2017 State of the Market Report for PJM

MC Special Session

March 22, 2018

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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 managers
- 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

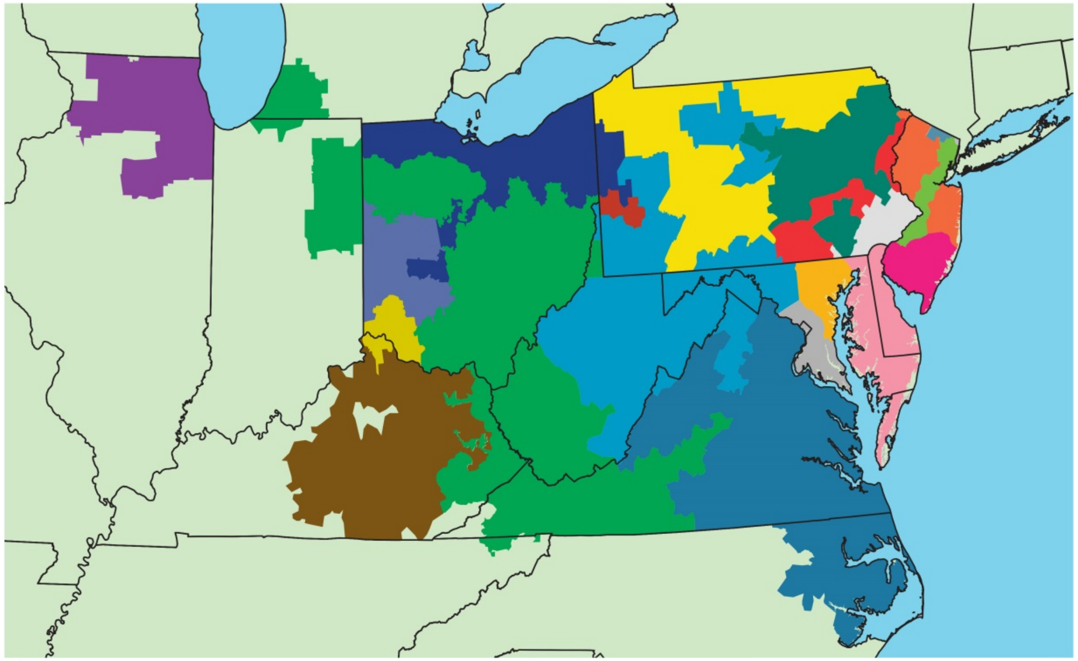
Role of Market Monitoring

- 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.**

PJM's footprint and its 20 control zones



Legend

- Allegheny Power System (APS)
- American Electric Power Co., Inc (AEP)
- American Transmission Systems, Inc. (ATSI)
- Atlantic Electric Company (AECO)
- Baltimore Gas and Electric Company (BGE)
- ComEd
- Dayton Power and Light Company (DAY)
- Delmarva Power and Light (DPL)
- Dominion
- Duke Energy Ohio/Kentucky (DEOK)
- Duquesne Light (DLCO)
- Eastern Kentucky Power Cooperative (EKPC)
- Jersey Central Power and Light Company (JCPL)
- Metropolitan Edison Company (Met-Ed)
- PECO Energy (PECO)
- Pennsylvania Electric Company (PENELEC)
- Pepco
- PPL Electric Utilities (PPL)
- Public Service Electric and Gas Company (PSEG)
- Rockland Electric Company (RECO)

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The energy market results were competitive

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

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Recommendations: Energy Market

- Cost based offers equal to short run marginal cost
  - Replace Manual 15 with clear definitions for cost-based offers
  - Clear definition of relevant operating expenses
  - Fuel cost policies: algorithmic, verifiable, systematic
- OEM parameters from CONE unit should be used for performance assessment and uplift
- Define explicit rules related to use of transmission penalty factors in setting LMP.
- Improve scarcity pricing.
- Local market power mitigation improvements (TPS)
  - Constant markup on price and cost based offers
  - Cost based offer with same fuel as price based offer
  - PLS parameters at least as flexible as price based offer

Total price per MWh by category: 2016 and 2017

Category	2016 $/MWh	2016 Percent of Total	2017 $/MWh	2017 Percent of Total	Percent Change
Load Weighted Energy	$29.23	58.5%	$30.99	58.2%	6.0%
Capacity	$10.96	21.9%	$11.23	21.1%	2.5%
Capacity	$10.96	21.9%	$11.23	21.1%	2.5%
Capacity (FRR)	$0.00	0.0%	$0.00	0.0%	0.0%
Transmission	$8.42	16.8%	$9.57	18.0%	13.7%
Transmission Service Charges	$7.81	15.6%	$8.84	16.6%	13.1%
Transmission Enhancement Cost Recovery	$0.52	1.0%	$0.64	1.2%	24.2%
Transmission Owner (Schedule 1A)	$0.09	0.2%	$0.10	0.2%	3.4%
Transmission Facility Charges	$0.00	0.0%	$0.00	0.0%	(100.0%)
Ancillary	$0.72	1.4%	$0.78	1.5%	8.9%
Reactive	$0.38	0.8%	$0.44	0.8%	14.8%
Regulation	$0.11	0.2%	$0.14	0.3%	26.8%
Black Start	$0.09	0.2%	$0.09	0.2%	4.3%
Synchronized Reserves	$0.05	0.1%	$0.06	0.1%	5.5%
Non-Synchronized Reserves	$0.01	0.0%	$0.01	0.0%	1.1%
Day Ahead Scheduling Reserve (DASR)	$0.07	0.1%	$0.05	0.1%	(38.7%)
Administration	$0.47	0.9%	$0.52	1.0%	9.6%
PJM Administrative Fees	$0.44	0.9%	$0.48	0.9%	10.0%
NERC/RFC	$0.03	0.1%	$0.03	0.1%	4.2%
RTO Startup and Expansion	$0.00	0.0%	$0.00	0.0%	3.3%
Energy Uplift (Operating Reserves)	$0.17	0.3%	$0.14	0.3%	(16.9%)
Demand Response	$0.01	0.0%	$0.01	0.0%	(35.3%)
Load Response	$0.01	0.0%	$0.01	0.0%	(35.3%)
Emergency Load Response	$0.00	0.0%	$0.00	0.0%	0.0%
Emergency Energy	$0.00	0.0%	$0.00	0.0%	0.0%
Total Price	$49.99	100.0%	$53.24	100.0%	6.5%

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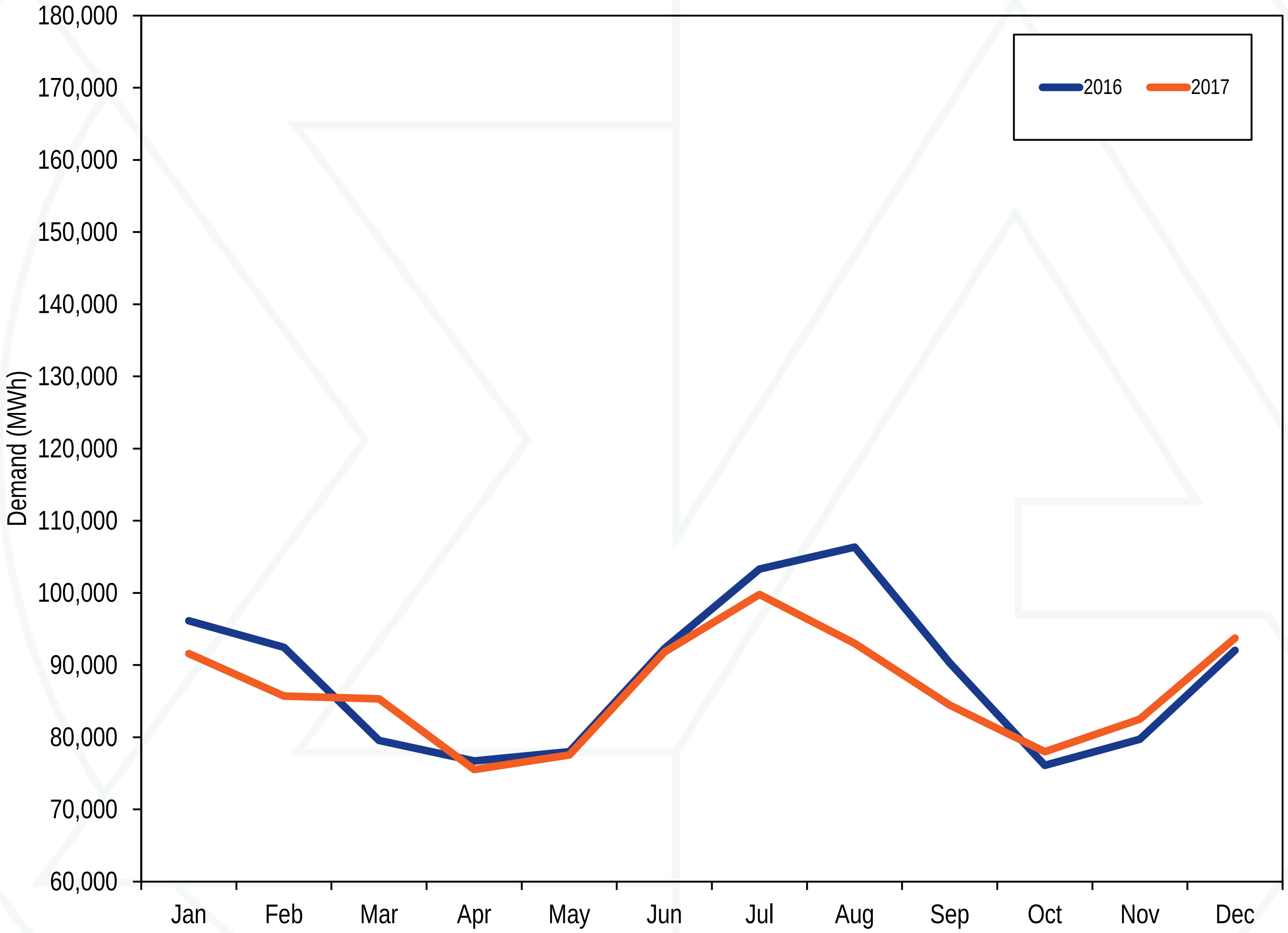
PJM Load: 1998 through 2017

	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%
2016	88,601	17,229	93,551	17,498	0.0%	3.4%	1.0%	4.3%
2017	86,618	15,170	90,755	15,082	(2.2%)	(11.9%)	(3.0%)	(13.8%)

PJM real-time monthly average hourly load



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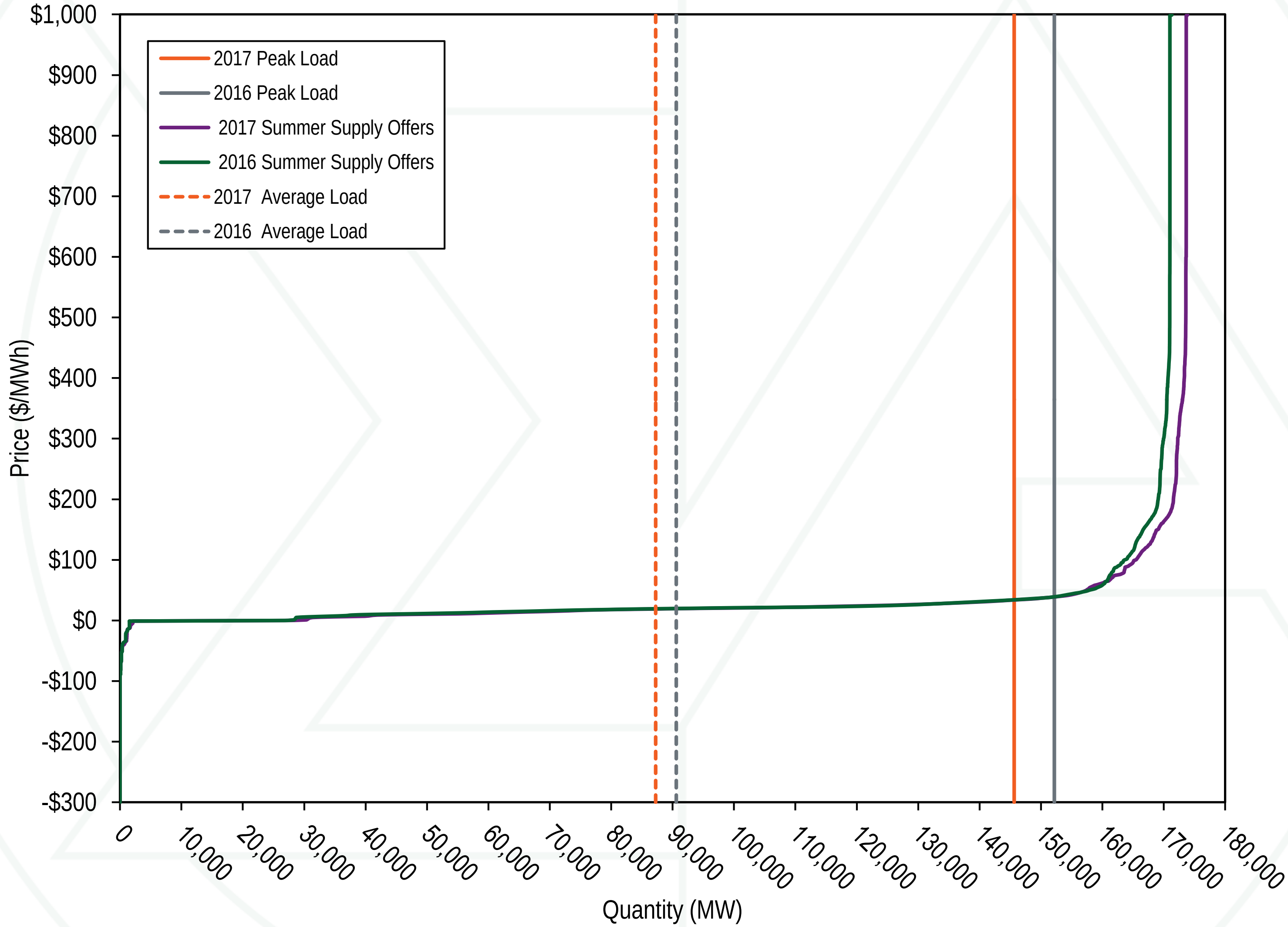
Average RT generation supply curves: summer



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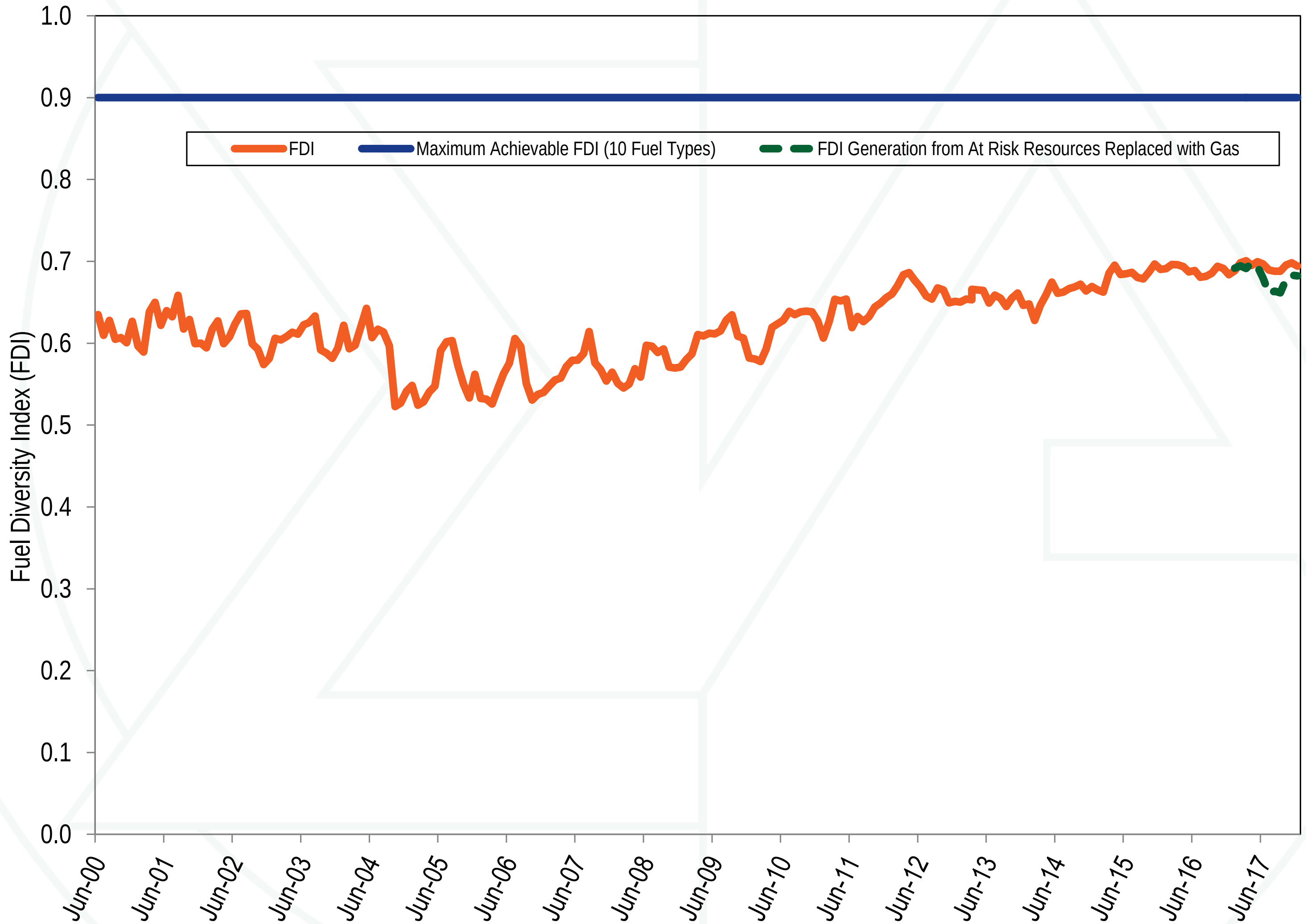
PJM generation by fuel source

		2016 GWh	Percent	2017 GWh	Percent	Change in Output
Coal		275,289.4	33.9%	256,613.8	31.8%	(6.8%)
	Bituminous	241,050.2	29.7%	220,789.4	27.3%	(8.4%)
	Sub Bituminous	28,949.8	3.6%	28,016.0	3.5%	(3.2%)
	Other Coal	5,289.5	0.7%	7,808.4	1.0%	47.6%
Nuclear		279,546.4	34.4%	287,575.8	35.6%	2.9%
Gas		217,199.0	26.7%	219,205.1	27.1%	0.9%
	Natural Gas	215,021.4	26.5%	216,758.6	26.8%	0.8%
	Landfill Gas	2,177.6	0.3%	2,433.1	0.3%	11.7%
	Other Gas	0.0	0.0%	13.4	0.0%	NA
Hydroelectric		13,686.8	1.7%	14,868.4	1.8%	8.6%
	Pumped Storage	4,840.2	0.6%	5,132.6	0.6%	6.0%
	Run of River	7,332.8	0.9%	8,119.8	1.0%	10.7%
	Other Hydro	1,513.8	0.2%	1,616.0	0.2%	6.8%
Wind		17,716.0	2.2%	20,714.1	2.6%	16.9%
Waste		4,358.9	0.5%	3,984.1	0.5%	(8.6%)
	Solid Waste	4,139.8	0.5%	3,740.7	0.5%	(9.6%)
	Miscellaneous	219.2	0.0%	243.4	0.0%	11.1%
Oil		2,163.2	0.3%	2,301.7	0.3%	6.4%
	Heavy Oil	270.7	0.0%	174.4	0.0%	(35.6%)
	Light Oil	340.7	0.0%	340.3	0.0%	(0.1%)
	Diesel	59.4	0.0%	81.7	0.0%	37.5%
	Gasoline	0.0	0.0%	0.0	0.0%	NA
	Kerosene	74.8	0.0%	15.2	0.0%	(79.6%)
	Jet Oil	0.0	0.0%	3.1	0.0%	NA
	Other Oil	1,417.7	0.2%	1,687.0	0.2%	19.0%
Solar, Net Energy Metering		1,019.4	0.1%	1,468.7	0.2%	44.1%
Energy Storage		15.7	0.0%	25.1	0.0%	59.6%
	Battery	15.7	0.0%	25.1	0.0%	59.6%
	Compressed Air	0.0	0.0%	0.0	0.0%	NA
Biofuel		1,541.5	0.2%	1,473.0	0.2%	(4.4%)
Geothermal		0.0	0.0%	0.0	0.0%	NA
Other Fuel Type		0.0	0.0%	0.0	0.0%	NA
Total		812,536.3	100.0%	808,229.7	100.0%	(0.5%)

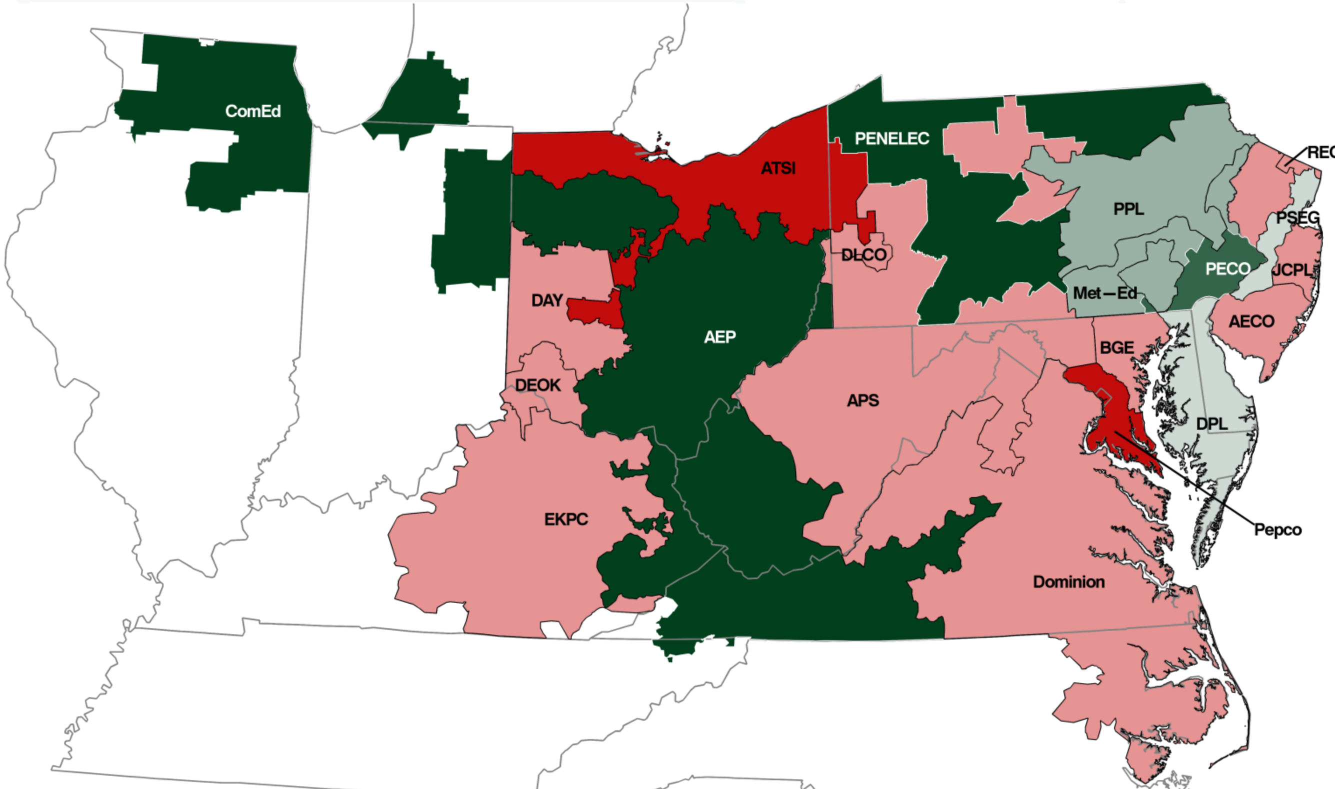
PJM capacity factor by unit type

	2016		2017		Change in 2017
Unit Type	Generation (GWh)	Capacity Factor	Generation (GWh)	Capacity Factor	from 2016
Battery	15.7	0.6%	25.1	0.9%	0.3%
Combined Cycle	187,657.9	62.0%	195,631.7	58.4%	(3.6%)
Combustion Turbine	17,265.2	6.9%	13,390.7	5.3%	(1.6%)
Diesel	291.2	10.1%	359.5	11.1%	1.0%
Diesel (Landfill gas)	1,489.0	50.3%	1,642.2	50.5%	0.2%
Fuel Cell	227.6	86.4%	226.7	86.2%	(0.1%)
Nuclear	279,546.4	91.3%	287,575.8	94.1%	2.9%
Pumped Storage Hydro	6,077.2	13.7%	6,475.4	14.6%	0.9%
Run of River Hydro	7,609.6	31.4%	8,393.0	32.0%	0.6%
Solar	1,000.9	17.3%	1,463.1	17.0%	(0.2%)
Steam	293,624.9	41.1%	272,325.1	40.7%	(0.4%)
Coal	276,539.4	46.2%	258,498.3	46.6%	0.4%
Natural Gas	10,463.1	12.3%	7,770.3	9.2%	(3.0%)
Oil	258.4	1.3%	154.6	0.8%	(0.5%)
Biomass	6,364.0	64.0%	5,901.9	59.5%	(4.5%)
Wind	17,716.0	27.6%	20,714.1	29.5%	1.9%
Total	812,521.7	47.2%	808,222.4	47.0%	(0.2%)

Fuel diversity index for energy



PJM real-time generation less real-time load

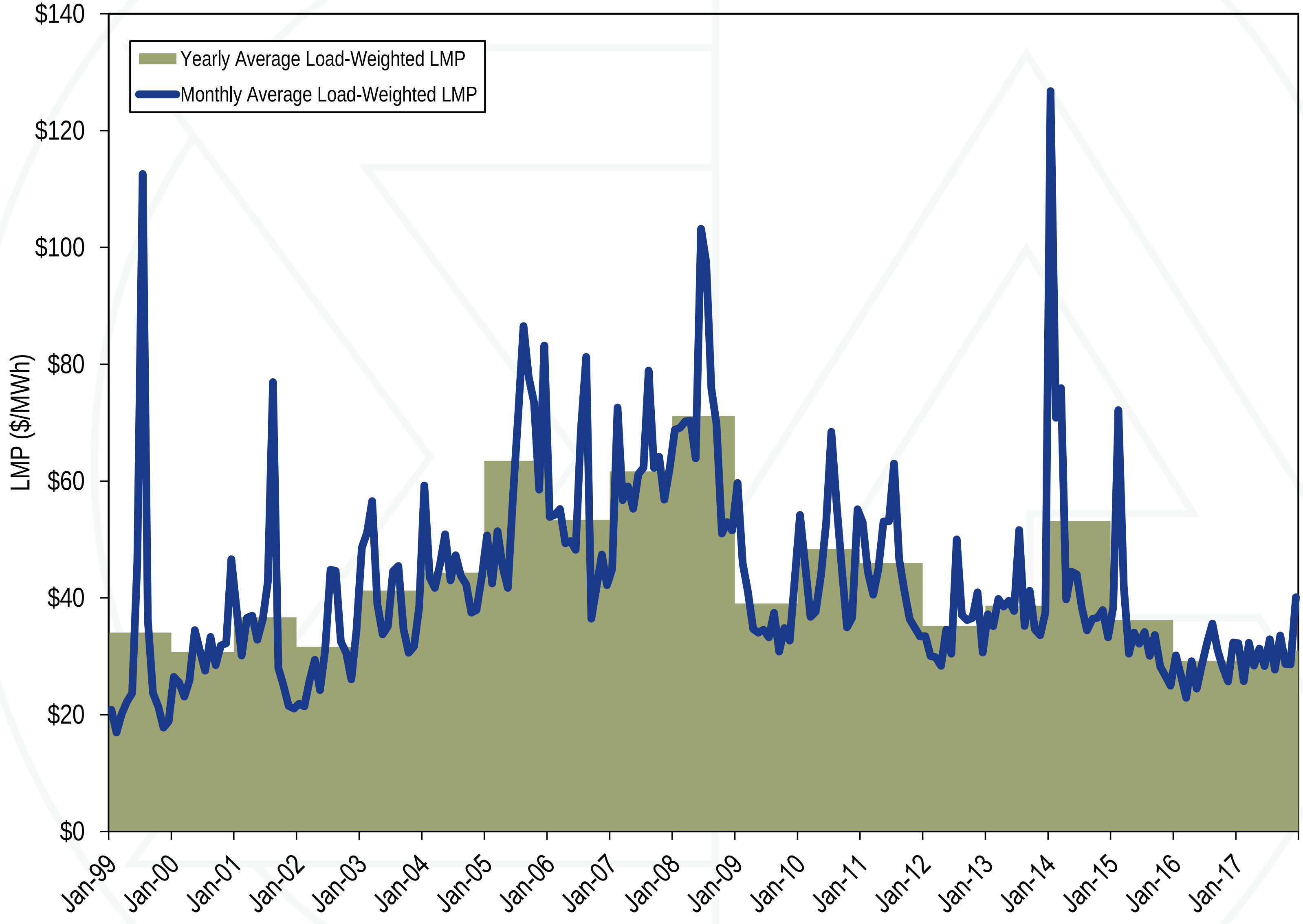


Zone	Net Gen Minus Load (GWh)	Zone	Net Gen Minus Load (GWh)	Zone	Net Gen Minus Load (GWh)	Zone	Net Gen Minus Load (GWh)
AECO	(3,315)	ComEd	33,880	DPL	(10,516)	PENELEC	26,656
AEP	27,058	DAY	(5,293)	EKPC	(4,659)	Pepco	(20,673)
APS	(205)	DEOK	(6,184)	JCPL	(3,874)	PPL	9,402
ATSI	(25,114)	DLCO	3,284	Met-Ed	6,870	PSEG	1,203
BGE	(10,322)	Dominion	(3,056)	PECO	24,187	RECO	(1,433)

PJM real-time, load-weighted, average LMP

	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%)
2016	$29.23	$25.01	$16.12	(19.2%)	(9.6%)	(48.1%)
2017	$30.99	$26.35	$19.32	6.0%	5.4%	19.9%

PJM real-time, load-weighted, average LMP



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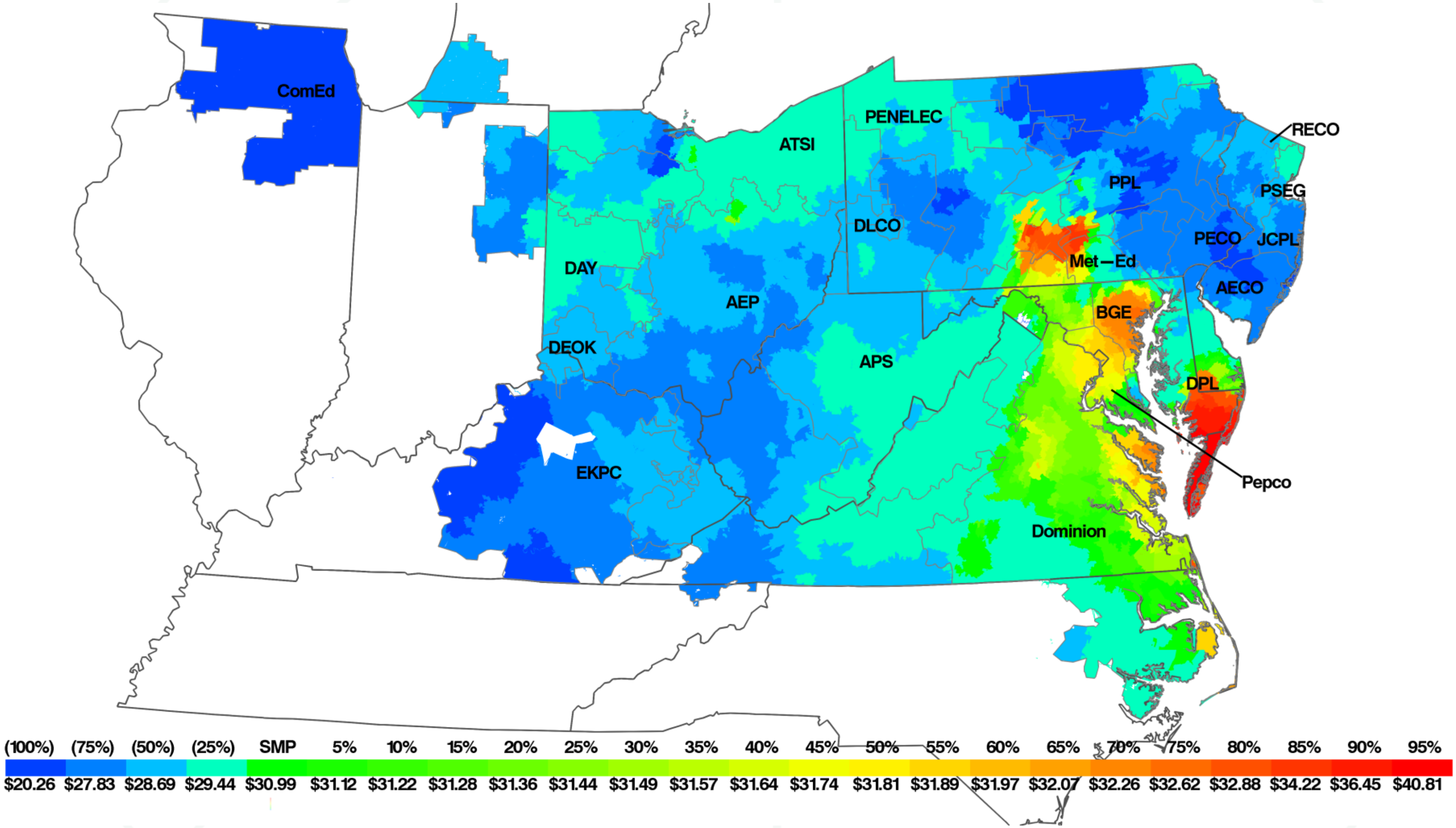
PJM real-time, load-weighted, average LMP



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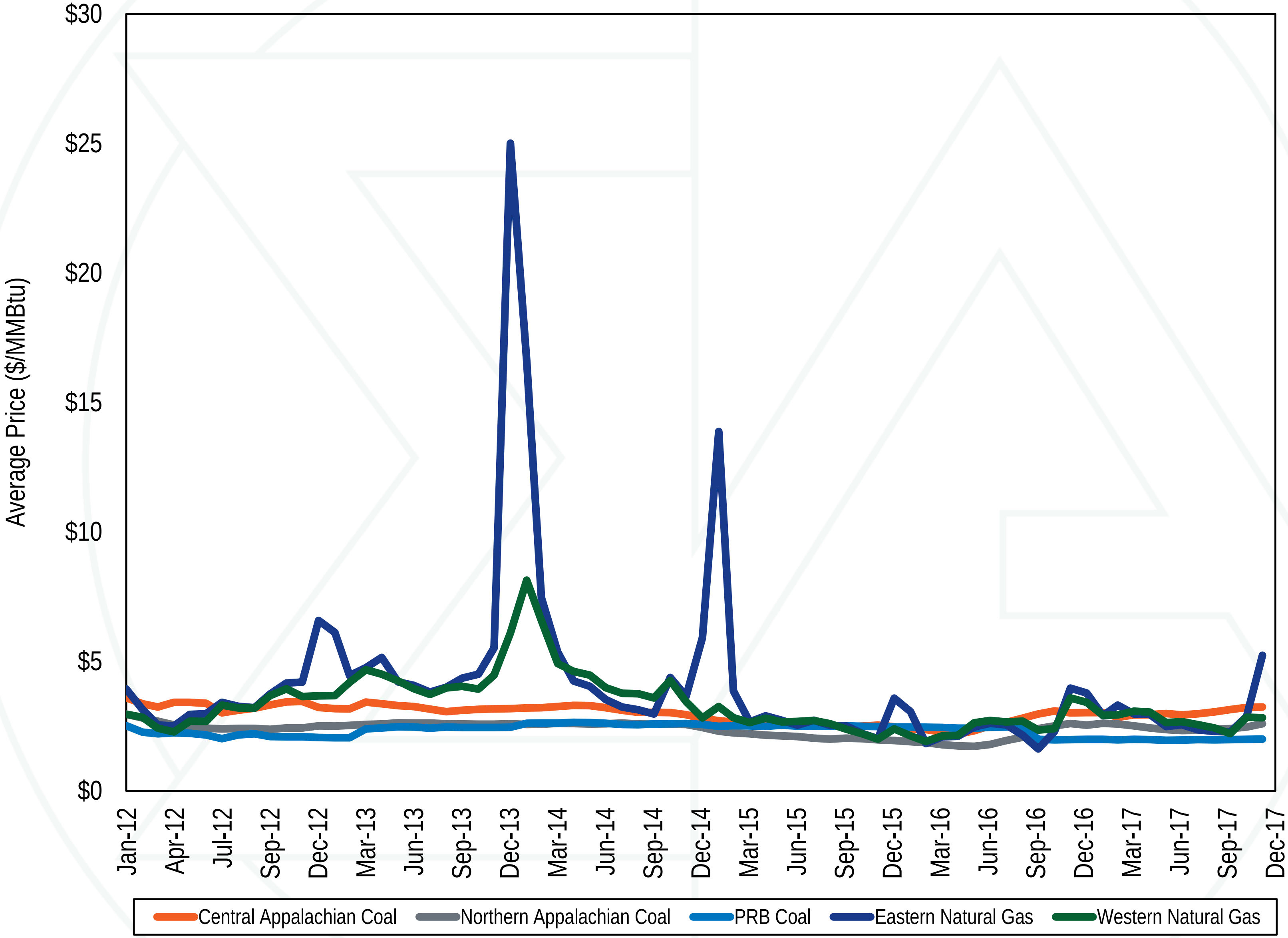
Spot average fuel prices



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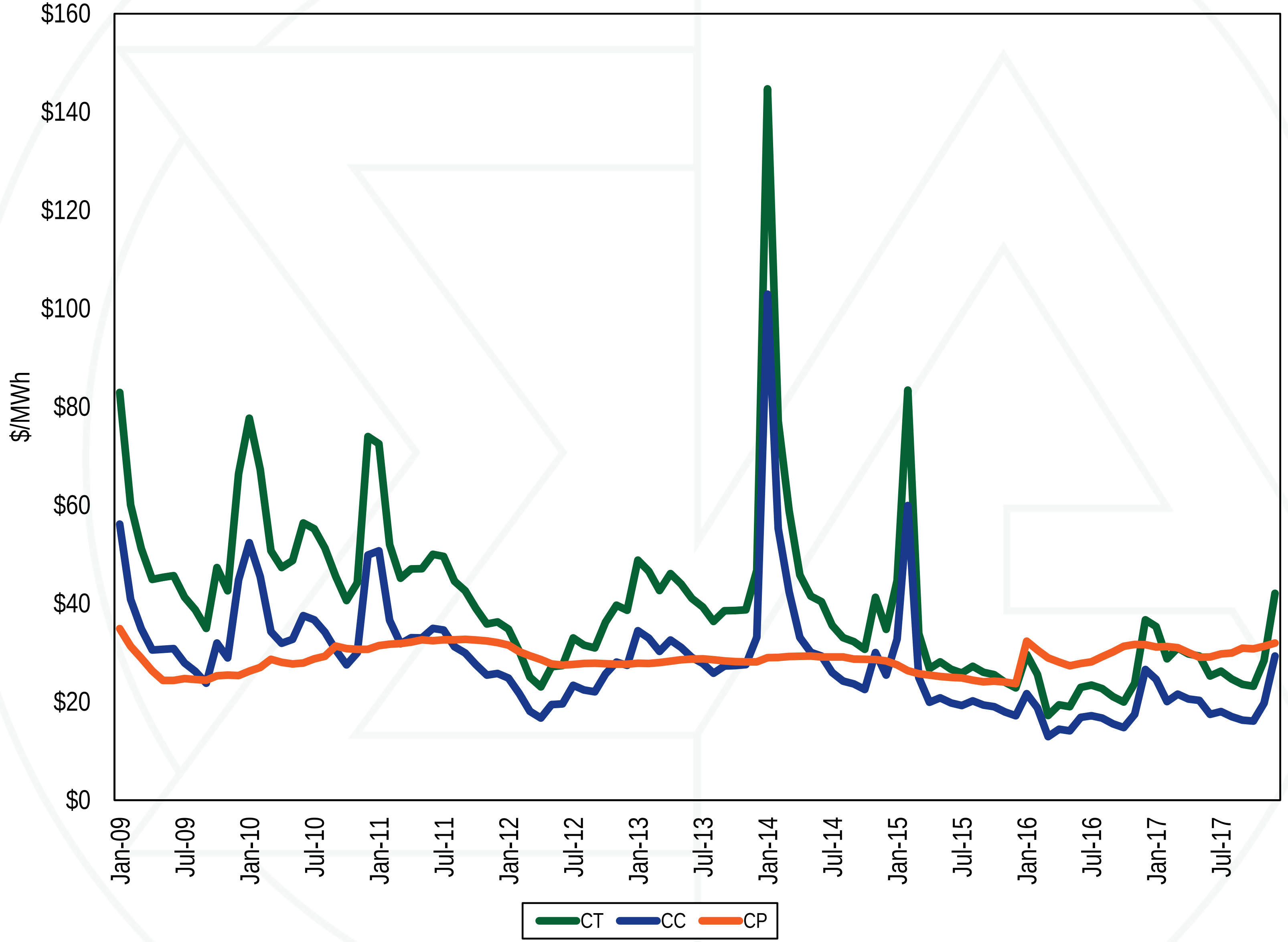
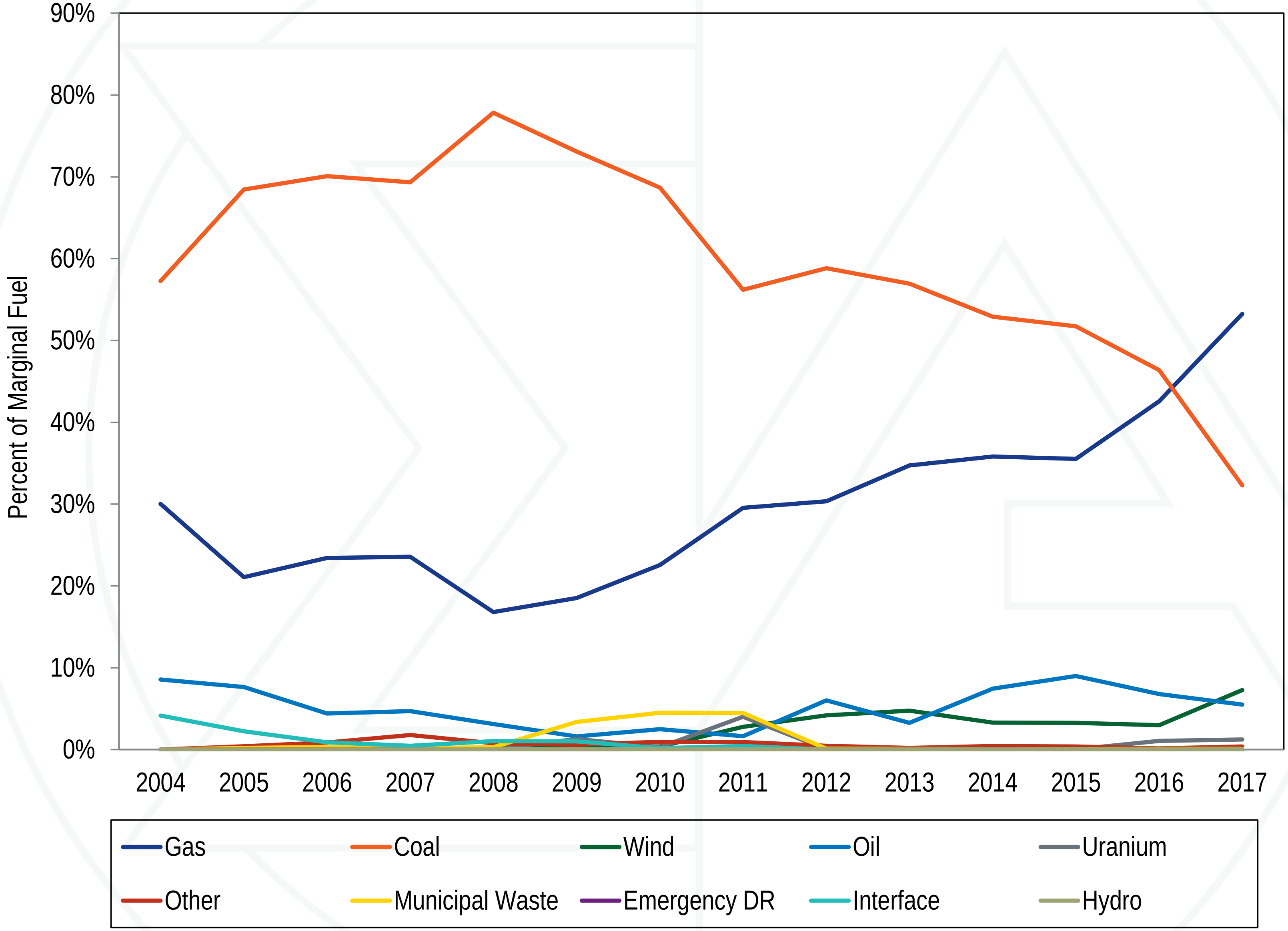
Short run marginal costs of generation



Type of fuel used by real-time marginal units



PJM RT annual, fuel-cost adjusted, load-weighted average LMP

	2017 Load-Weighted LMP	2017 Fuel-Cost Adjusted, Load-Weighted LMP	Change
Average	$30.99	$25.39	(18.1%)

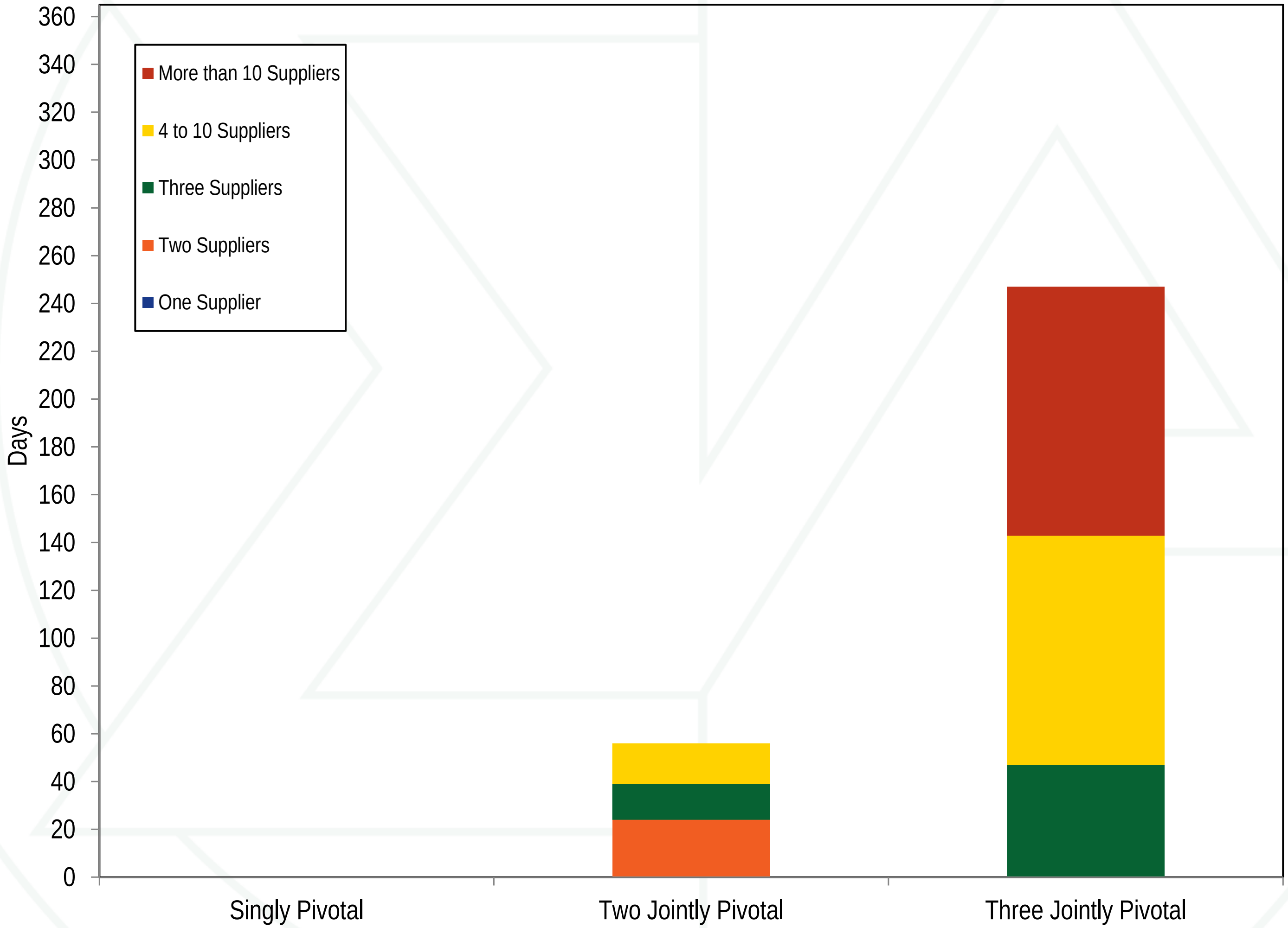
	2016 Load-Weighted LMP	2017 Fuel-Cost Adjusted, Load-Weighted LMP	Change
Average	$29.23	$25.39	(13.1%)

	2016 Load-Weighted LMP	2017 Load-Weighted LMP	Change
Average	$29.23	$30.99	6.0%

Components of PJM RT (Unadjusted), load-weighted, average LMP

Element	2016 Contribution to LMP	2016 Percent	2017 Contribution to LMP	2017 Percent	Change Percent
Gas	$7.76	26.5%	$12.15	39.2%	12.7%
Coal	$13.44	46.0%	$8.97	28.9%	(17.0%)
Markup	$0.27	0.9%	$2.55	8.2%	7.3%
Ten Percent Adder	$2.43	8.3%	$2.39	7.7%	(0.6%)
VOM	$2.04	7.0%	$1.70	5.5%	(1.5%)
NA	$1.48	5.1%	$0.81	2.6%	(2.5%)
LPA Rounding Difference	$0.15	0.5%	$0.78	2.5%	2.0%
Oil	$0.24	0.8%	$0.44	1.4%	0.6%
NO_x Cost	$0.42	1.4%	$0.41	1.3%	(0.1%)
Increase Generation Adder	$0.41	1.4%	$0.39	1.2%	(0.2%)
Ancillary Service Redispatch Cost	$0.32	1.1%	$0.25	0.8%	(0.3%)
CO_2 Cost	$0.09	0.3%	$0.09	0.3%	(0.0%)
SO_2 Cost	$0.07	0.3%	$0.06	0.2%	(0.1%)
Other	$0.15	0.5%	$0.06	0.2%	(0.3%)
Scarcity Adder	$0.00	0.0%	$0.05	0.2%	0.2%
Municipal Waste	$0.04	0.1%	$0.05	0.2%	0.0%
Opportunity Cost Adder	$0.00	0.0%	$0.04	0.1%	0.1%
Market-to-Market Adder	$0.01	0.0%	$0.00	0.0%	(0.0%)
Uranium	$0.00	0.0%	$0.00	0.0%	(0.0%)
Constraint Violation Adder	$0.00	0.0%	$0.00	0.0%	0.0%
LPA-SCED Differential	($0.01)	(0.0%)	($0.01)	(0.0%)	0.0%
Decrease Generation Adder	($0.03)	(0.1%)	($0.07)	(0.2%)	(0.1%)
Wind	($0.05)	(0.2%)	($0.11)	(0.4%)	(0.2%)
Total	$29.23	100.0%	$30.99	100.0%	0.0%

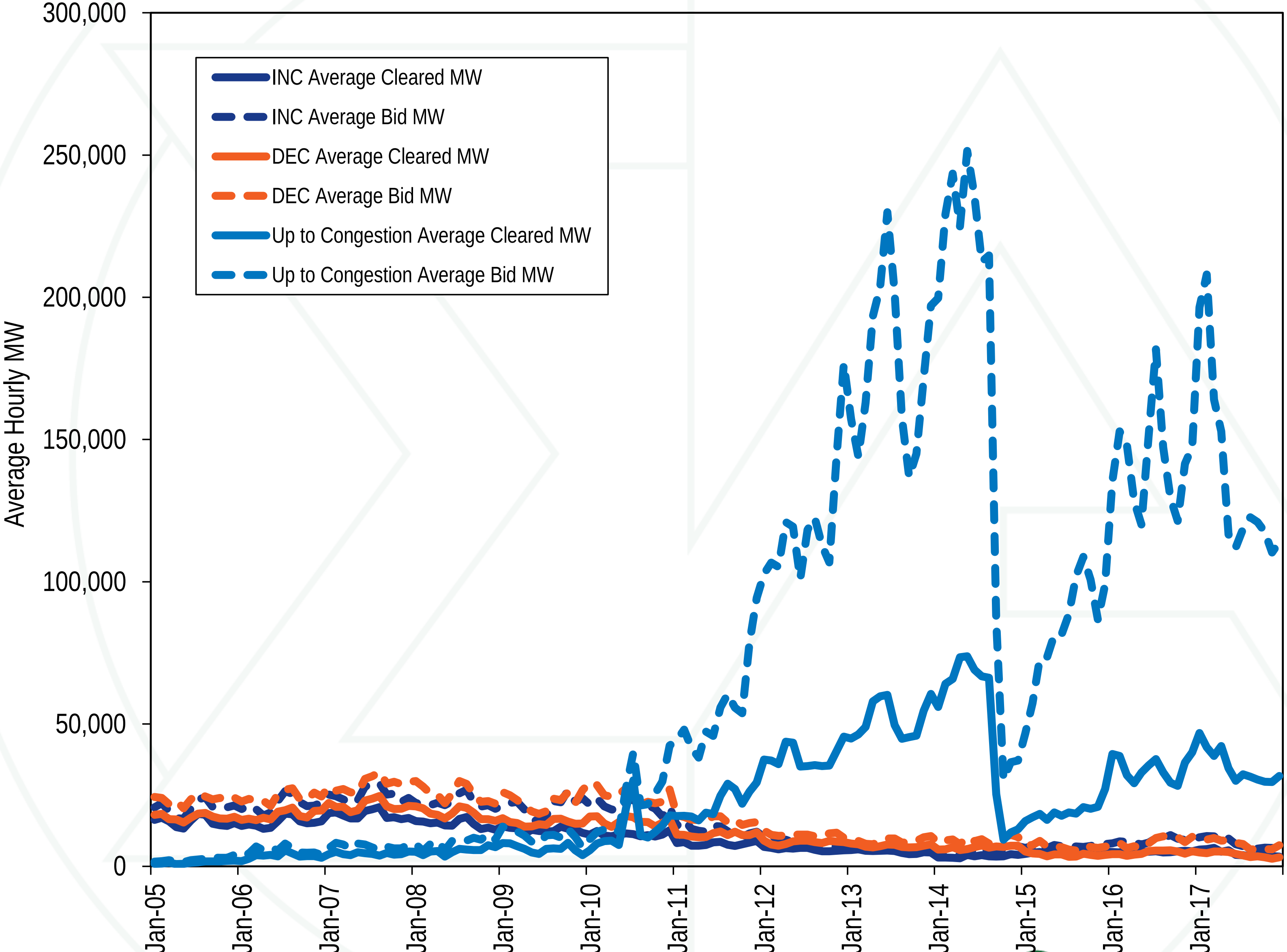
Days with pivotal suppliers in the PJM Day-Ahead Energy Market: 2017



Offer capping statistics – energy only

	Real Time		Day Ahead	
Year	Unit Hours Capped	MW Capped	Unit Hours Capped	MW Capped
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%
2016	0.4%	0.2%	0.1%	0.0%
2017	0.3%	0.2%	0.0%	0.0%

Monthly bid and cleared INCs, DECs and UTCs



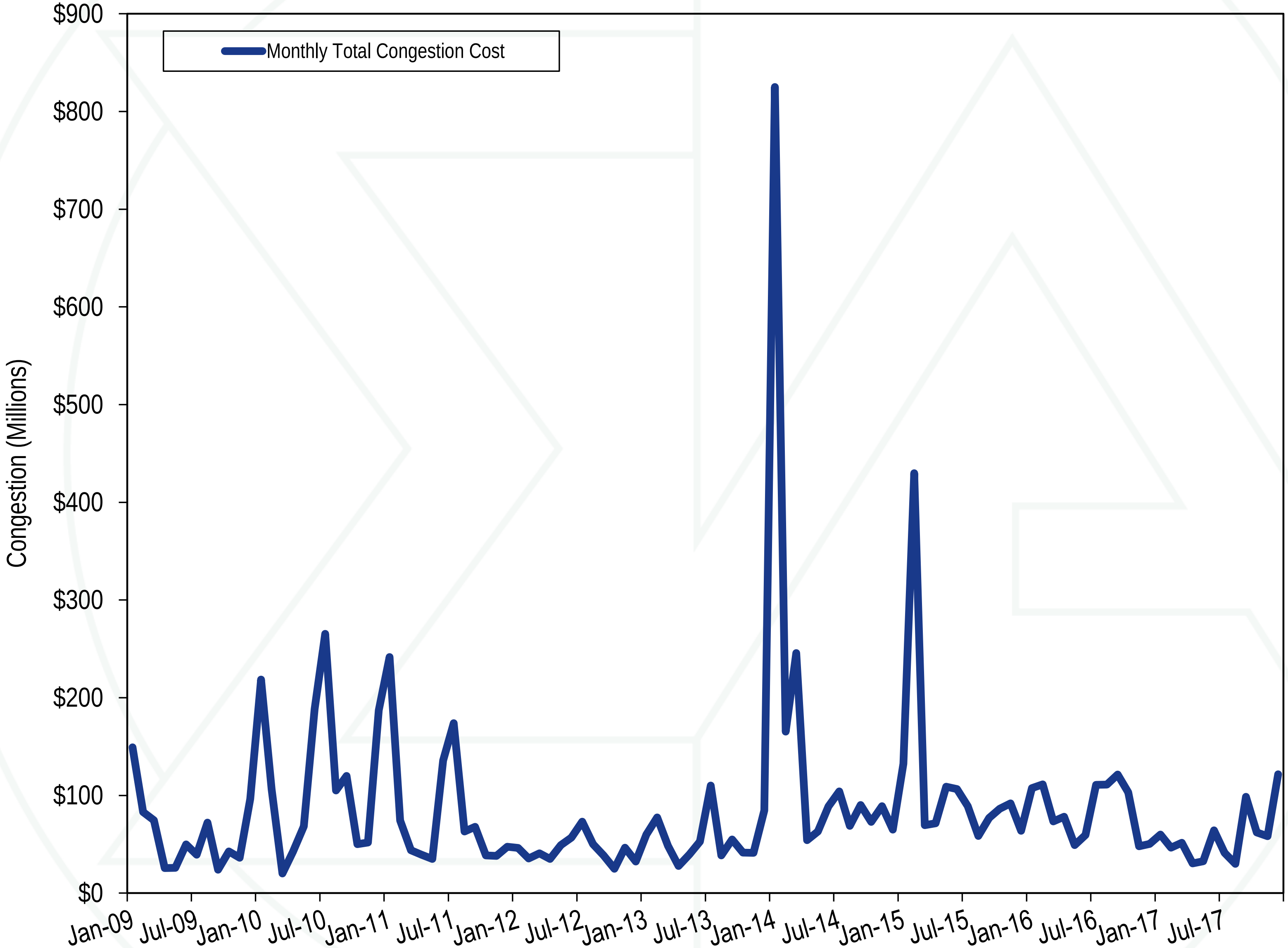
PJM UTC transactions by type of parent

	2016				2017			
Category	Total Up to Congestion Bid MWh	Percent	Total Up to Congestion Cleared MWh	Percent	Total Up to Congestion Bid MWh	Percent	Total Up to Congestion Cleared MWh	Percent
Financial	1,198,418,888	96.0%	282,808,931	93.6%	1,180,634,460	98.1%	293,713,948	96.0%
Physical	49,564,960	4.0%	19,231,146	6.4%	23,152,092	1.9%	12,250,315	4.0%
Total	1,247,983,848	100.0%	302,040,077	100.0%	1,203,786,552	100.0%	305,964,263	100.0%

Total PJM congestion

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%	$33,860	2.0%
2014	$1,932	185.5%	$50,030	3.9%
2015	$1,385	(28.3%)	$42,630	3.2%
2016	$1,024	(26.1%)	$39,050	2.6%
2017	$698	(31.9%)	$40,170	1.7%

PJM monthly total congestion cost



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

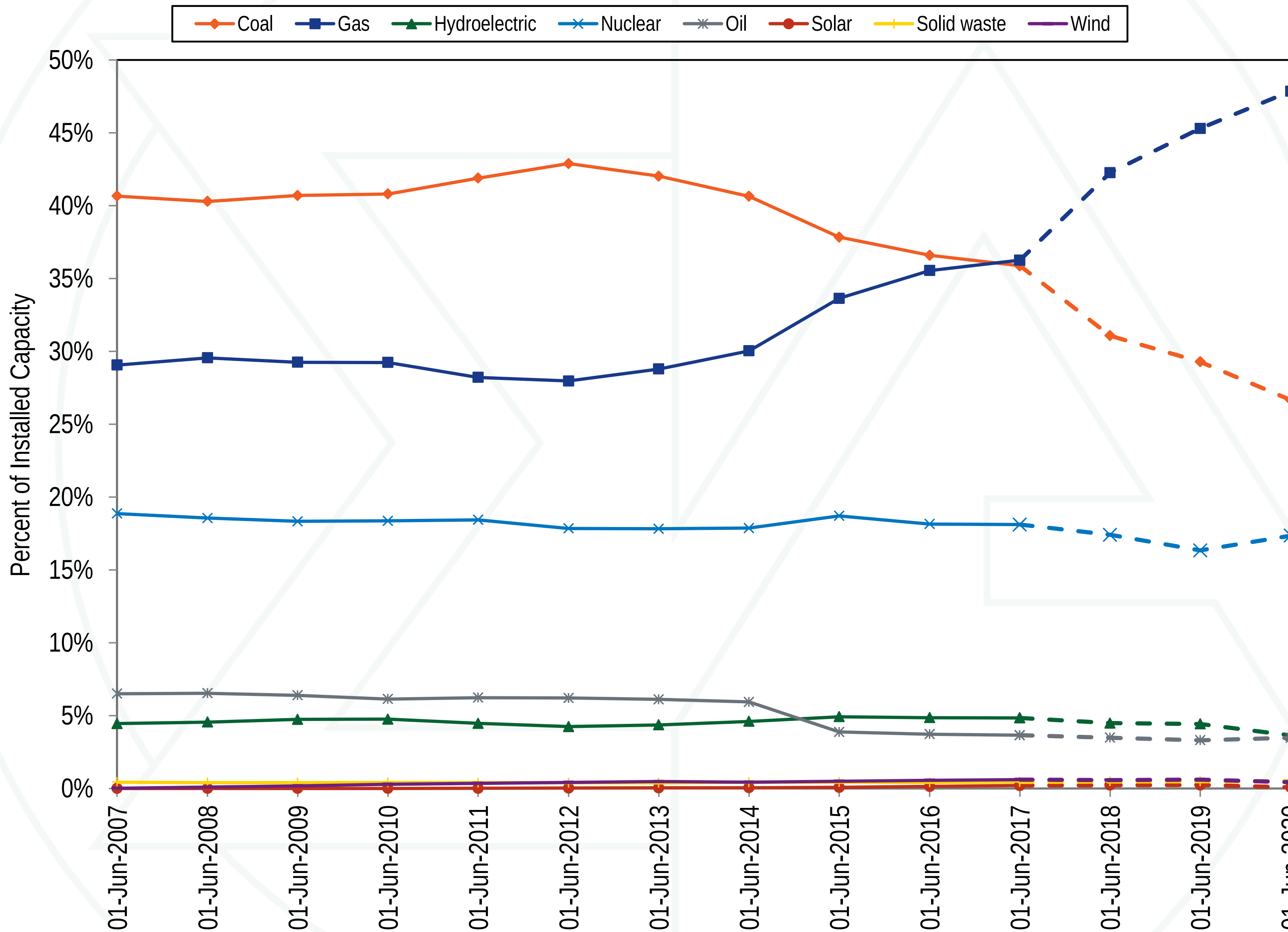
Recommendations: Capacity Market

- **Implement a MOPR for existing units (MOPR-Ex).**
- **All capacity imports should be deliverable to an LDA.**
- **Consistent definition of a capacity resource as physical at time of auction and delivery year.**
- **Definition of LDA should be dynamic and market based.**
- **Offer cap calculation should be based on economic logic of CP and actual PAH and not default to Net CONE*B.**
- **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.**
- **RMR rules should be modified.**

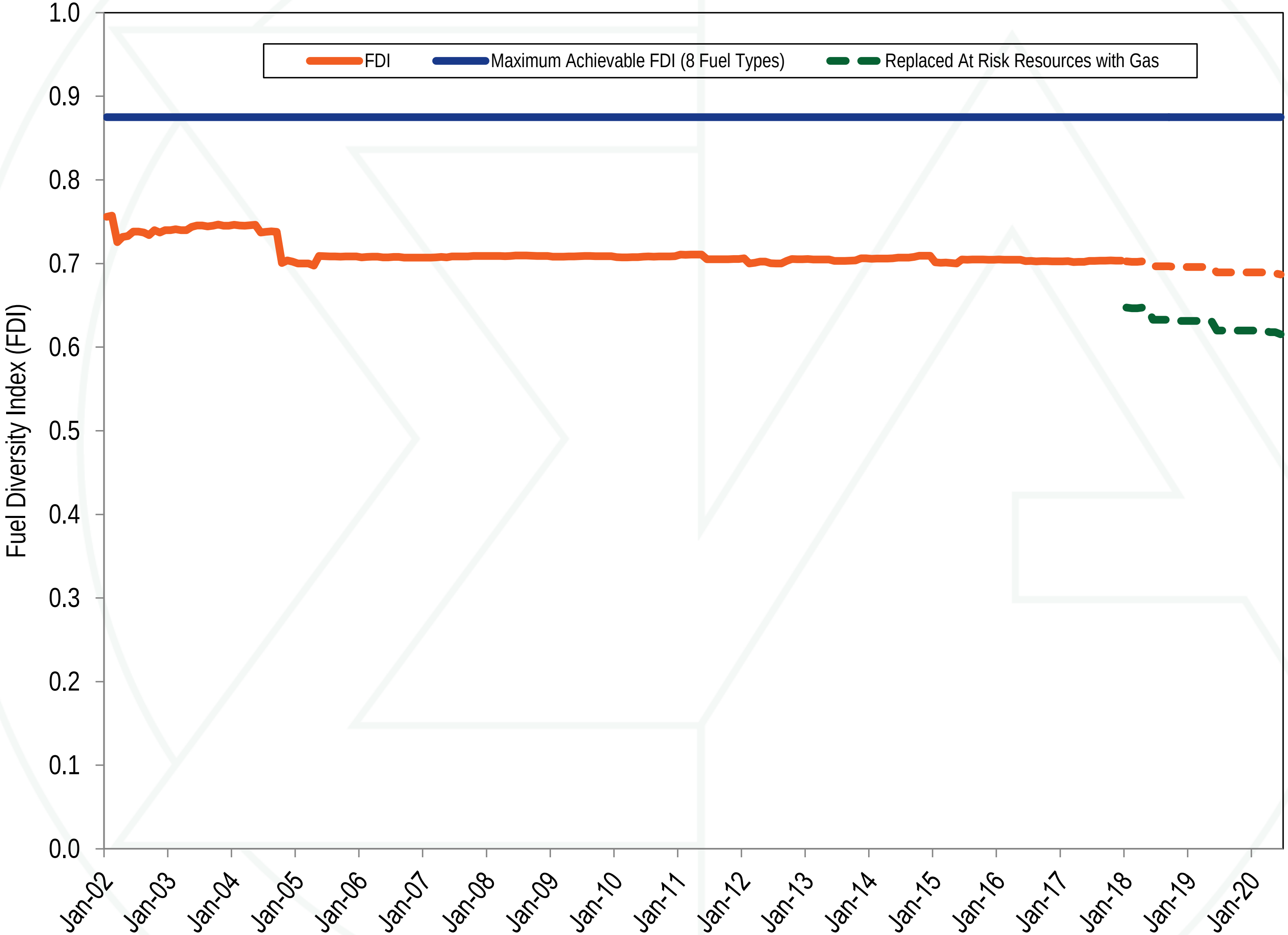
PJM installed capacity by fuel source

	1-Jan-17		31-May-17		1-Jun-17		31-Dec-17	
	MW	Percent	MW	Percent	MW	Percent	MW	Percent
Coal	66,622.2	36.5%	66,941.3	36.5%	65,688.0	35.9%	65,144.0	35.4%
Gas	65,110.3	35.7%	65,787.1	35.9%	66,397.6	36.3%	67,726.4	36.8%
Hydroelectric	8,850.4	4.9%	8,850.4	4.8%	8,870.2	4.8%	8,856.2	4.8%
Nuclear	33,043.4	18.1%	33,103.7	18.0%	33,163.5	18.1%	33,163.5	18.0%
Oil	6,733.6	3.7%	6,687.0	3.6%	6,684.4	3.7%	6,672.2	3.6%
Solar	262.3	0.1%	268.0	0.1%	366.8	0.2%	373.2	0.2%
Solid waste	769.4	0.4%	769.4	0.4%	814.4	0.4%	809.4	0.4%
Wind	1,019.1	0.6%	1,079.1	0.6%	1,114.3	0.6%	1,136.7	0.6%
Total	182,410.7	100.0%	183,486.0	100.0%	183,099.2	100.0%	183,881.6	100.0%

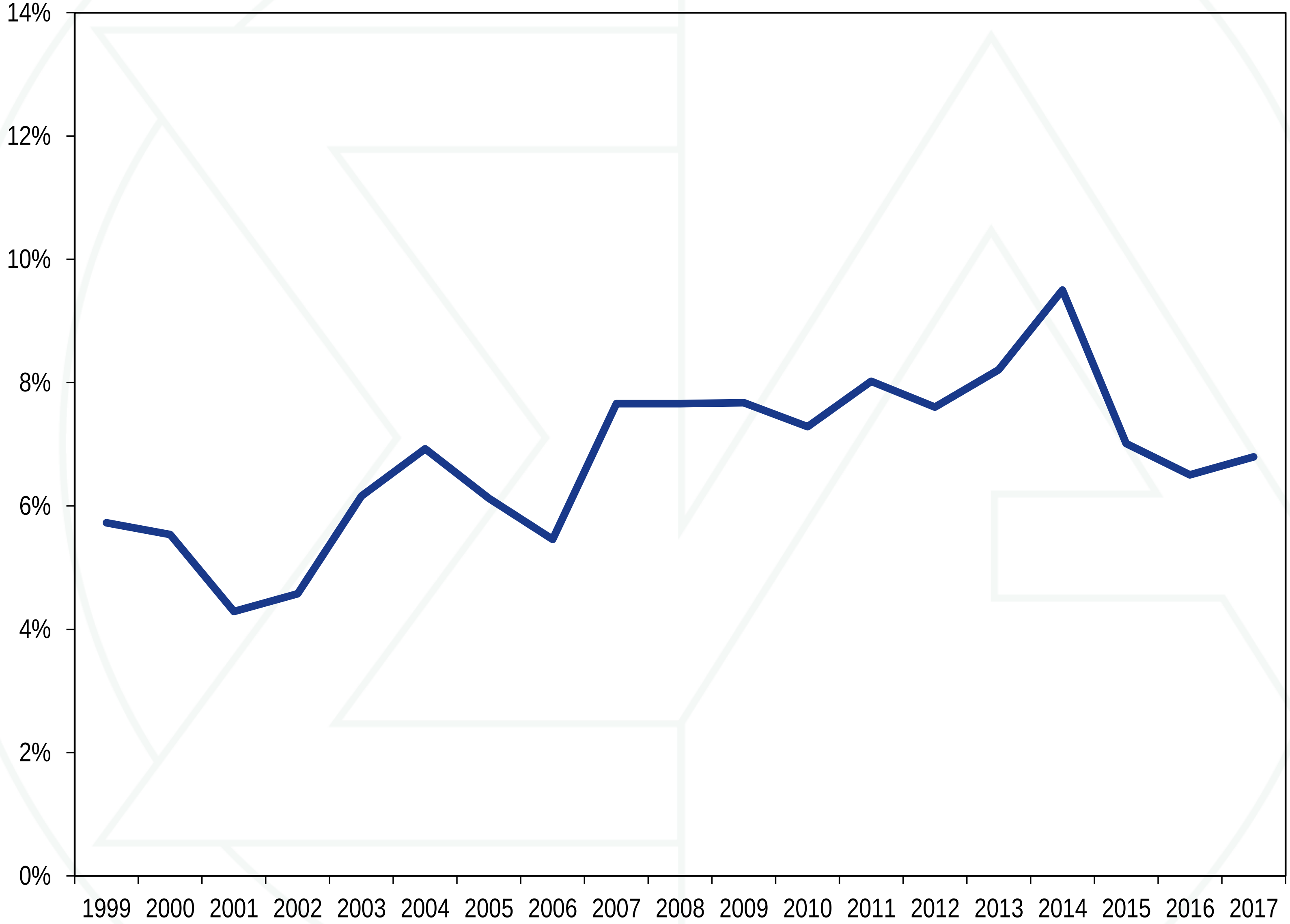
Percent of PJM installed capacity by fuel source



Fuel Diversity Index for PJM installed capacity

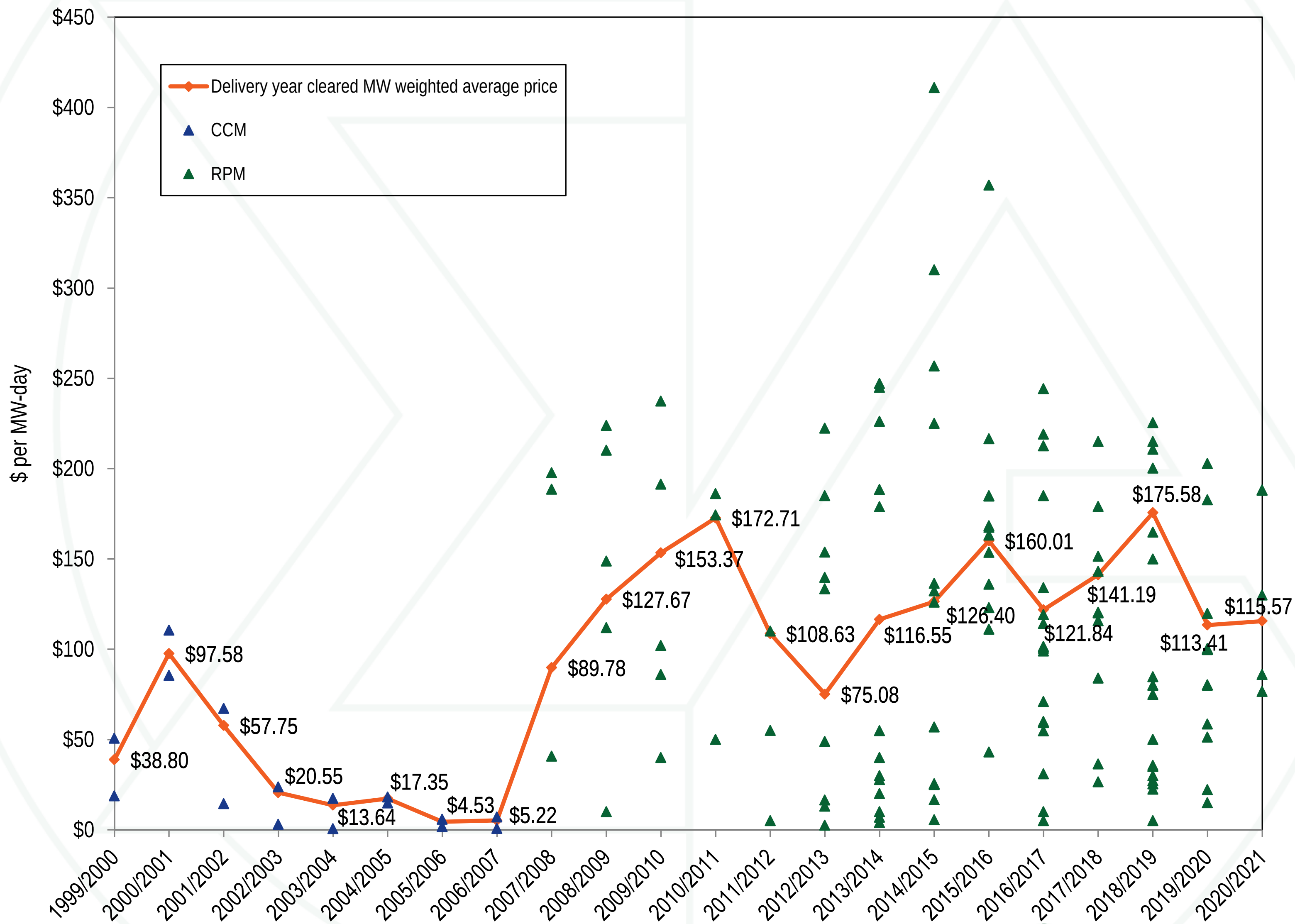


PJM EFORd

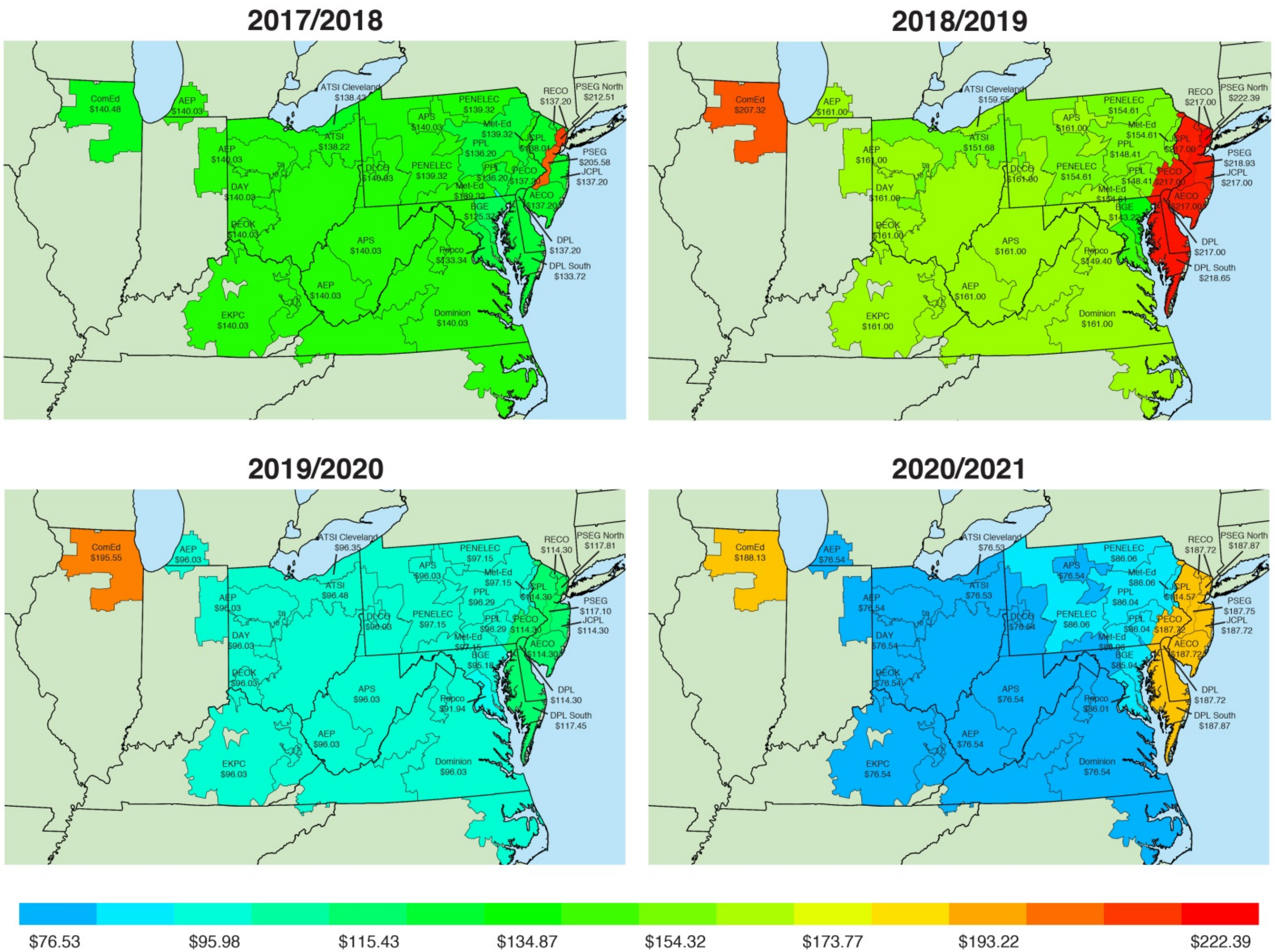


Monitoring Analytics

PJM capacity prices



PJM capacity prices



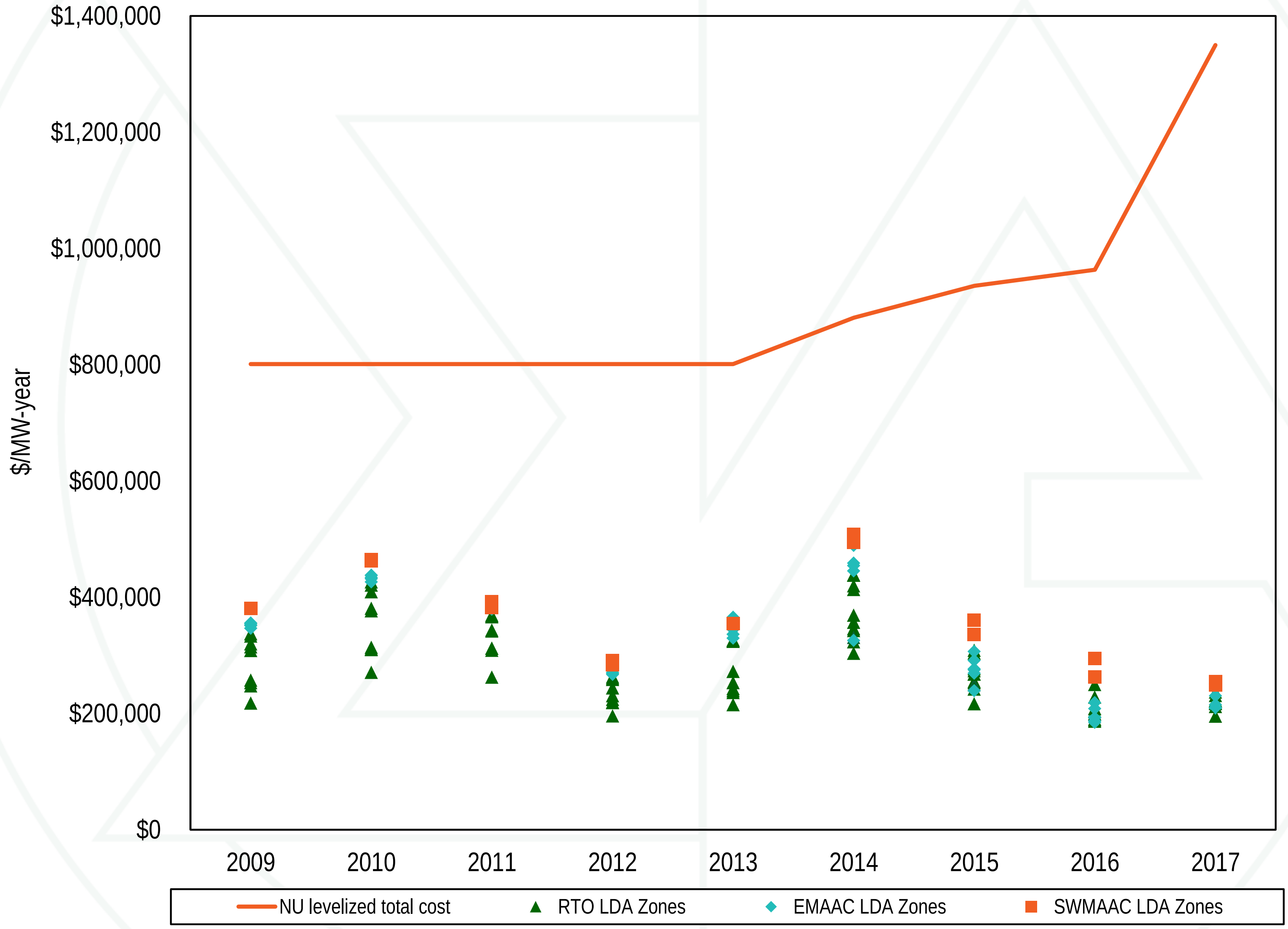
Monitoring Analytics

New entrant CT net revenue

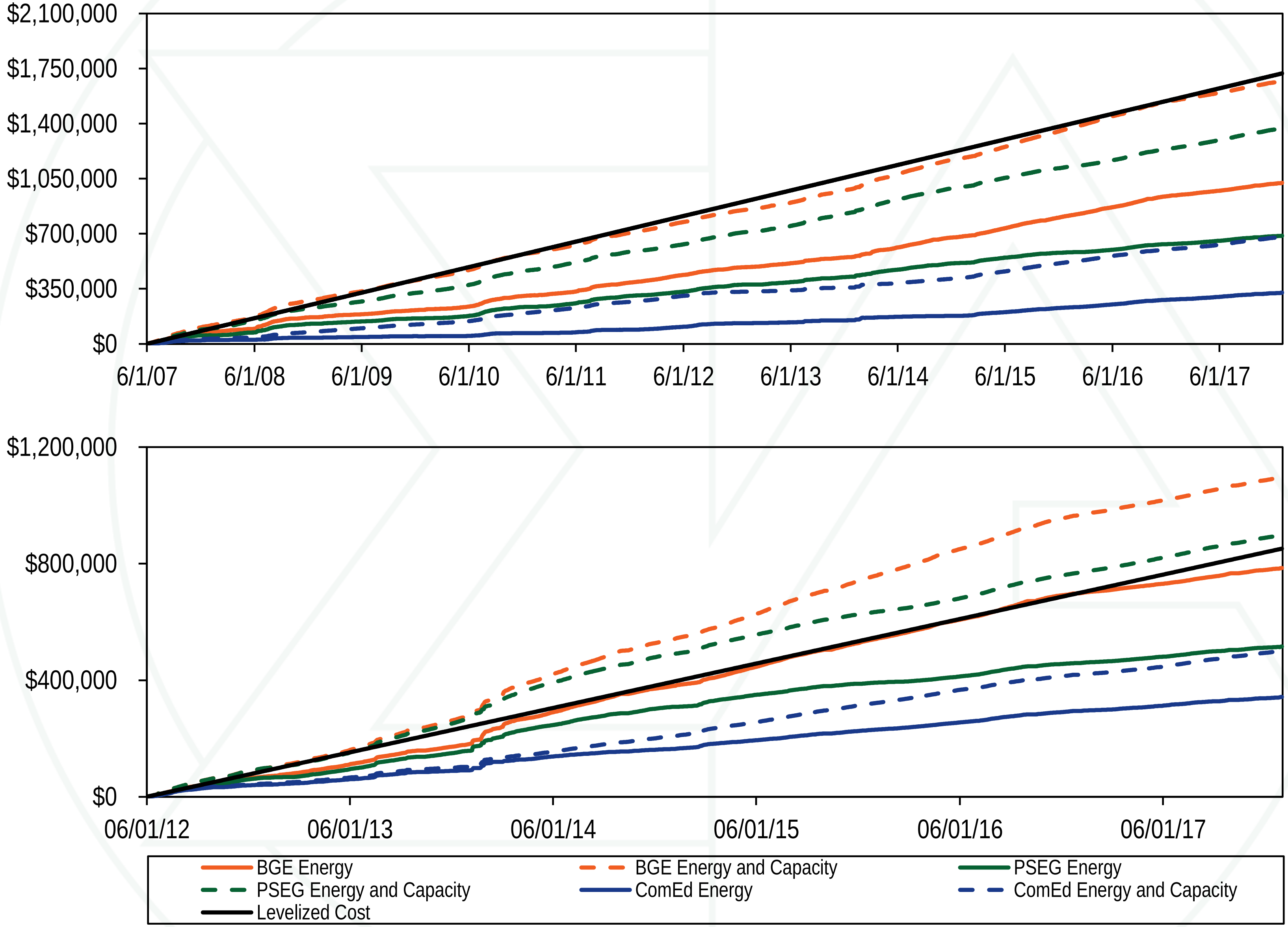
New entrant CC net revenue

New entrant CP net revenue

New entrant nuclear net revenue



Historical new entrant CC revenue adequacy



Monitoring Analytics

Proportion of units recovering avoidable costs

	Units with full recovery from energy and ancillary net revenue							Units with full recovery from all markets						
Technology	2011	2012	2013	2014	2015	2016	2017	2011	2012	2013	2014	2015	2016	2017
CC - Combined Cycle	55%	46%	50%	72%	59%	63%	62%	85%	79%	79%	95%	88%	93%	86%
CT - Aero Derivative	15%	6%	6%	53%	15%	8%	23%	100%	96%	76%	98%	100%	99%	99%
CT - Industrial Frame	26%	23%	17%	38%	13%	8%	18%	99%	98%	83%	100%	100%	100%	99%
Coal Fired	-	-	25%	78%	18%	19%	19%	-	-	54%	83%	69%	40%	52%
Diesel	48%	42%	37%	69%	56%	33%	46%	100%	100%	77%	100%	100%	100%	100%
Hydro	74%	61%	95%	97%	81%	79%	95%	81%	77%	97%	98%	100%	100%	97%
Nuclear	-	-	79%	100%	53%	16%	21%	-	-	95%	100%	89%	58%	68%
Oil or Gas Steam	8%	6%	11%	15%	3%	0%	9%	92%	78%	86%	85%	91%	88%	88%
Pumped Storage	100%	100%	95%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

Nuclear unit surplus (shortfall): historical price data 2013 through 2017

		Surplus (Shortfall) ($/MWh)														
		100% of NEI Capital Costs					2/3 of NEI Capital Costs					1/3 of NEI Capital Costs				
	ICAP	2013	2014	2015	2016	2017	2013	2014	2015	2016	2017	2013	2014	2015	2016	2017
Beaver Valley	1,777	$3.6	$13.8	$4.2	($0.8)	$1.4	$5.6	$15.8	$6.3	$1.3	$3.5	$7.7	$17.9	$8.3	$3.3	$5.5
Braidwood	2,330	($0.4)	$9.3	($0.2)	($3.5)	($2.7)	$1.6	$11.3	$1.9	($1.5)	($0.6)	$3.7	$13.4	$3.9	$0.6	$1.4
Byron	2,300	($1.5)	$7.0	($5.1)	($9.9)	($3.9)	$0.6	$9.0	($3.1)	($7.8)	($1.8)	$2.6	$11.1	($1.0)	($5.8)	$0.2
Calvert Cliffs	1,716	$16.4	$33.5	$15.1	$6.8	$4.9	$18.5	$35.5	$17.2	$8.9	$7.0	$20.5	$37.6	$19.2	$10.9	$9.0
Cook	2,071	$3.5	$12.4	$3.8	($0.9)	$0.3	$5.5	$14.5	$5.8	$1.2	$2.4	$7.6	$16.5	$7.9	$3.2	$4.4
Davis Besse	894	($4.3)	$9.4	$1.4	($4.6)	($7.6)	($1.4)	$12.2	$4.3	($1.7)	($4.8)	$1.5	$15.1	$7.2	$1.2	($1.9)
Dresden	1,787	$1.2	$11.1	$1.3	($1.9)	($1.3)	$3.2	$13.2	$3.4	$0.1	$0.7	$5.3	$15.2	$5.4	$2.2	$2.8
Hope Creek	1,161	$14.2	$27.9	$7.2	($2.6)	$0.1	$16.2	$30.0	$9.3	($0.6)	$2.2	$18.3	$32.0	$11.3	$1.5	$4.2
LaSalle	2,238	$0.3	$9.8	$0.1	($3.9)	($3.0)	$2.3	$11.8	$2.2	($1.8)	($0.9)	$4.4	$13.9	$4.2	$0.2	$1.1
Limerick	2,296	$14.0	$27.7	$7.5	($2.5)	$0.3	$16.1	$29.7	$9.5	($0.4)	$2.4	$18.1	$31.8	$11.6	$1.6	$4.4
North Anna	1,891	$7.9	$25.3	$11.9	$2.7	$3.6	$9.9	$27.3	$14.0	$4.7	$5.6	$12.0	$29.4	$16.0	$6.8	$7.7
Oyster Creek	615	$5.6	$19.0	($1.9)	($11.8)	($8.9)	$8.5	$21.9	$1.0	($8.9)	($6.0)	$11.4	$24.8	$3.9	($6.0)	($3.1)
Quad Cities	1,819	($4.7)	$2.6	($6.7)	($9.8)	($4.6)	($2.7)	$4.7	($4.6)	($7.7)	($2.5)	($0.6)	$6.7	($2.6)	($5.7)	($0.5)
Peach Bottom	2,251	$14.1	$27.5	$6.8	($2.8)	$0.1	$16.2	$29.5	$8.8	($0.7)	$2.2	$18.2	$31.6	$10.9	$1.3	$4.2
Perry	1,240	($3.7)	$8.3	$2.2	($4.6)	($6.6)	($0.8)	$11.2	$5.1	($1.7)	($3.7)	$2.0	$14.1	$8.0	$1.2	($0.8)
Salem	2,332	$14.1	$27.9	$7.2	($2.6)	$0.1	$16.2	$29.9	$9.2	($0.6)	$2.2	$18.2	$32.0	$11.3	$1.5	$4.2
Surry	1,690	$7.3	$23.7	$11.8	$2.3	$3.4	$9.4	$25.7	$13.8	$4.3	$5.5	$11.4	$27.8	$15.9	$6.4	$7.5
Susquehanna	2,520	$12.9	$26.5	$7.3	($2.2)	$0.5	$15.0	$28.6	$9.3	($0.1)	$2.5	$17.0	$30.6	$11.4	$1.9	$4.6
Three Mile Island	805	$3.3	$16.3	($4.0)	($12.6)	($9.3)	$6.1	$19.2	($1.1)	($9.7)	($6.4)	$9.0	$22.1	$1.8	($6.8)	($3.5)

Nuclear unit surplus (shortfall): forward price data 2013 through 2017

	Surplus (Shortfall) ($/MWh)								
	100% of NEI Capital Costs			2/3 of NEI Capital Costs			1/3 of NEI Capital Costs		
	2018	2019	2020	2018	2019	2020	2018	2019	2020
Beaver Valley	$8.81	$8.16	$6.41	$10.86	$10.21	$8.46	$12.91	$12.26	$10.51
Braidwood	$4.28	$6.45	$5.75	$6.33	$8.50	$7.80	$8.38	$10.55	$9.85
Byron	$4.64	$5.59	$4.95	$6.69	$7.64	$7.00	$8.74	$9.69	$9.05
Calvert Cliffs	$10.93	$10.65	$9.10	$12.98	$12.70	$11.15	$15.03	$14.75	$13.20
Cook	$7.57	$6.94	$5.22	$9.62	$8.99	$7.27	$11.67	$11.04	$9.32
Davis Besse	($1.04)	($1.57)	($3.30)	$1.85	$1.32	($0.41)	$4.74	$4.21	$2.48
Dresden	$6.68	$8.41	$7.74	$8.73	$10.46	$9.79	$10.78	$12.51	$11.84
Hope Creek	$7.46	$7.19	$6.93	$9.51	$9.24	$8.98	$11.56	$11.29	$11.03
LaSalle	$4.38	$6.49	$5.80	$6.43	$8.54	$7.85	$8.48	$10.59	$9.90
Limerick	$8.00	$7.74	$7.48	$10.05	$9.79	$9.53	$12.10	$11.84	$11.58
North Anna	$10.77	$10.32	$8.53	$12.82	$12.37	$10.58	$14.87	$14.42	$12.63
Oyster Creek	($1.56)	($1.53)	($1.79)	$1.33	$1.36	$1.10	$4.22	$4.25	$3.99
Quad Cities	$2.77	$4.36	$3.65	$4.82	$6.41	$5.70	$6.87	$8.46	$7.75
Peach Bottom	$7.46	$7.29	$7.04	$9.51	$9.34	$9.09	$11.56	$11.39	$11.14
Perry	$0.04	($0.58)	($2.32)	$2.93	$2.31	$0.57	$5.82	$5.20	$3.46
Salem	$7.44	$7.16	$6.90	$9.49	$9.21	$8.95	$11.54	$11.26	$11.00
Surry	$10.39	$9.86	$8.08	$12.44	$11.91	$10.13	$14.49	$13.96	$12.18
Susquehanna	$6.35	$5.97	$4.44	$8.40	$8.02	$6.49	$10.45	$10.07	$8.54
Three Mile Island	($3.41)	($3.78)	($5.29)	($0.52)	($0.89)	($2.40)	$2.37	$2.00	$0.49

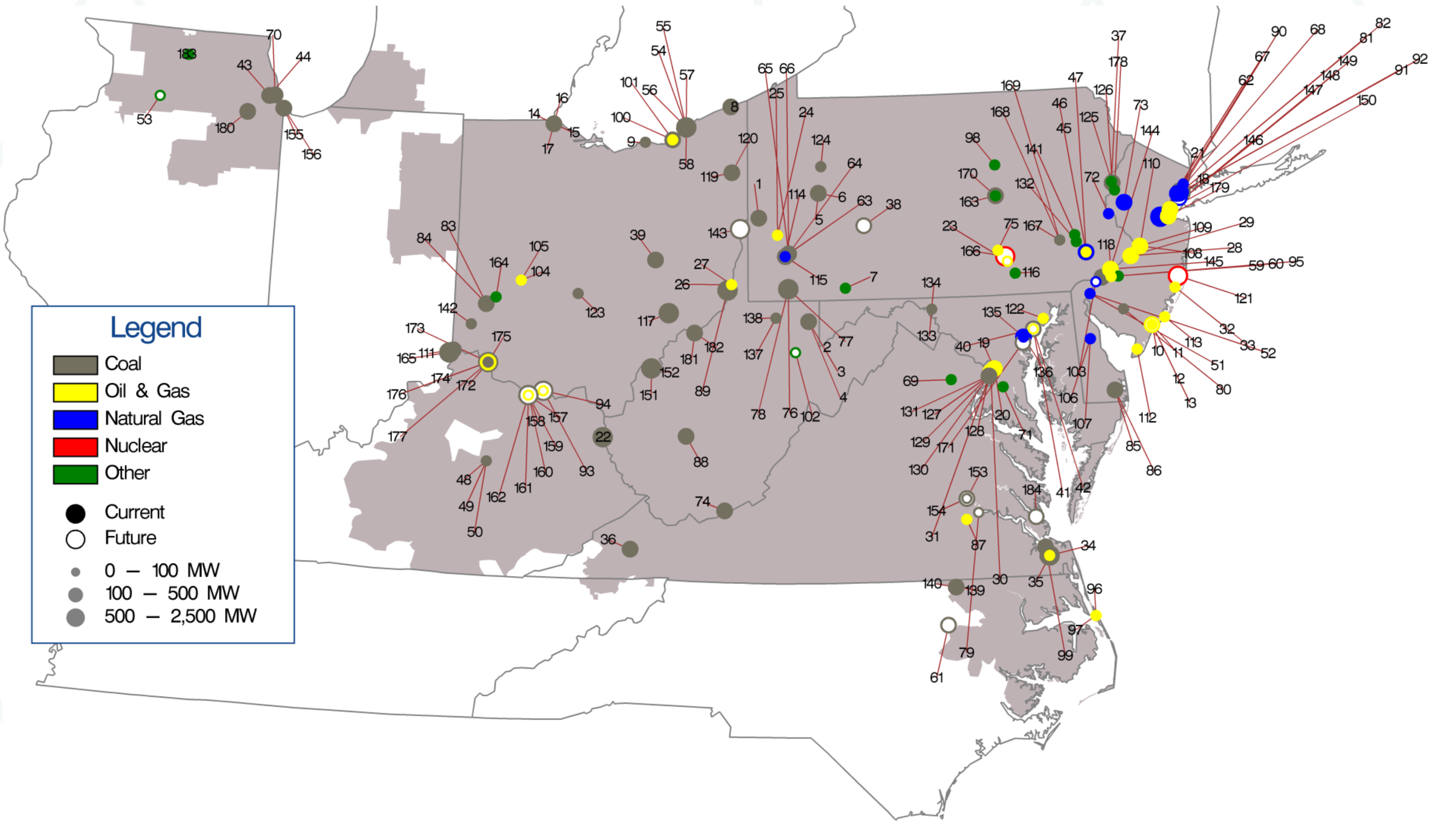
Profile of units at risk of retirement

Technology	No. Units	ICAP (MW)	Avg. 2017 Run Hrs	Avg. Unit Age (Yrs)	Avg. Heat Rate (Btu/MWh)
CC - Combined Cycle	5	590	497	33	11,302
CT - Aero Derivative	10	254	137	41	13,724
CT - Industrial Frame	40	955	94	41	14,434
Coal Fired (high)	46	21,039	3,346	46	10,428
Coal Fired (low) (90% ACR recovery)	38	17,302	3,304	46	10,390
Diesel or Oil or Gas Steam	12	889	968	36	11,701
Nuclear (high)	5	7,058	-	38	-
Nuclear (low) (forward looking)	3	2,939	-	38	-
Total (high)	118	30,785	1,560	42	12,312
Total (low)	108	22,929	1,404	42	12,441

PJM reserve margin: 2016 to 2020

	Generation and DR RPM Committed Less Deficiency UCAP (MW)	Forecast Peak Load	FRR Peak Load	PRD	RPM Peak Load	IRM	Pool Wide Average EFORd	Generation and DR RPM Committed Less Deficiency ICAP (MW)	Reserve Margin	Reserve Margin in Excess of IRM Percent	Reserve Margin in Excess of IRM ICAP (MW)
01-Jun-16	160,883.3	152,356.6	12,511.6	0.0	139,845.0	16.4%	5.91%	170,988.7	22.3%	5.9%	8,209.2
01-Jun-17	163,871.2	153,230.1	12,837.5	0.0	140,392.6	16.6%	5.94%	174,219.9	24.1%	7.5%	10,522.1
01-Jun-18	168,841.6	152,407.9	12,732.9	0.0	139,675.0	16.1%	6.07%	179,752.6	28.7%	12.6%	17,589.9
01-Jun-19	166,715.0	154,510.0	12,559.0	0.0	141,951.0	16.6%	6.59%	178,476.6	25.7%	9.1%	12,961.7
01-Jun-20	163,399.0	153,915.0	12,200.6	558.0	141,156.4	16.6%	6.59%	174,926.7	23.9%	7.3%	10,338.3

Map of PJM unit retirements: 2011 through 2020



RMR history

Unit Names	Owner	ICAP (MW)	Cost Recovery Method	Docket Numbers	Start of Term	End of Term
B.L. England 2	RC Cape May Holdings, LLC	150.0	Cost of Service Recovery Rate	ER17-1083	01-May-17	01-May-19
Yorktown 1	Dominion Virginia Power	159.0	Deactivation Avoidable Cost Rate	ER17-750	06-Jan-17	13-Mar-18
Yorktown 2	Dominion Virginia Power	164.0	Deactivation Avoidable Cost Rate	ER17-750	06-Jan-17	13-Mar-18
B.L. England 3	RC Cape May Holdings, LLC	148.0	Cost of Service Recovery Rate	ER17-1083	01-May-17	24-Jan-18
Ashtabula	FirstEnergy Service Company	210.0	Deactivation Avoidable Cost Rate	ER12-2710	01-Sep-12	11-Apr-15
Eastlake 1	FirstEnergy Service Company	109.0	Deactivation Avoidable Cost Rate	ER12-2710	01-Sep-12	15-Sep-14
Eastlake 2	FirstEnergy Service Company	109.0	Deactivation Avoidable Cost Rate	ER12-2710	01-Sep-12	15-Sep-14
Eastlake 3	FirstEnergy Service Company	109.0	Deactivation Avoidable Cost Rate	ER12-2710	01-Sep-12	15-Sep-14
Lakeshore	FirstEnergy Service Company	190.0	Deactivation Avoidable Cost Rate	ER12-2710	01-Sep-12	15-Sep-14
Elrama 4	GenOn Power Midwest, LP	171.0	Cost of Service Recovery Rate	ER12-1901	01-Jun-12	01-Oct-12
Niles 1	GenOn Power Midwest, LP	109.0	Cost of Service Recovery Rate	ER12-1901	01-Jun-12	01-Oct-12
Cromby 2 and Diesel	Exelon Generation Company, LLC	203.7	Cost of Service Recovery Rate	ER10-1418	01-Jun-11	01-Jan-12
Eddystone 2	Exelon Generation Company, LLC	309.0	Cost of Service Recovery Rate	ER10-1418	01-Jun-11	01-Jun-12
Brunot Island CT2A, CT2B, CT3 and CC4	Orion Power MidWest, L.P.	244.0	Cost of Service Recovery Rate	ER06-993	16-May-06	05-Jul-07
Hudson 1	PSEG Energy Resources & Trade LLC and PSEG Fossil LLC	355.0	Cost of Service Recovery Rate	ER05-644, ER11-2688	25-Feb-05	08-Dec-11
Sewaren 1-4	PSEG Energy Resources & Trade LLC and PSEG Fossil LLC	453.0	Cost of Service Recovery Rate	ER05-644	25-Feb-05	01-Sep-08

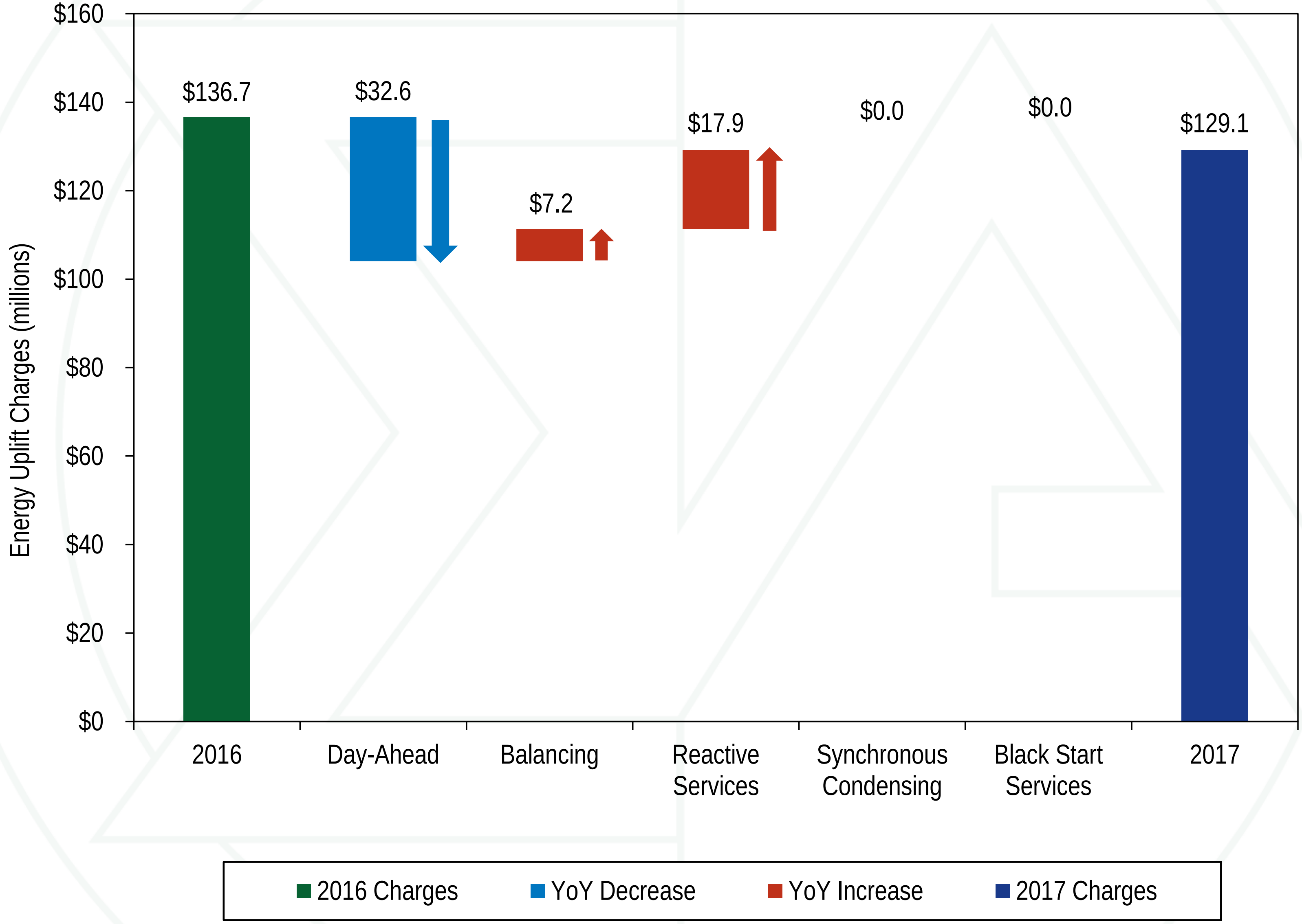
Recommendations: Energy Market Uplift

- **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.**
- **Reduce uplift**
  - **Increase transparency**
  - **Require flexible parameters**
  - **Eliminate day ahead uplift.**
  - **Eliminate segmentation**
  - **Include regulation net revenue offset in uplift calculation.**
  - **UTCs should pay uplift.**

Total energy uplift charges

	Total Energy Uplift Charges (Millions)	Change (Millions)	Percent Change	Energy Uplift as a Percent of Total PJM Billing
2001	$284.0	$67.0	30.9%	8.5%
2002	$273.7	($10.3)	(3.6%)	5.8%
2003	$376.5	$102.8	37.6%	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	($151.6)	(32.0%)	1.2%
2010	$623.2	$300.5	93.1%	1.8%
2011	$603.4	($19.8)	(3.2%)	1.7%
2012	$649.8	$46.4	7.7%	2.2%
2013	$843.0	$193.2	29.7%	2.5%
2014	$961.2	$118.2	14.0%	1.9%
2015	$312.0	($649.2)	(67.5%)	0.7%
2016	$136.7	($824.5)	(85.8%)	0.3%
2017	$129.1	($7.5)	(5.5%)	0.3%

Energy uplift charges changes by category



Energy uplift credits by unit type: 2017

Unit Type	Day-Ahead Operating Reserve	Balancing Operating Reserve	Canceled Resources	Local Constraints Control	Lost Opportunity Cost	Reactive Services	Synchronous Condensing	Black Start Services
Combined Cycle	9.2%	8.0%	0.0%	0.0%	10.7%	3.9%	0.0%	20.2%
Combustion Turbine	3.4%	76.3%	2.7%	90.3%	67.3%	2.9%	0.0%	79.8%
Diesel	0.1%	0.7%	0.0%	2.1%	3.0%	0.1%	0.0%	0.0%
Hydro	0.0%	0.0%	97.3%	0.0%	0.4%	0.0%	0.0%	0.0%
Nuclear	0.0%	0.0%	0.0%	0.0%	0.5%	0.0%	0.0%	0.0%
Solar	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Steam - Coal	78.7%	11.8%	0.0%	7.6%	5.7%	84.9%	0.0%	0.0%
Steam - Others	8.7%	3.0%	0.0%	0.0%	0.2%	8.2%	0.0%	0.0%
Wind	0.0%	0.3%	0.0%	0.0%	12.2%	0.0%	0.0%	0.0%
Total (Millions)	$24.7	$67.4	$0.0	$1.4	$14.6	$20.4	$0.0	$0.3

Top 10 units and organizations energy uplift credits: 2017

		Top 10 Units		Top 10 Organizations	
Category	Type	Credits (Millions)	Credits Share	Credits (Millions)	Credits Share
Day-Ahead Operating Reserve	Generators	$19.0	77.0%	$24.0	97.0%
Balancing Operating Reserve	Canceled Resources	$0.0	100.0%	$0.0	100.0%
	Generators	$9.1	13.6%	$48.8	72.4%
	Local Constraints Control	$1.0	75.1%	$1.4	100.0%
	Lost Opportunity Cost	$3.0	20.3%	$10.3	70.7%
Reactive Services		$18.8	92.1%	$20.4	99.9%
Synchronous Condensing		$0.0	0.0%	$0.0	0.0%
Black Start Services		$0.1	40.8%	$0.2	93.6%
Total		$42.6	33.1%	$100.3	77.9%

Operating reserve rates statistics ($/MWh): 2017

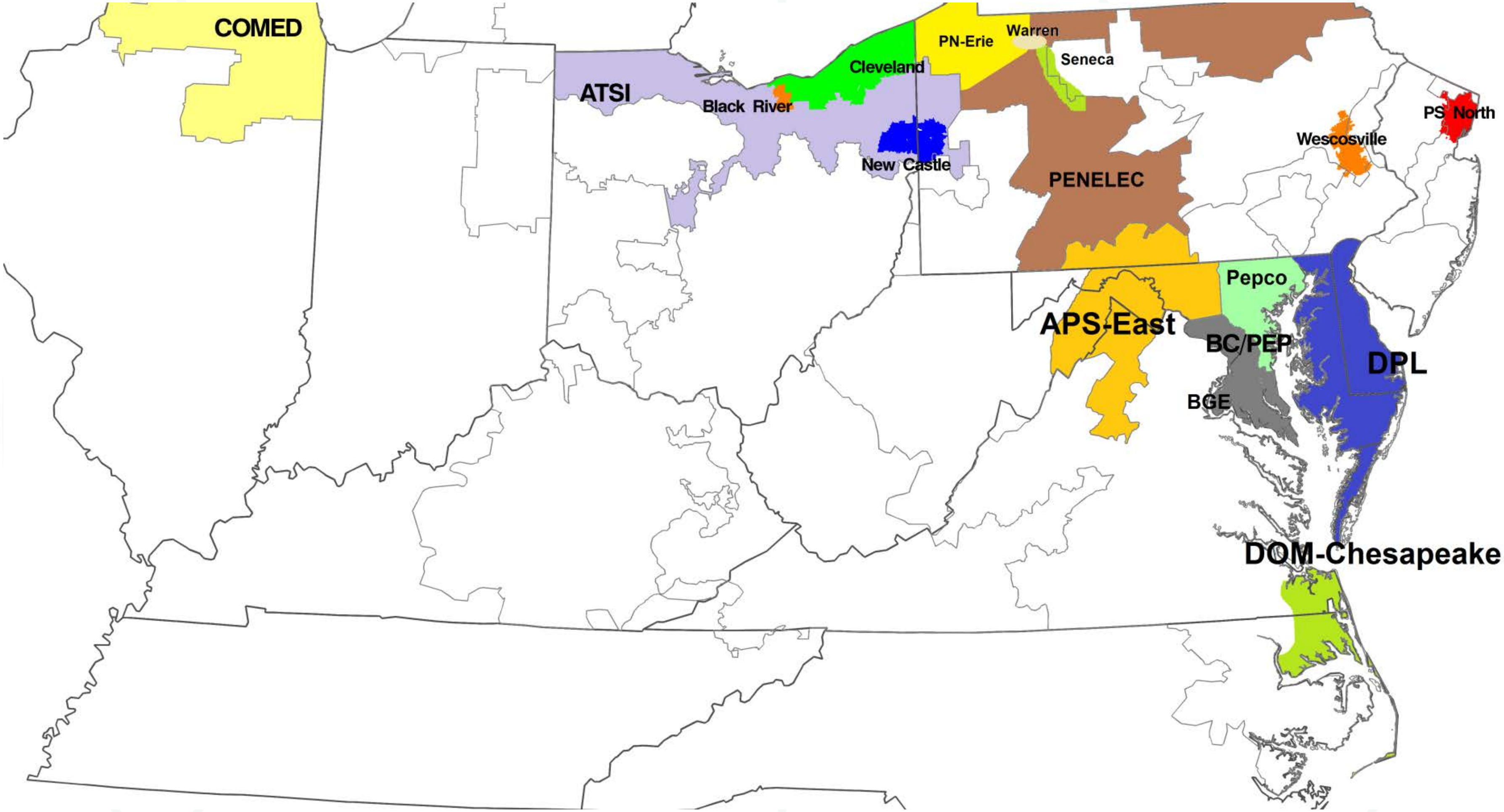
		Rates Charged ($/MWh)			
Region	Transaction	Maximum	Average	Minimum	Standard Deviation
East	INC	3.793	0.355	0.000	0.498
	DEC	3.860	0.386	0.002	0.498
	DA Load	0.346	0.030	0.000	0.042
	RT Load	0.869	0.037	0.000	0.073
	Deviation	3.793	0.355	0.000	0.498
West	INC	2.782	0.327	0.000	0.438
	DEC	2.816	0.357	0.002	0.437
	DA Load	0.346	0.030	0.000	0.042
	RT Load	0.390	0.028	0.000	0.048
	Deviation	2.782	0.327	0.000	0.438

Current and proposed average energy uplift rate by transaction: 2016 and 2017

		2016			2017		
	Transaction	Current Rates ($/MWh)	Proposed Rates - 100% UTC ($/MWh)	Proposed Rates - 0% UTC ($/MWh)	Current Rates ($/MWh)	Proposed Rates - 100% UTC ($/MWh)	Proposed Rates - 0% UTC ($/MWh)
East	INC	0.347	0.027	0.093	0.355	0.012	0.040
	DEC	0.418	0.027	0.093	0.386	0.012	0.040
	DA Load	0.071	0.004	0.006	0.030	0.003	0.004
	RT Load	0.031	0.058	0.058	0.037	0.027	0.027
	Deviation	0.347	0.387	0.451	0.355	0.504	0.531
West	INC	0.302	0.022	0.078	0.327	0.011	0.037
	DEC	0.372	0.022	0.078	0.357	0.011	0.037
	DA Load	0.071	0.004	0.006	0.030	0.003	0.004
	RT Load	0.023	0.058	0.058	0.028	0.027	0.027
	Deviation	0.302	0.312	0.366	0.327	0.415	0.440
UTC	East to East	NA	0.055	0.186	NA	0.024	0.081
	West to West	NA	0.044	0.156	NA	0.021	0.074
	East to/from West	NA	0.049	0.171	NA	0.023	0.077

Monitoring Analytics

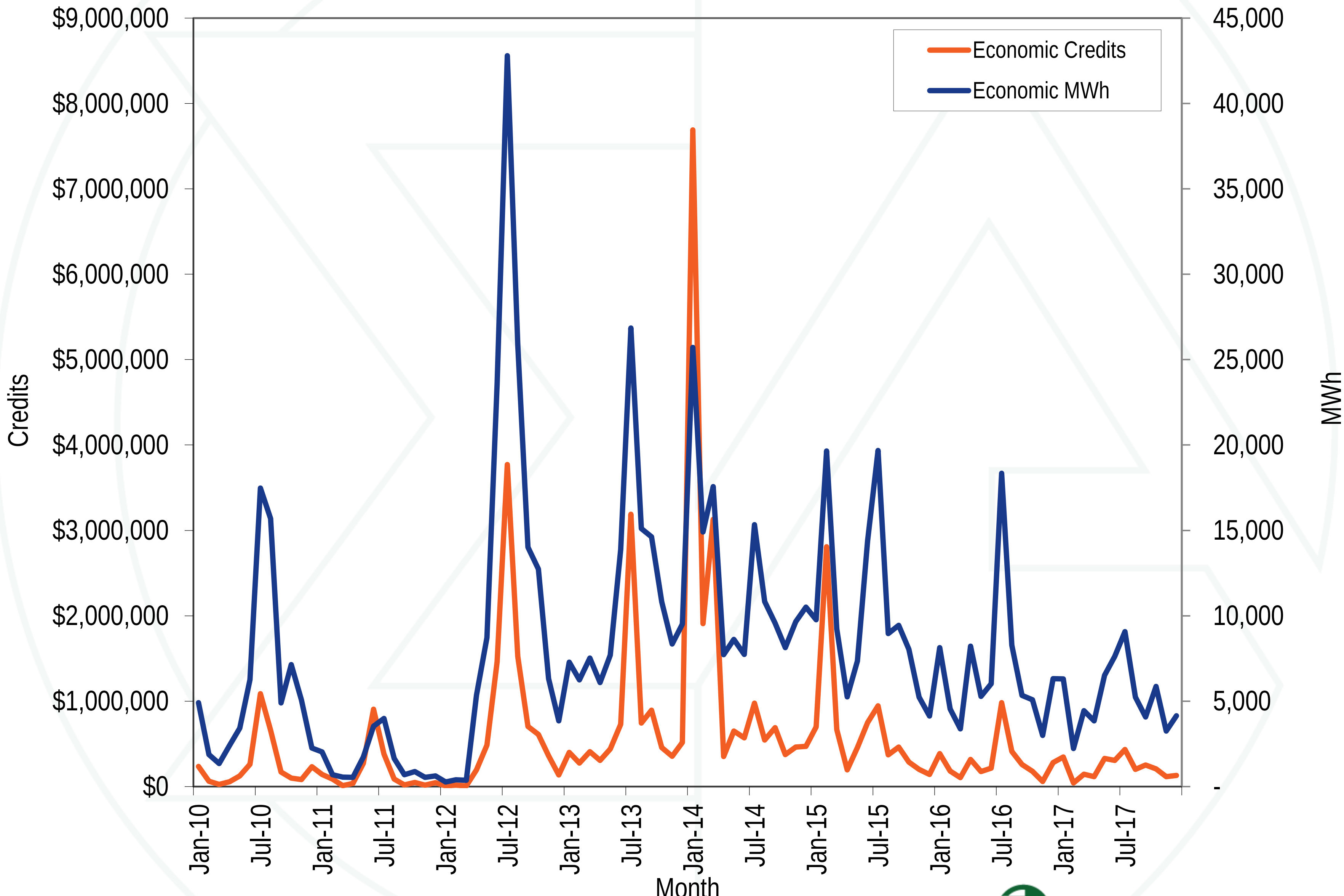
PJM Closed loop interfaces map



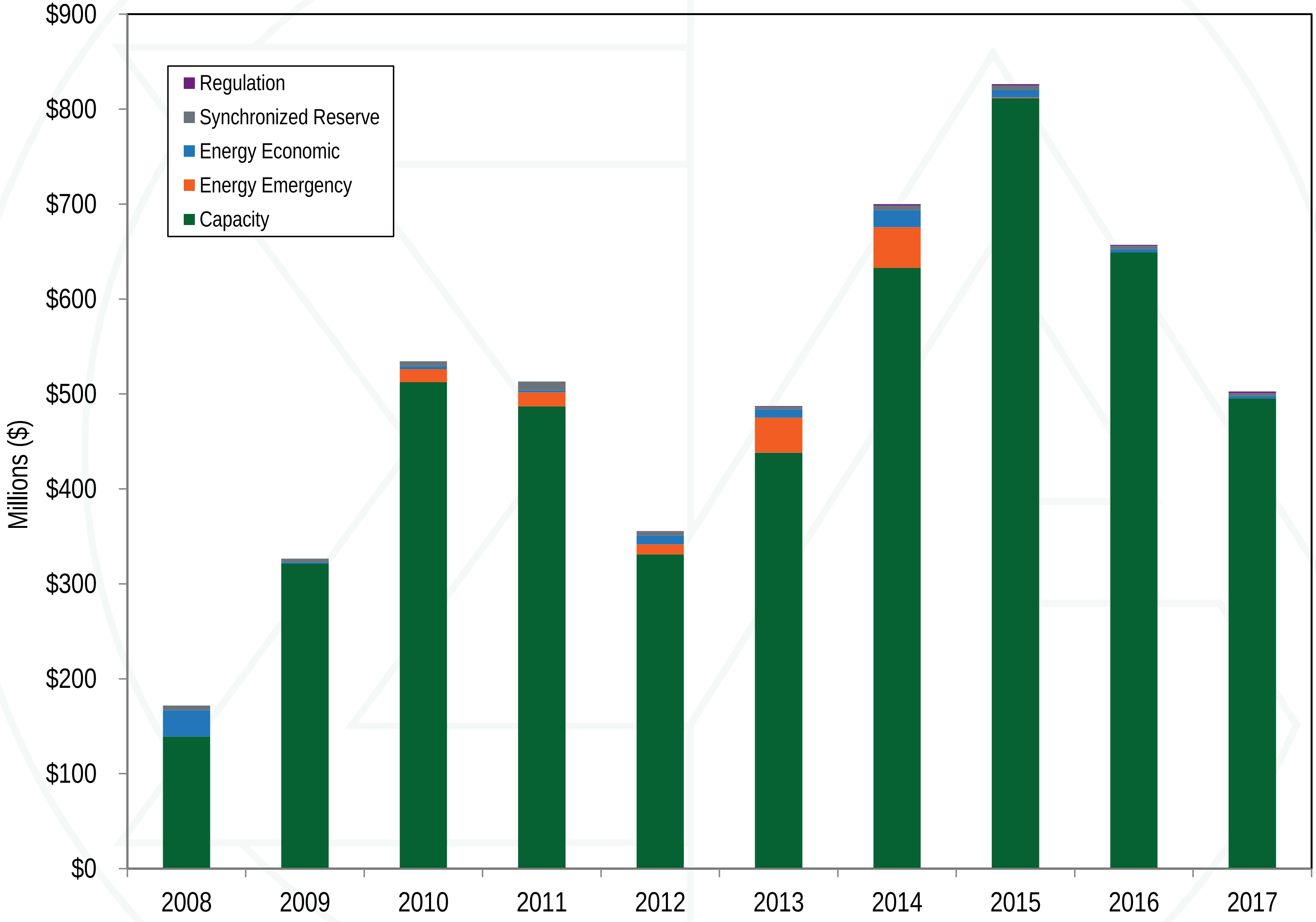
Recommendations: Demand Response

- Demand response should be removed from PJM capacity market.
  - On demand side of market
  - Redesign to facilitate customers' response to prices
  - Payment should be immediate
  - Impact on forecasts should be immediate
  - Metered use is sole basis for payment. No M&V.
- Eliminate guaranteed DR strike price; pay LMP
- DR offer cap should be the same as generation
- Demand response should be fully nodal
- Demand response should be an economic resource
- M&V: cap baselines at PLC uniformly including winter
- Eliminate net benefits test
- Eliminate bankrupt (partial/total) customers from program

Economic program credits and MWh by month



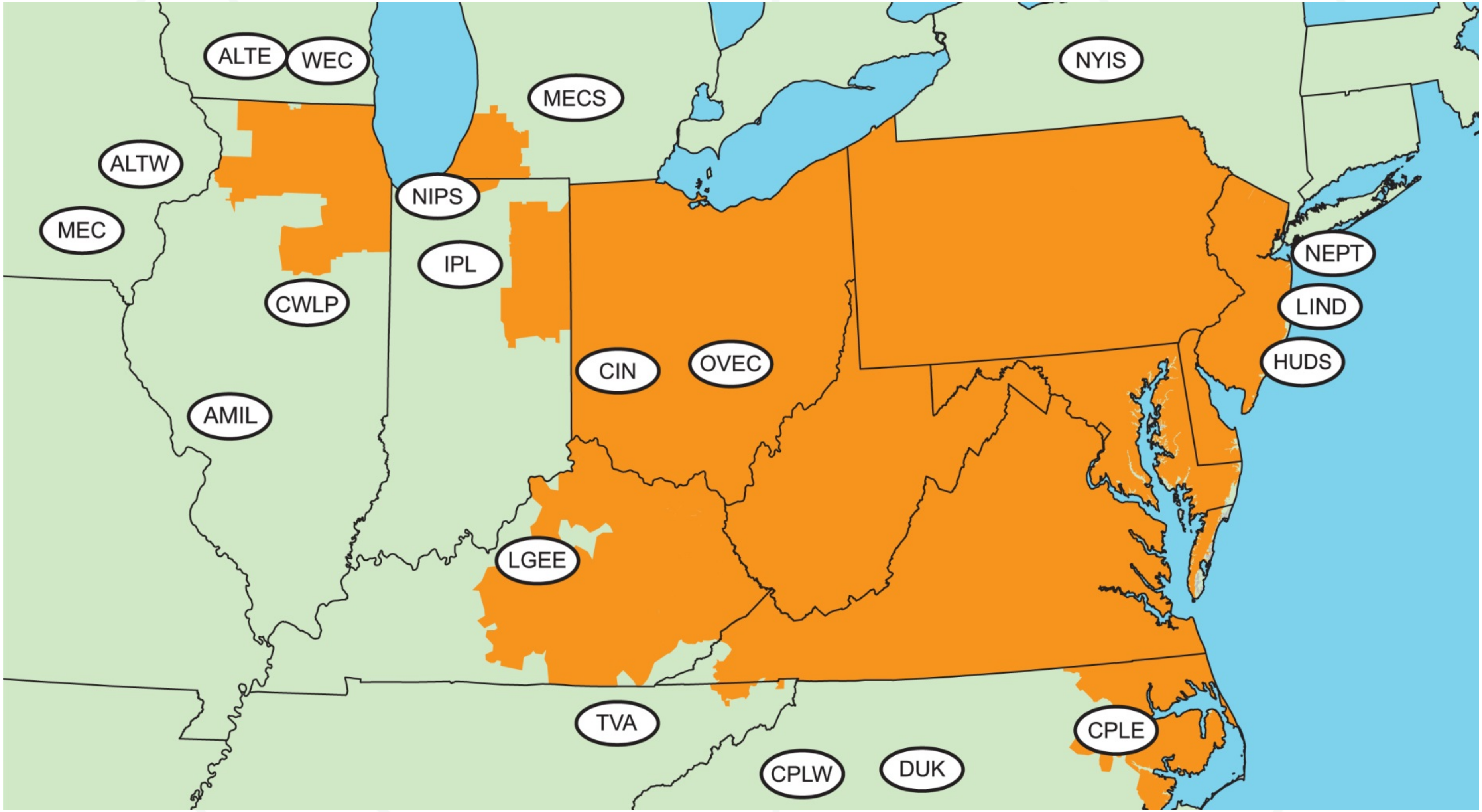
Demand response revenue by market



Recommendations: Transactions

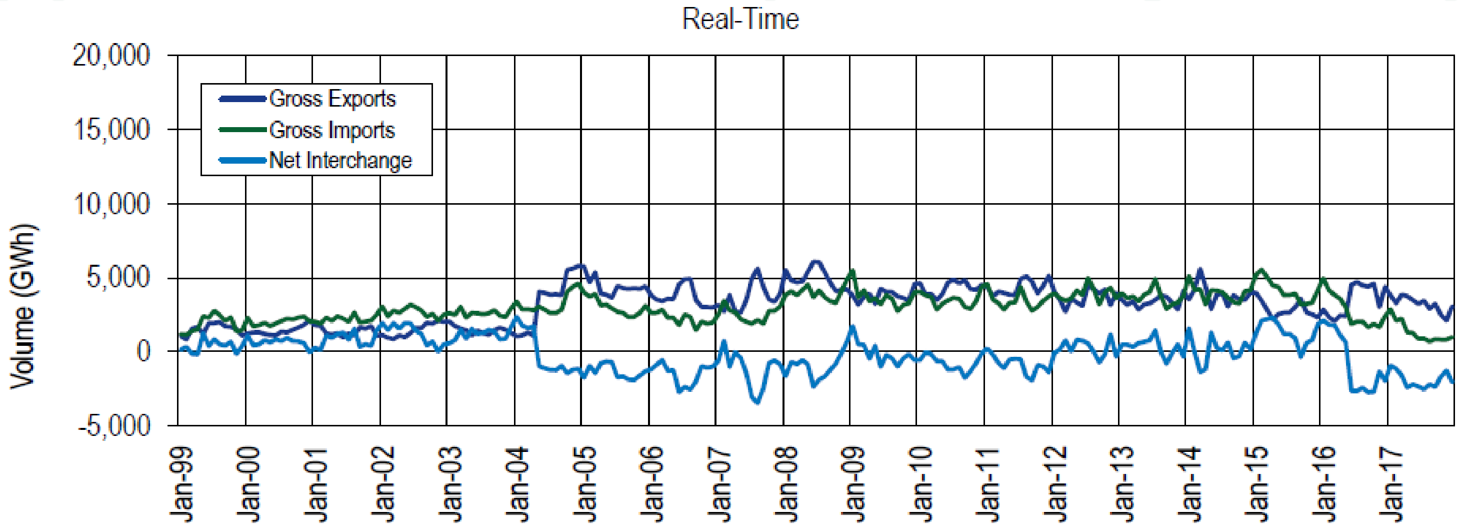
- **Submit transactions consistent with power flow not scheduled paths.**
- **Implement rules to prevent breaking up transactions to evade rules.**
- **Implement rules to prevent sham scheduling.**
- **Eliminate outdated definitions of interface pricing points.**
- **Permit unlimited spot imports.**
- **Interchange pricing should reflect LMP logic.**
  - **No need for scheduling physical transactions.**
- **Make actual flow data available for eastern interconnection to MMUs and RTOs/ISOs.**

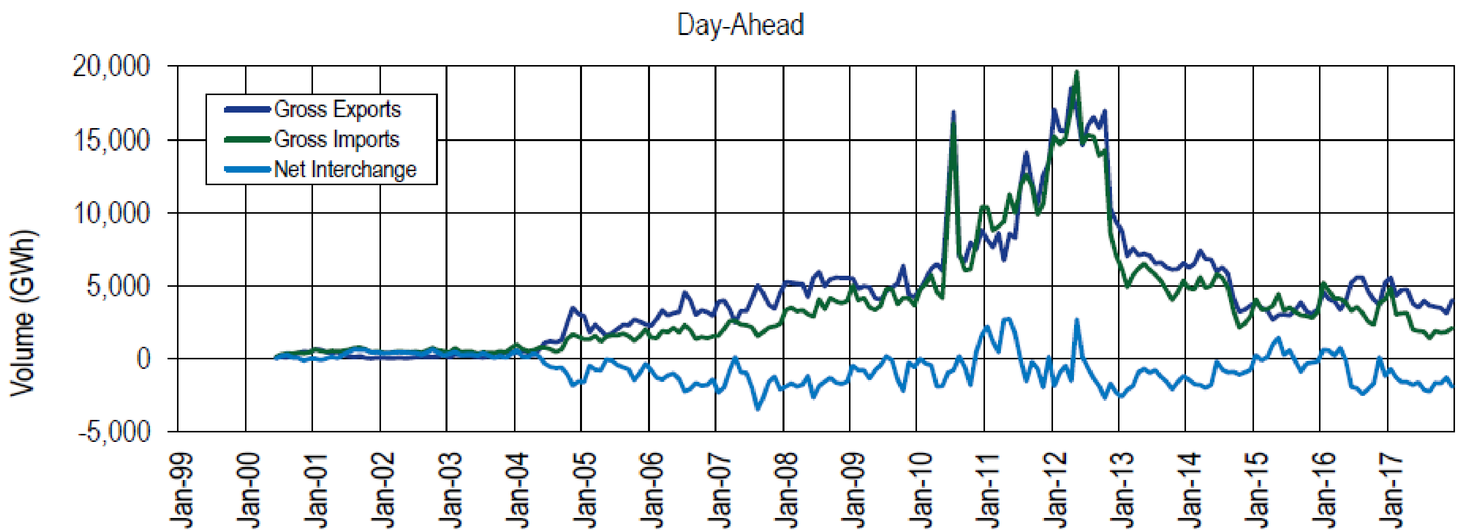
PJM's footprint and its external DA and RT scheduling interfaces



Monitoring Analytics

PJM RT and DA scheduled import and export transaction volume history





The regulation market results were competitive

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

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

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

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 operating schedule in the energy market.
- Eliminate payment of Tier 2 price to Tier 1 when non-synchronized reserve price > 0.
- Eliminate DASR Market.
- The cost of reactive capability should be incorporated in the capacity market.
- Implement rules governing tier 1 biasing.
- Minimum tank suction levels should be fixed.

Average price and cost for PJM regulation

Year	Weighted Regulation Market Price	Weighted Regulation Market Cost	Regulation Price as Percent Cost
2009	$22.99	$30.68	74.9%
2010	$18.00	$32.86	54.8%
2011	$16.48	$29.72	55.5%
2012	$19.02	$25.32	75.1%
2013	$30.85	$35.79	86.2%
2014	$44.48	$53.82	82.6%
2015	$31.92	$38.36	83.2%
2016	$15.73	$18.13	86.7%
2017	$16.78	$23.02	72.9%

Components of regulation cost: 2016 through 2017

Year	Month	Scheduled Regulation (MW)	Cost of Regulation Capability ($/MW)	Cost of Regulation Performance ($/MW)	Opportunity Cost ($/MW)	Total Cost ($/MW)
2016	Jan	412,599.7	$14.49	$1.97	$1.95	$18.41
	Feb	383,918.8	$16.00	$2.61	$1.40	$20.01
	Mar	396,882.6	$12.01	$2.25	$1.14	$15.40
	Apr	384,853.5	$17.38	$2.70	$1.67	$21.76
	May	391,328.7	$13.56	$3.50	$1.39	$18.45
	Jun	379,273.1	$13.33	$1.38	$1.10	$15.81
	Jul	386,423.4	$16.52	$2.27	$1.80	$20.60
	Aug	386,057.1	$16.74	$1.66	$1.56	$19.96
	Sep	376,493.8	$16.68	$2.32	$1.68	$20.67
	Oct	389,241.0	$14.11	$2.73	$1.19	$18.04
	Nov	374,665.6	$11.28	$3.11	$1.03	$15.42
	Dec	391,549.0	$10.14	$1.73	$1.25	$13.11
2016 Annual		4,653,286.2	$14.35	$2.35	$1.43	$18.14
2017	Jan	395,801.8	$13.19	$2.43	$1.69	$17.31
	Feb	356,168.1	$9.91	$3.68	$1.38	$14.97
	Mar	375,627.5	$13.93	$6.99	$1.98	$22.91
	Apr	371,527.5	$12.94	$9.78	$1.64	$24.36
	May	367,839.9	$16.77	$5.78	$1.77	$24.31
	Jun	386,015.3	$10.81	$7.95	$1.26	$20.02
	Jul	406,828.4	$13.19	$6.37	$1.82	$21.38
	Aug	403,294.0	$10.10	$9.34	$1.38	$20.82
	Sep	354,990.9	$18.83	$8.82	$1.96	$29.61
	Oct	365,994.1	$13.88	$8.51	$1.67	$24.07
	Nov	351,119.3	$14.55	$6.12	$2.09	$22.77
	Dec	395,269.5	$24.30	$5.29	$4.28	$33.86
2017 Annual		4,530,476.4	$14.37	$6.76	$1.91	$23.03

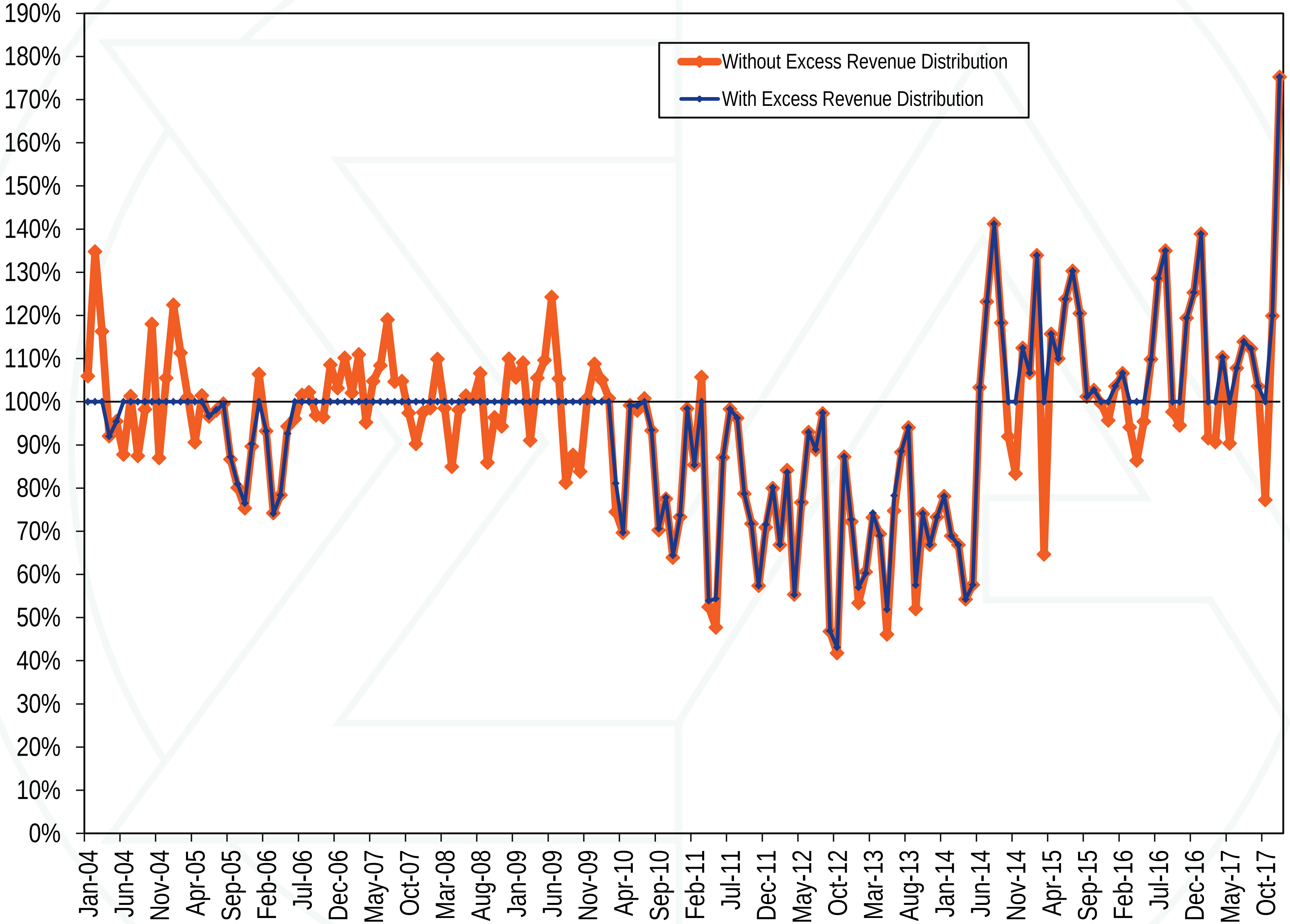
The FTR Auction Markets results were competitive

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

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 generation to load contract paths for allocating ARRs.**
- **Modify long term FTRs to include only a one year ahead FTR**
- **Ensure that full transmission capability of system be allocated to ARRs**
- **Eliminate portfolio netting.**

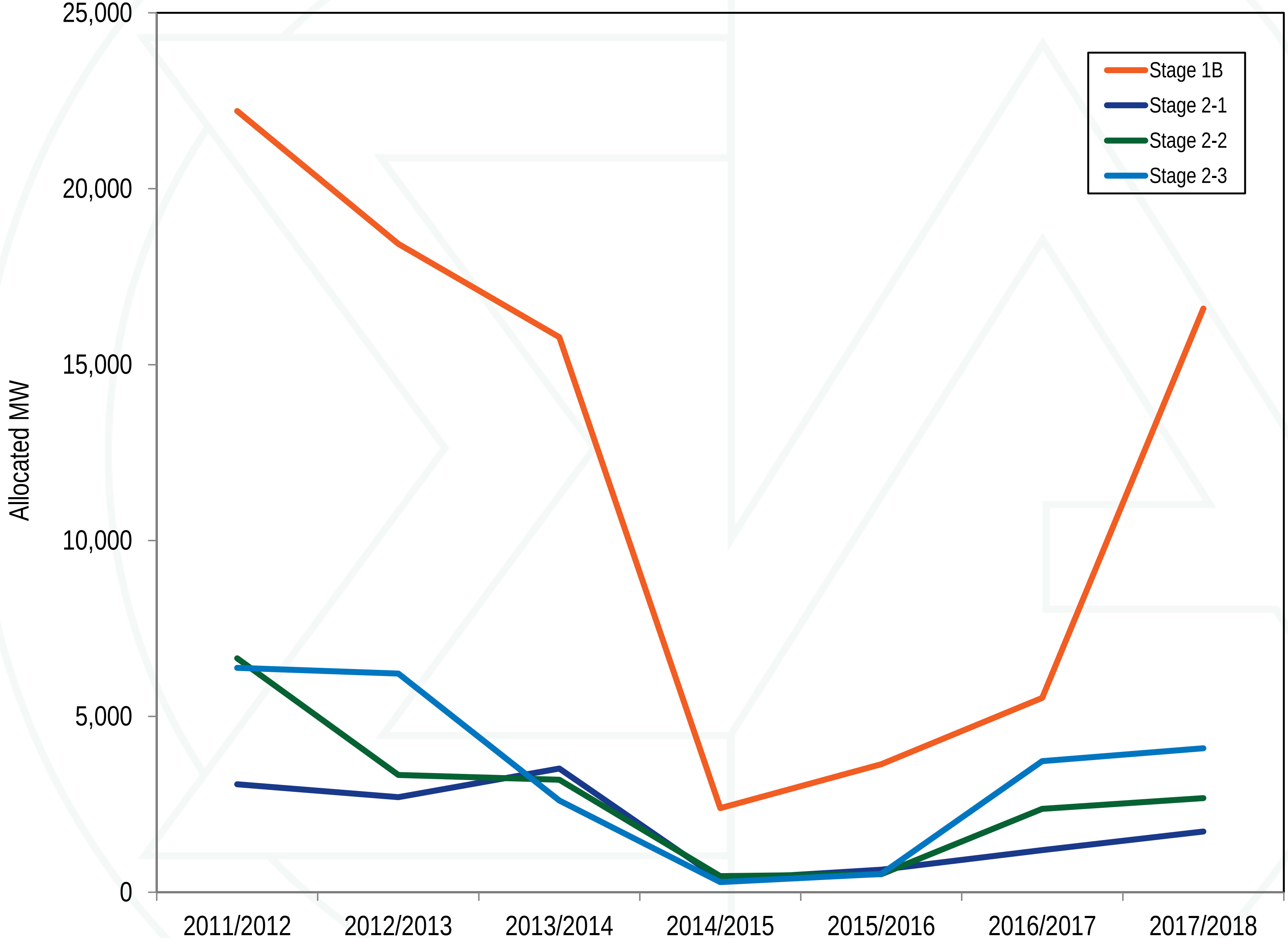
FTR payout ratio



PJM reported FTR payout ratio

Planning Period	FTR Payout Ratio
2003/2004	97.7%
2004/2005	100.0%
2005/2006	90.7%
2006/2007	100.0%
2007/2008	100.0%
2008/2009	100.0%
2009/2010	96.9%
2010/2011	85.0%
2011/2012	80.6%
2012/2013	67.8%
2013/2014	72.8%
2014/2015	100.0%
2015/2016	100.0%
2016/2017	100.0%
2017/2018	100.0%

Historic Stage 1B and Stage 2 ARR Allocations



ARR holder total congestion offset ($M)

	Old					Current				
				Total			Old	Current	ARR	
Planning Period	ARR Credits	FTR Credits	Total Congestion	ARR/FTR Offset	Percent Offset	New Offset	Revenue Received	Revenue Received	Holder Change	FTR Over Payment
2011/2012	$512.2	$249.8	$770.6	$762.0	98.9%	83.3%	$762.0	$598.6	($163.4)	$113.9
2012/2013	$349.5	$181.9	$575.8	$531.4	92.3%	68.0%	$531.4	$275.9	($255.5)	$62.1
2013/2014	$337.7	$456.4	$1,777.1	$794.0	44.7%	43.2%	$794.0	$574.1	($219.9)	$0.0
2014/2015	$482.4	$404.4	$1,390.9	$886.8	63.8%	57.2%	$886.8	$686.6	($200.2)	$400.6
2015/2016	$635.3	$223.4	$992.6	$858.8	86.5%	78.2%	$858.8	$744.8	($113.9)	$188.9
2016/2017	$640.0	$169.1	$824.6	$809.1	98.1%	89.5%	$809.1	$727.7	($81.4)	$179.0
2017/2018*	$334.0	$98.4	$477.7	$432.4	90.5%	79.4%	$432.4	$395.9	($36.5)	$80.4
Total	$3,291.2	$1,783.3	$6,809.3	$5,074.4	74.5%	64.6%	$5,074.4	$4,003.7	($1,070.7)	$1,024.7

* Seven months of 2017/2018 planning period

FTR profits by organization type

	FTR Direction				
Organization Type	Prevailing Flow	Self Scheduled Prevailing Flow	Counter Flow	Self Scheduled Counter Flow	All
Financial	$40,811,499		$46,900,257		$87,711,756
Physical	($9,369,683)		$10,028,710		$659,026
Physical ARR Holder	$17,192,244	$87,292,443	$14,251,815	($1,834,752)	$31,444,059
Total	$48,634,060	$87,292,443	$71,180,781	($1,834,752)	$119,814,841

Estimated additional Long Term FTR Auction revenue at Annual FTR Auction prices

	Long Term FTR Product				
Planning Period	Year 3	Year 2	Year 1	Three Year	Total Difference
2014/2015	$59,598,642	$30,284,173	$52,030,909	$926,989	$142,840,713
2015/2016	$67,896,588	$40,975,278	$9,936,078	$303,082	$119,111,026
2016/2017	$42,378,048	$3,854,373	$11,055,824	$1,079,901	$58,368,147
2017/2018	$6,134,076	($1,841,715)	$12,396,817	$227,524	$16,916,702
Total	$176,007,354	$73,272,109	$85,419,628	$2,537,496	$337,236,587

Long Term and Annual Auction cleared FTR MW

	Long Term FTR Product					
Planning Period	Year 3	Year 2	Year 1	Total Long Term	Annual (including self scheduled)	Long Term Percent of Total Cleared
2014/2015	81,666	86,754	131,911	300,330	356,522	45.7%
2015/2016	89,419	99,329	123,400	312,148	355,682	46.7%
2016/2017	97,837	95,637	107,182	300,656	397,258	43.1%
2017/2018	69,161	86,323	108,126	263,609	493,683	34.8%

Long Term FTR Auction compared to Annual FTR Auction

	Long Term FTR Product					
Planning Period	Year 3	Year 2	Year 1	Total Long Term	Annual (including self scheduled)	Long Term Percent of Total Net Revenue
2014/2015	$13,016,512	$7,176,209	$6,863,135	$27,055,856	$735,998,448	3.5%
2015/2016	$12,479,874	$7,378,550	$5,156,206	$25,014,630	$893,043,415	2.7%
2016/2017	$7,624,149	$2,105,984	$11,087,250	$20,817,382	$861,031,182	2.4%
2017/2018	$1,670,521	$7,210,445	$9,763,312	$18,644,279	$513,587,222	3.5%

Status of MMU reported recommendations: 1999 through 2017

Status	Priority High	Priority Medium	Priority Low	Total	Percent of Total
Adopted	20	15	19	54	22.5%
Partially Adopted (Continued Recommendation)	5	7	6	18	7.5%
Partially Adopted (Recommendation Closed)	2	4	5	11	4.6%
Partially Adopted (Total)	7	11	11	29	12.1%
Not Adopted	32	63	35	130	54.2%
Not Adopted (Pending before FERC)	4	2	0	6	2.5%
Not Adopted (Stakeholder Process)	2	6	2	10	4.2%
Not Adopted (Total)	38	71	37	146	60.8%
Replaced by Newer Recommendation	1	5	2	8	3.3%
Withdrawn	0	1	2	3	1.3%
Total	66	103	71	240	100.0%

Market Monitoring Unit

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

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