2022 State of the Market Report for PJM

Informational MC

IMM

April 13, 2023

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

Role of Market Monitoring

- Detailed rules required
- Detailed monitoring required:
  - Of participants
  - Of RTO
  - Of rules
- Market monitoring is primarily analytical
  - Adequacy of market rules
  - Compliance with market rules
  - Exercise of market power
  - Market manipulation

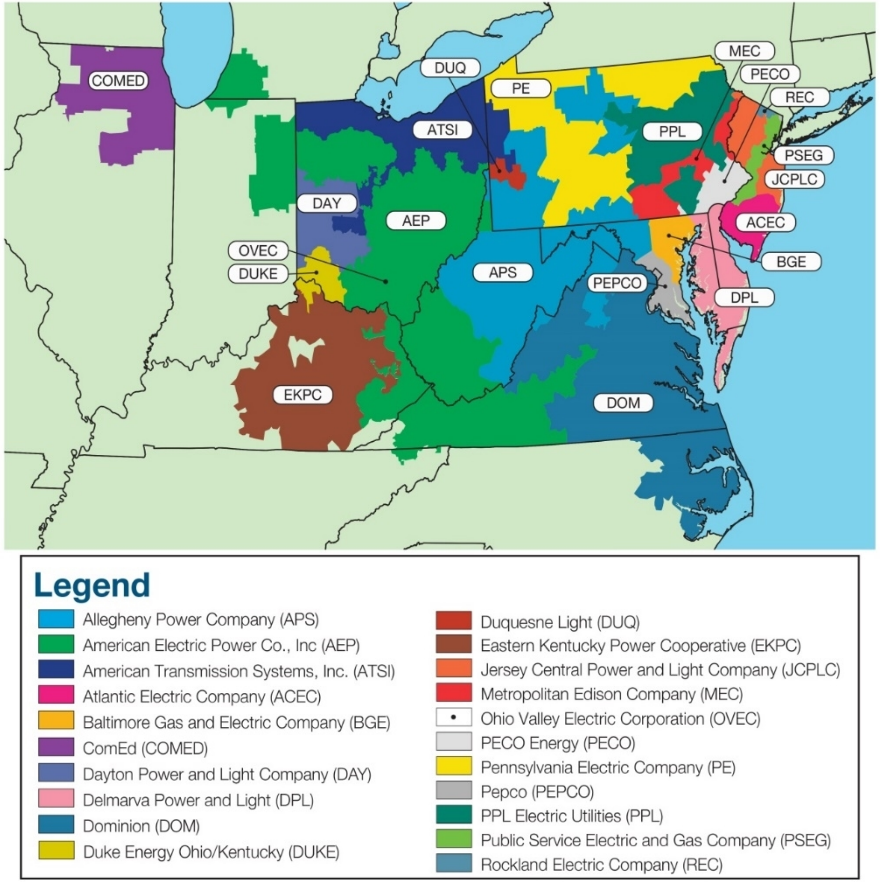
Role of Market Monitoring

- 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

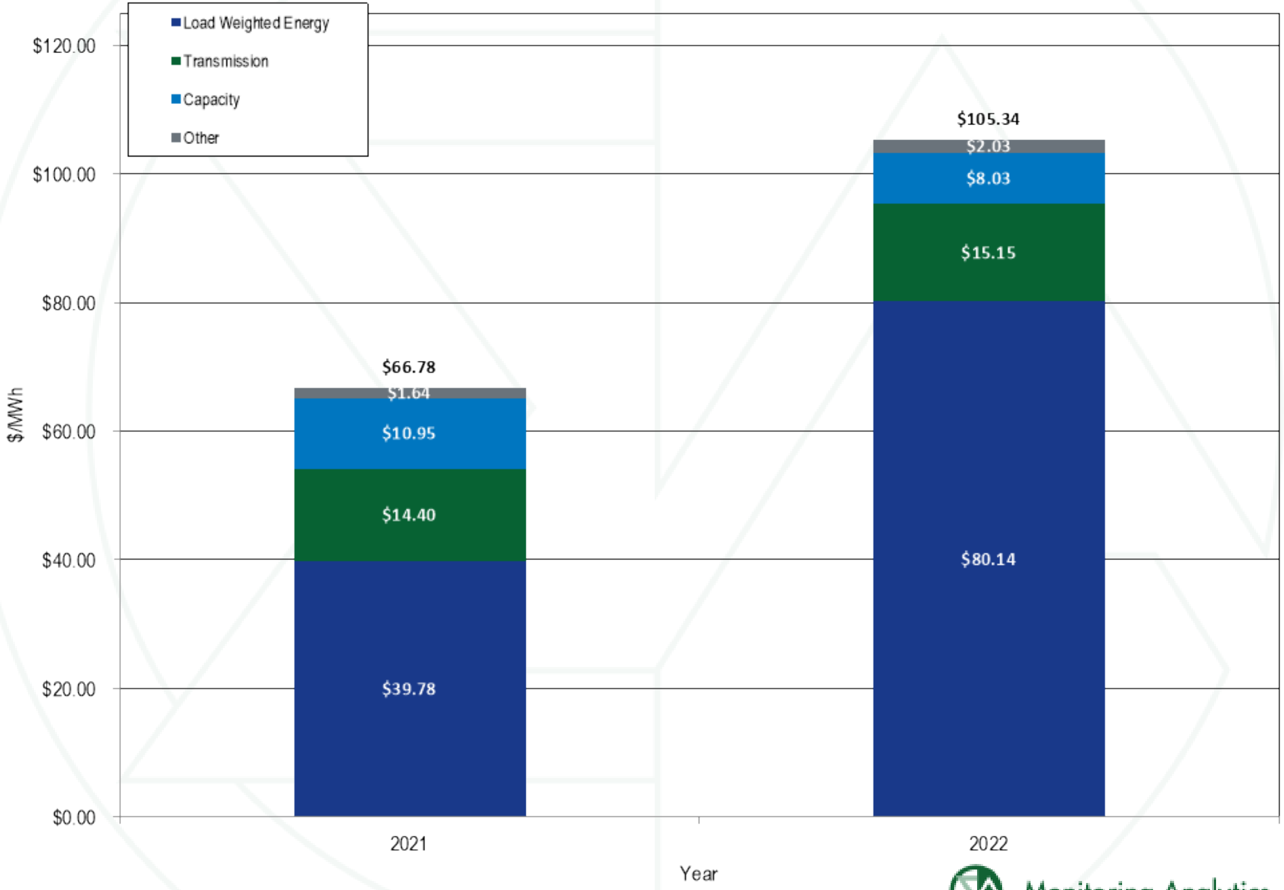
Market Monitoring Plan

- Monitor compliance with rules
  - Monitor the potential of market participants to exercise market power
  - Monitor for market manipulation
- Recommend changes to rules
  - Monitor actual or potential design flaws in rules
  - Monitor structural problems in the PJM market
- Report on market issues
  - State of the market reports
  - Other reports

PJM


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

Total price of wholesale power



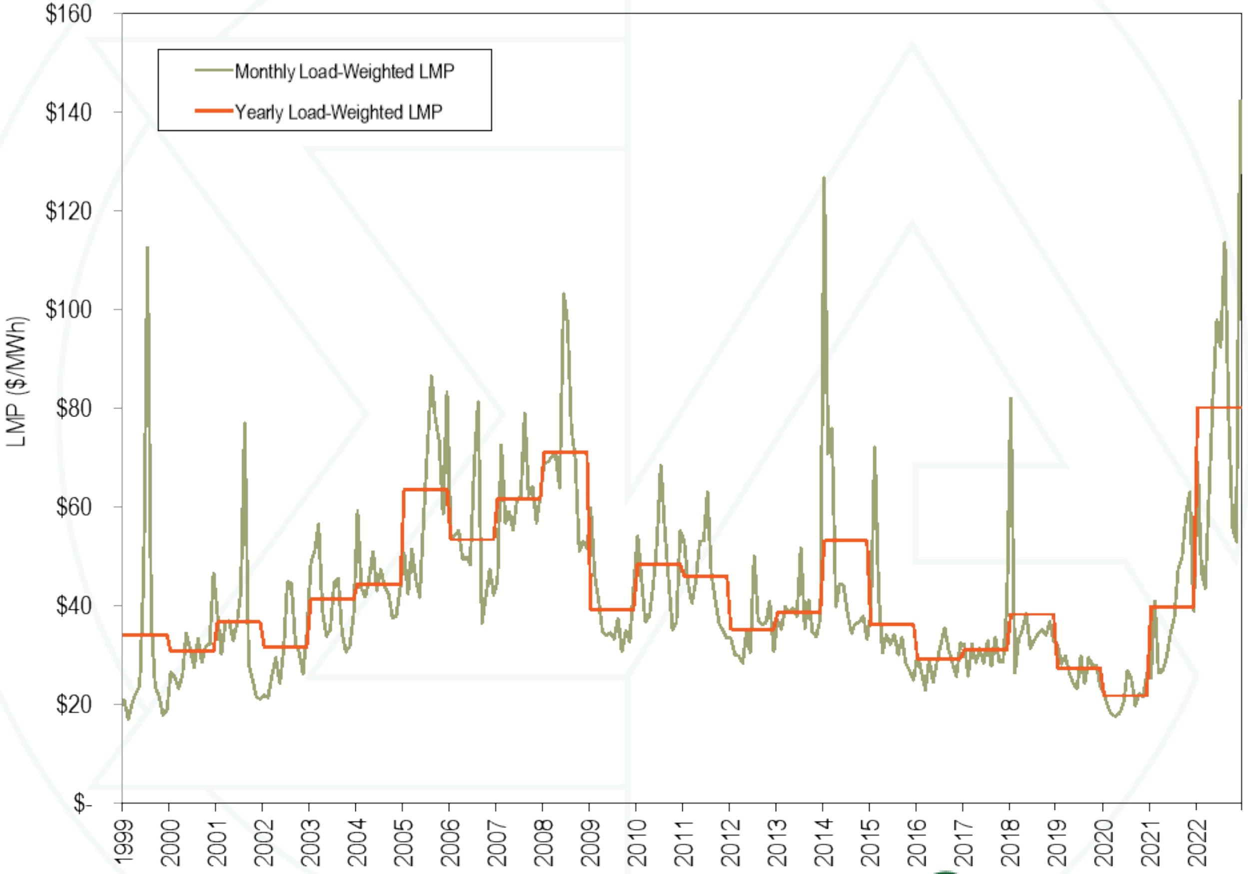
PJM summary statistics

	2021	2022	Percent Change
Average Hourly Load Plus Exports (MWh)	92,774	94,301	1.6%
Average Hourly Generation Plus Imports (MWh)	94,501	96,147	1.7%
Peak Load Plus Export (MWh)	151,680	149,531	(1.4%)
Installed Capacity at December 31 (MW)	186,593	183,385	(1.7%)
Load Weighted Average Real Time LMP ($/MWh)	$39.78	$80.14	101.4%
Total Congestion Costs ($ Million)	$995.3	$2,501.3	151.3%
Total Uplift Credits ($ Million)	$178.4	$289.9	62.5%
Total PJM Billing ($ Billion)	$54.13	$86.22	59.3%

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**

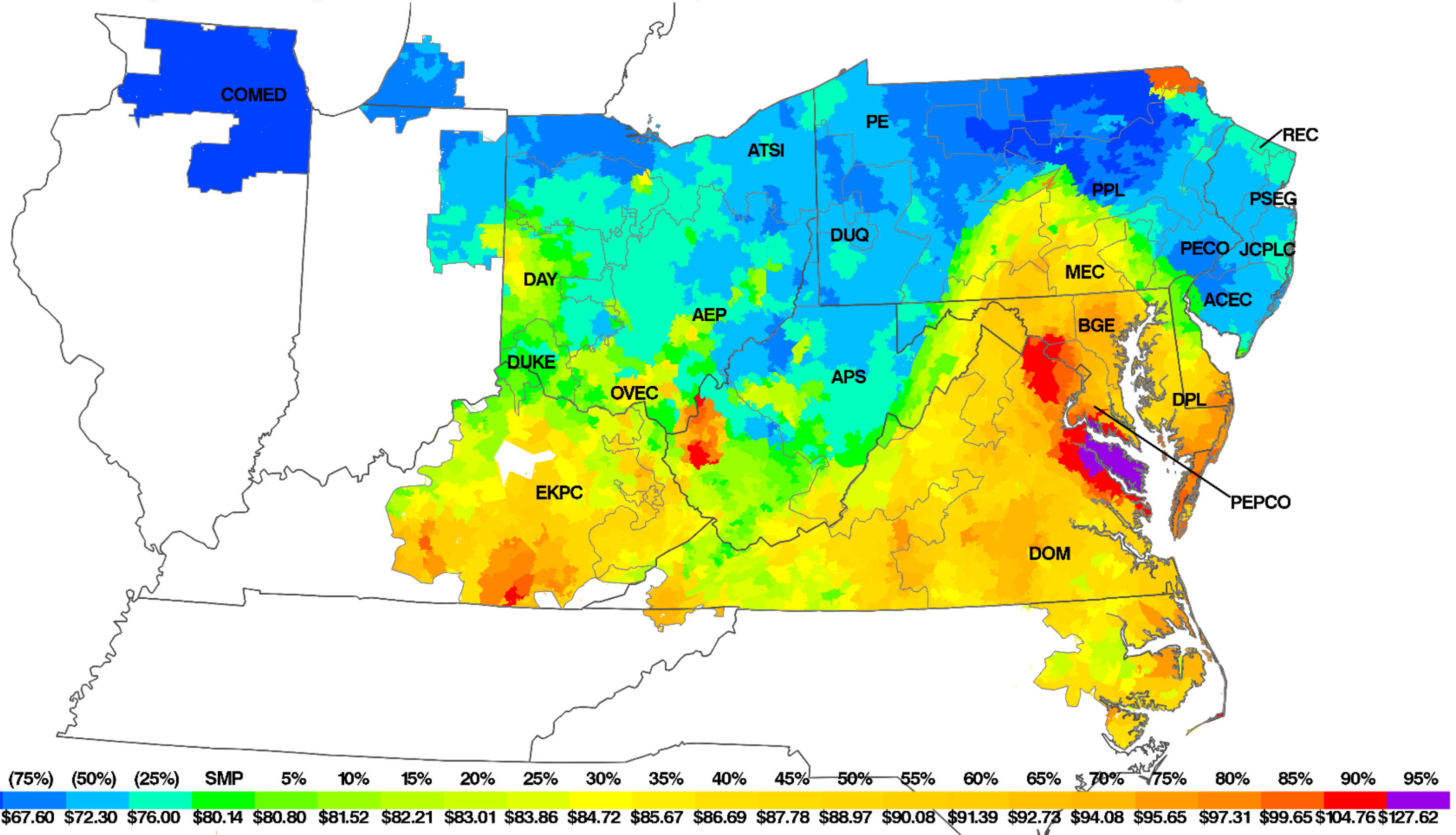
RT monthly and yearly load-weighted average LMP



Real-time load-weighted average LMP

	Real-Time Load-Weighted Average LMP			Year to Year Change			
	Average	Median	Standard Deviation	Average	Average Percent	Median	Standard Deviation
1998	$24.16	$17.60	$39.29	NA	NA	NA	NA
1999	$34.07	$19.02	$91.49	$9.91	41.0%	8.1%	132.8%
2000	$30.72	$20.51	$28.38	($3.34)	(9.8%)	7.9%	(69.0%)
2001	$36.65	$25.08	$57.26	$5.93	19.3%	22.3%	101.8%
2002	$31.60	$23.40	$26.75	($5.06)	(13.8%)	(6.7%)	(53.3%)
2003	$41.23	$34.96	$25.40	$9.64	30.5%	49.4%	(5.0%)
2004	$44.34	$40.16	$21.25	$3.10	7.5%	14.9%	(16.3%)
2005	$63.46	$52.93	$38.10	$19.12	43.1%	31.8%	79.3%
2006	$53.35	$44.40	$37.81	($10.11)	(15.9%)	(16.1%)	(0.7%)
2007	$61.66	$54.66	$36.94	$8.31	15.6%	23.1%	(2.3%)
2008	$71.13	$59.54	$40.97	$9.47	15.4%	8.9%	10.9%
2009	$39.05	$34.23	$18.21	($32.09)	(45.1%)	(42.5%)	(55.6%)
2010	$48.35	$39.13	$28.90	$9.30	23.8%	14.3%	58.7%
2011	$45.94	$36.54	$33.47	($2.41)	(5.0%)	(6.6%)	15.8%
2012	$35.23	$30.43	$23.66	($10.71)	(23.3%)	(16.7%)	(29.3%)
2013	$38.66	$33.25	$23.78	$3.43	9.7%	9.3%	0.5%
2014	$53.14	$36.20	$76.20	$14.47	37.4%	8.9%	220.4%
2015	$36.16	$27.66	$31.06	($16.98)	(31.9%)	(23.6%)	(59.2%)
2016	$29.23	$25.01	$16.12	($6.93)	(19.2%)	(9.6%)	(48.1%)
2017	$30.99	$26.35	$19.32	$1.76	6.0%	5.4%	19.9%
2018	$38.24	$29.55	$32.89	$7.25	23.4%	12.1%	70.2%
2019	$27.32	$23.63	$23.12	($10.92)	(28.6%)	(20.0%)	(29.7%)
2020	$21.77	$19.07	$12.50	($5.55)	(20.3%)	(19.3%)	(45.9%)
2021	$39.78	$32.11	$27.72	$18.02	82.8%	68.4%	121.8%
2022	$80.14	$60.09	$135.55	$40.36	101.4%	87.2%	389.1%

RT load-weighted average LMP



Components of RT load-weighted average LMP

	2021		2022		Change in
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Percent
Gas	$21.43	53.9%	$41.42	51.7%	(2.2%)
Positive Markup	$3.68	9.2%	$7.29	9.1%	(0.2%)
Coal	$4.11	10.3%	$5.66	7.1%	(3.3%)
Scarcity	$0.22	0.6%	$5.05	6.3%	5.7%
Ten Percent Adder	$2.54	6.4%	$4.70	5.9%	(0.5%)
Transmission Constraint Penalty Factor	$3.31	8.3%	$4.63	5.8%	(2.6%)
Market-to-Market	$0.41	1.0%	$2.48	3.1%	2.1%
Variable Maintenance	$1.36	3.4%	$2.40	3.0%	(0.4%)
NO_x Cost	$0.19	0.5%	$2.17	2.7%	2.2%
Emergency Demand Response	$0.00	0.0%	$1.75	2.2%	2.2%
CO_2 Cost	$1.08	2.7%	$1.74	2.2%	(0.5%)
Opportunity Cost Adder	$0.16	0.4%	$1.58	2.0%	1.6%
Ancillary Service Redispatch Cost	$0.35	0.9%	$1.45	1.8%	0.9%
Oil	$0.25	0.6%	$1.42	1.8%	1.2%
Variable Operations	$0.84	2.1%	$0.94	1.2%	(0.9%)
LPA Rounding Difference	$0.18	0.5%	$0.64	0.8%	0.3%
Increase Generation Differential	$0.13	0.3%	$0.35	0.4%	0.1%
NA	$1.51	3.8%	$0.25	0.3%	(3.5%)
Other	$0.01	0.0%	$0.02	0.0%	0.0%
Landfill Gas	$0.00	0.0%	$0.02	0.0%	0.0%
SO_2 Cost	$0.00	0.0%	$0.00	0.0%	(0.0%)
LPA-SCED Differential	$0.07	0.2%	($0.03)	(0.0%)	(0.2%)
Decrease Generation Differential	($0.03)	(0.1%)	($0.04)	(0.1%)	0.0%
Renewable Energy Credits	($0.03)	(0.1%)	($0.39)	(0.5%)	(0.4%)
PJM Administrative Cap	$0.00	0.0%	($1.39)	(1.7%)	(1.7%)
Negative Markup	($1.99)	(5.0%)	($3.96)	(4.9%)	0.1%
Total	$39.78	100.0%	$80.14	100.0%	0.0%

Energy market price increase

- The real-time load-weighted average LMP in 2022 increased 101.4 percent from the first nine months of 2021, from $39.78 per MWh to $80.14 per MWh.
- This is the highest average PJM price ($80.14 per MWh), the highest price increase ($40.36 per MWh) and the highest percent price increase (101.4 percent) for a year since the creation of PJM markets in 1999.

Components of Increase in real-time load-weighted average LMP: 2022

Component	2021	2022	Increase in LMP	Percent
Fuel and Consumables	$26.62	$49.45	$22.82	56.6%
Emission Related	$1.40	$5.11	$3.71	9.2%
Market Power Related	$5.59	$10.42	$4.83	12.0%
Scarcity	$0.22	$5.05	$4.83	12.0%
Transmission Constraint Penalty Factor	$3.31	$4.63	$1.31	3.2%
Ancillary Service Redispatch Cost	$0.35	$1.45	$1.11	2.7%
Emergency Demand Response	$0.00	$1.75	$1.75	4.3%
PJM Administrative Cap	$0.00	($1.39)	($1.39)	(3.5%)
All Other	$2.28	$3.67	$1.39	3.4%
Total	$39.78	$80.14	$40.36	100.0%

Components of LMP increase

- $40.36 per MWh increase in the real-time load weighted average LMP
- $22.82 per MWh (56.6 percent) was an increase in the fuel and consumables cost components of LMP
- $3.71 per MWh (9.2 percent) was an increase in the emissions cost components of LMP
- $4.83 per MWh (12.0 percent) was an increase in the sum of the markup, maintenance, and ten percent adder components of LMP
- $4.83 per MWh (12.0 percent) was an increase in the scarcity component of LMP
- $1.31 per MWh (3.2 percent) was an increase in the transmission constraint penalty factor component of LMP

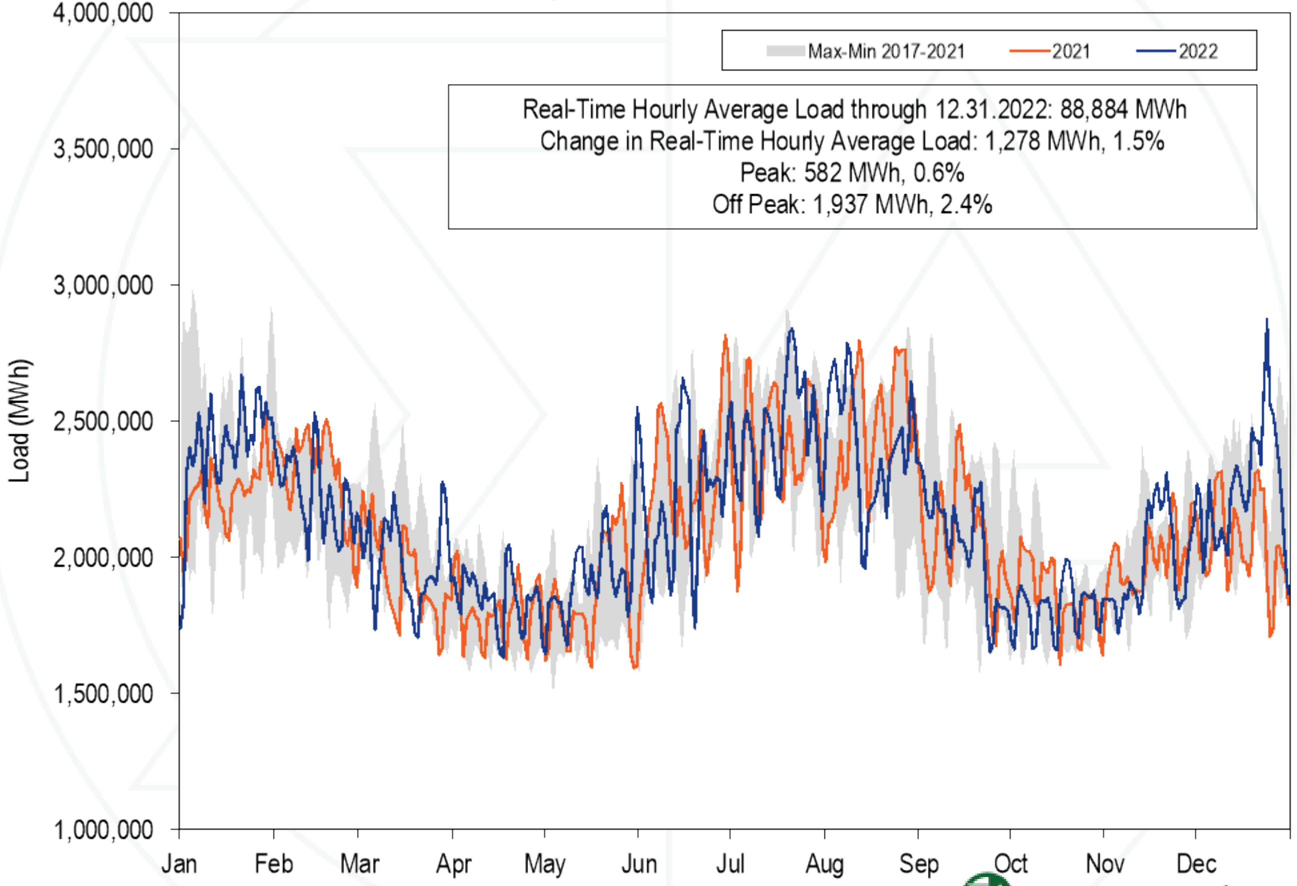
Recommendations: Energy Market

- 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.

Recommendations: Energy Market

- **Major maintenance should not be included in cost-based offers**
- **PJM should not reduce line ratings in SCED to trigger transmission constraint penalty factor.**

Real-time daily load: 2021 and 2022



RT load and load plus exports

	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	92,920	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%
2022	88,884	15,689	94,301	16,047	1.5%	(0.2%)	1.6%	(2.7%)

Generation by fuel source

		2021		2022		Change in
		GWh	Percent	GWh	Percent	Output
Coal		184,412.3	22.2%	167,650.0	20.0%	(9.1%)
	Bituminous	163,753.6	19.7%	144,880.5	17.2%	(11.5%)
	Sub Bituminous	14,421.7	1.7%	16,210.5	1.9%	12.4%
	Other Coal	6,237.0	0.7%	6,558.9	0.8%	5.2%
Nuclear		272,670.4	32.8%	271,522.1	32.3%	(0.4%)
Gas		314,885.1	37.9%	335,974.2	40.0%	6.7%
	Natural Gas CC	289,136.6	34.8%	309,420.5	36.8%	7.0%
	Natural Gas CT	19,894.4	2.4%	18,581.9	2.2%	(6.6%)
	Natural Gas Other Units	4,132.1	0.5%	6,501.5	0.8%	57.3%
	Other Gas	1,722.0	0.2%	1,470.4	0.2%	(14.6%)
Hydroelectric		16,624.8	2.0%	15,995.8	1.9%	(3.8%)
	Pumped Storage	5,037.3	0.6%	6,092.9	0.7%	21.0%
	Run of River	10,278.6	1.2%	7,945.5	0.9%	(22.7%)
	Other Hydro	1,308.9	0.2%	1,957.4	0.2%	49.6%
Wind		27,651.4	3.3%	31,491.0	3.7%	13.9%
Waste		4,475.9	0.5%	4,056.0	0.5%	(9.4%)
Oil		2,290.7	0.3%	2,698.9	0.3%	17.8%
	Heavy Oil	65.6	0.0%	76.4	0.0%	16.4%
	Light Oil	524.4	0.1%	878.9	0.1%	67.6%
	Diesel	27.7	0.0%	163.1	0.0%	489.3%
	Other Oil	1,673.1	0.2%	1,580.5	0.2%	(5.5%)
Solar		7,412.2	0.9%	9,243.0	1.1%	24.7%
Battery		36.5	0.0%	25.4	0.0%	(30.2%)
Biofuel		1,191.7	0.1%	1,371.1	0.2%	15.1%
Total		831,650.8	100.0%	840,027.6	100.0%	1.0%

Real-time hourly average load

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	Load		Load Plus Exports		Load		Load Plus Exports	
	Load	Standard Deviation	Demand	Standard Deviation	Load	Standard Deviation	Demand	Standard Deviation
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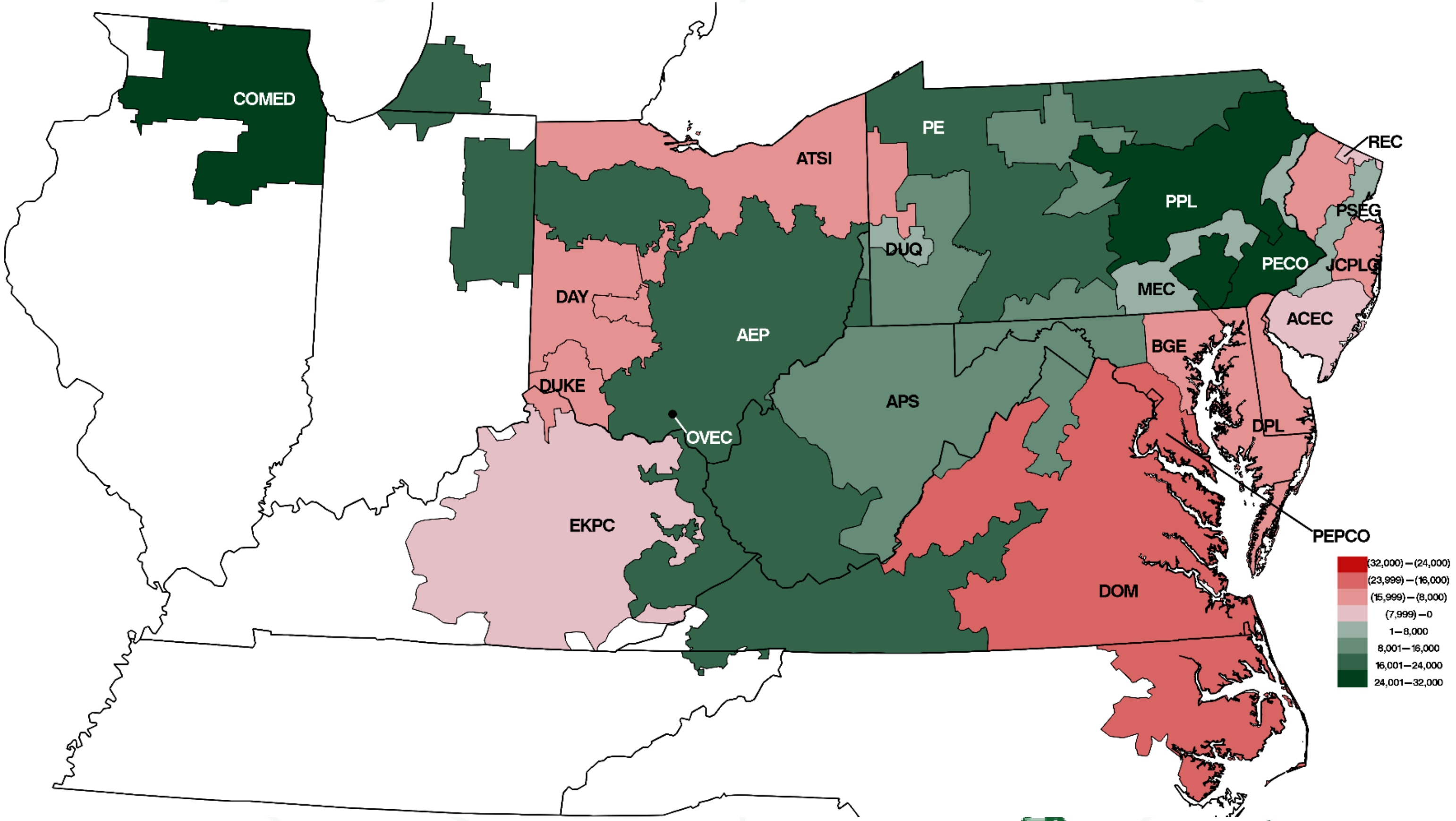
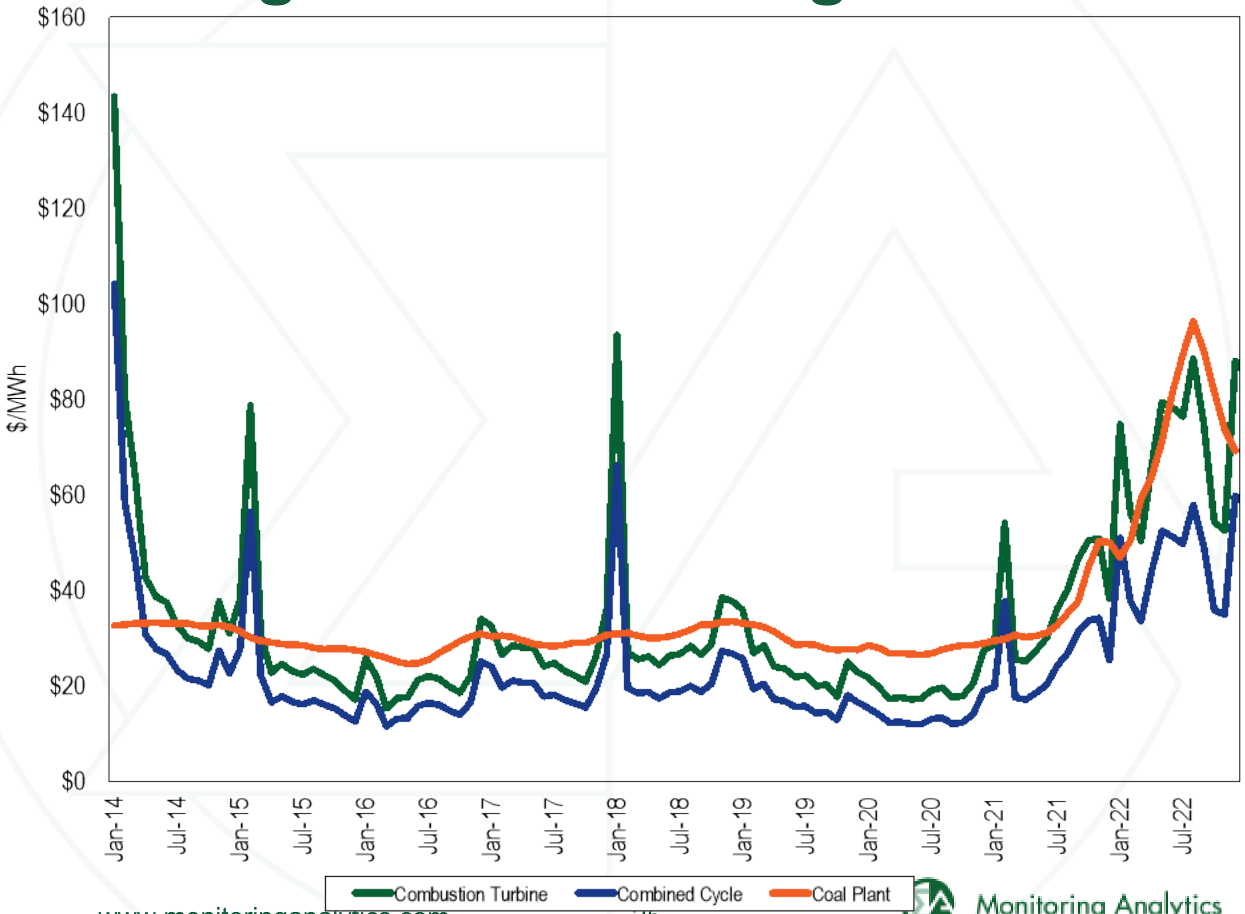
RT generation less RT load

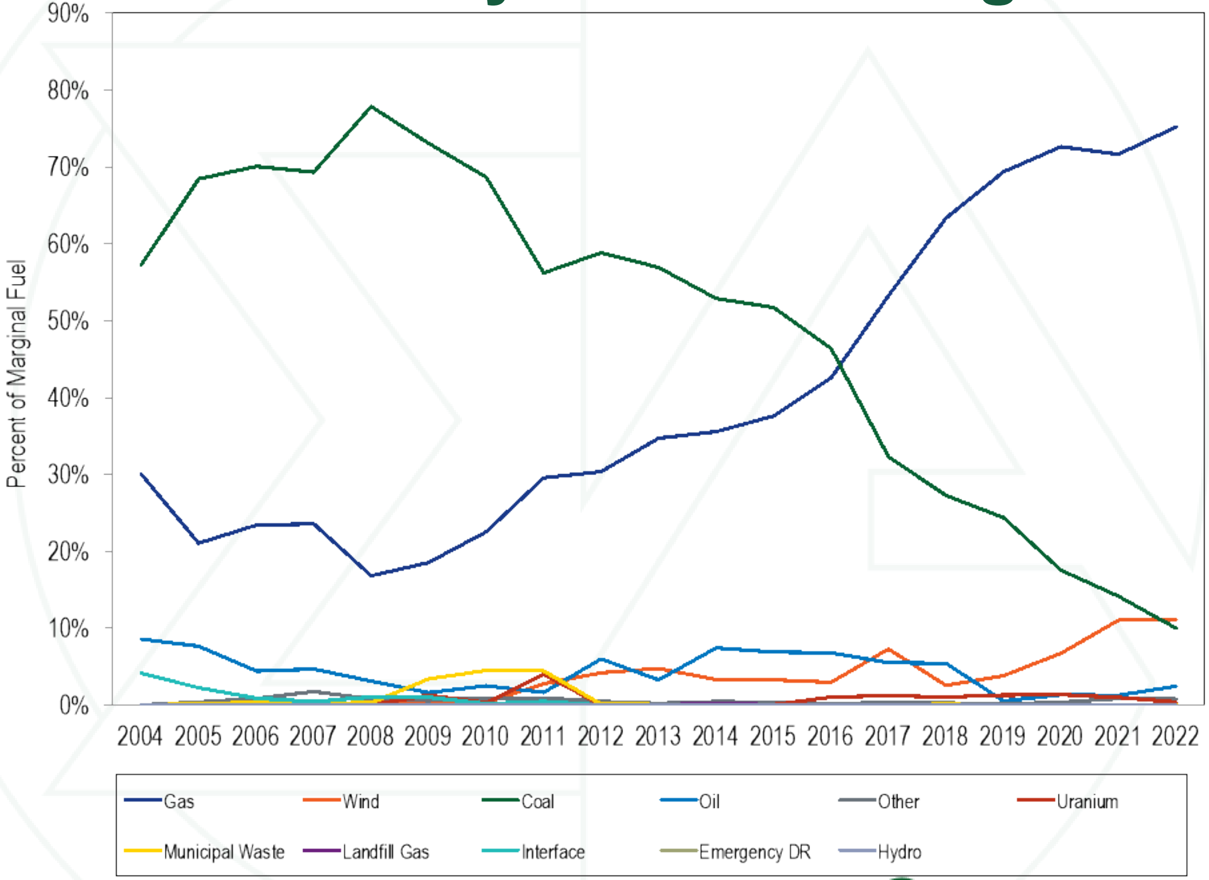


Monitoring Analytics

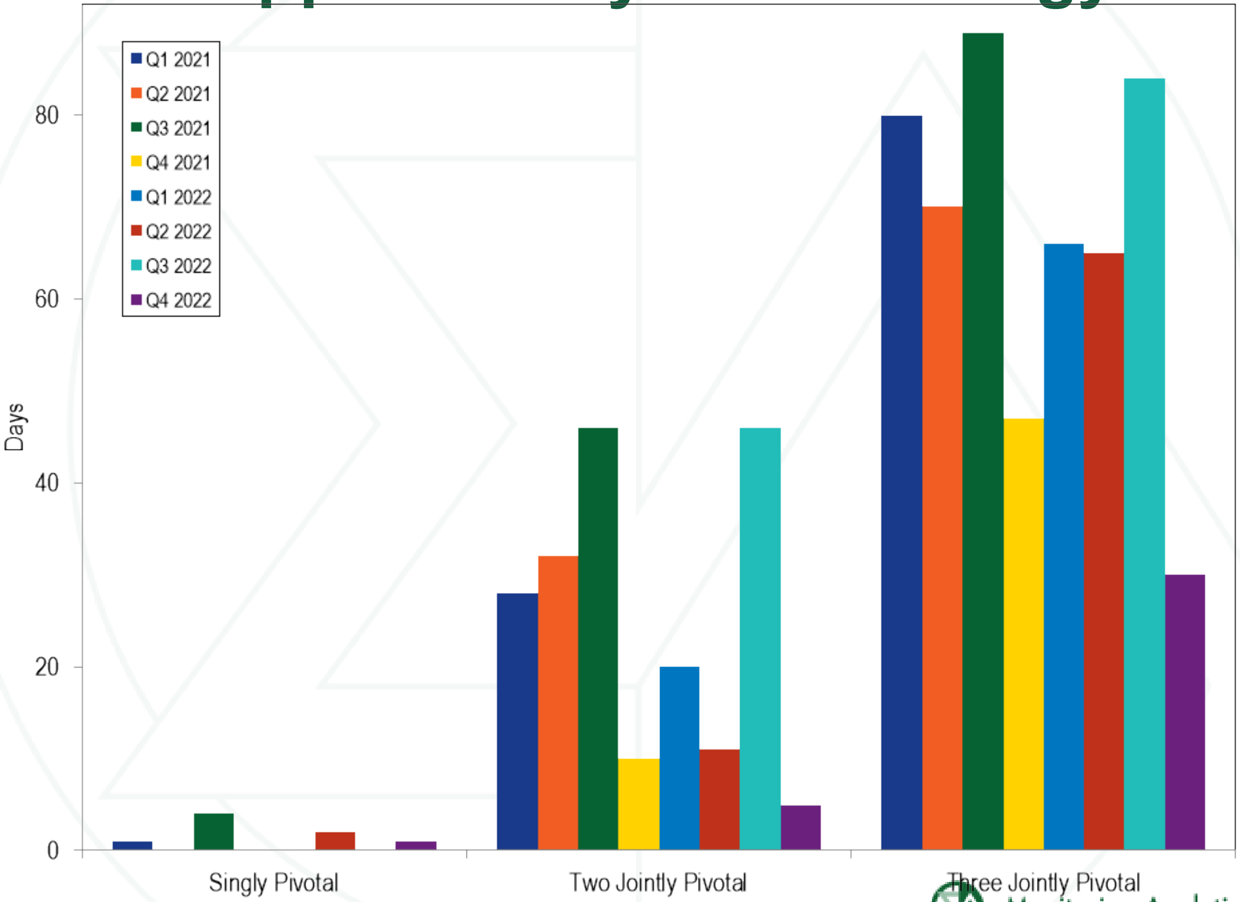
Average short run marginal costs



Type of fuel used by real-time marginal units



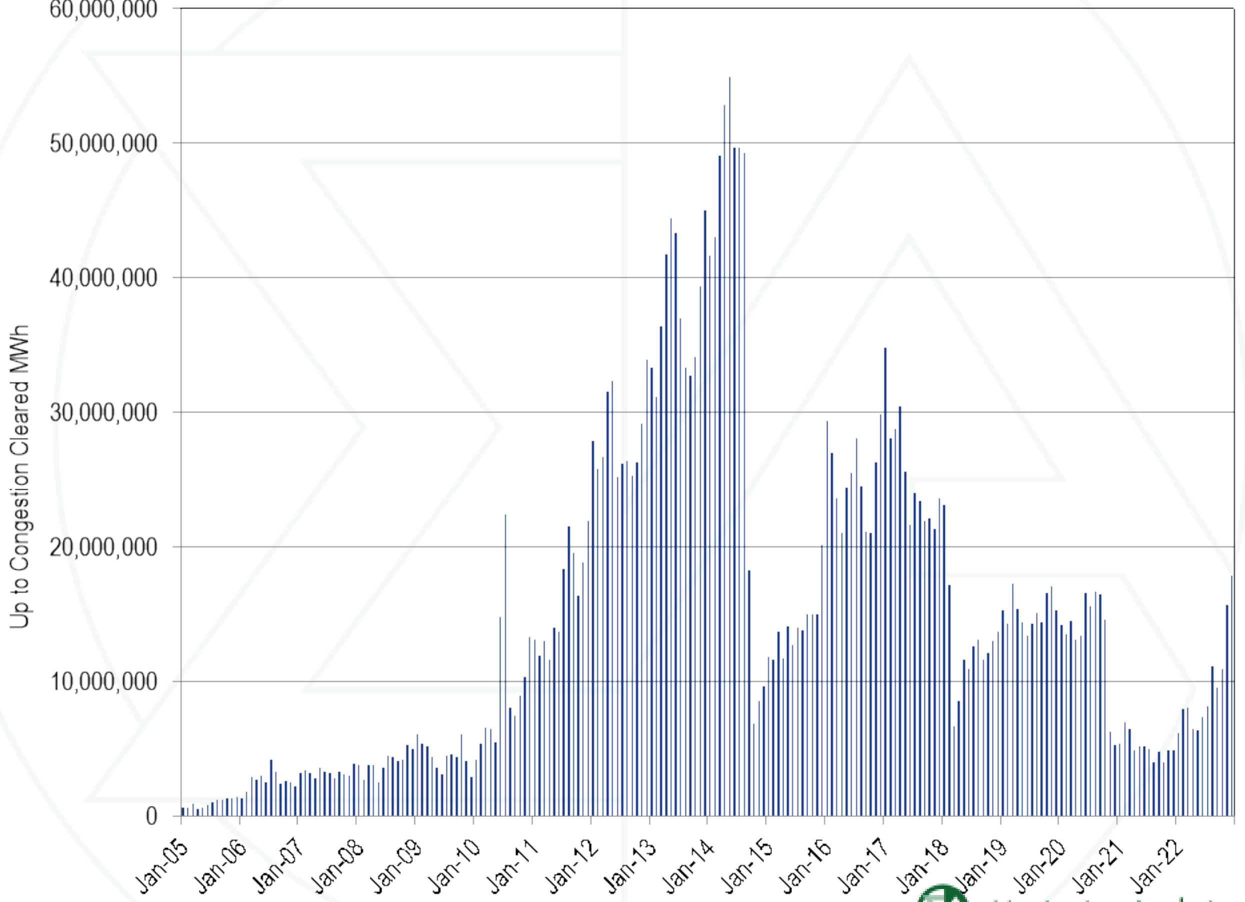
Pivotal suppliers: day-ahead energy market



Marginal units with markup and local market power

	Day-ahead Market			Real-time Market		
Markup Category	Not Failing TPS Test	Failing TPS Test	Percent in Category	Not Failing TPS Test	Failing TPS Test	Percent in Category
Negative Markup	22.3%	4.1%	26.4%	30.8%	7.9%	38.7%
Zero Markup	15.7%	4.8%	20.5%	15.2%	8.5%	23.7%
$0 to $5	12.3%	1.4%	13.6%	15.5%	3.0%	18.5%
$5 to $10	7.6%	1.1%	8.6%	6.1%	0.8%	6.9%
$10 to $15	6.6%	0.9%	7.5%	2.9%	0.4%	3.4%
$15 to $20	5.2%	0.6%	5.8%	2.5%	0.3%	2.8%
$20 to $25	4.5%	0.5%	5.0%	1.5%	0.2%	1.8%
$25 to $50	7.3%	1.1%	8.3%	2.4%	0.5%	2.9%
$50 to $75	2.2%	0.5%	2.7%	0.5%	0.2%	0.7%
$75 to $100	0.6%	0.1%	0.8%	0.2%	0.1%	0.3%
Above $100	0.5%	0.1%	0.6%	0.2%	0.2%	0.4%
Total Positive Markup	46.7%	6.4%	53.1%	31.9%	5.8%	37.7%
Total	84.8%	15.2%	100.0%	77.9%	22.1%	100.0%

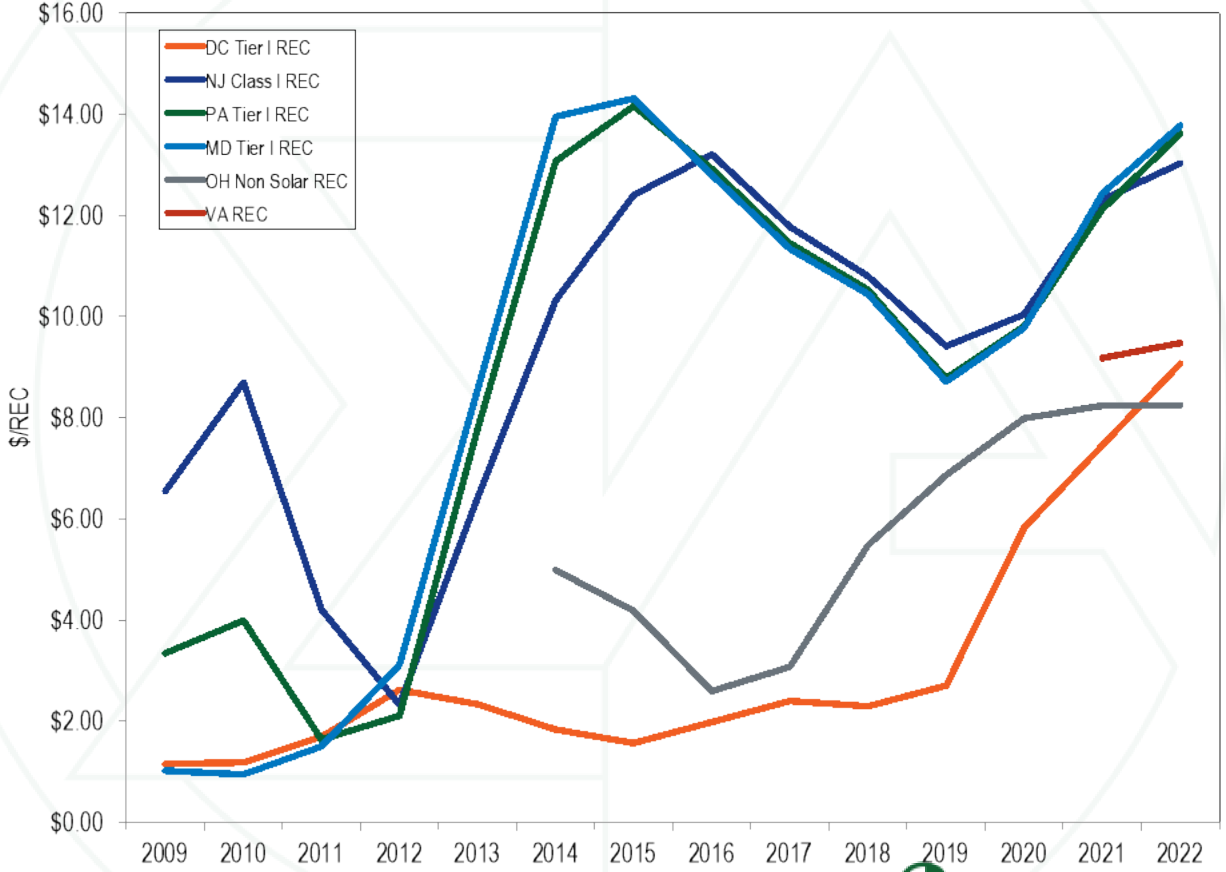
UTC cleared bids



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%
2022	$2,501	151.3%	$86,220	2.9%

Average tier 1 REC price by jurisdiction



Monitoring Analytics

Renewable energy credits (RECs)

- 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.
- Cleared separately from PJM energy market and PJM capacity market.

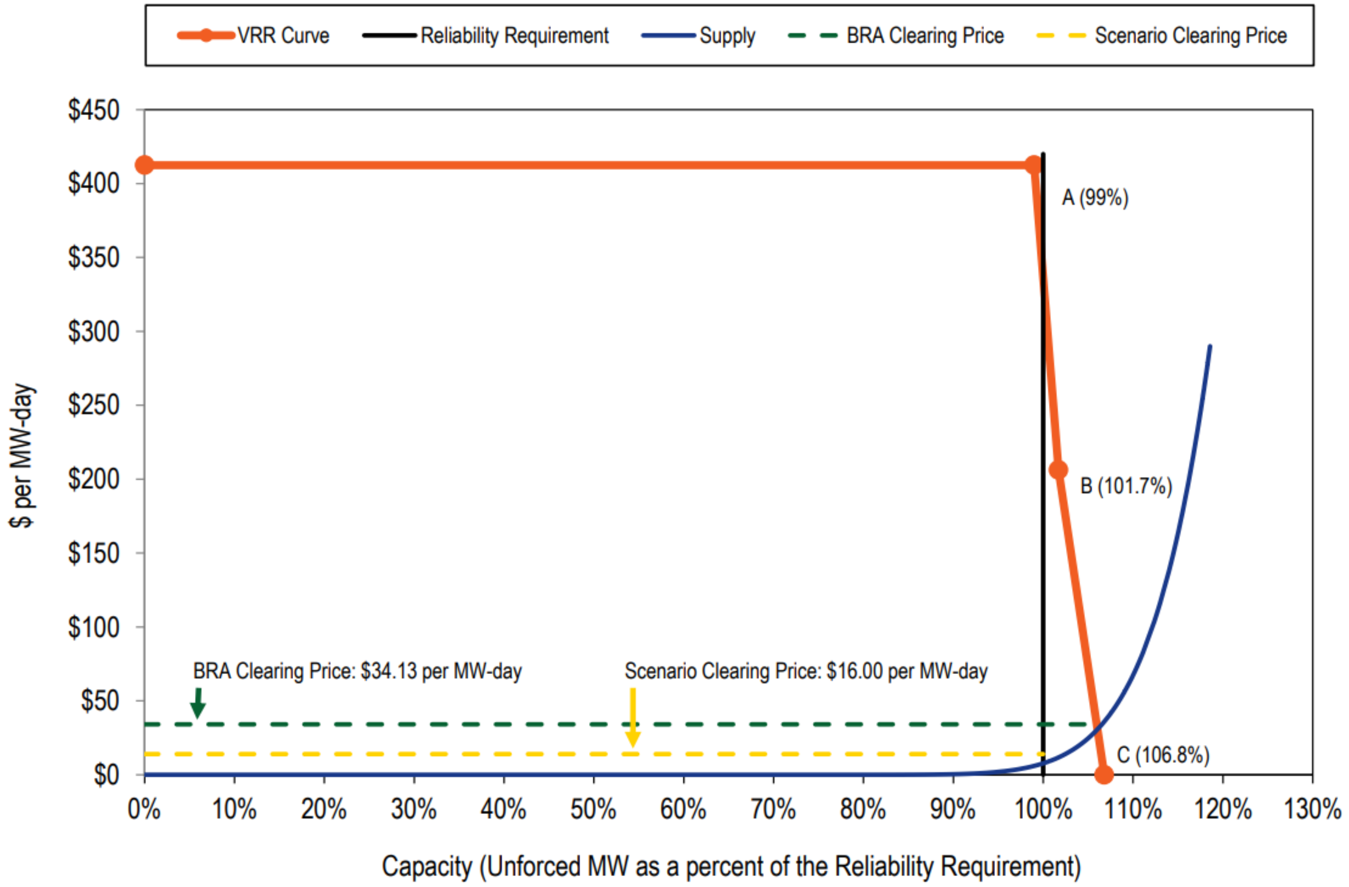
The capacity market results were competitive

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

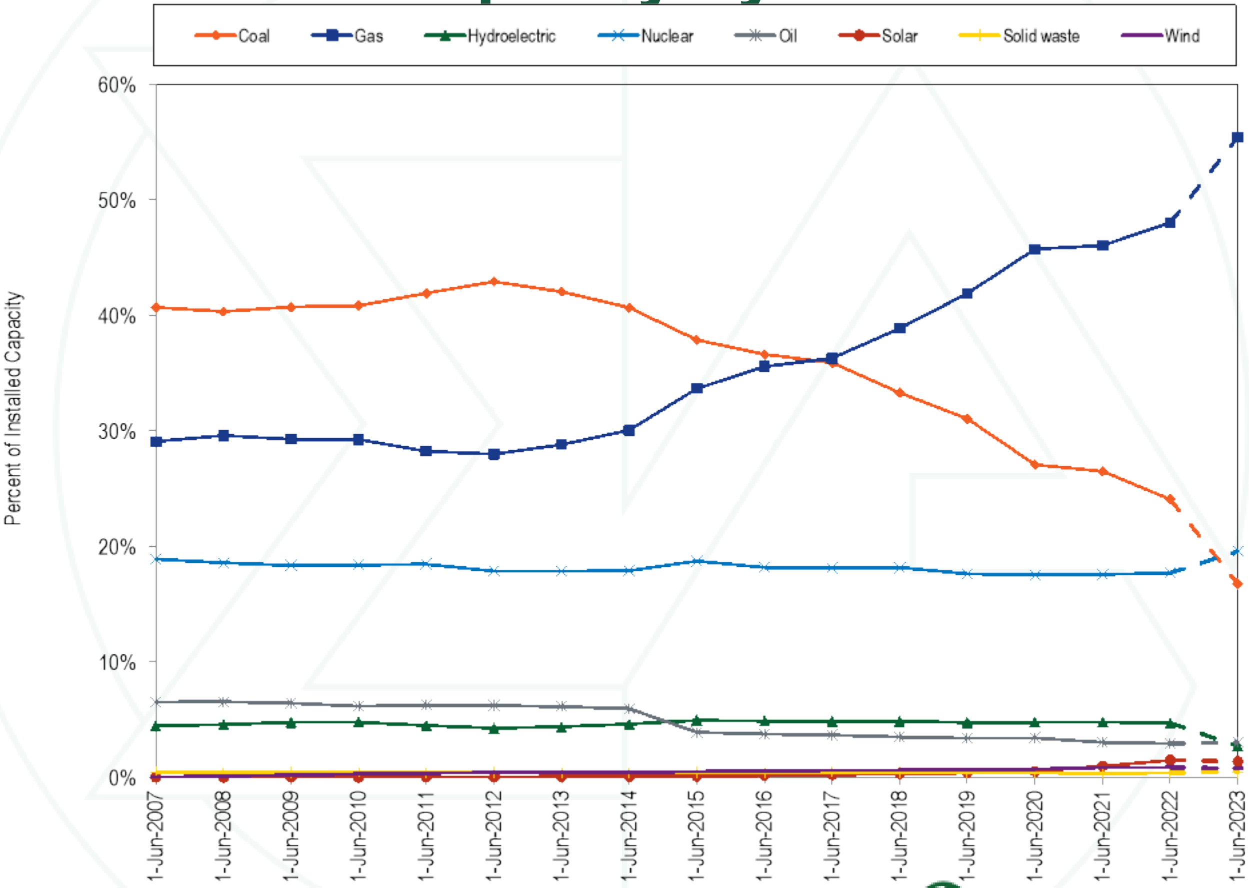
Capacity market issues

- Capacity performance design
- Market seller offer cap
- Forward looking energy net revenue offset
- VRR curve shape and location
- Definition of capacity
- Intermittent capacity definition: ELCC
- DR/EE
- MOPR
- Reserve margin

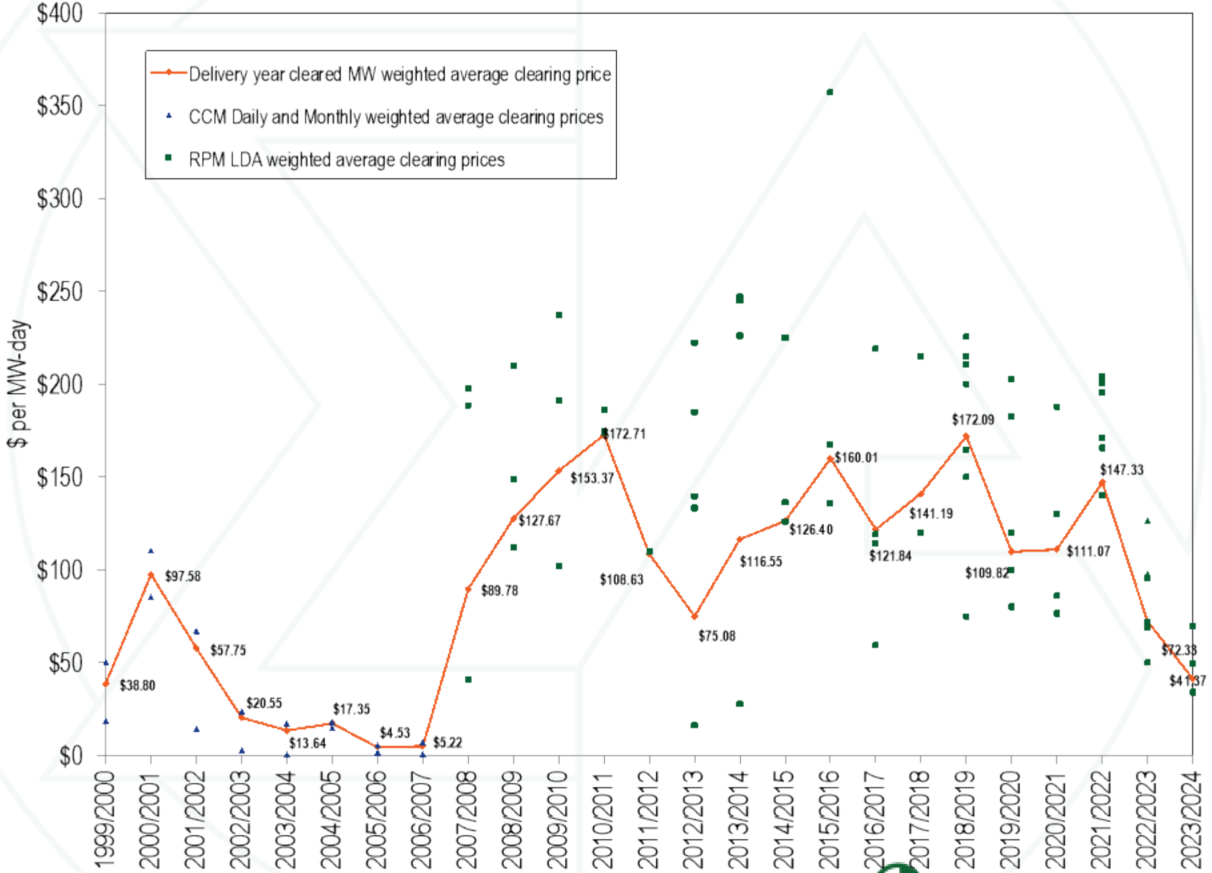
VRR curve Impacts: 2023/2024 Delivery Year



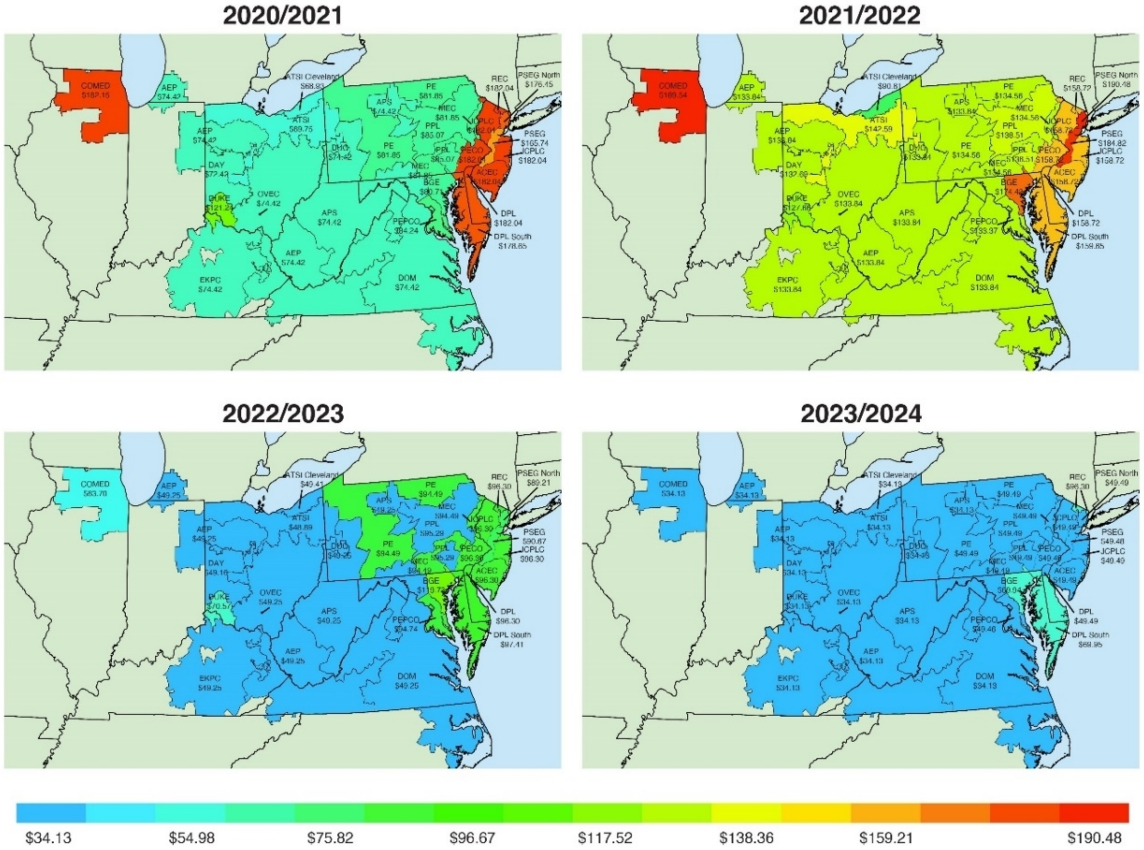
Installed capacity by fuel source



History of capacity prices



Map of RPM capacity prices



Monitoring Analytics

2023/2024 RPM BRA: RPM revenue impacts

Scenario	Scenario Description	RPM Revenue ($ per Delivery Year)	Scenario Impact RPM Revenue ($ per Delivery Year)	Percent
0	Actual Results	$2,196,444,791	NA	NA
1	Downward sloping VRR curve	$1,212,977,260	$983,467,530	81.1%
2	Modified VRR curve	$1,790,941,751	$405,503,039	22.6%
3	Over forecast peak load	$1,729,724,427	$466,720,364	27.0%
4	Change in ComEd CETL	$2,196,444,791	$0	0.0%
5	Change in MAAC CETL	$2,191,931,381	$4,513,409	0.2%
6	Overstated intermittent capacity	$2,254,726,706	($58,281,915)	(2.6%)
7	Demand resources	$4,111,765,958	($1,915,321,168)	(46.6%)
8	EE offers and EE add back	$2,114,675,175	$81,769,616	3.9%
9	PRD	$2,206,858,085	($10,413,294)	(0.5%)
10	Seasonal products	$2,277,928,225	($81,483,434)	(3.6%)
11	Seasonal matching across LDAs	$2,195,770,974	$673,816	0.0%
12	Capacity imports	$2,288,709,765	($92,264,974)	(4.0%)
13	Combined scenarios 6,7,8,9,10,12	$4,919,185,790	($2,722,740,999)	(55.3%)
14	Nuclear offers	$2,196,444,791	$0	0.0%
15	Combined scenarios 2,6,7,12	$2,901,559,097	($705,114,306)	(24.3%)

2023/2024 RPM BRA: RPM cleared UCAP MW impacts

			Scenario Impact	
Scenario	Scenario Description	Cleared UCAP (MW)	Cleared UCAP (MW)	Percent
0	Actual Results	144,870.6	NA	NA
1	Downward sloping VRR curve	131,564.3	13,306.3	10.1%
2	Modified VRR curve	141,119.4	3,751.2	2.7%
3	Over forecast peak load	139,895.0	4,975.6	3.6%
4	Change in ComEd CETL	144,870.6	0.0	0.0%
5	Change in MAAC CETL	145,199.1	(328.5)	(0.2%)
6	Overstated intermittent capacity	144,828.9	41.7	0.0%
7	Demand resources	143,568.3	1,302.2	0.9%
8	EE offers and EE add back	139,399.5	5,471.1	3.9%
9	PRD	145,126.7	(256.1)	(0.2%)
10	Seasonal products	144,526.3	344.3	0.2%
11	Seasonal matching across LDAs	144,814.6	56.0	0.0%
12	Capacity imports	144,768.4	102.2	0.1%
13	Combined scenarios 6,7,8,9,10,12	137,535.0	7,335.6	5.3%
14	Nuclear offers	144,870.6	0.0	0.0%
15	Combined scenarios 2,6,7,12	140,596.2	4,274.4	3.0%

Reserve margin: 2023/2024 RPM BRA

	Reserve Margin Calculation	
Forecast peak load ICAP (MW)	149,680.0	A
FRR peak load ICAP (MW)	28,755.0	B
PRD ICAP (MW)	235.0	C
Installed reserve margin (IRM)	14.8%	D
Pool-wide average EFORd	5.04%	E
Forecast pool requirement (FPR)	1.0901	F=(1+D)*(1-E)
Cleared UCAP (generation and DR)	139,399.5	G
Cleared ICAP (generation and DR)	146,798.1	H=G/(1-E)
RPM peak load ICAP (MW)	120,690.0	J=A-B-C
Reserve margin ICAP (MW)	26,108.1	K=H-J
Reserve margin (%)	21.6%	L=K/J
Reserve cleared in excess of IRM ICAP (MW)	8,246.0	M=K-D*J
Reserve cleared in excess of IRM (%)	6.8%	N=M/J
RPM peak load UCAP (MW)	114,607.2	P=J*(1-E)
RPM reliability requirement UCAP (MW)	131,564.2	Q=J*F
Reserve margin UCAP (MW)	24,792.3	R=G-P
Reserve cleared in excess of IRM UCAP (MW)	7,835.3	S=G-Q

RPM reserve margin: June 1, 2018, to June 1, 2023

	01-Jun-18	01-Jun-19	01-Jun-20	01-Jun-21	01-Jun-22	01-Jun-23	
Forecast peak load ICAP (MW)	152,407.9	151,643.5	148,355.3	149,482.9	149,263.6	149,680.0	A
FRR peak load ICAP (MW)	12,732.9	12,284.2	11,488.3	11,717.7	28,292.8	28,755.0	B
PRD ICAP (MW)	0.0	0.0	558.0	510.0	230.0	235.0	C
Installed reserve margin (IRM)	16.1%	16.0%	15.5%	14.7%	14.9%	14.8%	D
Pool wide average EFORd	6.07%	6.08%	5.78%	5.22%	5.08%	5.04%	E
Forecast pool requirement (FPR)	1.0905	1.0895	1.0882	1.0871	1.0906	1.0901	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	137,944.8	140,017.0	G
RPM committed less deficiency ICAP (MW) (generation and DR)	171,662.5	172,781.2	169,348.8	165,260.2	145,327.4	147,448.4	H=G/(1-E)
RPM peak load ICAP (MW)	139,675.0	139,359.3	136,309.0	137,255.2	120,740.8	120,690.0	J=A-B-C
Reserve margin ICAP (MW)	31,987.5	33,421.9	33,039.8	28,005.0	24,586.6	26,758.4	K=H-J
Reserve margin (%)	22.9%	24.0%	24.2%	20.4%	20.4%	22.2%	L=K/J
Reserve margin in excess of IRM ICAP (MW)	9,499.8	11,124.4	11,911.9	7,828.5	6,596.3	8,896.3	M=K-D*J
Reserve margin in excess of IRM (%)	6.8%	8.0%	8.7%	5.7%	5.5%	7.4%	N=M/J
RPM peak load UCAP (MW)	131,196.7	130,886.3	128,430.3	130,090.5	114,607.2	114,607.2	P=J*(1-E)
RPM reliability requirement UCAP (MW)	152,315.6	151,832.0	148,331.5	149,210.1	131,679.9	131,564.2	Q=J*F
Reserve margin UCAP (MW)	30,045.9	31,389.8	31,130.1	26,543.1	23,337.6	25,409.8	R=G-P
Reserve cleared in excess of IRM UCAP (MW)	8,927.0	10,444.1	11,228.9	7,423.5	6,264.9	8,452.8	S=G-Q
Projected replacement capacity UCAP (MW)	0.0	0.0	0.0	0.0	0.0	0.0	T
Projected reserve margin	22.9%	24.0%	24.2%	20.4%	20.4%	22.2%	U=(H-T/(1-E))/J-1

Reserve margin

- Total reserves: 24,792.3 MW
- Required reserves: 16,957.0
- Excess reserves: 7,835.3
- Cleared DR: 8,203.3 MW
  - 104.7 percent of excess reserves
- Cleared capacity with no must offer requirement: 7,534.3 MW
  - 96.2 percent of excess reserves
- Sum of DR and no must offer: 15,737.6 MW
  - 92.8 percent of required reserves
  - 63.5 percent of total reserves
- Total capacity with no must offer requirement: 17,037.1 MW

Reliability and Markets: Issues

- Apparent excess reserves are not robust
  - Coal retirements (environmental/not economics)
  - Uncertainty about new capacity: renewables and gas
- Solution is to focus on reinforcing the fundamentals of the capacity market: reliable price signals
  - Aggregate
  - Locational
- Solution is not one off tweaks to capacity market parameters
- Solution is not to weaken market power mitigation rules (PJM's MSOC proposal weakens mitigation).
- Prices were not too low in 2023/2024 BRA.

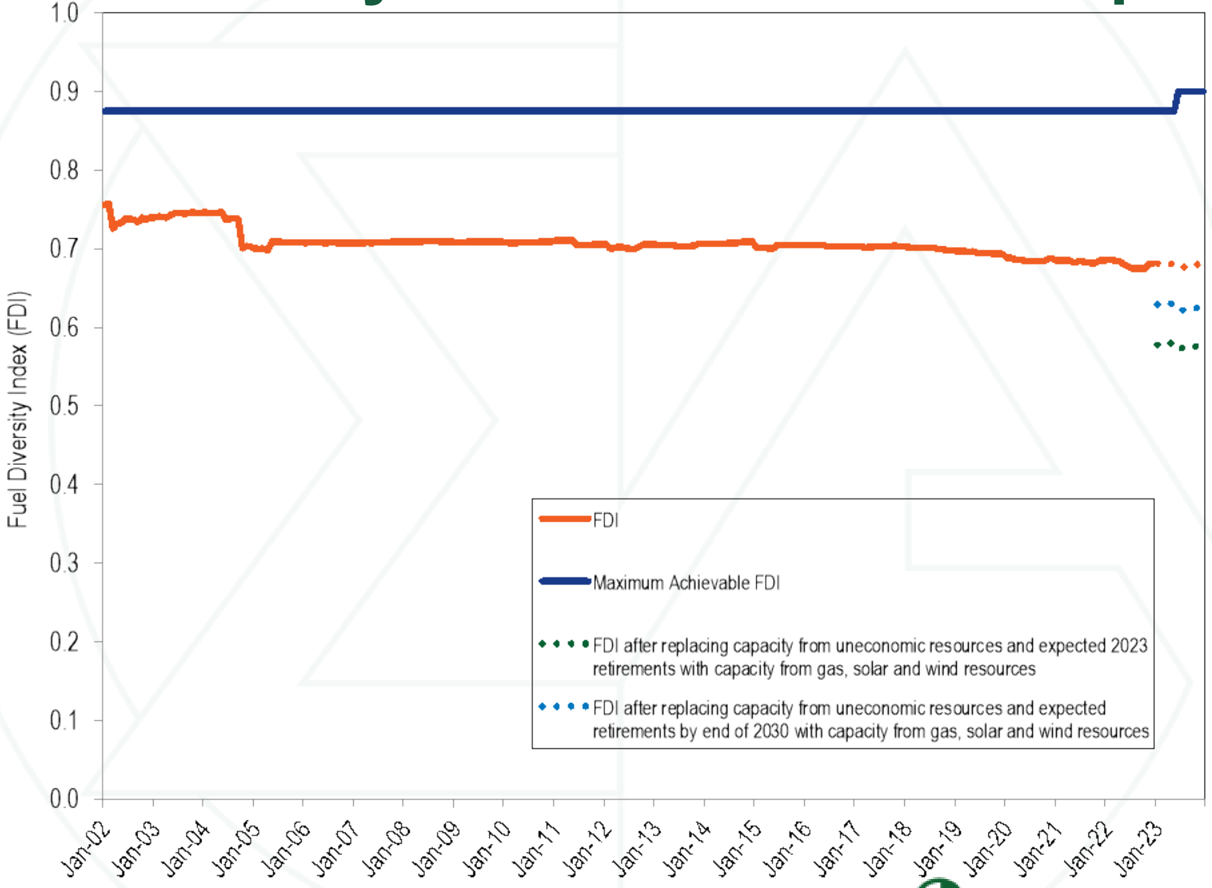
Capacity market basics

- The capacity market is a competitive mechanism that exists to make the energy market work.
- What are the essential, realistic, implementable elements of a capacity market design?

Reliability and Markets: Issues

- Correcting/defining the role/obligations of demand response resources is key to a workable capacity market.
  - Should look like any other supply side resource.
  - Economic resource. Not emergency resource.
  - Must offer in energy market.
  - Offer caps and same rules for all offers.
  - Must be available.
- Potential issues for PJM system control and markets if DER follows the demand response model.
- Role/obligations of energy efficiency (EE) resources.
  - EE should not be part of capacity market per PJM rules.

Fuel Diversity Index for installed capacity



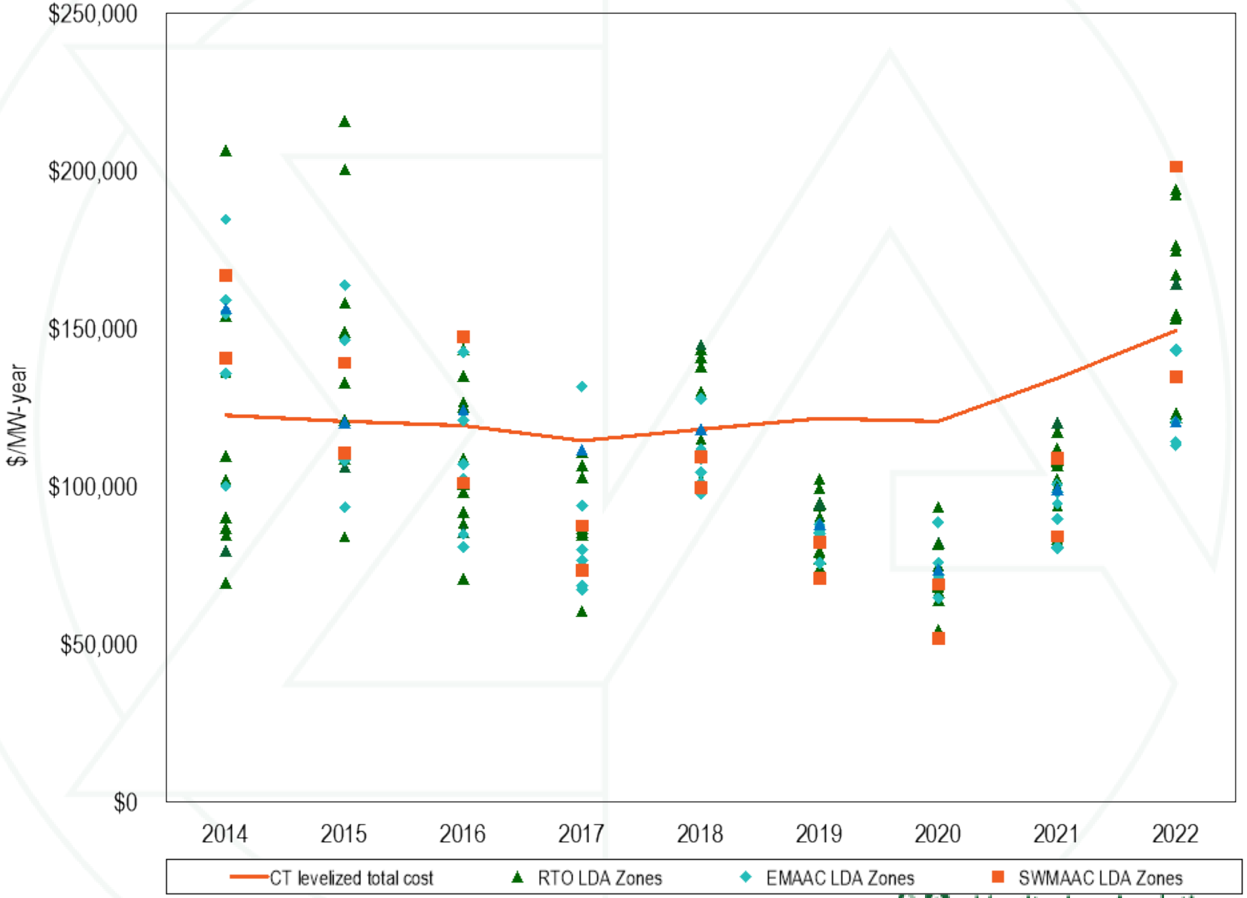
Effective capacity in interconnection queues

Unit Type	MW in Queue	Completion Rate Adjusted MW in Queue	Completion Rate and ELCC Adjusted MW in Queue
Battery	52,926.0	1,328.7	1,102.8
CC	12,767.4	7,799.0	7,799.0
CT - Natural Gas	5,002.3	3,396.3	3,396.3
CT - Oil	9.0	8.2	8.2
CT - Other	392.9	33.0	33.0
Fuel Cell	8.0	2.5	2.5
Hydro - Pumped Storage	730.0	707.2	707.2
Hydro - Run of River	112.8	52.3	52.3
Nuclear	98.2	45.4	45.4
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	128,320.3	20,712.9	11,185.0
Solar + Storage	40,179.0	33.8	18.2
Solar + Wind	209.0	0.0	0.0
Steam - Coal	65.0	23.1	23.1
Steam - Natural Gas	5.0	4.6	4.6
Steam - Oil	0.0	0.0	0.0
Steam - Other	20.0	5.4	5.4
Wind	46,393.4	6,964.0	1,044.6
Wind + Storage	240.0	0.0	0.0
Total	287,492.7	41,120.1	25,431.3

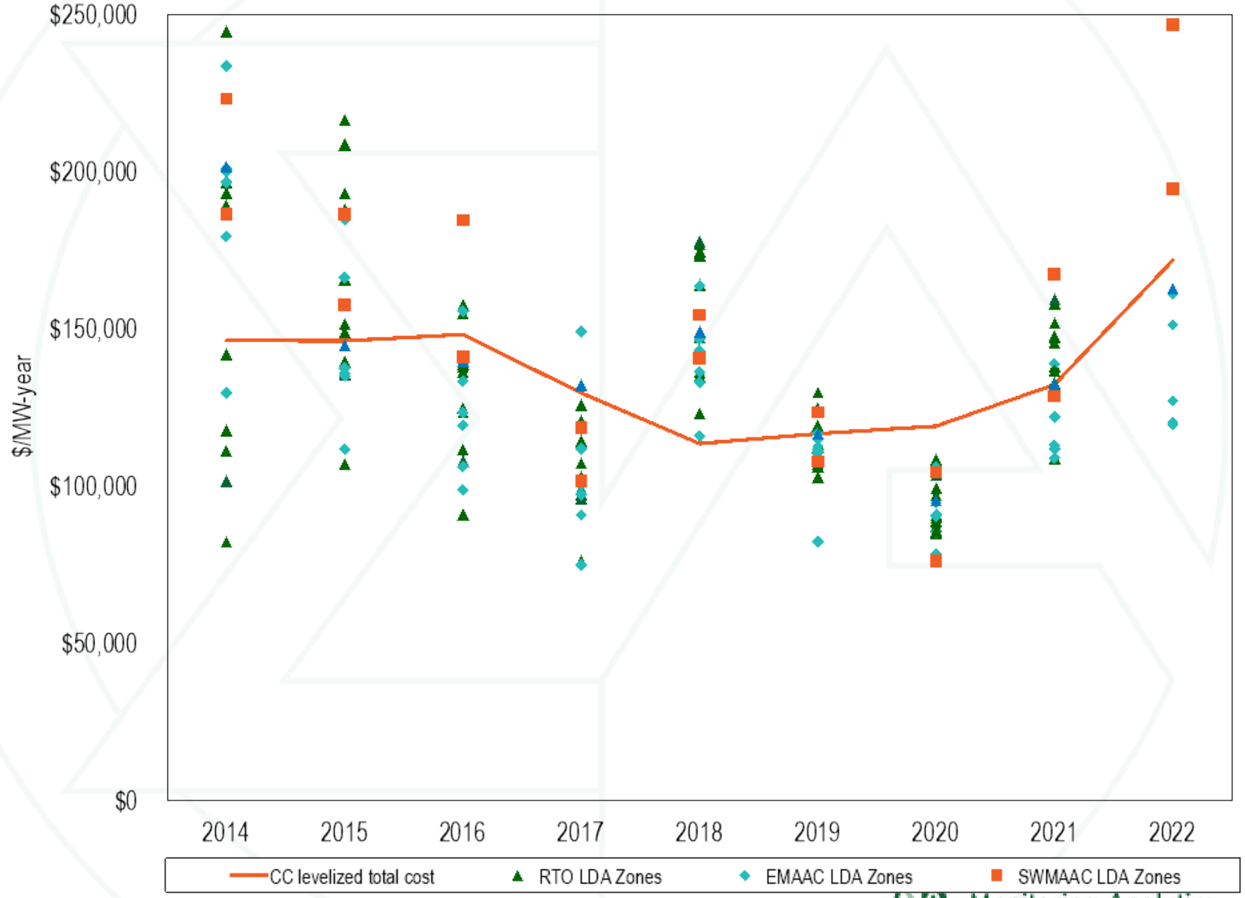
Proportion of units recovering avoidable costs

	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	2020	2021	2022	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
CC - Combined Cycle	55%	46%	50%	72%	59%	63%	57%	66%	64%	67%	50%	72%	85%	79%	79%	95%	88%	93%	89%	98%	90%	93%	83%	80%
CT - Aero Derivative	15%	6%	6%	53%	15%	8%	10%	30%	46%	42%	2%	7%	100%	96%	76%	98%	100%	99%	100%	99%	96%	96%	89%	33%
CT - Industrial Frame	26%	23%	17%	38%	13%	8%	3%	21%	30%	21%	2%	6%	99%	98%	83%	100%	100%	100%	100%	96%	92%	86%	84%	27%
Coal Fired	31%	17%	27%	78%	16%	15%	12%	11%	2%	2%	22%	27%	82%	36%	54%	83%	64%	40%	36%	63%	31%	5%	66%	33%
Diesel	48%	42%	37%	69%	56%	33%	32%	39%	11%	37%	25%	35%	100%	100%	77%	100%	100%	100%	100%	97%	91%	89%	83%	83%
Hydro	74%	61%	95%	97%	81%	79%	95%	94%	90%	72%	95%	100%	81%	77%	97%	98%	100%	100%	97%	98%	100%	74%	95%	100%
Nuclear	-	-	50%	94%	17%	6%	17%	53%	0%	0%	88%	100%	-	-	61%	100%	56%	17%	50%	88%	81%	0%	100%	100%
Oil or Gas Steam	8%	6%	11%	15%	3%	0%	0%	10%	73%	6%	10%	10%	92%	78%	86%	85%	91%	88%	81%	76%	66%	34%	67%	10%
Pumped Storage	100%	100%	95%	100%	100%	100%	100%	100%	100%	100%	29%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Solar	-	95%	97%	99%	97%	95%	95%	98%	96%	95%	100%	97%	-	95%	97%	99%	97%	95%	95%	98%	96%	95%	100%	97%
Wind	88%	85%	96%	93%	92%	89%	93%	91%	88%	79%	94%	99%	88%	85%	96%	93%	92%	89%	93%	91%	89%	79%	95%	99%

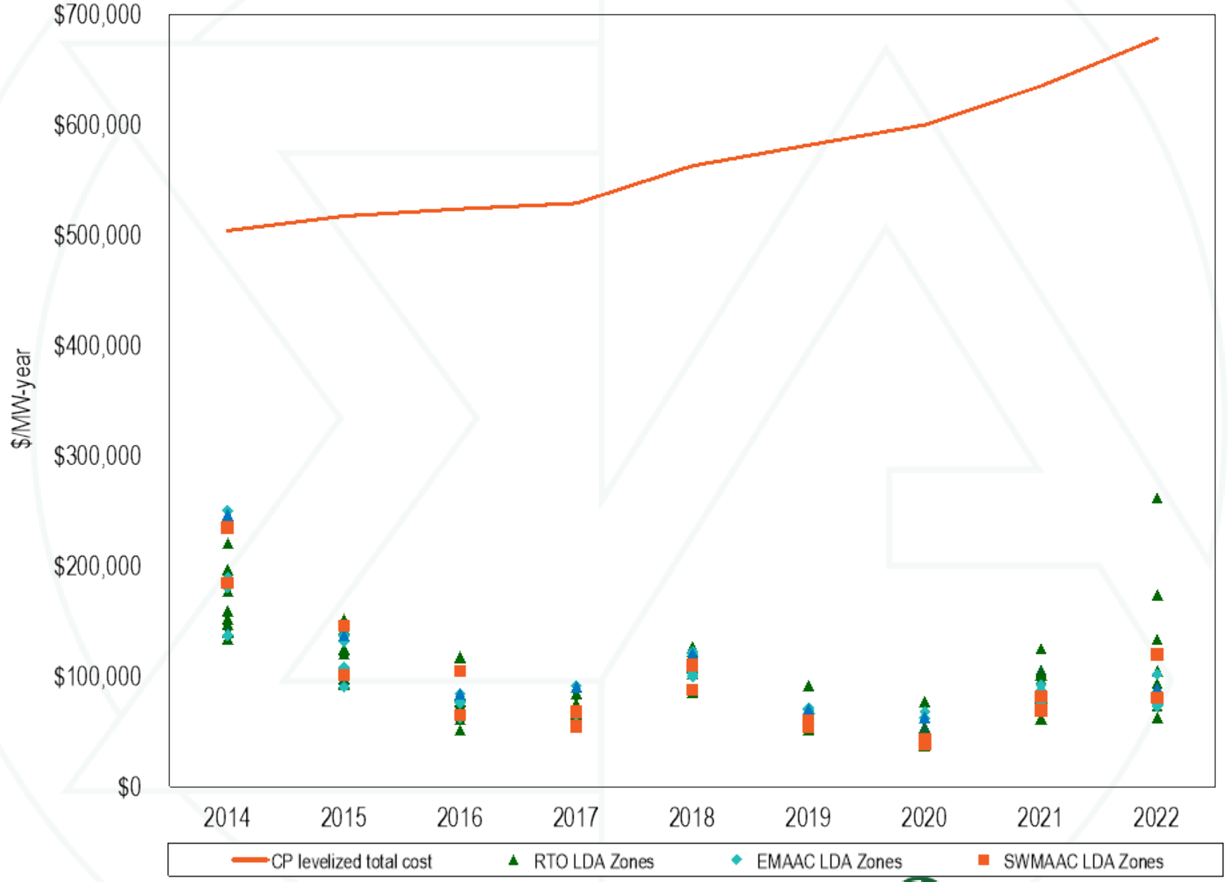
New entrant CT net revenue and total cost by LDA



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	2022
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	($2.7)	$15.0	$45.1
Braidwood	2,337	$24.9	$2.5	$6.4	$3.4	($6.1)	($2.6)	$7.2	($1.2)	($3.2)	($1.6)	$5.9	$3.9	($0.0)	$15.1	$39.1
Byron	2,300	$24.5	($1.3)	$3.4	($0.6)	($9.4)	($3.6)	$4.9	($6.1)	($9.6)	($2.8)	$5.8	$3.2	($0.6)	$14.1	$38.7
Calvert Cliffs	1,726	$60.6	$20.9	$28.6	$17.9	$4.5	$14.6	$31.6	$14.1	$7.2	$6.1	$16.3	$5.4	($0.9)	$19.4	$57.6
Davis Besse	894	NA	NA	NA	NA	($13.2)	($7.0)	$6.6	($1.2)	($4.0)	($8.4)	($0.9)	($6.3)	($15.1)	$5.9	$36.5
Dresden	1,797	$25.6	$3.0	$7.6	$4.4	($5.2)	($1.0)	$9.1	$0.3	($1.5)	($0.1)	$7.1	$4.5	$0.5	$15.7	$40.3
Hope Creek	1,172	$54.0	$17.0	$24.5	$16.9	$2.6	$12.4	$26.0	$6.3	($1.9)	$1.6	$12.3	$1.8	($2.2)	$11.0	$40.6
LaSalle	2,265	$24.8	$2.5	$6.4	$3.3	($6.1)	($1.9)	$7.7	($0.9)	($3.6)	($1.9)	$6.0	$3.7	($0.2)	$14.8	$38.8
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	$1.6	($2.6)	$11.6	$41.0
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)	$17.9	NA
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	NA
Peach Bottom	2,550	$53.7	$16.9	$24.2	$16.1	$2.3	$12.3	$25.5	$5.8	($2.2)	$1.4	$11.9	$0.7	($2.7)	$11.5	$41.1
Perry	1,240	NA	NA	NA	NA	($13.2)	($6.4)	$5.5	($0.3)	($4.0)	($7.4)	$1.9	($5.8)	($15.1)	$6.3	$37.1
Quad Cities	1,819	$24.1	($0.4)	$2.4	($1.8)	($13.2)	($6.9)	$0.6	($7.7)	($9.5)	($3.5)	$4.3	$2.1	($2.4)	$12.7	$38.9
Salem	2,285	$54.0	$17.1	$24.5	$16.9	$2.6	$12.4	$26.0	$6.2	($2.1)	$1.5	$12.2	$1.6	($2.3)	$10.9	$40.4
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)	$17.2	NA
Susquehanna	2,494	$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)	$8.6	$38.6
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	NA

Nuclear unit forward annual surplus (shortfall)

	ICAP (MW)	Surplus (Shortfall) ($/MWh) 2023	Subsidy ($/MWh) 2023	Surplus (Shortfall) Excluding Subsidy ($ in millions) 2023	Surplus (Shortfall) Including Subsidy ($ in millions) 2023
Beaver Valley	1,808	$52.90		$775.5	$775.5
Braidwood	2,337	$44.44	$0.00	$801.3	$801.3
Byron	2,300	$39.48	$0.00	$694.0	$694.0
Calvert Cliffs	1,726	$62.47		$891.5	$891.5
Davis Besse	894	$41.88		$300.1	$300.1
Dresden	1,797	$45.79	$0.00	$636.3	$636.3
Hope Creek	1,172	$37.82	$10.00	$346.9	$444.0
LaSalle	2,265	$43.98	$0.00	$767.8	$767.8
Limerick	2,242	$42.46		$749.8	$749.8
North Anna	1,892	$60.02		NA	NA
Peach Bottom	2,550	$42.41		$851.8	$851.8
Perry	1,240	$44.60		$444.2	$444.2
Quad Cities	1,819	$36.92	$16.50	$510.3	$759.0
Salem	2,285	$37.70	$10.00	$674.0	$863.4
Surry	1,676	$58.74		NA	NA
Susquehanna	2,494	$40.49		$833.9	$833.9

Units at risk of retirement

	MW expected to retire								Total MW
	2023	2024	2025	2026	2027	2028	2029	2030	2023-2030
MW requested deactivation									
Coal	3,774	0	0	410	0	0	0	0	4,184
Natural Gas	1,459	132	0	0	0	0	0	0	1,590
Other	853	0	0	0	0	0	0	0	853
Total MW requested deactivation	6,086	132	0	410	0	0	0	0	6,628
MW expected to retire for regulatory reasons									
Coal	2,557	2,863	2,766	1,359	652	3,605	0	180	13,982
Natural Gas	320	318	0	1,027	2,375	0	0	4,900	8,940
Other	0	554	0	33	0	0	0	0	587
Total MW expected to retire for regulatory reasons	2,877	3,736	2,766	2,419	3,027	3,605	0	5,080	23,509
Additional MW uneconomic 2023-2025									
Coal									9,444
Natural Gas									9,011
Other									3,166
Total MW uneconomic									21,621
Total									
Coal	6,331	2,863	2,766	1,769	652	3,605	0	180	27,610
Natural Gas	1,779	450	0	1,027	2,375	0	0	4,900	19,541
Other	853	554	0	33	0	0	0	0	4,606
Total MW At Risk of Retirement	8,963	3,867	2,766	2,829	3,027	3,605	0	5,080	51,757

Historical retirements and expected retirements

	MW Retired													MW at Risk
	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2011-2022	2023-2030
Coal	543	5,908	2,590	2,239	7,065	243	2,038	3,167	4,111	2,132	1,020	5,385	36,440	27,610
Natural Gas	523	250	82	294	1,319	74	34	1,441	447	233	220	340	5,256	19,541
Other	131	804	187	437	879	83	41	935	899	891	70	440	5,797	4,606
Total MW	1,197	6,962	2,859	2,970	9,263	400	2,113	5,543	5,456	3,255	1,310	6,164	47,492	51,757

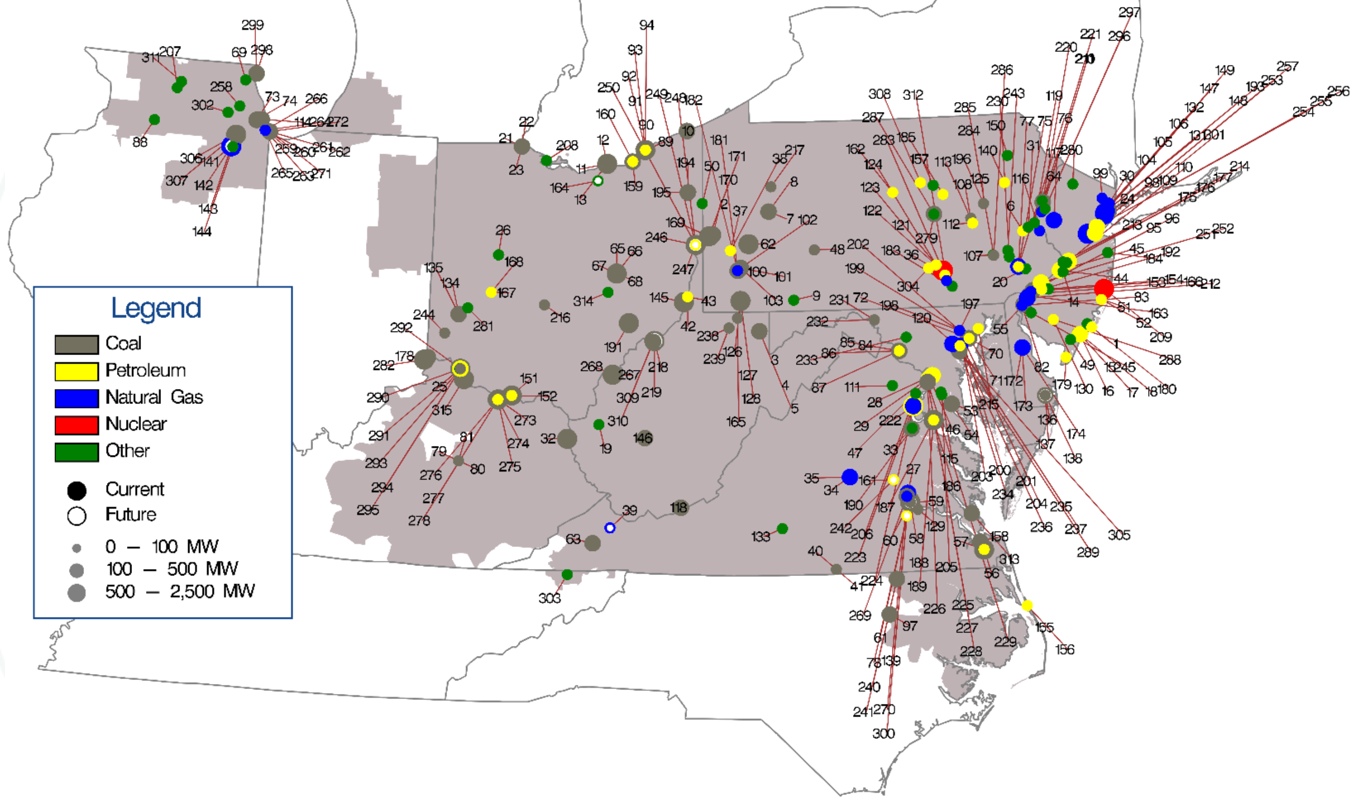
Units at risk of retirement: 50 percent of ACR

MW expected to retire 2023-2030	
MW requested deactivation	6,628
MW expected to retire for regulatory reasons	23,509
MW uneconomic 2023-2025 if ACR is reduced by 50 percent	
Coal	7,490
Natural Gas	1,160
Other	843
Total MW uneconomic	9,493
Total MW At Risk of Retirement	39,629

Gas pipeline capacity for replacement capacity

	51,757 MW At Risk		39,629 MW At Risk	
	2021	2022	2021	2022
Generation MWh				
Coal	96,434,916	88,385,951	84,969,554	76,448,164
Natural Gas	14,661,035	13,367,571	9,934,766	7,776,175
Other	1,159,165	1,480,549	1,109,324	1,362,766
Total	112,255,116	103,234,071	96,013,644	85,587,105
New gas plants needed (MWh)	97,594,081	89,866,500	86,078,878	77,810,930
New CC unit ICAP (MW)	1,182	1,182	1,182	1,182
New CC unit capacity factor	76%	76%	76%	76%
New CC unit heat rate (mmbtu/MWh)	6.369	6.369	6.369	6.369
Annual MWh from 1 new unit	7,878,188	7,878,188	7,878,188	7,878,188
Number of new CC units needed	13	12	11	10
All units run at full ICAP for 1 day (MWh)	368,784	340,416	312,048	283,680
Total Dth needed (Dth/day)	2,348,785	2,168,110	1,987,434	1,806,758
Total Bcf needed (Bcf/day)	2.3	2.2	2.0	1.8

Map of unit retirements: 2011 through 2026



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.
- MMU comments on transmission planning NOPR

Recommendations: Energy Market Uplift

- **PJM should ensure that units not following dispatch are not paid uplift.**
- **CTs should not be defined to be always following dispatch.**
- **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.**
- **Uplift should not be paid to units based on a fuel they are not burning.**
- **Uplift should not be paid to units on outage.**

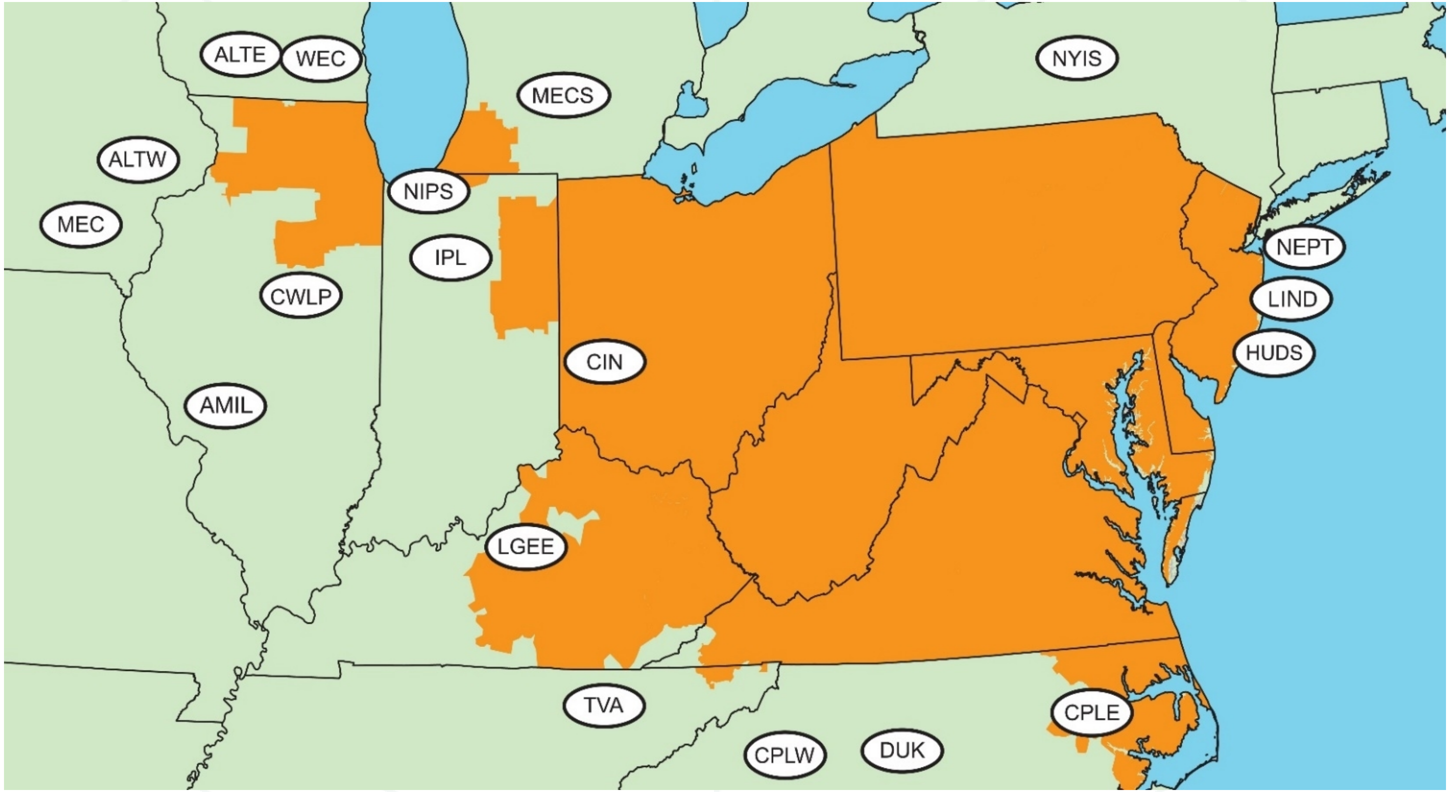
Monthly energy uplift charges

	2021 Charges (Millions)						2022 Charges (Millions)					
	Day-Ahead	Balancing	Reactive Services	Synchronous Condensing	Black Start Services	Total	Day-Ahead	Balancing	Reactive Services	Synchronous Condensing	Black Start Services	Total
Jan	$0.7	$6.8	$0.7	$0.0	$0.0	$8.2	$0.7	$14.6	$0.0	$0.0	$0.0	$15.3
Feb	$0.9	$13.7	$0.1	$0.0	$0.0	$14.6	$0.5	$5.1	$0.0	$0.0	$0.1	$5.6
Mar	$2.8	$8.5	$0.0	$0.0	$0.1	$11.4	$0.5	$7.0	$0.2	$0.0	$0.0	$7.8
Apr	$0.8	$17.1	$0.0	$0.0	$0.0	$18.0	$0.6	$13.4	$0.0	$0.0	$0.1	$14.1
May	$0.6	$8.7	$0.0	$0.0	$0.0	$9.4	$2.3	$12.1	$0.8	$0.0	$0.1	$15.3
Jun	$1.3	$16.5	$0.0	$0.0	$0.0	$17.8	$4.1	$20.1	$0.0	$0.0	$0.0	$24.2
Jul	$0.6	$19.7	$0.0	$0.0	$0.0	$20.3	$11.0	$25.7	$0.0	$0.0	$0.0	$36.7
Aug	$1.1	$21.2	$0.0	$0.0	$0.0	$22.3	$8.3	$32.1	$0.2	$0.0	$0.0	$40.6
Sep	$1.9	$7.3	$0.0	$0.0	$0.0	$9.2	$7.2	$13.4	$0.0	$0.0	$0.0	$20.6
Oct	$0.4	$14.2	$0.0	$0.0	$0.1	$14.7	$0.3	$12.8	$0.1	$0.0	$0.1	$13.3
Nov	$0.8	$21.6	$0.2	$0.0	$0.0	$22.6	$1.2	$13.2	$0.0	$0.0	$0.1	$14.5
Dec	$1.6	$8.2	$0.0	$0.0	$0.0	$9.9	$22.0	$59.5	$0.2	$0.0	$0.0	$81.7
Total	$13.7	$163.5	$0.9	$0.0	$0.3	$178.4	$58.8	$229.1	$1.5	$0.0	$0.5	$289.9
Share	7.7%	91.7%	0.5%	0.0%	0.2%	100.0%	20.3%	79.0%	0.5%	0.0%	0.2%	100.0%

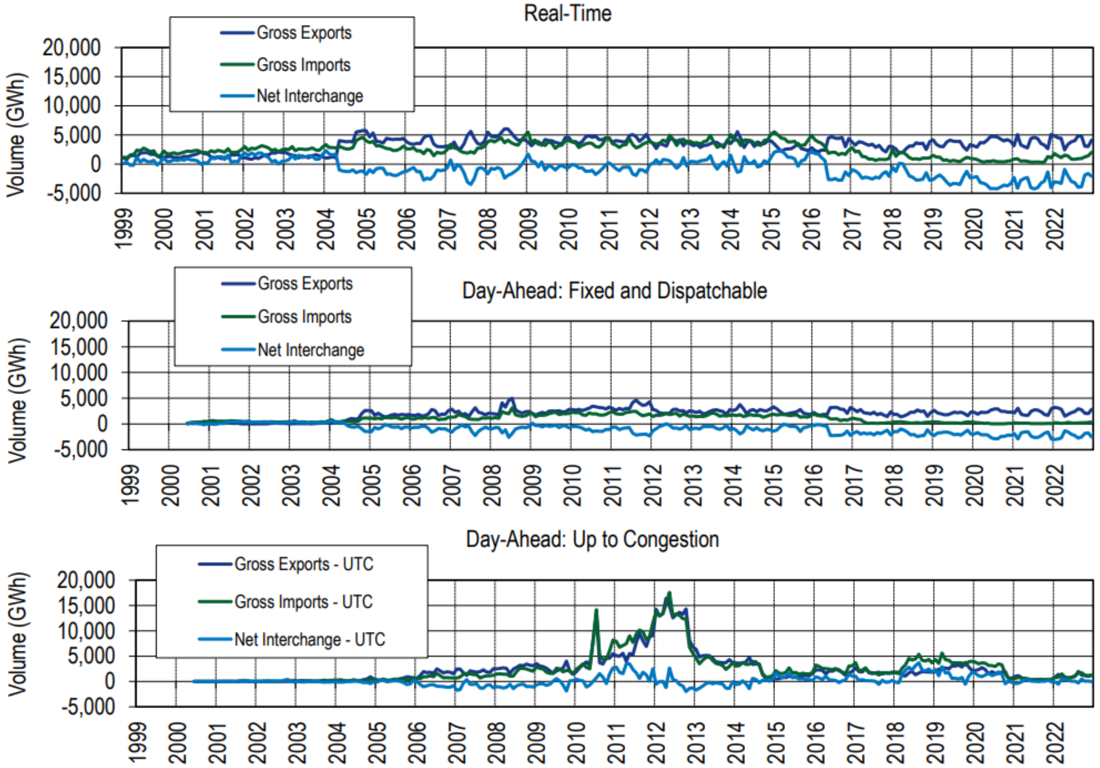
Total energy uplift credits by unit type

Unit Type	2021 Credits (Millions)	2022 Credits (Millions)	Change	Percent Change	2021 Share	2022 Share
Combined Cycle	$5.9	$33.7	$27.8	471.0%	3.3%	11.6%
Combustion Turbine	$153.5	$174.5	$21.0	13.7%	86.0%	60.2%
Diesel	$1.6	$3.1	$1.5	94.5%	0.9%	1.1%
Hydro	$0.3	$1.1	$0.8	299.6%	0.2%	0.4%
Nuclear	$0.0	$0.0	($0.0)	(93.9%)	0.0%	0.0%
Solar	$0.0	$0.1	$0.1	860.2%	0.0%	0.0%
Steam - Coal	$13.5	$35.2	$21.7	160.7%	7.6%	12.1%
Steam - Other	$3.3	$39.8	$36.5	1,100.1%	1.9%	13.7%
Wind	$0.3	$2.5	$2.1	623.3%	0.2%	0.8%
Total	$178.4	$289.9	$111.5	62.5%	100.0%	100.0%

PJM's footprint and its external scheduling interfaces



Scheduled import and export transaction volume history



Monitoring Analytics

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 synchronized reserve market results were competitive: October through December, 2022

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

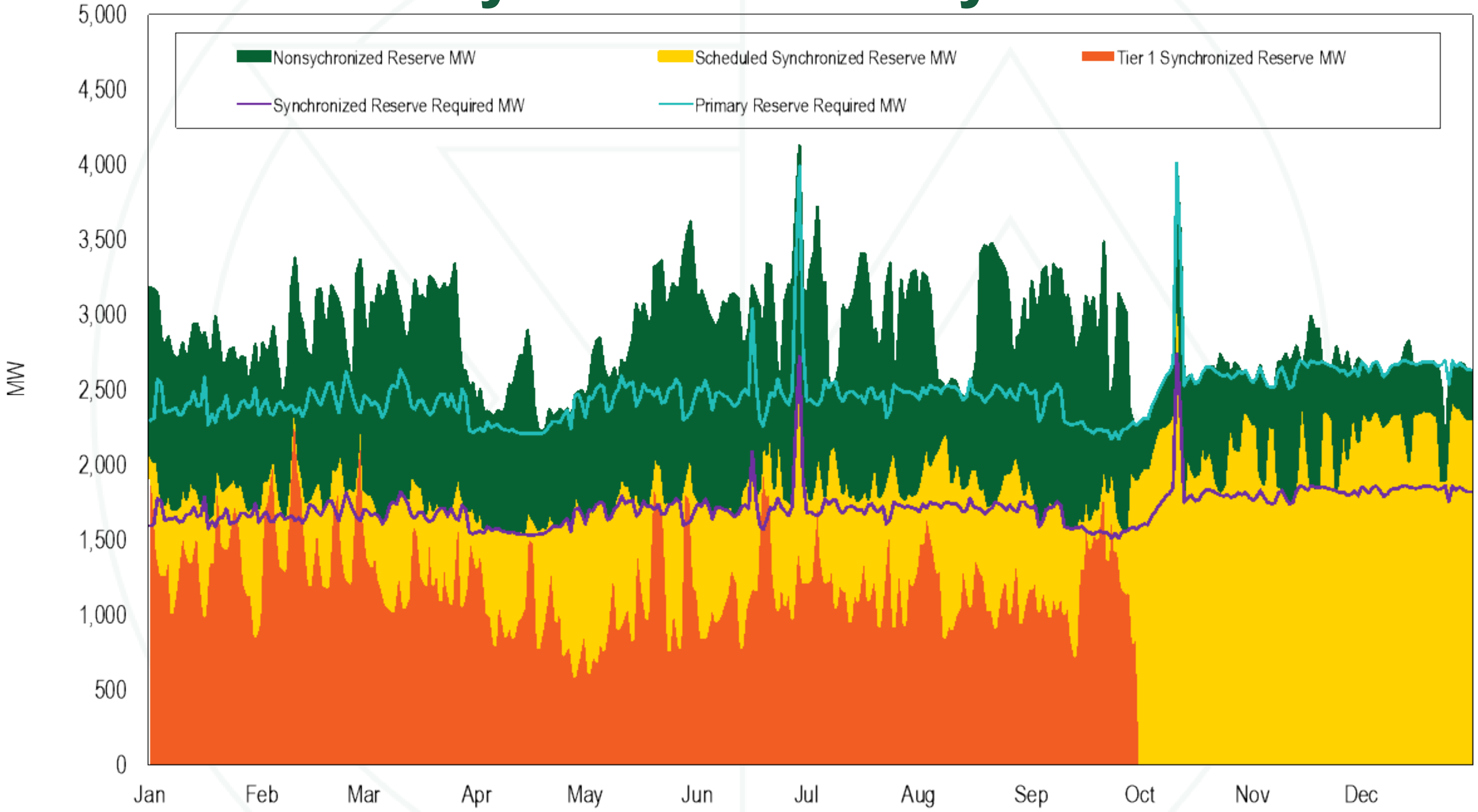
The 30 minute reserve market results were competitive: October through December, 2022

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

Adopted Recommendations: Reserve Markets

- **Removal of $7.50 per MWh margin and variable operations and maintenance costs for synchronized reserve offers.**
- **Removal of tier 1 reserve payment triggered by a nonzero nonsynchronized reserve price.**
- **Enforcement of a synchronized reserve must offer requirement.**
- **Removal of DGP adjustment to reserve clearing.**
- **Termination of VACAR reserve sharing agreement**
- **Real-time obligation for day-ahead 30 minute reserves**
- **Opportunity cost basis for 30 minute reserve offers**

Primary reserve MW by source



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.**
- **LOC should be based on actual unit ramp rates. Current LOC overstated significantly.**
- **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

	Revenue								Pre 2017/2018 (Without Balancing)		2017/2018 (With Balancing)		Post 2017/2018 (With Balancing and Surplus)		Effective Offset	
Planning Period	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	103.4%
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	$469.7	$500.3	$2,082.0	($457.4)	$1,624.6	($101.7)	($0.0)	($0.0)	$868.3	53.4%	$512.5	31.5%	$512.5	31.5%	$512.5	31.5%
2022/2023*	$576.2	$519.3	$1,771.5	($355.1)	$1,416.4	($63.8)	$38.8	$134.3	$1,031.7	72.8%	$779.2	55.0%	$874.7	61.8%	$874.7	61.8%
Total	$5,935.9	$3,546.0	$15,291.5	($3,057.2)	$12,234.3	($386.8)	$351.7	$1,670.4	$9,095.1	74.3%	$6,776.4	55.4%	$8,095.2	66.2%	$8,223.4	67.2%

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	$2.0	$0.1	($4.52)	$0.38	($2.0)	$18.3	($3.1)	($1.4)	$13.8	(14.7%)
AEP	$48.1	$74.9	($52.7)	$18.5	$88.8	$279.4	($35.9)	($16.8)	$226.7	39.2%
APS	$37.7	$21.3	($20.9)	$9.8	$47.8	$107.3	($14.5)	($6.4)	$86.4	55.3%
ATSI	$22.7	$0.6	($27.1)	$3.9	($0.0)	$135.8	($18.3)	($8.8)	$108.7	(0.0%)
BGE	$85.8	$4.8	($13.6)	$15.0	$92.1	$71.0	($9.4)	($4.2)	$57.4	160.5%
COMED	$25.0	$0.0	($37.5)	$4.2	($8.3)	$187.8	($24.9)	($12.6)	$150.3	(5.5%)
DAY	$5.3	$0.7	($7.2)	$1.0	($0.2)	$33.6	($4.9)	($2.3)	$26.4	(0.7%)
DOM	$24.3	$369.0	($55.4)	$4.8	$342.7	$284.3	($40.0)	($15.4)	$228.9	149.8%
DPL	$49.3	$7.7	($9.9)	$1.1	$48.2	$65.2	($7.4)	($2.5)	$55.3	87.2%
DUKE	$25.8	$5.5	($11.3)	$20.6	$40.6	$54.6	($7.8)	($3.6)	$43.3	93.9%
DUQ	$6.5	$0.2	($5.6)	$9.5	$10.5	$20.9	($3.8)	($1.8)	$15.4	68.7%
EKPC	$4.0	$0.1	($5.5)	$0.7	($0.8)	$28.4	($3.7)	($1.8)	$22.9	(3.4%)
EXT	$1.0	$0.0	($8.1)	$0.0	($7.1)	$34.3	($8.1)	$0.0	$26.2	(27.3%)
JCPLC	$4.5	$0.0	($11.5)	$0.8	($6.3)	$54.2	($8.4)	($3.1)	$42.7	(14.9%)
MEC	$27.3	$3.0	($7.8)	$4.9	$27.4	$34.2	($5.7)	($2.1)	$26.4	104.0%
OVEC	$0.0	$0.0	($0.4)	$0.0	($0.4)	$3.0	($0.4)	$0.0	$2.7	(13.6%)
PE	$11.1	$6.1	($7.3)	$2.8	$12.8	$36.3	($5.0)	($2.2)	$29.0	44.1%
PECO	$15.7	$8.3	($16.7)	$3.6	$10.9	$81.4	($11.4)	($5.3)	$64.7	16.9%
PEPCO	$42.1	$3.7	($12.5)	$7.5	$40.9	$64.0	($8.7)	($3.8)	$51.5	79.5%
PPL	$80.5	$11.1	($19.4)	$14.9	$87.0	$90.0	($14.0)	($5.4)	$70.6	123.3%
PSEG	$56.9	$2.2	($19.3)	$10.3	$50.0	$83.6	($13.3)	($6.0)	$64.2	77.8%
REC	$0.5	$0.0	($0.7)	$0.1	($0.1)	$3.8	($0.5)	($0.2)	$3.2	(1.9%)
Total	$576.2	$519.3	($355.1)	$134.3	$874.7	$1,771.5	($249.2)	($105.9)	$1,416.4	61.8%

Offset available to load if all ARRs self scheduled

	20/21 Planning Period					21/22 Planning Period					22/23 Planning Period*				
	SS FTR	Residual ARR Credits	Bal+M2M Charges	Congestion +M2M	Offset	SS FTR	Residual ARR Credits	Bal+M2M Charges	Congestion +M2M	Offset	SS FTR	Residual ARR Credits	Bal+M2M Charges	Congestion +M2M	Offset
ACEC	$1.8	$0.3	($2.7)	$5.5	(11.1%)	$0.4	$0.1	($5.2)	$14.8	(31.4%)	$0.8	$0.0	($4.5)	$13.8	(26.7%)
AEP	$77.3	$1.2	($38.1)	$110.9	36.4%	$132.5	$0.5	($65.7)	$240.4	28.0%	$72.7	$0.4	($52.7)	$226.7	9.0%
APS	$42.0	$0.2	($14.8)	$45.2	60.7%	$93.3	$1.6	($29.7)	$122.8	53.1%	$20.8	$1.9	($20.9)	$86.4	2.1%
ATSI	$30.7	$0.0	($19.5)	$50.6	22.1%	$47.3	$0.0	($32.3)	$117.9	12.7%	$35.2	$0.2	($27.1)	$108.7	7.7%
BGE	$79.7	$0.2	($9.1)	$24.8	285.0%	$147.0	$0.1	($17.0)	$59.9	217.3%	$97.6	$0.0	($13.6)	$57.4	146.4%
COMED	$69.6	$0.0	($28.5)	$78.3	52.5%	$51.9	$0.2	($44.7)	$159.9	4.6%	$10.3	$0.5	($37.5)	$150.3	(17.8%)
DAY	$8.0	$0.0	($5.3)	$11.0	24.9%	$7.1	$0.2	($8.6)	$26.2	(4.7%)	$3.2	$0.0	($7.2)	$26.4	(15.2%)
DOM	$117.0	$1.6	($37.9)	$87.9	91.8%	$556.6	$11.5	($22.0)	$370.9	147.3%	$321.1	$9.4	($55.4)	$228.9	120.2%
DPL	$56.4	$5.7	($6.7)	$36.2	153.1%	$52.3	$2.9	($80.3)	($21.1)	119.3%	$40.3	$0.9	($9.9)	$55.3	56.7%
DUKE	$40.9	$0.0	($8.4)	$17.4	187.5%	$50.8	$0.7	($12.3)	$23.7	165.4%	$29.7	$0.0	($11.3)	$43.3	42.4%
DUQ	$8.9	$0.0	($4.0)	$6.2	79.7%	$7.0	$0.0	($6.4)	$45.3	1.2%	$6.4	$0.0	($5.6)	$15.4	5.6%
EKPC	$6.6	$0.0	($4.2)	$8.4	29.3%	$10.1	$0.0	($7.0)	$21.9	14.2%	$6.0	$0.0	($5.5)	$22.9	2.3%
EXT	$0.3	$0.0	($13.8)	$11.0	(122.3%)	$1.9	$0.0	($9.9)	$19.9	(40.0%)	NA	$0.0	($8.1)	$26.2	(30.9%)
JCPLC	$0.9	$0.0	($6.1)	$12.9	(40.1%)	$4.4	$0.0	($12.8)	$39.0	(21.7%)	$2.4	$0.0	($11.5)	$42.7	(21.3%)
MEC	$8.0	$0.0	($5.3)	$16.5	16.6%	$31.3	$0.0	($11.6)	$33.2	59.5%	$35.2	$0.0	($7.8)	$26.4	103.7%
OVEC	NA	$0.0	($0.3)	$0.9	(28.8%)	NA	$0.0	($0.4)	$1.5	(29.4%)	NA	$0.0	($0.4)	$2.7	(13.6%)
PE	$13.5	$0.0	($6.5)	$16.4	42.8%	$29.7	$0.1	($18.5)	$31.8	35.5%	$8.5	$0.2	($7.3)	$29.0	4.7%
PECO	$14.0	$0.3	($10.9)	$24.9	13.4%	$6.2	$0.8	($12.0)	$78.0	(6.5%)	$12.2	$0.0	($16.7)	$64.7	(7.0%)
PEPCO	$37.3	$0.0	($8.3)	$20.5	141.9%	$59.2	$0.0	($15.5)	$53.8	81.2%	$44.4	$0.0	($12.5)	$51.5	61.9%
PPL	$43.7	$1.3	($11.5)	$30.8	108.7%	$160.3	$0.0	($21.5)	$103.3	134.4%	$80.5	$0.0	($19.4)	$70.6	86.4%
PSEG	$43.2	$0.4	($13.9)	$25.0	118.4%	$94.0	$0.2	($23.1)	$76.0	93.4%	$18.8	$0.4	($19.3)	$64.2	(0.3%)
REC	$1.0	$0.0	($0.6)	$2.1	21.0%	$1.1	$0.0	($0.8)	$5.3	6.2%	$0.2	$0.0	($0.7)	$3.2	(14.0%)
Total	$700.9	$11.2	($256.2)	$643.4	70.9%	$1,544.3	$18.8	($457.4)	$1,624.6	68.1%	$846.4	$13.9	($355.1)	$1,416.4	35.7%

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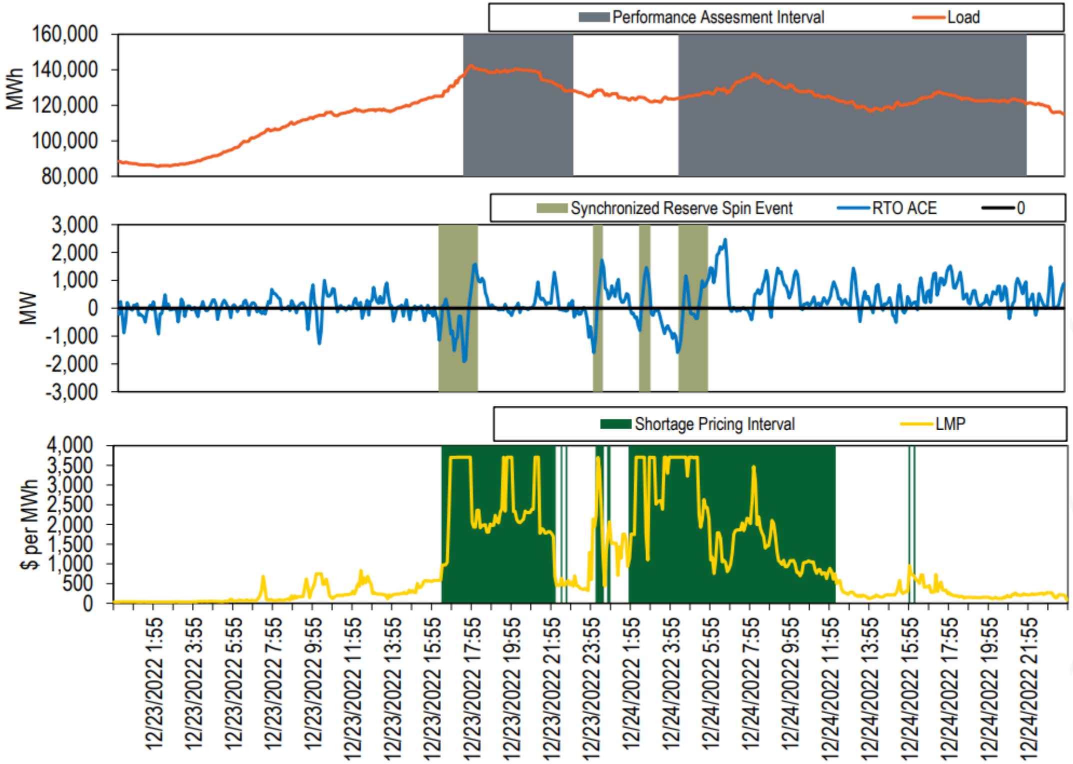
FTR profits and revenues by organization type and FTR direction: 2022/2023: June through December

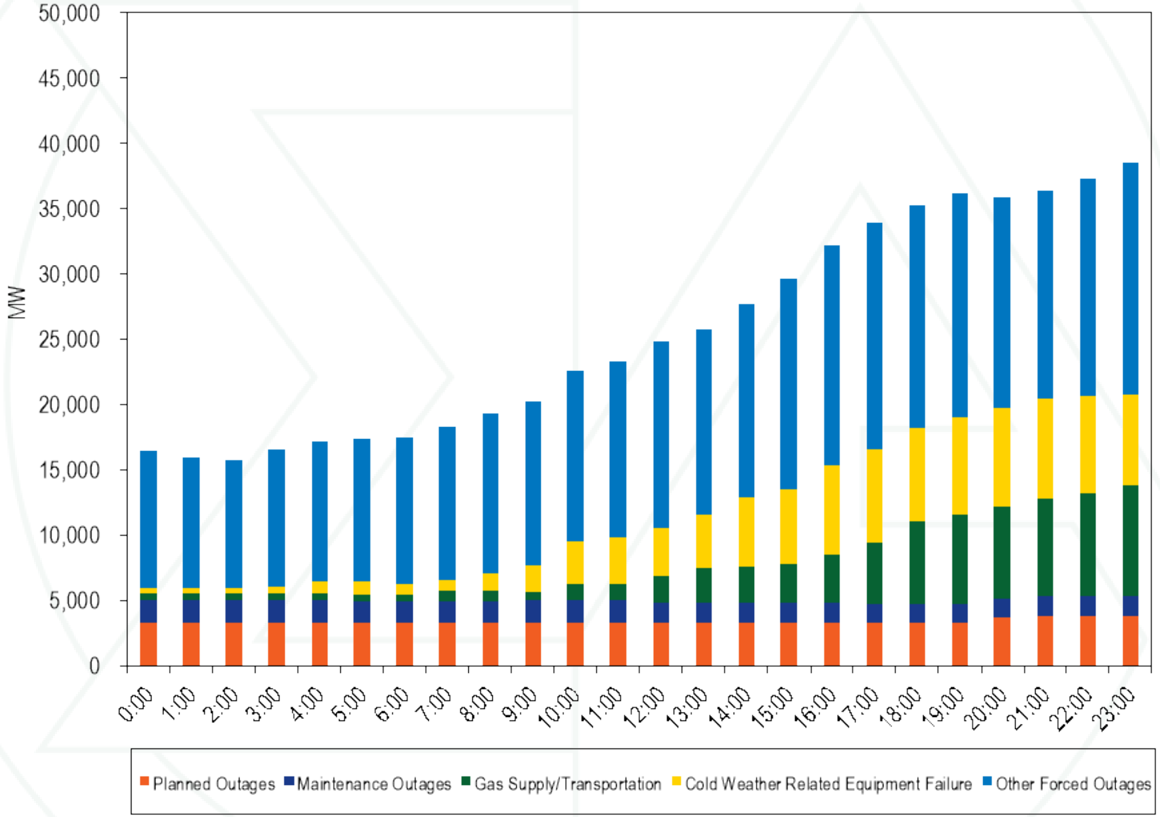
	Purchased FTRs Profit			Self Scheduled FTRs Revenue Returned		
Organization Type	Prevailing Flow	Counter Flow	Total	Prevailing Flow	Counter Flow	Total
Financial	$473,690,828	($60,497,082)	$413,193,747			
Physical	$111,162,560	($16,030,547)	$95,132,013			
Physical ARR	$86,443,439	($54,103,879)	$32,339,560	$518,589,688	$8,216,410	$526,806,098
Total	$671,296,827	($130,631,507)	$540,665,320	$518,589,688	$8,216,410	$526,806,098

Winter Storm Elliott

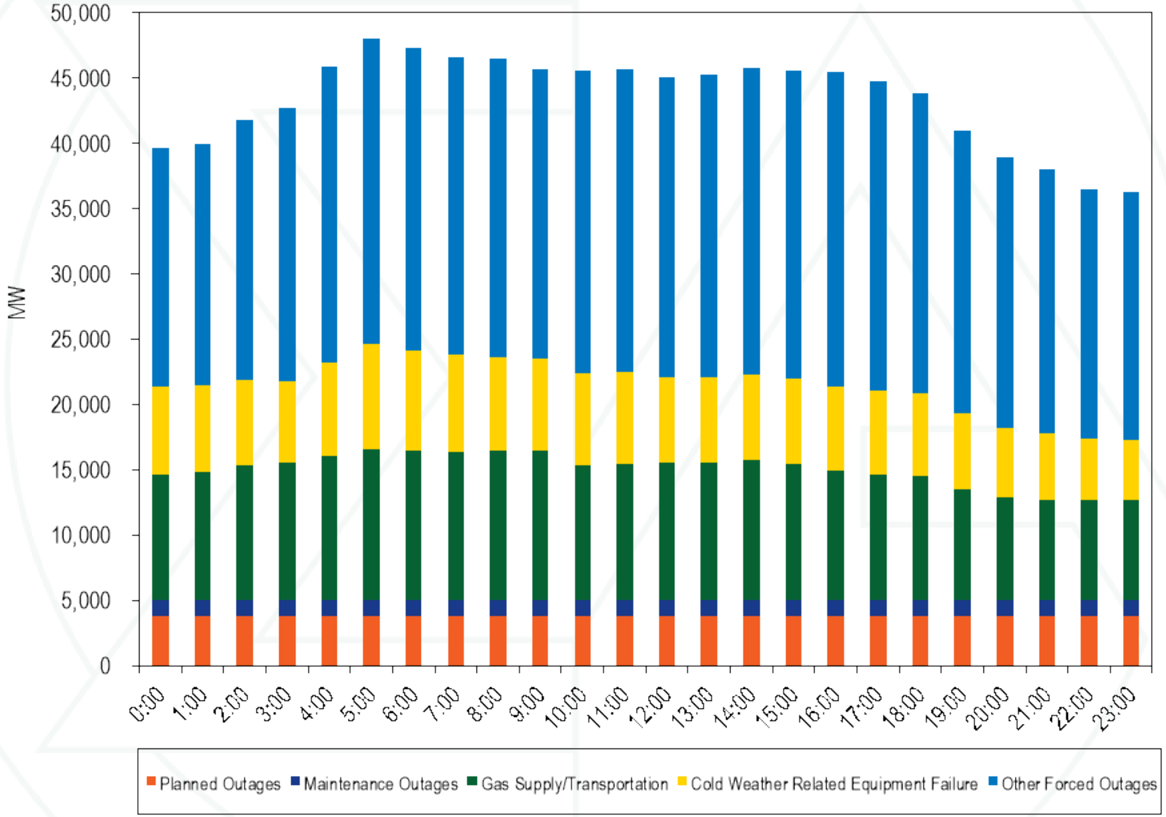
Load, Area Control Error, and LMP: December 23 and 24, 2022



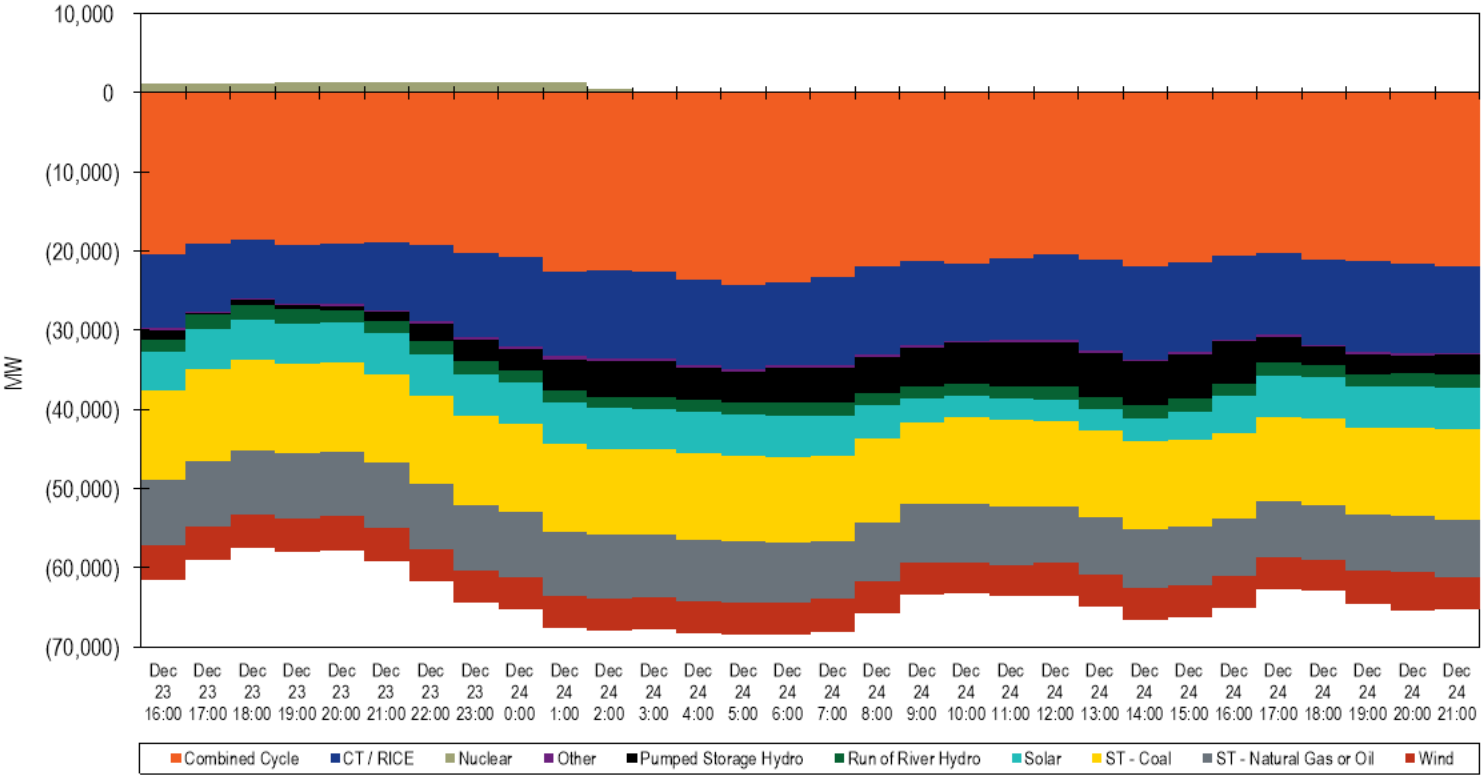
December 23, 2022 outages



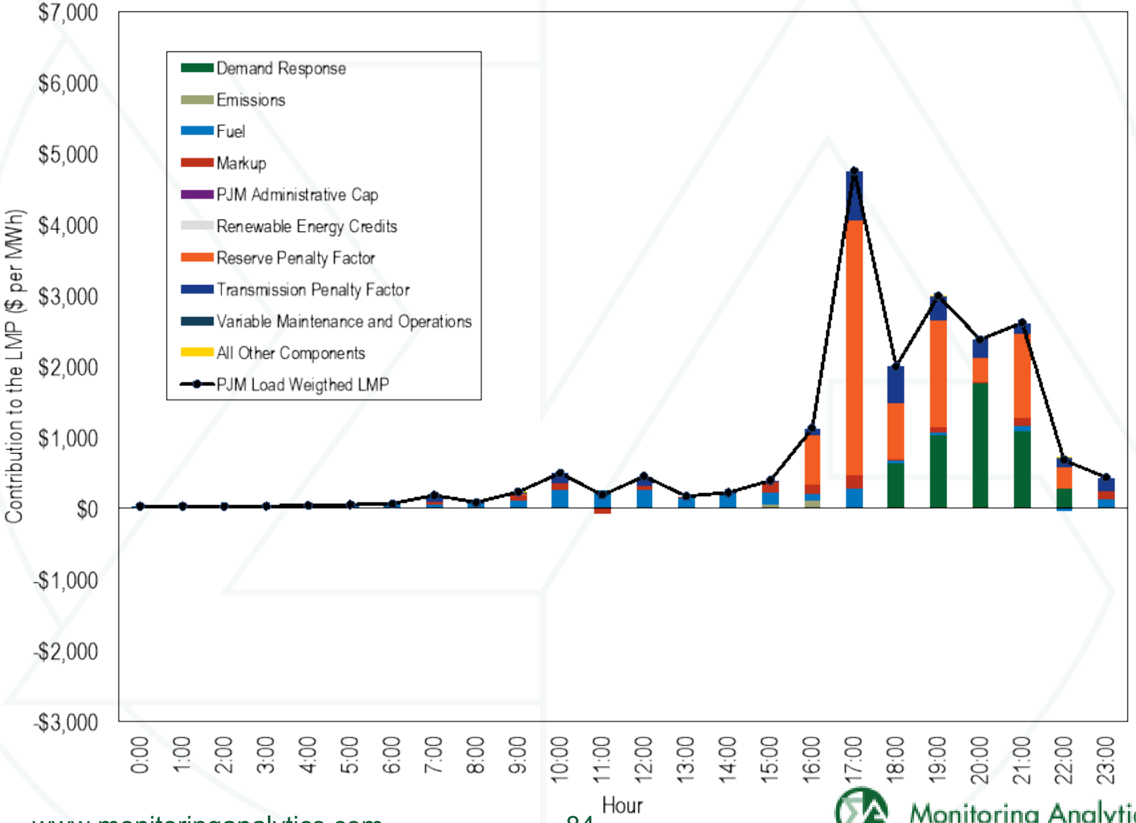
December 24, 2022 outages



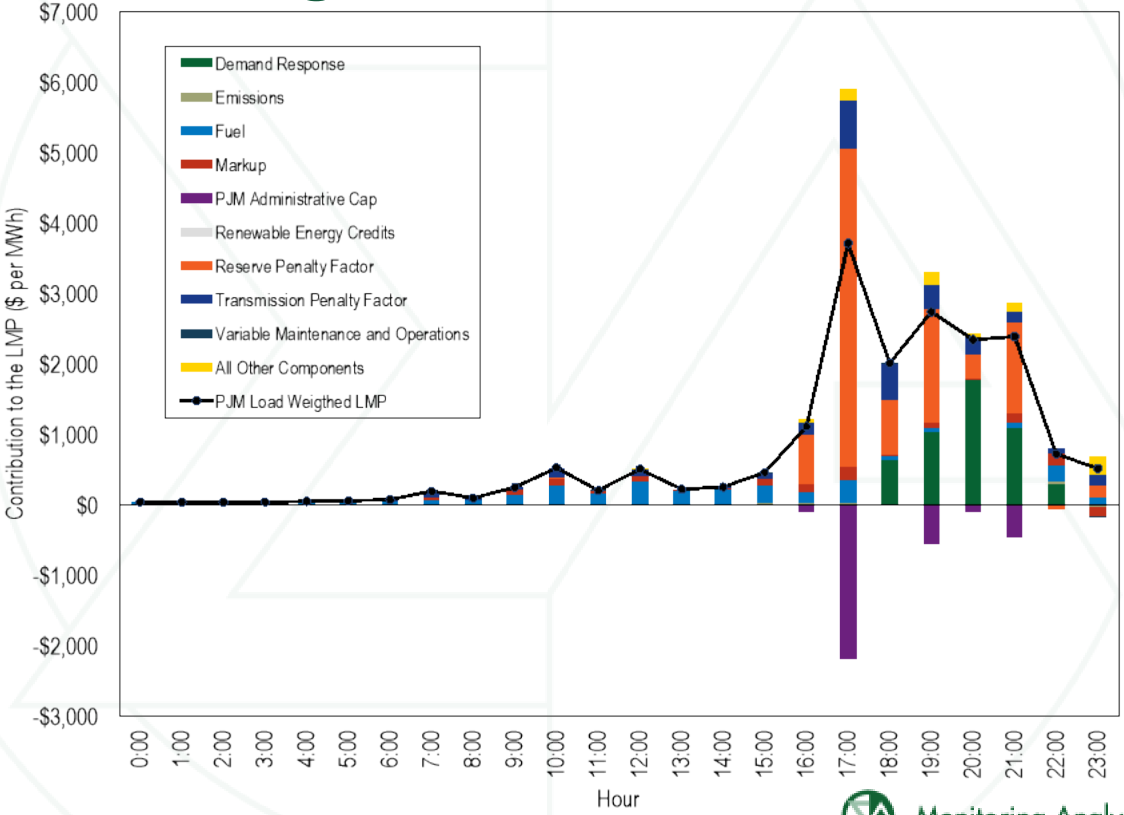
December 23, 1600 EPT through December 24, 2200 EPT unit performance



Components of real-time dispatch run load-weighted average LMP: December 23



Components of real-time pricing run load-weighted average LMP: December 23



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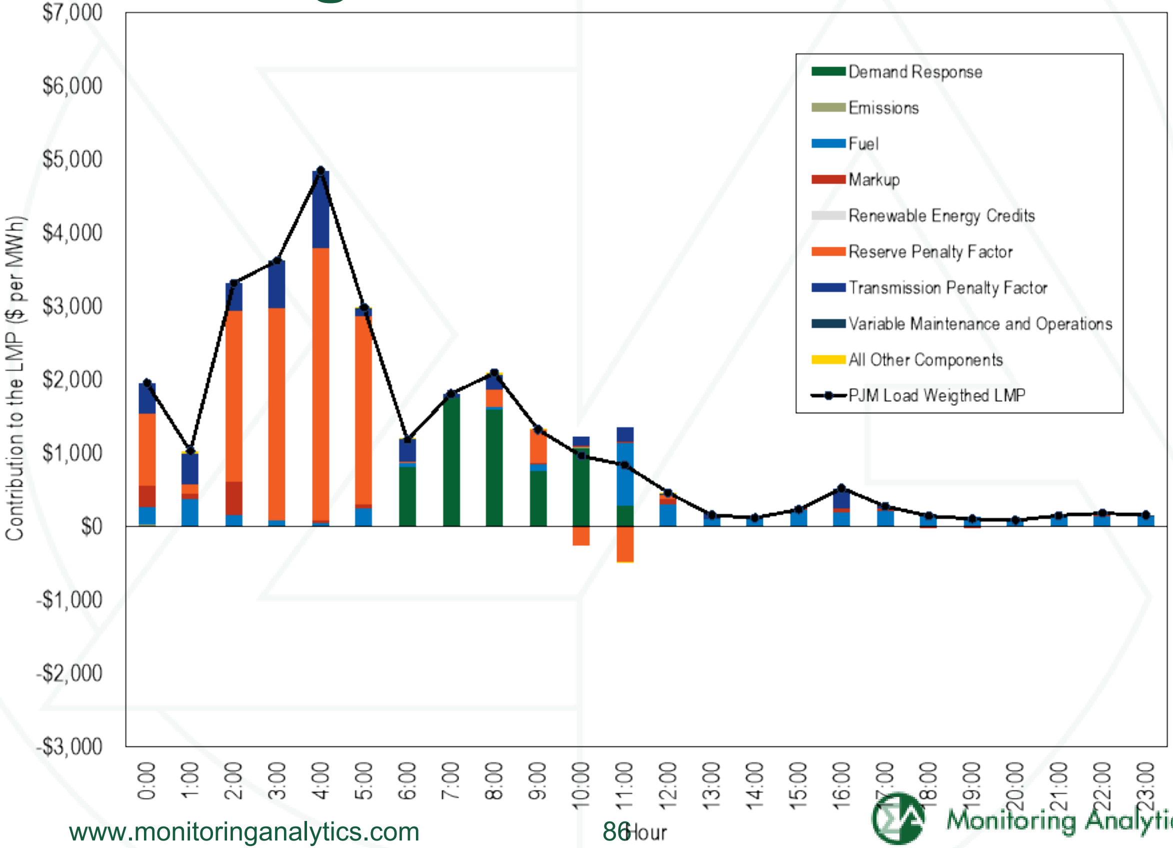
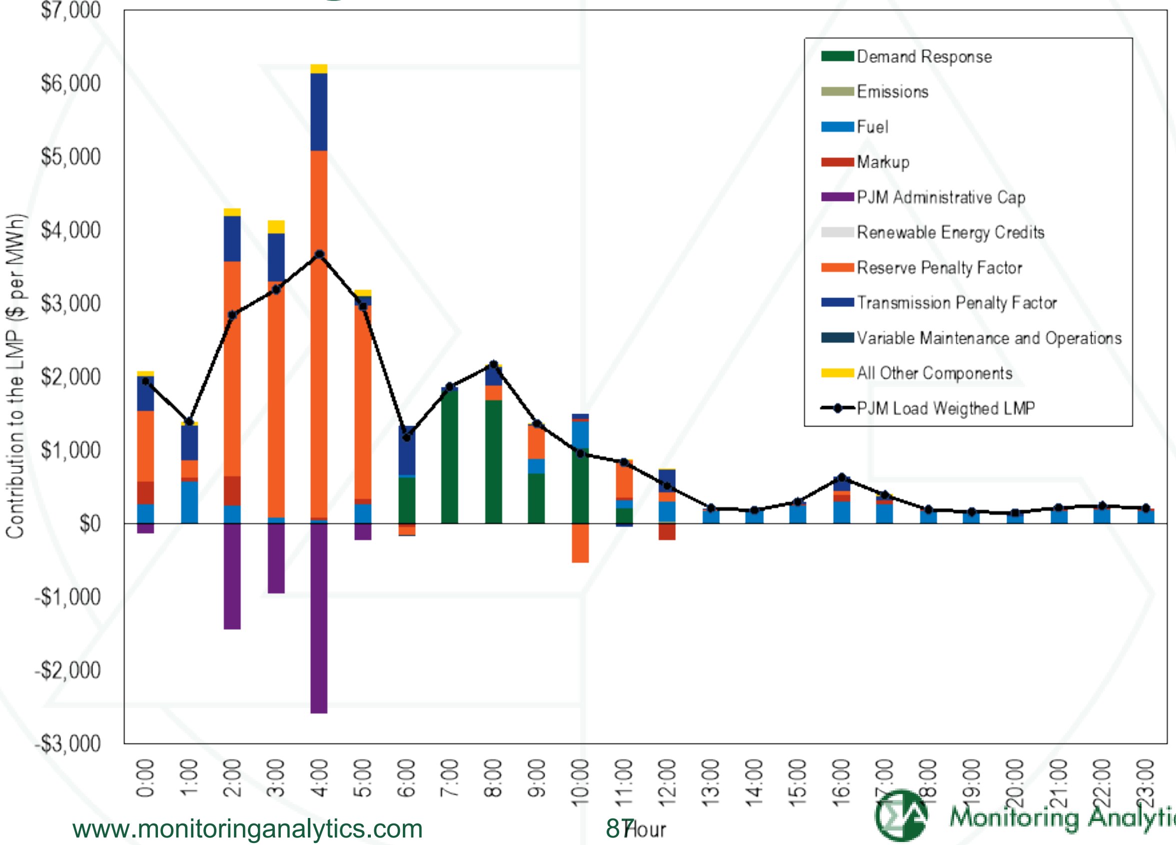
Components of real-time dispatch run load-weighted average LMP: December 24



Components of real-time pricing run load-weighted average LMP: December 24



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