2020 Q3 Report on Market Issues and Performance

February 10, 2020

Department of Market Monitoring, California ISO

Amelia Blanke, Ph.D., Manager of Monitoring and Reporting

http://www.caiso.com/Documents/2020ThirdQuarterReportonMarketIssuesandPerformance-Feb4-2021.pdf

Highlights of Q3 2020 market performance

- Load curtailment (August 14-15)
- Prices and wholesale energy costs increase
  - lower hydro
  - high regional demand
  - slightly higher gas prices
- Average load decreases, but peak loads increase
- Generation outages increase
- Congestion increases
- Offset costs, ancillary service costs, bid cost recovery, and losses to ratepayers from congestion revenue rights sold in the auction also increase.

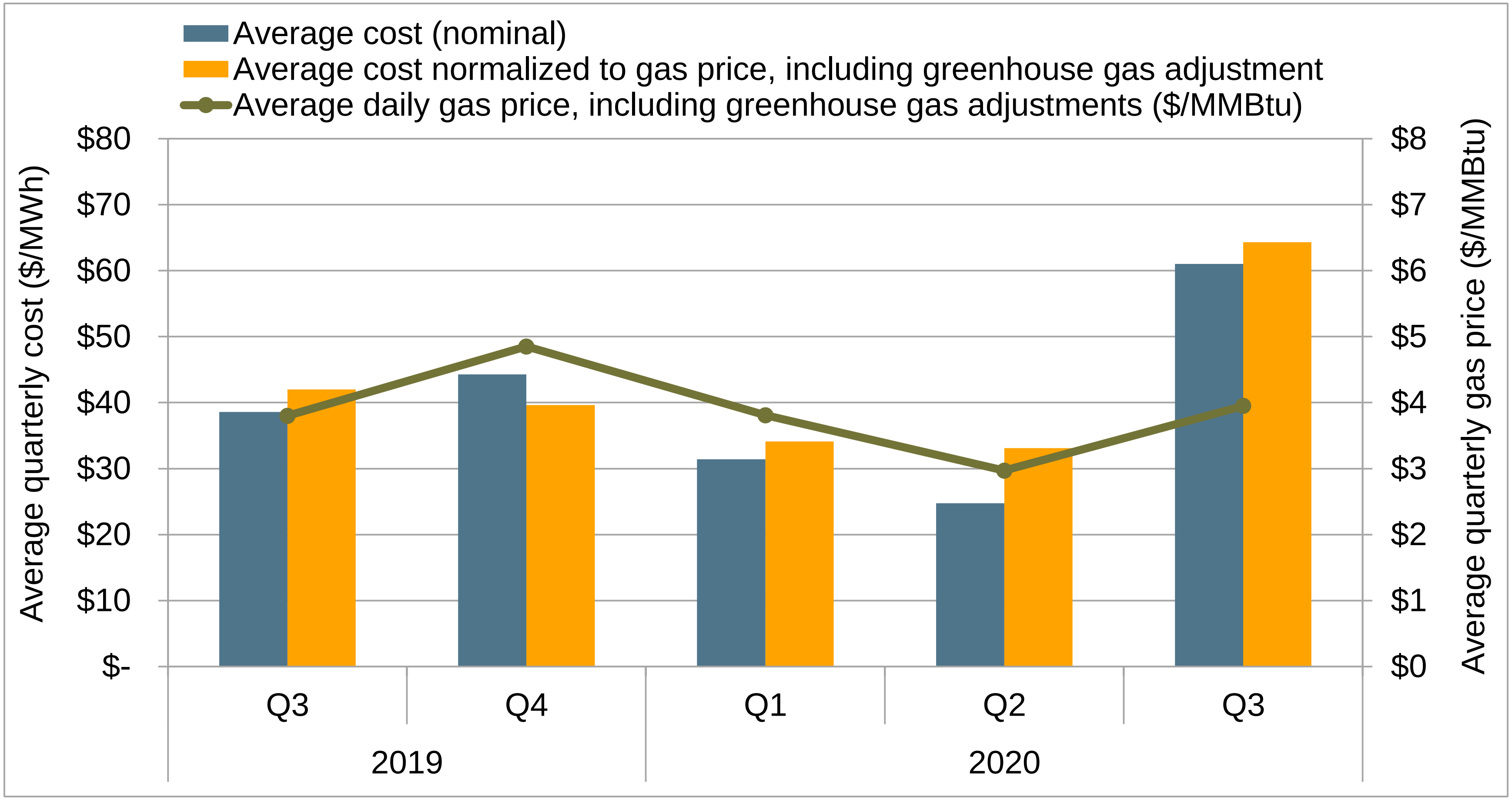
Western energy imbalance market highlights

- Peak prices in NV Energy, Arizona Public Service, and Salt River Project exceeded the rest of the system
- Northwest prices regularly lower than the rest of the system due to limited transfer capability
- Sufficiency test failures and power balance violations drove prices up, particularly in NV Energy
- Significant transfer capability between the ISO and south western BAAs energy to flow with little congestion.

Special issues covered in Q3 market report

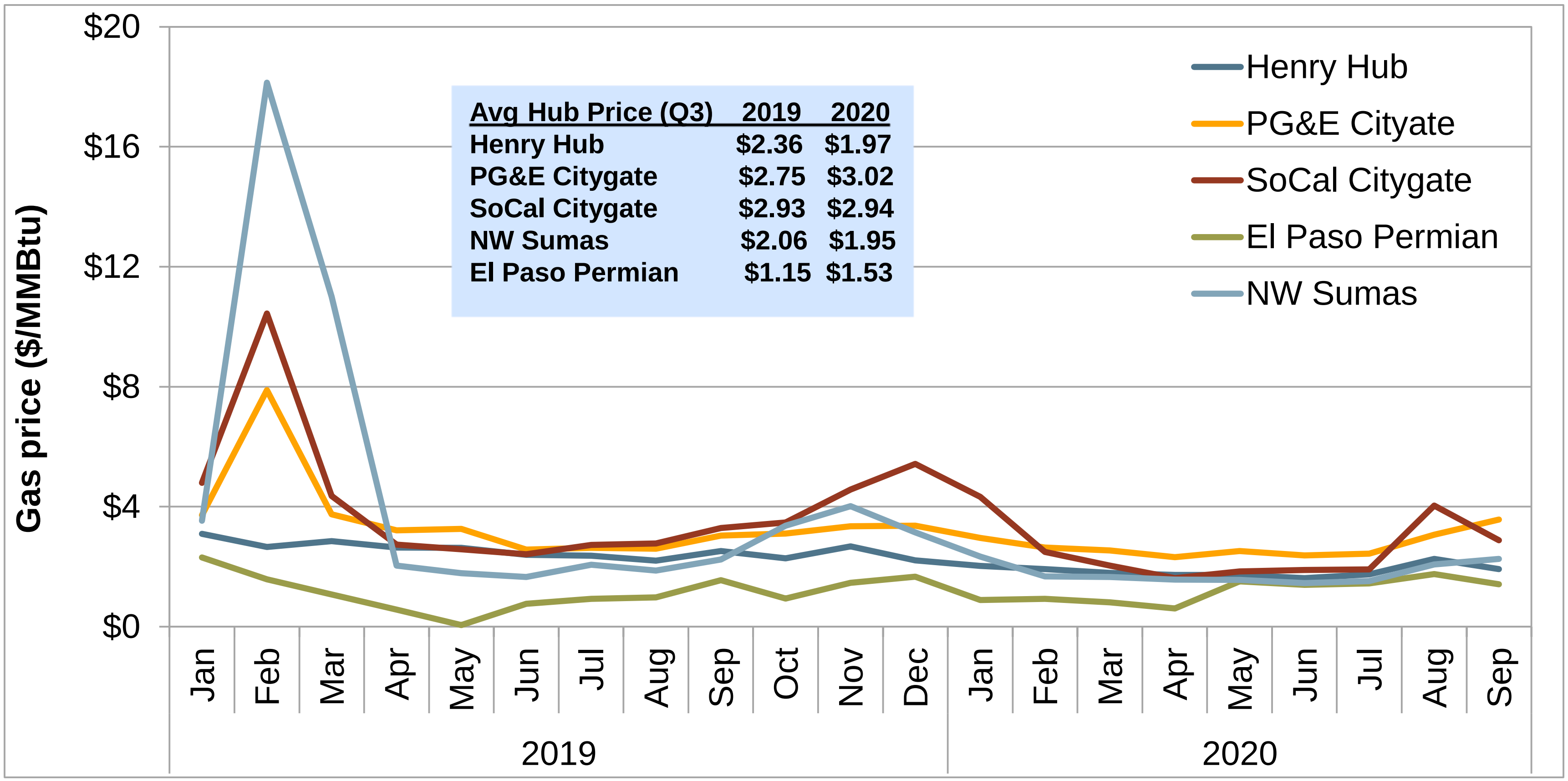
- Load curtailment eventd
- Load under-scheduling
- Hourly block import compensation
- Resource adequacy showings and performance
- System market power
  - Structural competitiveness
  - Bidding behavior
  - Market power had very limited effect on system prices

Total CAISO Q3 wholesale costs increased ~60% to $3.8 billion compared to Q3 2019 -- driven by lower hydro, periods of high load and slightly higher gas prices.

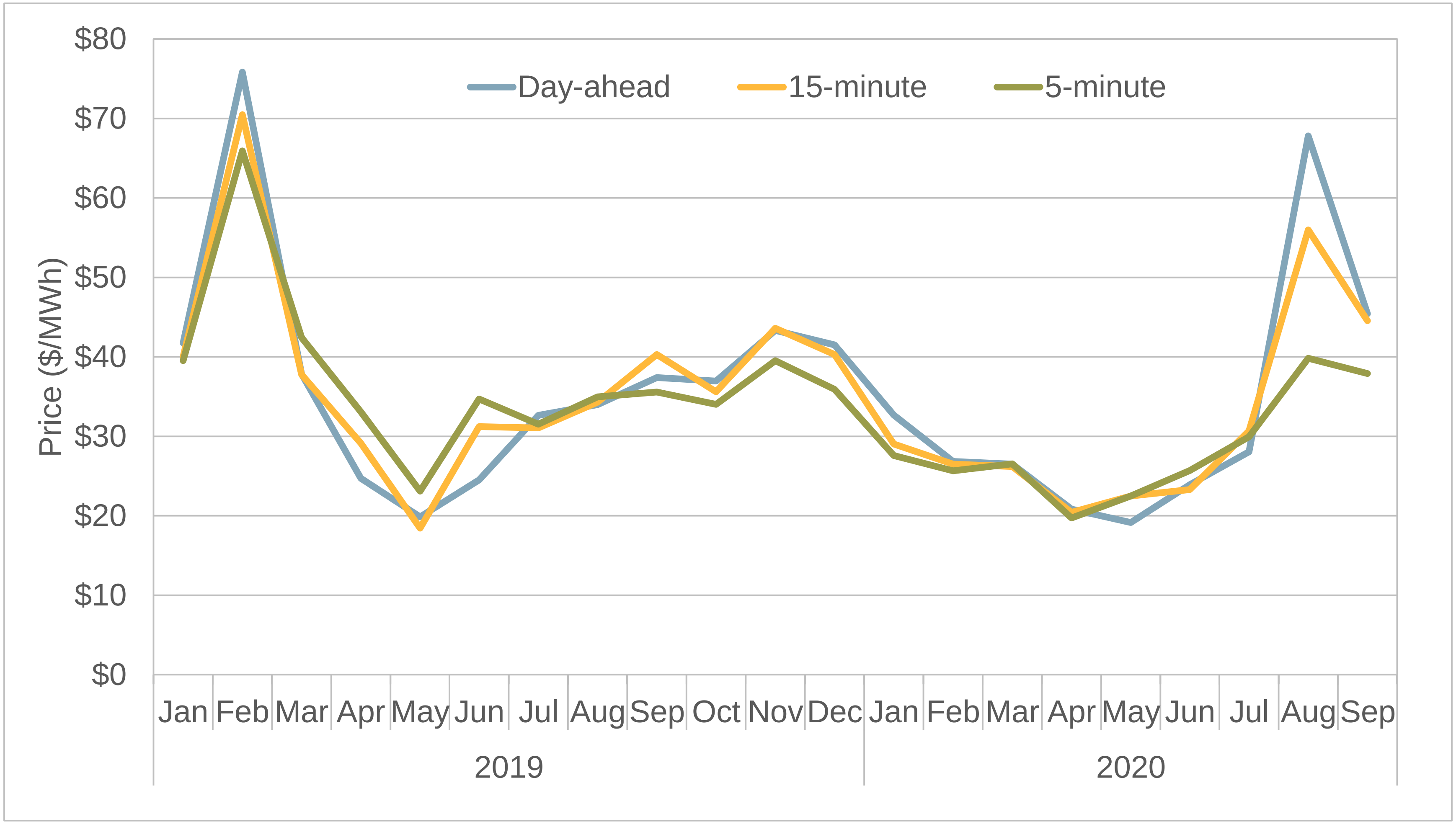


Gas prices declined across major gas trading hubs in the west compared to the first half of 2019.

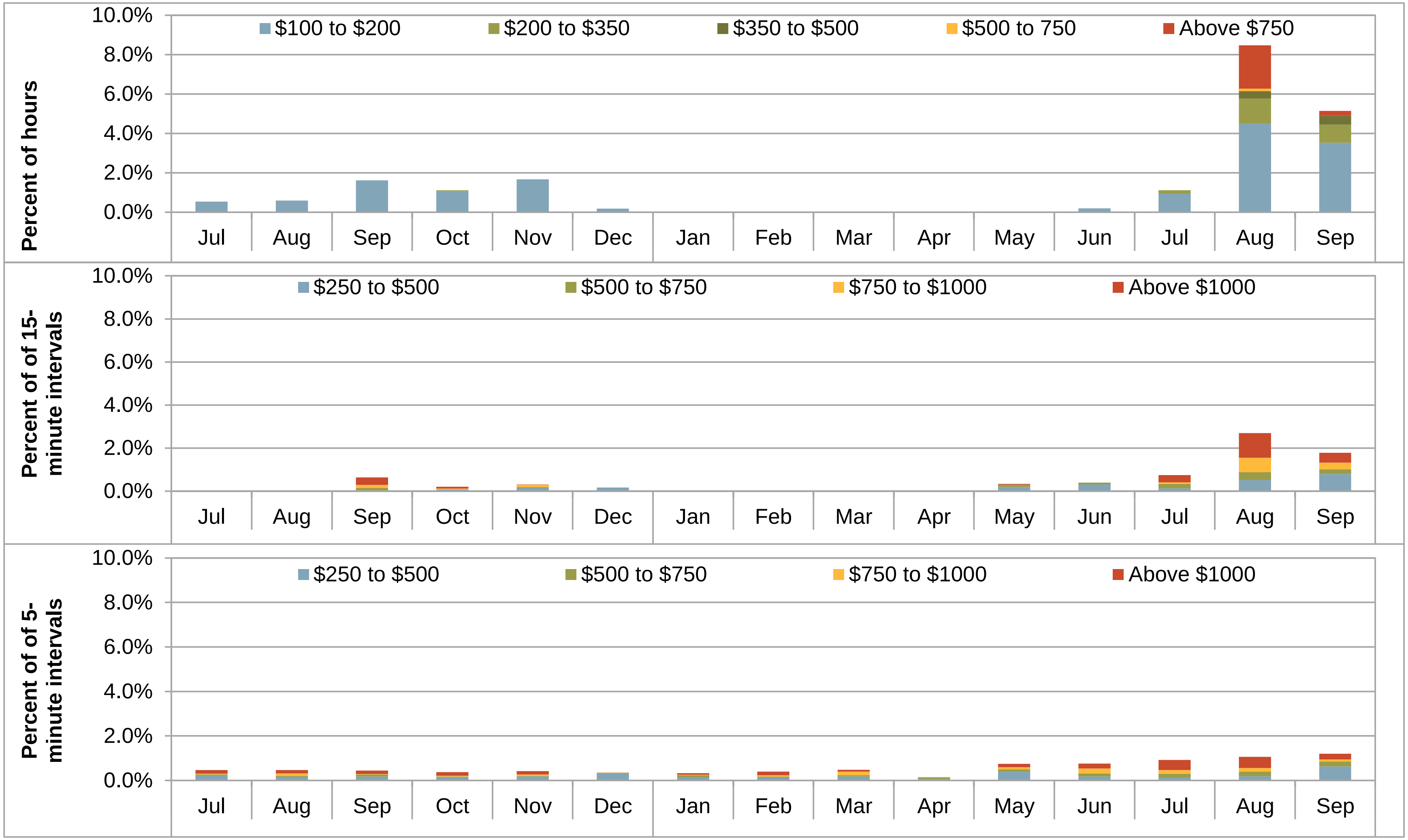
Load weighted Q3 gas prices up 4% from Q3 2019



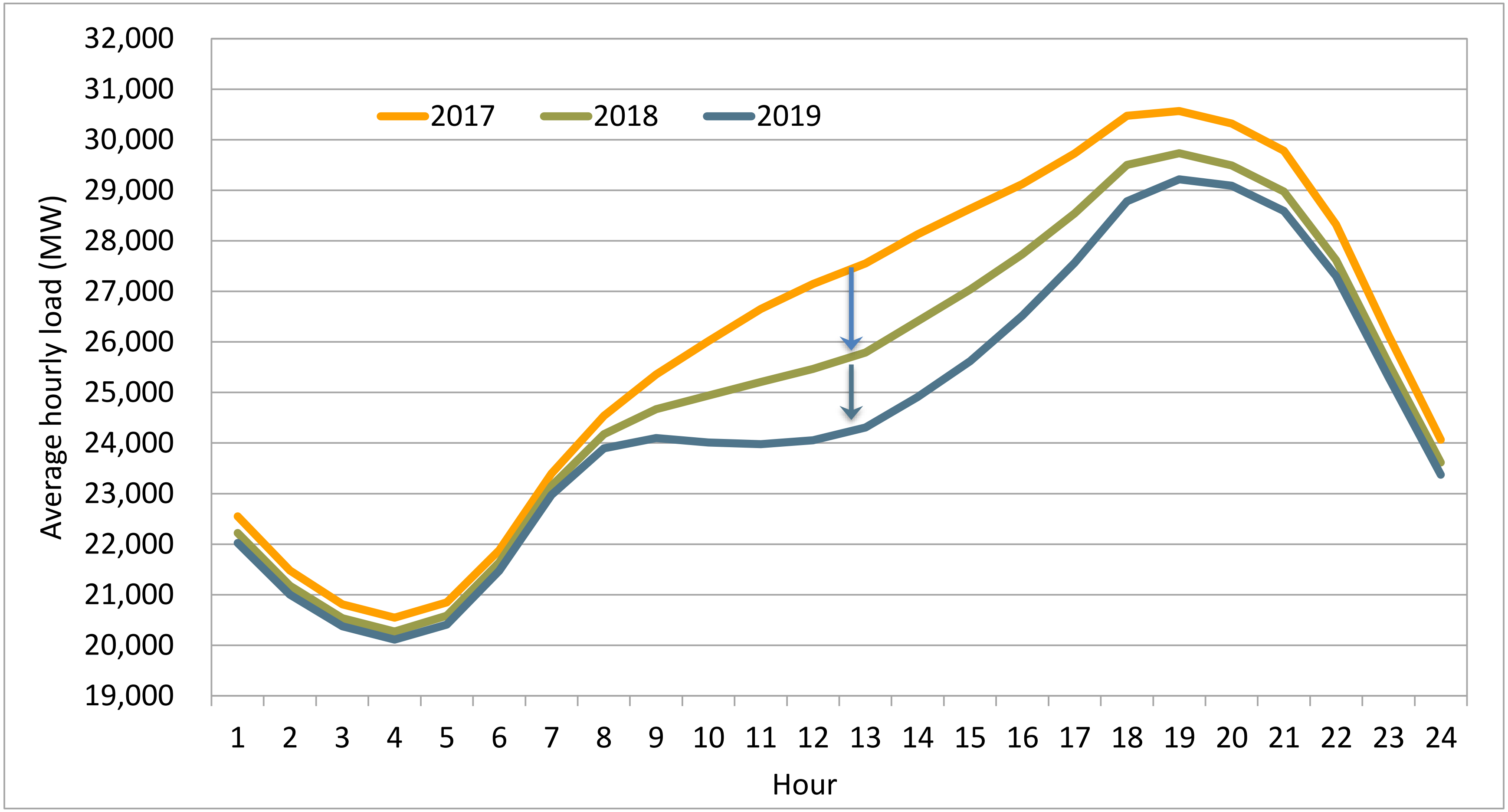
Day-ahead prices ($47/MWh) exceed 15-minute prices ($44/MWh) and 5-minute prices ($36/MWh)



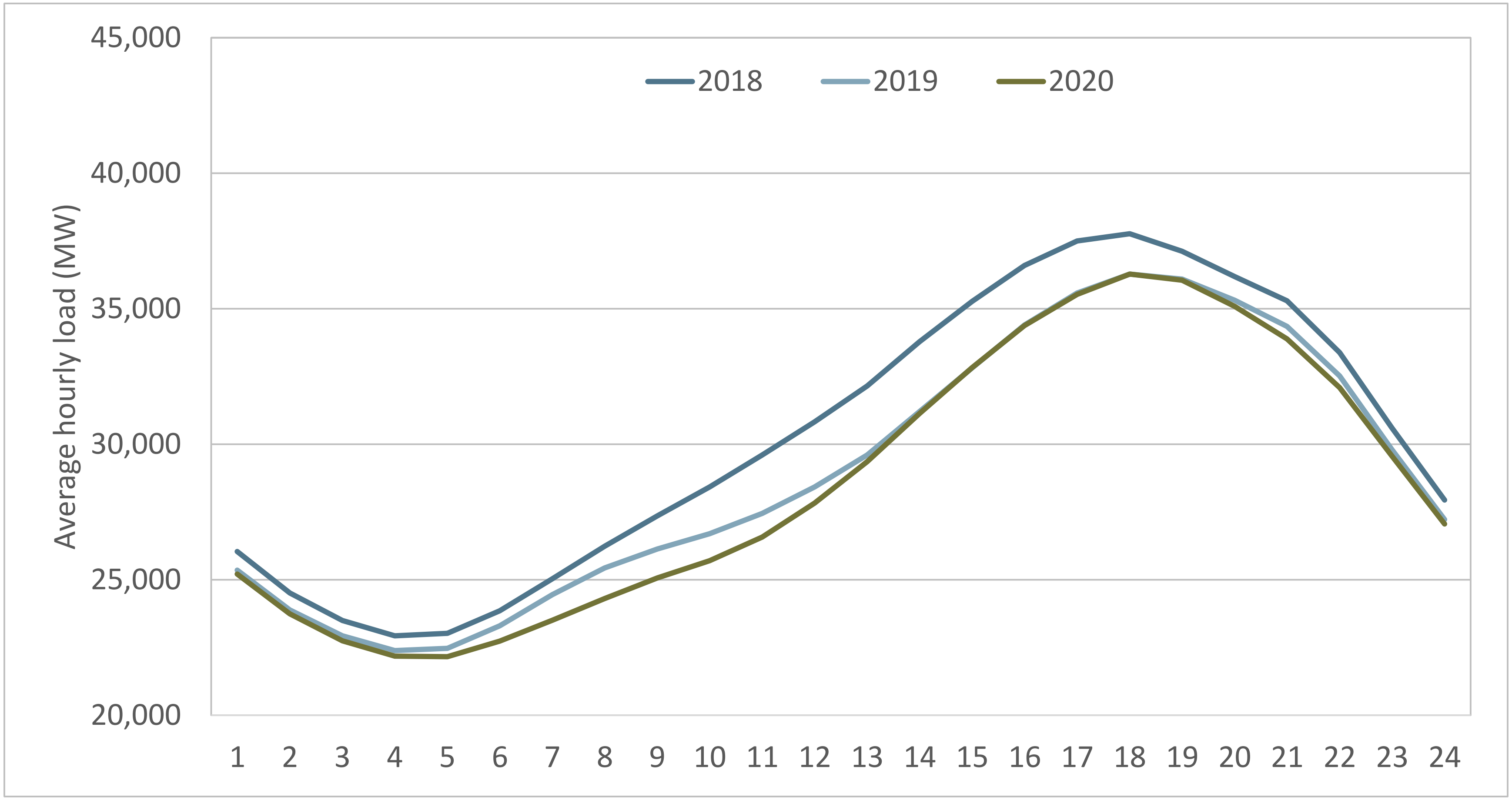
High day-ahead prices more than twice as frequent as high real-time prices (IFM, FMM, RTD)



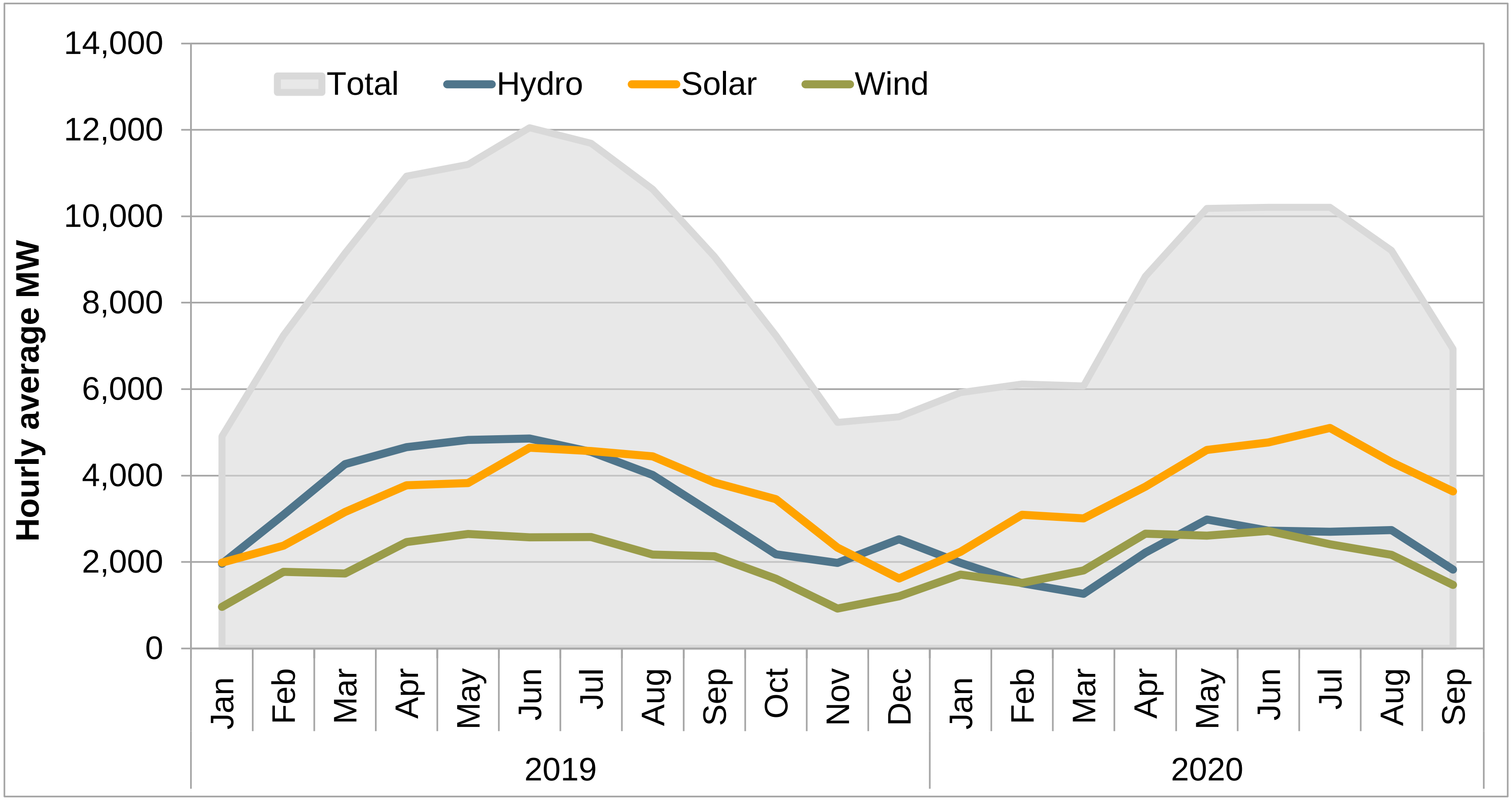
In 2019, average hourly loads continue to decrease due to behind-the-meter solar generation and energy efficiency initiatives, plus lower statewide temperatures



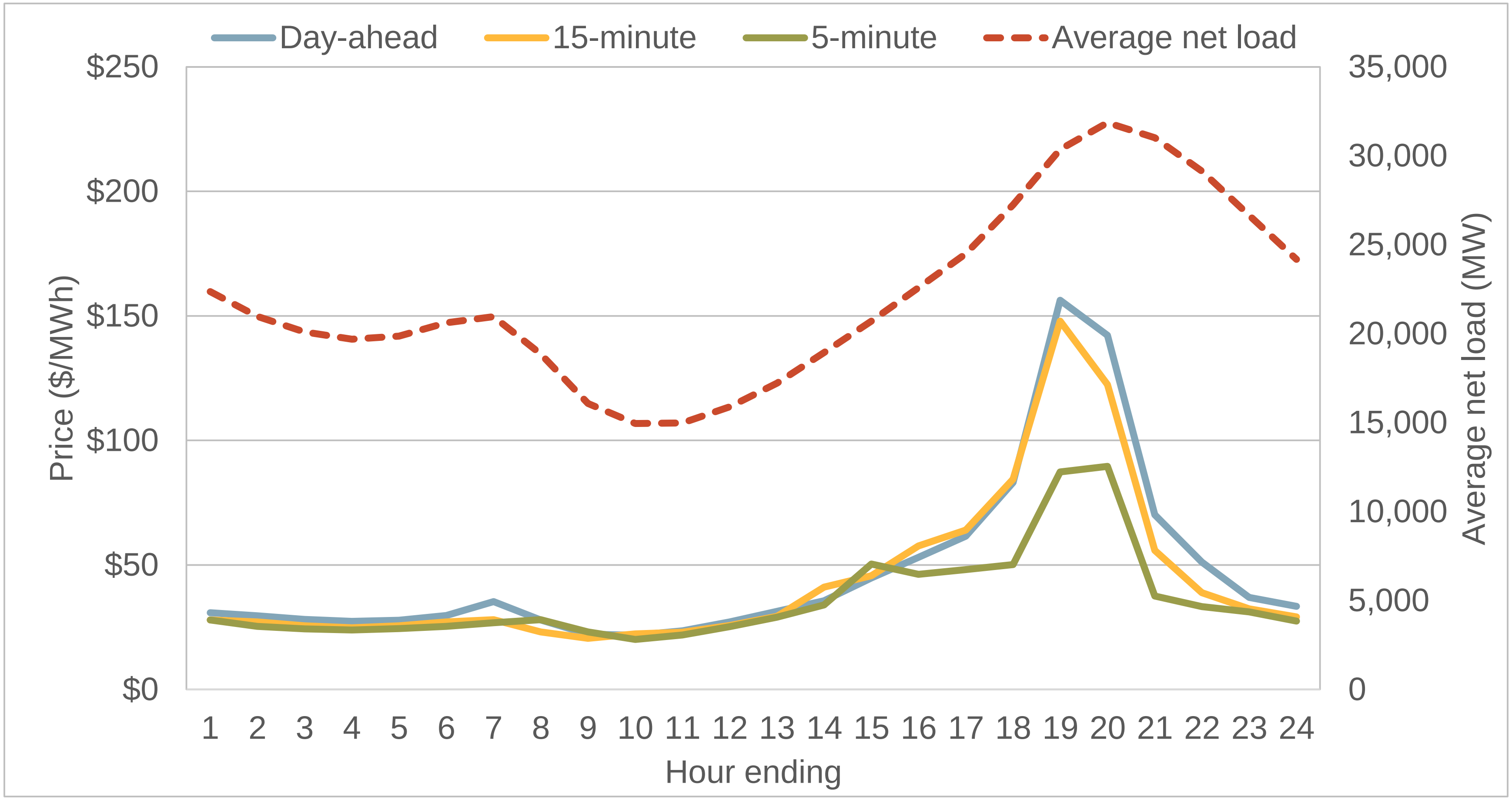
COVID impact to lower overall load, but higher peaks



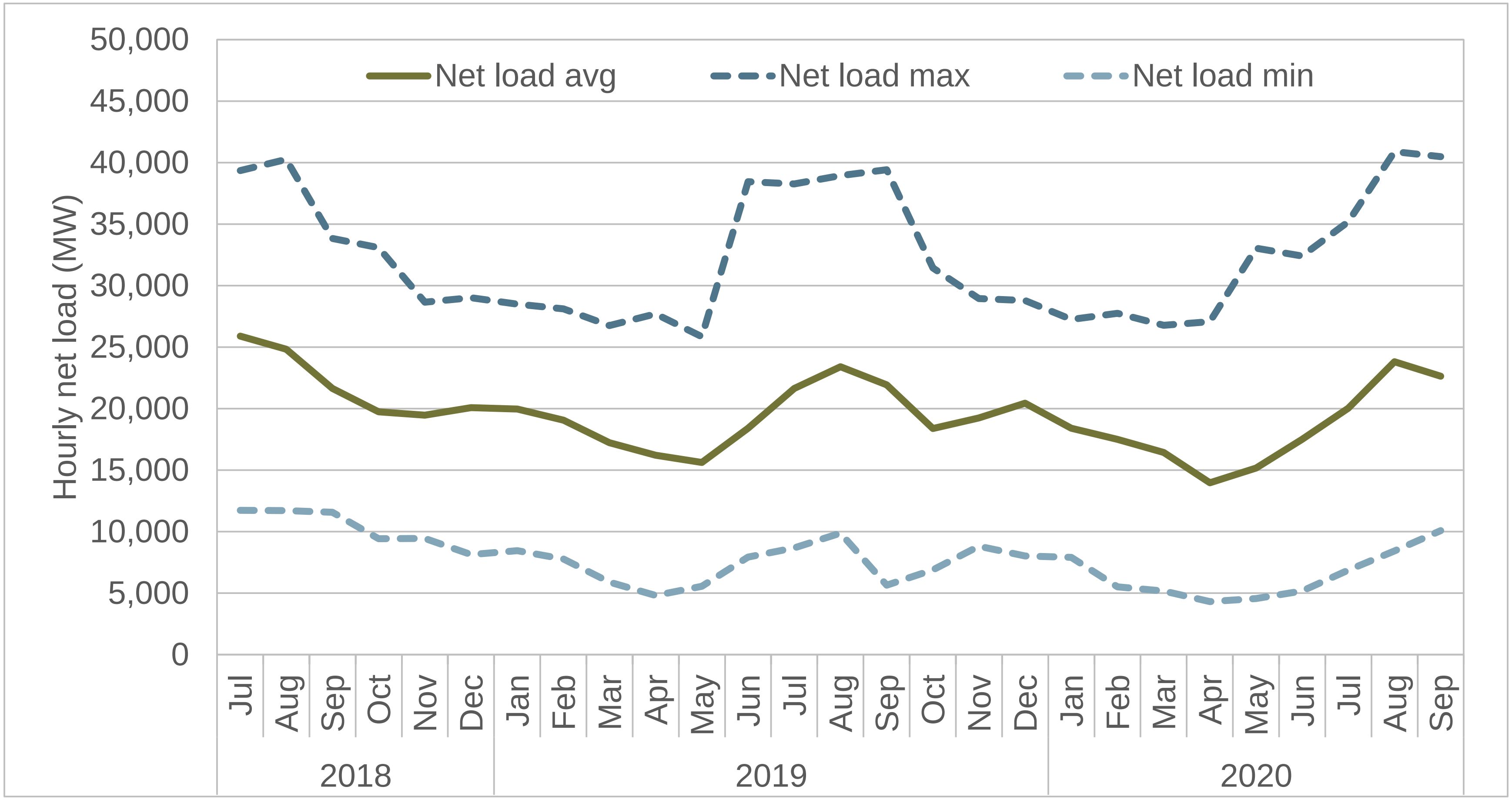
Renewable generation decreased by 16 percent over Q3 2019 due to lower hydro production (down 38 percent)



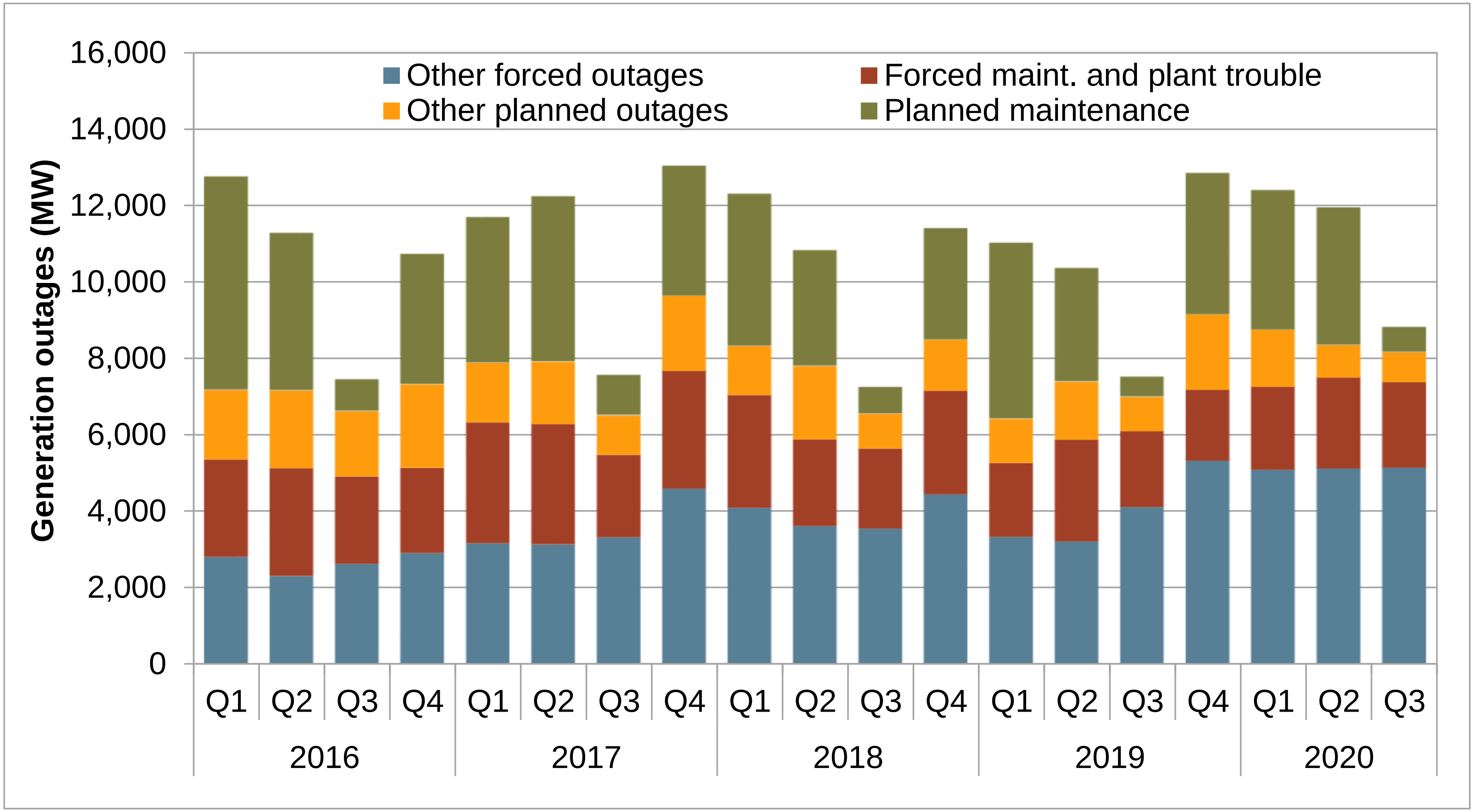
Average prices up – with highest average prices in net load peak hours,



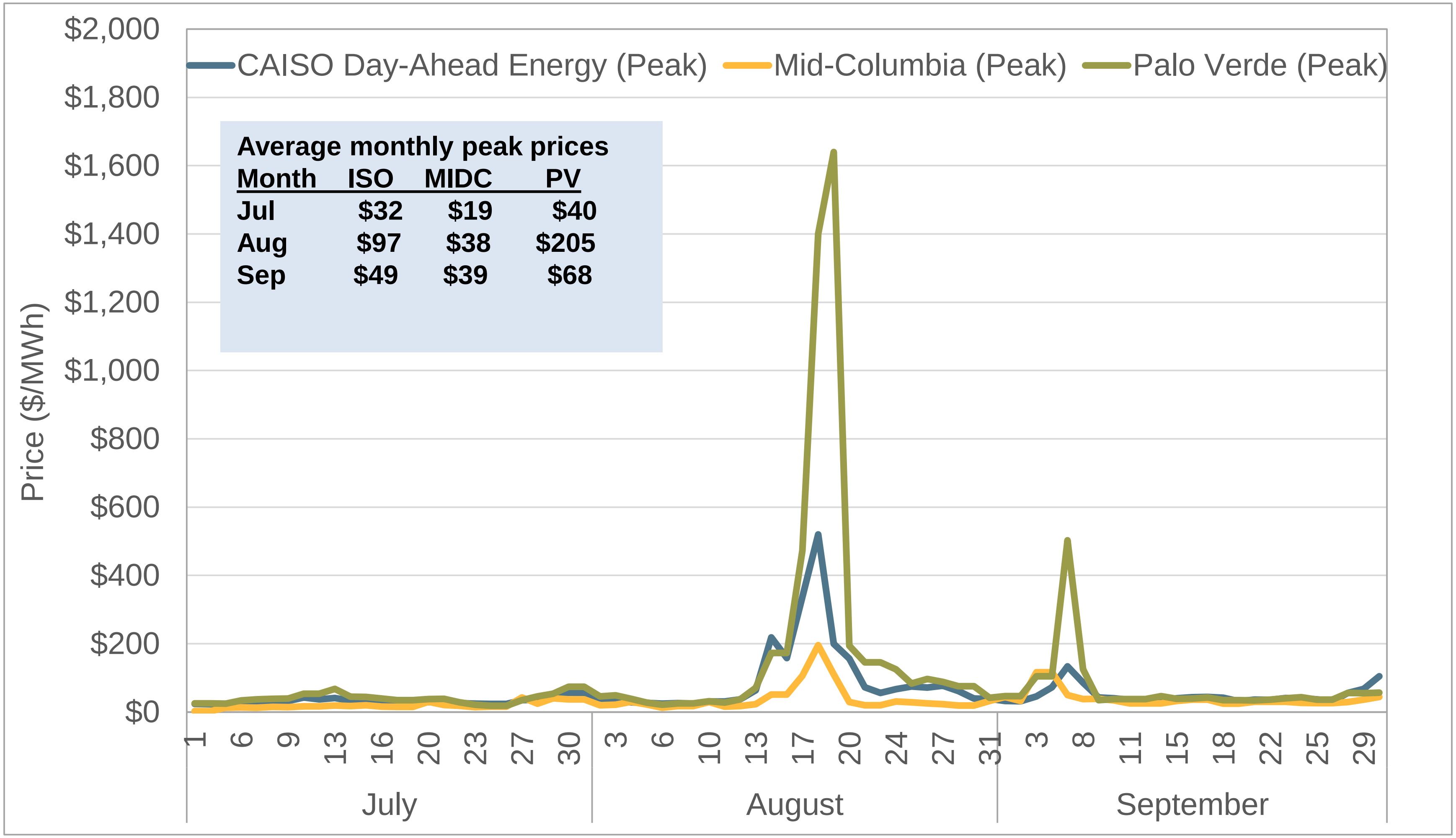
Average, minimum and maximum hourly net load (2018-2020)



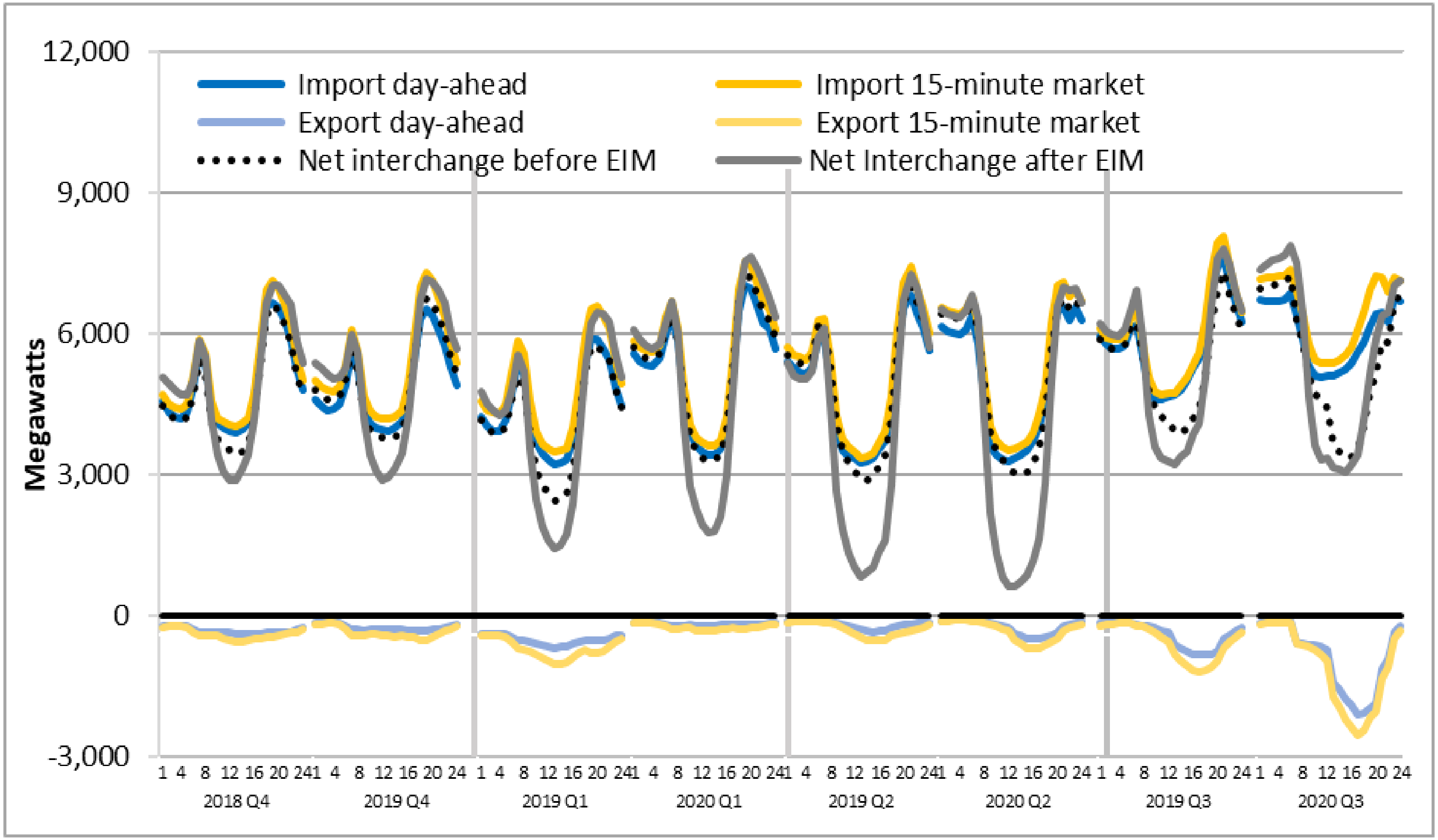
Generation outages increase relative to prior years



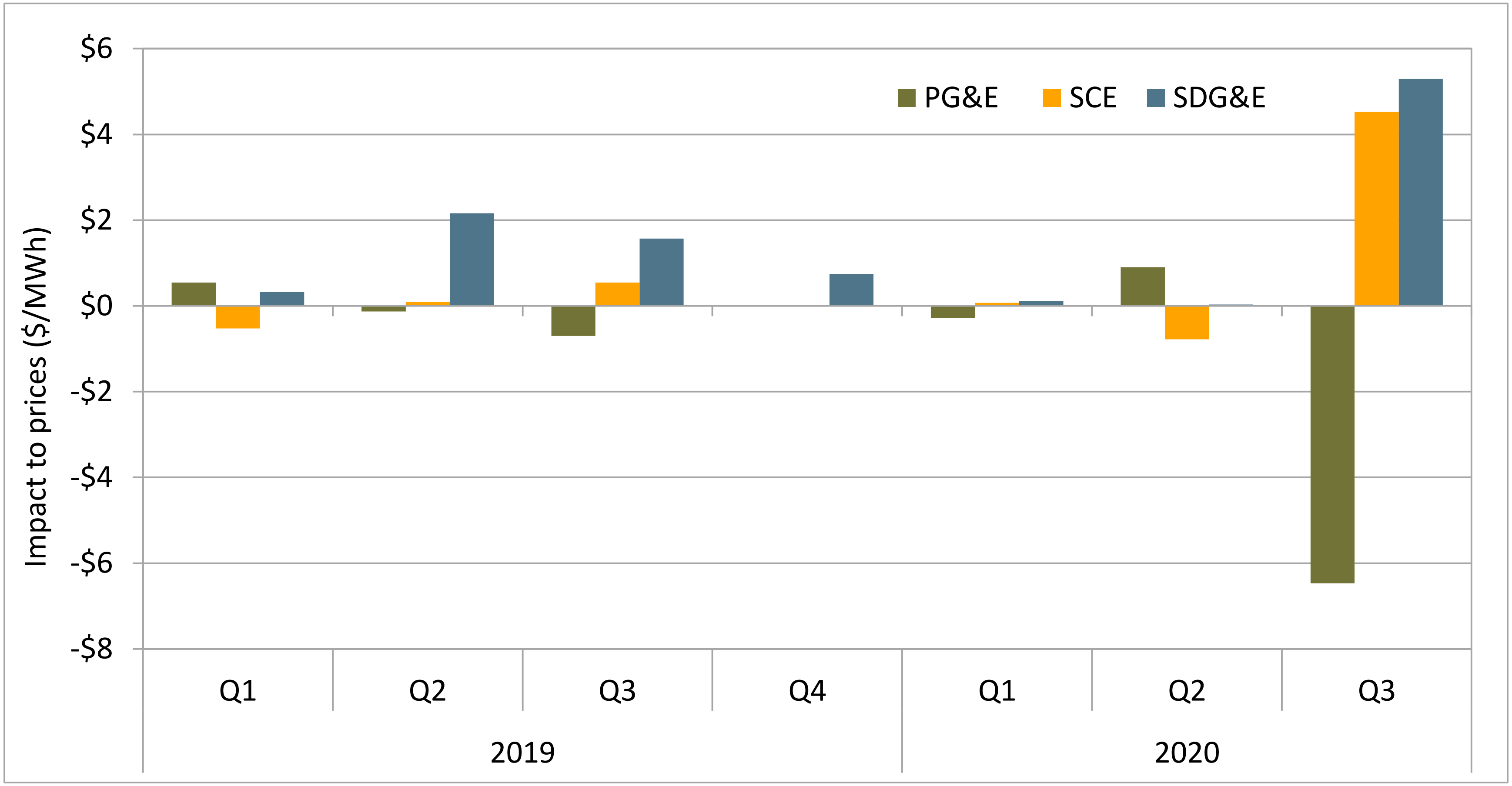
Day-ahead ISO and bilateral market prices (Jul – Sep)



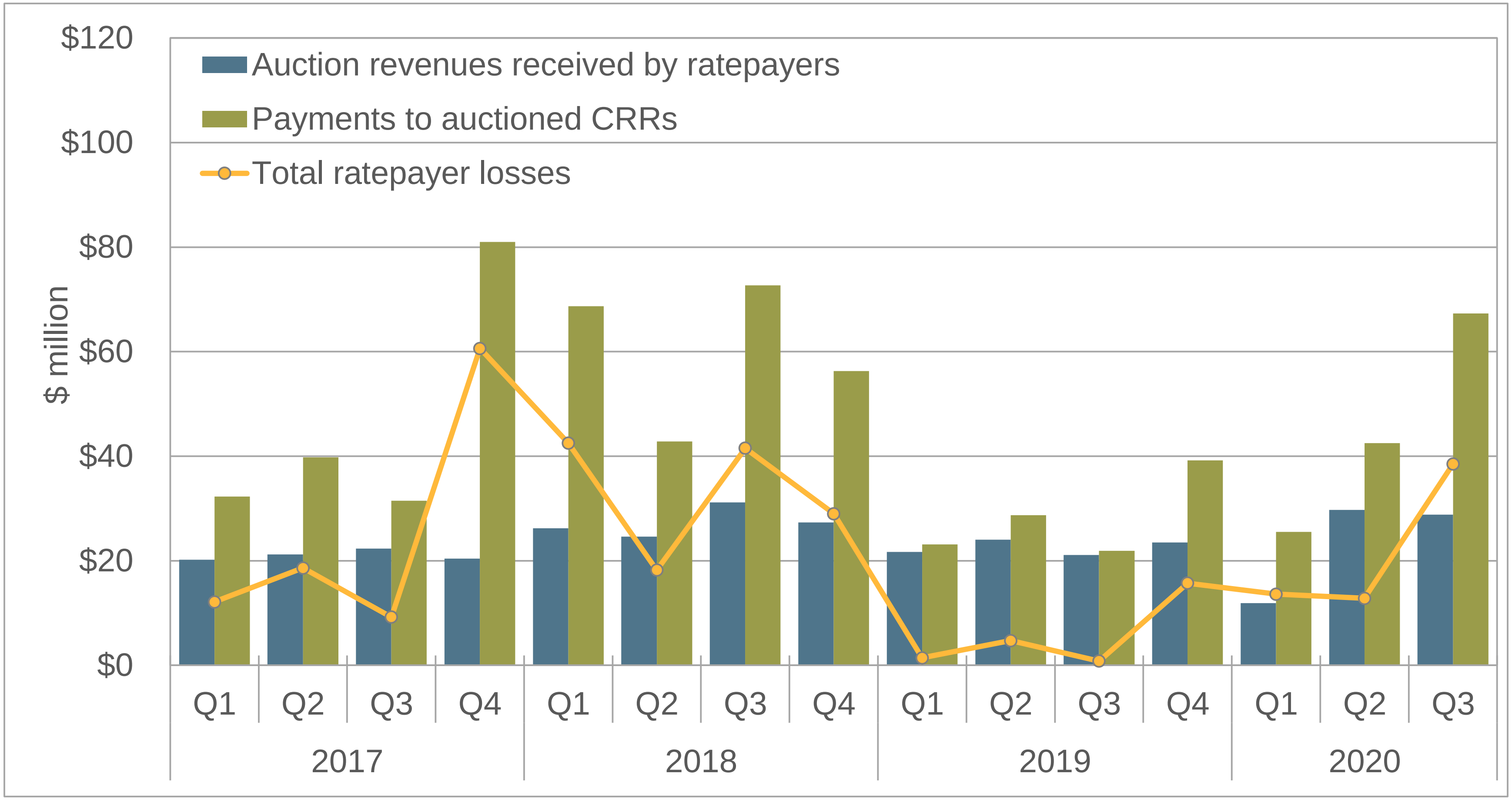
Average hourly net interchange by quarter



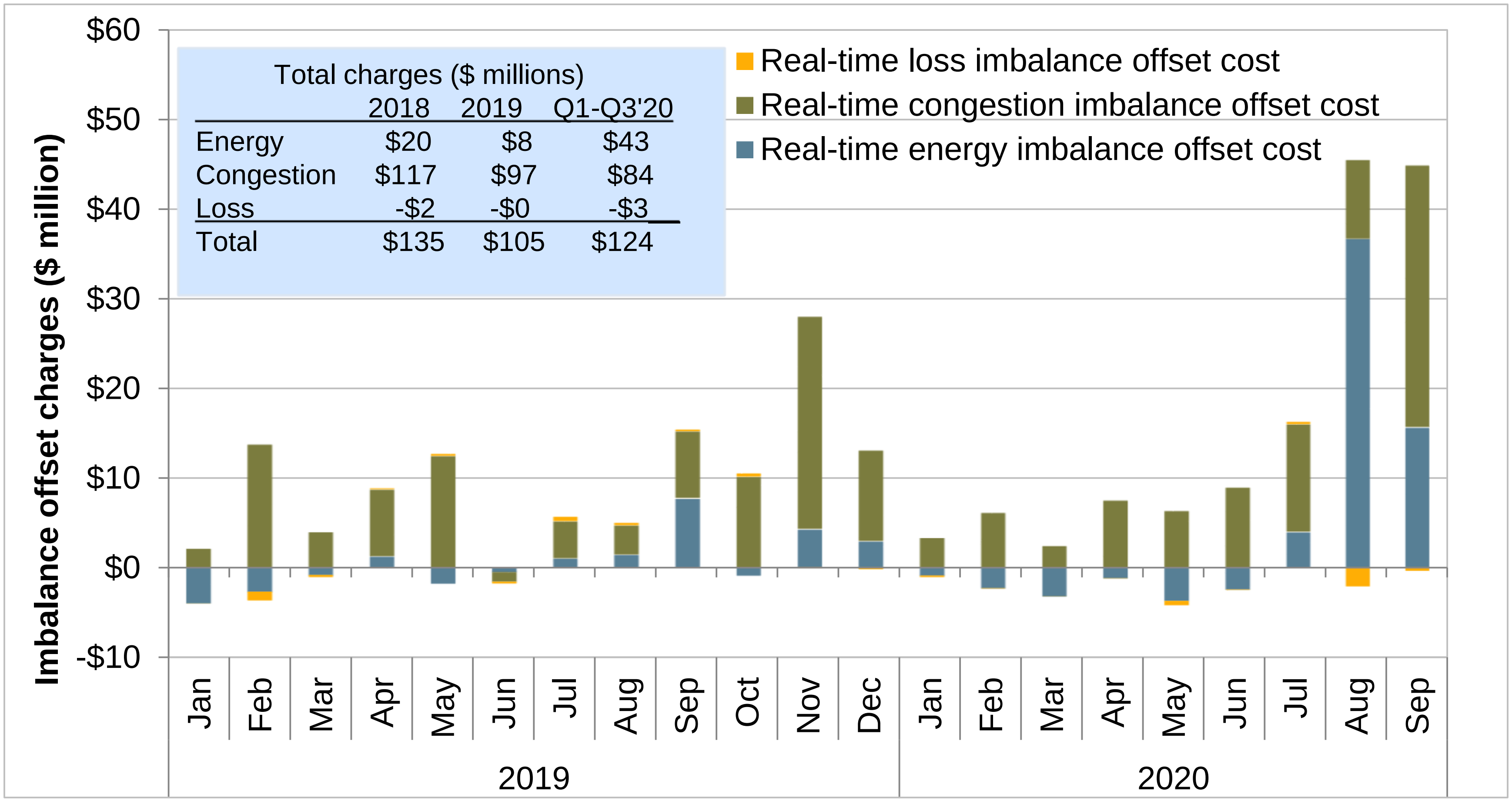
Congestion increased in the third quarter. The $220 million day-ahead congestion rent was more than double the third quarter of 2019 ($79 million).



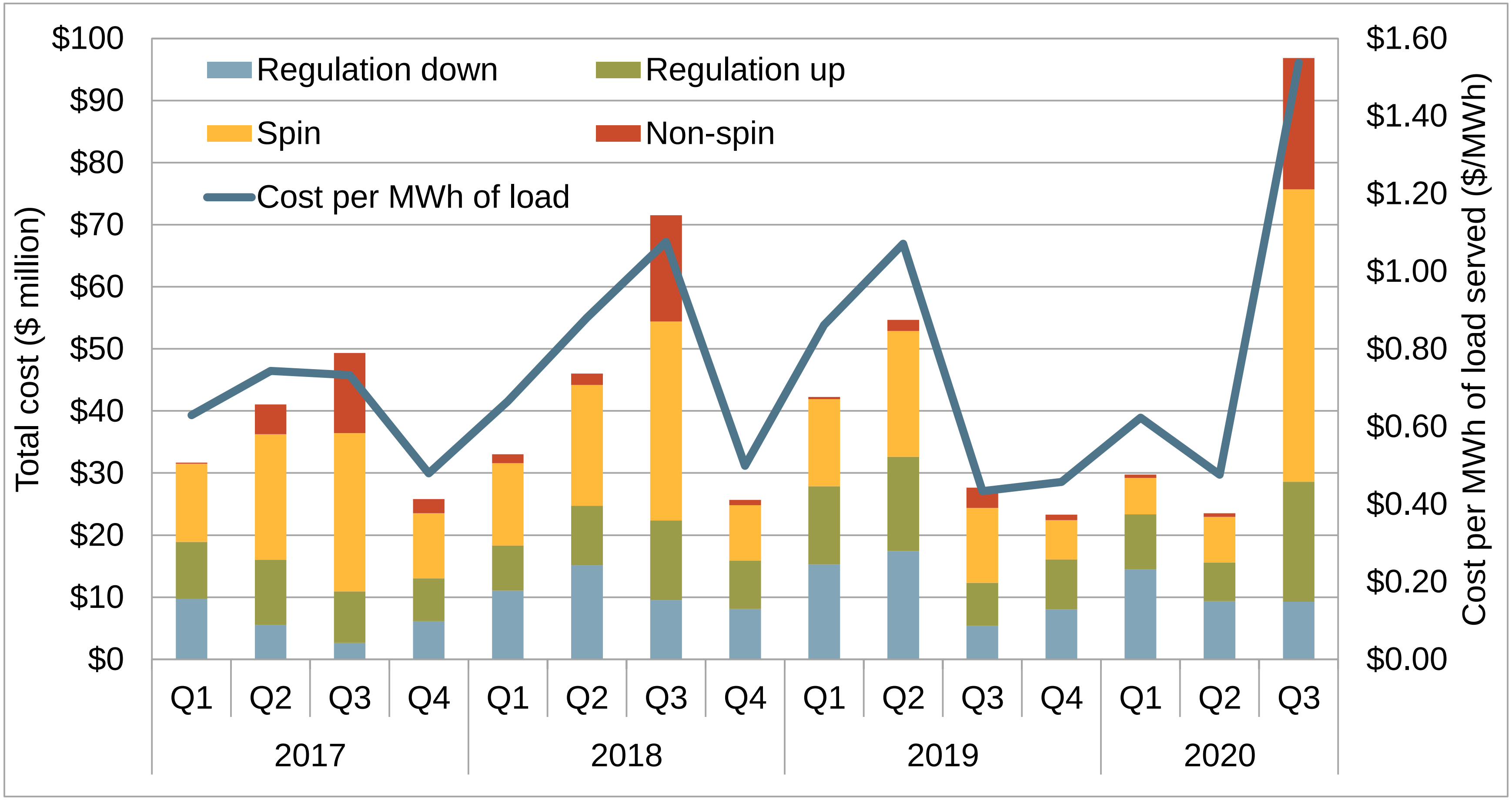
Congestion revenue rights auction revenues were $38 million less than payments made to non-load-serving entities, about 17 percent of day-ahead congestion rent.



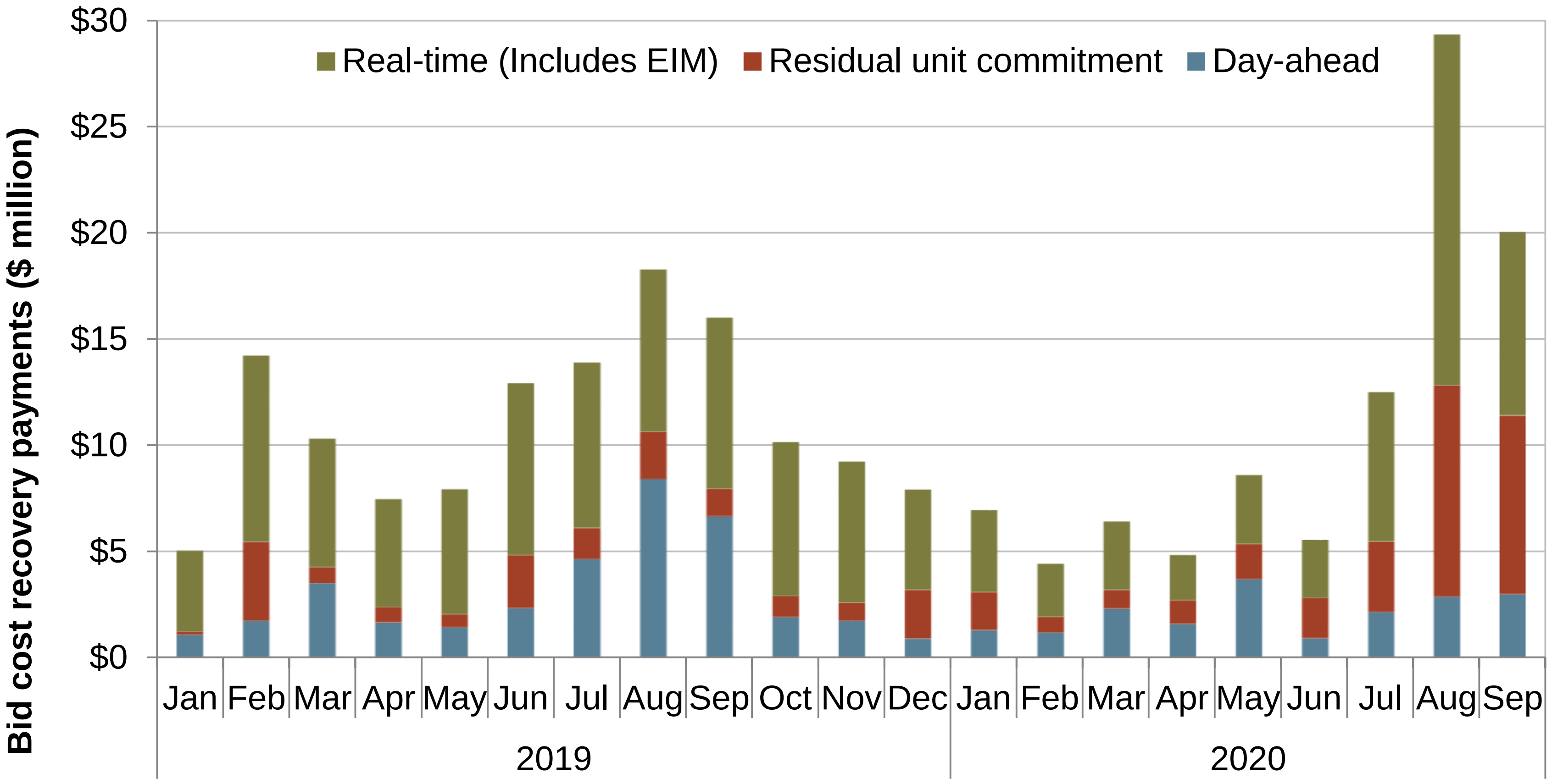
Real-time offset costs increased to $104 million, almost as high as the total offset cost in 2019.



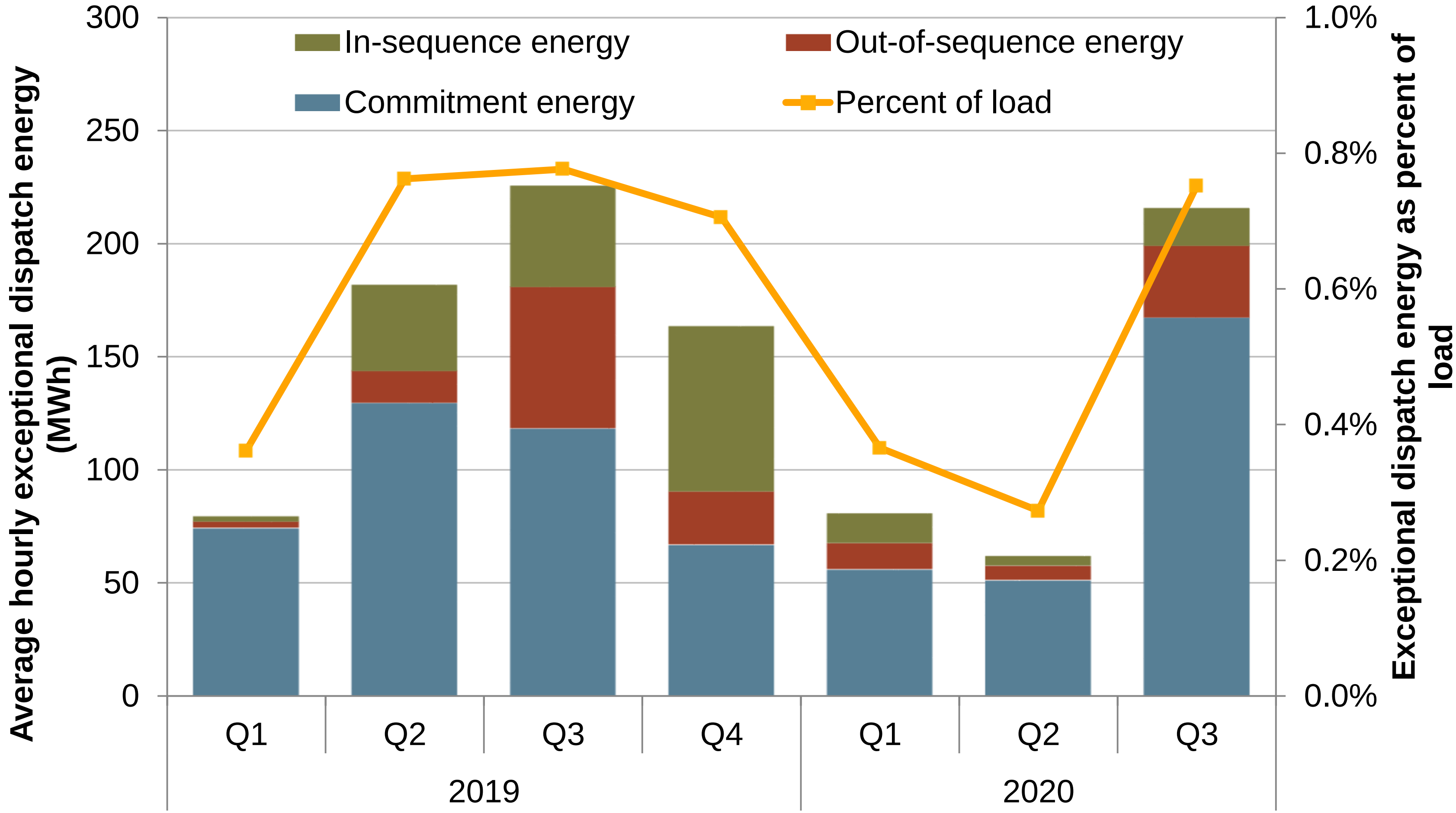
Ancillary service payments increased significantly during the third quarter to about $97 million



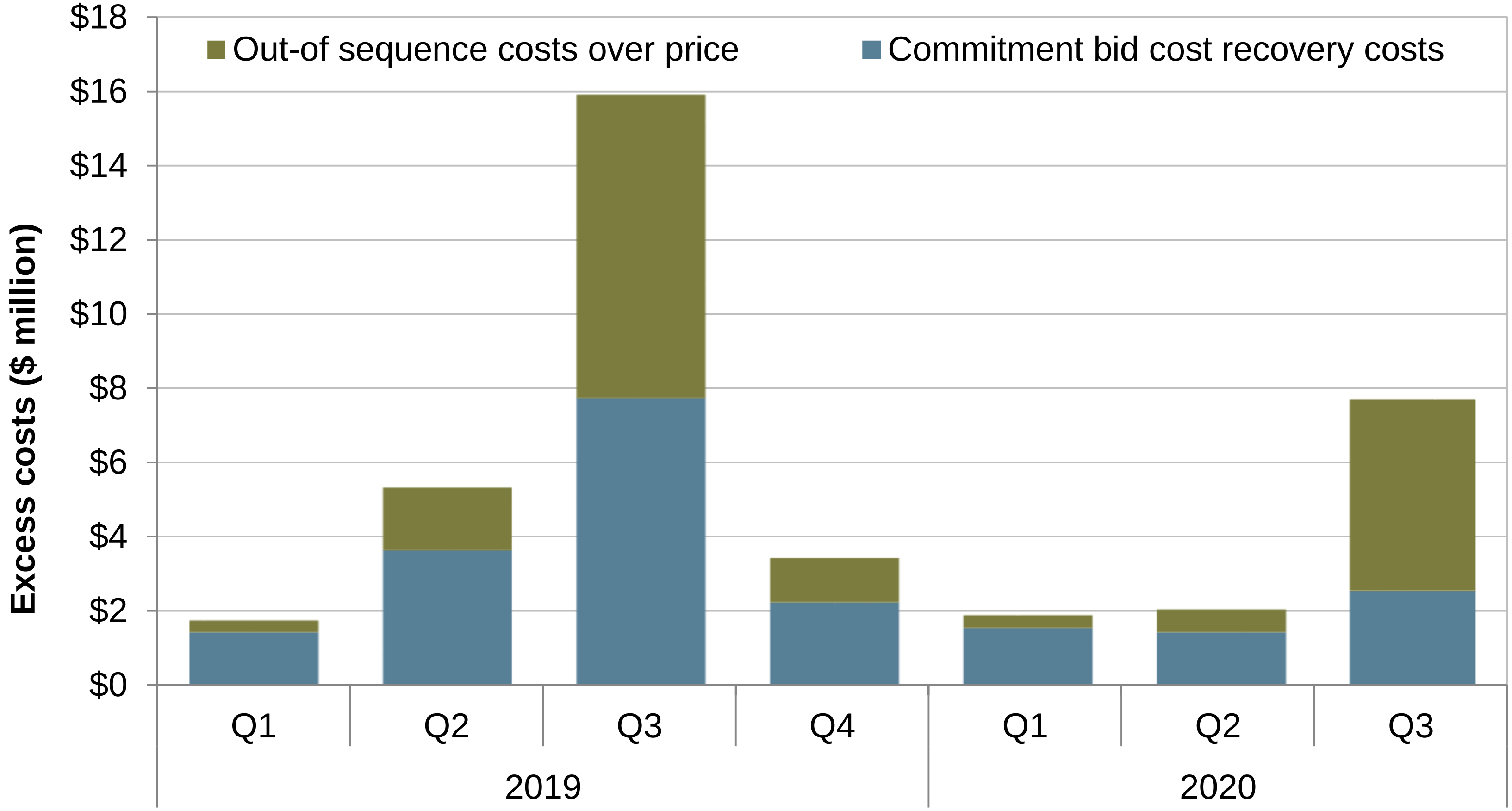
Bid cost recovery payments rose to $62 million, about $14 million more than the third quarter of 2019.



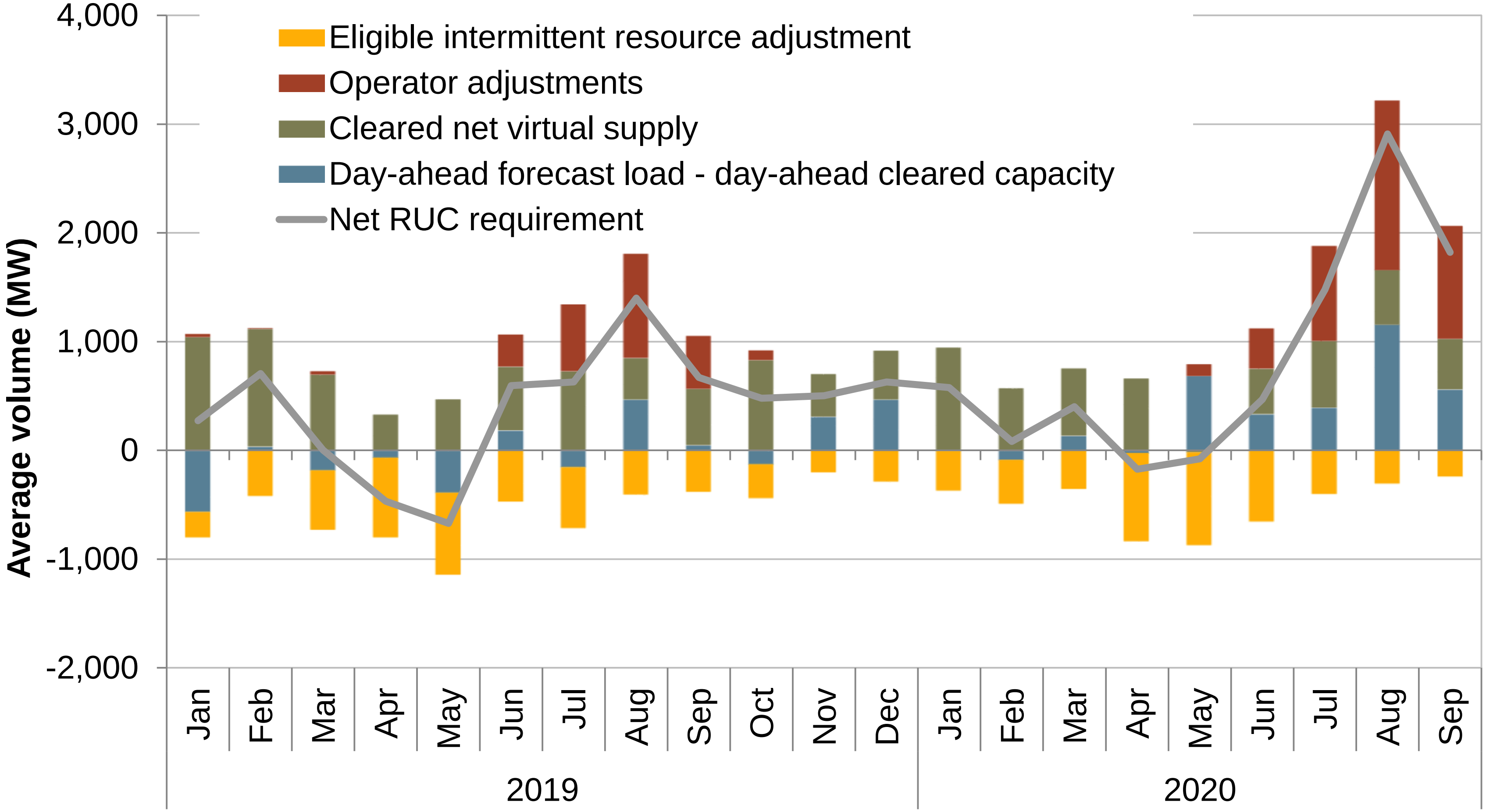
Average hourly energy from exceptional dispatch



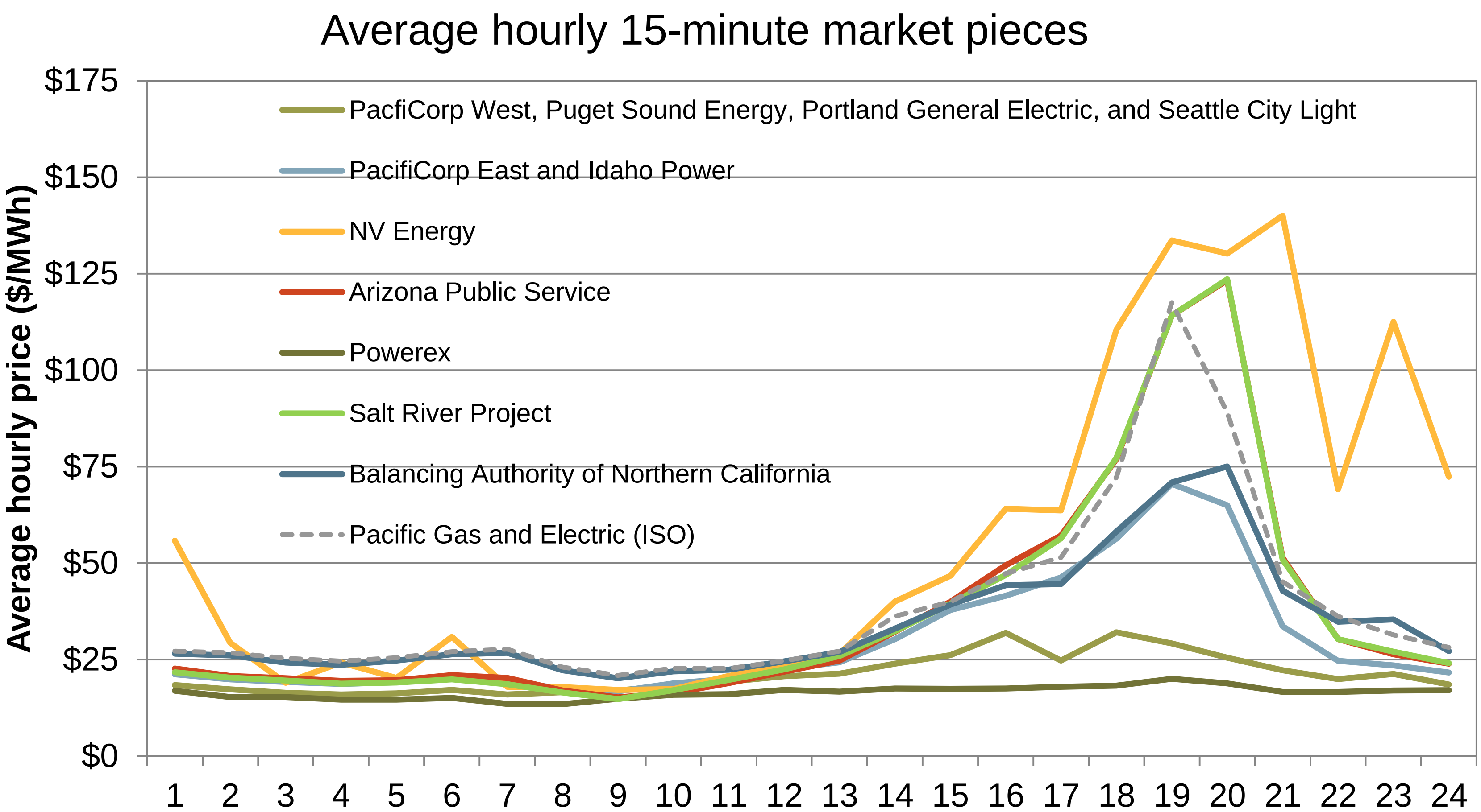
Above market exceptional dispatch costs total $7.5 million



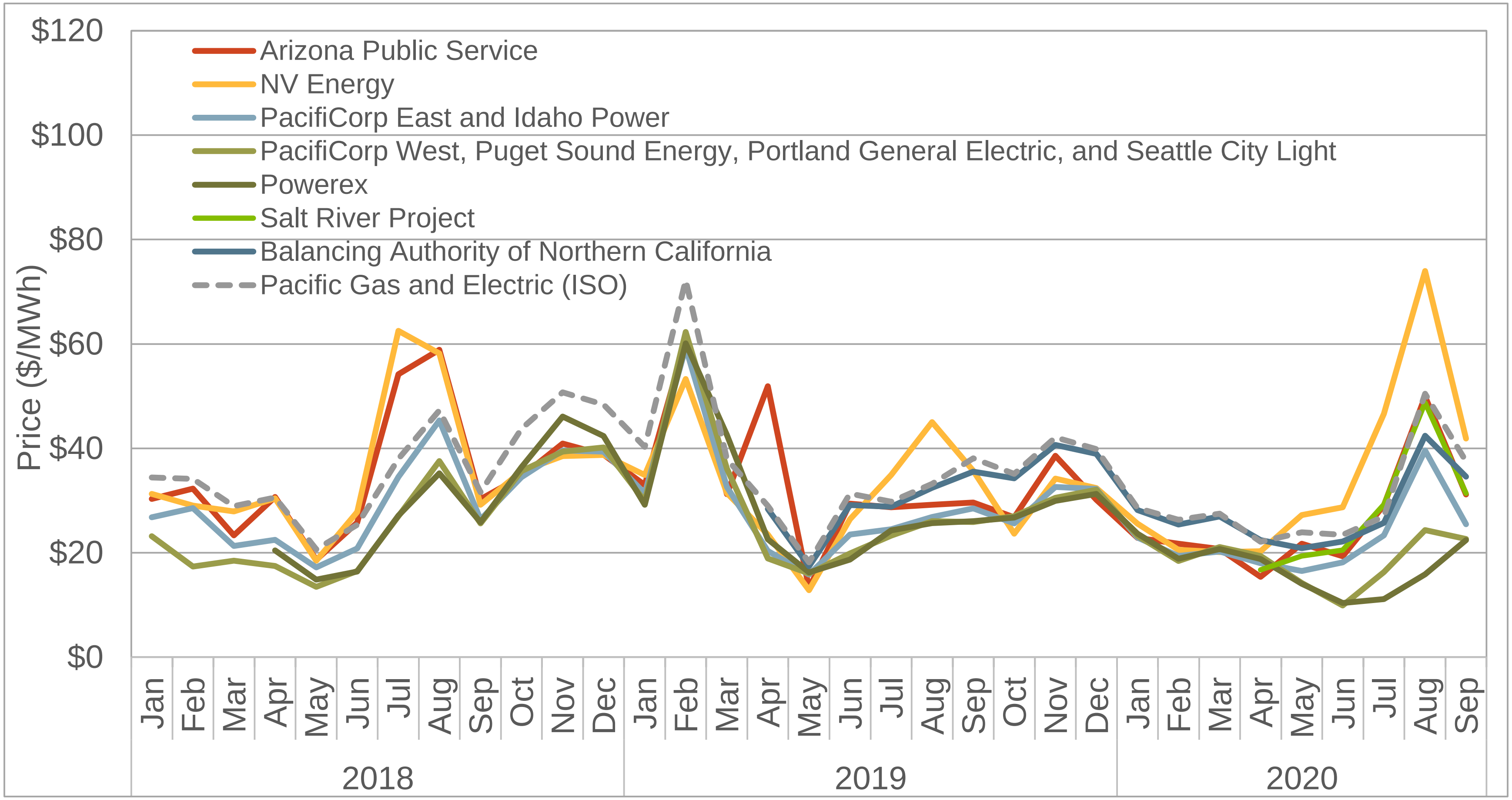
Operator adjustment a growing determinant of residual unit commitment procurement



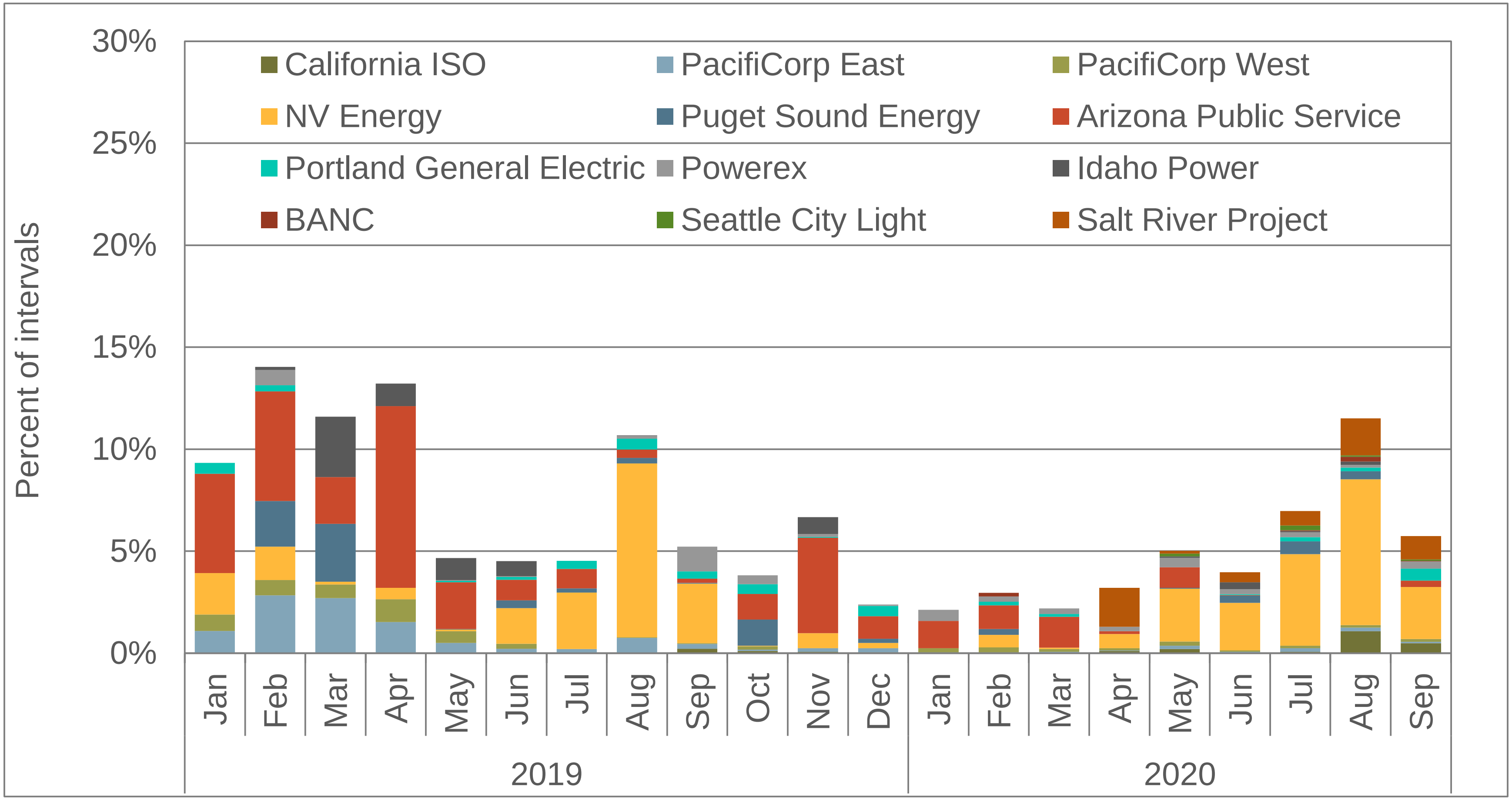
Peak prices in southwest (NV Energy, Arizona Public Service, and Salt River Project) exceeded the rest of the system



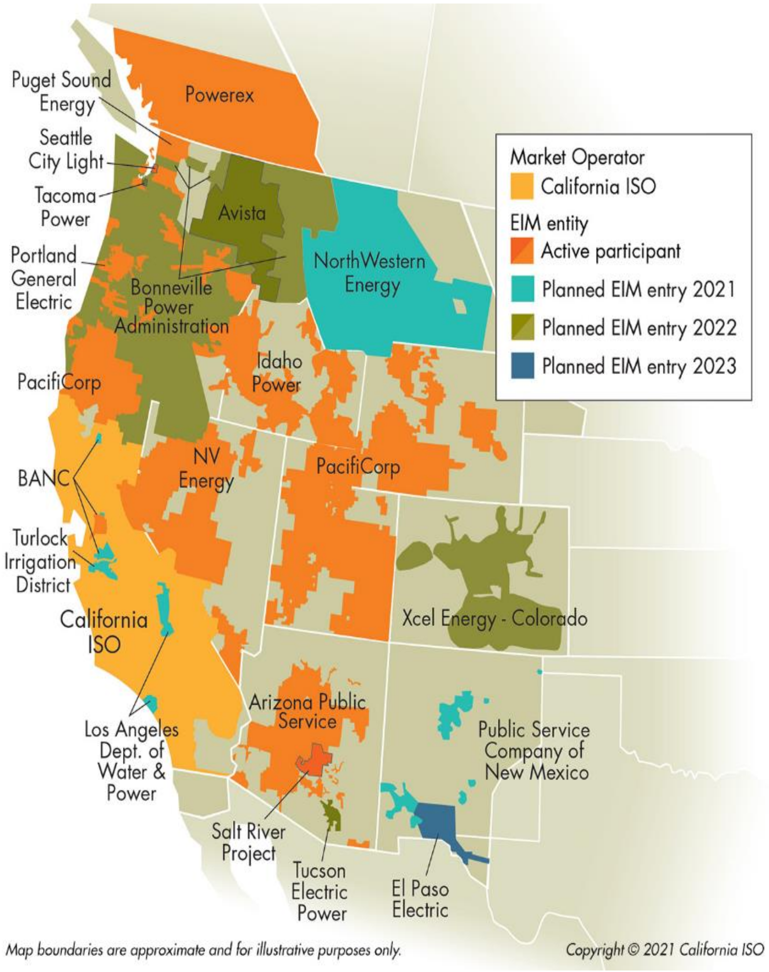
Peak prices in southwest (NV Energy, Arizona Public Service, and Salt River Project) exceeded the rest of the system



Frequency of upward failed sufficiency tests by month



Energy imbalance market transfer limits



	15-minute market		5-minute market	
	Congestion Frequency	Price Impact ($/MWh)	Congestion Frequency	Price Impact ($/MWh)
BANC	1%	-$2.89	1%	-$0.30
Arizona Public Service	2%	-$2.33	2%	$0.50
NV Energy	6%	$15.06	5%	$21.70
Idaho Power	7%	-$3.97	4%	-$0.73
PacifiCorp East	7%	-$3.98	4%	-$0.19
Salt River Project	10%	-$2.40	9%	-$0.41
PacifiCorp West	38%	-$9.18	25%	-$4.07
Seattle City Light	43%	-$9.66	32%	-$4.82
Puget Sound Energy	43%	-$9.08	32%	-$3.94
Portland General Electric	50%	-$9.08	35%	-$3.58
Powerex	61%	-$13.88	52%	-$8.69

Average 15-minute market energy imbalance market limits (July – September)

From Balancing Authority Area	To Balancing Authority Area: CISO	BANC	NEVP	AZPS	SRP	PACE	IPCO	PACW	PGE	PSEI	SCL	PWRX	*Total export limit*
California ISO		1,310	3,370	860	1,480			0	20	0		100	7,140
BANC	1,310												1,310
NV Energy	3,850			330		840	590						5,610
Arizona Public Service	2,230		240		7,880	710							11,060
Salt River Project	2,660			4,900		0							7,560
PacifiCorp East			630	440	0		1,250	220					2,540
Idaho Power			530			2,050		490		40	30		3,140
PacifiCorp West	130					480	450		280	300	20		1,660
Portland GE	30							300		0	20		350
Puget Sound Energy	0						0	300	0		350	150	800
Seattle City Light							30	30	30	360			450
Powerex	0									230			230
Total import limit	10,210	1,310	4,770	6,530	9,360	4,080	2,320	1,340	330	930	420	250	

Special issues covered in Q3 market report

- Load curtailment event
- Load under-scheduling
- Hourly block import compensation
- Resource adequacy showings and performance
- System market power
  - Structural competitiveness
  - Bidding behavior
  - Market power had very limited effect on system prices

Key findings 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 net imports into CAISO.
- **Residual unit commitment (RUC) process and related real-time bid processing design**. Detailed discussion of this to follow.

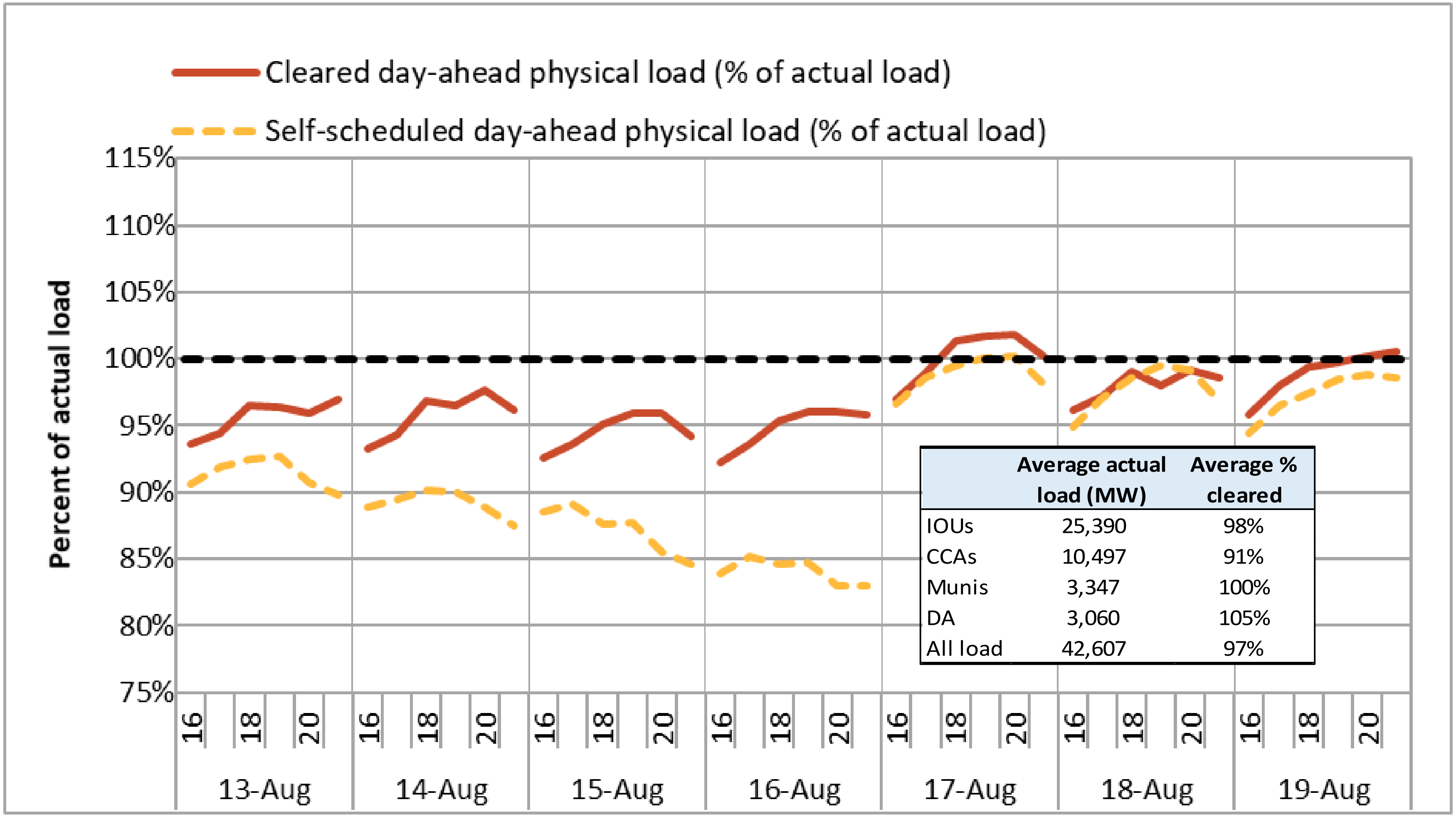
Additional findings

- The Western energy imbalance market functioned well and helped facilitate transfers of available capacity in real-time across the west.
- DMM has carefully reviewed major outages which occurred on August 14-15 – and found no indication of false outages/manipulation.
- Contrary to some suggestions in the media, DMM has found no evidence that market results on these days were the result of market manipulation.

DMM Recommendations

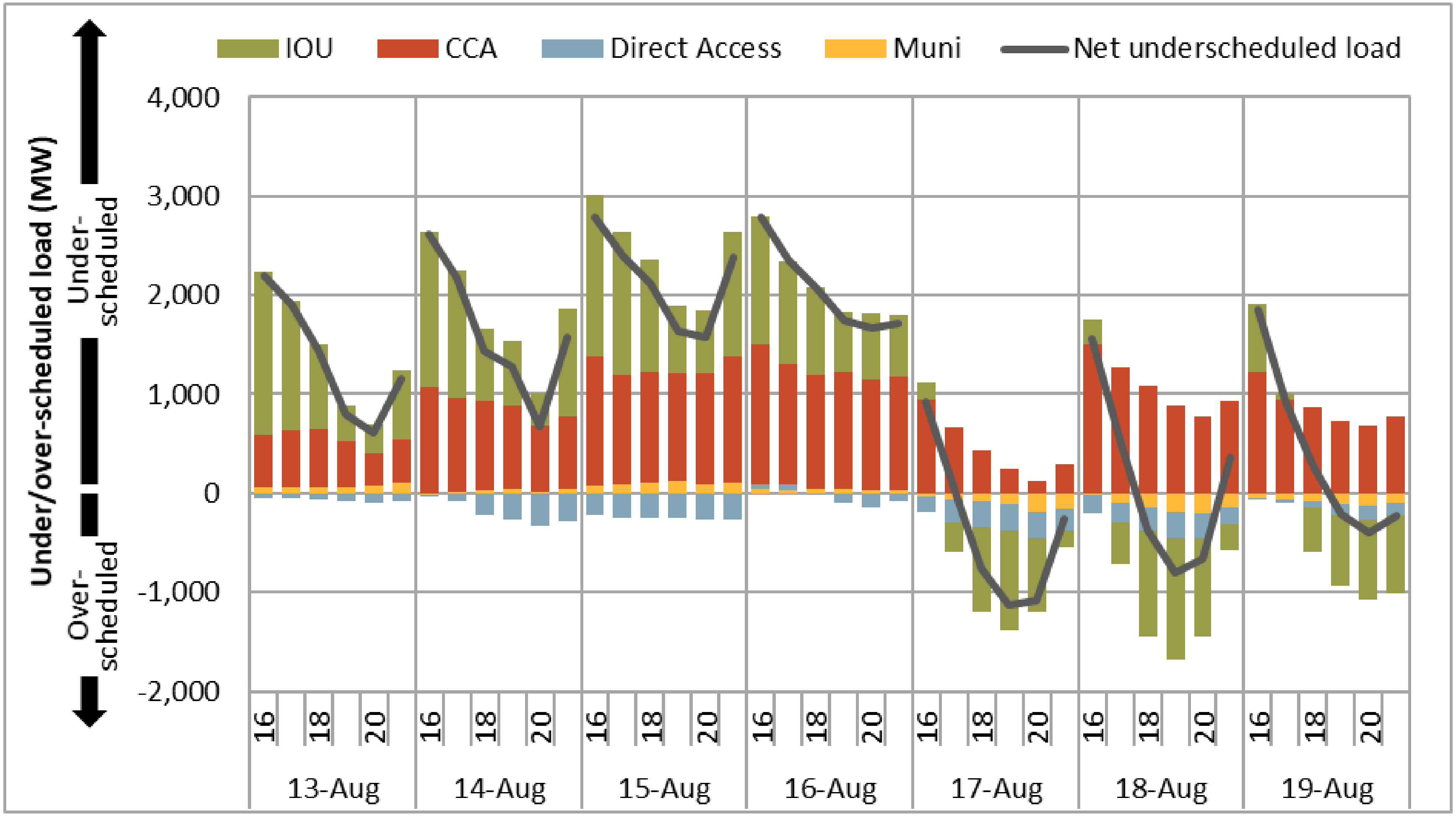
- **Resource adequacy:** Place high priority on key recommendations in CAISO/CPUC/CEC report:
  - Increase resource adequacy requirements to more accurately reflect risk of extreme weather events.
  - Continue to work with stakeholders to clarify and revise the counting rules for resource adequacy capacity.
- **Exports/imports**: Further changes and clarifications in the rules and processes for limiting/curtailing exports should be discussed and pursued by CAISO in conjunction with other balancing areas.
- **Demand Response:** Ensure a higher portion of demand response used to meet resource adequacy requirements is available during critical net load hours.

Self-scheduled, bid-in, or cleared load as a percent of actual load *(all load)*

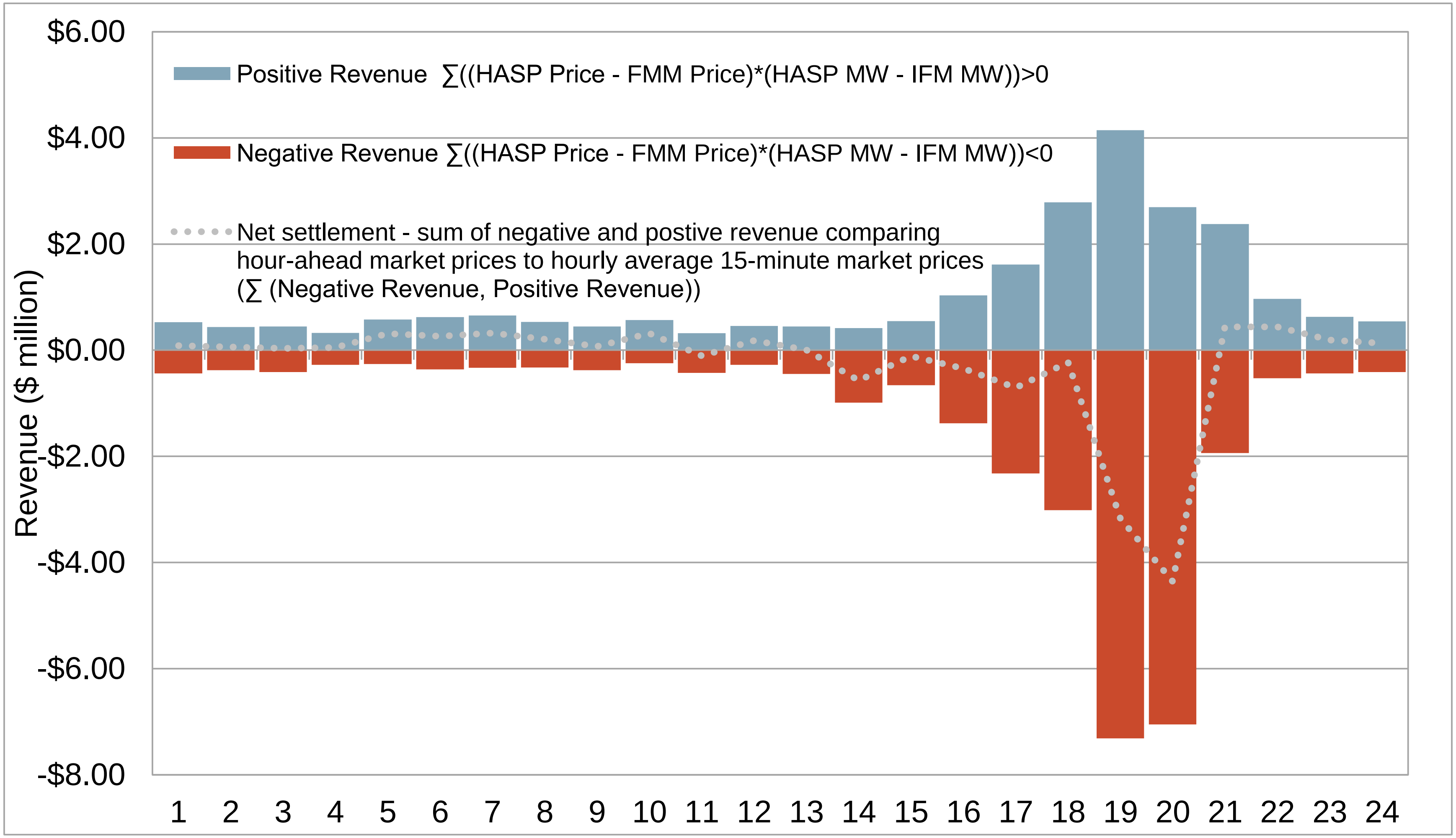


	Average actual load (MW)	Average % cleared
IOUs	25,390	98%
CCAs	10,497	91%
Munis	3,347	100%
DA	3,060	105%
All load	42,607	97%

Under-scheduled load by entity type



2020 Q3 intertie hour-ahead versus 15-minute compensation ($ million)



Overall resource adequacy availability was not unusually low during hours of load curtailments

Resource type	Date	Hour ending	Total resource adequacy capacity (MW)	Day-ahead market				Real-time market		
				Adjusted for outages		Bids and self-schedules		Bids and self-schedules		Bids and self-schedules below cap
				MW	% of total RA Cap.	MW	% of total RA Cap.	MW	% of total RA Cap.	MW
Total	8/14/2020	19	51,373	49,313	96%	45,889	89%	45,003	88%	6,370
		20	51,373	49,373	96%	44,090	86%	43,128	84%	8,245
	8/15/2020	19	51,333	48,894	95%	45,044	88%	45,221	88%	6,112
		20	51,333	48,955	95%	43,365	84%	43,879	85%	7,454

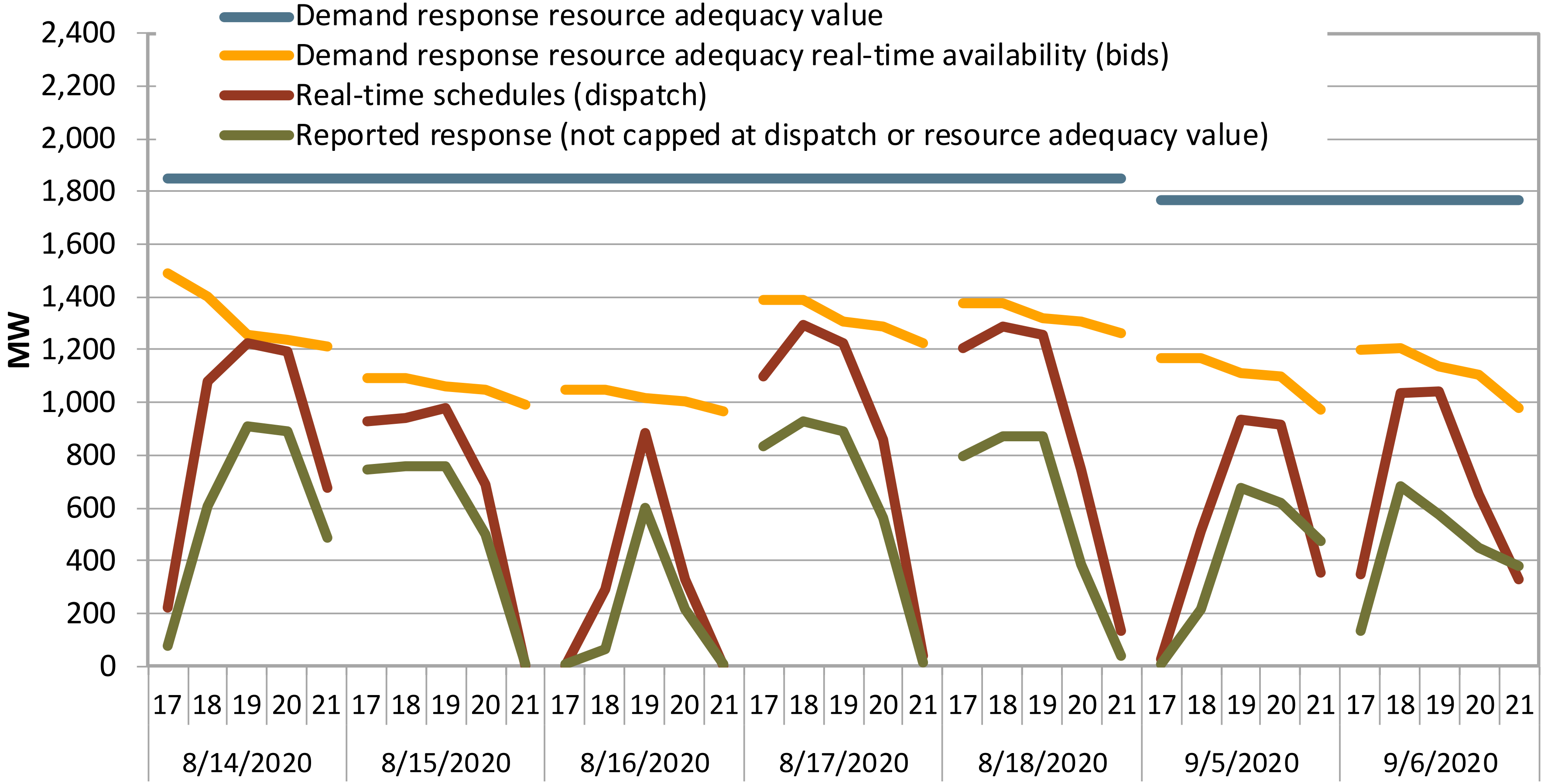
Availability = Total MW self-scheduled and/or bid
into CASO day-ahead and real-time market.

Source: DMM Report, Table 3-1, p. 27

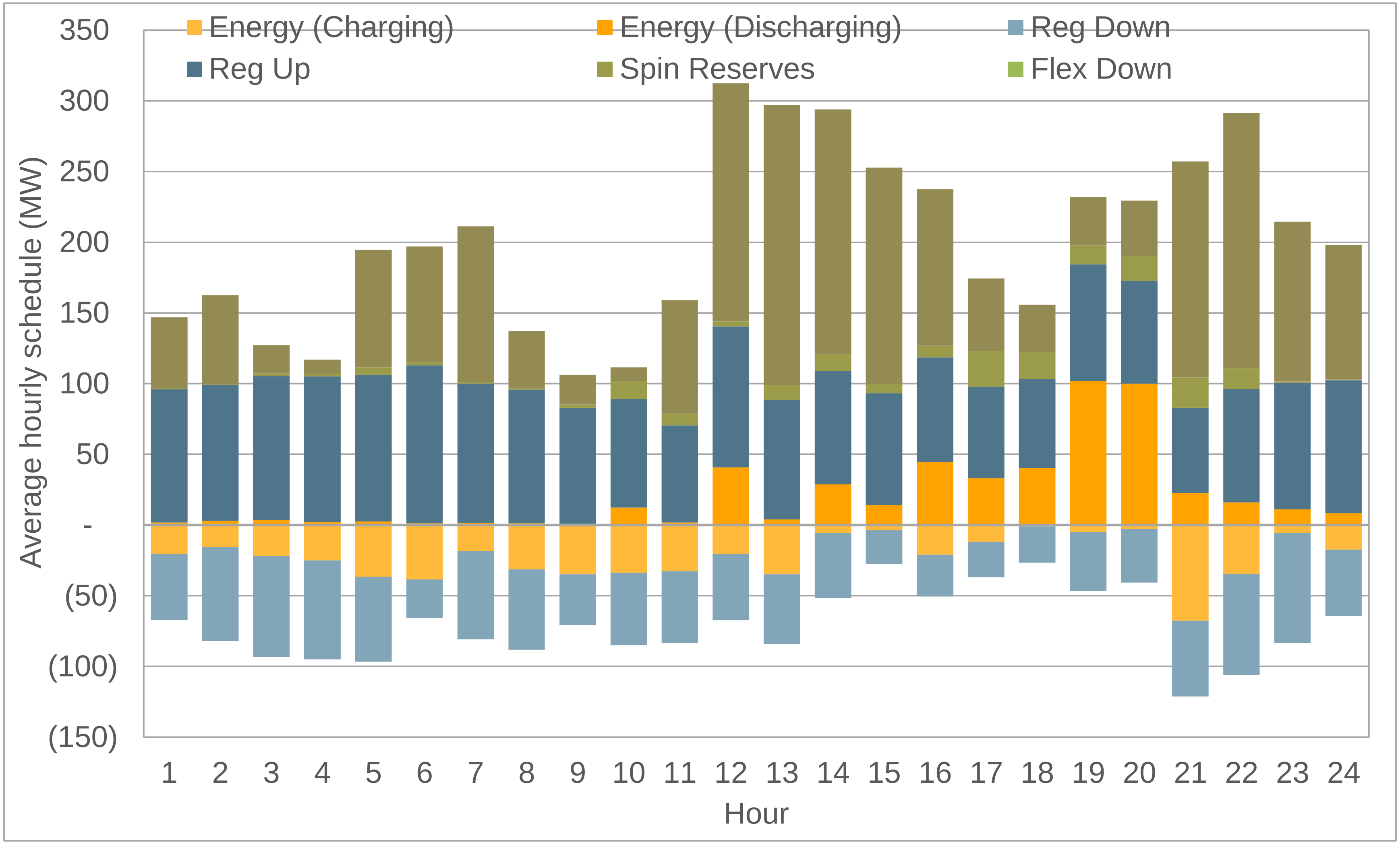
Overall resource adequacy availability was not unusually low during highest load hours of Q3, similar to 2019

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	19,659	18,572	94%	18,571	94%	18,190	93%	18,157	92%
Other generators	1,441	1,361	94%	1,361	94%	1,350	94%	1,350	94%
Subtotal	**21,100**	**19,933**	**94%**	**19,932**	**94%**	**19,540**	**93%**	**19,507**	**92%**
Other:									
Imports	4,475	4,437	99%	4,135	92%	4,463	100%	3,783	85%
Imports - MSS	331	331	100%	109	33%	331	100%	119	36%
Use-limited gas units	8,206	7,923	97%	7,890	96%	7,788	95%	7,729	94%
Hydro generators	6,491	5,836	90%	5,531	85%	5,720	88%	5,422	84%
Nuclear generators	2,818	2,776	99%	2,769	98%	2,776	99%	2,769	98%
Solar generators	2,937	2,923	100%	2,034	69%	2,907	99%	2,043	70%
Wind generators	1,191	1,177	99%	802	67%	1,174	99%	786	66%
Qualifying facilities	984	973	99%	819	83%	964	98%	830	84%
Other non-dispatchable	519	511	98%	471	91%	488	94%	468	90%
Subtotal	**27,952**	**26,887**	**96%**	**24,560**	**88%**	**26,611**	**95%**	**23,949**	**86%**
Total	**49,052**	**46,820**	**95%**	**44,492**	**91%**	**46,151**	**94%**	**43,456**	**89%**

Aggregate performance of all demand response (self-reported)

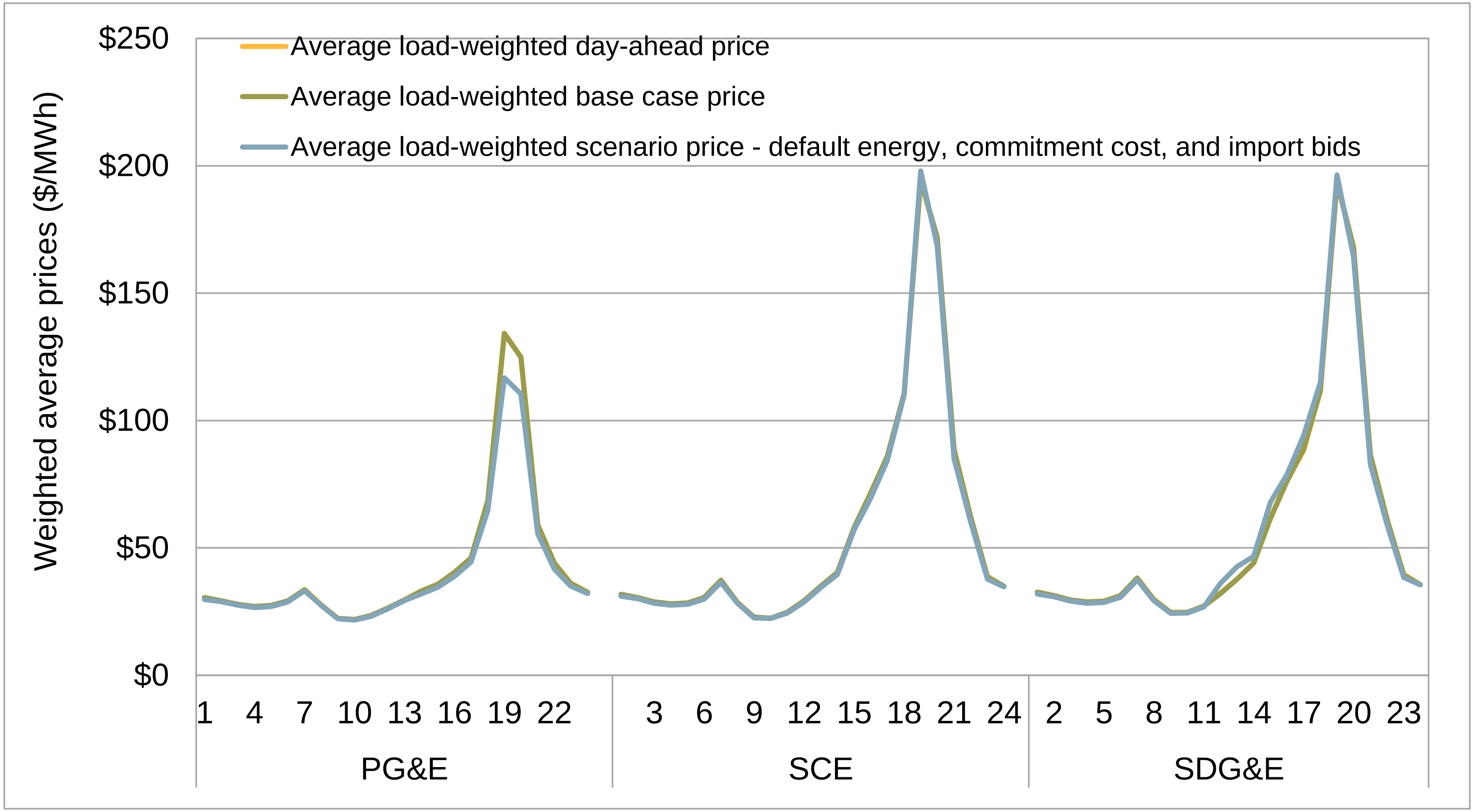


Average real-time battery schedules (August 14-18)

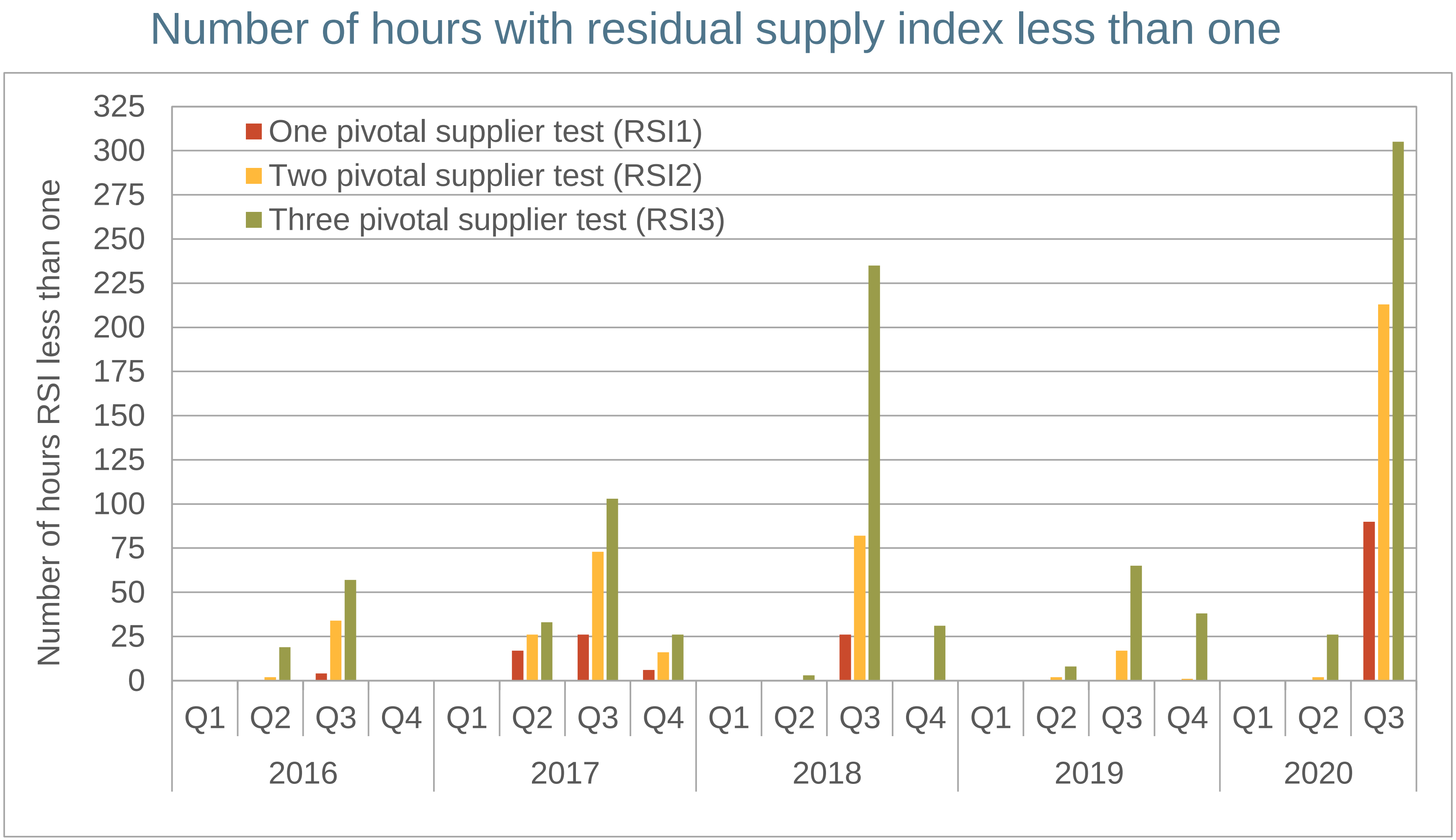


Although market was structurally uncompetitive many hours, overall market results were competitive in the third quarter.

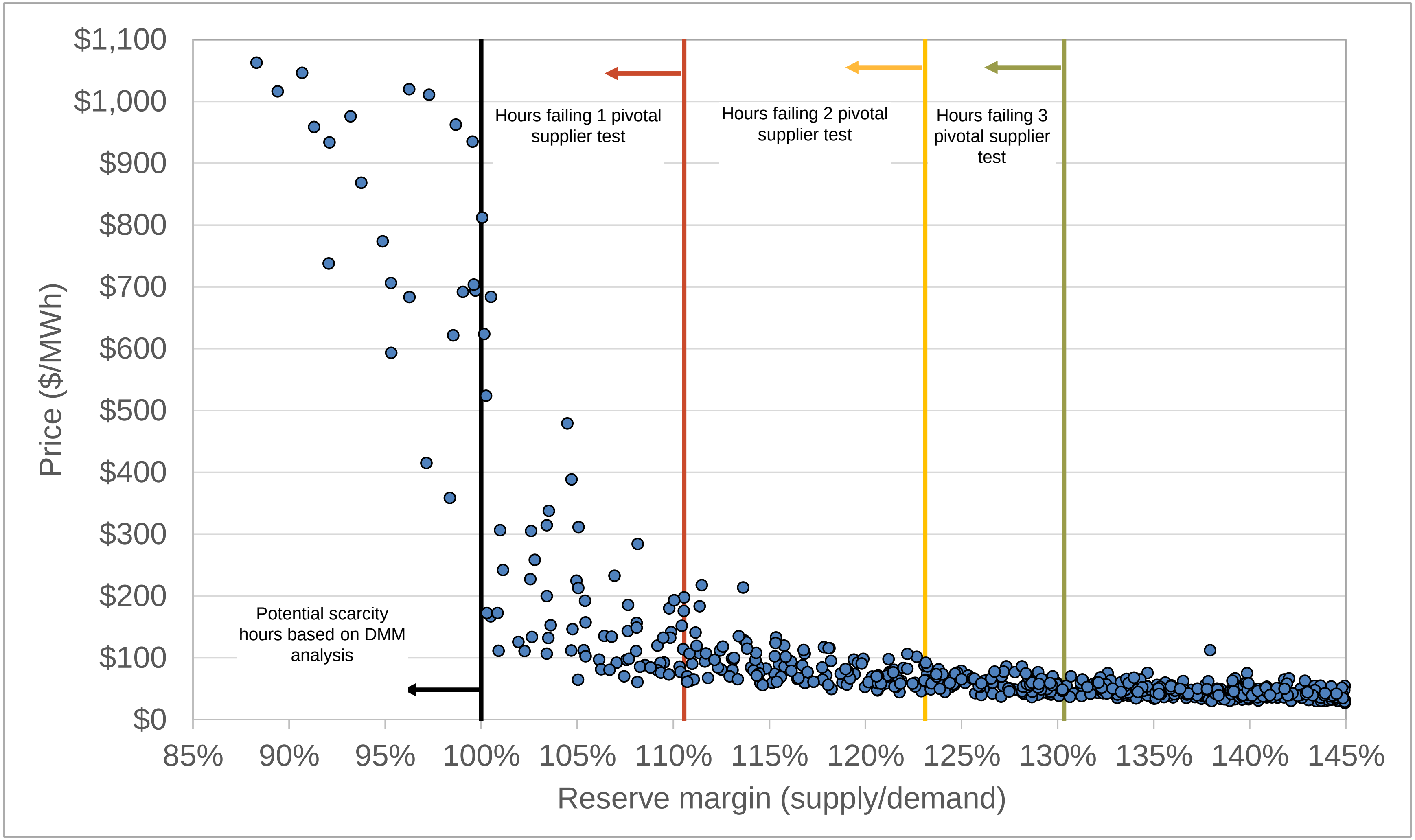
Quarterly average price-cost markup was about $1.42/MWh (2.6 percent)



The CAISO market was structurally uncompetitive during the high load days in August



Comparison of potential scarcity and non-competitive hours



Comparison of day-ahead market bids vs marginal costs for gas-fired units (August 18, hour-ending 19)