2020 Q1-Q2 Report on Market Issues and Performance

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http://www.caiso.com/Documents/2020FirstQuarterReportonMarketIssuesandPerformance-Sep112020.pdf
http://www.caiso.com/Documents/2020SecondQuarterReportonMarketIssuesandPerformance-Oct62020.pdf

Highlights of first half of 2020 market performance

- Wholesale energy costs down
  - low gas prices, lower load
- Electricity prices decreased (Q1 to Q2 2020)
- Q2 average day-ahead prices lower than real-time.
- Ancillary service costs increase in Q1 and decrease in Q2
- Bid cost recovery payments low
- Congestion revenue rights losses to ratepayers:
  - 18% congestion rent Q1 ($14 million)
  - 14% congestion rent Q2 ($13 million)
  - 6% congestion rent 2019 ($23 million)
  - 21% congestion rent 2018 ($131 million)
- Imbalance conformance high, exceptional dispatch low

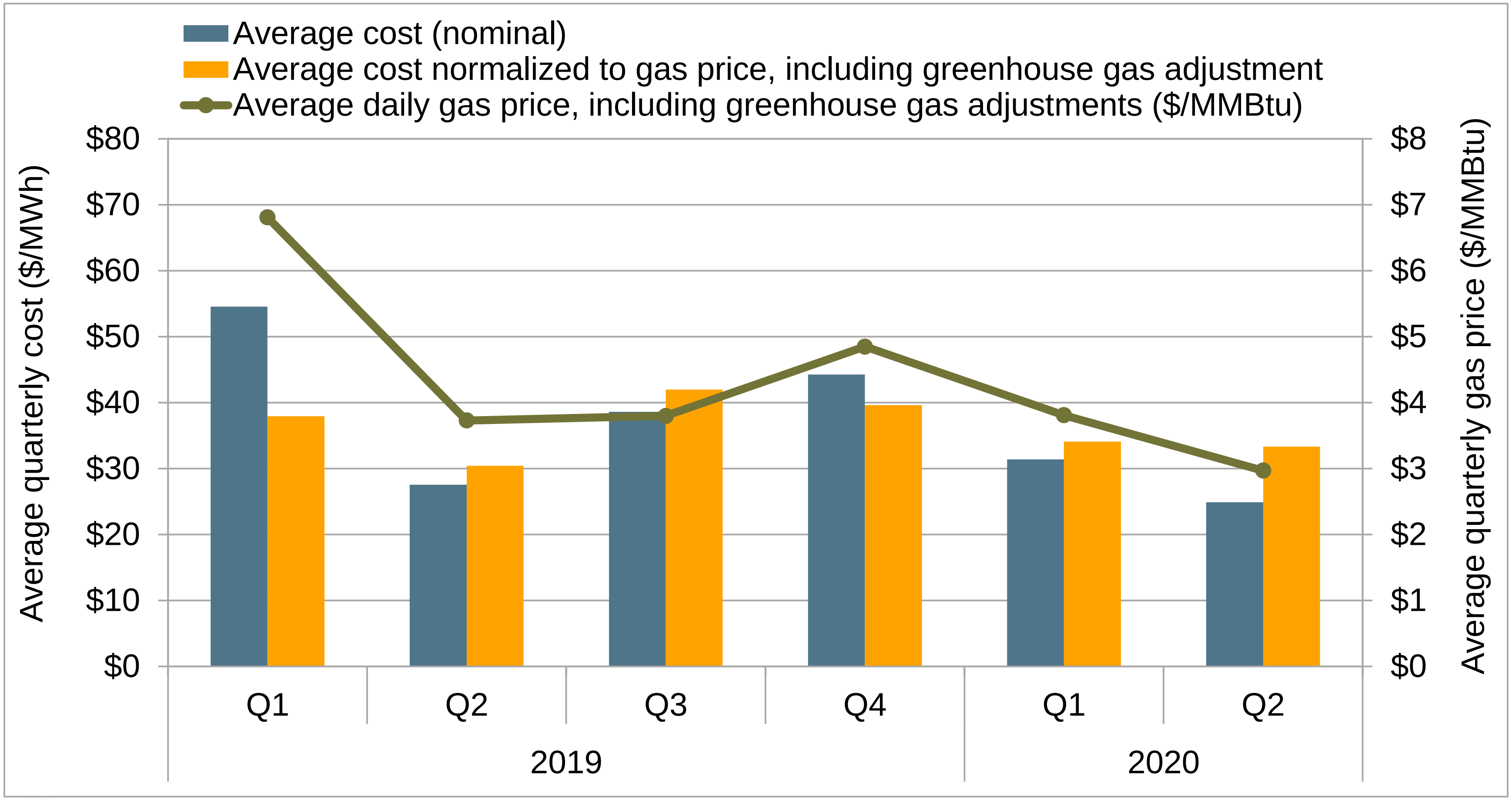
Western energy imbalance market highlights

- New members on April 1, 2020:
  - Seattle City Light
  - Salt River Project
- 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 in Arizona Public Service and NV Energy
- Congestion imbalance offset costs related to base schedules remained low

Special issues covered in Q1-Q2 market report

- COVID-19 estimated impact on day-ahead energy prices
- Downward dispatch of renewable resources
- Day-ahead market software simulation under different scenarios to assess competitiveness

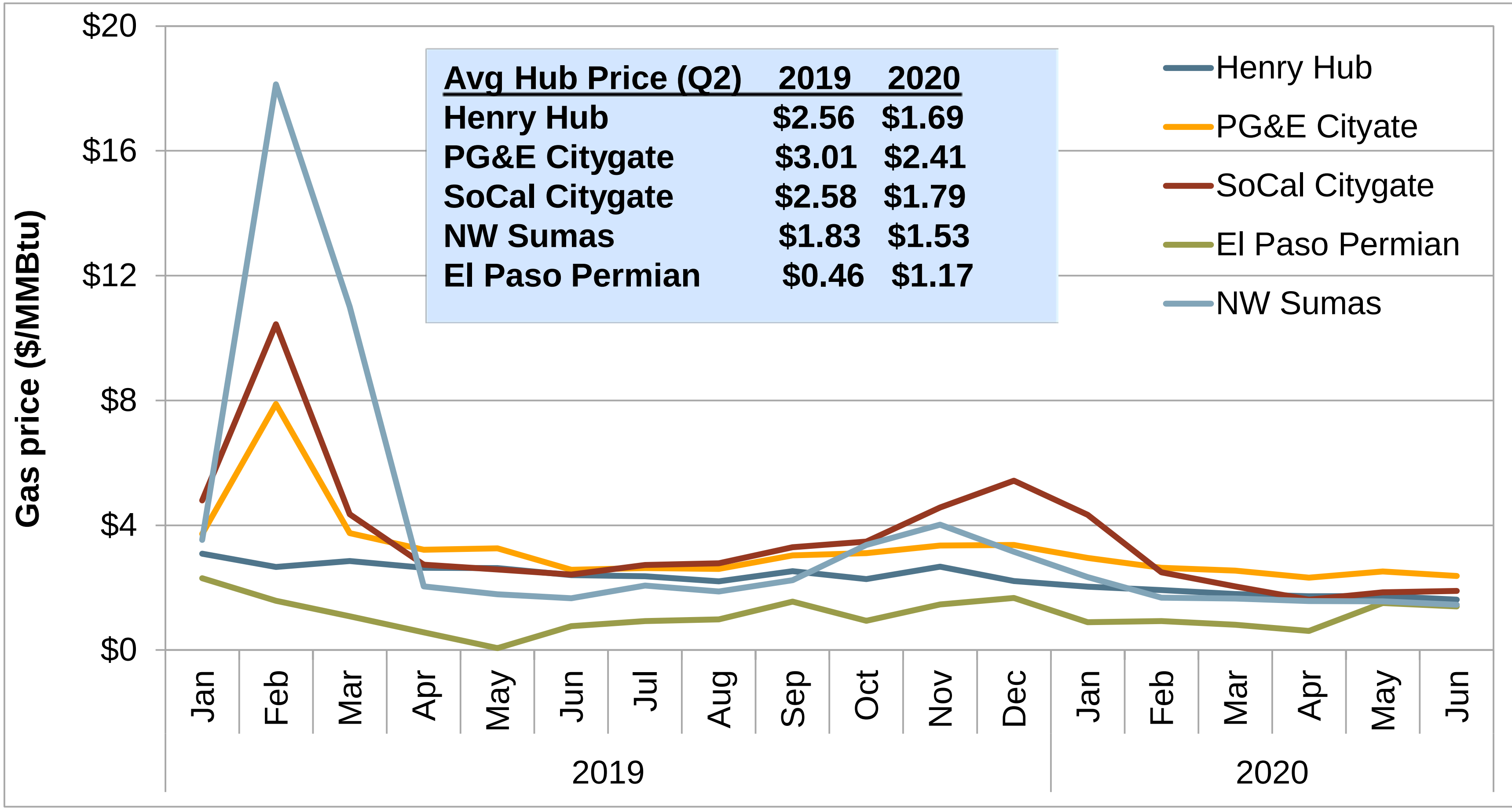
Total CAISO Q2 wholesale costs decreased 14% compared to Q2 2019, driven by lower gas prices and lower load. Renewables down 15%, due to lower hydro.



Q1 CAISO wholesale costs totaled $1.5 billion or about $31/MWh
Q2 CAISO wholesale costs totaled $1.2 billion or about $25/MWh

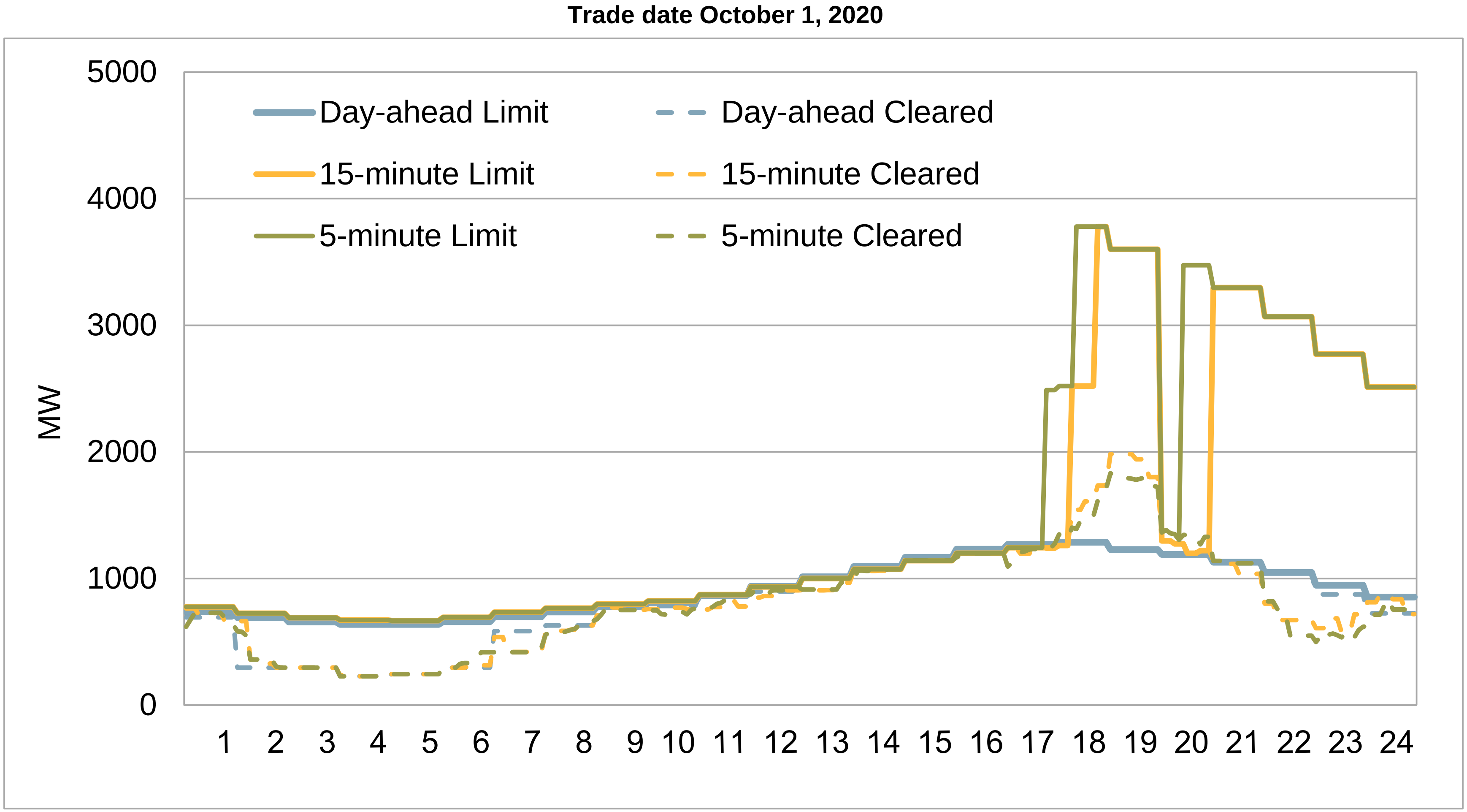
	Q1 2019	Q2 2019	Q3 2019	Q4 2019	Q1 2020	Q2 2020	Change Q2 2019-Q2 2020
Day-ahead energy costs	$ 52.23	$ 24.08	$ 35.94	$ 41.36	$ 29.45	$ 22.36	$ (1.72)
Real-time energy costs (incl. flex ramp)	$ 0.31	$ 1.30	$ 0.97	$ 1.45	$ 0.49	$ 1.23	$ (0.07)
Grid management charge	$ 0.46	$ 0.47	$ 0.45	$ 0.46	$ 0.45	$ 0.47	$ 0.01
Bid cost recovery costs	$ 0.56	$ 0.50	$ 0.72	$ 0.46	$ 0.34	$ 0.36	$ (0.14)
Reliability costs (RMR and CPM)	$ 0.06	$ 0.06	$ 0.06	$ 0.06	$ 0.03	$ 0.00	$ (0.06)
Average total energy costs	**$ 53.61**	**$ 26.41**	**$ 38.14**	**$ 43.80**	**$ 30.76**	**$ 24.42**	**$ (1.99)**
Reserve costs (AS and RUC)	$ 0.94	$ 1.15	$ 0.46	$ 0.49	$ 0.65	$ 0.50	$ (0.65)
Average total costs of energy and reserve	**$ 54.55**	**$ 27.56**	**$ 38.60**	**$ 44.29**	**$ 31.41**	**$ 24.93**	**$ (2.64)**

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



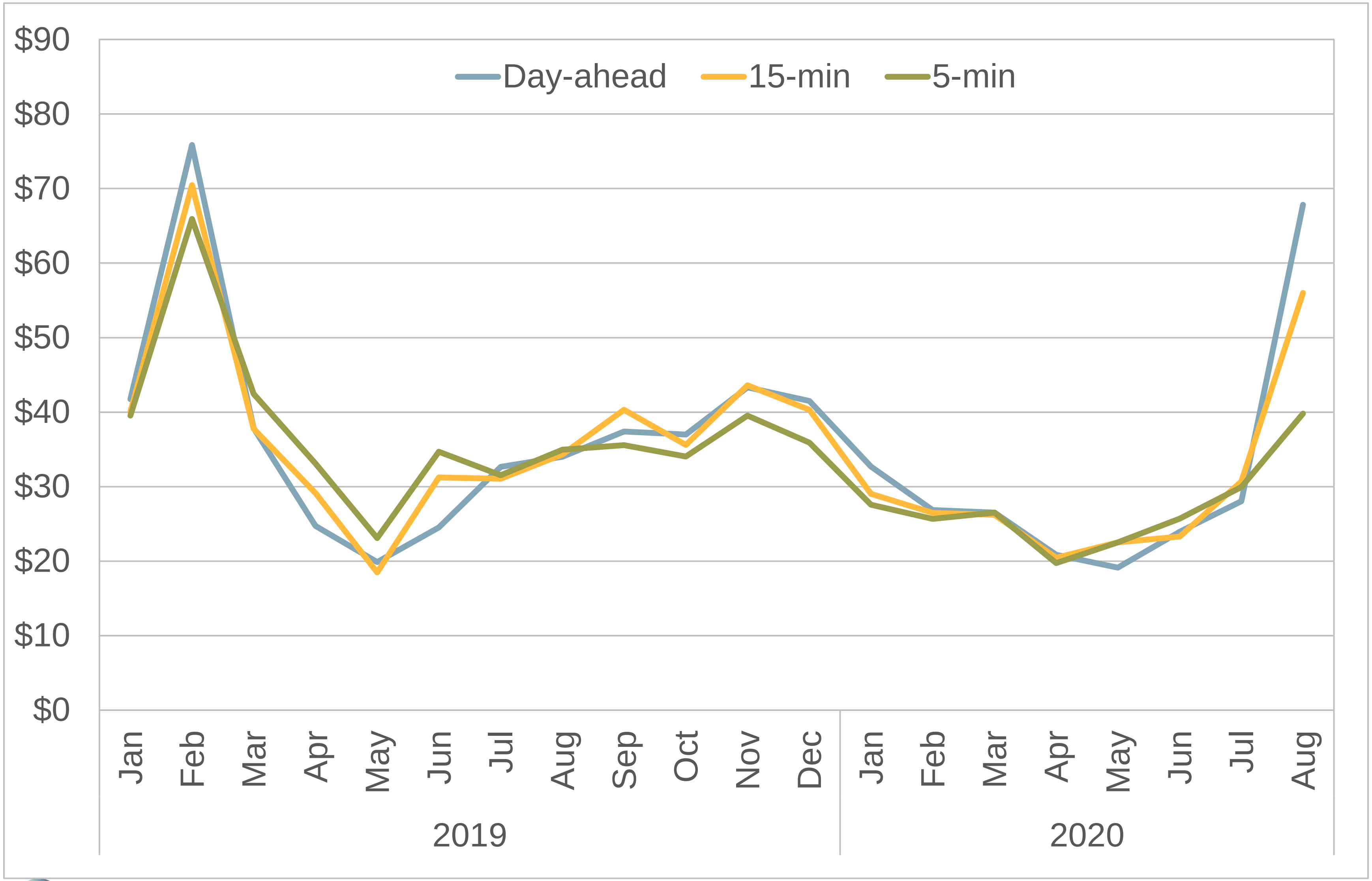
http://www.caiso.com/Documents/CPUC-ResponsetoJudgesRulingSeekingComments-SafeandReliableGasSystems-R20-01-007-Aug142020.pdf

In Q2 2020, gas burn nomograms were activated on 3 occasions and shaped based on gross load methodology

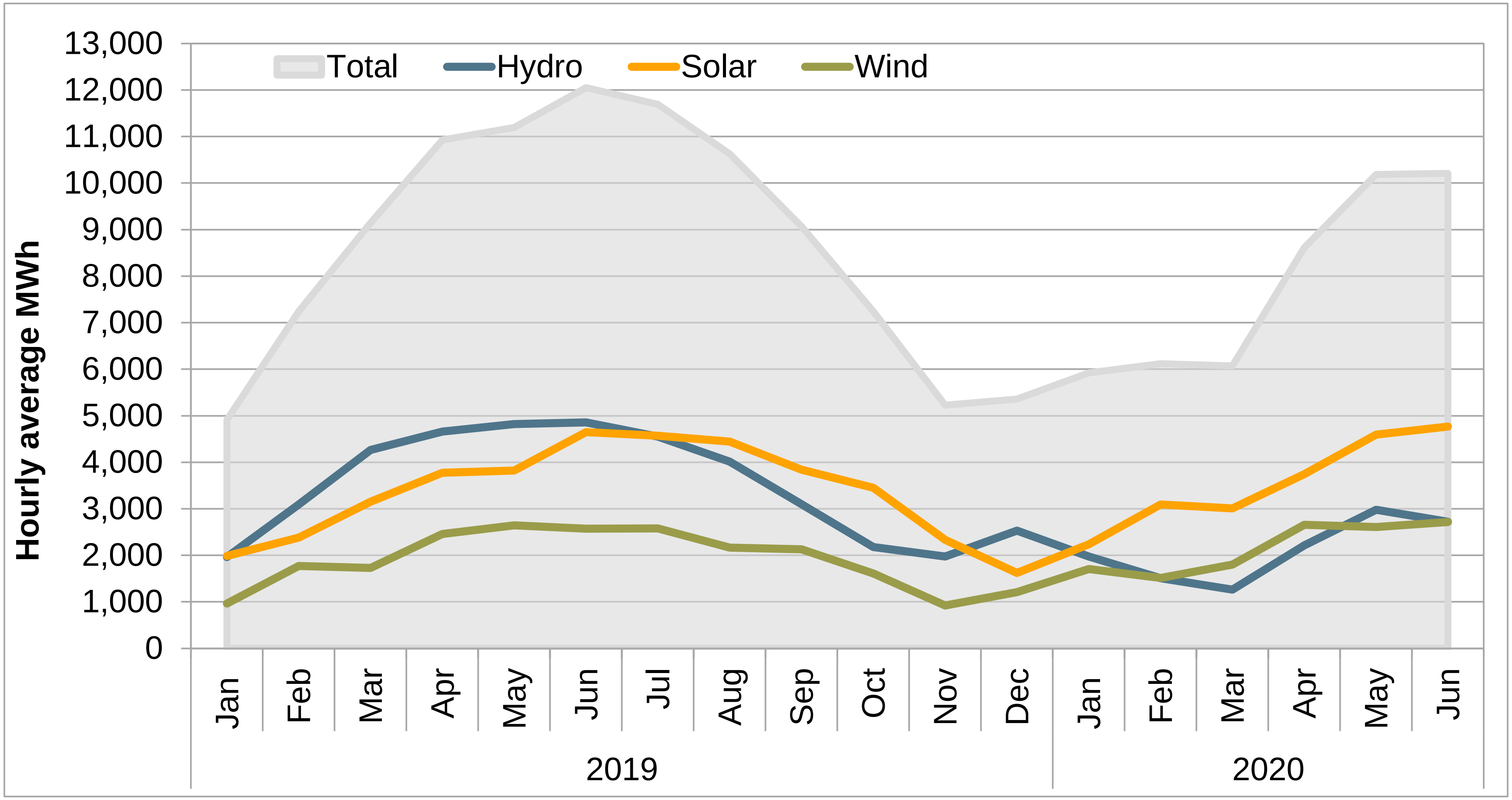


BPM PRR 1262 Aliso Canyon gas-electric coordination Phase 5 enhancements:
https://bpmcm.caiso.com/Pages/ViewPRR.aspx?PRRID=1262&IsDlg=0

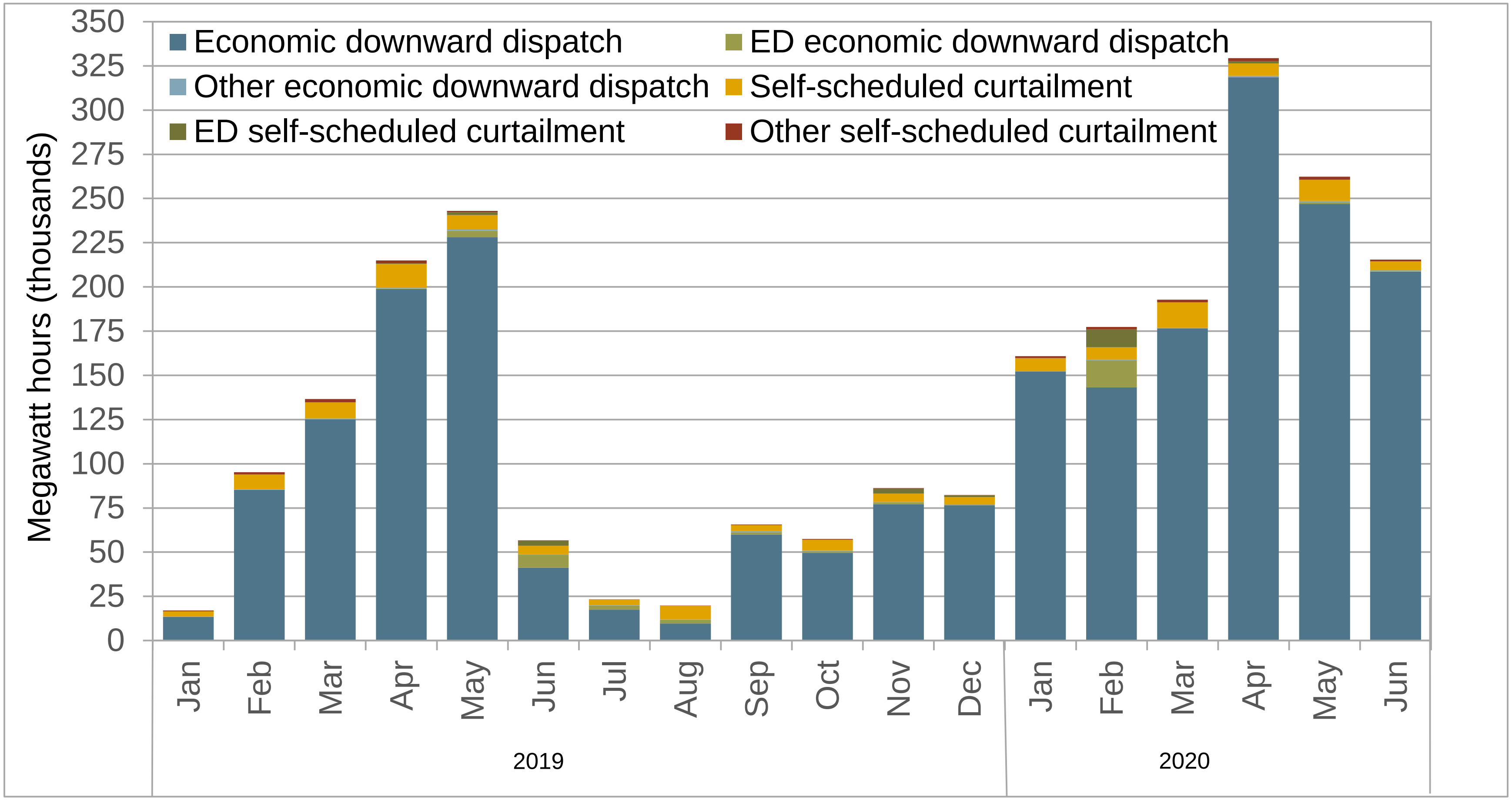
Recent record high prices increase average costs



In Q2 2020, renewable generation decreased by 15 percent over Q2 2019 due to lower hydro production

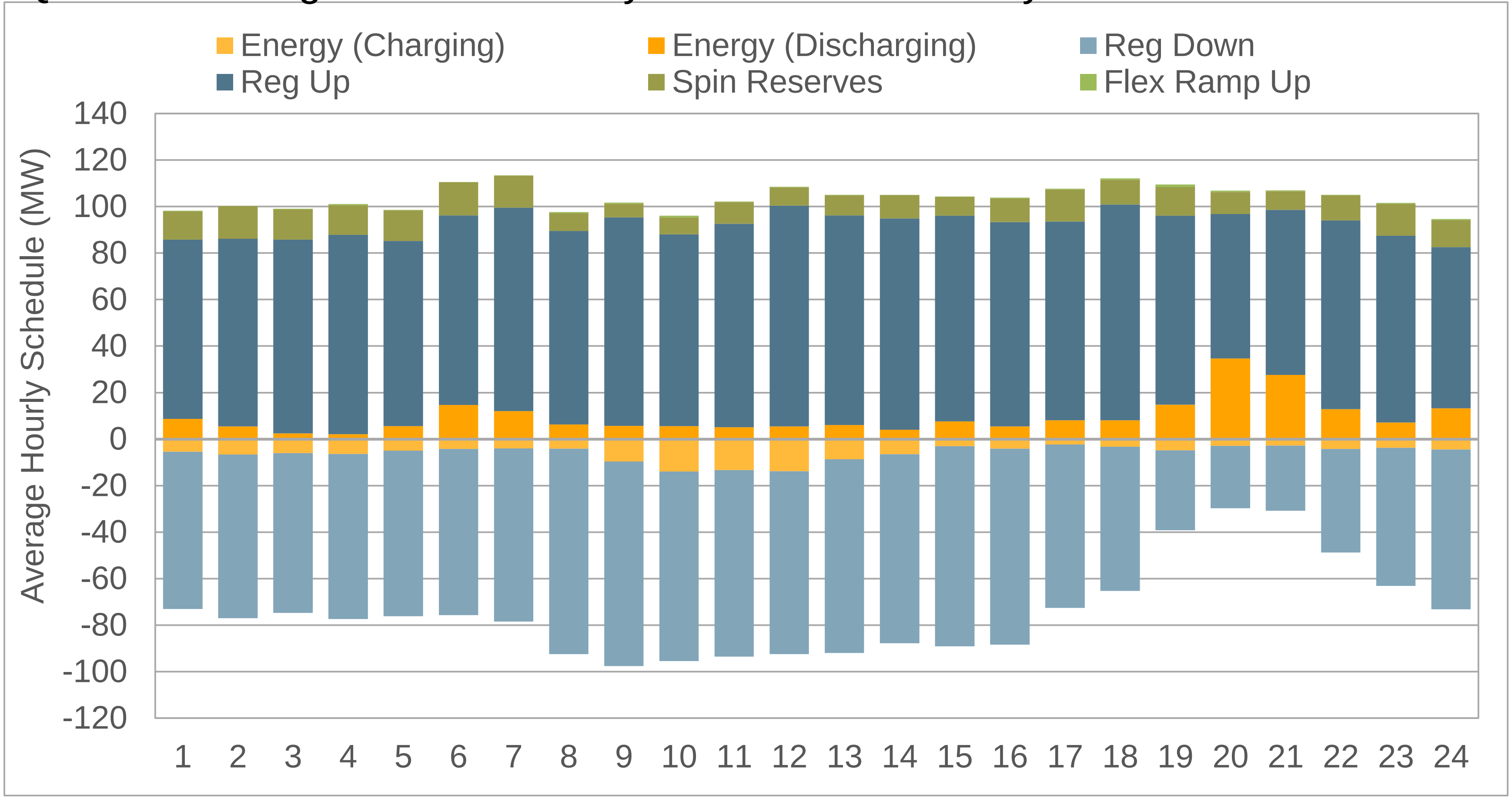


Downward dispatch of renewable resources was considerably higher in the ISO for Q2 2020 compared to Q1 2019.



As of June 2020, battery capacity participating and bidding in the ISO market was about 137 MW

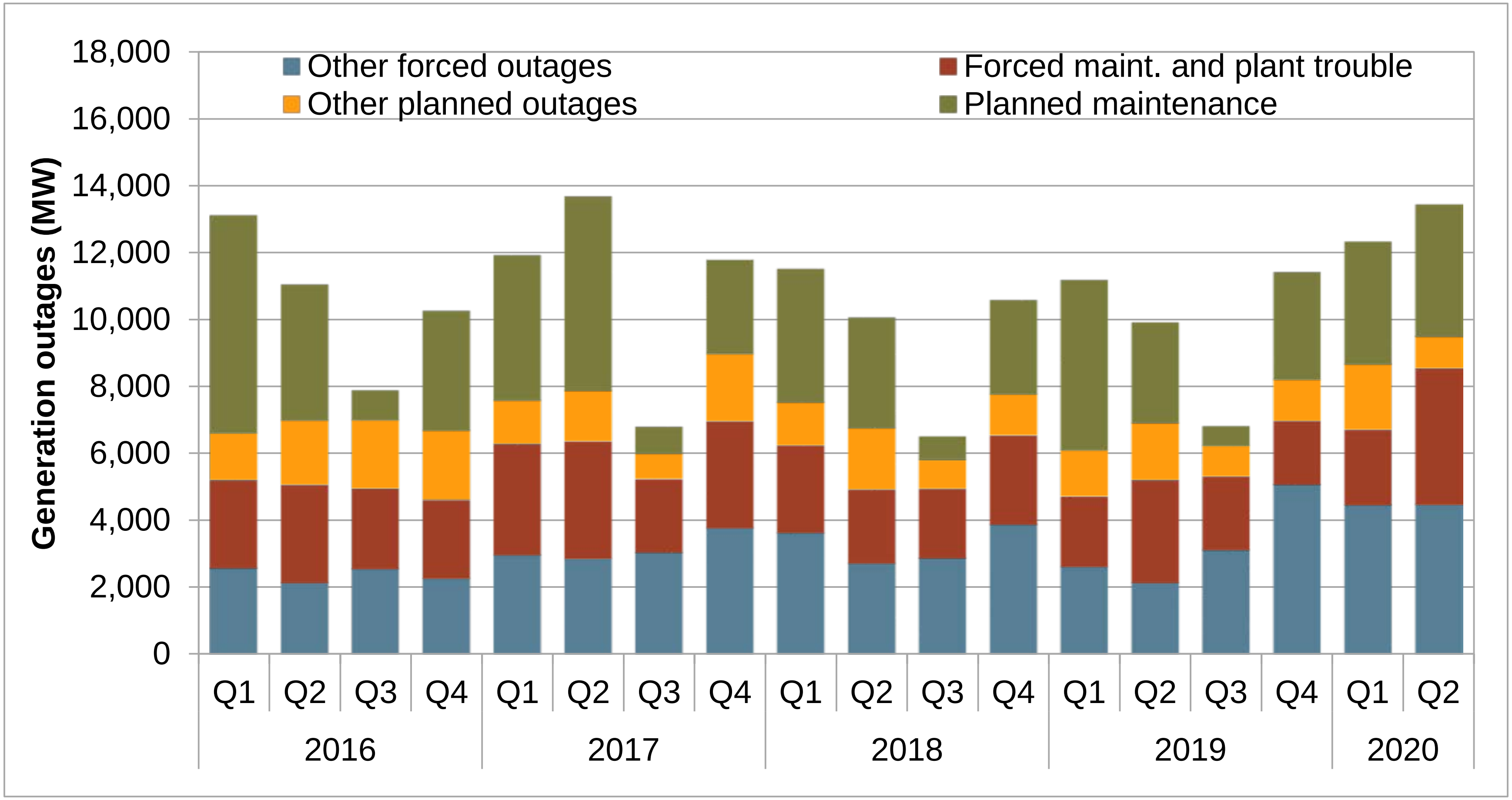
Q2 2020 Average real-time hourly schedules for battery resources



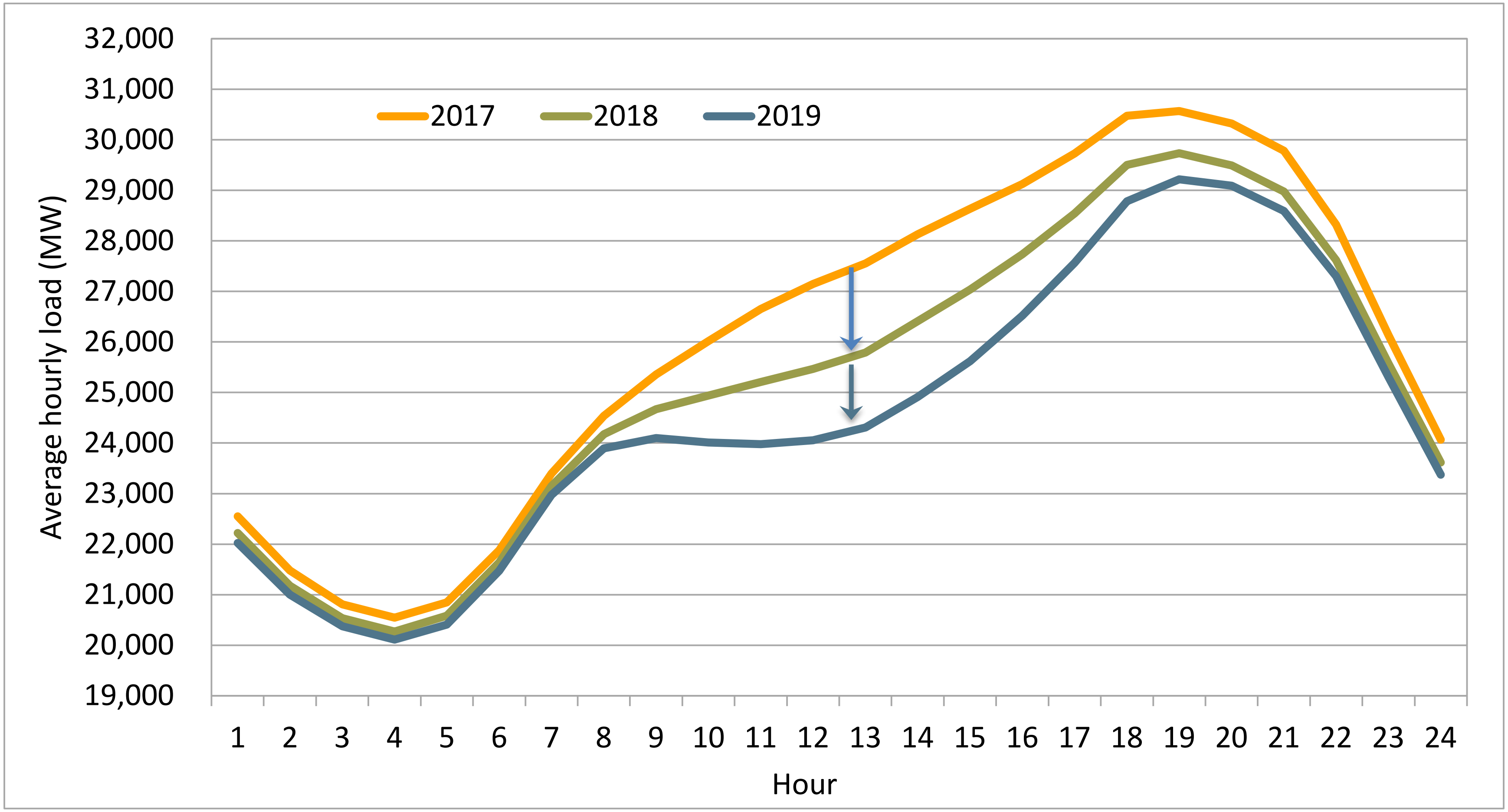
Energy storage and distributed energy resources phase 3 implementation

- Implemented November 13
- Added new demand response dispatch options (hourly and 15-minute)
  - As of June 2020, about 93 percent of total registered demand response capacity has switched to these options
- Removed single load-serving entity aggregation requirement
  - As of June 2020, capacity sized under 1 MW under a single SC within the same sub-LAP represented 31 percent of total demand response reflected on monthly RA supply plans

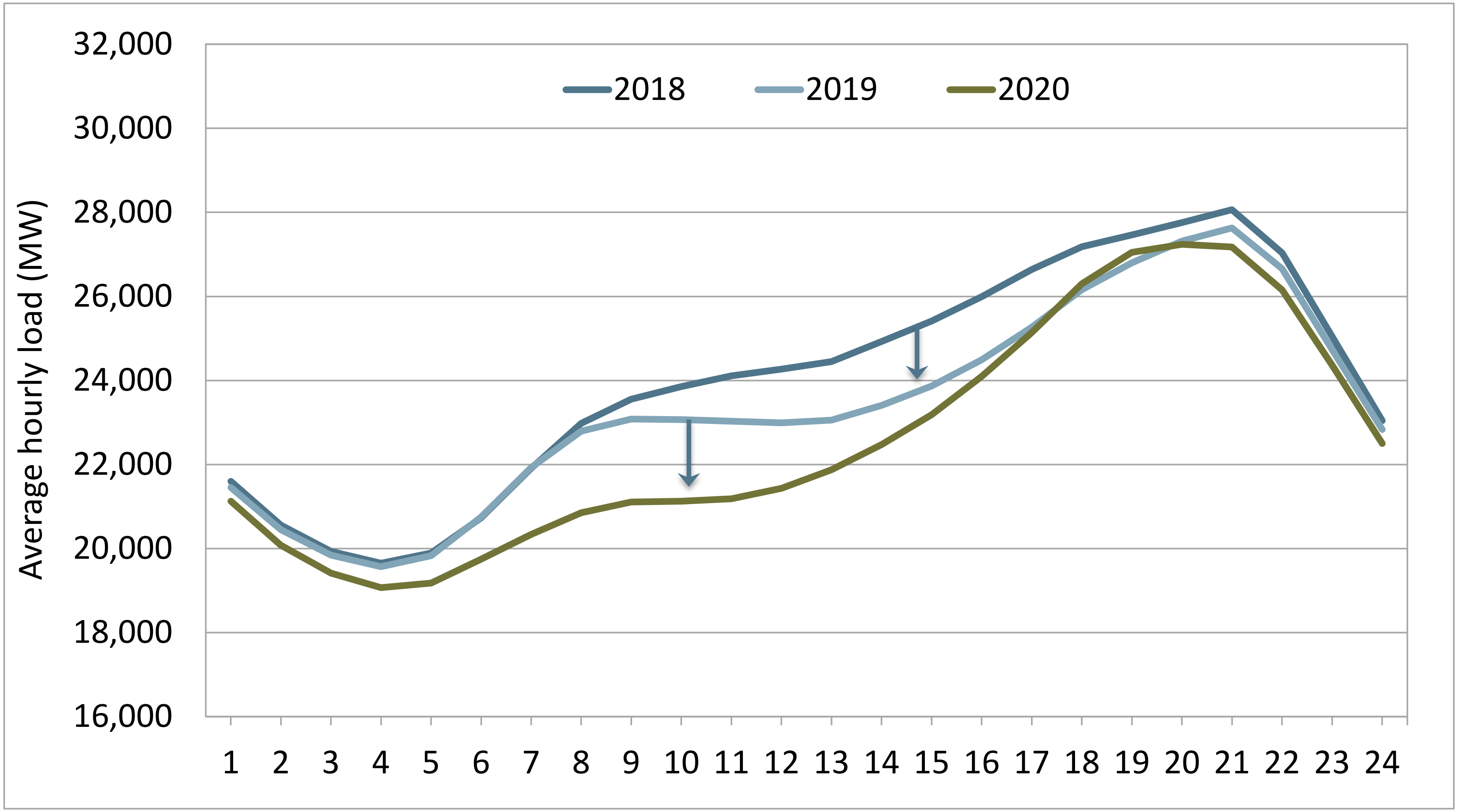
During the first half of 2020, generation outages deviated from a seasonal pattern shown by an increase in outages in Q2 2020



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



Lower overall loads in Q2, but peaks can be high
COVID impact to lower overall load, but higher peaks

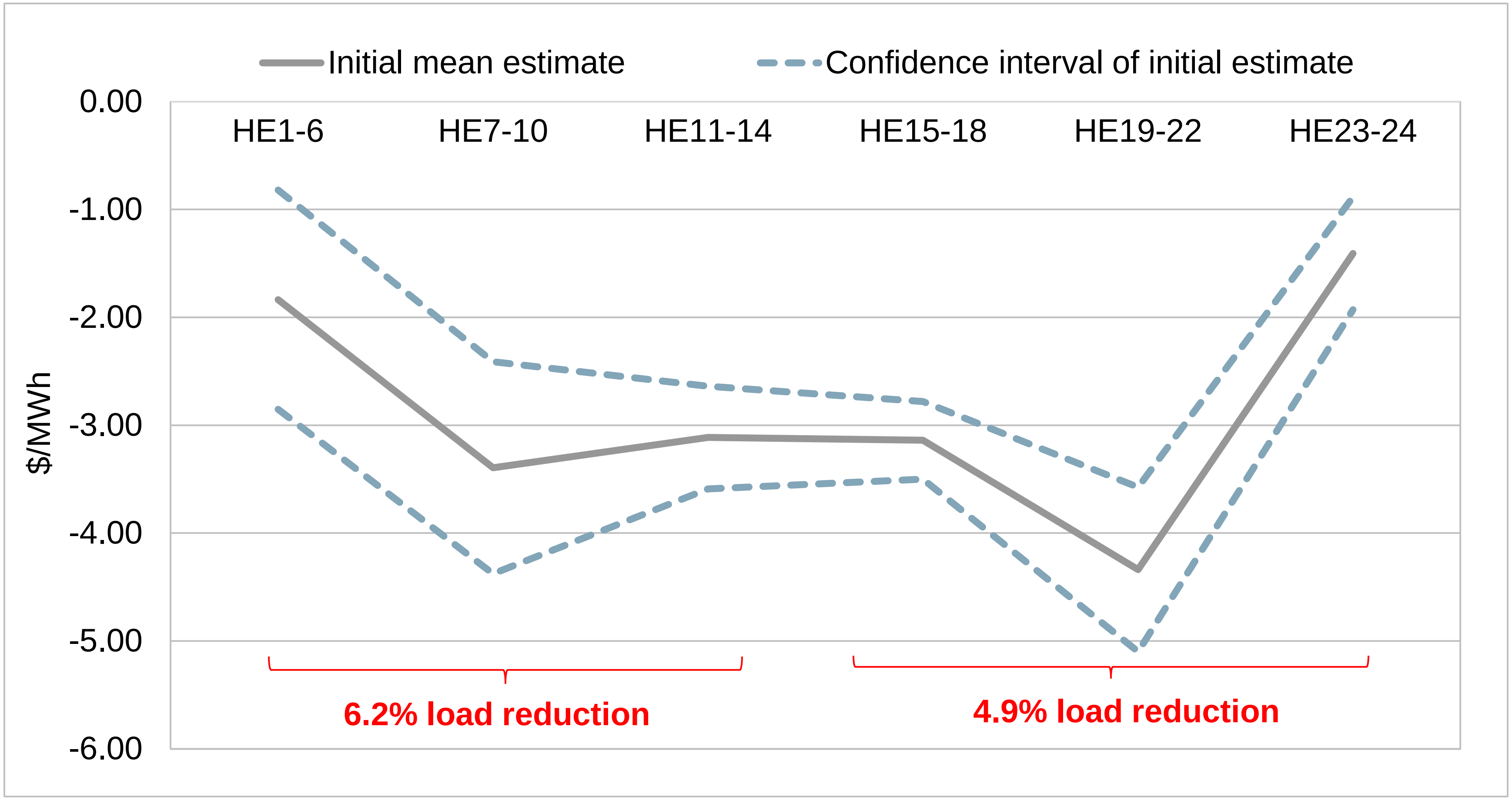


DMM estimated price impacts from lower load associated with Covid-19, controlling for gas prices and renewable generation

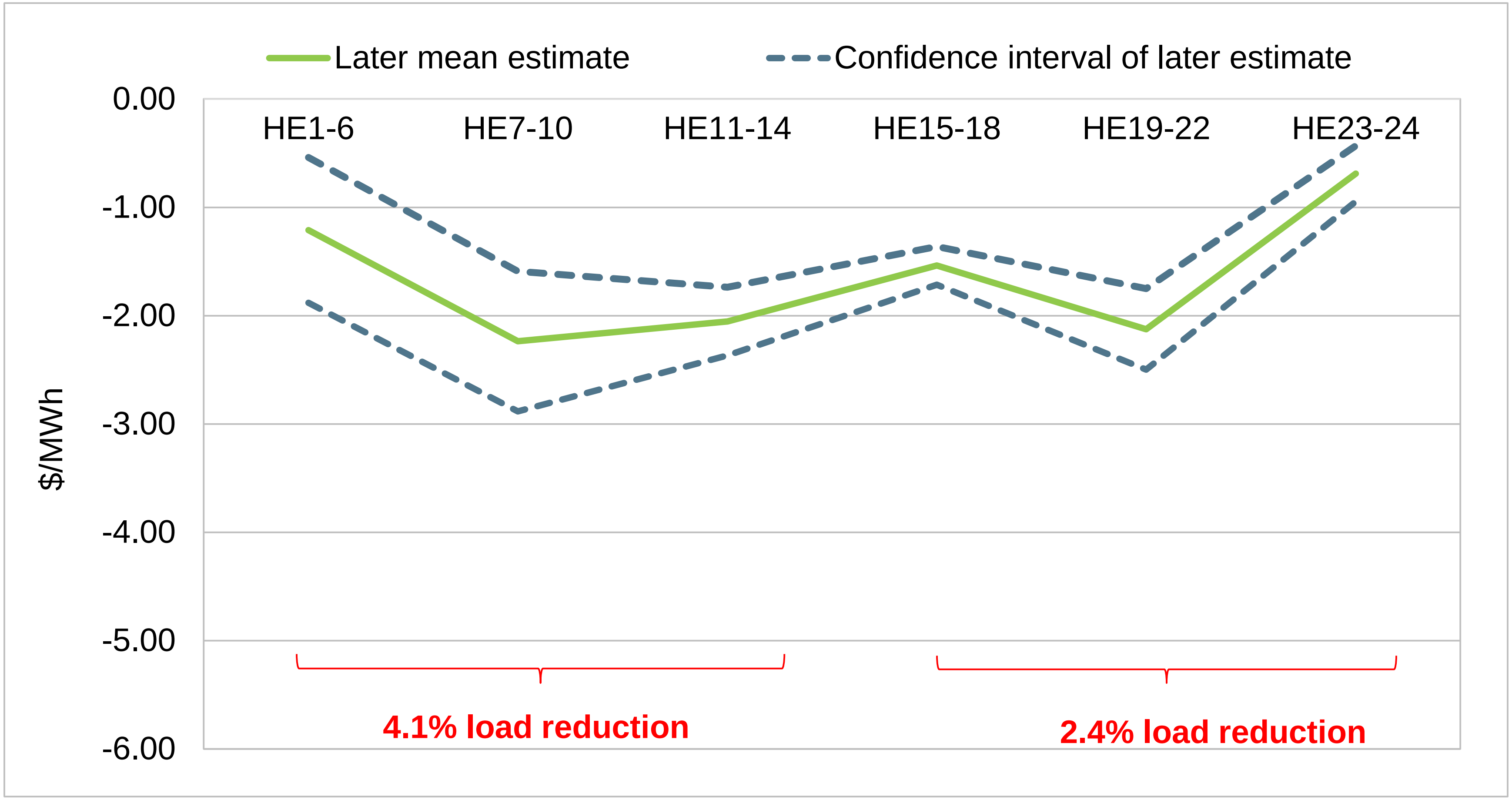
	HE1-6	HE7-10	HE11-14	HE15-18	HE19-22	HE23-24
log(Load forecast)	29.42	54.37	49.89	64.46	89.05	28.89
	(3.54)	(6.78)	(12.82)	(17.06)	(11.16)	(5.27)
log(VER forecast)	-2.47	-7.41	-18.46	-11.11	-5.13	-2.86
	(-3.25)	(-5.54)	(-10.92)	(-9.91)	(-5.51)	(-4.26)
log(Gas price)	22.31	25.18	13.31	22.19	37.15	26.38
	(8.23)	(8.81)	(7.57)	(9.41)	(10.92)	(10.23)
log(Hydro self-schedules)	-3.30	-2.95	-3.31	-5.89	*-0.89*	-3.05
	(-2.66)	(-2.41)	(-3.55)	(-4.41)	*(-0.51)*	(-2.23)
Observations	669	669	669	669	669	669
Adjusted R-squared	0.869	0.888	0.907	0.922	0.857	0.867
AR(2) error	Yes	Yes	Yes	Yes	Yes	Yes
Hour, day-type, month intercepts	Yes	Yes	Yes	Yes	Yes	Yes
HCCME standard errors	Yes	Yes	Yes	Yes	Yes	Yes

Results from linear-log, iterated seemingly unrelated regressions of hourly day-ahead market price on load forecast, variable energy resource forecast, daily Socal-Citygate gas price, and self-scheduled hydro generation. Models include AR(2) errors as well as hour, day-type, and month intercepts. Standard errors adjusted for heteroskedasticity. Estimated coefficients are presented with t-stats in parentheses. Coefficients that are not statistically significant are italicized.

DMM estimates that the initial reductions in load due to COVID-19 resulted in a reduction in day-ahead market prices of about $2-$4/MWh during the morning peak and $4-$5/MWh for the evening peak



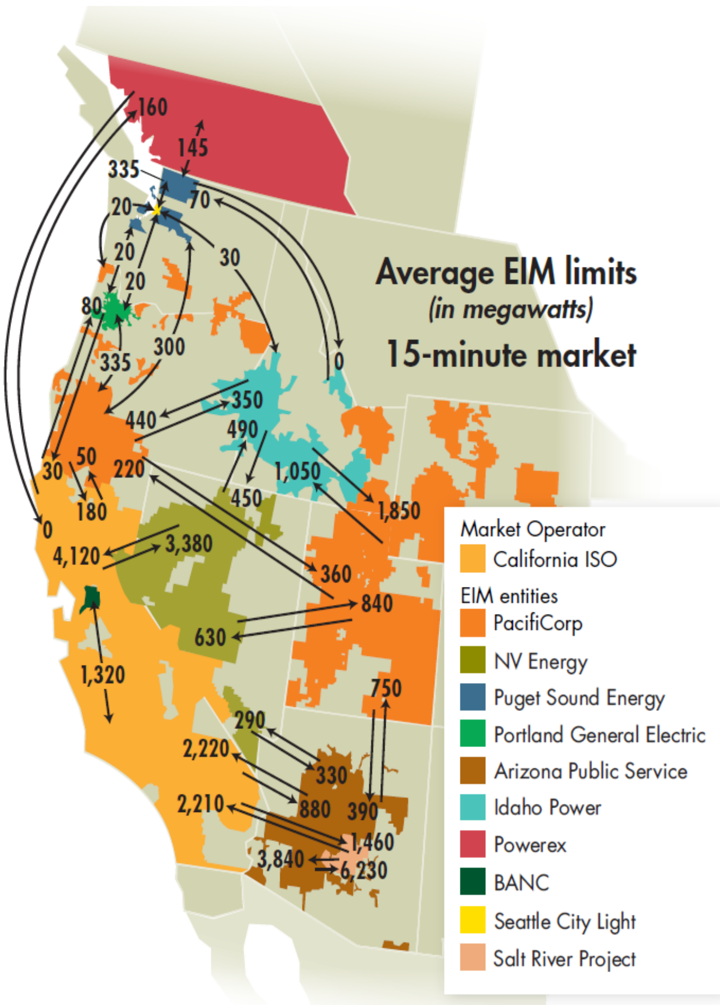
Lower average load reductions published more recently by the ISO resulted in a reduction of about $2-$3/MWh in day-ahead market prices during both the morning and evening peaks.



Western energy imbalance market highlights

- New members on April 1, 2020:
  - Seattle City Light (SCL)
  - Salt River Project (SRP)
- SRP’s average 15-minute transfer limit to the ISO averaged 2,209 MW for exports and 1,458 MW for imports.
- SCL has no transfer capacity with the ISO BAA
- 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 in Arizona Public Service and NV Energy
- Congestion imbalance offset costs related to base schedules remained low

Energy imbalance market transfer limits

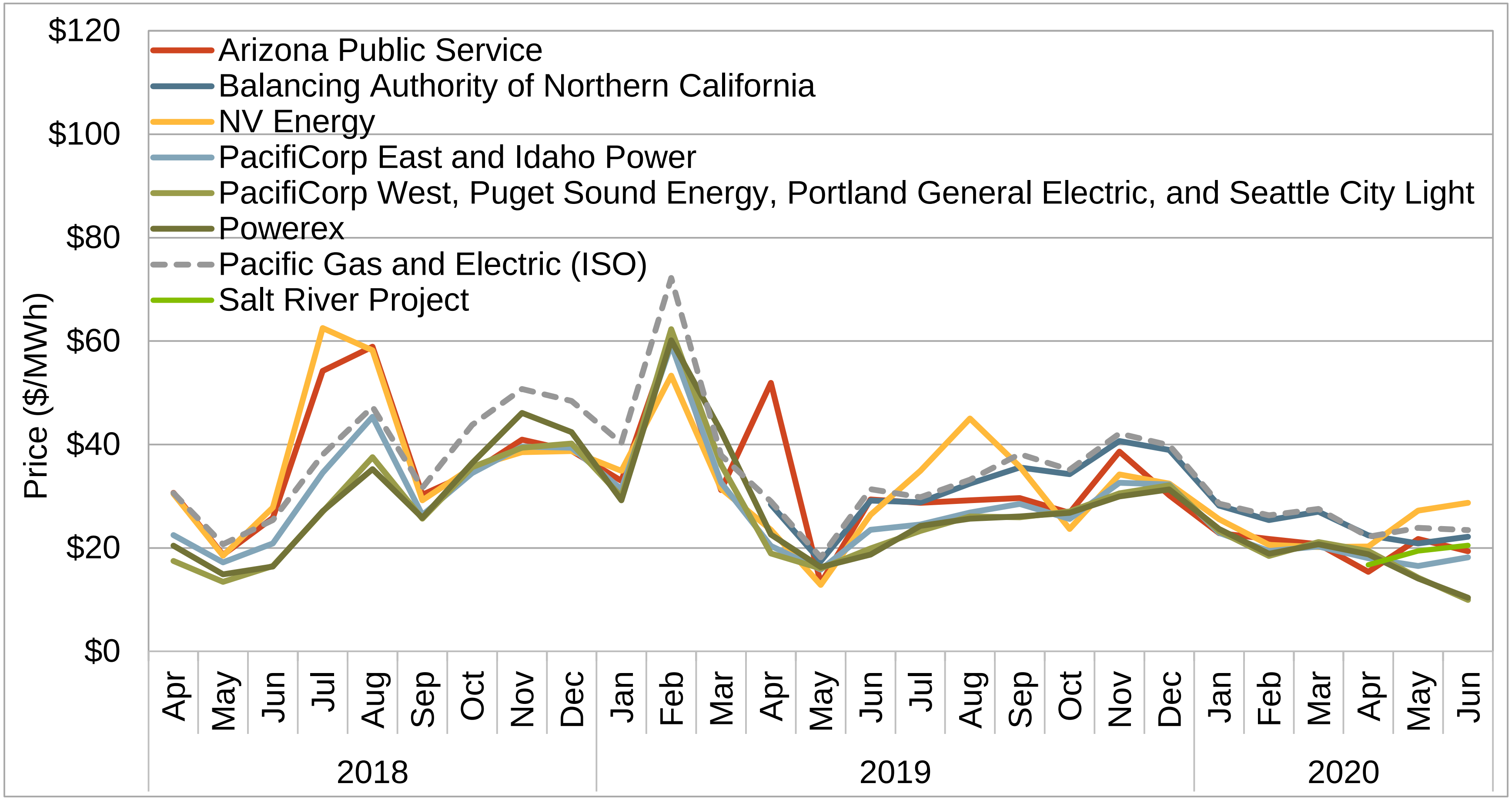


	15-minute market		5-minute market	
	Congested from area	Congested into area	Congested from area	Congested into area
BANC	1%	0%	1%	0%
NV Energy	4%	2%	3%	1%
Arizona Public Service	1%	5%	1%	4%
PacifiCorp East	4%	7%	2%	6%
Idaho Power	4%	8%	2%	6%
Salt River Project	3%	14%	3%	13%
PacifiCorp West	30%	11%	23%	9%
Portland General Electric	32%	11%	26%	9%
Seattle City Light	32%	11%	27%	10%
Puget Sound Energy	32%	12%	27%	10%
Powerex	36%	10%	34%	15%

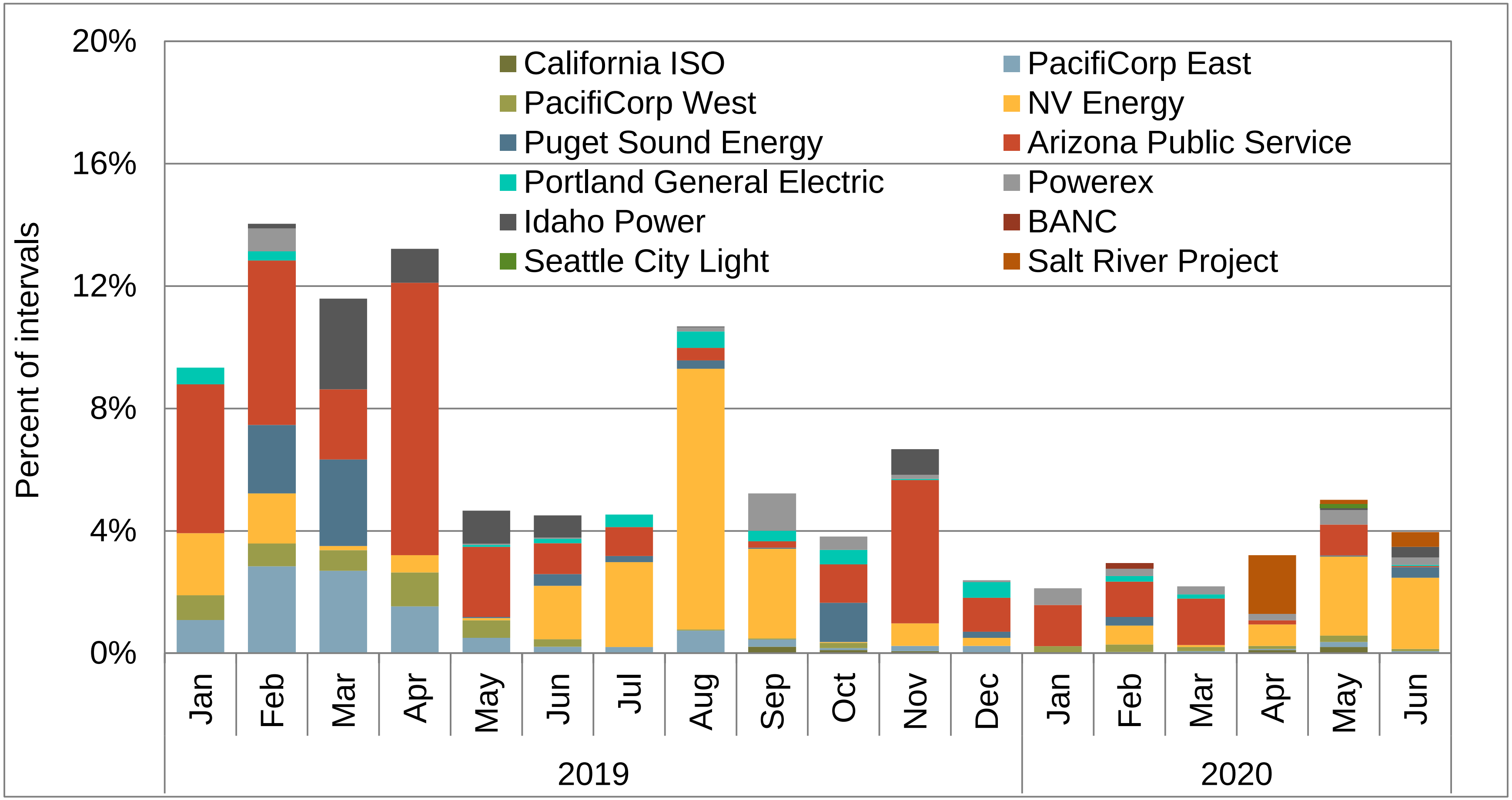
Energy imbalance market changes:

- SCL and SRP added April 1
- SCL and SRP have about 1,048 MW and 6,547 MW of participating capacity, respectively.

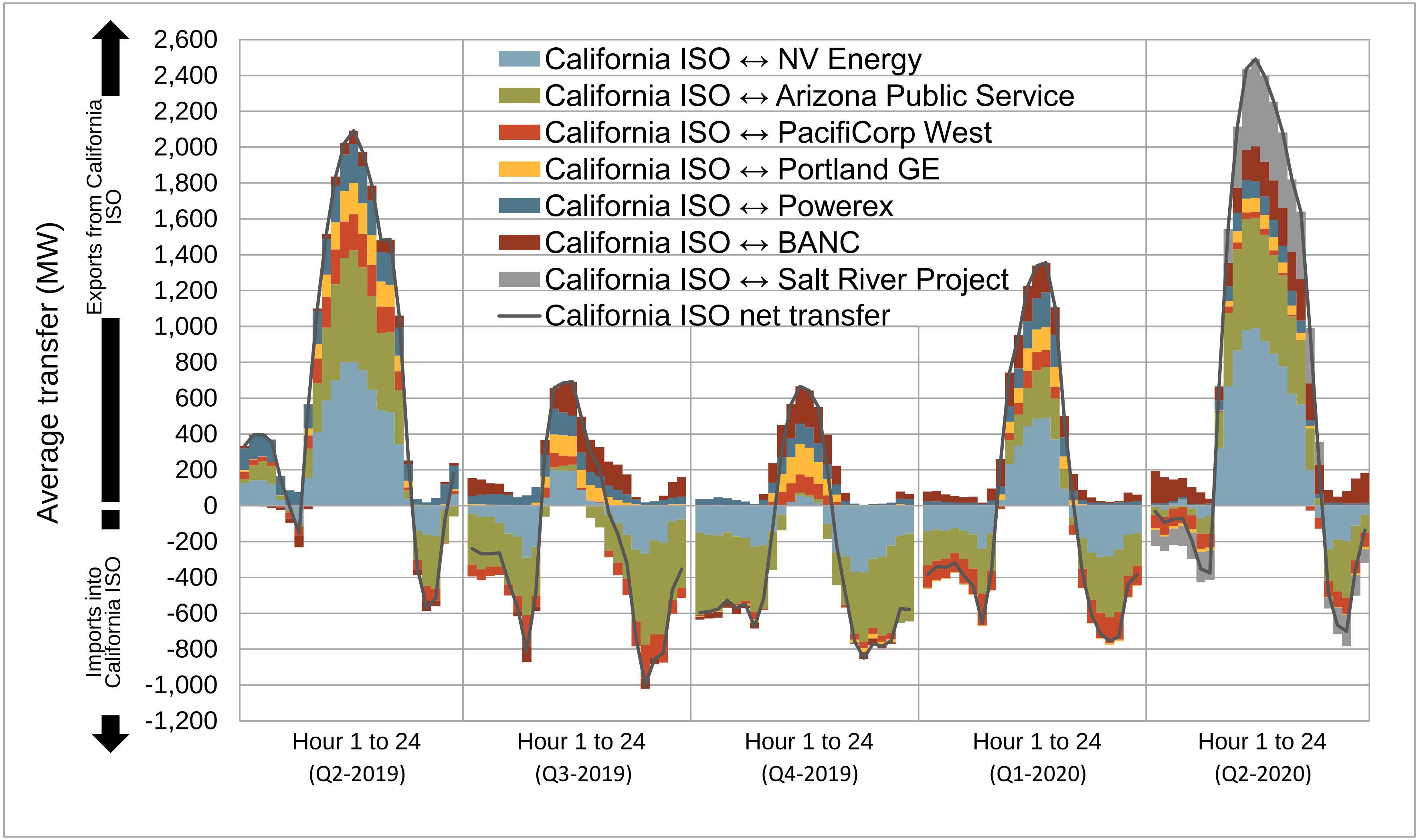
Prices in NV Energy and APS driven up by power balance constraint violations following resource sufficiency test failures in some months (15 minute market)



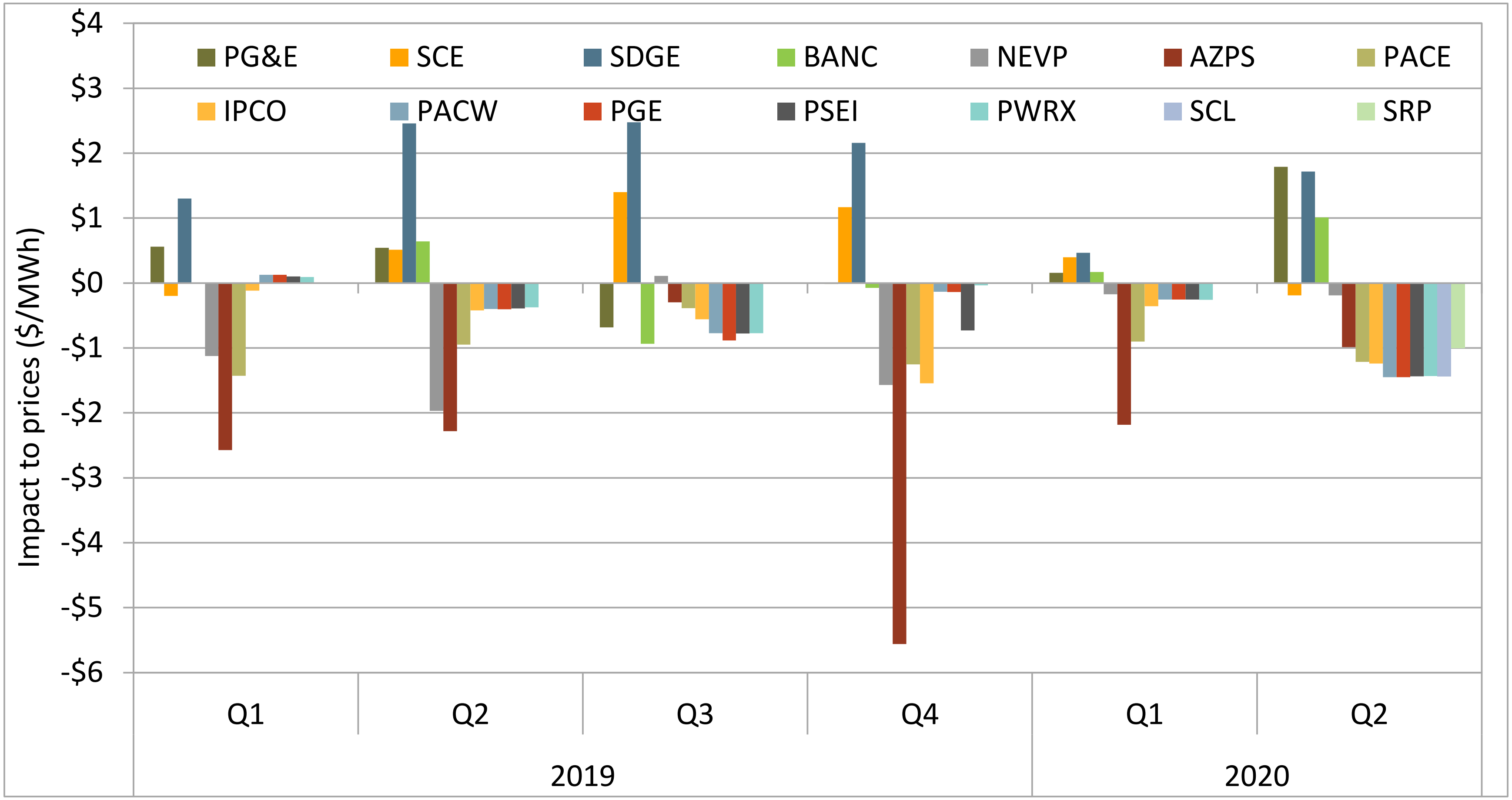
APS and NV Energy failed the upward sufficiency test most frequently in Q1 and Q2, respectively



California ISO - average hourly 15-minute market transfer



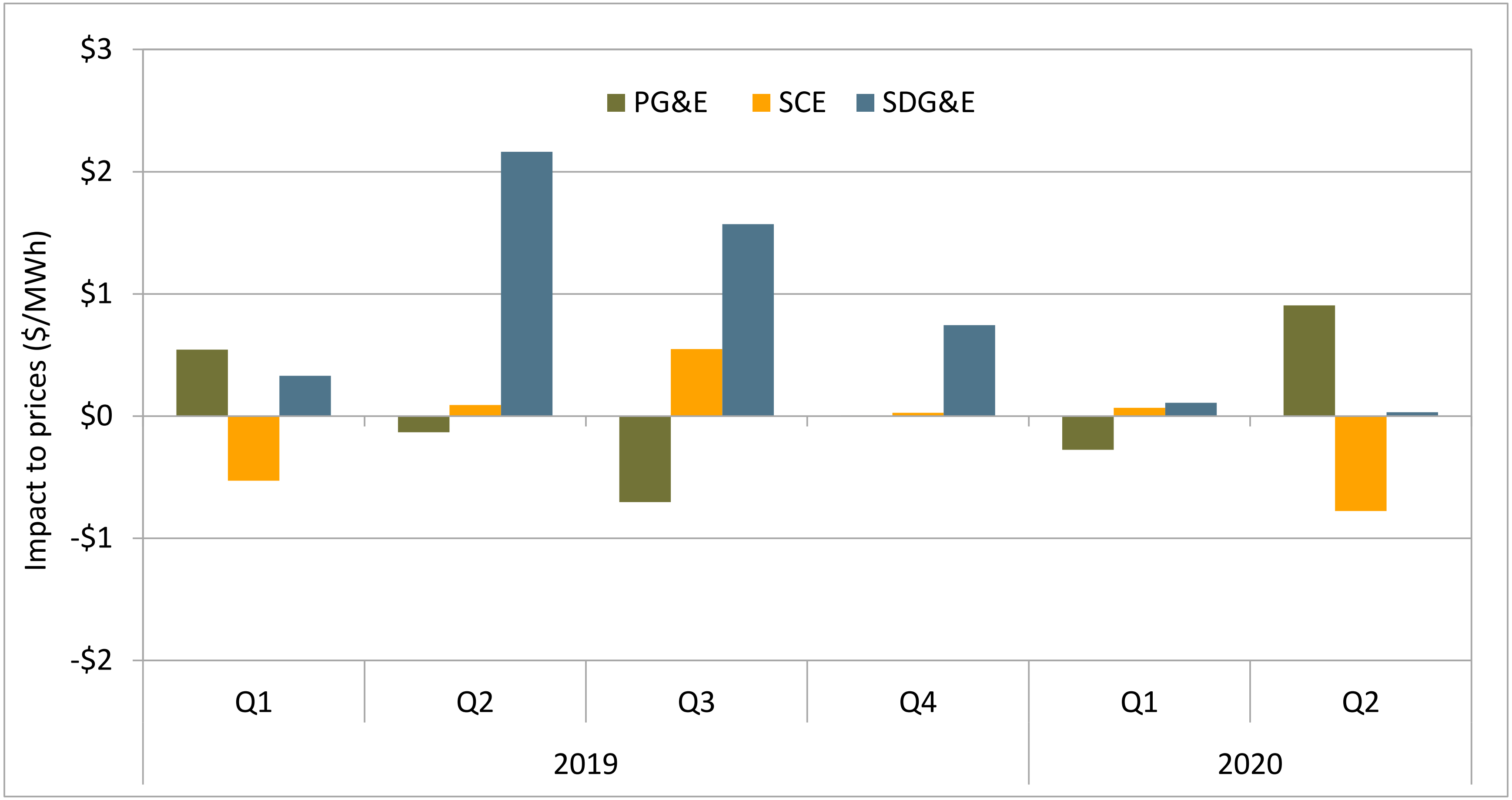
Impact of internal congestion on 15-minute prices



Estimated 15-minute market EIM internal constraint congestion imbalances ($ million)

	Annual				2019				2020	2020
Balancing Authority Area	2016	2017	2018	2019	Q1	Q2	Q3	Q4	Q1	Q2
Arizona Public Service	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
BANC				$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Powerex	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
California ISO	-$51.1	-$26.2	-$70.4	-$92.3	-$17.9	-$18.4	-$14.0	-$42.0	-$12.7	-$23.2
Idaho Power Company			$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
NV Energy	-$0.3	-$0.8	-$0.3	-$0.4	-$0.3	-$0.1	$0.0	$0.0	$0.0	-$0.4
PacifiCorp - East	-$4.0	-$18.1	-$2.0	$0.7	$0.8	$0.0	$0.1	-$0.3	-$0.7	-$0.1
PacifiCorp - West	$0.0	$0.0	-$0.1	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Portland General Electric		$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Puget Sound Energy	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0

Overall impact of congestion on prices in the day-ahead market continues to be lower in 2020

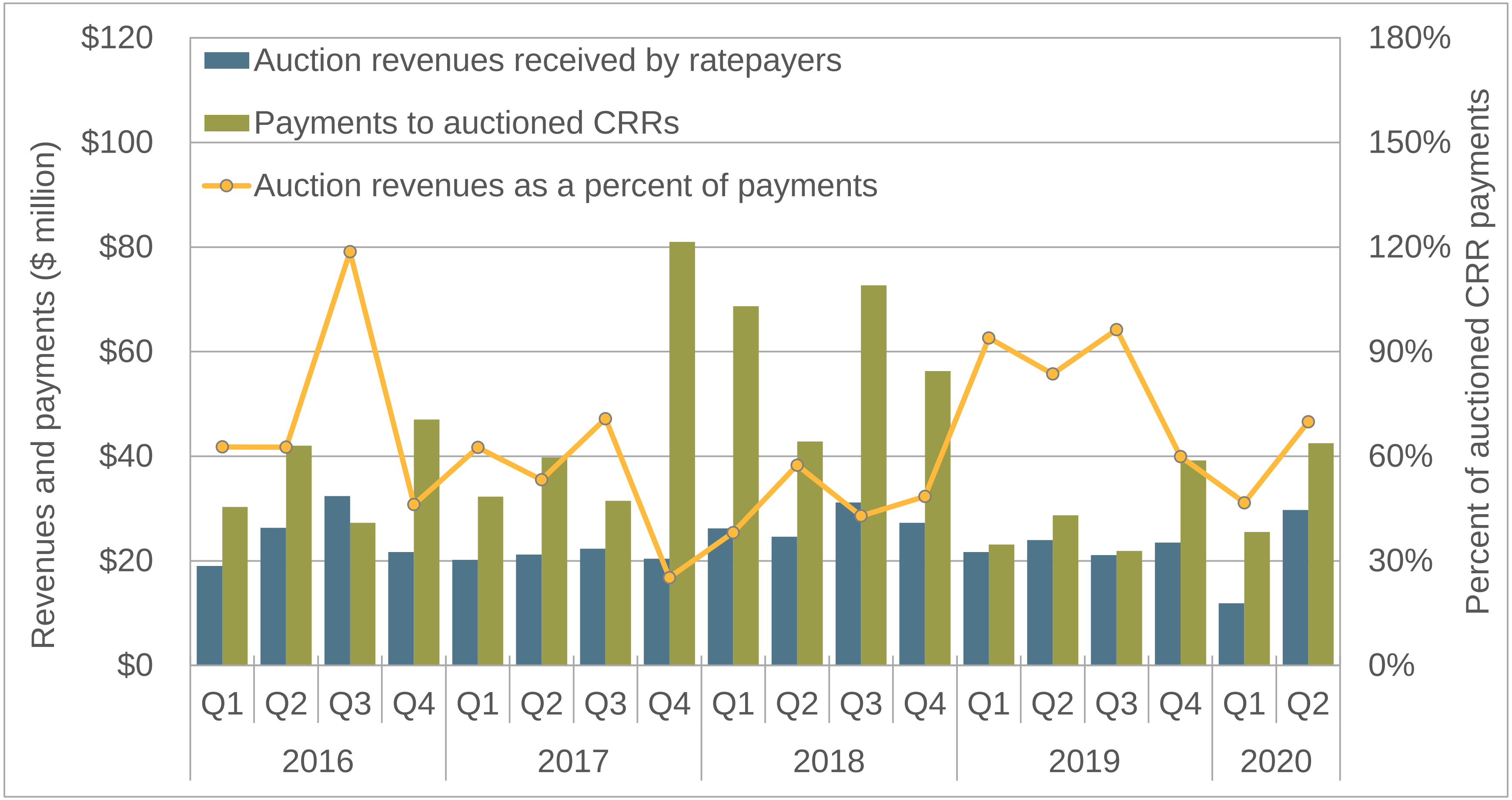


Congestion revenue right auction changes implemented January 2019

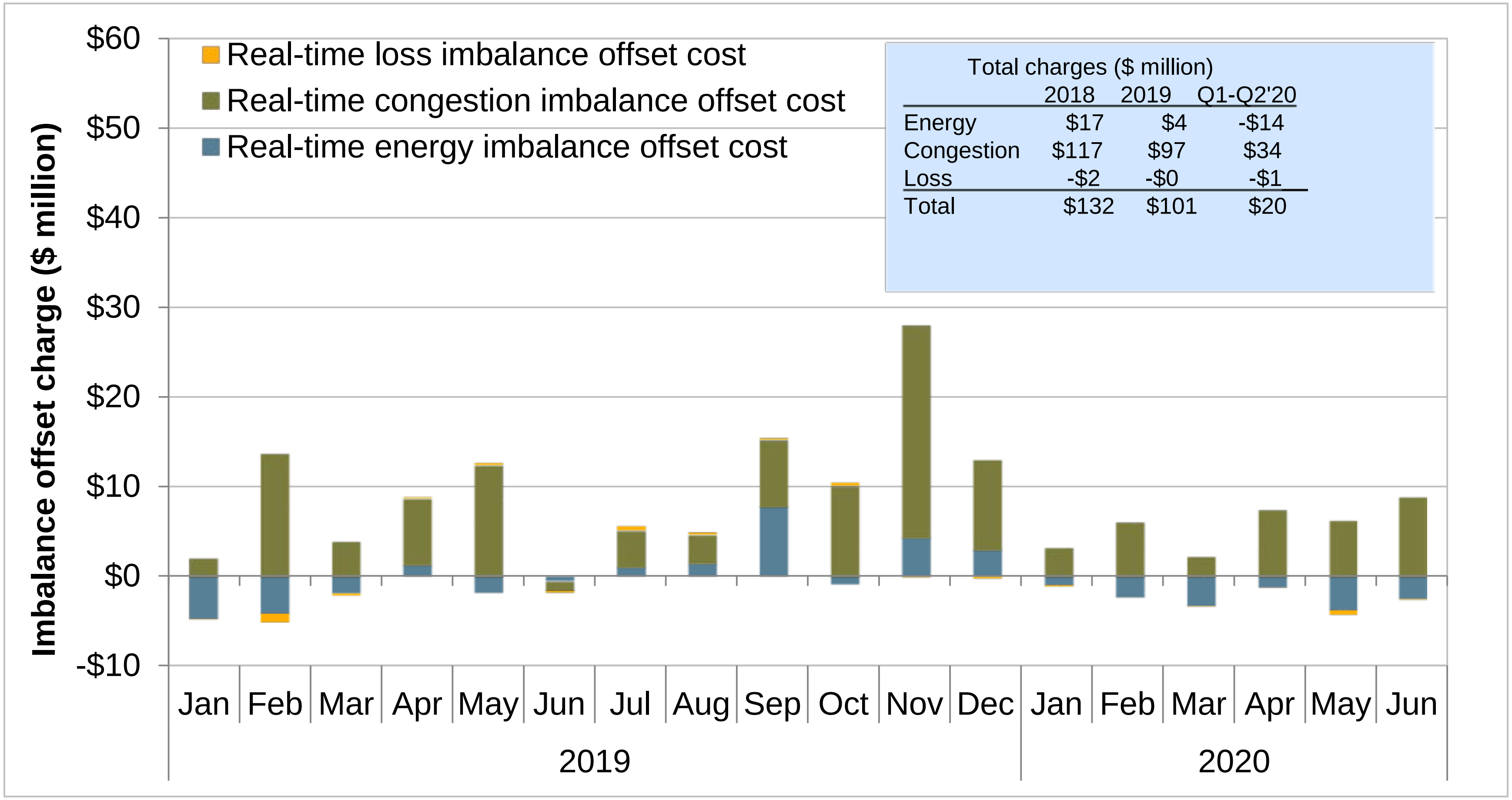
- **Track 1A:**
  - Significantly reduces the number and pairs of nodes at which congestion revenue rights can be purchased in the auction.
  - Designed to limit auction sales to pairs of nodes with physical generation / load due to potential use as hedges for actual sales and trading of energy.

- **Track 1B.**
  - Limits the net payments to CRR holders if payments exceed congestion charges collected in the day-ahead market on a targeted constraint-by-constraint basis.

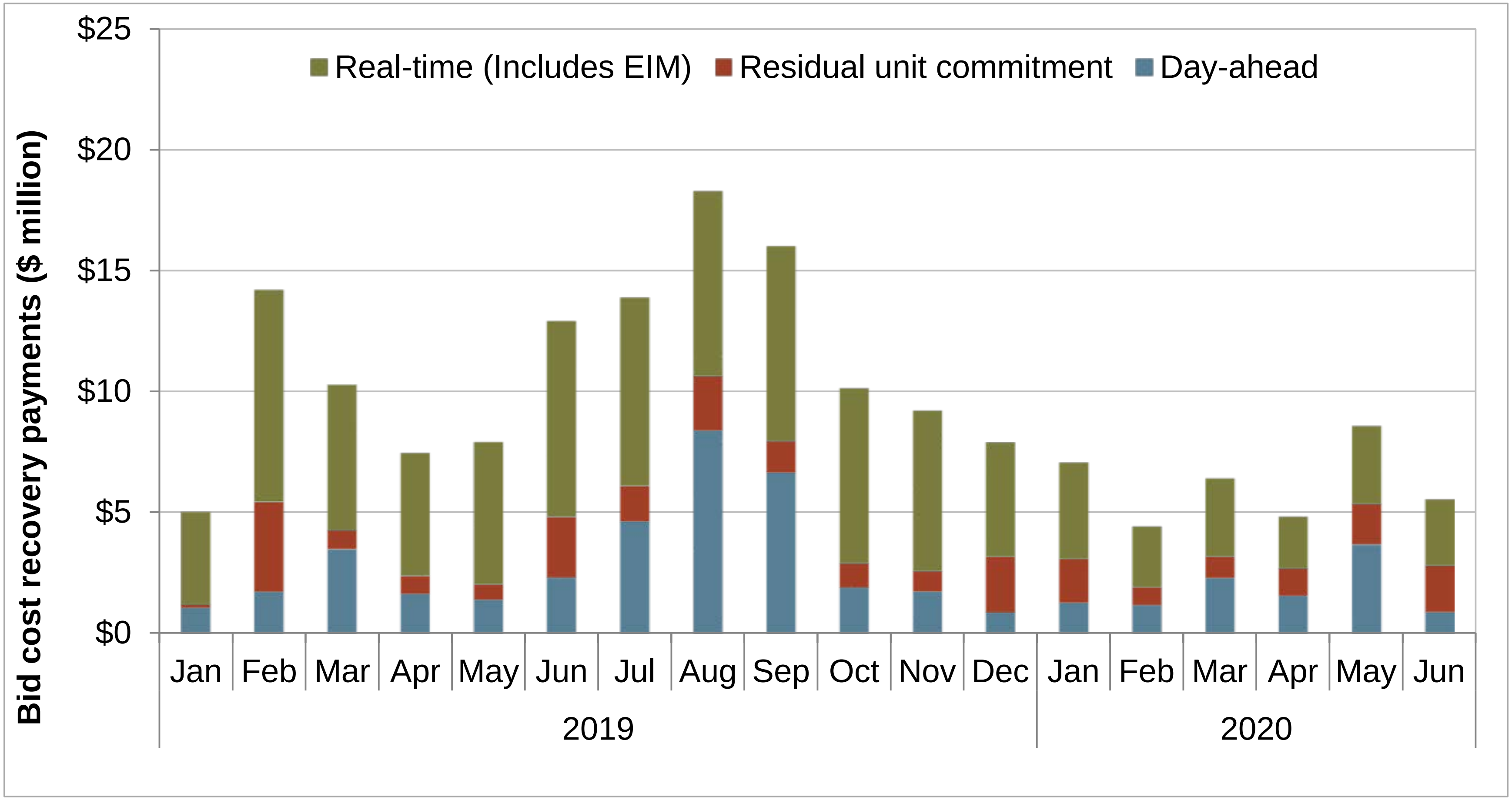
Congestion revenue right Q1 and Q2 losses total $26 million, exceeding 2019 total losses ($23 million)
auction revenues and payments to non-load-serving entities



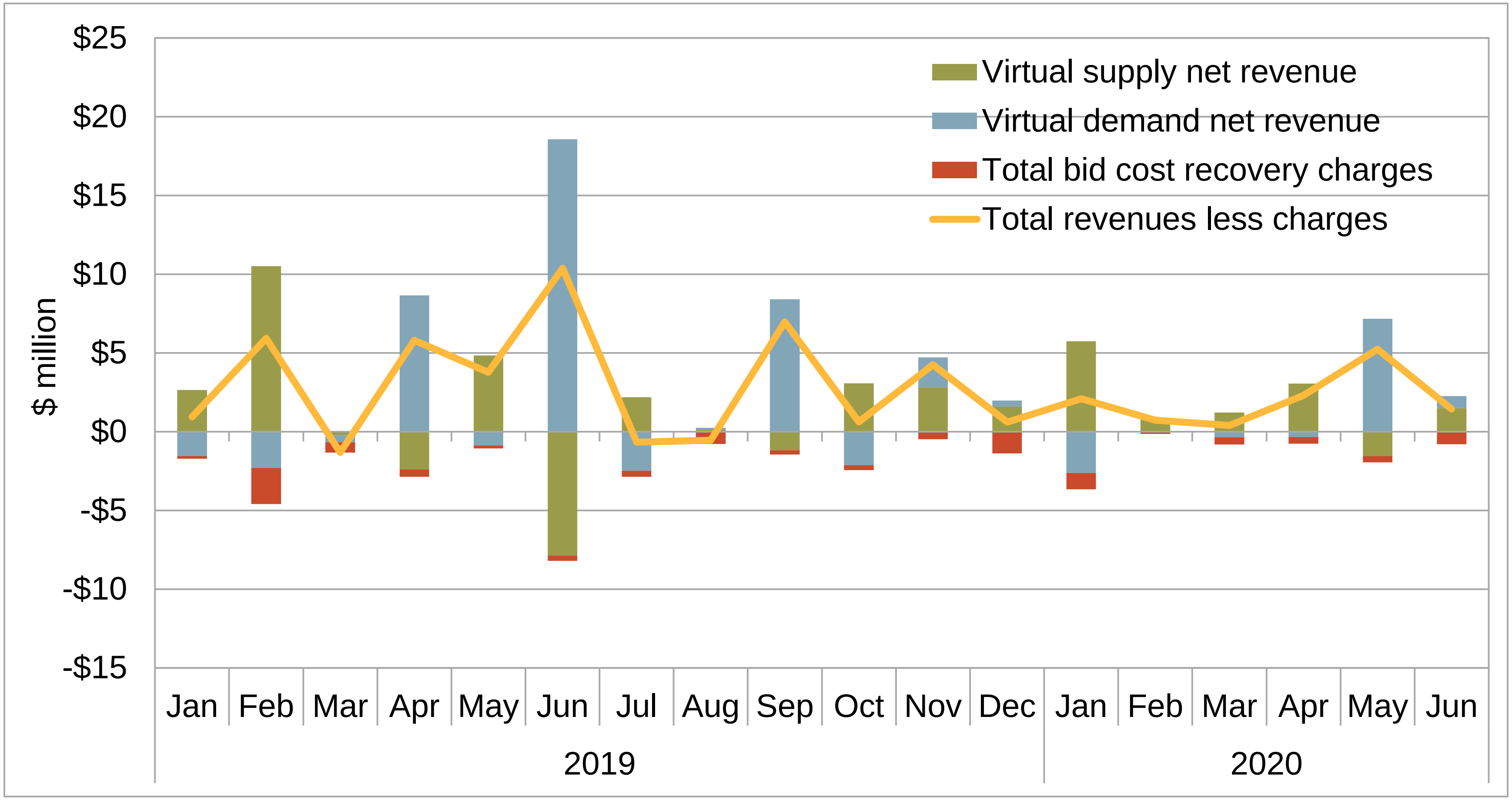
Q2 2020 real-time offset costs were about $15 million, up from $5 million in Q1 2020.



Q2 2020 bid cost recovery $19 million compared to $18 million in Q1 2020 and $28 million in Q2 2019



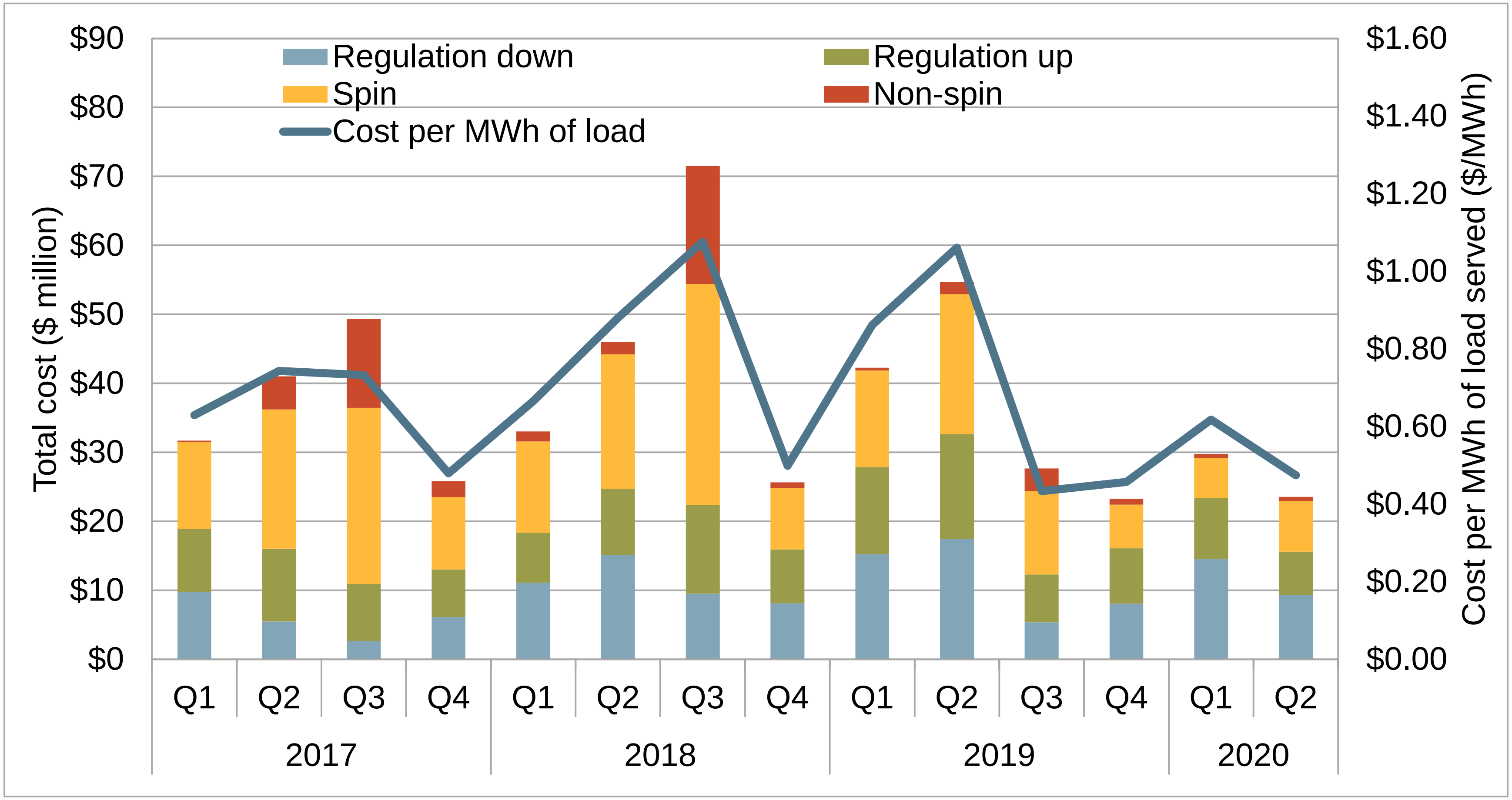
For Q1 and Q2, convergence bidding revenues totaled $12 million, with most revenue to financial entities



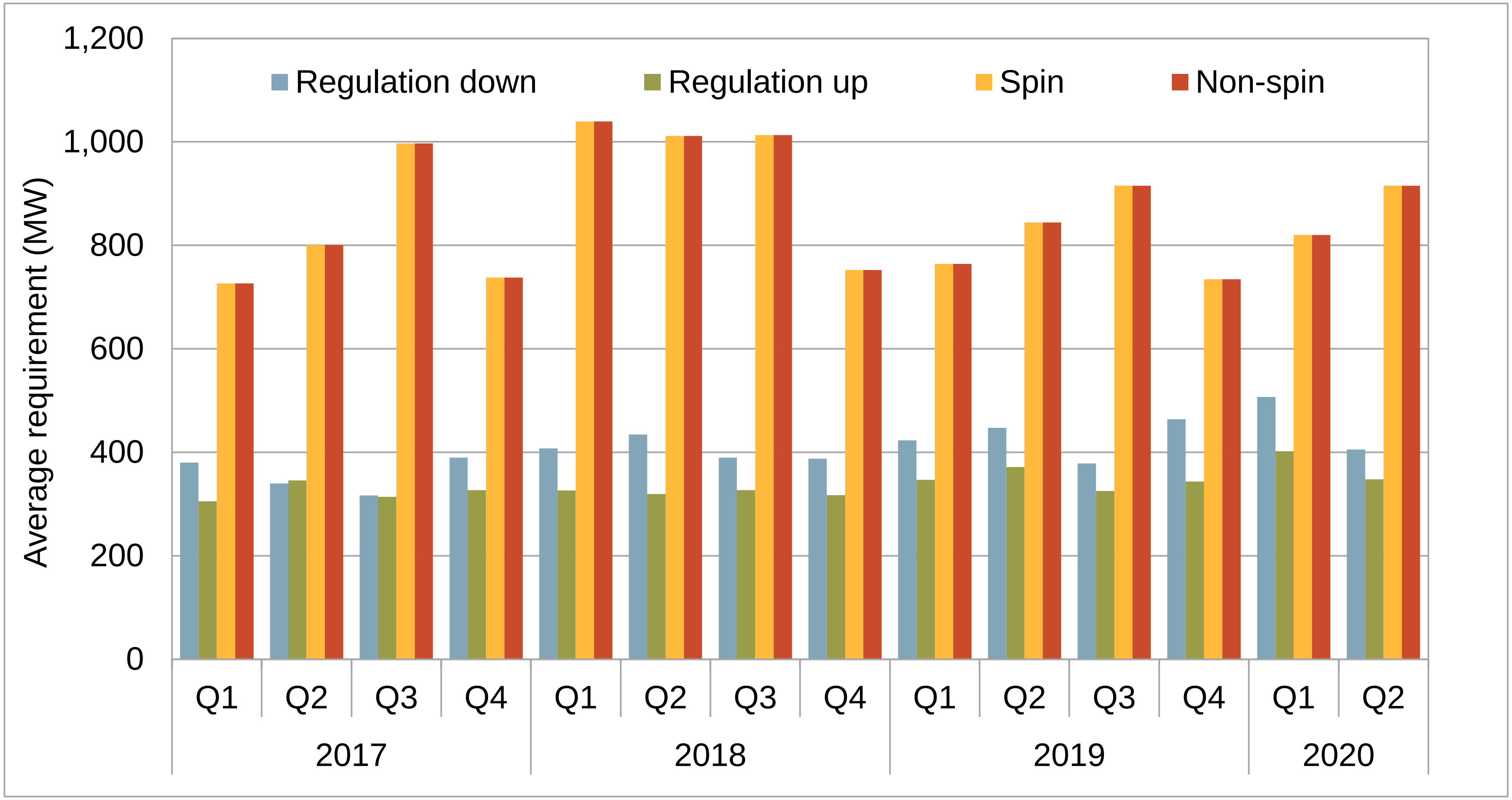
Flexible ramping capacity

- Flexible ramping prices were frequently zero during the first half of 2020
- Total uncertainty payments to generators were around $0.25 million total in Q1 and Q2, compared to around $4 million in 2019
- 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
- Recently, the ISO Board approved several flexible ramping product enhancements designed to address:
  – procurement of capacity from resources not able to meet system uncertainty because of resource characteristics or congestion
  – efficient real-time unit commitment reducing the need for out-of-market actions to meet intra-hour ramping uncertainty

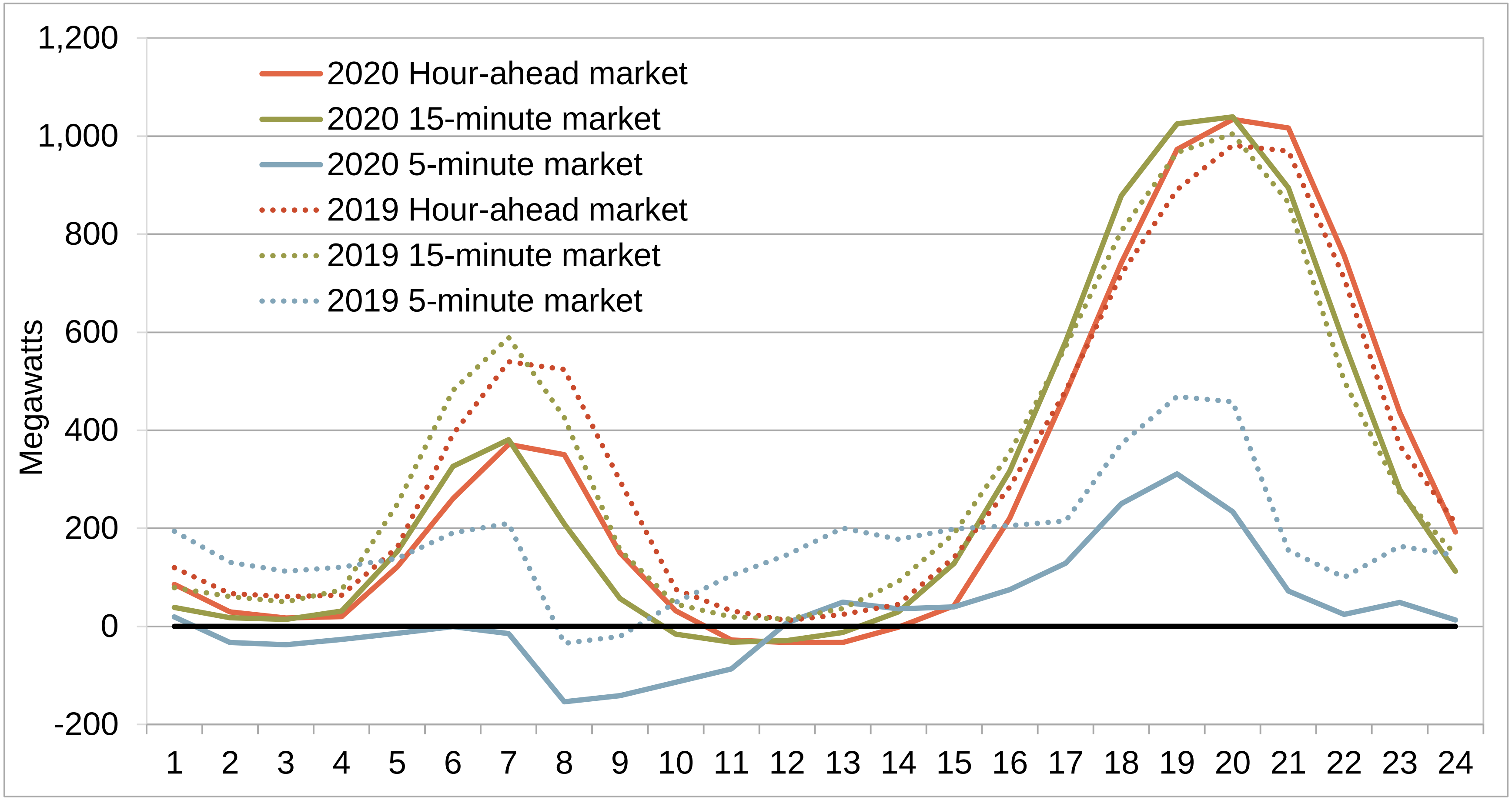
In Q2 2020, ancillary service payments decreased to $24 million, compared to $30 million in Q1 2020 and $55 million during Q2 2019.



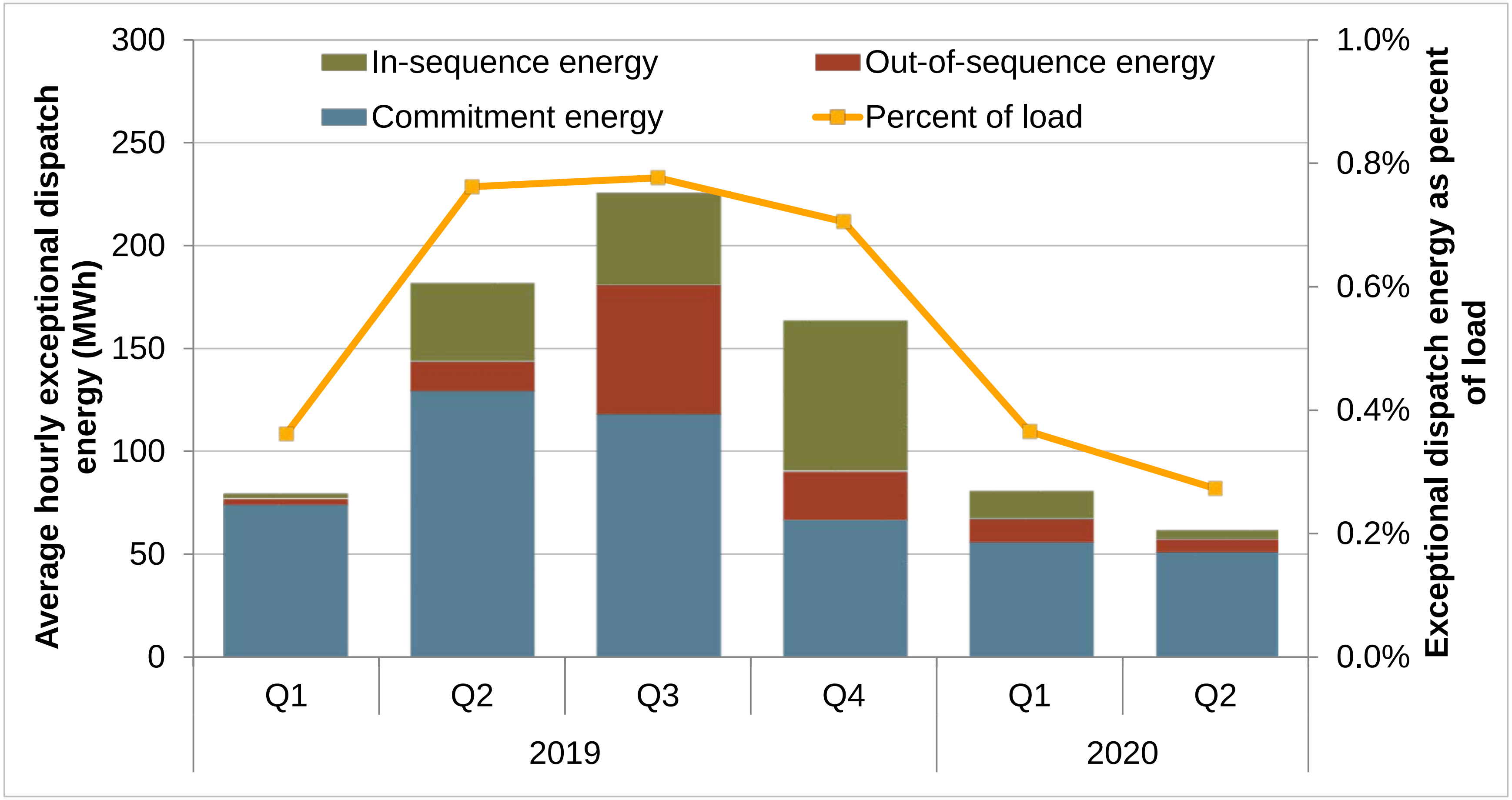
In Q1 and Q2, average requirements for spinning and non-spinning operating reserves continued to increase



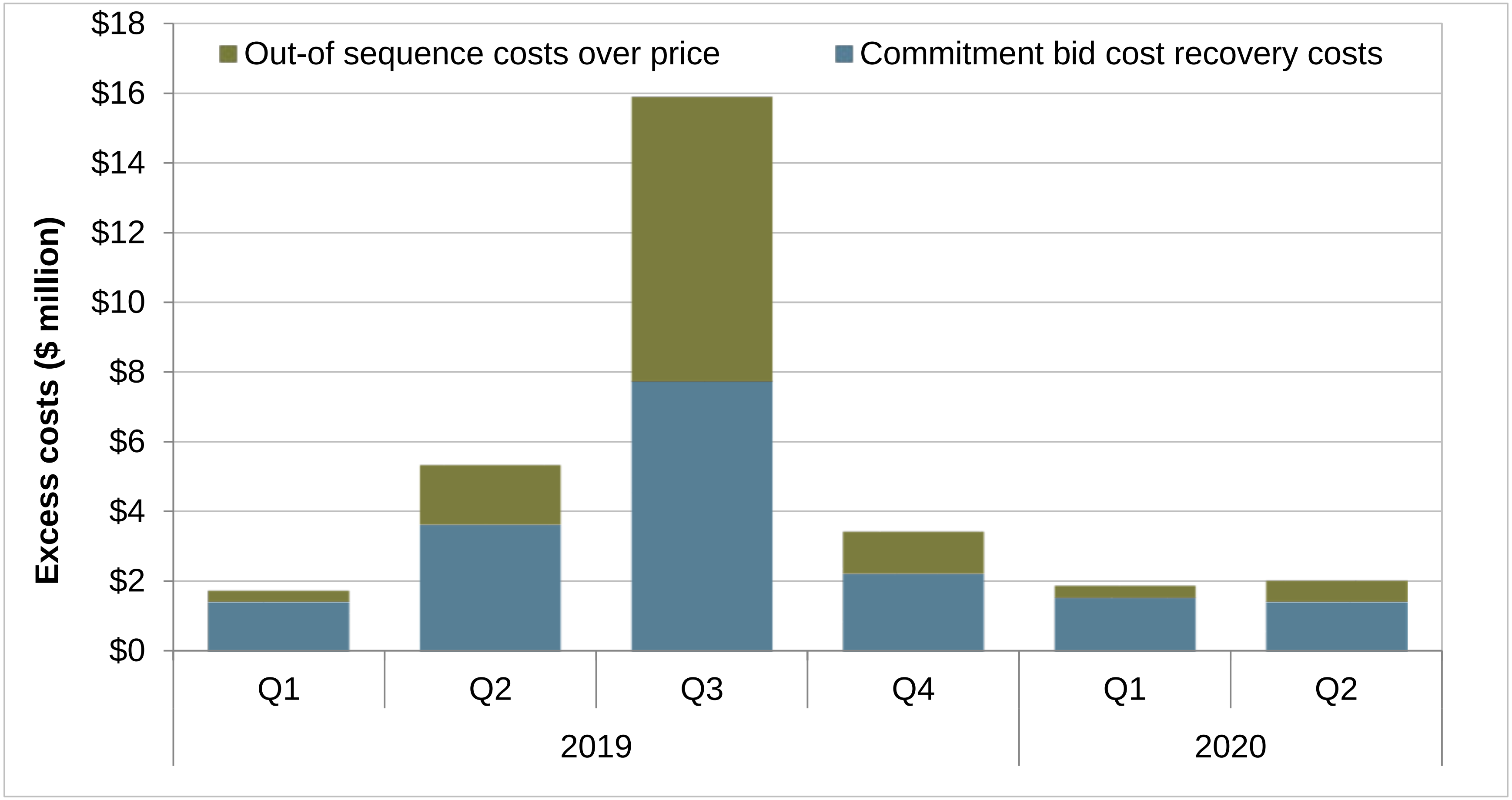
Average hourly load adjustment increase despite moderate system conditions (Q2 2019, Q2 2020)



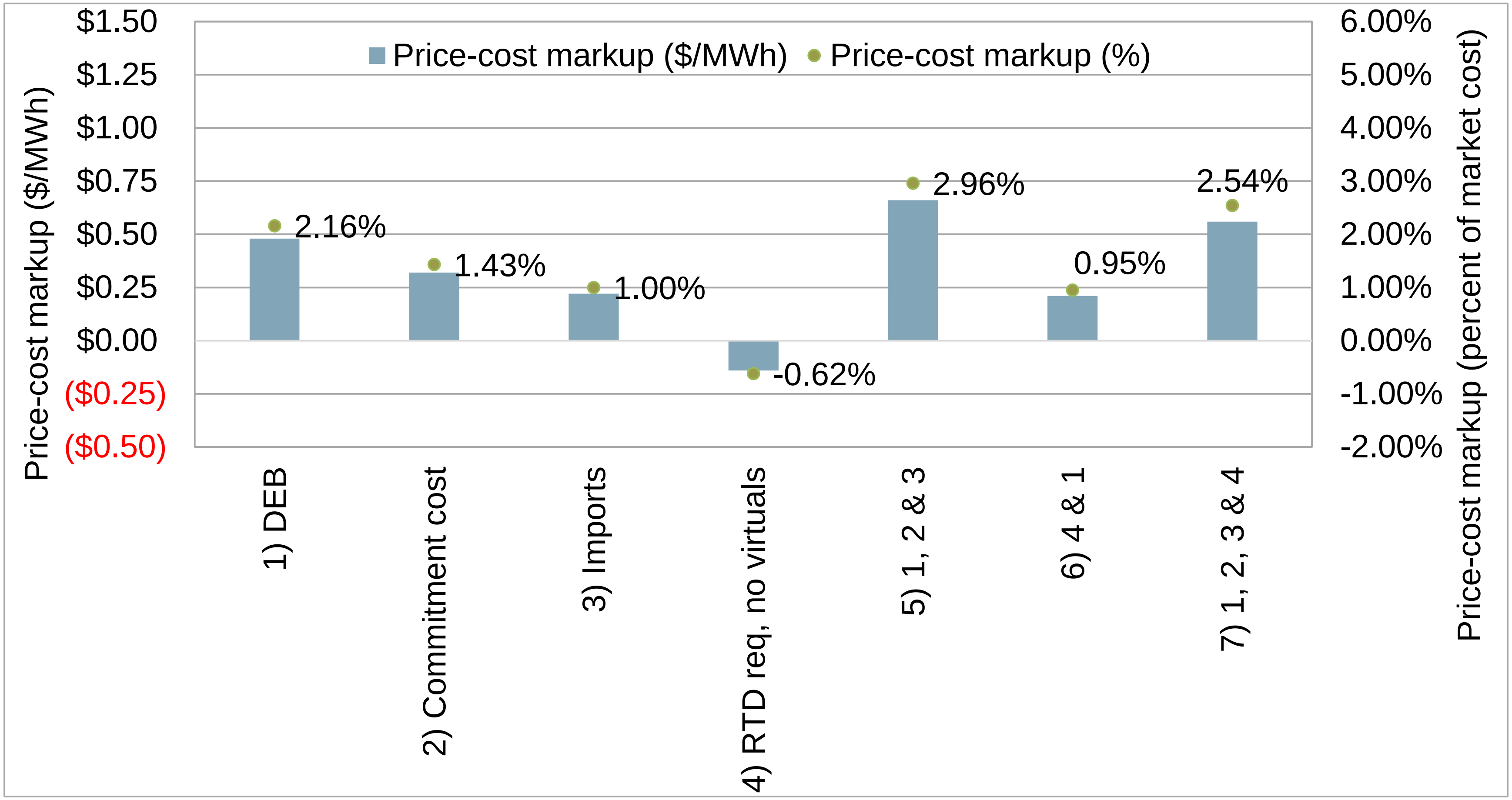
Average hourly energy from exceptional dispatch under 0.5% system load in Q1 and Q2 2020



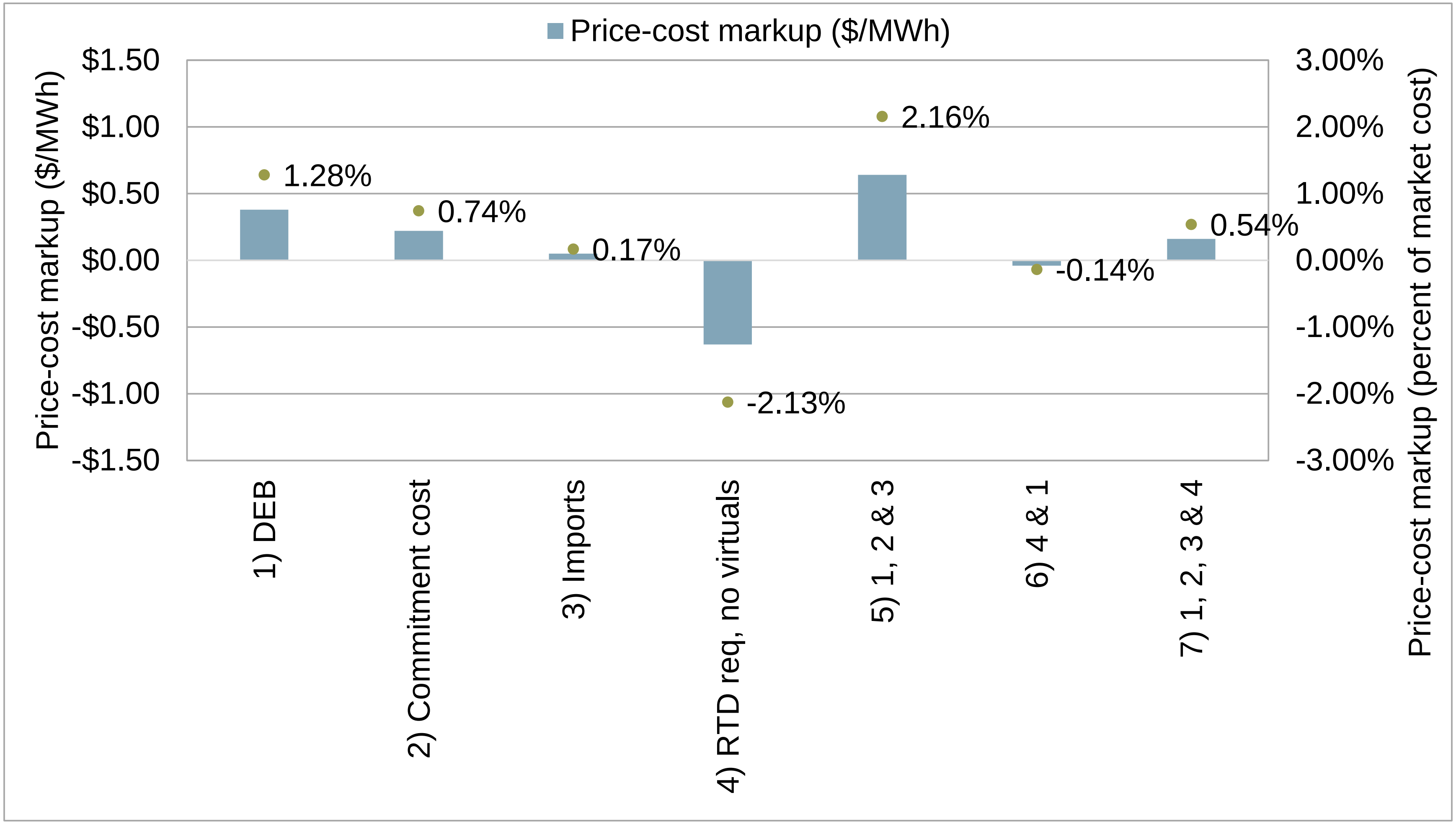
For the first half of 2020, total exceptional dispatch costs about $4.9 million



DMM assesses the competitiveness of the ISO's energy markets through day-ahead market software simulation under different scenarios (Q2).

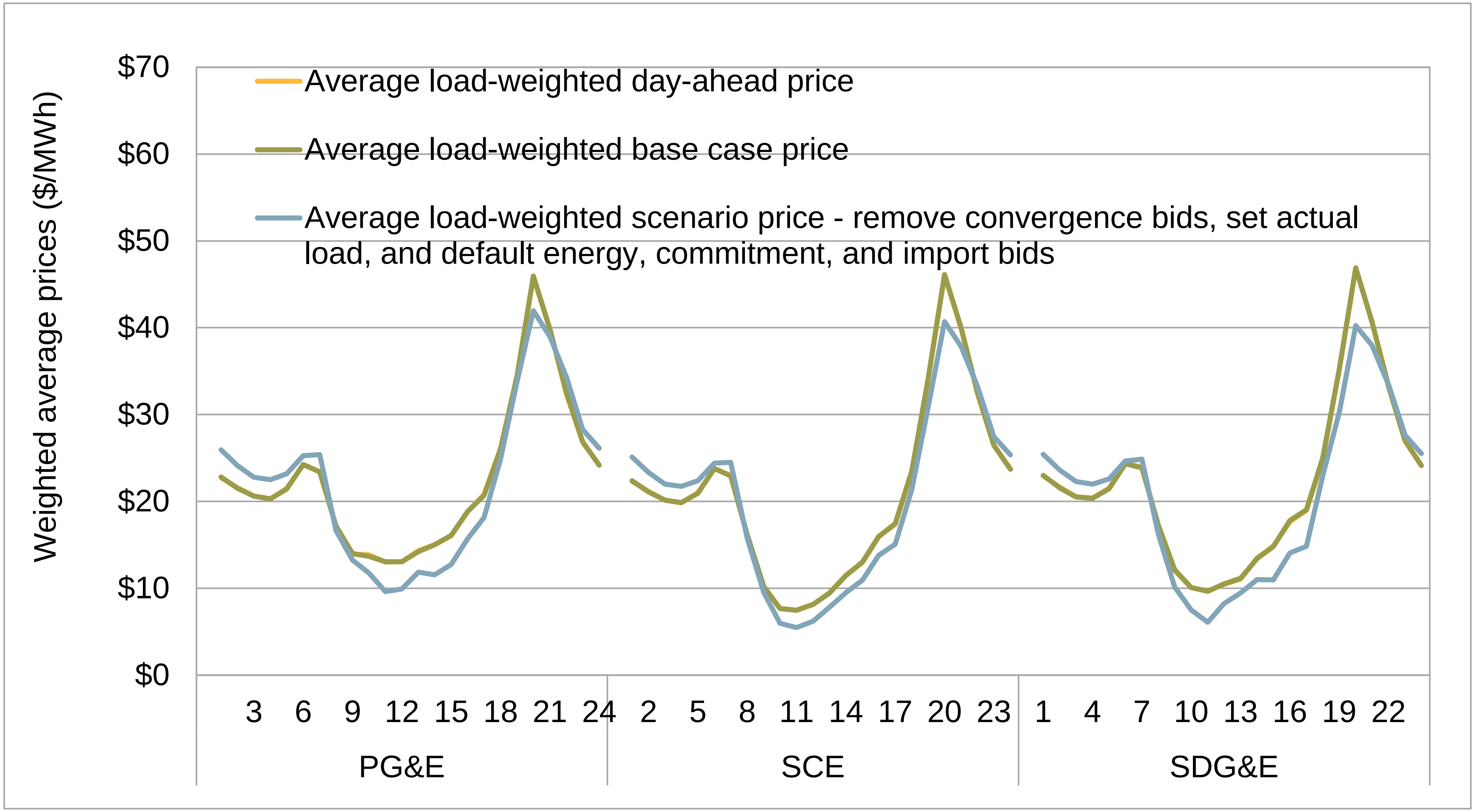


By these measures, markets were even more competitive in Q1

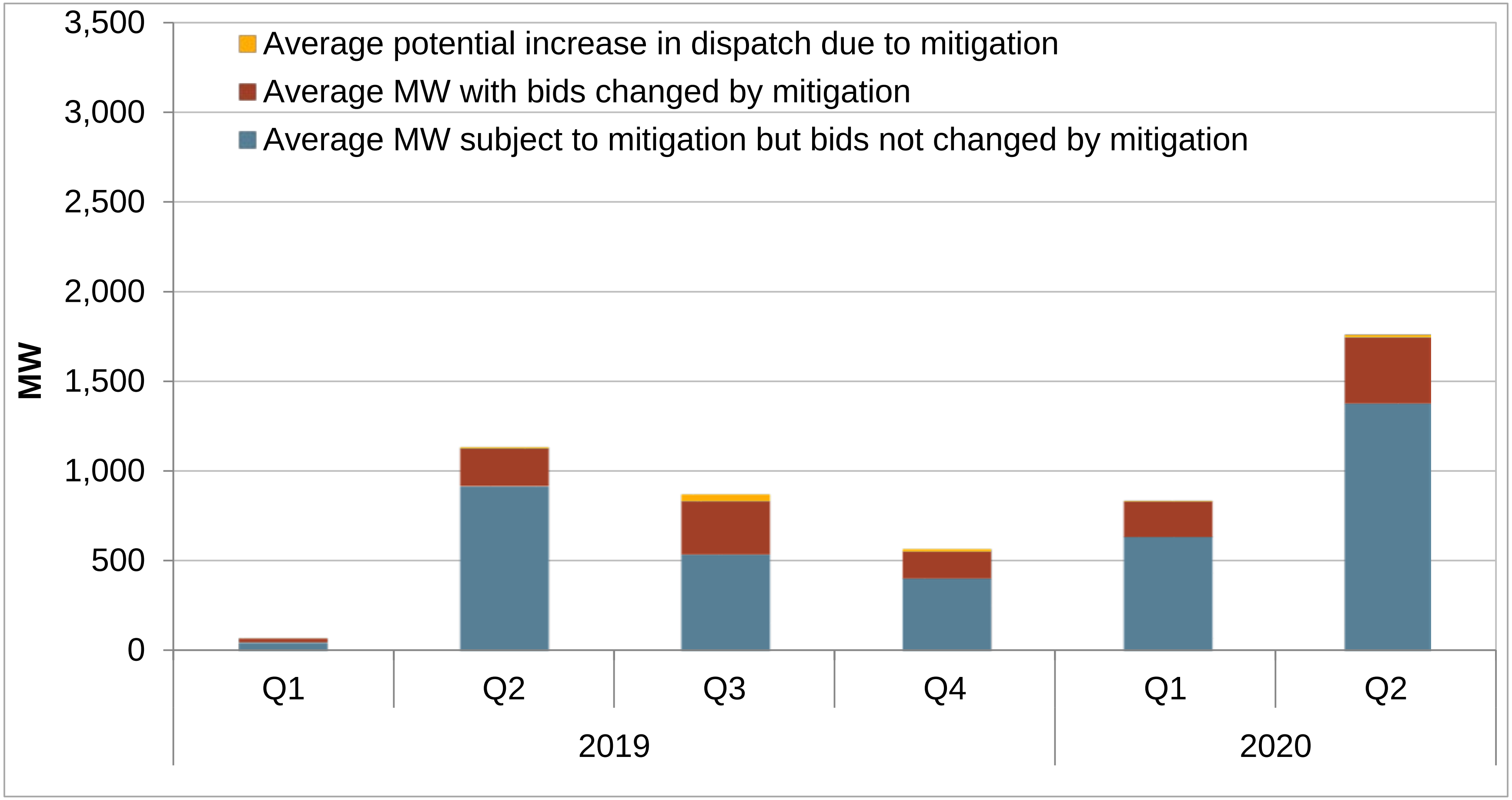


The ISO's energy markets were competitive in Q2 (combined scenarios)

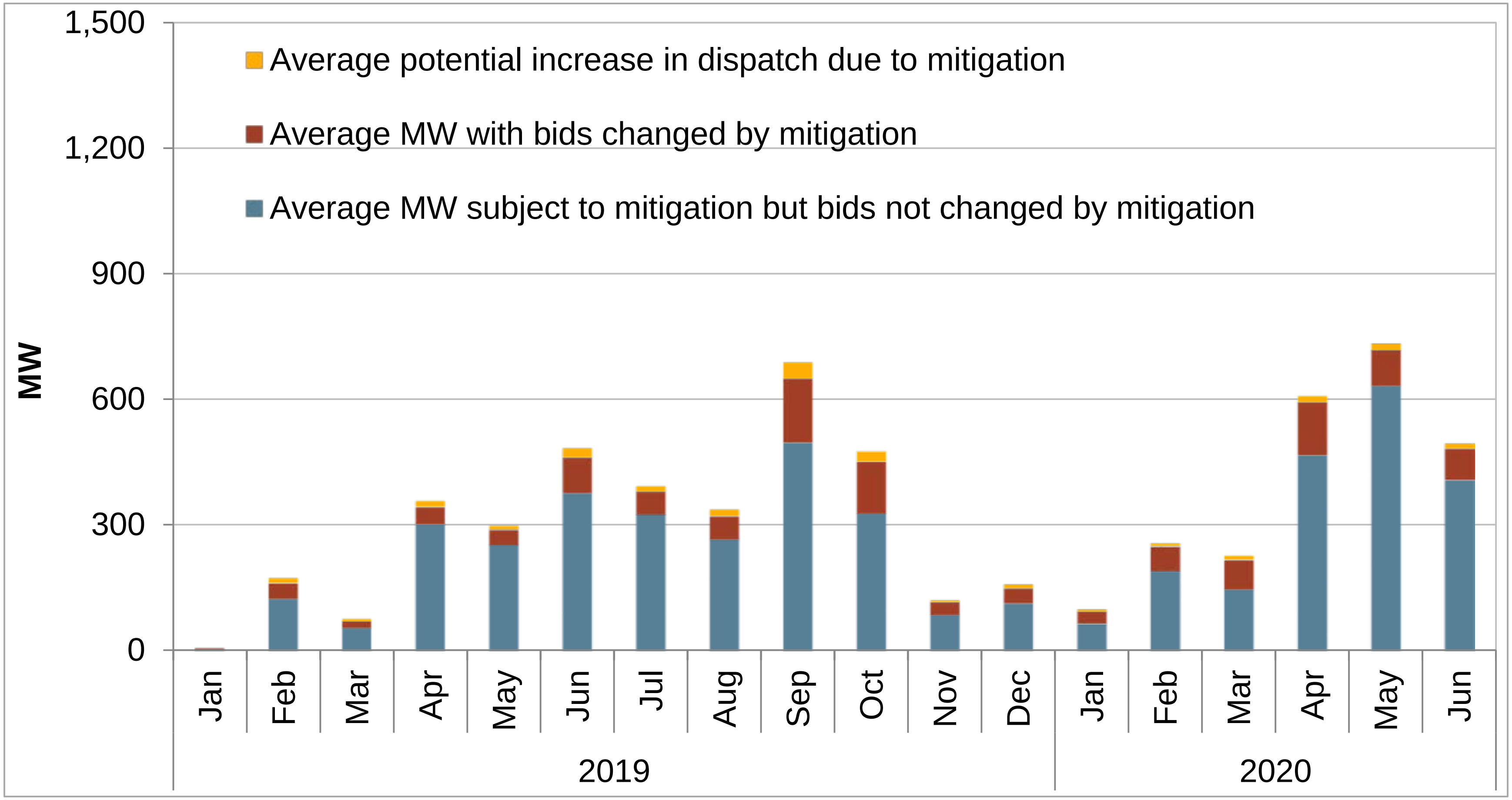
Energy prices about equal to competitive baseline prices calculated by DMM



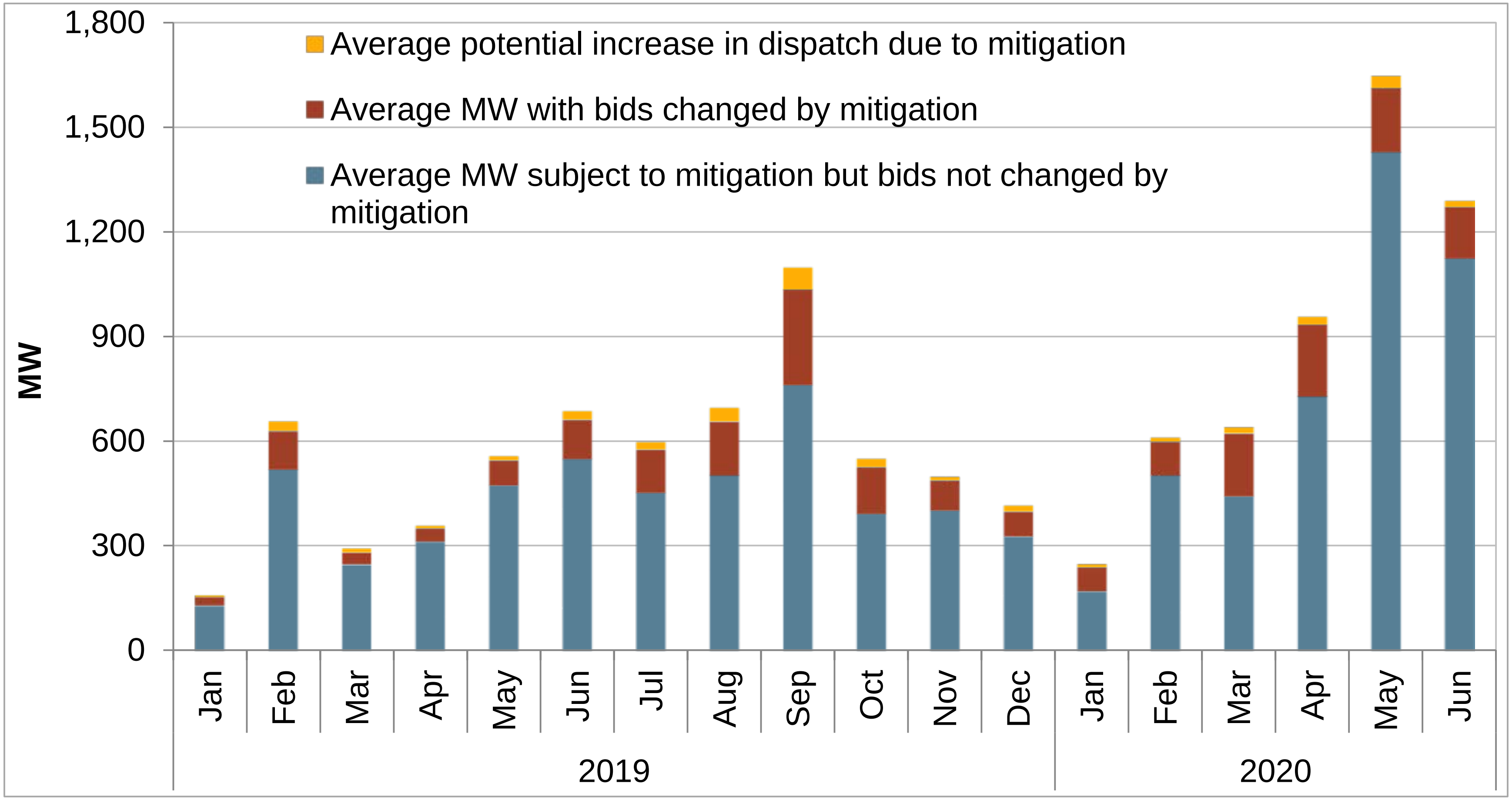
Average incremental energy with bids changed by mitigation in the day-ahead market remains low (ISO)



Average incremental energy mitigated in 15-minute real-time market (ISO)

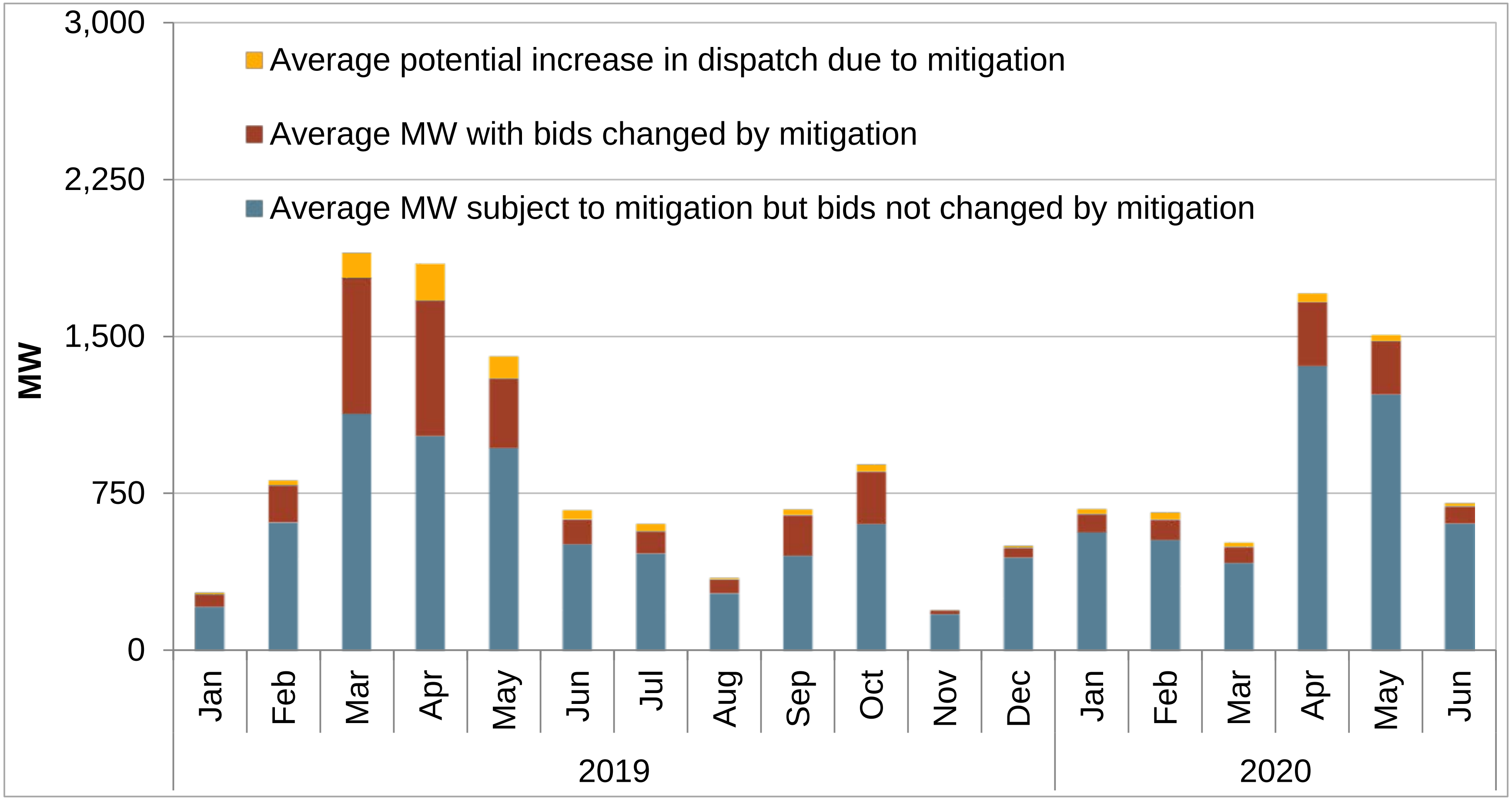


Average incremental energy mitigated in 5-minute real-time market (ISO)



Elimination of carryover mitigation reduced rates of mitigation in the EIM

Average incremental energy mitigated in 15-minute real-time market (EIM)



Questions?