2015 State of the Market Report for PJM

March 10, 2016

Washington, D.C.

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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**
  - **To PJM Board for administration of the contract**

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
- FERC has enforcement authority
- 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 manipulation**
- **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**

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.
- Monitor for market manipulation.

Figure 1-1 PJM's footprint and its 20 control zones

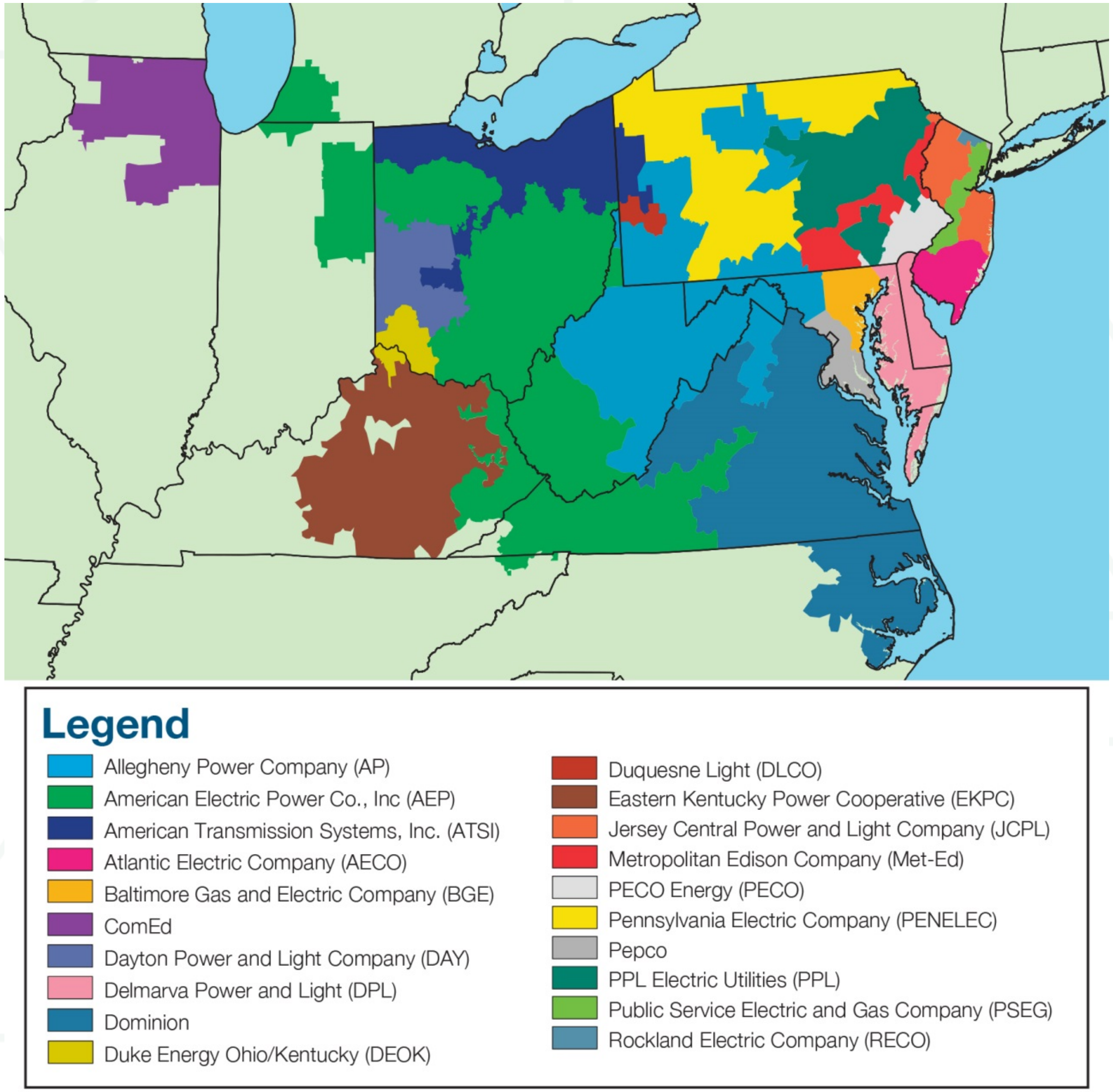


Table 3-1 The energy market results were competitive

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

State of the Market Report Recommendations: Energy Market

- Aggregate offer cap > $1,000 only if cost based
- Local market power mitigation improvements
  - Constant markup on price and cost based offers
  - Cost based offer on same fuel as price based offer
  - PLS parameters at least as flexible as price based offer
- OEM parameters should be used for performance assessment and uplift
- Define explicit rules related to use of transmission penalty factors in setting LMP.

Table 1-8 Total price per MWh by category: 2014 and 2015

Category	2014 $/MWh	2014 Percent of Total	2015 $/MWh	2015 Percent of Total	2014 to 2015 Percent Change Totals
Load Weighted Energy	$53.14	74.2%	$36.16	63.6%	(31.9%)
Capacity	$9.01	12.6%	$11.12	19.6%	23.5%
Transmission Service Charges	$5.95	8.3%	$7.08	12.5%	19.0%
Transmission Enhancement Cost Recovery	$0.42	0.6%	$0.51	0.9%	19.2%
PJM Administrative Fees	$0.44	0.6%	$0.44	0.8%	0.1%
Energy Uplift (Operating Reserves)	$1.18	1.6%	$0.38	0.7%	(67.7%)
Reactive	$0.40	0.6%	$0.37	0.7%	(6.0%)
Regulation	$0.33	0.5%	$0.23	0.4%	(28.8%)
Capacity (FRR)	$0.20	0.3%	$0.13	0.2%	(38.7%)
Synchronized Reserves	$0.21	0.3%	$0.12	0.2%	(41.4%)
Day Ahead Scheduling Reserve (DASR)	$0.05	0.1%	$0.10	0.2%	115.5%
Transmission Owner (Schedule 1A)	$0.09	0.1%	$0.09	0.2%	1.2%
Black Start	$0.08	0.1%	$0.06	0.1%	(15.5%)
NERC/RFC	$0.02	0.0%	$0.03	0.0%	19.5%
Non-Synchronized Reserves	$0.02	0.0%	$0.02	0.0%	2.1%
Load Response	$0.02	0.0%	$0.02	0.0%	(15.2%)
RTO Startup and Expansion	$0.01	0.0%	$0.01	0.0%	(49.0%)
Transmission Facility Charges	$0.00	0.0%	$0.00	0.0%	134.6%
Emergency Load Response	$0.06	0.1%	$0.00	0.0%	(98.9%)
Emergency Energy	$0.01	0.0%	$0.00	0.0%	(100.0%)
Total	$71.62	100.0%	$56.86	100.0%	(20.6%)

Figure 3-4 Average PJM aggregate real-time generation supply curves by offer price: Summer of 2014 and 2015

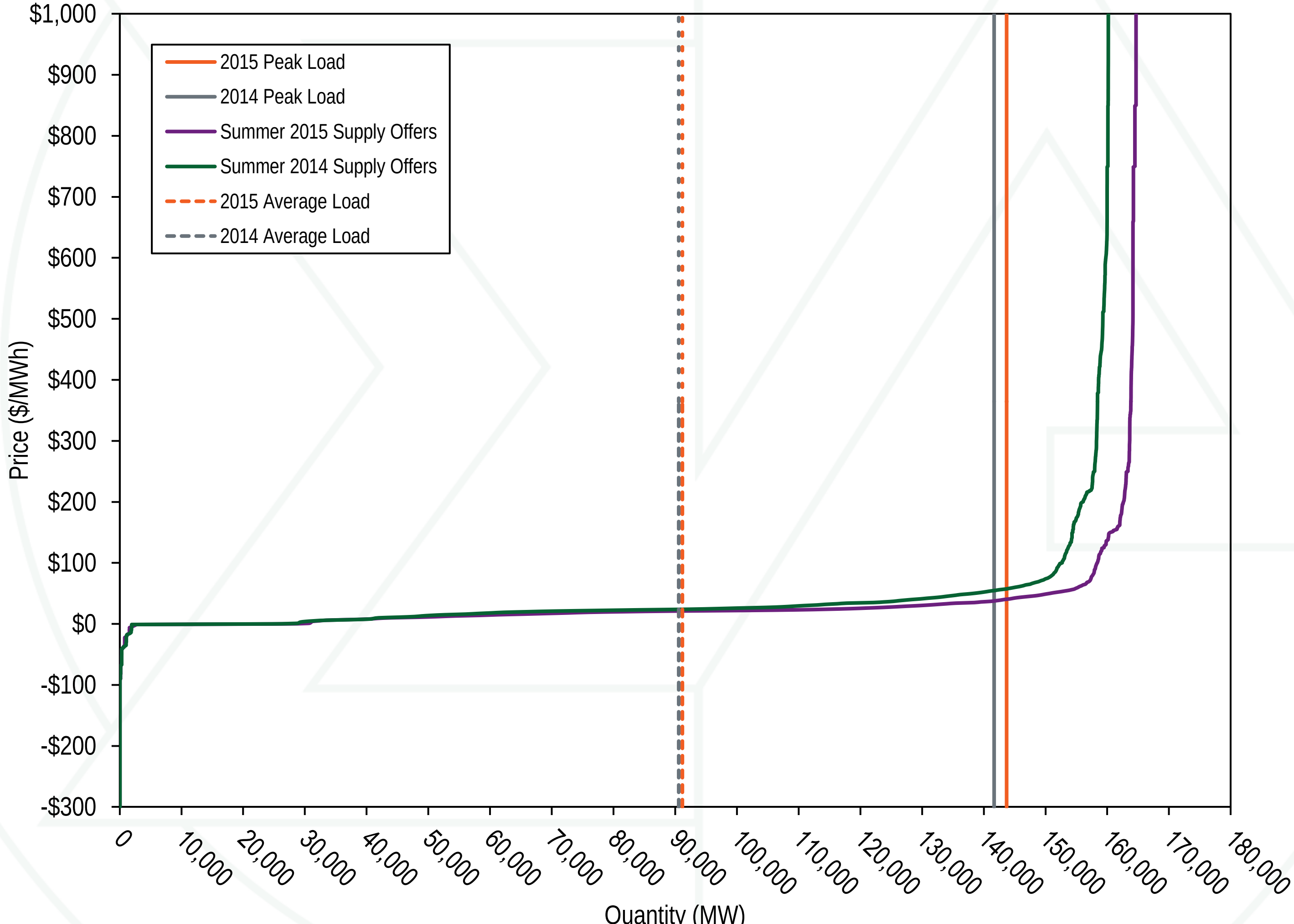


Table 3-15 PJM real-time average hourly load and real-time average hourly load plus average hourly exports: 1998 through 2015

	PJM Real-Time Demand (MWh)				Year-to-Year Change			
	Load		Load Plus Exports		Load		Load Plus Exports	
	Load	Standard Deviation	Demand	Standard Deviation	Load	Standard Deviation	Demand	Standard Deviation
1998	28,578	5,511	28,578	5,511	NA	NA	NA	NA
1999	29,641	5,955	29,641	5,955	3.7%	8.1%	3.7%	8.1%
2000	30,113	5,529	31,341	5,728	1.6%	(7.2%)	5.7%	(3.8%)
2001	30,297	5,873	32,165	5,564	0.6%	6.2%	2.6%	(2.9%)
2002	35,776	7,976	37,676	8,145	18.1%	35.8%	17.1%	46.4%
2003	37,395	6,834	39,380	6,716	4.5%	(14.3%)	4.5%	(17.5%)
2004	49,963	13,004	54,953	14,947	33.6%	90.3%	39.5%	122.6%
2005	78,150	16,296	85,301	16,546	56.4%	25.3%	55.2%	10.7%
2006	79,471	14,534	85,696	15,133	1.7%	(10.8%)	0.5%	(8.5%)
2007	81,681	14,618	87,897	15,199	2.8%	0.6%	2.6%	0.4%
2008	79,515	13,758	86,306	14,322	(2.7%)	(5.9%)	(1.8%)	(5.8%)
2009	76,034	13,260	81,227	13,792	(4.4%)	(3.6%)	(5.9%)	(3.7%)
2010	79,611	15,504	85,518	15,904	4.7%	16.9%	5.3%	15.3%
2011	82,541	16,156	88,466	16,313	3.7%	4.2%	3.4%	2.6%
2012	87,011	16,212	92,135	16,052	5.4%	0.3%	4.1%	(1.6%)
2013	88,332	15,489	92,879	15,418	1.5%	(4.5%)	0.8%	(3.9%)
2014	89,099	15,763	94,471	15,677	0.9%	1.8%	1.7%	1.7%
2015	88,594	16,663	92,665	16,784	(0.6%)	5.7%	(1.9%)	7.1%

Figure 3-15 PJM real-time monthly average hourly load: 2014 and 2015

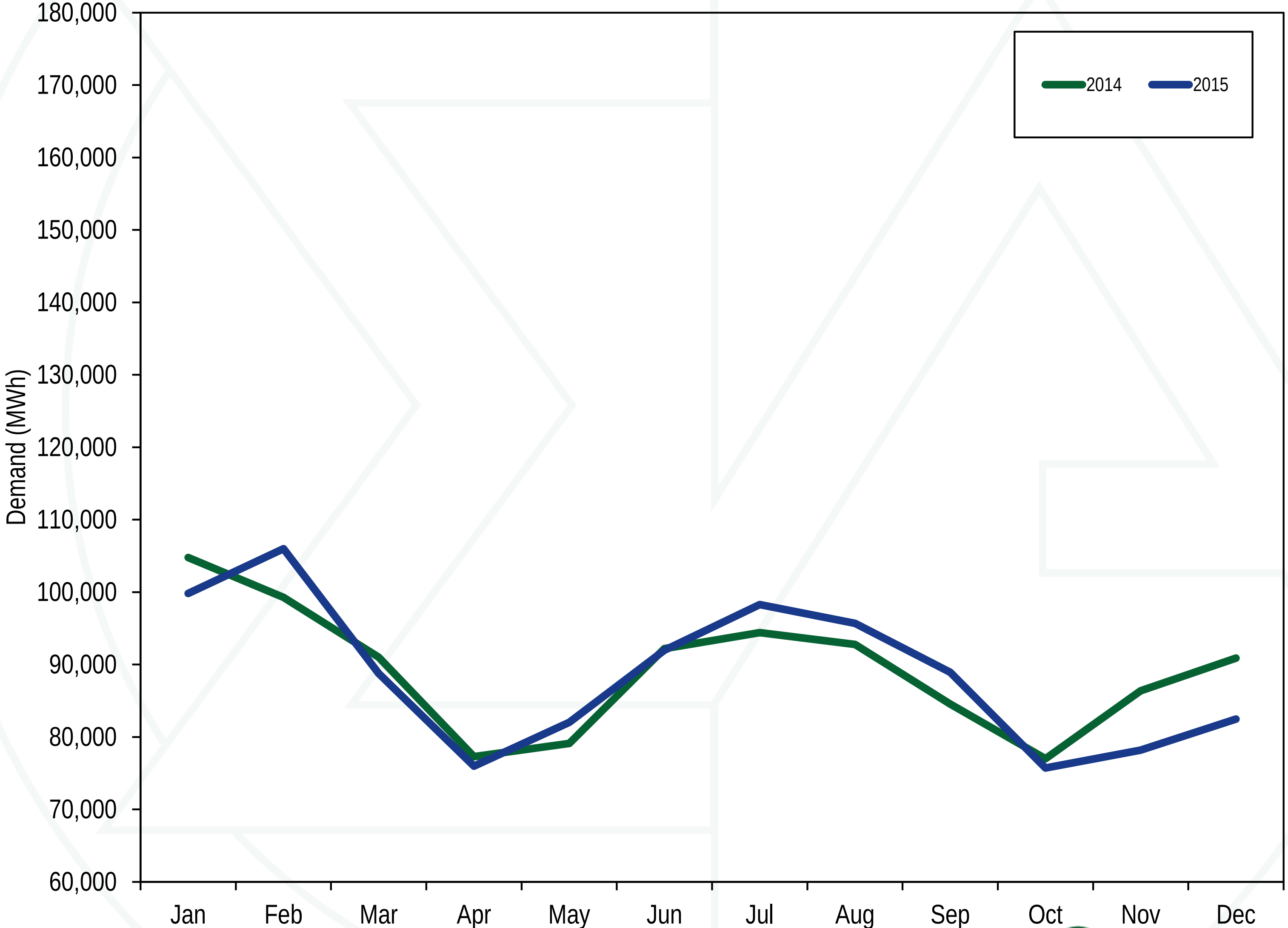


Table 3-63 PJM real-time, load-weighted, average LMP (Dollars per MWh): 1998 through 2015

	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%
2012	$35.23	$30.43	$23.66	(23.3%)	(16.7%)	(29.3%)
2013	$38.66	$33.25	$23.78	9.7%	9.3%	0.5%
2014	$53.14	$36.20	$76.20	37.4%	8.9%	220.4%
2015	$36.16	$27.66	$31.06	(31.9%)	(23.6%)	(59.2%)

Figure 3-35 PJM real-time, monthly and annual, load-weighted, average LMP: 1999 through 2015

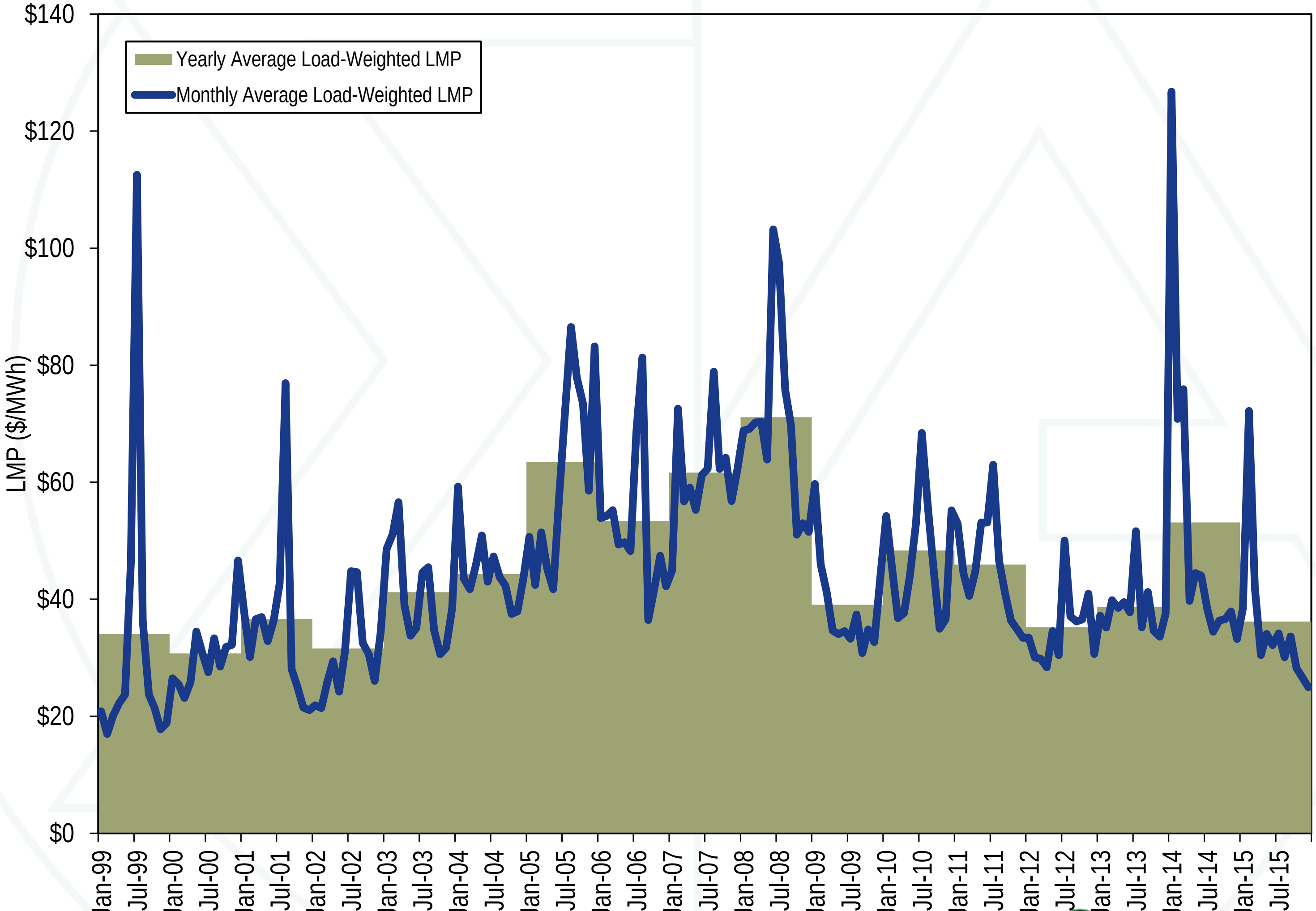


Figure 3-36 Spot average fuel price comparison with fuel delivery charges: 2012 through 2015 ($/MMBtu)

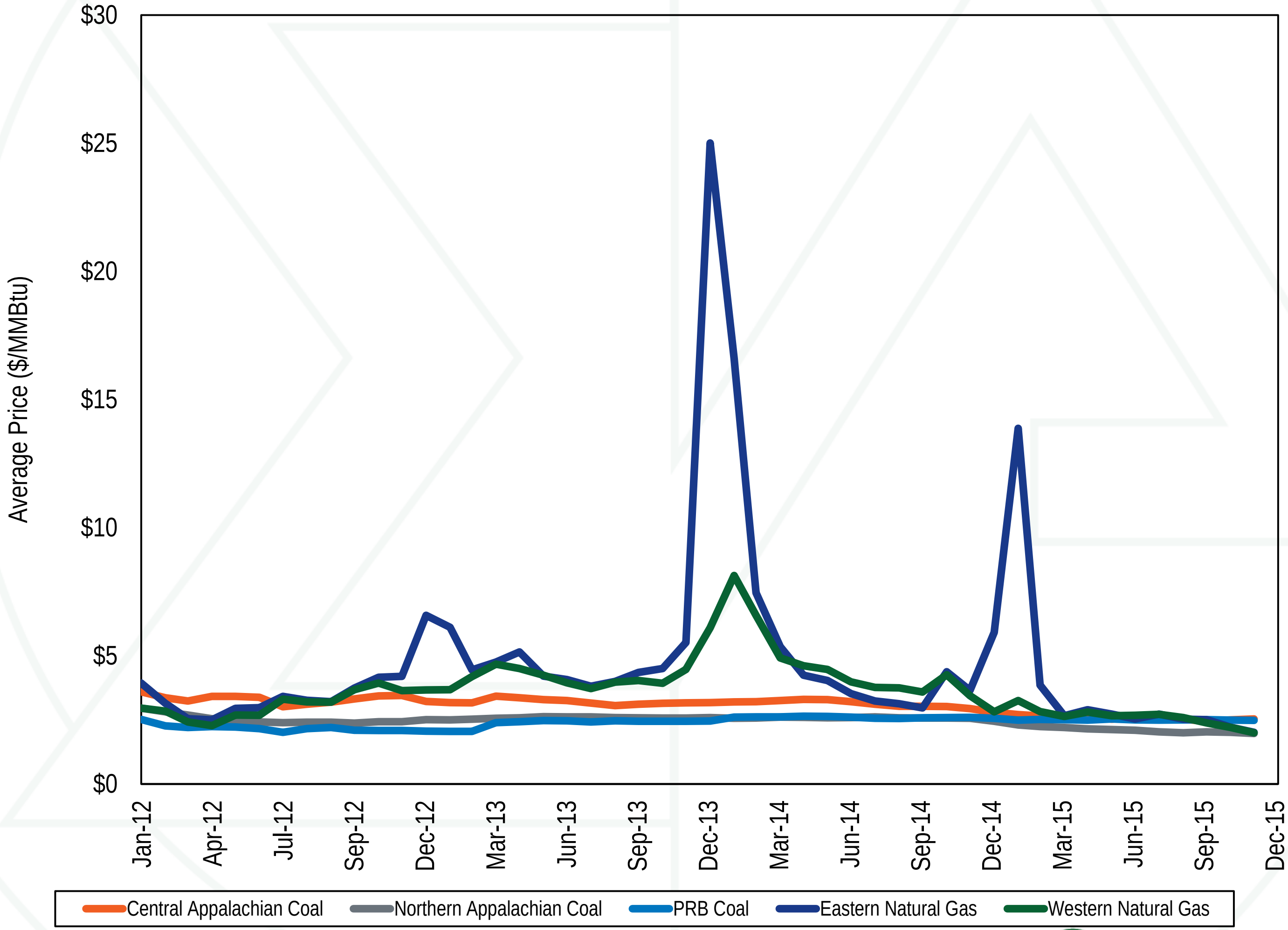


Figure 7-5 Average short run marginal costs: 2009 through 2015

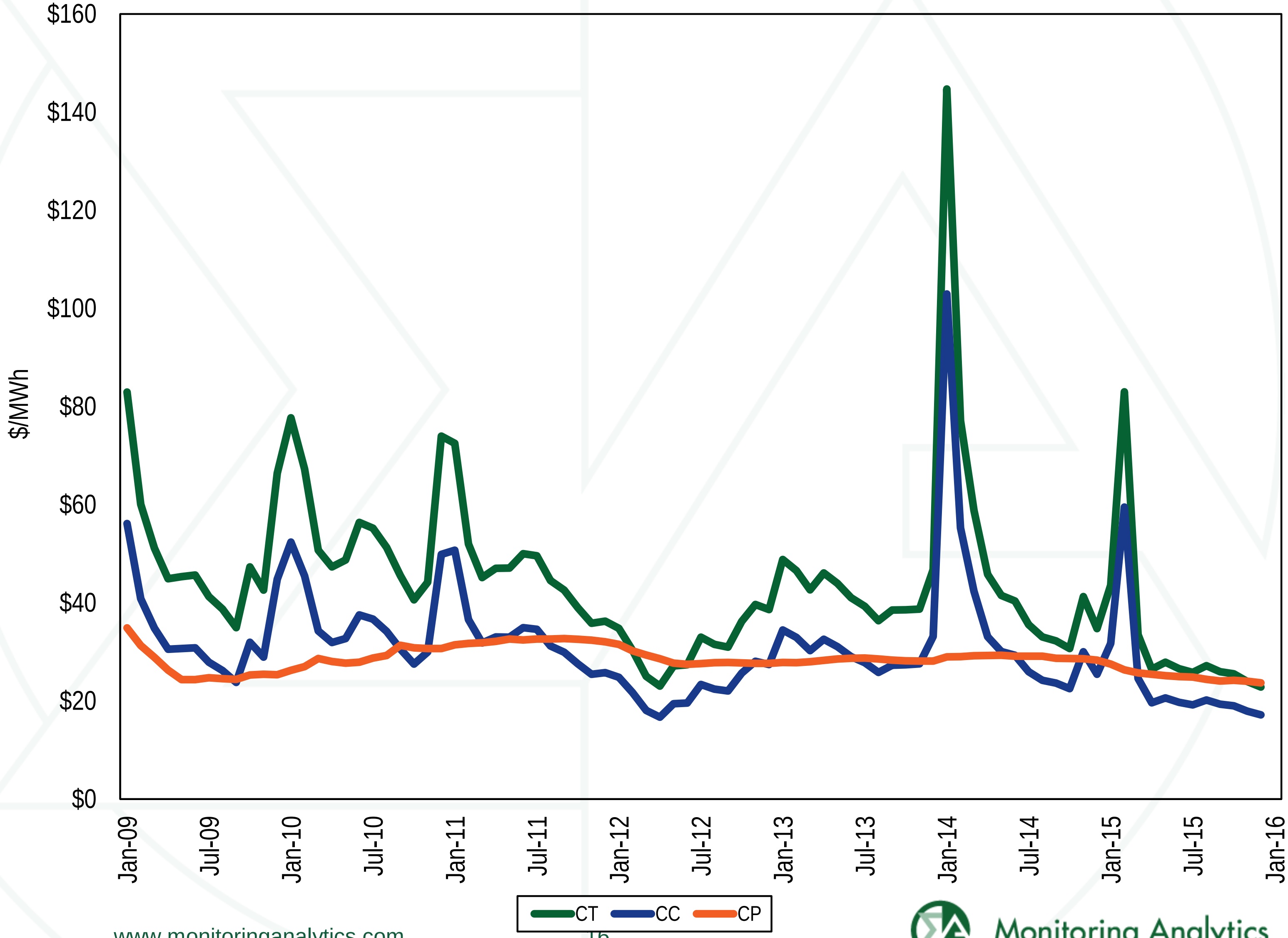


Table 3-65 PJM real-time annual, fuel-cost adjusted, load-weighted average LMP (Dollars per MWh): year over year

	2015 Load-Weighted LMP	2015 Fuel-Cost-Adjusted, Load-Weighted LMP	Change
Average	$36.16	$41.91	15.9%
	2014 Load-Weighted LMP	2015 Fuel-Cost-Adjusted, Load-Weighted LMP	Change
Average	$53.14	$41.91	(21.1%)
	2014 Load-Weighted LMP	2015 Load-Weighted LMP	Change
Average	$53.14	$36.16	(31.9%)

Table 3-8 PJM generation (By fuel source (GWh)): 2014 and 2015

	2014		2015		
	GWh	Percent	GWh	Percent	Change in Output
Coal	349,961.9	43.3%	287,634.7	36.6%	(17.8%)
Standard Coal	346,053.6	42.8%	284,414.0	36.2%	(17.8%)
Waste Coal	3,908.3	0.5%	3,220.7	0.4%	(17.6%)
Nuclear	277,635.6	34.4%	279,106.5	35.5%	0.5%
Gas	144,140.0	17.8%	184,083.2	23.4%	27.7%
Natural Gas	140,463.4	17.4%	180,307.8	22.9%	28.4%
Landfill Gas	2,369.0	0.3%	2,404.2	0.3%	1.5%
Biomass Gas	1,307.6	0.2%	1,371.2	0.2%	4.9%
Hydroelectric	14,394.3	1.8%	13,066.6	1.7%	(9.2%)
Pumped Storage	7,138.7	0.9%	5,946.1	0.8%	(16.7%)
Run of River	7,255.5	0.9%	7,120.5	0.9%	(1.9%)
Wind	15,540.5	1.9%	16,609.7	2.1%	6.9%
Waste	4,833.3	0.6%	4,729.7	0.6%	(2.1%)
Solid Waste	4,251.4	0.5%	4,175.4	0.5%	(1.8%)
Miscellaneous	581.8	0.1%	554.3	0.1%	(4.7%)
Oil	1,073.2	0.1%	917.6	0.1%	(14.5%)
Heavy Oil	464.3	0.1%	610.9	0.1%	31.6%
Light Oil	511.8	0.1%	247.8	0.0%	(51.6%)
Diesel	75.3	0.0%	56.9	0.0%	(24.4%)
Kerosene	21.7	0.0%	1.8	0.0%	(91.6%)
Jet Oil	0.0	0.0%	0.0	0.0%	NA
Solar, Net Energy Metering	400.9	0.0%	542.7	0.0%	35.4%
Battery	6.5	0.0%	7.6	0.0%	17.5%
Total	807,986.2	100.0%	786,698.2	100.0%	(2.6%)

Table 5-26 PJM capacity factor (By unit type (GWh)): 2014 and 2015

	2014		2015		
Unit Type	Generation (GWh)	Capacity Factor	Generation (GWh)	Capacity Factor	Change in 2015 from 2014
Battery	6.5	0.7%	7.6	0.5%	(0.3%)
Combined Cycle	126,790.6	55.3%	159,420.8	60.6%	5.4%
Combustion Turbine	9,944.9	3.7%	14,213.8	5.6%	1.9%
Diesel	565.3	14.9%	574.2	15.2%	0.2%
Diesel (Landfill gas)	1,489.0	45.9%	1,508.6	45.6%	(0.3%)
Fuel Cell	222.7	84.7%	227.1	86.4%	1.7%
Nuclear	277,635.6	94.0%	279,106.5	94.5%	0.5%
Pumped Storage Hydro	7,152.9	14.9%	6,038.4	12.8%	(2.1%)
Run of River Hydro	7,241.4	31.1%	7,028.3	29.3%	(1.7%)
Solar	399.8	15.6%	533.0	16.0%	0.5%
Steam	360,995.9	49.9%	301,260.0	45.6%	(4.3%)
Wind	15,540.5	27.8%	16,609.7	28.3%	0.5%
Total	807,985.1	48.8%	786,528.0	48.6%	(0.2%)

Table 3-19 Offer-capping statistics – energy only: 2011 to 2015

	Real Time		Day Ahead	
Year	Unit Hours Capped	MW Capped	Unit Hours Capped	MW Capped
2011	0.6%	0.2%	0.0%	0.0%
2012	0.8%	0.4%	0.1%	0.1%
2013	0.4%	0.2%	0.1%	0.0%
2014	0.5%	0.2%	0.2%	0.1%
2015	0.4%	0.2%	0.2%	0.1%

Table 3-68 Components of PJM real-time (Adjusted), load-weighted, average LMP: 2014 and 2015

	2014		2015		Change
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Percent
Coal	$17.73	33.4%	$15.62	43.2%	9.8%
Gas	$18.71	35.2%	$9.85	27.2%	(8.0%)
VOM	$2.65	5.0%	$2.38	6.6%	1.6%
Markup	$3.32	6.2%	$1.75	4.8%	(1.4%)
Ten Percent Adder	$2.33	4.4%	$1.40	3.9%	(0.5%)
Oil	$2.80	5.3%	$1.25	3.5%	(1.8%)
Ancillary Service Redispatch Cost	$0.52	1.0%	$1.06	2.9%	2.0%
LPA Rounding Difference	$0.07	0.1%	$0.94	2.6%	2.5%
NA	$1.56	2.9%	$0.89	2.4%	(0.5%)
SO2 Cost	$0.01	0.0%	$0.35	1.0%	0.9%
NOx Cost	$0.13	0.2%	$0.29	0.8%	0.6%
Increase Generation Adder	$0.69	1.3%	$0.24	0.7%	(0.6%)
CO2 Cost	$0.23	0.4%	$0.21	0.6%	0.1%
Other	$0.03	0.1%	$0.15	0.4%	0.4%
Municipal Waste	$0.02	0.0%	$0.01	0.0%	(0.0%)
Market-to-Market Adder	($0.00)	(0.0%)	$0.01	0.0%	0.0%
FMU Adder	$0.62	1.2%	$0.00	0.0%	(1.2%)
Emergency DR Adder	$1.83	3.4%	$0.00	0.0%	(3.4%)
Scarcity Adder	$0.10	0.2%	$0.00	0.0%	(0.2%)
Constraint Violation Adder	$0.00	0.0%	($0.00)	(0.0%)	(0.0%)
Uranium	($0.01)	(0.0%)	($0.00)	(0.0%)	0.0%
Decrease Generation Adder	($0.17)	(0.3%)	($0.06)	(0.2%)	0.2%
Wind	($0.01)	(0.0%)	($0.07)	(0.2%)	(0.2%)
LPA-SCED Differential	($0.01)	(0.0%)	($0.11)	(0.3%)	(0.3%)
Total	$53.14	100.0%	$36.16	100.0%	0.0%

Table 11-8 Total PJM congestion (Dollars (Millions)): 2008 through 2015

	Congestion Costs (Millions)			
	Congestion Cost	Percent Change	Total PJM Billing	Percent of PJM Billing
2008	$2,052	NA	$34,306	6.0%
2009	$719	(65.0%)	$26,550	2.7%
2010	$1,423	98.0%	$34,771	4.1%
2011	$999	(29.8%)	$35,887	2.8%
2012	$529	(47.0%)	$29,181	1.8%
2013	$677	28.0%	$33,862	2.0%
2014	$1,932	185.5%	$50,030	3.9%
2015	$1,385	(28.3%)	$42,630	3.2%

Figure 11-1 PJM monthly total congestion cost (Dollars (Millions)): 2009 through 2015

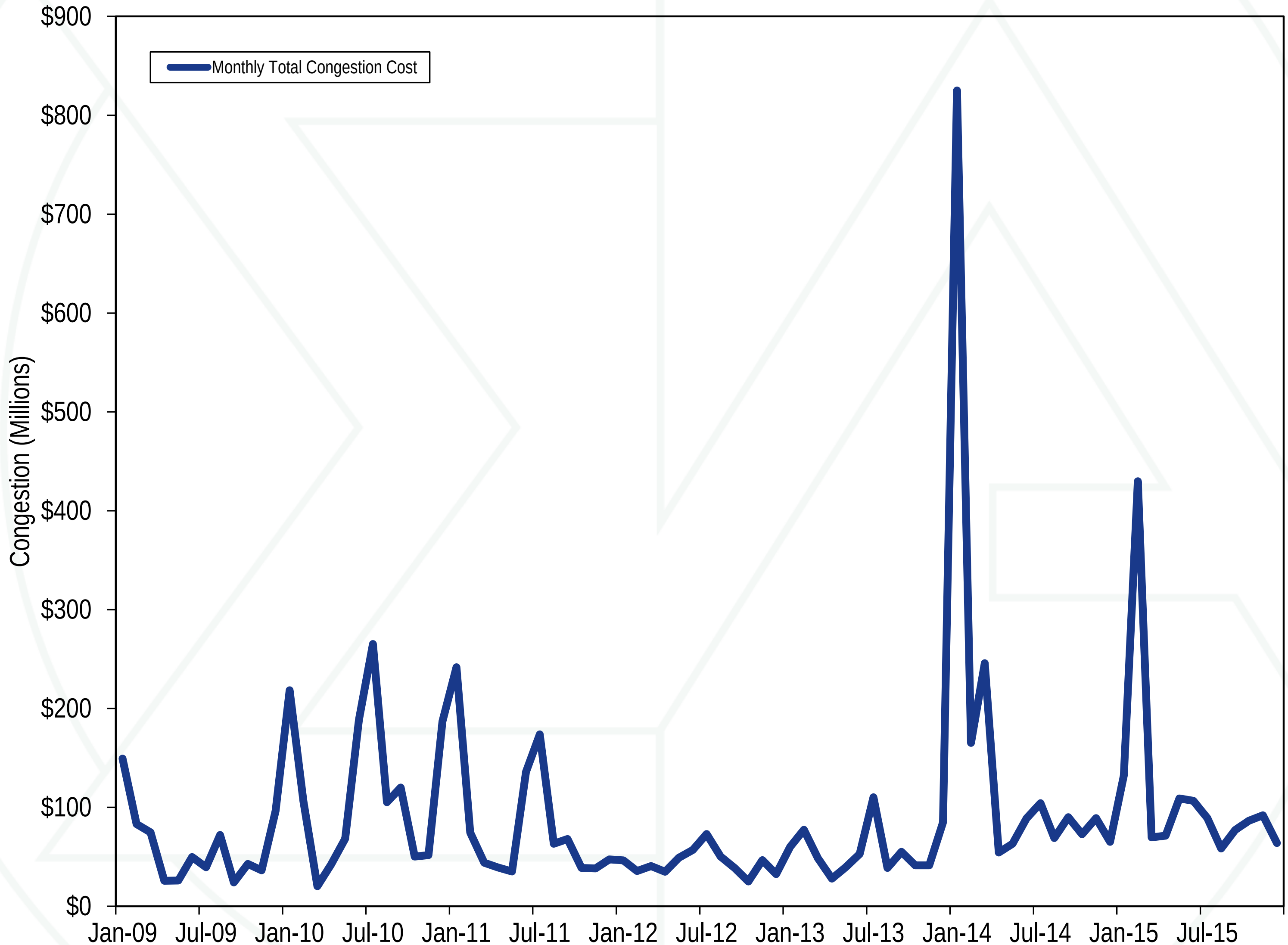


Table 5-1 The capacity market results were competitive

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

State of the Market report Recommendations: Capacity Market

- Implement consistent definition of a capacity resource as physical at time of auction and delivery year.
- Net revenue calculation for Net CONE should reflect actual flexibility of reference technology.
- Net revenue calculation for offer caps should be based on lower of price or cost.
- Improve market clearing rules by including make whole and nesting in optimization.
- Maintain performance incentives and product definitions in Capacity Performance design.

Table 5-3 PJM installed capacity (By fuel source): January 1, May 31, June 1, and December 31, 2015

	1-Jan-15		31-May-15		1-Jun-15		31-Dec-15	
	MW	Percent	MW	Percent	MW	Percent	MW	Percent
Coal	72,741.3	39.6%	72,343.5	39.5%	66,878.1	37.8%	66,674.8	37.5%
Gas	59,662.6	32.5%	59,862.3	32.7%	59,460.1	33.6%	60,487.4	34.0%
Hydroelectric	8,765.3	4.8%	8,690.8	4.7%	8,698.8	4.9%	8,787.5	4.9%
Nuclear	32,947.1	17.9%	33,078.4	18.1%	33,071.5	18.7%	33,071.5	18.6%
Oil	7,907.6	4.3%	7,299.7	4.0%	6,853.4	3.9%	6,851.8	3.9%
Solar	97.5	0.1%	97.5	0.1%	128.0	0.1%	128.0	0.1%
Solid waste	781.9	0.4%	781.9	0.4%	771.3	0.4%	769.4	0.4%
Wind	822.7	0.4%	822.7	0.4%	876.2	0.5%	912.4	0.5%
Total	183,726.0	100.0%	182,976.8	100.0%	176,737.4	100.0%	177,682.8	100.0%

Figure 5-1 Percentage of PJM installed capacity (By fuel source): June 1, 2007 through June 1, 2018

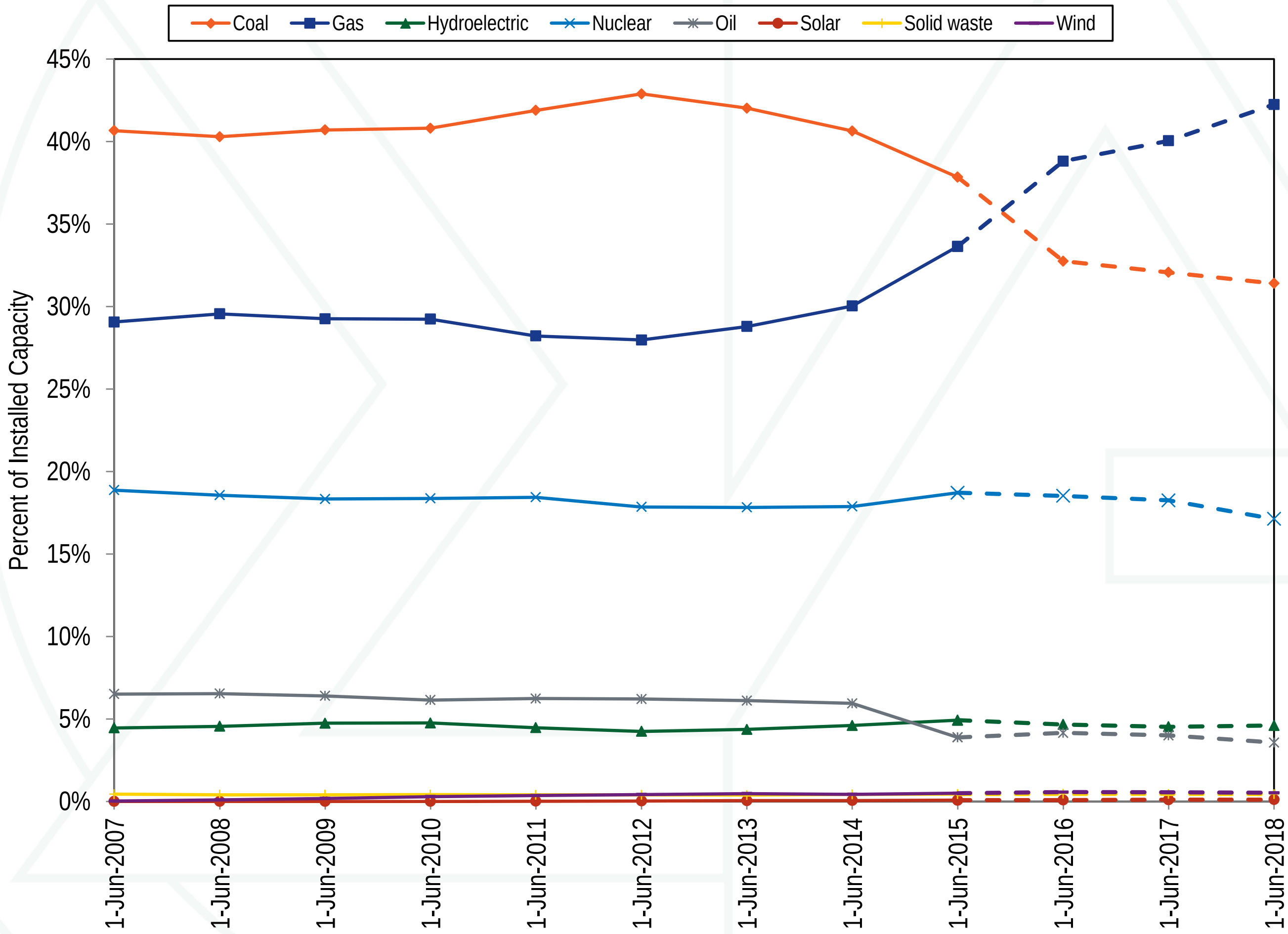


Figure 5-10 Trends in the PJM equivalent demand forced outage rate (EFORd): 1999 through 2015

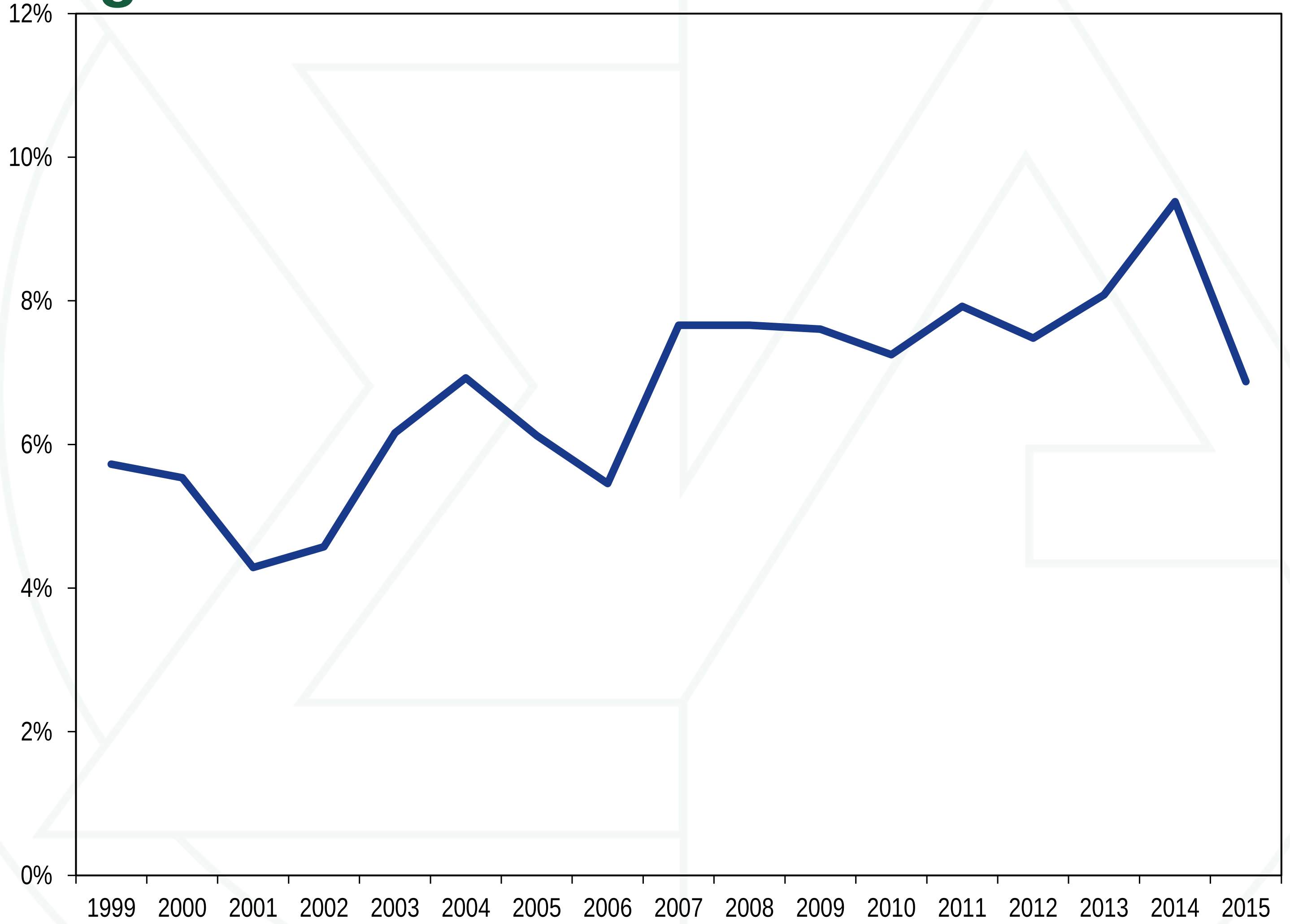


Table 5-35 PJM EFORd, XEFORd and EFORp data by unit type: 2015

	EFORd	XEFORd	EFORp	Difference EFORd and XEFORd	Difference EFORd and EFORp
Combined Cycle	2.7%	2.6%	1.3%	0.1%	1.3%
Combustion Turbine	8.9%	7.8%	4.8%	1.2%	4.1%
Diesel	9.0%	8.3%	4.5%	0.7%	4.5%
Hydroelectric	4.7%	4.2%	3.0%	0.6%	1.7%
Nuclear	1.4%	1.4%	1.2%	0.1%	0.3%
Steam	10.0%	9.8%	6.9%	0.2%	3.1%
Total	6.9%	6.6%	4.5%	0.3%	2.4%

Figure 5-11 PJM distribution of EFORd data by unit type: 2015

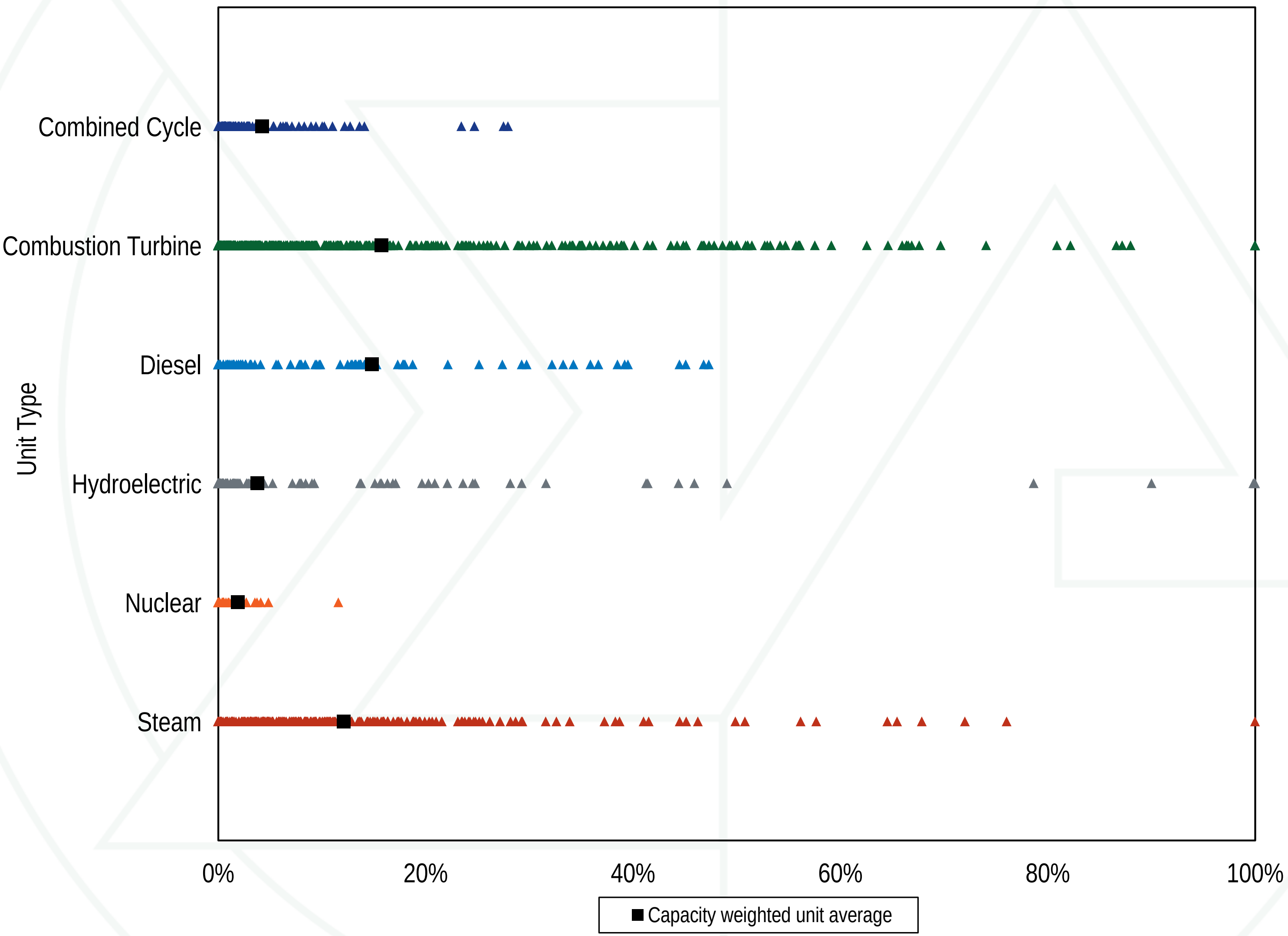


Figure 7-2 Hourly spark spread for peak hours: 2011 through 2015

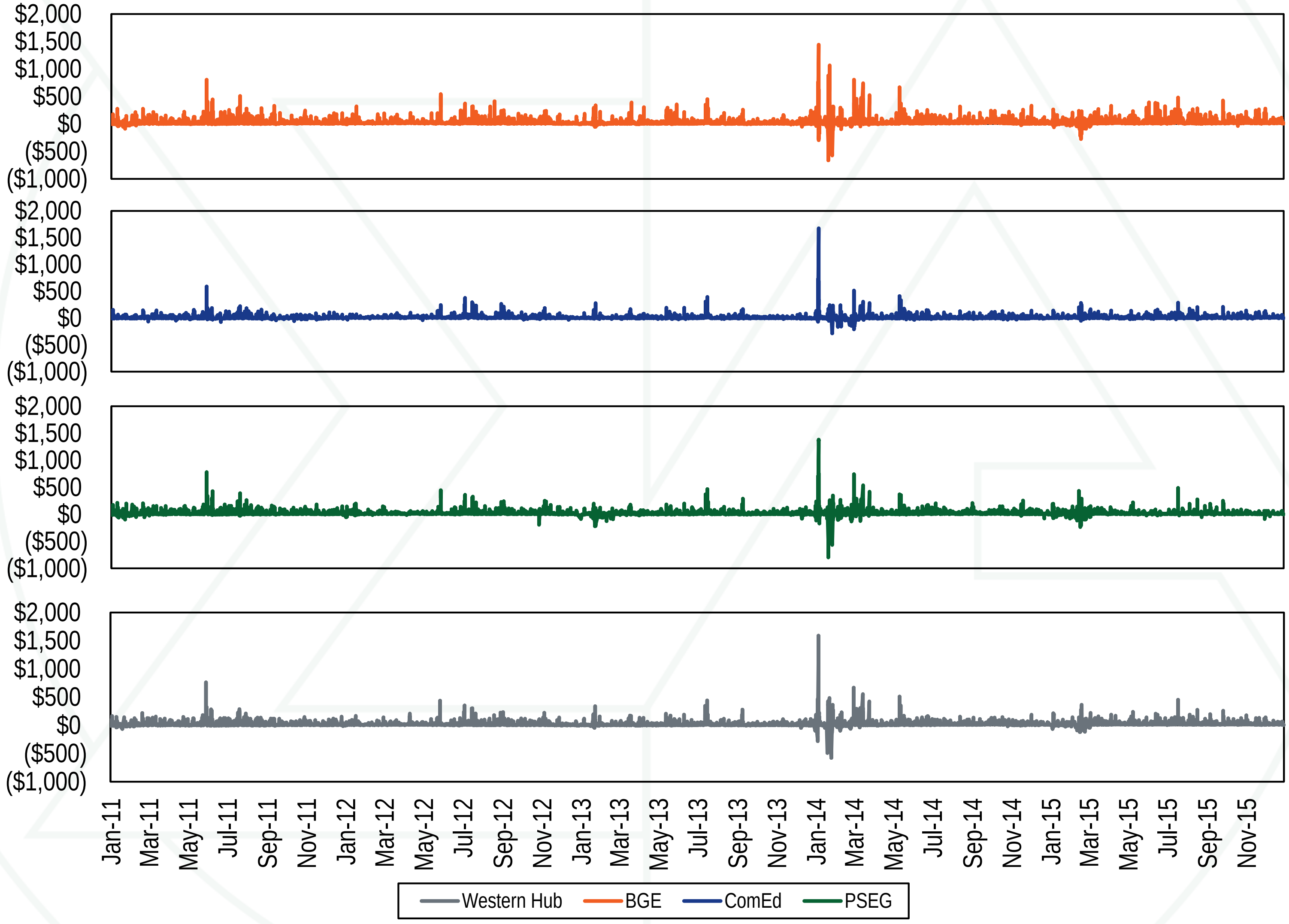


Figure 7-3 Hourly dark spread for peak hours: 2011 through 2015

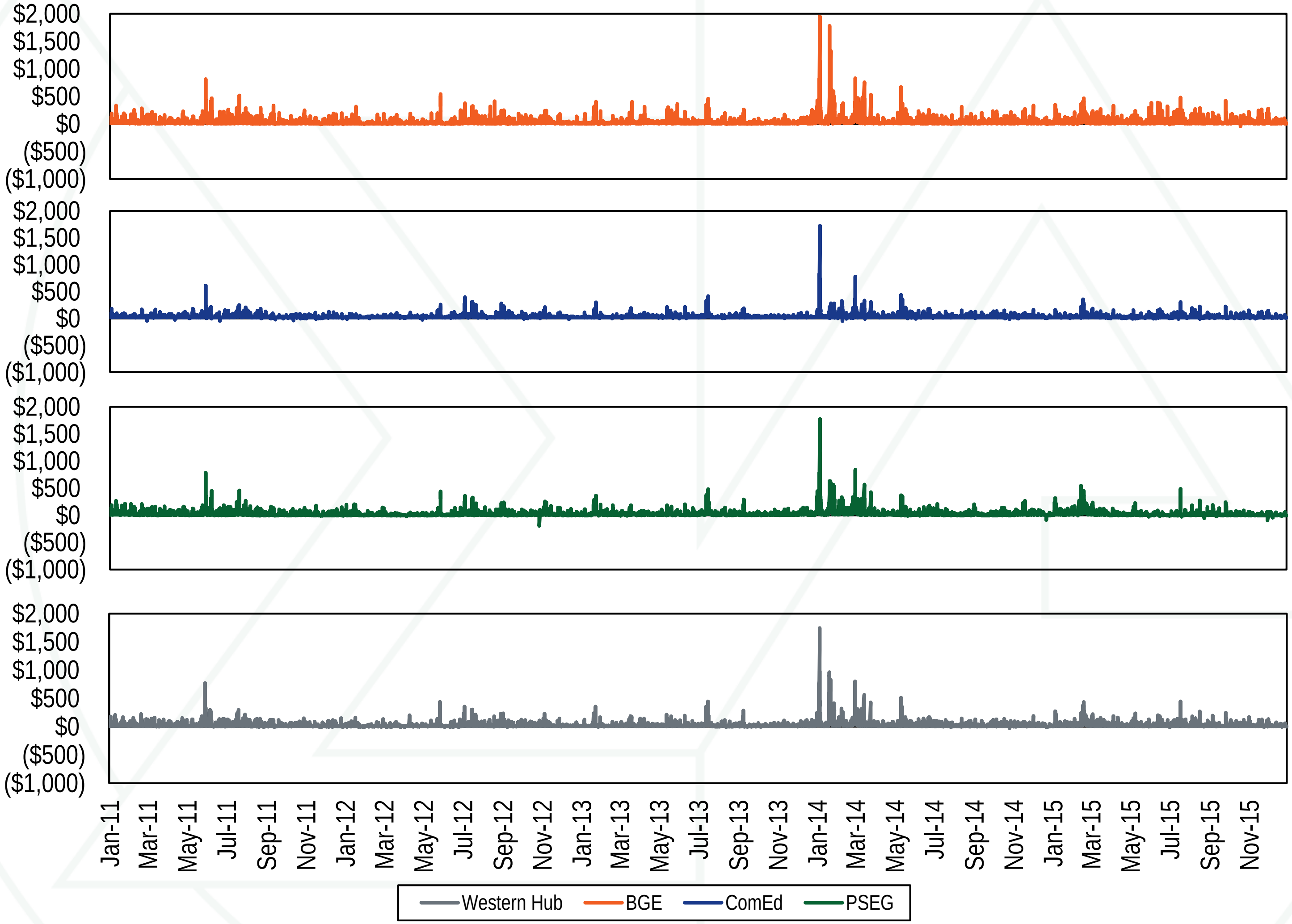


Figure 7-4 Quark spread for selected zones: 2011 through 2015

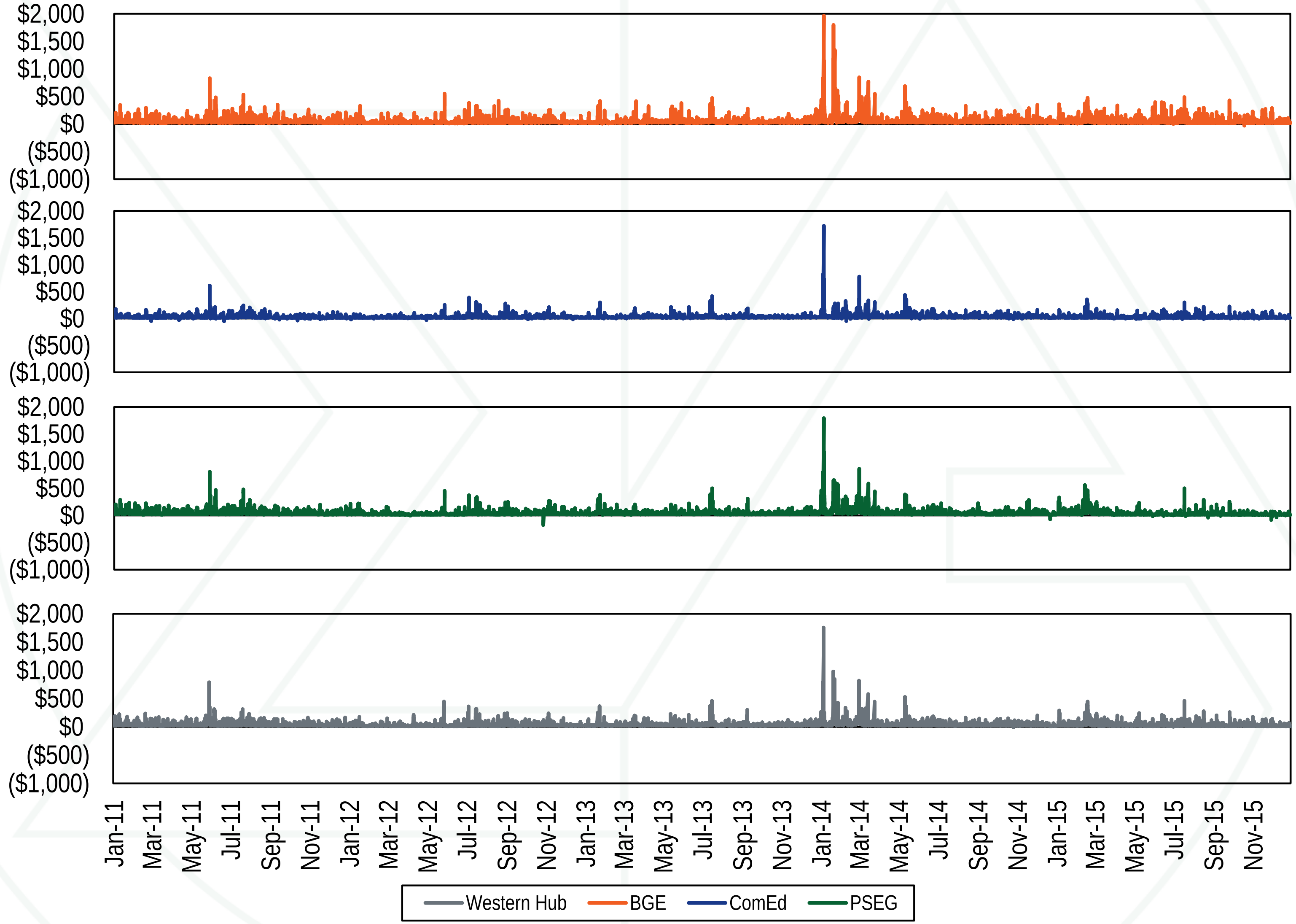


Figure 5-6 History of PJM capacity prices: 1999/2000 through 2018/2019

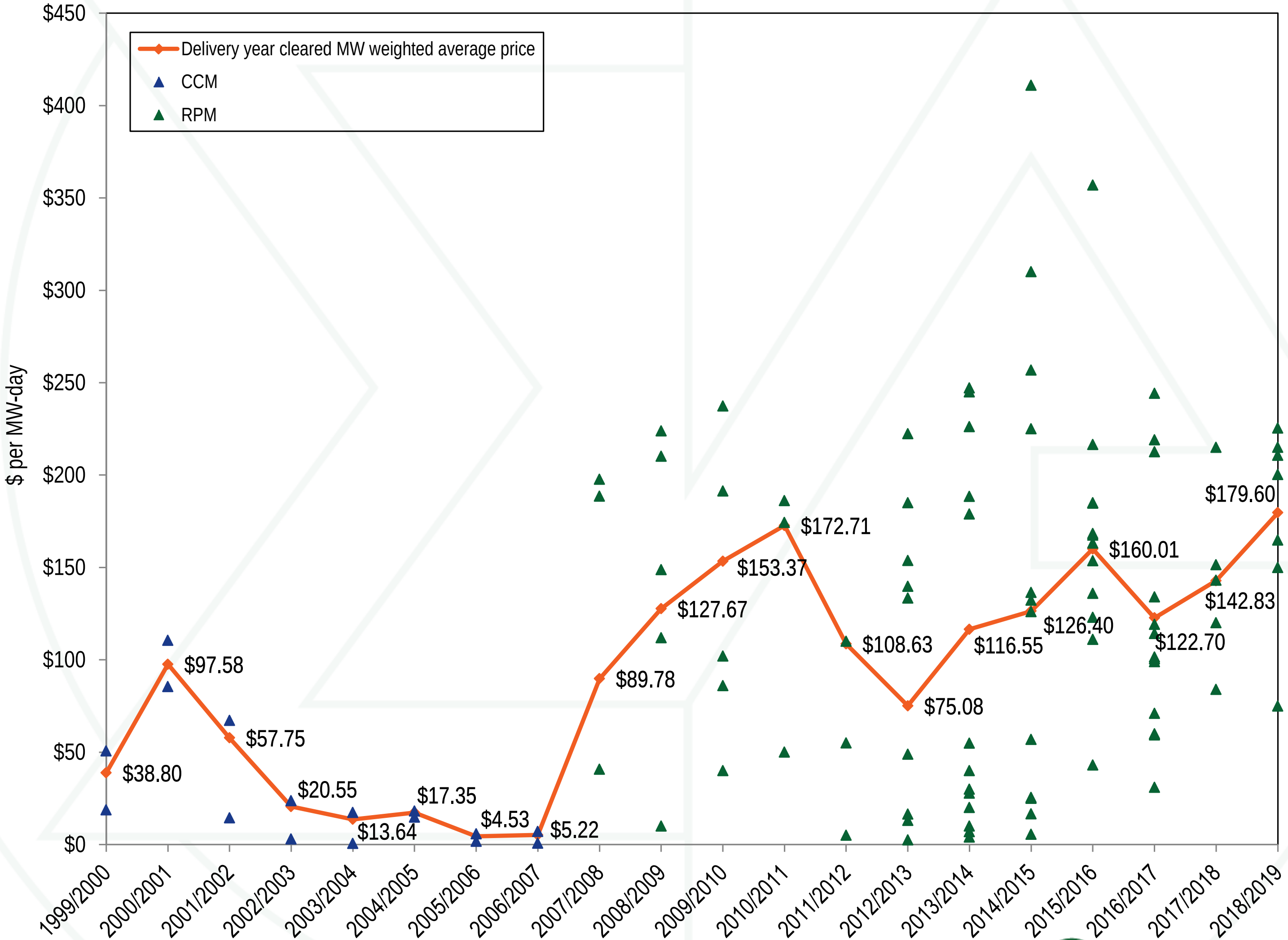
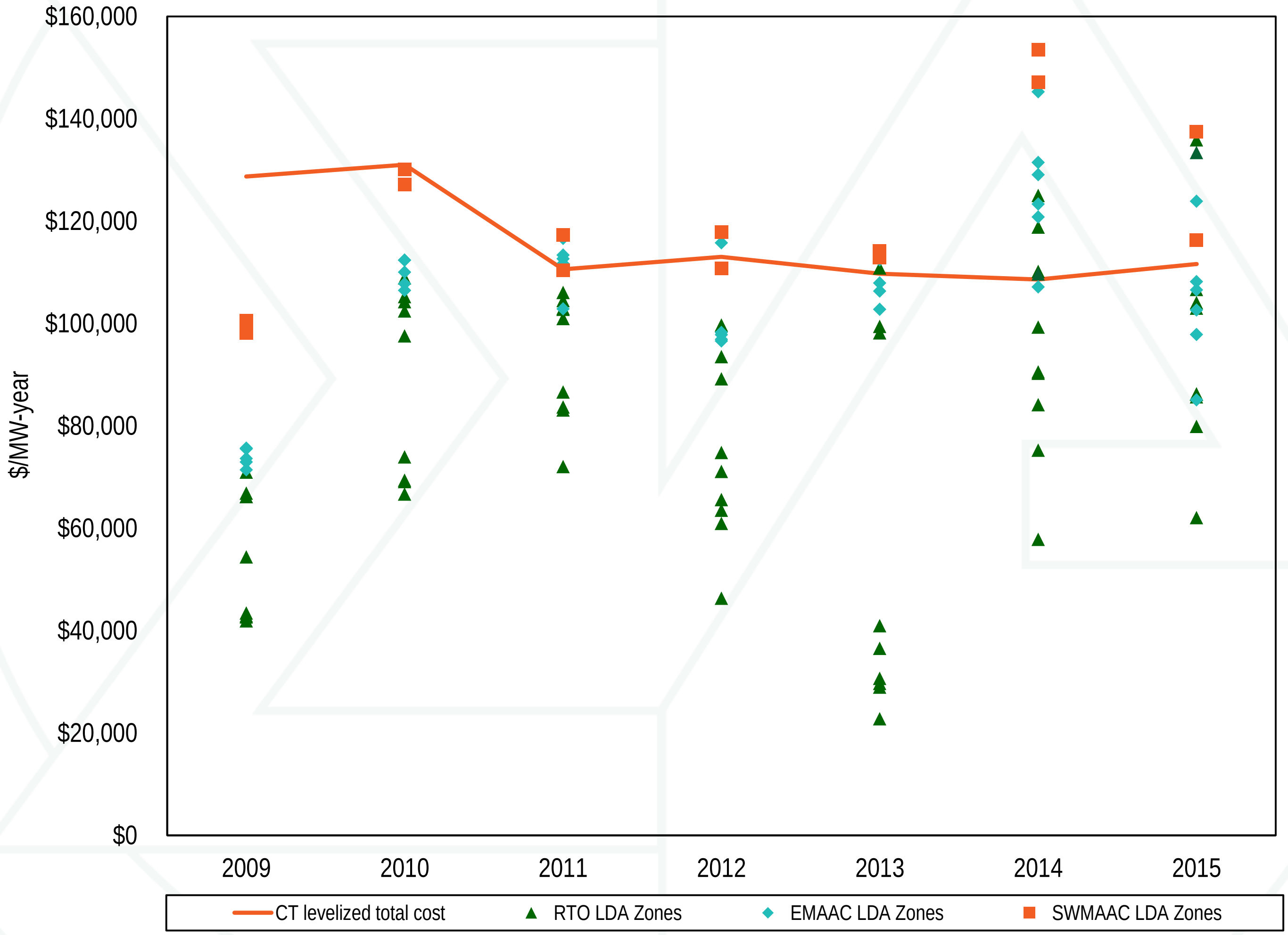
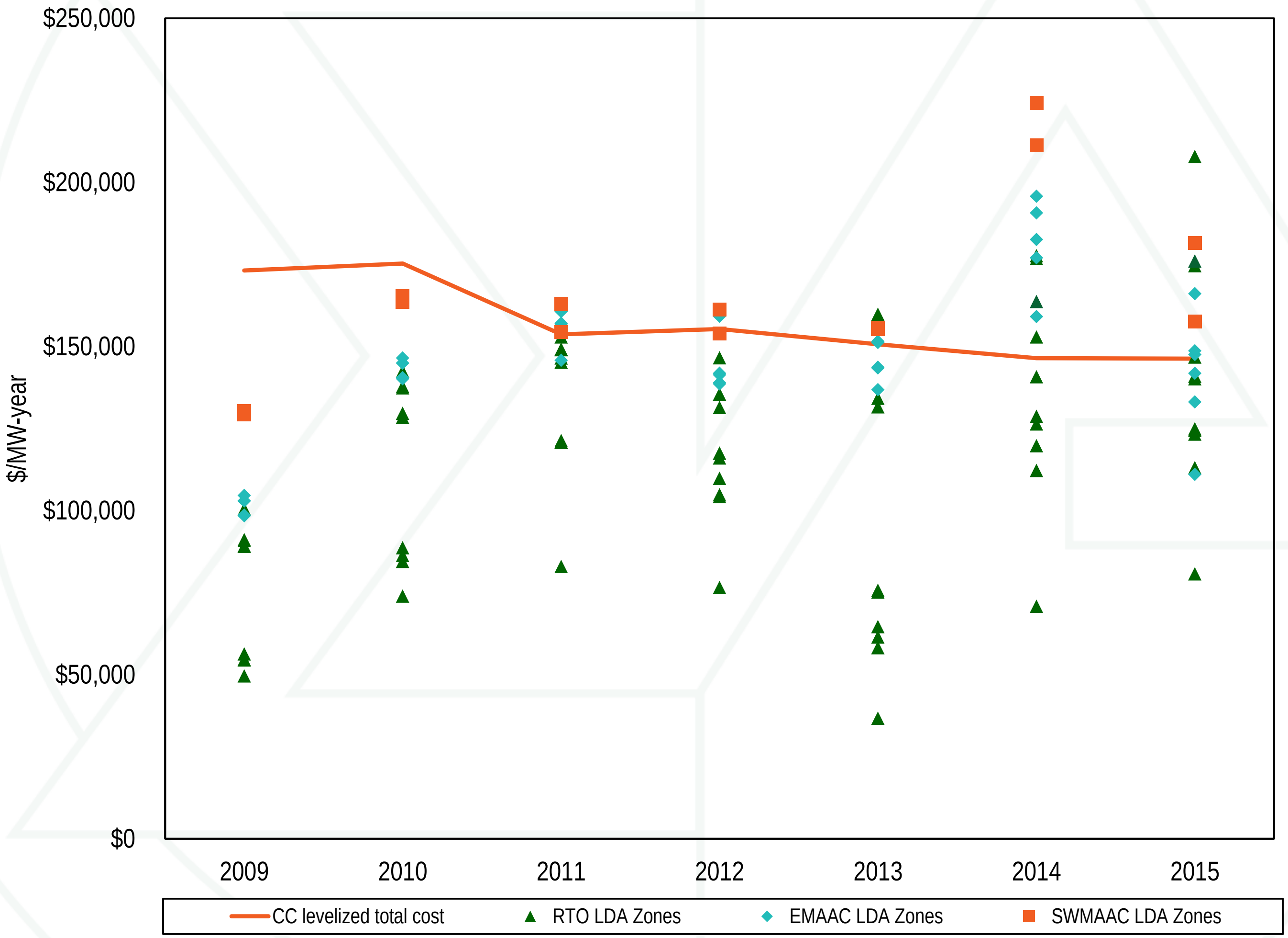


Figure 7-6 New entrant CT net revenue and 20-year levelized total cost by LDA (Dollars per installed MW-year): 2009 through 2015



Monitoring Analytics

Figure 7-7 New entrant CC net revenue and 20-year levelized total cost by LDA (Dollars per installed MW-year): 2009 through 2015



Monitoring Analytics

Figure 7-8 New entrant CP net revenue and 20-year levelized total cost by LDA (Dollars per installed MW-year): 2009 through 2015

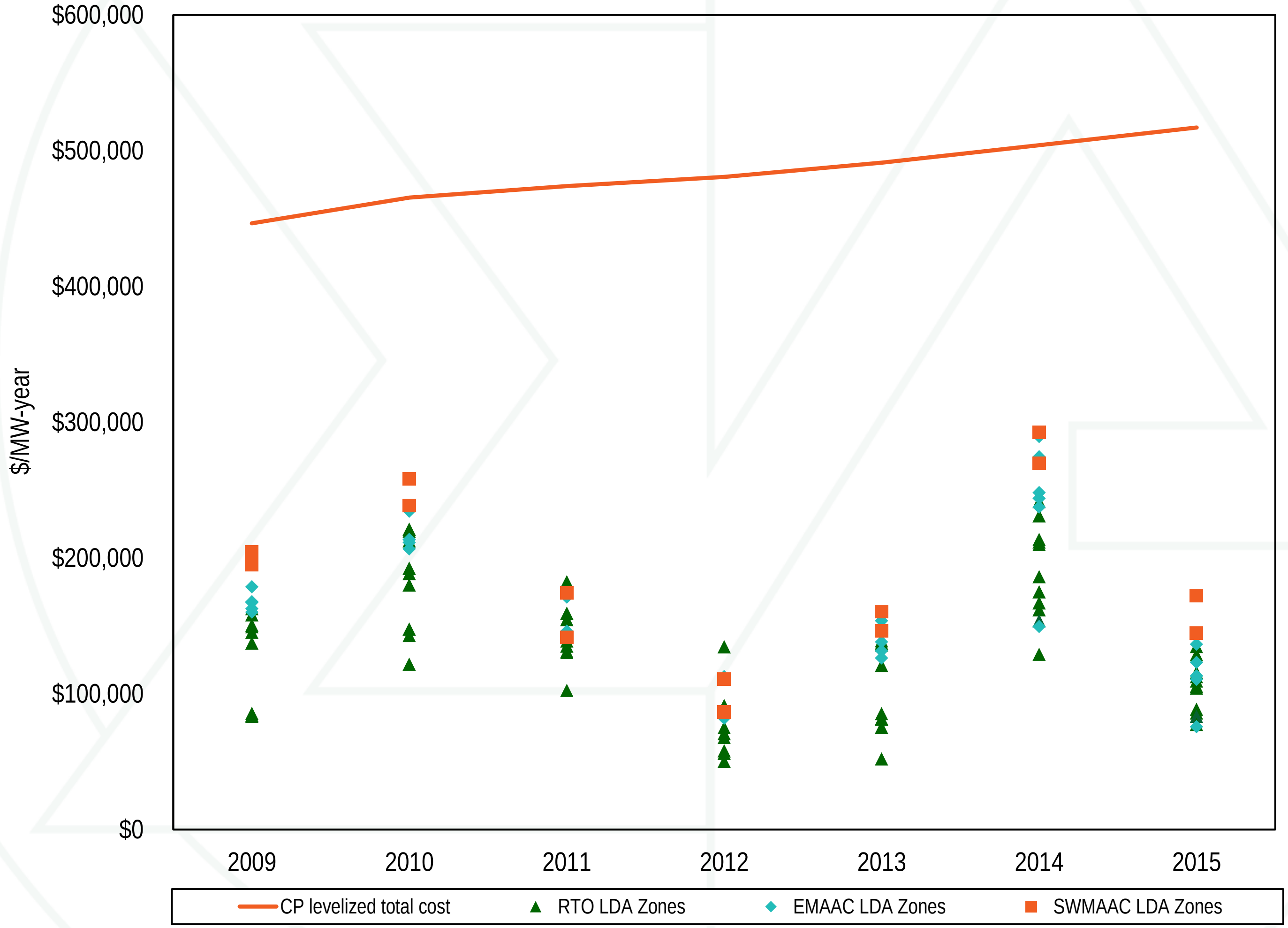


Figure 7-9 New entrant NU net revenue and 20-year levelized total cost by LDA (Dollars per installed MW-year): 2009 through 2015

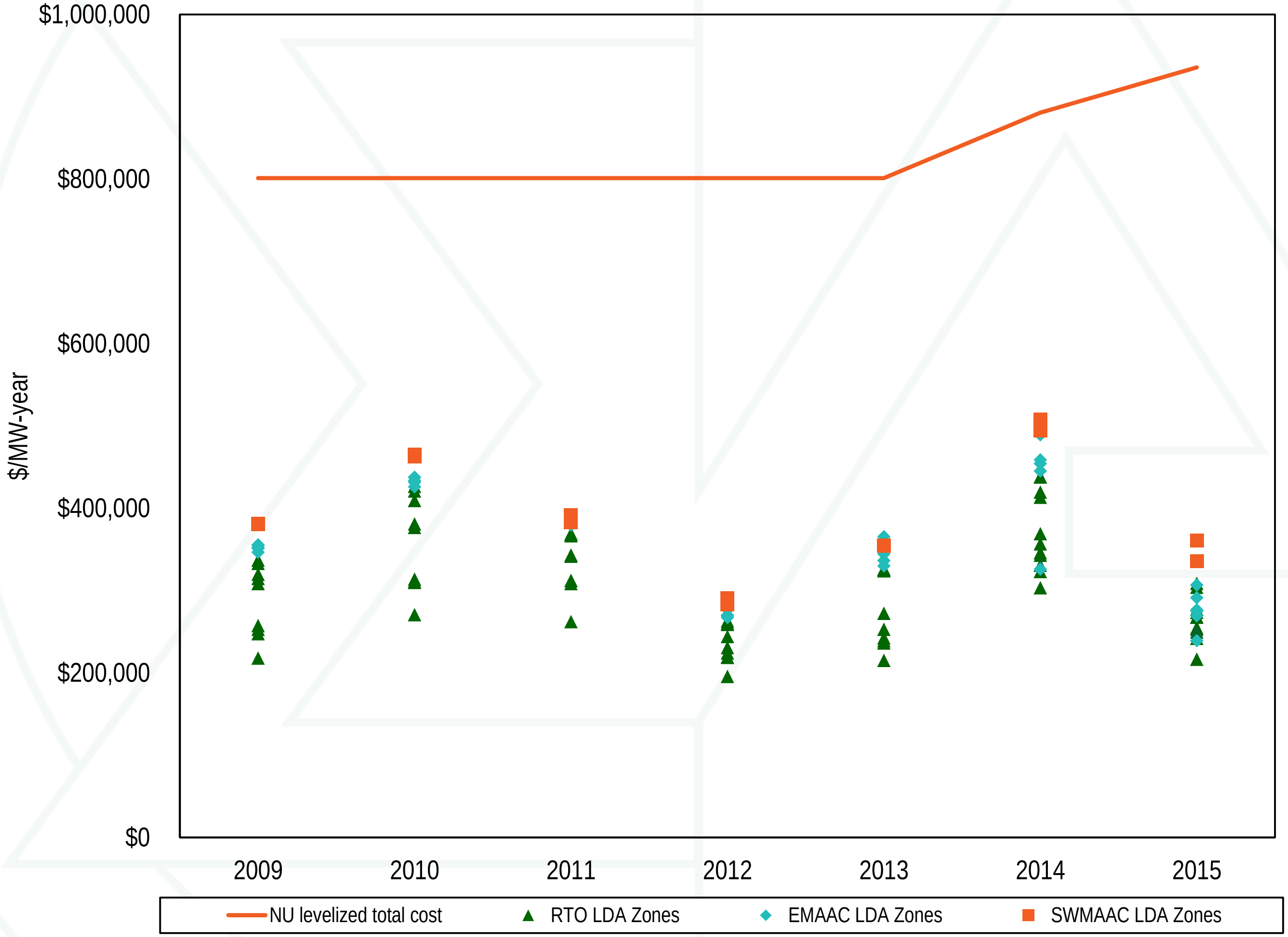


Table 7-18 Percent of 20-year levelized total costs recovered by solar energy and capacity net revenue (Dollars per installed MW-year)

Zone	2012	2013	2014	2015
PSEG	96%	151%	172%	175%

Table 7-30 Proportion of units recovering avoidable costs from all markets: 2009 through 2015

	Units with full recovery from all markets						
Technology	2009	2010	2011	2012	2013	2014	2015
CC - NUG Cogeneration Frame B or E Technology	91%	96%	96%	90%	100%	100%	94%
CC - Two or Three on One Frame F Technology	100%	100%	81%	85%	74%	82%	100%
CT - First & Second Generation Aero (P&W FT 4)	98%	100%	100%	100%	94%	100%	100%
CT - First & Second Generation Frame B	99%	99%	93%	90%	88%	97%	97%
CT - Second Generation Frame E	100%	99%	93%	94%	99%	100%	100%
CT - Third Generation Aero	74%	99%	99%	90%	75%	96%	100%
CT - Third Generation Frame F	100%	100%	93%	93%	91%	97%	100%
Diesel	100%	98%	90%	84%	76%	93%	94%
Hydro and Pumped Storage	100%	100%	100%	100%	100%	100%	100%
Nuclear	NA	NA	NA	NA	NA	NA	NA
Oil or Gas Steam	95%	89%	82%	75%	83%	93%	87%
Sub-Critical Coal	80%	85%	76%	46%	57%	79%	62%
Super Critical Coal	77%	94%	82%	41%	59%	89%	50%

Table 7-31 Profile of units that did not recover avoidable costs from total market revenues in two of the last three years or did not clear the 16/17 BRA or 17/18 BRA but cleared in previous auctions

Technology	No. Units	ICAP (MW)	Avg. 2015 Run Hrs	Avg. Heat Rate	Avg. Unit Age (Yrs)
CT	3	139	403	11,295	21
Coal	23	11,736	5,697	10,291	47
Diesel	1	4	191	10,550	46
Oil or Gas Steam	1	30	4,765	14,226	28
Total	28	11,908	3,197	11,391	34

Table 12-6 Summary of PJM unit retirements by fuel (MW): 2011 through 2020

	Coal	Diesel	Heavy Oil	Kerosene	Landfill Gas	Light Oil	Natural Gas	Nuclear	Wind	Wood Waste	Total
Retirements 2011	543.0	0.0	0.0	0.0	0.0	63.7	522.5	0.0	0.0	0.0	1,129.2
Retirements 2012	5,907.9	0.0	0.0	0.0	0.0	788.0	250.0	0.0	0.0	16.0	6,961.9
Retirements 2013	2,589.9	2.9	166.0	0.0	3.8	85.0	0.0	0.0	0.0	8.0	2,855.6
Retirements 2014	2,427.0	50.0	0.0	184.0	15.3	0.0	294.0	0.0	0.0	0.0	2,970.3
Retirements 2015	7,661.8	10.3	0.0	644.2	2.0	212.0	1,319.0	0.0	10.4	0.0	9,859.7
Planned Retirements Post-2015	2,467.0	59.0	108.0	0.0	2.0	0.0	661.8	614.5	0.0	0.0	3,912.3
Total	21,596.6	122.2	274.0	828.2	23.1	1,148.7	3,047.3	614.5	10.4	24.0	27,689.0

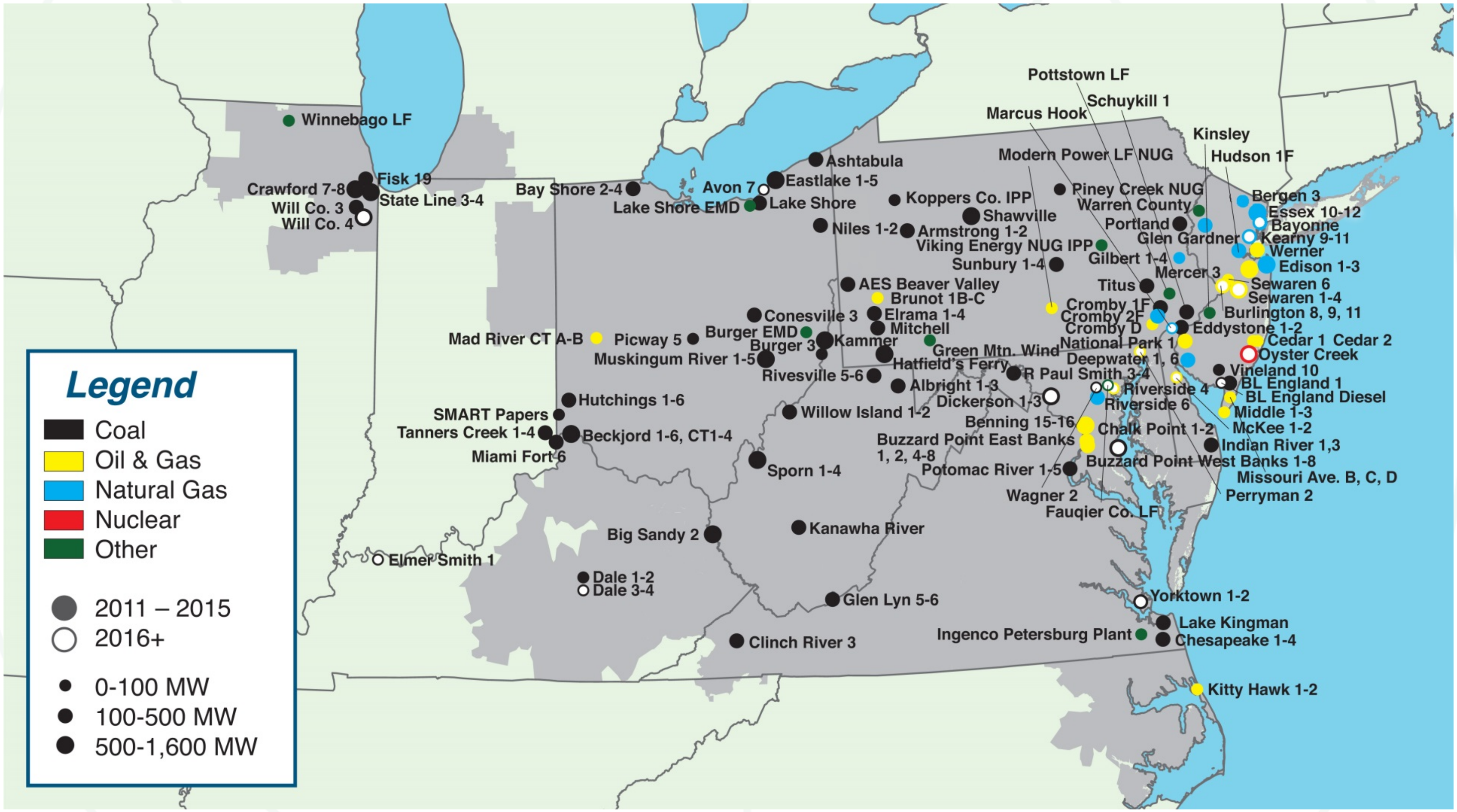
Table 12-10 Unit deactivations in 2015

Company	Unit Name	ICAP (MW)	Primary Fuel	Zone Name	Average Age (Years)	Retirement Date
Calpine Corporation	Cedar 1	44.0	Kerosene	AECO	43	28-Jan-15
First Energy	Eastlake 2	109.0	Coal	ATSI	62	06-Apr-15
First Energy	Eastlake 1	109.0	Coal	ATSI	62	09-Apr-15
First Energy	Eastlake 3	109.0	Coal	ATSI	61	10-Apr-15
First Energy	Ashtabula 5	210.0	Coal	ATSI	57	11-Apr-15
First Energy	Lake Shore 18	190.0	Coal	ATSI	53	13-Apr-15
First Energy	Lake Shore EMD	4.0	Diesel	ATSI	49	15-Apr-15
NRG Energy	Will County	251.0	Coal	ComEd	58	15-Apr-15
EKPC	Dale 1-2	46.0	Coal	EKPC	61	16-Apr-15
Calpine Corporation	Cedar 2	21.6	Kerosene	AECO	43	01-May-15
NRG Energy	Gilbert 1-4	98.0	Natural gas	JCPL	45	01-May-15
NRG Energy	Glen Gardner 1-8	160.0	Natural gas	JCPL	44	01-May-15
Calpine Corporation	Middle 1-3	74.7	Kerosene	AECO	45	01-May-15
Calpine Corporation	Missouri Ave B, C, D	57.9	Kerosene	AECO	46	01-May-15
NRG Energy	Werner 1-4	212.0	Light oil	JCPL	43	01-May-15
PSEG	Bergen 3	21.0	Natural gas	PSEG	48	01-Jun-15
AEP	Big Sandy 2	800.0	Coal	AEP	46	01-Jun-15
PSEG	Burlington 8, 11	205.0	Kerosene	PSEG	48	01-Jun-15
AEP	Clinch River 3	230.0	Coal	AEP	54	01-Jun-15
PSEG	Edison 1-3	504.0	Natural gas	PSEG	44	01-Jun-15
PSEG	Essex 10-11	352.0	Natural gas	PSEG	44	01-Jun-15
PSEG	Essex 12	184.0	Natural gas	PSEG	43	01-Jun-15
AEP	Glen Lyn 5-6	325.0	Coal	AEP	65	01-Jun-15
AES Corporation	Hutchings 1-3, 5-6	271.8	Coal	DAY	65	01-Jun-15
AEP	Kammer 1-3	600.0	Coal	AEP	57	01-Jun-15
AEP	Kanawha River 1-2	400.0	Coal	AEP	62	01-Jun-15
PSEG	Mercer 3	115.0	Kerosene	PSEG	48	01-Jun-15
Duke Energy Kentucky	Miami Fort 6	163.0	Coal	DEOK	55	01-Jun-15
AEP	Muskingum River 1-5	1,355.0	Coal	AEP	60	01-Jun-15
PSEG	National Park 1	21.0	Kerosene	PSEG	46	01-Jun-15
AEP	Picway 5	95.0	Coal	AEP	60	01-Jun-15
PSEG	Sewaren 6	105.0	Kerosene	PSEG	50	01-Jun-15
AEP	Sporn 1-4	580.0	Coal	AEP	64	01-Jun-15
AEP	Tanners Creek 1-4	982.0	Coal	AEP	60	01-Jun-15
NRG Energy	Shawville 4	175.0	Coal	PENELEC	55	02-Jun-15
NRG Energy	Shawville 3	175.0	Coal	PENELEC	56	07-Jun-15
NRG Energy	Shawville 1	122.0	Coal	PENELEC	61	12-Jun-15
NRG Energy	Shawville 2	125.0	Coal	PENELEC	61	14-Jun-15
Portsmouth Genco	Lake Kingman	115.0	Coal	Dominion	27	19-Jun-15
AES Corporation	AES Beaver Valley	124.0	Coal	DLCO	28	01-Sep-15
First Energy	Burger EMD	6.3	Diesel	ATSI	43	18-Sep-15
NextEra Energy, Inc.	ł (Green Mountain) Wind Farm	10.4	Wind	PENELEC	15	05-Nov-15
Waste Management	Pottstown LF (Moser)	2.0	Landfill Gas	PECO	24	07-Dec-15
Total		9,859.7				

Table 12-7 Planned retirement of PJM units: as of December 31, 2015

Unit	Zone	ICAP (MW)	Fuel	Unit Type	Projected Deactivation Date
Perryman 2	BGE	51.0	Diesel	Combustion Turbine	01-Jan-16
Fauquier County Landfill	Dominion	2.0	Diesel	Diesel	29-Feb-16
Yorktown 1-2	Dominion	323.0	Coal	Steam	31-Mar-16
Dale 3-4	EKPC	149.0	Coal	Steam	16-Apr-16
Avon Lake 7	ATSI	94.0	Coal	Steam	16-Apr-16
BL England Diesels	AECO	8.0	Diesel	Diesel	31-May-16
Riverside 4	BGE	74.0	Natural gas	Steam	01-Jun-16
McKee 1-2	DPL	34.0	Heavy Oil	Combustion Turbine	31-May-17
Sewaren 1-4	PSEG	453.0	Kerosene	Combustion Turbine	01-Nov-17
Will County 4	ComEd	510.0	Coal	Steam	31-May-18
Bayonne Cogen Plant (CC)	PSEG	158.0	Natural gas	Steam	01-Nov-18
MH50 Marcus Hook Co-gen	PECO	50.8	Natural gas	Steam	13-May-19
Chalk Point 1-2	Pepco	667.0	Coal	Steam	31-May-19
Dickerson 1-3	Pepco	537.0	Coal	Steam	31-May-19
Elmer Smith U1	External	52.0	Coal	Steam	01-Jun-19
Oyster Creek	JCPL	614.5	Nuclear	Nuclear	31-Dec-19
Wagner 2	BGE	135.0	Coal	Steam	01-Jun-20
Total		3,912.3			

Figure 12-1 Map of PJM unit retirements: 2011 through 2020



State of the Market Report Recommendations: Energy Market Uplift

- **PJM should not use closed loop interfaces to override LMP logic to accommodate:**
  - **Issues with DR product, e.g. non nodal.**
  - **Issues with reactive power modeling.**
  - **Issues with scarcity pricing, e.g. not locational.**
- **PJM should not use price setting logic to override LMP logic to reduce uplift.**
- **Eliminate day ahead uplift.**
- **Include net revenue offset in uplift calculation.**
- **UTC should pay uplift.**
- **Eliminate use of IBTs in calculating deviations.**

Table 4-1 Day-ahead and balancing operating reserve credits and charges

Credits Received For:	Credits Category:		Charges Category:	Charges Paid By:	
	Day-Ahead				
Day-Ahead Import Transactions and Generation Resources	Day-Ahead Operating Reserve Transactions Day-Ahead Operating Reserve Generator	→	Day-Ahead Operating Reserve	Day-Ahead Load Day-Ahead Export Transactions Decrement Bids	in RTO Region
Economic Load Response Resources	Day-Ahead Operating Reserves for Load Response	→	Day-Ahead Operating Reserve for Load Response	Day-Ahead Load Day-Ahead Export Transactions Decrement Bids	in RTO Region
	Unallocated Negative Load Congestion Charges Unallocated Positive Generation Congestion Credits	→	Unallocated Congestion	Day-Ahead Load Day-Ahead Export Transactions Decrement Bids	in RTO Region
	Balancing				
Generation Resources	Balancing Operating Reserve Generator	→	Balancing Operating Reserve for Reliability	Real-Time Load plus Real-Time Export Transactions	in RTO, Eastern or Western Region
			Balancing Operating Reserve for Deviations	Deviations	
			Balancing Local Constraint	Applicable Requesting Party	
Canceled Resources	Balancing Operating Reserve Startup Cancellation	→	Balancing Operating Reserve for Deviations	Deviations	in RTO Region
Lost Opportunity Cost (LOC)	Balancing Operating Reserve LOC				
Real-Time Import Transactions	Balancing Operating Reserve Transaction				
Economic Load Response Resources	Balancing Operating Reserves for Load Response	→	Balancing Operating Reserve for Load Response	Deviations	in RTO Region

Table 4-3 Total energy uplift charges: 2001 through 2015

	Total Energy Uplift Charges (Millions)	Annual Change (Millions)	Annual Percent Change	Energy Uplift as a Percent of Total PJM Billing
2001	$284.0	$67.1	30.9%	8.5%
2002	$273.7	($10.3)	(3.6%)	5.8%
2003	$376.5	$102.8	37.5%	5.4%
2004	$537.6	$161.1	42.8%	6.1%
2005	$712.6	$175.0	32.6%	3.1%
2006	$365.6	($347.0)	(48.7%)	1.7%
2007	$503.3	$137.7	37.7%	1.6%
2008	$474.3	($29.0)	(5.8%)	1.4%
2009	$322.7	($151.5)	(31.9%)	1.2%
2010	$623.2	$300.4	93.1%	1.8%
2011	$603.4	($19.8)	(3.2%)	1.7%
2012	$649.9	$46.5	7.7%	2.2%
2013	$842.8	$192.9	29.7%	2.5%
2014	$960.5	$117.7	14.0%	1.9%
2015	$314.2	($646.3)	(67.3%)	0.9%

Figure 4-8 Energy uplift charges change from 2014 to 2015 by category

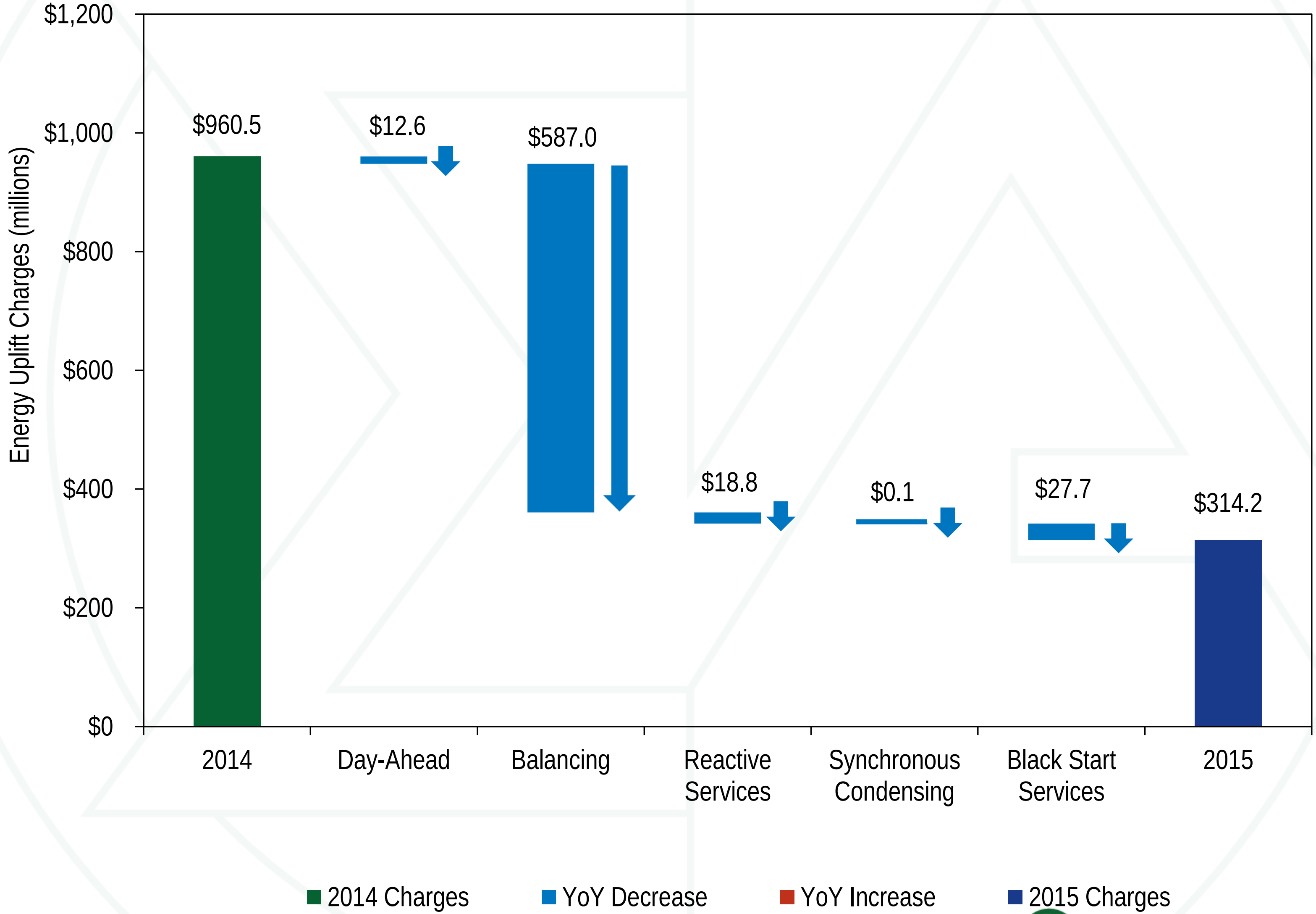


Table 4-17 Energy uplift credits by category: 2014 and 2015

Category	Type	2014 Credits (Millions)	2015 Credits (Millions)	Change	Percent Change	2014 Share	2015 Share
Day-Ahead	Generators	$111.3	$98.5	($12.8)	(11.5%)	11.6%	31.4%
	Imports	$0.0	$0.0	$0.0	178.8%	0.0%	0.0%
	Load Response	$0.0	$0.2	$0.2	3,298.2%	0.0%	0.1%
Balancing	Canceled Resources	$1.4	$0.2	($1.2)	(85.8%)	0.1%	0.1%
	Generators	$627.2	$113.6	($513.7)	(81.9%)	65.3%	36.1%
	Imports	$0.1	$0.2	$0.0	39.0%	0.0%	0.1%
	Load Response	$0.0	$0.1	$0.1	258.4%	0.0%	0.0%
	Local Constraints Control	$1.9	$0.9	($1.1)	(55.7%)	0.2%	0.3%
	Lost Opportunity Cost	$155.8	$84.8	($71.1)	(45.6%)	16.2%	27.0%
Reactive Services	Day-Ahead	$24.9	$7.7	($17.2)	(69.1%)	2.6%	2.4%
	Local Constraints Control	$0.0	$0.0	($0.0)	(87.3%)	0.0%	0.0%
	Lost Opportunity Cost	$0.2	$0.1	($0.1)	(52.9%)	0.0%	0.0%
	Reactive Services	$3.4	$2.7	($0.7)	(21.3%)	0.4%	0.9%
	Synchronous Condensing	$0.9	$0.2	($0.7)	(81.7%)	0.1%	0.1%
Synchronous Condensing		$0.1	$0.0	($0.1)	(76.1%)	0.0%	0.0%
Black Start Services	Day-Ahead	$27.4	$4.3	($23.1)	(84.2%)	2.9%	1.4%
	Balancing	$5.2	$0.5	($4.7)	(91.0%)	0.5%	0.1%
	Testing	$0.4	$0.4	$0.0	7.1%	0.0%	0.1%
Total		$960.3	$314.2	($646.1)	(67.3%)	100.0%	100.0%

Table 4-18 Energy uplift credits by unit type: 2014 and 2015

Unit Type	2014 Credits (Millions)	2015 Credits (Millions)	Change	Percent Change	2014 Share	2015 Share
Combined Cycle	$399.2	$72.5	($326.6)	(81.8%)	41.6%	23.1%
Combustion Turbine	$256.1	$114.1	($142.0)	(55.4%)	26.7%	36.4%
Diesel	$3.0	$1.9	($1.1)	(36.8%)	0.3%	0.6%
Hydro	$1.7	$1.1	($0.5)	(32.4%)	0.2%	0.4%
Nuclear	$0.3	$0.4	$0.2	62.7%	0.0%	0.1%
Solar	$0.0	$0.0	($0.0)	(100.0%)	0.0%	0.0%
Steam - Coal	$178.1	$89.8	($88.3)	(49.6%)	18.6%	28.6%
Steam - Other	$113.7	$29.1	($84.6)	(74.4%)	11.8%	9.3%
Wind	$8.1	$4.7	($3.4)	(41.9%)	0.8%	1.5%
Total	$960.2	$313.7	($646.4)	(67.3%)	100.0%	100.0%

Table 4-20 Top 10 units and organizations energy uplift credits: 2015

		Top 10 Units		Top 10 Organizations	
Category	Type	Credits (Millions)	Credits Share	Credits (Millions)	Credits Share
Day-Ahead	Generators	$58.8	59.7%	$94.2	95.6%
Balancing	Canceled Resources	$0.2	93.7%	$0.2	100.0%
	Generators	$50.8	44.8%	$91.2	80.3%
	Local Constraints Control	$0.8	88.2%	$0.9	100.0%
	Lost Opportunity Cost	$19.2	22.6%	$64.3	75.8%
Reactive Services		$9.1	85.6%	$10.6	99.9%
Synchronous Condensing		$0.0	94.7%	$0.0	100.0%
Black Start Services		$4.8	93.1%	$5.1	99.5%
Total		$107.2	34.2%	$244.8	78.0%

Table 4-13 Operating reserve rates statistics ($/MWh): 2015

		Rates Charged ($/MWh)			
Region	Transaction	Maximum	Average	Minimum	Standard Deviation
East	INC	17.264	1.072	0.006	1.878
	DEC	17.522	1.187	0.039	1.941
	DA Load	1.600	0.115	0.000	0.160
	RT Load	0.773	0.050	0.000	0.093
	Deviation	17.264	1.072	0.006	1.878
West	INC	17.264	1.036	0.006	1.854
	DEC	17.522	1.151	0.039	1.919
	DA Load	1.600	0.115	0.000	0.160
	RT Load	0.772	0.042	0.000	0.086
	Deviation	17.264	1.036	0.006	1.854

Table 4-39 Current and proposed average energy uplift rate by transaction: 2014 and 2015

		2014			2015		
	Transaction	Current Rates ($/MWh)	Proposed Rates - 50% UTC ($/MWh)	Proposed Rates - 0% UTC ($/MWh)	Current Rates ($/MWh)	Proposed Rates - 50% UTC ($/MWh)	Proposed Rates - 0% UTC ($/MWh)
East	INC	2.275	0.215	0.681	1.072	0.149	0.383
	DEC	2.404	0.215	0.681	1.187	0.149	0.383
	DA Load	0.129	0.020	0.024	0.115	0.013	0.015
	RT Load	0.450	0.466	0.466	0.050	0.118	0.118
	Deviation	2.275	1.303	1.765	1.072	0.501	0.732
West	INC	2.069	0.177	0.568	1.036	0.147	0.383
	DEC	2.199	0.177	0.568	1.151	0.147	0.383
	DA Load	0.129	0.020	0.024	0.115	0.013	0.015
	RT Load	0.439	0.466	0.466	0.042	0.118	0.118
	Deviation	2.069	1.218	1.604	1.036	0.432	0.666
UTC	East to East	NA	0.430	1.362	NA	0.299	0.765
	West to West	NA	0.355	1.136	NA	0.294	0.766
	East to/from West	NA	0.393	1.249	NA	0.296	0.766

Table 9-39 Credit risk associated with varying levels of potential uplift: September 8, 2014 through December 31, 2015

Uplift ($/MWh)	Credit risk if uplift is applied to both sides of UTC
$0.05	$20,134,462
$0.10	$40,268,925
$0.15	$60,403,387
$0.20	$80,537,850
$0.25	$100,672,312
$0.30	$120,806,775
$0.35	$140,941,237
$0.40	$161,075,700
$0.45	$181,210,162
$0.50	$201,344,624
$0.55	$221,479,087
$0.60	$241,613,549
$0.65	$261,748,012
$0.70	$281,882,474
$0.75	$302,016,937
$0.80	$322,151,399
$0.85	$342,285,861
$0.90	$362,420,324
$0.95	$382,554,786
$1.00	$402,689,249

State of the Market Report Recommendations: Demand Response

- **Demand response should be removed from PJM markets.**
  - **Facilitate customers' response to prices**
  - **Participation facilitated by PJM provision of data**
- **Eliminate strike price; pay LMP**
- **Demand response should be fully nodal**
  - **Compliance across zones should be eliminated**
- **M&V: cap baselines at PLC uniformly**
- **Eliminate net benefits test**
  - **Pay LMP – retail generation rate**

Table 6-1 Overview of demand response programs

	Emergency and Pre-Emergency Load Response Program			Economic Load Response Program
	Load Management (LM)			
Market	Capacity Only	Capacity and Energy	Energy Only	Energy Only
Capacity Market	DR cleared in RPM	DR cleared in RPM	Not included in RPM	Not included in RPM
Dispatch Requirement	Mandatory Curtailment	Mandatory Curtailment	Voluntary Curtailment	Dispatched Curtailment
Penalties	RPM event or test compliance penalties	RPM event or test compliance penalties	NA	NA
Capacity Payments	Capacity payments based on RPM clearing price	Capacity payments based on RPM clearing price	NA	NA
Energy Payments	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 full LMP. Energy payment for hours of dispatched curtailment.

Figure 6-2 Economic program credits and MWh by month: January 2010 through December 2015

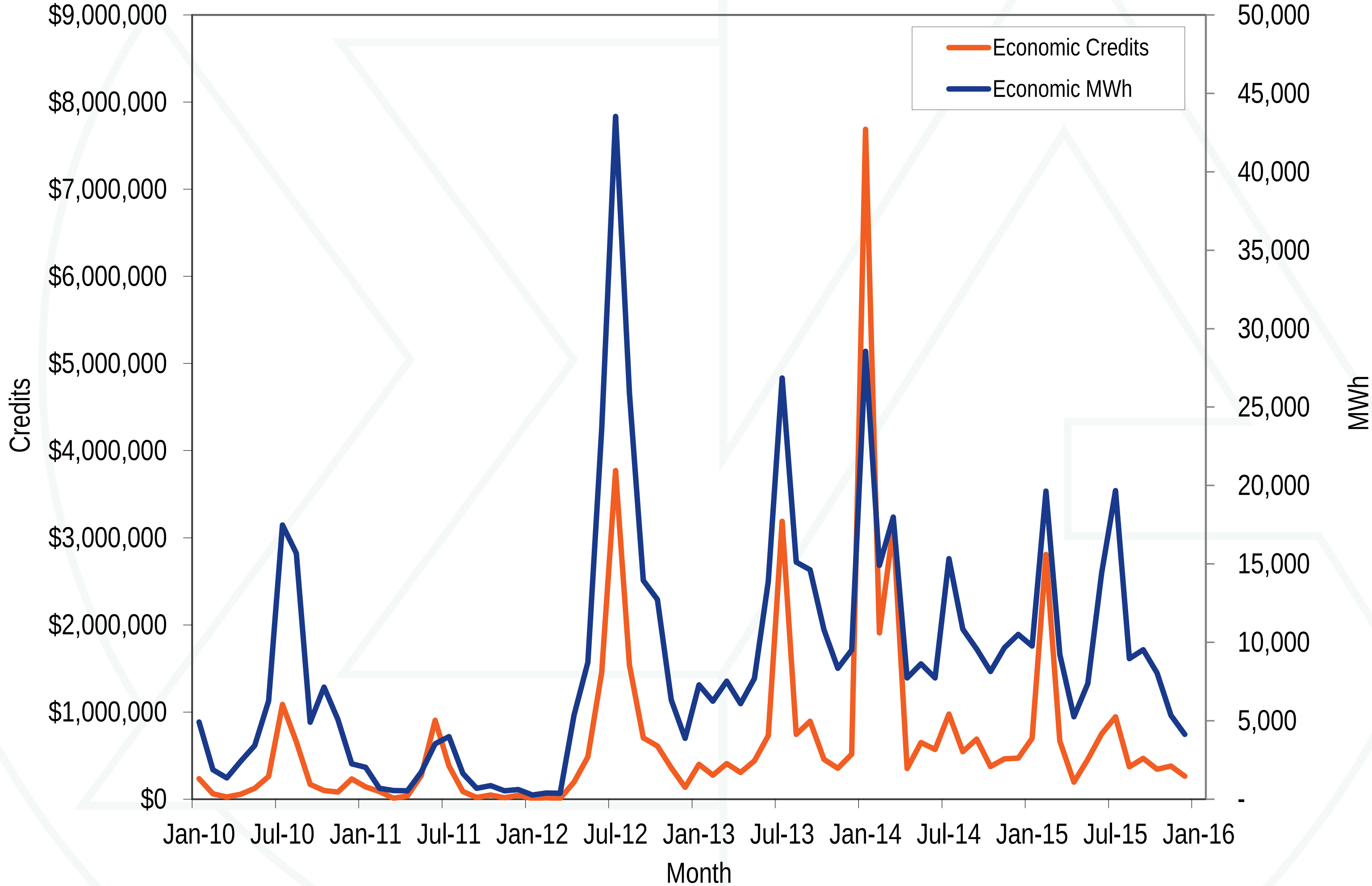
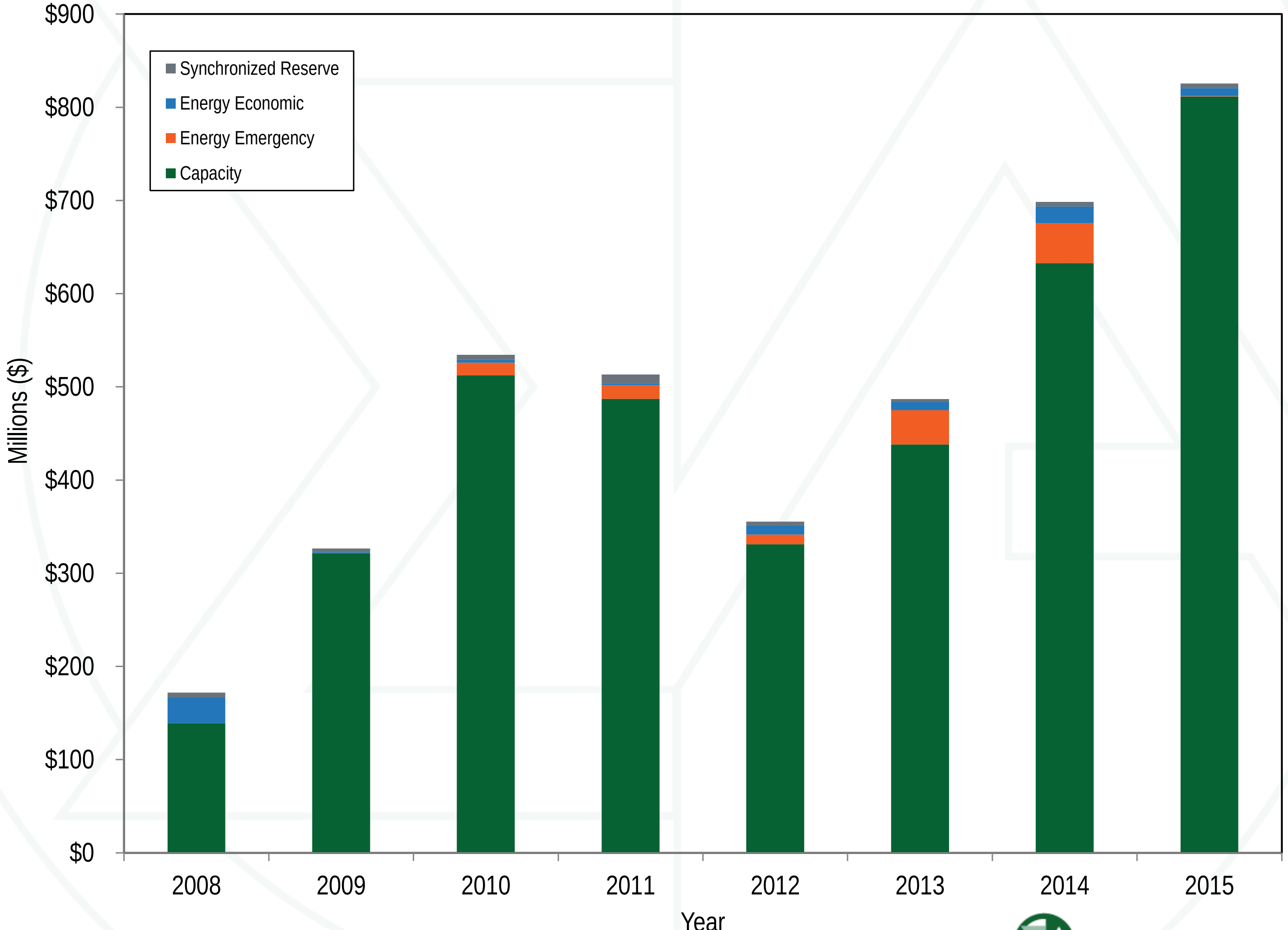


Figure 6-1 Demand response revenue by market: 2008 through 2015



State of the Market Report Recommendations: Transactions

- Interchange pricing should reflect LMP logic.
  - No need for scheduling physical transactions.
- Permit unlimited spot transactions.
- Submit transactions consistent with power flow not scheduled paths.
- Implement rules to prevent sham scheduling.
- FERC should ensure that actual flow data be available for eastern interconnection to MMUs and RTOs/ISOs.
- PJM should request a credit evaluation from UTC traders re exposure to uplift payments.

Figure 9-3 PJM's footprint and its external day-ahead and real-time scheduling interfaces

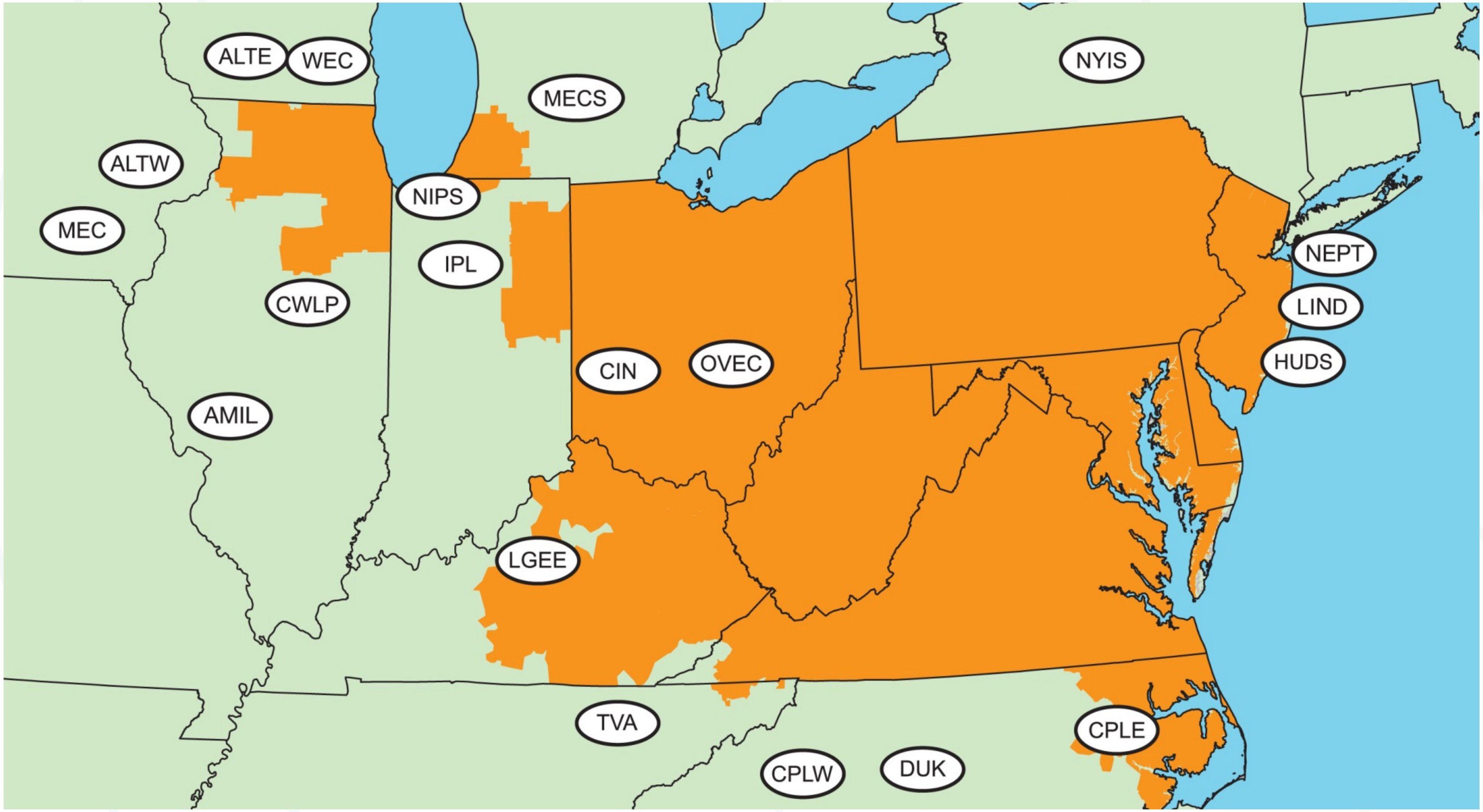
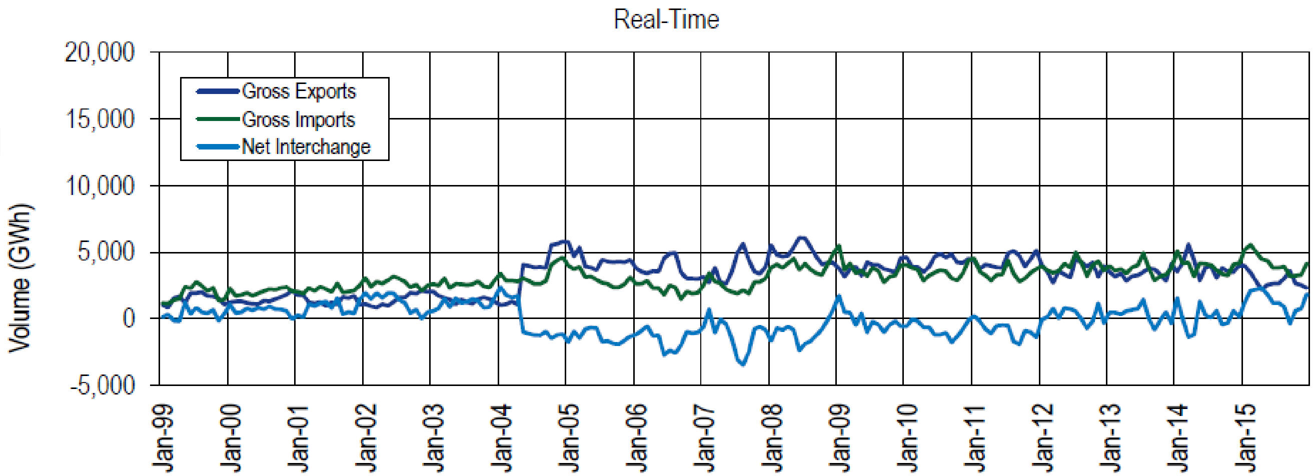


Figure 9-2 PJM real-time and day-ahead scheduled import and export transaction volume history: 1999 through 2015



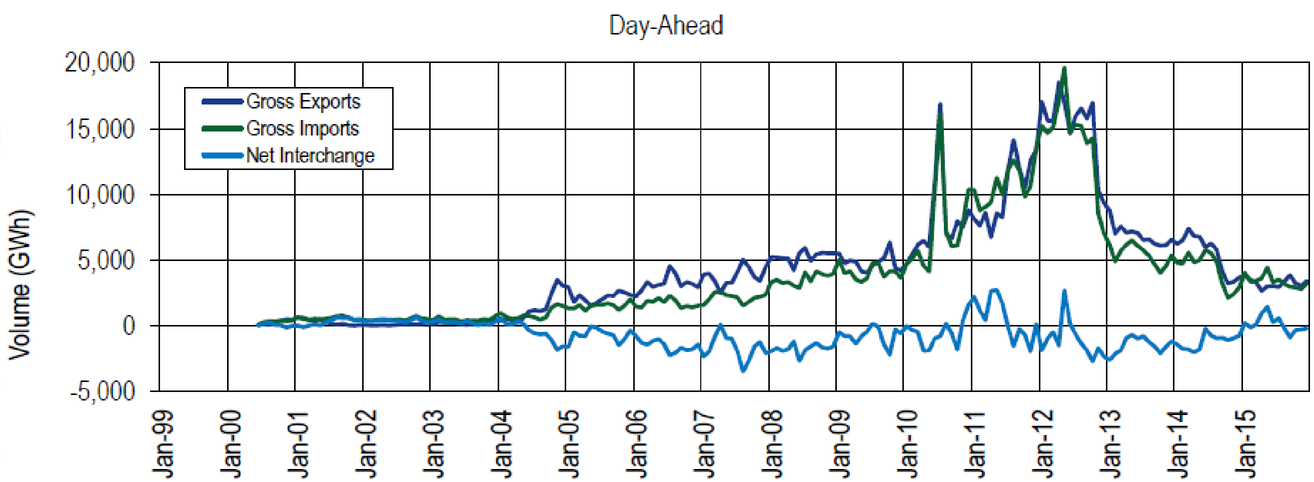


Table 10-1 The Regulation Market results were competitive

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

Table 10-2 The Tier 2 Synchronized Reserve Market results were competitive

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

Table 10-3 The Day-Ahead Scheduling Reserve Market results were competitive

Market Element	Evaluation	Market Design
Market Structure	Not Competitive	
Participant Behavior	Mixed	
Market Performance	Competitive	Mixed

State of the Market Report Recommendations: Ancillary Services

- **Regulation market should incorporate consistent application of marginal benefit factor including optimization, assignment and settlements.**
- **LOC should be based on unit's schedule in the energy market.**
- **Eliminate payment of Tier 2 price to Tier 1 when non-synchronized reserve price > 0.**
- **Eliminate DASR Market.**

Table 10-4 History of ancillary services costs per MWh of Load: 2004 through 2015

Year	Regulation	Scheduling, Dispatch, and System Control	Reactive	Synchronized Reserve	Total
2004	$0.50	$0.60	$0.25	$0.13	$1.48
2005	$0.79	$0.47	$0.26	$0.11	$1.63
2006	$0.53	$0.48	$0.29	$0.08	$1.38
2007	$0.63	$0.47	$0.29	$0.06	$1.45
2008	$0.68	$0.40	$0.31	$0.08	$1.47
2009	$0.34	$0.32	$0.37	$0.05	$1.08
2010	$0.34	$0.38	$0.41	$0.07	$1.20
2011	$0.32	$0.34	$0.42	$0.10	$1.18
2012	$0.26	$0.40	$0.43	$0.04	$1.13
2013	$0.24	$0.39	$0.80	$0.04	$1.47
2014	$0.31	$0.37	$0.37	$0.20	$1.25
2015	$0.23	$0.41	$0.37	$0.12	$1.13

Figure 10-34 PJM regulation market daily weighted average market-clearing price, marginal unit opportunity cost and offer price (Dollars per MW): 2015

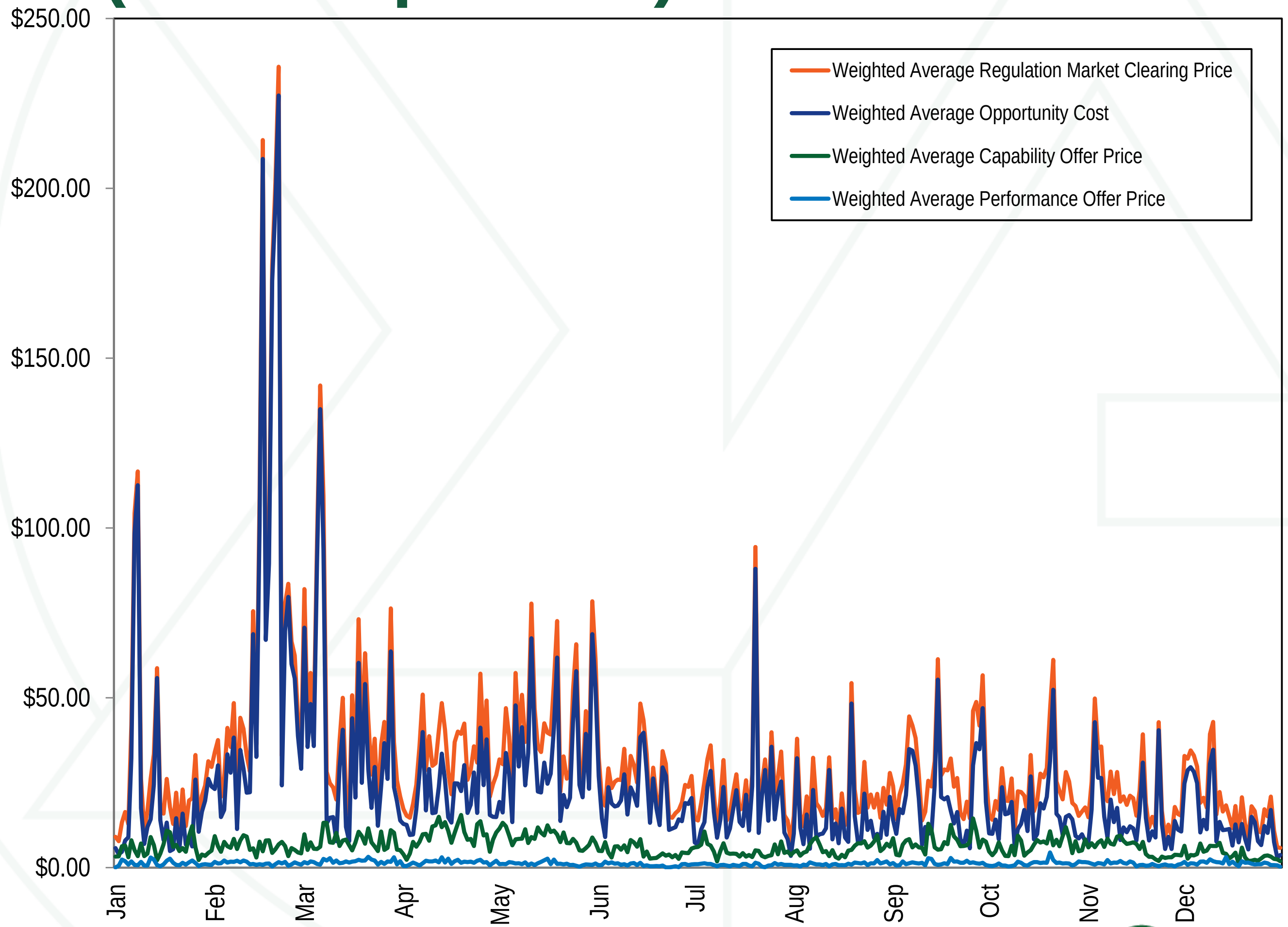


Table 10-43 Comparison of average price and cost for PJM Regulation, 2011 through 2015

Year	Weighted Regulation Market Price	Weighted Regulation Market Cost	Regulation Price as Percent Cost
2011	$16.48	$29.72	55.5%
2012	$19.02	$25.32	75.1%
2013	$30.85	$35.79	86.2%
2014	$44.47	$53.81	82.6%
2015	$31.92	$38.36	83.2%

Table 10-42 Components of regulation cost: 2015

Month	Scheduled Regulation (MW)	Cost of Regulation Capability ($/MW)	Cost of Regulation Performance ($/MW)	Opportunity Cost ($/MW)	Total Cost ($/MW)
Jan	394,350.5	$24.34	$3.82	$4.94	$33.10
Feb	356,397.3	$69.13	$5.98	$14.00	$89.11
Mar	394,659.0	$41.41	$6.19	$7.86	$55.46
Apr	378,682.3	$28.42	$6.07	$4.79	$39.29
May	395,717.3	$39.63	$5.02	$8.50	$53.15
Jun	382,956.8	$23.58	$3.40	$3.17	$30.15
Jul	394,920.8	$22.28	$3.07	$3.73	$29.08
Aug	392,404.7	$18.21	$3.76	$3.30	$25.26
Sep	379,683.3	$26.44	$4.90	$4.58	$35.92
Oct	400,990.0	$19.91	$5.08	$2.20	$27.19
Nov	404,303.3	$19.05	$4.52	$1.72	$25.28
Dec	408,183.5	$16.81	$4.33	$1.71	$22.84

Table 10-12 Tier 1 compensation as currently implemented by PJM

Tier 1 Compensation by Type of Hour as Currently Implemented by PJM		
Hourly Parameters	No Synchronized Reserve Event	Synchronized Reserve Event
NSRMCP=$0	T1 credits = $0	T1 credits = Synchronized Energy Premium Price * actual response MWh
NSRMCP>$0	T1 credits = T2 SRMCP * estimated tier 1 MW	T1 credits = T2 SRMCP * min(calculated tier 1 MW, actual response MWh)

Table 10-13 Tier 1 compensation as recommended by MMU

Hourly Parameters	Tier 1 Compensation by Type of Hour as Recommended by MMU	
	No Synchronized Reserve Event	Synchronized Reserve Event
NSRMCP=$0	T1 credits = $0	T1 credits = Synchronized Energy Premium Price * actual response MWh
NSRMCP>$0	T1 credits = $0	T1 credits = Synchronized Energy Premium Price * actual response MWh

Table 10-10 Weighted price of tier 1 synchronized reserve attributable to a non-synchronized reserve price above zero: January 2014 to December 2015

Year	Month	Total Hours When NSRMCP>$0	Weighted Average SRMCP for Hours When NSRMCP>$0	Total Tier 1 MW Credited for Hours When NSRMCP>$0	Total Tier 1 Credits Paid When NSRMCP>$0	Average Tier 1 MW Paid
2014	Jan	155	$93.26	53,014	$4,874,314	414.9
2014	Feb	15	$40.18	65,332	$337,903	560.5
2014	Mar	67	$44.56	34,150	$1,513,636	509.7
2014	Apr	99	$16.07	57,047	$916,275	576.2
2014	May	61	$15.85	50,455	$799,911	827.1
2014	Jun	4	$35.46	3,335	$118,273	833.9
2014	Jul	5	$17.02	3,941	$67,078	788.1
2014	Aug	0	NA	NA	NA	NA
2014	Sep	0	NA	NA	NA	NA
2014	Oct	3	$21.59	2,146	$46,319	715.2
2014	Nov	28	$15.73	38,188	$599,147	1,363.8
2014	Dec	104	$6.93	163,552	$1,133,507	1,739.9
2014	Total	541	$30.67	471,159	$10,406,363	832.9
2015	Jan	148	$13.59	274,996	$3,727,945	1,858.1
2015	Feb	194	$24.83	369,111	$9,164,267	1,902.6
2015	Mar	181	$16.33	305,967	$4,985,446	1,690.4
2015	Apr	66	$25.56	102,117	$2,587,076	1,547.2
2015	May	72	$20.35	106,027	$2,158,080	1,472.6
2015	Jun	95	$17.64	185,148	$3,183,436	1,948.9
2015	Jul	46	$35.12	64,516	$2,265,614	1,402.5
2015	Aug	38	$22.40	48,479	$1,078,199	1,275.8
2015	Sep	36	$31.53	51,968	$1,522,913	1,060.5
2015	Oct	113	$17.10	126,879	$2,169,670	1,122.8
2015	Nov	29	$14.65	29,156	$427,056	1,005.4
2015	Dec	51	$16.07	53,898	$865,969	1,005.4
2015	Total	1,069	$21.26	1,718,263	$34,135,671	1,441.0

Table 13-1 The FTR Auction Markets results were competitive

Market Element	Evaluation	Market Design
Market Structure	Competitive	
Participant Behavior	Competitive	
Market Performance	Competitive	Flawed

State of the Market Report Recommendations: FTR/ARR

- **ARR/FTR design should be modified to ensure that all congestion revenues are returned to load.**
- **All FTR auction revenues should be returned to load.**
- **Eliminate use of 1998 generation to load paths.**
- **Eliminate use of counterflow FTRs.**
- **Eliminate portfolio netting.**
- **Apply FTR forfeiture rule to UTCs in the same way applied to other virtuals.**

Figure 13-13 FTR payout ratio by month, excluding and including excess revenue distribution: January 2004 through December 2015

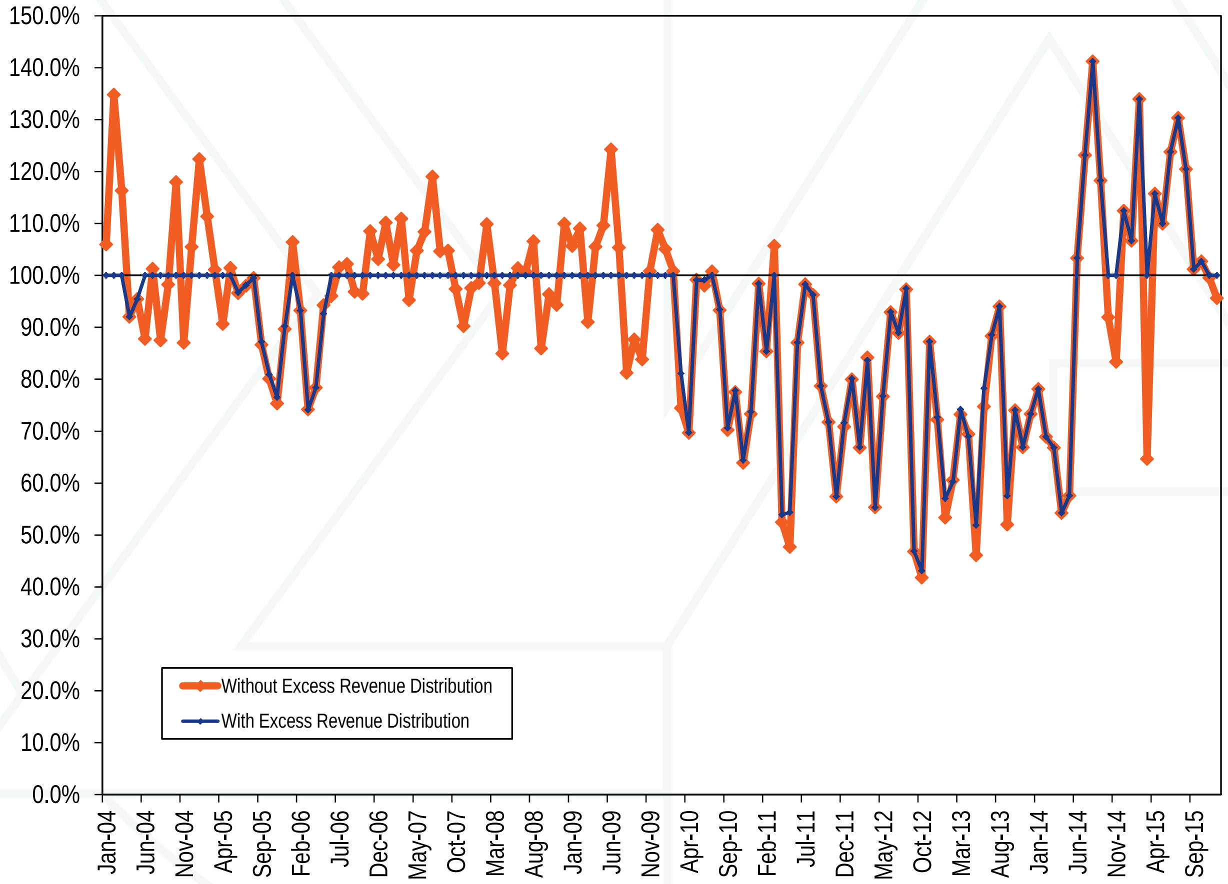


Figure 13-1 Historic Stage 1B and Stage 2 ARR Allocations from the 2011 to 2012 through 2015 to 2016 planning periods

Figure 13-6 Annual Bid FTR Auction volume: Planning period 2009 to 2010 through 2015 to 2016

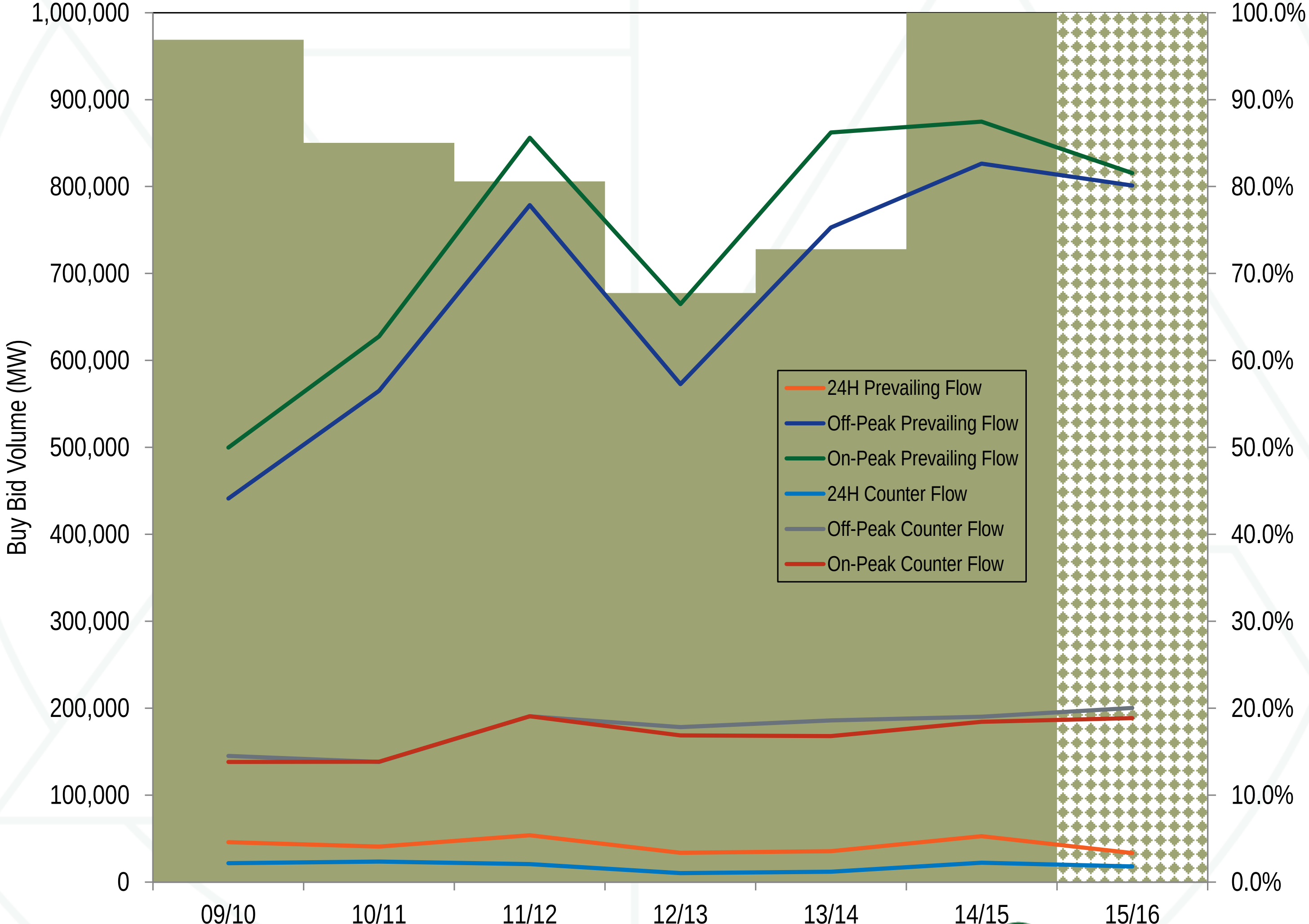


Figure 13-10 Annual FTR Auction volume-weighted average buy bid price: Planning period 2009 to 2010 through 2015 to 2016

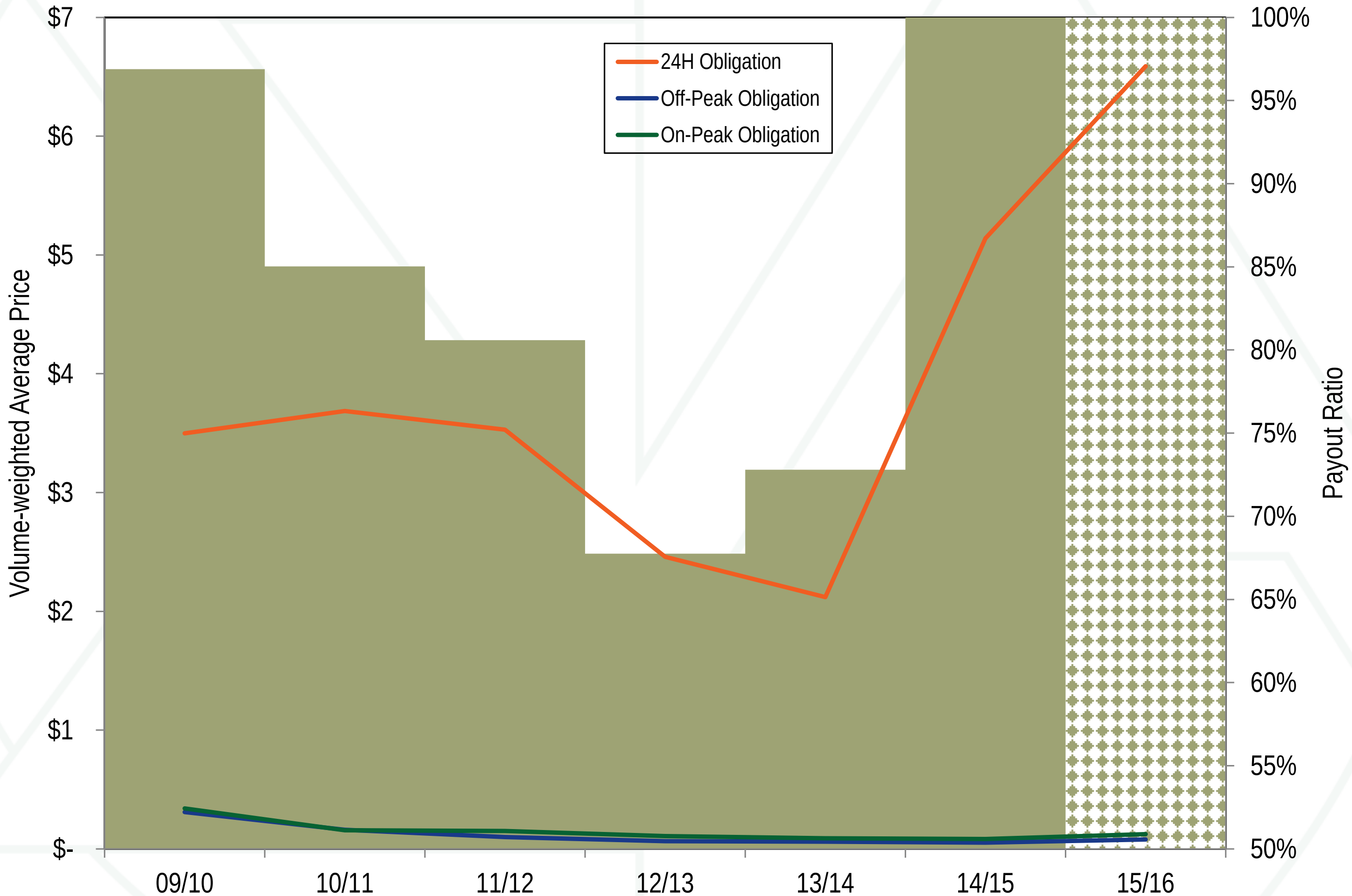


Figure 13-9 Long Term, Annual and Monthly FTR Auction bid and cleared volume: June 2003 through December 2015

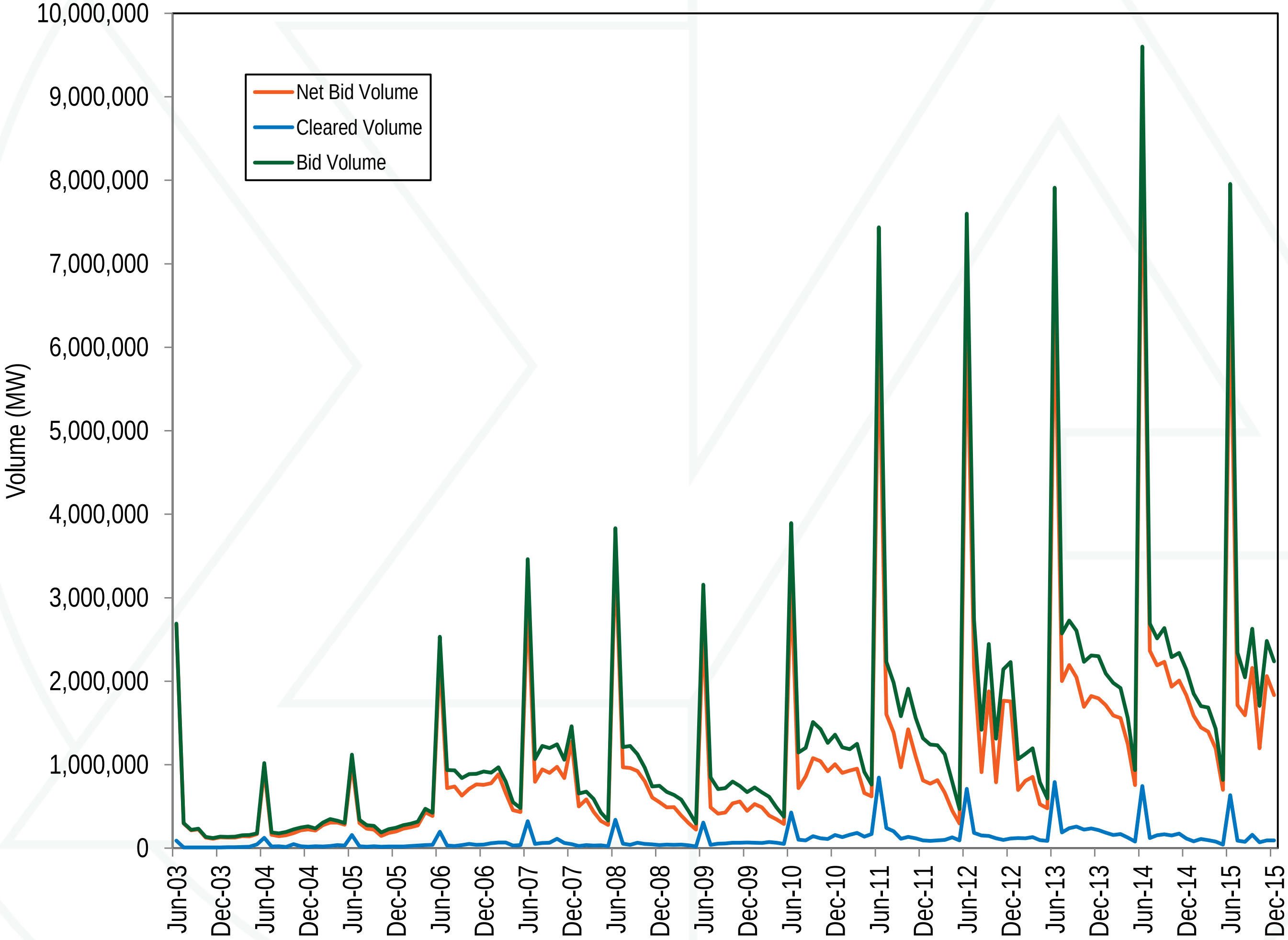


Figure 13-17 Monthly FTR forfeitures for physical and financial participants: June 2010 through December 2015

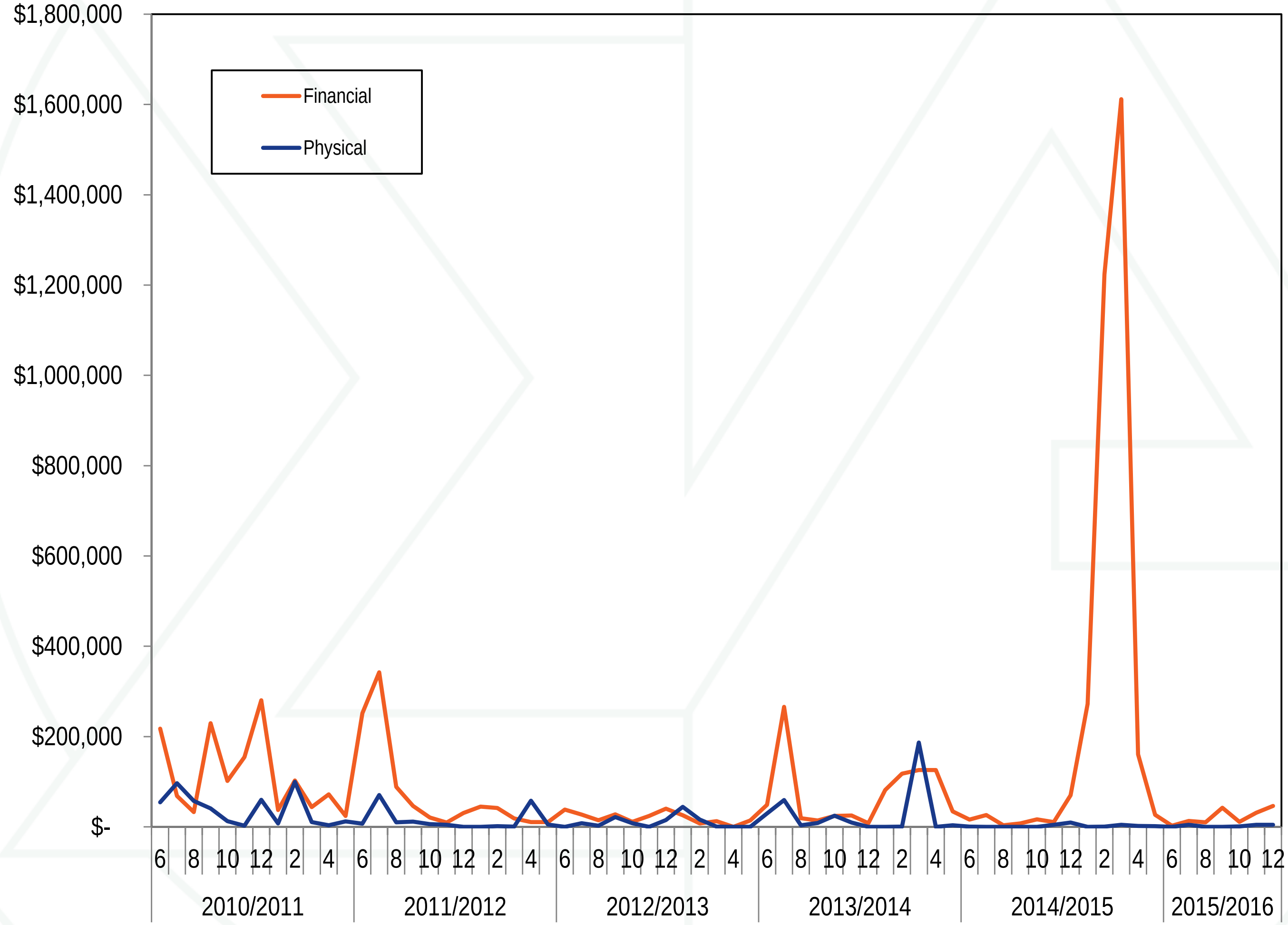


Figure 13-18 FTR forfeitures for INCs/DECs and INCs/DECs/UTCs for both the PJM and MMU methods: January 2013 through December 2015

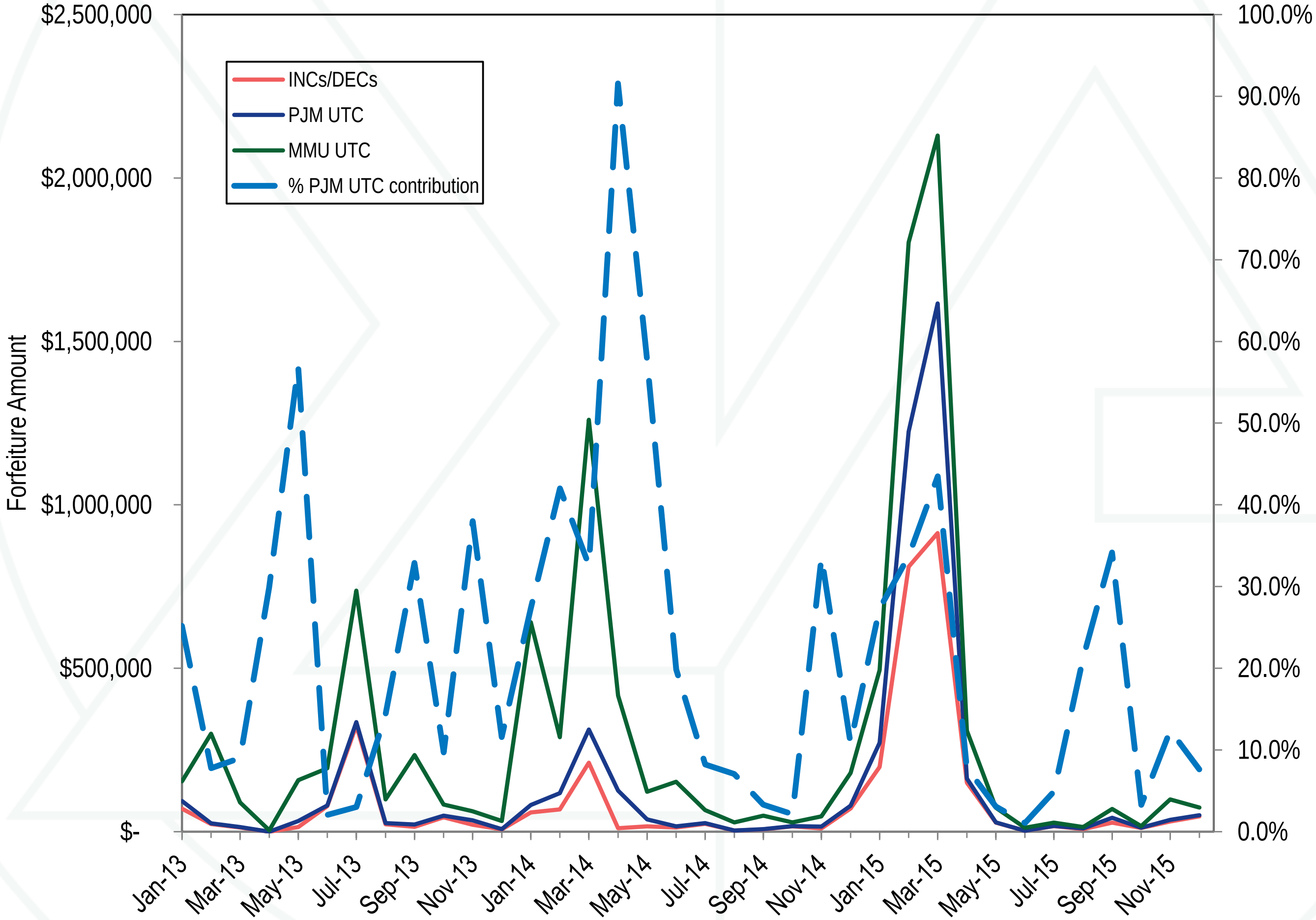


Table 13-13 Long Term FTR Auction patterns of ownership by FTR direction: Planning periods 2016 to 2019

		FTR Direction		
Trade Type	Organization Type	Prevailing Flow	Counter Flow	All
Buy Bids	Physical	29.9%	21.5%	26.2%
	Financial	70.1%	78.5%	73.8%
	Total	100.0%	100.0%	100.0%
Sell Offers	Physical	29.2%	24.3%	27.5%
	Financial	70.8%	75.7%	72.5%
	Total	100.0%	100.0%	100.0%

Table 13-44 ARR and FTR total congestion offset (in millions) for ARR holders: Planning periods 2014 to 2015 and 2015 to 2016

Planning Period	ARR Credits	FTR Credits	Total Congestion	Total ARR/FTR Offset	Percent Offset
2013/2014	$337.7	$410.5	$1,777.1	$748.1	42.1%
2014/2015	$284.6	$142.7	$1,390.9	$427.4	30.7%
2015/2016*	$372.3	$119.6	$573.1	$491.9	85.8%

*Shows seven months through December 31, 2015

Table 13-26 FTR profits by organization type and FTR direction: 2015

	FTR Direction				
Organization Type	Prevailing Flow	Self Scheduled Prevailing Flow	Counter Flow	Self Scheduled Counter Flow	All
Physical	$153,200,377	$324,887,334	($25,582,647)	$1,042,334	$453,547,398
Financial	$147,619,734	NA	$34,662,401	NA	$182,282,134
Total	$300,820,110	$324,887,334	$9,079,754	$1,042,334	$635,829,532

Figure 3-29 PJM monthly cleared up to congestion transactions by type (MW): January 2005 through December 2015

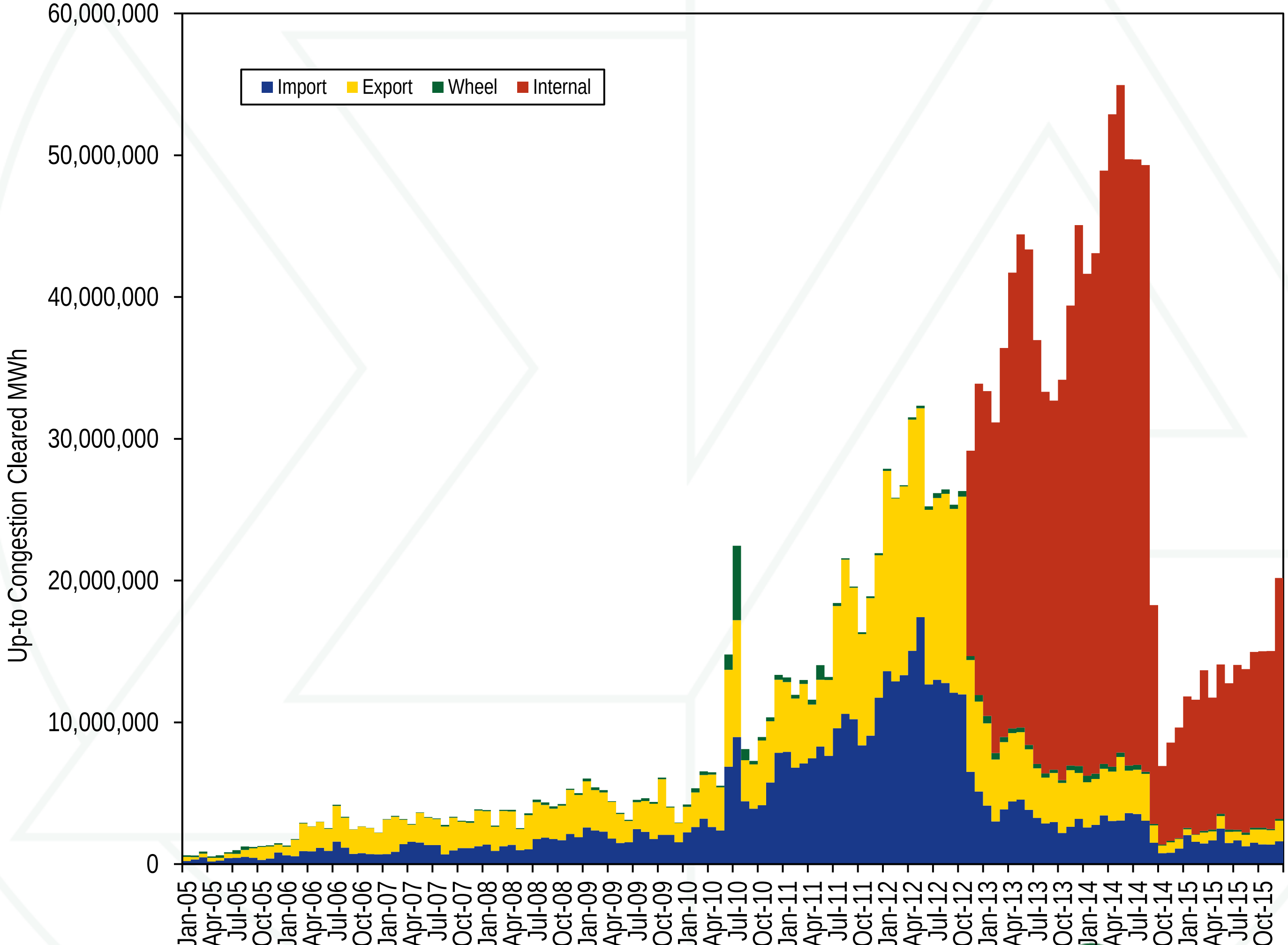


Table 3-37 PJM up to congestion transactions by type of parent organization (MW): 2014 and 2015

	2014		2015	
Category	Total Up to Congestion MW	Percent	Total Up to Congestion MW	Percent
Financial	407,879,549	94.0%	134,555,951	79.8%
Physical	25,839,452	6.0%	34,117,122	20.2%
Total	433,719,001	100.0%	168,673,073	100.0%

Table 2-1 Status of MMU reported recommendations: 1999 through 2015

Status	Priority High	Priority Medium	Priority Low	Total	Percent of Total
Adopted	20	13	16	49	24.4%
Partially Adopted	6	10	8	24	11.9%
Not Adopted	20	39	44	103	51.2%
Not Adopted (Pending before FERC)	3	1	0	4	2.0%
Not Adopted (Stakeholder Process)	6	7	1	14	7.0%
Not Adopted (Total)	29	47	45	121	60.2%
Replaced by Newer Recommendation	1	5	1	7	3.5%
Total	56	75	70	201	100%

Market Monitoring Unit

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

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