2011 State of the Market Report for PJM

March 15, 2012

Monitoring Analytics

Market Monitoring Unit

- **Monitoring Analytics, LLC**
  - **Independent company**
  - **Formed August 1, 2008**
- **Independent Market Monitor for PJM**
  - **Independent from Market Participants**
  - **Independent from RTO management**
  - **Independent from RTO board of directors**
- **MMU Accountability**
  - **To FERC (per FERC MMU Orders and MM Plan)**
  - **To PJM markets**

Role of Market Monitoring

- Market monitoring is required by FERC Orders
- Role of competition under FERC regulation
  - Mechanism to regulate prices
  - Competitive outcome = just and reasonable
- Relevant model of competition is not laissez faire
- Competitive outcomes are not automatic
- Detailed rules required
- Detailed monitoring required:
  - Of participants
  - Of RTO
  - Of rules

Role of Market Monitoring

- **Market monitoring is primarily analytical**
  - **Adequacy of market rules**
  - **Compliance with market rules**
  - **Exercise of market power**
- **Market monitoring provides inputs to prospective mitigation**
- **Market monitoring provides retrospective mitigation**
- **Market monitoring provides information**
  - **To FERC**
  - **To state regulators**
  - **To market participants**
  - **To RTO**
- **FERC has enforcement authority**

Market Monitoring Plan

- **Monitor compliance with rules.**
- **Monitor actual or potential design flaws in rules.**
- **Monitor structural problems in the PJM market.**
- **Monitor the potential of market participants to exercise market power.**

Figure 1-1 PJM's footprint and its 18 control zones

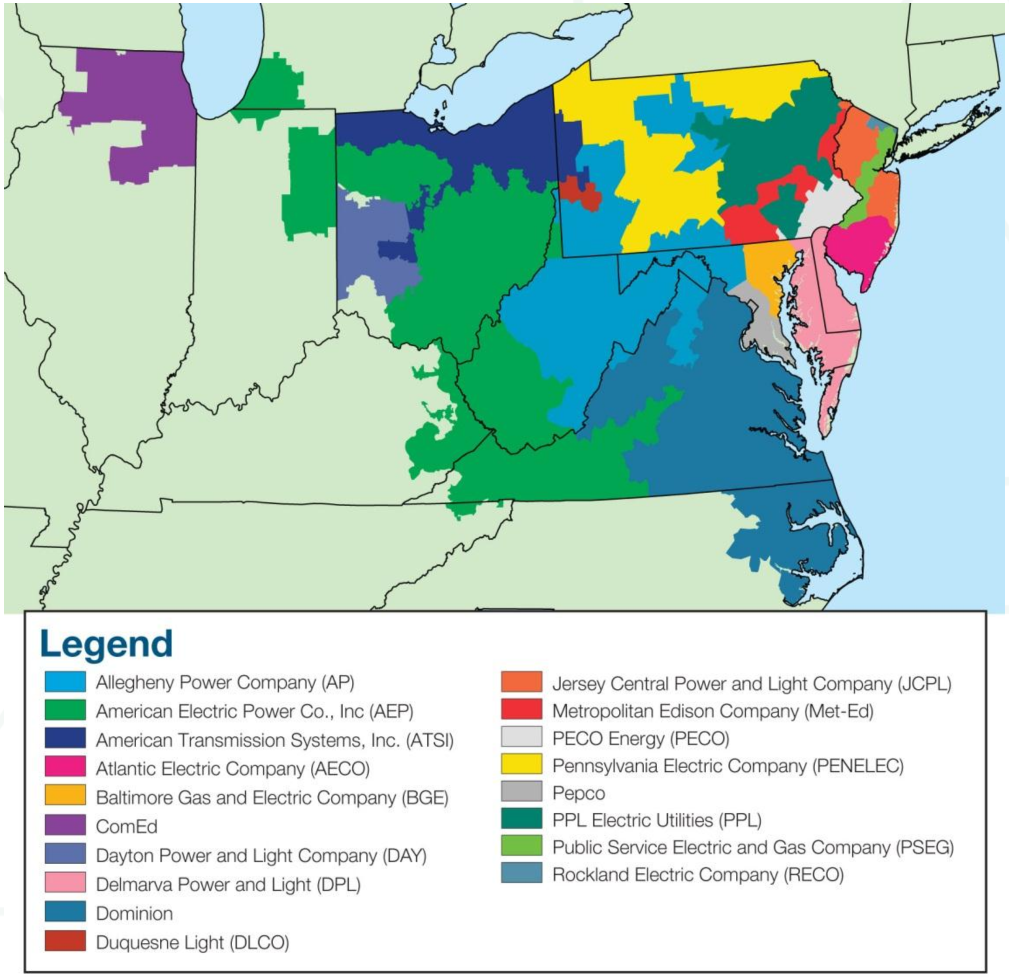

Table 1-1 The Energy Market results were competitive

Market Element	Evaluation	Market Design
Market Structure: Aggregate Market	Competitive	
Market Structure: Local Market	Not Competitive	
Participant Behavior	Competitive	
Market Performance	**Competitive**	**Effective**

Table 1-2 The Capacity Market results were competitive

Market Element	Evaluation	Market Design
Market Structure: Aggregate Market	Not Competitive	
Market Structure: Local Market	Not Competitive	
Participant Behavior: Local Market	Competitive	
Market Performance	**Competitive**	**Mixed**

Table 1-3 The Regulation Market results were not competitive

Market Element	Evaluation	Market Design
Market Structure	Not Competitive	
Participant Behavior	Competitive	
Market Performance	**Not Competitive**	**Flawed**

Table 1-4 The Synchronized Reserve Markets results were competitive

Market Element	Evaluation	Market Design
Market Structure: Regional Markets	Not Competitive	
Participant Behavior	Competitive	
Market Performance	**Competitive**	**Effective**

Table 1-5 The Day-Ahead Scheduling Reserve Market results were competitive

Market Element	Evaluation	Market Design
Market Structure	Competitive	
Participant Behavior	Mixed	
Market Performance	**Competitive**	**Mixed**

Table 1-6 The FTR Auction Markets results were competitive

Market Element	Evaluation	Market Design
Market Structure	Competitive	
Participant Behavior	Competitive	
Market Performance	**Competitive**	**Effective**

State of the Market Recommendations

- Operating reserves.
  - Improve process of identifying reasons for paying credits.
  - Up to congestion transactions should pay operating reserve charges.
- Capacity market.
  - Improve rules to promote efficient outcomes.
  - Define obligations more clearly.
  - Improve performance incentives.
  - Clarify terms of RMR service.

State of the Market Recommendations

- **Demand response**
  - **Eliminate limited DR products.**
  - **Implement subzonal dispatch/nodal dispatch.**
  - **Simplify Emergency Program.**
  - **Improve measurement and verification.**
- **Environment and renewables**
  - **Bring renewable energy credit markets into PJM markets**
- **Ancillary**
  - **Regulation**
  - **Synchronized reserve**
  - **Black start**

State of the Market Recommendations

- **Transactions.**
  - **Update interface price weights**
  - **Eliminate internal sources and sinks**
  - **Loop flow data**
  - **All pricing arrangements with other balancing authorities consistent with market principles**
- **Planning**
  - **Continue to address interconnection process**
- **Congestion and marginal losses**
  - **Address anomalous loss results via software review**
- **FTRs**
  - **Analysis of revenue adequacy**

Table 1-7 Total price per MWh by category and total revenues by category: 2010 and 2011

Category	2010 $/MWh	2011 $/MWh	Percent Change Totals	2010 Percent of Total	2011 Percent of Total
Energy	$48.35	$45.94	(5.0%)	72.5%	73.4%
Capacity	$12.15	$9.72	(20.0%)	18.2%	15.5%
Transmission Service Charges	$4.00	$4.42	10.5%	6.0%	7.1%
Operating Reserves (Uplift)	$0.79	$0.79	1.1%	1.2%	1.3%
Reactive	$0.44	$0.42	(6.6%)	0.7%	0.7%
PJM Administrative Fees	$0.36	$0.37	3.4%	0.5%	0.6%
Regulation	$0.35	$0.32	(6.6%)	0.5%	0.5%
Transmission Enhancement Cost Recovery	$0.21	$0.29	39.0%	0.3%	0.5%
Synchronized Reserves	$0.06	$0.09	47.4%	0.1%	0.1%
Transmssion Owner (Schedule 1A)	$0.09	$0.09	1.5%	0.1%	0.1%
Day Ahead Scheduling Reserve (DASR)	$0.01	$0.05	391.9%	0.0%	0.1%
Black Start	$0.02	$0.02	22.4%	0.0%	0.0%
NERC/RFC	$0.02	$0.02	(7.6%)	0.0%	0.0%
RTO Startup and Expansion	$0.01	$0.01	(1.9%)	0.0%	0.0%
Load Response	$0.00	$0.01	28.6%	0.0%	0.0%
Transmission Facility Charges	$0.00	$0.00	19.1%	0.0%	0.0%
Total	$66.72	$62.56	(6.2%)	100.0%	100.0%

Figure 2-1 Average PJM aggregate supply curves: Summer 2010 and 2011

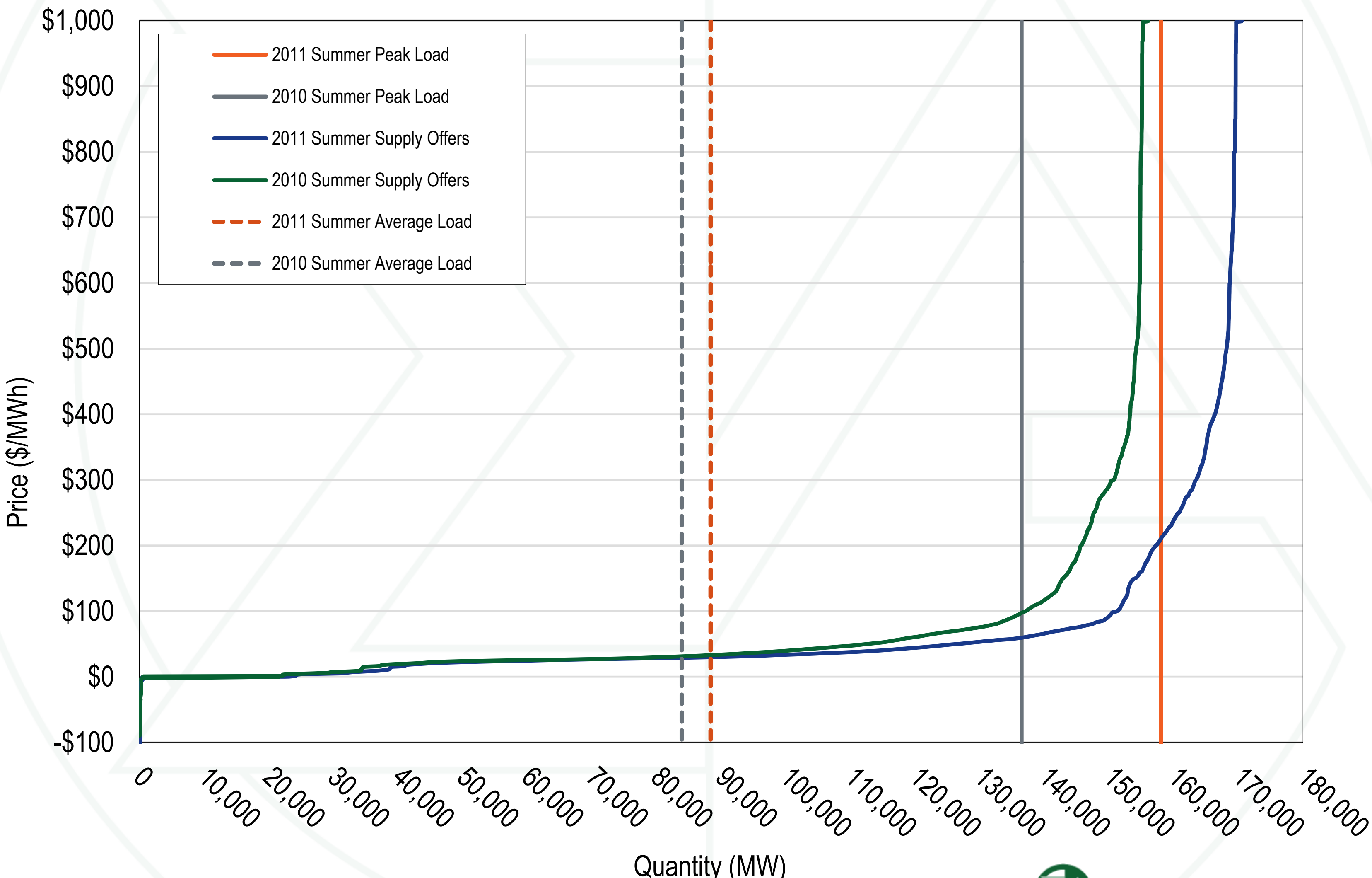

Table 2-2 PJM generation (By fuel source (GWh)): Calendar years 2010 and 2011

	2010		2011		Change in
	GWh	Percent	GWh	Percent	Output
Coal	363,035.1	48.7%	360,306.2	46.9%	(0.8%)
Standard Coal	350,539.2	47.0%	348,100.5	45.3%	(0.7%)
Waste Coal	12,495.9	1.7%	12,205.7	1.6%	(0.1%)
Nuclear	254,534.1	34.2%	262,968.3	34.2%	3.3%
Gas	93,455.9	12.5%	110,345.3	14.4%	18.1%
Natural Gas	91,729.4	12.3%	108,456.7	14.1%	18.2%
Landfill Gas	1,726.0	0.2%	1,887.9	0.2%	9.4%
Biomass Gas	0.5	0.0%	0.6	0.0%	39.4%
Hydroelectric	14,384.4	1.9%	15,277.9	2.0%	6.2%
Wind	9,688.2	1.3%	11,561.1	1.5%	19.3%
Waste	6,731.5	0.9%	5,559.6	0.7%	(17.4%)
Solid Waste	5,033.9	0.7%	4,442.9	0.6%	(11.7%)
Miscellaneous	1,697.7	0.2%	1,116.6	0.1%	(34.2%)
Oil	3,313.3	0.4%	2,136.0	0.3%	(35.5%)
Heavy Oil	2,748.3	0.4%	1,749.8	0.2%	(36.3%)
Light Oil	508.8	0.1%	356.6	0.0%	(29.9%)
Diesel	32.3	0.0%	16.9	0.0%	(47.9%)
Kerosene	23.8	0.0%	12.8	0.0%	(46.4%)
Jet Oil	0.1	0.0%	0.1	0.0%	1.0%
Solar	5.7	0.0%	55.7	0.0%	872.5%
Battery	0.3	0.0%	0.2	0.0%	(24.8%)
Total	745,148.6	100.0%	768,210.2	100.0%	3.1%

Figure 2-2 PJM footprint annual peak loads: 2002 to 2011

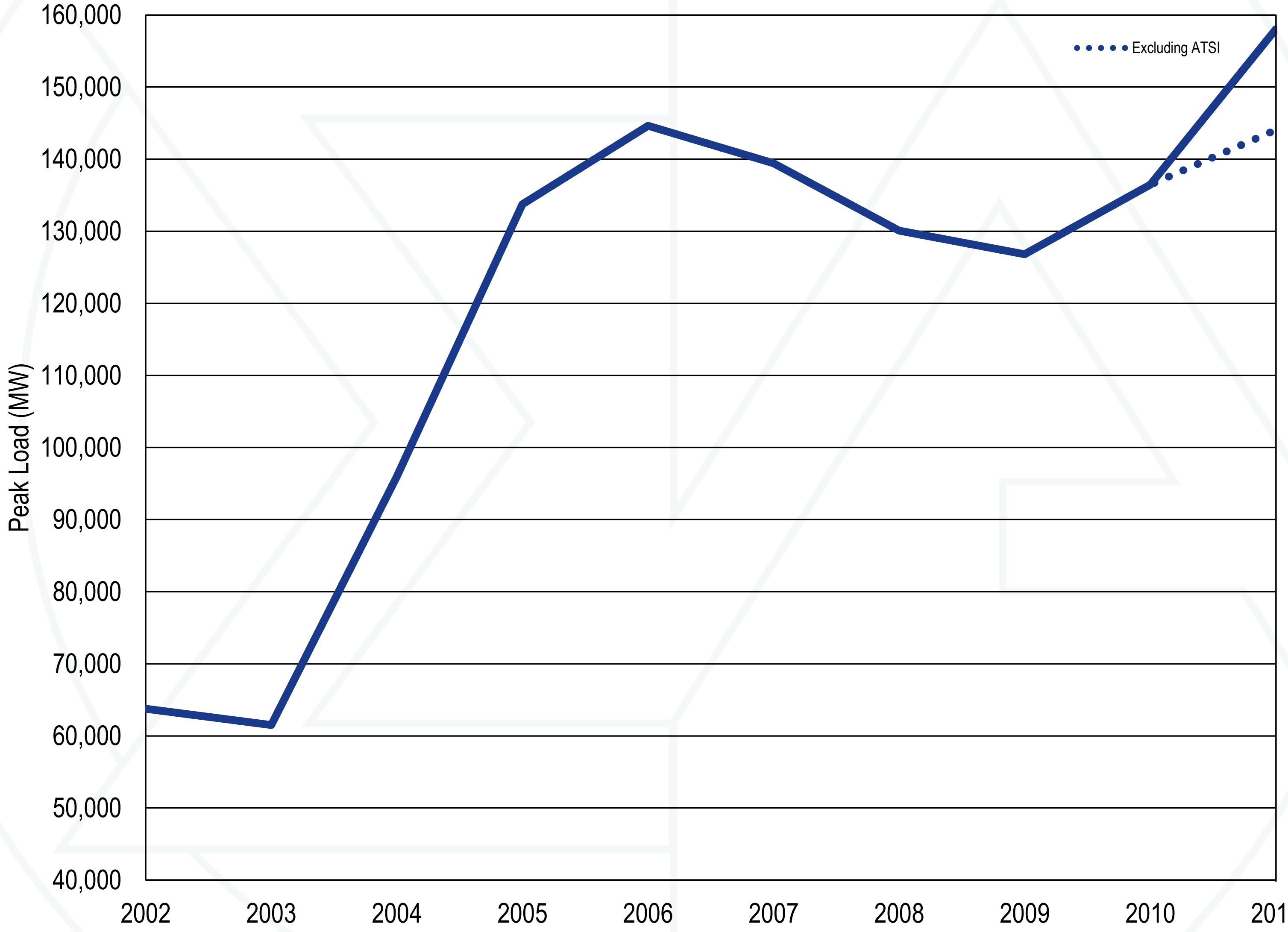

Table 2-4 Actual PJM footprint peak loads: 2002 to 2011

Year	Date	Hour Ending (EPT)	PJM Load (MW)	Annual Change (MW)	Annual Change (%)
2002	Wed, August 14	16	63,762	NA	NA
2003	Fri, August 22	16	61,499	(2,263)	(3.5%)
2004	Mon, December 20	19	96,016	34,517	56.1%
2005	Tue, July 26	16	133,761	37,746	39.3%
2006	Wed, August 02	17	144,644	10,883	8.1%
2007	Wed, August 08	16	139,428	(5,216)	(3.6%)
2008	Mon, June 09	17	130,100	(9,328)	(6.7%)
2009	Mon, August 10	17	126,798	(3,302)	(2.5%)
2010	Tue, July 06	17	136,460	9,662	7.6%
2011 (with ATSI)	Thu, July 21	17	158,016	21,556	15.8%
2011 (without ATSI)	Thu, July 21	17	144,063	7,603	5.6%

Table 2-28 PJM real-time average hourly load: Calendar years 1998 through 2011

	PJM Real-Time Load (MWh)		Year-to-Year Change	
Year	Average Load	Load Standard Deviation	Average Load	Load Standard Deviation
1998	28,578	5,511	NA	NA
1999	29,641	5,956	3.7%	8.1%
2000	30,113	5,529	1.6%	(7.2%)
2001	30,297	5,873	0.6%	6.2%
2002	35,731	8,013	17.9%	36.4%
2003	37,398	6,832	4.7%	(14.7%)
2004	49,963	13,004	33.6%	90.3%
2005	78,150	16,296	56.4%	25.3%
2006	79,471	14,534	1.7%	(10.8%)
2007	81,581	14,618	2.7%	0.6%
2008	79,515	13,758	(2.5%)	(5.9%)
2009	76,035	13,260	(4.4%)	(3.6%)
2010	79,611	15,504	4.7%	16.9%
2011	82,541	16,156	3.7%	4.2%

Figure 2-8 PJM real-time average hourly load: Calendar years 2010 and 2011

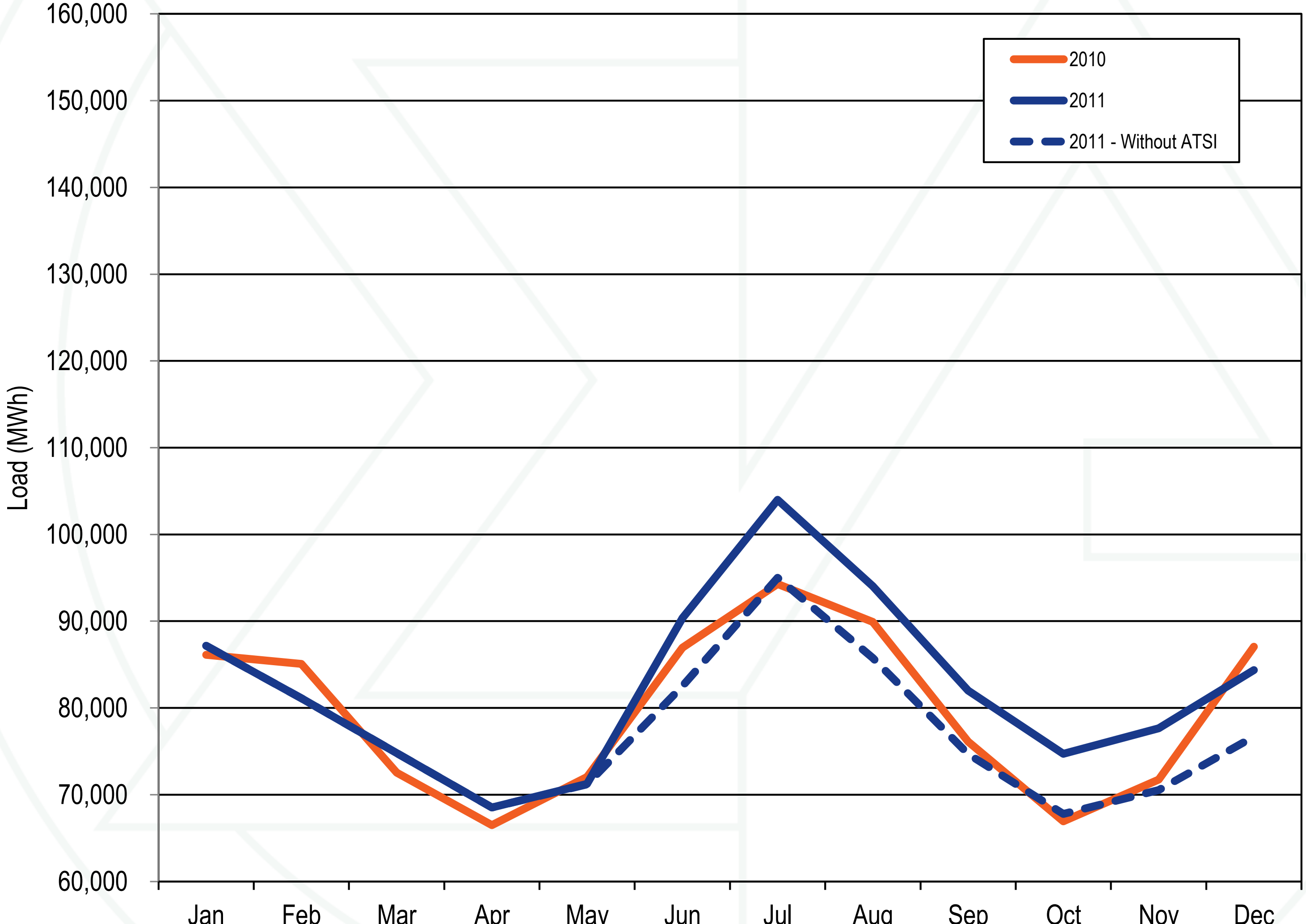

Table 2-37 PJM real-time, annual, load-weighted, average LMP (Dollars per MWh): Calendar years 1998 through 2011

	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%	132.8%
2000	$30.72	$20.51	$28.38	(9.8%)	7.9%	(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%)	(0.7%)
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%
2009	$39.05	$34.23	$18.21	(45.1%)	(42.5%)	(55.6%)
2010	$48.35	$39.13	$28.90	23.8%	14.3%	58.7%
2011	$45.94	$36.54	$33.47	(5.0%)	(6.6%)	15.8%

Figure 2-16 PJM real-time, monthly, load-weighted, average LMP: Calendar years 2007 through 2011

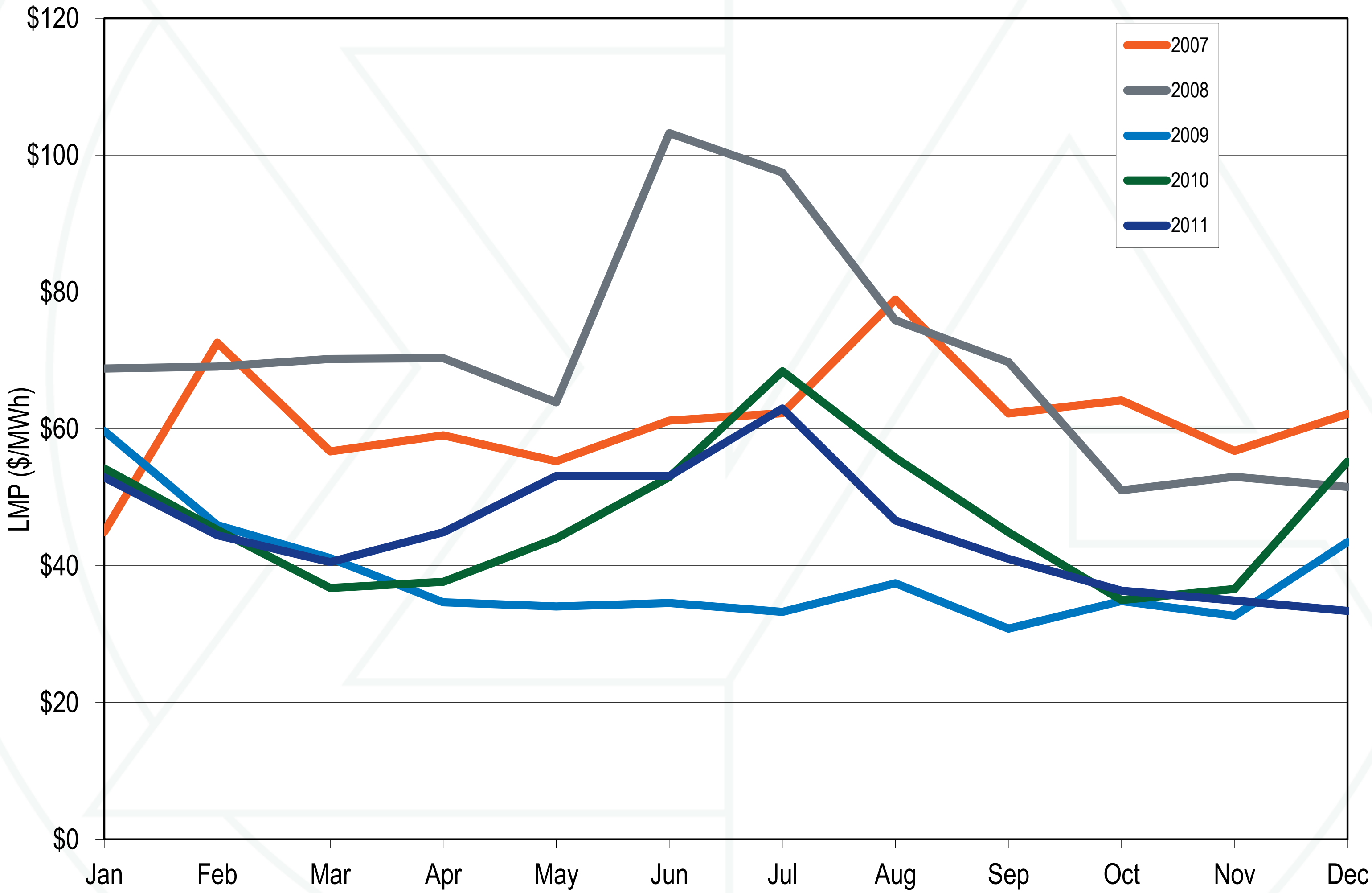

Figure 2-17 Spot average fuel price comparison: Calendar years 2010 through 2011

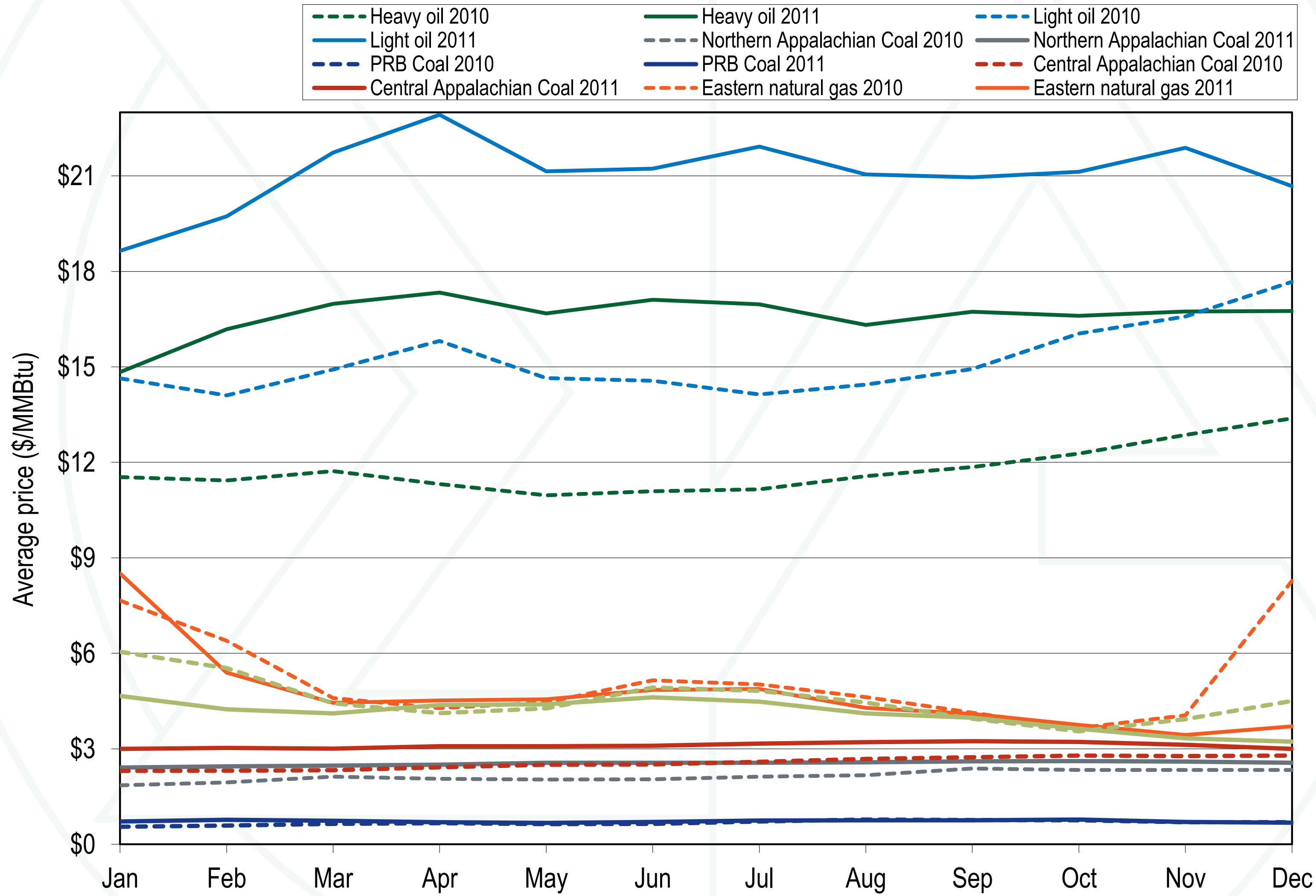

Table 2-38 PJM real-time annual, fuel-cost-adjusted, load-weighted average LMP (Dollars per MWh): Year-over-year method

	2011 Load-Weighted LMP	2011 Fuel-Cost-Adjusted, Load-Weighted LMP	Change
Average	$45.94	$44.75	(2.6%)
	2010 Load-Weighted LMP	2011 Fuel-Cost-Adjusted, Load-Weighted LMP	Change
Average	$48.35	$44.75	(7.4%)
	2010 Load-Weighted LMP	2011 Load-Weighted LMP	Change
Average	$48.35	$45.94	(5.0%)

Table 2-7 Annual offer-capping statistics: Calendar years 2007 through 2011

	Real Time		Day Ahead	
	Unit Hours Capped	MW Capped	Unit Hours Capped	MW Capped
2007	1.1%	0.2%	0.2%	0.0%
2008	1.0%	0.2%	0.2%	0.1%
2009	0.4%	0.1%	0.1%	0.0%
2010	1.2%	0.4%	0.2%	0.1%
2011	0.9%	0.4%	0.0%	0.0%

Table 2-39 Components of PJM real-time, annual, load-weighted, average LMP: Calendar year 2011

Element	Contribution to LMP	Percent
Coal	$21.30	46.4%
Gas	$14.32	31.2%
10% Cost Adder	$3.95	8.6%
VOM	$2.52	5.5%
Markup	$1.28	2.8%
Oil	$1.21	2.6%
NA	$0.73	1.6%
NOX	$0.31	0.7%
CO2	$0.31	0.7%
FMU Adder	$0.12	0.3%
SO2	$0.04	0.1%
Unit LMP Differential	$0.02	0.1%
Municipal Waste	$0.00	0.0%
Uranium	$0.00	0.0%
M2M Adder	($0.00)	(0.0%)
Shadow Price Limit Adder	($0.00)	(0.0%)
Wind	($0.03)	(0.1%)
Dispatch Differential	($0.12)	(0.3%)
Total	$45.94	100.0%

Table 4-3 PJM installed capacity (By fuel source): January 1, May 31, June 1, and December 31, 2011

	1-Jan-11		31-May-11		1-Jun-11		31-Dec-11	
	MW	Percent	MW	Percent	MW	Percent	MW	Percent
Coal	67,986.0	40.9%	67,879.4	40.7%	76,968.3	42.4%	75,190.4	42.0%
Gas	47,736.6	28.7%	47,831.1	28.7%	50,729.0	28.0%	50,529.3	28.3%
Hydroelectric	7,954.5	4.8%	7,991.8	4.8%	8,029.6	4.4%	8,047.0	4.5%
Nuclear	30,552.2	18.4%	30,822.2	18.5%	33,145.6	18.3%	32,492.6	18.2%
Oil	10,949.5	6.6%	10,854.1	6.5%	11,212.3	6.2%	11,217.3	6.3%
Solar	0.0	0.0%	1.9	0.0%	15.3	0.0%	15.3	0.0%
Solid waste	680.1	0.4%	680.1	0.4%	705.1	0.4%	705.1	0.4%
Wind	551.3	0.3%	551.3	0.3%	633.5	0.3%	649.5	0.4%
Total	166,410.2	100.0%	166,611.9	100.0%	181,438.7	100.0%	178,846.5	100.0%

Figure 4-3 Trends in the PJM equivalent demand forced outage rate (EFORd): Calendar years 2007 to 2011

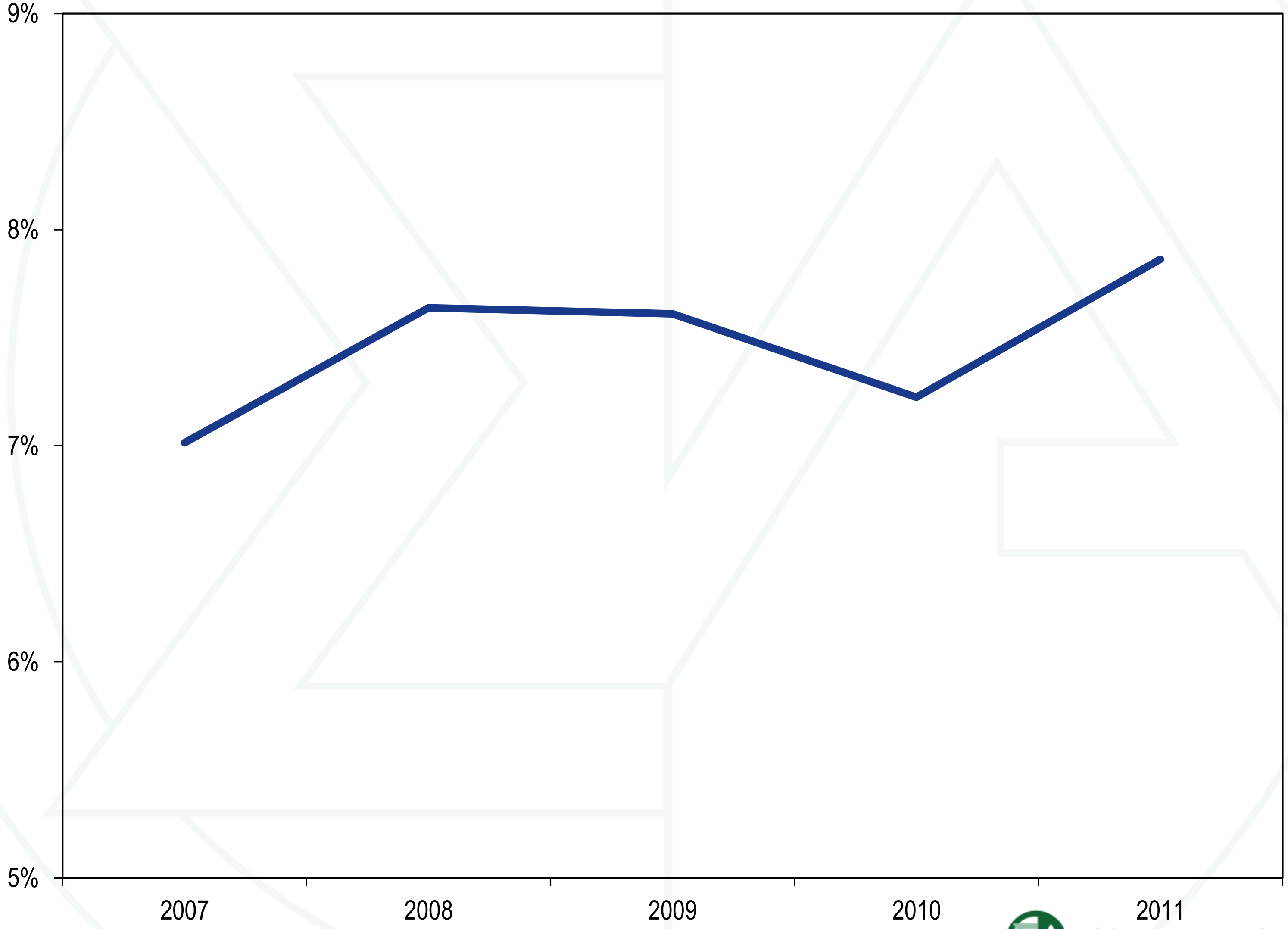

Table 4-31 PJM EFORd vs. XEFORd: Calendar year 2011

	EFORd	XEFORd	Difference
Combined Cycle	3.2%	3.0%	0.2%
Combustion Turbine	7.8%	6.4%	1.5%
Diesel	9.0%	3.0%	6.0%
Hydroelectric	2.2%	1.7%	0.5%
Nuclear	2.8%	1.6%	1.2%
Steam	11.2%	10.1%	1.1%
Total	7.9%	6.8%	1.0%

Figure 4-4 PJM 2011 distribution of EFORd data by unit type

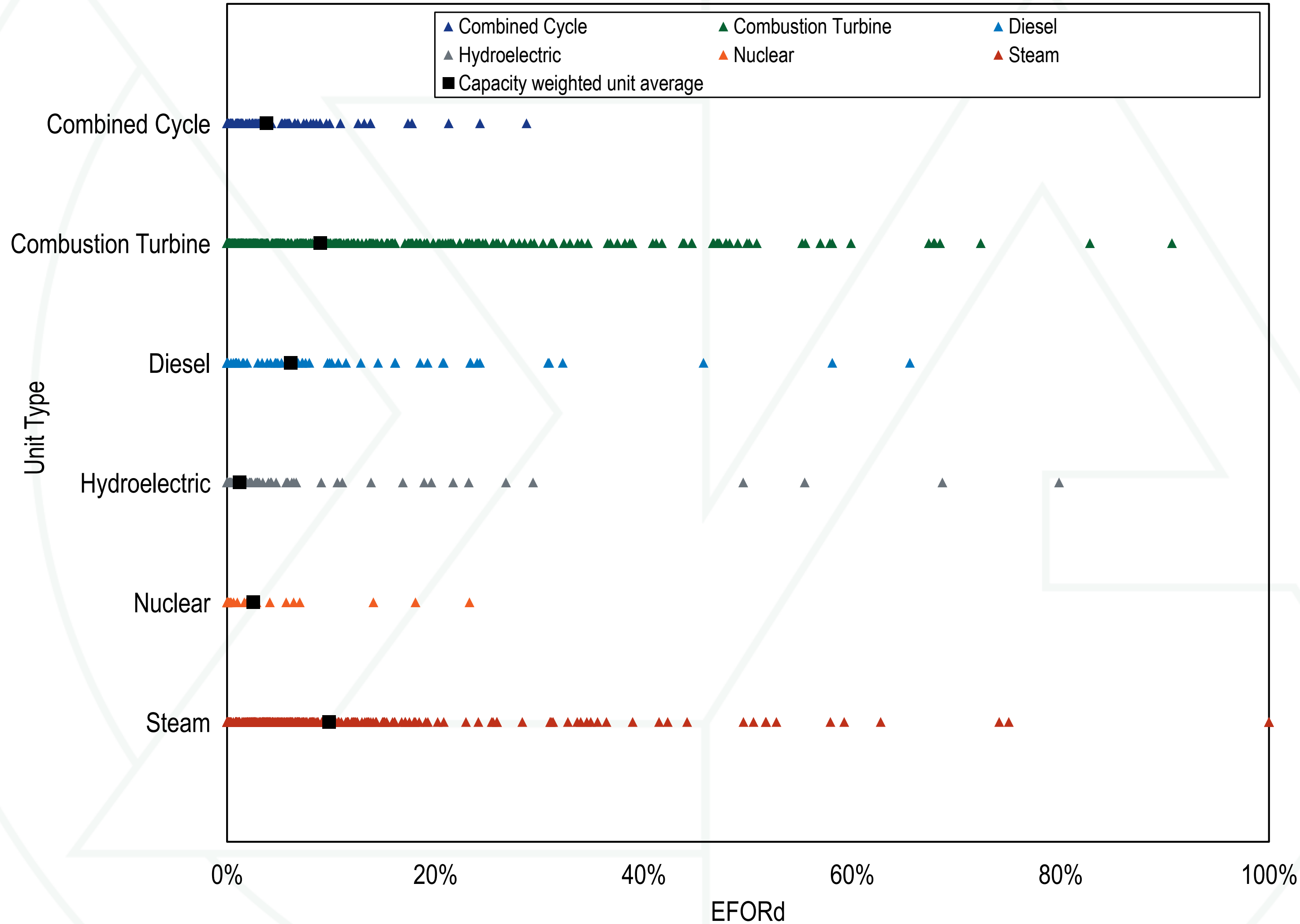

Figure 4-1 History of capacity prices: Calendar year 1999 through 2014

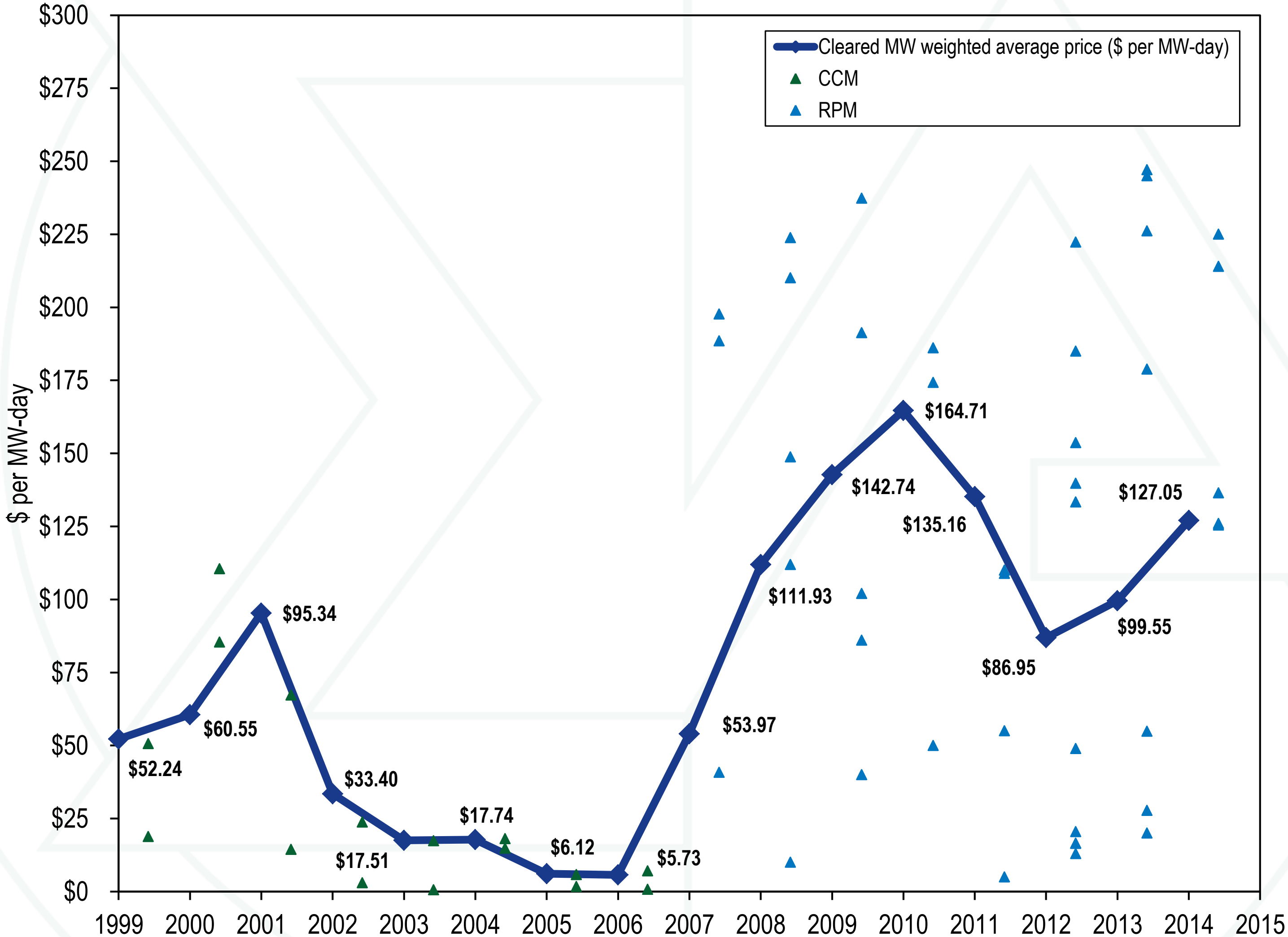

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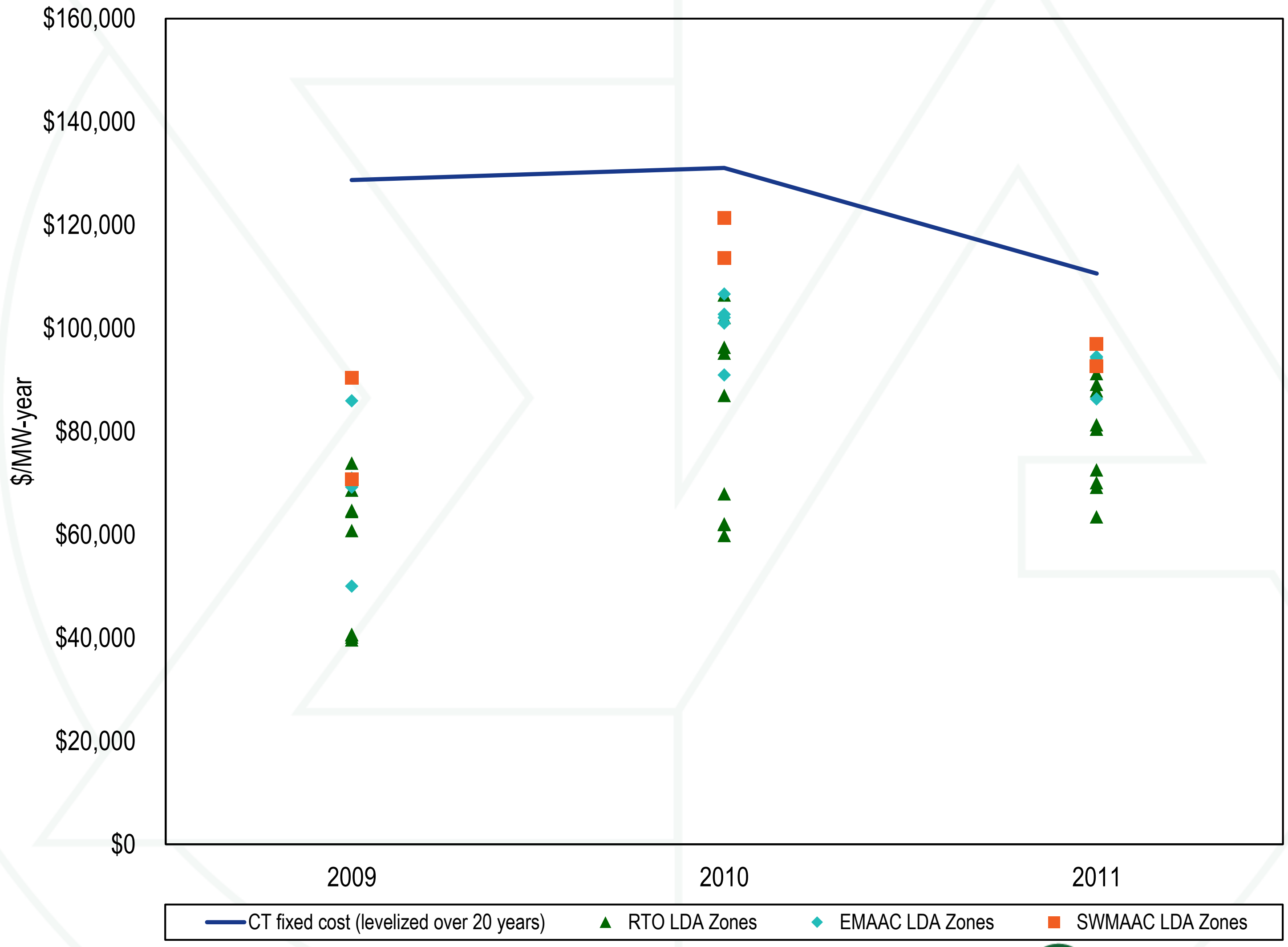
Figure 6-2 New entrant CT net revenue and 20-year levelized fixed cost by LDA (Dollars per installed MW-year)



Monitoring Analytics

Figure 6-4 New entrant CC net revenue and 20-year levelized fixed cost by LDA (Dollars per installed MW-year)

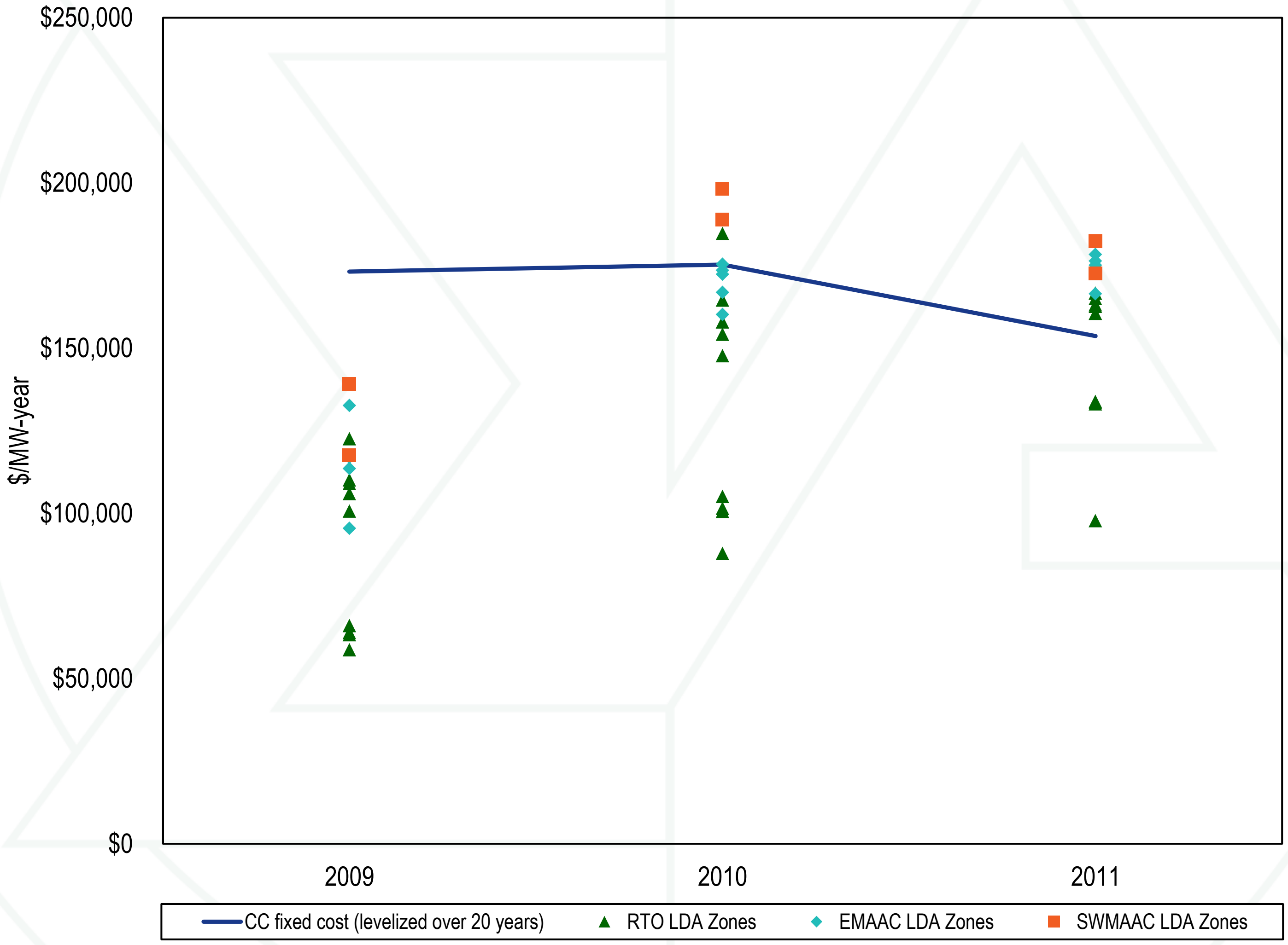


Figure 6-6 New entrant CP net revenue and 20-year levelized fixed cost by LDA (Dollars per installed MW-year)

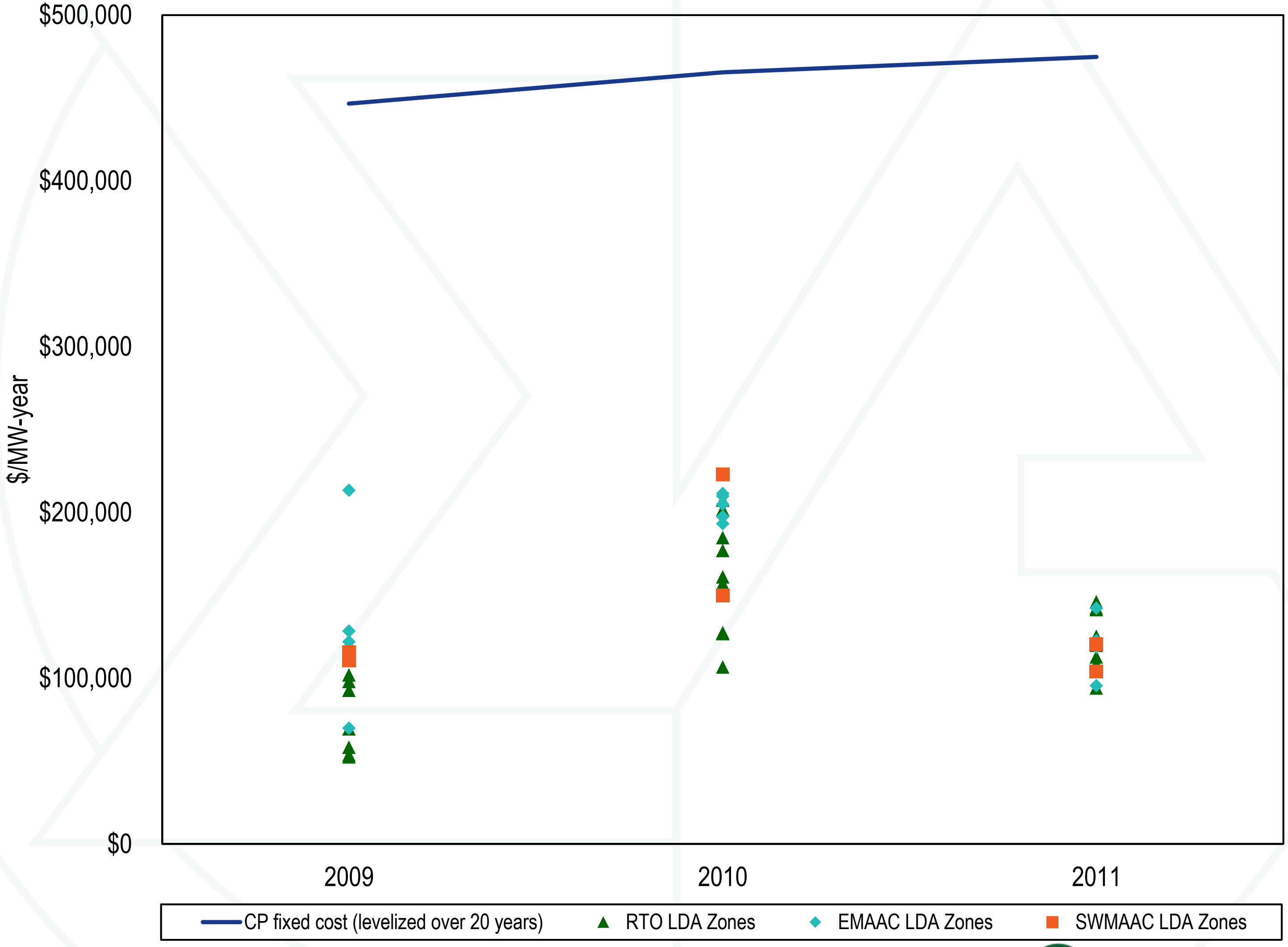


Table 11-2 Capacity additions of plants greater than 500 MW: Calendar year 2011

Plant Name	Zone	Unit Type	ICAP (MW)
Dresden Energy Facility	AEP	Combined Cycle	545
Longview Power	APS	Coal Steam	700
Fremont Energy Center	ATSI	Combined Cycle	685
Bear Garden Generating Station	Dominion	Combined Cycle	590
York Energy Center	PECO	Combined Cycle	565

Table 6-25 Proportion of units recovering avoidable costs from energy and ancillary markets as well as total markets for calendar years 2009 to 2011

	2009		2010		2011	
Technology	Units with full recovery from energy markets	Units with full recovery from all markets	Units with full recovery from energy markets	Units with full recovery from all markets	Units with full recovery from energy markets	Units with full recovery from all markets
CC - NUG Cogeneration Frame B or E Technology	57%	96%	83%	92%	64%	89%
CC - Two of Three on One Frame F Technology	63%	89%	84%	100%	87%	97%
CT - First & Second Generation Aero (P&W FT 4)	24%	99%	34%	100%	32%	99%
CT - First & Second Generation Frame B	30%	100%	34%	98%	29%	94%
CT - Second Generation Frame E	60%	100%	67%	100%	82%	100%
CT - Third Generation Aero	23%	99%	49%	99%	87%	99%
CT - Third Generation Frame F	41%	98%	69%	100%	79%	98%
Diesel	69%	97%	71%	97%	61%	91%
Hydro	100%	100%	100%	100%	96%	100%
Nuclear	100%	100%	100%	100%	100%	100%
Oil or Gas Steam	36%	90%	40%	87%	43%	86%
Pumped Storage	45%	100%	90%	100%	70%	100%
Sub-Critical Coal	66%	88%	73%	88%	63%	77%
Super Critical Coal	74%	91%	77%	80%	81%	88%

Table 6-26 Profile of coal units

	Coal plants with less than full recovery of avoidable costs	Coal plants with full recovery of avoidable costs
Total Installed Capacity (ICAP)	5,642	36,383
Avg. Installed Capacity (ICAP)	235	319
Avg. Age of Plant (Years)	46	38
Avg. Heat Rate (Btu/kWh)	11,135	10,701
Avg. Run Hours (Hours)	4,300	5,627
Avg. Avoidable Costs ($/MW-year)	512	146

Table 6-27 Installed capacity associated with levels of avoidable cost recovery: Calendar year 2011

Groups of coal plants by percent recovery of avoidable cost	Installed capacity (MW)	Percent of total
0% - 65%	3,793	9%
65% - 75%	111	0%
75% - 90%	465	1%
90% - 100%	1,273	3%
> 100%	36,383	87%
Total	42,025	100%

Table 6-29 Attributes of coal plants with and without MATS compliant environmental controls

	Coal plants lacking NOx, SO2, or particulate controls	Coal plants with NOx, SO2, and particulate controls
Number of units (excluding announced or expected deactivations)	80	58
ICAP within MAAC	6,618	5,247
ICAP in rest of RTO	10,487	19,674
Total installed capacity (ICAP)	17,104	24,921
ICAP associated with plants older than 40 years	14,248	9,216
ICAP associated with small coal plants (200 MW or less)	5,958	2,001
ICAP associated with medium coal plants (200 to 500 MW)	2,495	4,915
ICAP associated with large coal plants (500 MW or greater)	8,652	18,005
ICAP associated with 100 percent recovery of avoidable costs	14,927	21,456
ICAP associated with less than 100 percent recovery of avoidable costs	2,177	3,465

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Table 6-30 At risk coal plants

	Coal plants covering less than	
	100% of avoidable costs or 100% of APIR (if any)	125% of avoidable costs or 125% of APIR (if any)
Number of units	26	30
ICAP within MAAC	1,630	1,765
ICAP in rest of RTO	4,135	5,172
Total installed capacity (ICAP)	5,764	6,936

Table 11-11 Summary of PJM unit Retirements (MW), Calendar year 2011 through 2019

	MW
Retirements 2011	1,322.3
Planned Retirements 2012	7,189.0
Planned Retirements Post-2012	10,374.7
Total	18,886.0

Table 11-15 Unit deactivations: Calendar year 2011

Company	Unit Name	ICAP	Primary Fuel	Zone Name	Age (Years)	Retirement Date
Dominion Resources, Inc.	Kitty Hawk GT1	18.0	Light Oil	Dominion	39	Mar 15, 2011
Dominion Resources, Inc.	Kitty Hawk GT2	16.0	Light Oil	Dominion	39	Mar 15, 2011
Dominion Resources, Inc.	Chesapeake 8	17.5	Light Oil	Dominion	41	Mar 15, 2011
Dominion Resources, Inc.	Chesapeake 9	16.9	Light Oil	Dominion	41	Mar 15, 2011
Dominion Resources, Inc.	Chesapeake 10	16.9	Light Oil	Dominion	41	Mar 15, 2011
Dominion Resources, Inc.	Chesapeake 7	16.0	Light Oil	Dominion	40	Apr 08, 2011
NRG Energy Inc.	Indian River 1	90.0	Coal	DPL	50	May 01, 2011
Exelon Corporation	Cromby 1	144.0	Coal	PECO	55	May 31, 2011
Exelon Corporation	Eddystone 1	279.0	Coal	PECO	49	May 31, 2011
GenOn Energy, Inc.	Brunot Island 1B	15.0	Light Oil	DLCO	39	Jun 01, 2011
GenOn Energy, Inc.	Brunot Island 1C	15.0	Light Oil	DLCO	39	Jun 01, 2011
FirstEnergy Corp.	Burger 3	94.0	Coal	ATSI	61	Sep 01, 2011
Public Service Enterprise Group Incorporated	Hudson 1	383.0	Natural Gas	PSEG	39	Dec 08, 2011
Exelon Corporation	Cromby 2	201.0	Natural Gas	PECO	54	Dec 31, 2011

Table 11-12 Planned deactivations of PJM units in Calendar year 2012 as of March 1, 2012

Unit	Zone	MW	Projected Deactivation Date
Sporn 5	AEP	440.0	31-Dec-11
State Line 3-4	ComEd	515.0	01-Apr-12
Viking Energy NUG IPP	PPL	16.0	01-May-12
Beckjord 1-3	DEOK	316.0	01-May-12
Benning 15-16	Pepco	548.0	31-May-12
Buzzard Point East Banks 1, 2, 4-8	Pepco	112.0	31-May-12
Buzzard Point West Banks 1-8	Pepco	128.0	31-May-12
Eddystone 2	PECO	309.0	31-May-12
Niles	ATSI	217.0	01-Jun-12
Elrama 1-4	DLCO	460.0	01-Jun-12
Kearny 10-11	PSEG	250.0	01-Jun-12
Vineland 10	AECO	23.0	01-Sep-12
Albright	APS	283.0	01-Sep-12
Armstrong 1-2	APS	343.0	01-Sep-12
R Paul Smith 3-4	APS	115.0	01-Sep-12
Rivesville 5-6	APS	121.0	01-Sep-12
Willow Island 1-2	APS	217.0	01-Sep-12
Ashtabula	ATSI	210.0	01-Sep-12
Bay Shore 2-4	ATSI	419.0	01-Sep-12
Eastlake 1-5	ATSI	1,149.0	01-Sep-12
Lake Shore	ATSI	190.0	01-Sep-12
Potomac River 1-5	Pepco	482.0	01-Oct-12
Total		6,863.0	

Table 11-13 Planned deactivations of PJM units after calendar year 2012, as of March 1, 2012

Unit	Zone	MW	Projected Deactivation Date
Ingenco Petersburg Plant	Dominion	02.9	31-May-13
Indian River 3	DPL	169.7	31-Dec-13
Big Sandy 1-2	AEP	1,078.0	31-Dec-14
Clinch River 3	AEP	230.0	31-Dec-14
Conesville 3	AEP	165.0	31-Dec-14
Glen Lyn 5-6	AEP	325.0	31-Dec-14
Kammer	AEP	600.0	31-Dec-14
Kanawha River	AEP	400.0	31-Dec-14
Muskingum River 1-4	AEP	790.0	31-Dec-14
Picway 5	AEP	95.0	31-Dec-14
Sporn	AEP	580.0	31-Dec-14
Tanners Creek 1-3	AEP	488.1	31-Dec-14
Chesapeake 1-2	Dominion	222.0	31-Dec-14
Yorktown 1	Dominion	159.0	31-Dec-14
Portland	Met-Ed	401.0	01-Jan-15
Beckjord 4-6	DEOK	802.0	01-Apr-15
Avon Lake	ATSI	732.0	01-Apr-15
New Castle	ATSI	330.5	01-Apr-15
Titus	Met-Ed	243.0	01-Apr-15
Shawville	PENELEC	597.0	01-Apr-15
Glen Gardner	JCPL	160.0	01-May-15
Kearny 9	PSEG	21.0	01-May-15
Bergen 3	PSEG	21.0	01-Jun-15
Burlington 8	PSEG	21.0	01-Jun-15
Mercer 3	PSEG	115.0	01-Jun-15
National Park 1	PSEG	21.0	01-Jun-15
Sewaren 6	PSEG	105.0	01-Jun-15
Chesapeake 3-4	Dominion	354.0	31-Dec-15
Oyster Creek	JCPL	614.5	31-Dec-19
Total		9,842.7	

Table 11-14 HEDD Units in PJM as of December 31, 2011

Unit	Zone	MW
Carlls Corner 1-2	AECO	72.6
Cedar Station 1-3	AECO	66.0
Cumberland 1	AECO	92.0
Mickleton 1	AECO	72.0
Middle Street 1-3	AECO	75.3
Missouri Ave. B,C,D	AECO	60.0
Sherman Ave.	AECO	92.0
Vineland West CT	AECO	26.0
Forked River 1-2	JCPL	65.0
Gilbert 4-7, 9, C1-C4	JCPL	446.0
Glen Gardner A1-A4, B1-B4	JCPL	160.0
Lakewood 1-2	JCPL	316.1
Parlin NUG	JCPL	114.0
Sayreville C1-C4	JCPL	224.0
South River NUG	JCPL	299.0
Werner C1-C4	JCPL	212.0
Bayonne	PSEG	118.5
Bergen 3	PSEG	21.0
Burlington 111-114, 121-124, 91-94, 8	PSEG	557.0
Camden	PSEG	145.0
Eagle Point 1-2	PSEG	127.1
Edison 11-14, 21-24, 31-34	PSEG	504.0
Elmwood	PSEG	67.0
Essex 101-104, 111-114, 121,124	PSEG	536.0
Kearny 9-11, 121-124	PSEG	446.0
Linden 1-2	PSEG	1,230.0
Mercer 3	PSEG	115.0
National Park	PSEG	21.0
Newark Bay	PSEG	120.2
Pedricktown	PSEG	120.3
Salem 3	PSEG	38.4
Sewaren 6	PSEG	105.0
Total		6,663.5

Figure 11-1 Unit retirements in PJM Calendar year 2011 through 2019

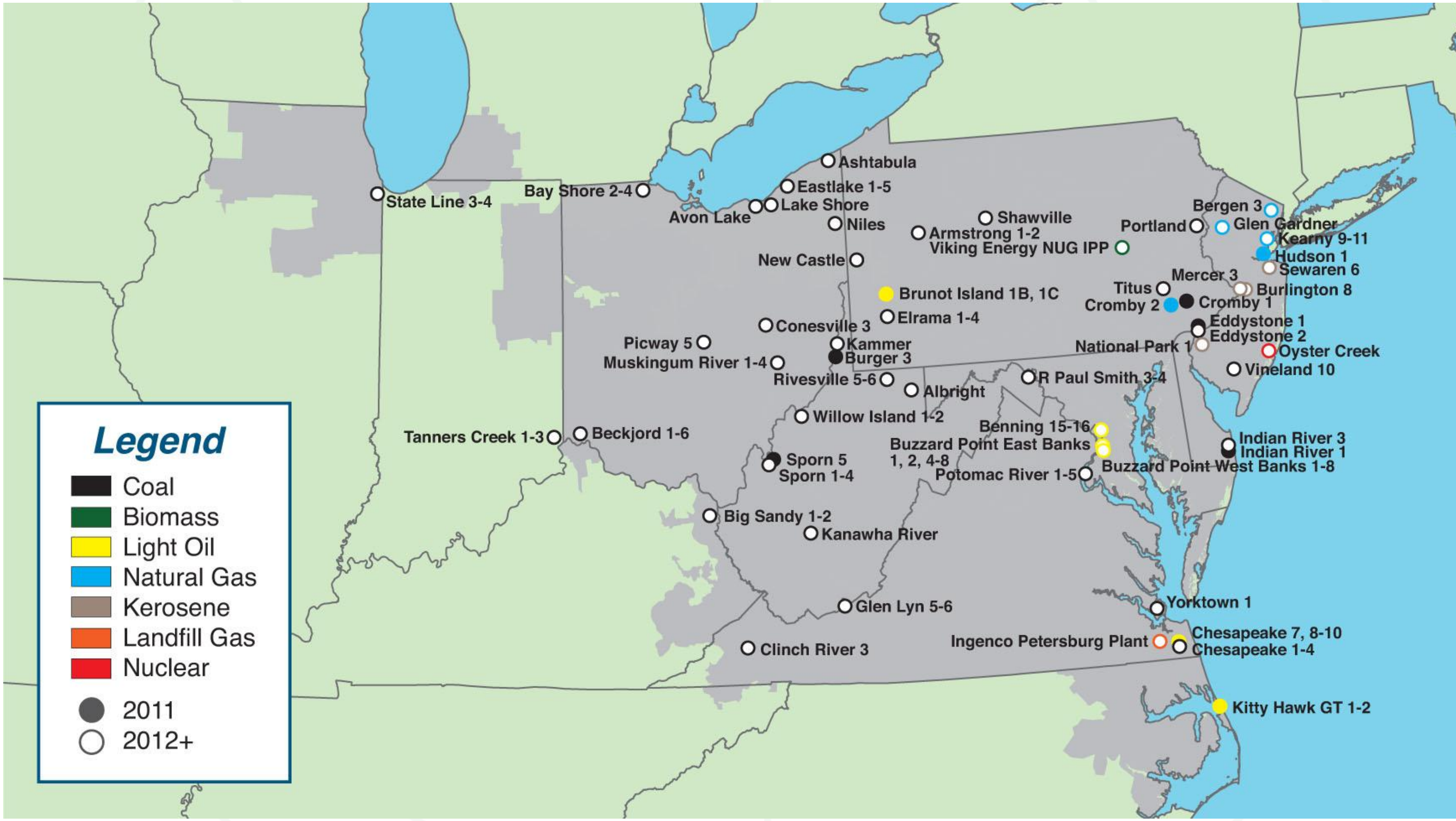

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Figure 2-20 Hourly volume of bid and cleared INC, DEC and Up-to Congestion bids (MW) by month: January, 2005 through December, 2011

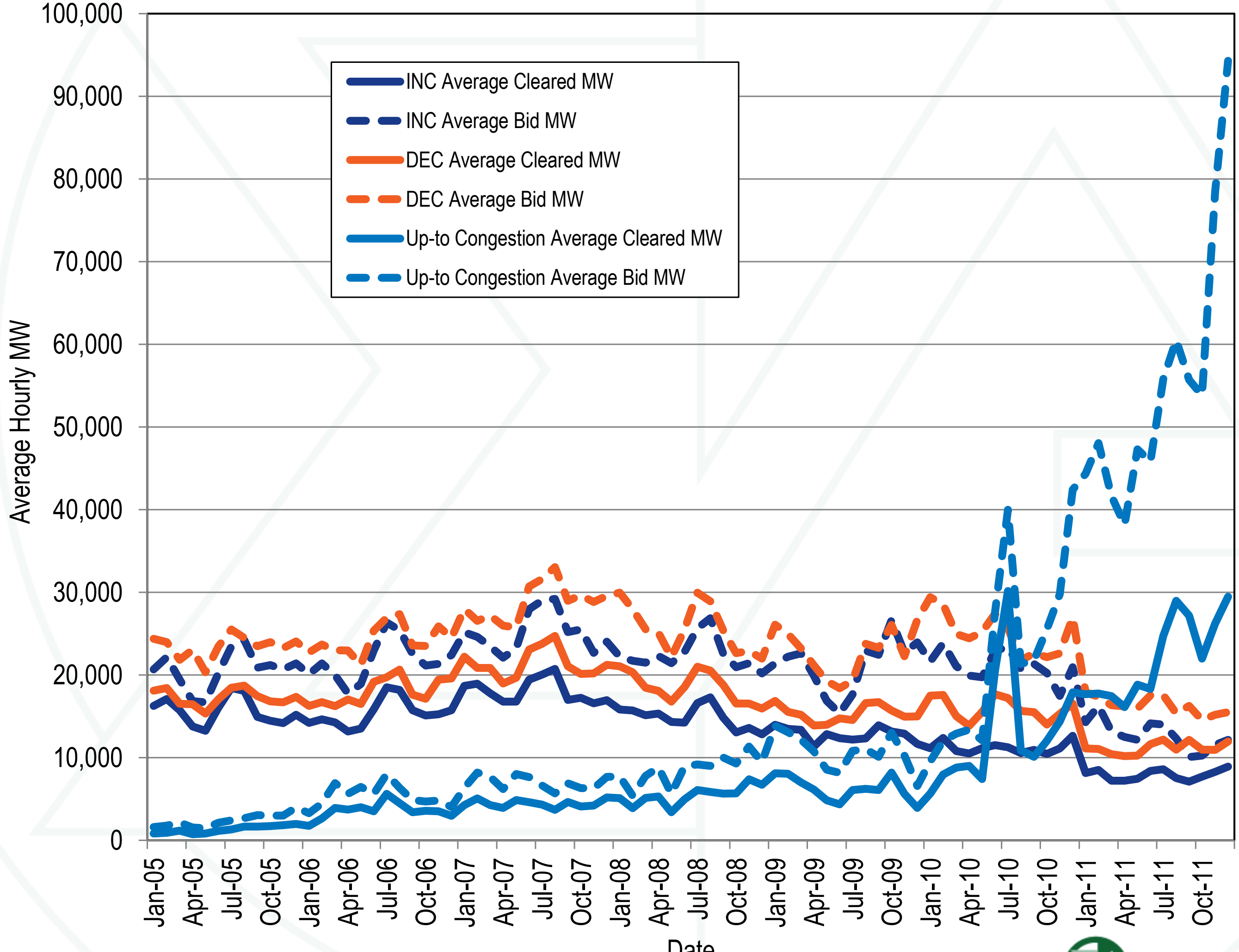

Table 2-47 PJM up-to congestion transactions by type of parent organization (MW): Calendar years 2010 and 2011

	2010		2011	
Category	Total Up-to Congestion MW	Percentage	Total Up-to Congestion MW	Percentage
Financial	110,269,067	97.25%	187,509,868	96.84%
Physical	3,121,859	2.75%	6,113,860	3.16%
Total	113,390,926	100.0%	193,623,729	100.00%

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Table 3-1 Operating reserve credits and charges

Credits received for:		Charges paid by:
	Day-Ahead	
Day-Ahead Import Transactions Demand-Side Response Resources Generation Resources	→	Day-Ahead Demand Bid Day-Ahead Export Transactions Decrement Bids
Synchronous Condensing	→	Real-Time Export Transactions Real-Time Load
	Balancing	
Generation Resources: Deviations	→	Real-Time Deviations from Day-Ahead Schedule by RTO, East and West Region
Generation Resources: Reliability	→	Real-Time Load plus Export Transactions by RTO, East and West Region
Canceled Resources Demand-Side Response Resources Lost Opportunity Cost Performing Annual Scheduled Black Start Tests Providing Quick Start Reserve Real-Time Import Transactions	→	Real-Time Deviations from Day-Ahead Schedule in the entire RTO
Controlling Local Transmission Constraints	→	Applicable Requesting Party
Providing Reactive Service	→	Zonal Real-Time Load

Table 3-6 Total day-ahead and balancing operating reserve charges: Calendar years 1999 to 2011

	Total Operating Reserve Charges	Annual Credit Change	Operating Reserve as a Percent of Total PJM Billing	Day-Ahead Rate ($/MWh)	Balancing RTO Deviation Rate ($/MWh)	Balancing RTO Reliability Rate ($/MWh)
1999	$133,897,428	NA	7.5%	NA	NA	NA
2000	$216,985,147	62.1%	9.6%	0.3412	0.5346*	NA
2001	$290,867,269	34.0%	8.7%	0.2746	1.0700*	NA
2002	$237,102,574	(18.5%)	5.0%	0.1635	0.7873*	NA
2003	$289,510,257	22.1%	4.2%	0.2261	1.1971*	NA
2004	$414,891,790	43.3%	4.8%	0.2300	1.2362*	NA
2005	$682,781,889	64.6%	3.0%	0.0762	2.7580*	NA
2006	$322,315,152	(52.8%)	1.5%	0.0781	1.3315*	NA
2007	$459,124,502	42.4%	1.5%	0.0570	2.3310*	NA
2008	$429,253,836	(6.5%)	1.3%	0.0844	2.1132*	NA
2009	$325,842,346	(24.1%)	1.2%	0.1201	0.6723	0.0092
2010	$572,286,706	75.6%	1.6%	0.1130	0.9120	0.0580
2011	$578,072,070	1.0%	1.6%	0.1068	0.9455	0.0681

Table 3-9 Regional balancing charges allocation: Calendar year 2011

Charge	Allocation	RTO		East		West		Total	
Reliability Charges	Real-Time Load	$49,417,097	10.5%	$9,996,503	2.1%	$27,029,746	5.7%	$86,443,346	18.4%
	Real-Time Exports	$2,032,004	0.4%	$589,969	0.1%	$1,626,901	0.3%	$4,248,873	0.9%
	Total	$51,449,101	10.9%	$10,586,472	2.3%	$28,656,646	6.1%	$90,692,219	19.3%
Deviation Charges	Demand	$92,658,511	19.7%	$25,062,023	5.3%	$4,296,258	0.9%	$122,016,792	26.0%
	Supply	$28,234,803	6.0%	$6,642,217	1.4%	$1,482,909	0.3%	$36,359,930	7.7%
	Generator	$31,622,306	6.7%	$6,223,171	1.3%	$1,923,194	0.4%	$39,768,671	8.5%
	Total	$152,515,621	32.4%	$37,927,411	8.1%	$7,702,362	1.6%	$198,145,393	42.1%
Lost Opportunity Cost and Canceled Resources Charges	Demand	$112,133,882	23.9%	$0	0.0%	$0	0.0%	$112,133,882	23.9%
	Supply	$31,779,830	6.8%	$0	0.0%	$0	0.0%	$31,779,830	6.8%
	Generator	$37,372,185	7.9%	$0	0.0%	$0	0.0%	$37,372,185	7.9%
	Total	$181,285,897	38.6%	$0	0.0%	$0	0.0%	$181,285,897	38.6%
Total Balancing Charges		$385,250,619	81.9%	$48,513,882	10.3%	$36,359,008	7.7%	$470,123,510	100%

Figure 3-2 Daily balancing operating reserve rates ($/MWh)

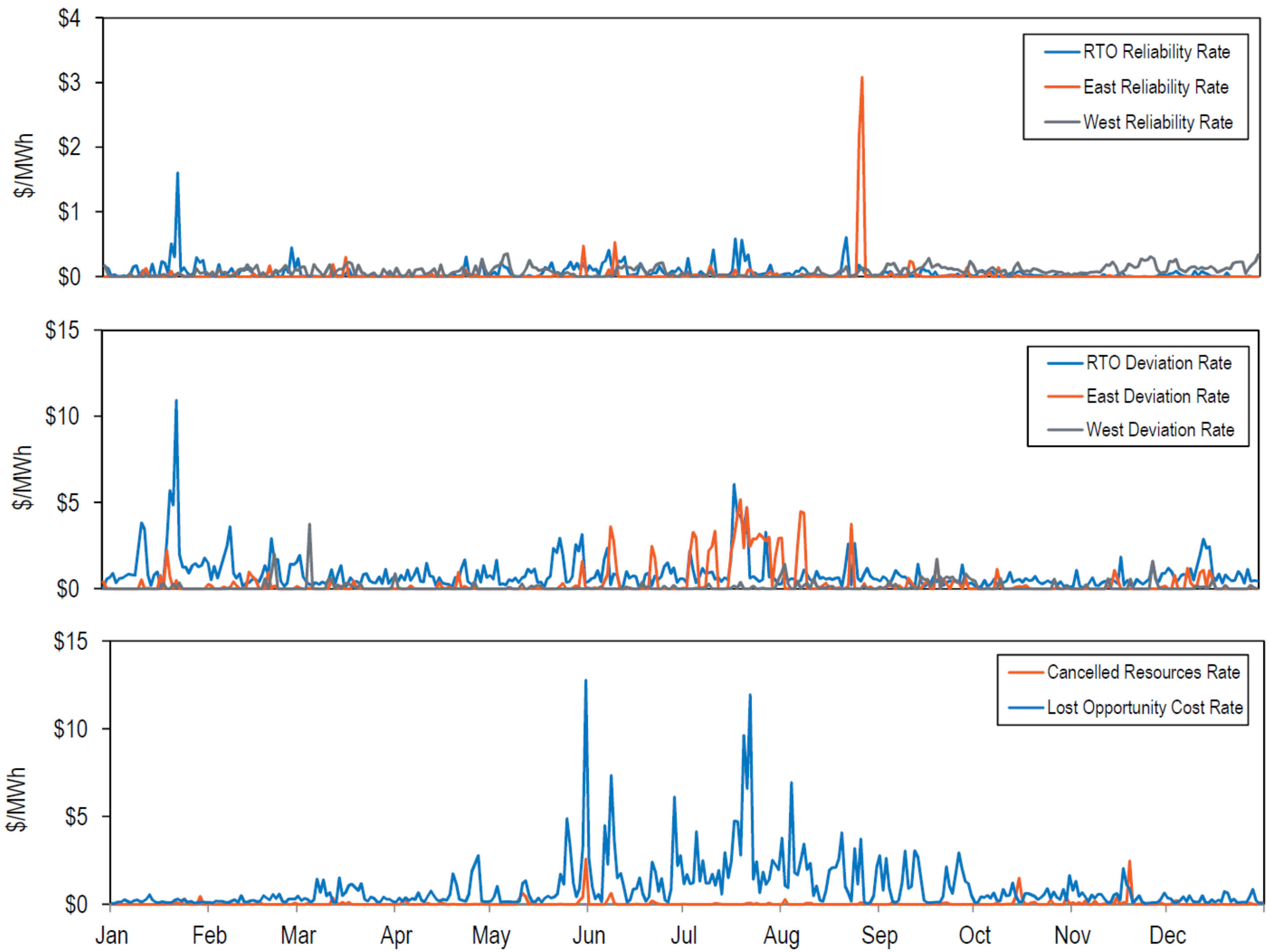

Table 3-11 Operating reserve rates statistics ($/MWh): Calendar year 2011

		Rates Charged ($/MWh)			
Region	Transaction	Maximum	Average	Minimum	Standard Deviation
East	INC	18.2083	2.2488	0.2377	2.5207
	DEC	18.2352	2.3581	0.3475	2.5039
	DA Load	0.4574	0.1094	0.0000	0.0727
	RT Load	3.2005	0.0910	0.0000	0.2454
	Deviation	18.2083	2.2488	0.2377	2.5207
West	INC	17.6208	2.0011	0.0867	2.0831
	DEC	17.6302	2.1104	0.3215	2.0690
	DA Load	0.4574	0.1094	0.0000	0.0727
	RT Load	1.6650	0.1458	0.0000	0.1401
	Deviation	17.6208	2.0011	0.0867	2.0831

Table 3-42 ALR and voltage support units' credits impact on the balancing operating reserve rates ($/MWh)

		Balancing Operating Reserve Rates ($/MWh)		Impact	
Category	Region	Without Units' Credits	Current	($/MWh)	Percentage
Reliability	RTO	0.0668	0.0681	0.0012	1.9%
	East	0.0274	0.0274	0.0000	0.0%
	West	0.0037	0.0775	0.0738	2,017.5%
Deviation	RTO	0.9207	0.9455	0.0248	2.7%
	East	0.4232	0.4232	0.0000	0.0%
	West	0.1032	0.1082	0.0050	4.9%

Table 3-44 Up-to Congestion Transactions Impact on the Operating Reserve Rates: Calendar year 2011

	Current Rates ($/MWh)	Rates Including Up-To Congestion Transactions ($/MWh)	Difference ($/MWh)	Percentage Difference
Day-Ahead	0.1068	0.0865	(0.0204)	(19.1%)
RTO Deviations	0.9455	0.2807	(0.6648)	(70.3%)
East Deviations	0.4232	0.1714	(0.2518)	(59.5%)
West Deviations	0.1082	0.0240	(0.0842)	(77.8%)
Lost Opportunity Cost	1.0678	0.3170	(0.7508)	(70.3%)
Canceled Resources	0.0560	0.0166	(0.0394)	(70.3%)

Table 3-23 Top 10 operating reserve revenue units (By percent of total system): Calendar years 2001 to 2011

	Top 10 Units Credit Share	Percent of Total PJM Units
2001	46.7%	1.8%
2002	32.0%	1.5%
2003	39.3%	1.3%
2004	46.3%	0.9%
2005	27.7%	0.8%
2006	29.7%	0.8%
2007	29.7%	0.8%
2008	18.8%	0.8%
2009	37.1%	0.8%
2010	33.2%	0.8%
2011	28.1%	0.8%

Table 5-1 Overview of Demand Side Programs

Emergency Load Response Program			Economic Load Response Program
Load Management (LM)			
Capacity Only	Capacity and Energy	Energy Only	Energy Only
Registered ILR only	DR cleared in RPM; Registered ILR	Not included in RPM	Not included in RPM
Mandatory Curtailment	Mandatory Curtailment	Voluntary Curtailment	Voluntary Curtailment
RPM event or test compliance penalties	RPM event or test compliance penalties	NA	NA
Capacity payments based on RPM clearing price	Capacity payments based on RPM price	NA	NA
No energy payment	Energy payment based on submitted higher of "minimum dispatch price" and LMP. Energy payment during PJM declared Emergency Event mandatory curtailments.	Energy payment based on submitted higher of "minimum dispatch price" and LMP. Energy payment only for voluntary curtailments.	Energy payment based on LMP less generation and transmission component of retail rate. Energy payment for hours of voluntary curtailment.

Figure 5-1 Demand Response revenue by market: Calendar years 2002 through 2011

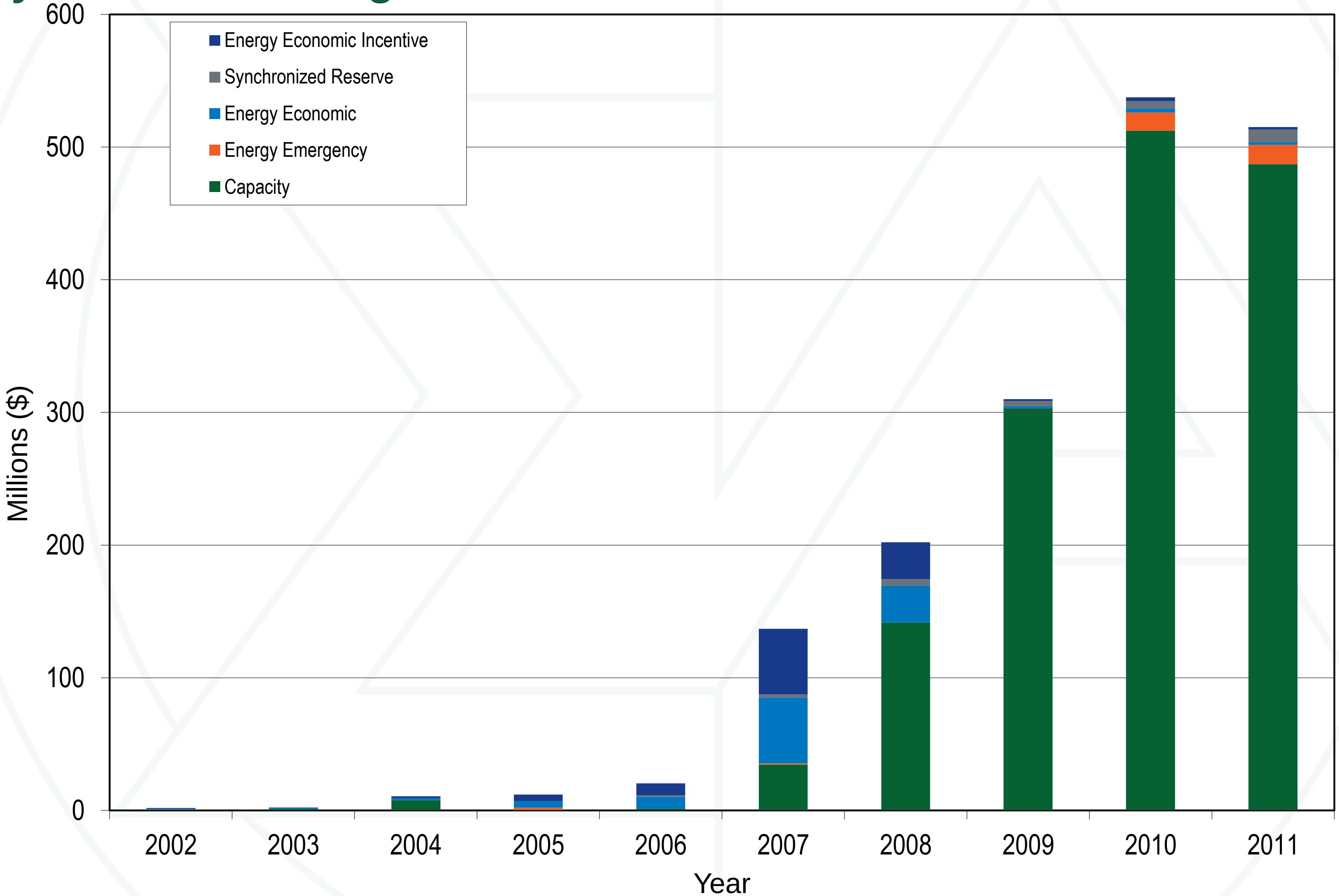

Table 5-12 Registered MW in the Load Management Program by program type: Delivery years 2007 through 2011

Delivery Year	Total DR MW	Total ILR MW	Total LM MW
2007/2008	560.7	1,584.6	2,145.3
2008/2009	1,017.7	3,480.5	4,498.2
2009/2010	1,020.5	6,273.8	7,294.3
2010/2011	1,070.0	7,982.4	9,052.4
2011/2012	2,792.1	8,730.5	11,522.7

Table 5-18 Distribution of GLD participant event days and observed load reductions across ranges of load reduction as a percentage of Peak Load Contribution (PLC) for the events in the 2011/2012 Delivery Year

Ranges of load reduction as a percentage of PLC	Number of GLD participant event days	Proportion of total GLD participant event days	Cumulative Proportion	Observed reductions (MW)	Proportion of total GLD observed reductions	Cumulative Proportion
0% - 25%	1,017	50%	50%	157.7	14%	14%
25% - 50%	323	16%	66%	153.6	13%	27%
50% - 75%	234	11%	77%	144.7	13%	40%
75% - 100%	172	8%	86%	112.1	10%	49%
100% - 150%	183	9%	95%	249.4	22%	71%
150% - 200%	40	2%	97%	214.0	19%	90%
200% - 300%	36	2%	98%	24.7	2%	92%
300% or greater	35	2%	100%	95.8	8%	100%
Total	2,040	100%		1,152.0	100%	

Figure 8-3 PJM's footprint and its external interfaces

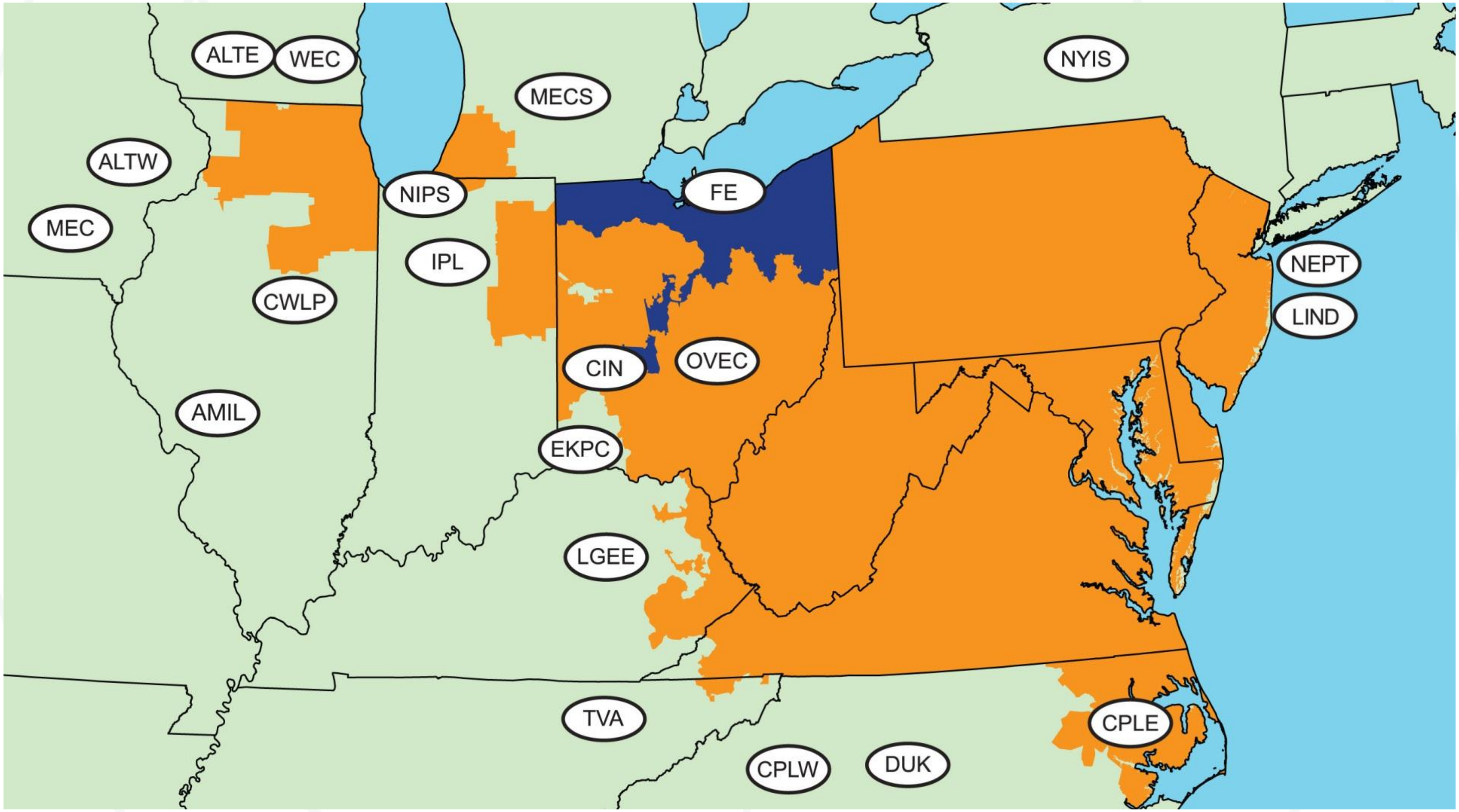

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Figure 8-2 PJM real-time and day-ahead scheduled import and export transaction volume history: January, 1999 through December, 2011

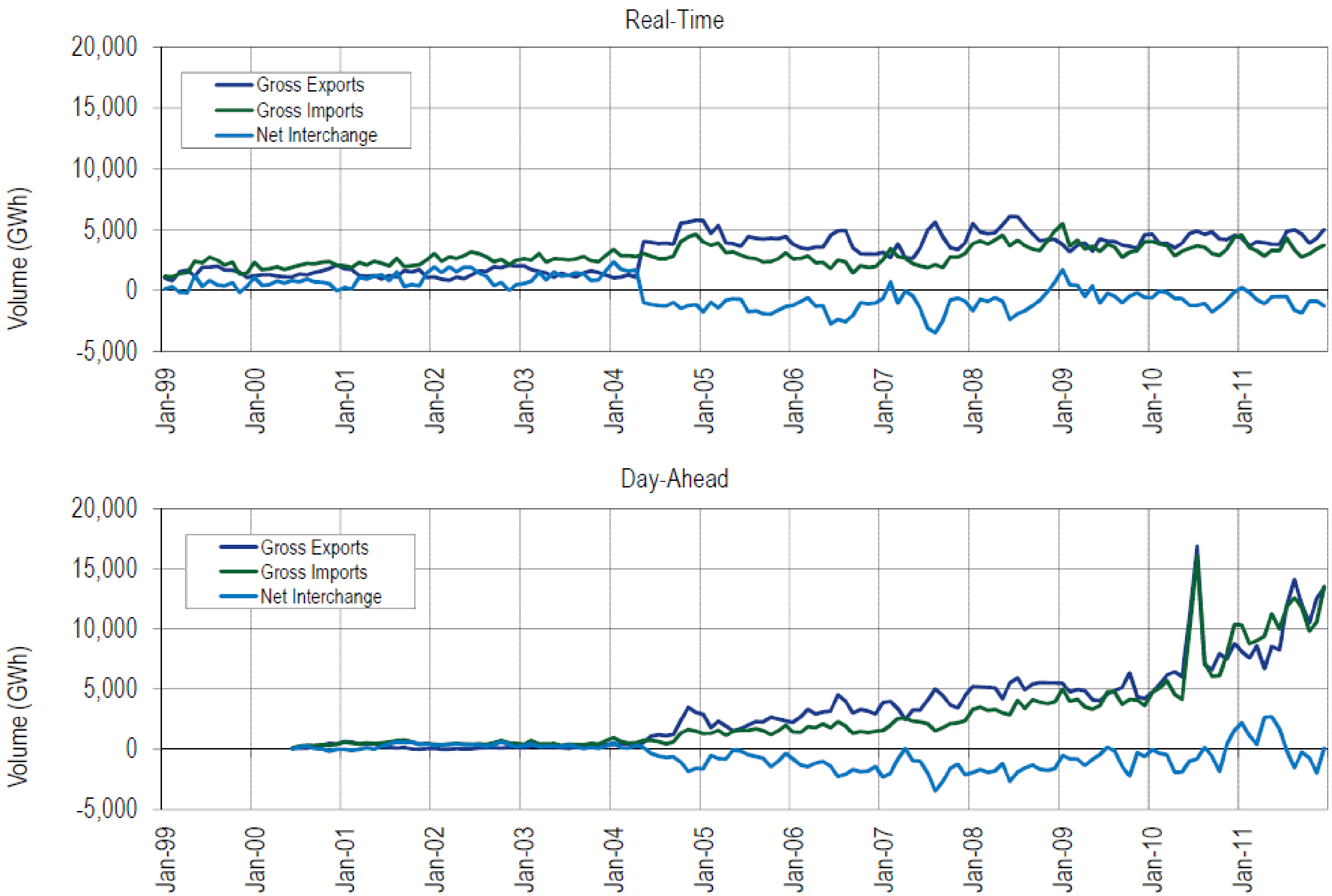
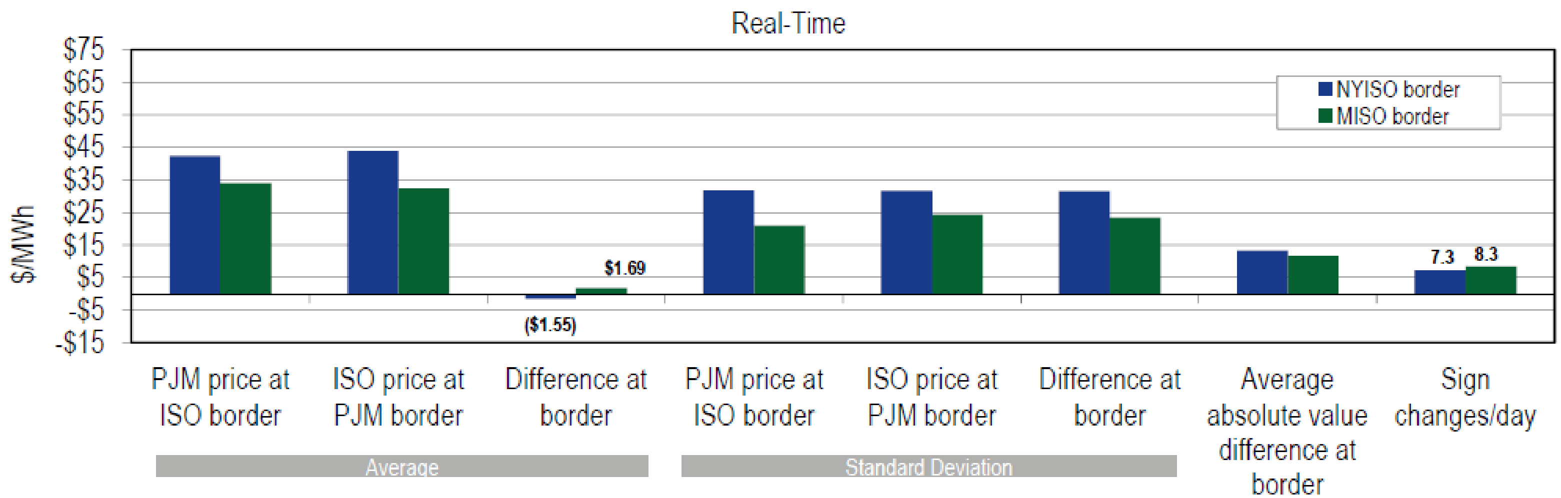


Figure 8-6 PJM, NYISO and MISO real-time and day-ahead border price averages: Calendar year 2011



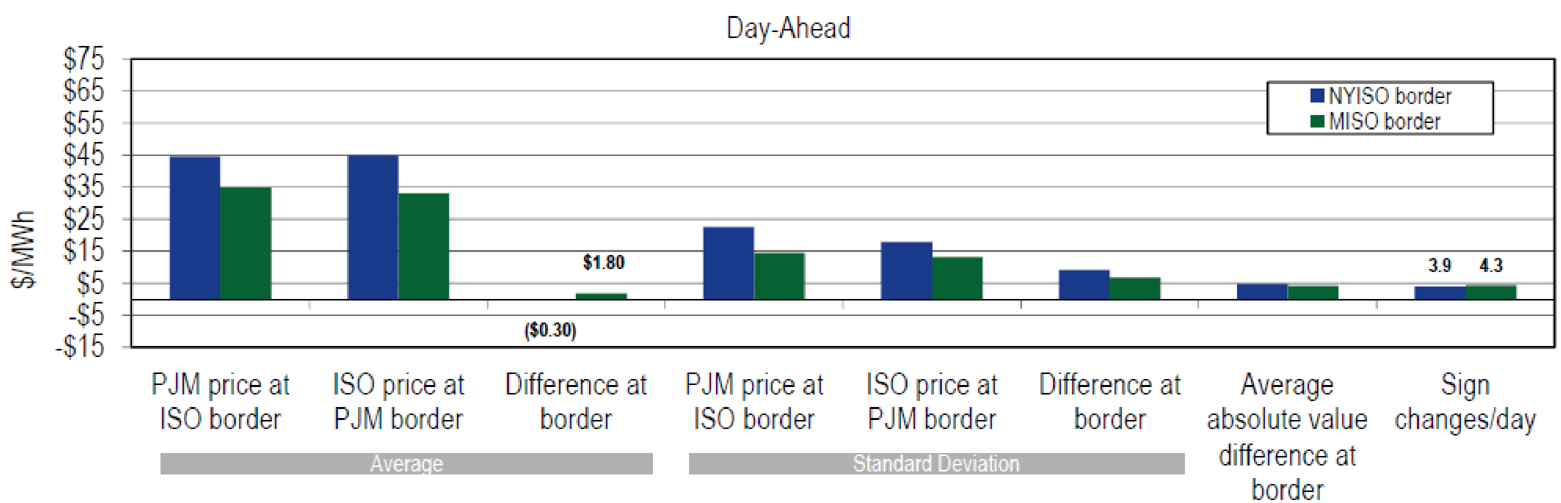


Table 9-4 History of ancillary services costs per MW of Load: 2001 through 2011

Year	Regulation	Scheduling, Dispatch, and System Control	Reactive	Synchronized Reserve	Supplementary Operating Reserve
2001	$0.50	$0.44	$0.22	$0.00	$1.07
2002	$0.45	$0.53	$0.21	$0.07	$0.63
2003	$0.50	$0.61	$0.24	$0.14	$0.83
2004	$0.50	$0.60	$0.25	$0.13	$0.90
2005	$0.79	$0.47	$0.26	$0.11	$0.93
2006	$0.53	$0.48	$0.29	$0.08	$0.43
2007	$0.63	$0.47	$0.29	$0.06	$0.58
2008	$0.68	$0.40	$0.31	$0.08	$0.59
2009	$0.34	$0.32	$0.37	$0.05	$0.48
2010	$0.34	$0.38	$0.41	$0.07	$0.73
2011	$0.32	$0.34	$0.42	$0.10	$0.77

Table 9-12 Comparison of weighted price and cost for PJM Regulation, August 2005 through December 2011

Year	Simple Average Regulation Market Price	Weighted Regulation Market Price	Regulation Market Cost	Regulation Price as Percentage of Cost
2005	$64.21	$64.03	$77.39	83%
2006	$31.13	$32.69	$44.98	73%
2007	$35.30	$36.86	$52.91	70%
2008	$41.78	$42.09	$64.43	65%
2009	$23.52	$23.56	$29.87	79%
2010	$17.96	$18.08	$32.07	56%
2011	$16.38	$16.21	$29.28	55%

Table 9-13 Summary of changes to Regulation Market design

Prior Regulation Market Rules (Effective May 1, 2005 through November 30, 2008)	New Regulation Market Rules (Effective December 1, 2008)
1. No structural test for market power.	1. Three Pivotal Supplier structural test for market power.
2. Offers capped at cost for identified dominant suppliers. (American Electric Power Company(AEP) and Virginia Electric Power Company (Dominion)) Price offers capped at $100 per MW.	2. Offers capped at cost for owners that fail the TPS test. Price offers capped at $100 per MW.
3. Cost based offers include a margin of $7.50 per MW.	3. Cost based offers include a margin of $12.00 per MW.
4. Opportunity cost calculated based on the offer schedule on which the unit is dispatched in the energy market.	4. Opportunity cost calculated based on the lesser of the price-based offer schedule or the highest cost-based offer schedule in the energy market.
5. All regulation net revenue above offer plus opportunity cost credited against operating reserve credits to unit owners.	5. No regulation market revenue above offer plus opportunity cost credited against operating reserve credits to unit owners.

Table 9-19 Comparison of weighted average price and cost for PJM Synchronized Reserve, 2005 through 2011

Year	Simple Average Synchronized Reserve Market Price	Weighted Average Synchronized Reserve Market Price	Weighted Average Synchronized Reserve Cost	Synchronized Reserve Price as Percent of Cost
2005	$10.89	$13.29	$17.59	76%
2006	$10.67	$14.57	$21.65	67%
2007	$11.57	$11.22	$16.26	69%
2008	$7.76	$10.65	$16.43	65%
2009	$6.58	$7.75	$9.77	79%
2010	$8.49	$10.55	$14.41	73%
2011	$9.48	$11.81	$15.48	76%

Table 10-14 Total annual PJM congestion (Dollars (Millions)): Calendar years 1999 to 2011

	Congestion Charges	Percent Change	Total PJM Billing	Percent of PJM Billing
1999	$65	NA	NA	NA
2000	$132	103.1%	$2,300	5.7%
2001	$271	105.3%	$3,400	8.0%
2002	$453	67.2%	$4,700	9.6%
2003	$464	2.4%	$6,900	6.7%
2004	$750	61.7%	$8,700	8.6%
2005	$2,092	178.8%	$22,630	9.2%
2006	$1,603	(23.4%)	$20,945	7.7%
2007	$1,846	15.1%	$30,556	6.0%
2008	$2,117	14.7%	$34,306	6.2%
2009	$719	(66.0%)	$26,550	2.7%
2010	$1,424	98.0%	$34,770	4.1%
2011	$998	(29.9%)	$35,887	2.8%
Total	$12,933	NA	$231,644	5.6%

Table 12-10 Comparison of self scheduled FTRs: Planning periods 2009 to 2010, 2010 to 2011 and 2011 to 2012

Planning Period	Self-Scheduled FTRs (MW)	Maximum Possible Self-Scheduled FTRs (MW)	Percent of ARRs Self-Scheduled as FTRs
2009/2010	68,589	109,612	62.6%
2010/2011	55,732	102,046	54.6%
2011/2012	46,017	103,735	44.4%

Table 12-5 Annual FTR Auction patterns of ownership by FTR direction: Planning period 2011 to 2012

			FTR Direction		
Trade Type	Organization Type	Self-Scheduled FTRs	Prevailing Flow	Counter Flow	All
Buy Bids	Physical	Yes	17.2%	1.0%	11.9%
		No	26.7%	14.2%	22.6%
		Total	43.9%	15.2%	34.4%
	Financial	No	56.1%	84.8%	65.6%
	Total		100.0%	100.0%	100.0%
Sell Offers	Physical		9.5%	9.8%	9.5%
	Financial		90.5%	90.2%	90.5%
	Total		100.0%	100.0%	100.0%

Figure 12-13 FTR payout ratio with adjustments by month, excluding and including excess revenue distribution: January 2004 to December 2011

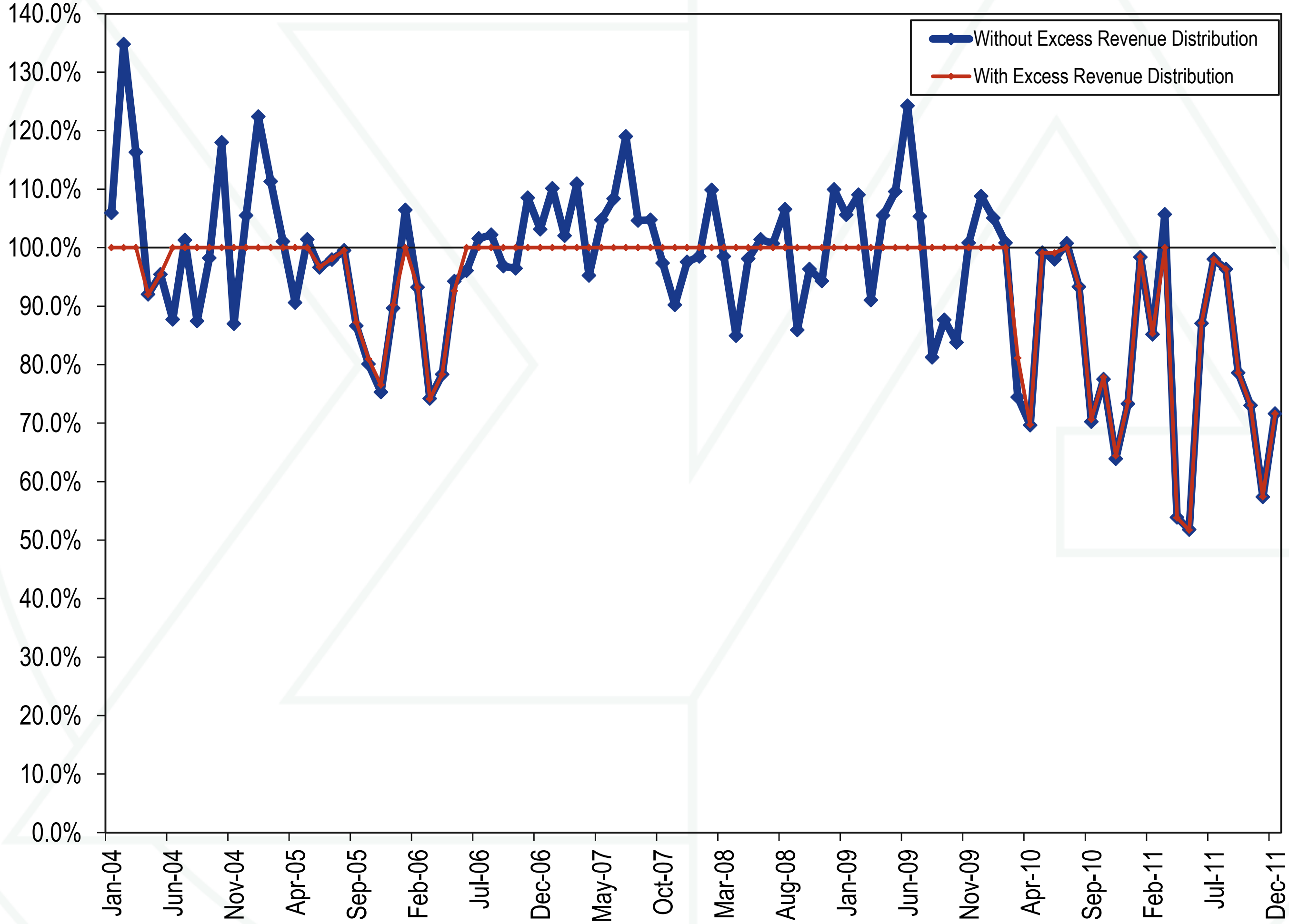


Table 12-35 ARR and FTR congestion offset by control zone: Planning period 2010 to 2011

Control Zone	ARR Credits	FTR Credits	FTR Auction Revenue	Total ARR and FTR Offset	Congestion	Total Offset - Congestion Difference	Percent Offset
AECO	$6,095,482	$15,356,788	$8,369,233	$13,083,037	$34,090,353	($21,007,316)	38.4%
AEP	$194,446,396	$194,595,085	$191,920,958	$197,120,523	$175,041,297	$22,079,227	>100%
AP	$308,392,416	$323,569,671	$266,825,782	$365,136,305	$272,379,630	$92,756,674	>100%
BGE	$33,678,997	$76,071,503	$47,988,952	$61,761,548	$83,727,088	($21,965,540)	73.8%
ComEd	$91,566,097	$104,050,751	$81,016,415	$114,600,433	$266,104,165	($151,503,732)	43.1%
DAY	$5,788,157	$2,228,889	$1,857,768	$6,159,278	$5,209,352	$949,926	>100%
DLCO	$5,052,309	$4,342,645	($4,464,852)	$13,859,806	$269,563,349	($255,703,542)	5.1%
Dominion	$176,257,284	$255,309,914	$183,744,171	$247,823,027	$53,782,364	$194,040,663	>100%
DPL	$12,954,039	$28,003,826	$21,098,243	$19,859,622	$22,397,356	($2,537,734)	88.7%
External	$20,706,621	($4,725,192)	($7,470,423)	$23,451,852	($25,134,091)	$48,585,943	>100%
JCPL	$18,916,958	$50,076,625	$22,815,912	$46,177,671	$63,099,463	($16,921,792)	73.2%
Met-Ed	$13,935,697	$18,983,528	$8,126,867	$24,792,358	$3,088,074	$21,704,285	>100%
PECO	$23,365,352	$62,384,191	$30,955,754	$54,793,789	($4,607,904)	$59,401,692	>100%
PENELEC	$23,704,470	$61,042,705	$30,722,474	$54,024,701	$91,672,220	($37,647,520)	58.9%
Pepco	$22,895,504	$126,337,038	$124,122,586	$25,109,956	$92,132,782	($67,022,825)	27.3%
PPL	$27,383,200	$29,847,535	$17,822,265	$39,408,470	$730,025	$38,678,445	>100%
PSEG	$44,042,817	$86,676,270	$73,683,481	$57,035,606	($4,896,944)	$61,932,550	>100%
RECO	$93,249	($2,241,262)	($1,299,731)	($848,282)	$3,487,775	($4,336,057)	0.0%
Total	$1,029,275,045	$1,431,910,509	$1,097,835,855	$1,363,349,699	$1,401,866,354	($38,516,655)	97.3%

Market Monitoring Unit

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