2022 Annual Report on Market Issues and Performance

July 28, 2023

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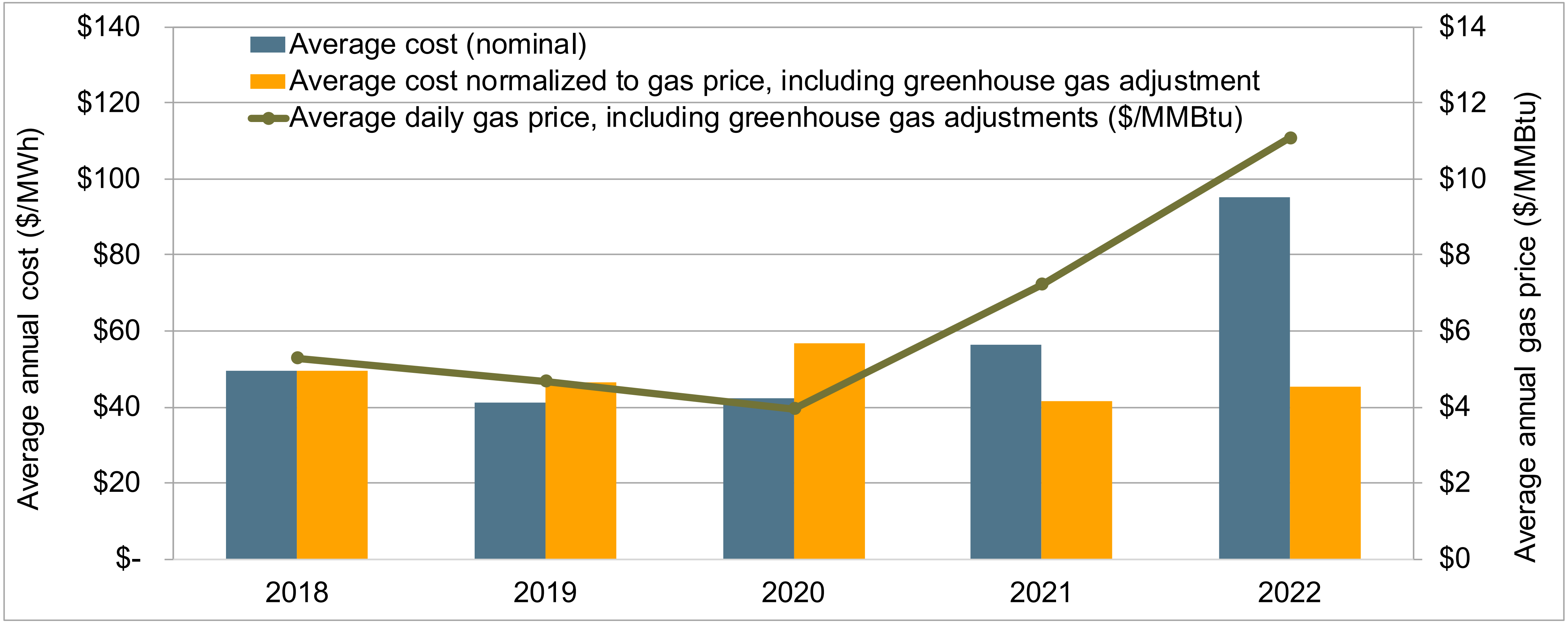
http://www.caiso.com/Documents/2022-Annual-Report-on-Market-Issues-and-Performance-Jul-11-2023.pdf
http://www.caiso.com/Documents/2022-Special-Report-on-Battery-Storage-Jul-7-2023.pdf
http://www.caiso.com/market/Pages/MarketMonitoring/Default.aspx

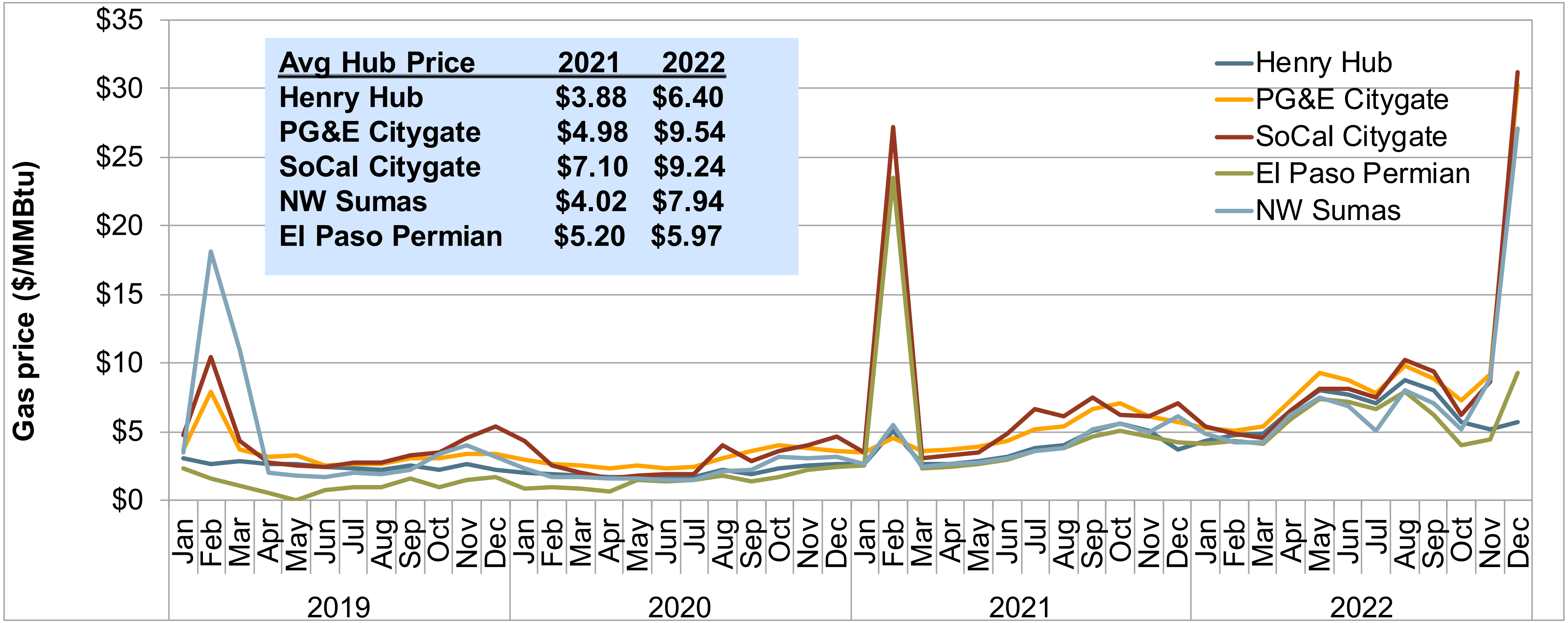
Total CAISO wholesale costs rose about 70% -- or 10% after accounting for higher gas and greenhouse gas costs



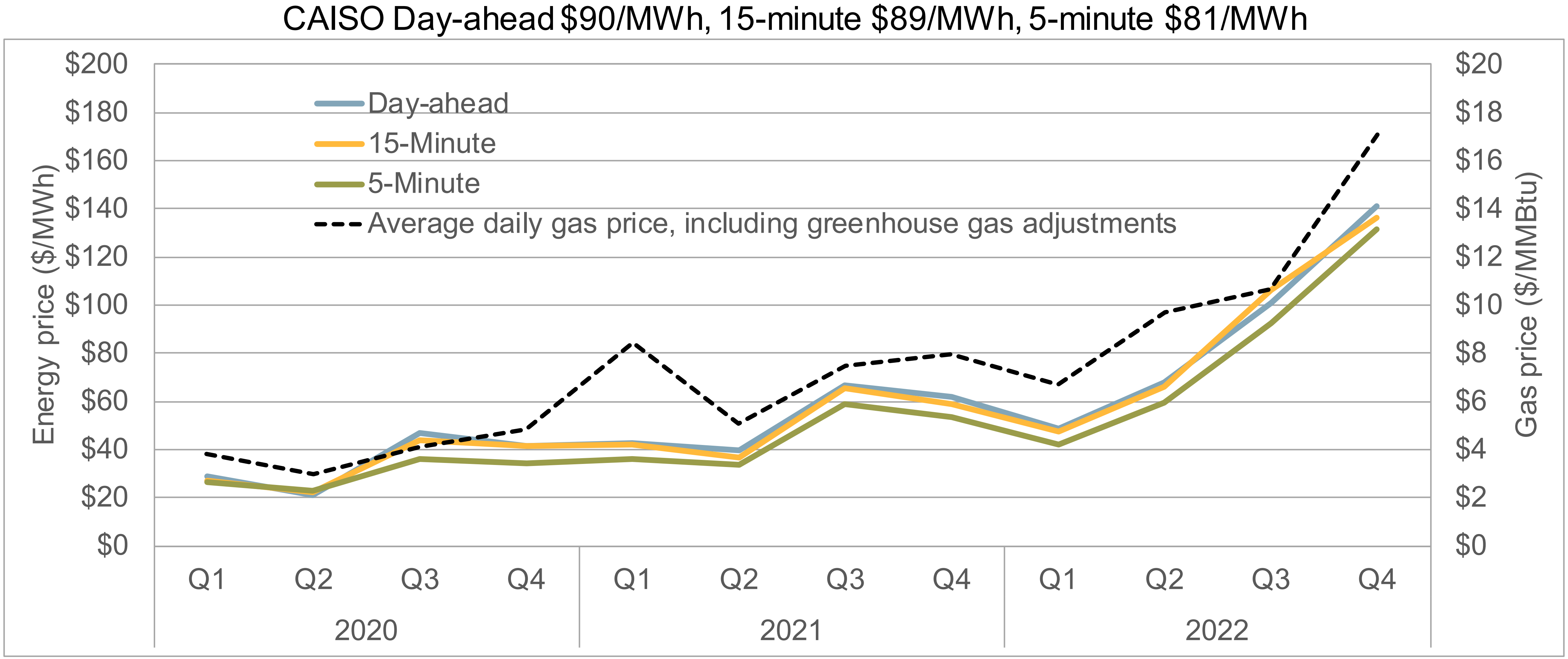
Total CAISO wholesale costs totaled $21.6 billion ($95/MWh)

	2018	2019	2020	2021	2022	Change '21-'22
Day-ahead energy costs	$ 46.05	$ 38.13	$ 38.61	$ 53.09	$ 89.12	$ 36.03
Real-time energy costs (incl. flex ramp)	$ 0.59	$ 1.02	$ 1.65	$ 1.21	$ 3.13	$ 1.92
Grid management charge	$ 0.46	$ 0.46	$ 0.46	$ 0.43	$ 0.42	$ (0.01)
Bid cost recovery costs	$ 0.68	$ 0.56	$ 0.60	$ 0.70	$ 1.12	$ 0.42
Reliability costs (RMR and CPM)	$ 0.68	$ 0.06	$ 0.07	$ 0.19	$ 0.22	$ 0.03
Average total energy costs	**$ 48.47**	**$ 40.23**	**$ 41.40**	**$ 55.61**	**$ 94.01**	**$ 38.40**
Reserve costs (AS and RUC)	$ 0.87	$ 0.75	$ 1.02	$ 0.79	$ 1.11	$ 0.32
Average total costs of energy and reserve	**$ 49.34**	**$ 40.98**	**$ 42.42**	**$ 56.40**	**$ 95.12**	**$ 38.72**

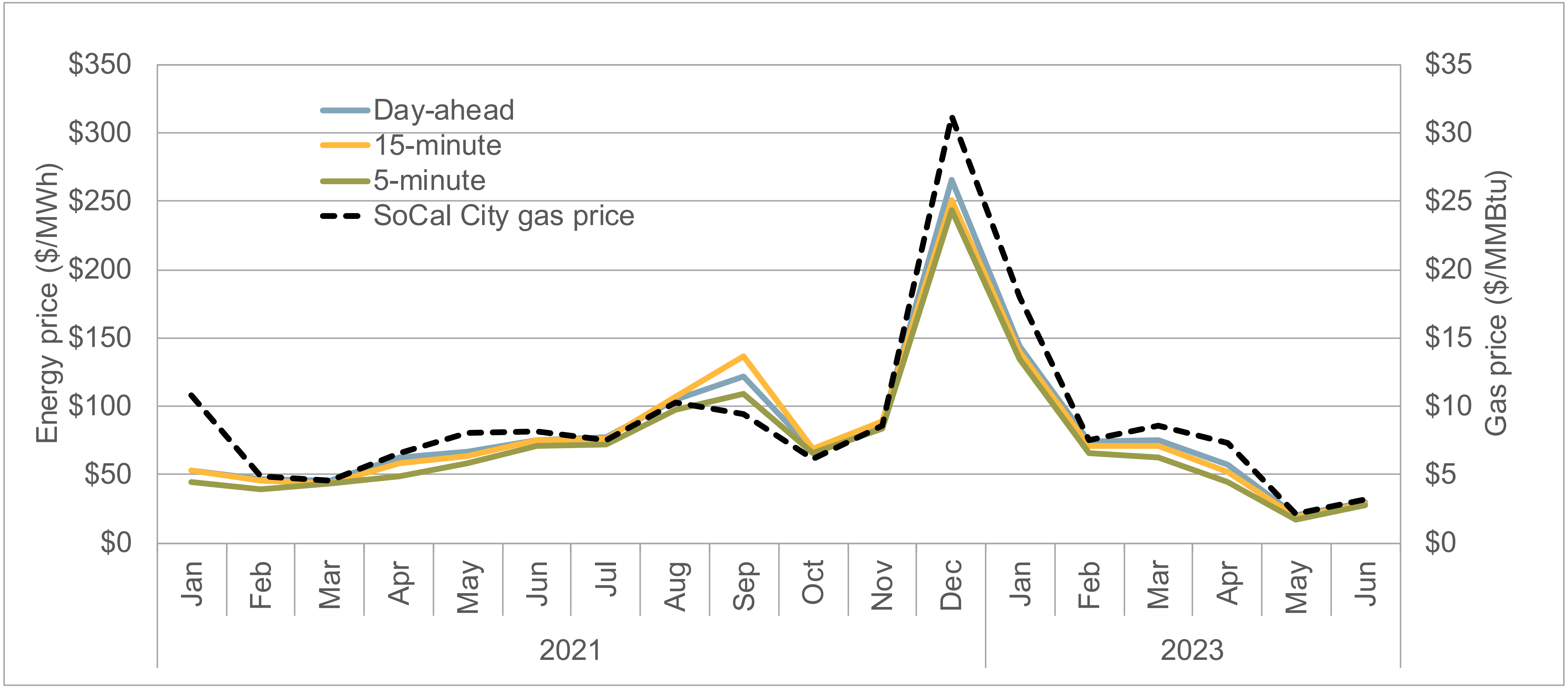
Natural gas prices increased across the West and in California, averaging over $9/MMBtu at both California hubs



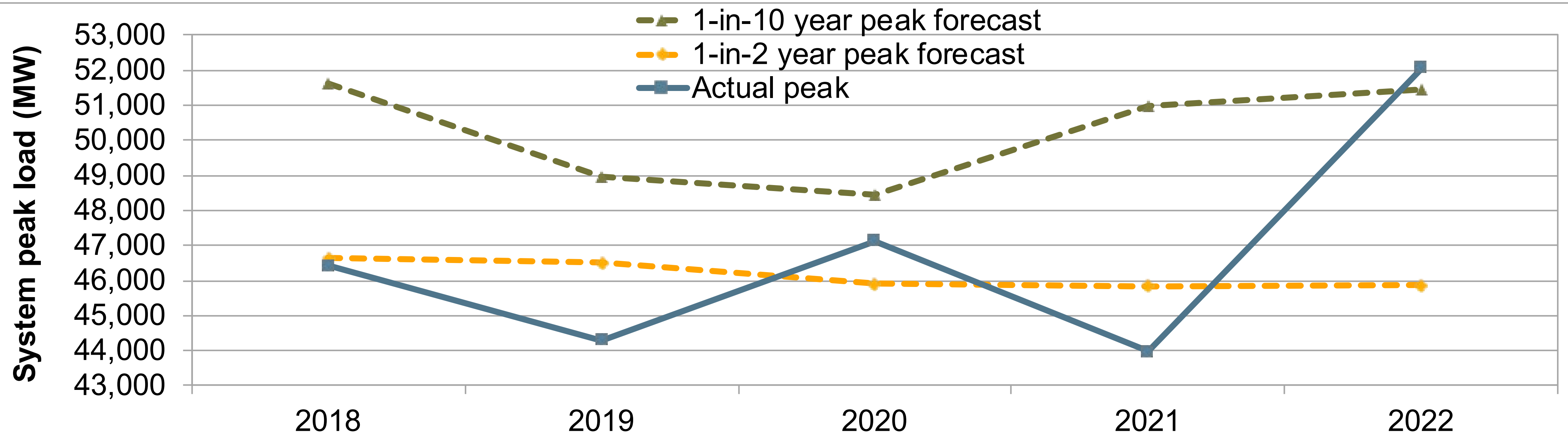
Day-ahead prices were slightly higher than 15-minute prices, with 5-minute prices significantly lower than day-ahead and 15-minute prices



Electricity prices have tracked closely with changes in gas prices



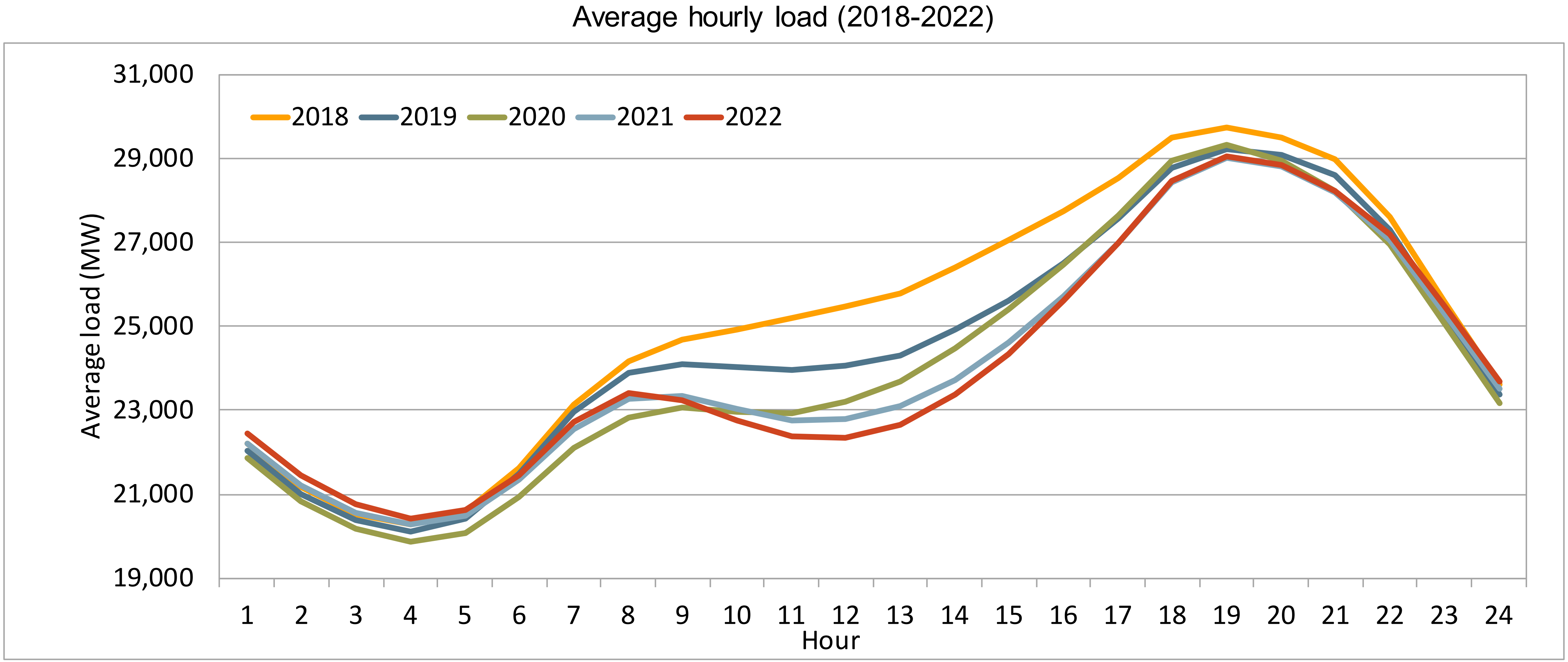
CAISO peak load at record level, while overall total load stayed the same



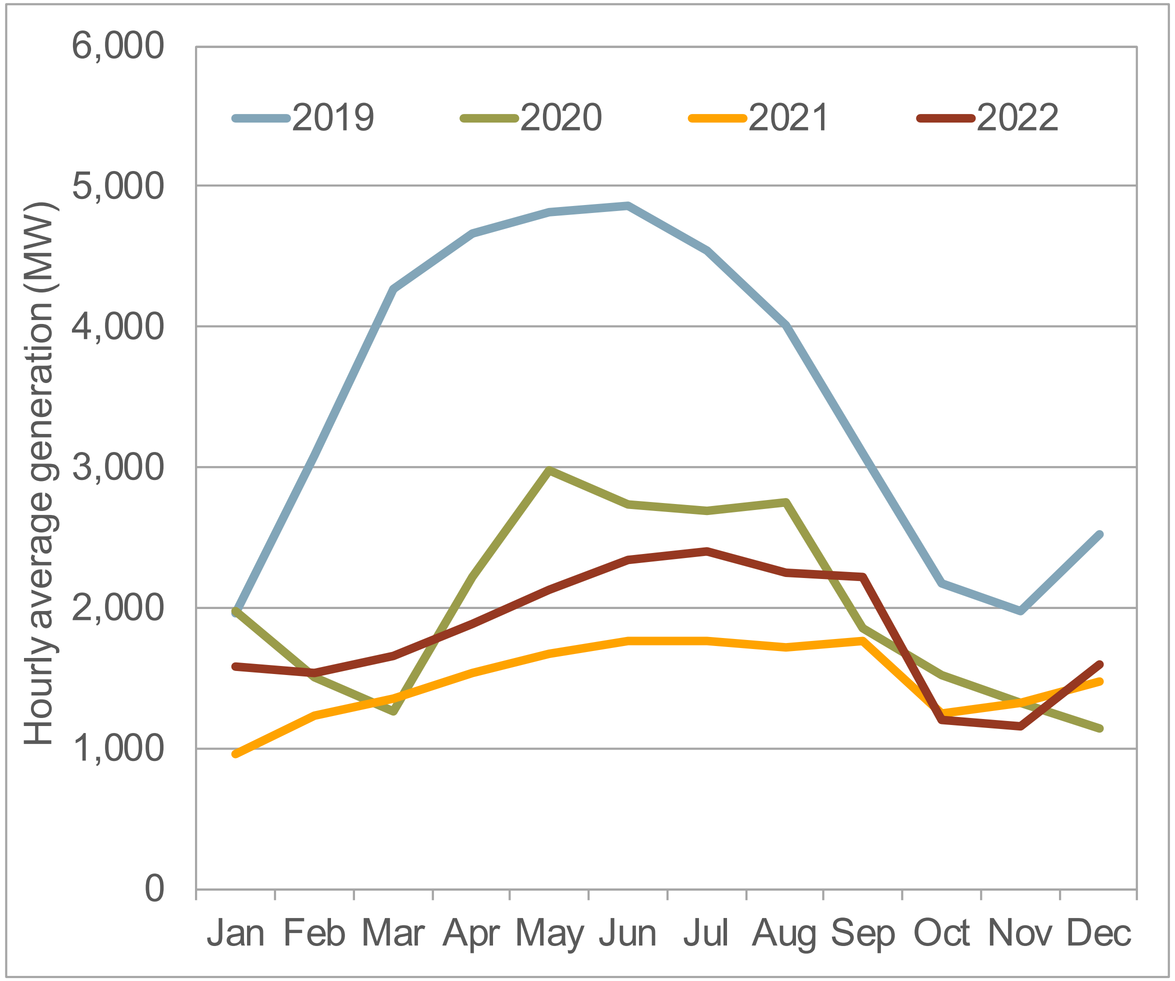
Year	Annual total energy (GWh)	Average load (MW)	% change	Annual peak load (MW)	% change
2018	220,458	25,169	-3.2%	46,427	-7.4%
2019	214,955	24,541	-2.5%	44,301	-4.6%
2020	211,919	24,128	-1.7%	47,121	6.4%
2021	211,020	24,092	-0.1%	43,982	-6.7%
2022	210,879	24,059	-0.1%	52,061	18.4%

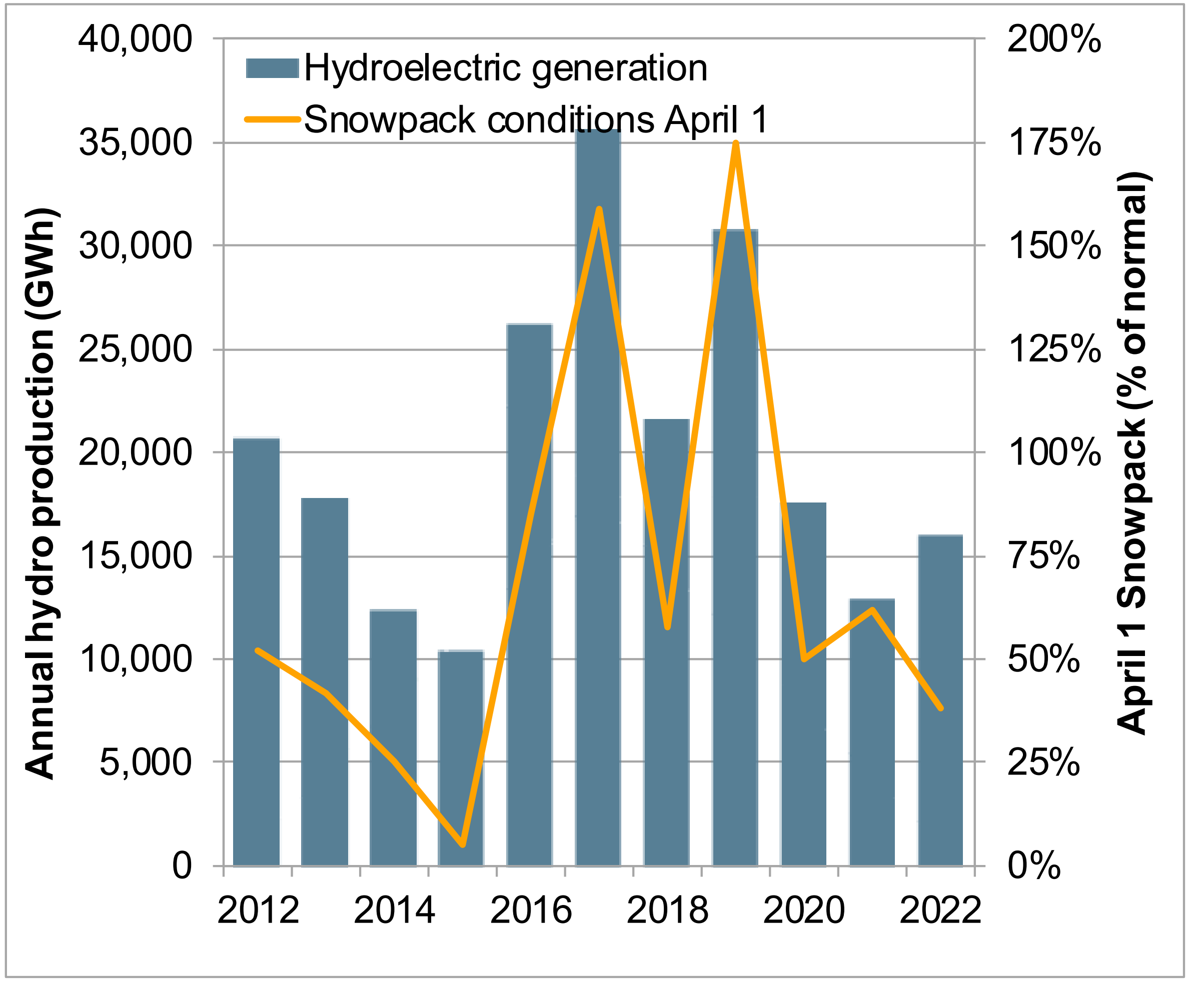
https://www.caiso.com/documents/californiaisopeakloadhistory.pdf

Higher CAISO behind-the-meter solar generation and energy efficiency initiatives all contributed to lower CAISO system load

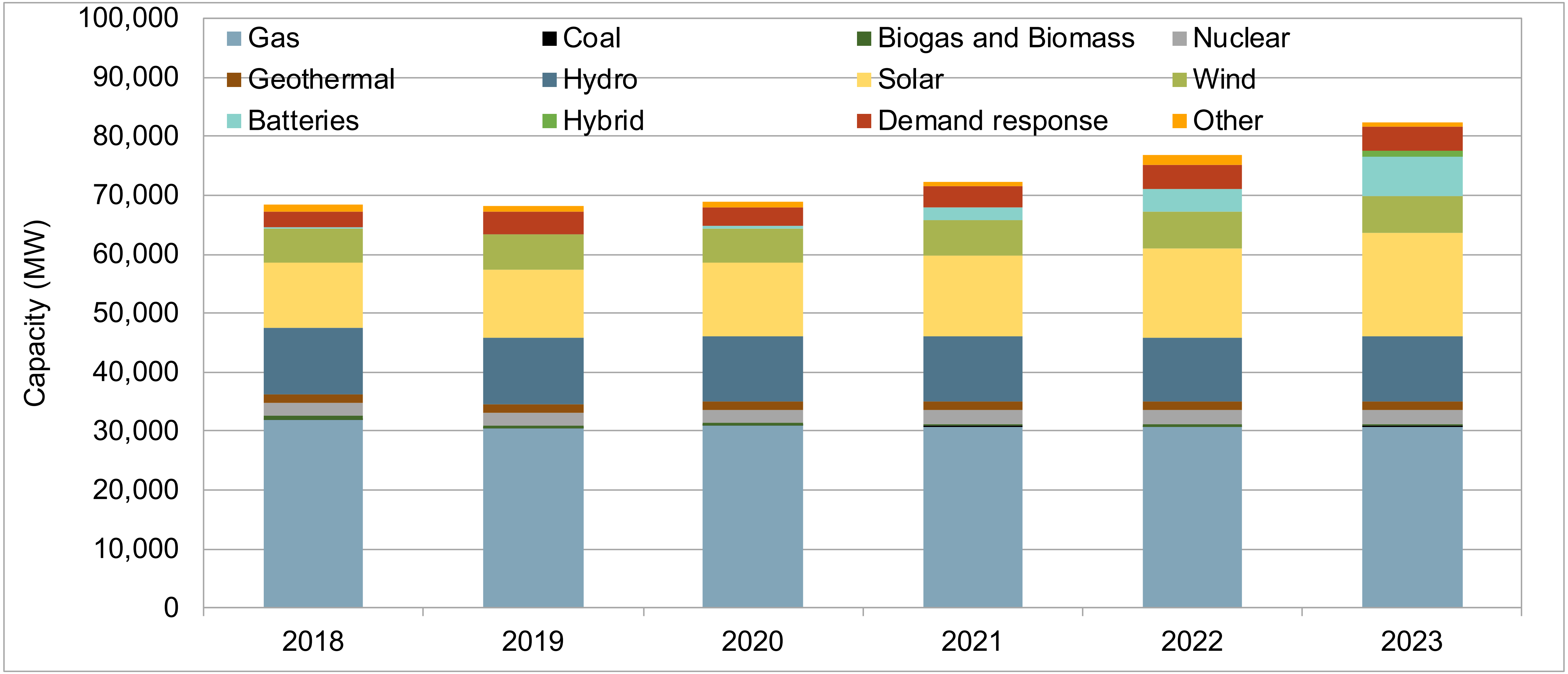


Hydroelectric generation increased in CAISO, but drought continued across California and the Southwest



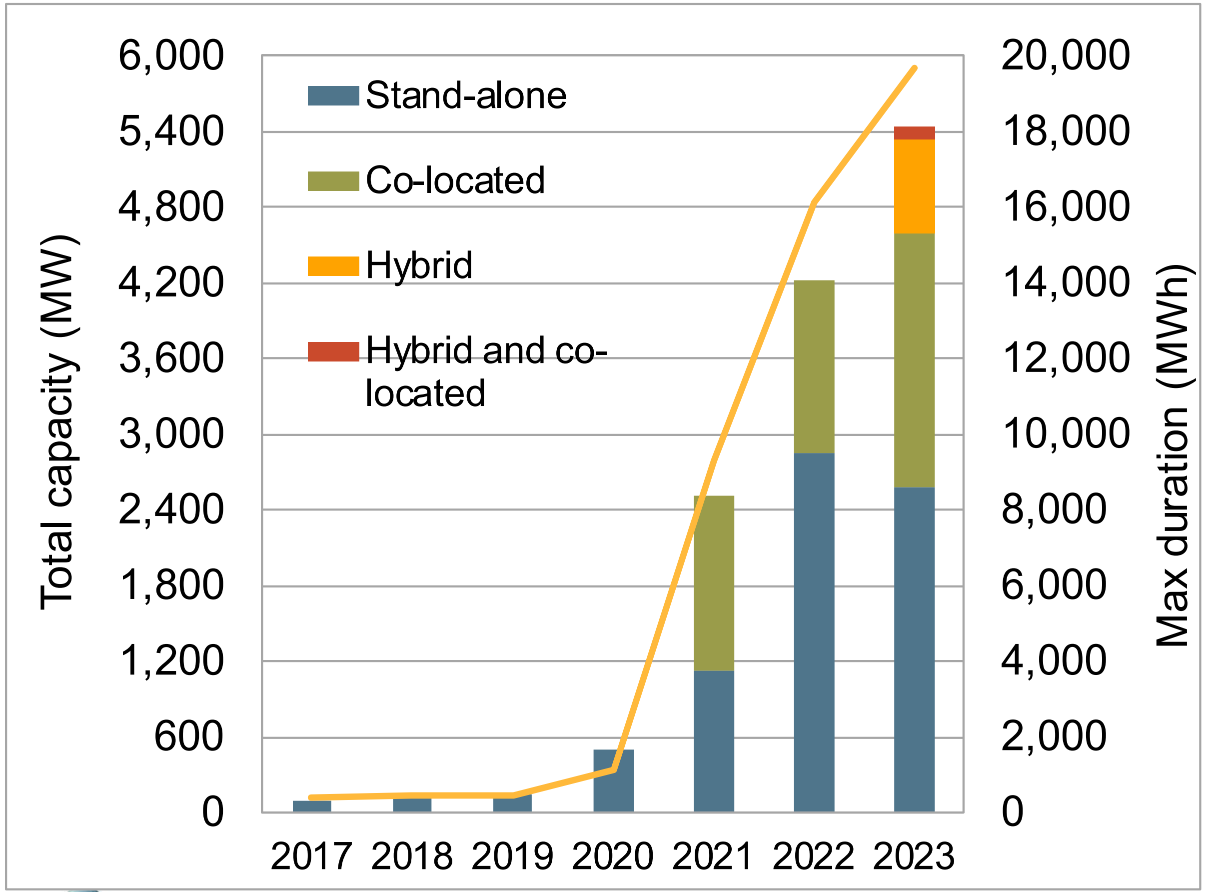


Gas capacity retiring is being largely replaced with renewables (mainly solar) and storage

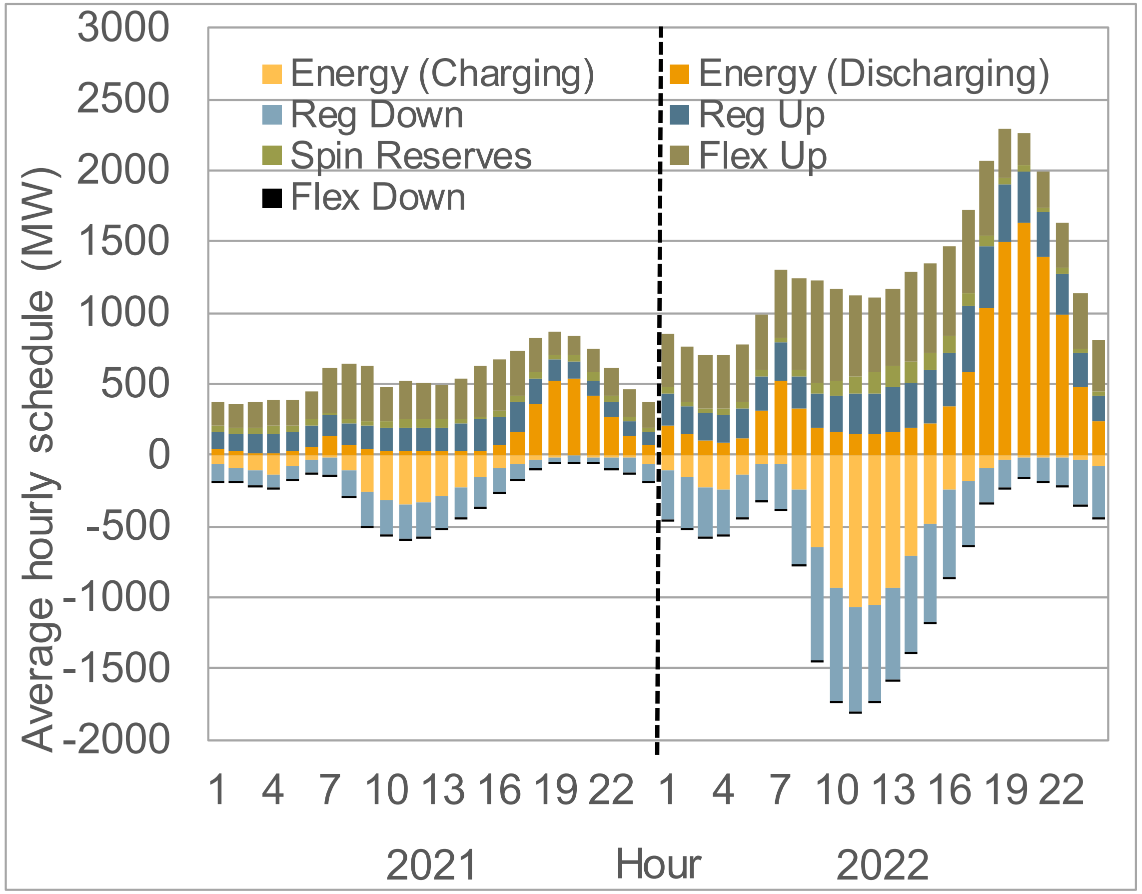


Dramatic growth in battery capacity has been paired with market changes to improve storage modeling

Battery capacity (2017–2023)

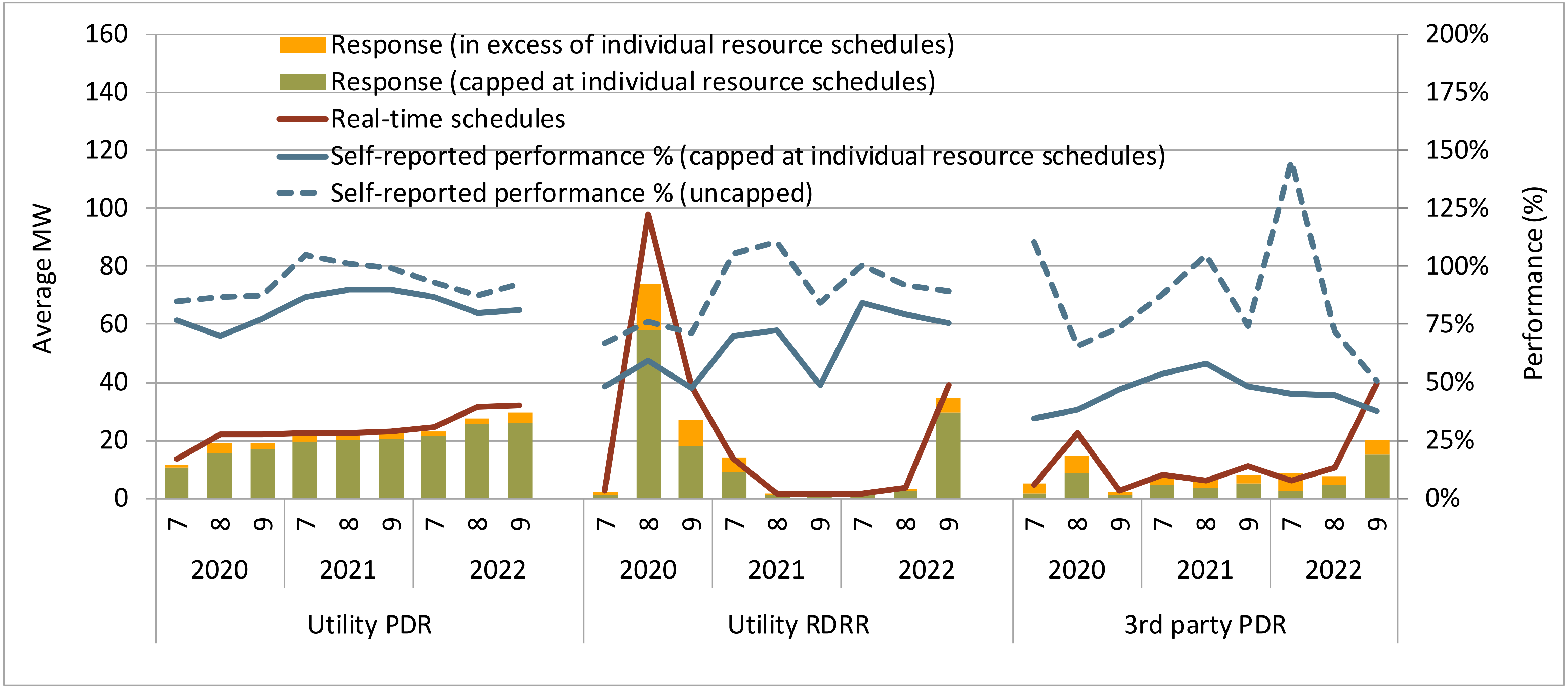


Average hourly real-time battery schedules

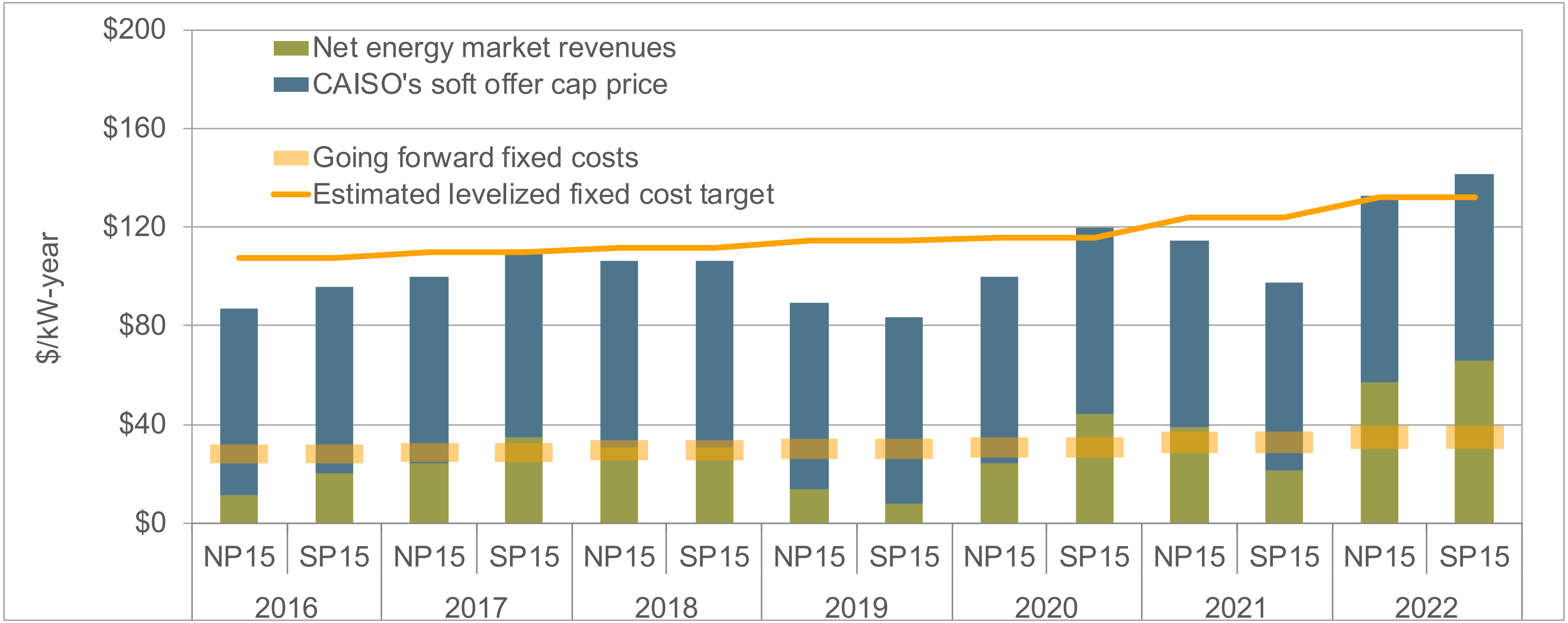


http://www.caiso.com/Documents/2022-Special-Report-on-Battery-Storage-Jul-7-2023.pdf

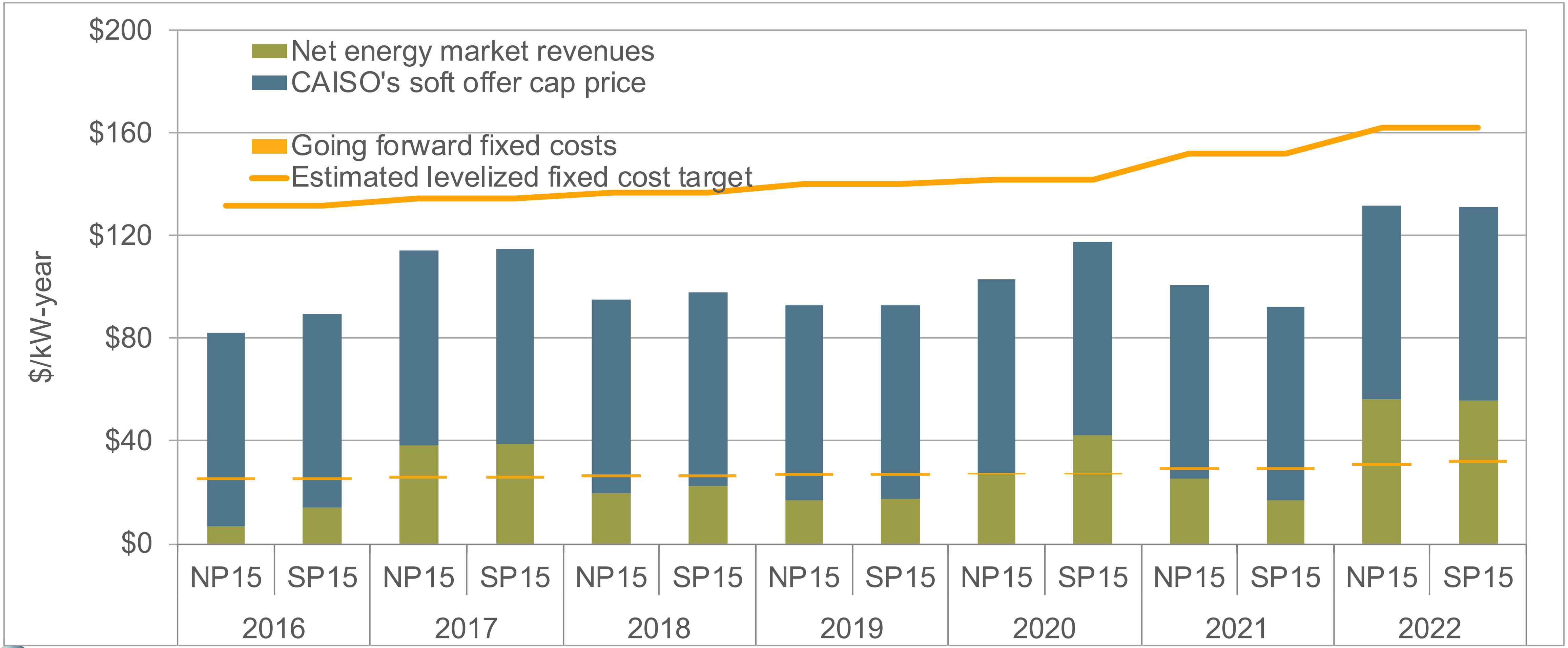
Demand response resource adequacy performance, July-Sept 4-9 p.m.



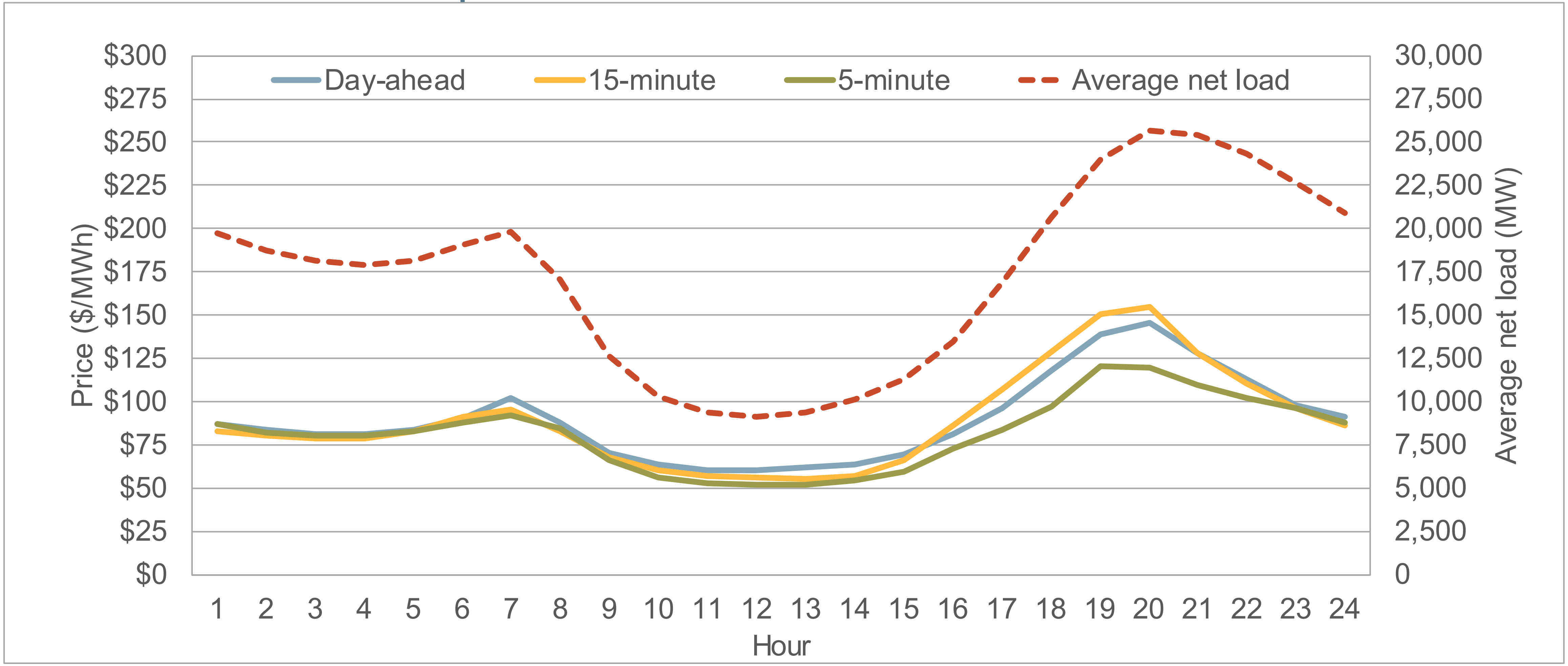
Estimated net revenue of hypothetical combined cycle unit rose to $57/kW-year in NP15 and $66/kW-year in SP15, above going forward fixed costs



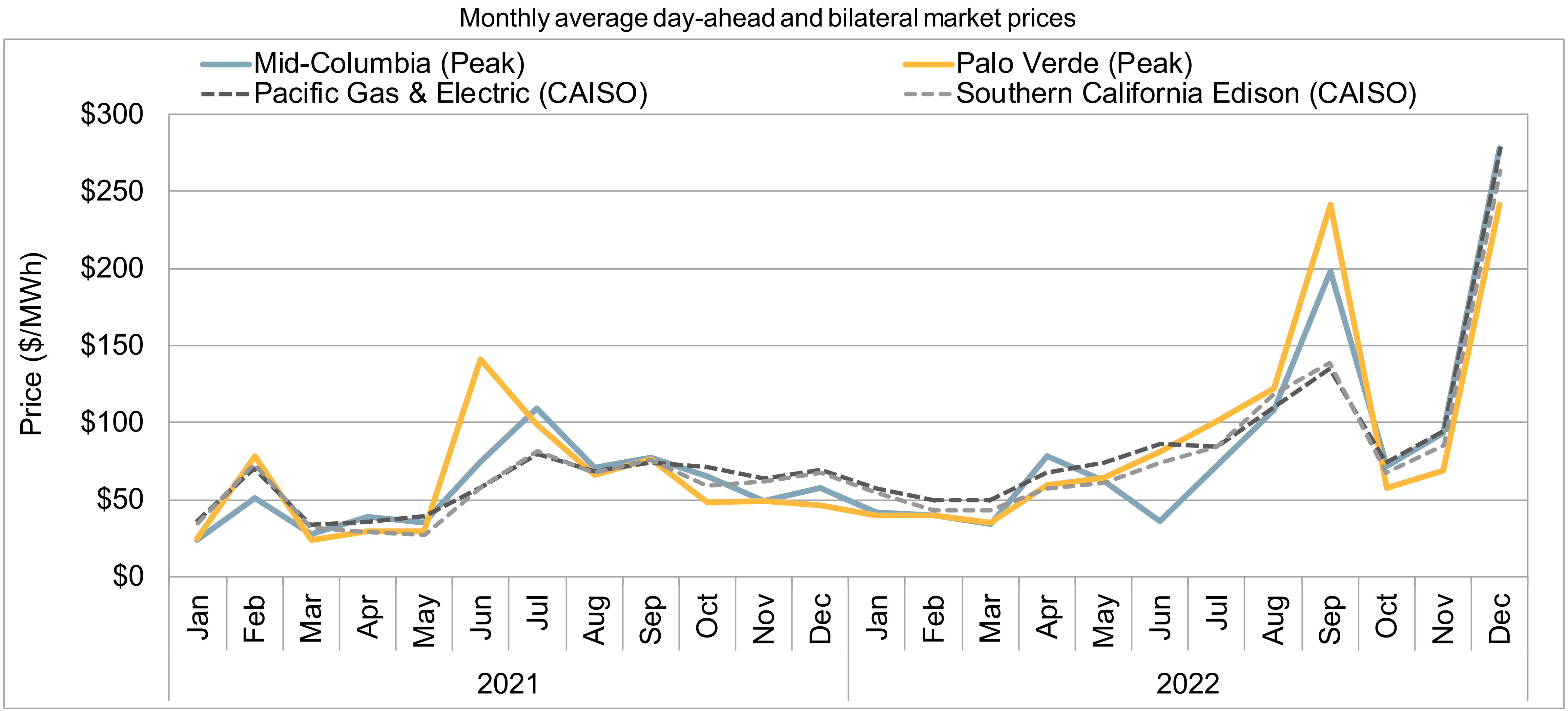
Estimated net revenues of hypothetical combustion turbine rose to $56/kW-year in NP15 and SP15, above going forward fixed costs



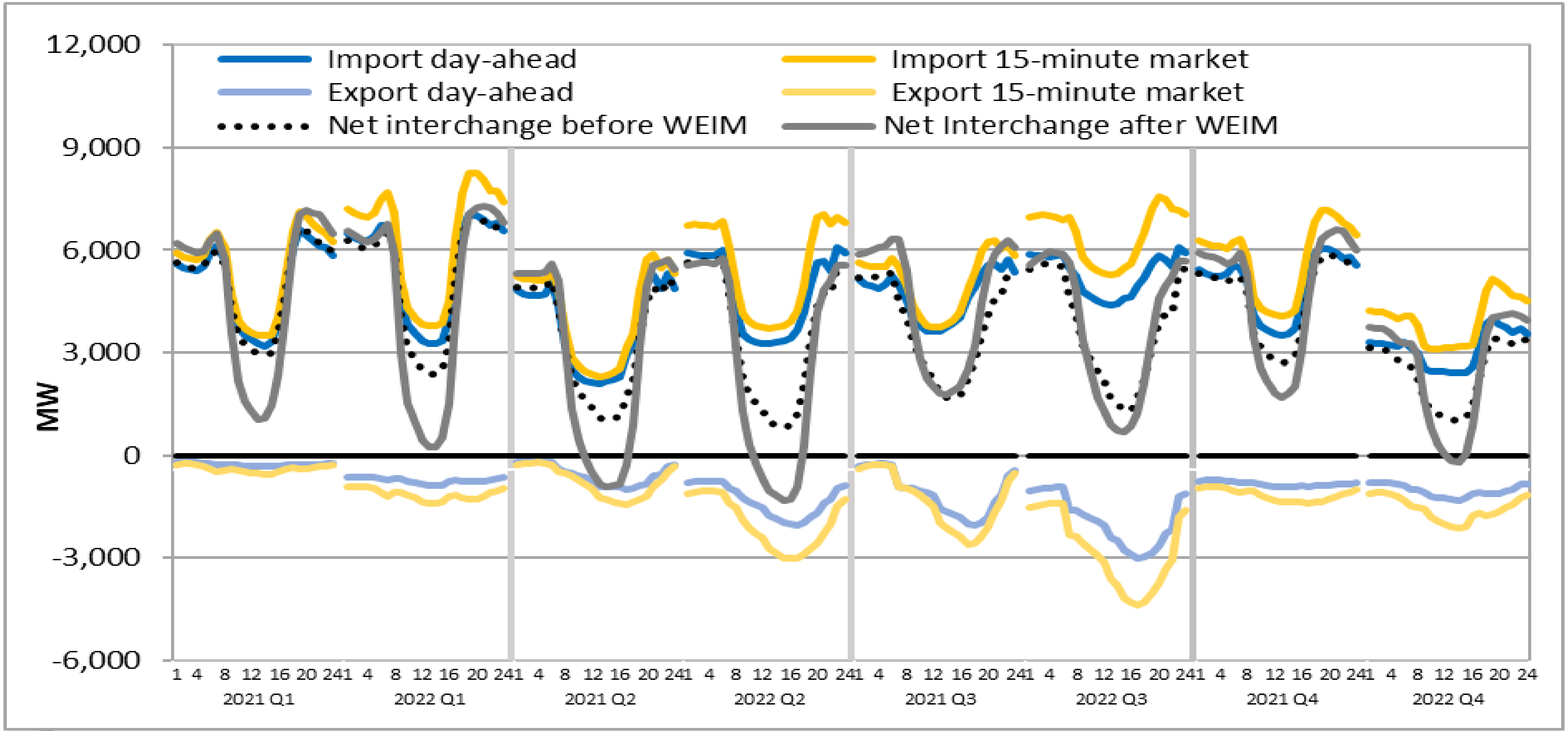
Average hourly prices mirror net load, with day-ahead prices higher than 5-minute real-time in peak hours



High prices in September driven by high regional demand

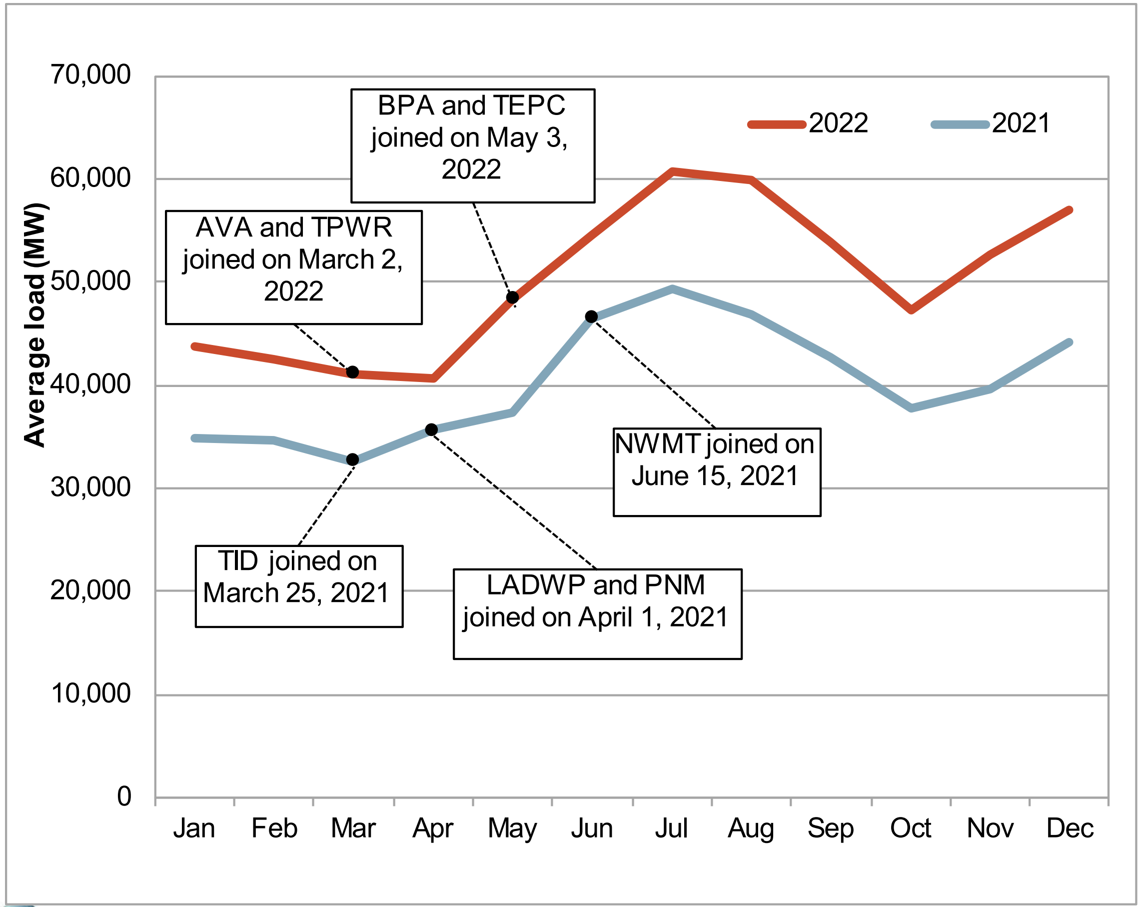


Net imports fell in each quarter, from both Northwest and Southwest



Western energy imbalance market expands, improving structure and performance of the real-time market

Non-CAISO WEIM load



2022 Peak load measures

	Peak load		Load during WEIM system peak (06-Sep-22)	
BAA	Date	Load (MW)	Load (MW)	Percentage
CISO	6-Sep-22	49,312	49,269	37.9%
PACE	6-Sep-22	9,408	9,408	7.2%
NEVP	12-Jul-22	8,867	8,682	6.7%
BCHA	19-Dec-22	11,899	7,800	6.0%
BPAT	22-Dec-22	10,941	7,305	5.6%
SRP	11-Jul-22	7,512	6,850	5.3%
AZPS	11-Jul-22	7,373	6,720	5.2%
LADWP	6-Sep-22	6,041	5,941	4.6%
BANC	6-Sep-22	4,744	4,710	3.6%
PGE	2-Jun-22	4,354	3,481	2.7%
IPCO	3-Aug-22	3,793	3,413	2.6%
PACW	23-Feb-22	3,976	3,234	2.5%
PSEI	22-Dec-22	5,017	2,950	2.3%
TEPC	11-Jul-22	2,890	2,462	1.9%
PNM	19-Jul-22	2,617	2,163	1.7%
NWMT	22-Dec-22	2,016	1,586	1.2%
AVA	22-Dec-22	2,206	1,562	1.2%
SCL	22-Dec-22	1,863	1,109	0.9%
TIDC	6-Sep-22	728	722	0.6%
TPWR	24-Mar-22	1,310	505	0.4%
Total			**129,872**	

Expansion of the Western Energy Imbalance Market (WEIM) helped improve the overall structure and performance of the real-time market

- 2 new members of the WEIM in 2020
- 4 new members of the WEIM in 2021
- 4 new members of the WEIM in 2022
- 3 new members of the WEIM in 2023

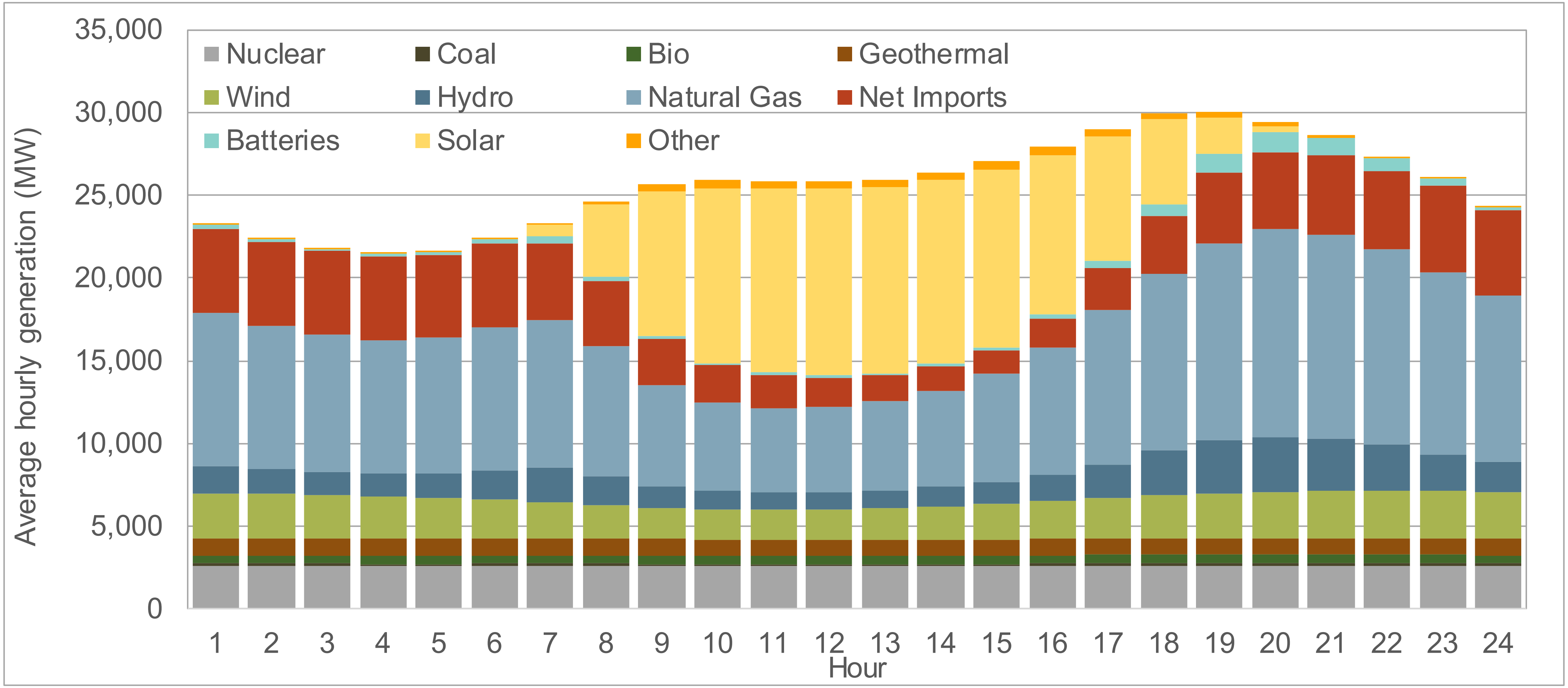
- The WEIM, including the ISO, now accounts for about 75 percent of WECC peak load

- Northwest prices regularly different from the rest of the system due to limited transfer capability

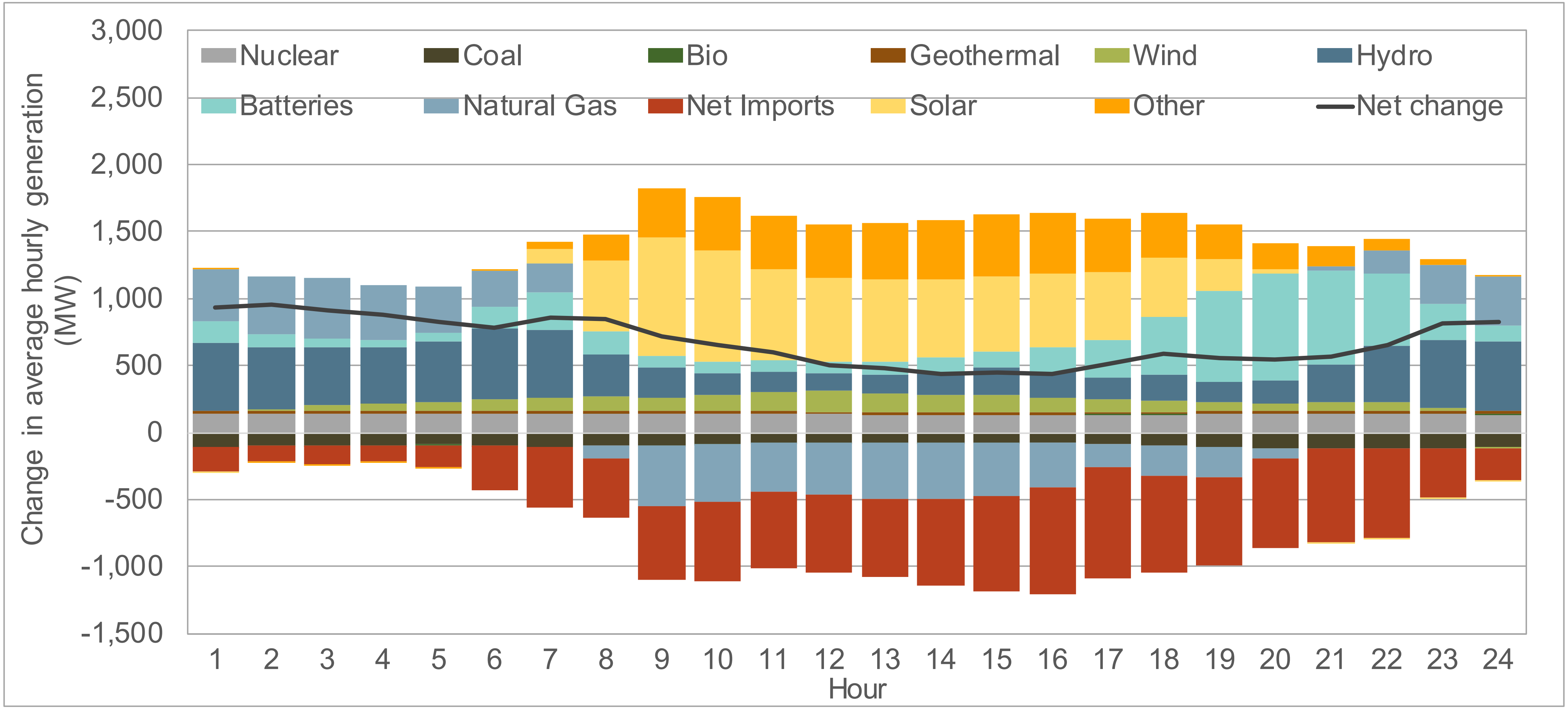
- Peak California area prices exceed other areas due to GHG and congestion

*Avangrid office; generation-only BAA with distribution across multiple states.
Map boundaries are approximate and for illustrative purposes only.

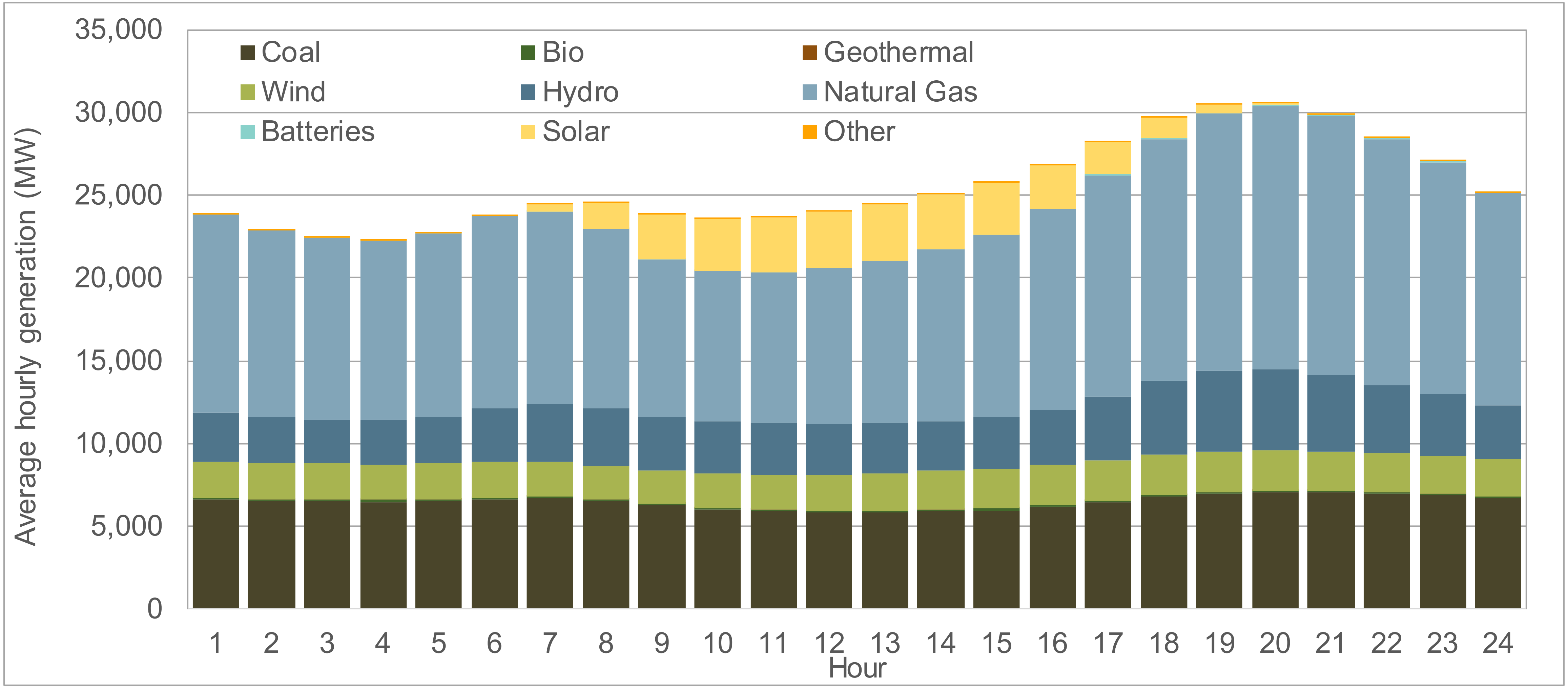
Average hourly generation in CAISO by fuel type (2022)



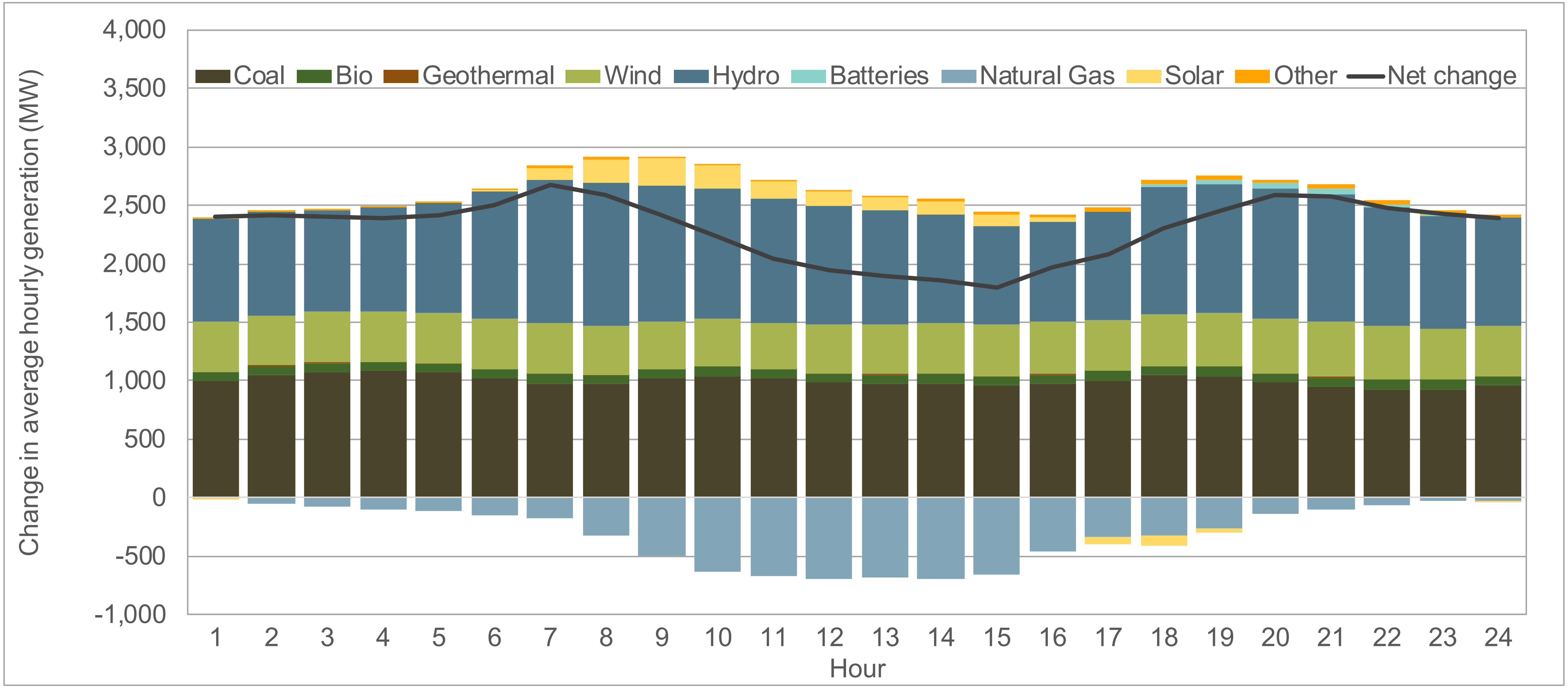
Change in average hourly generation by fuel type (2021 to 2022)



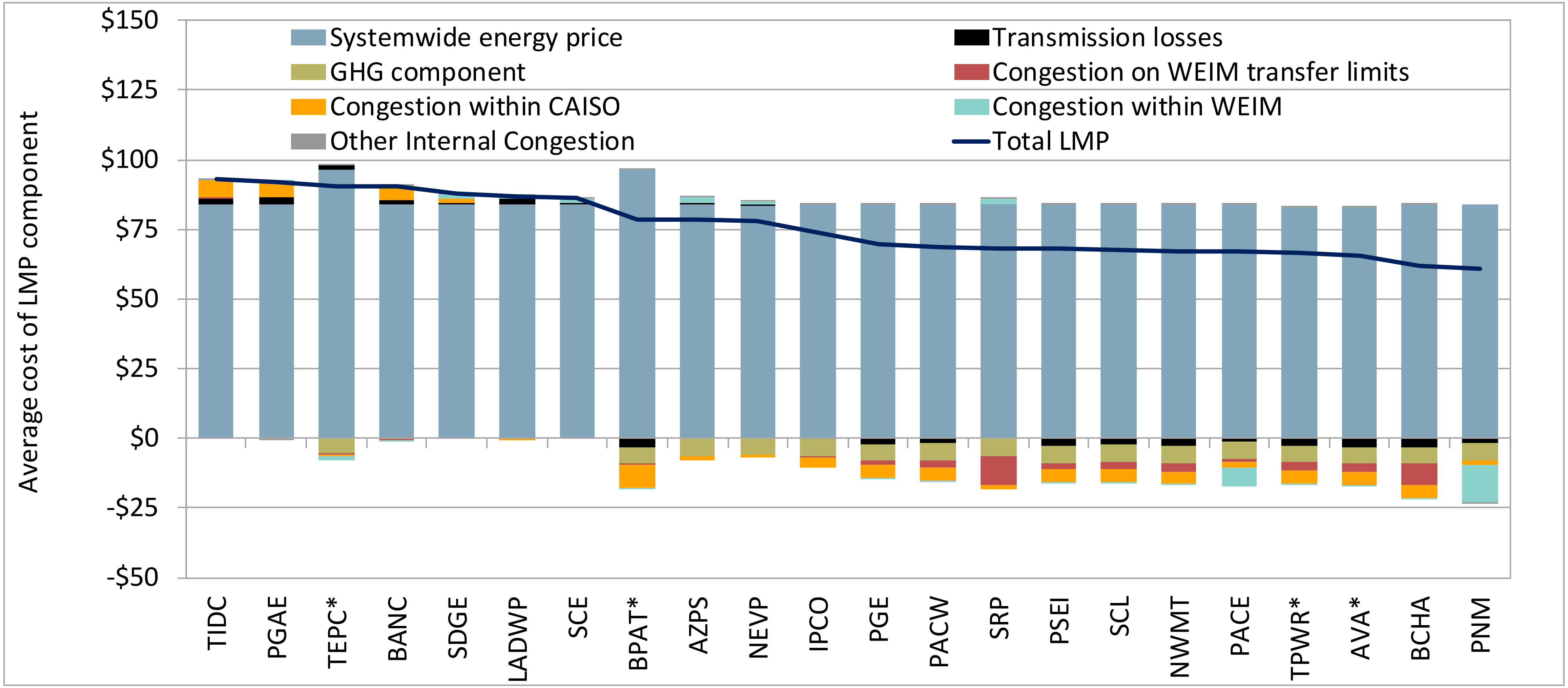
Average hourly participating non-CAISO WEIM generation by fuel type, 2022



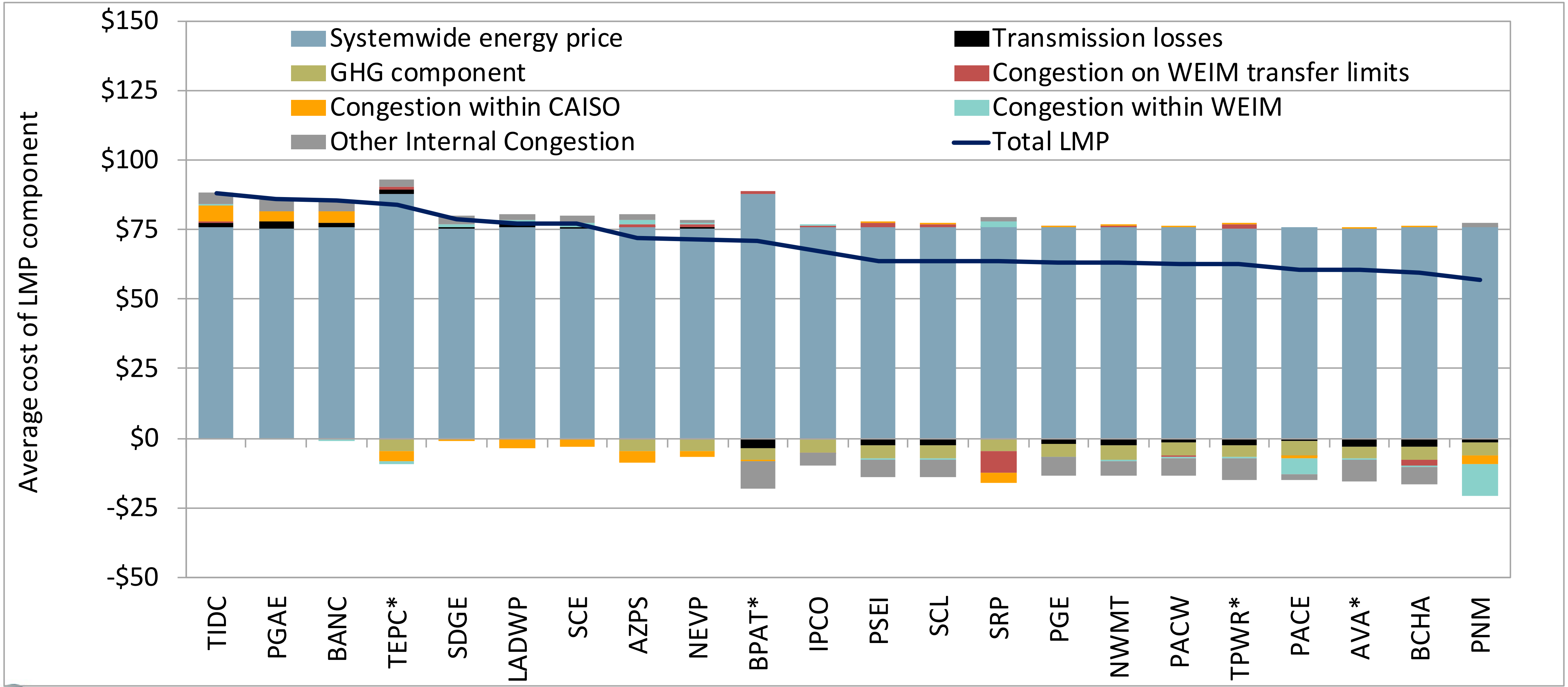
Change in average hourly WEIM generation by fuel type (2021 to 2022)



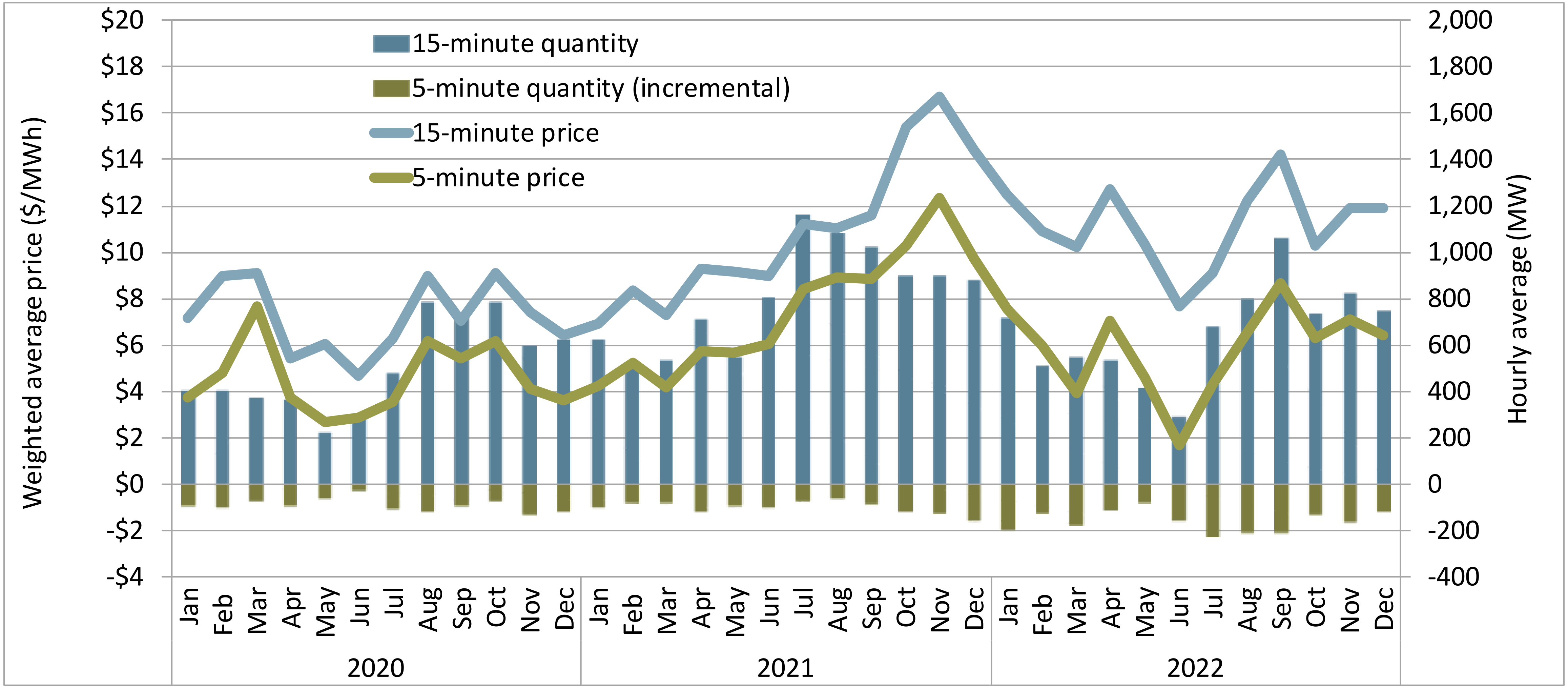
Impact of congestion and greenhouse gas on 15-minute prices (2022)



Impact of congestion and greenhouse gas on 5-minute prices (2022)



Energy imbalance market greenhouse gas price and cleared quantity



Prices and transfers of energy reflect differences in regional supply conditions and transfer limitations

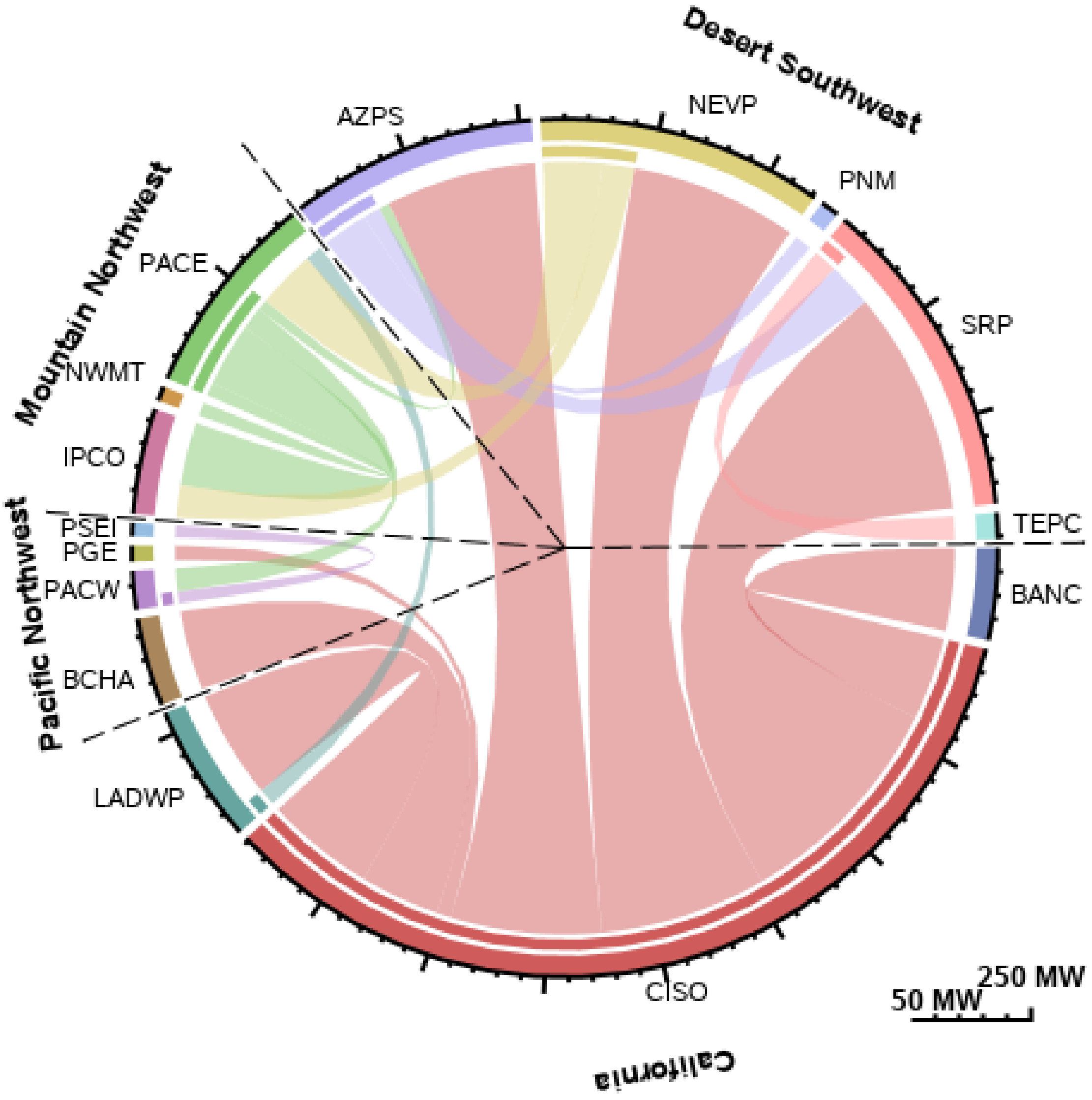
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
SMEC	$77	$74	$73	$72	$77	$85	$90	$78	$66	$60	$57	$57	$56	$57	$64	$81	$100	$120	$138	$142	$116	$101	$90	$80
PG&E (CAISO)	$84	$82	$80	$80	$84	$92	$97	$87	$73	$67	$65	$64	$63	$65	$74	$91	$110	$129	$147	$152	$129	$112	$97	$86
SCE (CAISO)	$82	$79	$78	$77	$81	$89	$94	$80	$62	$53	$50	$49	$49	$51	$60	$81	$104	$127	$152	$157	$127	$110	$96	$85
BANC	$82	$79	$78	$77	$82	$90	$94	$84	$73	$69	$67	$66	$66	$67	$77	$92	$110	$126	$142	$144	$119	$107	$95	$84
Turlock ID	$83	$81	$79	$79	$83	$90	$95	$85	$77	$72	$72	$72	$72	$73	$81	$97	$110	$125	$143	$149	$123	$108	$95	$86
LADWP	$82	$78	$77	$77	$81	$89	$93	$80	$64	$55	$52	$51	$51	$53	$62	$82	$105	$127	$151	$158	$127	$108	$96	$85
NV Energy	$72	$70	$69	$69	$72	$79	$80	$70	$63	$53	$51	$51	$51	$51	$58	$75	$93	$111	$135	$138	$109	$91	$85	$75
Arizona PS	$75	$72	$69	$70	$74	$82	$84	$71	$58	$50	$47	$46	$46	$48	$56	$74	$95	$114	$137	$142	$114	$97	$88	$77
Tucson Electric*	$85	$82	$80	$80	$85	$93	$93	$80	$68	$63	$62	$63	$64	$66	$75	$99	$120	$141	$173	$167	$131	$107	$100	$89
Salt River Project	$62	$59	$58	$58	$64	$71	$72	$62	$49	$46	$43	$44	$46	$46	$50	$63	$81	$101	$123	$112	$96	$81	$78	$67
PSC New Mexico	$51	$51	$51	$52	$55	$64	$67	$56	$47	$42	$37	$39	$38	$41	$49	$65	$78	$92	$113	$114	$86	$66	$56	$53
PacifiCorp East	$59	$57	$56	$55	$60	$67	$70	$62	$54	$52	$49	$49	$48	$50	$55	$68	$83	$96	$110	$113	$89	$75	$69	$62
Idaho Power	$65	$62	$61	$61	$65	$73	$77	$73	$64	$61	$61	$60	$60	$61	$63	$75	$90	$97	$108	$115	$93	$81	$76	$68
NorthWestern	$60	$57	$56	$56	$60	$67	$73	$68	$63	$63	$60	$60	$58	$58	$60	$70	$79	$86	$89	$87	$81	$73	$71	$62
Avista Utilities*	$65	$62	$60	$60	$64	$71	$75	$71	$67	$66	$66	$66	$64	$64	$66	$77	$85	$90	$93	$90	$85	$78	$77	$68
BPA*	$75	$70	$67	$67	$70	$78	$81	$80	$77	$78	$78	$79	$78	$79	$81	$87	$100	$110	$110	$116	$108	$103	$91	$78
Tacoma Power*	$67	$63	$61	$61	$64	$69	$71	$71	$70	$71	$71	$72	$70	$69	$72	$75	$84	$90	$93	$95	$87	$80	$79	$70
PacifiCorp West	$62	$58	$57	$57	$60	$66	$67	$67	$63	$62	$63	$62	$60	$59	$61	$69	$81	$90	$97	$99	$81	$73	$73	$63
Portland GE	$61	$58	$57	$57	$60	$66	$68	$69	$65	$64	$64	$62	$61	$60	$62	$70	$83	$93	$98	$99	$82	$75	$73	$64
Puget Sound Energy	$62	$58	$56	$56	$60	$65	$65	$66	$65	$65	$65	$65	$64	$63	$65	$69	$76	$83	$87	$87	$79	$73	$73	$65
Powerex	$60	$57	$56	$56	$59	$61	$62	$59	$60	$58	$58	$58	$56	$56	$58	$62	$70	$72	$72	$72	$71	$69	$67	$62
Seattle City Light	$64	$58	$56	$56	$60	$64	$65	$66	$66	$65	$65	$65	$63	$63	$65	$69	$76	$83	$85	$86	$80	$74	$72	$64

Hour

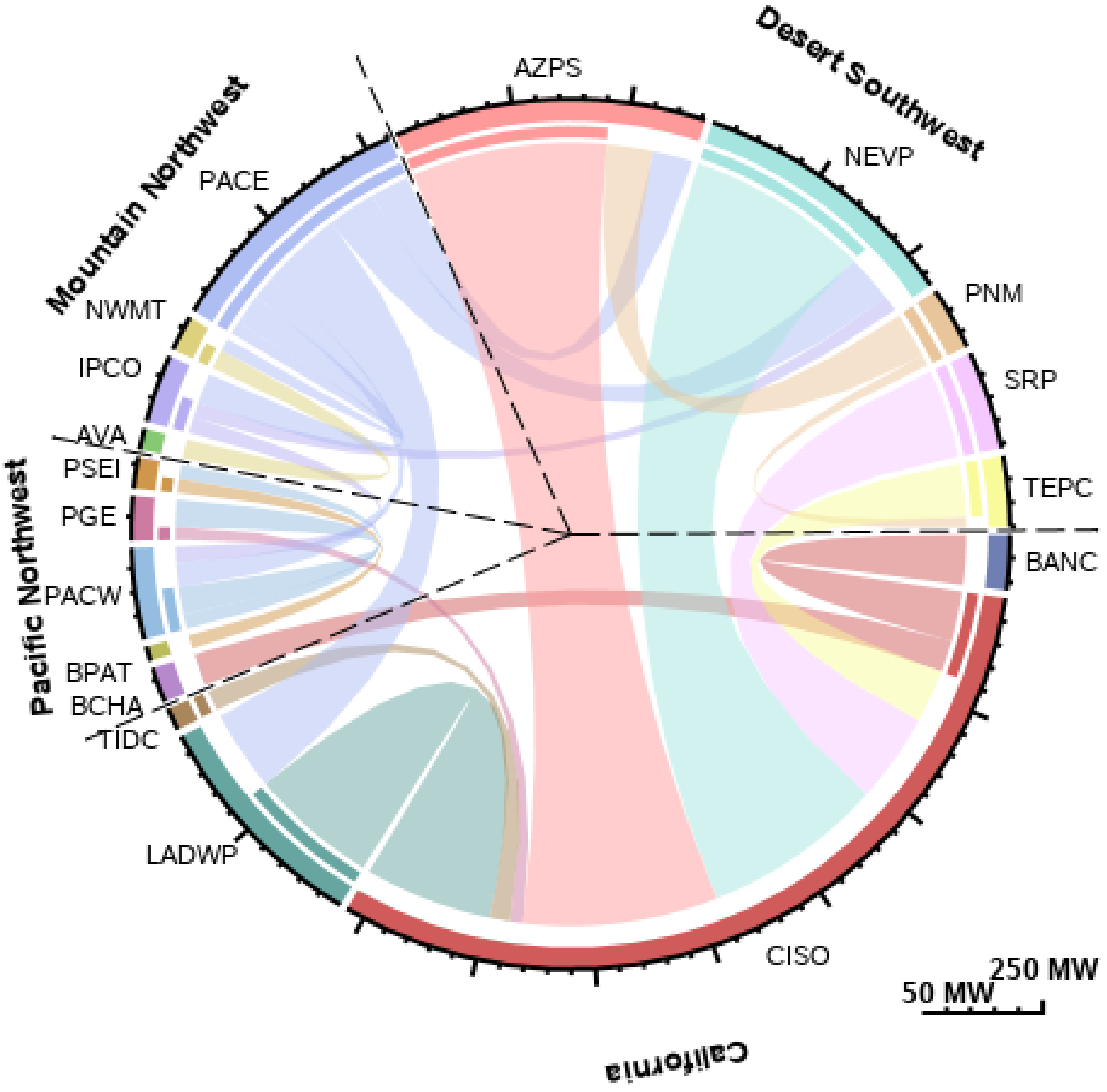
WEIM transfer constraint congestion had greater impact on prices than internal constraint congestion in all areas outside of the ISO, lowering prices in Northwest

	15-minute market		5-minute market	
	Congested from area	Congested into area	Congested from area	Congested into area
BANC	0%	0%	0%	0%
L.A. Dept. of Water and Power	0%	0%	0%	0%
Arizona Public Service	1%	0%	1%	1%
NV Energy	1%	0%	1%	1%
Public Service Company of NM	1%	0%	1%	1%
Turlock Irrigation District	0%	2%	0%	2%
PacifiCorp East	6%	1%	4%	1%
Tucson Electric Power*	2%	4%	1%	6%
Idaho Power	6%	7%	4%	7%
Salt River Project	13%	3%	12%	4%
NorthWestern Energy	12%	8%	8%	8%
Avista Utilities*	13%	7%	8%	8%
PacifiCorp West	22%	9%	12%	7%
Portland General Electric	22%	12%	13%	9%
Bonneville Power Admin.*	21%	21%	16%	20%
Tacoma Power*	25%	21%	19%	23%
Puget Sound Energy	27%	19%	21%	21%
Seattle City Light	27%	19%	21%	21%
Powerex	34%	17%	36%	32%

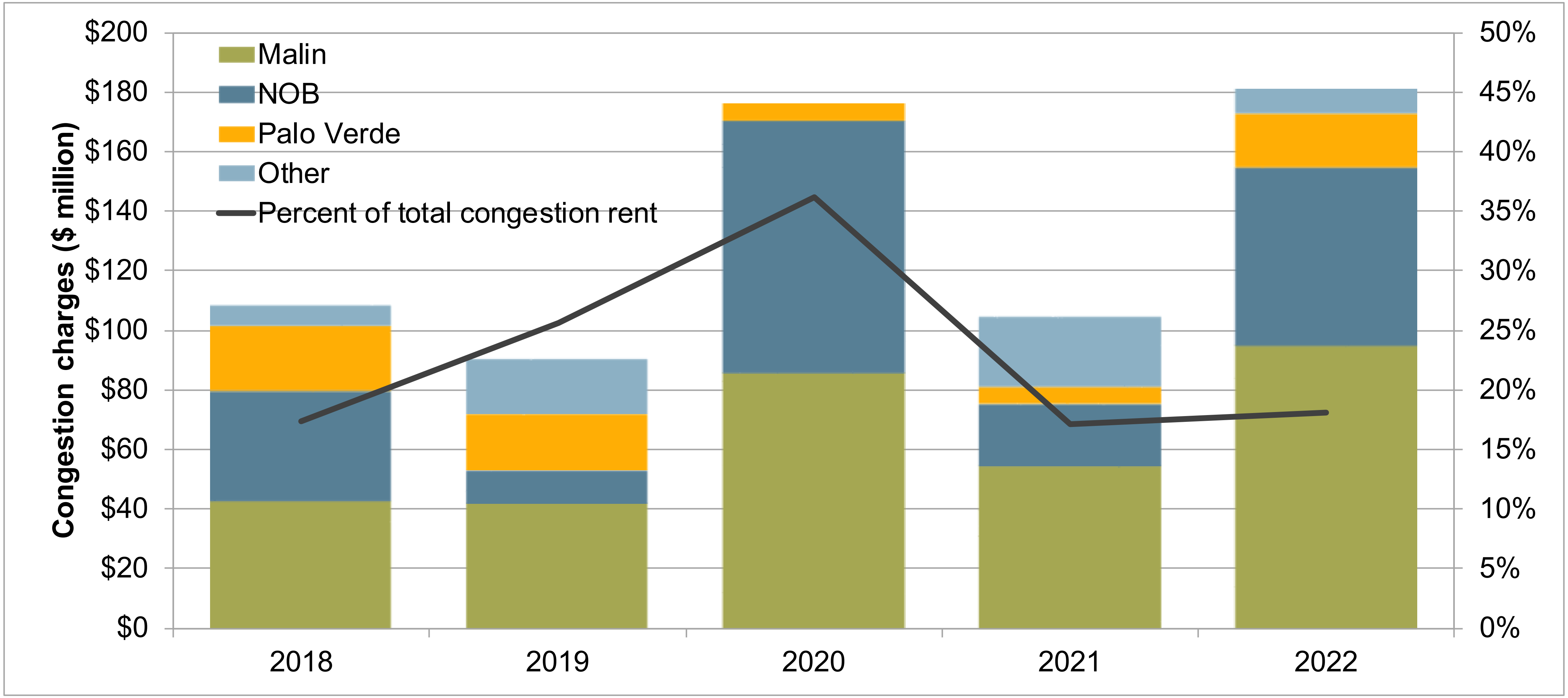
Average 15-minute WEIM exports mid-day hours, March – May, 2022



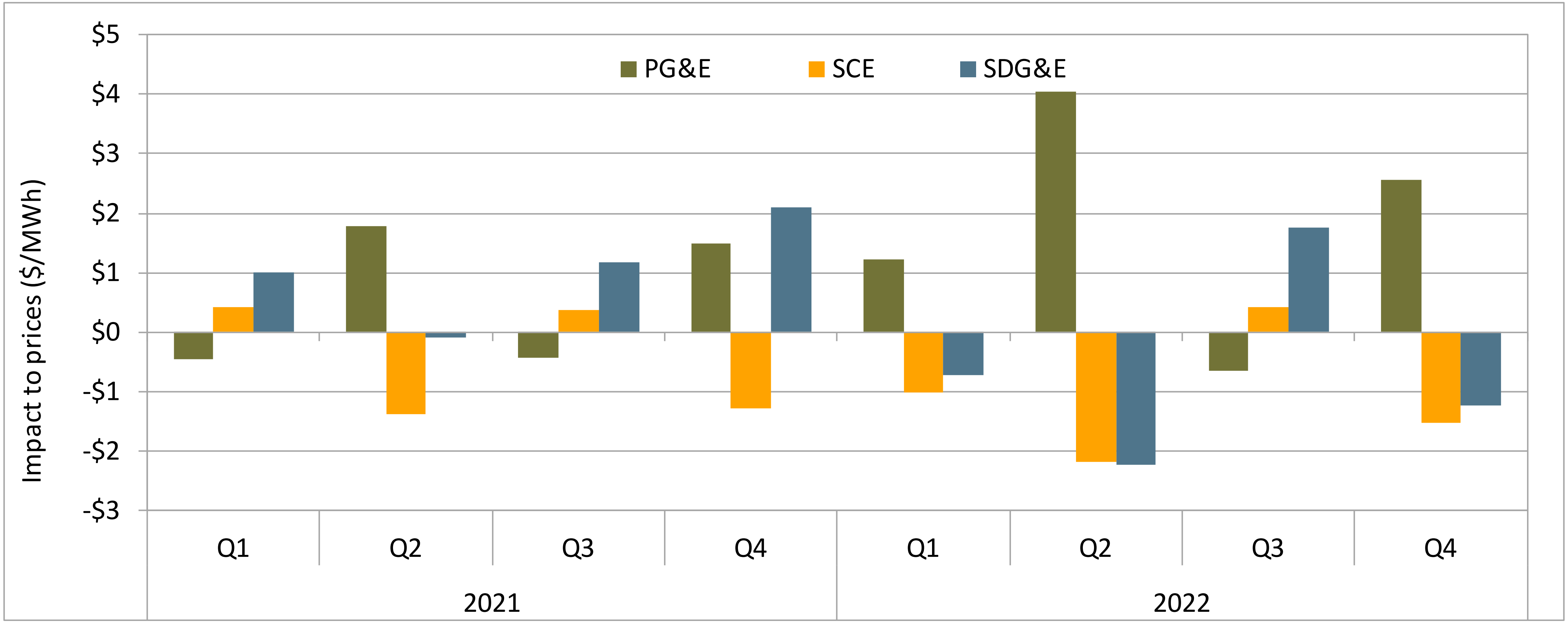
Average 15-minute WEIM exports, peak load hours June – September, 2022



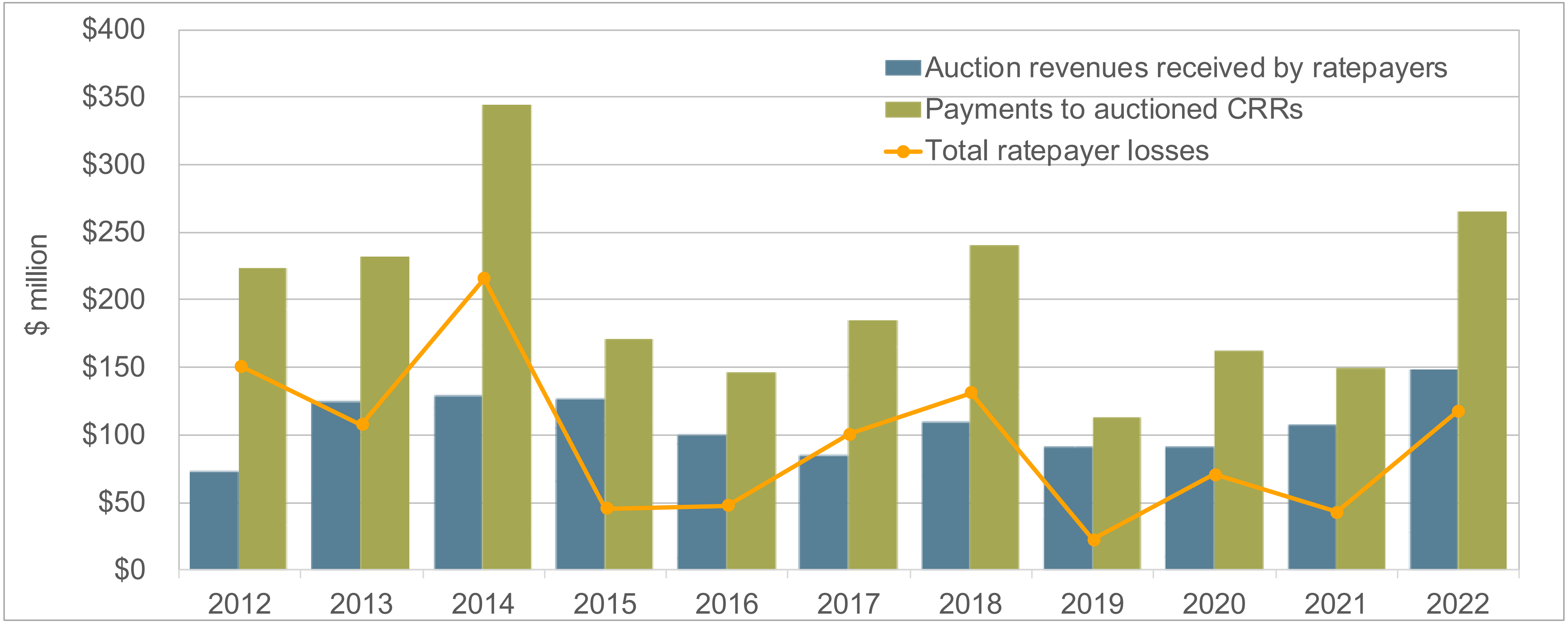
Day-ahead import congestion charges on major interties (2018-2022)



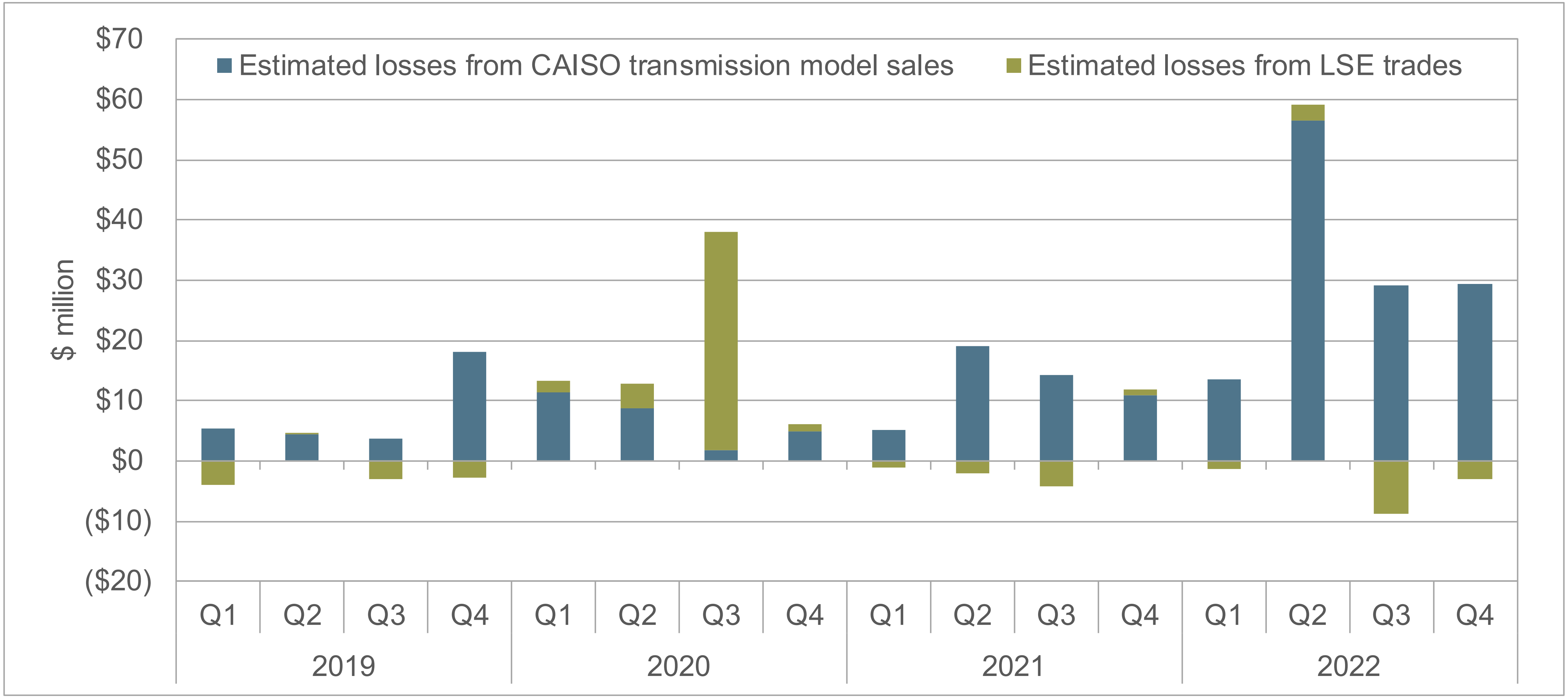
Day-ahead congestion impact decreases, congestion revenues total 5% of total day-ahead market energy costs, similar to 2021



Transmission ratepayers lost about $118 million from auctioned CRRs in 2022, the highest loss since market changes implemented in 2019



Estimated CRR auction loss breakout by CAISO and load serving entity

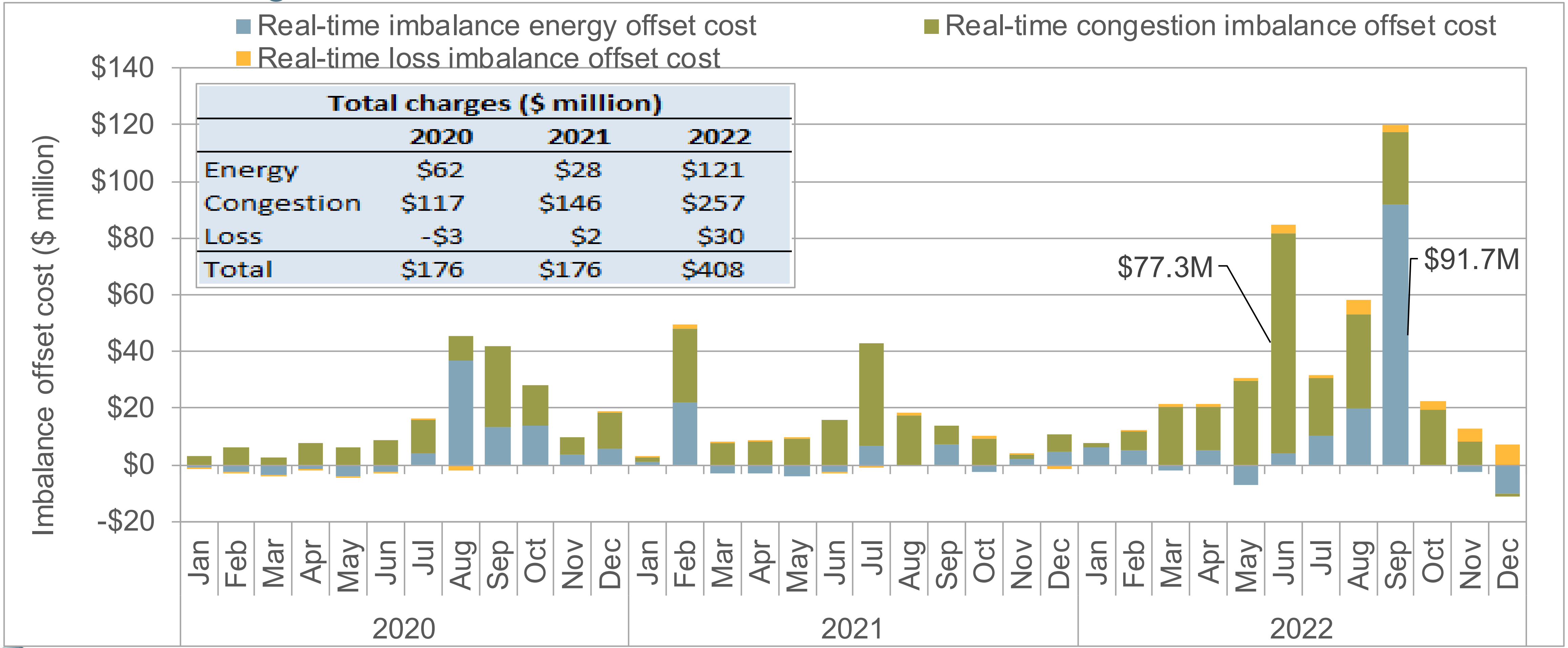


Congestion revenue right auction changes implemented January 2019

- Implemented in response to systematic losses from congestion revenue right auction sales since 2009
- Transmission ratepayer losses are significantly lower, but rising
  - Averaged $45 million per year 2019-2021, compared to $114 million in the 7 years before the changes. $118 million losses in 2022
  - Transmission ratepayers were paid 63 cents per dollar paid to auctioned congestion revenue rights, about 48 cents per dollar before the changes

DMM believes the current auction is unnecessary and could be eliminated or (if the ISO believes a market is necessary for hedging) replaced with a market of willing buyers and sellers

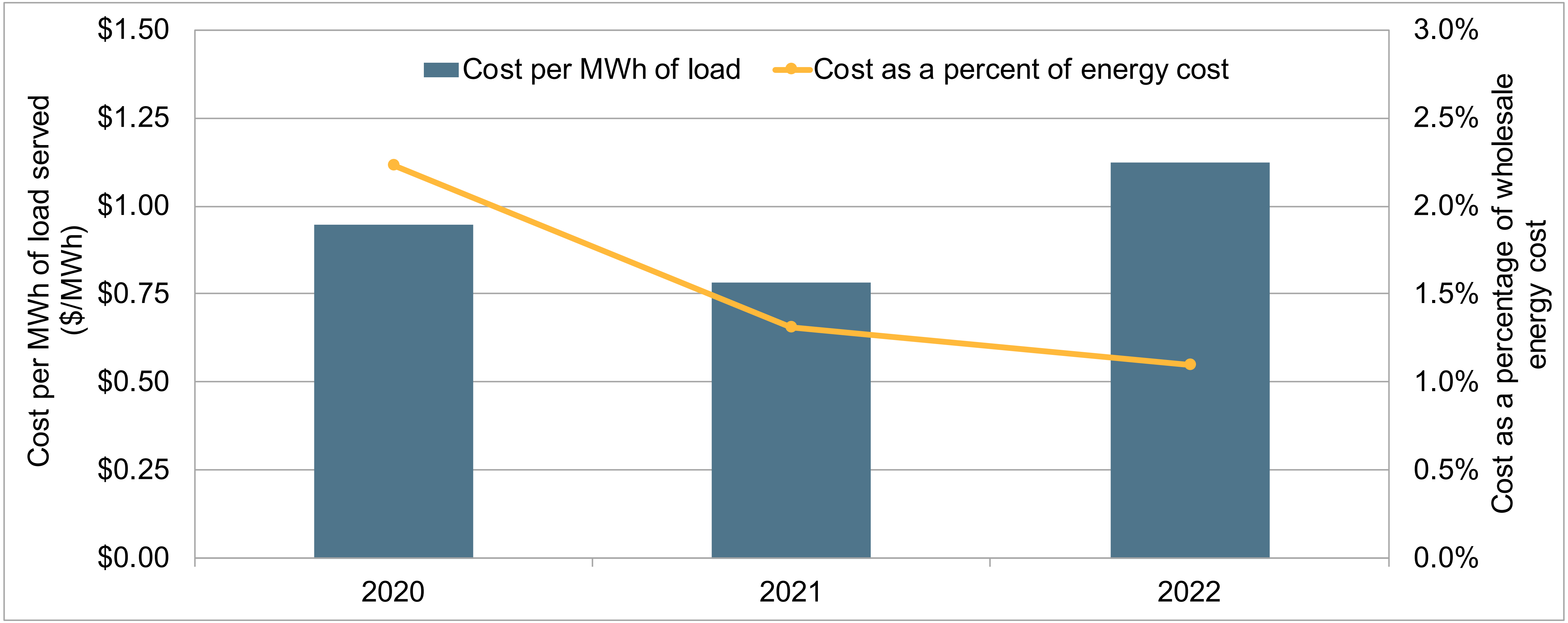
Real-time imbalance offset costs increased to $408 million; most energy offsets due to differences between the price paid to generation, and the price paid by load and congestion offset costs were due to reductions in constraint limits



Total charges ($ million)

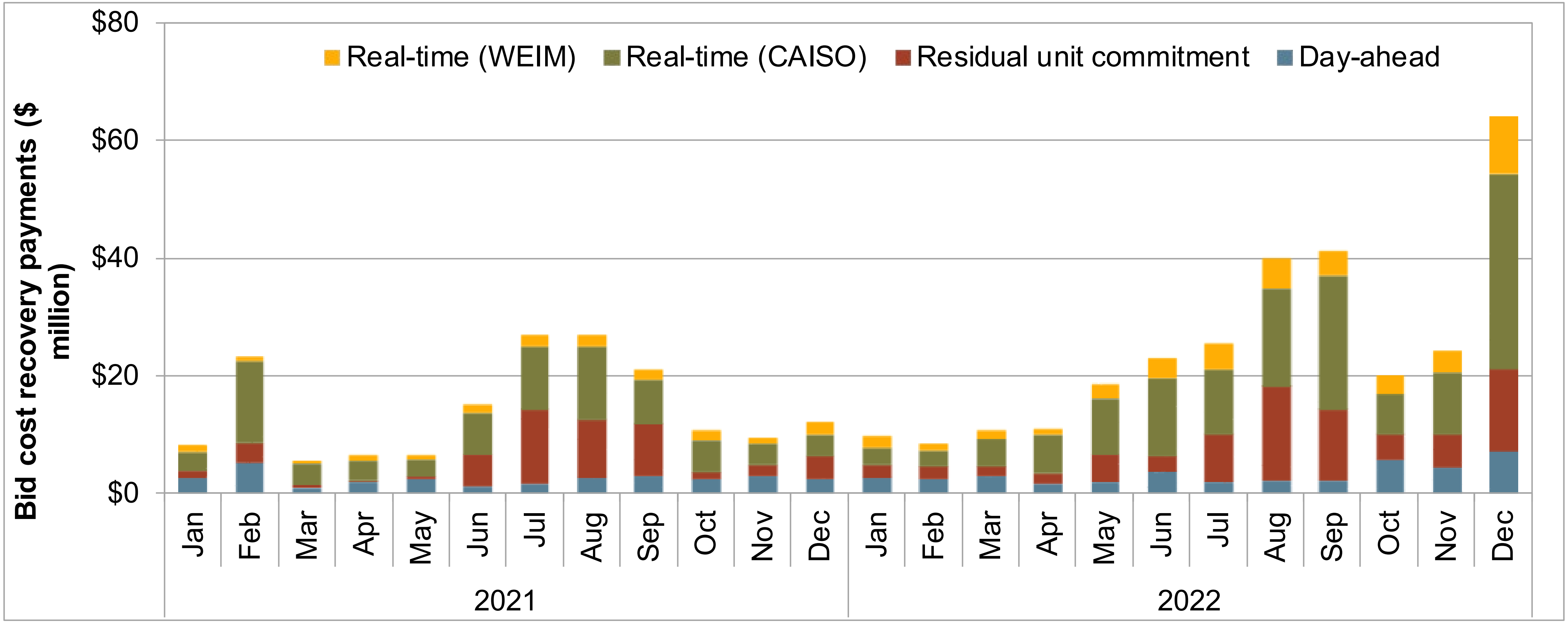
	2020	2021	2022
Energy	$62	$28	$121
Congestion	$117	$146	$257
Loss	-$3	$2	$30
Total	$176	$176	$408

Ancillary service costs increased to $237 million, and 1.1% of wholesale energy costs



Bid cost recovery payments in CAISO increased to $297 million from $158 million in 2021 (but equaled 1.2% of total energy in both 2021 and 2022)

WEIM bid cost recovery = $42 million



Total bid cost recovery payments in CAISO by technology (2021–2022)

System	Technology type	Bid cost recovery payments ($)		Percent of total bid cost recovery payments (%)	
		2021	2022	2021	2022
CISO	Batteries	$3,612,062	$30,330,699	2%	12%
CISO	Once-through-cooling	$56,382,130	$63,073,832	36%	25%
CISO	Combined Cycle	$56,073,876	$77,554,525	36%	30%
CISO	Frame turbine: non-Fast start	$0	$159,200	0%	<1%
CISO	Gas turbine: non-Fast start	$4,599,725	$11,615,876	3%	5%
CISO	Gas turbine: Fast start cogeneration	$377,313	$489,399	<1%	<1%
CISO	Gas turbine: Fast start (includes Frame CTs and Gas	$17,976,008	$32,019,625	11%	13%
CISO	Reciprocating engines: Fast start (includes cogens)	$10,944	$6,709	<1%	<1%
CISO	Reciprocating engines: non-Fast start	$4,531,553	$9,606,152	3%	4%
CISO	Hydro	$1,582,710	$1,866,557	1%	1%
CISO	Other	$2,183,520	$6,346,394	1%	2%
CISO	QF/CHP/Must-take	$6,641,987	$19,630,826	4%	8%
CISO	Reliability must-run	$2,506,434	$2,284,017	2%	1%

Convergence bidding net profits rose to about $106 million
from $36 million in 2021

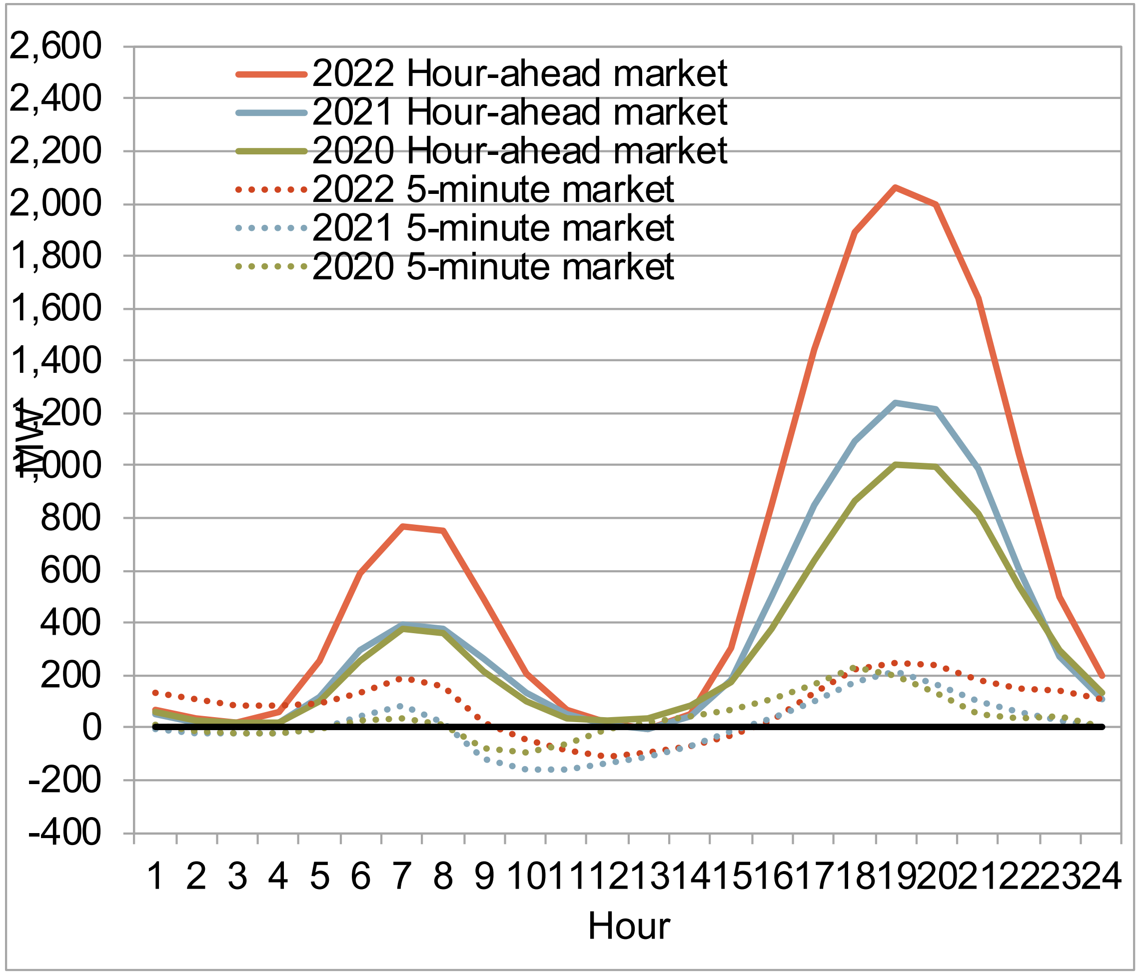
Trading entities	Average hourly megawatts			Revenues\Losses ($ million)				Total revenue after BCR
	Virtual demand	Virtual supply	Total	Virtual demand	Virtual supply before BCR	Virtual bid cost recovery	Virtual supply after BCR	
2022								
Financial	1,521	1,956	3,477	$27.05	$76.79	-$18.68	$58.11	$85.16
Marketer	491	686	1,177	$10.34	$19.15	-$8.11	$11.04	$21.38
Physical load	0	27	28	$0.09	$0.32	-$2.68	-$2.36	-$2.27
Physical generation	13	13	26	$1.61	$0.25	-$0.14	$0.11	$1.72
Total	**2,025**	**2,682**	**4,708**	**$39.09**	**$96.51**	**-$29.61**	**$66.90**	**$105.99**

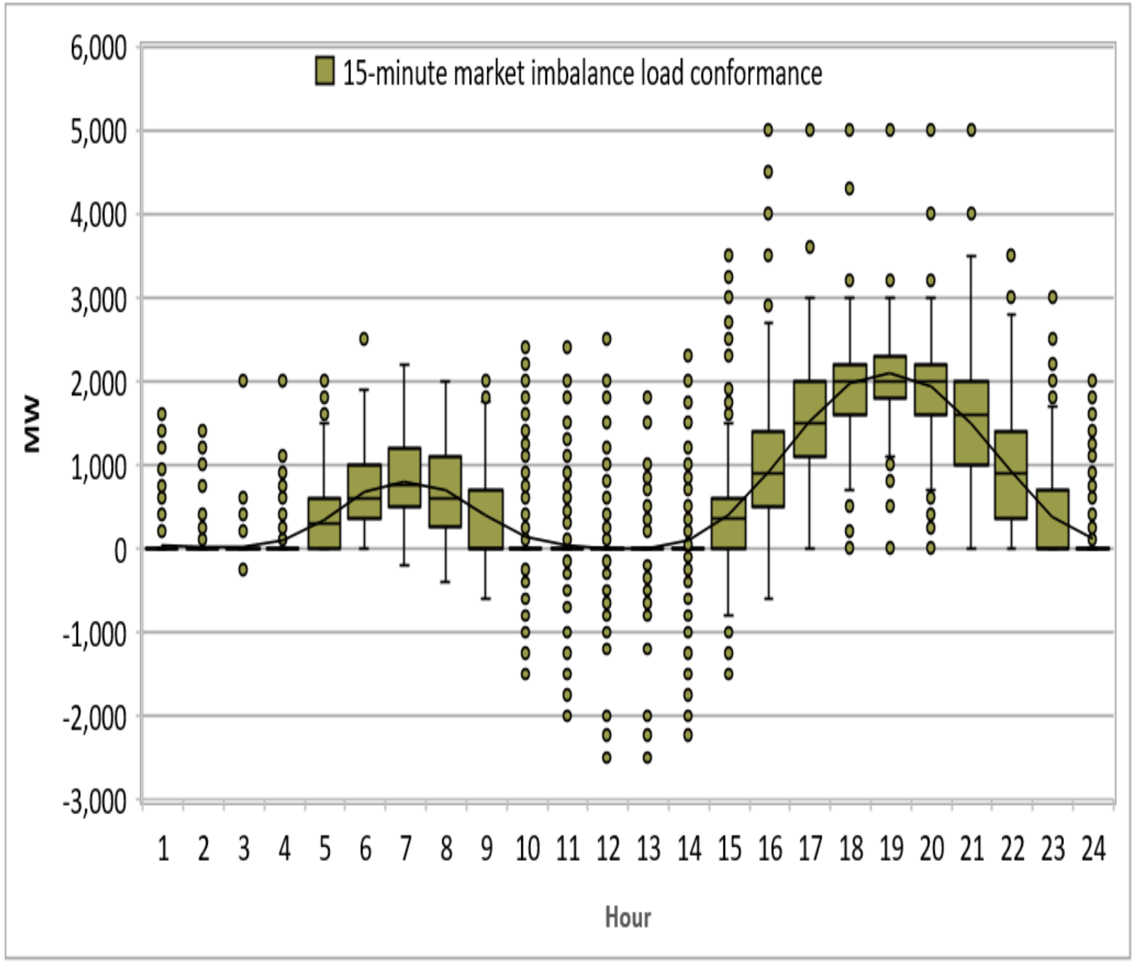
Trading entities	Average hourly megawatts			Revenues\Losses ($ million)				Total revenue after BCR
	Virtual demand	Virtual supply	Total	Virtual demand	Virtual supply before BCR	Virtual bid cost recovery	Virtual supply after BCR	
2021								
Financial	1,172	1,823	2,995	$3.37	$47.31	-$16.75	$30.56	$33.93
Marketer	342	500	842	-$4.08	$12.89	-$4.81	$8.08	$4.00
Physical load	0	27	27	$0.00	$0.21	-$0.81	-$0.60	-$0.60
Physical generation	17	53	70	-$0.98	$0.92	-$0.98	-$0.06	-$1.04
Total	**1,531**	**2,403**	**3,934**	**-$1.69**	**$61.33**	**-$23.35**	**$37.98**	**$36.29**

Flexible ramping capacity

- Designed to enhance reliability and market performance by procuring real-time ramping capacity to help manage variability and uncertainty
- Flexible ramping prices were frequently zero
- Minimum area constraint implemented in November 2020, only in the 15-minute market
  - added to the 5-minute market on February 16, 2022
  - Frequently binding in CAISO, but not other areas
- DMM supported the ISO's planned February 2023 implementation of (nodal procurement):
  - Procurement of capacity from resources not able to meet system uncertainty because of resource characteristics or congestion
  - This can reduce the effectiveness of the product to manage net load volatility and prevent power balance violations
- Uncertainty over load and the future availability of resources to meet that load contributes to operators needing to enter systematic and large imbalance conformance adjustments

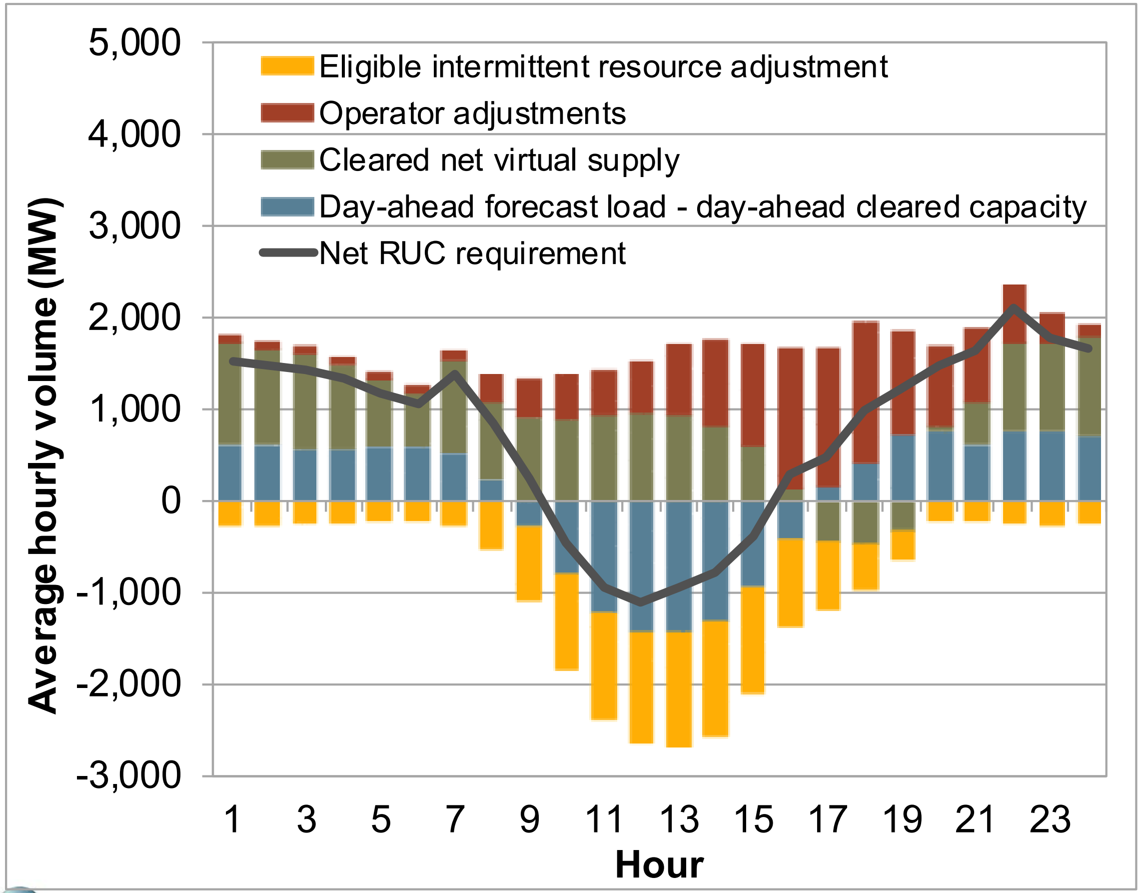
Load adjustment by grid operators in real-time markets grew higher, particularly in ramping hours



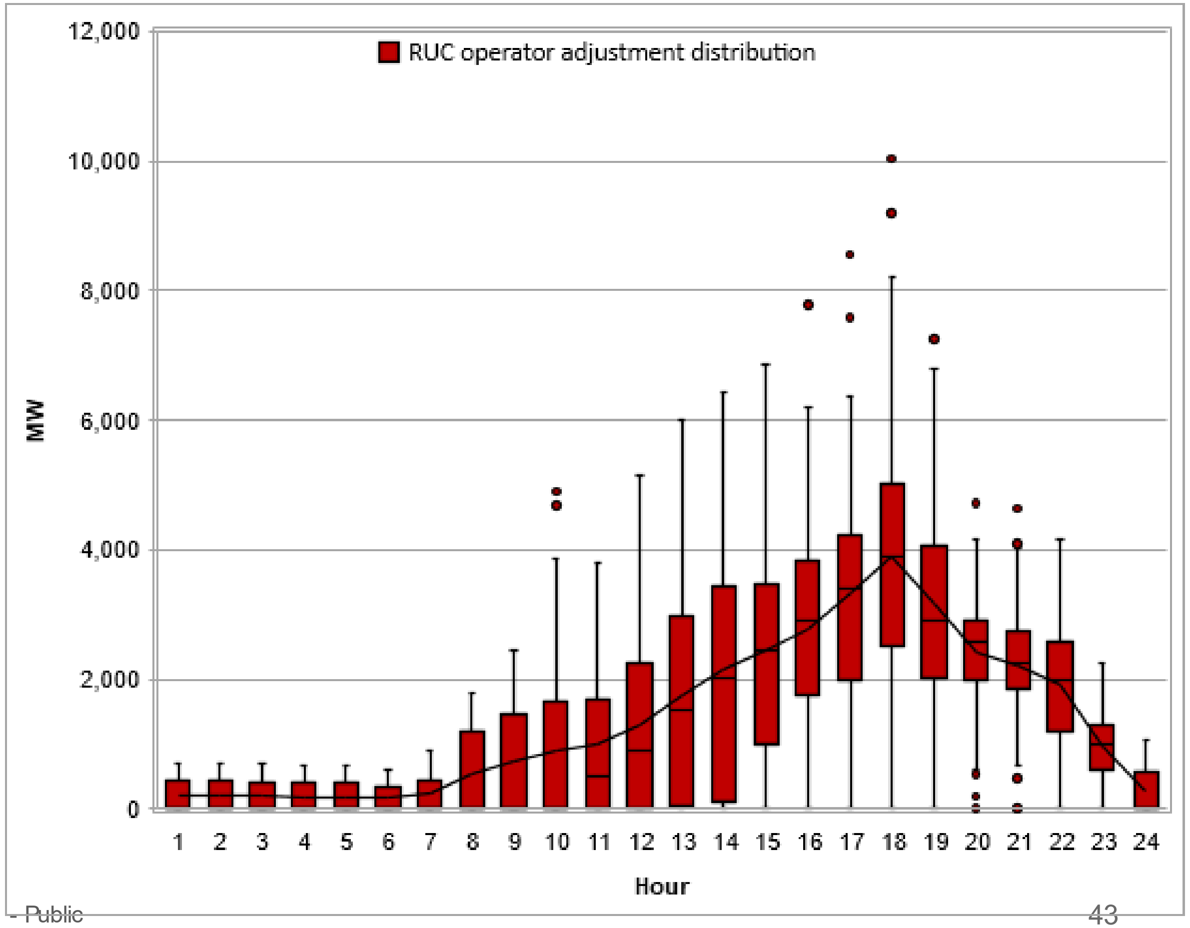


California ISO operator adjustments to load used in day-ahead residual unit commitment process also increased

RUC requirement determinants

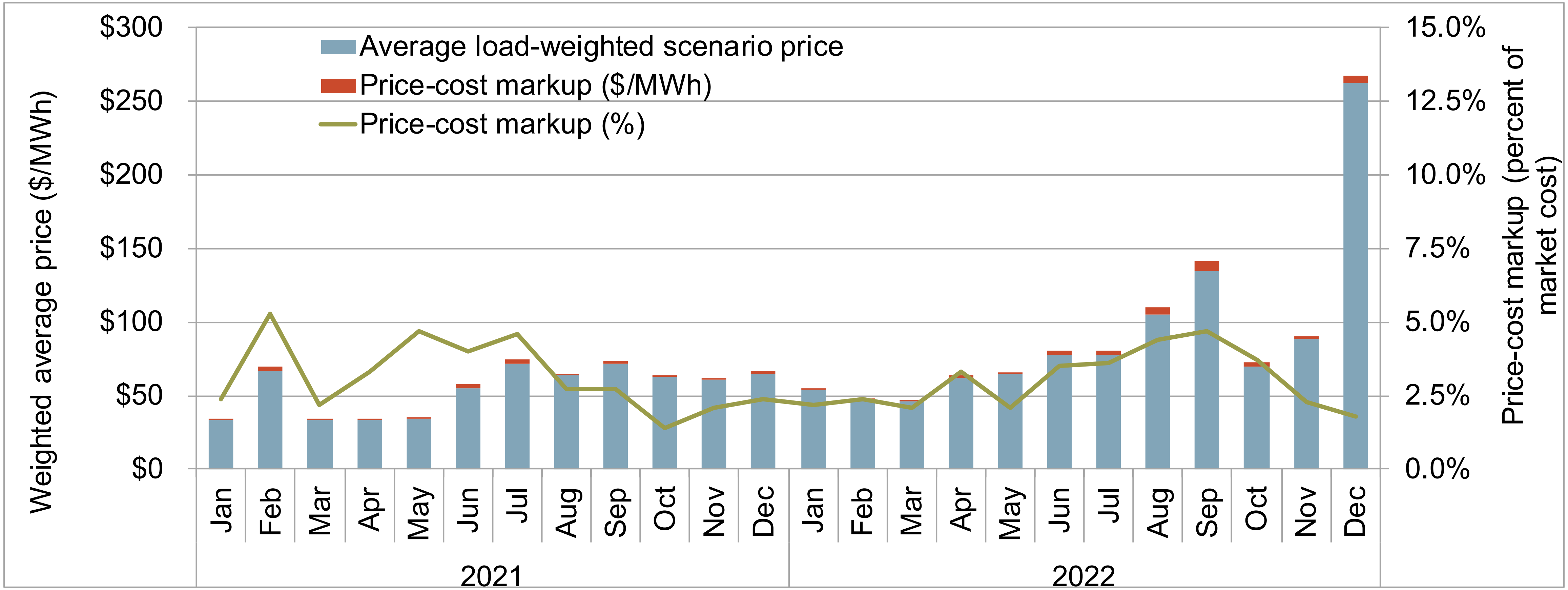


Operator adjustments (Jul – Sep)

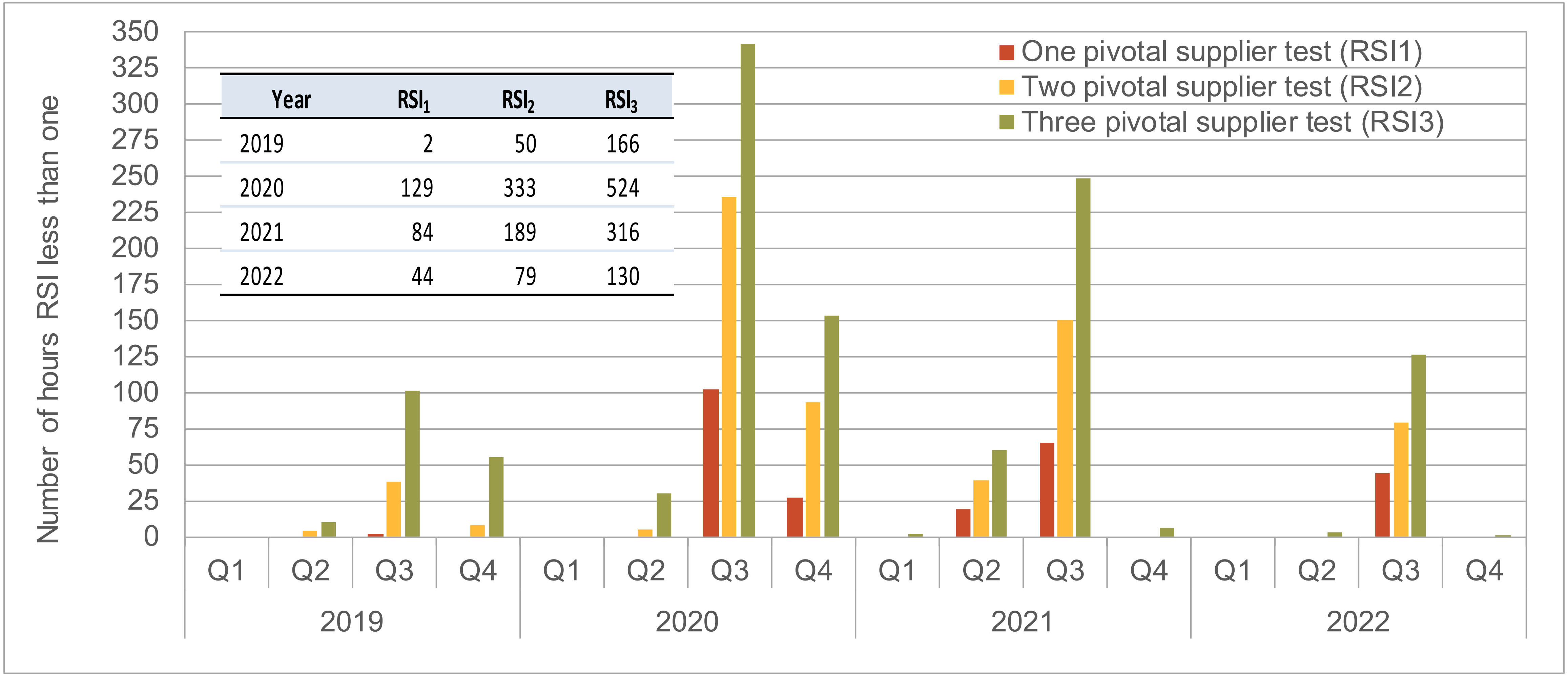


The ISO's energy markets were competitive in 2022, with energy prices about equal to competitive baseline prices calculated by DMM

Total markup about $3.04 or about 3.1% up from $1.41/MWh or about 2.5 percent in 2021



Day-ahead market was more structurally competitive than 2020 and 2021



Year	RSI_1	RSI_2	RSI_3
2019	2	50	166
2020	129	333	524
2021	84	189	316
2022	44	79	130

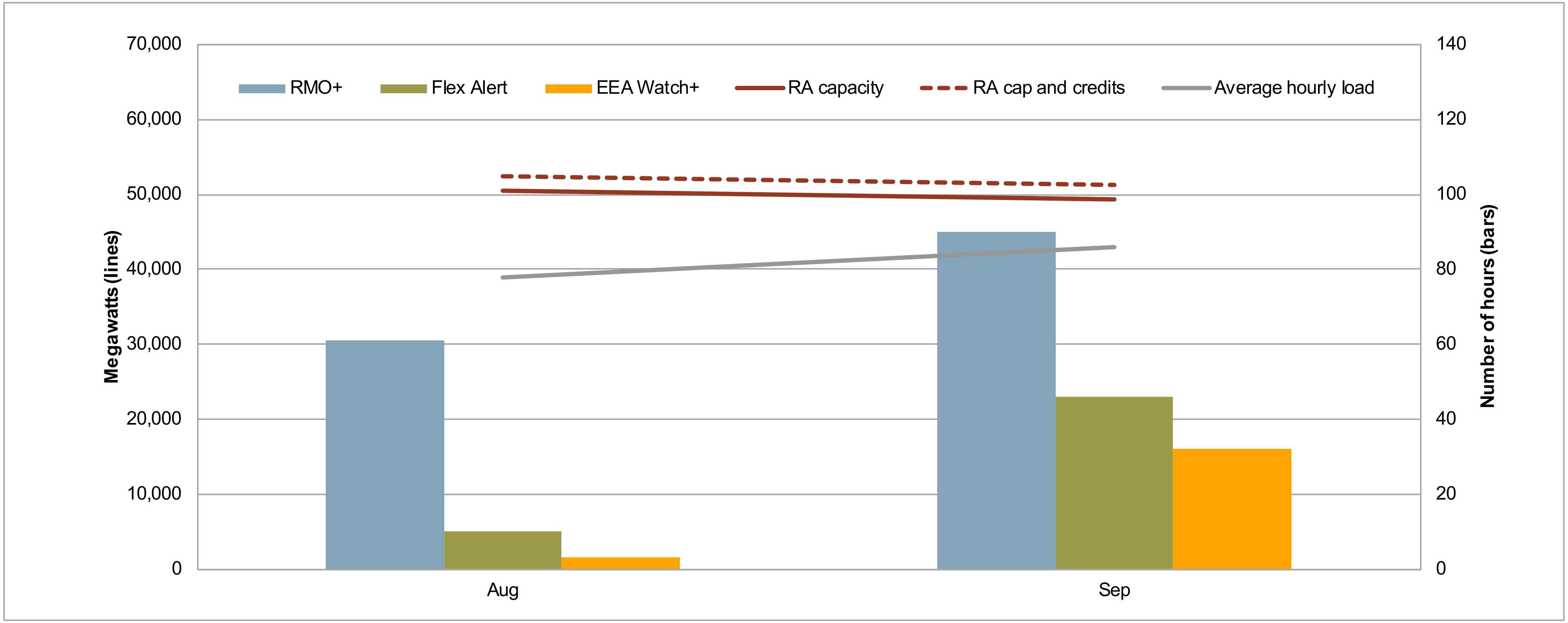
State policy also contributed to competitive market outcomes in CAISO

- California relies on long-term procurement planning and resource adequacy requirements placed on load serving entities by the CPUC to ensure that sufficient capacity is available to meet system and local reliability requirements
- CPUC policies also have a major impact on the type of different generating resources retained and added to the CAISO system
- Load shift from investor owned utilities to community choice aggregators
- Decrease in long-term capacity contracts

Average total system resource adequacy capacity, availability, and performance by system emergency notification category

Year	Alert category	Number of hours	Total RA capacity	Day-ahead market			Real-time market				Meter	Uncapped meter
				Capacity de-rate	Bids and self-schedule	Schedules	Capacity de-rate	Bids and self-schedule	Schedules	Uncapped schedules		
2020	RMO+	390	47,723	94%	87%	61%	93%	86%	58%	68%	55%	64%
	Flex Alert+	154	48,602	95%	87%	67%	93%	85%	63%	73%	61%	68%
	Alert+	97	45,404	95%	89%	72%	94%	88%	68%	79%	65%	73%
2021	RMO+	359	41,480	93%	88%	57%	92%	87%	52%	66%	50%	63%
	Flex Alert+	38	48,878	94%	88%	81%	92%	87%	77%	87%	73%	81%
	Alert+	14	49,359	93%	85%	80%	92%	85%	77%	85%	73%	80%
2022	RMO+	151	49,799	95%	90%	75%	94%	89%	69%	83%	64%	77%
	Flex Alert+	56	49,509	95%	91%	85%	93%	89%	77%	88%	72%	81%
	EEA Watch+	35	49,390	95%	90%	87%	93%	89%	79%	89%	74%	81%
	EEA 2+	17	49,490	95%	91%	89%	93%	90%	82%	92%	78%	85%

Average hourly resource adequacy capacity and load (2022 emergency notification hours)



Average system resource adequacy capacity, availability, and performance by fuel type (emergency notification hours)

Resource type	Total RA capacity	Day-ahead market			Real-time market					Meter	Uncapped meter
		Capacity de-rate	Bids and self-schedule	Schedules	Capacity de-rate	Bids and self-schedule	Schedules	Uncapped schedules	Uncapped schedules + AS		
Must-Offer:											
Gas-fired generators	19,415	93%	93%	91%	90%	90%	86%	88%	89%	89%	83%
Other generators	1,489	93%	93%	88%	93%	93%	91%	97%	97%	88%	93%
Subtotal	20,903	93%	93%	91%	91%	90%	86%	89%	90%	90%	83%
Other:											
Imports	3,171	98%	95%	93%	100%	94%	92%	94%	94%	90%	90%
Imports-MSS	273	100%	46%	46%	100%	49%	46%	46%	46%	46%	46%
Use-limited gas units	9,010	93%	92%	90%	91%	90%	73%	76%	86%	68%	68%
Hydro generators	5,335	97%	93%	92%	95%	92%	67%	78%	103%	63%	63%
Nuclear generators	2,774	100%	100%	100%	100%	100%	100%	104%	104%	99%	99%
Solar generators	2,036	100%	51%	51%	98%	57%	54%	157%	157%	47%	47%
Wind generators	1,141	100%	56%	55%	100%	80%	79%	165%	165%	65%	65%
Qualifying facilities	876	97%	95%	94%	92%	90%	88%	106%	106%	86%	86%
Demand response (PDR)	417	97%	67%	24%	94%	51%	35%	36%	36%	14%	14%
Storage	2,774	93%	92%	70%	92%	92%	51%	53%	84%	31%	31%
Other non-dispatchable	679	96%	91%	78%	93%	90%	83%	89%	96%	76%	76%
Subtotal	28,487	96%	88%	84%	95%	88%	73%	88%	99%	67%	79%
Total	**49,390**	**95%**	**90%**	**87%**	**93%**	**89%**	**79%**	**89%**	**95%**	**74%**	**81%**

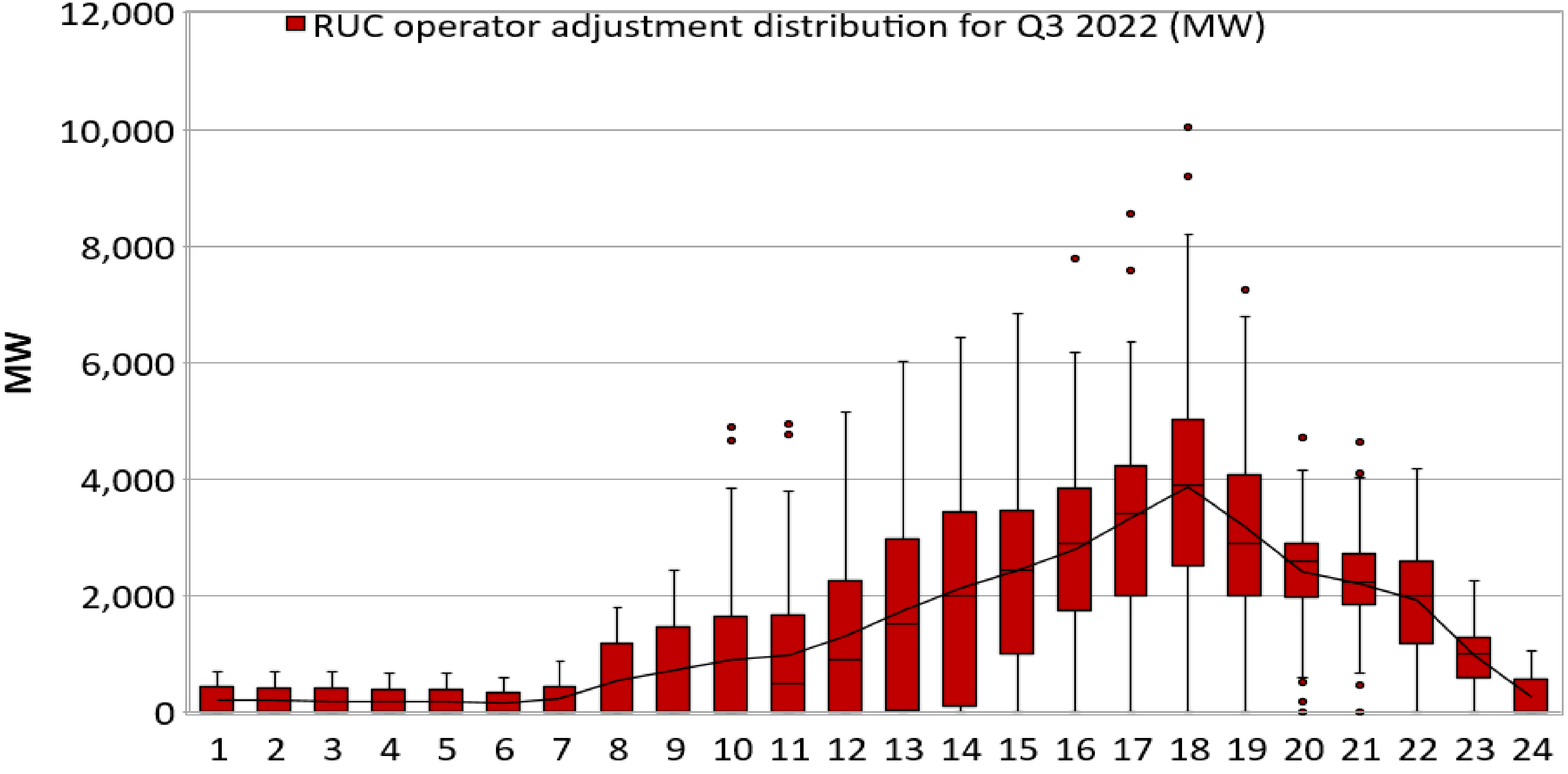
Out-of-market operations during extreme system conditions

- 2020 (extreme demand, highest in California)
  - Load bias
  - Virtual bidding suspended
  - Exceptional dispatch on the ties
  - Regional coordination and emergency assistance
  - Post event changes to export prioritization
- 2021 (fire threatens major intertie and winter storm Uri)
  - Load bias
  - Exceptional dispatches on the ties
  - Manual congestion management
  - New higher bid caps and reference level adjustments
- 2022 (record high extended demand west-wide)
  - Load bias
  - Operator process to reprioritize dispatches on the ties
  - Exceptional dispatch on the ties
  - Regional coordination and emergency assistance

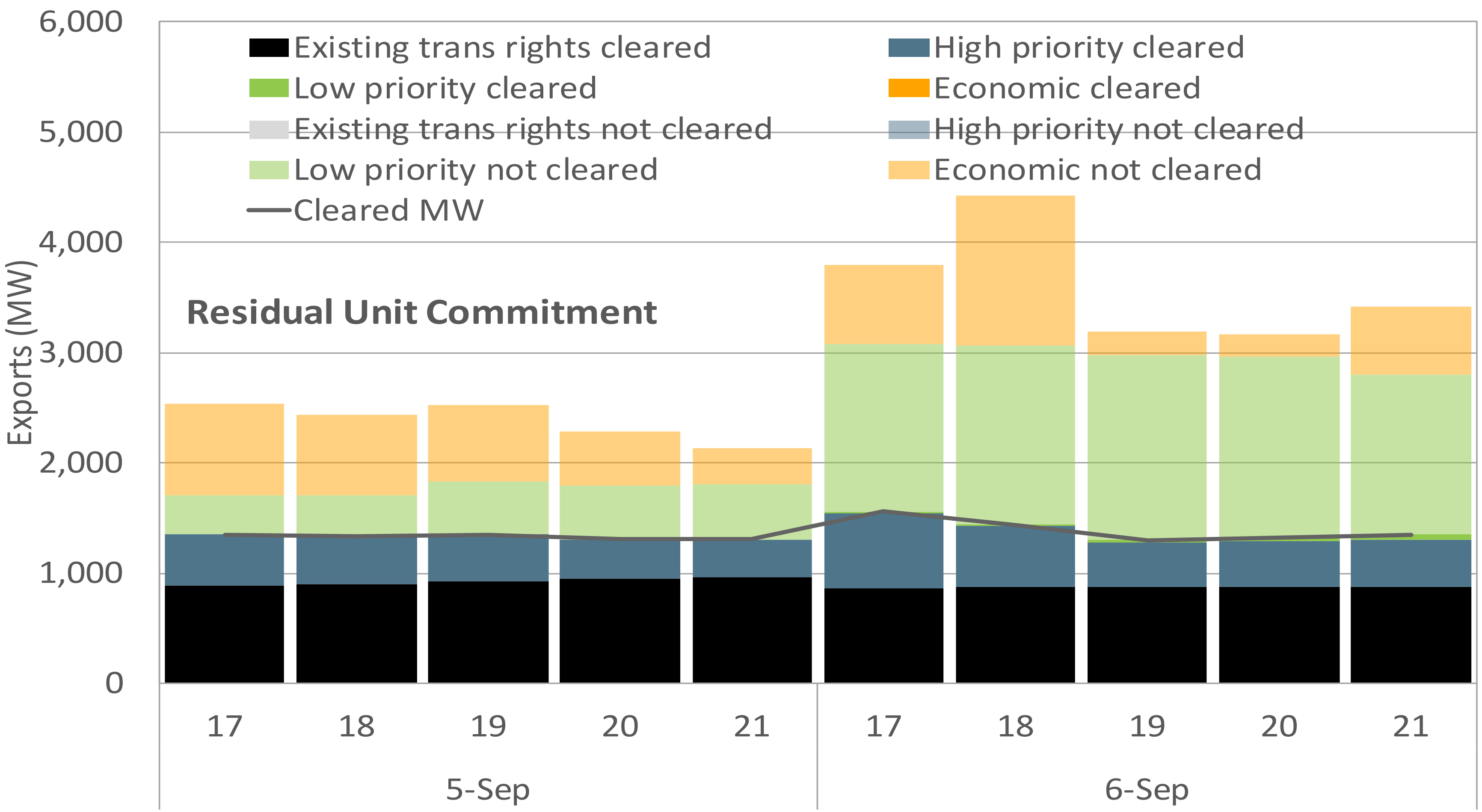
2022 Summer high demand event August 31 – September 9

- Record high CAISO load part of an extended regional heat event
- High bilateral market price indices reflected regional market conditions
- The maximum import bid cap allowed imports to bid up to the hard bid cap ($2,000/MWh)
- Penalty prices doubled, rising up to $2,000/MWh on days with high bilateral market prices
- Balancing areas declaring emergencies were able to import supplemental energy, both through emergency assistance from other balancing areas and Western Energy Imbalance Market imports
- California ISO supply was additionally supplemented by out of market imports, non-market capacity procured through California's strategic reserve, and through voluntary demand reduction

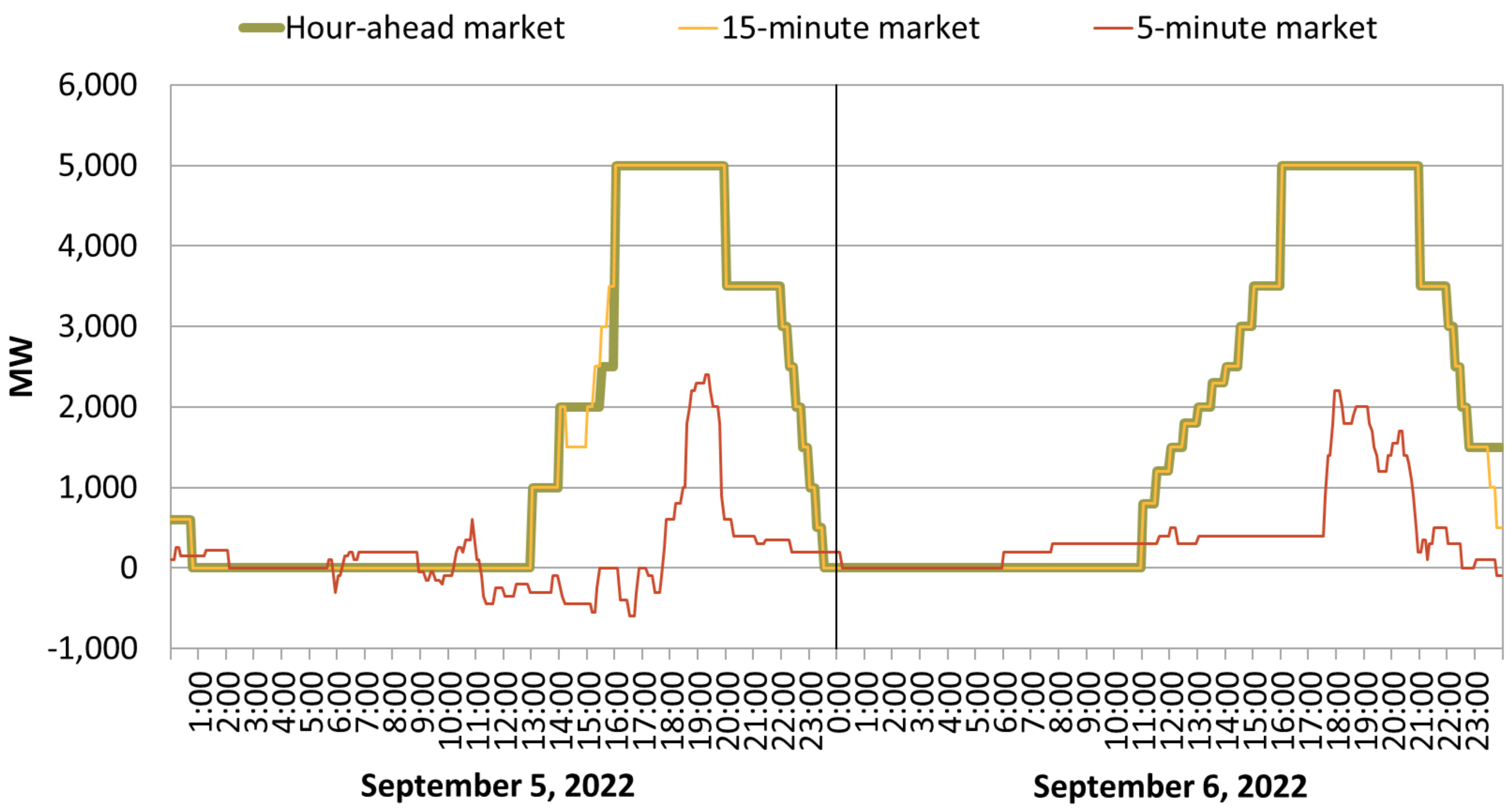
Operators increased RUC requirement significantly, causing some exports to clear the financial day-ahead market (IFM) but not the RUC process



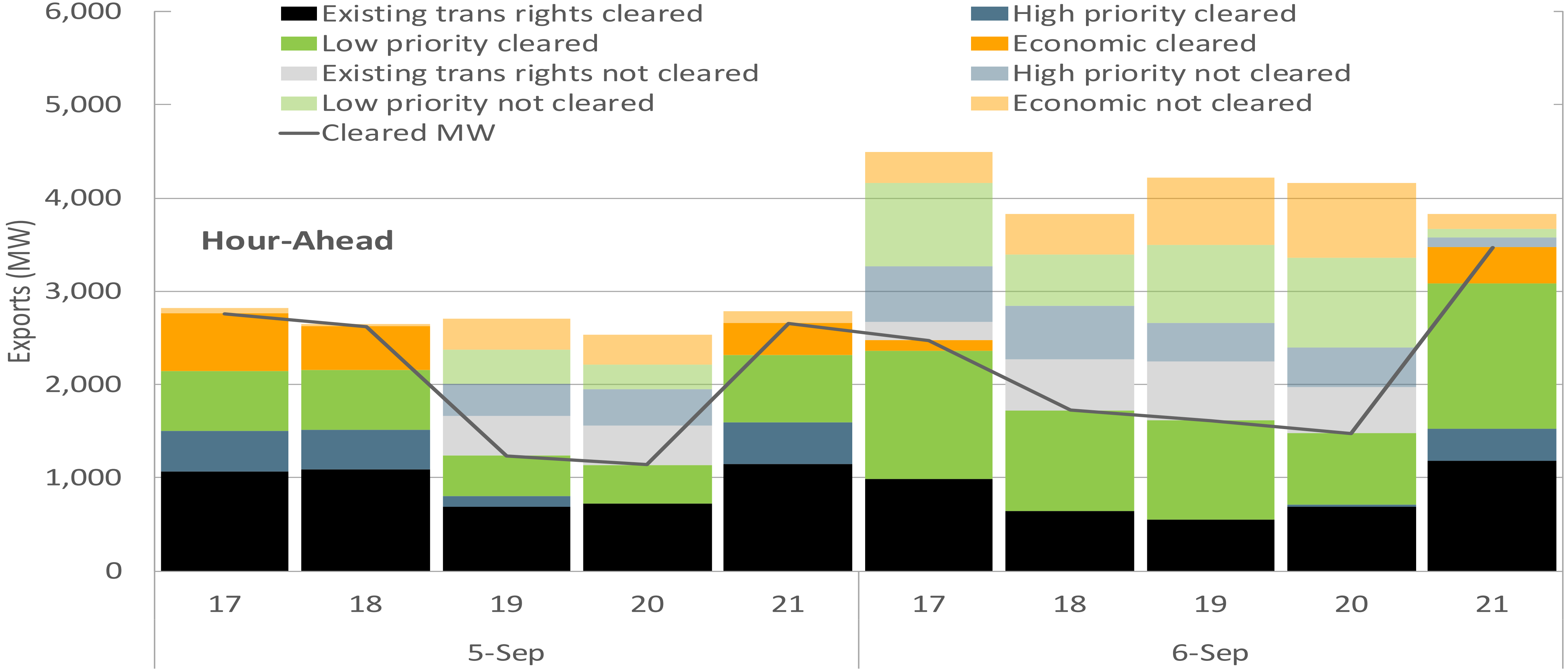
IFM schedules that did not receive RUC awards were primarily low priority self schedules and economic bids that cleared in IFM



Very high load bias in HASP and 15-minute market also prevented some exports from clearing in real-time market



Hour-ahead market curtailed high priority exports while scheduling low priority exports



Recommendations

- Expanded day-ahead market enhancement (EDAM)
  - Given the large potential long-term benefits of a west-wide day-ahead market and the enormous challenges in initiating such a market, DMM supports the CAISO proceeding with the final EDAM design approved in 2023, while the ISO continues working with stakeholders to resolve some crucial design elements.

- Day-ahead market enhancements (DAME)

  DMM supports the development of a day-ahead imbalance reserve product, but recommends:

  - Continue to refine the imbalance reserve product demand curve, considering potential reductions of the bid cap after implementation.
  - More carefully consider whether it would ultimately be more efficient to procure imbalance reserves in the residual unit commitment market.
  - Develop mechanisms to allow the real-time market to efficiently determine whether or not to preserve imbalance reserves procured in the day-ahead market.

Recommendations

- Congestion revenue rights
  - Eliminate or further limit auction of congestion revenue rights
  - If need for congestion hedging instruments considered so important, then establish market for hedges based on willing buyers and sellers
- Western EIM resource sufficiency tests (capacity & ramping)
  - Implementation of emergency energy assistance
  - Continued refinement of the uncertainty estimate added to the ramping test
- Flexible ramping product (real-time)
  - Implemented locational procurement
  - Continued refinement of uncertainty estimates
  - Expand time horizon beyond current 15-minute period (e.g. 2-3 hours?)

Recommendations

- Export and wheeling schedules
  - The ISO has developed longer-term comprehensive rules for transmission scheduling priority to be effective by summer 2024
  - DMM supports these changes
  - Further refinement may be needed to make less transmission capacity available, while increasing the firmness of these transmission rights to a level more analogous to the OATT framework
- Battery storage
  - Modeling energy storage costs (state of charge)
  - Exceptional dispatches (development of operator tools)
  - Bid cost recovery rules
  - Resource adequacy battery capacity
  - Market power mitigation

The CPUC has identified options for addressing issues and is moving forward with more detailed market design options and decisions:

- New slice of day resource adequacy framework
- CAISO resource adequacy performance incentives may need to be stronger
- Consider raising the $0/MW bid cap for resource adequacy imports
- **Demand response:** The CPUC has taken numerous steps to address DMM's recommendations:
  - Re-examine demand response counting methodologies
  - Remove the planning reserve margin adder applied to demand response capacity counted towards system resource adequacy requirements
  - Consider developing a performance-based penalty or incentive structure for resource adequacy resources

DMM supports these efforts and views the options being considered by the CPUC as potentially effective steps