2019 Annual Report on Market Issues and Performance

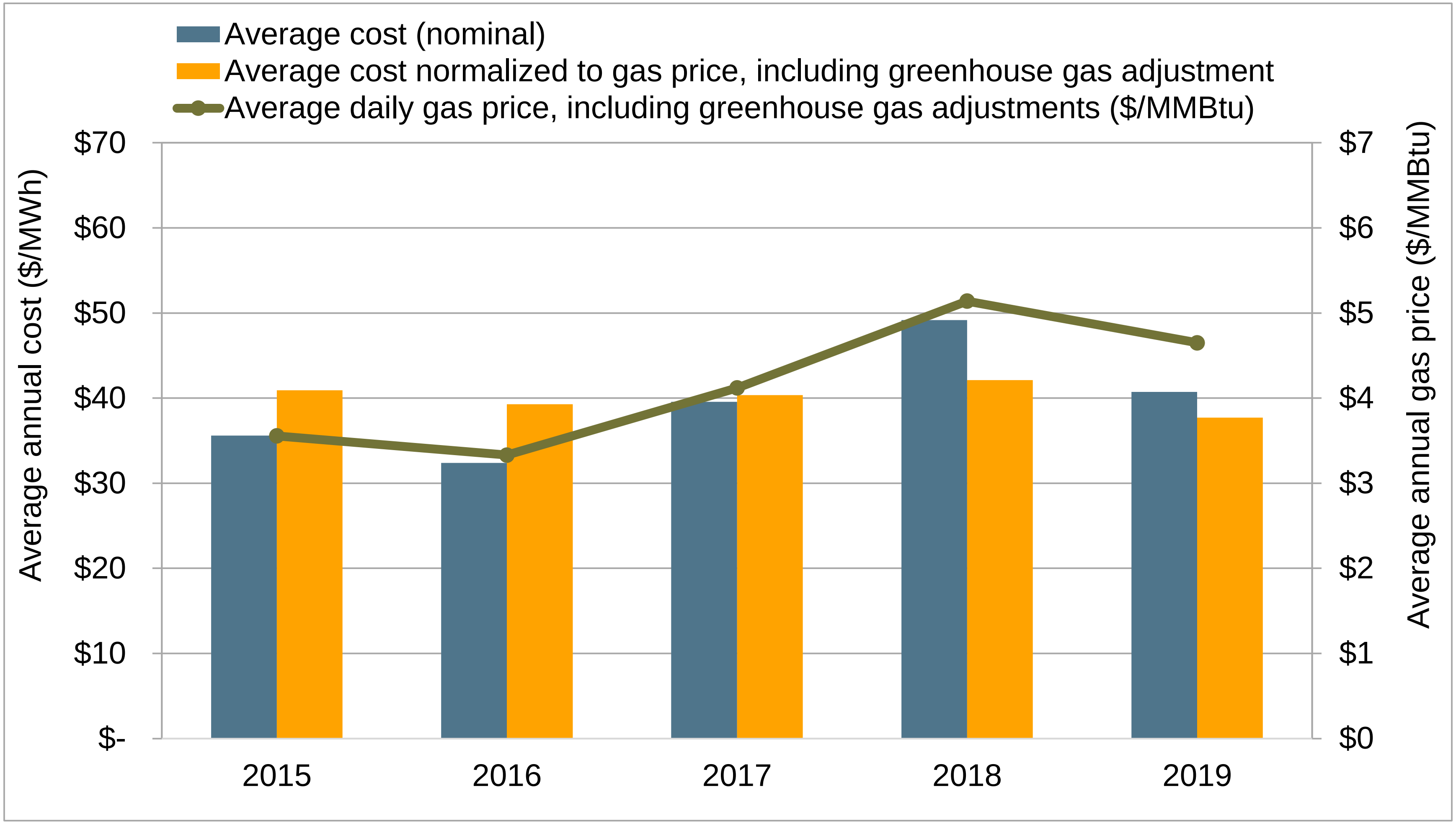
July 6, 2020

Amelia Blanke

Manager, Monitoring & Reporting

Department of Market Monitoring

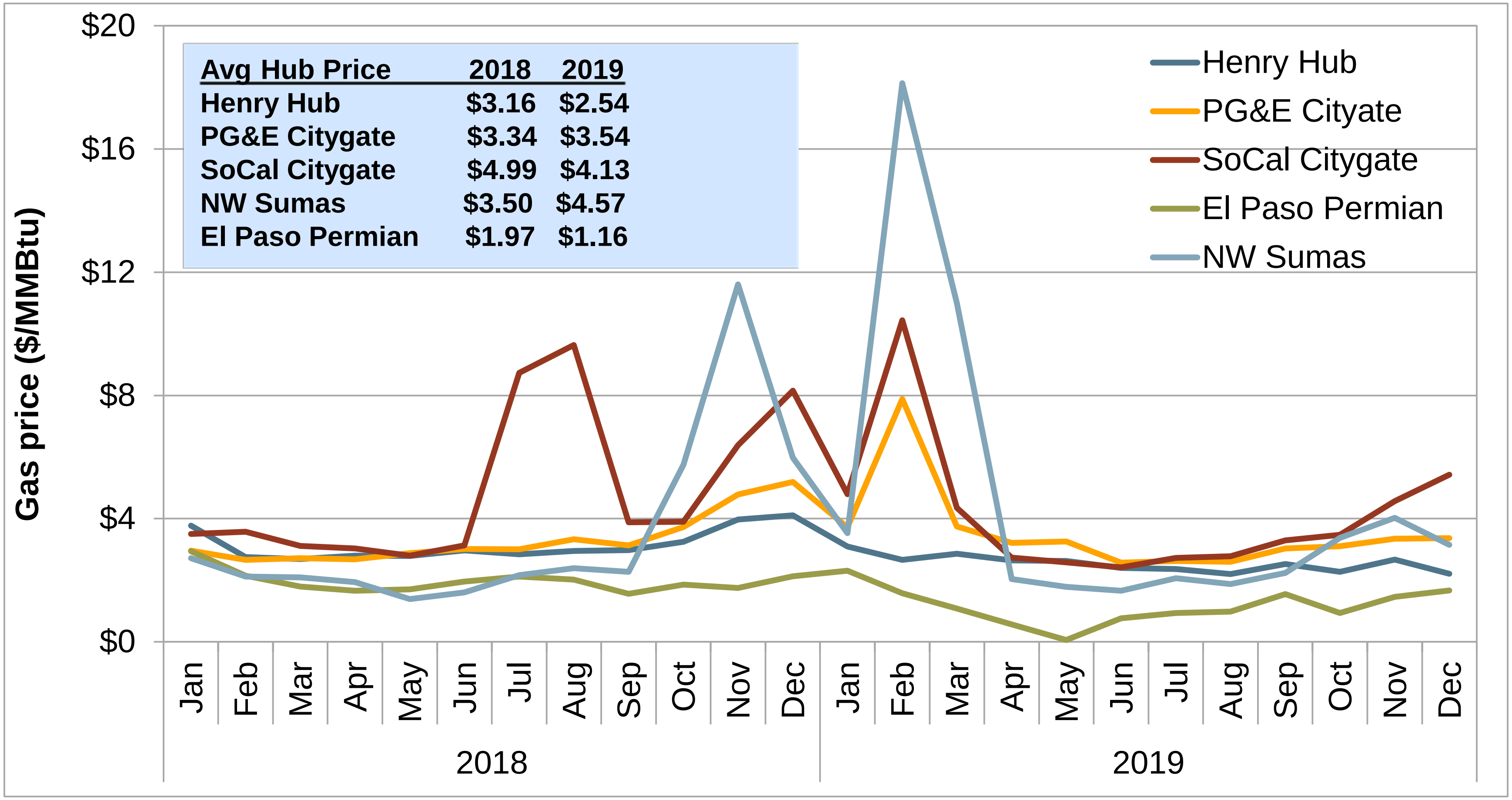
Total ISO wholesale costs decreased 17% -- or about 10% increase after accounting for 10% decrease in gas cost



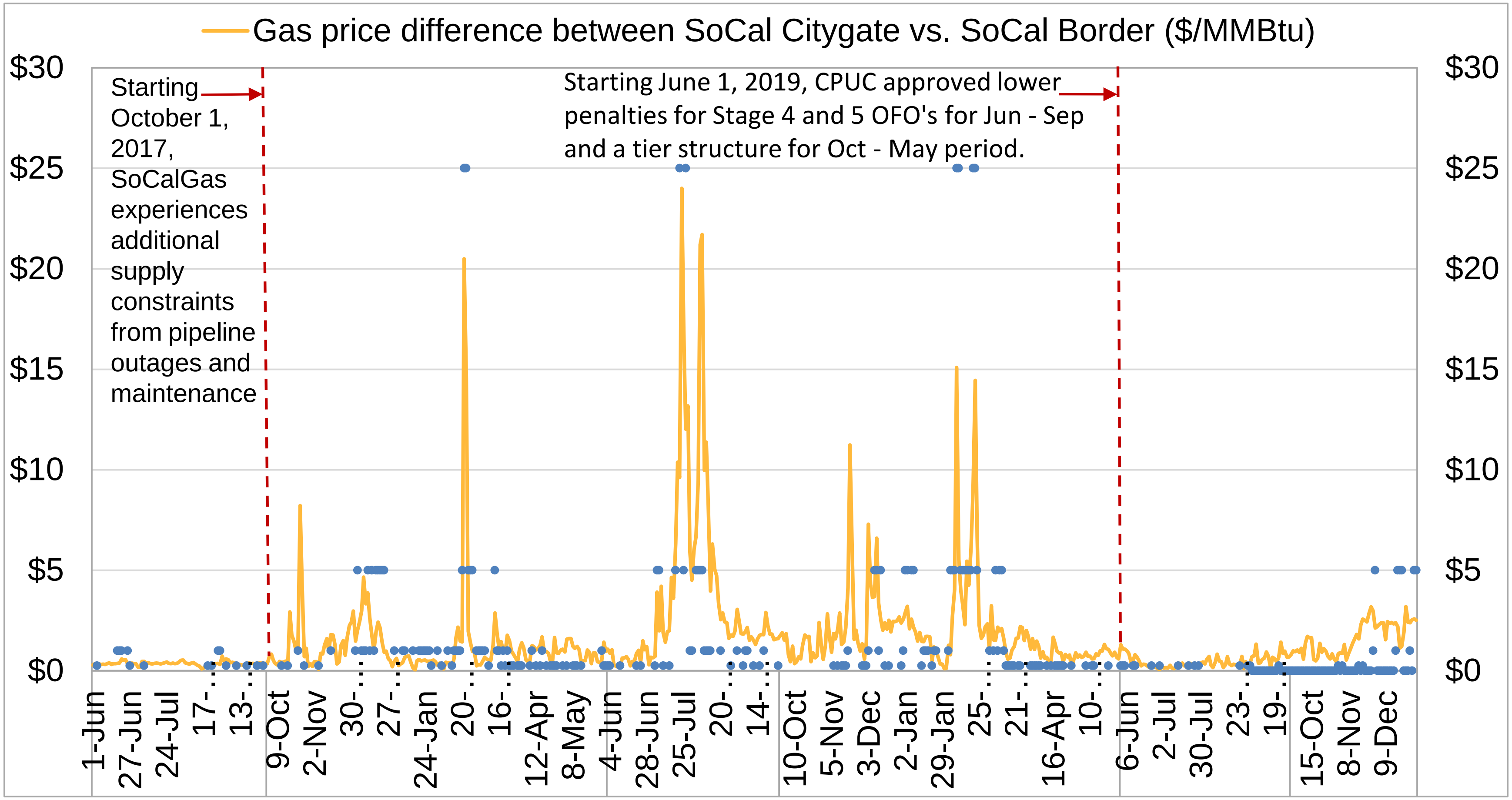
Total CAISO wholesale costs totaled $8.8 billion ($41/MWh)

	2015	2016	2017	2018	2019	Change '18-'19
Day-ahead energy costs	$ 34.23	$ 30.49	$ 37.40	$ 46.05	$ 38.12	$ (7.94)
Real-time energy costs (incl. flex ramp)	$ 0.18	$ 0.54	$ 0.73	$ 0.60	$ 1.01	$ 0.42
Grid management charge	$ 0.42	$ 0.42	$ 0.44	$ 0.46	$ 0.46	$ (0.00)
Bid cost recovery costs	$ 0.38	$ 0.30	$ 0.41	$ 0.69	$ 0.57	$ (0.11)
Reliability costs (RMR and CPM)	$ 0.12	$ 0.11	$ 0.10	$ 0.73	$ 0.06	$ (0.67)
Average total energy costs	**$ 35.33**	**$ 31.86**	**$ 39.09**	**$ 48.52**	**$ 40.22**	**$ (8.31)**
Reserve costs (AS and RUC)	$ 0.27	$ 0.53	$ 0.71	$ 0.87	$ 0.74	$ (0.13)
Average total costs of energy and reserve	**$ 35.60**	**$ 32.39**	**$ 39.80**	**$ 49.40**	**$ 40.96**	**$ (8.44)**

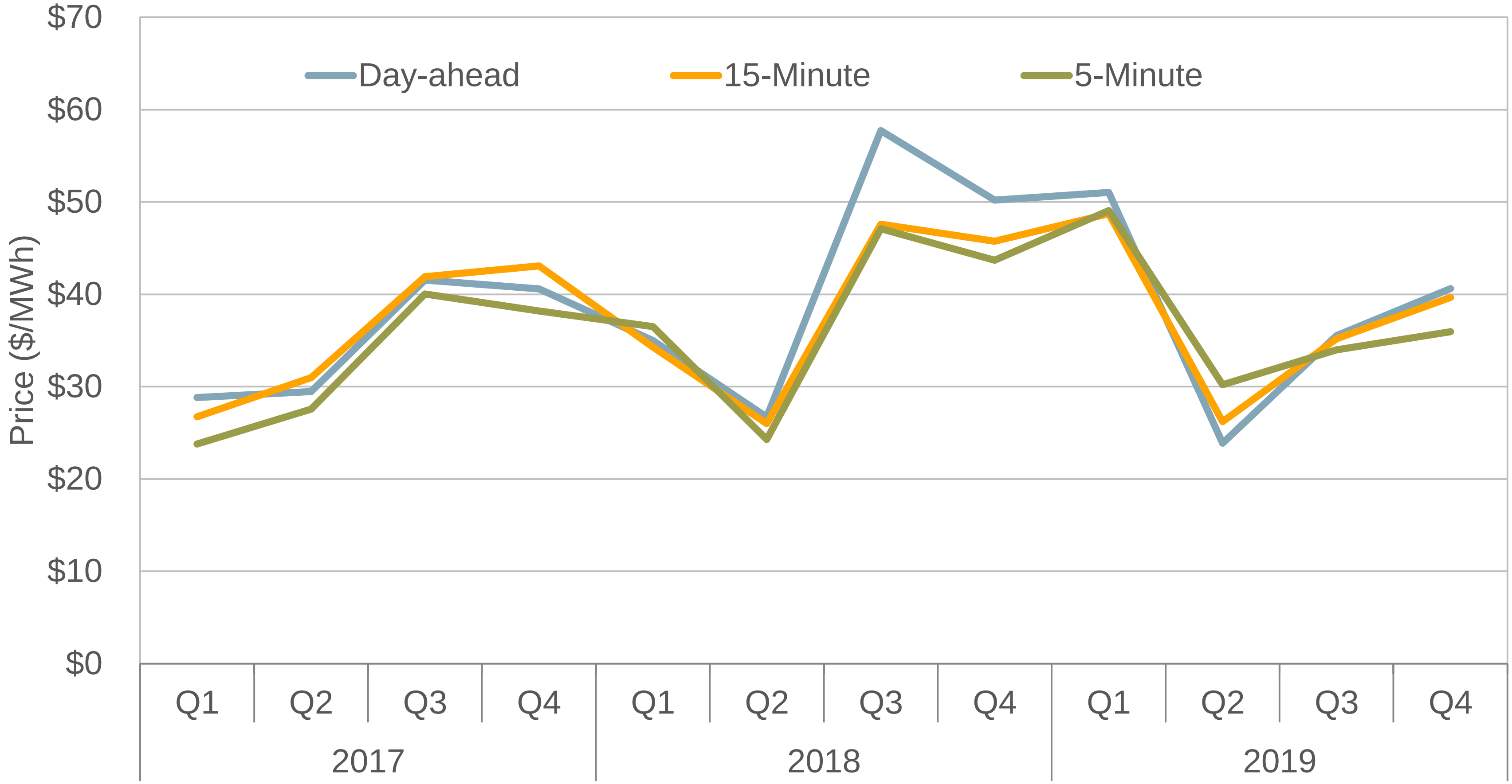
Day-ahead prices were often driven by gas prices



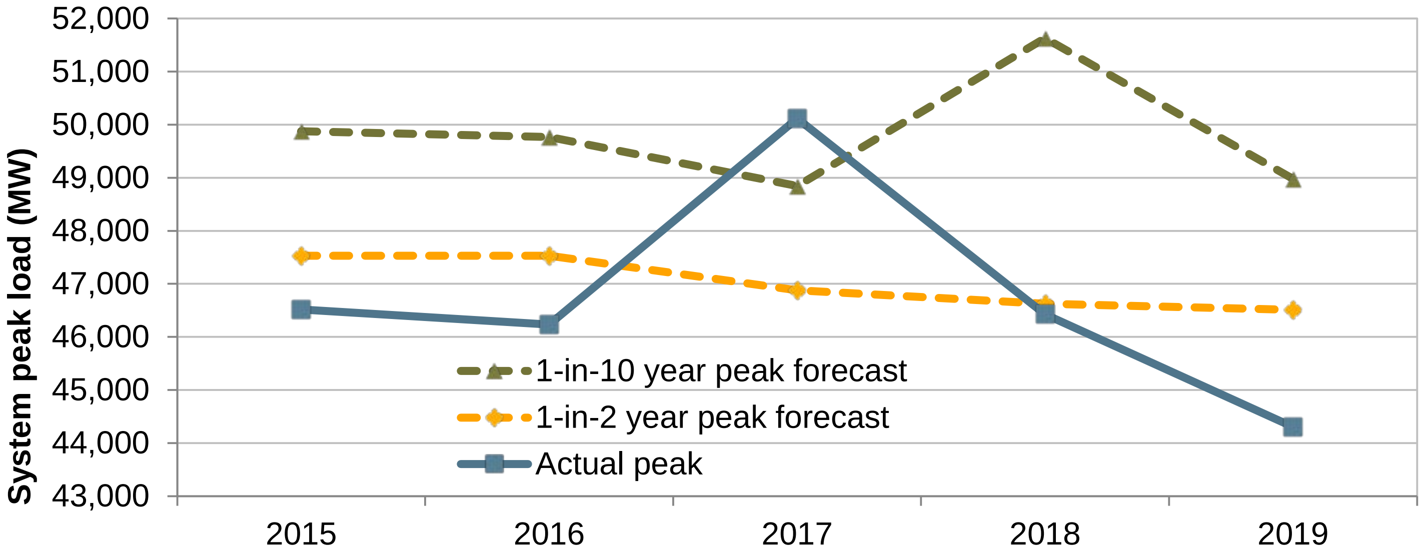
SoCal Citygate gas price spikes were driven by gas supply limitations and potential for high noncompliance charges (OFOs).



Average day-ahead prices ($38/MWh) were slightly higher than 15-minute prices ($37.5/MWh) and 5-minute prices ($37/MWh)

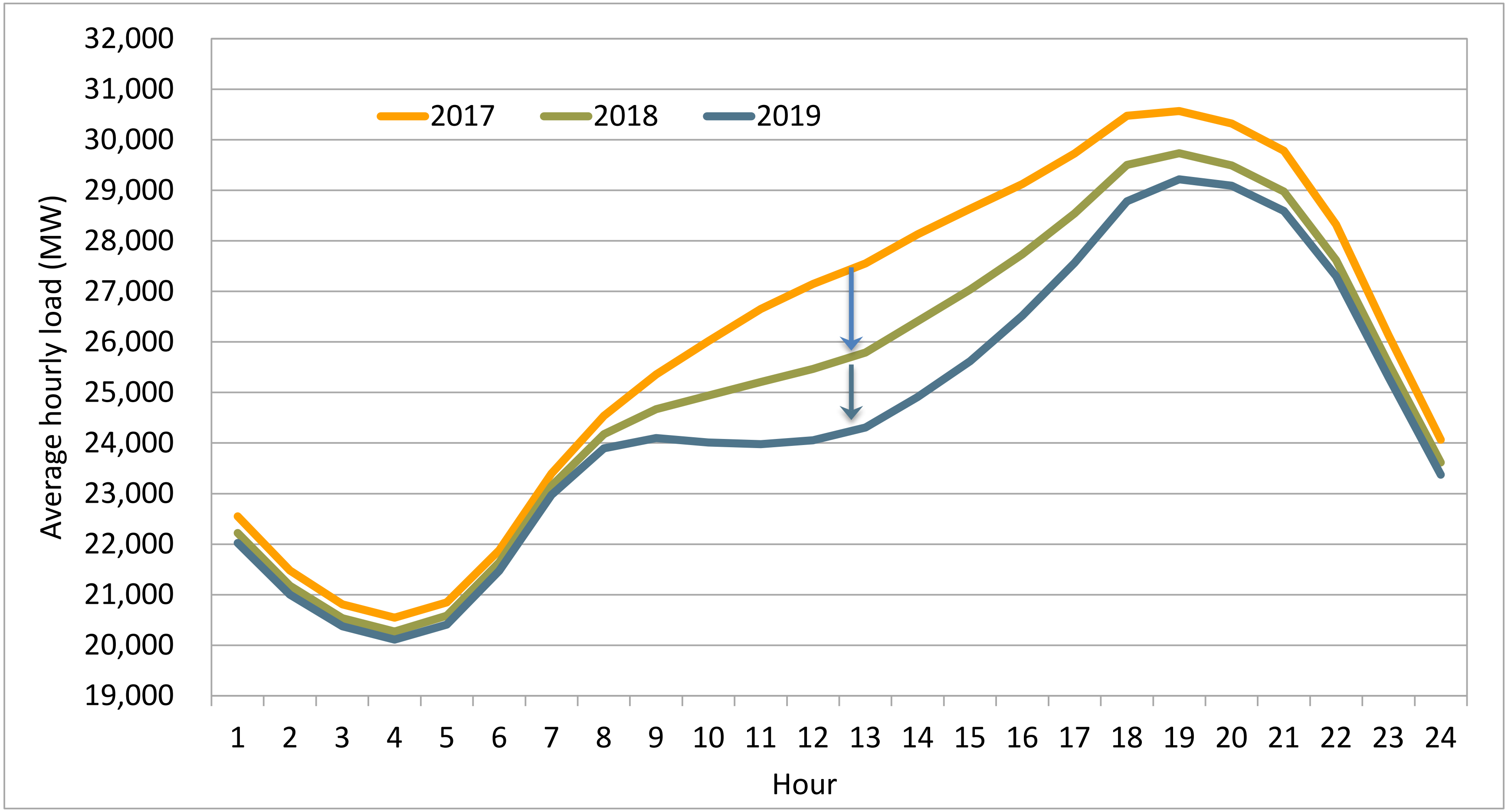


Peak loads and overall energy loads lower in 2019

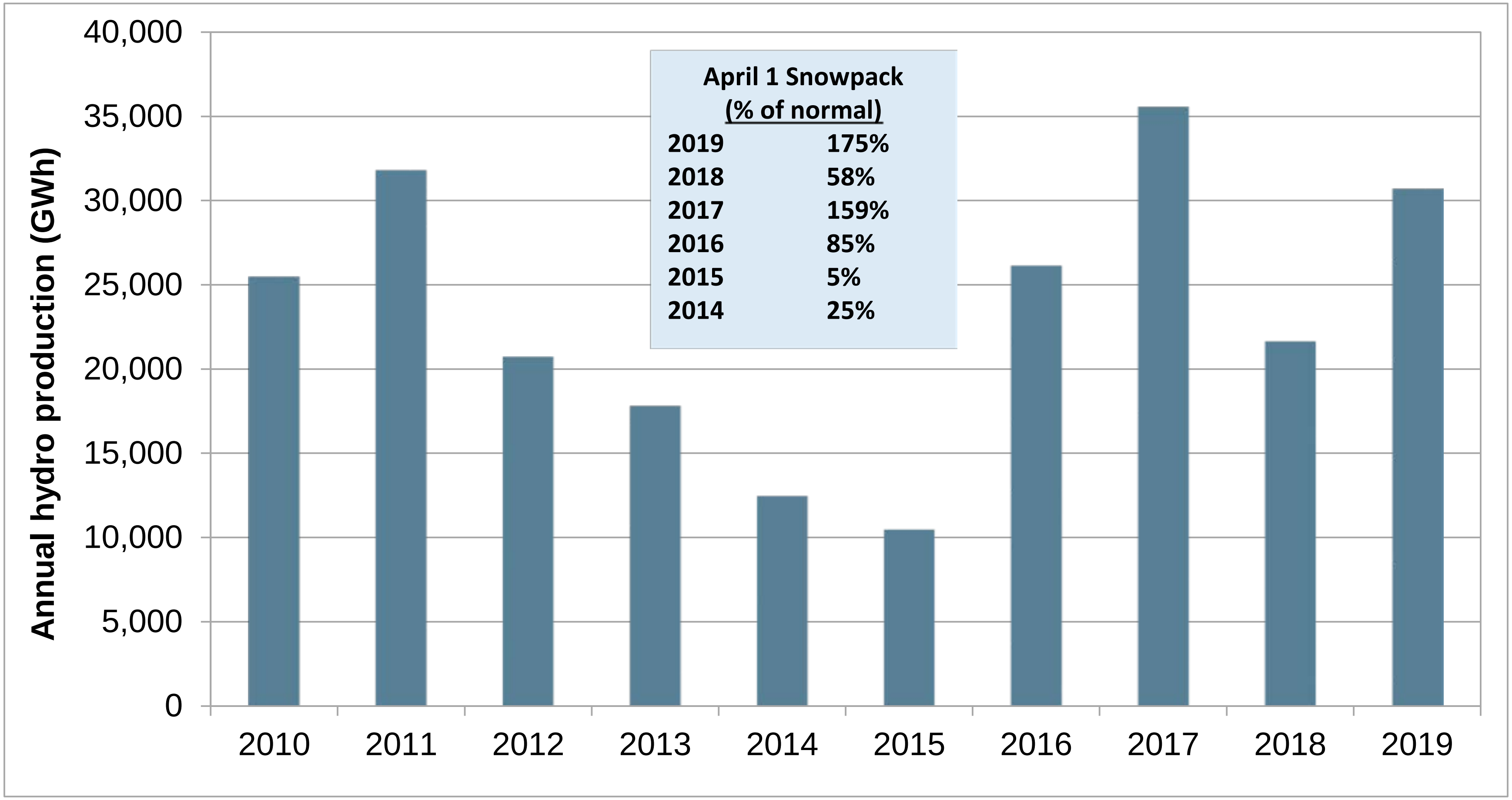


Year	Annual total energy (GWh)	Average load (MW)	% change	Annual peak load (MW)	% change
2017	227,749	26,002	0.0%	50,116	8.4%
2018	220,458	25,169	-3.2%	46,427	-7.4%
2019	214,955	24,541	-2.5%	44,301	-4.6%

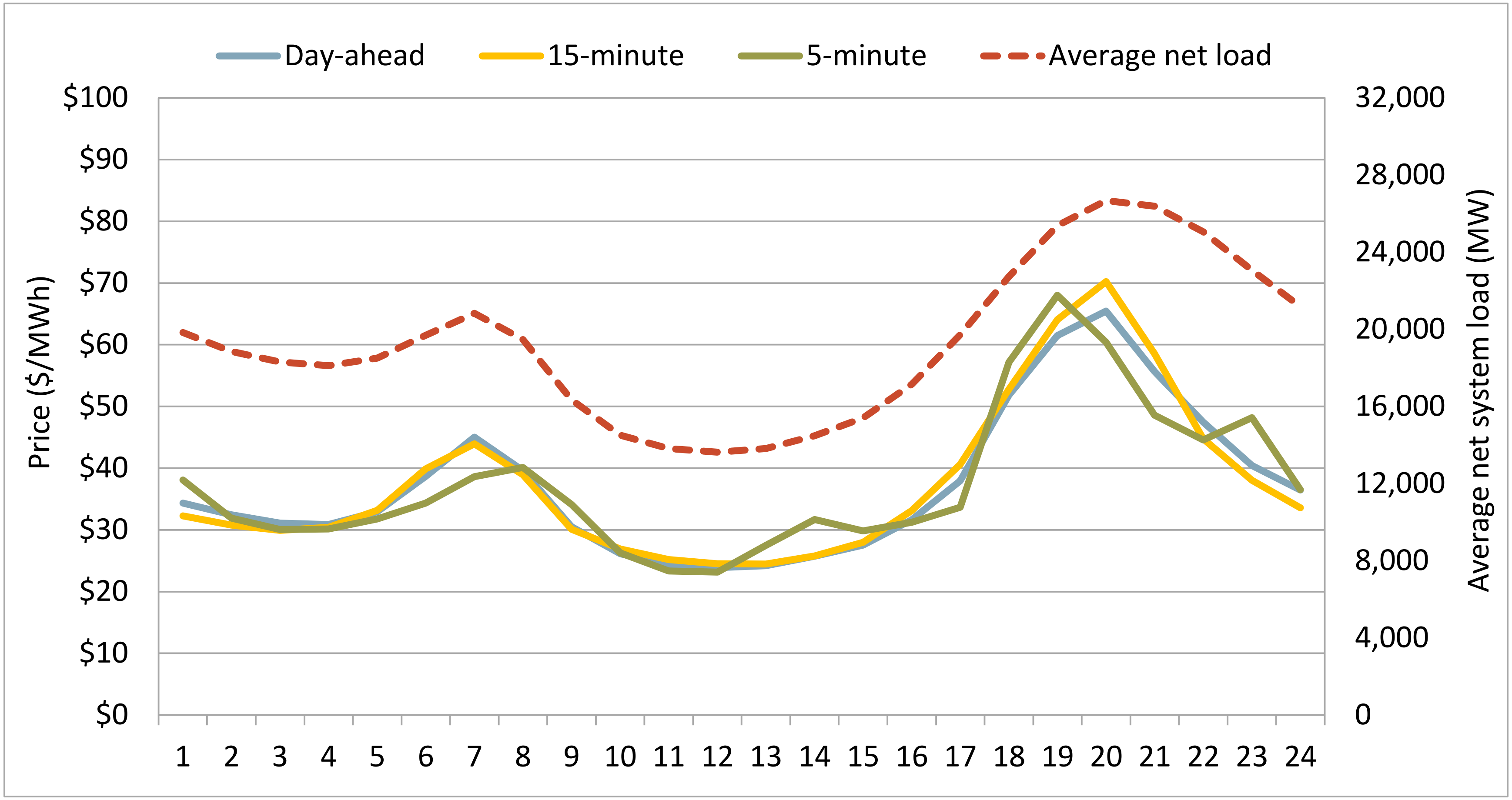
Average hourly loads continue to decrease due to behind-the-meter solar generation and energy efficiency initiatives, plus lower statewide temperatures in 2019



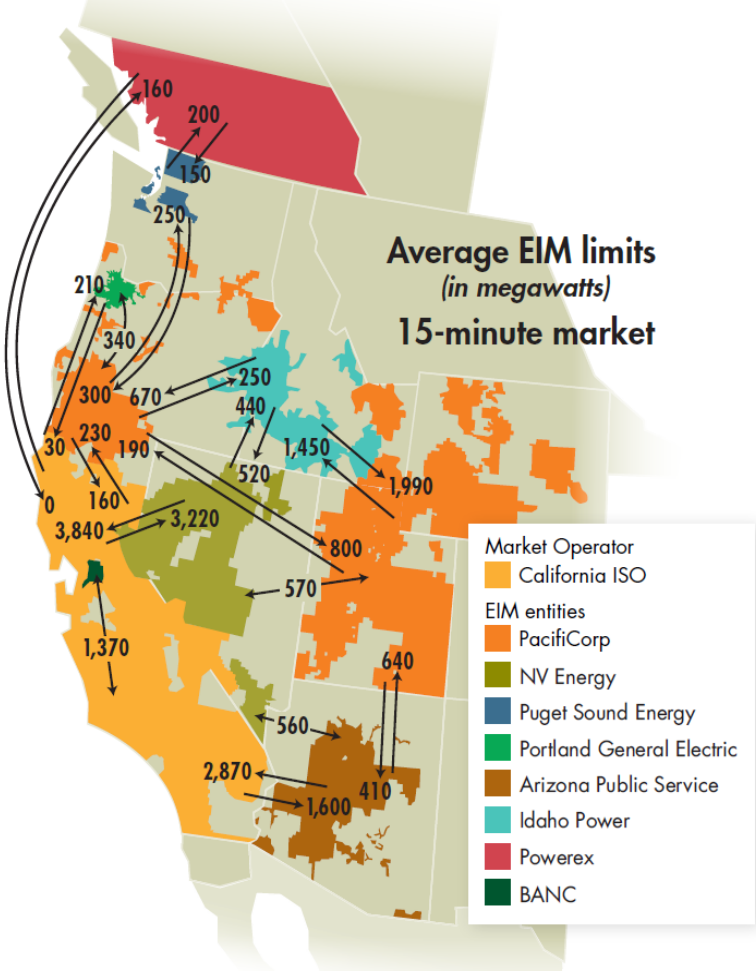
Hydroelectric generation increased to around 14% of supply, compared to 10% in 2018 and 15% in 2017



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

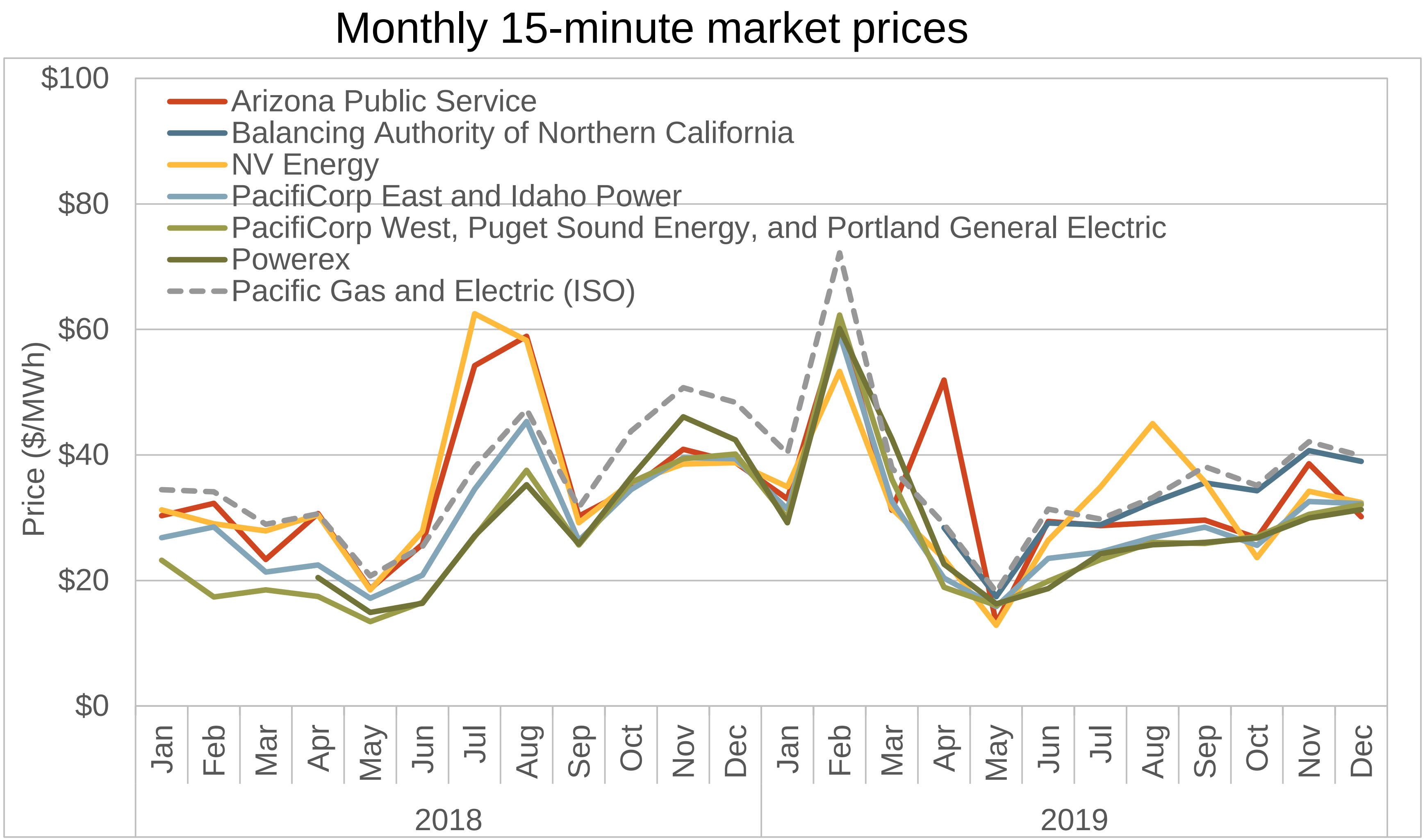


Expansion of the western energy imbalance market (EIM) helped improve the overall structure and performance of the real-time market

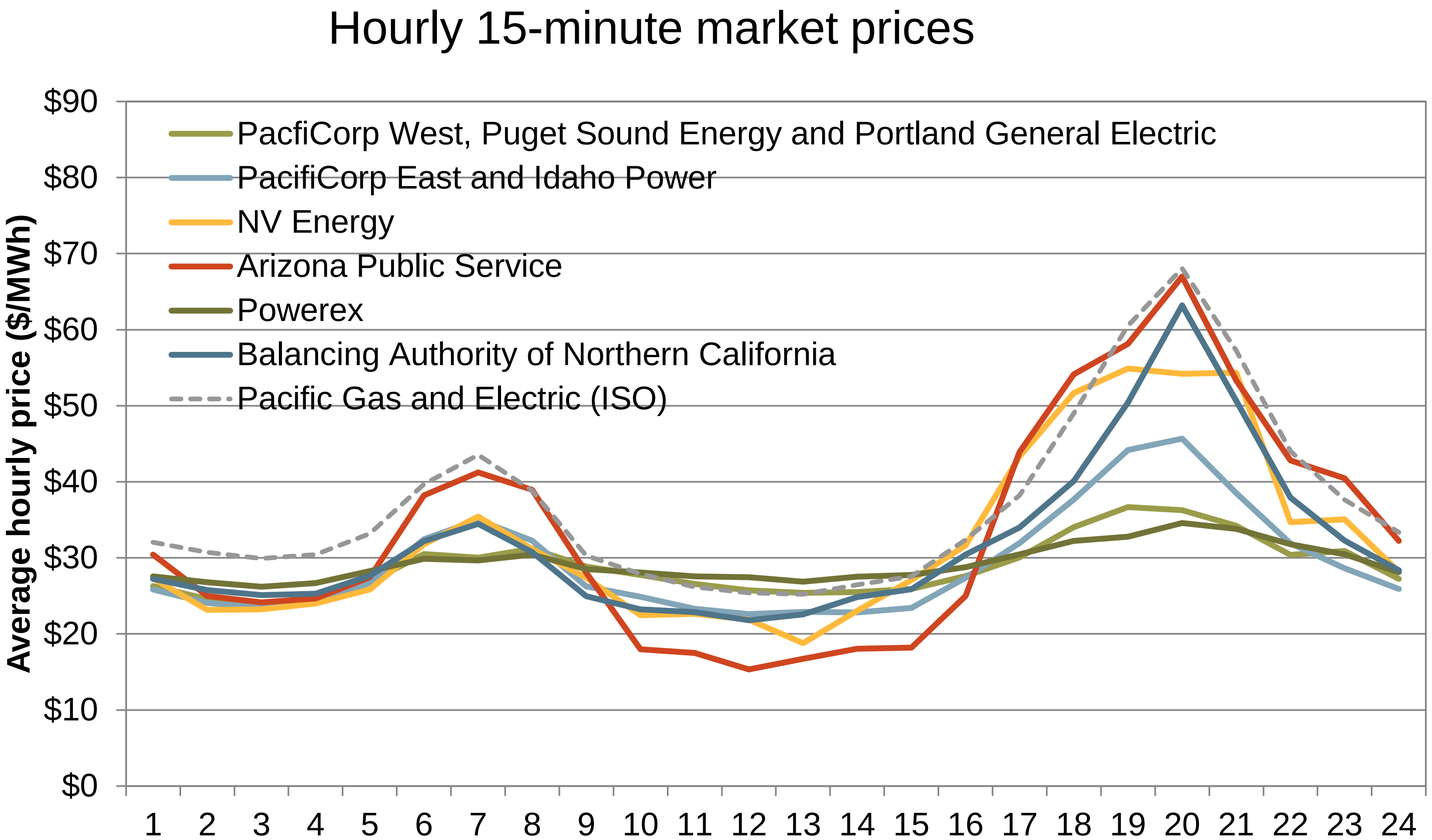


- One new member joined in April (BANC/SMUD)
- The EIM/CAISO system now accounts for over half of WECC peak load
- Load conformance limiter changes increased frequency of prices at the cap (Feb)
- Sufficiency test changes reduced frequency of test failures (May)
- EIM supply that can be delivered into CA lower due to change in EIM greenhouse gas accounting made in Nov. 2018

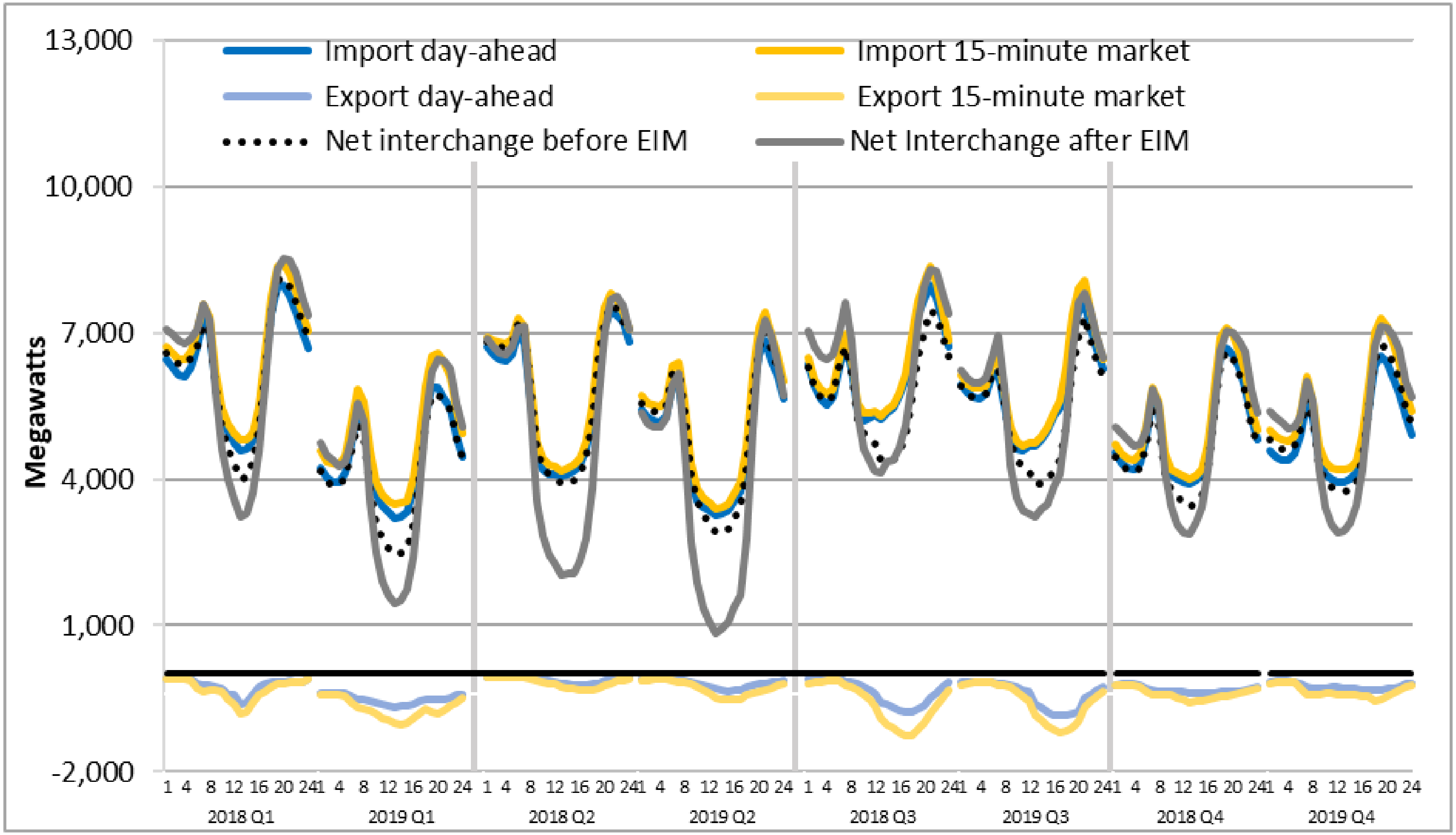
On average, prices in the CAISO are higher than other energy imbalance market balancing areas



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



Net imports into CAISO (excluding EIM) decreased 15% in 2019 due to lower imports from the Northwest.

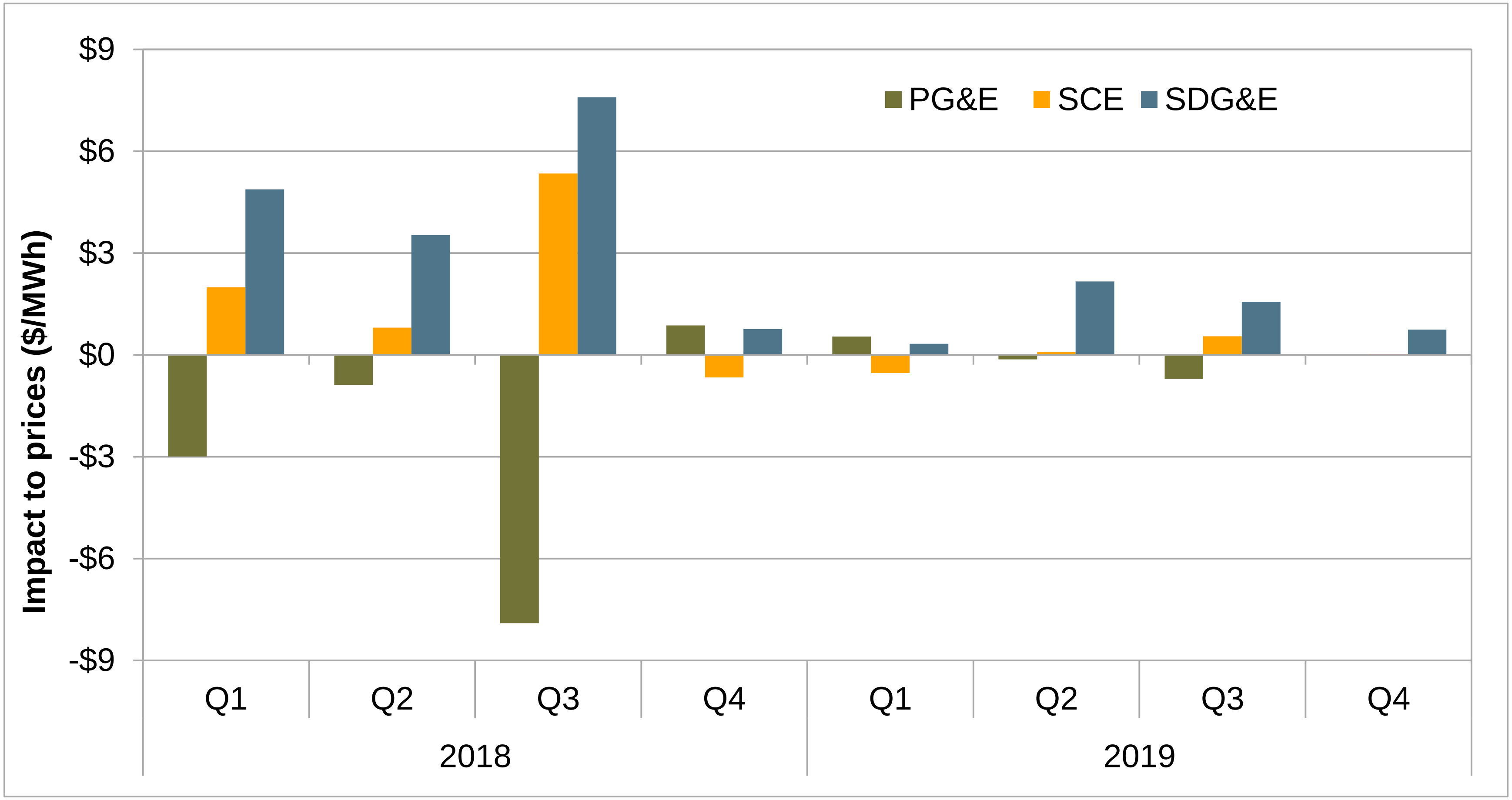


Congestion on transfer constraints from EIM areas into CAISO resulted in lower prices in Northwest EIM areas.

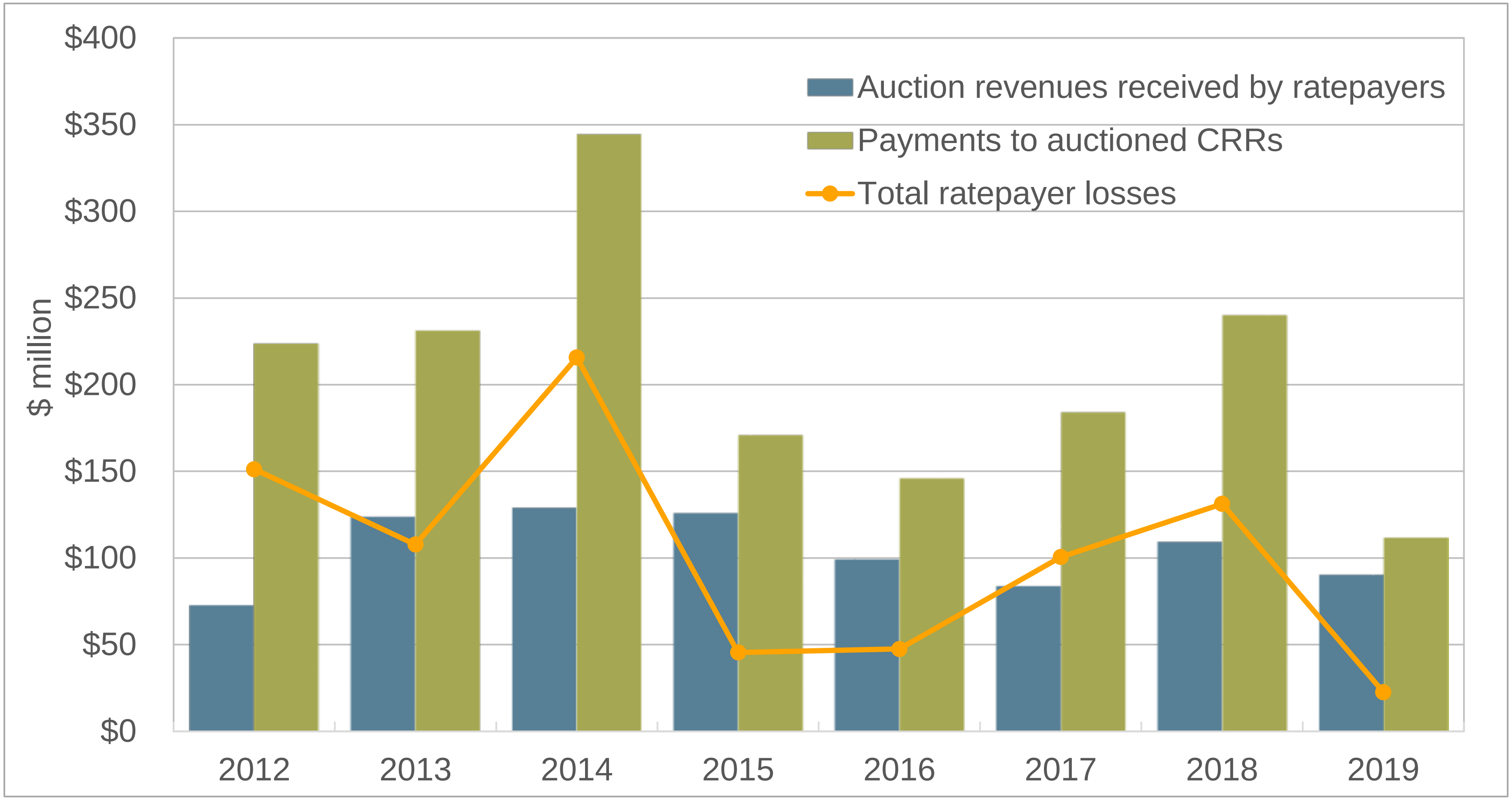
	15-minute market		5-minute market	
	Congestion Frequency	Price Impact ($/MWh)	Congestion Frequency	Price Impact ($/MWh)
BANC*	1%	-$0.39	1%	-$0.23
Arizona Public Service	3%	$4.84	4%	$4.32
NV Energy	5%	$2.25	5%	$3.45
PacifiCorp East	5%	-$0.08	5%	$0.75
Idaho Power	6%	-$0.55	6%	$0.33
PacifiCorp West	26%	-$2.33	20%	-$2.60
Portland General Electric	28%	-$2.59	22%	-$2.84
Puget Sound Energy	31%	-$2.21	26%	-$2.53
Powerex	47%	-$2.06	52%	-$3.15

Day-ahead congestion had lower impact on prices in 2019

Congestion revenues totaled 4.3 percent of day-ahead market energy costs, compared to about 6.8 percent in 2018.



Transmission ratepayers lost over $22 million from auctioned CRRs in 2019, down from $131 million in 2018.

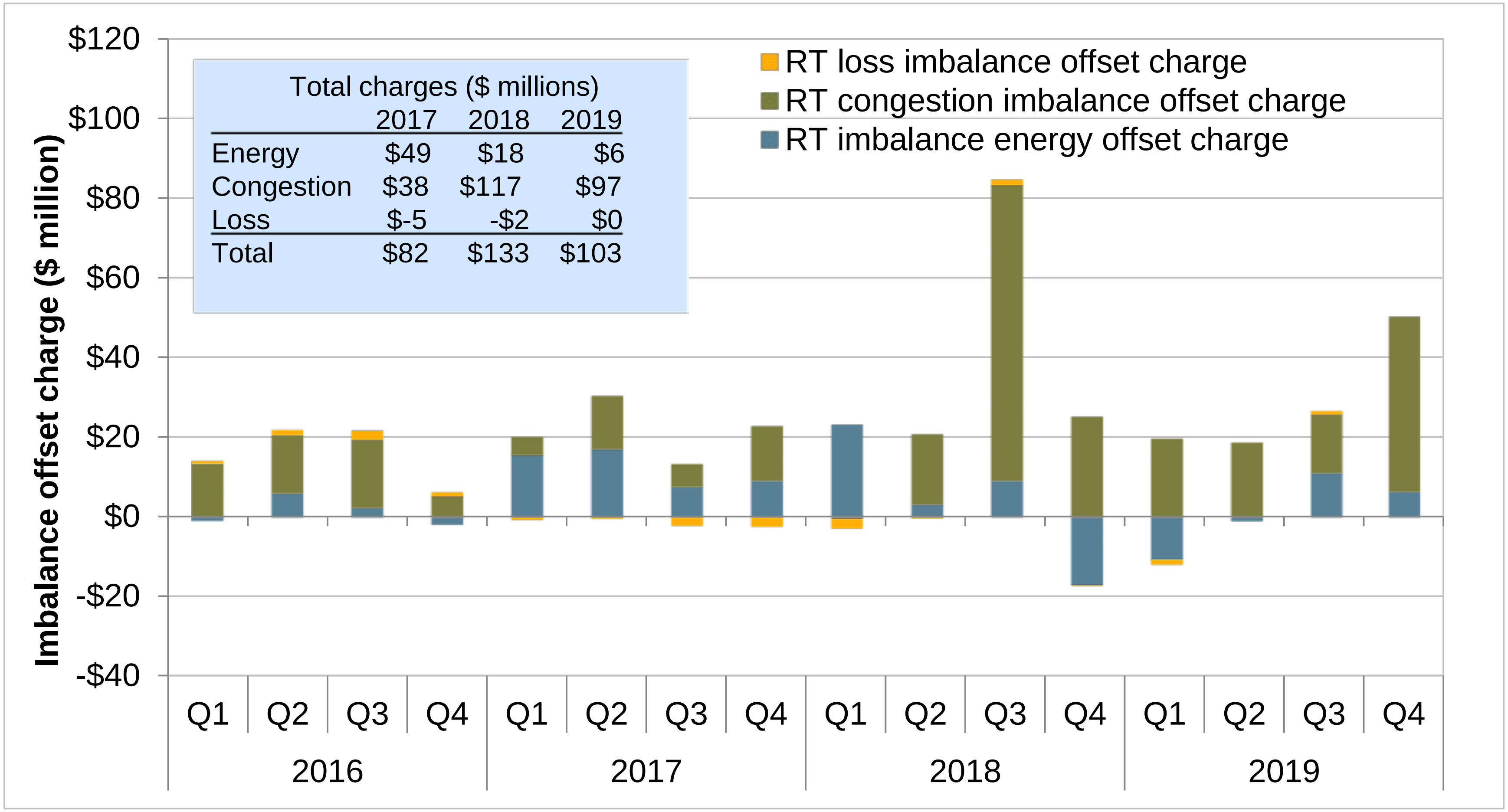


Congestion revenue right auction changes implemented January 2019

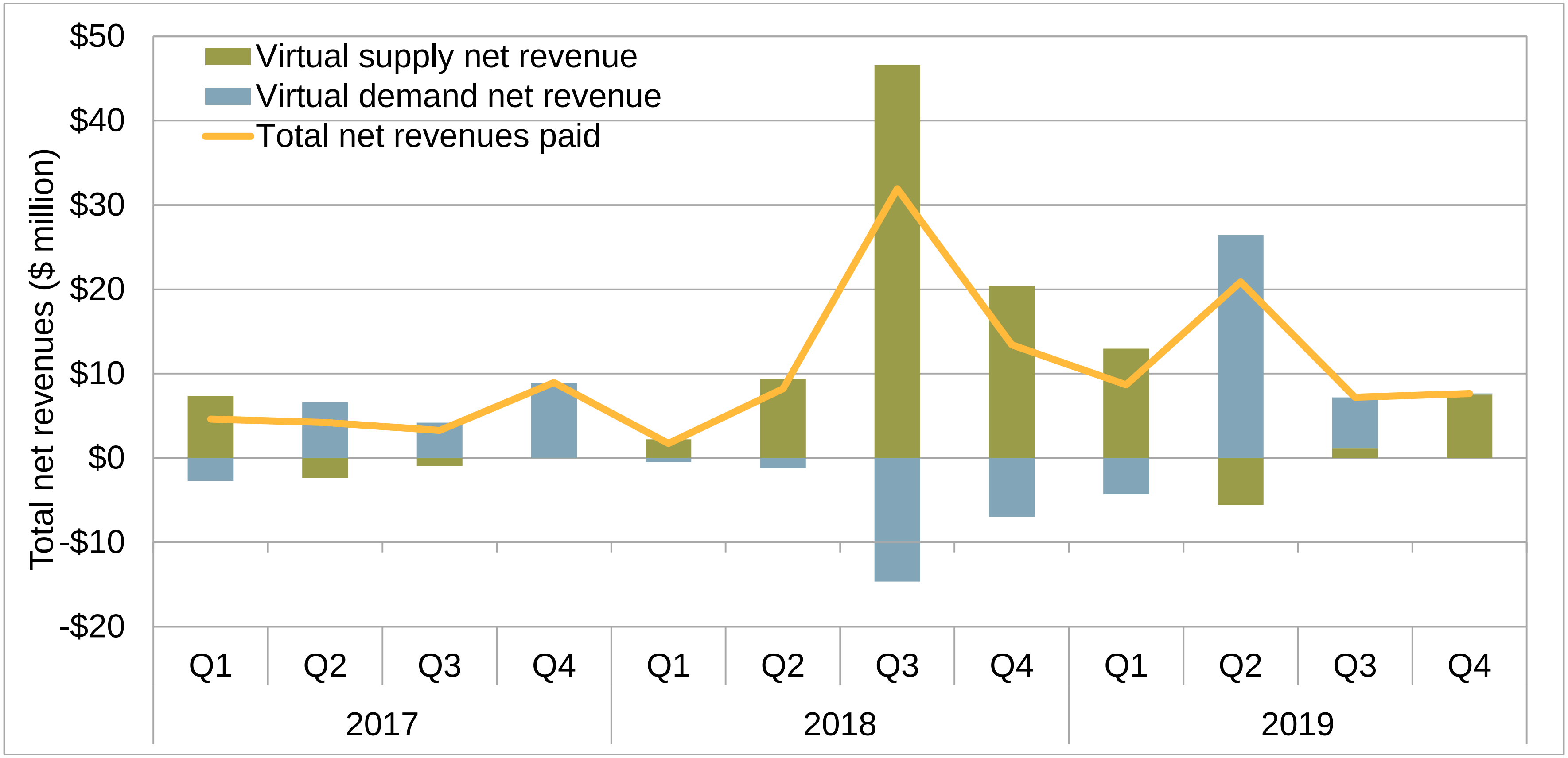
- Implemented in response to systematic losses from congestion revenue right auction sales since 2009
- Transmission ratepayer losses are significantly lower due to auction changes and lower congestion.
  - Day-ahead congestion revenues $354 million in 2019, compared to $628 million in 2018.
  - Losses from auctioned rights equal 6% of total congestion revenue in 2019, compared to 21% in 2018.
- DMM continues to believe the current auction is unnecessary and could be eliminated
  - If the CAISO/stakeholders believe a market is necessary for hedging, replace auction with a market of willing buyers and sellers.
- DMM has recommended consideration of changes to CRR allocation process to load serving entities.

Real-time imbalance offset costs decreased by 23% to $103 million.

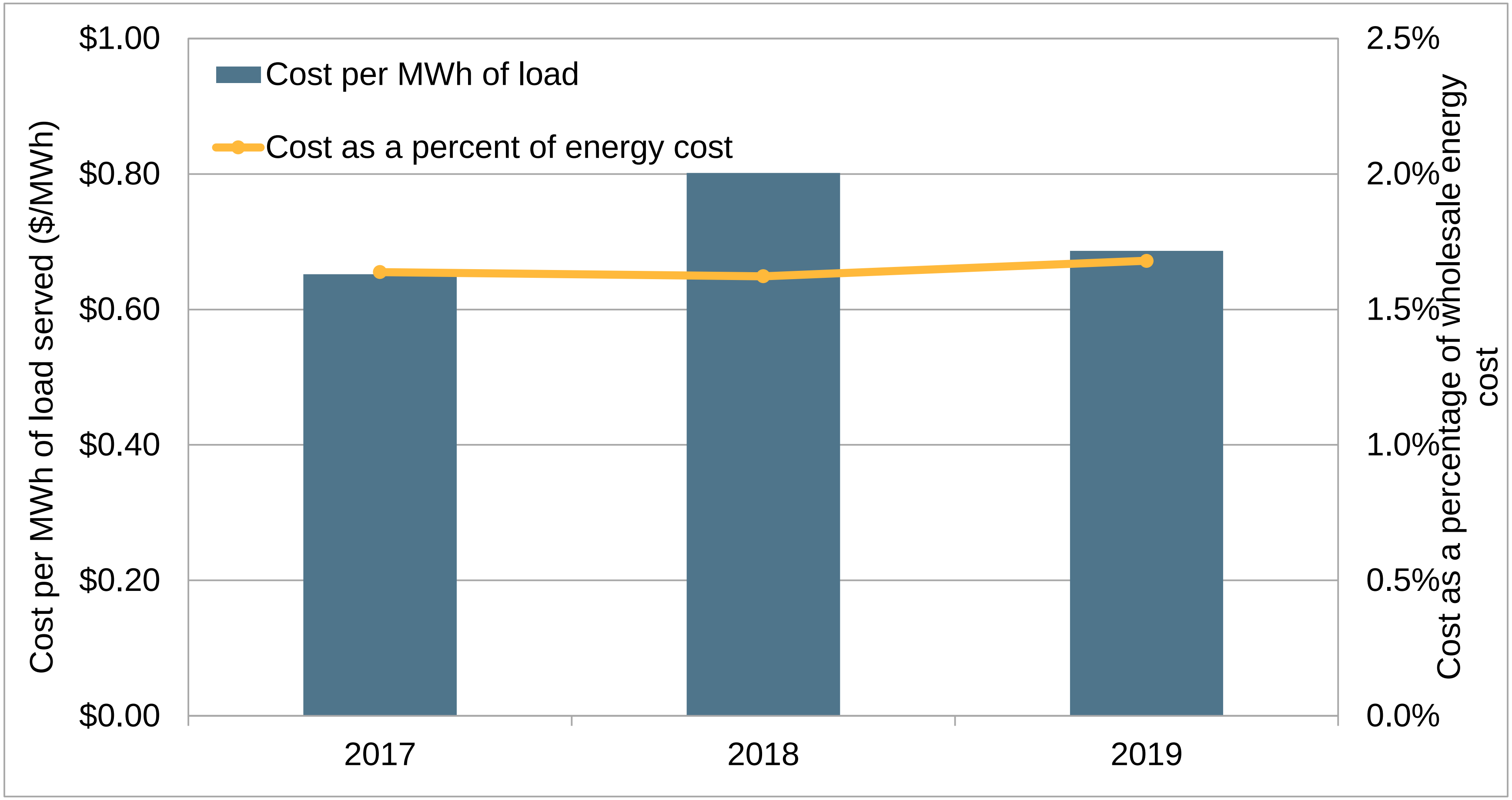
Most congestion offset costs were due to reductions in constraint limits between day-ahead and real-time markets.



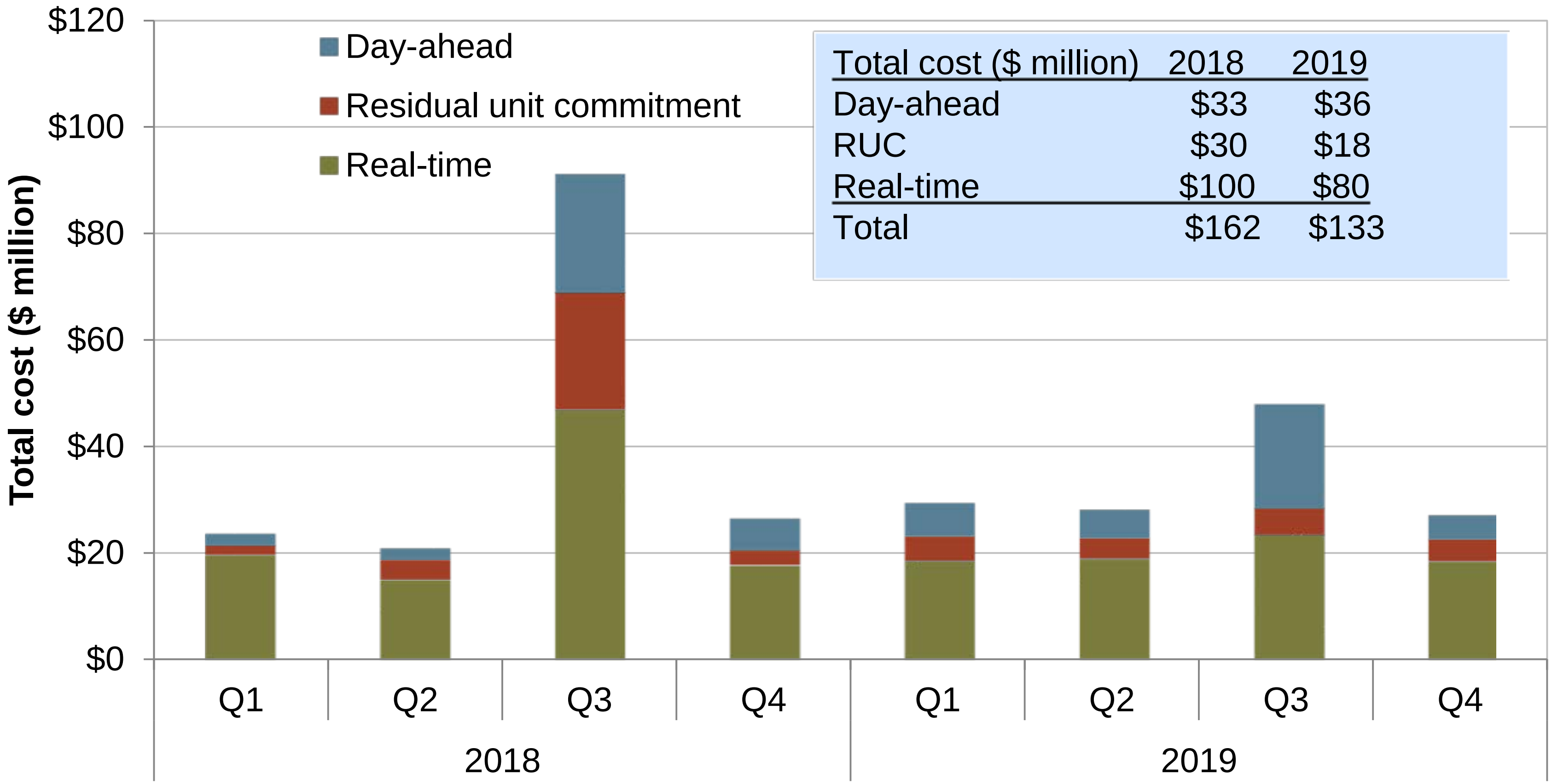
Convergence bidding profit of $37 million, down from $40 million in 2018 (after accounting for uplift allocation).



Ancillary service costs decreased to $149 million, but remained at about 1.7% of wholesale energy costs.



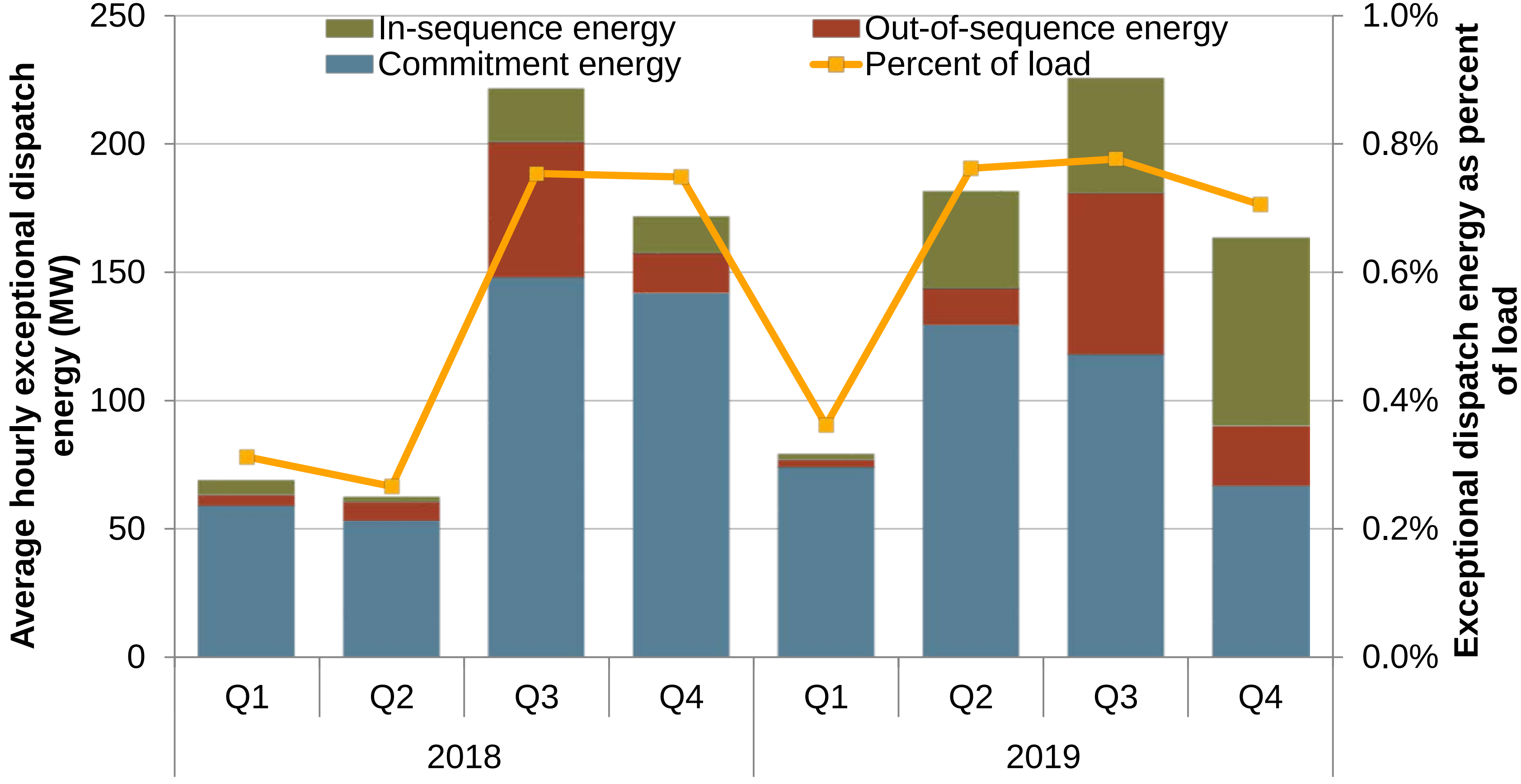
Bid cost recovery payments in the CAISO decreased to $123 million or about 1.4 % of total energy costs.



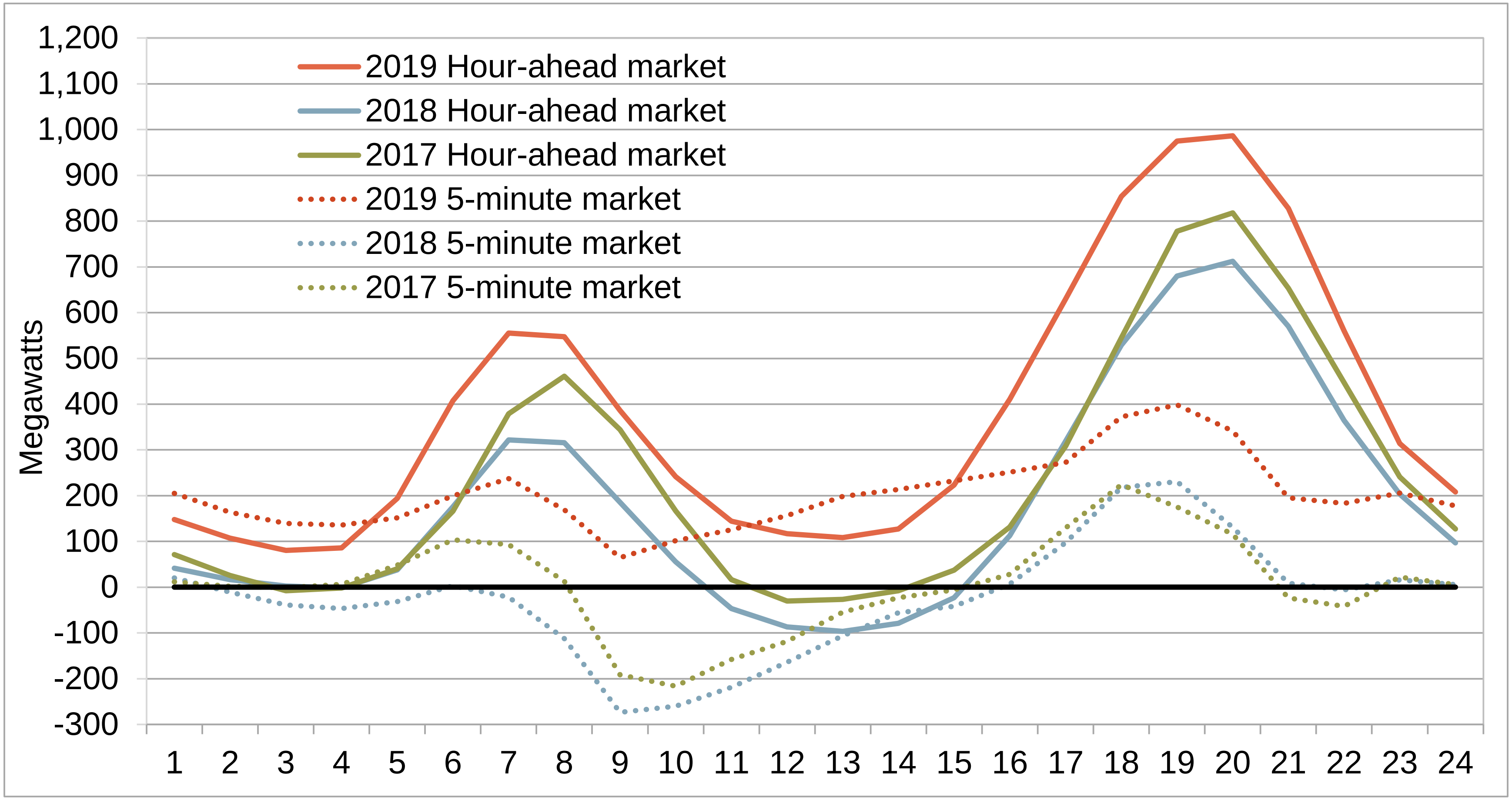
Total cost ($ million)	2018	2019
Day-ahead	$33	$36
RUC	$30	$18
Real-time	$100	$80
Total	$162	$133

Total energy from exceptional dispatches increased in 2019, but still account for a low portion of system load (0.7%).

Total exceptional dispatch costs decreased to $29 million from $52 million in 2018



Load adjustment in hour-ahead scheduling process by grid operators remained high, particularly in ramping hours.



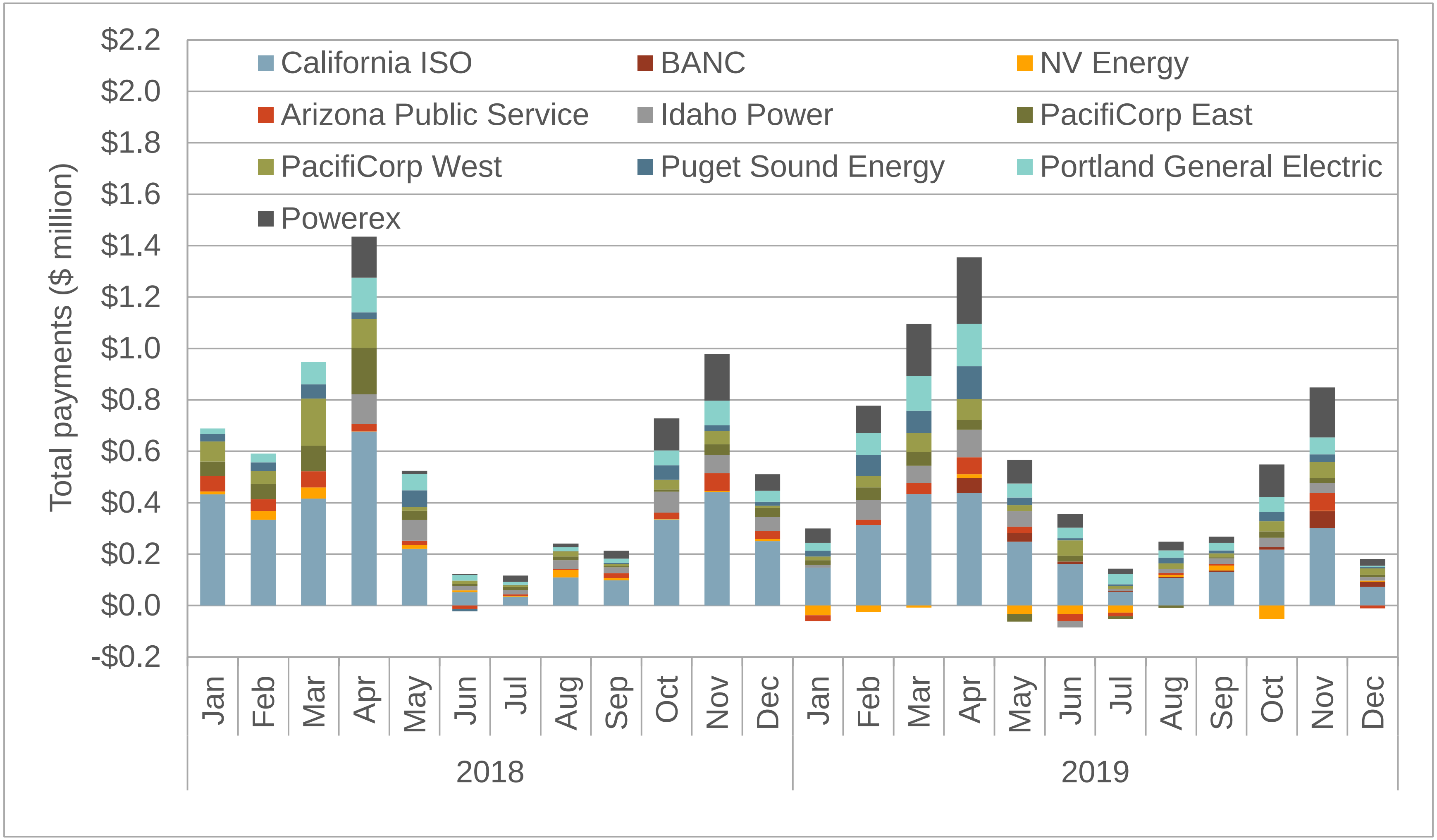
Flexible ramping product (FRP)

- Product is designed to enhance reliability and market performance by procuring real-time ramping capacity to help manage variability and uncertainty.
- Flexible ramping product prices were usually zero (since demand constraint was non-binding) or very low.
- Total payments to generators decreased to $6.3 million, down from $7.1 million in 2018 and $25 million in 2017.
- A significant portion of ramping capacity being procured is from resources that are not able to meet system uncertainty because of resource or transmission limits.
- Ineffectiveness of flexible ramping product reflected by increasing need of grid operators to make large manual load adjustments and manual (exceptional) dispatches to increase ramping capacity from gas-fired resources.

Improvements needed in flexible ramping product

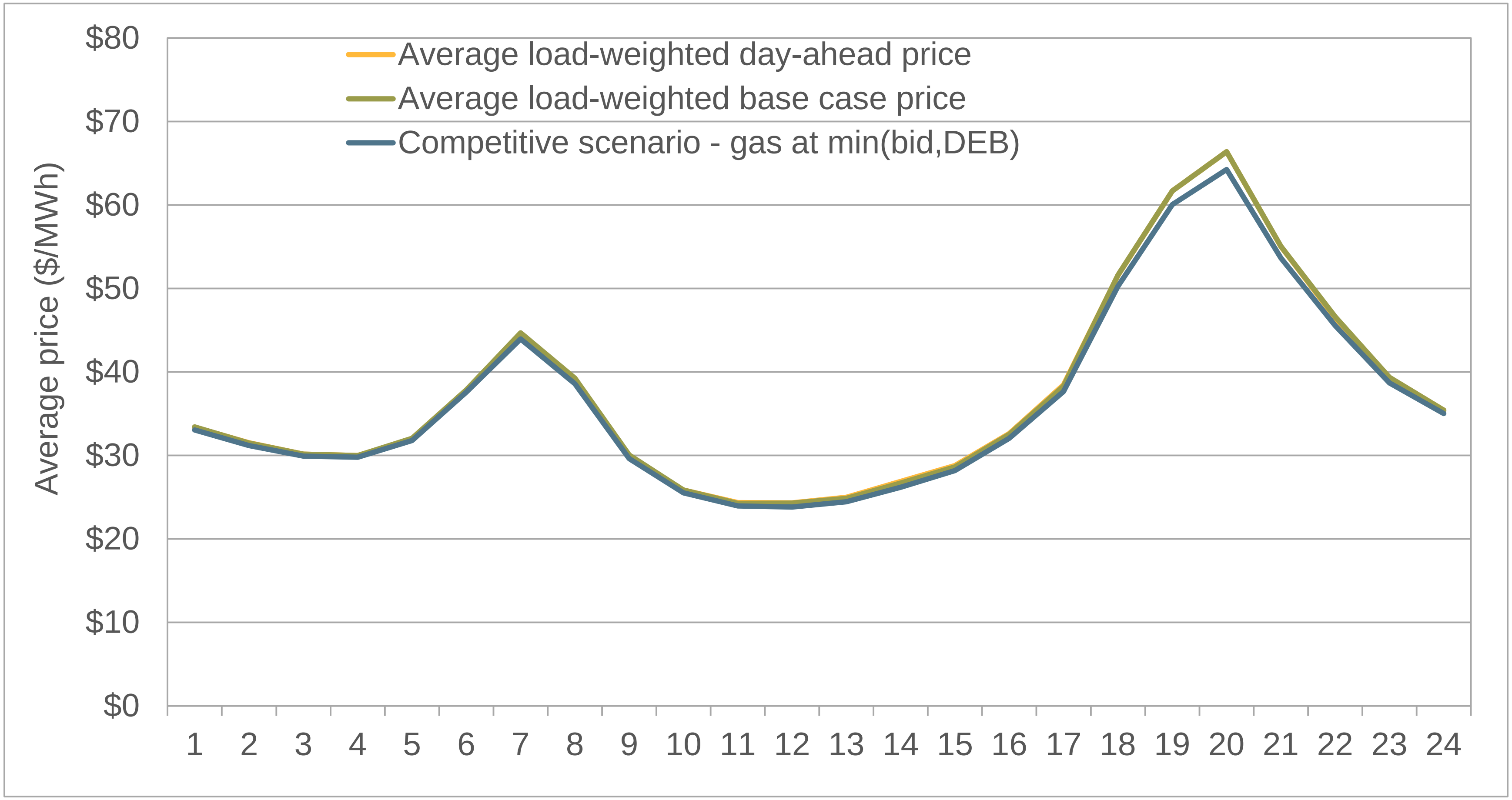
- CAISO initiative to enhance flexible ramping product
  - Proposing to procure capacity taking transmission limits between balancing areas into account.
  - A 2019 ISO initiative allowed demand response resources to register as 15-minute or 60-minute dispatchable, not eligible for flexible ramping.
- DMM continues to recommend also extending the time horizon of uncertainty used to set flexible ramping requirements
  - Currently product requirements set based on ramping uncertainty between the 15-minute and the 5-minute market or between 5-minute intervals.
  - DMM recommends enhancing product to procure ramping capacity based on potential need over longer time horizon (e.g. 1 to 3 hours)
  - See presentation on *Enhancing the flexible ramping product to better address net load uncertainty,* June 12, 2020.
    - http://www.caiso.com/Documents/Presentation-Real-TimeFlexRampProductEnhancements-WesternEIMBodyofStateRegulators-June122020.pdf

Monthly flexible ramping payments by area

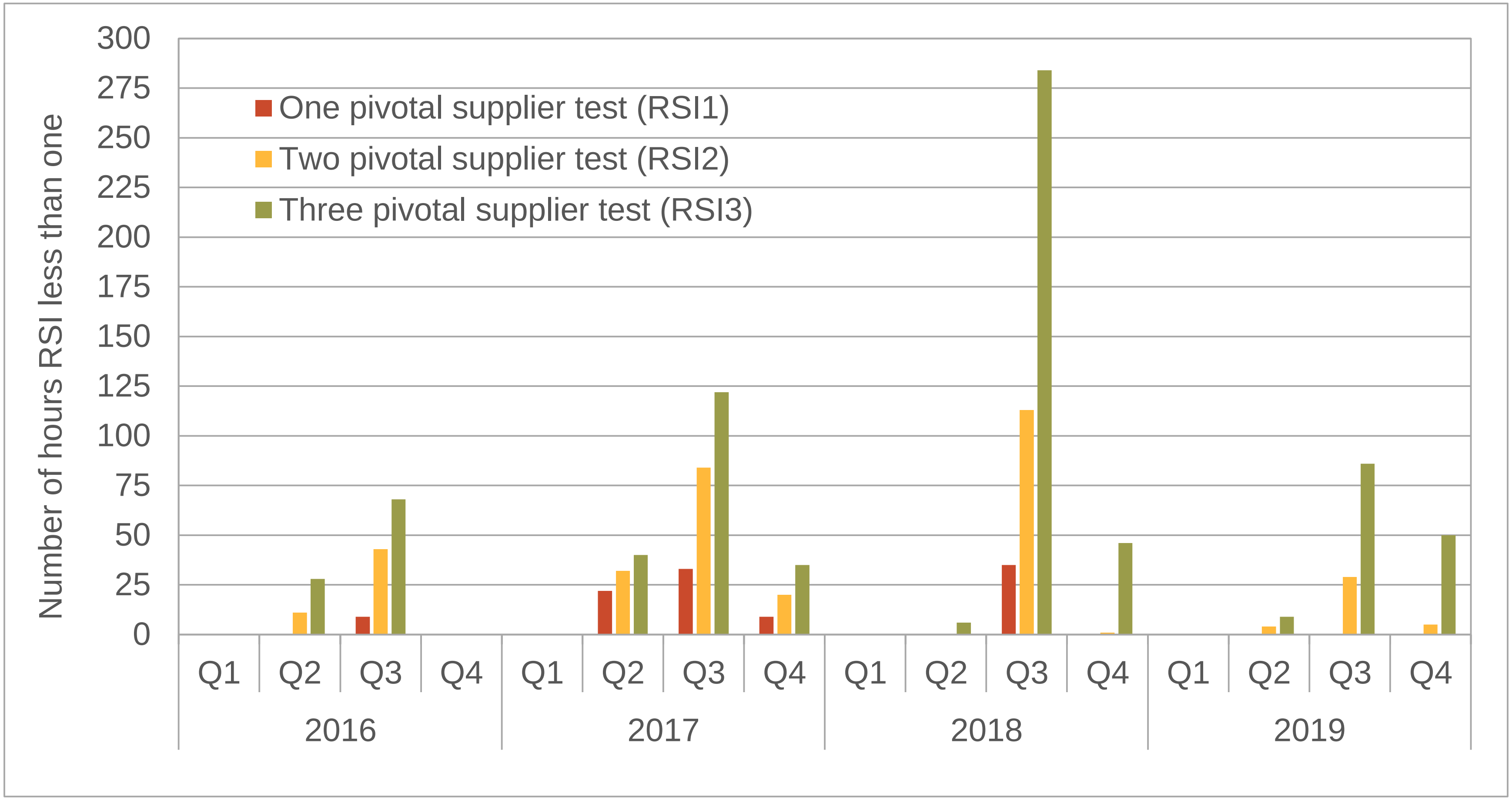


The ISO's energy markets were competitive in 2019

Energy prices about equal to competitive baseline prices calculated by DMM



Day-ahead market was more structurally competitive relative to 2017 and 2018

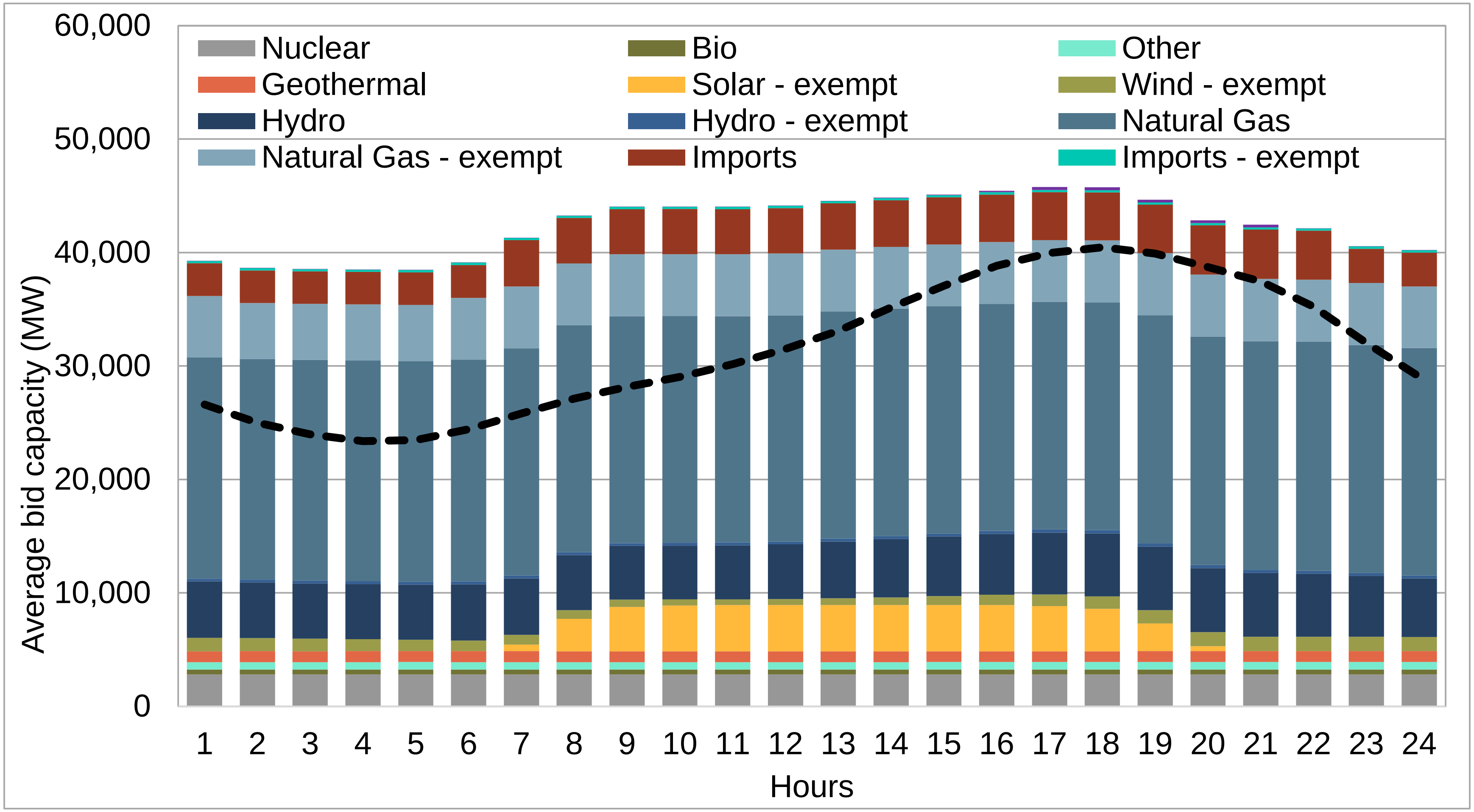


Market competitiveness and mitigation

- Market for capacity needed to meet local requirements is structurally uncompetitive in all local areas.
- Mitigation of exceptional dispatches reduced cost by about $8 million
  - *DMM recommending that new "RA Max" exceptional dispatches be subject to mitigation to strong potential for suppliers to exercise market power*
- Opportunity cost adders to reflect gas unit limitations implemented and now included in commitment cost bid caps.
- More than a third of start-up and minimum load bids for gas capacity bids at or close to bid caps.
- CAISO introduced a new default energy bid option to reflect potential opportunity costs of hydro resources.

On high load days, resource adequacy resources bid in enough capacity to meet average hourly load

Average hourly bids by fuel type and RAAIM category (days with 210 highest load hours)

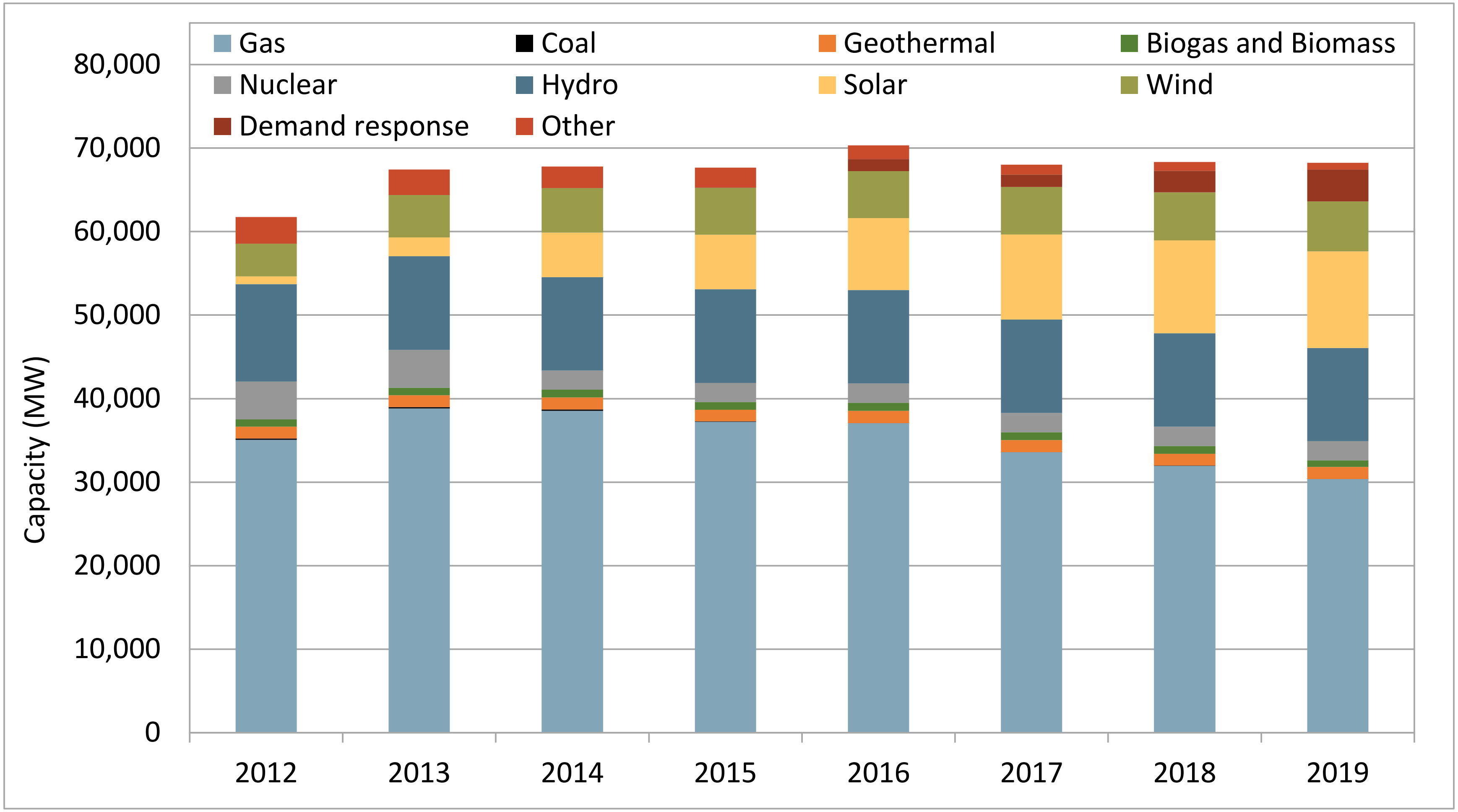


In the real-time market, less than 80 percent of system resource adequacy capacity was bid or self-scheduled during high load hours

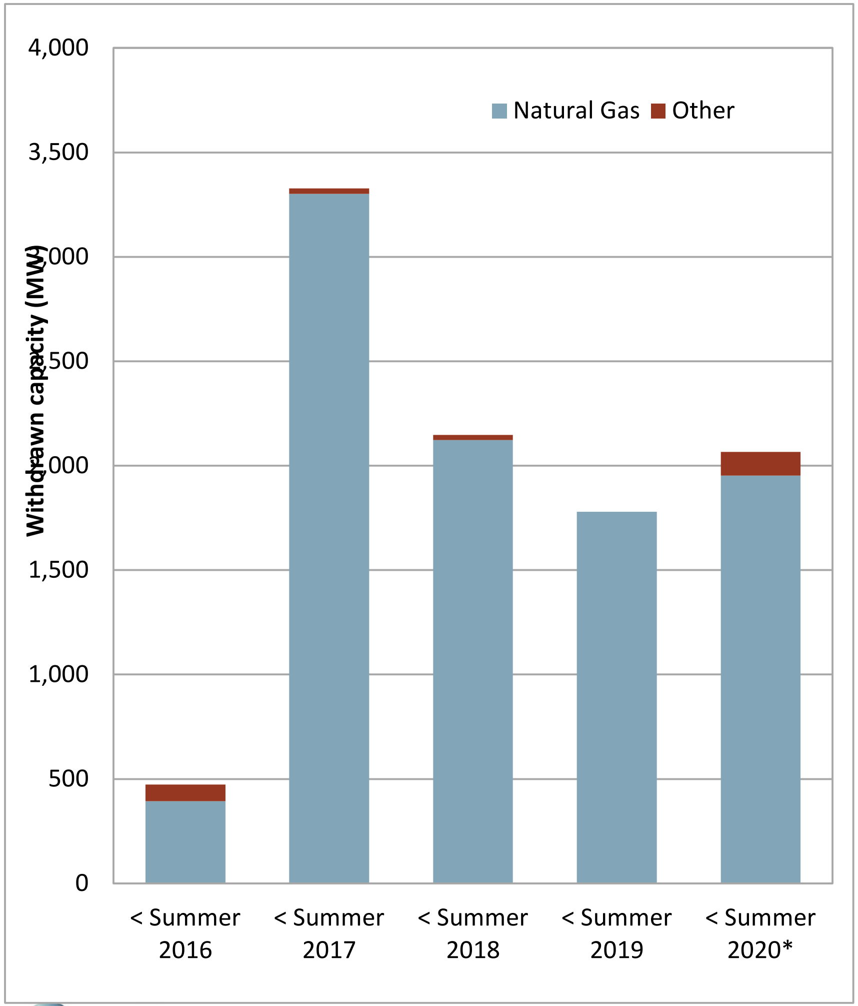
Average system resource adequacy capacity and availability by fuel type (210 highest load hours)

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	19,499	18,497	95%	18,497	95%	14,977	77%	14,376	74%
Other generators	1,490	1,402	94%	1,402	94%	1,402	94%	1,342	90%
Subtotal	**20,989**	**19,899**	**95%**	**19,899**	**95%**	**16,379**	**78%**	**15,718**	**75%**
Other:									
Imports	4,704	4,669	99%	4,440	94%	4,078	87%	3,289	70%
Use-limited gas units	6,708	6,479	97%	6,386	95%	6,395	95%	5,961	89%
Hydro generators	6,551	6,278	96%	5,800	89%	6,265	96%	5,711	87%
Nuclear generators	2,872	2,857	99%	2,856	99%	2,857	99%	2,756	96%
Solar generators	4,176	4,164	100%	2,896	69%	4,145	99%	2,799	67%
Wind generators	1,704	1,698	100%	1,082	63%	1,698	100%	1,057	62%
Qualifying facilities	1,078	1,062	98%	880	82%	948	88%	803	75%
Other non-dispatchable	686	664	97%	483	70%	582	85%	509	74%
Subtotal	**28,479**	**27,871**	**98%**	**24,823**	**87%**	**26,968**	**95%**	**22,885**	**80%**
Total	**49,468**	**47,770**	**97%**	**44,722**	**90%**	**43,347**	**88%**	**38,603**	**78%**

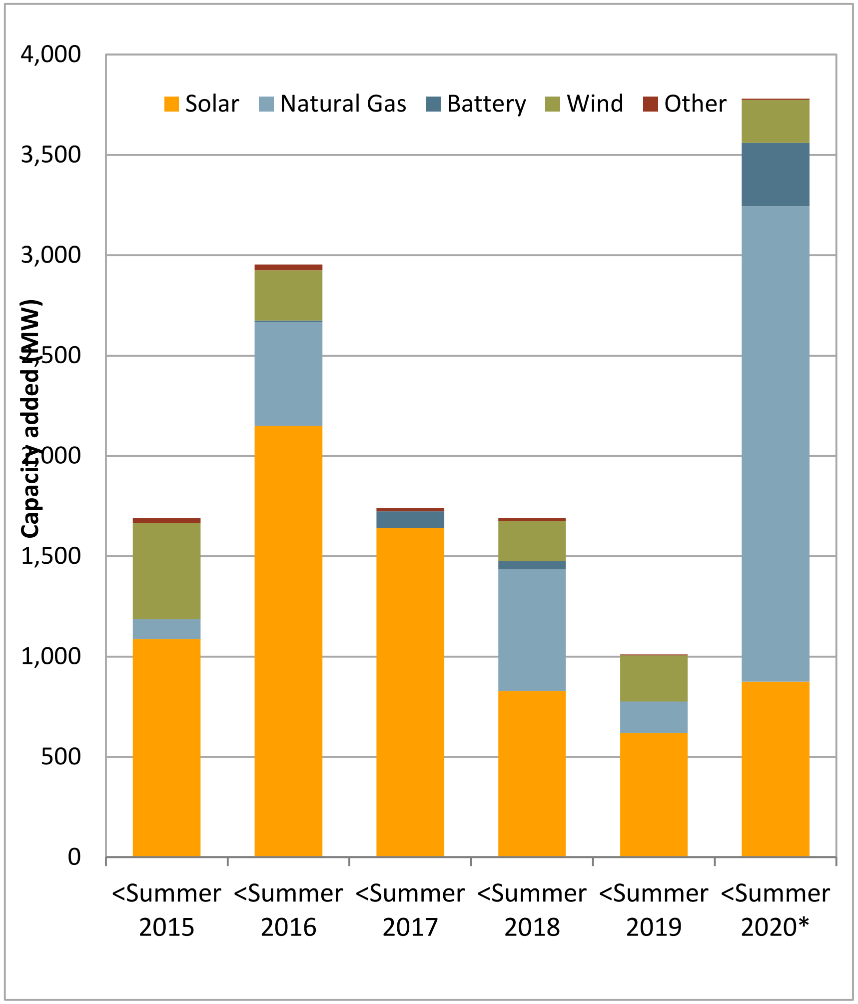
Gas capacity retiring is being largely replaced with renewables (mainly solar)



Withdrawals from ISO market participation

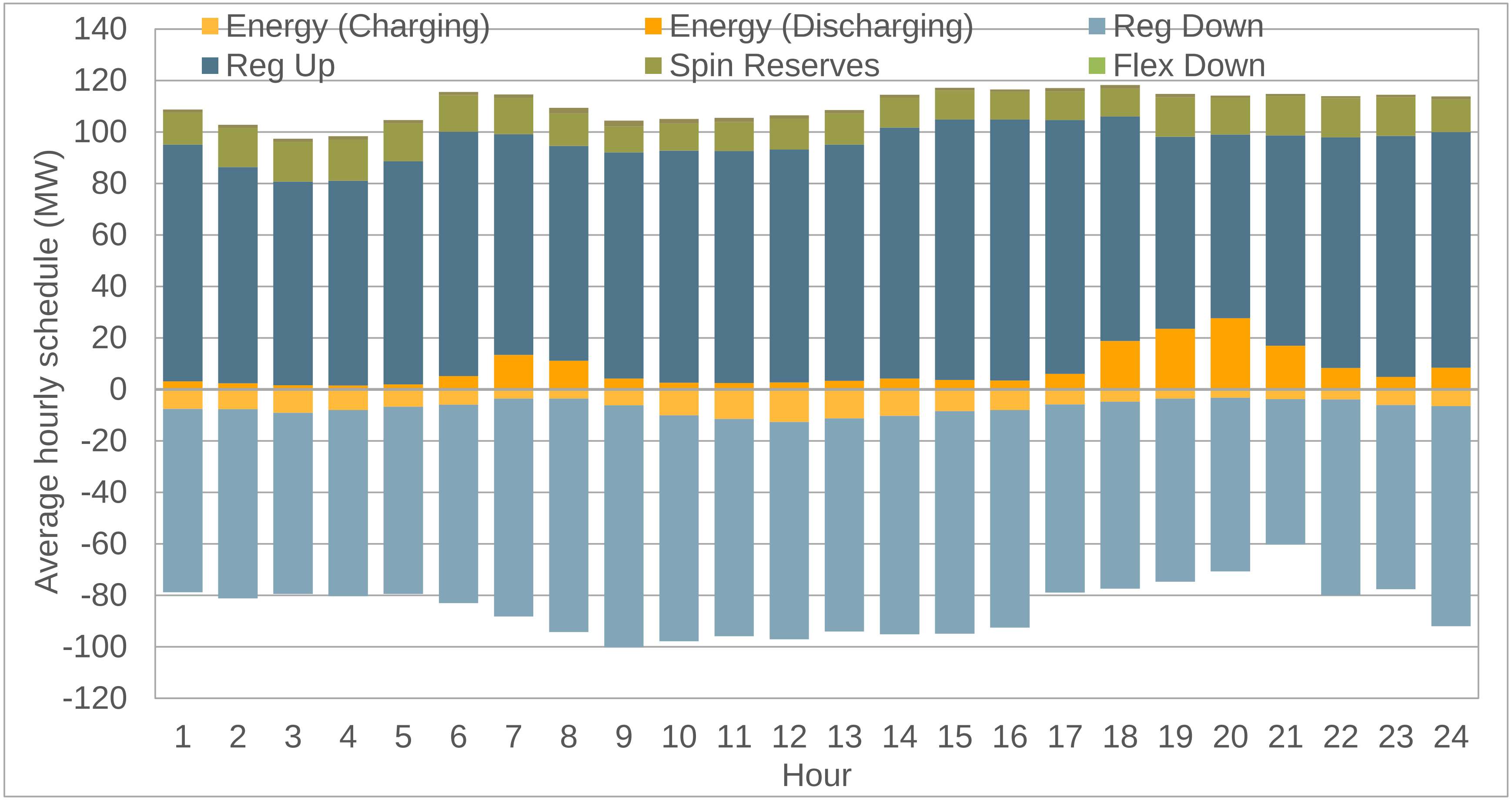


Additions to ISO market

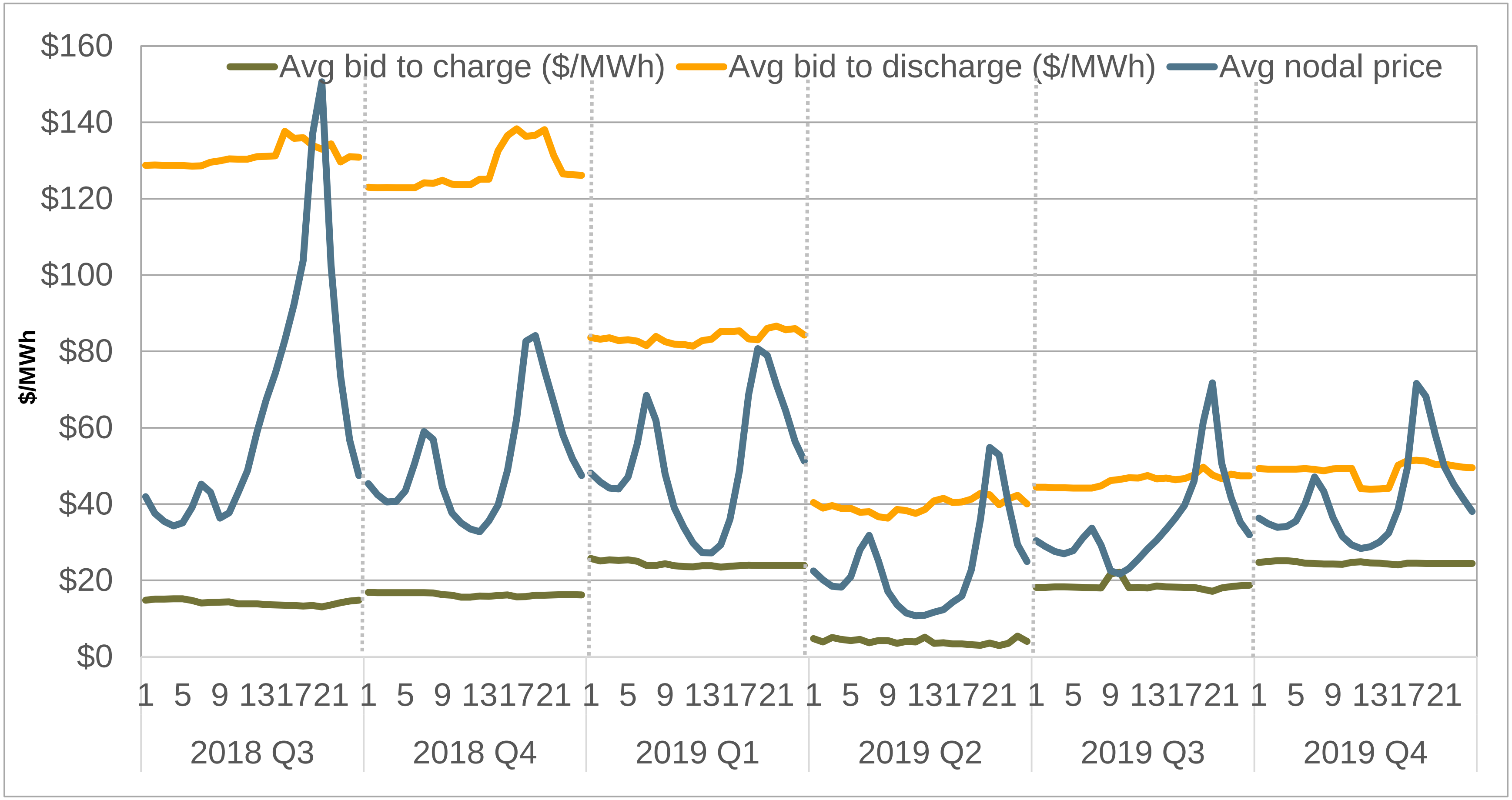


Capacity from battery storage resources remained unchanged at 136 MW

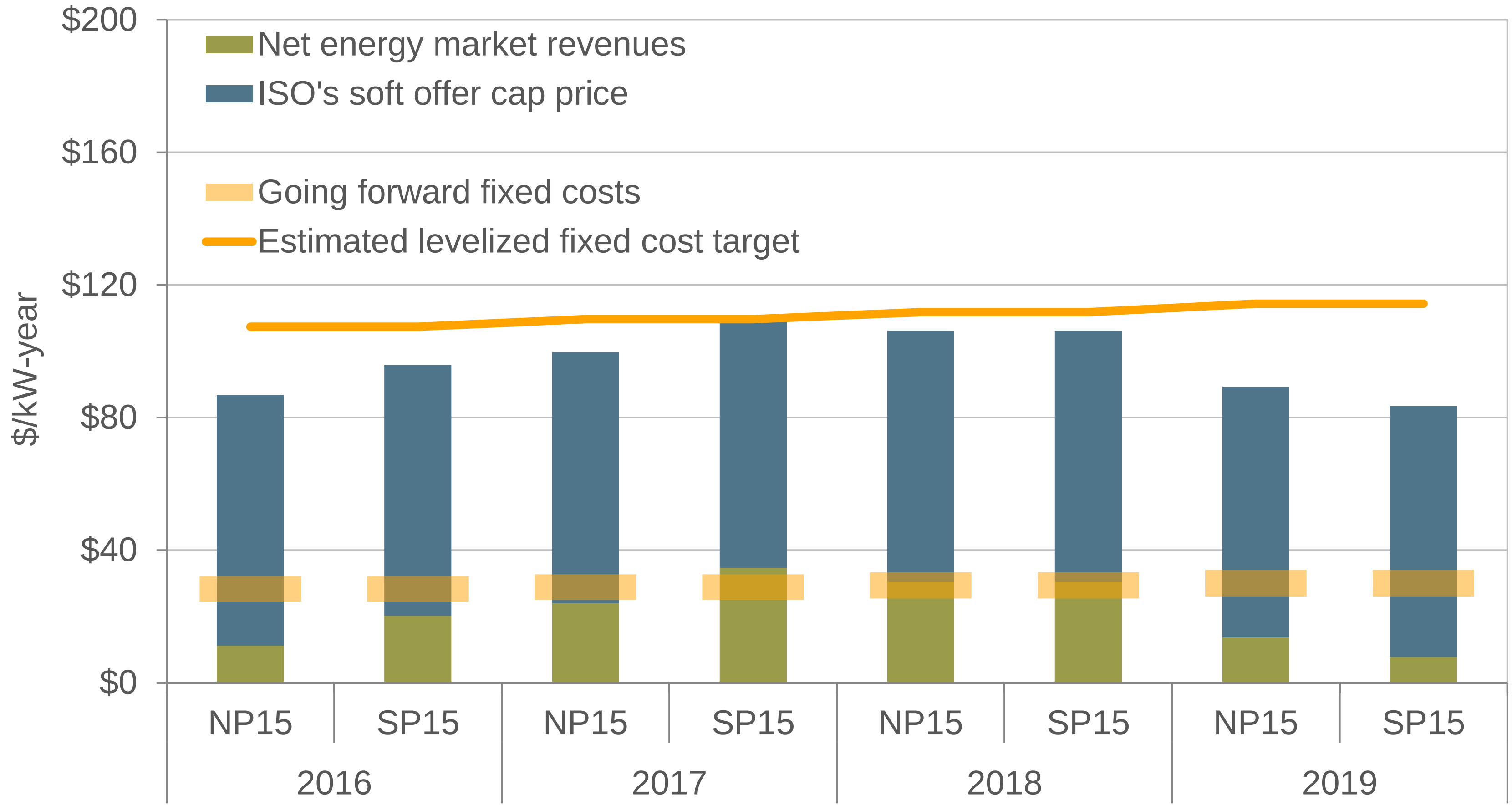
Average hourly schedules for battery resources



Average day-ahead hourly bids for battery resources compared to nodal resource prices (Q3 2018 – 2019)



Estimated net revenue of hypothetical combined cycle unit in NP15 and SP15 was about $38/kW-year.



Estimated net revenues of hypothetical combustion turbine dropped to about $22/kW-year.