2019 State of the Market Report for PJM

Press Briefing

March 12, 2020

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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

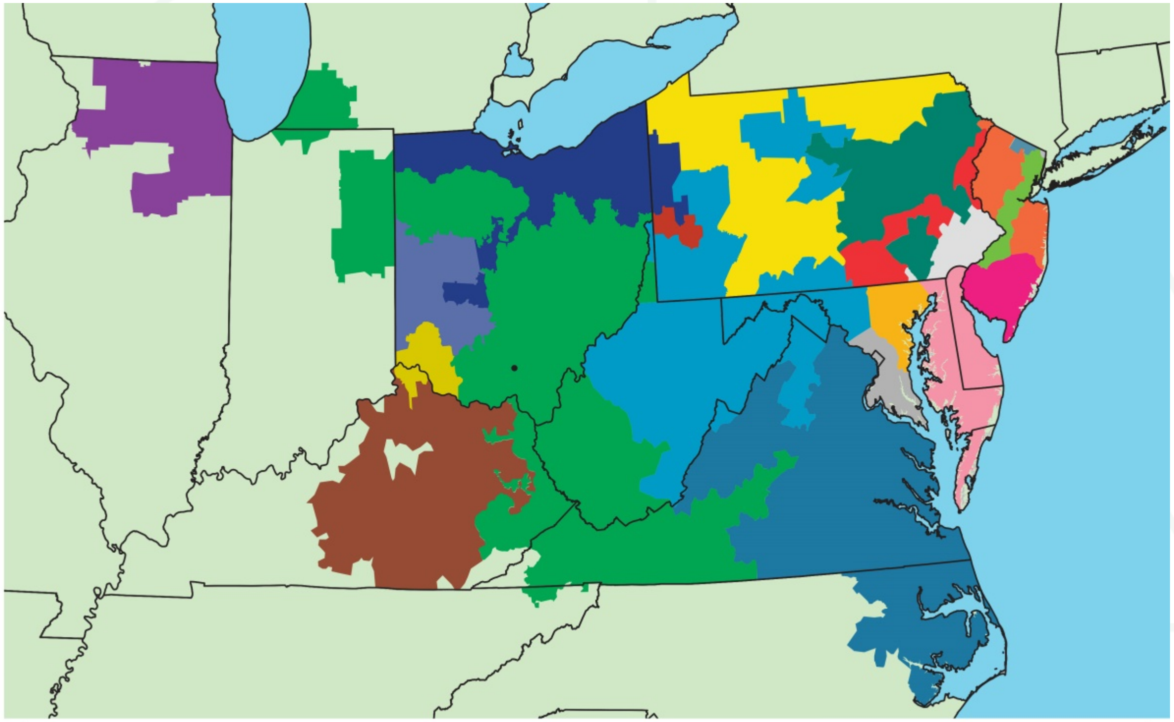
Role of Market Monitoring

- 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 functions:**
  - **Reporting**
  - **Market design**
  - **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**

PJM’s footprint and its 21 control zones



Legend

- Allegheny Power Company (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)
- Ohio Valley Electric Corporation (OVEC)
- PECO Energy (PECO)
- Pennsylvania Electric Company (PENELEC)
- Pepco
- PPL Electric Utilities (PPL)
- Public Service Electric and Gas Company (PSEG)
- Rockland Electric Company (RECO)

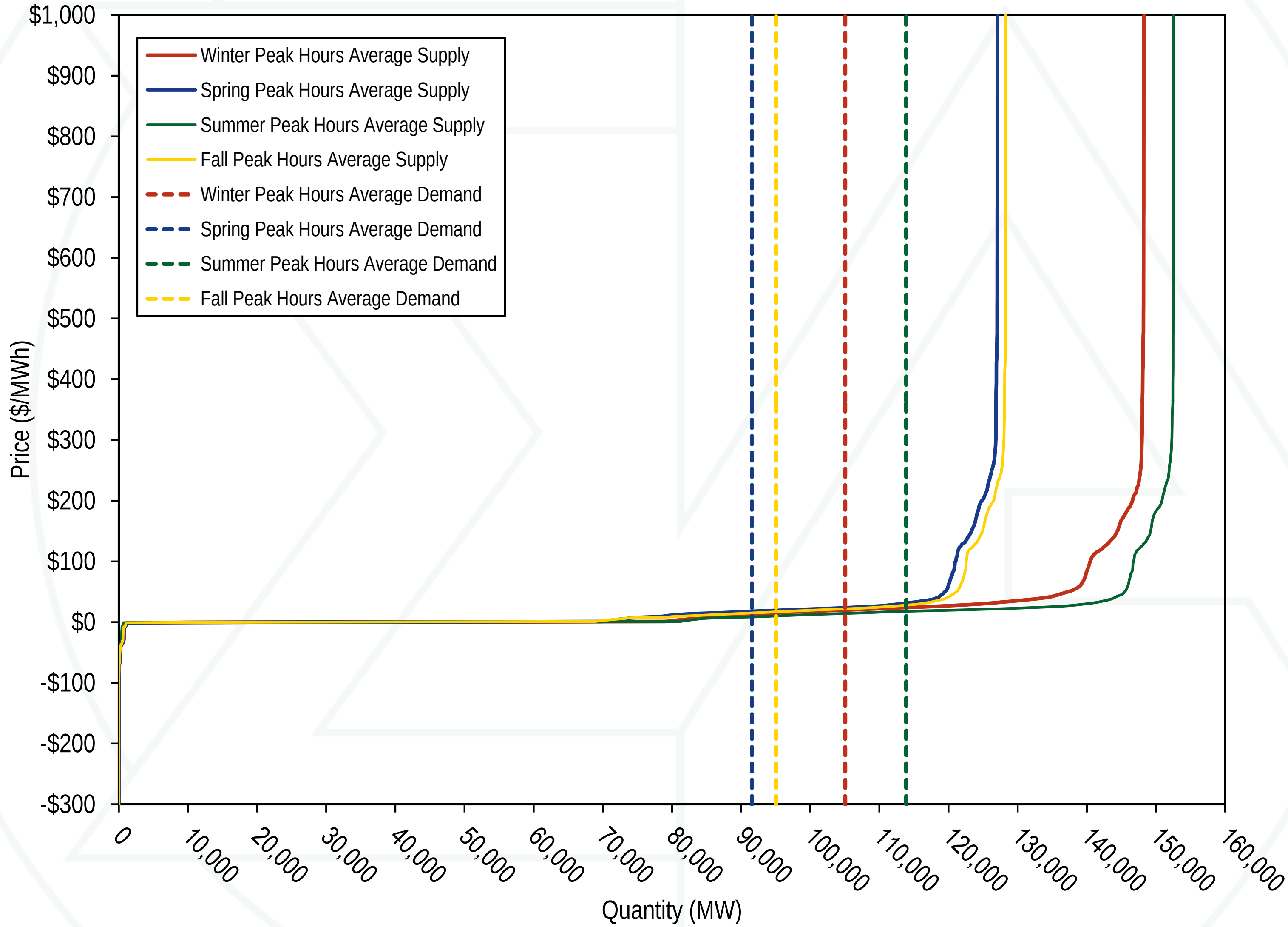
The energy market results were competitive

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

Recommendations: Energy Market

- **Correct flaws in implementation of market power mitigation rules:**
  - **Cost-based offers equal to short run marginal cost**
  - **Clear definitions for cost-based offers in Manual 15**
  - **Clear definition of relevant operating expenses**
  - **Fuel cost policies: algorithmic, verifiable, systematic**
- **Parameter limited schedules should use the most flexible parameters and be applied whenever a resource fails the TPS test or operates under an emergency or alert.**
- **Review and use accurate transmission line ratings.**
- **Real time dispatch and pricing should be more transparent and follow a rule based, scheduled approach.**
- **Prioritize and implement more accurate generator modelling, combined cycle modelling and soak time.**
- **Penalty for misuse of real time values for parameters**

Average hourly seasonal real-time supply curve



Monitoring Analytics

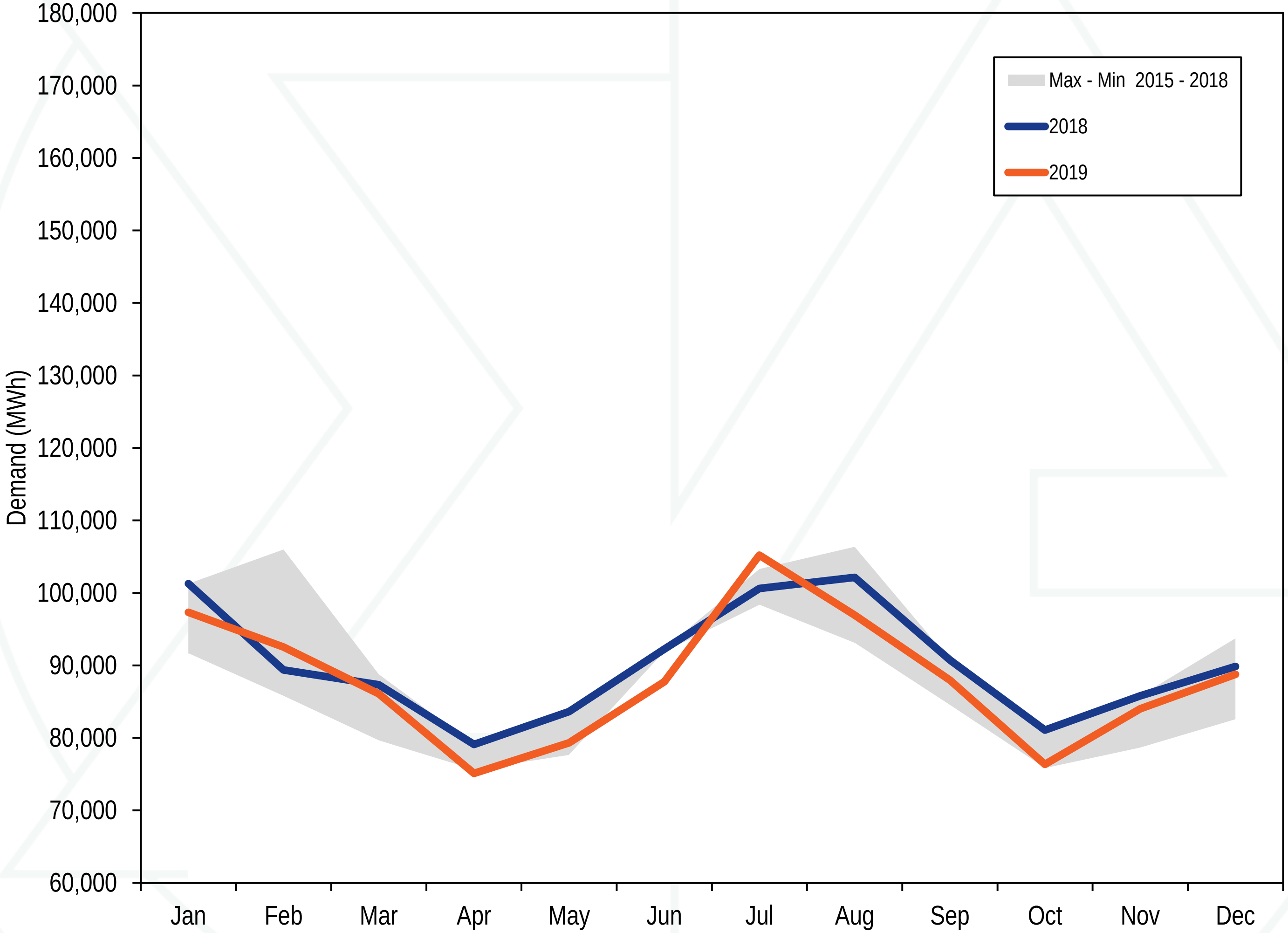
Total price per MWh by category

Category	2018 $/MWh	2018 ($ Millions)	2018 Percent of Total	2019 $/MWh	2019 ($ Millions)	2019 Percent of Total	Percent Change
Load Weighted Energy	$24.65	$19,498	61.4%	$17.28	$13,337	54.3%	(29.9%)
Capacity	$8.37	$6,624	20.9%	$7.13	$5,506	22.4%	(14.8%)
Capacity	$8.34	$6,600	20.8%	$7.12	$5,497	22.4%	(14.6%)
Capacity (FRR)	$0.00	$0	0.0%	$0.00	$0	0.0%	0.0%
Capacity (RMR)	$0.03	$24	0.1%	$0.01	$9	0.0%	(62.7%)
Transmission	$6.10	$4,823	15.2%	$6.57	$5,069	20.6%	7.7%
Transmission Service Charges	$5.67	$4,483	14.1%	$6.16	$4,756	19.4%	8.7%
Transmission Enhancement Cost Recovery	$0.37	$292	0.9%	$0.35	$270	1.1%	(5.4%)
Transmission Owner (Schedule 1A)	$0.06	$48	0.2%	$0.06	$43	0.2%	(6.8%)
Transmission Seams Elimination Cost Assignment (SECA)	$0.00	$0	0.0%	$0.00	$0	0.0%	0.0%
Transmission Facility Charges	$0.00	$0	0.0%	$0.00	$0	0.0%	0.0%
Ancillary	$0.51	$407	1.3%	$0.46	$352	1.4%	(11.2%)
Reactive	$0.26	$206	0.7%	$0.28	$214	0.9%	6.2%
Regulation	$0.12	$94	0.3%	$0.07	$57	0.2%	(37.6%)
Black Start	$0.05	$42	0.1%	$0.05	$41	0.2%	0.4%
Synchronized Reserves	$0.04	$32	0.1%	$0.03	$22	0.1%	(30.9%)
Non-Synchronized Reserves	$0.01	$9	0.0%	$0.01	$7	0.0%	(13.4%)
Day Ahead Scheduling Reserve (DASR)	$0.03	$24	0.1%	$0.01	$11	0.0%	(52.2%)
Administration	$0.32	$257	0.8%	$0.32	$249	1.0%	(0.6%)
PJM Administrative Fees	$0.30	$239	0.8%	$0.30	$231	0.9%	(1.1%)
NERC/RFC	$0.02	$16	0.1%	$0.02	$17	0.1%	7.4%
RTO Startup and Expansion	$0.00	$2	0.0%	$0.00	$1	0.0%	0.0%
Energy Uplift (Operating Reserves)	$0.15	$119	0.4%	$0.07	$56	0.2%	(52.3%)
Demand Response	$0.00	$3	0.0%	$0.00	$2	0.0%	(26.8%)
Load Response	$0.00	$3	0.0%	$0.00	$2	0.0%	(48.8%)
Emergency Load Response	$0.00	$0	0.0%	$0.00	$1	0.0%	0.0%
Emergency Energy	$0.00	$0	0.0%	$0.00	$0	0.0%	0.0%
Total Price	$40.11	$31,731	100.0%	$31.83	$24,571	100.0%	(20.6%)
Total Load (GWh)	791,094			771,929			(2.4%)
Total Billing ($ Billions)	$31.73			$24.57			(22.6%)

PJM load

	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
2001	30,297	5,873	32,165	5,564	NA	NA	NA	NA
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	91,015	15,083	(2.2%)	(11.9%)	(2.7%)	(13.8%)
2018	90,308	15,982	94,351	16,142	4.3%	5.4%	3.7%	7.0%
2019	88,120	15,867	92,917	16,087	(2.4%)	(0.7%)	(1.5%)	(0.3%)

Real-time monthly average hourly load



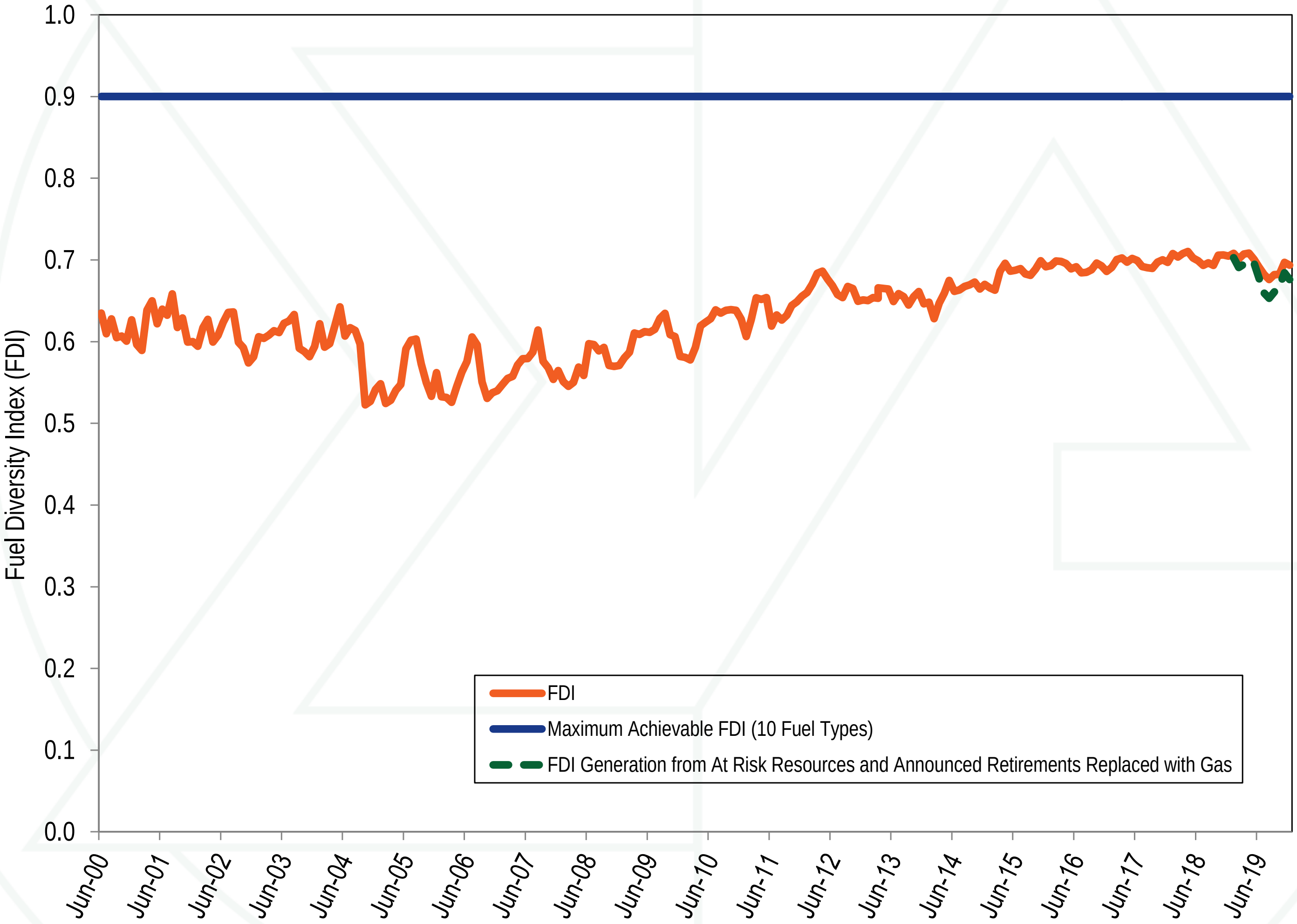
Generation (By fuel source (GWh))

	2018		2019		
	GWh	Percent	GWh	Percent	Change in Output
Coal	239,612.2	28.6%	197,165.3	23.8%	(17.7%)
Bituminous	201,123.6	24.0%	169,958.4	20.5%	(15.5%)
Sub Bituminous	30,136.0	3.6%	20,981.8	2.5%	(30.4%)
Other Coal	8,352.6	1.0%	6,225.2	0.8%	(25.5%)
Nuclear	286,155.4	34.2%	278,911.8	33.6%	(2.5%)
Gas	259,051.4	30.9%	302,116.9	36.4%	16.6%
Natural Gas	256,701.9	30.6%	299,966.8	36.2%	16.9%
Landfill Gas	2,309.7	0.3%	2,146.6	0.3%	(7.1%)
Other Gas	39.8	0.0%	3.5	0.0%	(91.2%)
Hydroelectric	19,415.5	2.3%	16,696.7	2.0%	(14.0%)
Pumped Storage	5,582.0	0.7%	4,642.9	0.6%	(16.8%)
Run of River	12,051.5	1.4%	10,728.7	1.3%	(11.0%)
Other Hydro	1,782.0	0.2%	1,325.1	0.2%	(25.6%)
Wind	21,628.0	2.6%	24,167.1	2.9%	11.7%
Waste	4,507.6	0.5%	4,237.3	0.5%	(6.0%)
Solid Waste	4,236.1	0.5%	4,147.6	0.5%	(2.1%)
Miscellaneous	271.5	0.0%	89.8	0.0%	(66.9%)
Oil	3,580.9	0.4%	1,788.0	0.2%	(50.1%)
Heavy Oil	435.5	0.1%	102.9	0.0%	(76.4%)
Light Oil	975.2	0.1%	271.9	0.0%	(72.1%)
Diesel	363.7	0.0%	71.7	0.0%	(80.3%)
Gasoline	0.0	0.0%	0.0	0.0%	NA
Kerosene	59.7	0.0%	10.1	0.0%	(83.1%)
Jet Oil	8.0	0.0%	0.0	0.0%	(100.0%)
Other Oil	1,738.8	0.2%	1,331.4	0.2%	(23.4%)
Solar, Net Energy Metering	2,110.6	0.3%	2,780.6	0.3%	31.7%
Battery	14.4	0.0%	18.8	0.0%	30.9%
Biofuel	1,572.5	0.2%	1,279.6	0.2%	(18.6%)
Total	837,648.4	100.0%	829,162.1	100.0%	(1.0%)

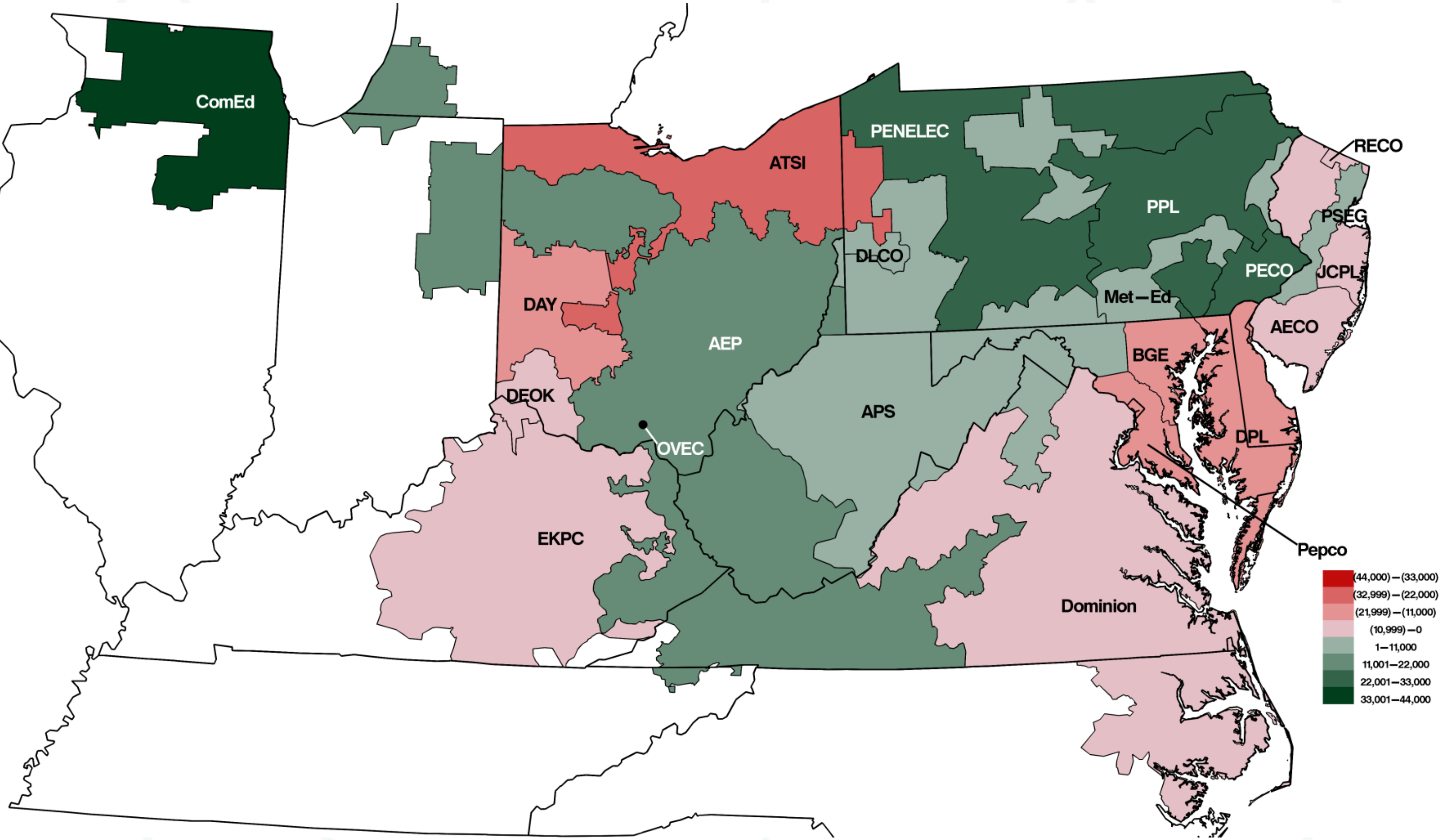
Capacity Factor by unit type

	2018		2019		Change in 2019
Unit Type	Generation (GWh)	Capacity Factor	Generation (GWh)	Capacity Factor	from 2018
Battery	14.3	0.6%	18.8	0.6%	0.1%
Combined Cycle	234,614.7	59.3%	278,310.5	63.6%	4.3%
Single Fuel	194,921.2	62.6%	236,429.8	68.6%	6.0%
Dual Fuel	39,693.5	47.1%	41,880.7	45.1%	(2.1%)
Combustion Turbine	17,590.9	6.9%	16,351.6	6.4%	(0.5%)
Single Fuel	11,561.4	6.2%	11,201.7	6.0%	(0.2%)
Dual Fuel	6,029.4	8.9%	5,149.9	7.5%	(1.4%)
Diesel	314.7	9.5%	262.3	7.6%	(1.9%)
Single Fuel	304.7	10.3%	257.5	8.3%	(2.0%)
Dual Fuel	9.9	2.7%	4.8	1.3%	(1.4%)
Diesel (Landfill gas)	1,780.5	51.6%	1,656.6	49.1%	(2.5%)
Fuel Cell	225.9	82.9%	212.8	77.0%	(5.9%)
Nuclear	286,155.4	94.2%	278,911.8	93.6%	(0.6%)
Pumped Storage Hydro	7,004.9	15.8%	5,621.2	12.7%	(3.1%)
Run of River Hydro	12,410.6	46.8%	11,075.5	41.6%	(5.2%)
Solar	2,104.9	17.7%	2,725.4	18.5%	0.9%
Steam	253,796.2	39.0%	209,793.2	35.7%	(3.4%)
Biomass	6,421.4	62.7%	5,837.3	60.1%	(2.5%)
Coal	241,022.0	44.4%	197,733.8	40.6%	(3.8%)
Single Fuel	235,262.5	45.8%	193,841.1	42.4%	(3.5%)
Dual Fuel	5,759.5	19.6%	3,892.7	13.2%	(6.4%)
Natural Gas	5,987.5	37.1%	6,122.3	41.0%	3.9%
Single Fuel	637.8	43.6%	403.9	49.1%	5.5%
Dual Fuel	5,349.7	23.2%	5,718.4	23.1%	(0.1%)
Oil	365.2	1.3%	99.8	0.5%	(0.8%)
Wind	21,626.8	28.4%	24,167.0	29.6%	1.2%
Total	837,644.2	47.3%	829,110.9	47.2%	(0.1%)

Fuel diversity index for energy



Real-time generation less real-time load

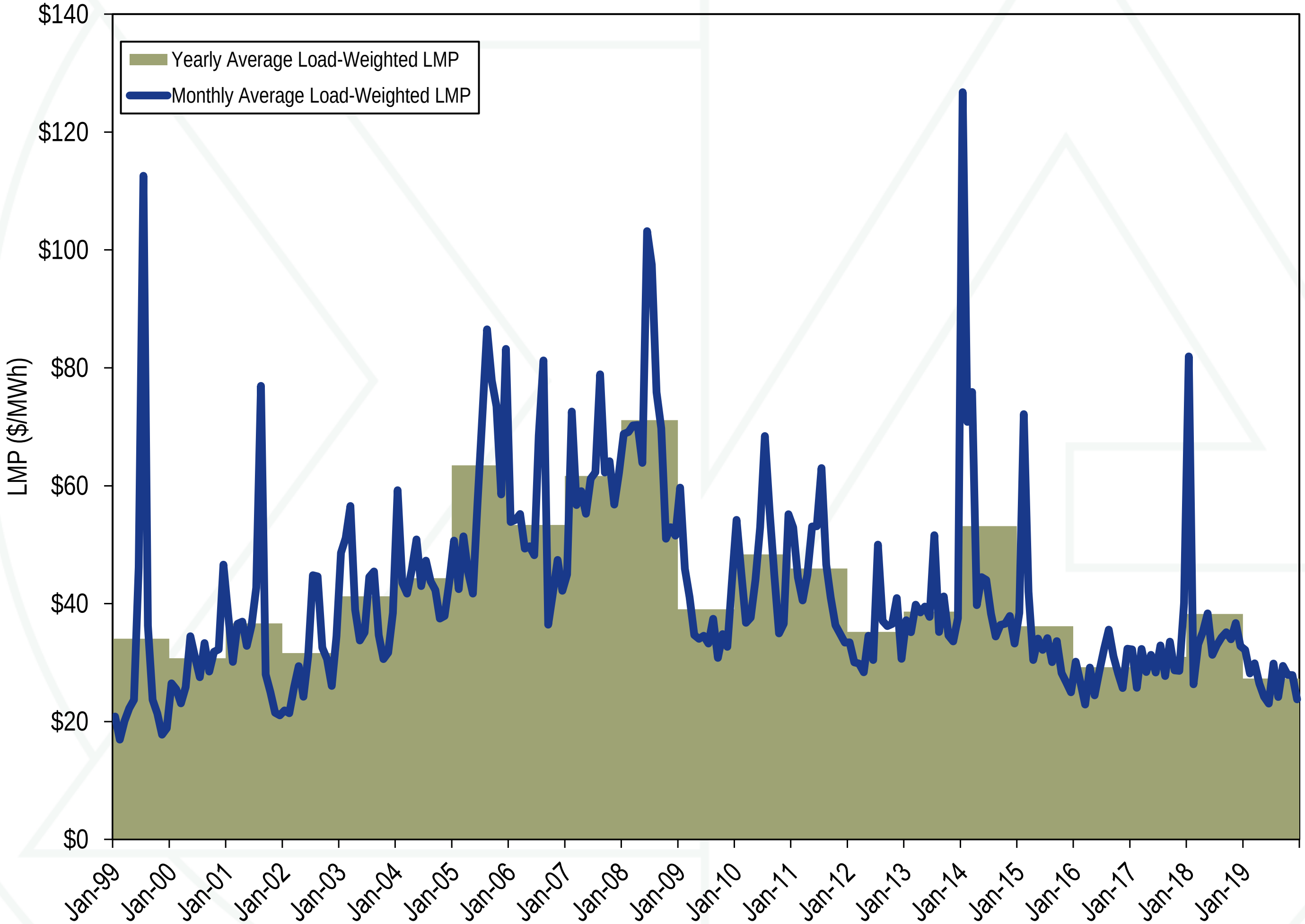


Monitoring Analytics

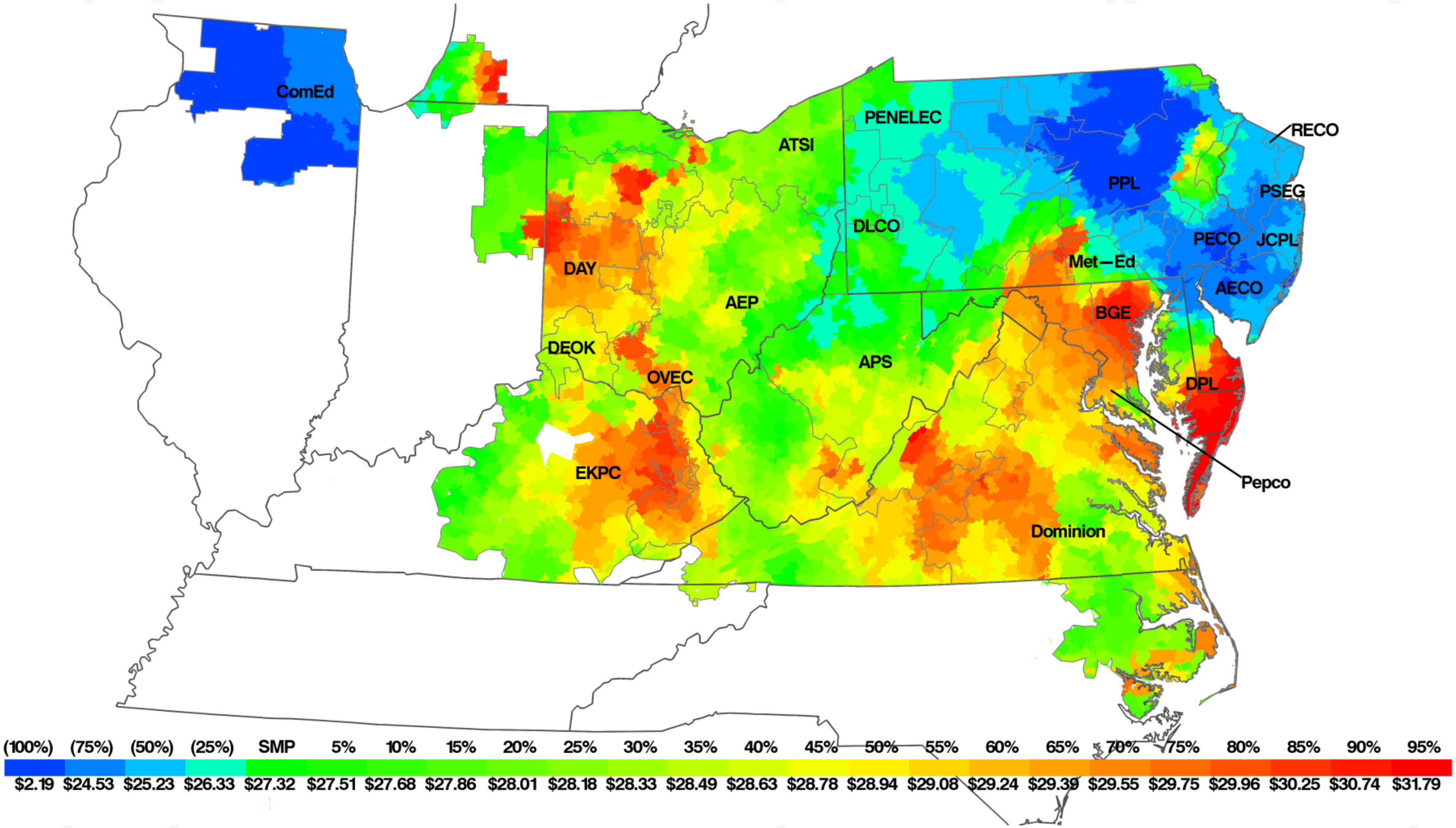
Real-time, load-weighted, average LMP

	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%
2018	$38.24	$29.55	$32.89	23.4%	12.1%	70.2%
2019	$27.32	$23.63	$23.12	(28.6%)	(20.0%)	(29.7%)

Real-time, load-weighted, average LMP

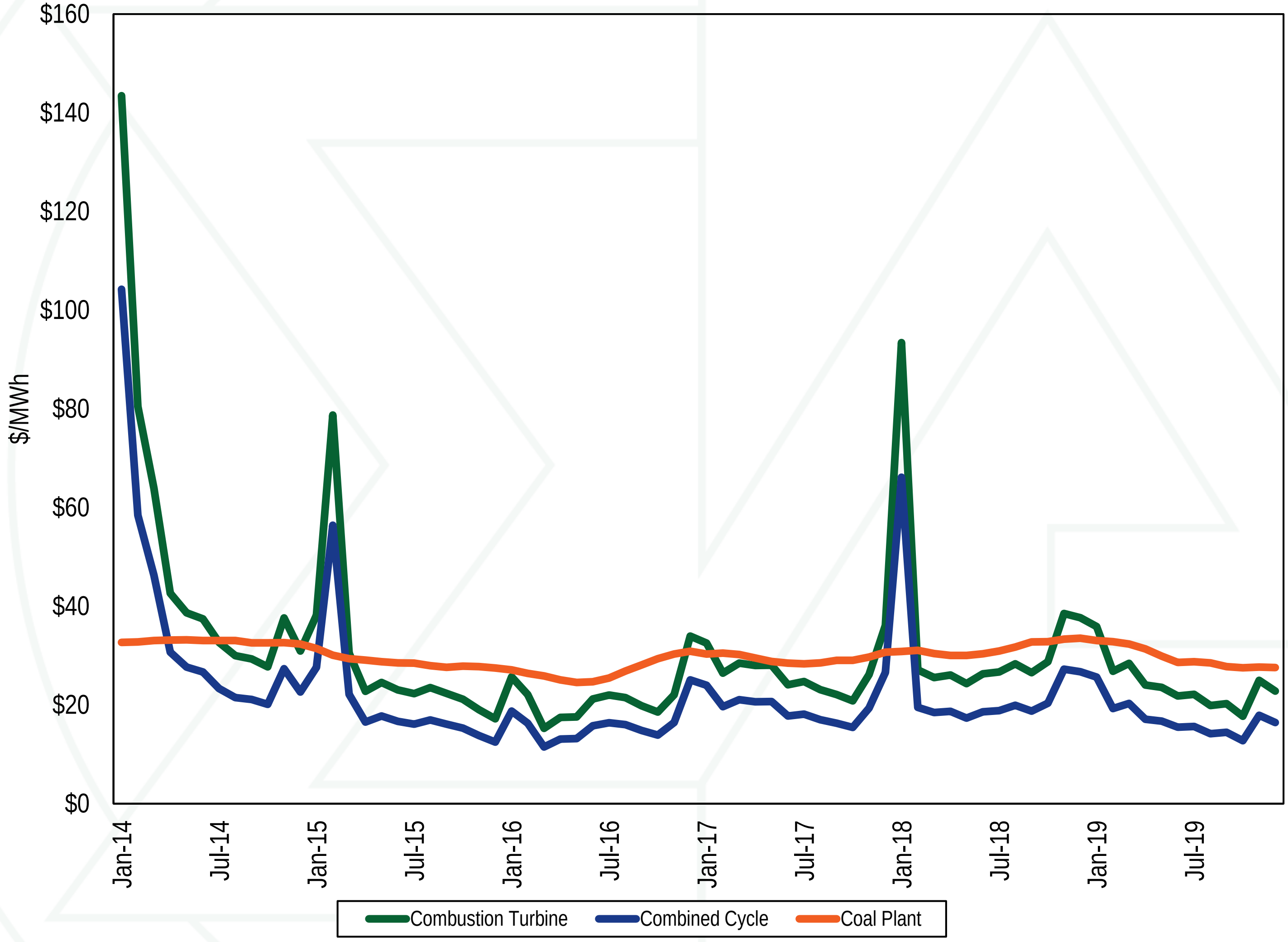


Real-time, load-weighted, average LMP

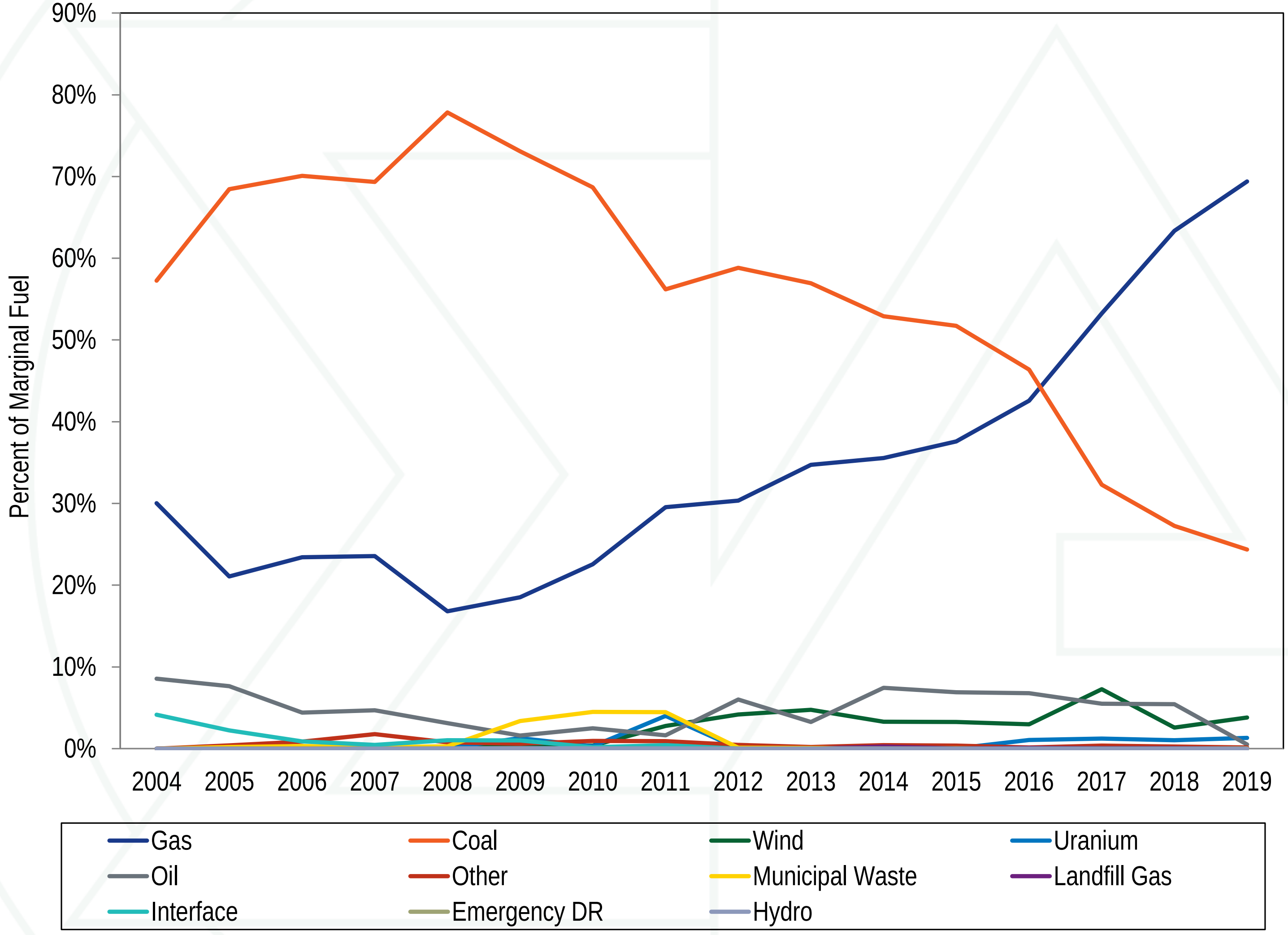


Monitoring Analytics

Average short run marginal costs



Type of fuel used (by real-time marginal units)



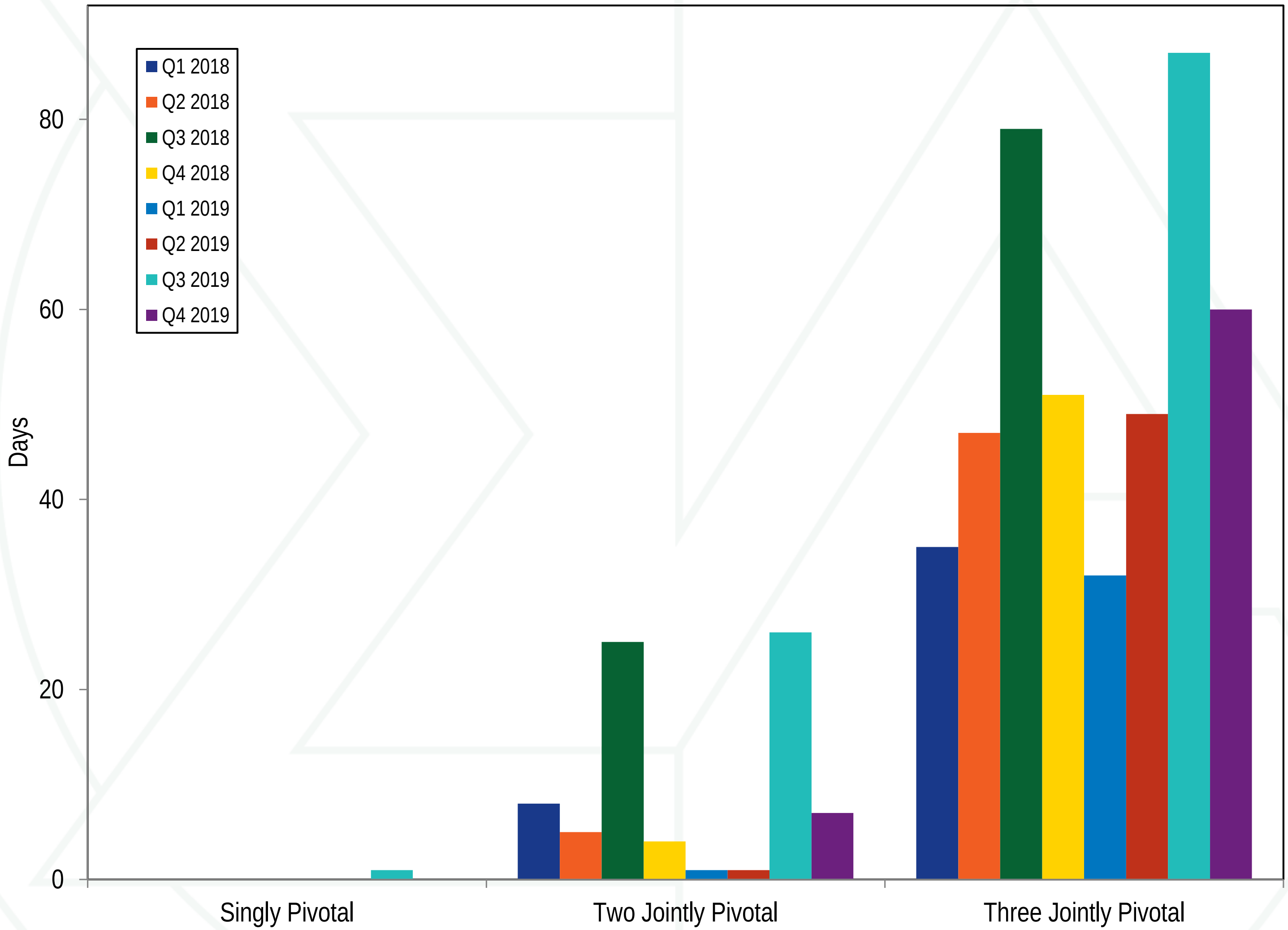
Real-time, fuel-cost adjusted, load-weighted average LMP

	2019 Fuel-Cost Adjusted, Load-Weighted LMP	2019 Load-Weighted LMP	Change	Percent Change
Average	$31.86	$27.32	($4.54)	(14.2%)
	2018 Load-Weighted LMP	2019 Fuel-Cost Adjusted, Load-Weighted LMP	Change	Percent Change
Average	$38.24	$31.86	($6.39)	(16.7%)
	2018 Load-Weighted LMP	2019 Load-Weighted LMP	Change	Change
Average	$38.24	$27.32	($10.92)	(28.6%)

Components of real-time, load-weighted, average LMP

	2018		2019		Change
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Percent
Gas	$16.26	42.5%	$11.50	42.1%	(0.4%)
Coal	$7.44	19.5%	$7.21	26.4%	6.9%
Ten Percent Adder	$2.74	7.2%	$2.07	7.6%	0.4%
Constraint Violation Adder	($0.00)	(0.0%)	$1.85	6.8%	6.8%
VOM	$1.46	3.8%	$1.71	6.2%	2.4%
Markup	$4.56	11.9%	$1.58	5.8%	(6.2%)
NA	$1.78	4.6%	$0.36	1.3%	(3.3%)
Ancillary Service Redispatch Cost	$0.44	1.2%	$0.24	0.9%	(0.3%)
Scarcity Adder	$0.02	0.1%	$0.24	0.9%	0.8%
CO_2 Cost	$0.16	0.4%	$0.21	0.8%	0.3%
LPA Rounding Difference	$0.61	1.6%	$0.15	0.5%	(1.0%)
Opportunity Cost Adder	$0.10	0.3%	$0.10	0.4%	0.1%
Increase Generation Adder	$0.82	2.1%	$0.10	0.4%	(1.8%)
Oil	$1.75	4.6%	$0.06	0.2%	(4.3%)
NO_x Cost	$0.09	0.2%	$0.02	0.1%	(0.2%)
LPA-SCED Differential	($0.02)	(0.0%)	$0.01	0.0%	0.1%
Other	$0.06	0.1%	$0.00	0.0%	(0.1%)
Market-to-Market Adder	$0.01	0.0%	$0.00	0.0%	(0.0%)
SO_2 Cost	$0.01	0.0%	$0.00	0.0%	(0.0%)
Landfill Gas	$0.00	0.0%	$0.00	0.0%	0.0%
Uranium	($0.00)	(0.0%)	$0.00	0.0%	0.0%
Municipal Waste	$0.10	0.3%	$0.00	0.0%	(0.3%)
Wind	($0.01)	(0.0%)	$0.00	0.0%	0.0%
Renewable Energy Credits	($0.03)	(0.1%)	($0.02)	(0.1%)	(0.0%)
Decrease Generation Adder	($0.10)	(0.3%)	($0.05)	(0.2%)	0.1%
Total	$38.24	100.0%	$27.32	100.0%	0.0%

Pivotal suppliers in the day-ahead energy market

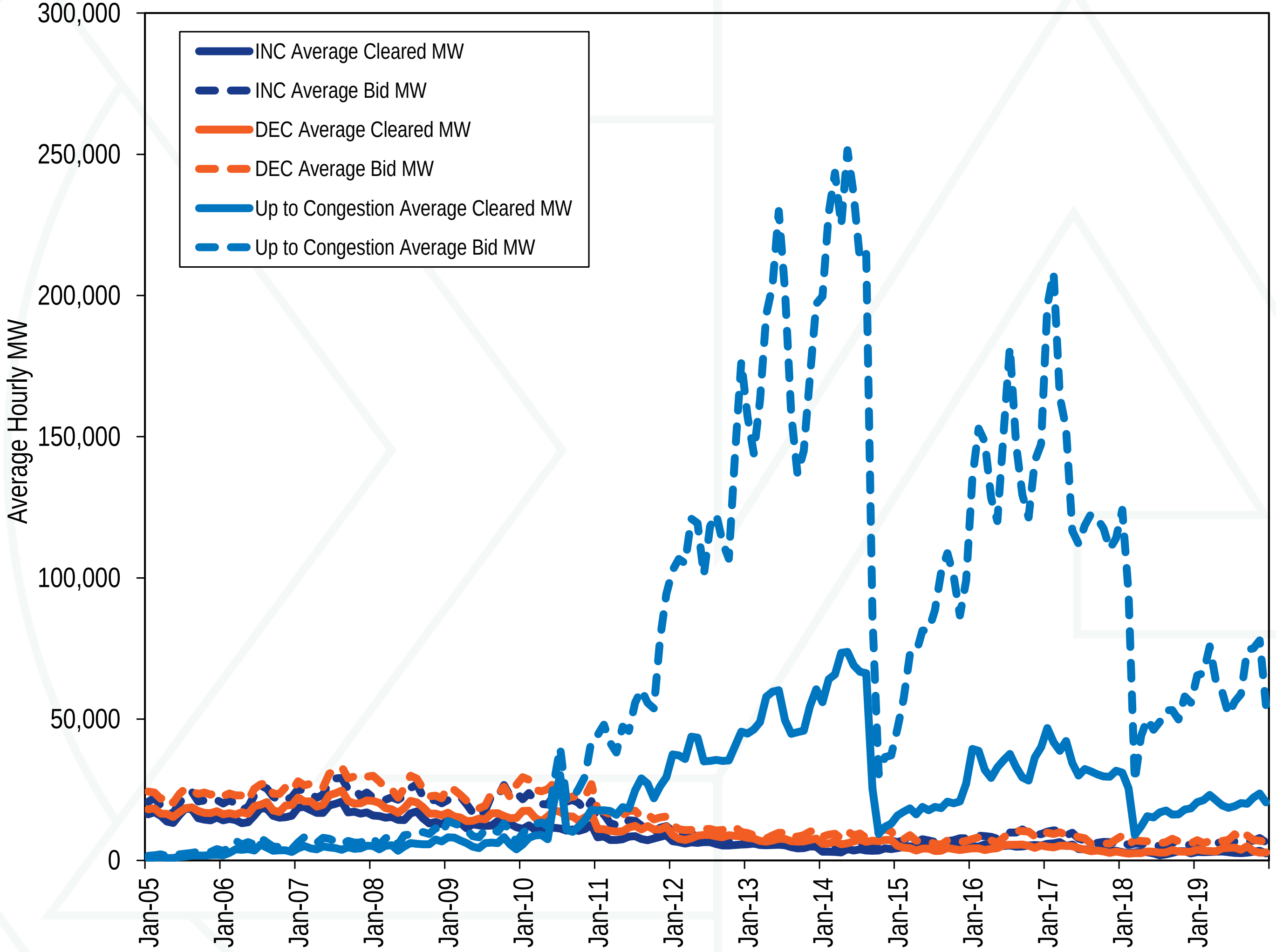


Monitoring Analytics

Offer capping – energy only

	Real-Time		Day-Ahead	
Year	Unit Hours Capped	MWh Capped	Unit Hours Capped	MWh Capped
2015	0.4%	0.2%	0.2%	0.2%
2016	0.4%	0.2%	0.0%	0.0%
2017	0.3%	0.2%	0.0%	0.0%
2018	0.9%	0.5%	0.1%	0.1%
2019	1.7%	1.3%	1.3%	0.9%

Monthly bid and cleared INCs, DECs and UTCs



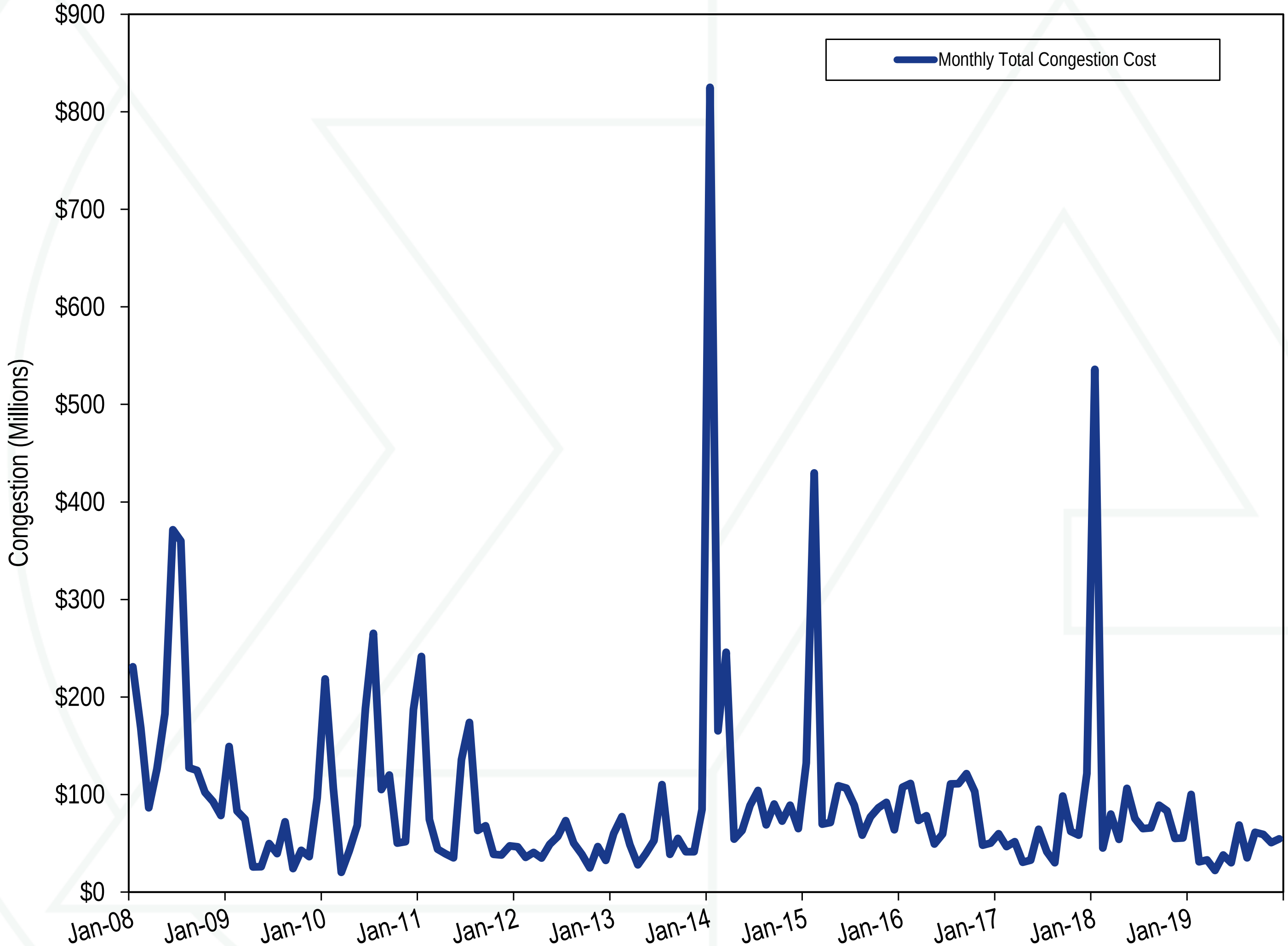
UTC transactions by type of parent organization

	2018				2019			
Category	Total Up to Congestion Bid	Percent	Total Up to Congestion Cleared MWh	Percent	Total Up to Congestion Bid	Percent	Total Up to Congestion Cleared MWh	Percent
Financial	502,640,657	97.8%	147,233,232	95.4%	555,951,114	97.7%	174,145,737	95.3%
Physical	11,131,422	2.2%	7,154,781	4.6%	13,031,324	2.3%	8,626,176	4.7%
Total	513,772,079	100.0%	154,388,014	100.0%	568,982,438	100.0%	182,771,913	100.0%

Total congestion

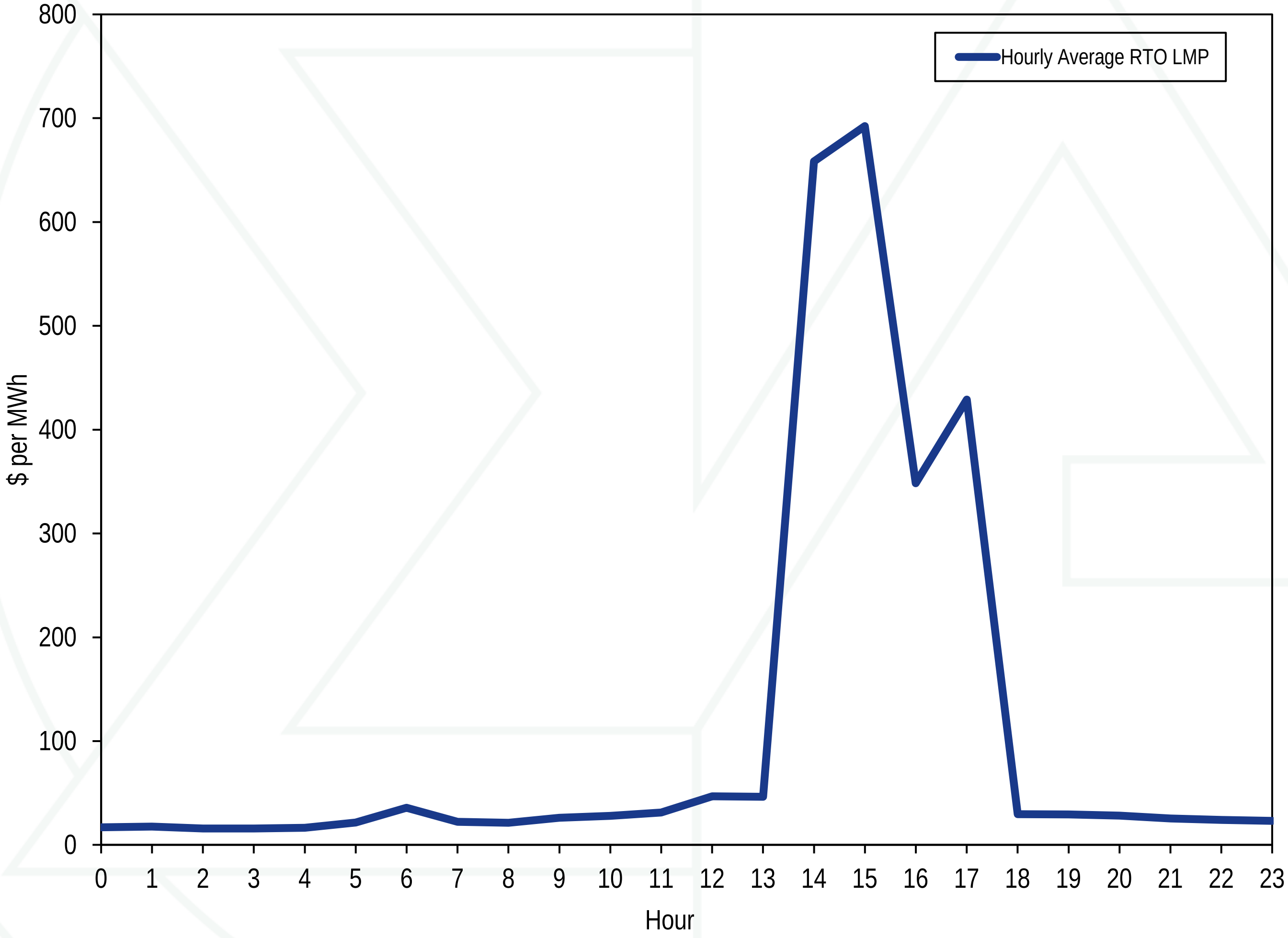
Congestion Costs (Millions)				
	Congestion Cost	Percent Change	Total PJM Billing	Percent of PJM Billing
2008	$2,052	NA	$34,300	6.0%
2009	$719	(65.0%)	$26,550	2.7%
2010	$1,423	98.0%	$34,770	4.1%
2011	$999	(29.8%)	$35,890	2.8%
2012	$529	(47.0%)	$29,180	1.8%
2013	$677	28.0%	$33,860	2.0%
2014	$1,932	185.5%	$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%
2018	$1,310	87.8%	$49,790	2.6%
2019	$583	(55.5%)	$39,200	1.5%

Monthly total congestion



Monitoring Analytics

Real-time hourly load weighted average LMP: October 1, 2019



RT SCED solutions not approved from 1648 through 1714 EPT: Oct 1, 2019

SCED Case ID	SCED Target Time	Load Bias Solution		
		Low	Mid	High
1	01-Oct 17:00			
2	01-Oct 17:05			
3	01-Oct 17:05			
4	01-Oct 17:10	Shortage	Shortage	Shortage
5	01-Oct 17:10	Shortage	Shortage	Shortage
6	01-Oct 17:15	Shortage	Shortage	Shortage
7	01-Oct 17:15		Shortage	Shortage
8	01-Oct 17:20		Shortage	Shortage
9	01-Oct 17:20			Shortage

The capacity market results were not competitive

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

Recommendations: Capacity Market

- Offer cap calculation should be based on economic logic of CP and actual PAH and not default to Net CONE*B.
- Consistent definition of a capacity resource as physical at time of auction and delivery year.
- Net revenue calculation for offer caps should be based on lower of price or cost.
- All capacity imports should be deliverable to an LDA.
- Definition of LDA should be dynamic and market based.
- Improve market clearing rules by including make whole and nesting in optimization.
- Maintain performance incentives and product definitions in Capacity Performance design.
- Modify RMR rules to eliminate overpayment.
- Set the maximum price on the VRR curve to net CONE.

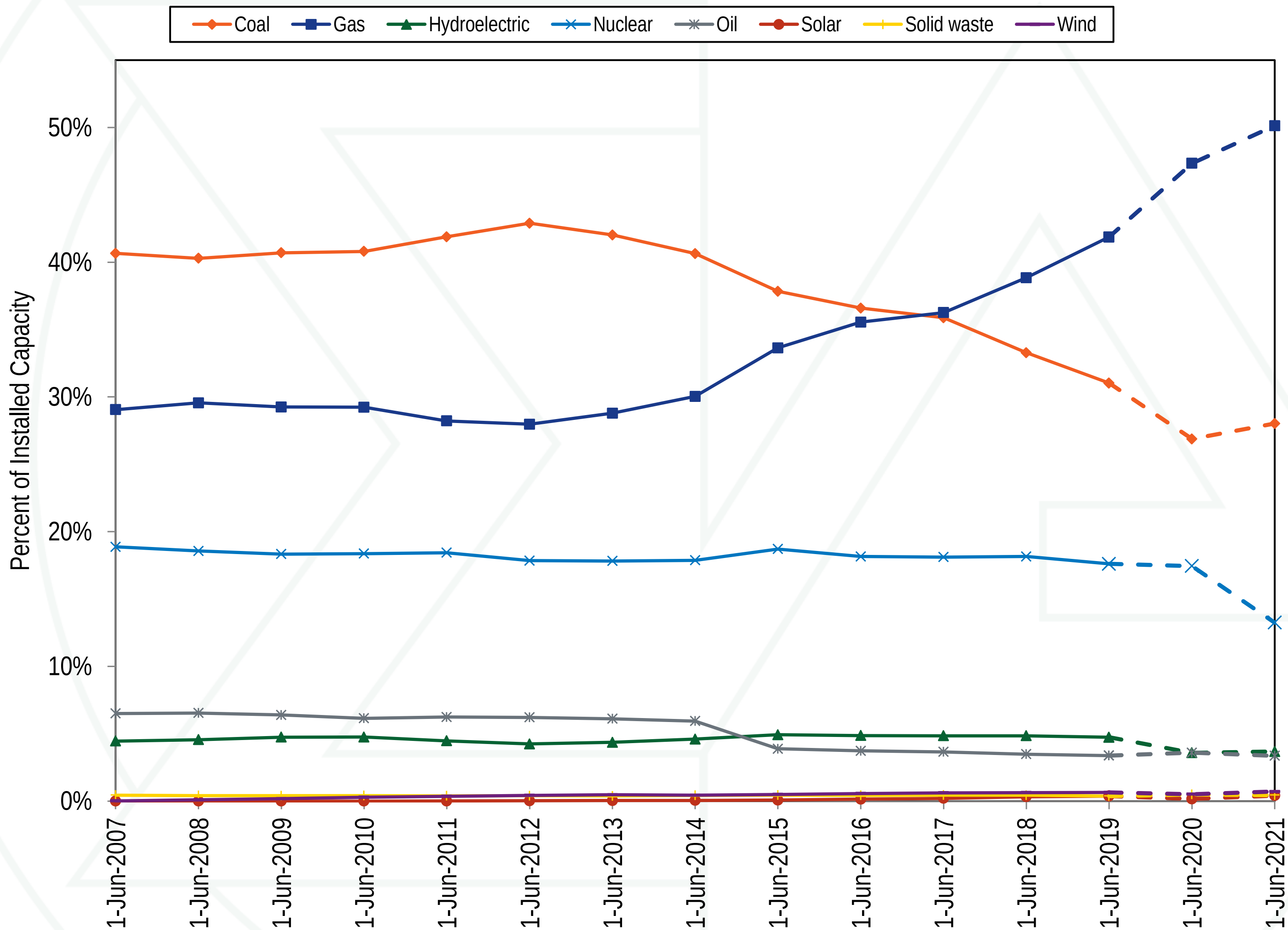
Recommendations: Capacity Market

- Implement Sustainable Market Rule (SMR).
- Offer cap calculation should be based on economic logic of CP and actual PAH and not default to Net CONE*B.
- 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.
- 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.

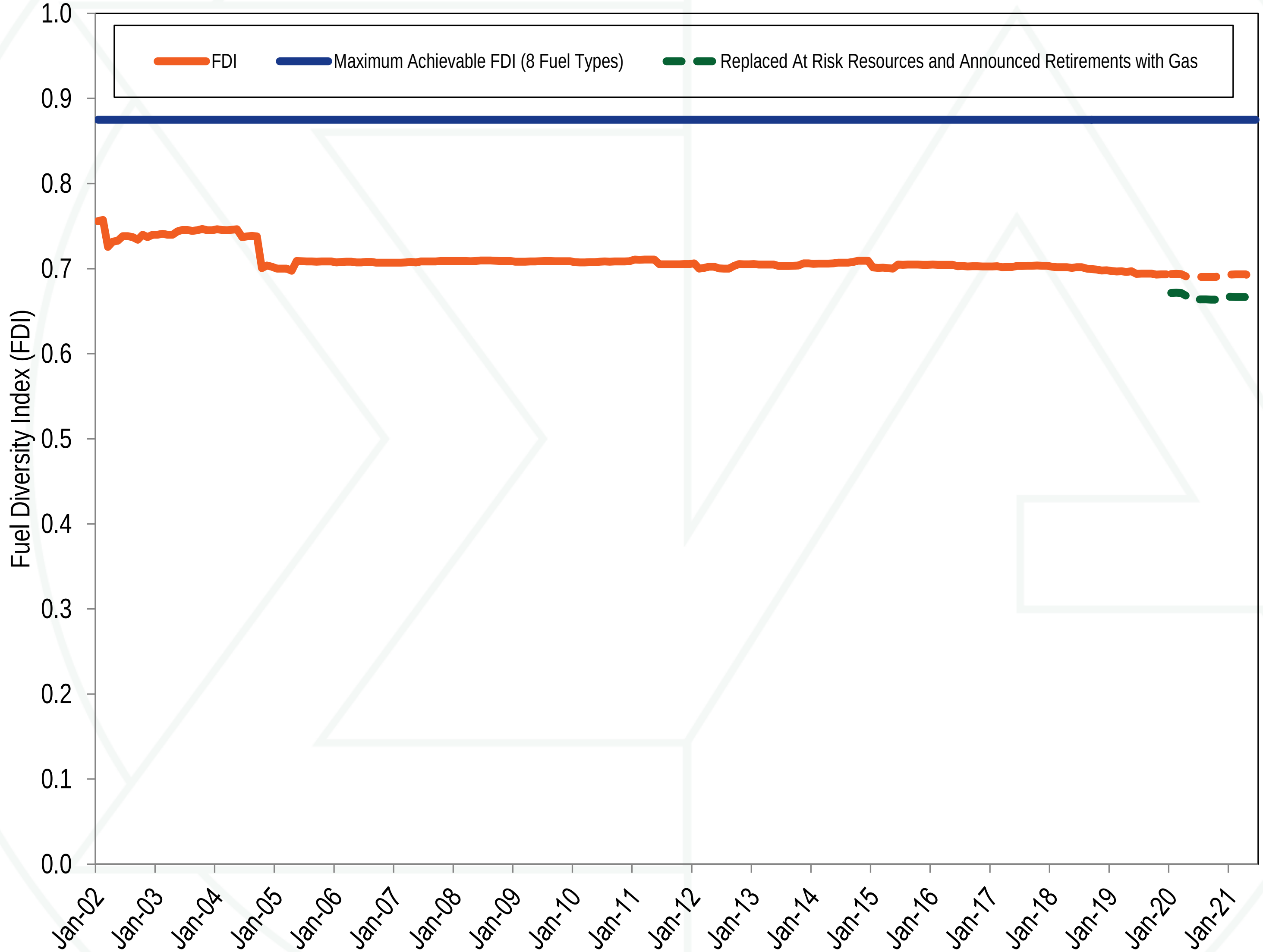
Installed capacity by fuel source

	01-Jan-19		31-May-19		01-Jun-19		31-Dec-19	
	MW	Percent	MW	Percent	MW	Percent	MW	Percent
Coal	60,763.4	32.6%	58,833.6	31.7%	58,043.9	31.0%	56,311.0	30.5%
Gas	75,261.2	40.4%	75,770.8	40.9%	78,475.8	41.9%	78,230.9	42.3%
Hydroelectric	8,888.2	4.8%	8,873.9	4.8%	8,873.9	4.7%	8,873.9	4.8%
Nuclear	32,684.5	17.5%	33,000.7	17.8%	33,001.7	17.6%	32,297.9	17.5%
Oil	6,388.2	3.4%	6,342.2	3.4%	6,330.2	3.4%	6,311.0	3.4%
Solar	640.0	0.3%	686.2	0.4%	702.6	0.4%	791.0	0.4%
Solid waste	712.3	0.4%	712.3	0.4%	702.3	0.4%	695.6	0.4%
Wind	1,158.3	0.6%	1,158.3	0.6%	1,192.2	0.6%	1,232.2	0.7%
Total	186,496.1	100.0%	185,378.0	100.0%	187,322.6	100.0%	184,743.5	100.0%

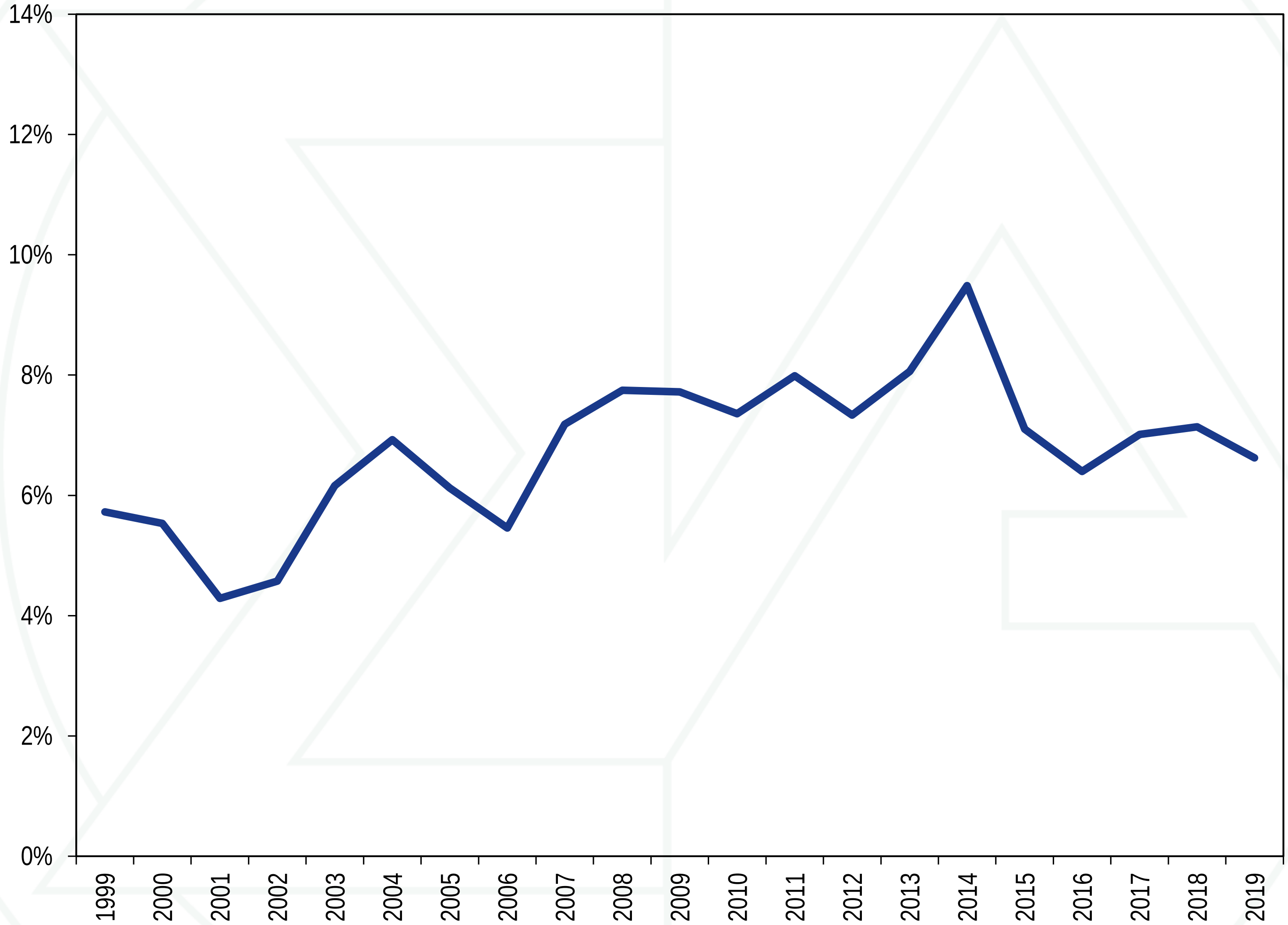
Percent of installed capacity (by fuel source)



Fuel Diversity Index for capacity



PJM EFORd


14%
12%
10%
8%
6%
4%
2%
0%
1999
2000
2001
2002
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2008
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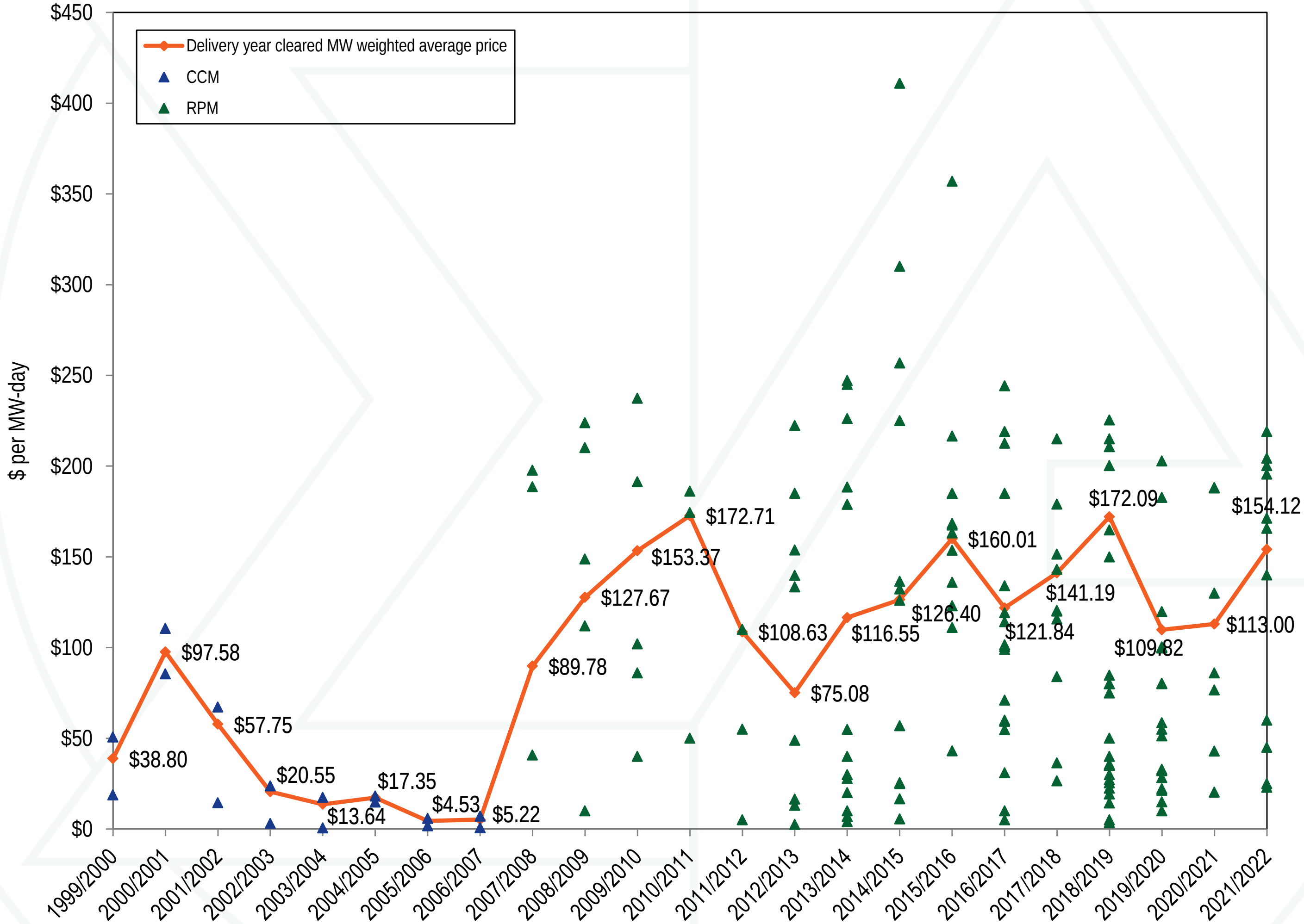
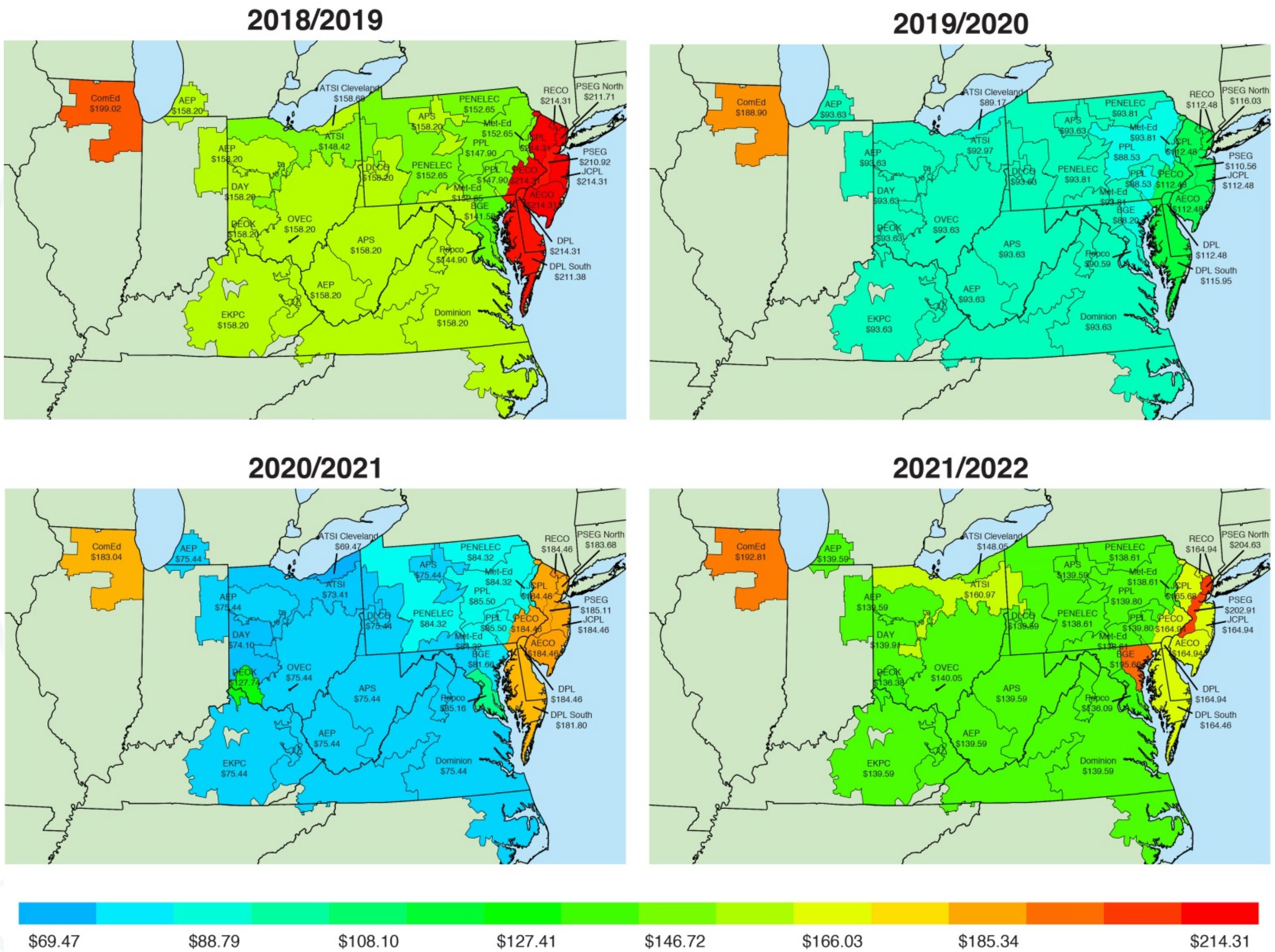
2016
2017
2018
2019

History of capacity prices



Monitoring Analytics

Map of RPM capacity prices

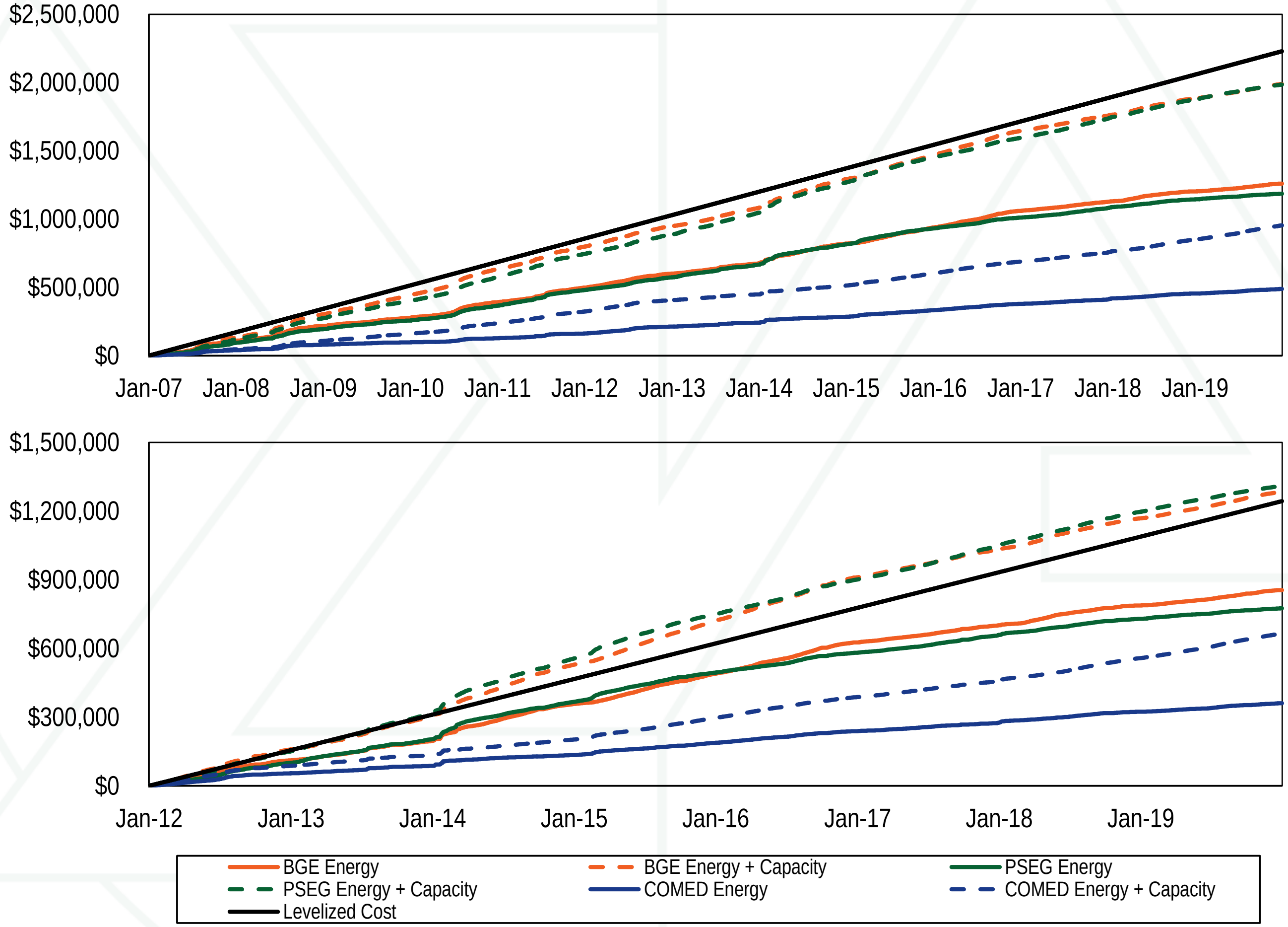


Monitoring Analytics

Levelized cost of energy: 2019

	CT	CC	CP	DS	Nuclear	Wind (On Shore)	Wind (Off Shore)	Solar
Levelized cost ($/MW-year)	$121,612	$116,781	$581,567	$169,859	$1,383,428	$214,618	$710,472	$243,936
Short run marginal costs ($/MWh)	$24.03	$17.15	$29.65	$150.66	$0.00	$0.00	$0.00	$0.00
Capacity factor (%)	52%	77%	24%	1%	94%	26%	45%	17%
Levelized cost of energy ($/MWh)	$51	$34	$307	$3,039	$168	$93	$180	$163

Historical new entrant CC revenue adequacy



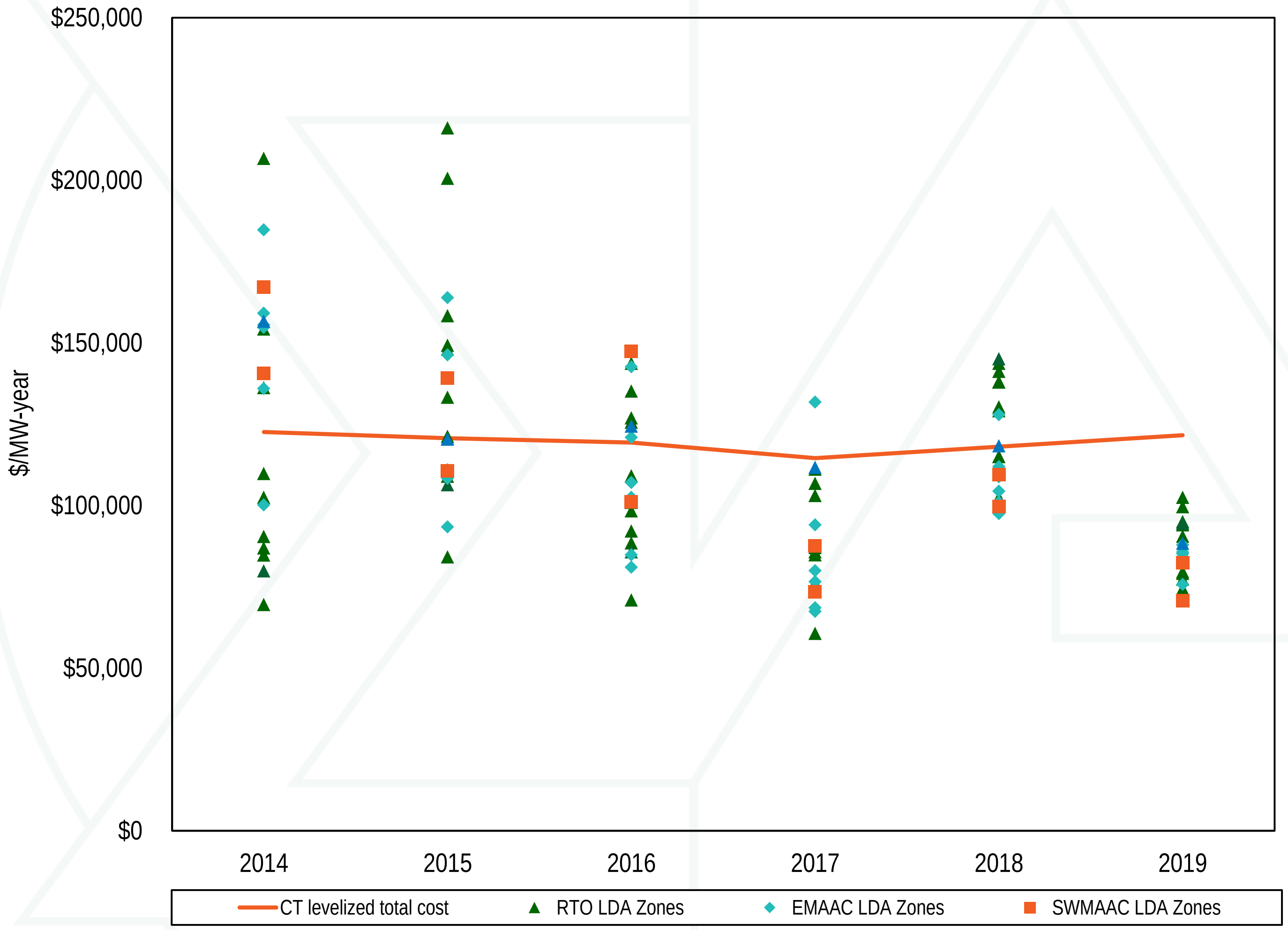
Avoidable cost recovery by quartile

Technology	Total Installed Capacity (ICAP)	Recovery of avoidable costs from energy and ancillary net revenue			Recovery of avoidable costs from all markets		
		First quartile	Median	Third quartile	First quartile	Median	Third quartile
CC - Combined Cycle	31,318	38%	214%	380%	415%	561%	796%
CT - Aero Derivative	5,893	4%	31%	69%	381%	511%	592%
CT - Industrial Frame	21,030	0%	9%	24%	292%	438%	642%
Coal Fired	47,966	0%	0%	14%	51%	71%	104%
Diesel	289	0%	0%	7%	210%	354%	474%
Hydro	2,329	285%	304%	450%	425%	473%	659%
Nuclear	30,351	74%	79%	89%	102%	106%	109%
Oil or Gas Steam	10,490	0%	0%	1%	106%	149%	209%
Pumped Storage	4,721	187%	429%	429%	769%	1,011%	1,089%

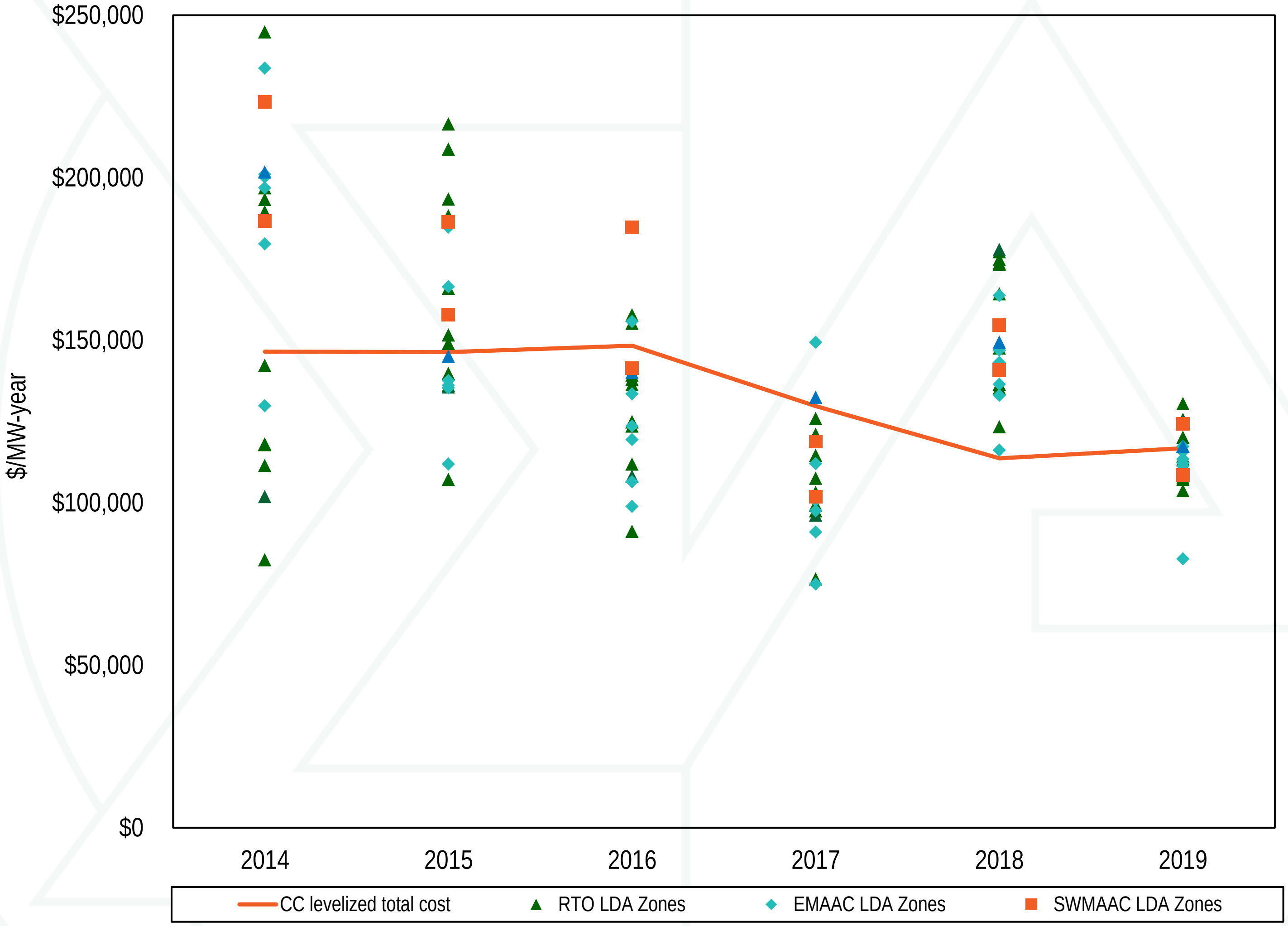
Proportion of units recovering avoidable costs

	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	2018	2019	2011	2012	2013	2014	2015	2016	2017	2018	2019
CC - Combined Cycle	55%	46%	50%	72%	59%	63%	57%	66%	66%	85%	79%	79%	95%	88%	93%	89%	98%	97%
CT - Aero Derivative	15%	6%	6%	53%	15%	8%	10%	30%	7%	100%	96%	76%	98%	100%	99%	100%	99%	96%
CT - Industrial Frame	26%	23%	17%	38%	13%	8%	3%	21%	7%	99%	98%	83%	100%	100%	100%	100%	96%	88%
Coal Fired	31%	17%	27%	78%	16%	15%	12%	11%	2%	82%	36%	54%	83%	64%	40%	36%	63%	26%
Diesel	48%	42%	37%	69%	56%	33%	32%	39%	9%	100%	100%	77%	100%	100%	100%	100%	97%	91%
Hydro	74%	61%	95%	97%	81%	79%	95%	94%	95%	81%	77%	97%	98%	100%	100%	97%	98%	100%
Nuclear	-	-	50%	94%	17%	6%	17%	53%	0%	-	-	61%	100%	56%	17%	50%	88%	81%
Oil or Gas Steam	8%	6%	11%	15%	3%	0%	0%	10%	75%	92%	78%	86%	85%	91%	88%	81%	76%	76%
Pumped Storage	100%	100%	95%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

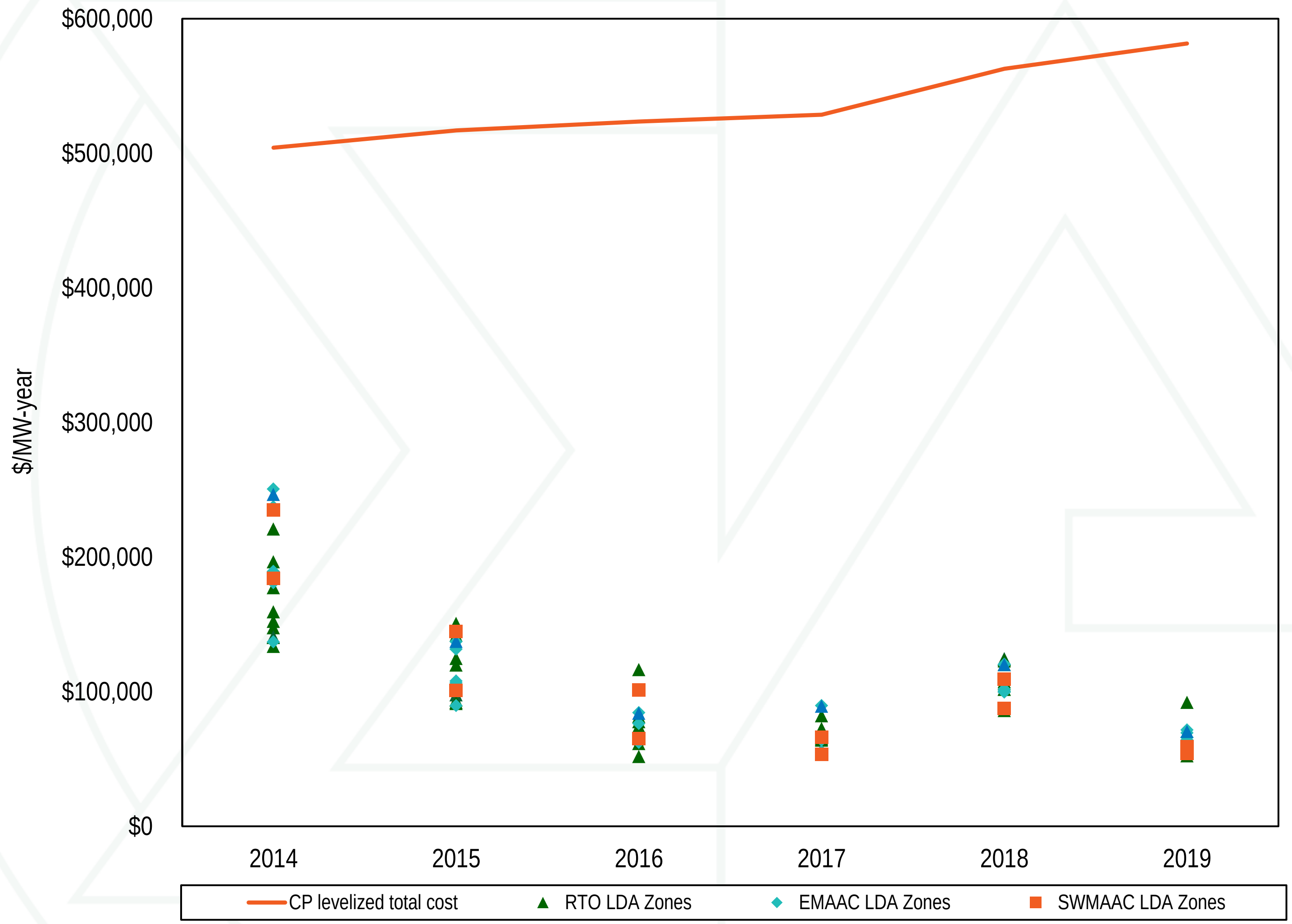
New entrant CT net revenue and cost



New entrant CC net revenue and cost

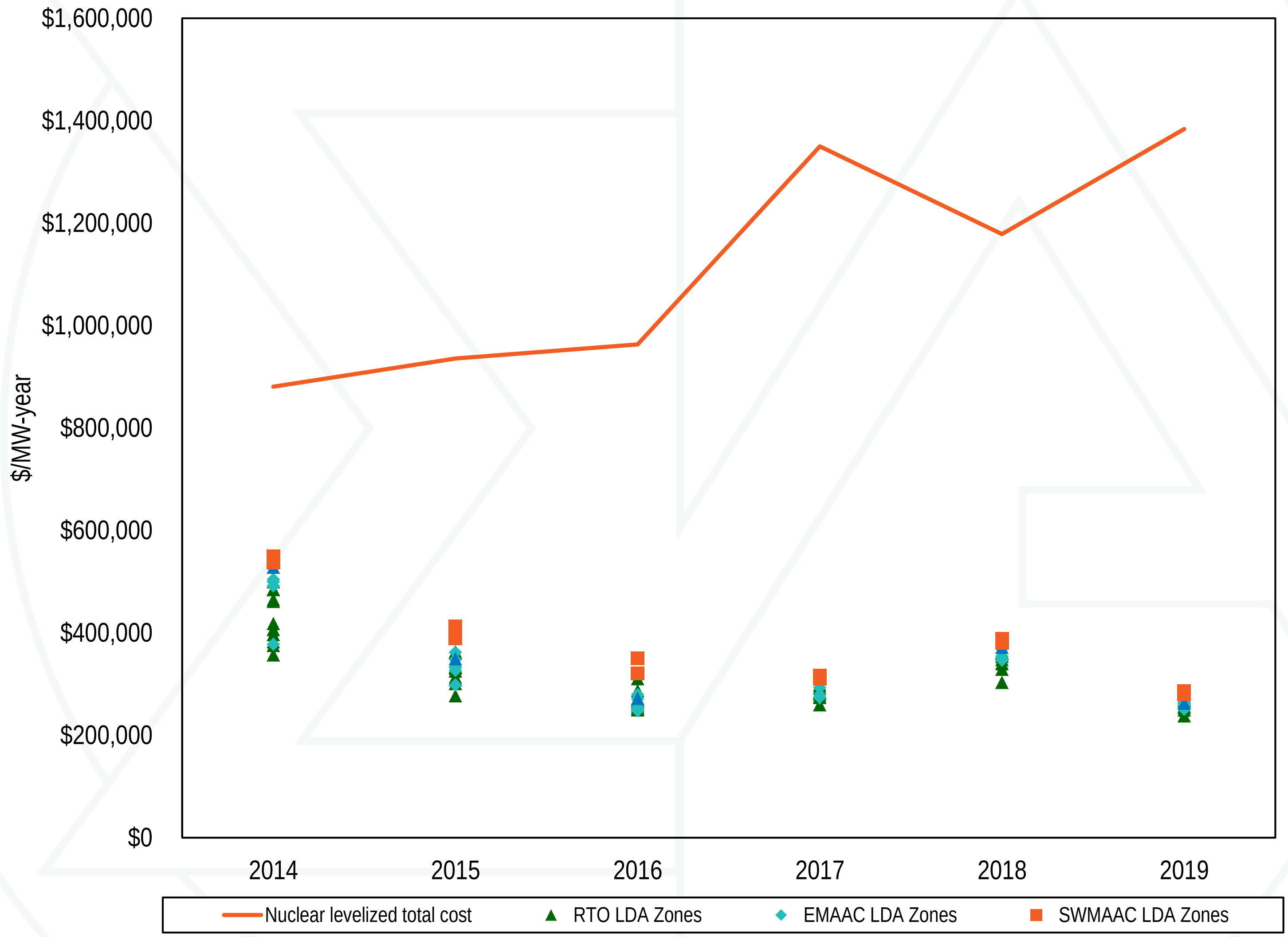


New entrant coal plant net revenue and cost



Monitoring Analytics

New entrant nuclear plant net revenue and cost



Nuclear unit forward annual surplus (shortfall)

	ICAP (MW)	Surplus (Shortfall) ($/MWh) 2020	Surplus (Shortfall) ($/MWh) 2021	Surplus (Shortfall) ($ in millions) 2020	Surplus (Shortfall) ($ in millions) 2021
Beaver Valley	1,808	$0.92	$3.41	$13.6	$50.3
Braidwood	2,337	$3.02	$4.09	$57.8	$78.1
Byron	2,300	$2.00	$3.05	$37.7	$57.2
Calvert Cliffs	1,708	$2.29	$4.76	$32.0	$66.4
Davis Besse	894	($12.10)	($8.79)	($88.7)	($64.2)
Dresden	1,797	$3.57	$4.67	$52.5	$68.7
Hope Creek	1,172	$1.50	$3.52	$14.4	$33.7
LaSalle	2,271	$2.82	$3.89	$52.5	$72.2
Limerick	2,242	$1.28	$3.30	$23.5	$60.4
North Anna	1,892	$1.61	$4.13	$24.9	$63.9
Peach Bottom	2,347	$0.66	$2.63	$12.7	$50.4
Perry	1,240	($11.50)	($8.14)	($116.9)	($82.5)
Quad Cities	1,819	$0.77	$1.82	$11.5	$27.0
Salem	2,328	$1.22	$3.24	$23.2	$61.6
Surry	1,676	$0.81	$3.32	$11.1	$45.5
Susquehanna	2,520	($3.24)	($1.07)	($67.0)	($21.9)

Nuclear unit implied net ACR

	ICAP	Net ACR ($/MWh)			Net ACR ($/MW-Day)			Net ACR Excluding Capital ($/MW-Day)		
	(MW)	2020	2021	2022	2020	2021	2022	2020	2021	2022
Beaver Valley	1,808	$2.90	$1.63	$1.75	$69.69	$39.10	$41.94	$0.00	$0.00	$0.00
Braidwood	2,337	$5.58	$4.43	$4.54	$133.91	$106.36	$108.98	$0.00	$0.00	$0.00
Byron	2,300	$6.60	$5.47	$5.58	$158.29	$131.40	$133.83	$23.41	$0.00	$0.00
Calvert Cliffs	1,708	$1.79	$0.45	$0.57	$42.85	$10.80	$13.79	$0.00	$0.00	$0.00
Davis Besse	894	$15.92	$14.64	$14.75	$382.12	$351.30	$353.94	$181.96	$151.14	$153.78
Dresden	1,797	$5.03	$3.85	$3.95	$120.73	$92.29	$94.88	$0.00	$0.00	$0.00
Hope Creek	1,172	$5.56	$4.22	$4.28	$133.47	$101.37	$102.72	$0.00	$0.00	$0.00
LaSalle	2,271	$5.77	$4.63	$4.73	$138.60	$111.06	$113.60	$3.72	$0.00	$0.00
Limerick	2,242	$5.79	$4.44	$4.50	$138.90	$106.65	$107.99	$4.02	$0.00	$0.00
North Anna	1,892	$2.21	$0.90	$1.03	$53.07	$21.66	$24.66	$0.00	$0.00	$0.00
Peach Bottom	2,347	$6.41	$5.12	$5.17	$153.72	$122.76	$124.16	$18.84	$0.00	$0.00
Perry	1,240	$15.32	$13.99	$14.10	$367.76	$335.74	$338.40	$167.60	$135.58	$138.24
Quad Cities	1,819	$7.82	$6.70	$6.79	$187.78	$160.83	$162.89	$52.90	$25.95	$28.01
Salem	2,328	$5.85	$4.50	$4.56	$140.32	$108.10	$109.40	$5.44	$0.00	$0.00
Surry	1,676	$3.01	$1.71	$1.82	$72.24	$41.13	$43.79	$0.00	$0.00	$0.00
Susquehanna	2,520	$7.31	$6.27	$6.38	$175.36	$150.58	$153.02	$40.48	$15.70	$18.14

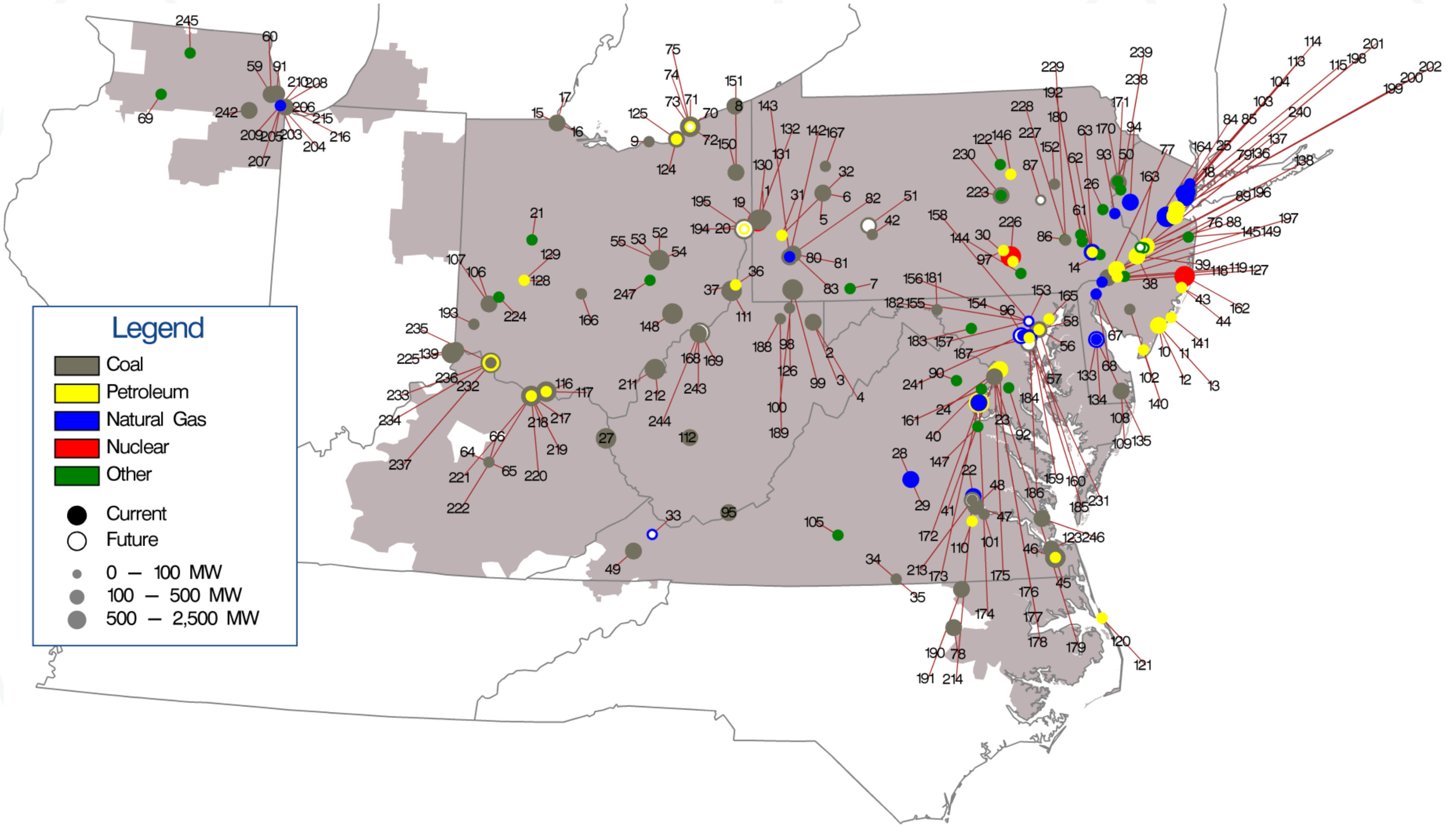
Profile of units at risk of retirement

Technology	No. Units	ACR ($/MW-day)	ICAP (MW)	Avg. 2019 Run Hrs	Avg. Unit Age (Yrs)	Avg. Heat Rate (Btu/MWh)
Coal Fired	8	$115.48	4,306	3,127	50	10,072
CT and Diesel	101	$107.96 CT / $55.96 DS	3,103	78	46	15,145
Nuclear	2	$940.46 single unit	2,134	-	37	-
Total	111	-	9,543	-	-	-

Reserve Margin

	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		Projected Replacement Capacity using Cleared Buy Bids UCAP (MW)	Projected Reserve Margin
										Percent	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	0.0	22.3%
01-Jun-17	163,872.0	153,230.1	12,837.5	0.0	140,392.6	16.6%	5.94%	174,220.7	24.1%	7.5%	10,522.9	0.0	24.1%
01-Jun-18	161,242.6	152,407.9	12,732.9	0.0	139,675.0	16.1%	6.07%	171,662.5	22.9%	6.8%	9,499.8	0.0	22.9%
01-Jun-19	162,276.1	151,643.5	12,284.2	0.0	139,359.3	16.0%	6.08%	172,781.2	24.0%	8.0%	11,124.4	0.0	24.0%
01-Jun-20	164,428.4	151,155.1	11,930.9	558.0	138,666.2	15.9%	6.04%	174,998.3	26.2%	10.3%	14,284.2	2,335.0	24.4%
01-Jun-21	161,959.4	151,832.3	11,982.6	510.0	139,339.7	15.8%	6.01%	172,315.6	23.7%	7.9%	10,960.2	1,232.8	22.7%

Map of PJM unit retirements



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	30-Apr-19
Yorktown 1	Dominion Virginia Power	159.0	Deactivation Avoidable Cost Rate	ER17-750	06-Jan-17	08-Mar-19
Yorktown 2	Dominion Virginia Power	164.0	Deactivation Avoidable Cost Rate	ER17-750	06-Jan-17	08-Mar-19
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: Planning

- **Increase the role of competition in transmission consistent with Order 1000**
  - **Eliminate the exemption of supplemental projects**
  - **Eliminate the exemption of end of life projects**
  - **Implement robust evaluation of competing cost containment project and cost of service project proposals**
- **The rules governing cost/benefit analysis for evaluation of transmission projects should be modified to include all costs in all zones.**

Recommendations: Energy Market Uplift

- **Develop and implement an accurate metric for following dispatch to determine uplift eligibility.**
- **Eliminate exemption for fast start resources from the requirement to follow dispatch to be eligible for uplift.**
- **Pay uplift based on the lower of the actual or dispatch MW.**
- **Calculate uplift on a 24 hour basis, not by segments or five minute intervals.**
- **Make transparent day ahead reliability commitments, according to the same rules as real time commitments.**
- **Do not use closed loop interfaces to artificially set price for the sole purpose of reducing uplift.**
- **Allocate uplift to UTC transactions.**

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	($175.3)	(56.2%)	0.4%
2017	$127.3	($9.4)	(6.9%)	0.3%
2018	$198.2	$70.9	55.7%	0.4%
2019	$88.6	($109.6)	(55.3%)	0.2%

Energy uplift credits by unit type

Unit Type	Day-Ahead Generator	Balancing Generator	Canceled Resources	Local Constraints Control	Lost Opportunity Cost	Reactive Services	Synchronous Condensing	Black Start Services
Combined Cycle	3.2%	4.1%	0.0%	7.6%	3.1%	0.0%	0.0%	24.6%
Combustion Turbine	1.7%	86.3%	0.0%	81.8%	93.7%	43.6%	0.0%	75.3%
Diesel	0.0%	0.8%	0.0%	10.2%	1.2%	1.4%	0.0%	0.1%
Hydro	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Nuclear	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Solar	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Steam - Coal	88.3%	5.3%	0.0%	0.0%	0.5%	55.1%	0.0%	0.0%
Steam - Other	6.9%	3.2%	0.0%	0.0%	0.3%	0.0%	0.0%	0.0%
Wind	0.0%	0.1%	0.0%	0.4%	1.1%	0.0%	0.0%	0.0%
Total (Millions)	$15.5	$52.1	$0.0	$2.9	$17.5	$0.6	$0.0	$0.2

Top 10 units and organizations energy uplift credits

		Top 10 Units		Top 10 Organizations	
Category	Type	Credits (Millions)	Credits Share	Credits (Millions)	Credits Share
Day-Ahead	Generators	$13.4	86.5%	$15.2	98.3%
Balancing	Canceled Resources	$0.0	0.0%	$0.0	0.0%
	Generators	$6.5	12.5%	$38.4	73.7%
	Local Constraints Control	$1.8	62.5%	$2.9	100.0%
	Lost Opportunity Cost	$4.3	25.0%	$12.9	75.0%
Reactive Services		$0.5	91.6%	$0.6	100.0%
Synchronous Condensing		$0.0	0.0%	$0.0	0.0%
Black Start Services		$0.1	39.7%	$0.2	88.7%
Total		$18.4	20.7%	$64.6	72.9%

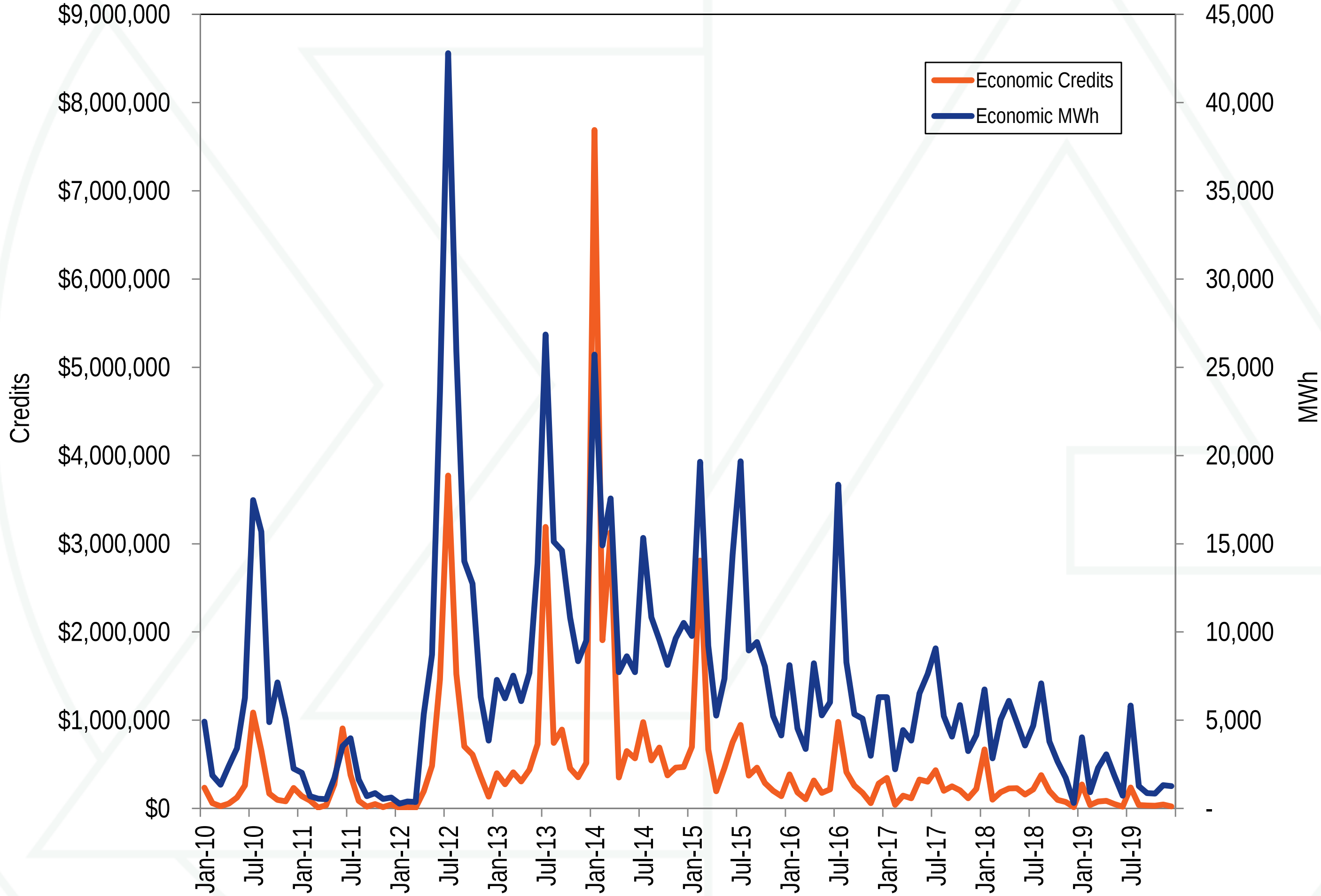
Operating reserve rates statistics ($/MWh)

		Rates Charged ($/MWh)			
Region	Transactio	Maximum	Average	Minimum	Standard Deviation
East	INC	2.283	0.323	<0.001	0.372
	DEC	2.298	0.342	<0.001	0.373
	DA Load	0.200	0.019	<0.001	0.031
	RT Load	0.437	0.027	<0.001	0.044
	Deviation	2.283	0.323	<0.001	0.372
West	INC	2.283	0.303	<0.001	0.359
	DEC	2.298	0.322	<0.001	0.361
	DA Load	0.200	0.019	<0.001	0.031
	RT Load	0.391	0.025	<0.001	0.040
	Deviation	2.283	0.303	<0.001	0.359

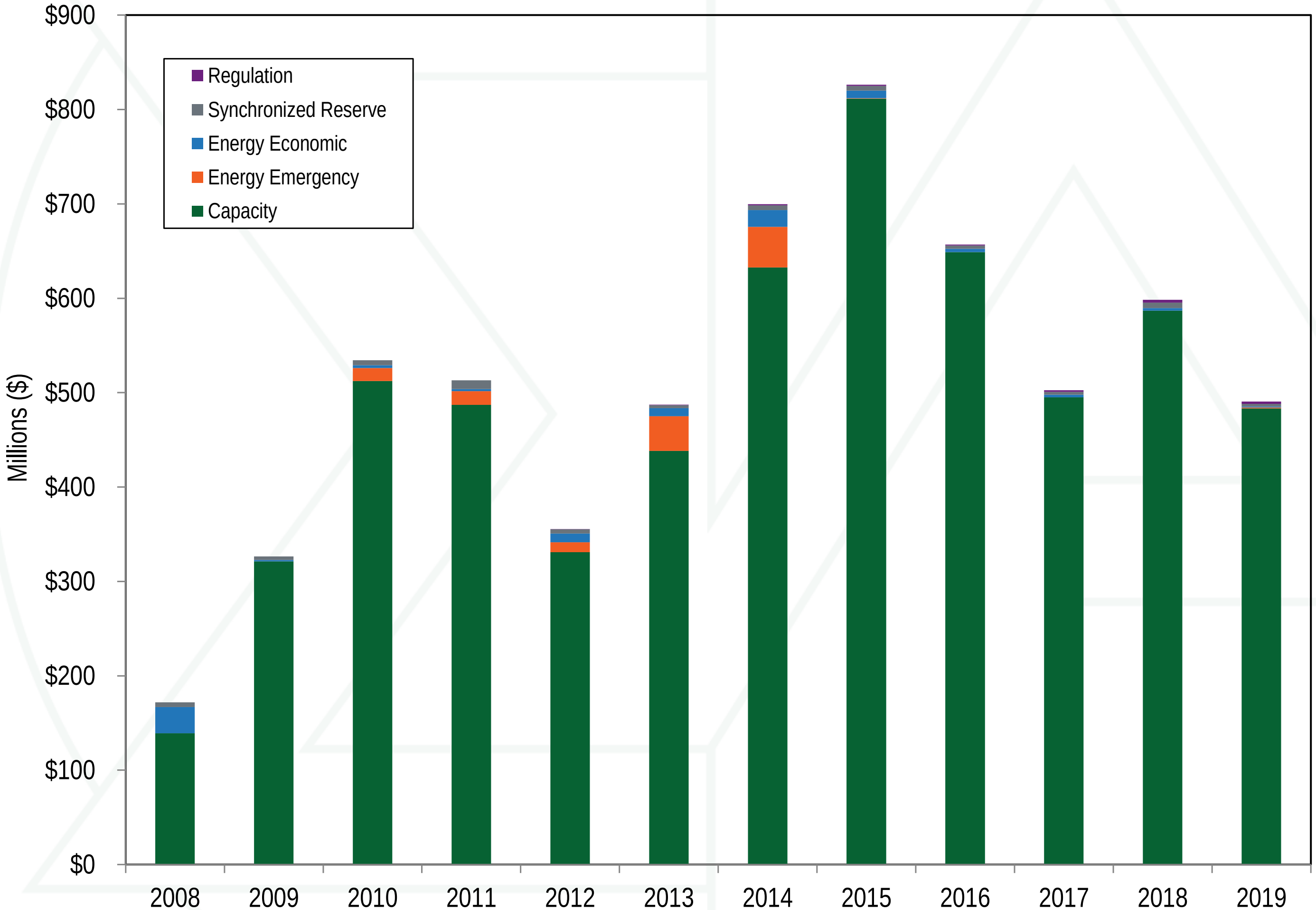
Recommendations: Demand Response

- **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**
- **EE should be removed from PJM Capacity Market.**

Economic program credits and MWh by month



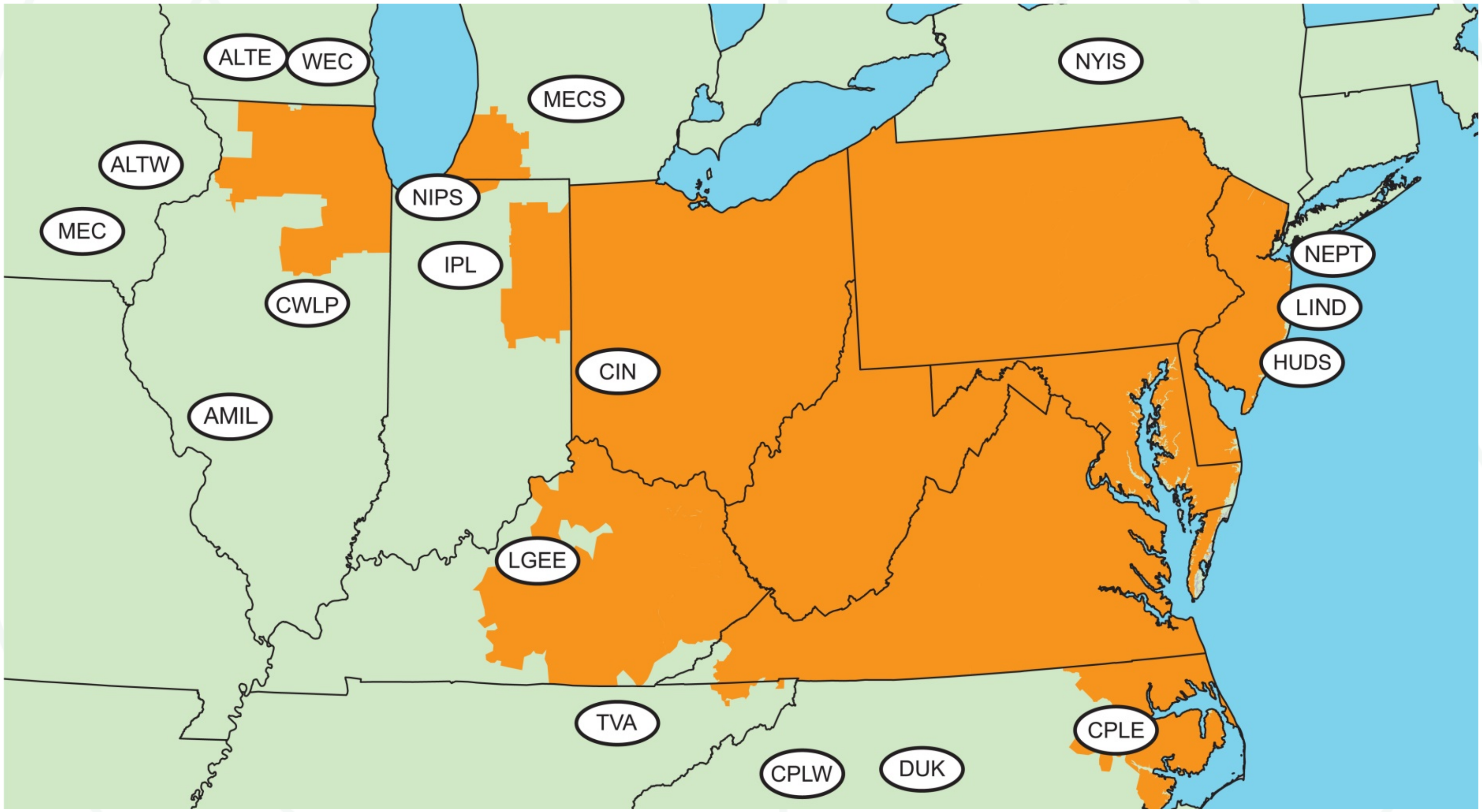
Demand response revenue by market



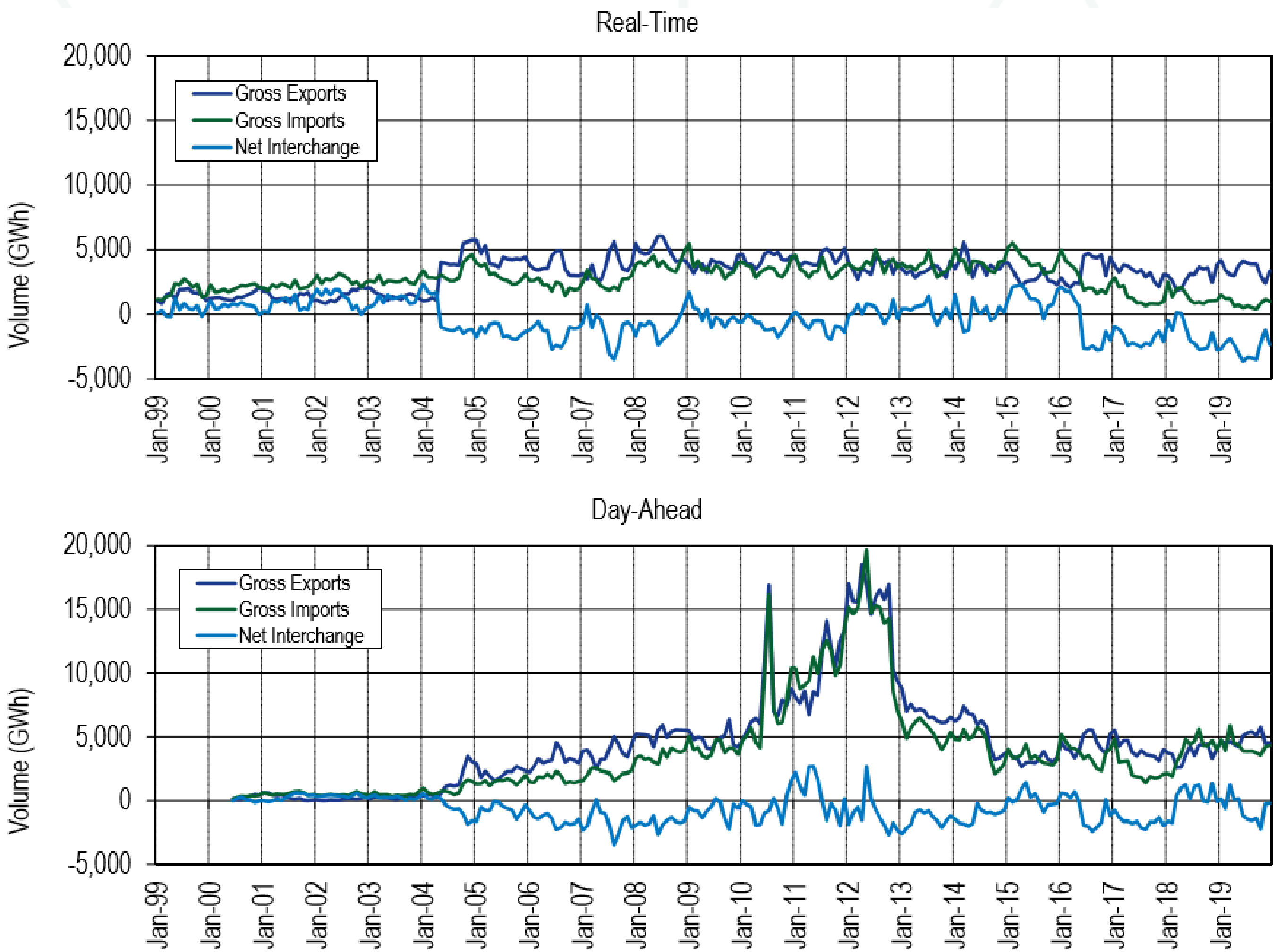
Recommendations: Transactions

- **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.**
- **Address firm flow entitlement rules that use stale data.**

PJM's footprint and its external scheduling interfaces



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 DASR 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.**
- **The $7.50 markup should be eliminated from synchronized reserve offers.**
- **Remove the ability to make dual offers (both RegA and RegD) from the regulation market.**
- **Nonperformance penalties for synchronized reserves should begin with the last successful response.**
- **The cost of reactive capability should be incorporated in the capacity market.**
- **Minimum tank suction levels should be fixed.**

Average price and cost for regulation

Year	Weighted Regulation Market Price	Weighted Regulation Market Cost	Regulation Price as Percent Cost
2009	$23.00	$7.68	299.2%
2010	$18.00	$14.85	121.2%
2011	$16.49	$13.23	124.6%
2012	$19.02	$12.90	147.5%
2013	$30.85	$35.79	86.2%
2014	$44.49	$53.82	82.7%
2015	$31.92	$38.36	83.2%
2016	$15.73	$18.13	86.7%
2017	$16.79	$23.03	72.9%
2018	$25.32	$31.93	79.3%
2019	$16.27	$20.31	80.1%

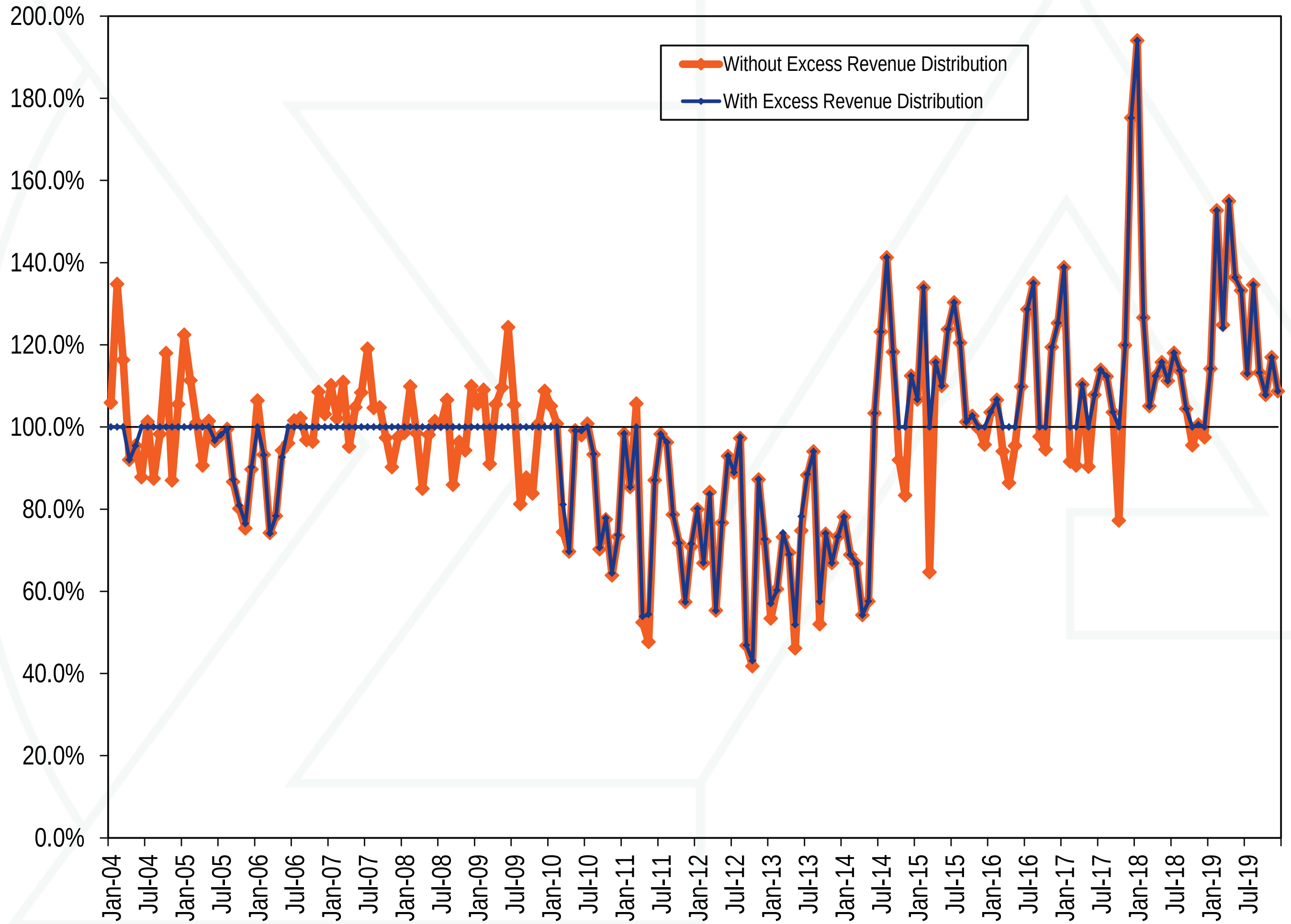
FTR auction markets results were competitive

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

Recommendations: FTR/ARR

- **ARR/FTR design should be modified to ensure that load has the right to all congestion revenues.**
- **Eliminate use of generation to load contract paths for allocating ARRs.**
- **Full system transmission capability assigned to ARRs.**
- **All FTR auction revenues and all congestion in excess of target allocations should be returned to load monthly.**
- **The long term FTR product should be eliminated.**

FTR payout ratio



ARR and FTR total congestion offset for ARR holders

Revenue							Pre 2017/2018 (Without Balancing)		2017/2018 (With Balancing)		Post 2017/2018 (With Surplus)	
Planning Period	ARR Credits	FTR Credits	Day Ahead Congestion	Balancing + M2M Congestion	Total Congestion	Surplus Revenue	Total ARR/FTR Offset	Percent Offset	Current Revenue Received	Percent Offset	New Revenue Received	New Offset
2011/2012	$512.2	$249.8	$1,025.4	($275.7)	$749.7	($192.5)	$762.0	101.6%	$598.6	79.8%	$563.0	79.8%
2012/2013	$349.5	$181.9	$904.7	($379.9)	$524.8	($292.3)	$531.4	101.3%	$275.9	52.6%	$257.5	52.6%
2013/2014	$337.7	$456.4	$2,231.3	($360.6)	$1,870.6	($678.7)	$794.0	42.4%	$574.1	30.7%	$623.1	30.7%
2014/2015	$482.4	$404.4	$1,625.9	($268.3)	$1,357.6	$139.6	$886.8	65.3%	$686.6	50.6%	$715.0	52.7%
2015/2016	$635.3	$223.4	$1,098.7	($147.6)	$951.1	$42.5	$858.8	90.3%	$744.8	78.3%	$745.2	78.4%
2016/2017	$640.0	$169.1	$885.7	($104.8)	$780.8	$72.6	$809.1	103.6%	$727.7	93.2%	$763.8	97.8%
2017/2018	$427.3	$294.2	$1,322.1	($129.5)	$1,192.6	$371.2	$721.5	60.5%	$595.7	50.0%	$886.5	74.3%
2018/2019	$529.1	$130.1	$832.7	($152.6)	$680.0	$112.3	$675.93	99.4%	$530.8	78.1%	$626.3	92.1%
2019/2020*	$315.8	$66.1	$438.9	($104.3)	$334.6	$73.2	$395.38	118.2%	$296.3	88.6%	$356.1	106.4%
Total	$4,229.4	$2,175.3	$10,365.3	($1,923.4)	$8,441.9	($352.2)	$6,434.9	76.2%	$5,030.7	59.6%	$5,536.7	65.6%

* Seven months of 2019/2020 planning period

FTR profits and revenues by organization type and FTR direction

	Purchased FTRs Profit			Self Scheduled FTRs Revenue Returned		
Organization Type	Prevailing Flow	Counter Flow	Total	Prevailing Flow	Counter Flow	Total
Financial	($98,538,105)	$121,282,178	$22,744,074	$0	$0	$0
Physical	($54,688,836)	$23,407,863	($31,280,973)	$70,092,097	$342,145	$70,434,243
Total	($153,226,941)	$144,690,041	($8,536,900)	$70,092,097	$342,145	$70,434,243

Market Monitoring Unit

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

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