2020 Annual Report on Market Issues and Performance

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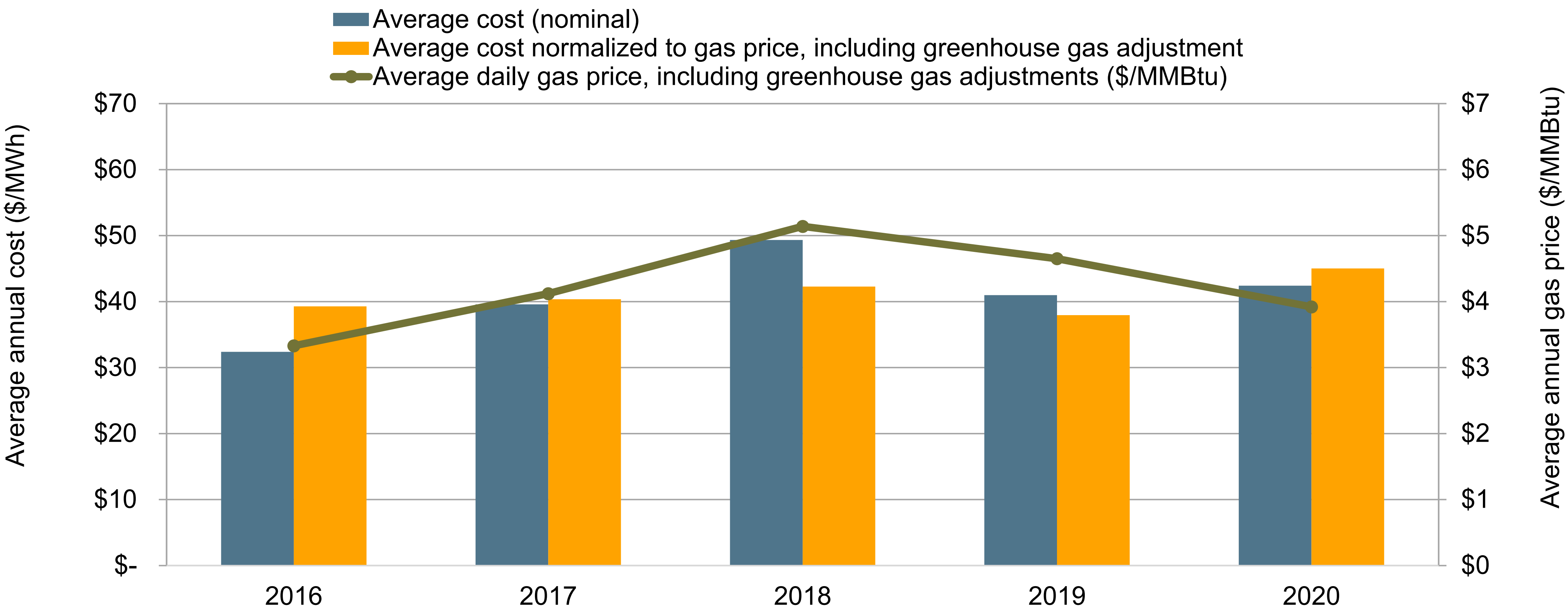
http://www.caiso.com/Documents/2020-Annual-Report-on-Market-Issues-and-Performance.pdf
http://www.caiso.com/market/Pages/MarketMonitoring/Default.aspx

Total ISO wholesale costs rose by 3% -- or 19% increase after accounting for lower gas costs

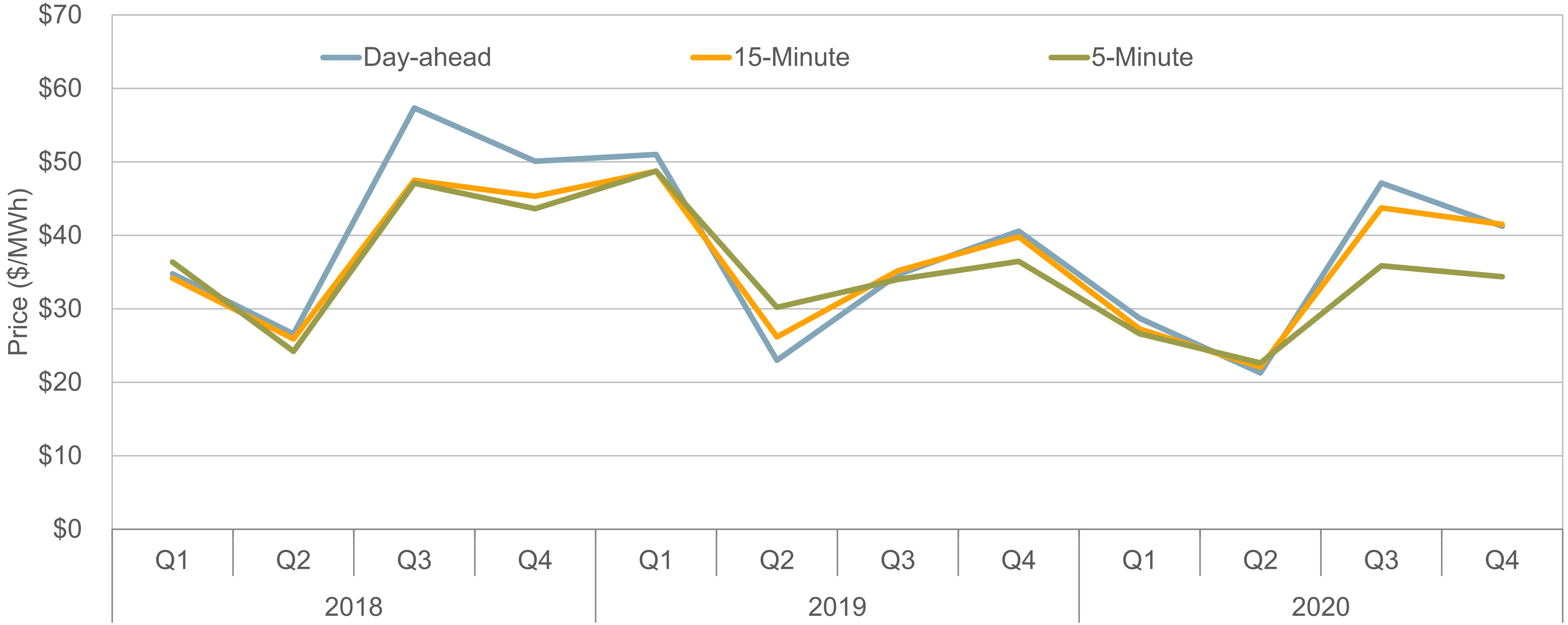


Total CAISO wholesale costs totaled $8.9 billion, $42/MWh

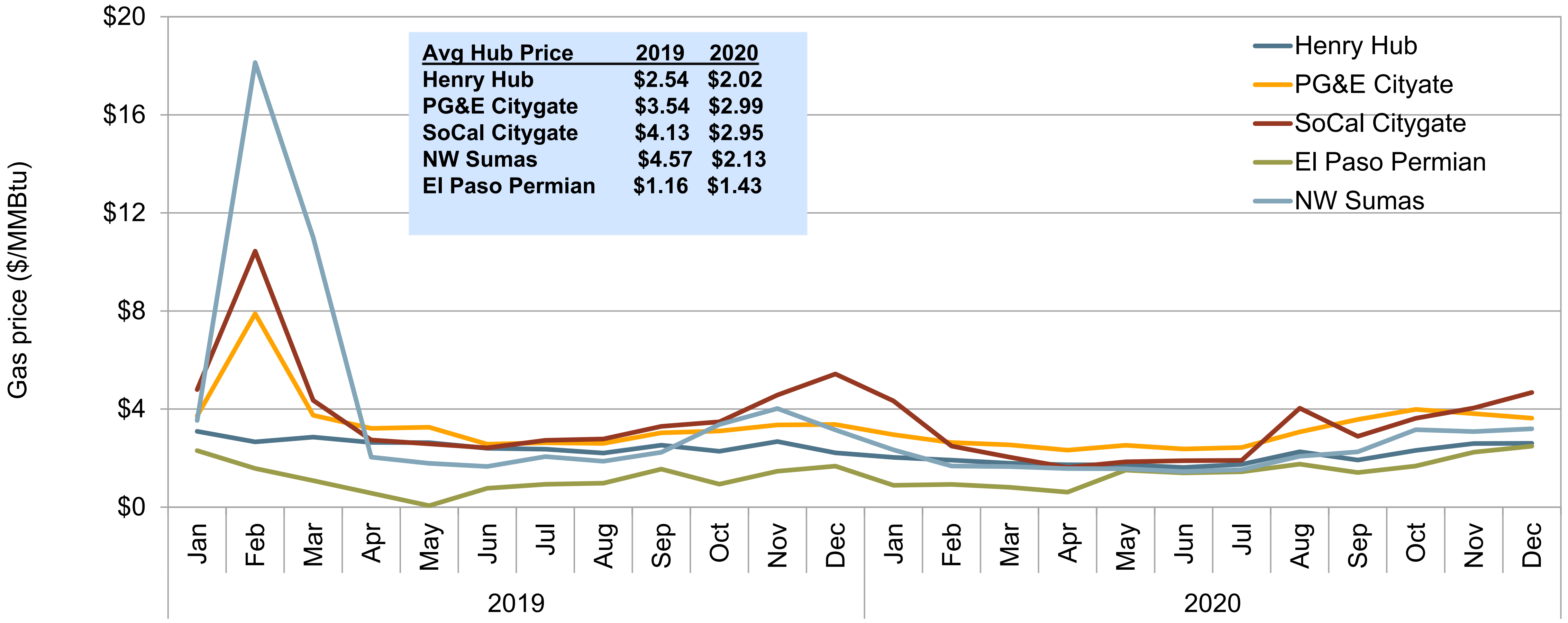
	2016	2017	2018	2019	2020	Change '19-'20
Day-ahead energy costs	$ 30.49	$ 37.40	$ 46.05	$ 38.13	$ 38.61	$ 0.48
Real-time energy costs (incl. flex ramp)	$ 0.54	$ 0.73	$ 0.59	$ 1.02	$ 1.64	$ 0.62
Grid management charge	$ 0.42	$ 0.44	$ 0.46	$ 0.46	$ 0.46	$ 0.01
Bid cost recovery costs	$ 0.30	$ 0.41	$ 0.68	$ 0.56	$ 0.60	$ 0.04
Reliability costs (RMR and CPM)	$ 0.11	$ 0.10	$ 0.68	$ 0.06	$ 0.07	$ 0.01
Average total energy costs	**$ 31.86**	**$ 39.09**	**$ 48.47**	**$ 40.23**	**$ 41.39**	**$ 1.16**
Reserve costs (AS and RUC)	$ 0.53	$ 0.71	$ 0.87	$ 0.75	$ 1.02	$ 0.28
Average total costs of energy and reserve	**$ 32.39**	**$ 39.80**	**$ 49.34**	**$ 40.98**	**$ 42.41**	**$ 1.43**

Day-ahead prices slightly higher than 15-minute market

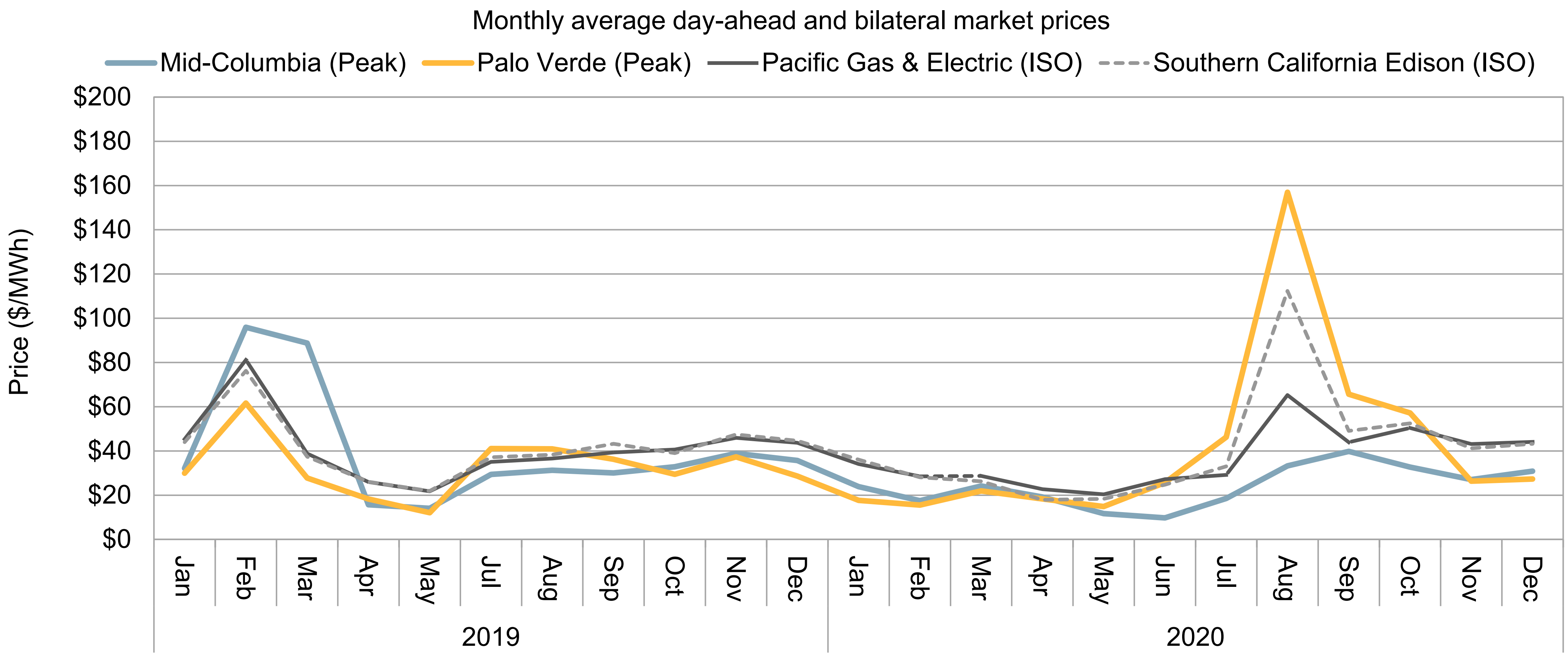
Day-ahead $35/MWh, 15-minute $34/MWh, 5-minute $30/MWh



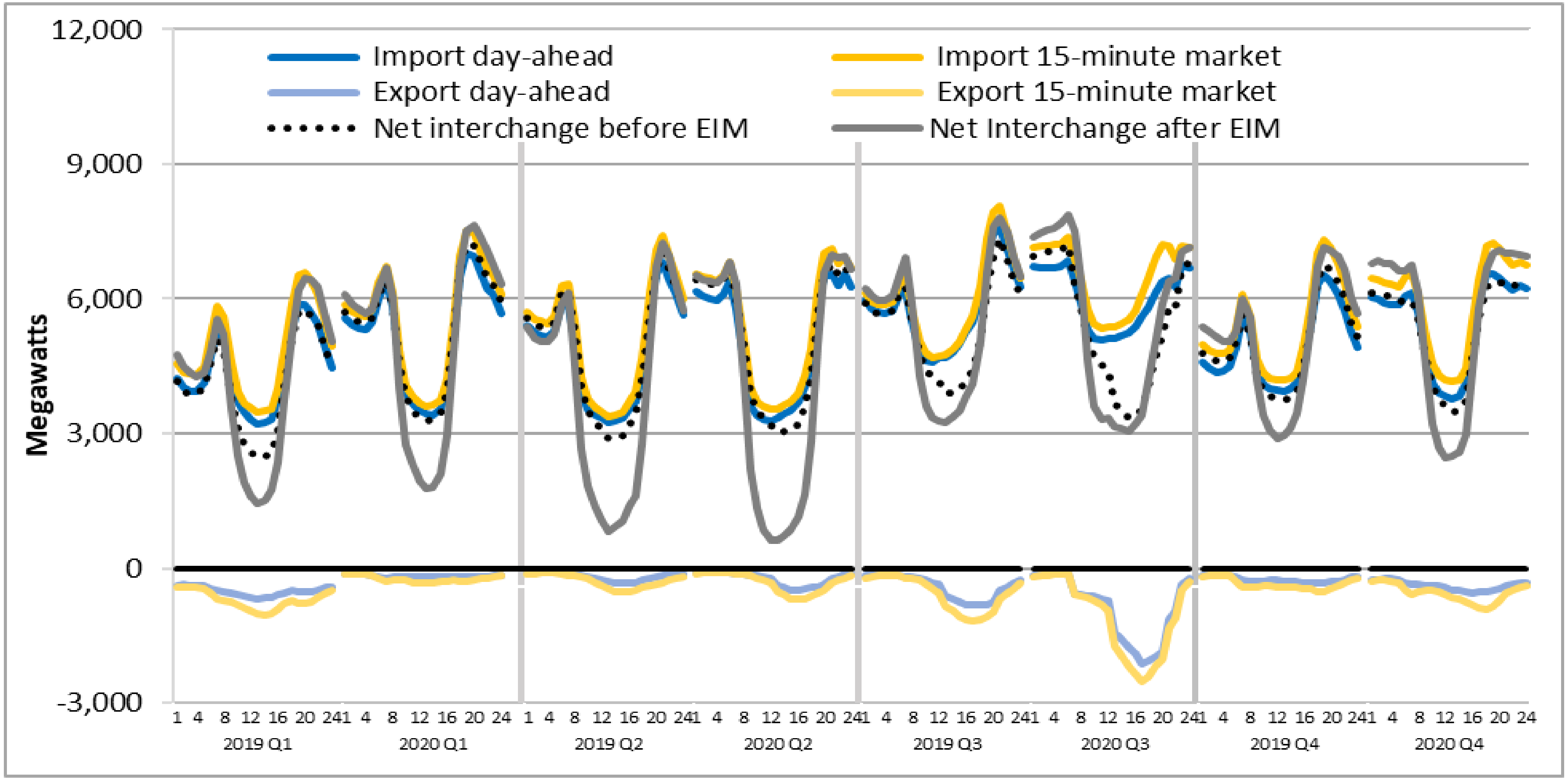
Day-ahead prices often driven by gas prices
Low natural gas prices support low electricity prices



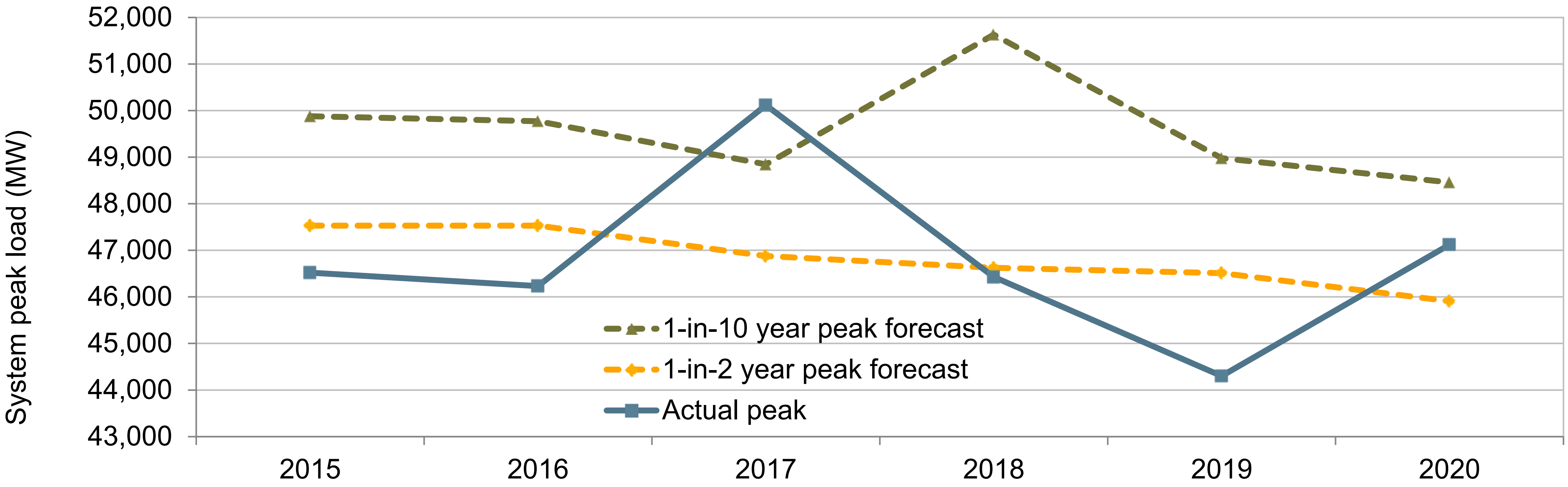
High prices in August and early September driven by high regional demand, not by high gas prices



Excluding EIM, net imports were static in 2020 but shifted from the Southwest to the Northwest

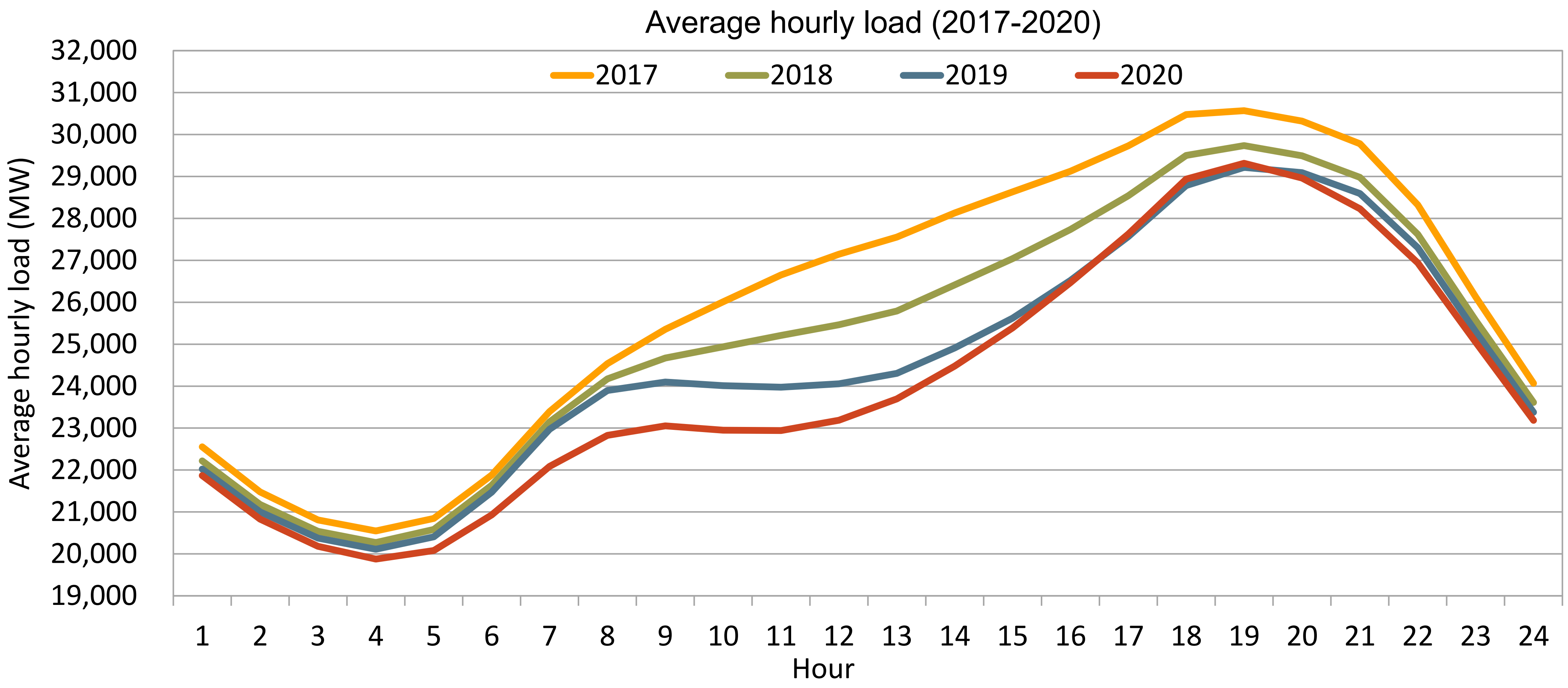


Higher peak loads and lower overall energy loads

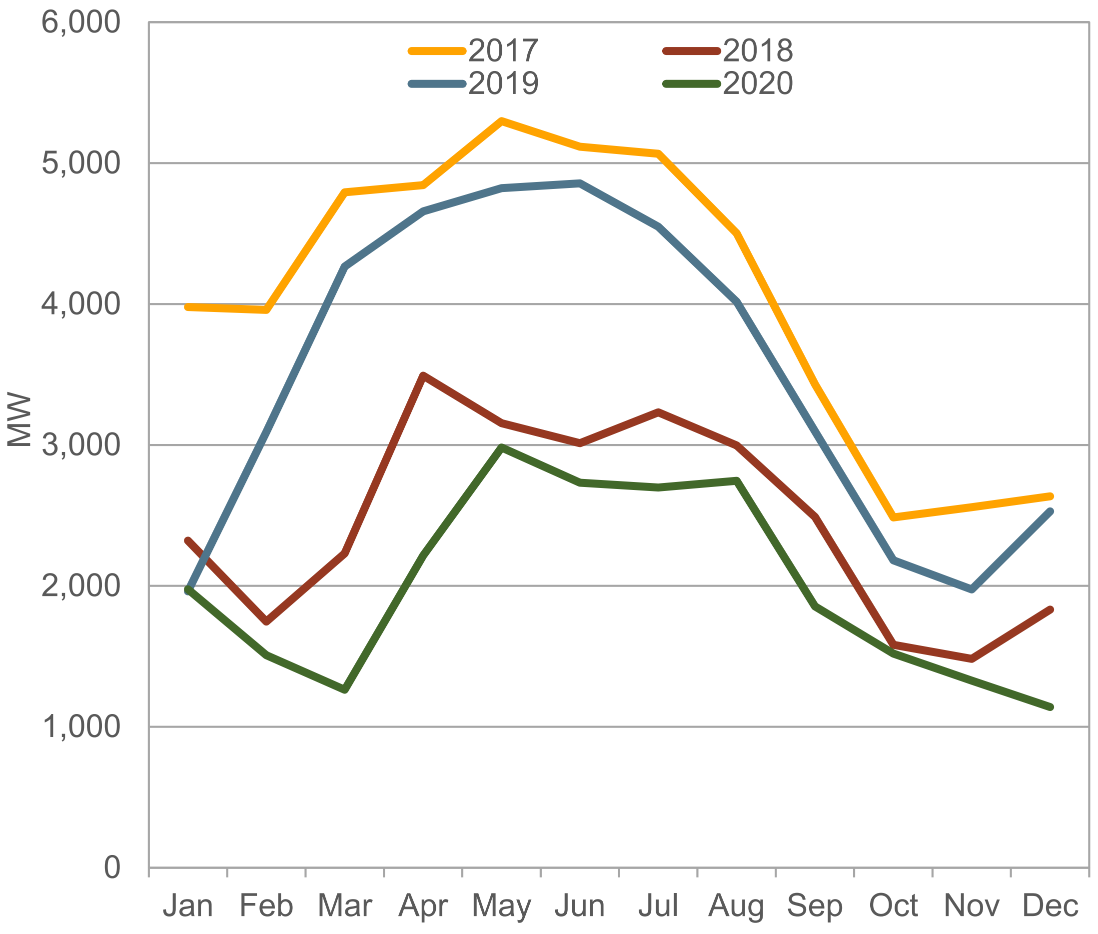


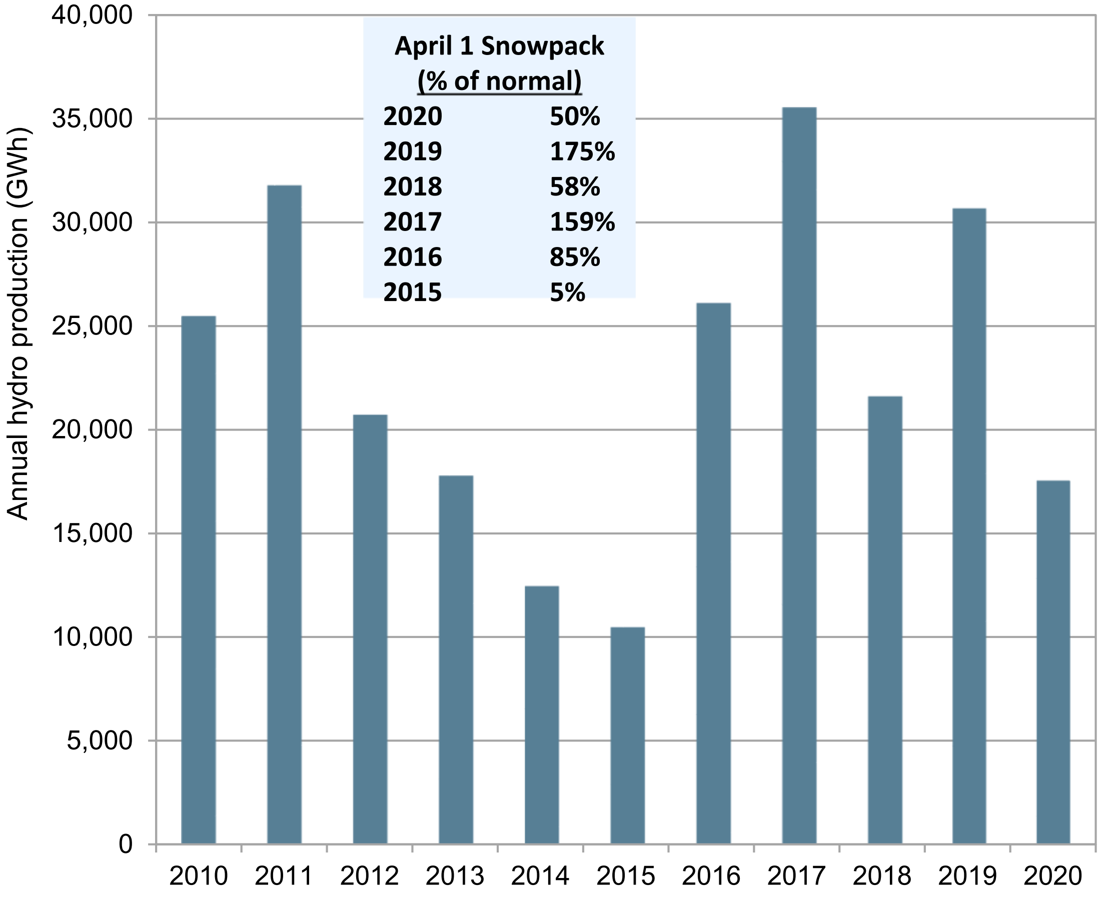
Year	Annual total energy (GWh)	Average load (MW)	% change	Annual peak load (MW)	% change
2017	227,749	26,002	0.0%	50,116	8.4%
2018	220,458	25,169	-3.2%	46,427	-7.4%
2019	214,955	24,541	-2.5%	44,301	-4.6%
2020	211,919	24,128	-1.7%	47,121	6.4%

Higher behind-the-meter solar generation, COVID-19 related load reductions energy efficiency initiatives despite higher statewide temperatures

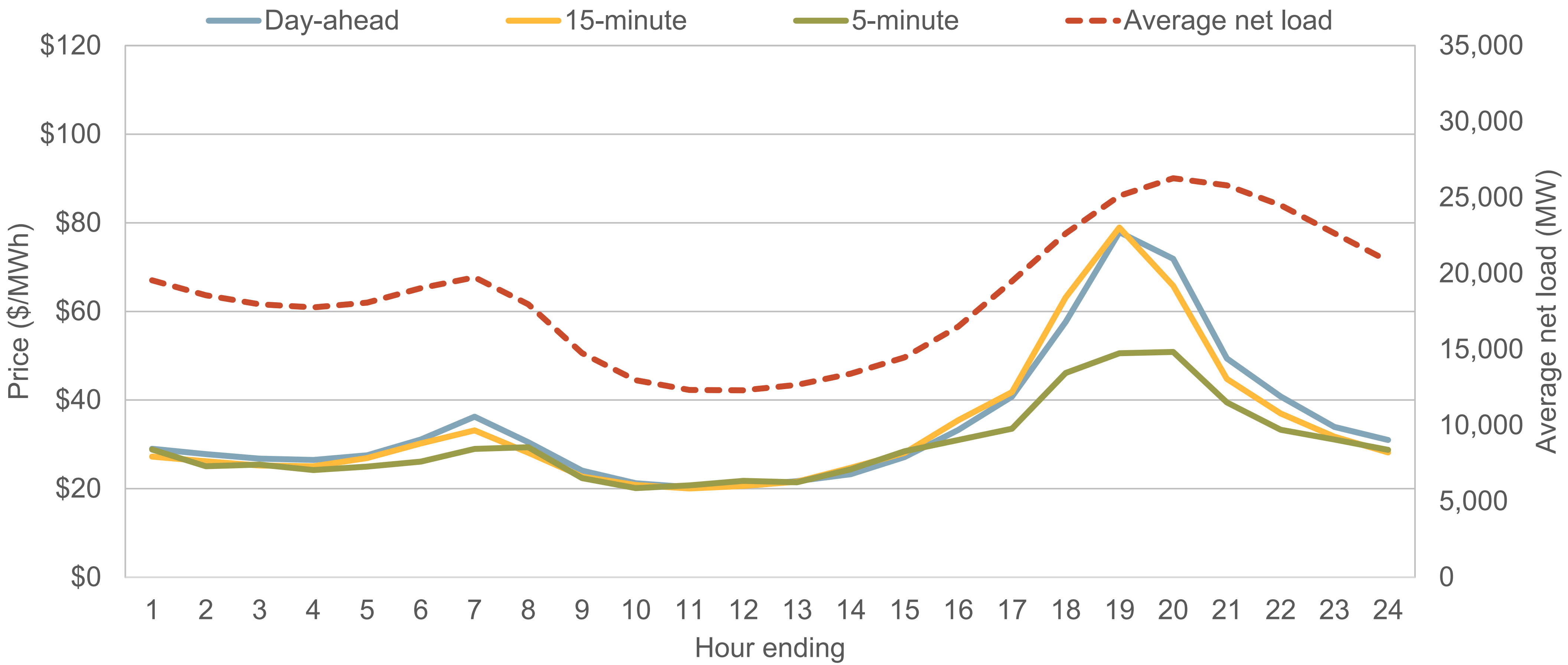


Hydroelectric generation decreased to around 8% of supply, compared to 14% in 2019, 10% in 2018 and 15% in 2017

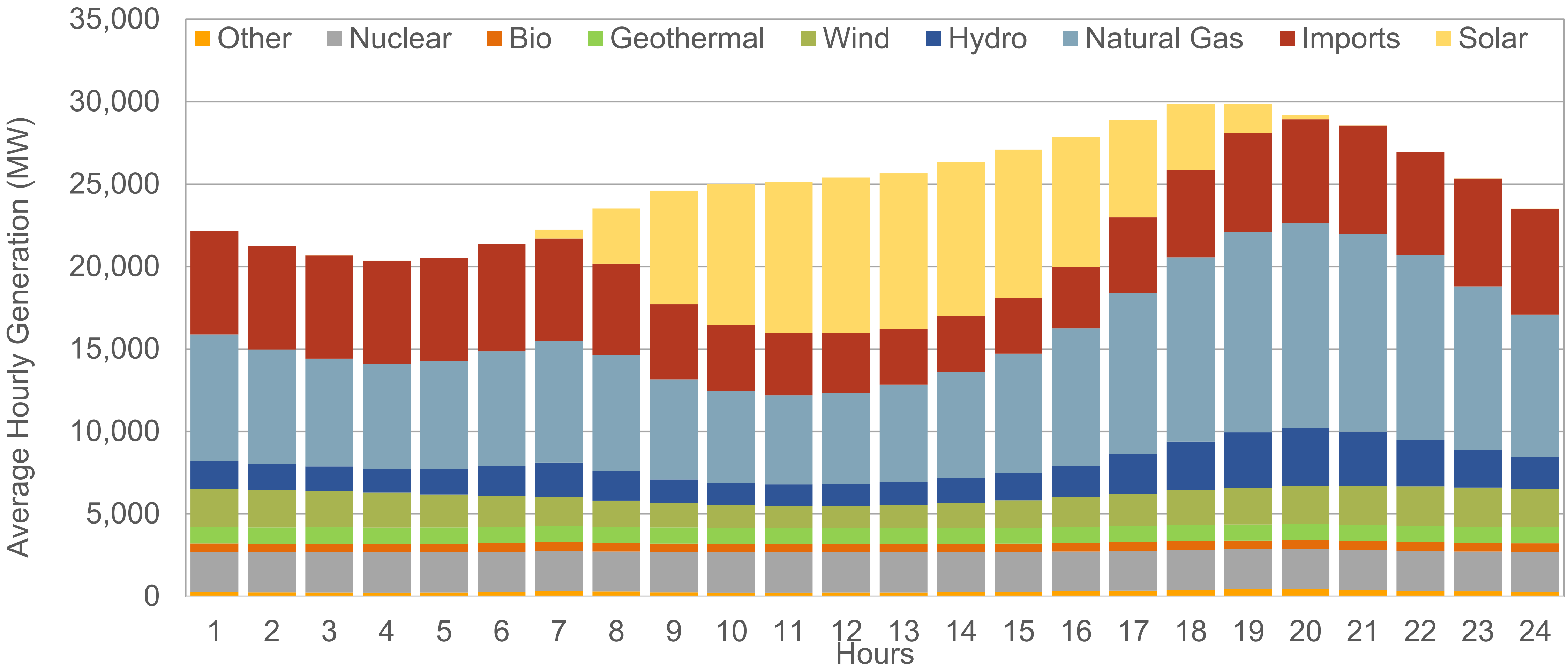




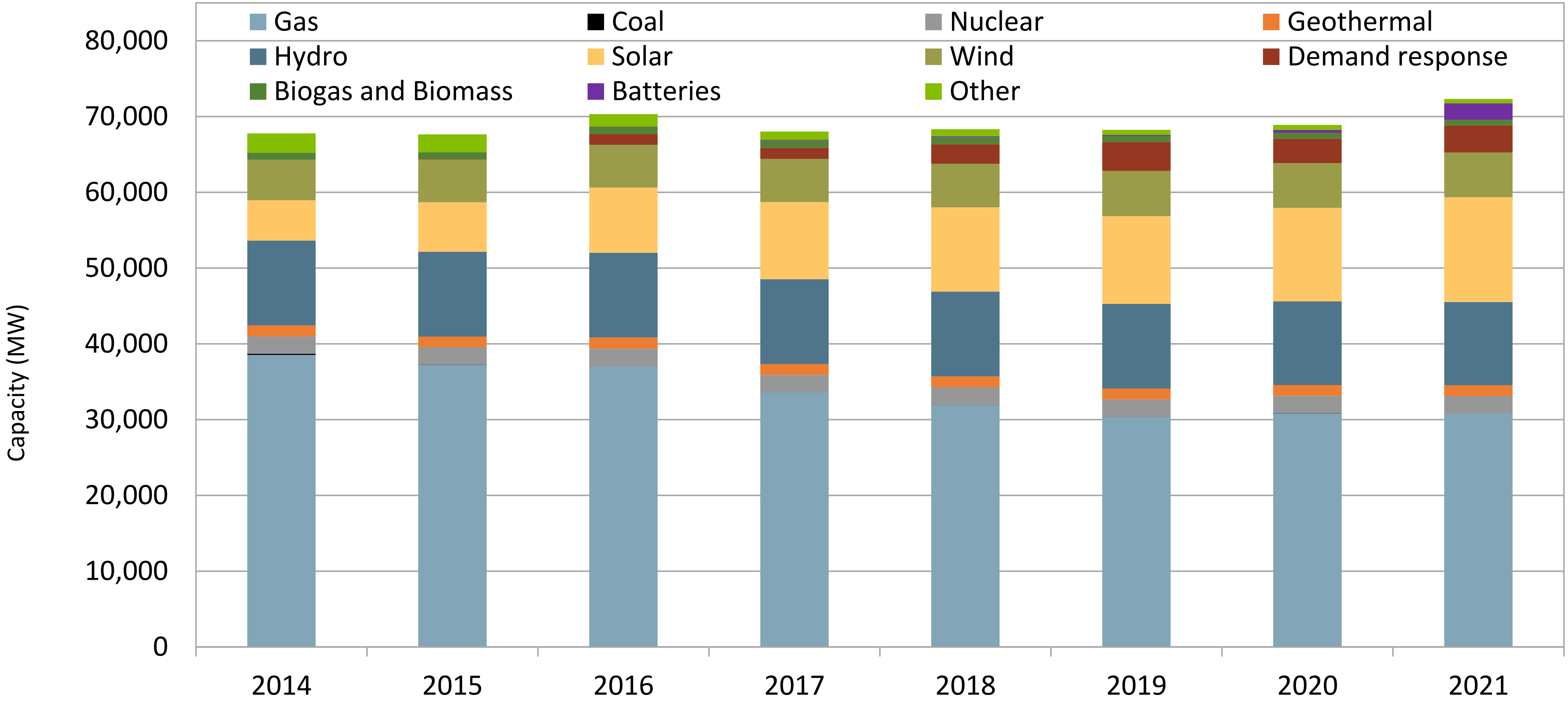
Average hourly prices mirror net load, with day-ahead prices lower than 5-minute real-time in peak hours



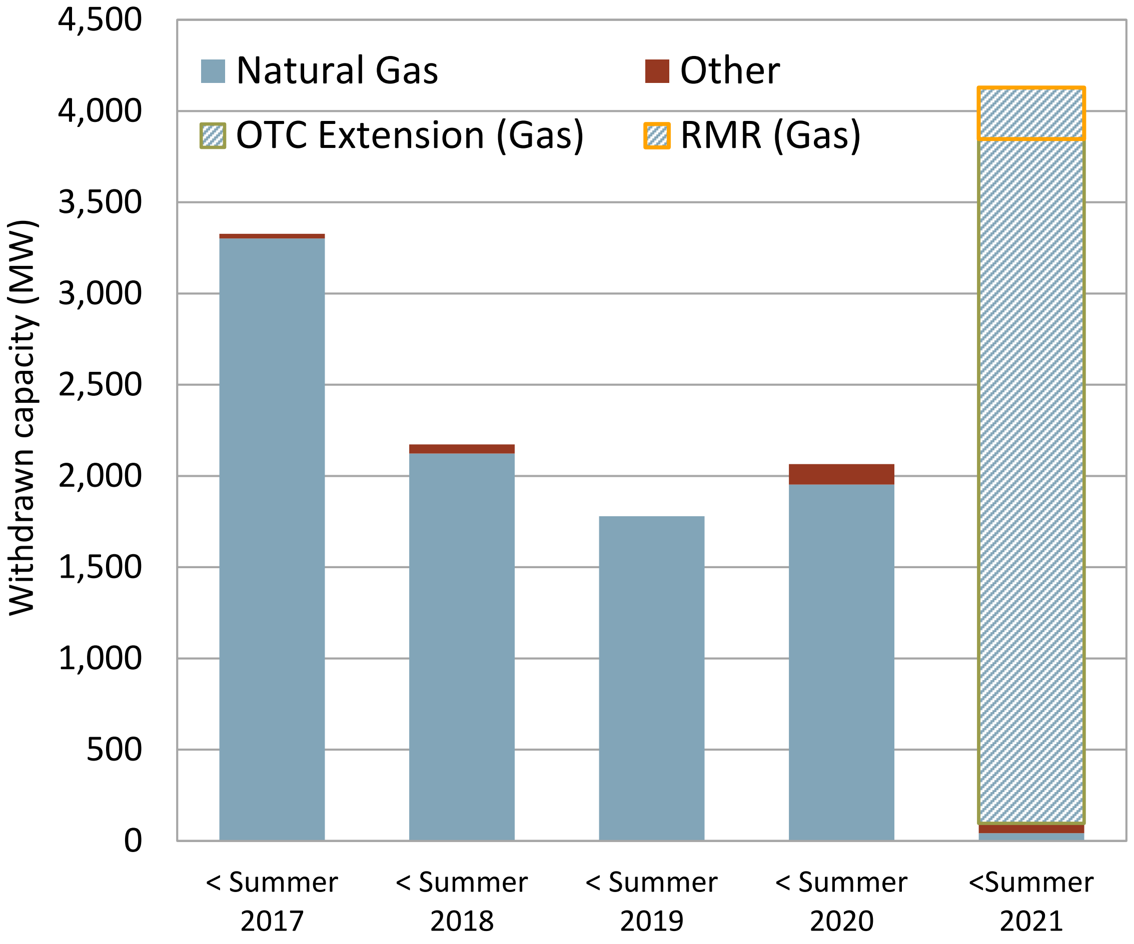
Average hourly generation by fuel type (2020)



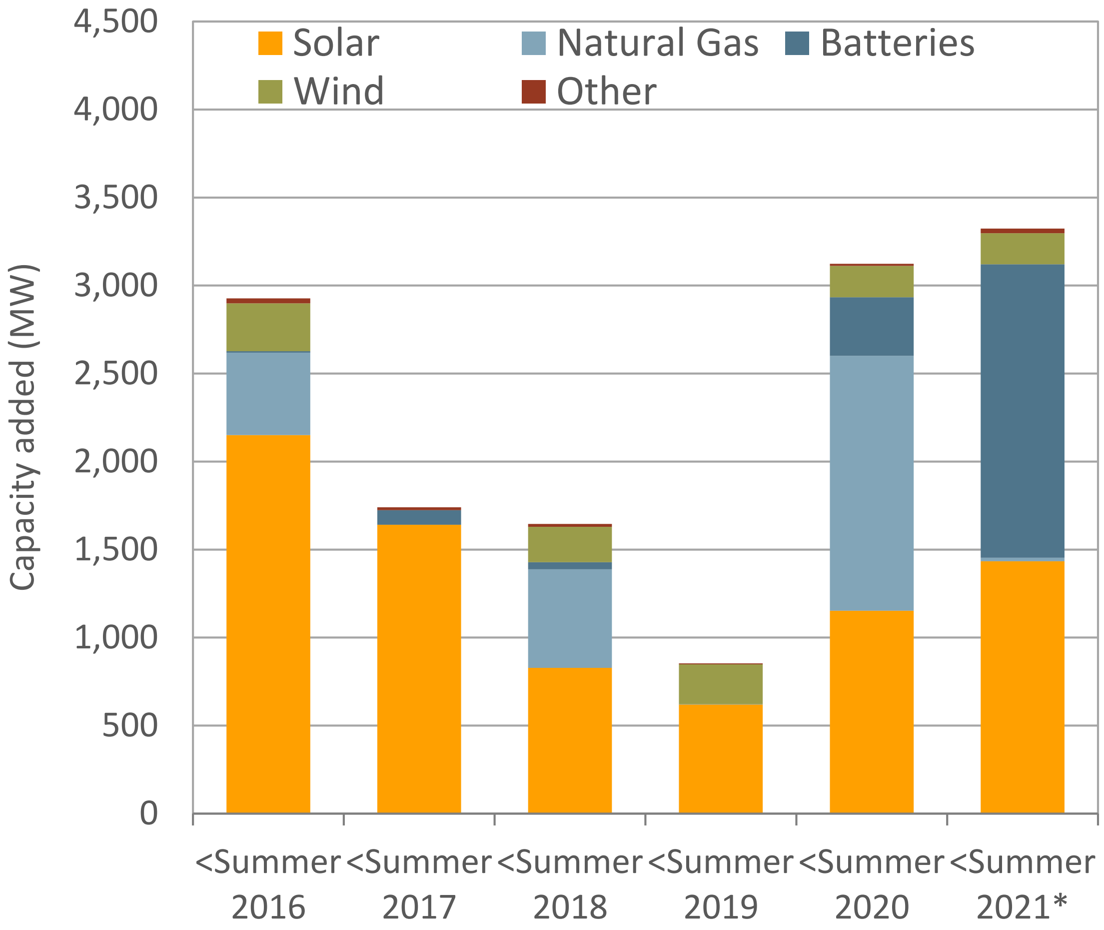
Gas capacity retiring is being largely replaced with renewables (mainly solar)



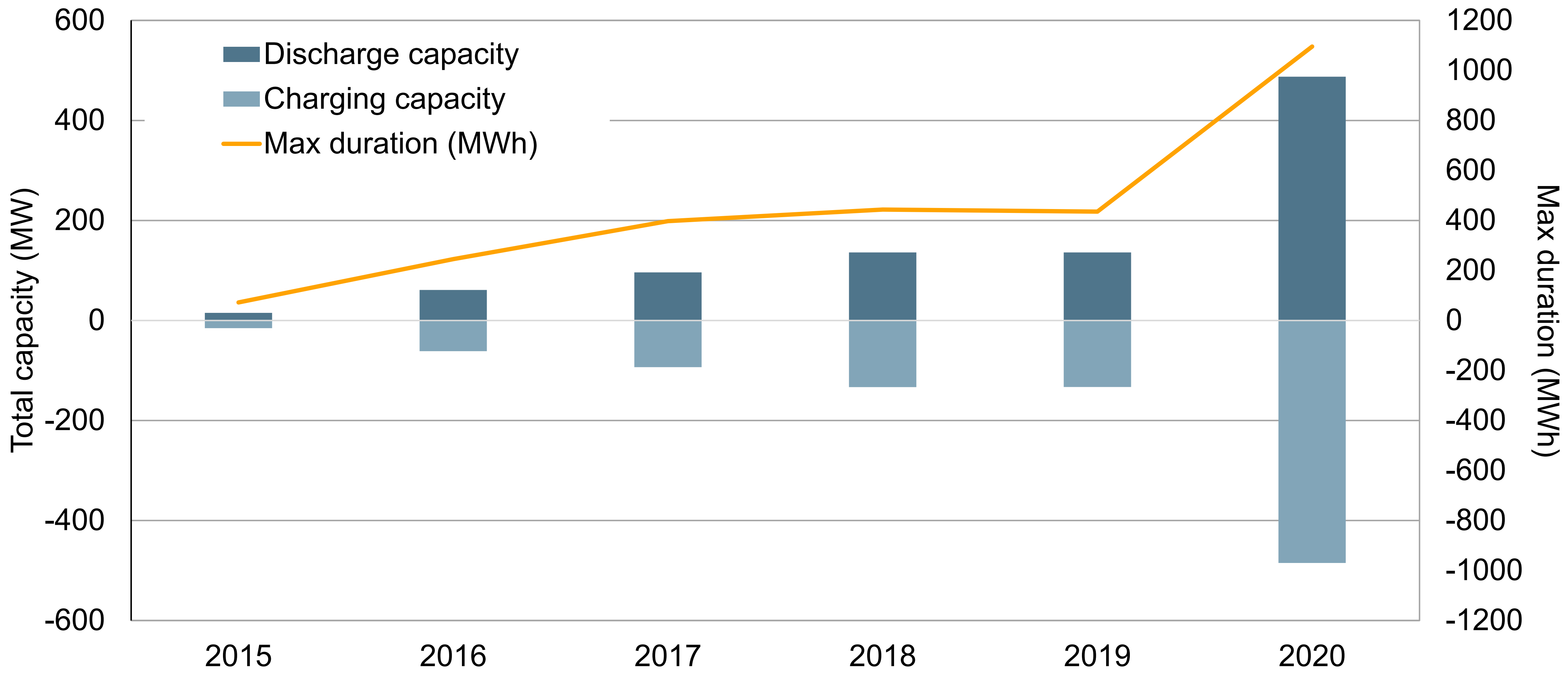
Withdrawals from ISO market participation



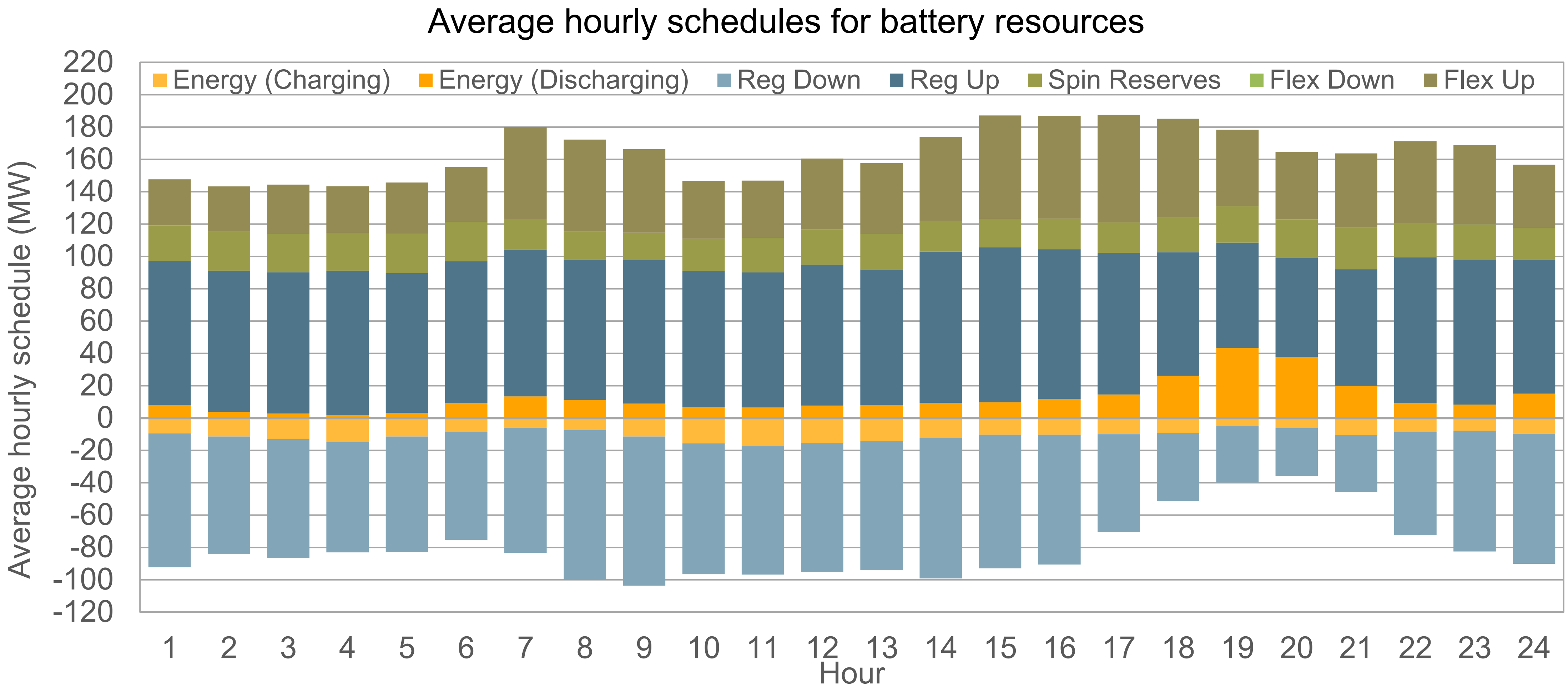
Additions to ISO market



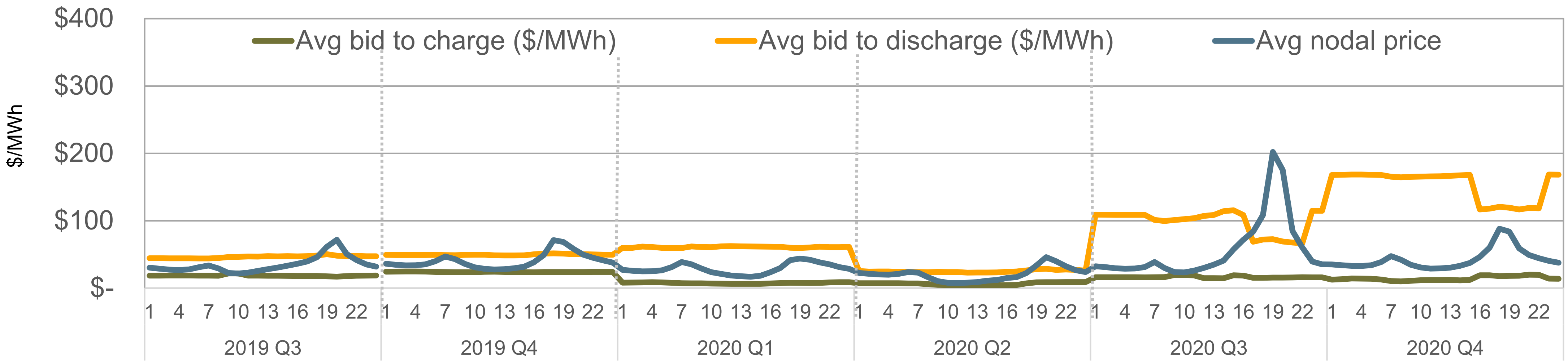
Battery capacity grew dramatically in 2019 and continues in 2020

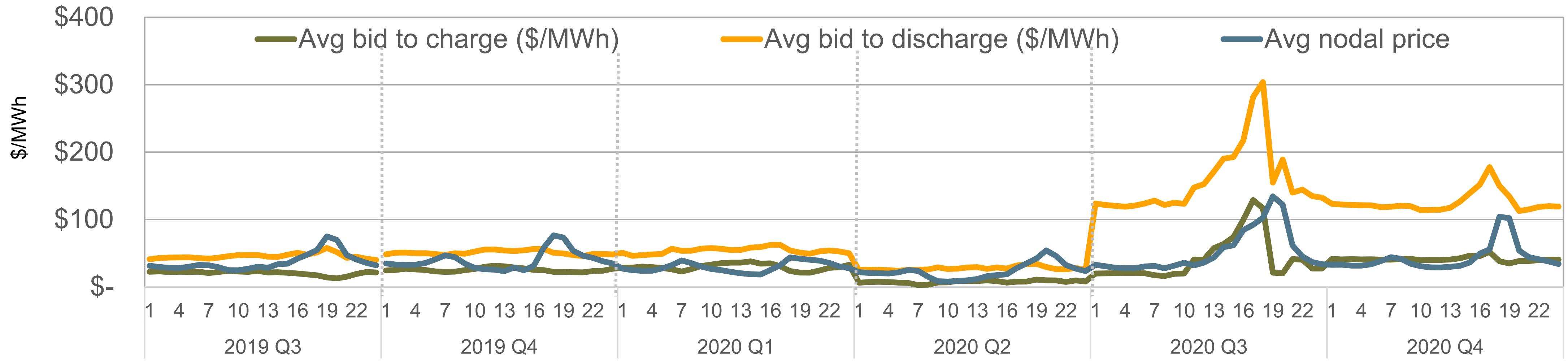


Capacity from battery storage resources grew from 136 MW to 488 MW



Average hourly battery bids and nodal prices, day-ahead (top) and real-time (bottom) (Q3 2019 – 2020)

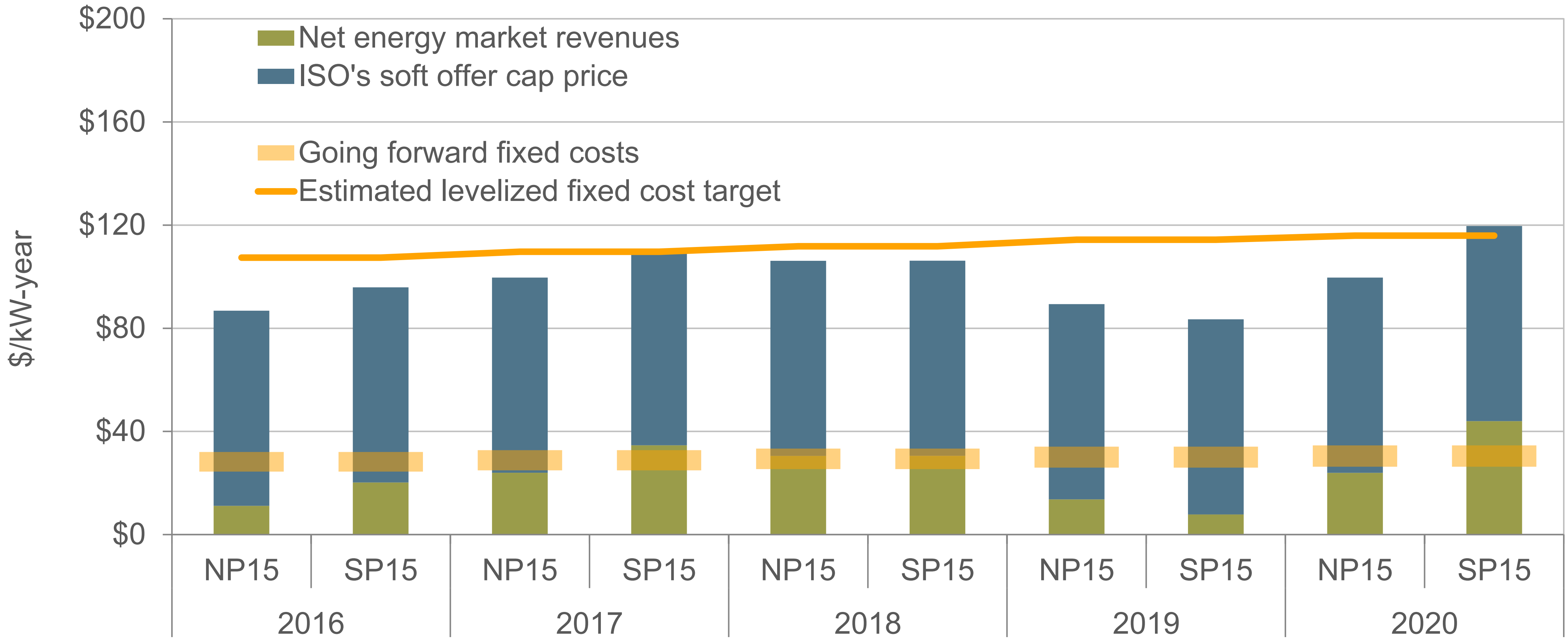




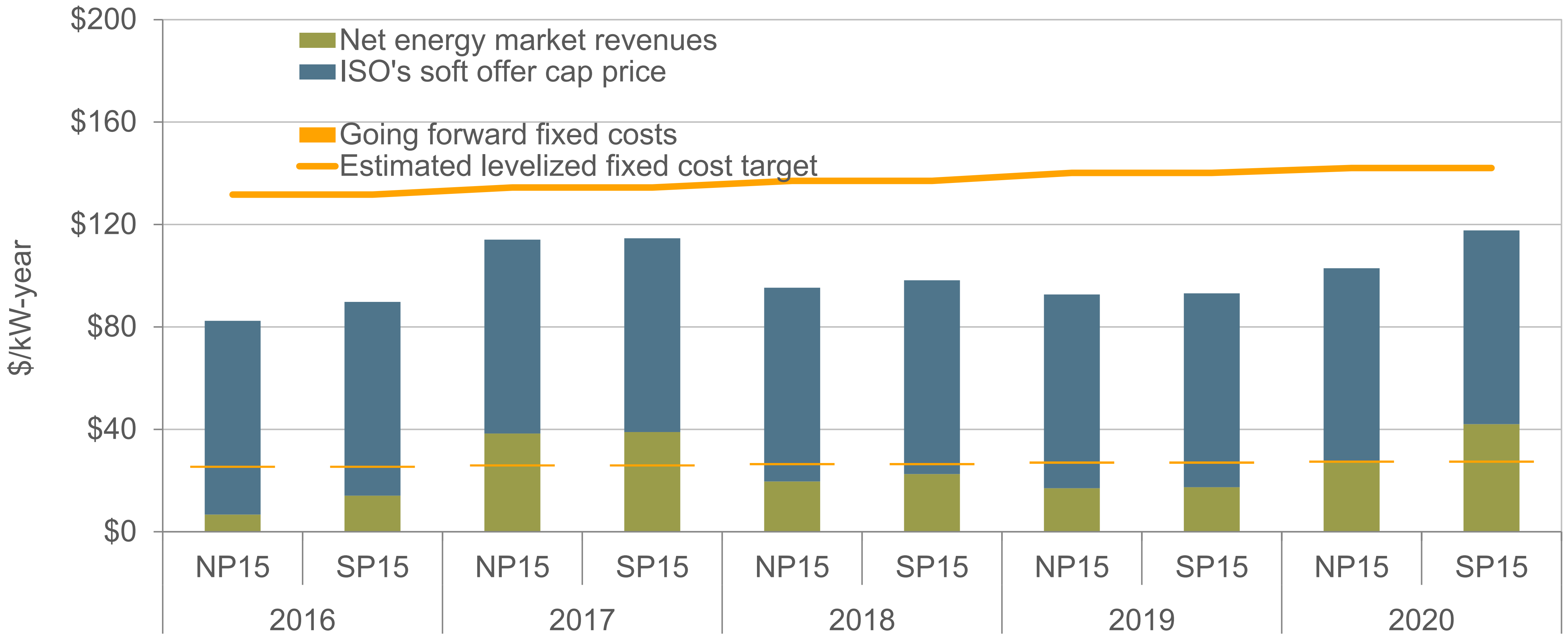
New battery energy storage net market revenues by local capacity area

Local capacity area	TAC area	Net market revenues ($/kW-yr)	
		Scenario 1	Scenario 2
		Energy arbitrage only	Energy and Regulation
Greater Bay Area	PG&E	$10.98	$102.41
North Coast & North Bay (NCNB)	PG&E	$16.58	$110.56
Greater Fresno	PG&E	$20.65	$118.86
Sierra	PG&E	$18.41	$108.38
Stockton	PG&E	$11.35	$103.79
Kern	PG&E	$12.59	$111.41
LA Basin	SCE	$27.52	$135.26
Big Creek/Ventura	SCE	$23.28	$132.08
San Diego/Imperial Valley	SDG&E	$24.93	$134.99
CAISO System		$16.20	$119.37

Estimated net revenue of hypothetical combined cycle unit in NP15 was $24/kW-year and SP15 was about $44/kW-year



Estimated net revenues of hypothetical combustion turbine rose to $27/kW-year in NP15 and $42/kW-year in SP15



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

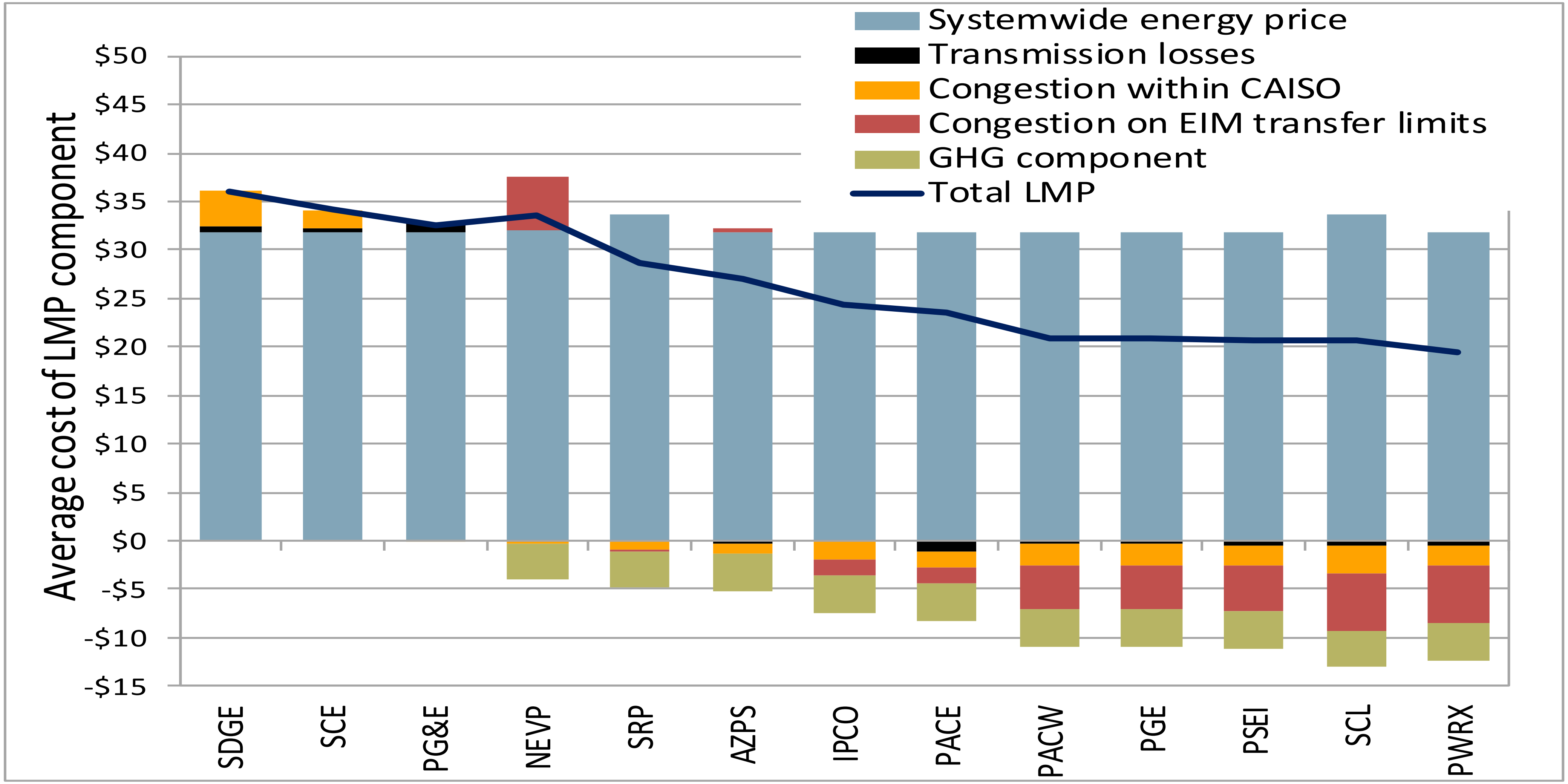
- Two new members of the EIM in 2020
- Five new members of the EIM in 2021

- The EIM, including the ISO, now accounts for over half of WECC peak load

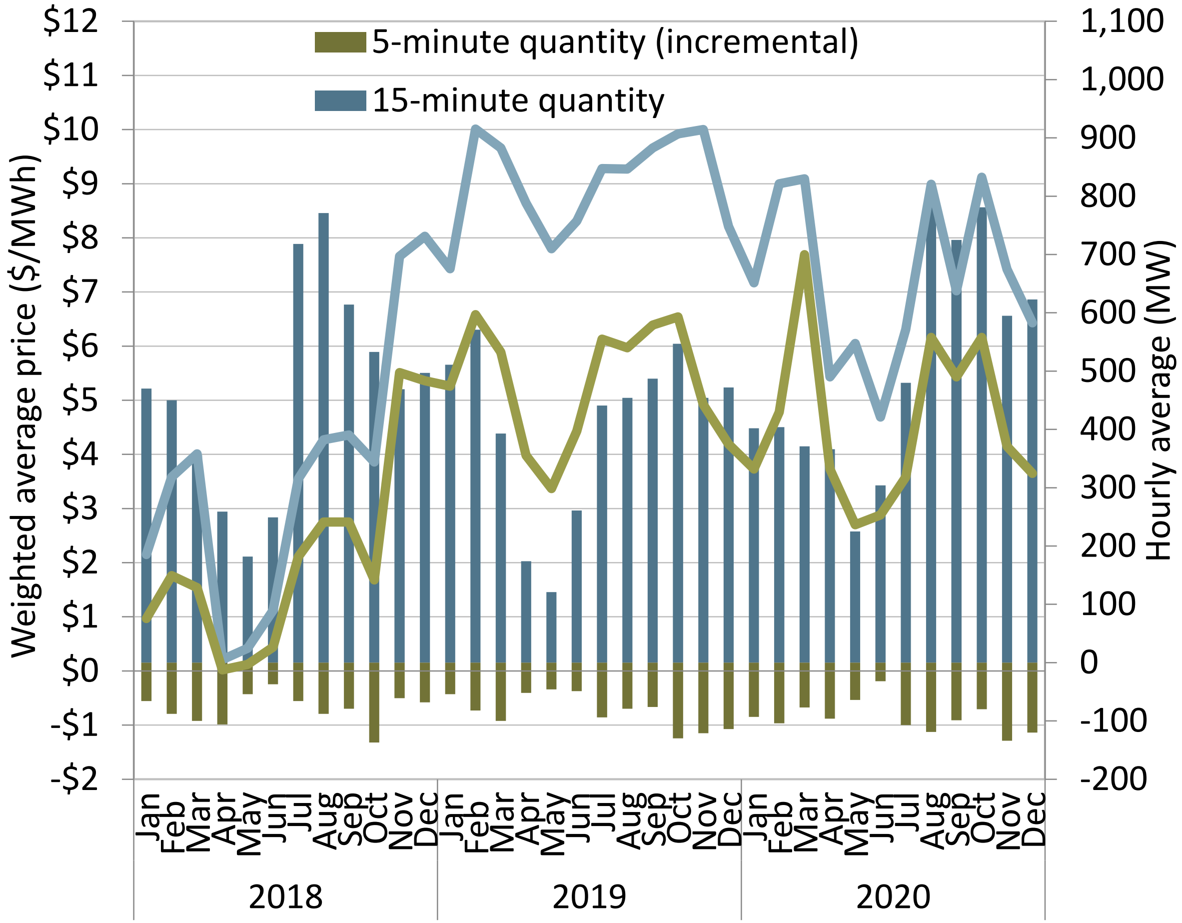
- Northwest prices regularly lower than the rest of the system due to limited transfer capability

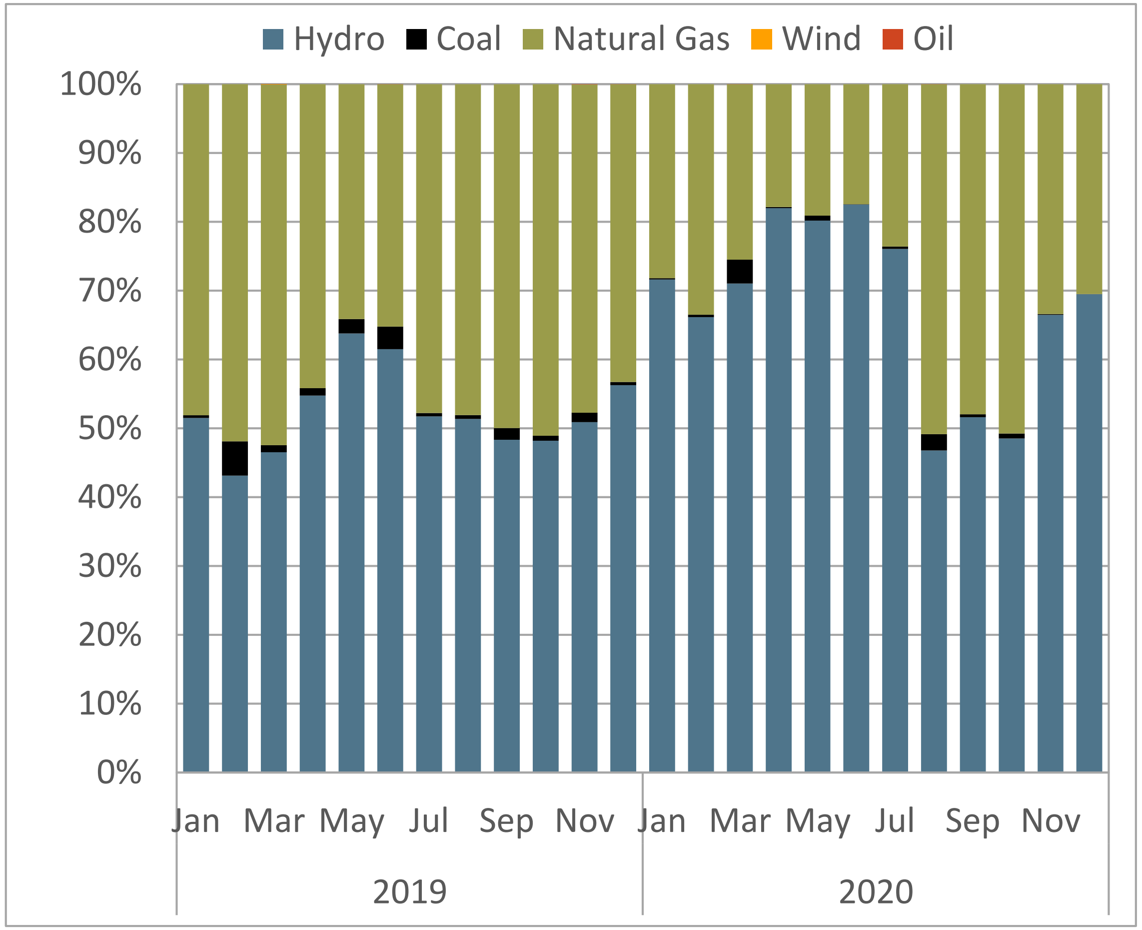
- Peak California area prices exceed other areas due to GHG and congestion

Impact of congestion and greenhouse gas on prices (2020)

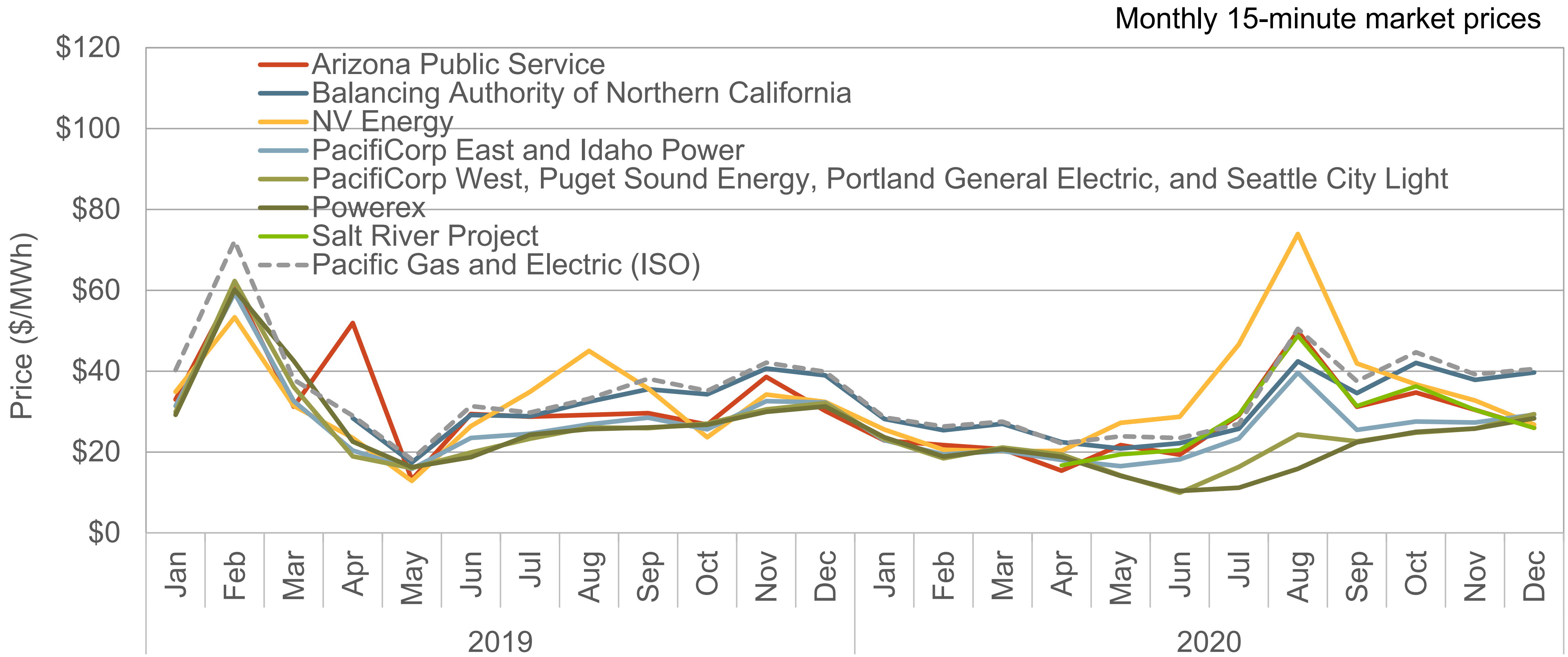


Energy imbalance market greenhouse gas price, cleared quantity and fuel type





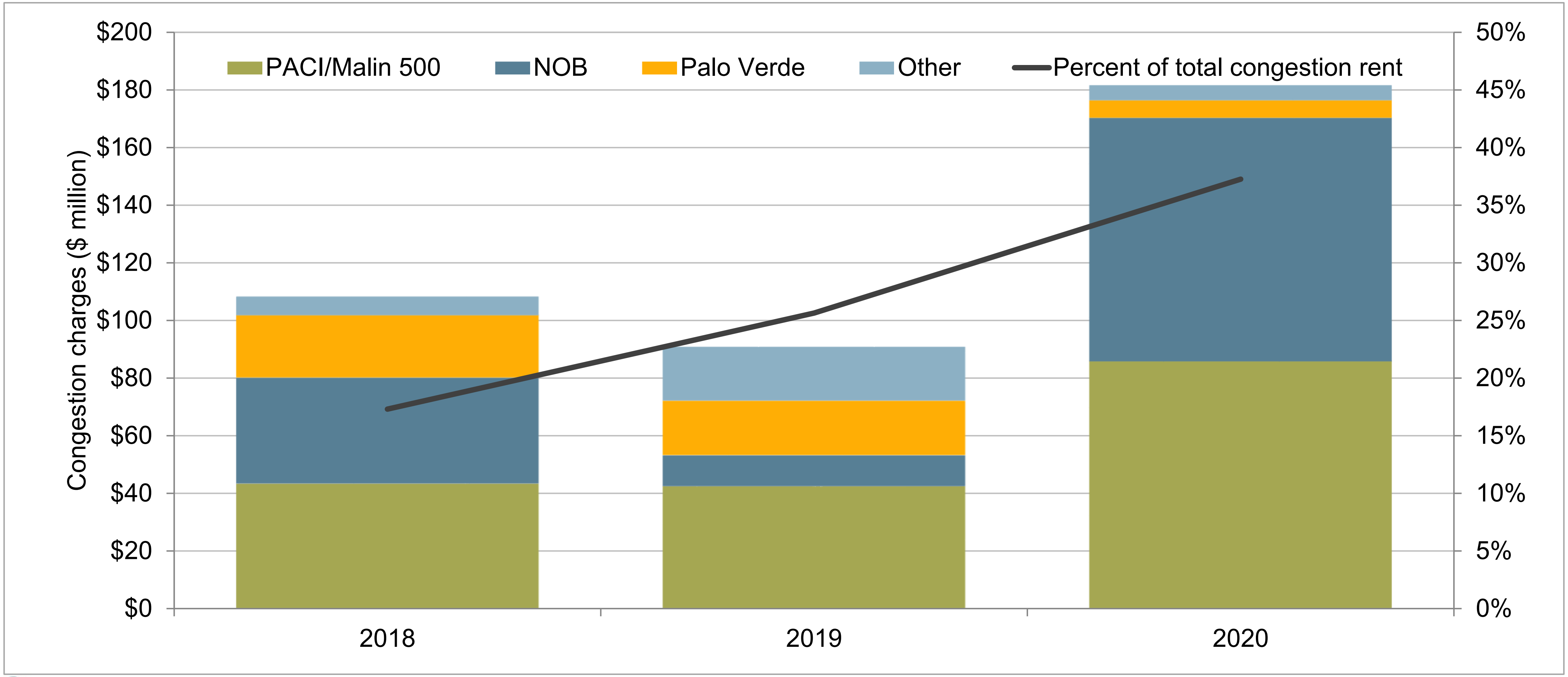
Prices and transfers of energy reflect differences in regional supply conditions and transfer limitations



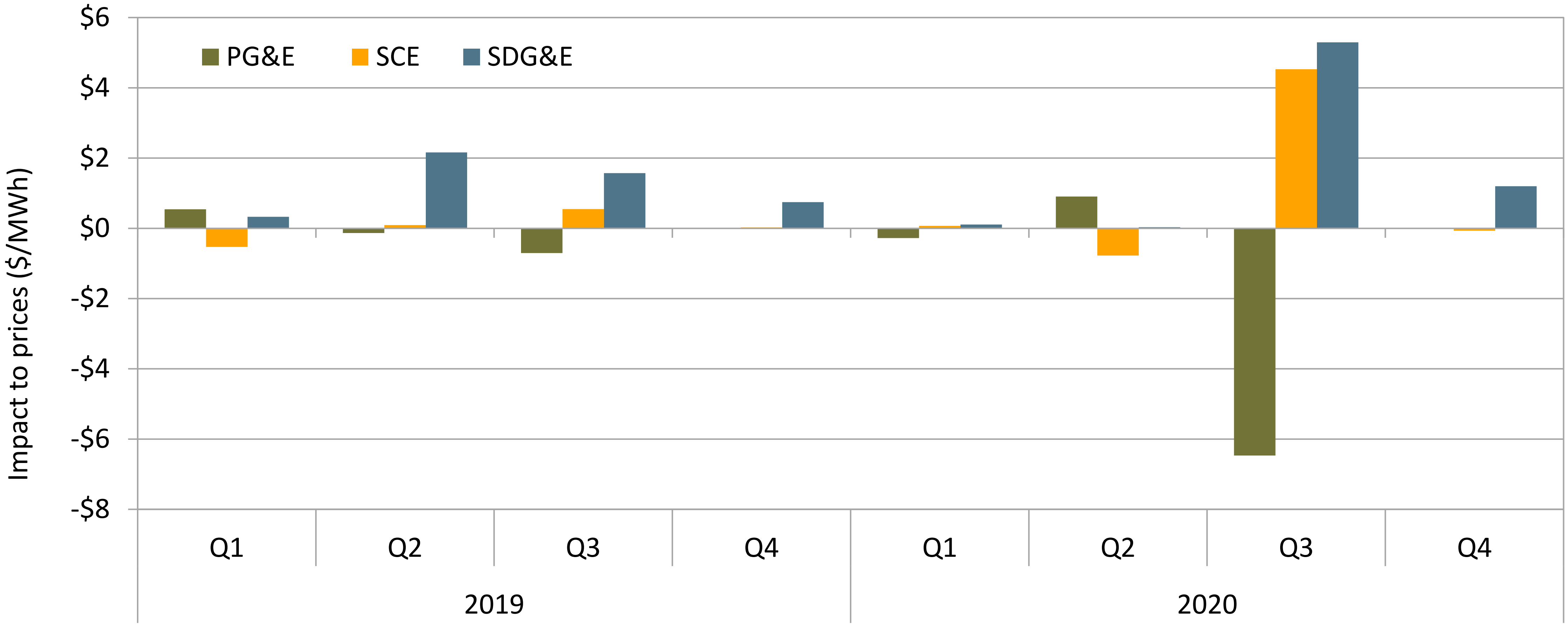
EIM transfer constraint congestion had greater impact on prices than internal constraint congestion in all areas outside of the ISO, lowering prices in Northwest

	15-minute market		5-minute market	
	Congestion Frequency	Price Impact ($/MWh)	Congestion Frequency	Price Impact ($/MWh)
BANC	1%	-$1.02	1%	-$0.15
Arizona Public Service	4%	$0.34	3%	$1.54
NV Energy	4%	$5.55	3%	$7.24
PacifiCorp East	8%	-$1.52	5%	-$0.38
Idaho Power	8%	-$1.61	5%	-$0.63
Salt River Project*	10%	-$0.17	10%	$1.34
PacifiCorp West	37%	-$4.54	25%	-$2.75
Portland General Electric	41%	-$4.53	29%	-$2.59
Puget Sound Energy	41%	-$4.60	33%	-$2.79
Seattle City Light*	44%	-$5.94	35%	-$3.86
Powerex	48%	-$5.77	48%	-$4.09

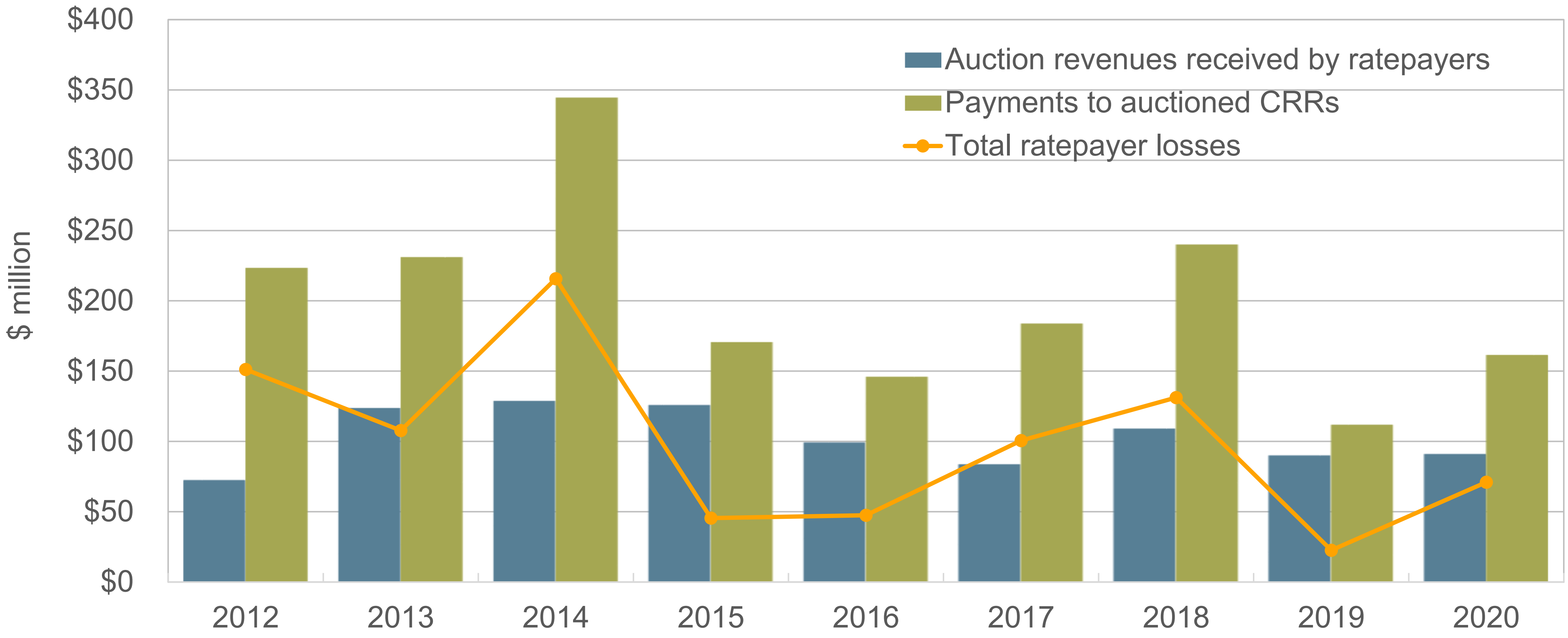
Day-ahead import congestion charges on major interties (2018-2020)



Day-ahead congestion impact increases, congestion revenues total 6.0% of total day-ahead market energy costs, compared to about 4.3% in 2019 and 6.8% in 2018



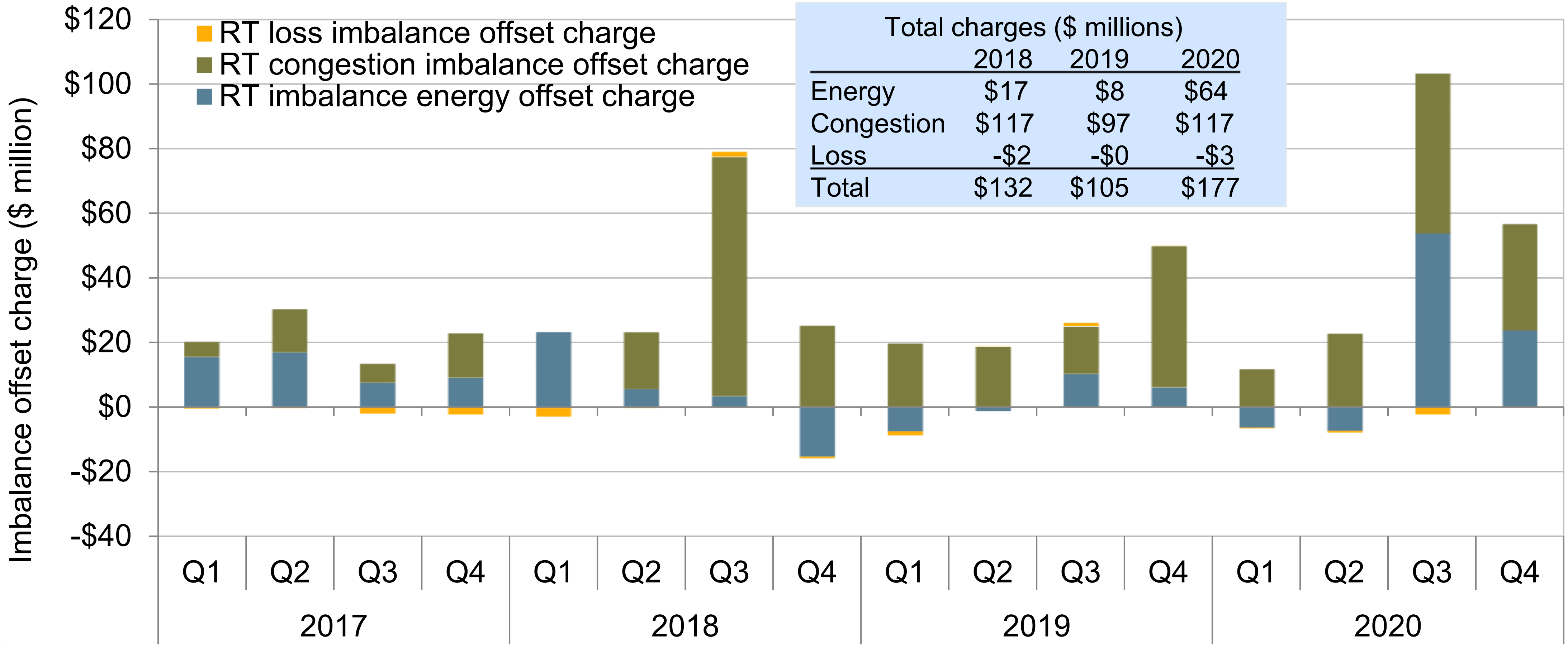
Transmission ratepayers lost over $70 million from auctioned CRRs in 2020, up from $22 million in 2019 but down from $131 million in 2018



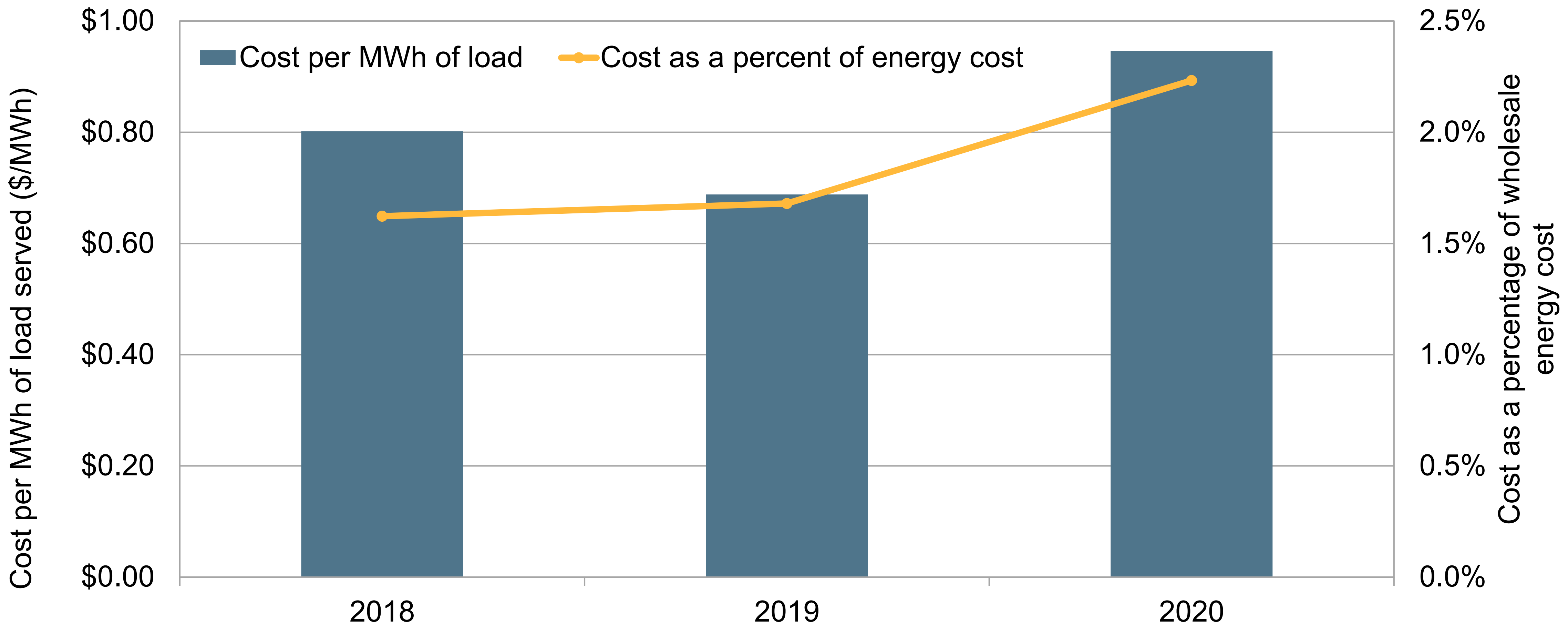
Congestion revenue right auction changes implemented January 2019

- Implemented in response to systematic losses from congestion revenue right auction sales since 2009
- Transmission ratepayer losses are significantly lower
  - Day-ahead congestion revenues $488 million, compared to $354 million in 2019 and 628 million in 2018
  - Losses from auctioned rights 14% compared to 6% in 2019, 21% in 2018.
- 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

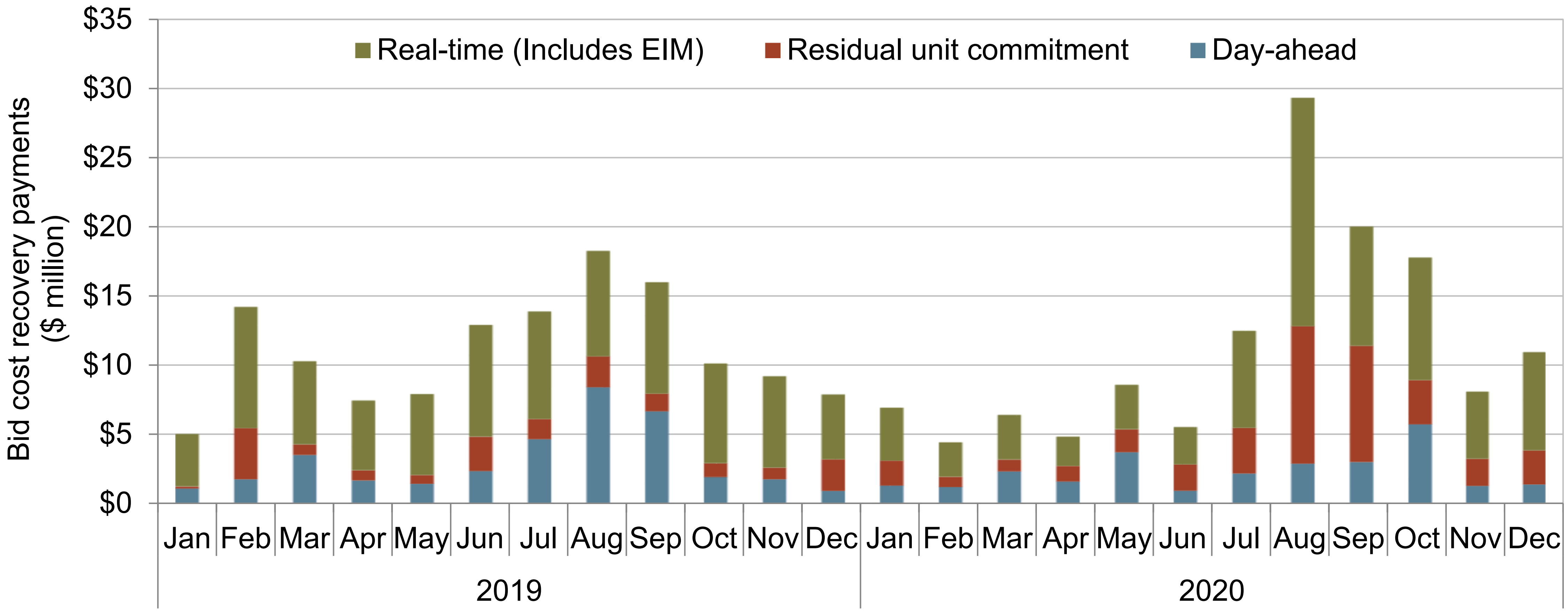
Real-time imbalance offset costs increased by 69% to $177 million; most congestion offset costs were due to reductions in constraint limits between day-ahead and real-time



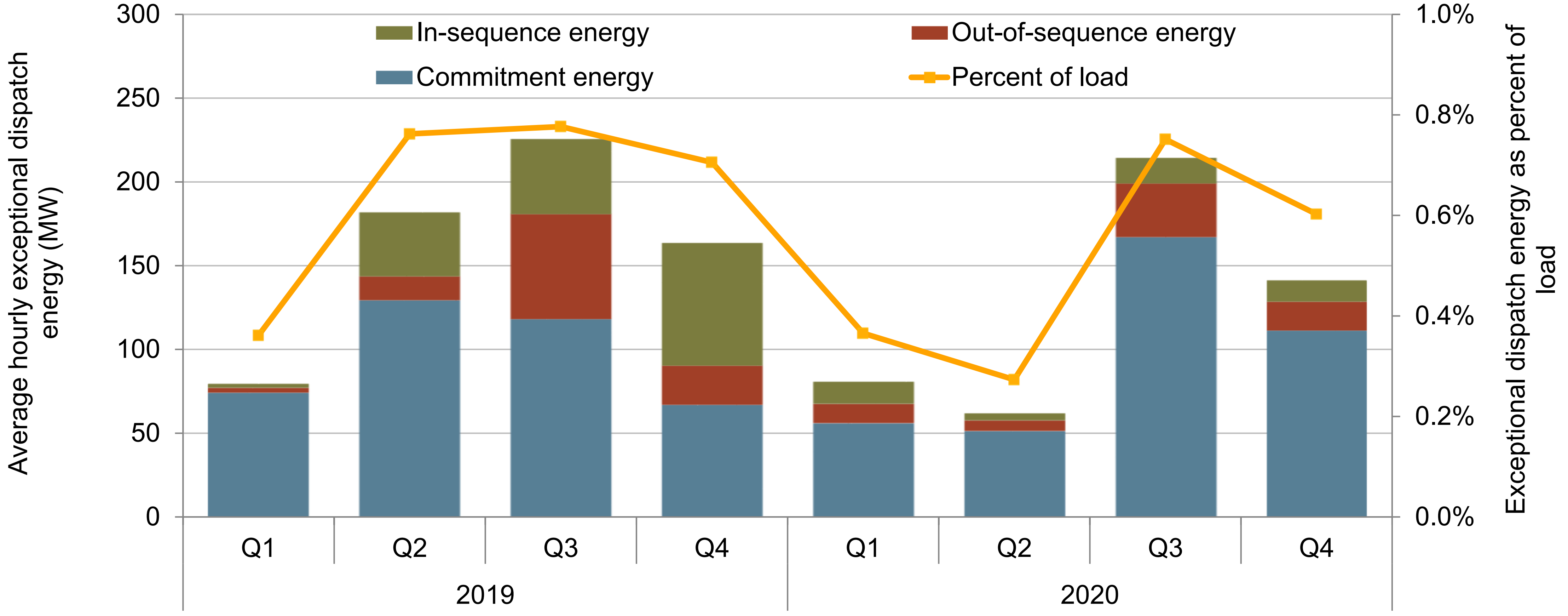
Ancillary service costs increased to $199 million and over 2.2% of wholesale energy costs



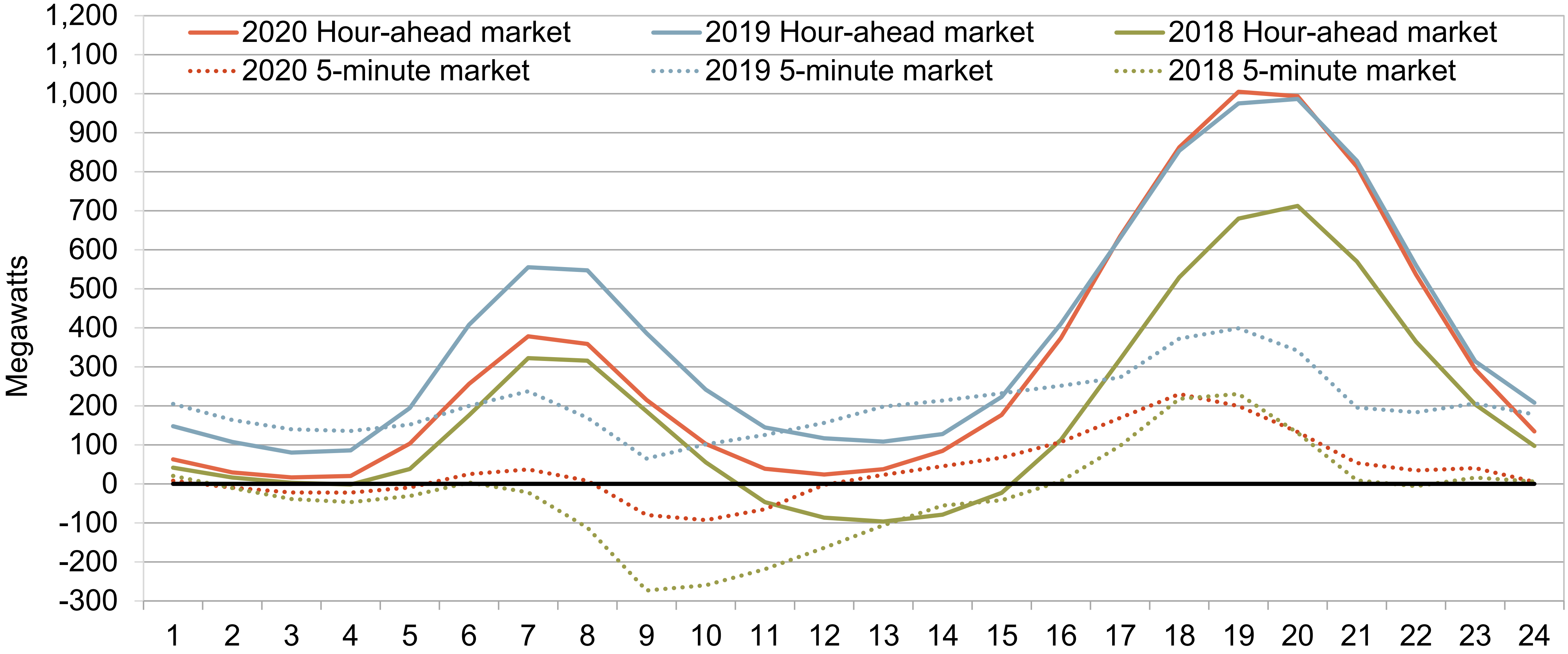
Bid cost recovery payments in the CAISO increased to $126 million or about 1.4 % of total energy costs, up from $123 million in 2019



Total energy from exceptional dispatches decreased in 2020, accounting for a low portion of system load (0.5%). Costs decrease to $16 million from $26 million in 2019



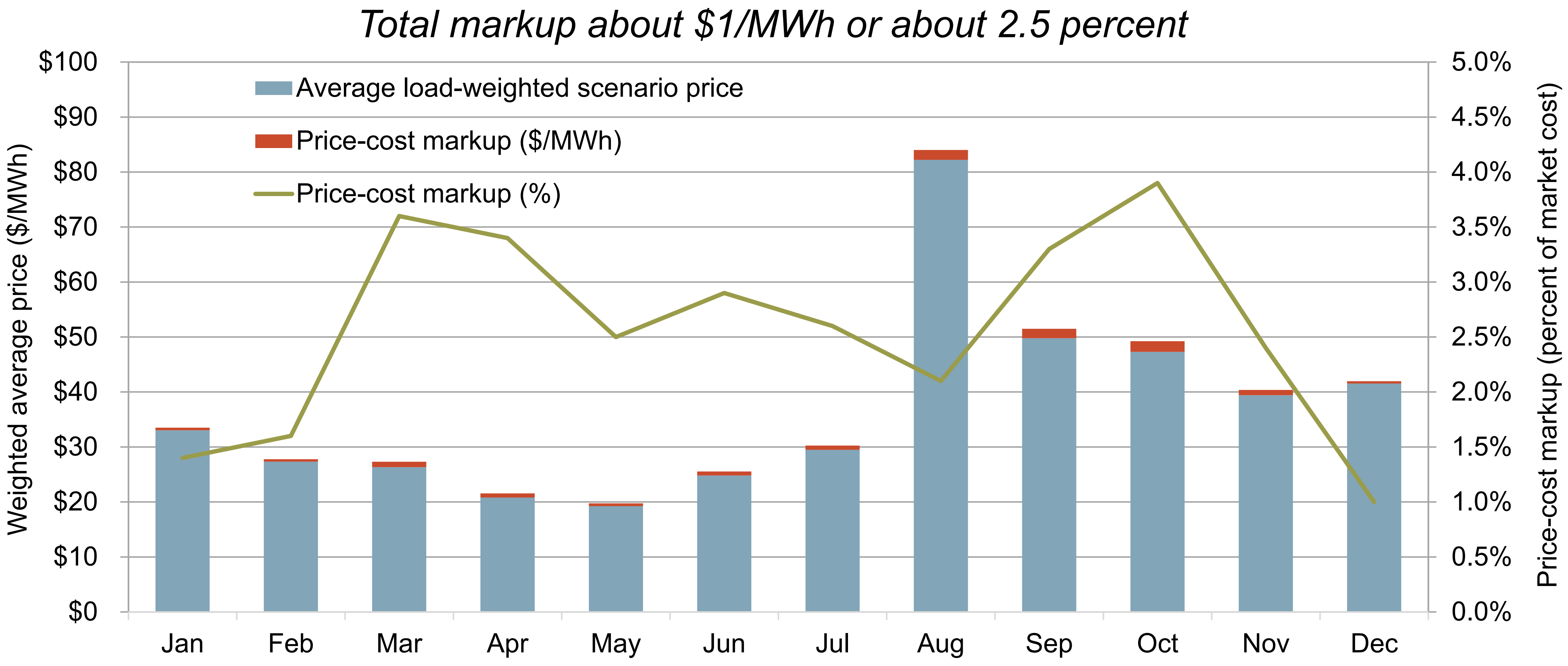
Load adjustment by grid operators remained high, particularly in ramping hours



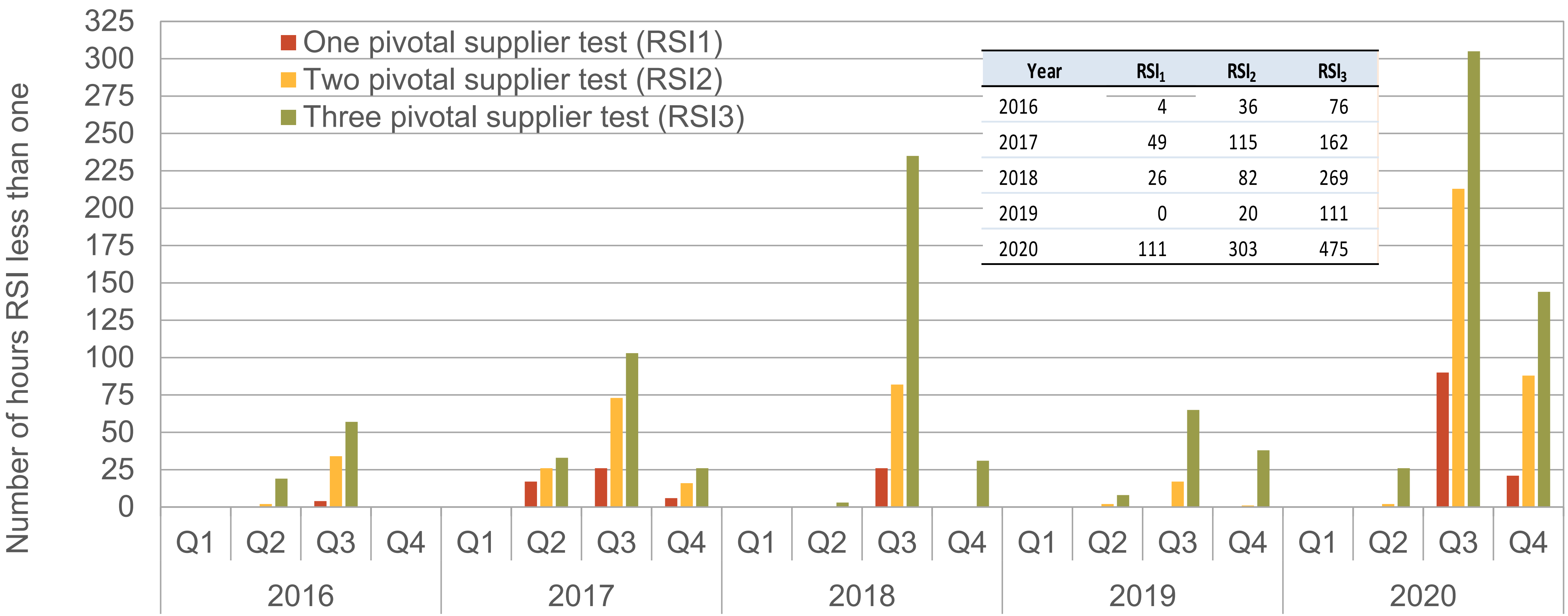
Flexible ramping capacity

- 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, only in the 15-minute market
- Total uncertainty payments to generators decreased to $4.6 million, down from $6.3 million in 2019, $7.1 million in 2018, and $25 million in 2017
- DMM supports the ISO’s stakeholder process to refine the product:
  - 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

The ISO's energy markets were competitive in 2020, with energy prices about equal to competitive baseline prices calculated by DMM



Day-ahead market was less structurally competitive than prior years



Year	RSI_1	RSI_2	RSI_3
2016	4	36	76
2017	49	115	162
2018	26	82	269
2019	0	20	111
2020	111	303	475

State policy creates a basis for competitive market outcomes

- California currently 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 ISO system

- Load shift from investor owned utilities to community choice aggregators

- Decrease in long-term capacity contracts

Average system resource adequacy capacity and availability by fuel type (210 highest load hours)

Resource type	Total resource adequacy capacity (MW)	Day-ahead market				Real-time market			
		Adjusted for outages		Bids and self-schedules		Adjusted for outages/availability		Bids and self-schedules	
		MW	% of total RA Cap.	MW	% of total RA Cap.	MW	% of total RA Cap.	MW	% of total RA Cap.
Must-Offer:									
Gas-fired generators	19,641	18,512	94%	18,511	94%	18,112	92%	18,077	92%
Other generators	1,437	1,350	94%	1,350	94%	1,339	93%	1,339	93%
Subtotal	**21,078**	**19,862**	**94%**	**19,861**	**94%**	**19,451**	**92%**	**19,416**	**92%**
Other:									
Imports	4,699	4,660	99%	4,155	88%	4,687	100%	3,827	81%
Use-limited gas units	8,164	7,856	96%	7,820	96%	7,728	95%	7,672	94%
Hydro generators	6,385	5,682	89%	5,385	84%	5,573	87%	5,279	83%
Nuclear generators	2,740	2,698	98%	2,691	98%	2,698	98%	2,691	98%
Solar generators	2,790	2,777	100%	1,950	70%	2,761	99%	1,969	71%
Wind generators	1,160	1,144	99%	770	66%	1,141	98%	756	65%
Qualifying facilities	969	959	99%	806	83%	949	98%	818	84%
Other non-dispatchable	743	733	99%	587	79%	720	97%	521	70%
Subtotal	**27,650**	**26,509**	**96%**	**24,164**	**87%**	**26,257**	**95%**	**23,533**	**85%**
Total	**48,728**	**46,371**	**95%**	**44,025**	**90%**	**45,708**	**94%**	**42,949**	**88%**

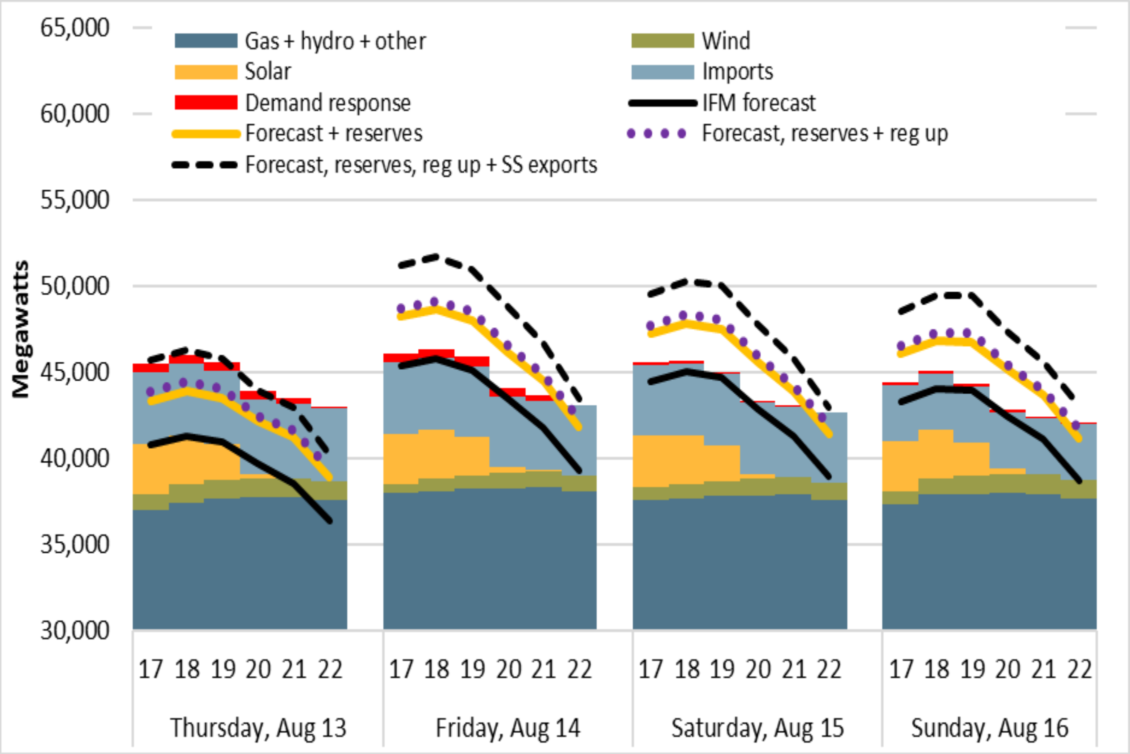
Key findings of DMM's report on August/September heatwave are consistent with CAISO/CPUC/CEC report

Load curtailments due to a series of contributing factors:

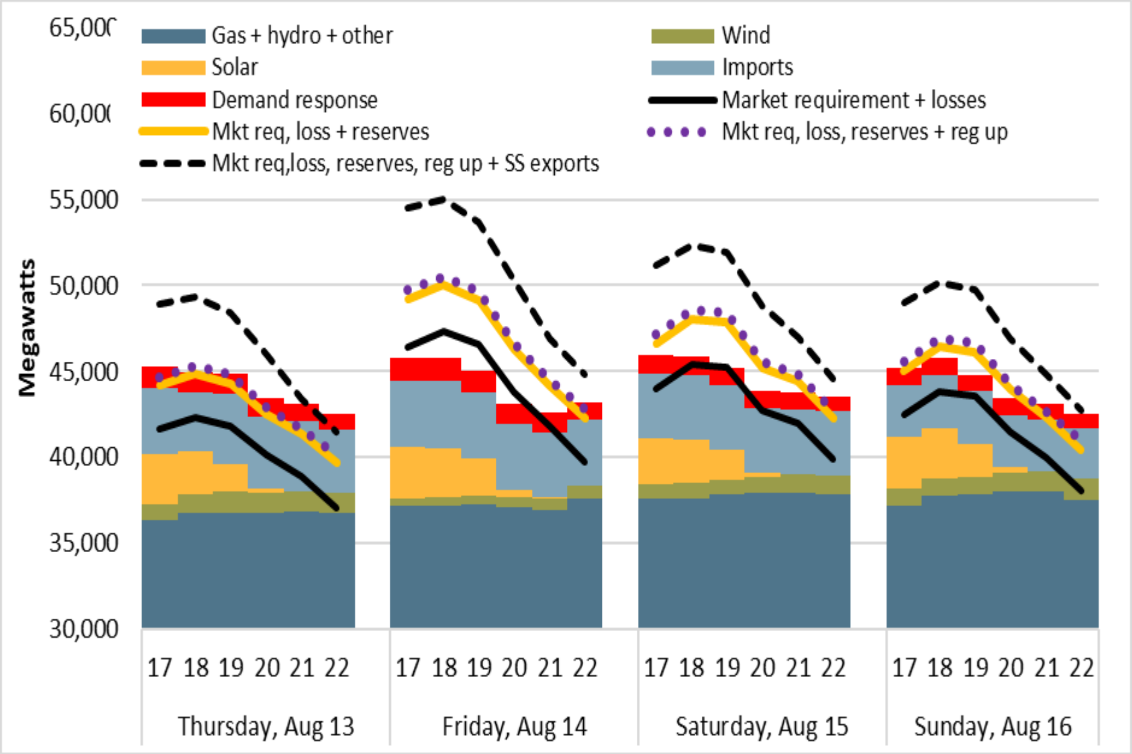
- **Extreme temperatures and energy demand** across the West, electricity demand well in excess of current resource planning targets.
- **California state resource adequacy requirements** based on 1-in-2 year loads plus a 15 percent planning reserve margin, insufficient to reflect actual system conditions.
- **Counting rules for resource adequacy capacity** which overestimate the actual capacity that is available from many resources during the early evening hours.
- **Transmission capacity from Pacific Northwest de-rated by about 650 MW** as a result of a weather-related forced outage which prevented additional available supply from being imported into the CAISO.
- **The sudden loss of several large gas fired units** contributed to curtailment events, although the overall level of gas capacity on outage was not unusually high.
- **Self-scheduling of relatively large volumes of exports** in the day-ahead market, which reduced <u>net imports</u> into CAISO.
- **Residual unit commitment (RUC) process and related real-time bid processing design**. Detailed discussion of this to follow.

Available capacity from resource adequacy units insufficient to meet demand in peak net load hours, when load was curtailed

Day-ahead



Real-time



The ISO took steps to ensure exports were limited to physically feasible levels

- Virtual bidding suspended effective August 18.
- Effective September 5, ISO made important changes to RUC and the real-time scheduling priority of day-ahead energy market export schedules that do not receive RUC awards.
- CAISO's current policy is still to prioritize exports that receive day-ahead RUC awards over native CAISO balancing area load in real-time.
- The rules and processes for limiting/curtailing exports used by the CAISO and other balancing areas should be reviewed, clarified, and potentially modified -- with a goal of establishing equal treatment and expectations of exports by all balancing areas.

Summary of key recommendations

- Enhance flexible ramping product
  - Implement locational procurement
  - Further modify to address uncertainty over longer time horizon (e.g. 1 to 3 hours)
- System market power mitigation
  - Delayed until Q4 2021
  - Resource adequacy imports
  - Scarcity pricing provisions
- Export and wheeling schedules
- EIM resource sufficiency tests
- Demand response resources
- Storage resources

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

- Multi-year framework for local resource adequacy requirements and procurement by load serving entities
- Central buyer framework for meeting any local RA requirements not met by RA capacity procured by CPUC-jurisdictional load serving entities
- Development of RA requirements that consider both energy and capacity needs across all hours of the day, including the peak net load hours
- Development of RA requirements that ensure sufficient flexible capacity needed to integrate a high level of renewables
- Strengthening requirements for imports to meet system level RA requirement

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

CAISO resource adequacy and capacity procurement recommendations

- Modify and clarify resource adequacy import requirements
  - Ensure availability in day-ahead and real-time markets

- Limit and manage reliance on energy and availability limited resources to meet resource adequacy capacity requirements
  - Demand response
  - battery resources
  - capacity ratings for intermittent resources.

- Resource adequacy performance incentives