

2021 State of the Market Report for PJM

Press Briefing
03.10.2022

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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

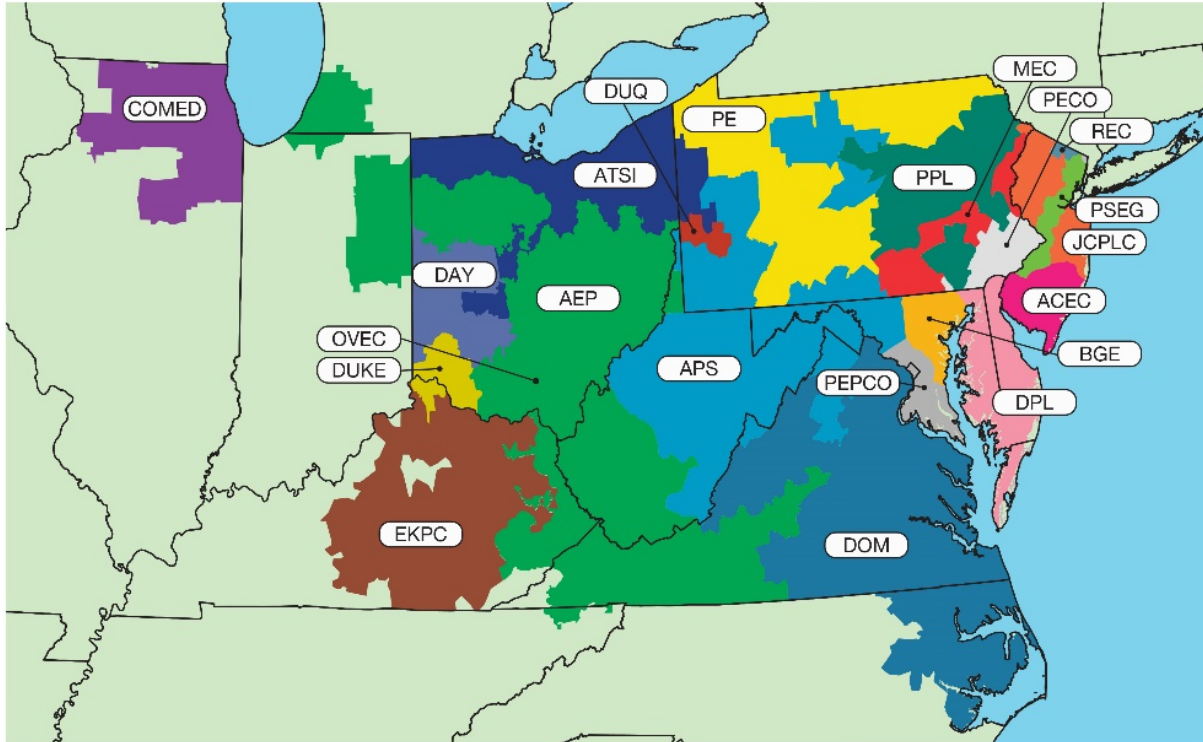


Market Monitoring Plan

- **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**



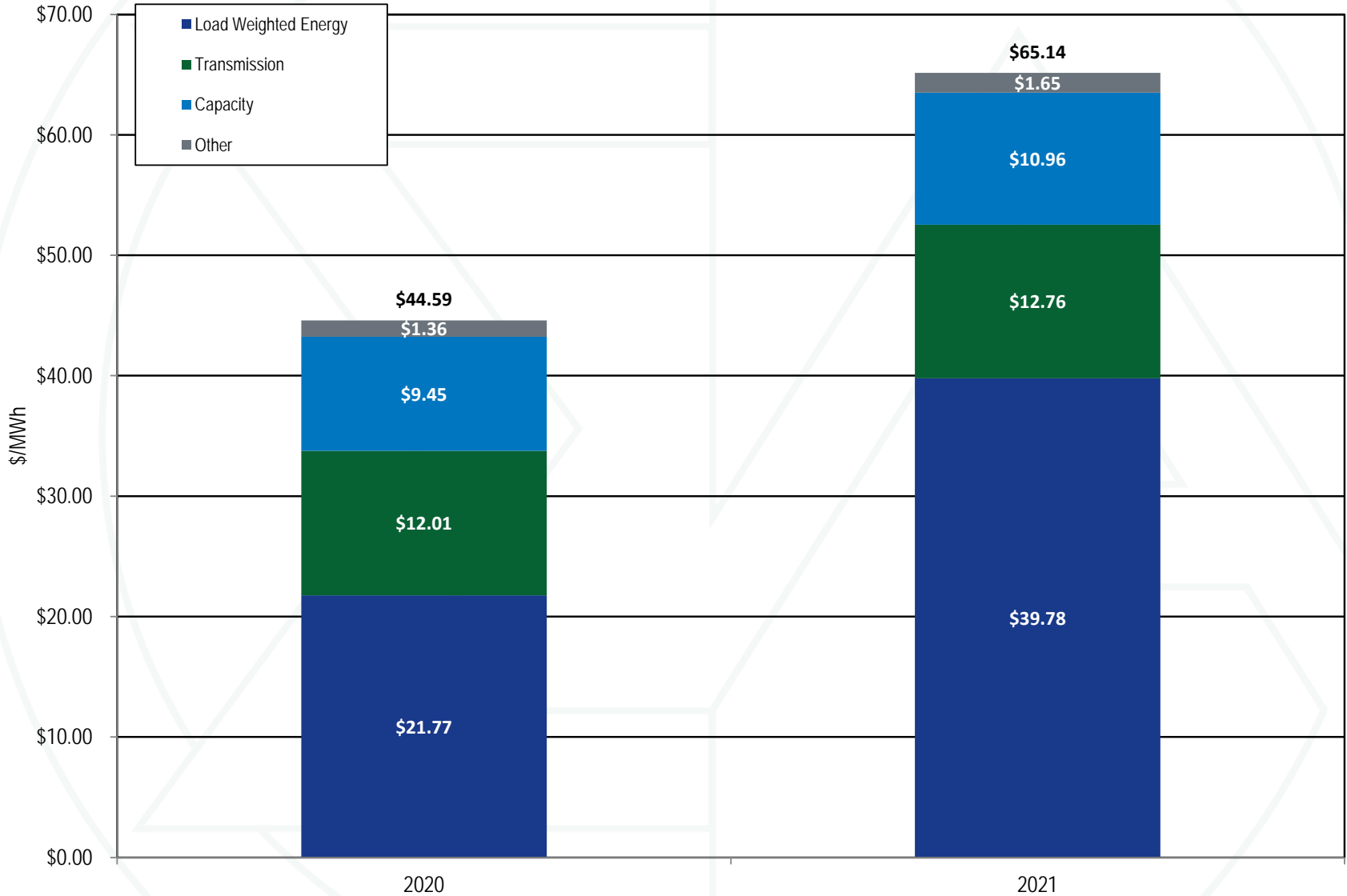
PJM



Legend

Allegheny Power Company (APS)	Duquesne Light (DUQ)
American Electric Power Co., Inc (AEP)	Eastern Kentucky Power Cooperative (EKPC)
American Transmission Systems, Inc. (ATSI)	Jersey Central Power and Light Company (JCPLC)
Atlantic Electric Company (ACEC)	Metropolitan Edison Company (MEC)
Baltimore Gas and Electric Company (BGE)	Ohio Valley Electric Corporation (OVEC)
ComEd (COMED)	PECO Energy (PECO)
Dayton Power and Light Company (DAY)	Pennsylvania Electric Company (PE)
Delmarva Power and Light (DPL)	Pepco (PEPCO)
Dominion (DOM)	PPL Electric Utilities (PPL)
Duke Energy Ohio/Kentucky (DUKE)	Public Service Electric and Gas Company (PSEG)
	Rockland Electric Company (REC)

Total price of wholesale power



PJM summary statistics

	2020	2021	Percent Change
Average Hourly Load Plus Exports (MW)	90,059	92,774	3.0%
Average Hourly Generation Plus Imports (MW)	91,674	94,501	3.1%
Peak Load (MW)	148,996	151,680	1.8%
Installed Capacity at December 31 (MW)	184,237	186,593	1.3%
Load Weighted Average Real Time LMP (\$/MWh)	\$21.77	\$39.78	82.8%
Total Congestion Costs (\$ Million)	\$528.7	\$995.3	88.3%
Total Uplift Credits (\$ Million)	\$90.9	\$178.3	96.1%
Total PJM Billing (\$ Billion)	\$36.28	\$54.13	49.2%

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

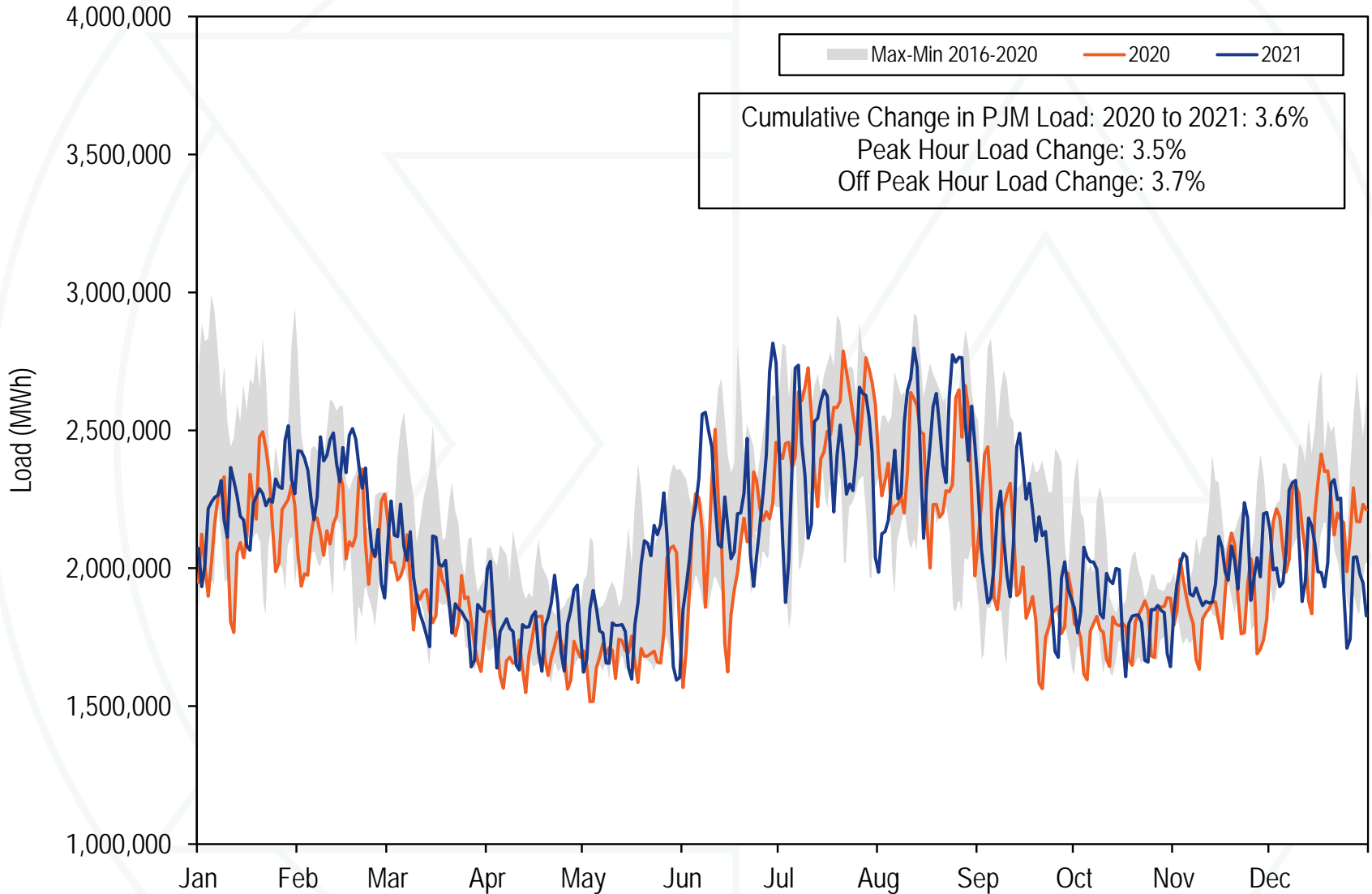


Recommendations: Energy Market

- **The day ahead energy market must offer requirement equal to ICAP for capacity resources should be enforced.**
- **Fuel cost policies should be verifiable and enforceable. All resources should be required to follow their fuel cost policies at all times.**
- **The loopholes in offer capping implementation should be closed.**
- **Virtual bidding should be eliminated at nodes that aggregate only small portions of the transmission system.**
- **Major maintenance should not be included in cost-based offers**



RT daily load: 2020 through 2021



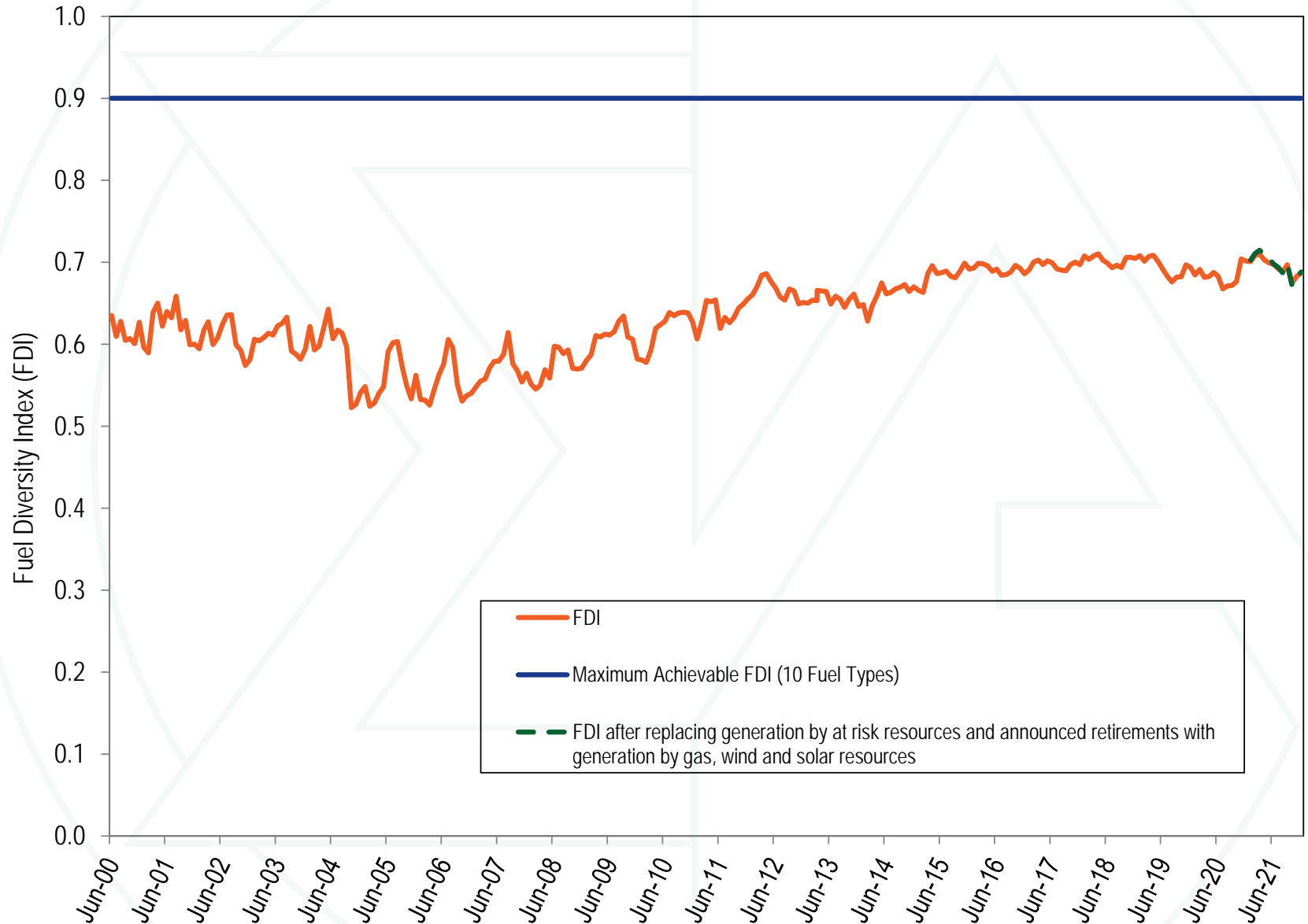
RT load and load plus exports

	PJM Real-Time Demand (MWh)				Year to Year Change			
	Load		Load Plus Exports		Load		Load Plus Exports	
	Standard	Standard	Standard	Standard	Standard	Standard	Standard	
	Load	Deviation	Demand	Deviation	Load	Deviation	Demand	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	92,920	16,085	(2.4%)	(0.7%)	(1.5%)	(0.4%)
2020	84,584	16,016	90,059	16,233	(4.0%)	0.9%	(3.1%)	0.9%
2021	87,606	15,725	92,774	16,485	3.6%	(1.8%)	3.0%	1.6%

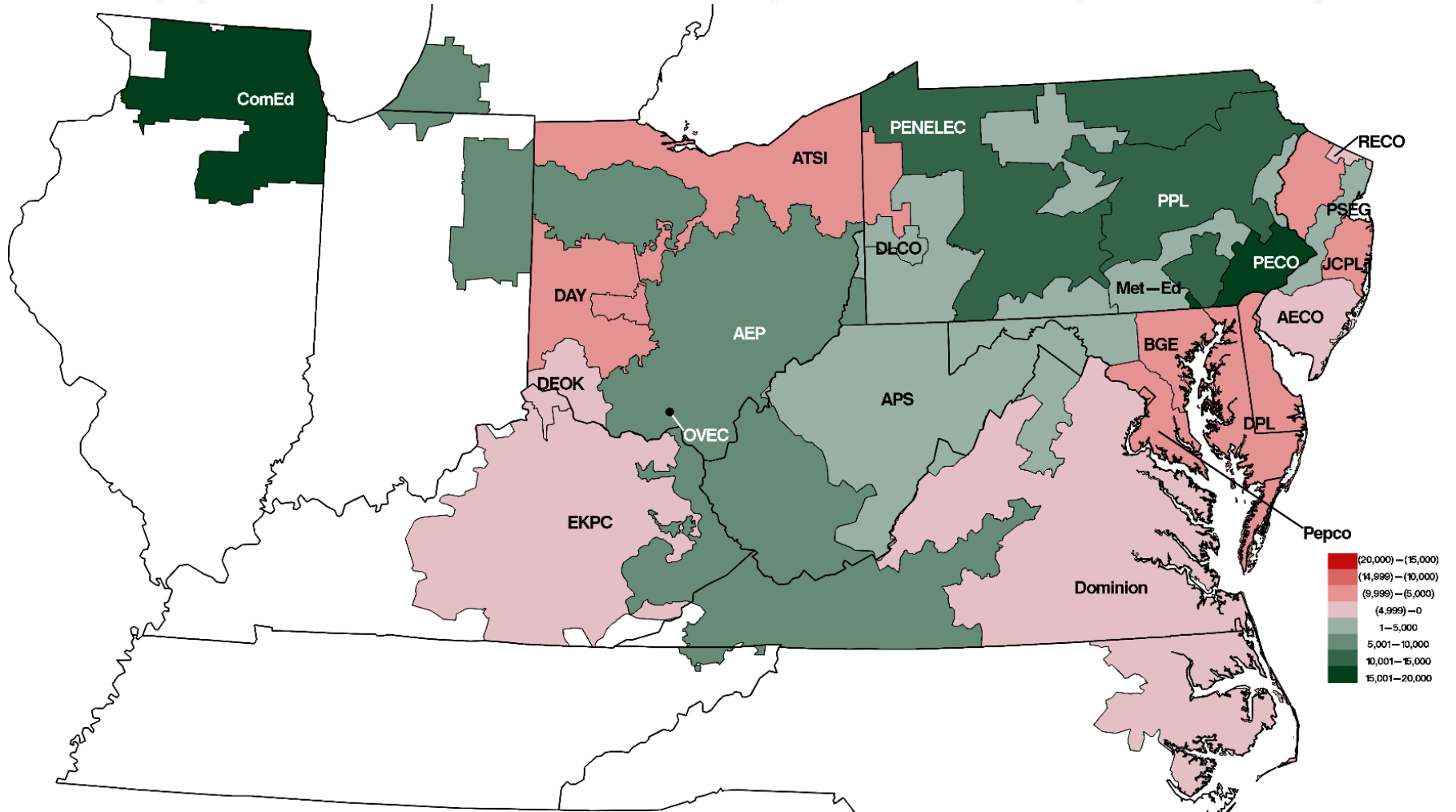
Generation by fuel source

	2020		2021		Change in Output
	GWh	Percent	GWh	Percent	
Coal	156,575.0	19.3%	184,412.3	22.2%	17.8%
Bituminous	143,556.3	17.7%	163,753.6	19.7%	14.1%
Sub Bituminous	7,726.0	1.0%	14,421.7	1.7%	86.7%
Other Coal	5,292.7	0.7%	6,237.0	0.7%	17.8%
Nuclear	276,607.6	34.2%	272,670.4	32.8%	(1.4%)
Gas	322,505.4	39.8%	314,885.1	37.9%	(2.4%)
Natural Gas CC	294,712.8	36.4%	289,136.6	34.8%	(1.9%)
Natural Gas CT	18,849.2	2.3%	19,894.4	2.4%	5.5%
Natural Gas Other Units	6,995.6	0.9%	4,132.1	0.5%	(40.9%)
Other Gas	1,947.8	0.2%	1,722.0	0.2%	(11.6%)
Hydroelectric	16,423.3	2.0%	16,624.8	2.0%	1.2%
Pumped Storage	4,950.4	0.6%	5,037.3	0.6%	1.8%
Run of River	10,036.7	1.2%	10,278.6	1.2%	2.4%
Other Hydro	1,436.2	0.2%	1,308.9	0.2%	(8.9%)
Wind	26,433.2	3.3%	27,651.4	3.3%	4.6%
Waste	4,423.1	0.5%	4,475.9	0.5%	1.2%
Oil	2,054.8	0.3%	2,290.7	0.3%	11.5%
Heavy Oil	86.0	0.0%	65.6	0.0%	(23.7%)
Light Oil	282.2	0.0%	524.4	0.1%	85.8%
Diesel	30.1	0.0%	27.7	0.0%	(8.0%)
Other Oil	1,656.4	0.2%	1,673.1	0.2%	1.0%
Solar	3,869.5	0.5%	7,412.2	0.9%	91.6%
Battery	36.1	0.0%	36.5	0.0%	1.0%
Biofuel	914.3	0.1%	1,191.7	0.1%	30.3%
Total	809,842.4	100.0%	831,650.8	100.0%	2.7%

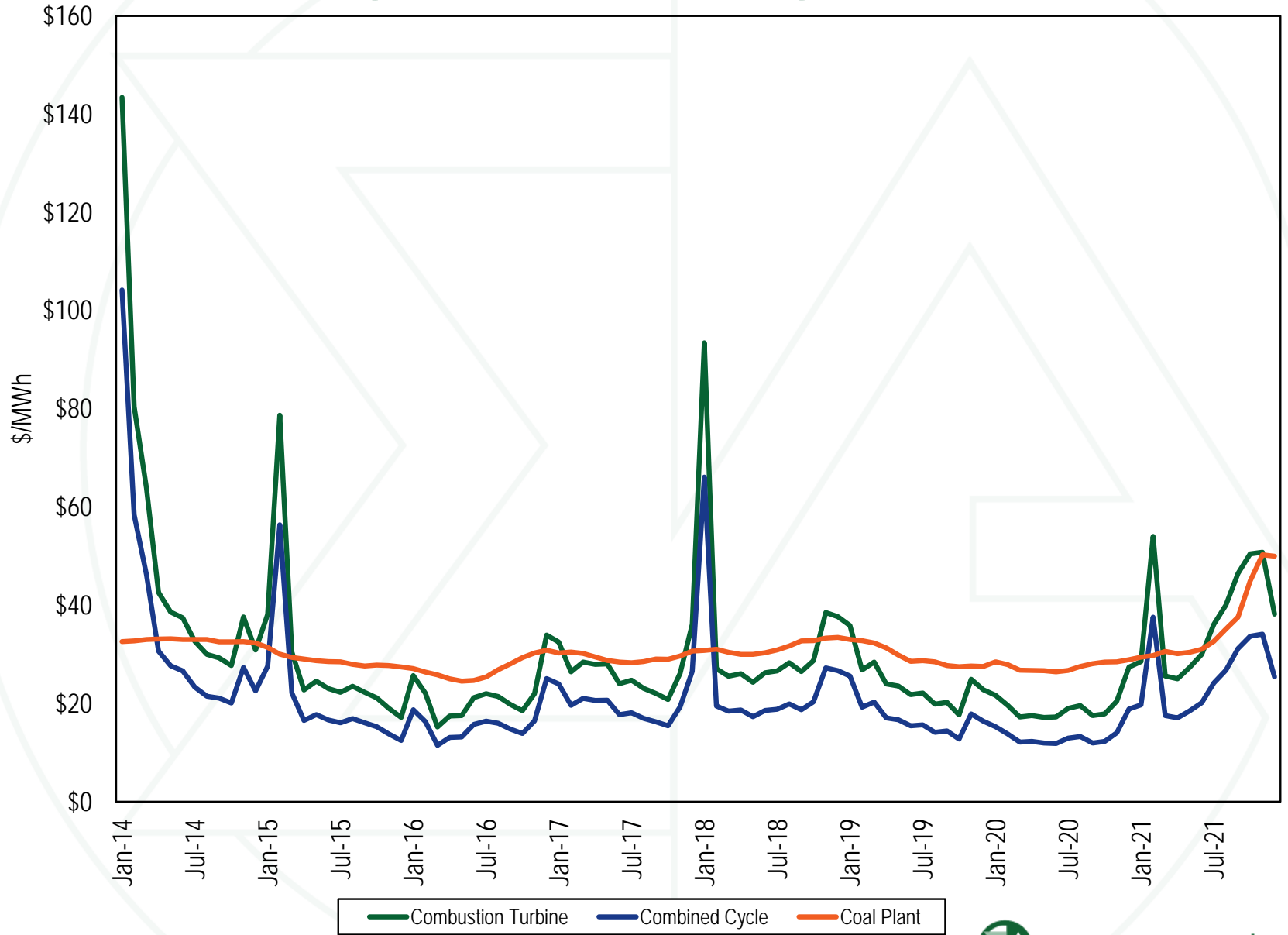
Fuel diversity index: energy



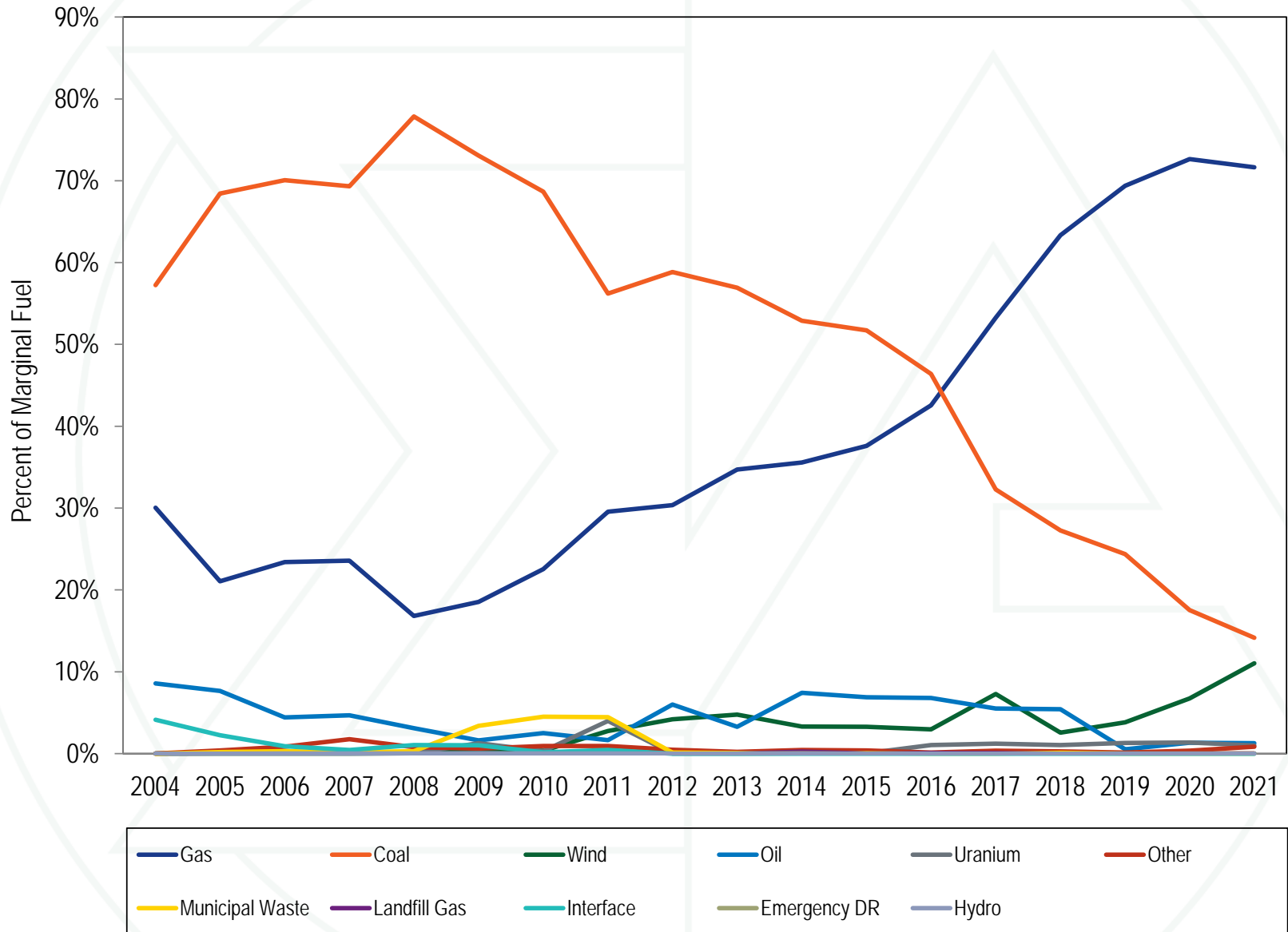
RT generation less RT load



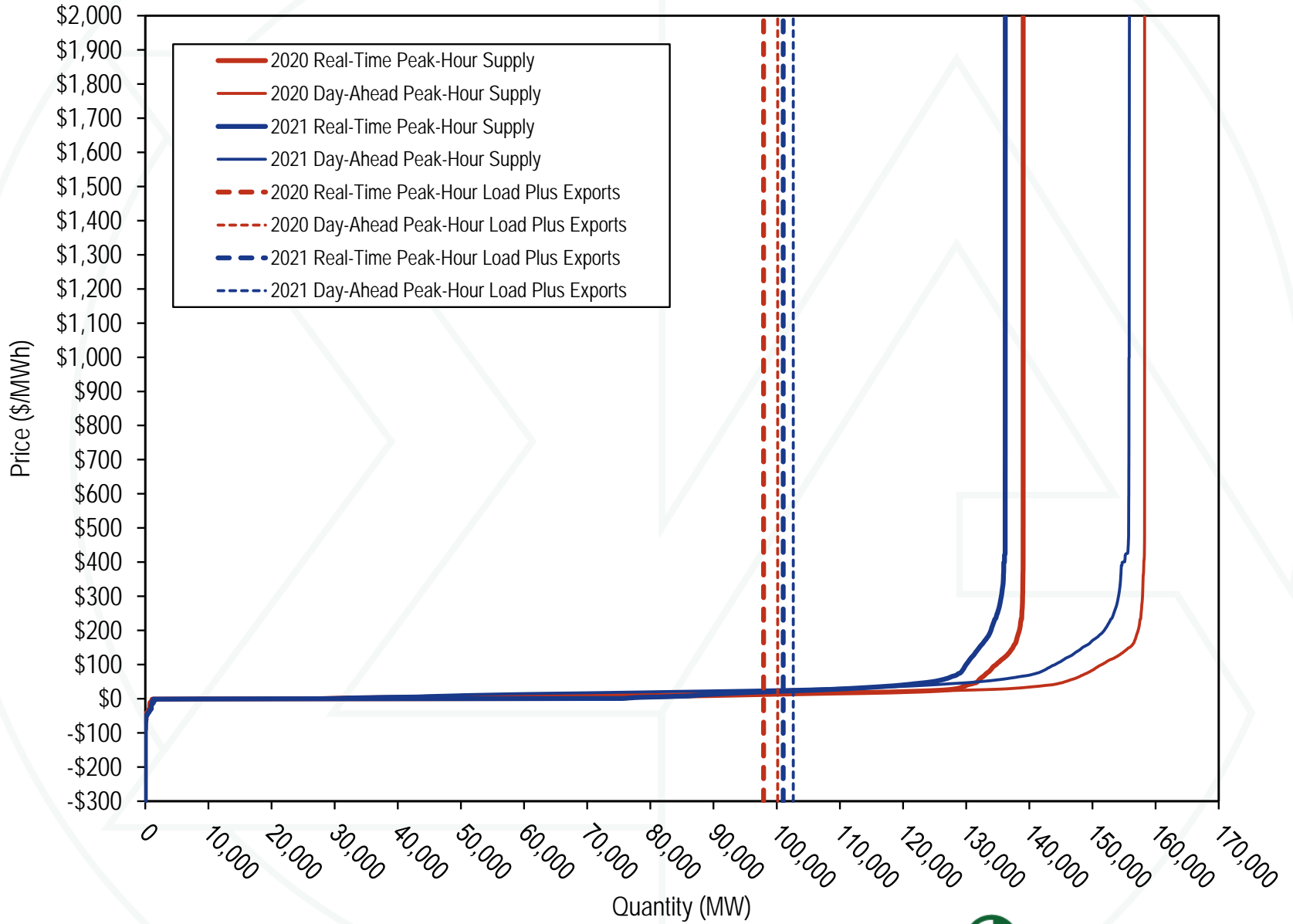
Average short run marginal costs



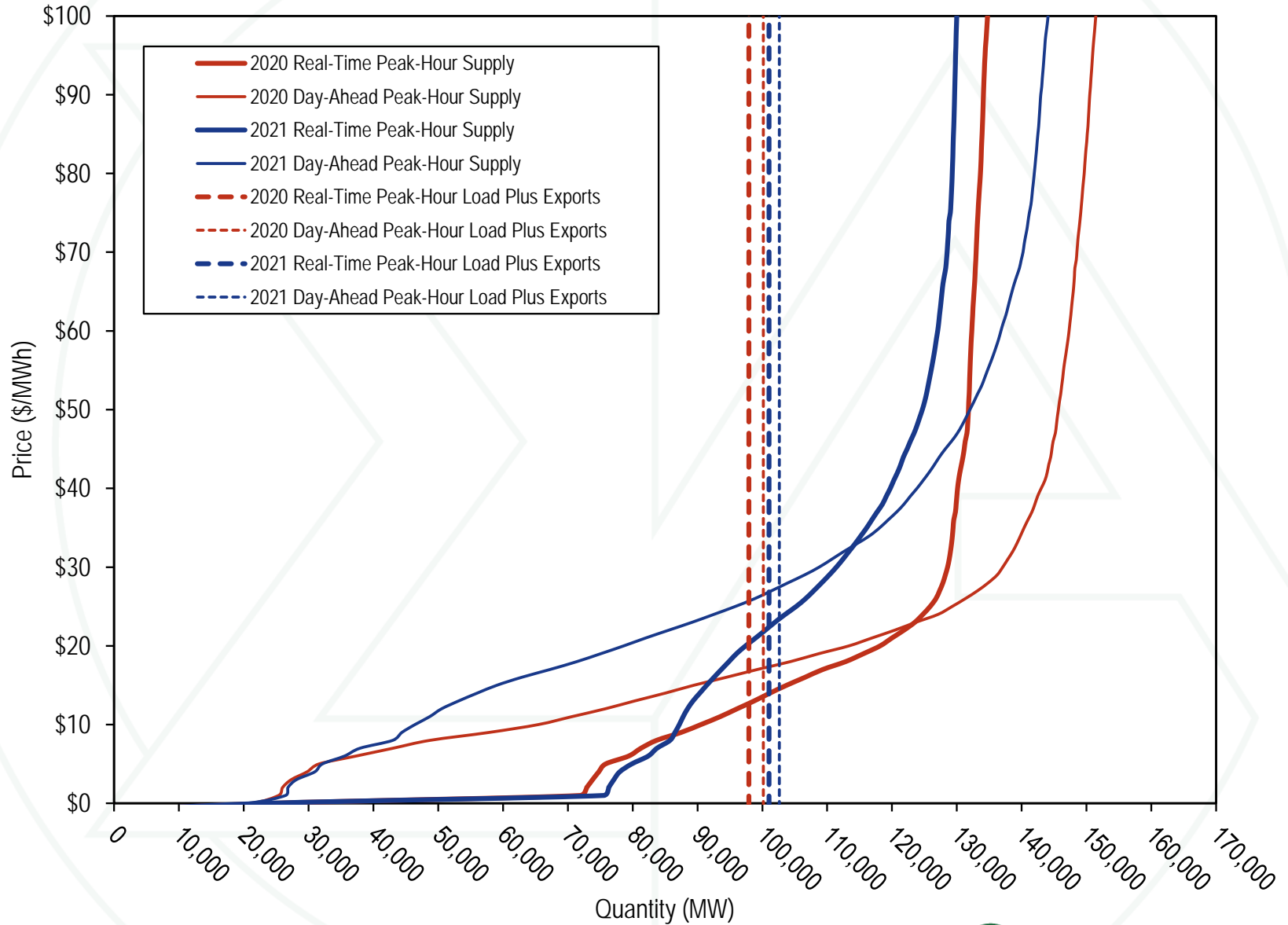
Type of fuel used by real-time marginal units



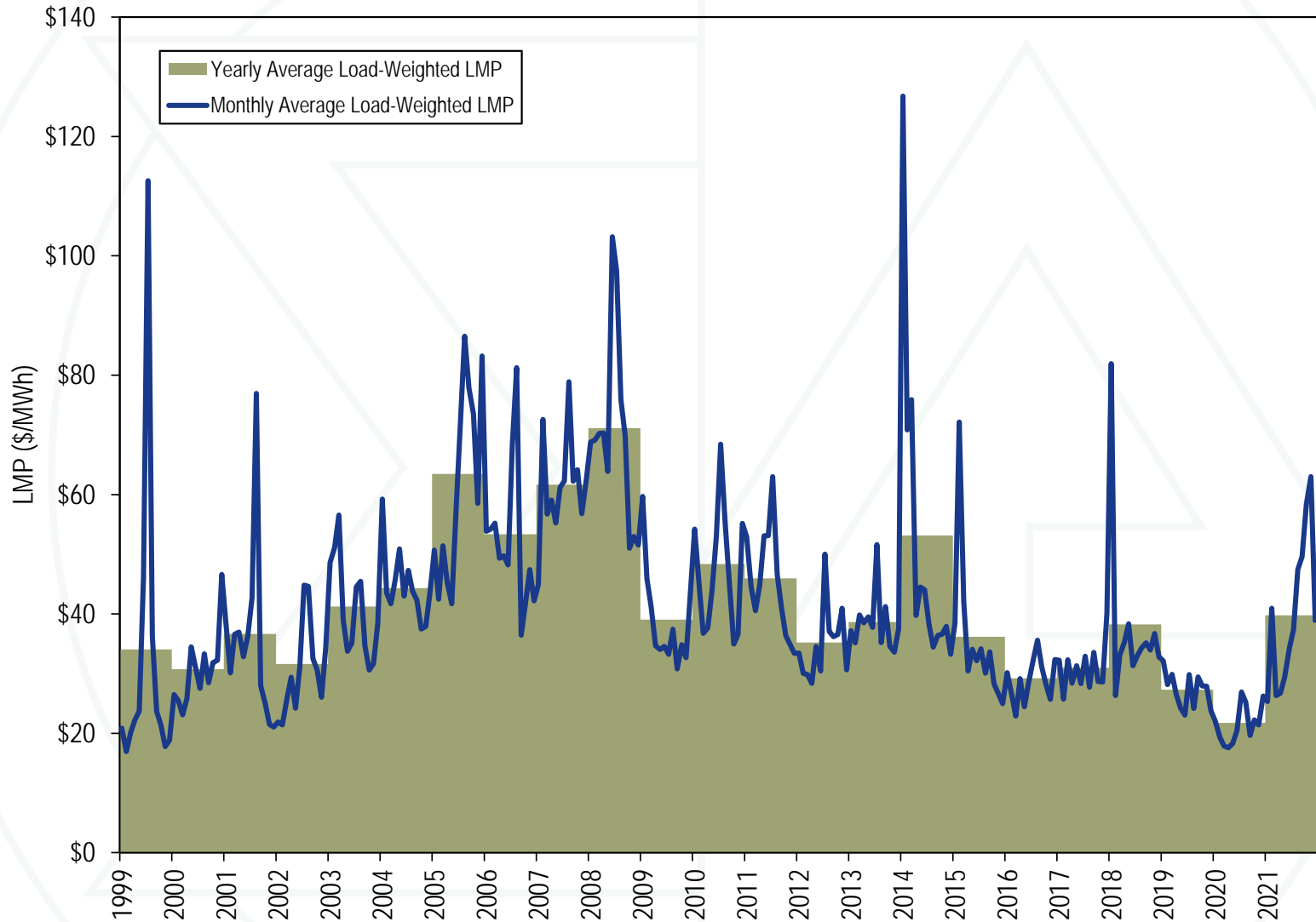
Real-time and day-ahead hourly supply curves



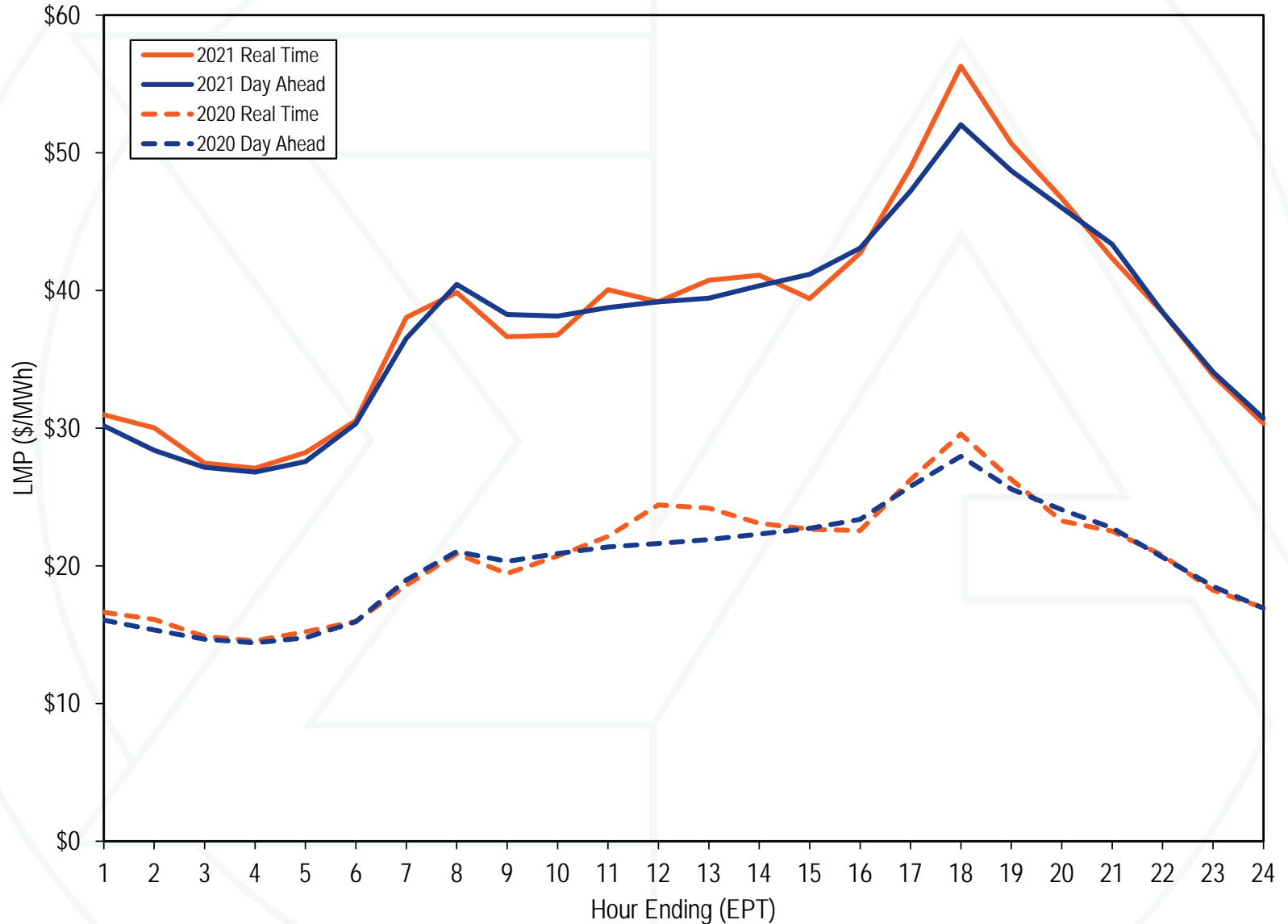
Typical dispatch range of supply curves



RT monthly and yearly load-weighted average LMP



DA and RT average LMP

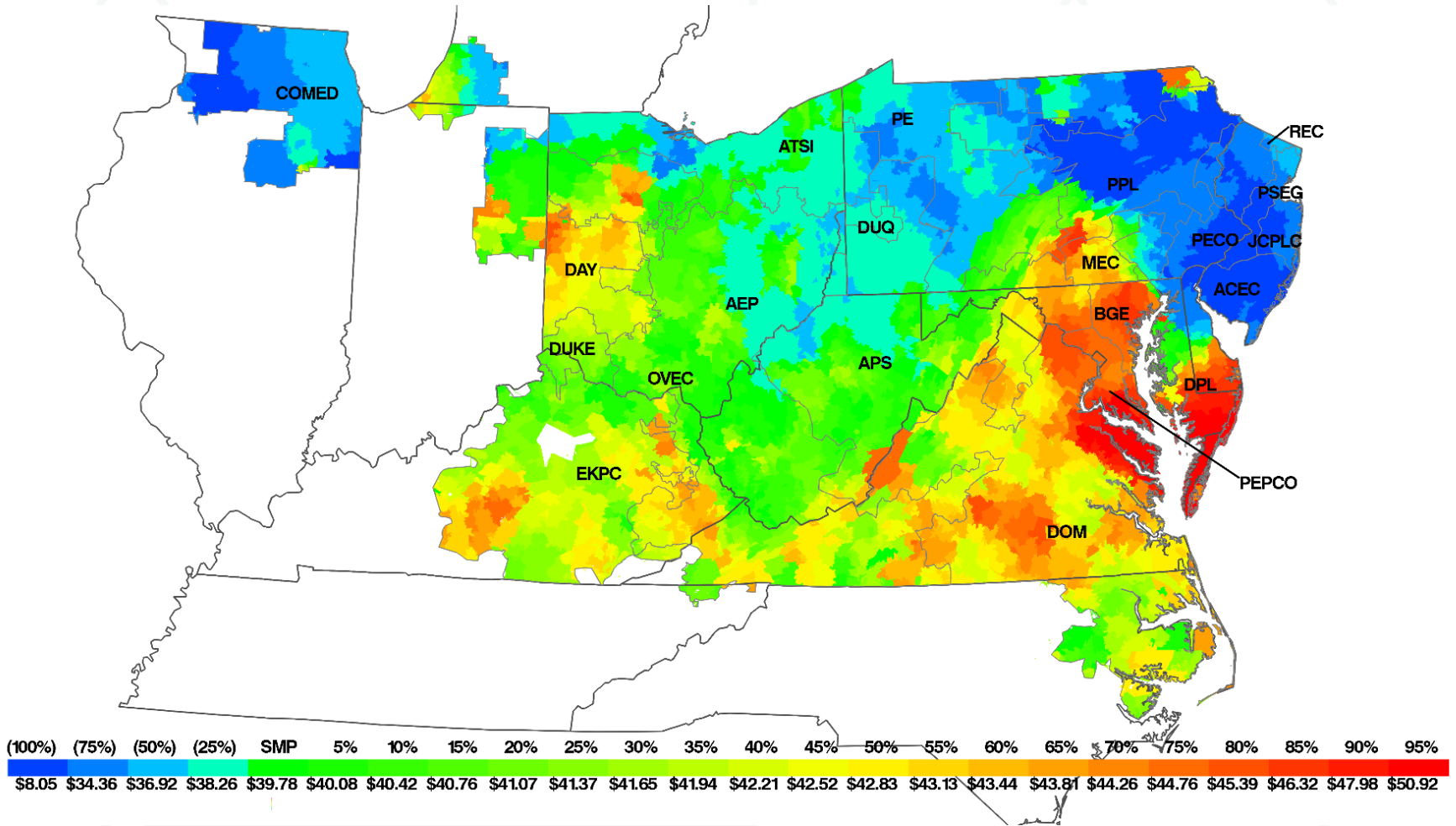


RT load-weighted average LMP

	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%)
2020	\$21.77	\$19.07	\$12.50	(20.3%)	(19.3%)	(45.9%)
2021	\$39.78	\$32.11	\$27.72	82.8%	68.4%	121.8%



RT load-weighted average LMP



RT fuel-cost adjusted load-weighted average LMP

	2021 Fuel-Cost Adjusted, Load-Weighted LMP	2021 Load-Weighted LMP	Change	Percent Change
Average	\$26.68	\$39.78	\$13.11	49.1%
	2020 Load-Weighted LMP	2021 Fuel-Cost Adjusted, Load-Weighted LMP	Change	Percent Change
Average	\$21.77	\$26.68	\$4.91	22.6%
	2020 Load-Weighted LMP	2021 Load-Weighted LMP	Change	Change
Average	\$21.77	\$39.78	\$18.02	82.8%



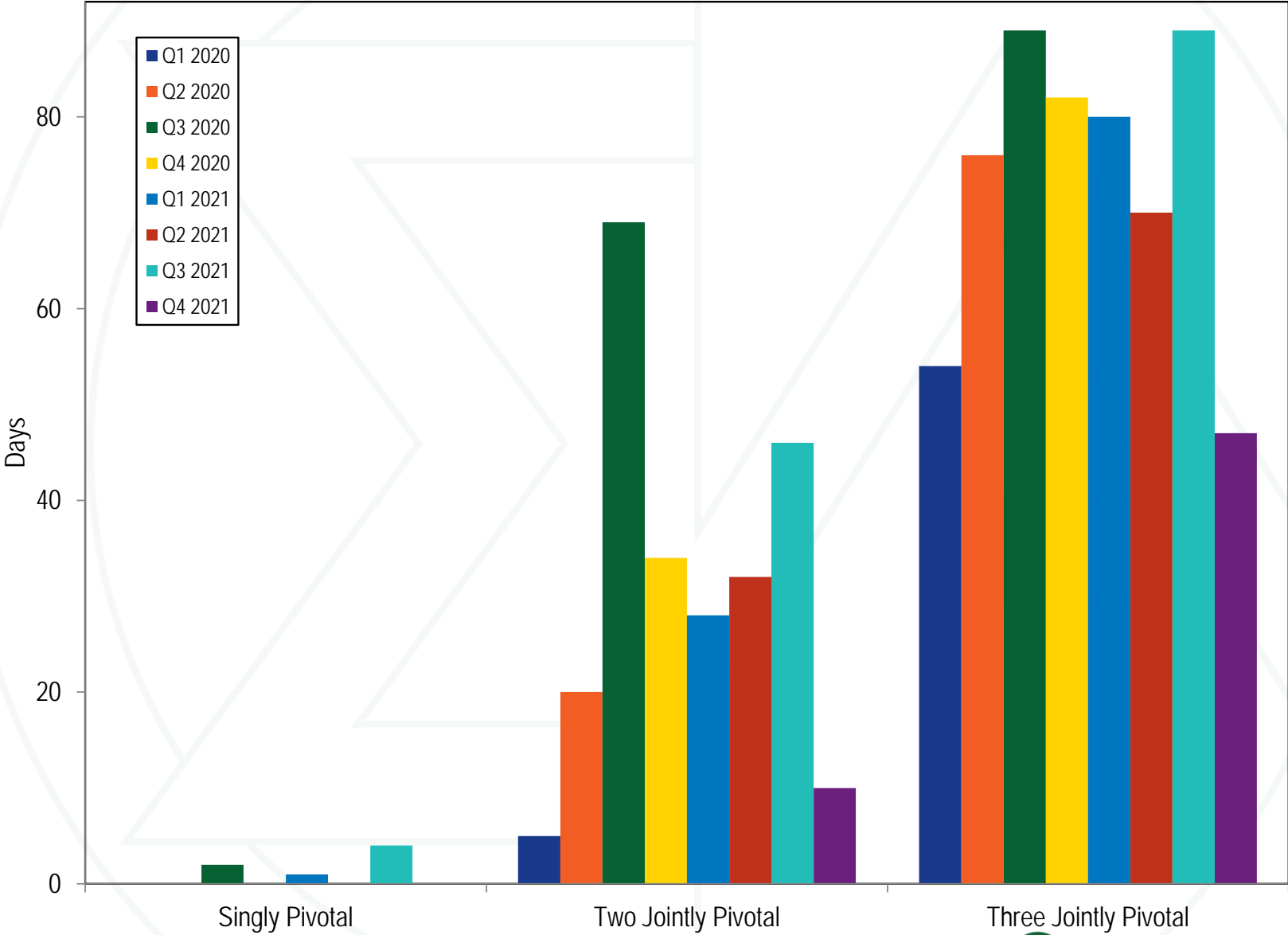
Components of RT load-weighted average LMP

Element	2020		2021		Change in Percent
	Contribution to LMP	Percent	Contribution to LMP	Percent	
Gas	\$9.03	41.5%	\$21.43	53.9%	12.4%
Coal	\$5.17	23.7%	\$4.11	10.3%	(13.4%)
Positive Markup	\$0.88	4.0%	\$3.68	9.2%	5.2%
Constraint Violation Adder	\$1.67	7.7%	\$3.31	8.3%	0.7%
Ten Percent Adder	\$1.68	7.7%	\$2.54	6.4%	(1.3%)
NA	\$0.91	4.2%	\$1.51	3.8%	(0.4%)
Variable Maintenance	\$1.34	6.2%	\$1.36	3.4%	(2.8%)
CO ₂ Cost	\$0.37	1.7%	\$1.08	2.7%	1.0%
Variable Operations	\$0.84	3.9%	\$0.84	2.1%	(1.7%)
Market-to-Market Adder	\$0.00	0.0%	\$0.41	1.0%	1.0%
Ancillary Service Redispatch Cost	\$0.13	0.6%	\$0.35	0.9%	0.3%
Oil	\$0.07	0.3%	\$0.25	0.6%	0.3%
Scarcity Adder	\$0.08	0.4%	\$0.22	0.6%	0.2%
NO _x Cost	\$0.01	0.0%	\$0.19	0.5%	0.5%
LPA Rounding Difference	\$0.18	0.8%	\$0.18	0.5%	(0.4%)
Opportunity Cost Adder	\$0.07	0.3%	\$0.16	0.4%	0.1%
Increase Generation Adder	\$0.06	0.3%	\$0.13	0.3%	0.0%
LPA-SCED Differential	\$0.01	0.1%	\$0.07	0.2%	0.1%
Other	\$0.00	0.0%	\$0.01	0.0%	0.0%
Landfill Gas	(\$0.00)	(0.0%)	\$0.00	0.0%	0.0%
SO ₂ Cost	\$0.00	0.0%	\$0.00	0.0%	(0.0%)
Uranium	\$0.00	0.0%	\$0.00	0.0%	(0.0%)
Renewable Energy Credits	(\$0.01)	(0.0%)	(\$0.03)	(0.1%)	(0.1%)
Decrease Generation Adder	(\$0.02)	(0.1%)	(\$0.03)	(0.1%)	0.0%
Negative Markup	(\$0.72)	(3.3%)	(\$1.99)	(5.0%)	(1.7%)
Total	\$21.77	100.0%	\$39.78	100.0%	0.0%

Components of LMP (no ten percent adder)

Element	2020		2021		Change in Percent
	Contribution to LMP	Percent	Contribution to LMP	Percent	
Gas	\$9.03	41.5%	\$21.43	53.9%	12.4%
Positive Markup	\$1.29	5.9%	\$5.12	12.9%	6.9%
Coal	\$5.17	23.7%	\$4.11	10.3%	(13.4%)
Constraint Violation Adder	\$1.67	7.7%	\$3.31	8.3%	0.7%
NA	\$1.83	8.4%	\$1.51	3.8%	(4.6%)
Variable Maintenance	\$1.34	6.2%	\$1.36	3.4%	(2.8%)
CO ₂ Cost	\$0.37	1.7%	\$1.08	2.7%	1.0%
Variable Operations	\$0.84	3.9%	\$0.84	2.1%	(1.7%)
Market-to-Market Adder	\$0.00	0.0%	\$0.41	1.0%	1.0%
Ancillary Service Redispatch Cost	\$0.13	0.6%	\$0.35	0.9%	0.3%
Oil	\$0.07	0.3%	\$0.25	0.6%	0.3%
Scarcity Adder	\$0.08	0.4%	\$0.22	0.6%	0.2%
NO _x Cost	\$0.01	0.0%	\$0.19	0.5%	0.5%
LPA Rounding Difference	\$0.18	0.8%	\$0.18	0.5%	(0.4%)
Opportunity Cost Adder	\$0.07	0.3%	\$0.16	0.4%	0.1%
Increase Generation Adder	\$0.06	0.3%	\$0.13	0.3%	0.0%
LPA-SCED Differential	\$0.01	0.1%	\$0.07	0.2%	0.1%
Other	\$0.00	0.0%	\$0.01	0.0%	0.0%
Landfill Gas	(\$0.00)	(0.0%)	\$0.00	0.0%	0.0%
Ten Percent Adder	\$0.00	0.0%	\$0.00	0.0%	0.0%
SO ₂ Cost	\$0.00	0.0%	\$0.00	0.0%	(0.0%)
Uranium	\$0.00	0.0%	\$0.00	0.0%	(0.0%)
Renewable Energy Credits	(\$0.01)	(0.0%)	(\$0.03)	(0.1%)	(0.1%)
Decrease Generation Adder	(\$0.02)	(0.1%)	(\$0.03)	(0.1%)	0.0%
Negative Markup	(\$0.37)	(1.7%)	(\$0.89)	(2.2%)	(0.5%)
Total	\$21.77	100.0%	\$39.78	100.0%	0.0%

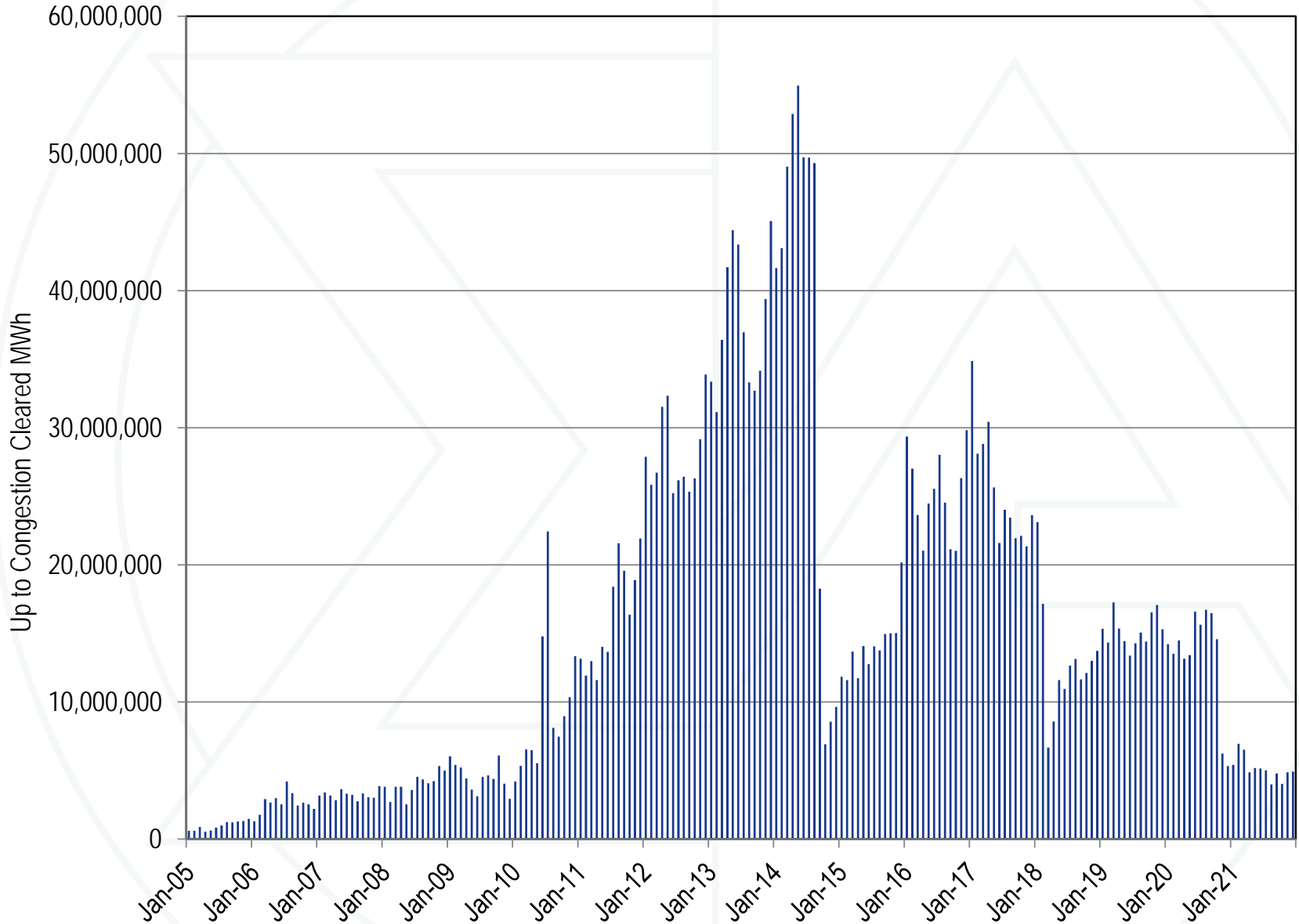
Pivotal suppliers: day-ahead energy market



Marginal units with markup and local market power

Markup Category	Day-ahead Market			Real-time Market		
	Not Failing TPS Test	Failing TPS Test	Percent in Category	Not Failing TPS Test	Failing TPS Test	Percent in Category
Negative Markup	28.7%	5.5%	34.2%	35.2%	9.2%	44.3%
Zero Markup	26.5%	6.5%	33.0%	15.6%	8.2%	23.8%
\$0 to \$5	18.9%	1.7%	20.6%	20.2%	2.9%	23.1%
\$5 to \$10	4.2%	0.5%	4.7%	3.4%	0.6%	3.9%
\$10 to \$15	2.0%	0.5%	2.4%	1.2%	0.2%	1.4%
\$15 to \$20	1.9%	0.2%	2.1%	0.8%	0.2%	1.0%
\$20 to \$25	0.5%	0.2%	0.7%	0.4%	0.2%	0.6%
\$25 to \$50	1.2%	0.4%	1.6%	0.9%	0.4%	1.3%
\$50 to \$75	0.4%	0.1%	0.5%	0.1%	0.1%	0.2%
\$75 to \$100	0.1%	0.0%	0.1%	0.1%	0.1%	0.2%
Above \$100	0.0%	0.0%	0.0%	0.1%	0.1%	0.2%
Total Positive Markup	29.1%	3.6%	32.7%	27.2%	4.7%	31.9%
Total	84.4%	15.6%	100.0%	78.0%	22.0%	100.0%

UTC cleared bids



Total congestion costs

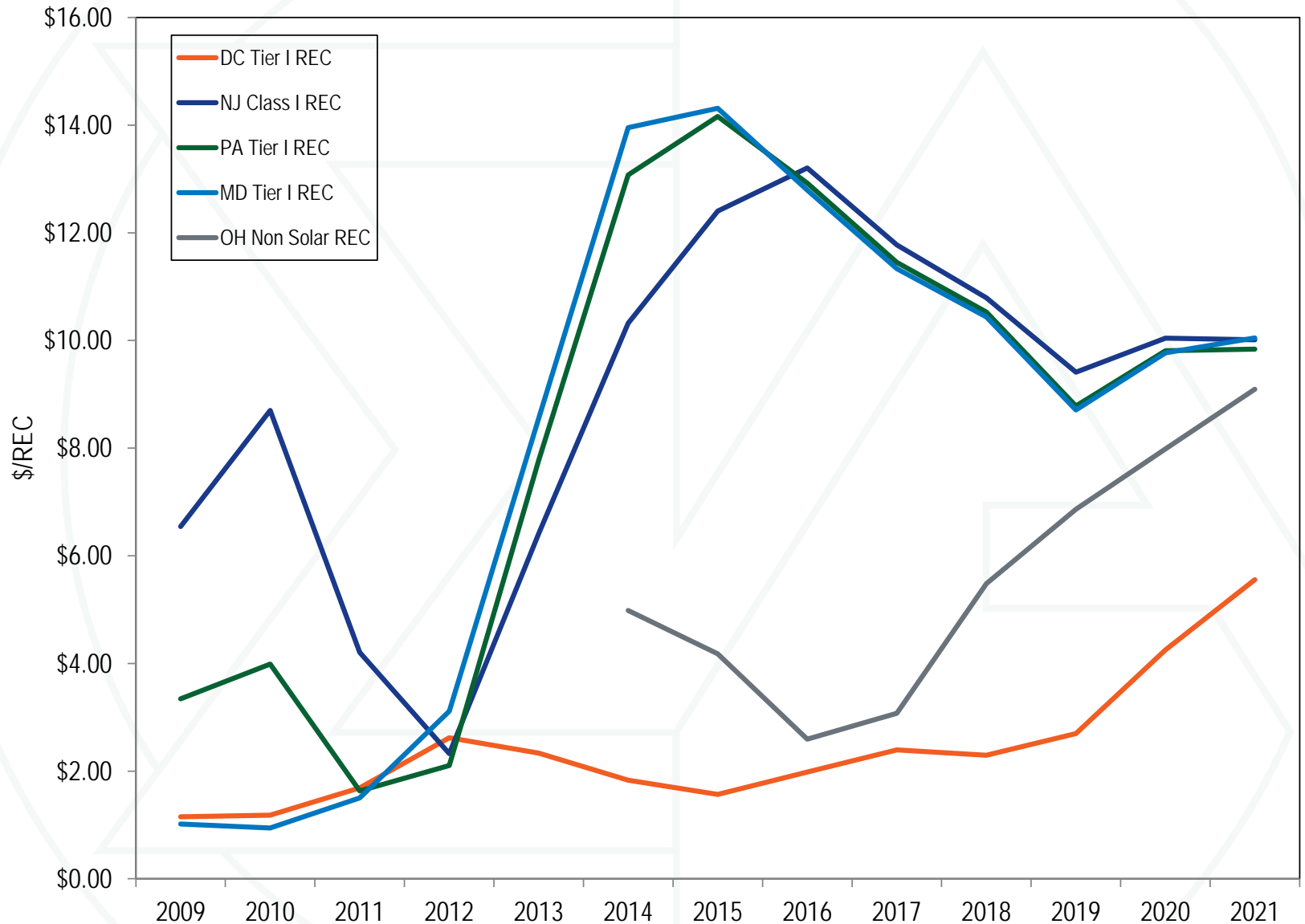
	Congestion Cost	Percent Change	Total PJM Billing	Percent of PJM Billing
2008	\$2,052	NA	\$34,300	6.0%
2009	\$719	(65.0%)	\$26,550	2.7%
2010	\$1,423	98.0%	\$34,770	4.1%
2011	\$999	(29.8%)	\$35,890	2.8%
2012	\$529	(47.0%)	\$29,180	1.8%
2013	\$677	28.0%	\$33,860	2.0%
2014	\$1,932	185.5%	\$50,030	3.9%
2015	\$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%)	\$41,680	1.4%
2020	\$529	(9.4%)	\$36,280	1.5%
2021	\$995	88.2%	\$54,130	1.8%



Renewable and alternative energy standards of PJM jurisdictions

Jurisdiction with RPS	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Delaware	21.00%	22.00%	23.00%	24.00%	25.00%	25.50%	26.00%	26.50%	27.00%	28.00%
Illinois	19.00%	20.50%	22.00%	23.50%	25.00%	28.00%	31.00%	34.00%	37.00%	40.00%
Maryland	33.30%	32.60%	34.40%	36.20%	38.00%	40.50%	44.00%	45.50%	50.00%	52.50%
Michigan	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%
New Jersey	23.50%	24.50%	29.50%	37.50%	40.50%	43.50%	46.50%	49.50%	52.50%	52.50%
North Carolina	12.50%	12.50%	12.50%	12.50%	12.50%	12.50%	12.50%	12.50%	12.50%	12.50%
Ohio	6.00%	6.50%	7.00%	7.50%	8.00%	8.50%	0.00%	0.00%	0.00%	0.00%
Pennsylvania	18.00%	18.00%	18.00%	18.00%	18.00%	18.00%	18.00%	18.00%	18.00%	18.00%
Virginia (Phase I utilities)	6.00%	7.00%	8.00%	10.00%	14.00%	17.00%	20.00%	24.00%	27.00%	30.00%
Virginia (Phase II utilities)	14.00%	17.00%	20.00%	23.00%	26.00%	29.00%	32.00%	35.00%	38.00%	41.00%
Washington, D.C.	26.25%	32.50%	38.75%	45.00%	52.00%	59.00%	66.00%	73.00%	80.00%	87.00%
Jurisdiction with Voluntary Standard										
Indiana	7.00%	7.00%	7.00%	7.00%	10.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Jurisdiction with No Standard										
Kentucky	No Renewable Portfolio Standard									
Tennessee	No Renewable Portfolio Standard									
West Virginia	No Renewable Portfolio Standard									

Average Tier I REC price by jurisdiction



Renewable energy credits

- **There should be a single PJM operated forward market for RECs, for a single product based on a common set of state definitions of renewable technologies, with a single clearing price, trued up to real time delivery.**
- **Only if states agree.**



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

Capacity market issues

- **Market seller offer cap**
- **VRR curve shape and location**
- **Definition of capacity**
- **Intermittent capacity definition: ELCC**
- **DR/EE**
- **MOPR**
- **Reserve margin**



2022/2023 RPM Base Residual Auction

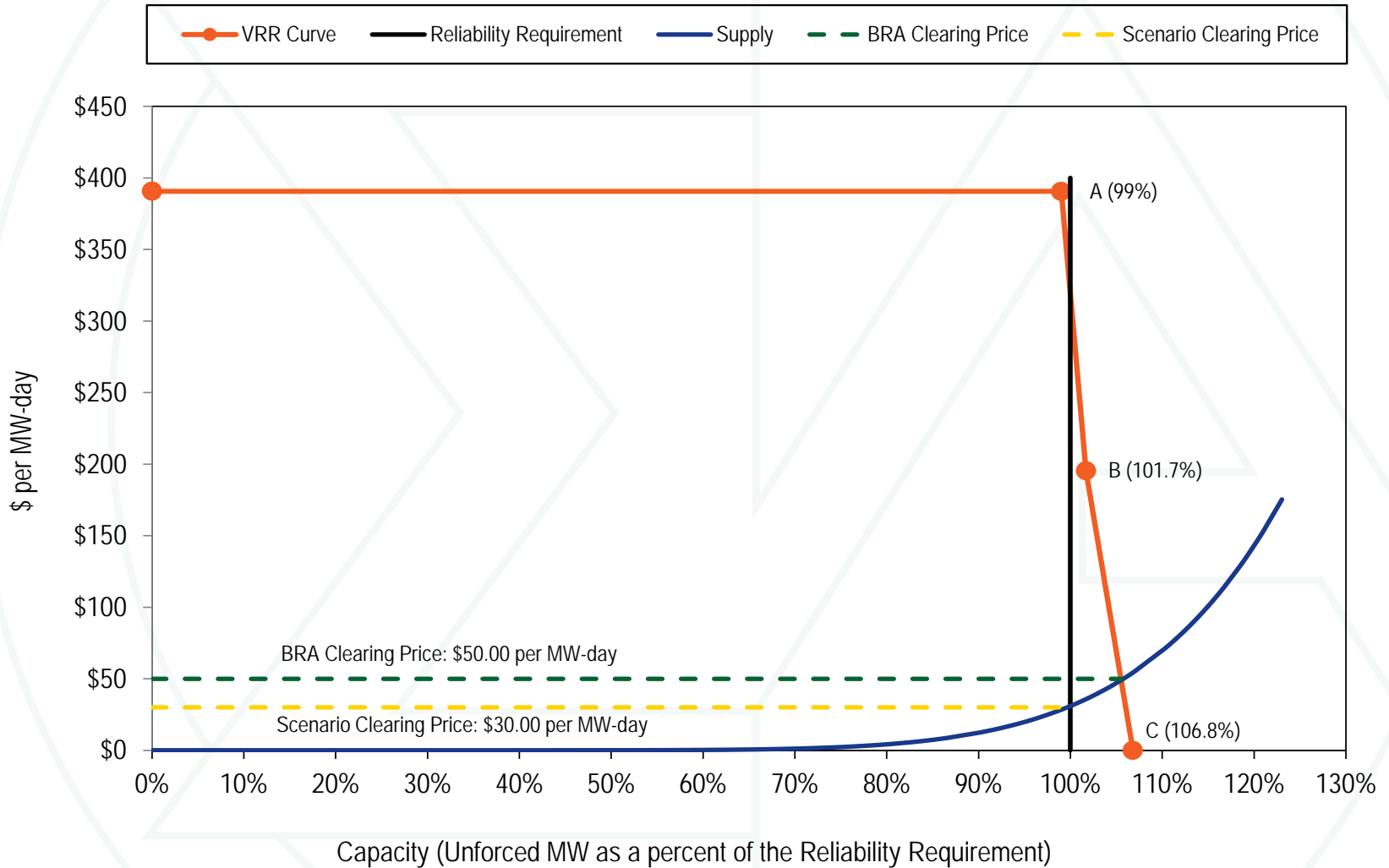
Scenario	Scenario Description	RPM Revenue	Scenario Impact	Percent
		(\$ per Delivery Year)	RPM Revenue (\$ per Delivery Year)	
0	Actual Results	\$3,916,990,303	NA	NA
1	Impact of Downward Sloping VRR Curve	\$2,659,527,128	\$1,257,463,175	47.3%
2	Impact of Forecast Peak Load	\$3,038,859,236	\$878,131,066	28.9%
3	Impact of ComEd CETL	\$4,045,468,797	(\$128,478,494)	(3.2%)
4	Impact of Dominion FRR	\$4,009,821,399	(\$92,831,097)	(2.3%)
5	Impact of Intermittent Capacity	\$4,209,145,809	(\$292,155,506)	(6.9%)
6	Inclusion of Demand Resources	\$4,667,530,509	(\$750,540,206)	(16.1%)
7	Inclusion of EE Offers and EE Addback	\$3,723,175,053	\$193,815,249	5.2%
8	Impact of Incorrect EE Addback	\$3,860,997,114	\$55,993,189	1.5%
9	Inclusion of PRD	\$3,971,098,221	(\$54,107,919)	(1.4%)
10	Inclusion of Seasonal Products	\$4,088,669,913	(\$171,679,610)	(4.2%)
11	Inclusion of Seasonal Matching Across LDAs	\$4,007,550,697	(\$90,560,395)	(2.3%)
12	Inclusion of Offers from External Generation	\$4,227,125,093	(\$310,134,790)	(7.3%)
13	Impact of DR, EE, PRD, Seasonal Resources, Capacity Imports, and Intermittent Capacity Overstatement	\$6,657,417,211	(\$2,740,426,908)	(41.2%)
14	Impact of Low MOPR Offers	\$4,078,113,024	(\$161,122,722)	(4.0%)
15	Inclusion of Nuclear Offers	\$3,480,464,207	\$436,526,096	12.5%
16	Impact of Noncompetitive Offers	\$3,694,010,658	\$222,979,644	6.0%



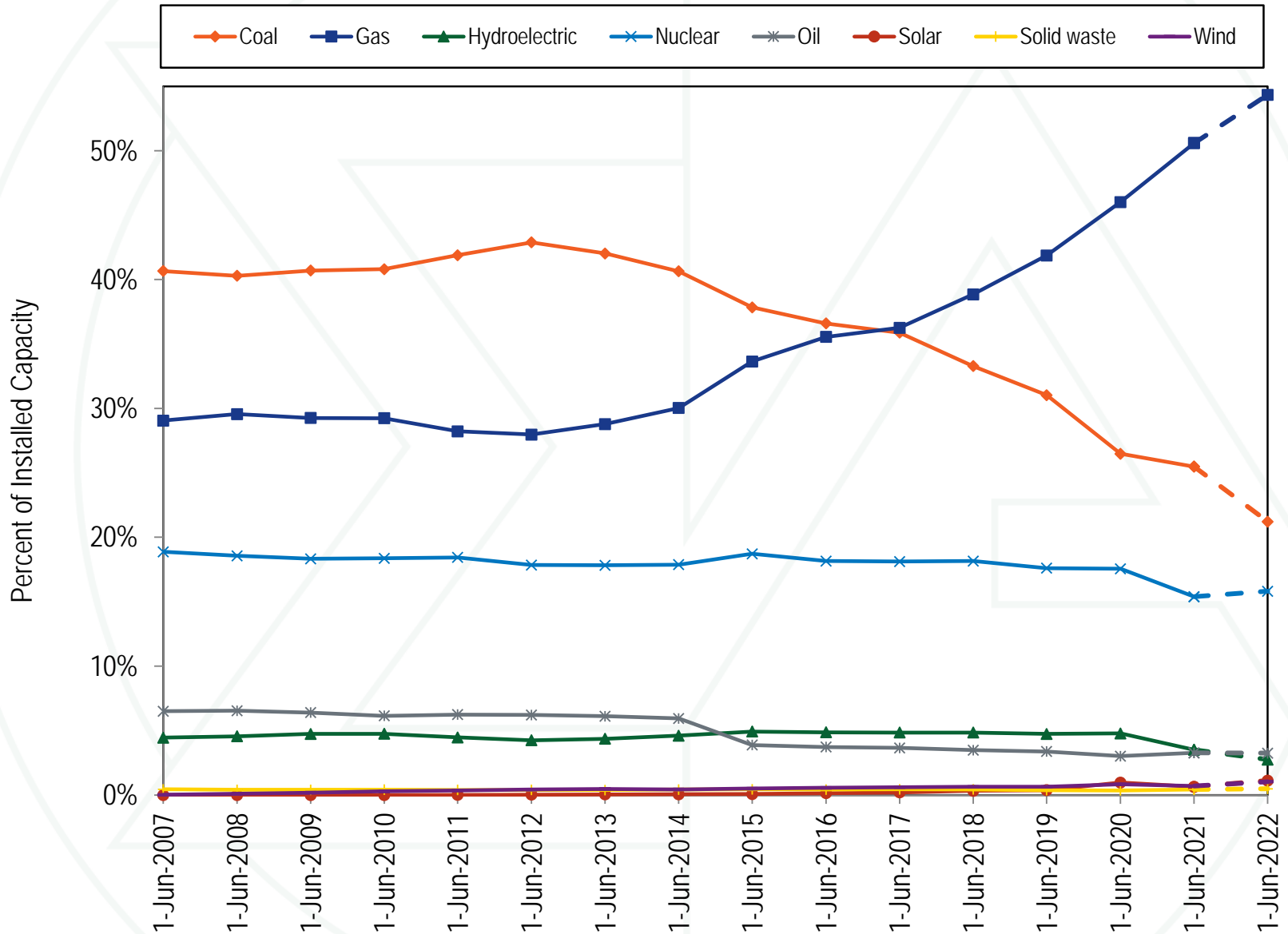
2022/2023 RPM Base Residual Auction

Scenario	Scenario Description	Cleared UCAP (MW)	Scenario Impact	
			Cleared UCAP (MW)	Percent
0	Actual Results	144,477.3	NA	NA
1	Impact of Downward Sloping VRR Curve	132,006.7	12,470.6	9.4%
2	Impact of Forecast Peak Load	138,811.6	5,665.7	4.1%
3	Impact of ComEd CETL	144,581.9	(104.6)	(0.1%)
4	Impact of Dominion FRR	143,140.5	1,336.8	0.9%
5	Impact of Intermittent Capacity	144,184.3	293.0	0.2%
6	Inclusion of Demand Resources	138,083.6	6,393.7	4.6%
7	Inclusion of EE Offers and EE Addback	139,272.3	5,205.0	3.7%
8	Impact of Incorrect EE Addback	144,068.6	408.7	0.3%
9	Inclusion of PRD	144,727.2	(249.9)	(0.2%)
10	Inclusion of Seasonal Products	144,052.8	424.5	0.3%
11	Inclusion of Seasonal Matching Across LDAs	144,363.9	113.4	0.1%
12	Inclusion of Offers from External Generation	143,951.3	526.0	0.4%
13	Impact of DR, EE, PRD, Seasonal Resources, Capacity Imports, and Intermittent Capacity Overstatement	136,610.7	7,866.6	5.8%
14	Impact of Low MOPR Offers	144,310.2	167.1	0.1%
15	Inclusion of Nuclear Offers	144,581.9	(104.6)	(0.1%)
16	Impact of Noncompetitive Offers	144,477.3	0.0	0.0%

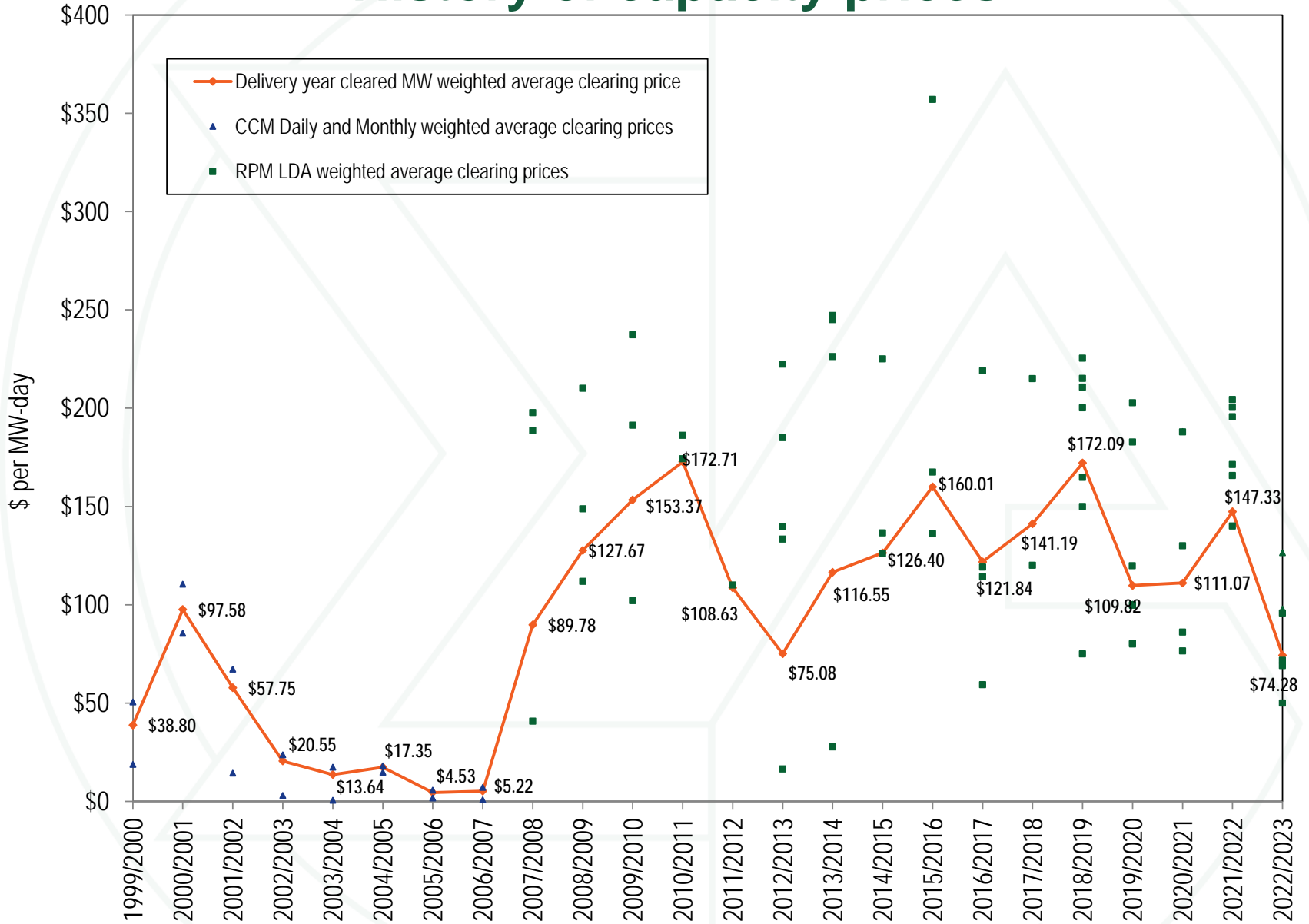
VRR curve impacts: 2022/2023 Delivery Year



Installed capacity by fuel source

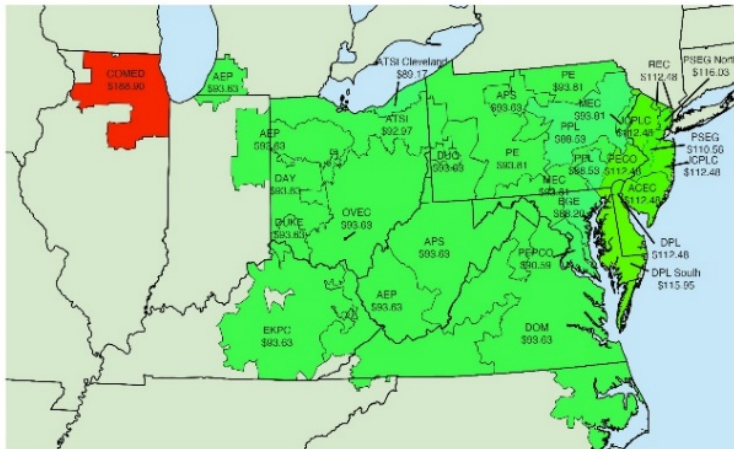


History of capacity prices

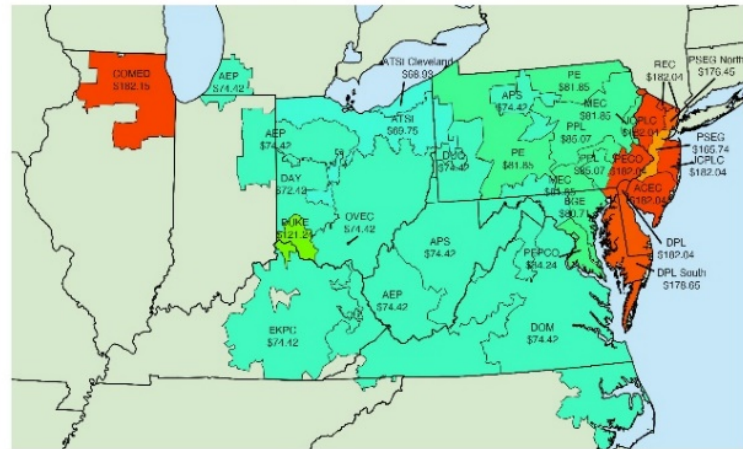


Map of RPM capacity prices

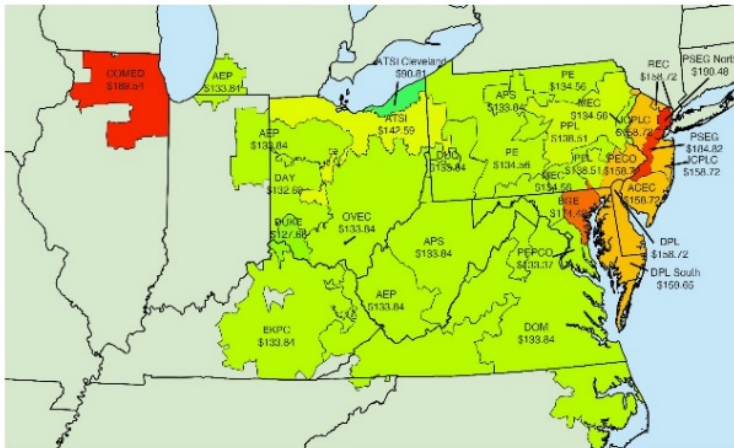
2019/2020



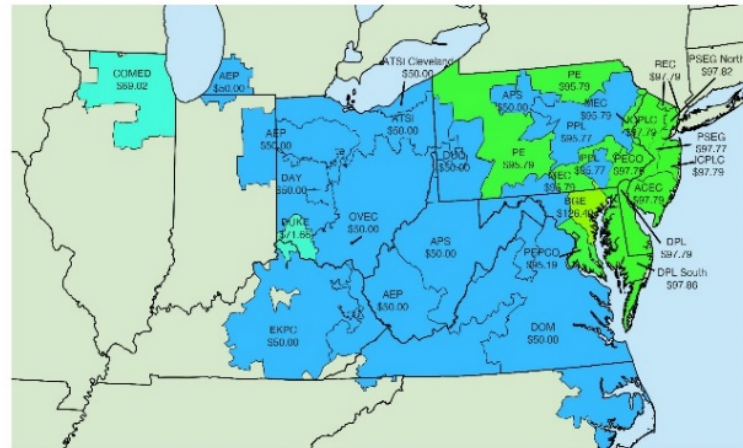
2020/2021



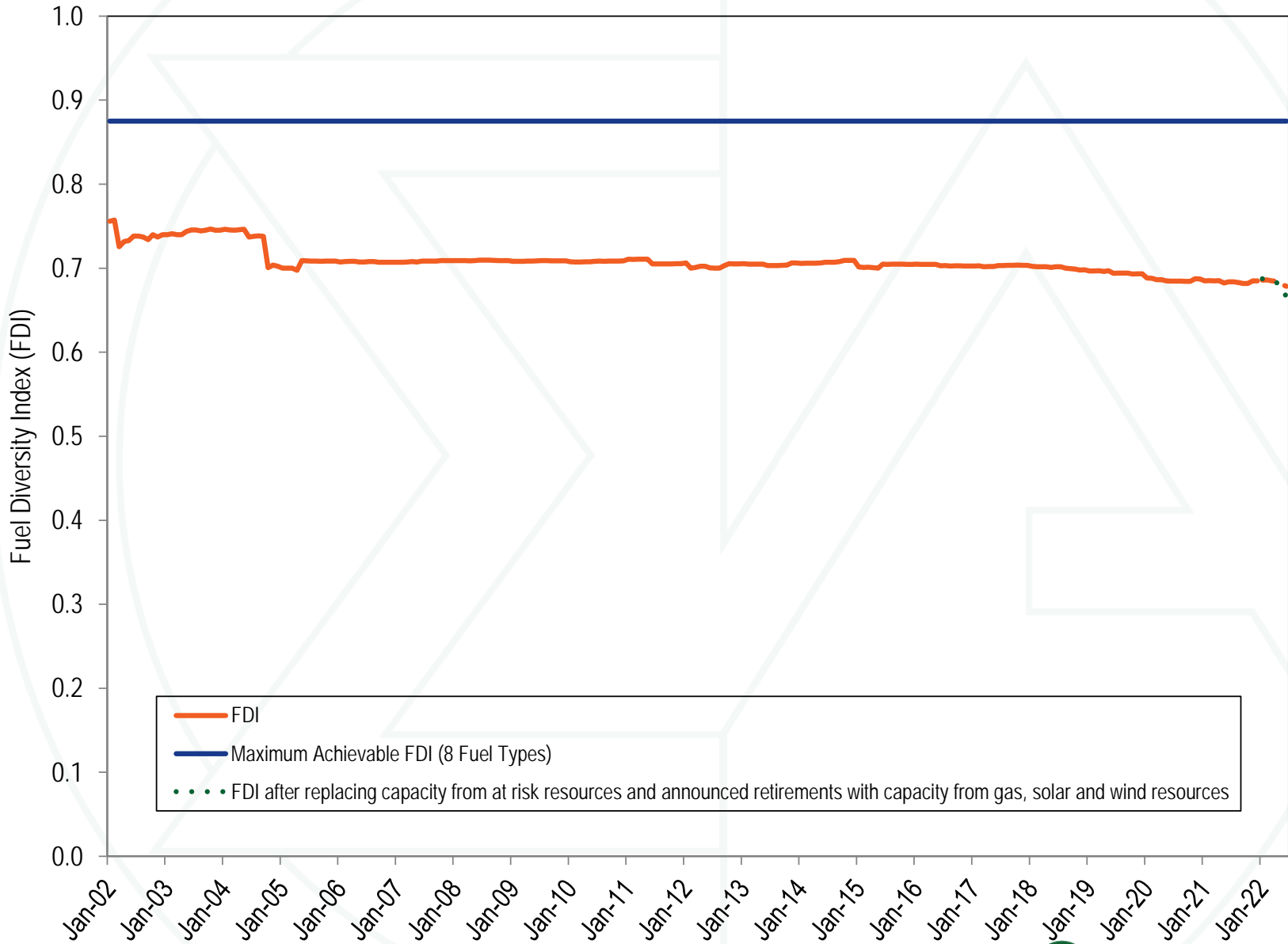
2021/2022



2022/2023



Fuel Diversity Index for installed capacity



RPM reserve margin

	01-Jun-18	01-Jun-19	01-Jun-20	01-Jun-21	01-Jun-22	
Forecast peak load ICAP (MW)	152,407.9	151,643.5	148,355.3	149,482.9	150,229.0	A
FRR peak load ICAP (MW)	12,732.9	12,284.2	11,488.3	11,717.7	28,535.5	B
PRD ICAP (MW)	0.0	0.0	558.0	510.0	230.0	C
Installed reserve margin (IRM)	16.1%	16.0%	15.5%	14.7%	14.5%	D
Pool wide average EFORD	6.07%	6.08%	5.78%	5.22%	5.08%	E
Forecast pool requirement (FPR)	1.0905	1.0895	1.0882	1.0871	1.0868	$F=(1+D)*(1-E)$
RPM committed less deficiency UCAP (MW) (generation and DR)	161,242.6	162,276.1	159,560.4	156,633.6	139,666.7	G
RPM committed less deficiency ICAP (MW) (generation and DR)	171,662.5	172,781.2	169,348.8	165,260.2	147,141.5	$H=G/(1-E)$
RPM peak load ICAP (MW)	139,675.0	139,359.3	136,309.0	137,255.2	121,463.5	$J=A-B-C$
Reserve margin ICAP (MW)	31,987.5	33,421.9	33,039.8	28,005.0	25,678.0	$K=H-J$
Reserve margin (%)	22.9%	24.0%	24.2%	20.4%	21.1%	$L=K/J$
Reserve margin in excess of IRM ICAP (MW)	9,499.8	11,124.4	11,911.9	7,828.5	8,065.8	$M=K-D*J$
Reserve margin in excess of IRM (%)	6.8%	8.0%	8.7%	5.7%	6.6%	$N=M/J$
RPM peak load UCAP (MW)	131,196.7	130,886.3	128,430.3	130,090.5	115,293.2	$P=J*(1-E)$
RPM reliability requirement UCAP (MW)	152,315.6	151,832.0	148,331.5	149,210.1	132,006.5	$Q=J*F$
Reserve margin UCAP (MW)	30,045.9	31,389.8	31,130.1	26,543.1	24,373.5	$R=G-P$
Reserve cleared in excess of IRM UCAP (MW)	8,927.0	10,444.1	11,228.9	7,423.5	7,660.2	$S=G-Q$
Projected replacement capacity UCAP (MW)	0.0	0.0	0.0	0.0	0.0	T
Projected reserve margin	22.9%	24.0%	24.2%	20.4%	21.1%	$U=(H-T)/(1-E))/J-1$



Reserve margin

- **Total reserves: 24,373.5 MW**
- **Excess reserves: 7,660.2**
- **Cleared DR: 8,710.3 MW**
 - **> Excess reserves**
- **Cleared capacity with no must offer requirement: 8,113.0 MW**
 - **> Excess reserves**
- **Sum of DR and no must offer: 16,823.3 MW**
 - **> Required reserves**
 - **69.0 percent of total reserves**

Effective capacity in interconnection queues

Unit Type	MW in Queue	Completion Rate Adjusted MW in Queue	Completion Rate and Derate Adjusted MW in Queue
Battery	38,301.5	1,460.5	1,460.5
CC	18,707.9	11,128.3	11,128.3
CT - Natural Gas	5,828.3	4,025.0	4,025.0
CT - Oil	17.0	13.2	13.2
CT - Other	396.6	33.3	33.3
Fuel Cell	8.0	2.5	2.5
Hydro - Pumped Storage	730.0	707.2	707.2
Hydro - Run of River	124.9	56.8	56.8
Nuclear	189.5	73.8	73.8
RICE - Natural Gas	14.4	3.7	3.7
RICE - Oil	0.0	0.0	0.0
RICE - Other	0.0	0.0	0.0
Solar	118,957.0	16,424.1	7,670.1
Solar + Storage	31,628.6	618.6	288.9
Solar + Wind	209.0	0.0	0.0
Steam - Coal	76.0	25.9	25.9
Steam - Natural Gas	11.0	10.0	10.0
Steam - Oil	0.0	0.0	0.0
Steam - Other	20.0	5.4	5.4
Wind	39,588.7	6,485.9	1,050.7
Wind + Storage	106.3	0.0	0.0
Total	254,914.6	41,074.4	26,555.3

Proportion of units recovering avoidable costs

Technology	Units with full recovery from energy and ancillary net revenue											Units with full recovery from all markets										
	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
CC - Combined Cycle	55%	46%	50%	72%	59%	63%	57%	66%	64%	67%	50%	85%	79%	79%	95%	88%	93%	89%	98%	90%	93%	83%
CT - Aero Derivative	15%	6%	6%	53%	15%	8%	10%	30%	46%	42%	2%	100%	96%	76%	98%	100%	99%	100%	99%	96%	96%	89%
CT - Industrial Frame	26%	23%	17%	38%	13%	8%	3%	21%	30%	21%	2%	99%	98%	83%	100%	100%	100%	100%	96%	92%	86%	84%
Coal Fired	31%	17%	27%	78%	16%	15%	12%	11%	2%	2%	22%	82%	36%	54%	83%	64%	40%	36%	63%	31%	5%	66%
Diesel	48%	42%	37%	69%	56%	33%	32%	39%	11%	37%	25%	100%	100%	77%	100%	100%	100%	100%	97%	91%	89%	83%
Hydro	74%	61%	95%	97%	81%	79%	95%	94%	90%	72%	95%	81%	77%	97%	98%	100%	100%	97%	98%	100%	74%	95%
Nuclear	-	-	50%	94%	17%	6%	17%	53%	0%	0%	88%	-	-	61%	100%	56%	17%	50%	88%	81%	0%	100%
Oil or Gas Steam	8%	6%	11%	15%	3%	0%	0%	10%	73%	6%	10%	92%	78%	86%	85%	91%	88%	81%	76%	66%	34%	67%
Pumped Storage	100%	100%	95%	100%	100%	100%	100%	100%	100%	100%	29%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Solar	-	95%	97%	99%	97%	95%	95%	98%	96%	95%	100%	-	95%	97%	99%	97%	95%	95%	98%	96%	95%	100%
Wind	88%	85%	96%	93%	92%	89%	93%	91%	88%	79%	94%	88%	85%	96%	93%	92%	89%	93%	91%	89%	79%	95%



New entrant CT net revenue and total cost by LDA



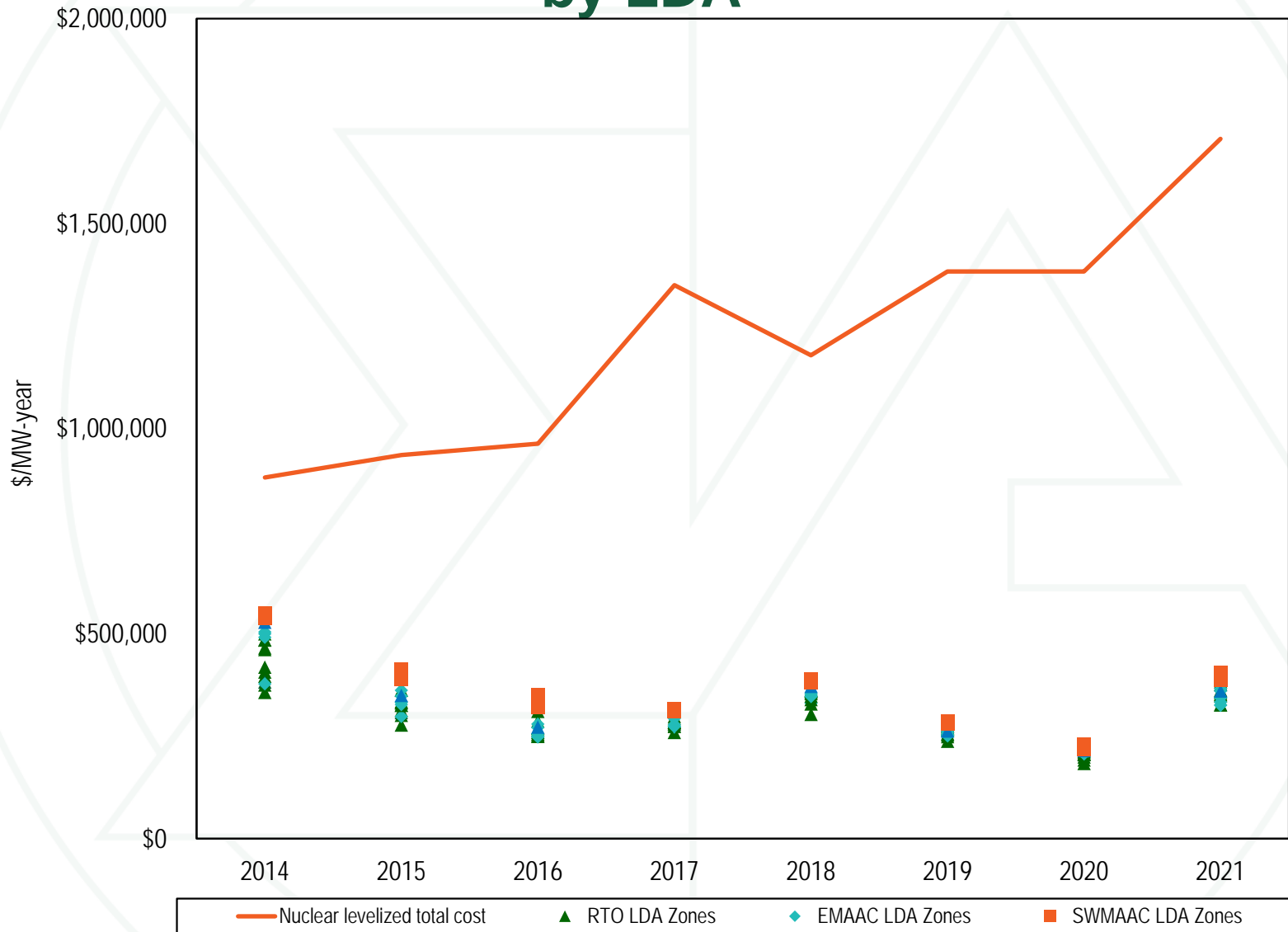
New entrant CC net revenue and total cost by LDA



New entrant CP net revenue and total cost by LDA



New entrant nuclear plant net revenue and total cost by LDA



Nuclear unit surplus (shortfall)

	ICAP	Surplus (Shortfall) (\$/MWh)													
	(MW)	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Beaver Valley	1,808	\$26.3	\$6.3	\$10.5	\$8.8	(\$3.3)	\$1.4	\$11.7	\$3.2	(\$0.4)	\$2.6	\$13.9	\$3.7	(\$2.6)	\$15.4
Braidwood	2,337	\$24.9	\$2.5	\$6.4	\$3.4	(\$6.1)	(\$2.6)	\$7.2	(\$1.2)	(\$3.1)	(\$1.5)	\$6.0	\$3.9	\$0.1	\$15.6
Byron	2,300	\$24.5	(\$1.3)	\$3.4	(\$0.6)	(\$9.4)	(\$3.6)	\$4.9	(\$6.1)	(\$9.5)	(\$2.7)	\$5.8	\$3.2	(\$0.5)	\$14.6
Calvert Cliffs	1,708	\$60.6	\$20.9	\$28.6	\$17.9	\$4.5	\$14.6	\$31.6	\$14.1	\$7.3	\$6.1	\$16.3	\$5.4	(\$0.9)	\$19.7
Davis Besse	894	NA	NA	NA	NA	(\$13.2)	(\$7.0)	\$6.6	(\$1.2)	(\$4.0)	(\$8.4)	(\$0.9)	(\$6.2)	(\$15.0)	\$3.9
Dresden	1,797	\$25.6	\$3.0	\$7.6	\$4.4	(\$5.2)	(\$1.0)	\$9.1	\$0.3	(\$1.5)	(\$0.0)	\$7.2	\$4.6	\$0.7	\$16.3
Hope Creek	1,172	\$54.0	\$17.0	\$24.5	\$16.9	\$2.6	\$12.4	\$26.0	\$6.3	(\$2.0)	\$1.6	\$12.3	\$1.7	(\$2.2)	\$11.4
LaSalle	2,271	\$24.8	\$2.5	\$6.4	\$3.3	(\$6.1)	(\$1.9)	\$7.7	(\$0.9)	(\$3.5)	(\$1.8)	\$6.0	\$3.8	(\$0.1)	\$15.4
Limerick	2,242	\$54.1	\$17.1	\$24.7	\$16.6	\$2.6	\$12.2	\$25.7	\$6.5	(\$2.1)	\$1.5	\$12.1	\$1.7	(\$2.5)	\$12.0
North Anna	1,892	\$52.0	\$14.6	\$25.5	\$16.8	\$0.2	\$5.7	\$23.2	\$10.9	\$3.0	\$4.7	\$16.0	\$4.8	(\$2.0)	\$18.2
Oyster Creek	608	\$47.5	\$8.4	\$15.9	\$7.2	(\$8.2)	\$3.3	\$16.4	(\$4.7)	(\$11.6)	(\$9.9)	NA	NA	NA	NA
Peach Bottom	2,347	\$53.7	\$16.9	\$24.2	\$16.1	\$2.3	\$12.3	\$25.5	\$5.8	(\$2.2)	\$1.4	\$11.8	\$0.7	(\$2.7)	\$11.9
Perry	1,240	NA	NA	NA	NA	(\$13.2)	(\$6.4)	\$5.5	(\$0.3)	(\$4.0)	(\$7.3)	\$1.9	(\$5.8)	(\$15.1)	\$4.3
Quad Cities	1,819	\$24.1	(\$0.4)	\$2.4	(\$1.8)	(\$13.2)	(\$6.9)	\$0.6	(\$7.7)	(\$9.5)	(\$3.4)	\$4.4	\$2.1	(\$2.3)	\$13.2
Salem	2,328	\$54.0	\$17.1	\$24.5	\$16.9	\$2.6	\$12.4	\$26.0	\$6.2	(\$2.3)	\$1.3	\$11.9	\$1.4	(\$2.5)	\$11.1
Surry	1,676	\$48.8	\$13.8	\$24.2	\$16.4	(\$0.0)	\$5.1	\$21.6	\$10.8	\$2.6	\$4.5	\$16.0	\$4.1	(\$2.6)	\$17.6
Susquehanna	2,520	\$46.8	\$15.2	\$22.4	\$16.1	\$1.4	\$11.1	\$24.6	\$6.3	(\$1.6)	\$1.8	\$10.1	(\$1.4)	(\$6.6)	\$8.9
Three Mile Island	803	\$40.7	\$6.5	\$13.3	\$4.6	(\$9.6)	\$0.9	\$13.7	(\$6.8)	(\$12.4)	(\$10.3)	(\$3.8)	NA	NA	NA



Nuclear unit forward annual surplus (shortfall)

	ICAP (MW)	Surplus (Shortfall) (\$/MWh)	Subsidy (\$/MWh)	Surplus (Shortfall) Excluding Subsidy (\$ in millions)	Surplus (Shortfall) Including Subsidy (\$ in millions)
		2022	2022	2022	2022
Beaver Valley	1,808	\$19.94		\$291.6	\$291.6
Braidwood	2,337	\$20.90	\$0.00	\$394.8	\$394.8
Byron	2,300	\$19.24	\$0.00	\$357.8	\$357.8
Calvert Cliffs	1,708	\$24.36		\$336.3	\$336.3
Davis Besse	894	\$7.95		\$58.0	\$58.0
Dresden	1,797	\$21.63	\$0.00	\$314.2	\$314.2
Hope Creek	1,172	\$17.86	\$10.00	\$169.3	\$263.5
LaSalle	2,271	\$20.63	\$0.00	\$378.6	\$378.6
Limerick	2,242	\$17.91		\$324.7	\$324.7
North Anna	1,892	\$23.30		\$356.4	\$356.4
Peach Bottom	2,347	\$17.87		\$339.1	\$339.1
Perry	1,240	\$8.90		\$89.9	\$89.9
Quad Cities	1,819	\$17.70	\$16.50	\$260.3	\$501.7
Salem	2,328	\$17.50	\$10.00	\$329.5	\$516.7
Surry	1,676	\$22.83		\$309.3	\$309.3
Susquehanna	2,520	\$14.10		\$287.8	\$287.8

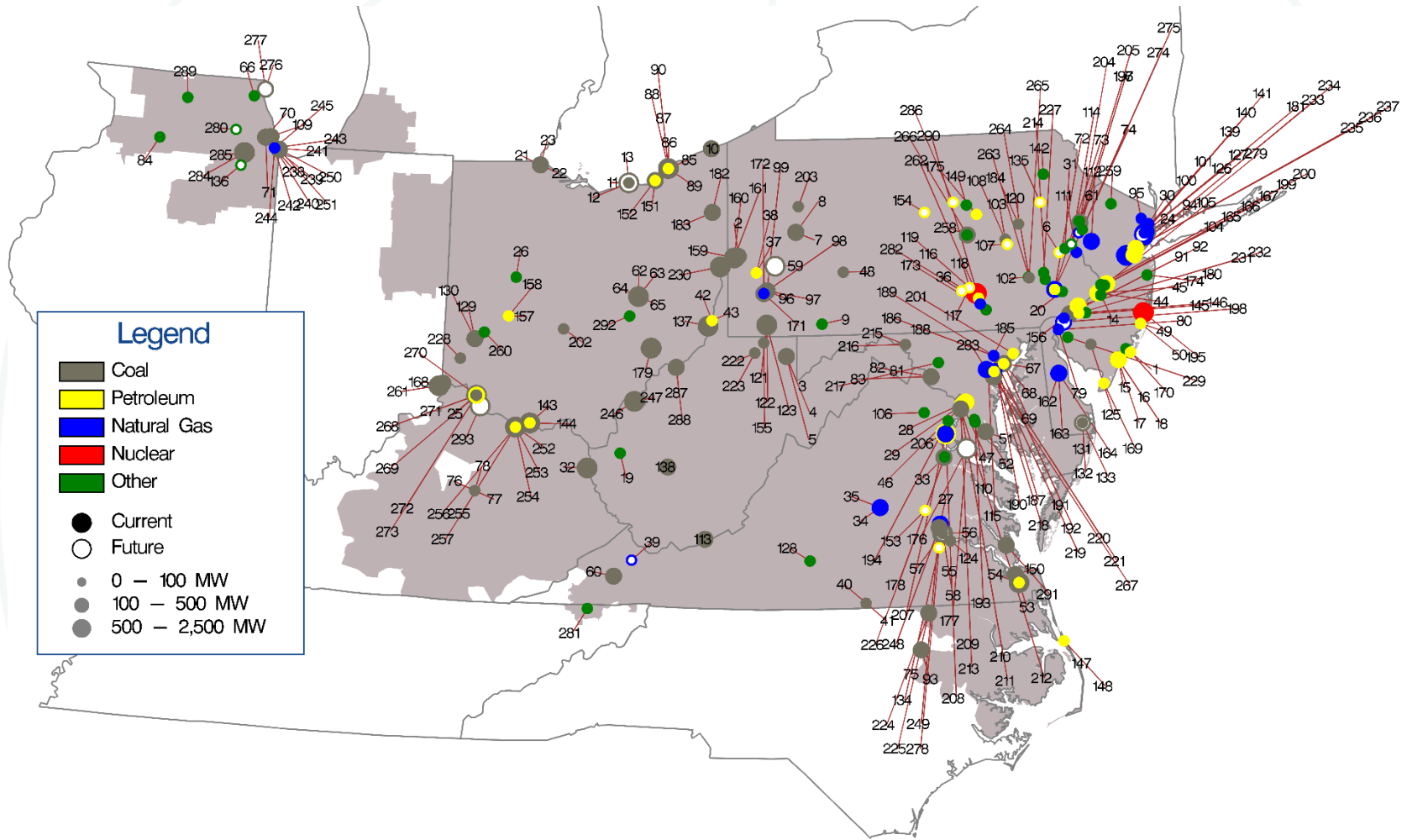


Profile of units at risk of retirement

	No. Units	ICAP (MW)	Avg. Unit Age (Yrs)	Avg. Heat Rate (Btu/Mwh)
Total	31	2,230	49	14,541



Map of unit retirements: 2011 through 2024



Recommendations: Planning

- **Modify the transmission project proposal templates to include data necessary to perform a detailed project lifetime financial analysis.**
- **All PJM transmission owners should use the same line rating method and implement dynamic line ratings (DLR), subject to NERC standards and guidelines, subject to review by NERC, PJM and the MMU, and approval by FERC.**
- **The market efficiency process should be eliminated. If retained, the cost/benefit calculation for economic projects needs to be corrected.**



Recommendations: Energy Market Uplift

- **PJM should ensure that units not following dispatch are not paid uplift.**
- **Flexible operating parameters should be required as a condition for receiving uplift.**
- **Uplift should not be paid to units backed down for reliability because there is no lost opportunity.**



Total energy uplift charges

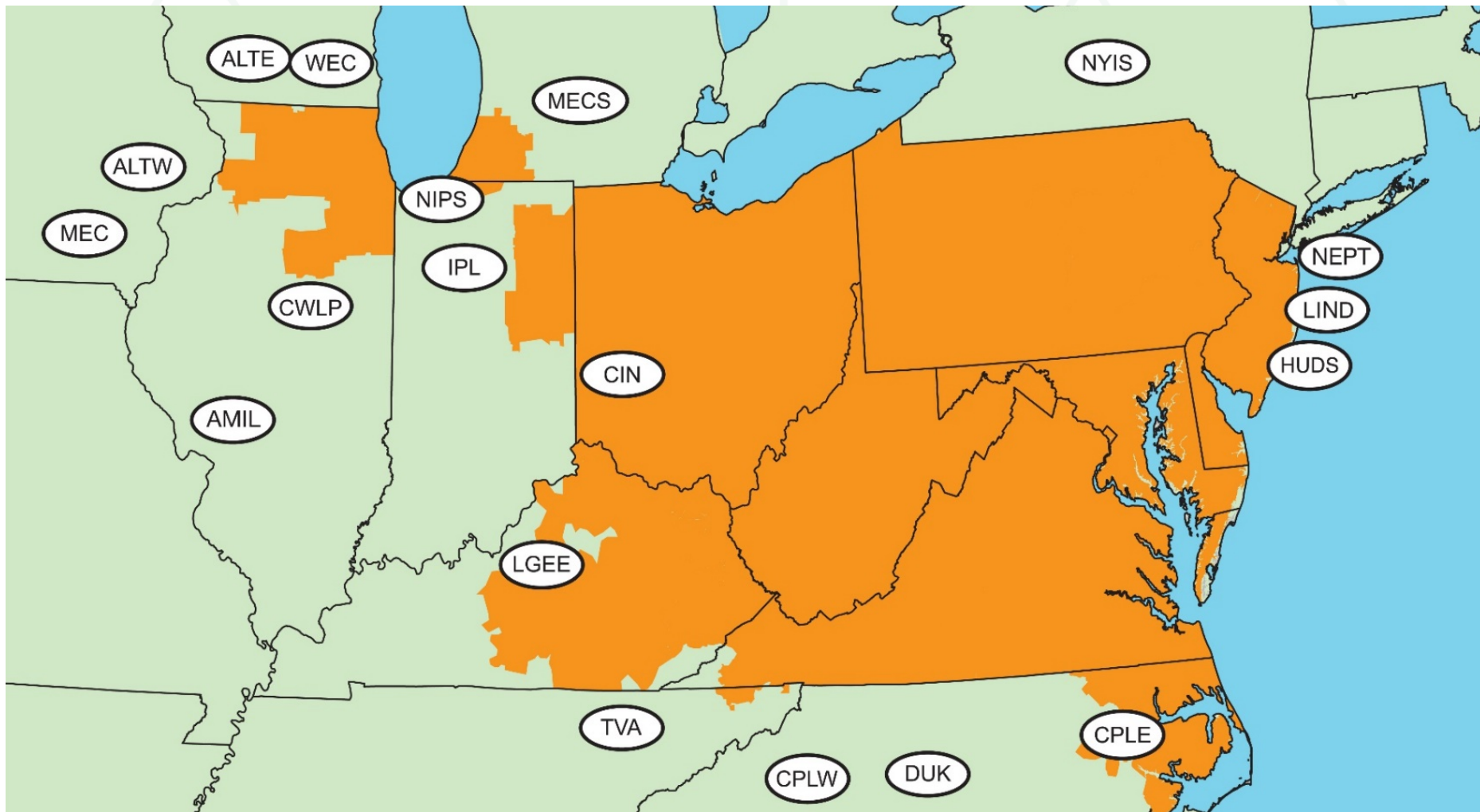
	Total Energy Uplift Charges (Millions)	Change (Millions)	Percent Change	Energy Uplift as a Percent of Total PJM Billing
2001	\$284.0	\$67.0	30.9%	8.5%
2002	\$273.7	(\$10.3)	(3.6%)	5.8%
2003	\$376.5	\$102.8	37.6%	5.4%
2004	\$537.6	\$161.1	42.8%	6.1%
2005	\$712.6	\$175.0	32.6%	3.1%
2006	\$365.6	(\$347.0)	(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	\$88.5	(\$109.7)	(55.3%)	0.2%
2020	\$90.9	(\$107.3)	(54.1%)	0.2%
2021	\$178.3	\$87.4	96.2%	0.5%

Operating reserve rates statistics

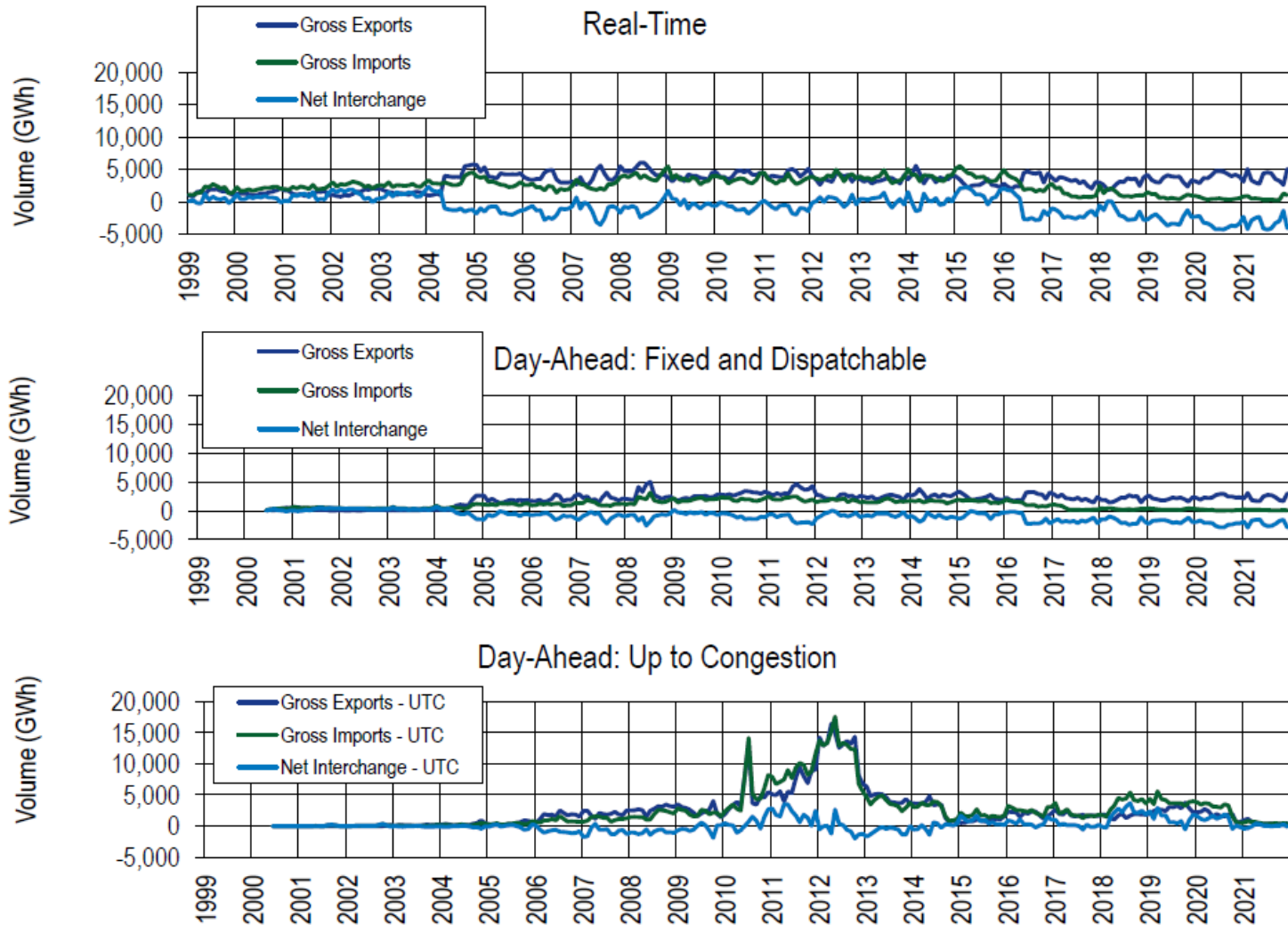
Region	Transaction	Rates Charged (\$/MWh)			Standard Deviation
		Maximum	Average	Minimum	
East	INC	3.012	0.467	<0.001	0.476
	DEC	3.029	0.482	<0.001	0.476
	DA Load	0.210	0.016	<0.001	0.028
	RT Load	0.835	0.084	<0.001	0.106
	Deviation	3.012	0.467	<0.001	0.476
West	INC	2.434	0.416	<0.001	0.429
	DEC	2.449	0.431	<0.001	0.430
	DA Load	0.210	0.016	<0.001	0.028
	RT Load	0.682	0.073	<0.001	0.095
	Deviation	2.434	0.416	<0.001	0.429



PJM's footprint and its external scheduling interfaces



Scheduled import and export transaction volume history



The regulation market results were not competitive

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

- **The regulation market should be modified to incorporate a consistent application of the marginal benefit factor (MBF) throughout the optimization, assignment and settlement process.**
- **Separate cost of service payments for reactive capability should be eliminated and the cost of reactive capability recovered in the capacity market.**
- **New CRF rates for black start units, incorporating current tax code changes, should be implemented immediately for all black start units.**



The FTR/ARR markets results were partially competitive

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

Recommendations: FTR/ARR

- **Rights to all congestion revenues should be assigned to load.**



Total congestion offset for load

Planning Period	Revenue								Pre 2017/2018 (Without Balancing)		2017/2018 (With Balancing)		Post 2017/2018 (With Balancing and Surplus)		Effective Offset	
	ARR Credits	Unadjusted FTR Credits	Day Ahead Congestion	Balancing + M2M Congestion	Total Congestion	Surplus Revenue Pre 2017/2018 Rules	Surplus Revenue 2017/2018 Rules	Post 2017/2018 Rules	Total ARR/FTR Offset	Percent Offset	Current Revenue Received	Percent Offset	New Revenue Received	New Offset	Cumulative Revenue	Offset
	2011/2012	\$515.6	\$310.0	\$1,025.4	(\$275.7)	\$749.7	(\$50.6)	\$35.6	\$113.9	\$775.0	103.4%	\$585.5	78.1%	\$663.8	88.5%	\$775.0
2012/2013	\$356.4	\$268.4	\$904.7	(\$379.9)	\$524.8	(\$94.0)	\$18.4	\$62.1	\$530.7	101.1%	\$263.2	50.2%	\$306.9	58.5%	\$530.7	101.1%
2013/2014	\$339.4	\$626.6	\$2,231.3	(\$360.6)	\$1,870.6	(\$139.4)	(\$49.0)	(\$49.0)	\$826.5	44.2%	\$556.3	29.7%	\$556.3	29.7%	\$826.5	44.2%
2014/2015	\$487.4	\$348.1	\$1,625.9	(\$268.3)	\$1,357.6	\$36.7	\$111.2	\$400.6	\$872.2	64.2%	\$678.4	50.0%	\$967.8	71.3%	\$872.2	64.2%
2015/2016	\$641.8	\$209.2	\$1,098.7	(\$147.6)	\$951.1	\$9.2	\$42.1	\$188.9	\$860.2	90.4%	\$745.5	78.4%	\$892.3	93.8%	\$860.2	90.4%
2016/2017	\$648.1	\$149.9	\$885.7	(\$104.8)	\$780.8	\$15.1	\$36.5	\$179.0	\$813.1	104.1%	\$729.6	93.4%	\$872.1	111.7%	\$813.1	104.1%
2017/2018	\$429.6	\$212.3	\$1,322.1	(\$129.5)	\$1,192.6	\$52.3	\$80.4	\$370.7	\$694.2	58.2%	\$592.8	49.7%	\$883.1	74.1%	\$592.8	49.7%
2018/2019	\$531.6	\$130.1	\$832.7	(\$152.6)	\$680.0	(\$5.8)	\$16.2	\$112.2	\$655.87	96.4%	\$525.3	77.2%	\$621.3	91.4%	\$621.3	91.4%
2019/2020	\$547.6	\$91.9	\$612.1	(\$169.4)	\$442.7	(\$1.6)	\$21.6	\$157.8	\$637.9	144.1%	\$491.7	111.1%	\$627.9	141.8%	\$627.9	141.8%
2020/2021	\$392.7	\$179.9	\$899.6	(\$256.2)	\$643.4	(\$43.2)	(\$0.0)	(\$0.0)	\$529.31	82.3%	\$316.4	49.2%	\$316.4	49.2%	\$316.4	49.2%
2021/2022*	\$275.0	\$166.3	\$815.5	(\$105.4)	\$710.0	(\$34.9)	(\$17.6)	(\$17.6)	\$406.5	57.2%	\$318.3	44.8%	\$318.3	44.8%	\$318.3	44.8%
Total	\$5,165.1	\$2,692.7	\$12,253.5	(\$2,350.1)	\$9,903.4	(\$256.2)	\$295.4	\$1,518.6	\$7,601.6	76.8%	\$5,803.1	58.6%	\$7,026.3	70.9%	\$7,154.4	72.2%

* seven months of 2021/2022 planning period



Zonal ARR/FTR total congestion offset

Zone	ARR Credits	Adjusted FTR Credits	Balancing+ M2M Charge	Surplus Allocation	Total Offset	Day Ahead Congestion	Balancing Congestion	M2M Payments	Total Congestion	Offset
ACEC	\$2.2	(\$0.0)	(\$1.1)	\$0.0	\$1.0	\$7.2	(\$1.0)	(\$0.1)	\$6.1	17.1%
AEP	\$25.1	\$25.5	(\$16.1)	\$0.0	\$34.5	\$132.8	(\$15.1)	(\$1.0)	\$116.7	29.6%
APS	\$17.6	\$12.9	(\$6.1)	\$0.0	\$24.5	\$57.2	(\$5.7)	(\$0.4)	\$51.1	47.8%
ATSI	\$12.2	\$0.5	(\$7.6)	\$0.0	\$5.2	\$62.6	(\$7.0)	(\$0.5)	\$55.1	9.4%
BGE	\$52.8	\$2.4	(\$3.8)	\$0.0	\$51.4	\$30.8	(\$3.6)	(\$0.3)	\$26.9	190.7%
COMED	\$24.6	\$4.3	(\$11.1)	\$0.0	\$17.8	\$95.7	(\$10.3)	(\$0.8)	\$84.6	21.1%
DAY	\$3.0	\$0.5	(\$2.1)	\$0.0	\$1.5	\$15.3	(\$1.9)	(\$0.1)	\$13.3	11.3%
DOM	\$18.5	\$76.8	(\$18.7)	\$0.0	\$76.6	\$125.8	(\$17.8)	(\$0.1)	\$107.9	71.0%
DPL	\$21.8	\$8.4	(\$2.3)	\$0.0	\$28.0	\$34.7	(\$2.1)	(\$0.9)	\$31.7	88.2%
DUKE	\$14.6	\$1.0	(\$3.1)	\$0.0	\$12.5	\$22.9	(\$2.9)	(\$0.2)	\$19.8	63.0%
DUQ	\$3.3	\$0.2	(\$1.5)	\$0.0	\$2.0	\$9.9	(\$1.4)	(\$0.2)	\$8.4	23.3%
EKPC	\$2.3	\$0.0	(\$1.5)	\$0.0	\$0.7	\$12.3	(\$1.4)	(\$0.1)	\$10.8	6.8%
EXT	\$0.4	\$0.0	(\$2.9)	\$0.0	(\$2.5)	\$13.2	(\$2.9)	\$0.0	\$10.3	(23.9%)
JCPLC	\$1.2	\$0.0	(\$2.7)	\$0.0	(\$1.5)	\$17.9	(\$2.5)	(\$0.2)	\$15.2	(9.8%)
MEC	\$4.6	\$1.4	(\$5.1)	\$0.0	\$0.9	\$19.7	(\$5.0)	(\$0.1)	\$14.6	5.8%
OVEC	\$0.0	\$0.0	(\$0.1)	\$0.0	(\$0.1)	\$0.5	(\$0.1)	\$0.0	\$0.4	(21.0%)
PE	\$6.0	\$5.9	(\$2.5)	\$0.0	\$9.4	\$19.9	(\$2.4)	(\$0.1)	\$17.3	54.4%
PECO	\$12.0	\$0.3	(\$4.2)	\$0.0	\$8.1	\$34.2	(\$3.8)	(\$0.3)	\$30.1	26.8%
PEPCO	\$13.5	\$3.3	(\$3.5)	\$0.0	\$13.3	\$27.0	(\$3.3)	(\$0.2)	\$23.5	56.8%
PPL	\$19.5	\$7.1	(\$4.6)	\$0.0	\$22.0	\$38.7	(\$4.2)	(\$0.3)	\$34.2	64.5%
PSEG	\$19.6	\$1.3	(\$4.8)	\$0.0	\$16.1	\$34.1	(\$4.4)	(\$0.4)	\$29.3	55.0%
REC	\$0.2	\$0.0	(\$0.2)	\$0.0	(\$0.0)	\$3.0	(\$0.2)	(\$0.0)	\$2.8	(0.3%)
Total	\$275.0	\$151.8	(\$105.4)	\$0.0	\$321.3	\$815.5	(\$99.1)	(\$6.4)	\$710.0	45.3%



Offset available to load if all ARRs self scheduled

	19/20 Planning Period				20/21 Planning Period				21/22 Planning Period*			
	SS FTR	Bal+M2M Charges	Congestion +M2M	Offset	SS FTR	Bal+M2M Charges	Congestion +M2M	Offset	SS FTR	Bal+M2M Charges	Congestion +M2M	Offset
ACEC	\$2.6	(\$2.1)	\$3.7	15.6%	\$1.8	(\$2.7)	\$5.5	(16.4%)	\$0.3	(\$1.1)	\$6.1	(12.9%)
AEP	\$62.7	(\$28.2)	\$81.9	42.1%	\$77.3	(\$38.1)	\$110.9	35.3%	\$67.3	(\$16.1)	\$116.7	43.9%
APS	\$31.2	(\$10.4)	\$31.9	65.1%	\$42.0	(\$14.8)	\$45.2	60.3%	\$39.5	(\$6.1)	\$51.1	65.4%
ATSI	\$27.9	(\$13.9)	\$36.8	38.1%	\$30.7	(\$19.5)	\$50.6	22.1%	\$34.4	(\$7.6)	\$55.1	48.8%
BGE	\$53.7	(\$6.7)	\$15.3	308.0%	\$79.7	(\$9.1)	\$24.8	284.2%	\$80.3	(\$3.8)	\$26.9	283.8%
COMED	\$40.6	(\$19.8)	\$65.2	31.9%	\$69.6	(\$28.5)	\$78.3	52.4%	\$40.4	(\$11.1)	\$84.6	34.6%
DAY	\$5.6	(\$3.9)	\$9.7	17.4%	\$8.0	(\$5.3)	\$11.0	24.9%	\$5.4	(\$2.1)	\$13.3	25.2%
DOM	\$32.8	(\$16.9)	\$59.2	26.9%	\$117.0	(\$37.9)	\$87.9	90.0%	\$121.9	(\$3.1)	\$107.9	110.1%
DPL	\$27.3	(\$8.7)	\$17.4	107.3%	\$56.4	(\$6.7)	\$36.2	137.4%	\$44.1	(\$1.5)	\$31.7	134.5%
DUKE	\$30.5	(\$6.0)	\$14.9	164.2%	\$40.9	(\$8.4)	\$17.4	187.2%	\$31.8	(\$18.7)	\$19.8	66.1%
DUQ	\$8.1	(\$3.2)	\$5.1	95.2%	\$8.9	(\$4.0)	\$6.2	79.7%	\$6.8	(\$2.3)	\$8.4	54.0%
EKPC	\$4.1	(\$2.9)	\$7.4	16.8%	\$6.6	(\$4.2)	\$8.4	29.3%	\$5.8	(\$1.5)	\$10.8	39.4%
EXT	\$0.9	(\$2.2)	(\$1.7)	74.3%	\$0.3	(\$13.8)	\$11.0	(122.3%)	\$0.7	(\$2.9)	\$10.3	(21.2%)
JCPLC	\$2.3	(\$4.6)	\$9.2	(25.5%)	\$0.9	(\$6.1)	\$12.9	(40.2%)	\$2.8	(\$2.7)	\$15.2	0.4%
MEC	\$0.8	(\$4.2)	\$8.7	(38.5%)	\$8.0	(\$5.3)	\$16.5	16.5%	\$18.1	(\$5.1)	\$14.6	89.0%
OVEC	NA	\$0.1	\$0.5	NA	NA	(\$0.3)	\$0.9	NA	NA	(\$0.1)	\$0.4	(21.0%)
PE	\$11.2	(\$3.8)	\$10.8	69.1%	\$13.5	(\$6.5)	\$16.4	42.8%	\$13.3	(\$4.2)	\$17.3	52.9%
PECO	\$16.8	(\$8.2)	\$13.4	63.8%	\$14.0	(\$10.9)	\$24.9	12.4%	\$16.0	(\$2.5)	\$30.1	44.7%
PEPCO	\$23.2	(\$6.1)	\$13.7	124.3%	\$37.3	(\$8.3)	\$20.5	141.7%	\$30.7	(\$3.5)	\$23.5	116.1%
PPL	\$39.2	(\$8.5)	\$20.5	149.9%	\$43.7	(\$11.5)	\$30.8	104.5%	\$80.9	(\$4.6)	\$34.2	223.6%
PSEG	\$21.3	(\$8.9)	\$18.4	67.2%	\$43.2	(\$13.9)	\$25.0	117.0%	\$34.2	(\$4.8)	\$29.3	100.3%
REC	\$0.2	(\$0.3)	\$0.6	(22.6%)	\$1.0	(\$0.6)	\$2.1	21.0%	\$0.6	(\$0.2)	\$2.8	16.0%
Total	\$443.0	(\$169.4)	\$442.7	61.8%	\$700.9	(\$256.2)	\$643.4	69.1%	\$675.3	(\$105.4)	\$710.0	80.3%

* First seven months of the 2021/2022 planning period

FTR profits and revenues by organization type and FTR direction: 2021/2022: June through December

Organization Type	Purchased FTRs Profit			Self Scheduled FTRs Revenue Returned		
	Prevailing Flow	Counter Flow	Total	Prevailing Flow	Counter Flow	Total
Financial	\$368,193,387	(\$115,621,164)	\$252,572,223			
Physical	\$140,109,205	(\$48,149,591)	\$91,959,614			
Physical ARR	\$47,118,705	(\$20,482,001)	\$26,636,704	\$147,661,864	(\$2,045,201)	\$145,616,663
Total	\$555,421,297	(\$184,252,755)	\$371,168,541	\$147,661,864	(\$2,045,201)	\$145,616,663



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