Modified allocation of operating reserves charges to better reflect causes**

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

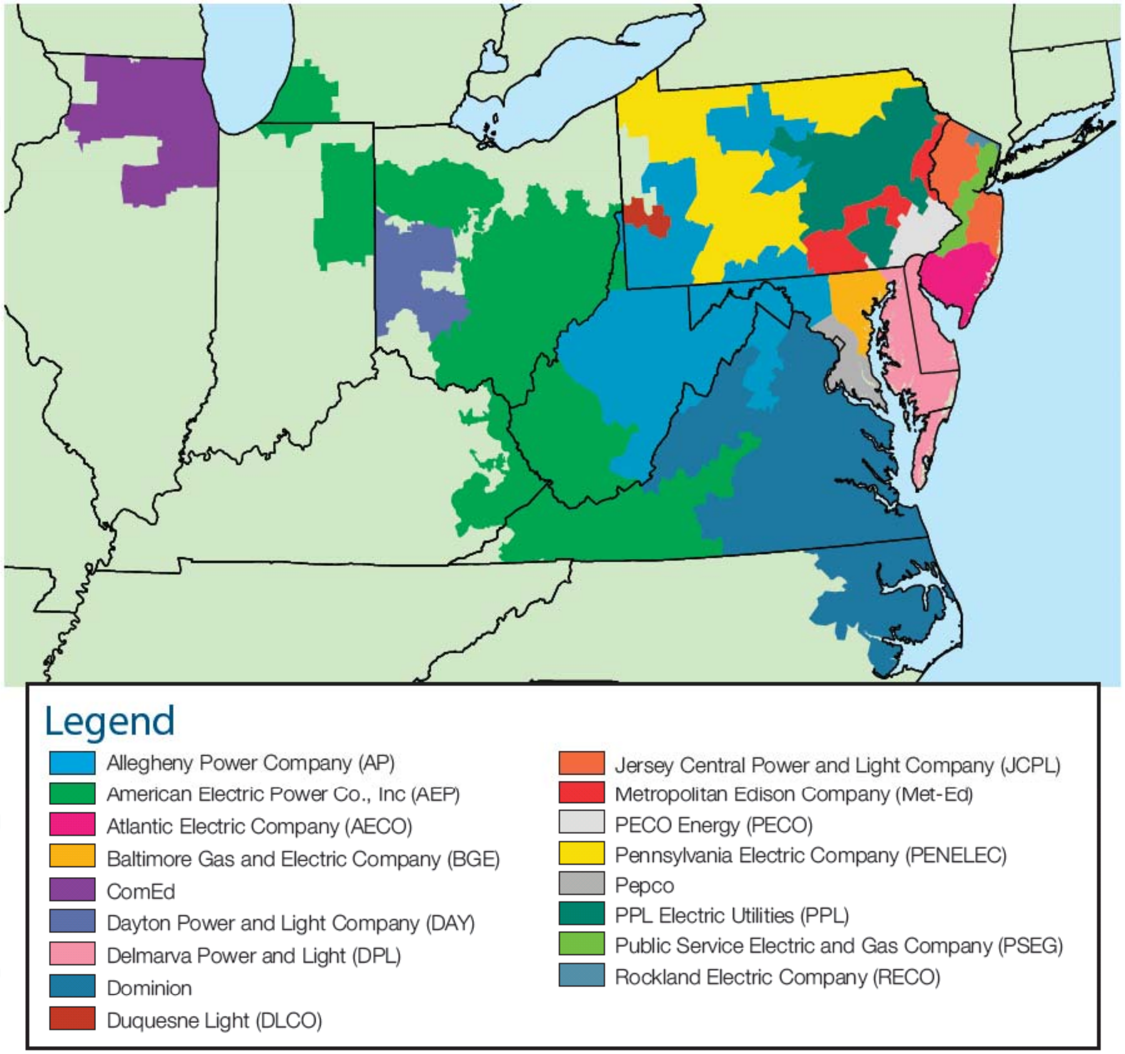

Figure 2-1 Average PJM aggregate supply curves: Summers 2007 and 2008

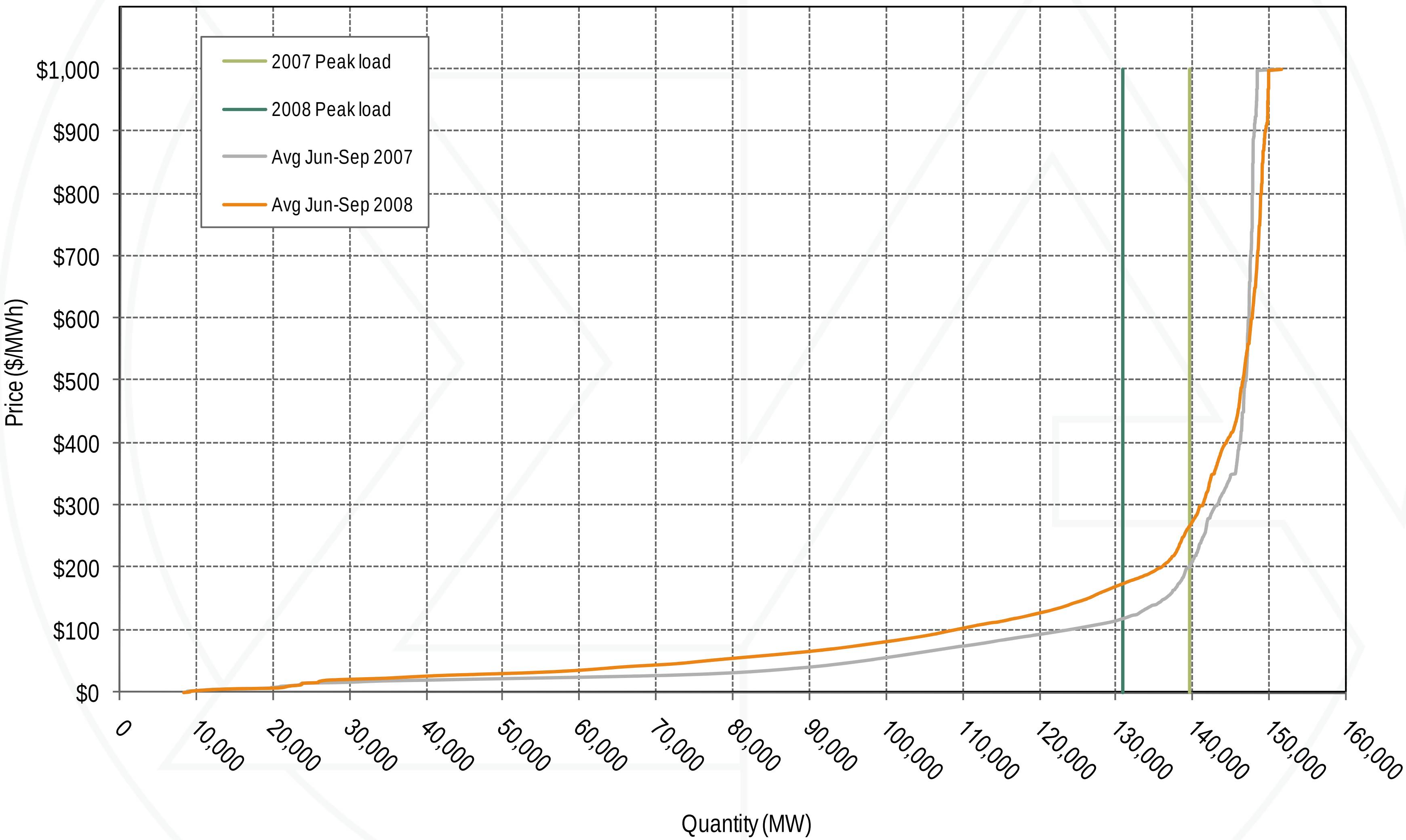

Table 3-30 PJM installed capacity (By fuel source): January 1, May 31, June 1, and December 31, 2008

	1-Jan-08		31-May-08		1-Jun-08		31-Dec-08	
	MW	Percent	MW	Percent	MW	Percent	MW	Percent
Coal	66,378	40.4%	66,334	40.5%	66,155	40.3%	67,065	40.7%
Oil	10,640	6.5%	10,638	6.5%	10,730	6.5%	10,715	6.5%
Gas	47,852	29.1%	47,728	29.1%	48,530	29.6%	48,340	29.3%
Nuclear	30,884	18.8%	30,884	18.9%	30,472	18.6%	30,468	18.5%
Solid waste	712	0.4%	712	0.4%	665	0.4%	665	0.4%
Hydroelectric	7,746	4.7%	7,391	4.5%	7,476	4.6%	7,476	4.5%
Wind	65	0.0%	65	0.0%	151	0.1%	166	0.1%
Total	164,277	100.0%	163,752	100.0%	164,179	100.0%	164,895	100.0%

Table 3-31 PJM generation (By fuel source (GWh)): Calendar year 2008

	GWh	Percent
Coal	404,719.1	55.0%
Gas	53,552.4	7.3%
Hydroelectric	12,341.3	1.7%
Nuclear	254,379.2	34.6%
Oil	1,918.1	0.3%
Solar	0.0	0.0%
Solid Waste	5,020.8	0.7%
Wind	3,313.4	0.5%
Total	735,244.3	100.0%

Table 2-2 Actual PJM footprint summer peak loads: 1999 to 2008

Year	Date	Hour Ending (EPT)	PJM Load (MW)	Difference (MW)
1999	06-Jul-99	1400	59,365	NA
2000	26-Jun-00	1600	56,727	(2,638)
2001	09-Aug-01	1500	54,015	(2,712)
2002	14-Aug-02	1600	63,762	9,747
2003	22-Aug-03	1600	61,500	(2,262)
2004	03-Aug-04	1700	77,887	16,387
2005	26-Jul-05	1600	133,763	55,876
2006	02-Aug-06	1700	144,644	10,881
2007	08-Aug-07	1600	139,428	(5,216)
2008	09-Jun-08	1700	130,100	(9,328)

Figure 2-2 PJM summer peak-load comparison: Monday, June 9, 2008, and Wednesday, August 8, 2007

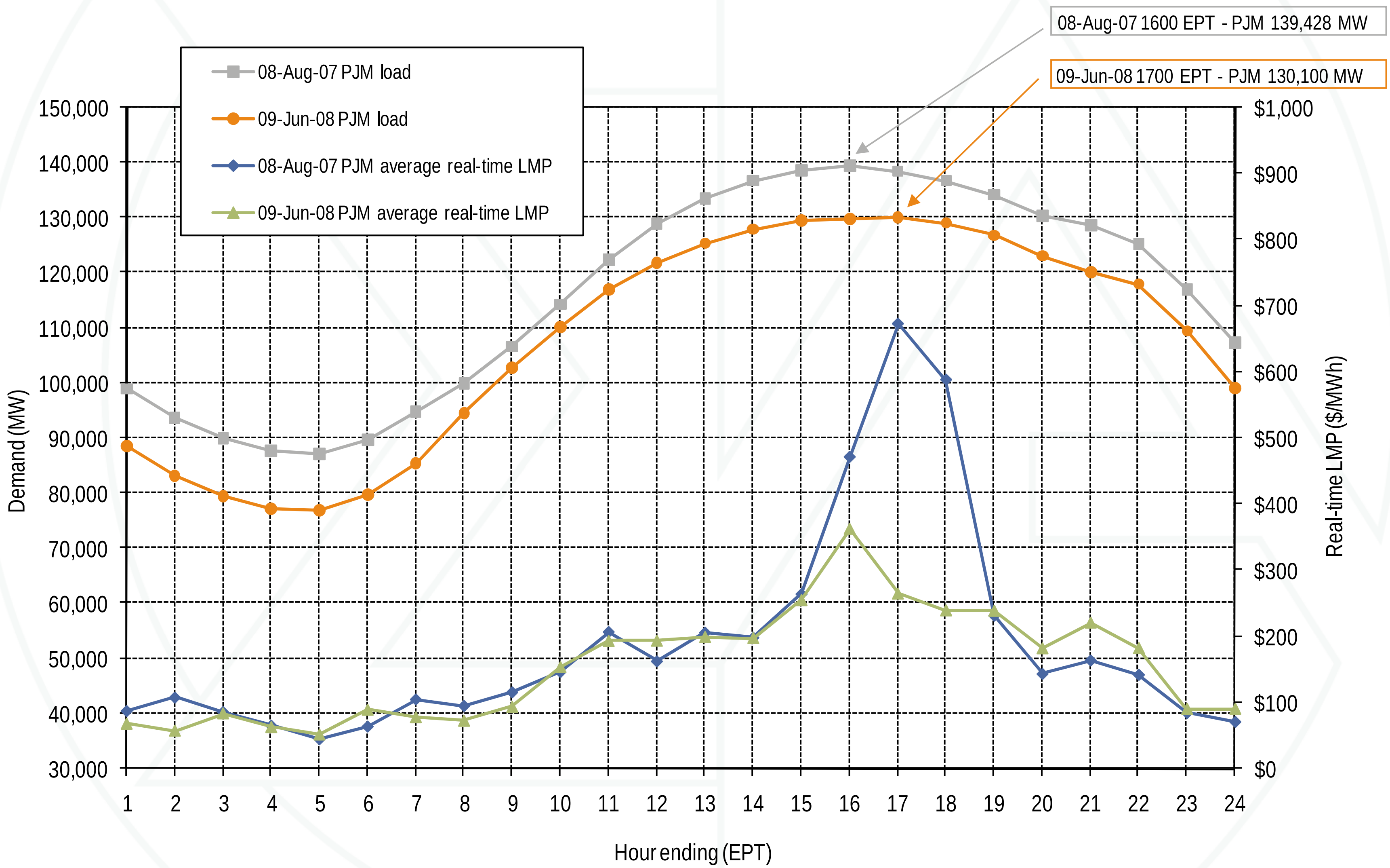

Figure 2-5 PJM real-time average load: Calendar years 2007 to 2008

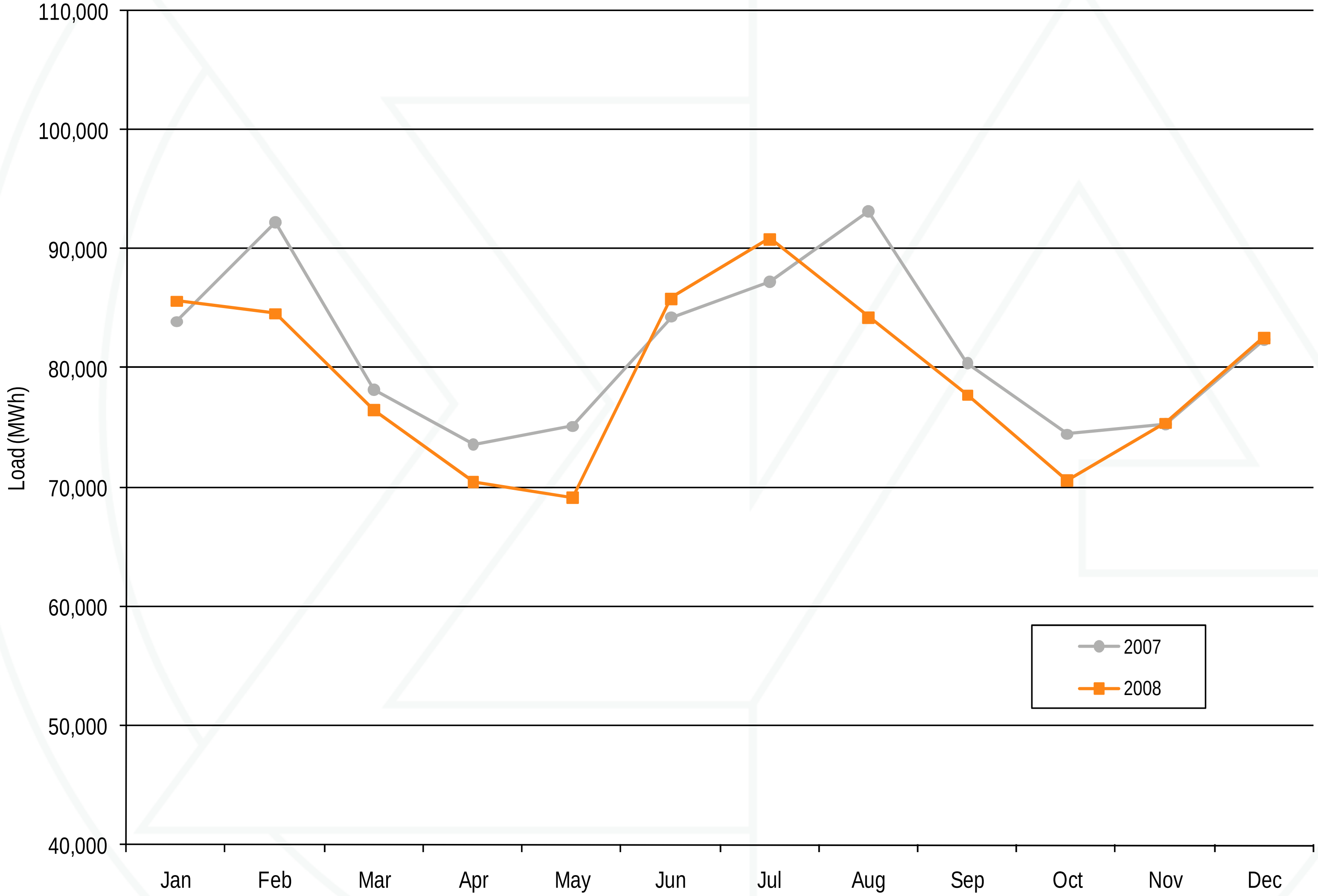

Table 2-53 PJM real-time, annual, load-weighted, average LMP (Dollars per MWh): Calendar years 1998 to 2008

	Real-Time, Load-Weighted, Average LMP			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	$24.16	$17.60	$39.29	NA	NA	NA
1999	$34.07	$19.02	$91.49	41.0%	8.1%	132.9%
2000	$30.72	$20.51	$28.38	(9.8%)	7.8%	(69.0%)
2001	$36.65	$25.08	$57.26	19.3%	22.3%	101.8%
2002	$31.60	$23.40	$26.75	(13.8%)	(6.7%)	(53.3%)
2003	$41.23	$34.96	$25.40	30.5%	49.4%	(5.0%)
2004	$44.34	$40.16	$21.25	7.5%	14.9%	(16.3%)
2005	$63.46	$52.93	$38.10	43.1%	31.8%	79.3%
2006	$53.35	$44.40	$37.81	(15.9%)	(16.1%)	(0.8%)
2007	$61.66	$54.66	$36.94	15.6%	23.1%	(2.3%)
2008	$71.13	$59.54	$40.97	15.4%	8.9%	10.9%

Table 2-54 Zonal real-time, annual, load-weighted, average LMP (Dollars per MWh): Calendar years 2007 to 2008

	2007	2008	Difference	Difference as Percent of 2007
AECO	$71.48	$90.55	$19.07	26.7%
AEP	$49.60	$56.65	$7.05	14.2%
AP	$61.25	$69.88	$8.63	14.1%
BGE	$75.96	$87.11	$11.15	14.7%
ComEd	$49.28	$53.63	$4.35	8.8%
DAY	$50.08	$57.81	$7.73	15.4%
DLCO	$47.26	$52.45	$5.19	11.0%
Dominion	$72.51	$82.88	$10.37	14.3%
DPL	$69.38	$83.88	$14.50	20.9%
JCPL	$71.90	$86.43	$14.53	20.2%
Met-Ed	$69.36	$79.81	$10.45	15.1%
PECO	$67.14	$80.76	$13.62	20.3%
PENELEC	$57.79	$66.47	$8.68	15.0%
Pepco	$76.74	$87.89	$11.15	14.5%
PPL	$66.13	$77.79	$11.66	17.6%
PSEG	$70.90	$85.54	$14.64	20.6%
RECO	$70.94	$85.26	$14.32	20.2%

Figure 2-11 PJM real-time, monthly, load-weighted, average LMP: Calendar years 2004 to 2008

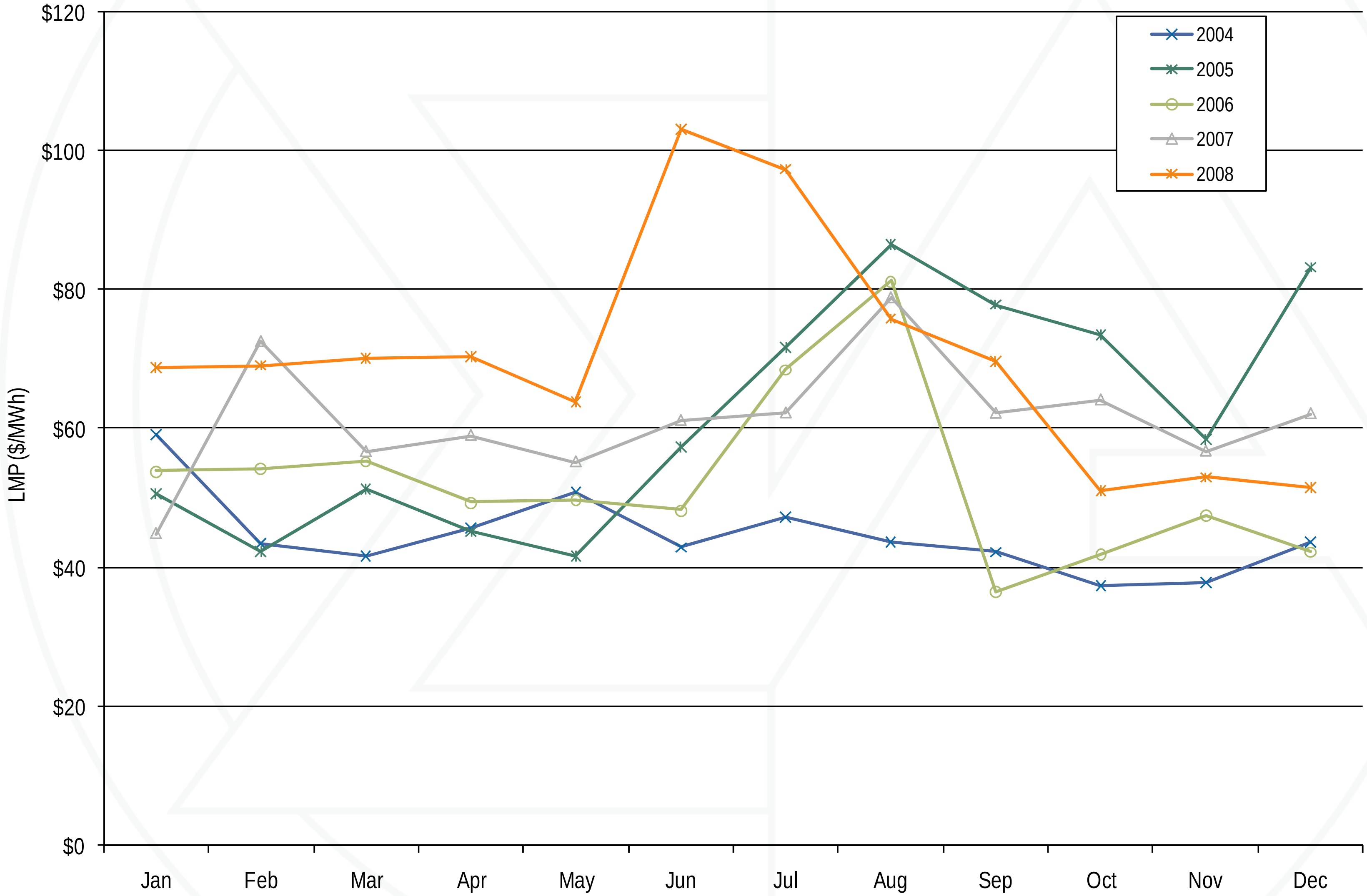

Figure 2-12 Spot average fuel price comparison: Calendar years 2007 to 2008

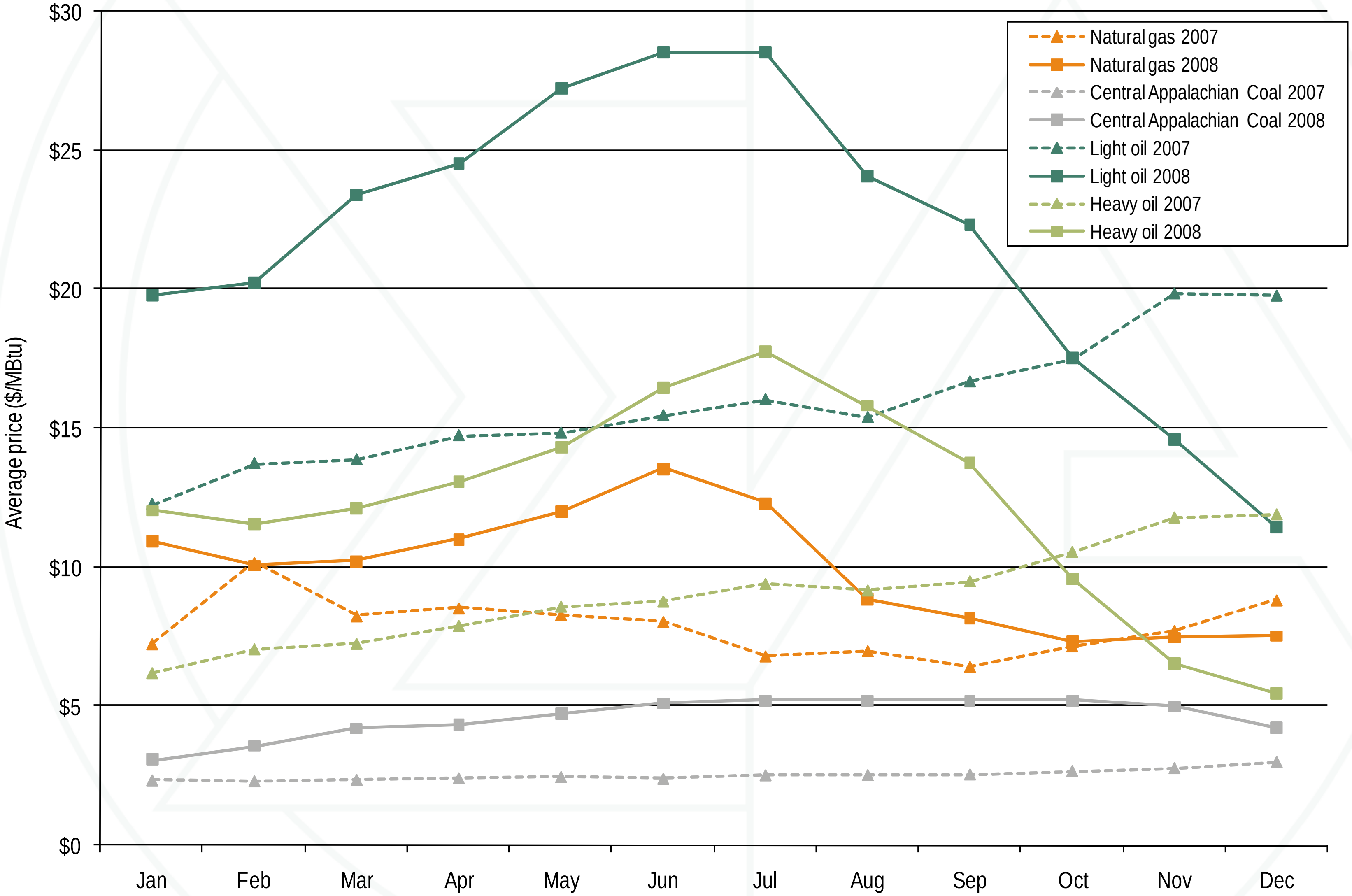

Figure 2-13 Spot average emission price comparison: Calendar years 2007 to 2008

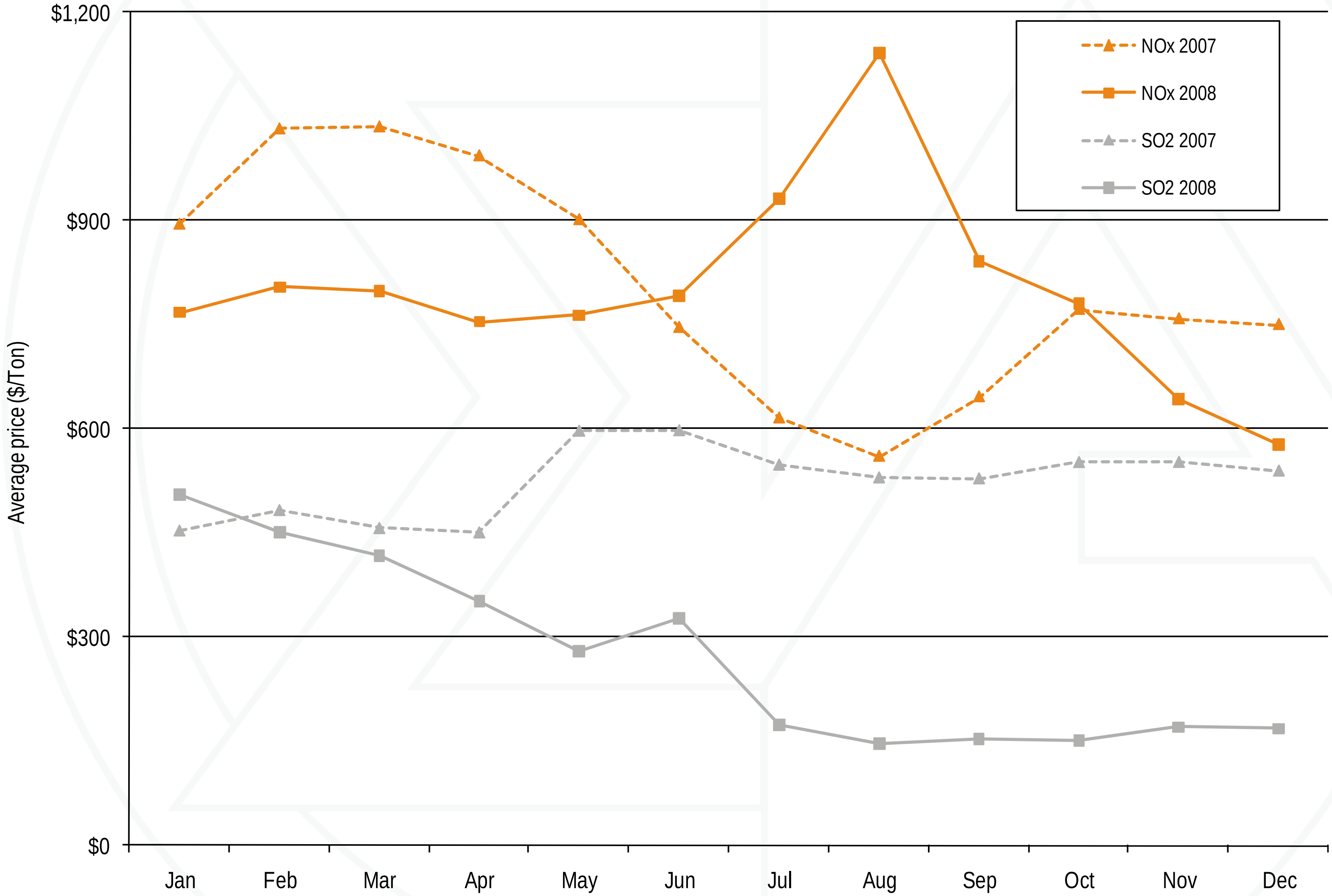

Table 2-56 PJM annual, fuel-cost-adjusted, load-weighted LMP (Dollars per MWh): Year-over-year method

	2007 Load-Weighted LMP	2008 Fuel-Cost-Adjusted, Load-Weighted LMP	Change
Average	$61.66	$51.79	(16.0%)

Table 2-57 Components of PJM annual, load-weighted, average LMP: Calendar year 2008

Element	Contribution to LMP	Percent
Gas	$36.03	50.7%
Coal	$26.44	37.2%
Oil	$2.56	3.6%
Uranium	$0.00	0.0%
FMU Adder	$0.30	0.4%
SO2	$1.80	2.5%
NOX	$0.72	1.0%
VOM	$3.00	4.2%
Markup	$2.04	2.9%
Offline CT Adder	$0.34	0.5%
UDS Override Differential	($1.79)	(2.5%)
Dipatch Differential	$0.03	0.0%
Small DFAX adjustment	($0.20)	(0.3%)
Flow violation adjustment	$0.01	0.0%
Unit LMP Differential	($0.27)	(0.4%)
NA	$0.12	0.2%
LMP	$71.13	100.0%

Table 2-41 Average markup component (By price category): Calendar year 2008

	Average Markup Component	Frequency
Below $20	($4.66)	2.5%
$20 to $39.99	($4.60)	22.0%
$40 to $59.99	($1.11)	31.2%
$60 to $79.99	$2.43	17.7%
$80 to $99.99	$5.09	10.1%
$100 to $119.99	$7.31	7.0%
$120 to $139.99	$10.89	3.9%
$140 to $159.99	$12.64	2.4%
Above $160	$20.73	3.1%

Retroactive change to LMP. Table 2-58 Zonal average LMP: Hours ending 15 through 21 and hour ending 24

	RT LMP Before Change	RT LMP After Change	Difference	Difference as Percent of LMP Before Change
AECO	$268.97	$268.11	($0.87)	(0.3%)
AEP	$64.03	$63.60	($0.43)	(0.7%)
AP	$140.92	$141.85	$0.93	0.7%
BGE	$178.44	$179.17	$0.73	0.4%
ComEd	$51.10	$50.90	($0.21)	(0.4%)
DAY	$60.83	$60.56	($0.27)	(0.5%)
DLCO	$101.39	$101.86	$0.47	0.5%
Dominion	$141.52	$143.95	$2.43	1.7%
DPL	$265.64	$265.49	($0.15)	(0.1%)
JCPL	$203.45	$202.74	($0.72)	(0.4%)
Met-Ed	$169.36	$167.79	($1.57)	(0.9%)
PECO	$404.47	$402.20	($2.28)	(0.6%)
PENELEC	$125.61	$125.91	$0.30	0.2%
Pepco	$170.50	$171.05	$0.54	0.3%
PPL	$156.12	$156.25	$0.13	0.1%
PSEG	$215.53	$214.71	($0.81)	(0.4%)
RECO	$161.07	$160.72	($0.35)	(0.2%)
PJM	$150.21	$150.20	($0.02)	(0.0%)

Retroactive change to LMP. Table 2-60 Bus average LMP: Hours ending 15 through 21 and hour ending 24

	RT LMP Before Change	RT LMP After Change	Difference	Difference as Percent of LMP Before Change
BARNJNDP115 KV TX1	$234.36	$258.74	$24.38	10.4%
BLBRANDP69 KV TX1	$204.82	$223.81	$18.99	9.3%
BONSACK 138 KV T1	$112.46	$88.36	($24.10)	(21.4%)
DRYBURG 115 KV TX1	$265.16	$295.01	$29.85	11.3%
DRYBURG 115 KV TX2	$265.16	$295.01	$29.85	11.3%
MTLAURE413 KV TX1	$265.11	$294.97	$29.86	11.3%
NIAGARA212 KV LOAD	$99.68	$89.82	($9.86)	(9.9%)
ROANOKE 138 KV T2	$98.56	$88.70	($9.87)	(10.0%)
VINTON 138 KV T1	$103.67	$88.84	($14.83)	(14.3%)
VINTON 138 KV T2	$103.67	$88.84	($14.83)	(14.3%)

Table 7-1 Total annual PJM congestion (Dollars (Millions)): Calendar years 2003 to 2008

	Congestion Charges	Percent Change	Total PJM Billing	Percent of PJM Billing
2003	$464	NA	$6,900	7%
2004	$750	62%	$8,700	9%
2005	$2,092	179%	$22,630	9%
2006	$1,603	(23%)	$20,945	8%
2007	$1,846	15%	$30,556	6%
2008	$2,117	15%	$34,306	6%
Total	$8,872		$124,037	7%

Table 7-9 Top 25 constraints affecting annual PJM congestion costs (By facility): Calendar year 2008

				Congestion Costs (Millions)									Percent of Total PJM Congestion Costs
				Day Ahead				Balancing					
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	2008
1	AP South	Interface	500	$196.2	($367.1)	$23.8	$587.1	($11.9)	$5.5	($11.7)	($29.1)	$558.0	26%
2	Cloverdale - Lexington	Line	AEP	$153.8	($77.5)	$9.0	$240.3	($20.6)	($18.6)	($9.1)	($11.0)	$229.3	11%
3	Mount Storm - Pruntytown	Line	AP	$60.1	($157.0)	$15.8	$232.8	($21.6)	($15.8)	($2.9)	($8.7)	$224.1	11%
4	Bedington - Black Oak	Interface	500	$52.2	($106.2)	$7.0	$165.5	($1.3)	($0.6)	($0.2)	($0.9)	$164.6	8%
5	West	Interface	500	$67.8	($42.5)	$8.0	$118.3	($2.0)	$8.2	($2.2)	($12.4)	$105.9	5%
6	Kammer	Transformer	500	$100.9	$23.3	$10.4	$88.0	($17.0)	($3.7)	$1.4	($11.9)	$76.1	4%
7	Sammis - Wylie Ridge	Line	AP	$18.4	($5.9)	$23.1	$47.4	($29.7)	$5.2	($71.9)	($106.9)	($59.5)	(3%)
8	Bedington	Transformer	AP	$21.5	($33.2)	$2.2	$56.9	($1.8)	($1.4)	($1.1)	($1.4)	$55.4	3%
9	5004/5005 Interface	Interface	500	$16.5	($34.9)	$3.0	$54.4	($2.8)	$6.9	($2.0)	($11.7)	$42.7	2%
10	Mount Storm	Transformer	AP	$22.3	($61.3)	$10.0	$93.6	($20.9)	$14.1	($15.9)	($50.9)	$42.7	2%
11	East	Interface	500	$21.7	($17.5)	$1.2	$40.4	($0.1)	($0.0)	$0.0	($0.0)	$40.4	2%
12	Atlantic - Larrabee	Line	JCPL	$41.1	($15.4)	$5.4	$61.9	($9.7)	$8.2	($4.8)	($22.7)	$39.2	2%
13	Meadow Brook	Transformer	AP	$21.8	($17.5)	$0.8	$40.1	($4.4)	($1.2)	($0.4)	($3.6)	$36.5	2%
14	Branchburg - Readington	Line	PSEG	$31.0	($12.2)	$4.8	$48.1	($6.4)	$8.8	($2.0)	($17.2)	$30.9	1%
15	East Frankfort - Crete	Line	ComEd	$7.7	($13.8)	$6.7	$28.2	$0.0	$0.0	$0.0	$0.0	$28.2	1%
16	Aqueduct - Doubs	Line	AP	$23.7	($3.9)	$0.5	$28.0	$0.0	($0.1)	($0.0)	$0.1	$28.1	1%
17	Central	Interface	500	$13.9	($11.1)	$1.6	$26.6	($0.1)	$0.0	$0.1	($0.0)	$26.6	1%
18	Axton	Transformer	AEP	$9.1	($15.4)	$1.6	$26.2	$0.0	$0.0	$0.0	$0.0	$26.2	1%
19	Unclassified	Unclassified	Unclassified	$10.9	($10.6)	$2.0	$23.4	$0.0	$0.0	($0.0)	($0.0)	$23.4	1%
20	Harwood - Susquehanna	Line	PPL	$9.0	($19.9)	$0.5	$29.4	($2.6)	$3.0	($0.7)	($6.3)	$23.2	1%
21	Krendale - Seneca	Line	AP	$18.6	$3.4	$7.4	$22.5	($0.1)	$0.0	($0.1)	($0.3)	$22.3	1%
22	Dickerson - Plesant View	Line	Pepco	$41.5	$24.9	$2.2	$18.8	($0.4)	($1.2)	($1.4)	($0.6)	$18.3	1%
23	Bristers - Ox	Line	Dominion	$8.7	($7.4)	($0.9)	$15.3	$0.5	$0.4	$0.4	$0.5	$15.8	1%
24	North Seaford - Pine Street	Line	DPL	$21.2	$5.4	$0.1	$16.0	($1.0)	($0.6)	($0.1)	($0.6)	$15.4	1%
25	Branchburg - Flagtown	Line	PSEG	$12.2	($4.1)	$0.2	$16.4	$0.5	$1.0	($1.1)	($1.6)	$14.8	1%

Table 2-85 Monthly volume of cleared and submitted INCs, DECs: Calendar year 2008

	Increment Offers				Decrement Bids			
	Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume	Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume
Jan	15,842	22,235	252	490	21,051	29,956	293	592
Feb	15,704	21,725	244	449	20,352	27,978	294	497
Mar	15,131	21,496	242	468	18,477	25,560	298	483
Apr	15,355	22,298	292	566	18,093	25,106	316	543
May	14,344	21,434	431	689	16,777	22,174	407	552
Jun	14,237	22,803	506	811	18,540	25,504	627	849
Jul	16,605	25,666	597	919	21,016	29,980	721	951
Aug	17,315	26,861	628	965	20,553	28,939	618	811
Sep	14,846	22,603	502	761	18,816	25,403	837	1,017
Oct	13,049	20,951	519	758	16,548	22,648	555	734
Nov	13,595	21,451	523	727	16,546	22,907	473	637
Dec	12,817	20,193	464	660	15,950	21,999	535	678
Annual	14,904	22,486	435	690	18,562	25,688	499	697

Figure 2-16 PJM day-ahead aggregate supply curves: 2008 example day

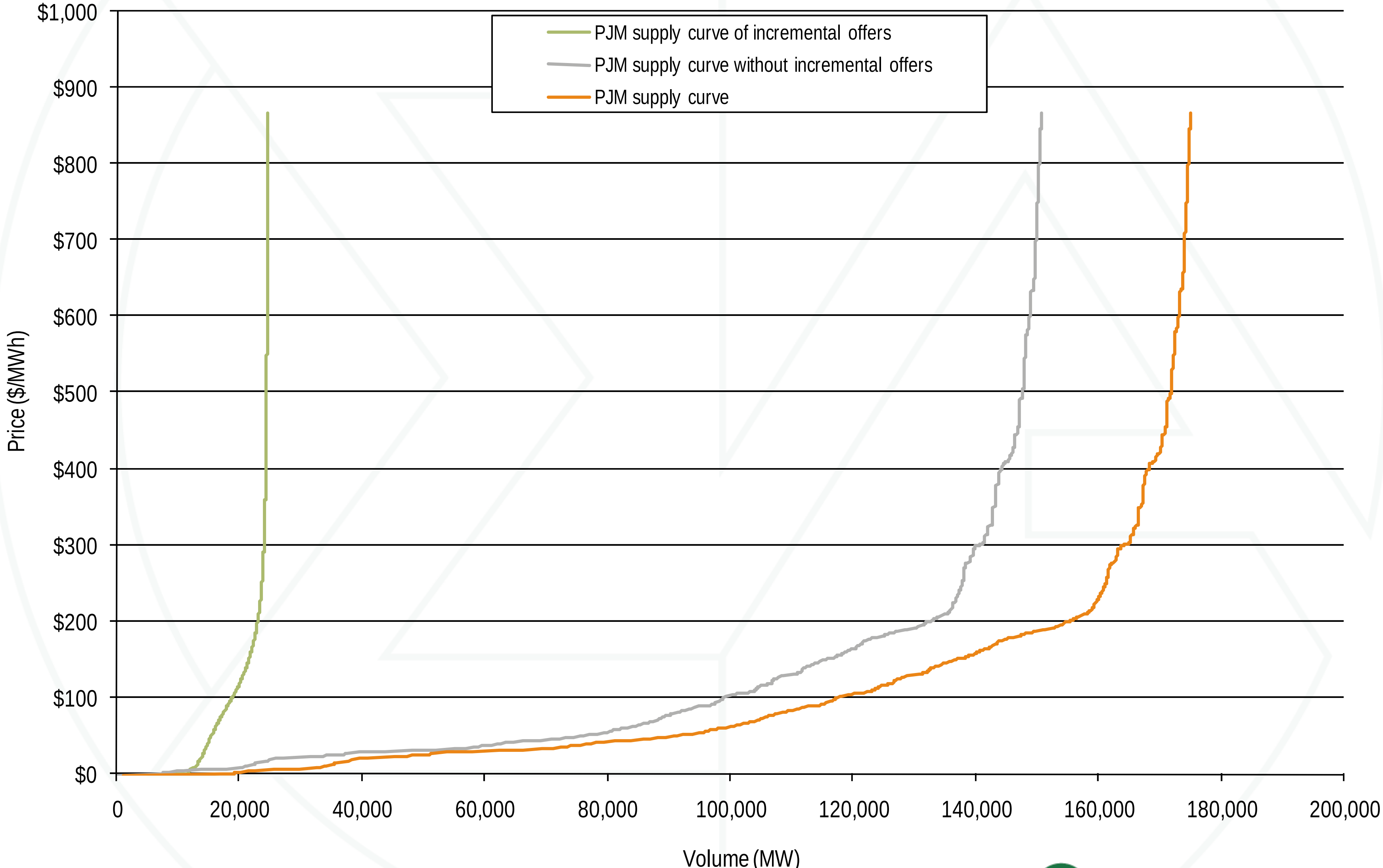

Table 2-79 Day-Ahead and Real-Time Energy Market LMP (Dollars per MWh): Calendar years 2000 to 2008

Year	Day Ahead	Real Time	Difference	Difference as Percent Real Time
2000	$31.97	$30.36	($1.61)	(5.3%)
2001	$32.75	$32.38	($0.37)	(1.1%)
2002	$28.46	$28.30	($0.16)	(0.6%)
2003	$38.73	$38.28	($0.45)	(1.2%)
2004	$41.43	$42.40	$0.97	2.3%
2005	$57.89	$58.08	$0.18	0.3%
2006	$48.10	$49.27	$1.17	2.4%
2007	$54.67	$57.58	$2.90	5.0%
2008	$66.12	$66.40	$0.28	0.4%

Figure 2-18 Monthly average of real-time minus day-ahead LMP: Calendar year 2008

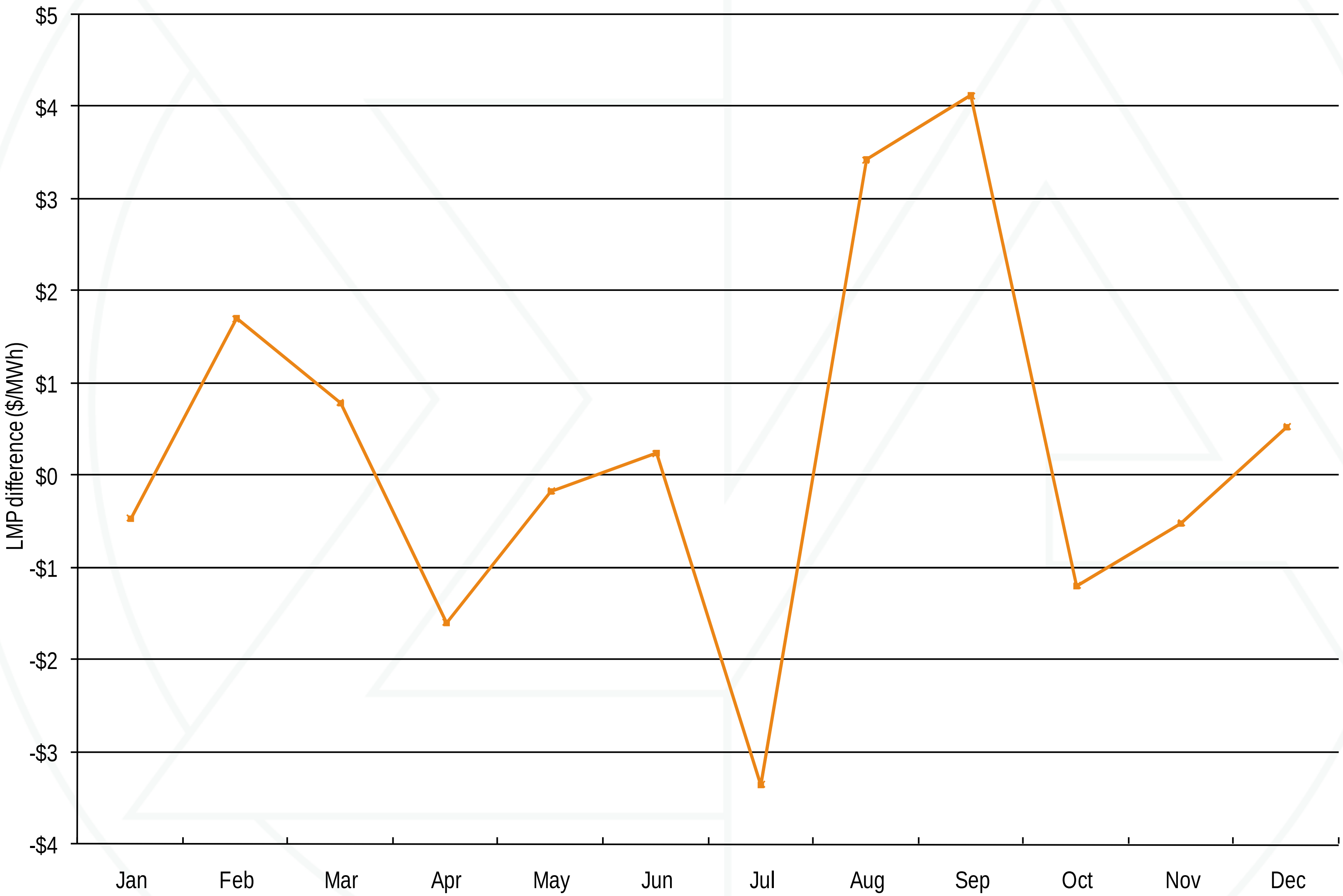

Figure 5-8 Trends in the PJM equivalent demand forced outage rate (EFORd): Calendar years 2004 to 2008

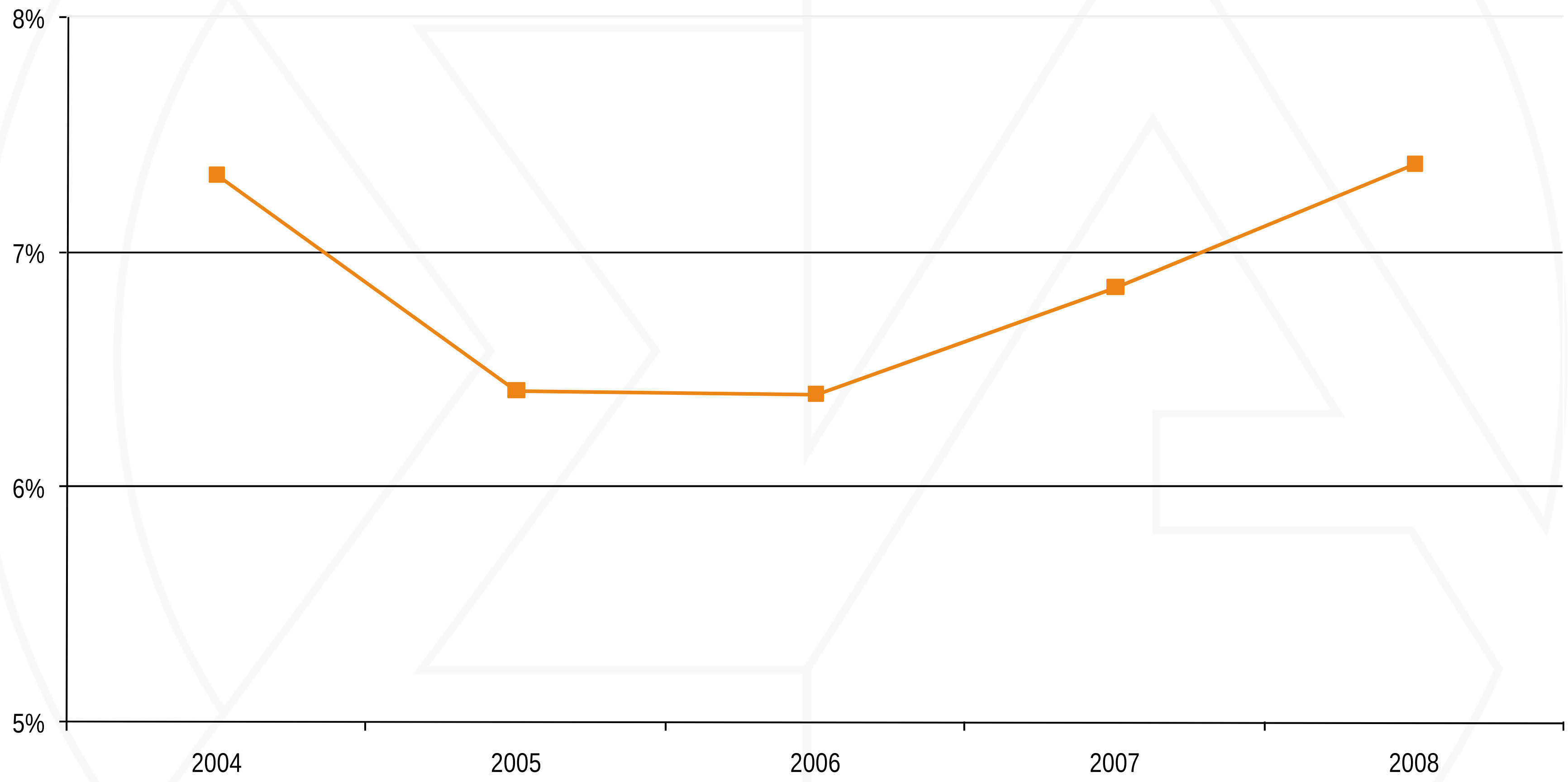

Table 2-3 PJM hourly Energy Market HHI: Calendar year 2008

	Hourly Market HHI
Average	1150
Minimum	847
Maximum	1434
Highest market share (One hour)	29%
Highest market share (All hours)	21%
# Hours	8784
# Hours HHI > 1800	0
% Hours HHI > 1800	0%

Table 2-4 PJM hourly Energy Market HHI (By segment): Calendar year 2008

	Minimum	Average	Maximum
Base	1225	1549	1984
Intermediate	683	2130	6216
Peak	632	5476	10000

Table 5-2 PJM Capacity Market load obligation served: June 1, 2008

	Obligation (MW)							
	PJM EDCs	PJM EDC Generating Affiliates	PJM EDC Marketing Affiliates	Non-PJM EDC Generating Affiliates	Non-PJM EDC Marketing Affiliates	Non-EDC Generating Affiliates	Non-EDC Marketing Affiliates	Total
Obligation	63,390.7	17,884.1	23,910.3	1,211.4	9,668.5	199.5	14,990.2	131,254.6
Percent of total obligation	48.3%	13.6%	18.2%	0.9%	7.4%	0.2%	11.4%	100.0%

Table 2-5 Annual offer-capping statistics: Calendar years 2004 to 2008

	Real Time		Day Ahead	
	Unit Hours Capped	MW Capped	Unit Hours Capped	MW Capped
2004	1.3%	0.4%	0.6%	0.2%
2005	1.8%	0.4%	0.2%	0.1%
2006	1.0%	0.2%	0.4%	0.1%
2007	1.1%	0.2%	0.2%	0.0%
2008	1.0%	0.2%	0.2%	0.1%

Table 2-6 Offer-capped unit statistics: Calendar year 2008

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

Table 2-42 Frequently mitigated units and associated units (By month): Calendar year 2008

	FMUs and AUs			Total Eligible
	Tier 1	Tier 2	Tier 3	for Any Adder
January	19	15	69	103
February	30	12	81	123
March	27	21	75	123
April	26	26	72	124
May	23	25	76	124
June	27	26	75	128
July	27	28	73	128
August	28	37	63	129
September	18	45	53	116
October	31	35	61	127
November	36	30	64	130
December	28	51	61	140

Table 2-7 Three pivotal supplier results summary for three regional constraints: Calendar year 2008

Constraint	Period	Total Tests Applied	Tests with One or More Passing Owners	Percent Tests with One or More Passing Owners	Tests with One or More Failing Owners	Percent Tests with One or More Failing Owners
5004/5005 Interface	Peak	723	652	90%	149	21%
	Off Peak	535	467	87%	130	24%
Bedington - Black Oak	Peak	666	491	74%	296	44%
	Off Peak	425	301	71%	193	45%
Kammer	Peak	2,328	1,450	62%	1,111	48%
	Off Peak	4,740	3,302	70%	2,130	45%

Table 2-17 Three pivotal supplier results summary for constraints located in the PSEG Control Zone: Calendar year 2008

Constraint	Period	Total Tests Applied	Tests with One or More Passing Owners	Percent Tests with One or More Passing Owners	Tests with One or More Failing Owners	Percent Tests with One or More Failing Owners
Athenia - Saddlebrook	Peak	79	5	6%	77	97%
	Off Peak	427	2	0%	426	100%
Branchburg - Readington	Peak	653	56	9%	646	99%
	Off Peak	195	3	2%	193	99%
Brunswick - Edison	Peak	536	0	0%	536	100%
	Off Peak	211	0	0%	211	100%
Cedar Grove - Clifton	Peak	772	106	14%	746	97%
	Off Peak	529	107	20%	484	91%
Cedar Grove - Roseland	Peak	117	37	32%	94	80%
	Off Peak	415	80	19%	381	92%

Table 2-83 Monthly average percentage of real-time self-supply load, bilateral-supply load and spot-supply load based on parent companies: Calendar years 2007 to 2008

	2007			2008			Difference in Percentage Points		
	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply
Jan	16.5%	14.4%	69.1%	14.3%	17.3%	68.4%	(2.2%)	2.9%	(0.7%)
Feb	16.5%	14.2%	69.3%	15.2%	17.3%	67.5%	(1.3%)	3.1%	(1.8%)
Mar	17.2%	14.6%	68.2%	16.0%	17.1%	66.9%	(1.2%)	2.5%	(1.3%)
Apr	17.4%	14.9%	67.7%	16.6%	18.0%	65.4%	(0.8%)	3.1%	(2.3%)
May	18.2%	14.1%	67.7%	16.0%	18.8%	65.3%	(2.2%)	4.7%	(2.4%)
Jun	16.9%	15.3%	67.8%	13.1%	21.0%	65.9%	(3.8%)	5.7%	(1.9%)
Jul	15.8%	17.2%	66.9%	13.7%	20.6%	65.7%	(2.1%)	3.4%	(1.2%)
Aug	15.5%	16.7%	67.8%	14.9%	22.6%	62.4%	(0.6%)	5.9%	(5.4%)
Sep	15.6%	17.1%	67.3%	14.7%	23.0%	62.2%	(0.9%)	5.9%	(5.1%)
Oct	17.3%	18.2%	64.5%	15.1%	22.7%	62.2%	(2.2%)	4.5%	(2.3%)
Nov	17.1%	17.0%	65.9%	14.8%	22.9%	62.3%	(2.3%)	5.9%	(3.6%)
Dec	15.7%	16.8%	67.5%	12.1%	20.5%	67.4%	(3.6%)	3.7%	(0.1%)
Annual	16.6%	15.9%	67.5%	14.6%	20.1%	65.2%	(2.0%)	4.2%	(2.3%)

Table 2-84 Monthly average percentage of day-ahead self-supply load, bilateral supply load, and spot-supply load based on parent companies: Calendar Years 2007 to 2008

	2007			2008			Difference in Percentage Points		
	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply
Jan	3.9%	12.9%	83.2%	4.2%	15.6%	80.2%	0.3%	2.7%	(3.0%)
Feb	4.1%	13.1%	82.8%	4.5%	16.0%	79.5%	0.4%	2.9%	(3.3%)
Mar	4.2%	13.3%	82.5%	4.7%	16.0%	79.3%	0.5%	2.7%	(3.2%)
Apr	4.5%	12.8%	82.7%	5.0%	16.8%	78.2%	0.5%	4.0%	(4.5%)
May	5.1%	12.5%	82.4%	5.0%	18.2%	76.8%	(0.1%)	5.7%	(5.6%)
Jun	4.5%	14.9%	80.6%	5.5%	20.2%	74.3%	1.0%	5.3%	(6.3%)
Jul	4.2%	15.9%	79.9%	5.6%	20.4%	74.0%	1.4%	4.5%	(5.9%)
Aug	4.1%	15.4%	80.5%	4.9%	20.2%	75.0%	0.8%	4.8%	(5.5%)
Sep	4.8%	15.5%	79.7%	5.4%	19.3%	75.3%	0.6%	3.8%	(4.4%)
Oct	4.9%	16.5%	78.6%	5.4%	20.3%	74.3%	0.5%	3.8%	(4.3%)
Nov	5.2%	15.6%	79.3%	5.6%	18.9%	75.5%	0.4%	3.3%	(3.8%)
Dec	5.2%	15.4%	79.3%	4.6%	19.1%	76.3%	(0.6%)	3.7%	(3.0%)
Annual	4.5%	14.5%	81.0%	5.0%	18.4%	76.5%	0.5%	3.9%	(4.5%)

Figure 2-20 Economic Program Payments: Calendar years 2007 (without incentive payments) and 2008

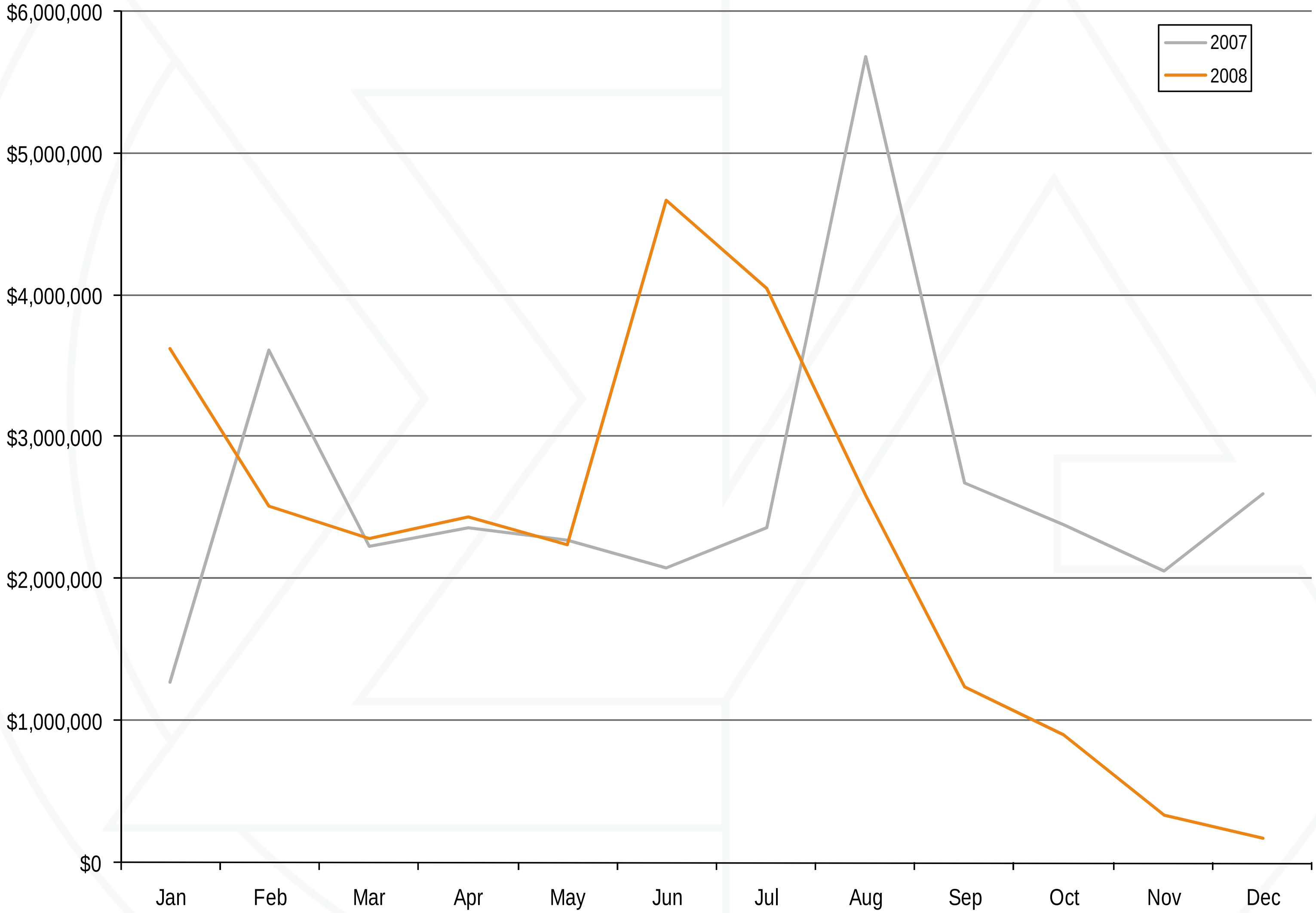

Table 2-95 Available ALM MW and LM MW: Within 2002 to 2008

	2002	2003	2004	2005	2006	2007	2008
1-Jun	1,342	1,265	1,412	2,035	1,655	2,140	4,414
1-Jul	1,304	1,255	1,228	2,042	1,679	2,145	4,498
1-Aug	1,285	1,156	1,226	2,042	1,679	2,145	4,498
1-Sep	1,275	1,158	1,224	2,038	1,678	2,145	4,498

Table 3-44 Total day-ahead and balancing operating reserve charges: Calendar years 1999 to 2008

	Total Operating Reserve Credits	Annual Credit Change	Operating Reserve as a Percent of Total PJM Billing	Day-Ahead $/MWh	Day-Ahead Change	Balancing $/MWh	Balancing Change
1999	$133,897,428	NA	7.5.%	NA	NA	NA	NA
2000	$216,985,147	62.1%	9.6%	0.3412	NA	0.5346	NA
2001	$290,867,269	34.0%	8.7%	0.2746	(19.5%)	1.0700	100.2%
2002	$237,102,574	(18.5%)	5.0%	0.1635	(40.4%)	0.7873	(26.4%)
2003	$289,510,257	22.1%	4.2%	0.2261	38.2%	1.1971	52.0%
2004	$414,891,790	43.3%	4.8%	0.2300	1.7%	1.2362	3.3%
2005	$682,781,889	64.6%	3.0%	0.0762	(66.9%)	2.7580	123.1%
2006	$322,315,152	(52.8%)	1.5%	0.0781	2.6%	1.3315	(51.7%)
2007	$459,124,502	42.4%	1.5%	0.0570	(27.0%)	2.3310	75.1%
2008	$429,253,836	(6.5%)	1.3%	0.0844	48.0%	2.1132	(9.3%)

Figure 3-10 Monthly average balancing operating reserve rate: Calendar years 2004 to 2008

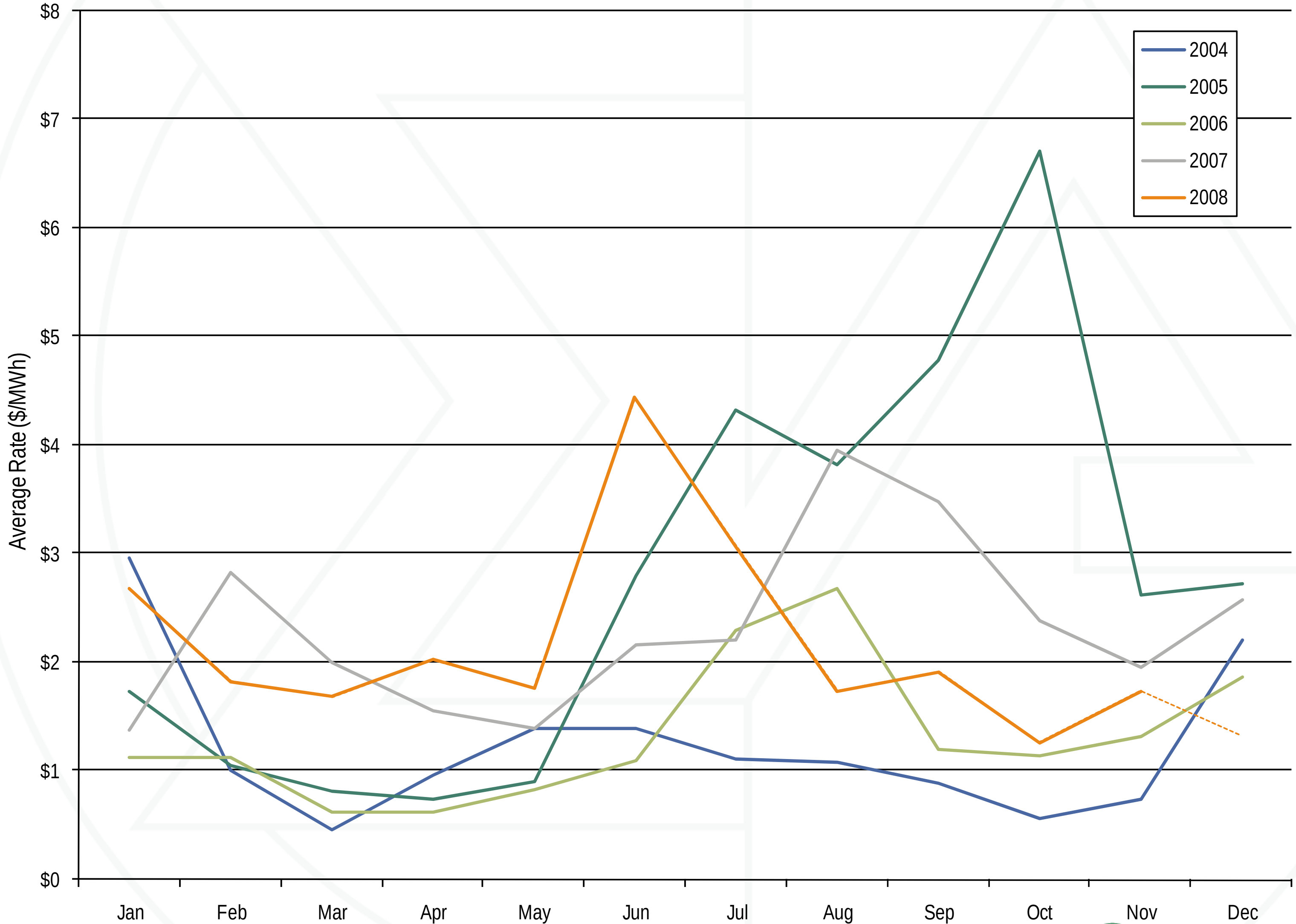

Table 3-47 Credits, deviations, rates, and charges by cost allocation category: Calendar month December 2008

	RTO Reliability	East Reliability	West Reliability	RTO Deviations	East Deviations	West Deviations
Credits ($)	$1,185,277	$24,194	$766,090	$15,989,374	$641,366	$29,114
RT Load and Exports (MWh)	63,904,484	34,102,518	29,801,966	(n/a)	(n/a)	(n/a)
Deviations (MWh)	(n/a)	(n/a)	(n/a)	15,757,287	8,922,102	6,736,430
Rates ($/MWh)	0.0179	0.0007	0.0290	0.9565	0.0681	0.0048
Charges ($)	$1,185,277	$24,194	$766,090	$15,989,374	$641,366	$29,114

Table 3-57 Top 10 units and organizations receiving total operating reserve credits: Calendar year 2008

	Units			Organizations		
Rank	Total Credit	Total Credit Share	Total Credit Cumulative Distribution	Total Credit	Total Credit Share	Total Credit Cumulative Distribution
1	$30,261,347	7.1%	7.1%	$106,695,434	24.9%	24.9%
2	$12,901,176	3.0%	10.1%	$43,552,146	10.2%	35.1%
3	$6,151,524	1.4%	11.5%	$36,049,644	8.4%	43.5%
4	$5,205,118	1.2%	12.7%	$34,340,514	8.0%	51.5%
5	$4,860,844	1.1%	13.9%	$23,358,959	5.5%	56.9%
6	$4,658,680	1.1%	14.9%	$21,919,710	5.1%	62.1%
7	$4,291,570	1.0%	16.0%	$17,022,398	4.0%	66.0%
8	$4,270,922	1.0%	16.9%	$16,040,512	3.7%	69.8%
9	$4,149,643	1.0%	17.9%	$15,767,381	3.7%	73.5%
10	$3,706,280	0.9%	18.8%	$15,309,222	3.6%	77.0%

Figure 3-12 Cumulative distribution of units receiving credits (By operating reserve category): Calendar year 2008

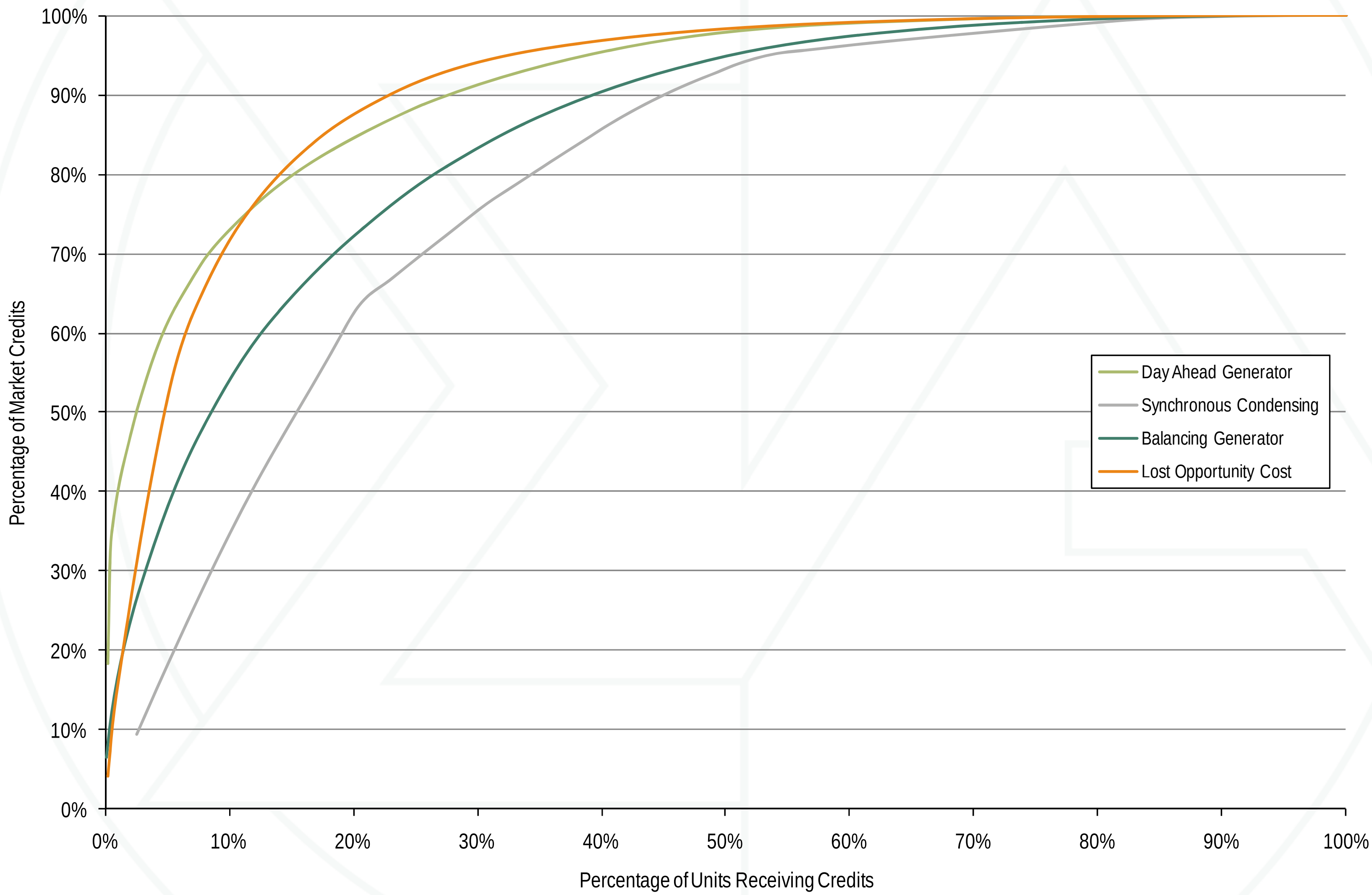

Table 5-5 PJM capacity summary (MW): June 1, 2007, through June 1, 2011

	01-Jun-07	01-Jun-08	01-Jun-09	01-Jun-10	01-Jun-11
Installed capacity (ICAP)	163,721.1	164,444.1	166,916.0	168,061.5	172,666.6
Unforced capacity	154,076.7	155,590.2	157,628.7	158,634.2	163,144.3
Cleared capacity	129,409.2	129,597.6	132,231.8	132,190.4	132,221.5
RPM reliability requirement (pre-FRR)	148,277.3	150,934.6	153,480.1	156,636.8	154,251.1
RPM reliability requirement (less FRR)	125,805.0	128,194.6	130,447.8	132,698.8	130,658.7
RPM net excess	5,240.5	5,011.1	3,403.3	1,149.2	3,156.6
Imports	2,809.2	2,460.3	2,505.4	2,750.7	6,420.0
Exports	(3,938.5)	(3,838.1)	(2,194.9)	(3,147.4)	(3,158.4)
Net exchange	(1,129.3)	(1,377.8)	310.5	(396.7)	3,261.6
DR cleared	127.6	536.2	892.9	939.0	1,364.9
ILR	1,636.3	3,608.1	2,107.5	2,110.5	1,593.8
FRR DR	445.6	452.8	488.2	452.9	452.9

Figure 5-1 History of capacity prices: Calendar year 1999 through 2011

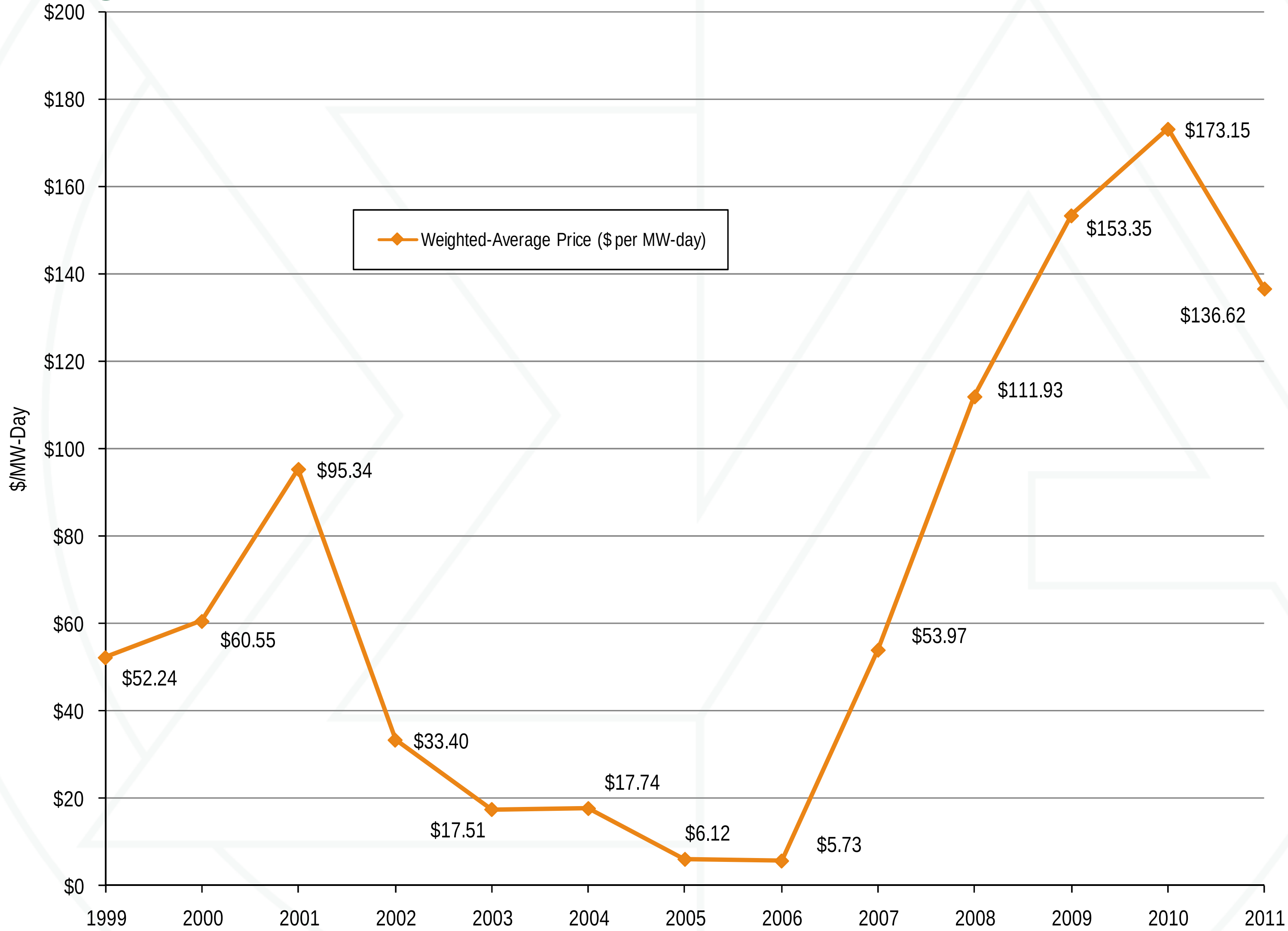

Table 5-10 Capacity prices: 2007/2008 through 2011/2012 RPM Auctions

	RPM Clearing Price ($ per MW-day)				
	RTO	EMAAC	SWMAAC	MAAC+APS	DPL-South
2007/2008 BRA	$40.80	$197.67	$188.54		
2008/2009 BRA	$111.92	$148.80	$210.11		
2008/2009 Third IA	$10.00		$223.85		
2009/2010 BRA	$102.04		$237.33	$191.32	
2010/2011 BRA	$174.29				$178.27
2011/2012 BRA	$110.00				

Table 5-11 RPM cost to load: 2008/2009 through 2011/2012 RPM Auctions

	Net Load Price ($/MW-Day)	UCAP Obligation (MW)	Annual Charges
2008/2009 BRA			
RTO	$113.22	79,814.6	$3,298,362,289
EMAAC	$145.24	35,755.4	$1,895,486,718
SWMAAC	$183.03	15,684.6	$1,047,824,603
2009/2010 BRA			
RTO	$102.04	57,520.9	$2,142,342,912
MAAC+APS	$188.55	60,399.9	$4,156,766,418
SWMAAC	$218.12	15,966.1	$1,271,121,892
2010/2011 BRA			
RTO	$174.29	129,253.2	$8,222,552,183
DPL	$178.27	4,595.0	$298,989,987
2011/2012 BRA			
RTO	$110.04	133,815.3	$5,389,363,034

Table 3-3 2008 PJM RPM auction-clearing capacity price and capacity revenue by LDA and zone: Effective for January 1, through December 31, 2008

		Delivery Year 2007/2008		Delivery Year 2008/2009		
Zone	LDA	$/MW-Day	$/MW in 2007	$/MW-Day	$/MW in 2008	2008 Total
AECO	EMAAC	$197.67	$30,046	$148.80	$31,843	$61,889
AEP	RTO	$40.80	$6,202	$111.92	$23,951	$30,152
AP	RTO	$40.80	$6,202	$111.92	$23,951	$30,152
BGE	SWMAAC	$188.54	$28,658	$210.11	$44,964	$73,622
ComEd	RTO	$40.80	$6,202	$111.92	$23,951	$30,152
DAY	RTO	$40.80	$6,202	$111.92	$23,951	$30,152
Dominion	RTO	$40.80	$6,202	$111.92	$23,951	$30,152
DLCO	RTO	$40.80	$6,202	$111.92	$23,951	$30,152
DPL	EMAAC	$197.67	$30,046	$148.80	$31,843	$61,889
JCPL	EMAAC	$197.67	$30,046	$148.80	$31,843	$61,889
Met-Ed	RTO	$40.80	$6,202	$111.92	$23,951	$30,152
PECO	EMAAC	$197.67	$30,046	$148.80	$31,843	$61,889
PENELEC	RTO	$40.80	$6,202	$111.92	$23,951	$30,152
Pepco	SWMAAC	$188.54	$28,658	$210.11	$44,964	$73,622
PPL	RTO	$40.80	$6,202	$111.92	$23,951	$30,152
PSEG	EMAAC	$197.67	$30,046	$148.80	$31,843	$61,889
RECO	EMAAC	$197.67	$30,046	$148.80	$31,843	$61,889
PJM	N/A	$88.09	$13,390	$124.58	$26,660	$40,050

Figure 3-4 New entrant CT real-time net revenue and 20-year levelized fixed cost as of 2008 by LDA (Dollars per installed MW-year): Calendar years 1999 to 2008

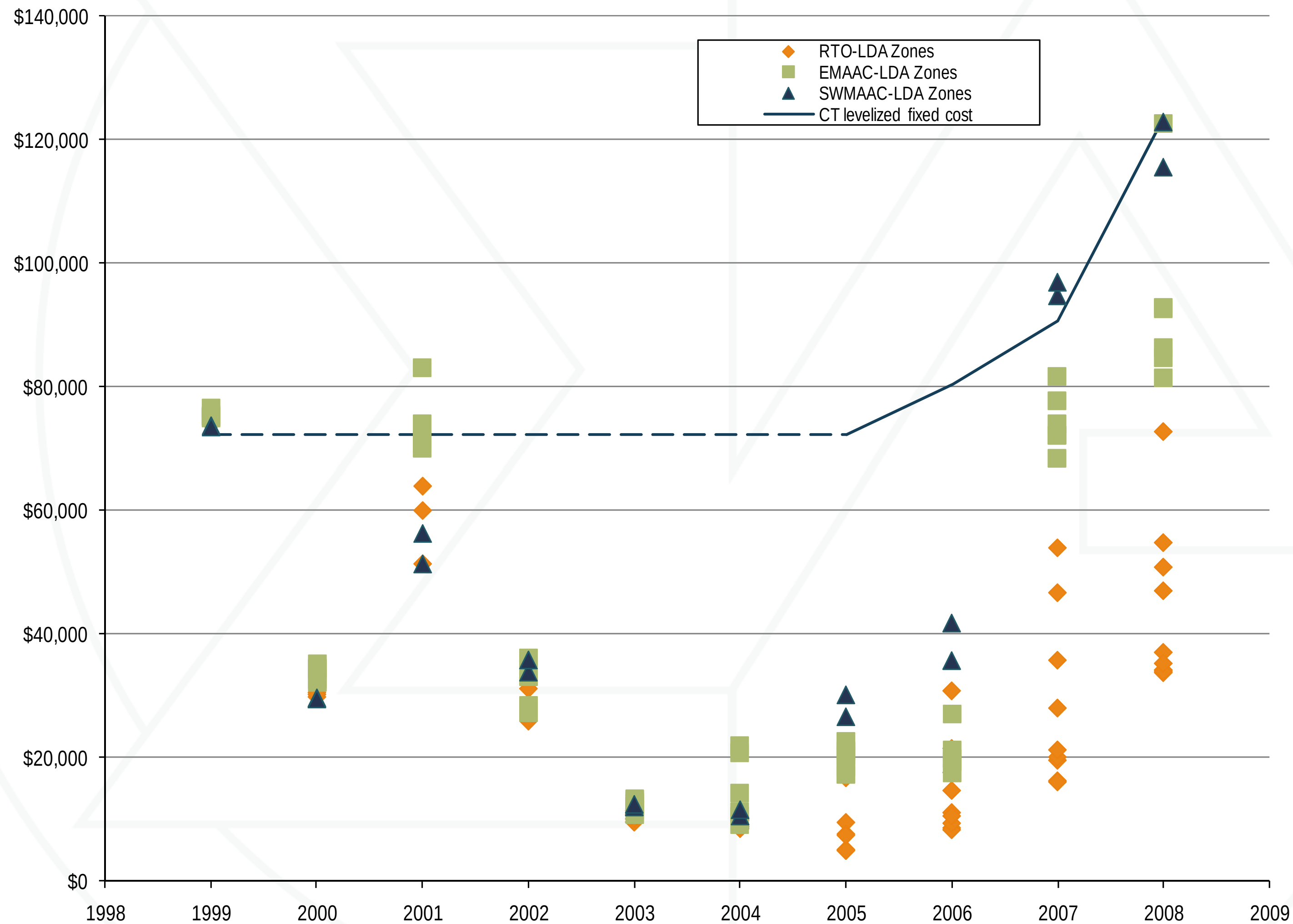

Figure 3-6 New entrant CC real-time net revenue and 20-year levelized fixed cost as of 2008 by LDA (Dollars per installed MW-year): Calendar years 1999 to 2008

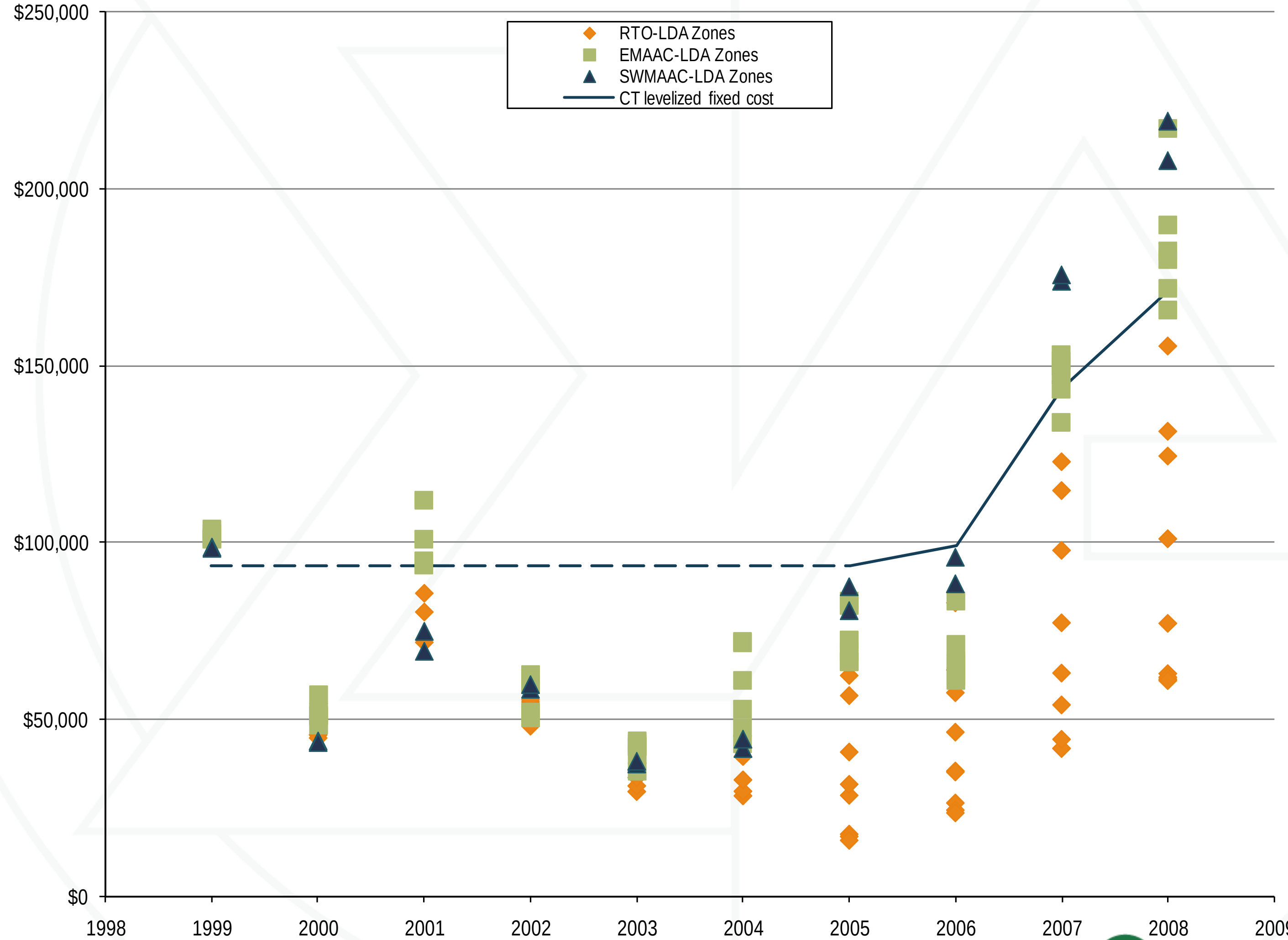

Figure 3-8 New entrant CP real-time net revenue and 20-year levelized fixed cost as of 2008 by LDA (Dollars per installed MW-year): Calendar years 1999 to 2008

Table 3-22 New entrant 20-year levelized fixed costs (By plant type (Dollars per installed MW-year))

	2005 20-Year Levelized Fixed Cost	2006 20-Year Levelized Fixed Cost	2007 20-Year Levelized Fixed Cost	2008 20-Year Levelized Fixed Cost
CT	$72,207	$80,315	$90,656	$123,640
CC	$93,549	$99,230	$143,600	$171,361
CP	$208,247	$267,792	$359,750	$492,780

Figure 4-3 PJM scheduled import and export transaction volume history: Calendar years 1999 to 2008

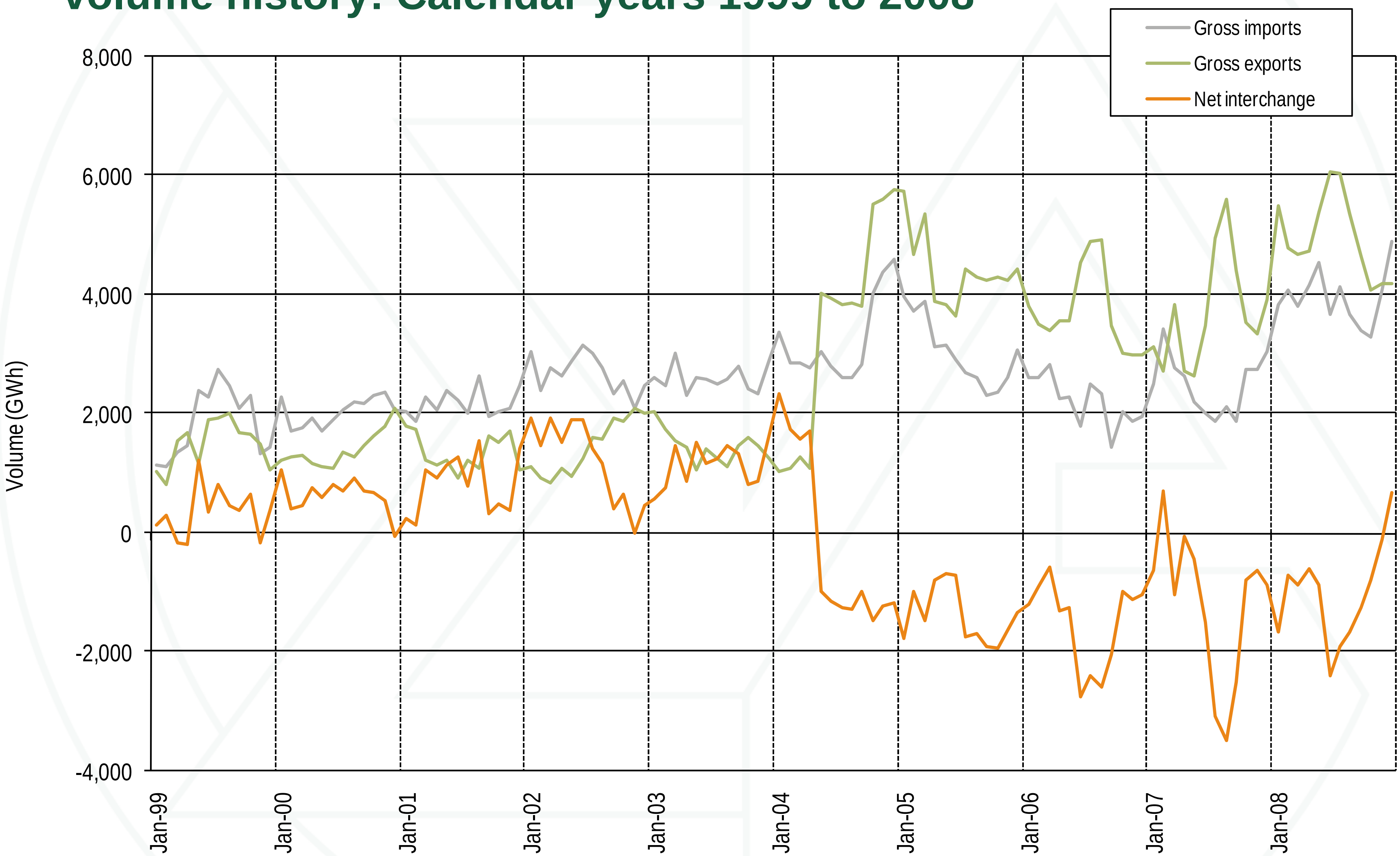

Table 4-12 Net scheduled and actual PJM interface flows (GWh): Calendar year 2008

	Actual	Net Scheduled	Difference	Difference (percent of net scheduled)
ALTE	(6,441)	(1,486)	(4,955)	333%
ALTW	(2,992)	(1,339)	(1,653)	123%
AMIL	5,060	(249)	5,309	(2132%)
CIN	2,301	3,950	(1,649)	(42%)
CPLE	6,804	(949)	7,753	(817%)
CPLW	(2,064)	(809)	(1,254)	155%
CWLP	(744)	(13)	(731)	5611%
DUK	(4,130)	(8)	(4,122)	50283%
EKPC	(586)	(1,447)	861	(59%)
FE	6,761	(2,450)	9,211	(376%)
IPL	2,736	(788)	3,524	(447%)
LGEE	1,325	1,680	(355)	(21%)
MEC	(3,699)	(1,742)	(1,957)	112%
MECS	(11,001)	3,013	(14,014)	(465%)
NEPT	(5,027)	(5,027)	-	0%
NIPS	(2,415)	(734)	(1,681)	229%
NYIS	(5,663)	(7,123)	1,460	(20%)
OVEC	7,591	9,553	(1,962)	(21%)
TVA	941	(3,124)	4,065	(130%)
WEC	1,385	(939)	2,324	(248%)
Total	(9,859)	(10,032)	174	(1.7%)

Table 6-5 Regulation market monthly three pivotal supplier results: Calendar year 2008

Month	Hours With Three Pivotal Suppliers
Jan	84%
Feb	83%
Mar	89%
Apr	88%
May	97%
Jun	77%
Jul	75%
Aug	80%
Sep	74%
Oct	89%
Nov	59%
Dec	92%

Figure 6-4 Monthly load-weighted, average regulation cost and price: Calendar year 2008

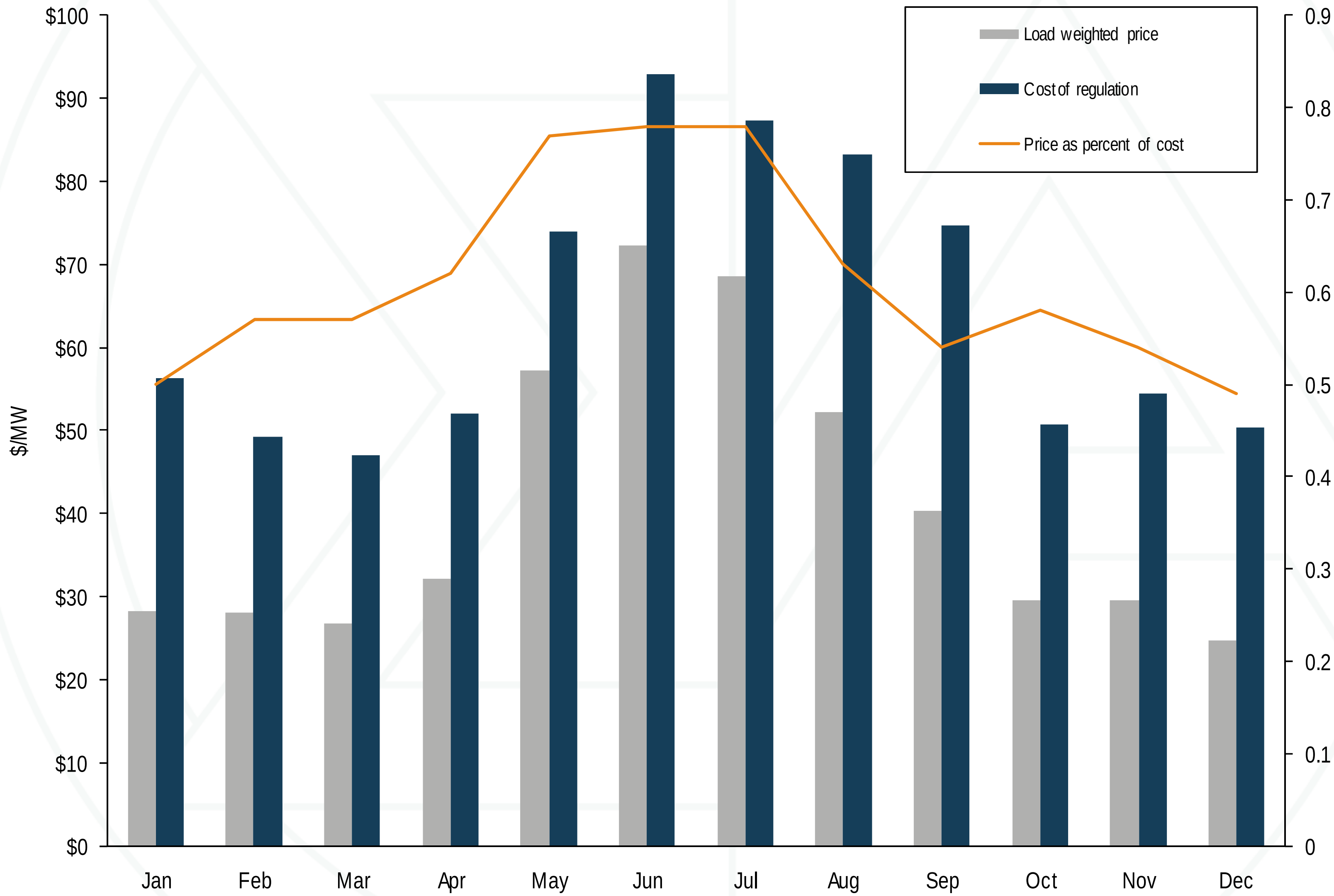

Figure 6-14 Comparison of RFC Tier 2 synchronized reserve price and cost (Dollars per MW): Calendar year 2008

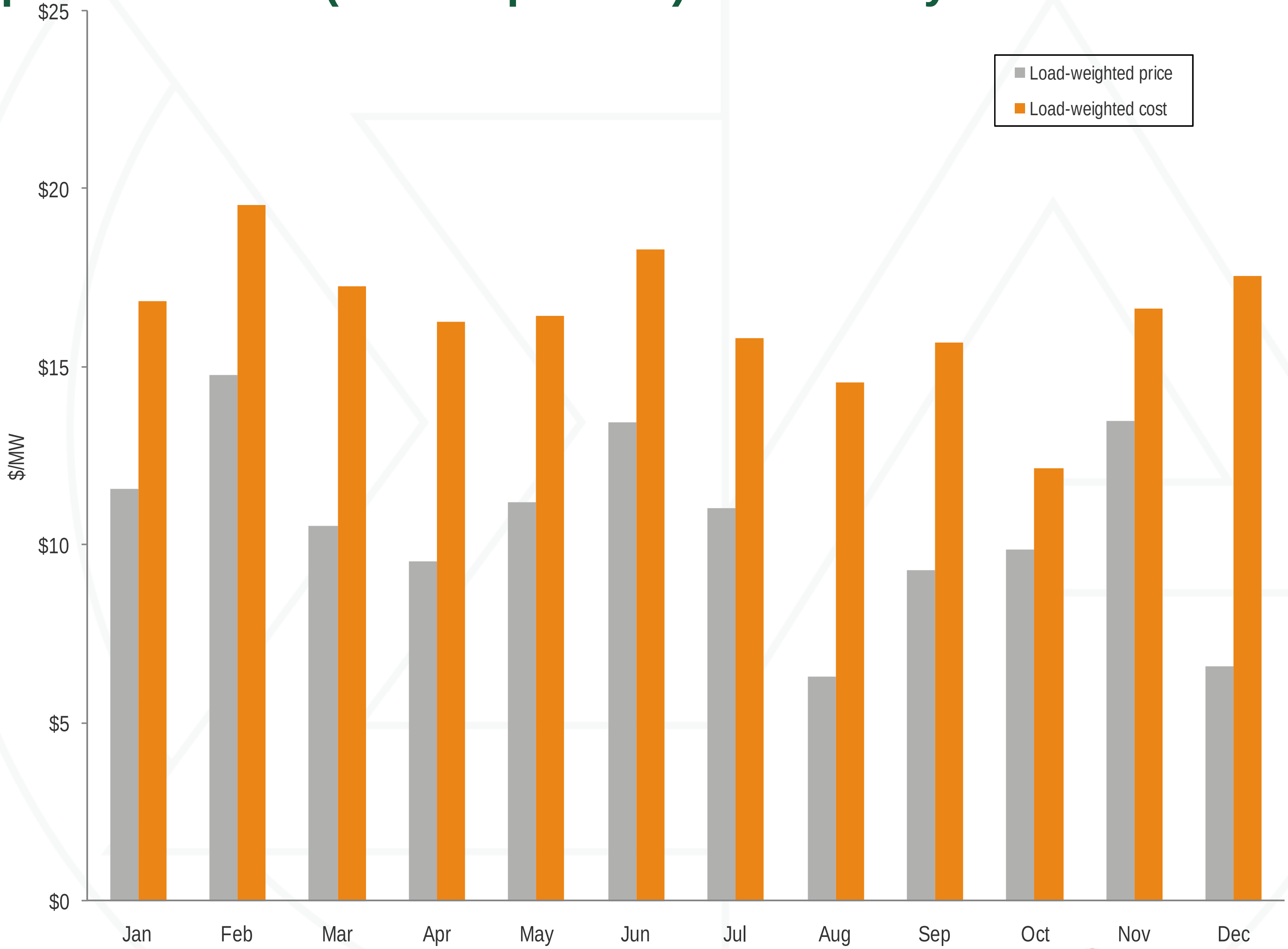

Figure 6-15 PJM RFC Zone Tier 2 synchronized reserve scheduled MW: Calendar year 2008

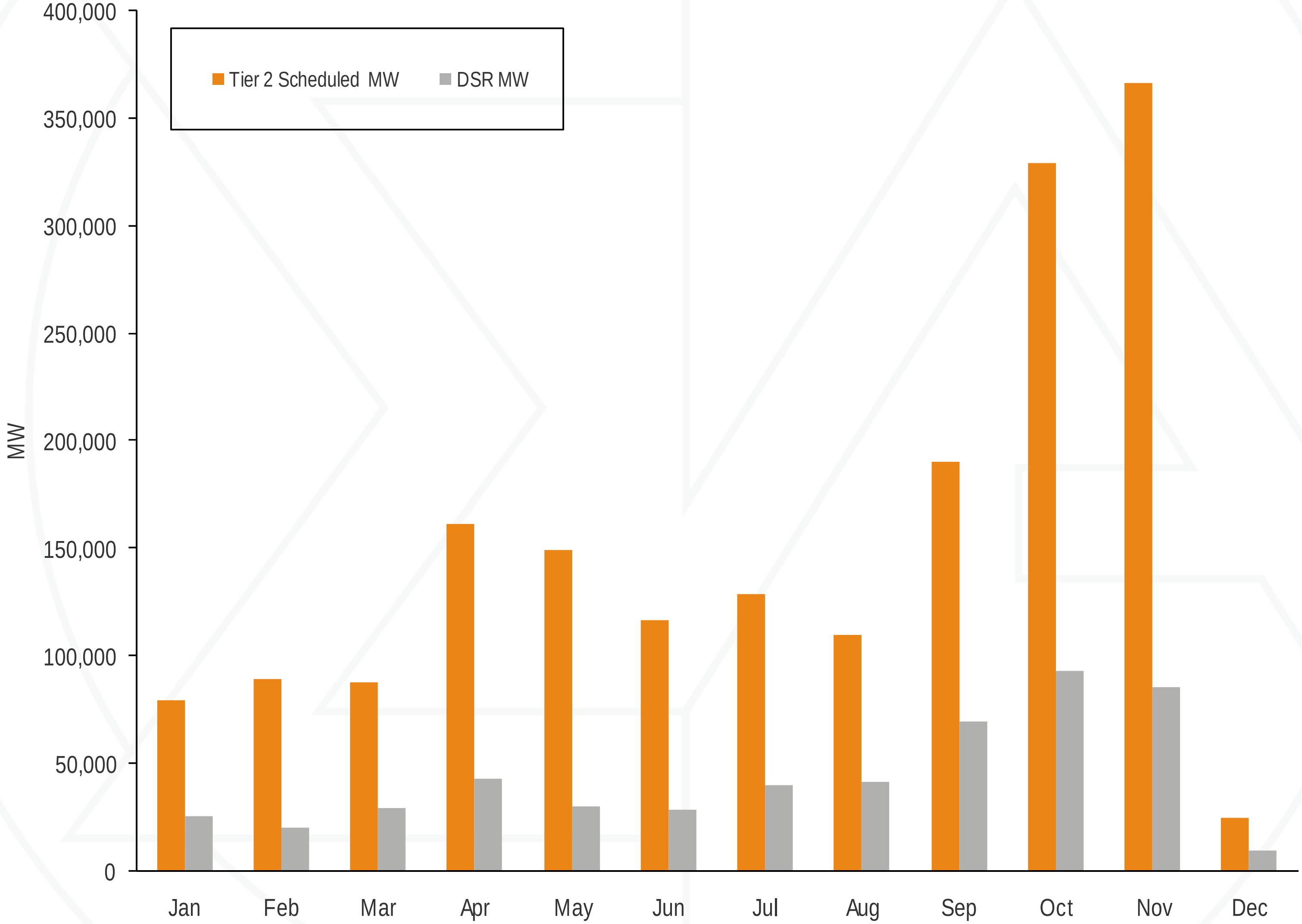

Table 6-9 2008 PJM, Day-Ahead Scheduling Reserve Market MW and clearing prices

Month	Average Required MW	Average Cleared MW	Minimum Clearing Price	Maximum Clearing Price	Load Weighted Price	Total Deficit MW	Total Load Reduction MW
Jun	1,622	1,622	$0.00	$7.80	$0.91	0	0
Jul	4,484	4,484	$0.00	$2.00	$0.55	0	0
Aug	6,044	6,044	$0.23	$1.50	$0.36	0	0
Sep	5,162	5,162	$0.14	$1.00	$0.23	0	0
Oct	4,825	4,825	$0.00	$0.22	$0.10	0	0
Nov	5,194	5,194	$0.00	$0.22	$0.09	0	386
Dec	5,633	5,633	$0.00	$0.75	$0.09	0	1,042

Table 6-10 2008 PJM, Day-Ahead Scheduling Reserve Market pivotal supplier results.

Month	Hours With Three Pivotal Suppliers
Jun	31%
Jul	38%
Aug	54%
Sep	80%
Oct	65%
Nov	23%
Dec	23%

Table 8-3 Long Term FTR Auction patterns of ownership by FTR direction: Planning periods 2009 to 2012

	FTR Direction		
Organization Type	Prevailing Flow	Counter Flow	All
Physical	36.7%	41.9%	39.2%
Financial	63.3%	58.1%	60.8%
Total	100.0%	100.0%	100.0%

Table 8-4 Annual FTR Auction patterns of ownership by FTR direction: Planning period 2008 to 2009

	FTR Direction		
Organization Type	Prevailing Flow	Counter Flow	All
Physical	54.2%	28.5%	46.5%
Financial	45.8%	71.5%	53.5%
Total	100.0%	100.0%	100.0%

Table 8-5 Monthly Balance of Planning Period FTR Auction patterns of ownership by FTR direction: January 2008 to December 2008

	FTR Direction		
Organization Type	Prevailing Flow	Counter Flow	All
Physical	33.3%	25.4%	29.6%
Financial	66.7%	74.6%	70.4%
Total	100.0%	100.0%	100.0%

Table 8-28 ARR and FTR congestion hedging: Planning periods 2007 to 2008 and 2008 to 2009

Planning Period	ARR Credits	FTR Credits	FTR Auction Revenue	Total ARR and FTR Hedge	Congestion	Total Hedge - Congestion Difference	Percent Hedged
2007/2008	$1,640,453,406	$2,038,912,131	$1,736,137,908	$1,943,227,629	$1,995,477,234	($52,249,605)	97.4%
2008/2009*	$1,384,429,209	$1,358,489,527	$1,458,303,545	$1,284,615,190	$1,322,177,077	($37,561,887)	97.2%

* Shows seven months ended 31-Dec-08

Market Monitoring Unit

- **The State of the Market Report is the work of the entire Market Monitoring Unit.**

Monitoring Analytics