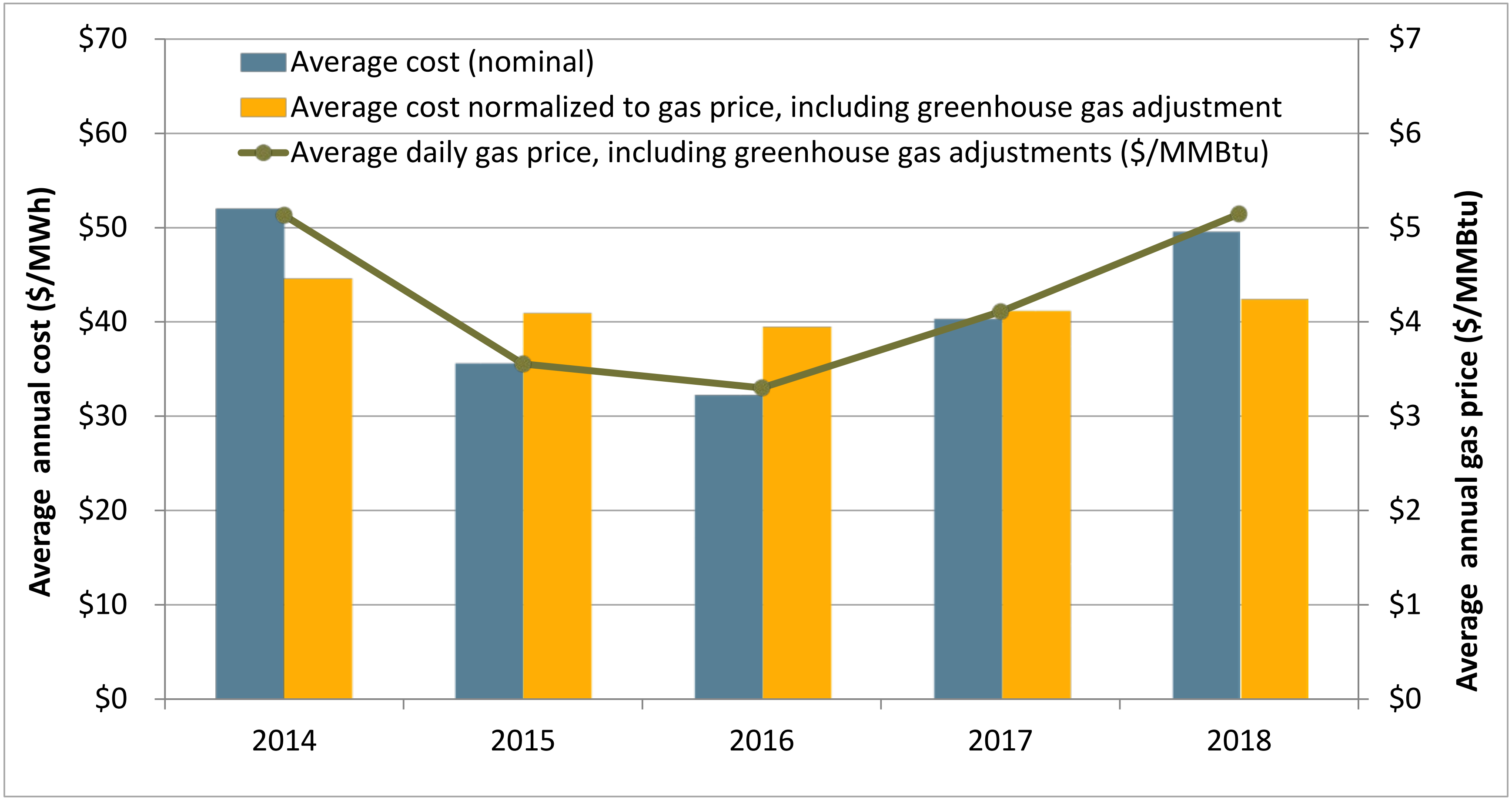
California ISO

2018 Annual Report

Presentation at the California Public Utilities Commission

June 18, 2019
Department of Market Monitoring

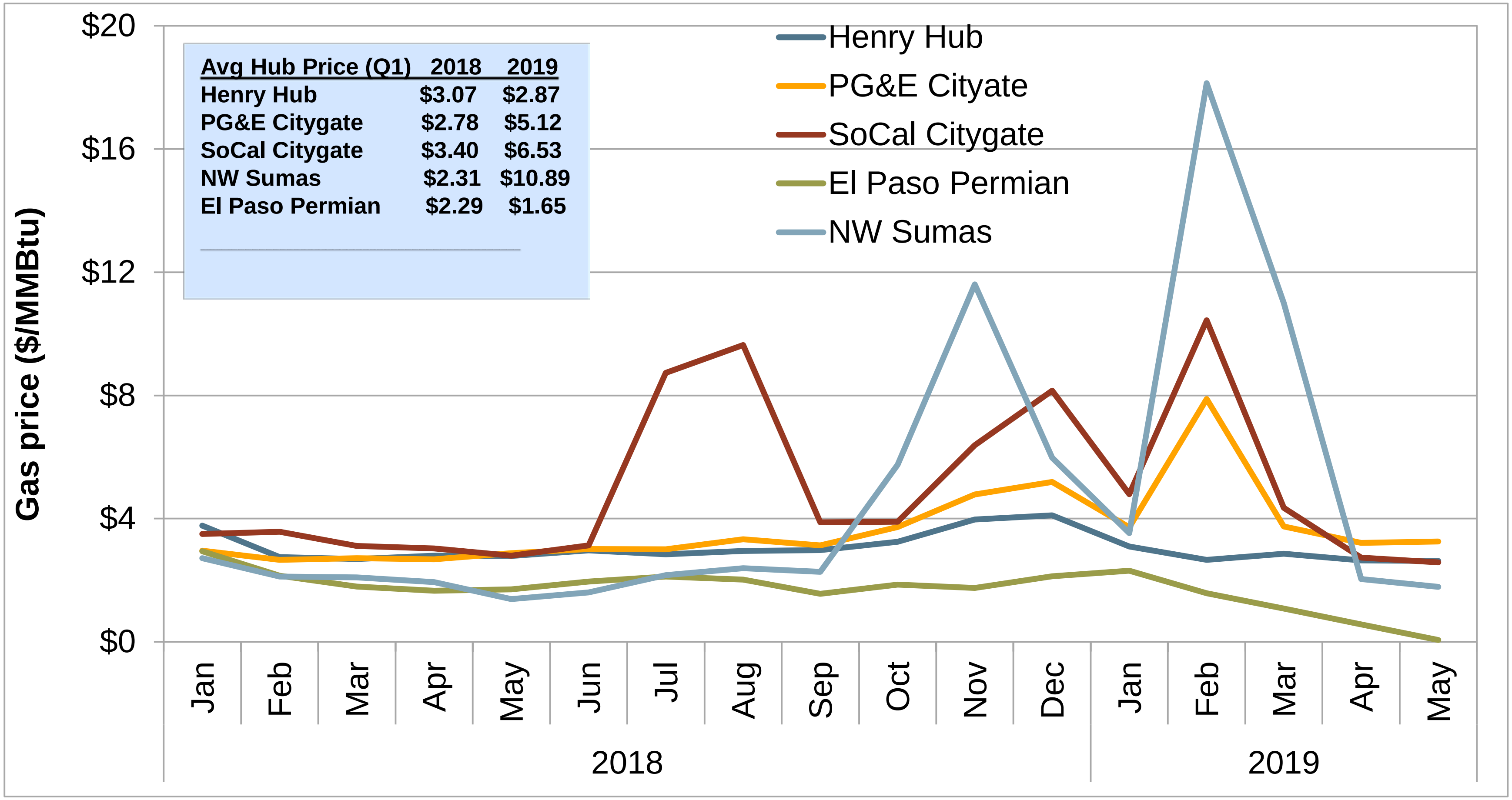
Total wholesale costs increased 24% -- or 4% increase after accounting for 25% increase in gas cost



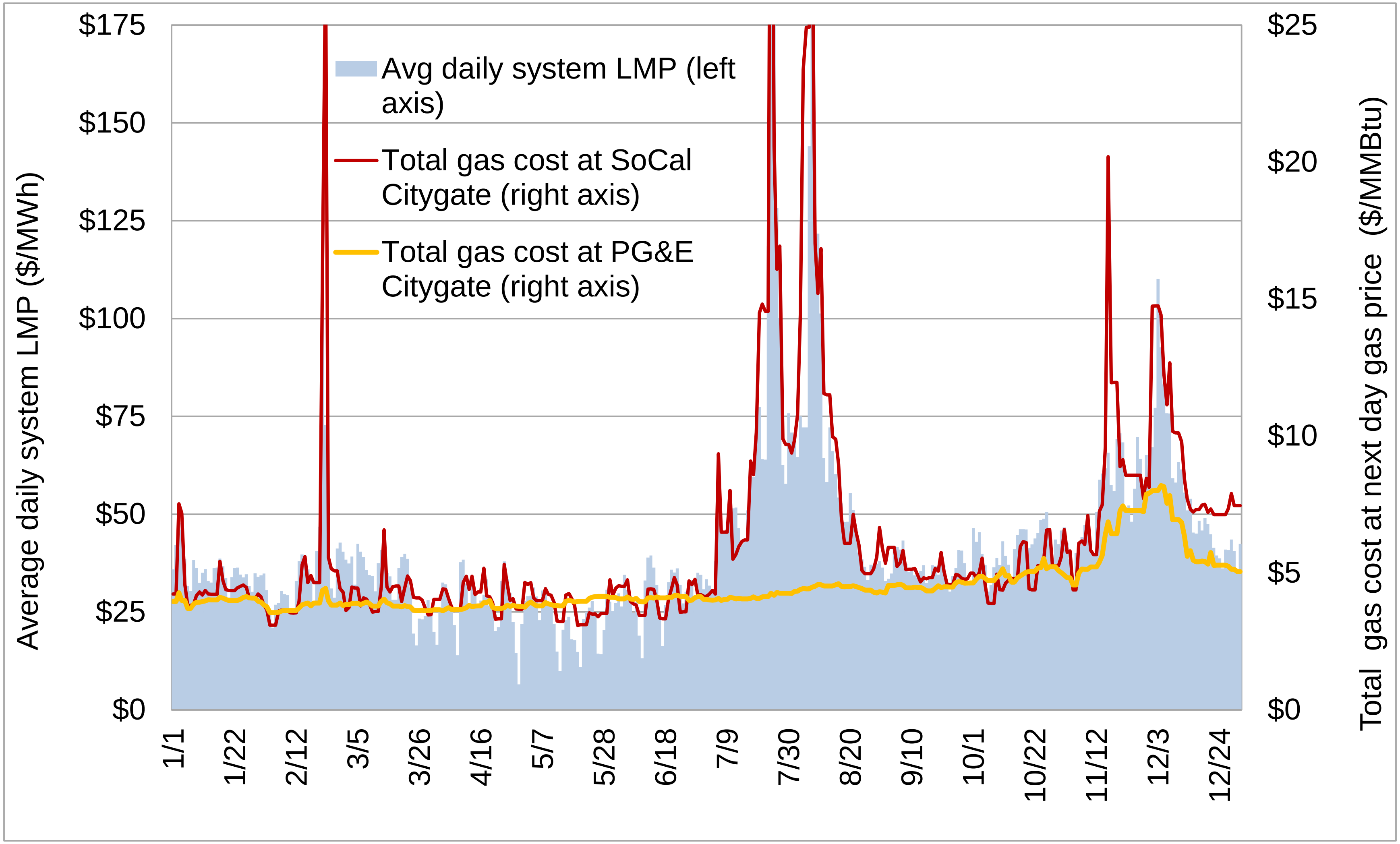
Total CAISO wholesale costs totaled $10.8 billion or about $49.50/MWh

	2014	2015	2016	2017	2018	Change '17-'18
Day-ahead energy costs	$ 49.53	$ 34.23	$ 30.49	$ 37.40	$ 46.06	$ 8.65
Real-time energy costs (incl. flex ramp)	$ 1.19	$ 0.18	$ 0.54	$ 0.90	$ 0.76	$ (0.14)
Grid management charge	$ 0.42	$ 0.42	$ 0.42	$ 0.43	$ 0.43	$ 0.01
Bid cost recovery costs	$ 0.40	$ 0.38	$ 0.30	$ 0.42	$ 0.69	$ 0.27
Reliability costs (RMR and CPM)	$ 0.14	$ 0.12	$ 0.11	$ 0.10	$ 0.73	$ 0.63
Average total energy costs	**$ 51.68**	**$ 35.33**	**$ 31.86**	**$ 39.25**	**$ 48.67**	**$ 9.42**
Reserve costs (AS and RUC)	$ 0.30	$ 0.27	$ 0.53	$ 0.71	$ 0.87	$ 0.16
Average total costs of energy and reserve	**$ 51.98**	**$ 35.60**	**$ 32.39**	**$ 39.96**	**$ 49.54**	**$ 9.58**

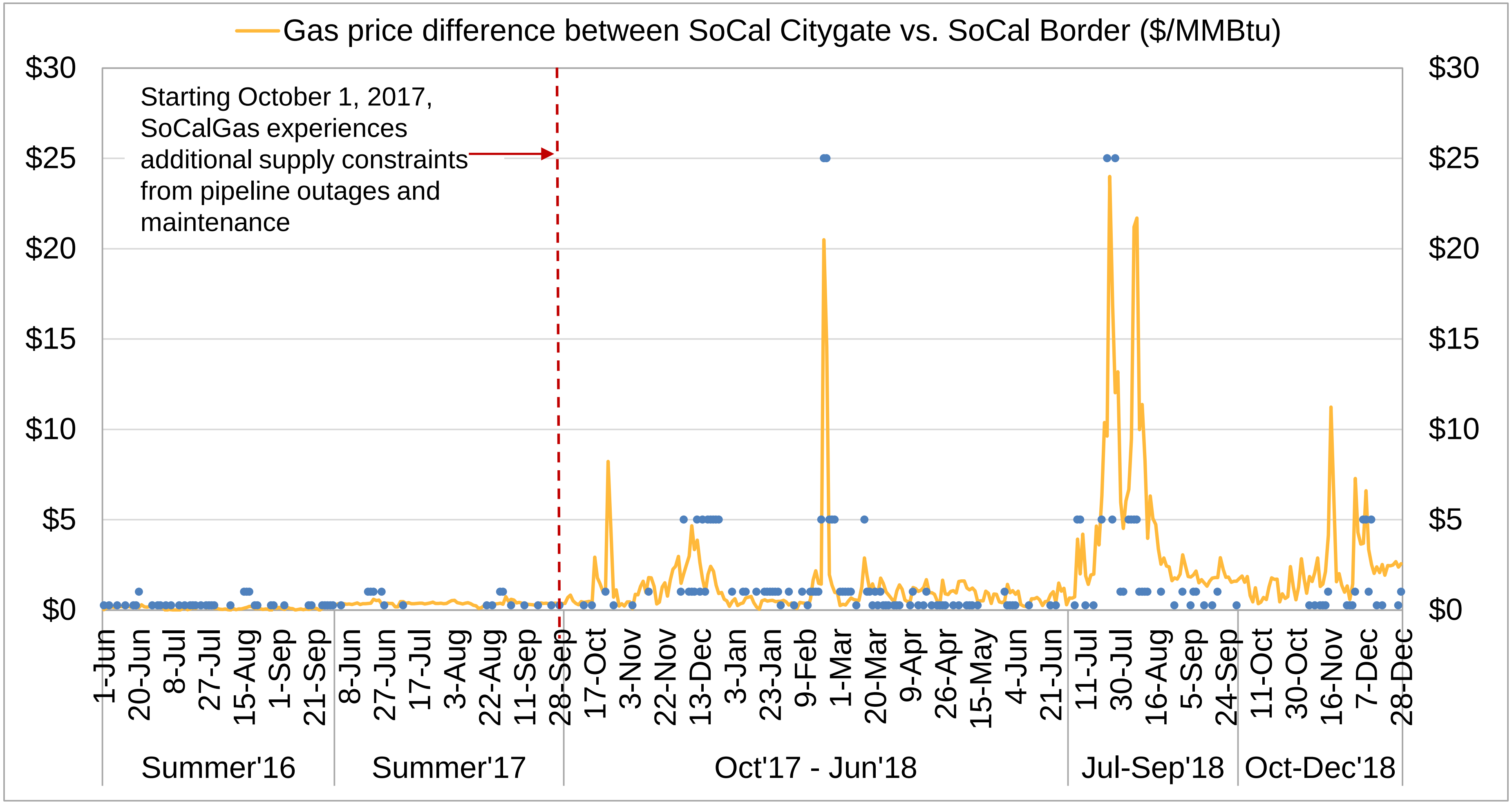
Day-ahead prices were often driven by high gas prices at SoCal Citygate



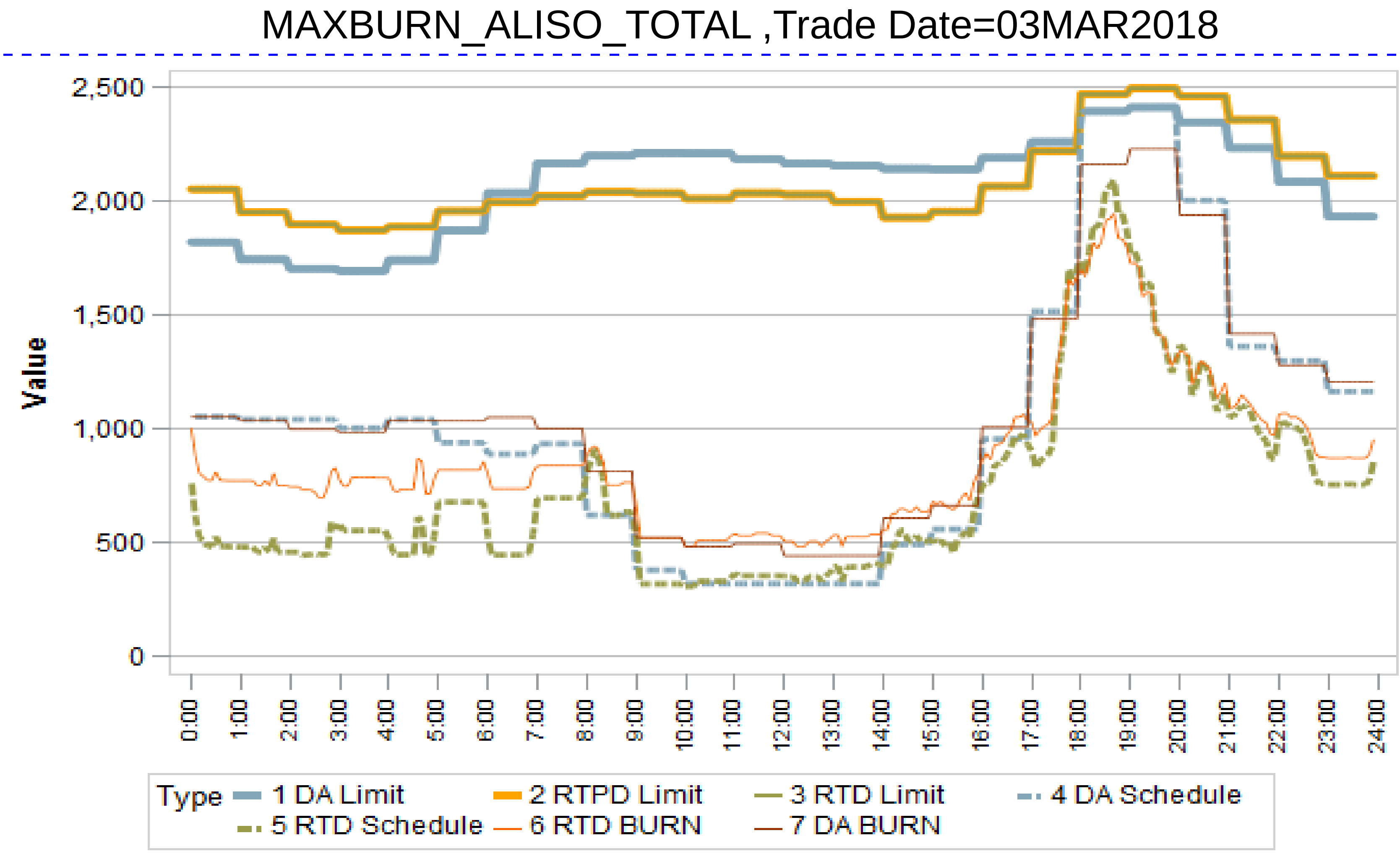
Average daily prices for electricity and natural gas (2018)



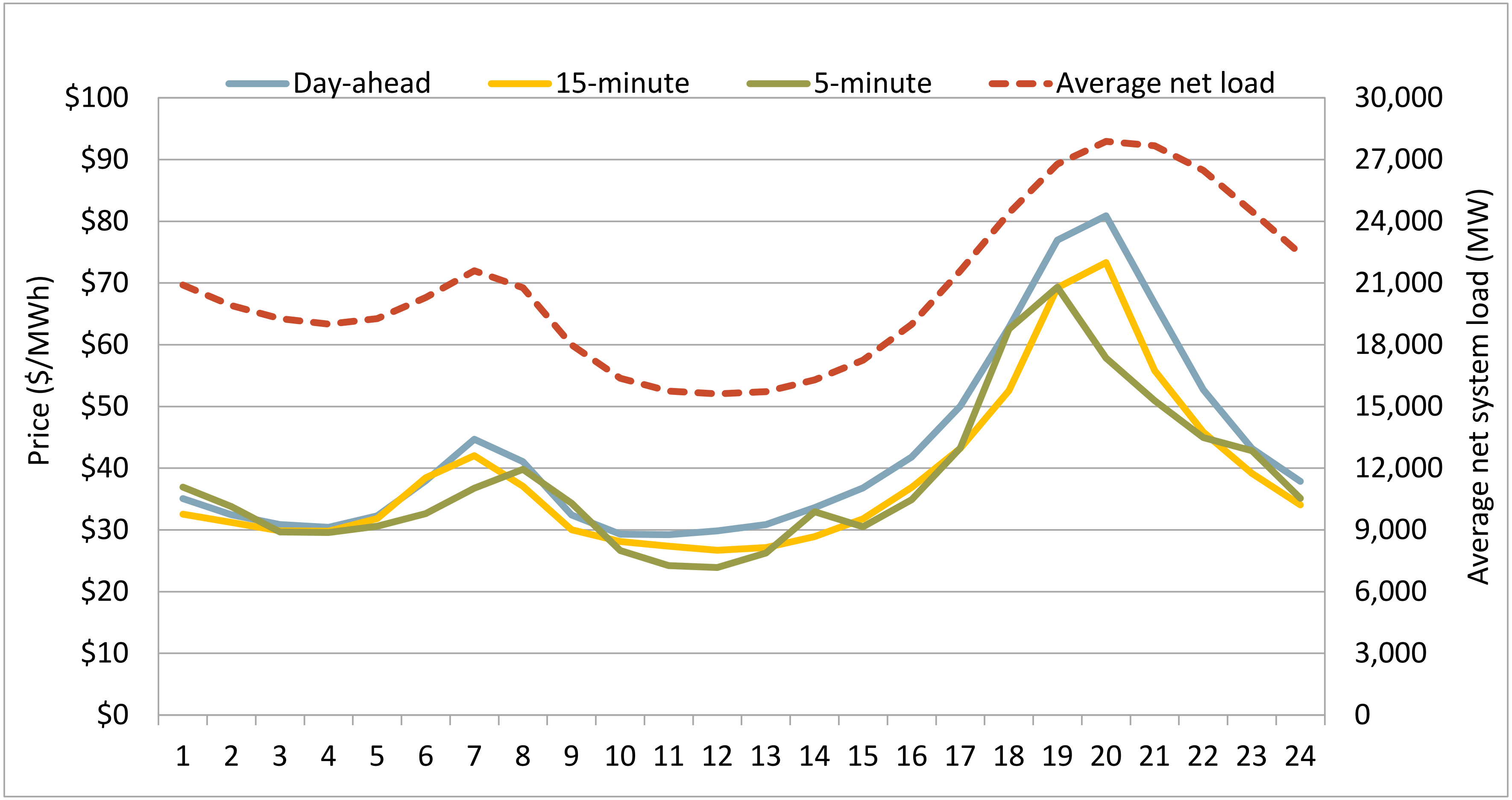
SoCal Citygate price spikes were driven by gas supply limitations and potential for high noncompliance charges (OFOs).



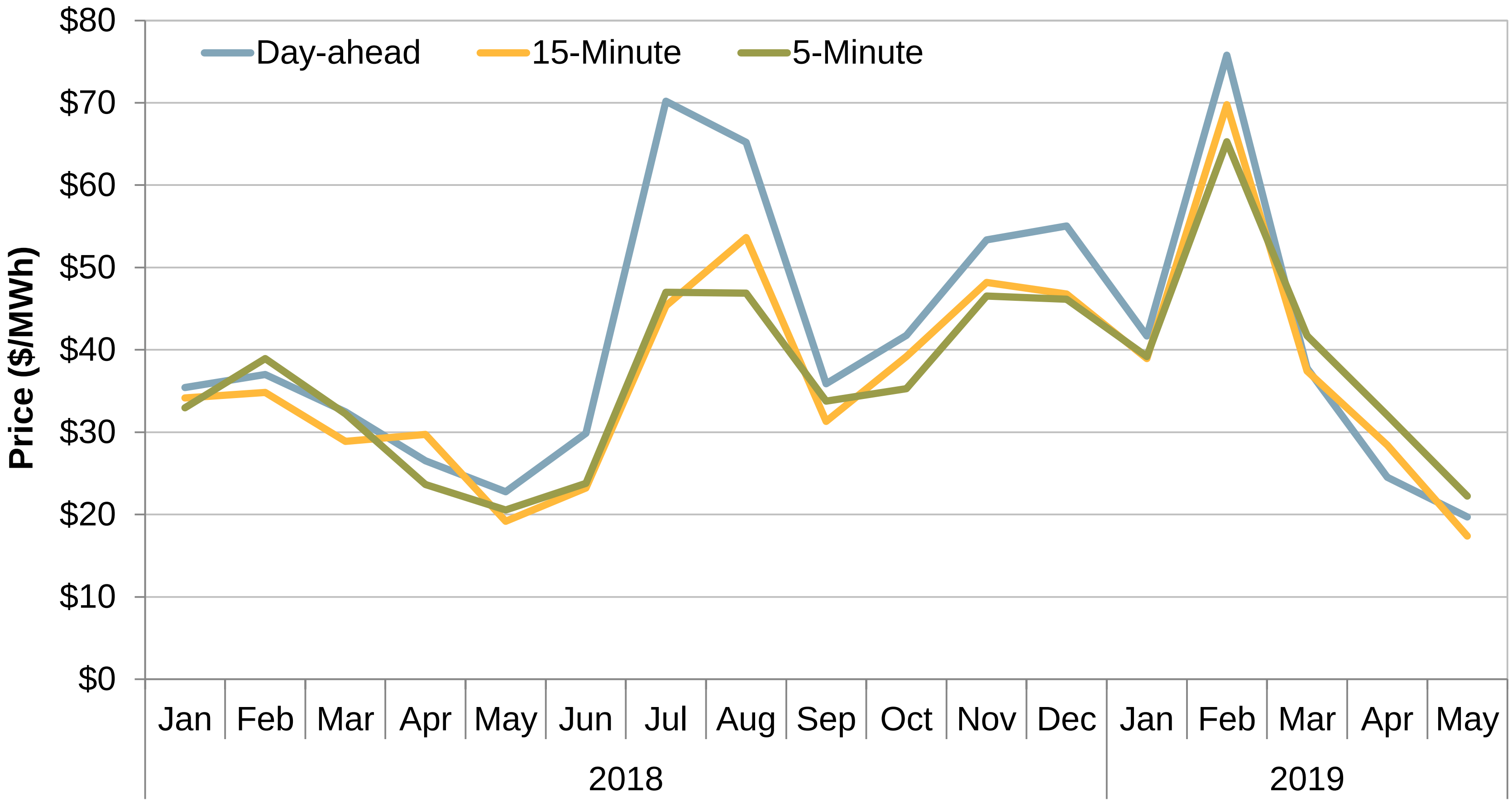
Aliso nomograms limit gas burn, but should be refined



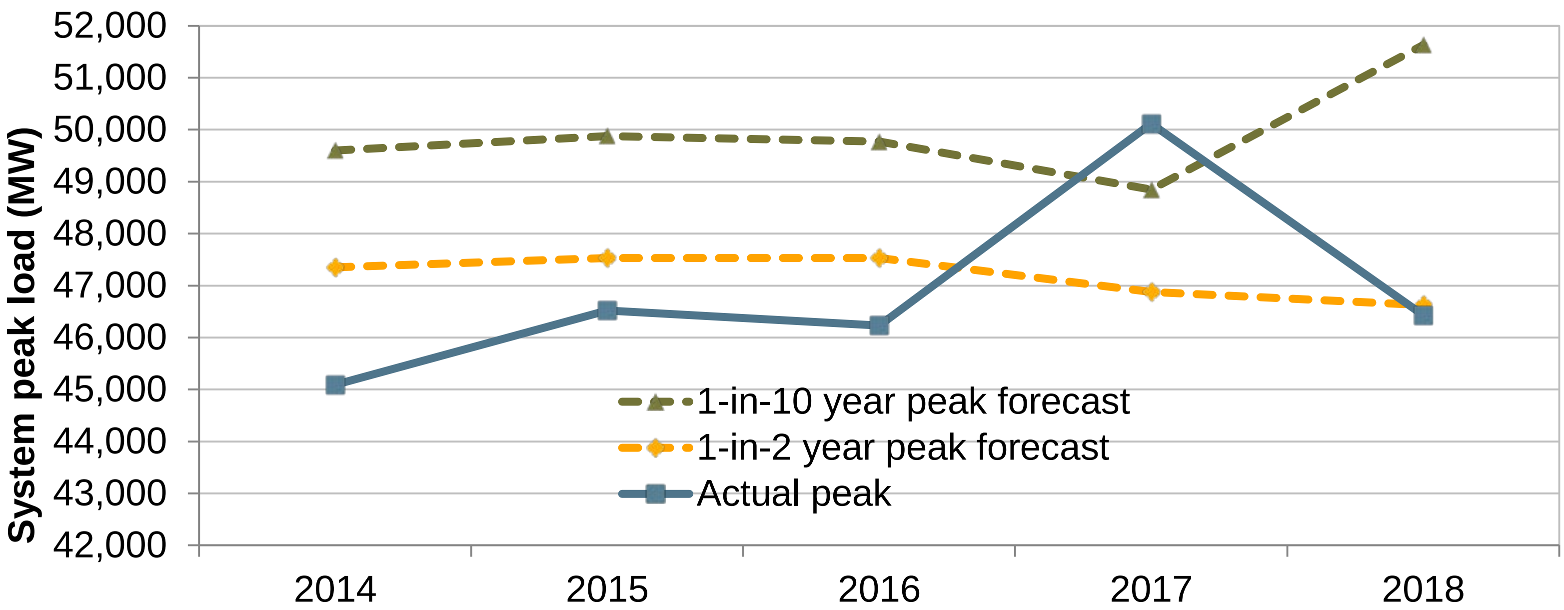
Average hourly prices mirror net load, with day-ahead prices systematically higher most hours.



System energy prices continue to be driven by gas prices and renewable supply conditions.

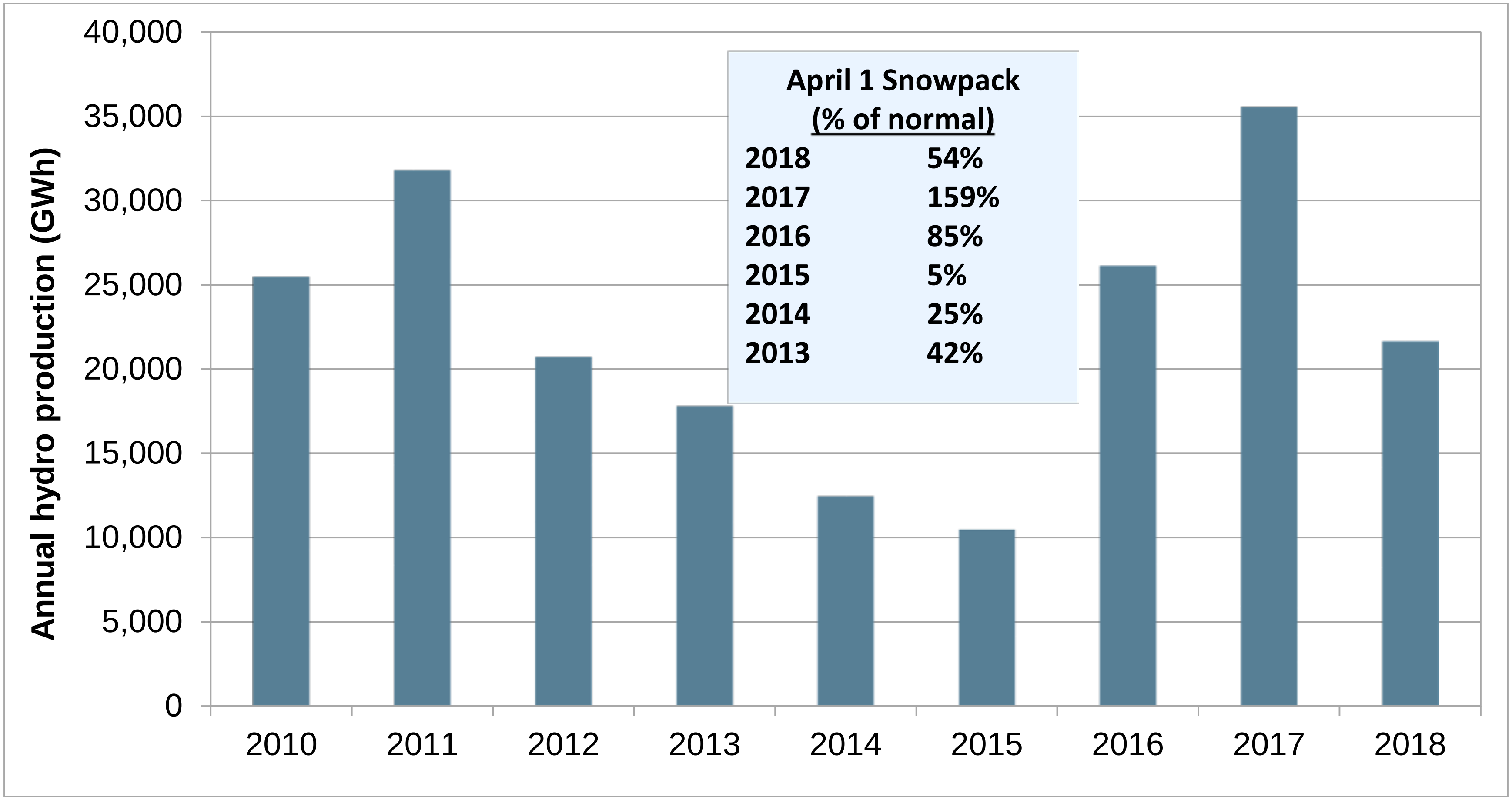


Lower peak loads and lower overall energy loads

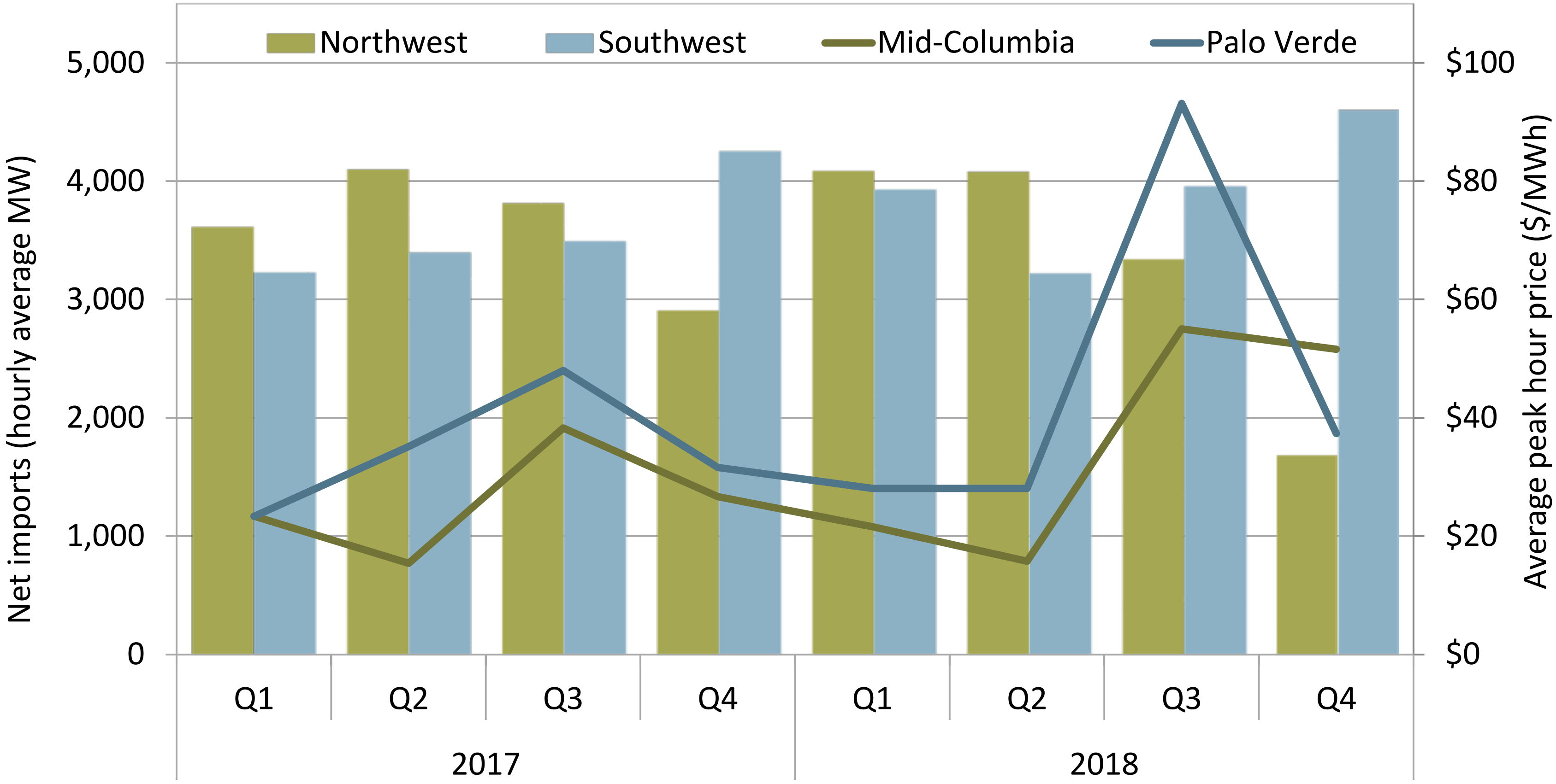


Year	Annual total energy (GWh)	Average load (MW)	% change	Annual peak load (MW)	% change
2014	231,610	26,440	-0.1%	45,090	0.0%
2015	231,495	26,426	0.0%	46,519	3.2%
2016	228,794	26,047	-1.4%	46,232	-0.6%
2017	228,191	26,049	0.0%	50,116	8.4%
2018	223,705	25,537	-2.0%	46,427	-7.4%

Hydroelectric generation decreased to around 10% of supply, compared to 15% in 2017 and 11% in 2016

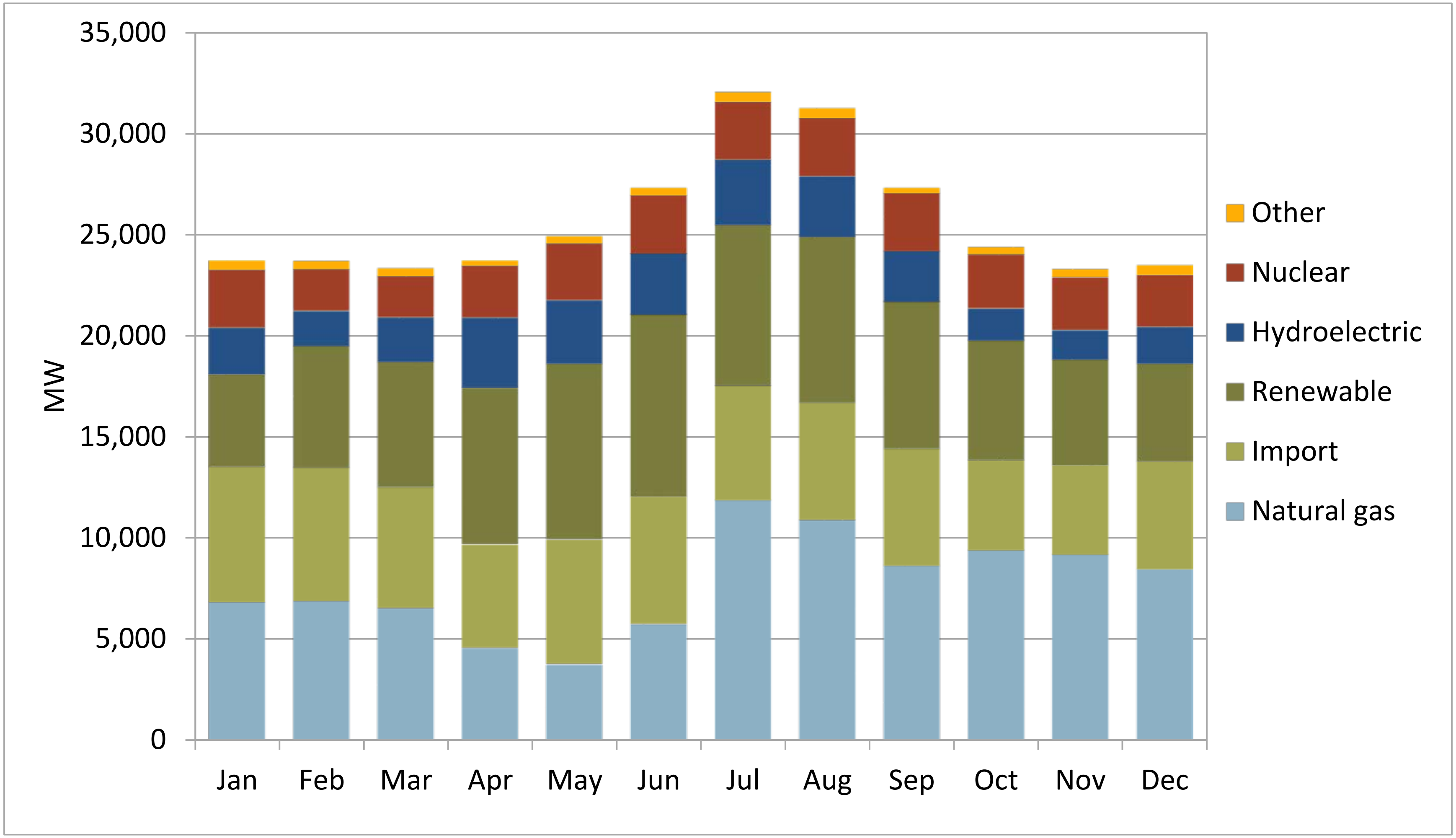


Net imports and average day-ahead prices at regional trading hubs (peak hours, 2017-2018)

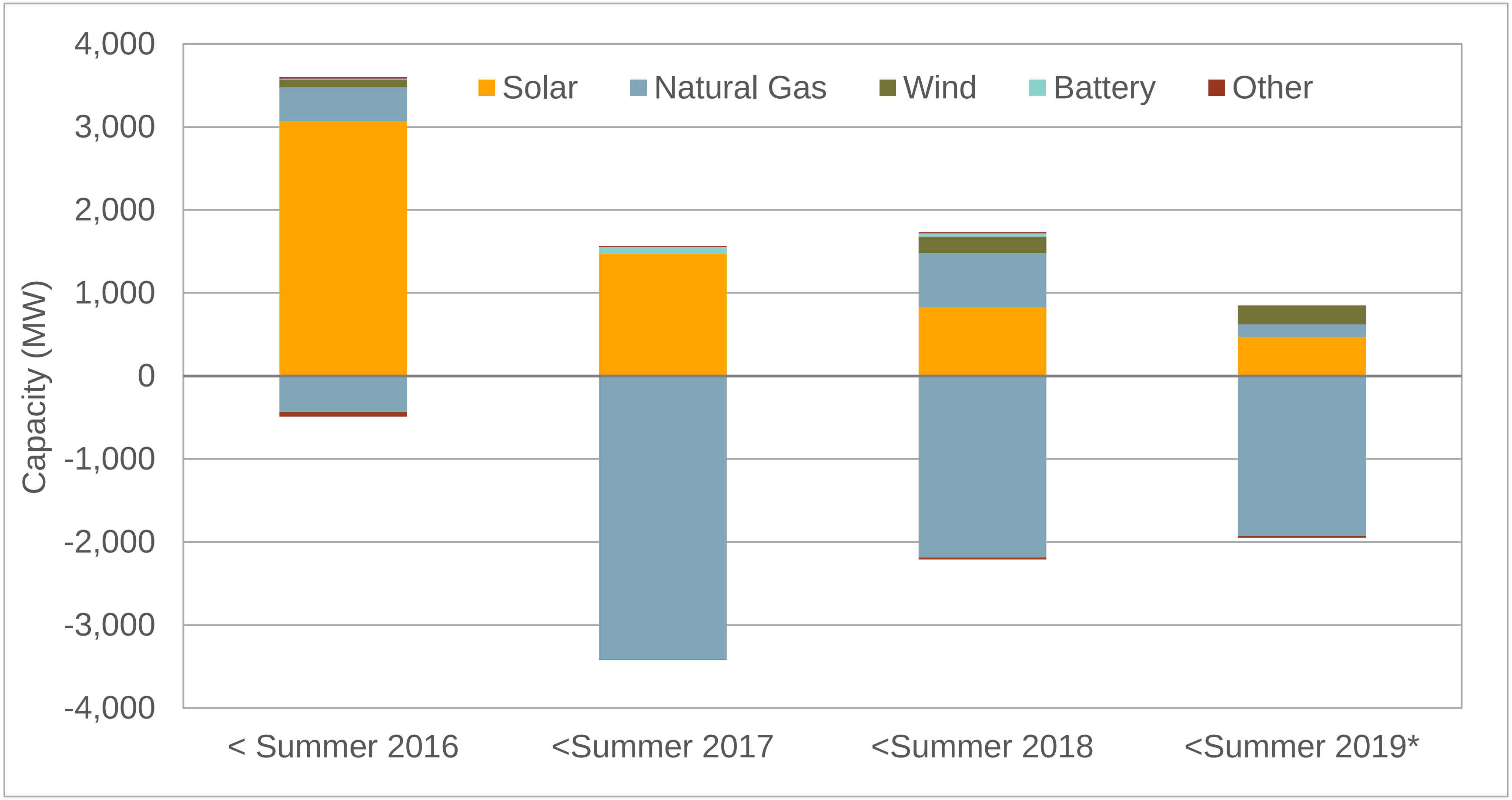


http://www.caiso.com/Documents/ImportResourceAdequacySpecialReport-Sept102018.pdf

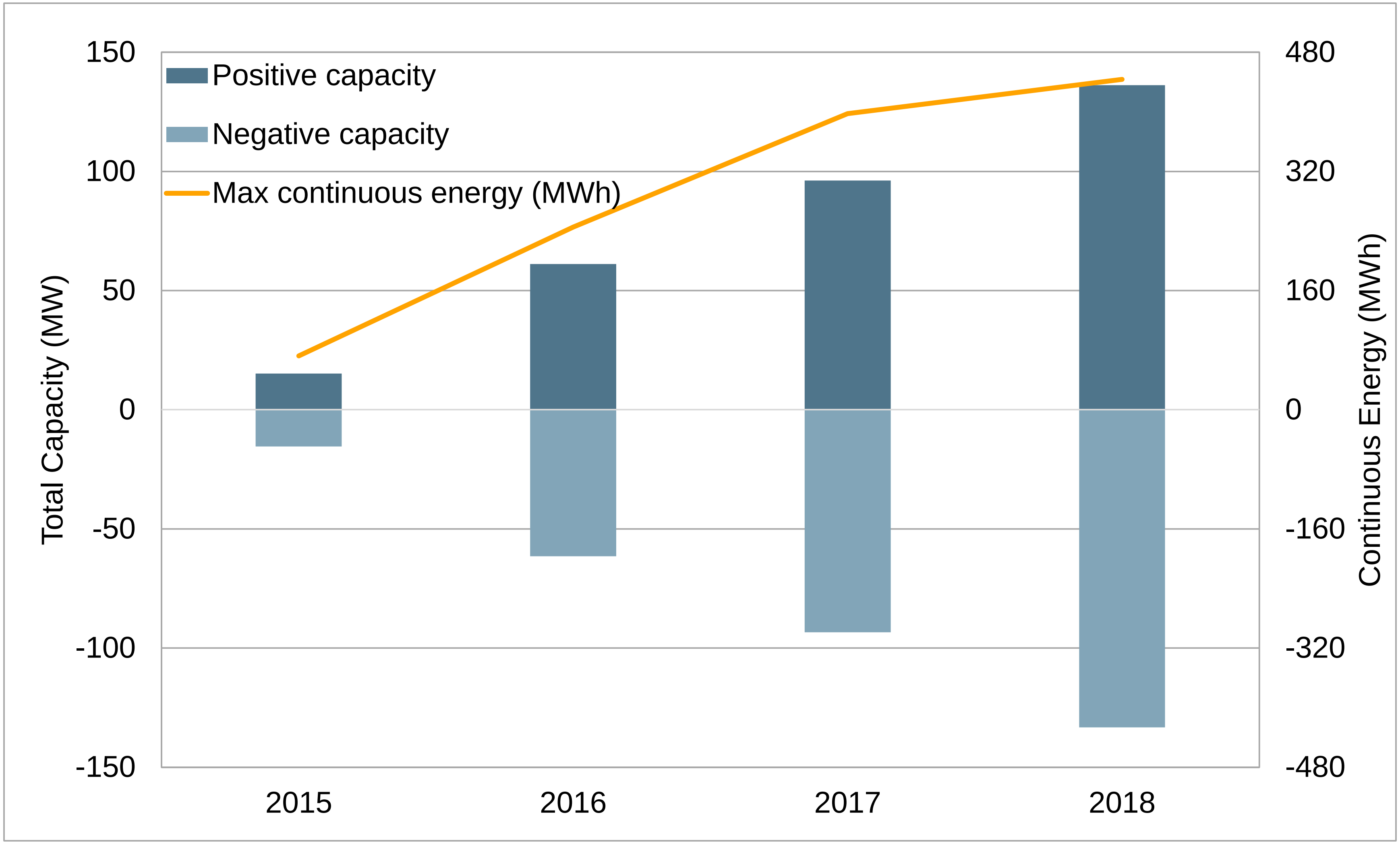
Reliance on gas is higher during months with higher loads



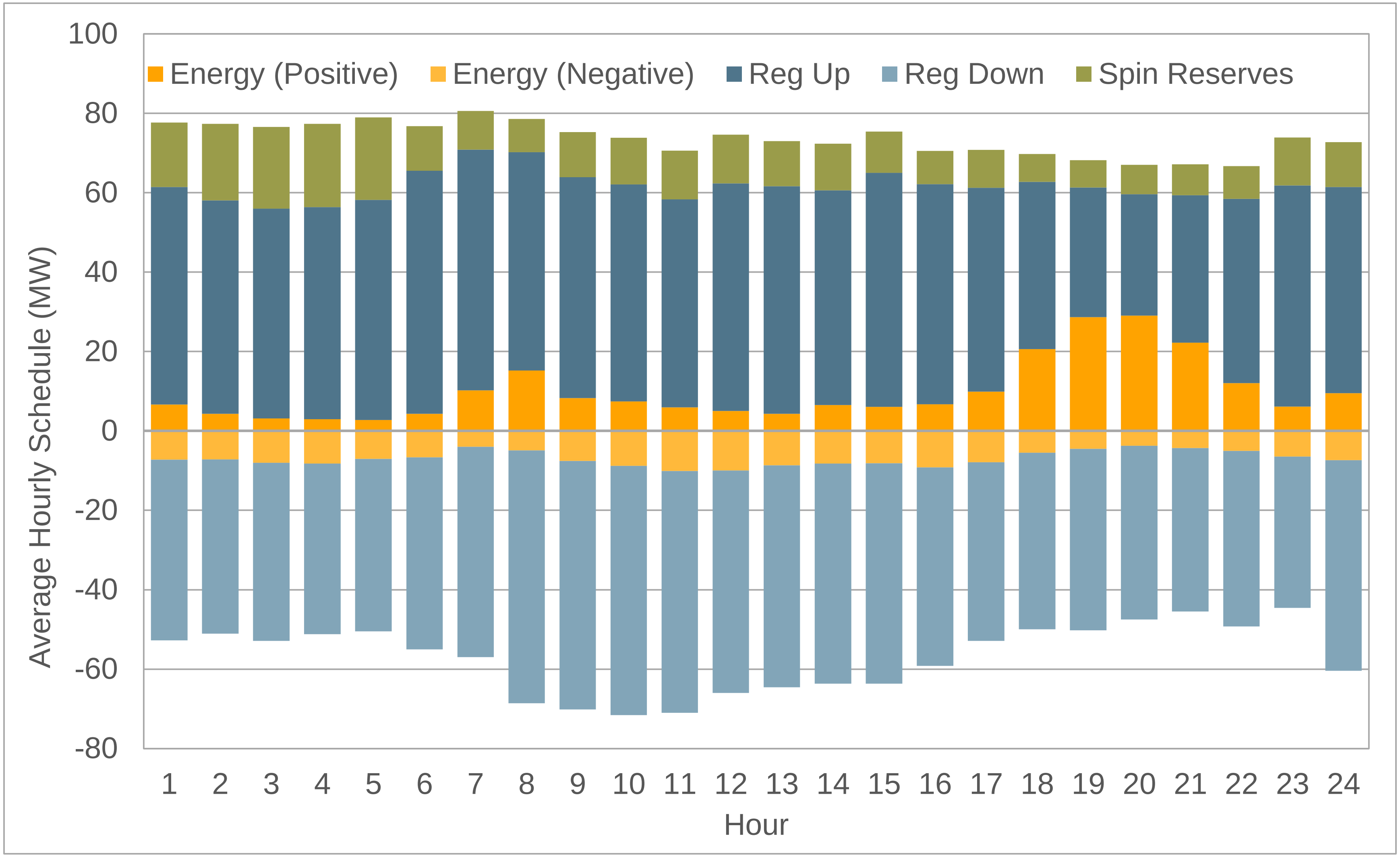
Gas capacity retiring is being largely replaced with renewables (mainly solar).



Battery capacity (2015-2018)



Average hourly schedules for battery resources.

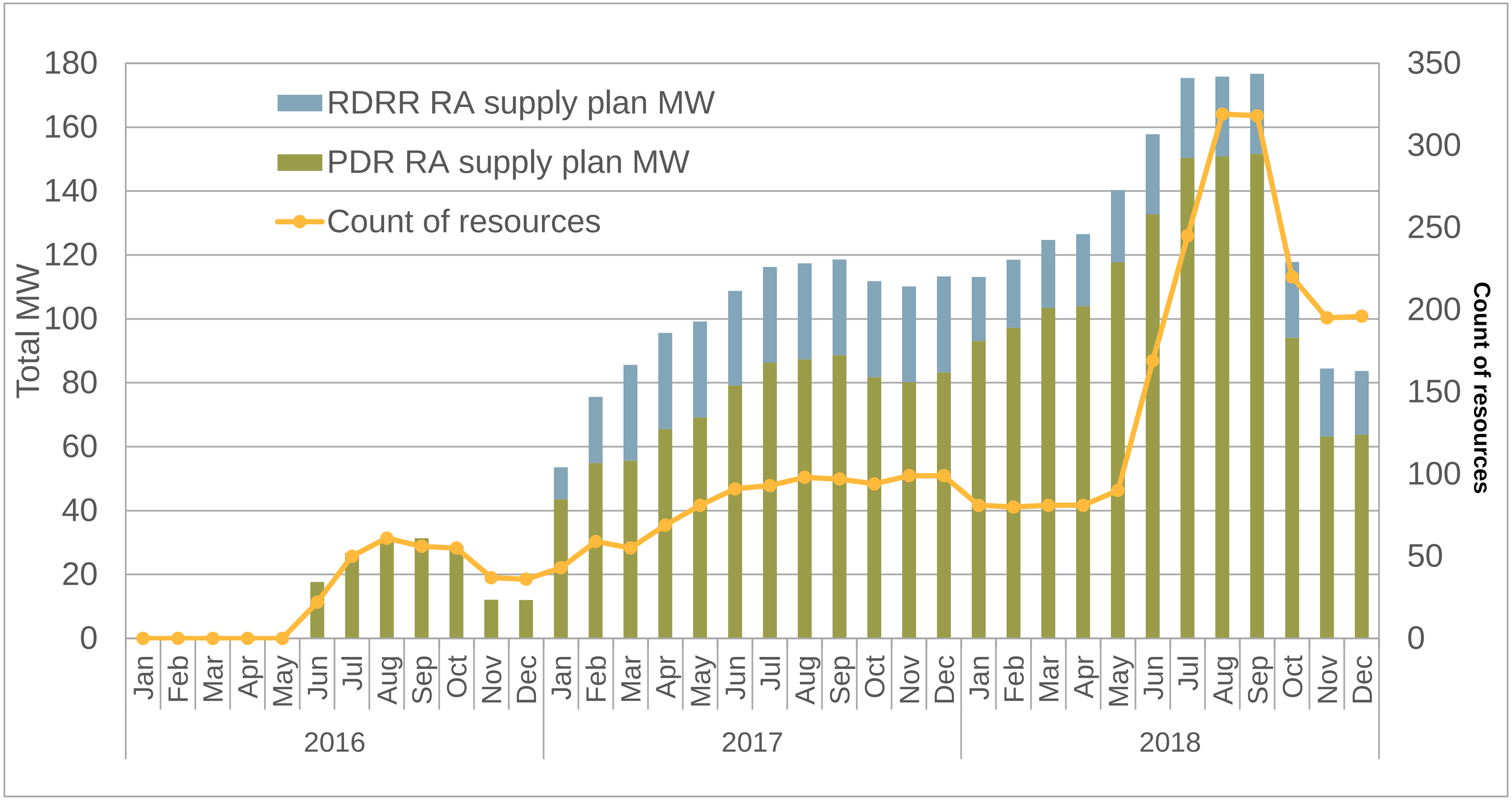


2018 Battery resource participation in CAISO's markets

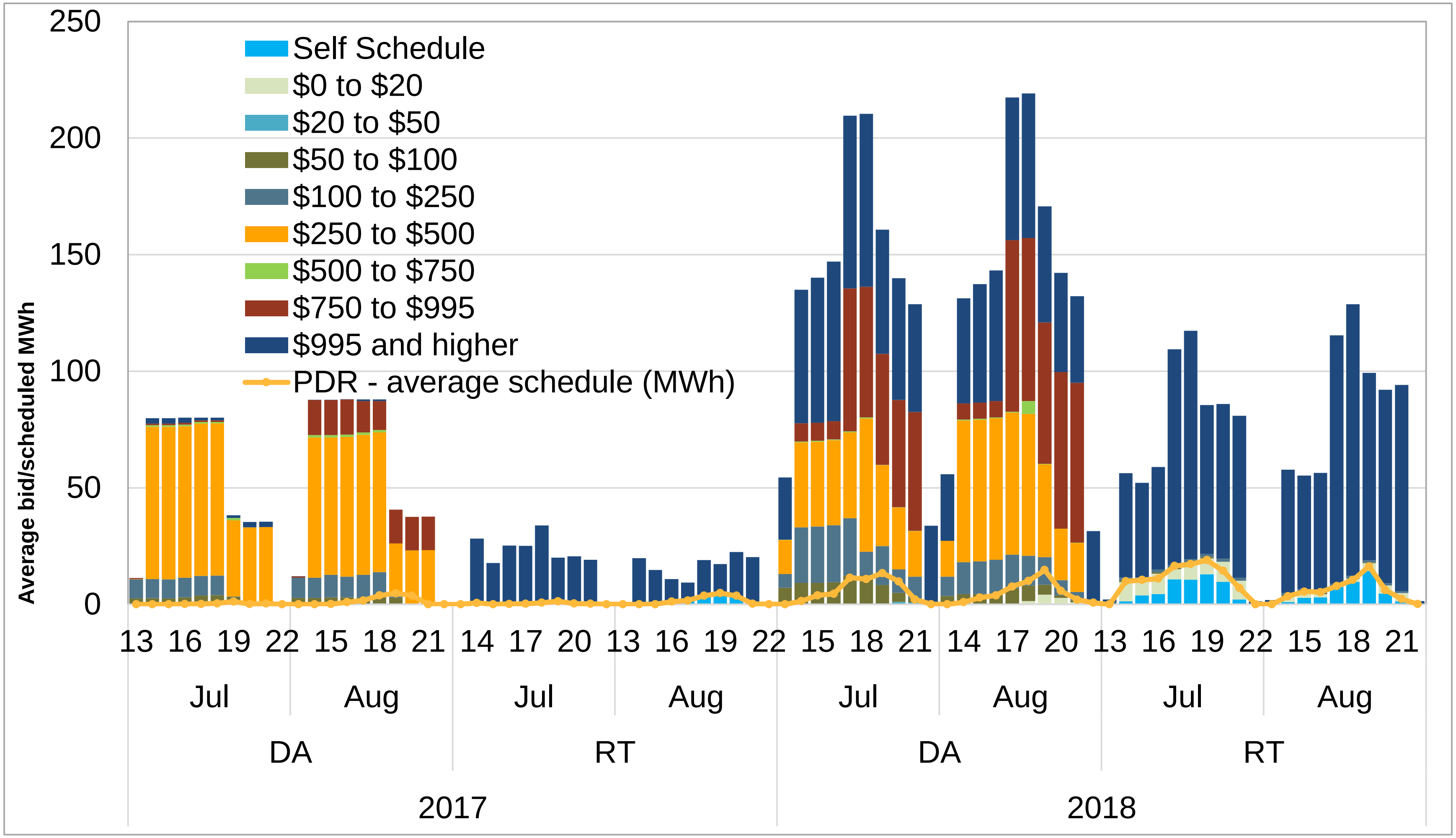
- Market revenues from regulation capacity awards (up and down), followed by energy in day-ahead market
- Average day-ahead energy bid price spread between charge and discharge energy was ~$90/MWh
- Regulation capacity (up and down) was generally offered below $20/MWh

  ~50% of regulation capacity was offered below $5/MWh.
- Bid prices for providing energy versus regulation products could reflect a difference in costs (perceived or actual) associated with cycling and battery degradation when a battery operates for energy versus regulation

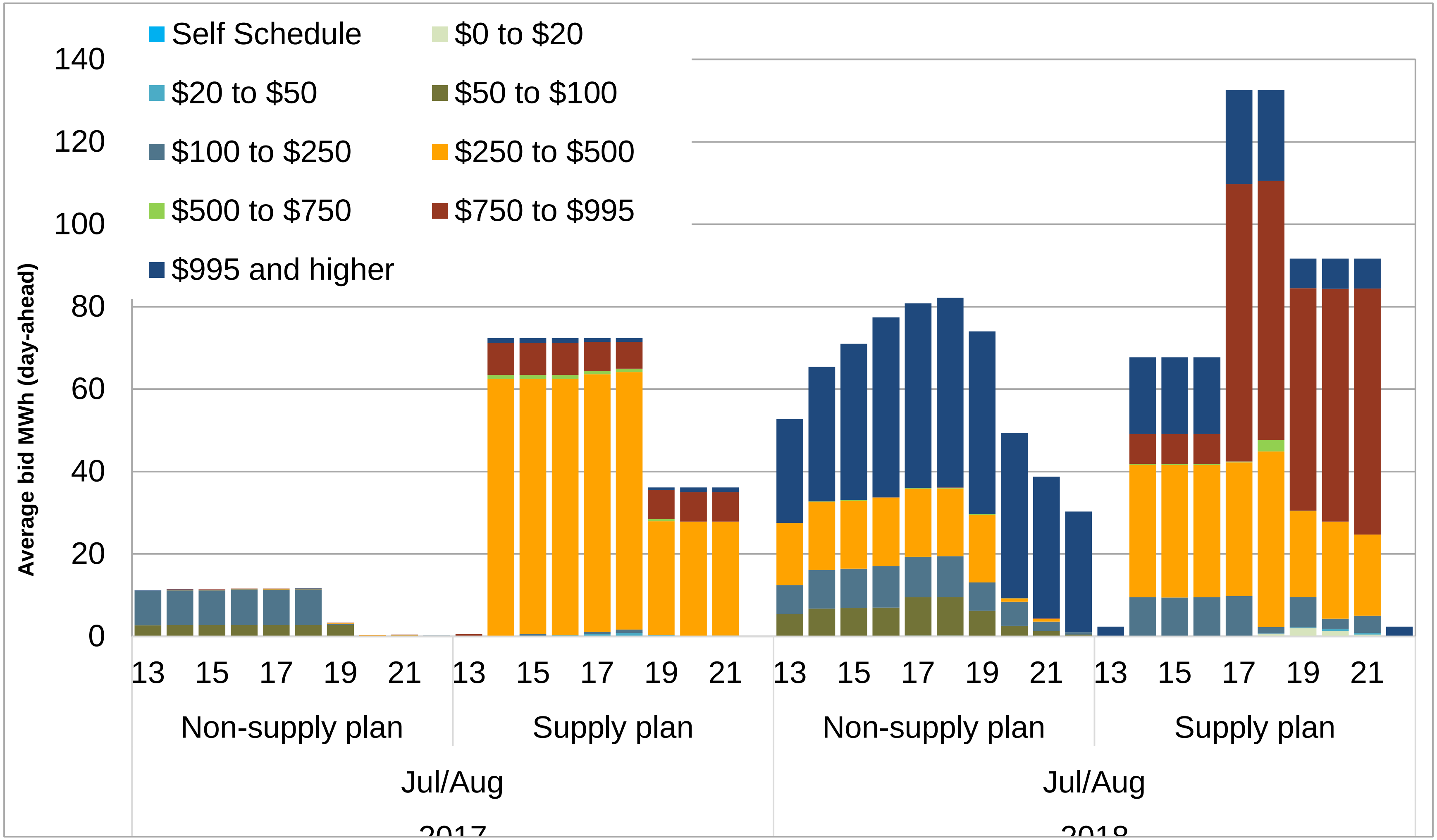
Demand response capacity reflected on monthly LSE RA supply plans



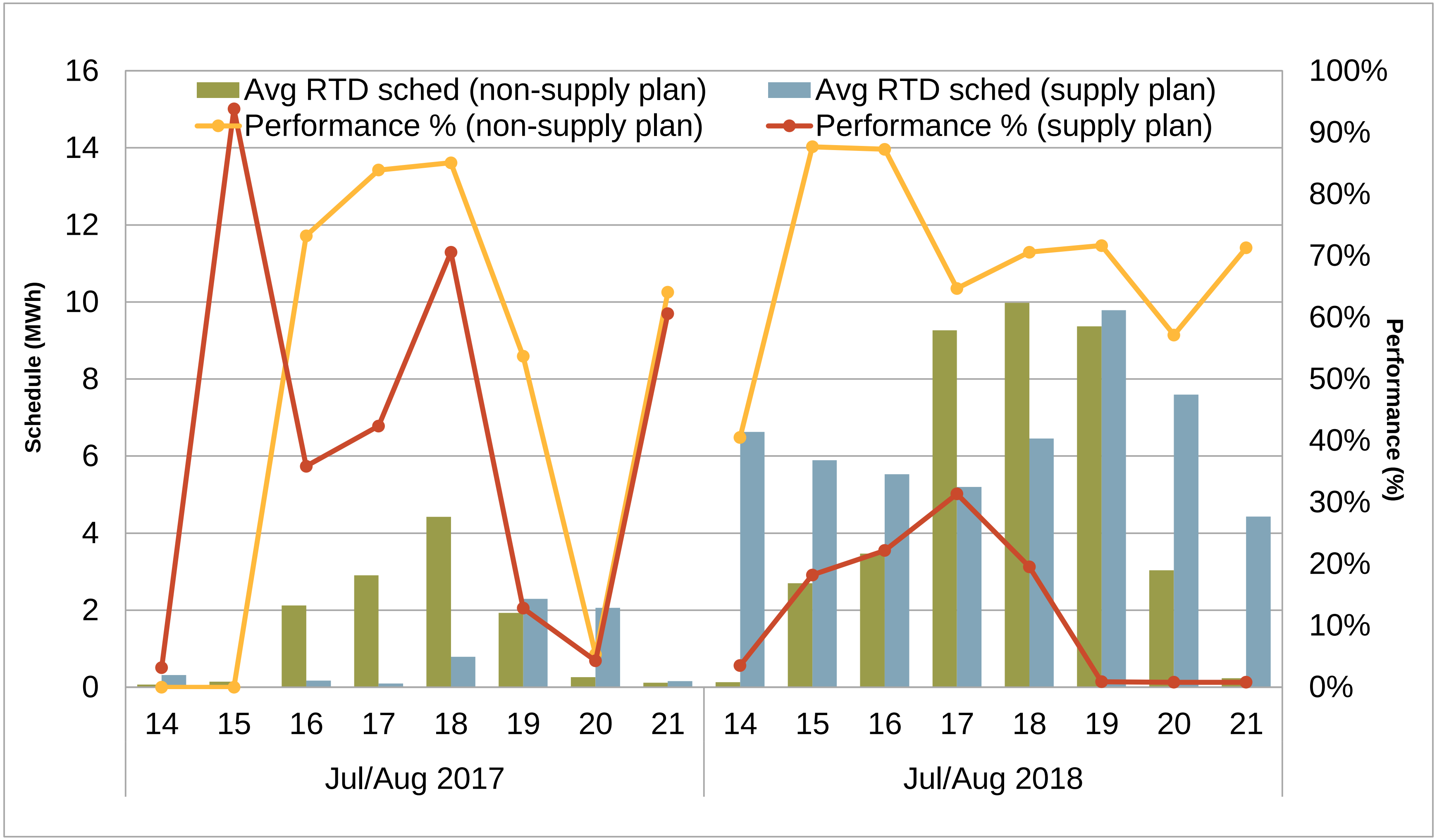
Proxy demand response bid prices and average schedules July and August (HE 13-22)



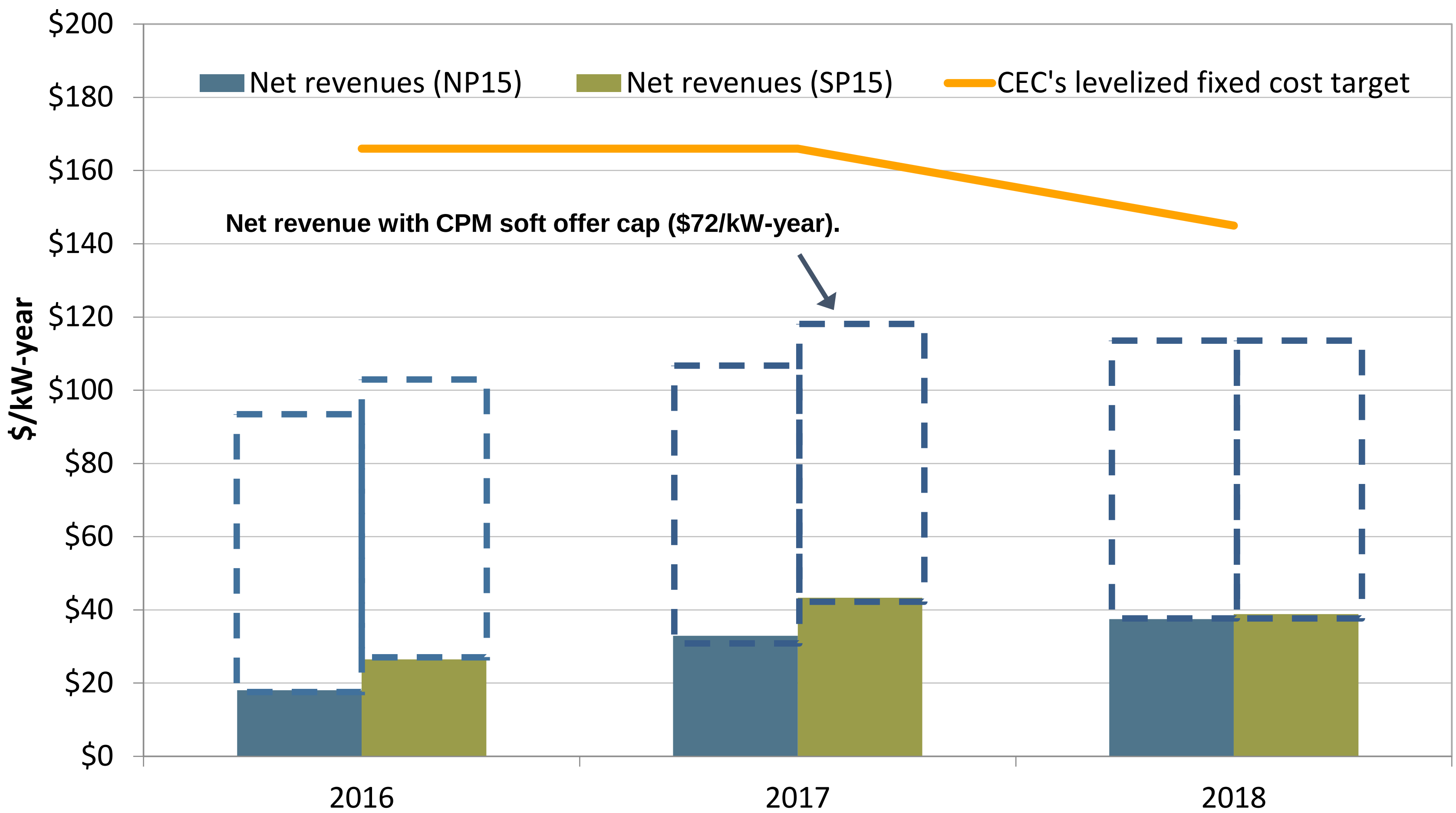
Supply plan and non-supply plan day-ahead PDR bid prices July and August



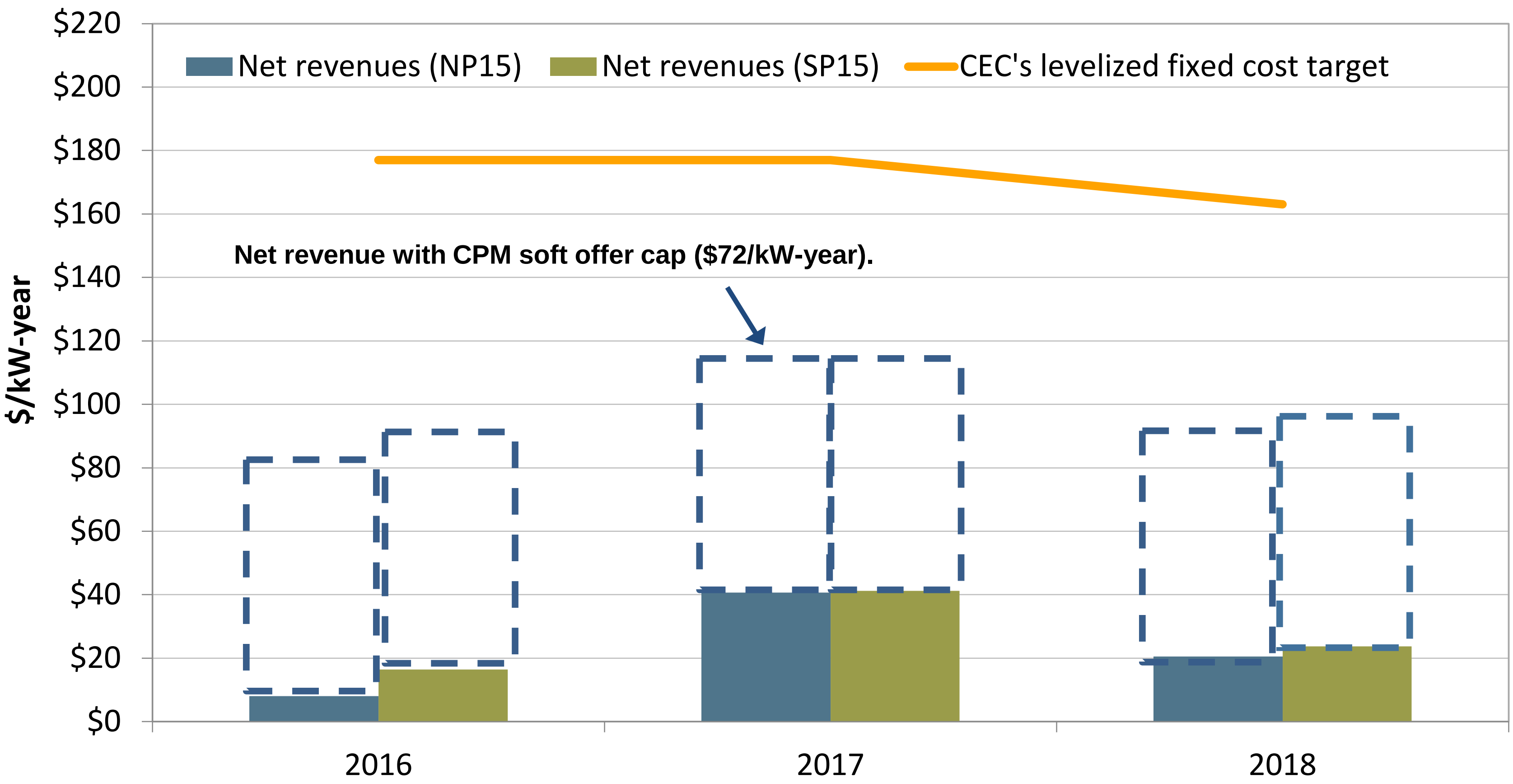
Proxy demand response schedules and performance July and August



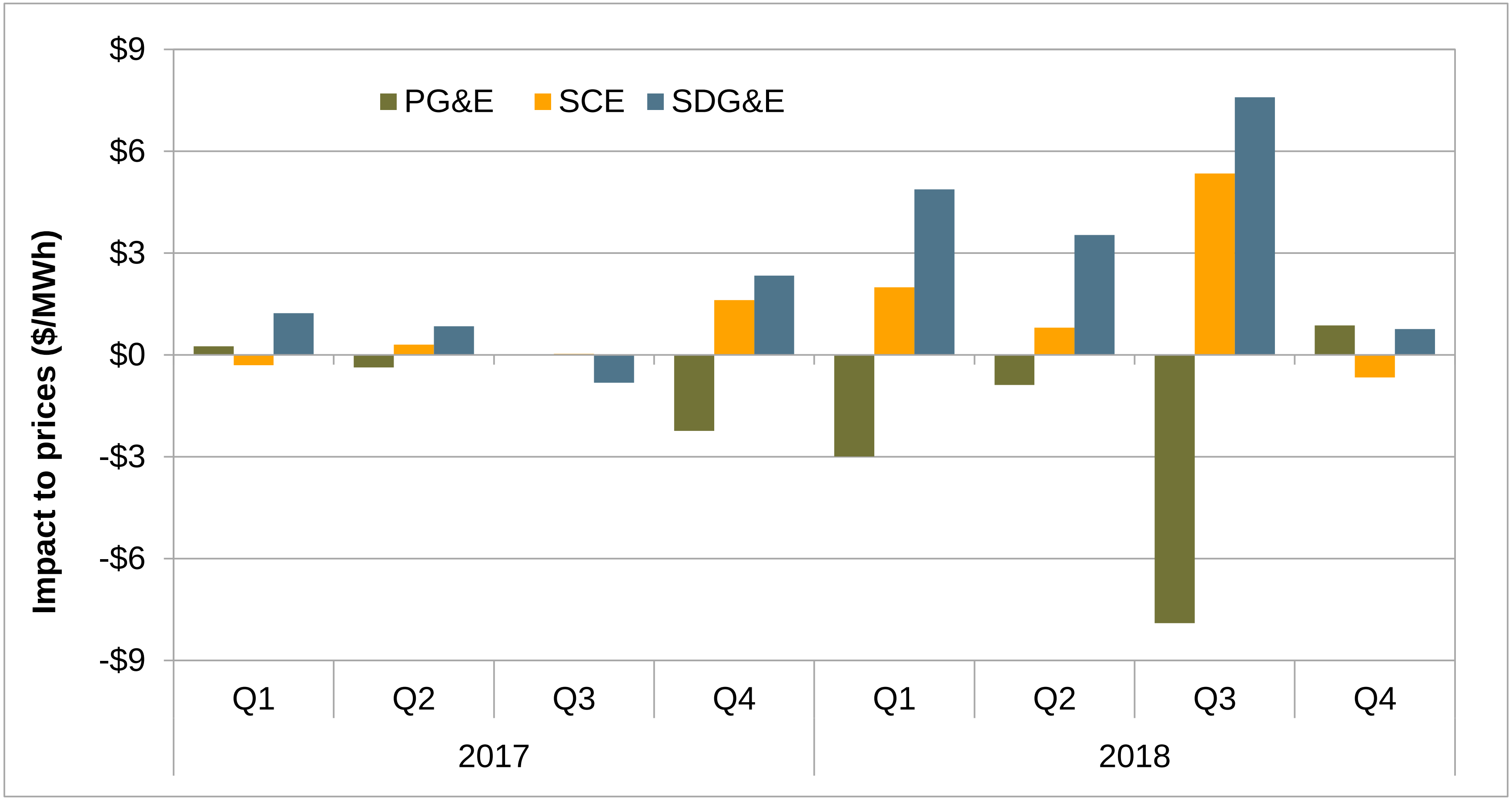
Estimated net energy market revenue of typical combined cycle unit in NP15 and SP15 was about $38/kW-year.



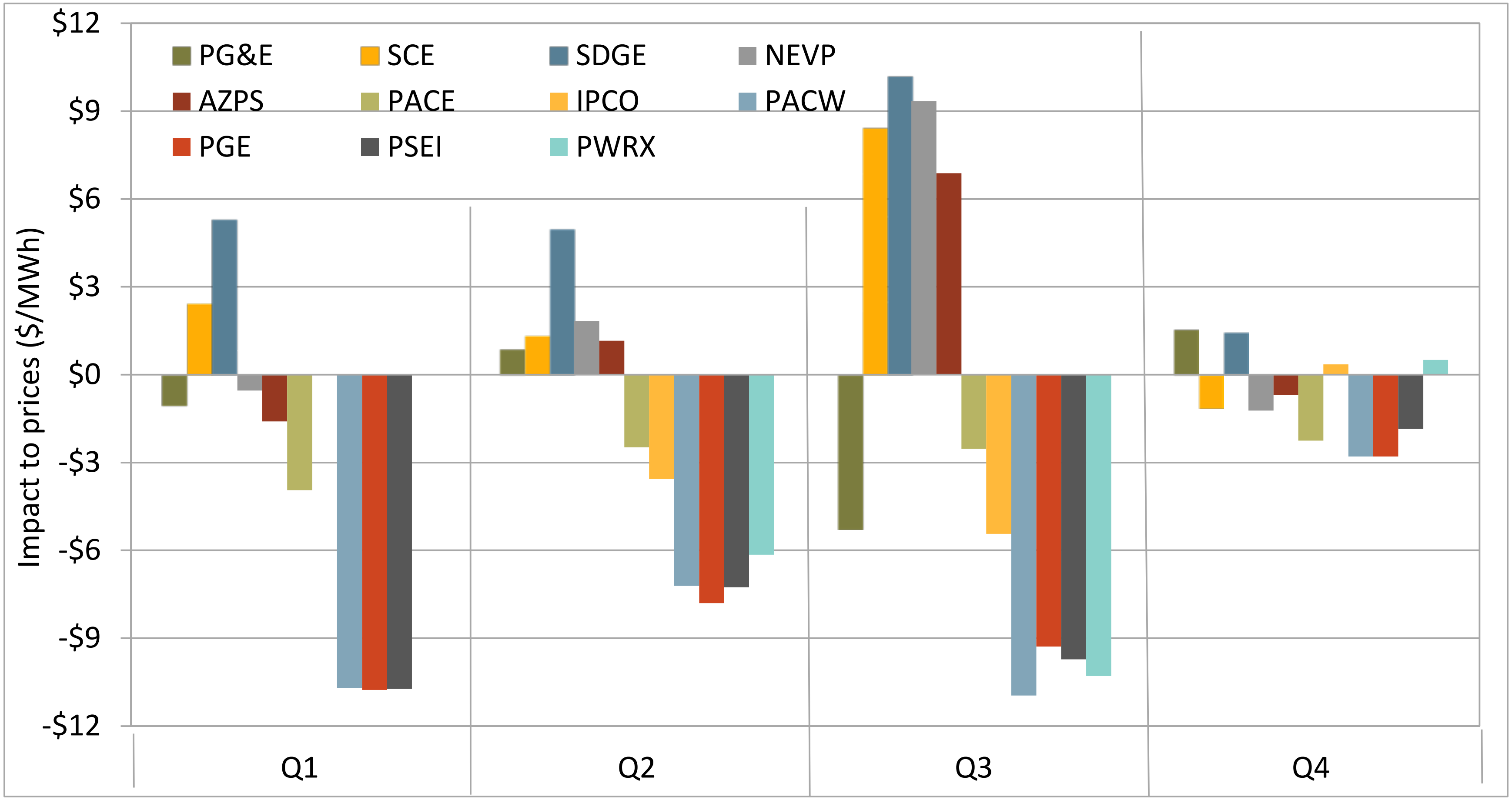
Estimated net energy market revenue of typical combustion turbine dropped to about $22/kW-year.



Overall impact of congestion on prices in different areas increased in the day-ahead market.

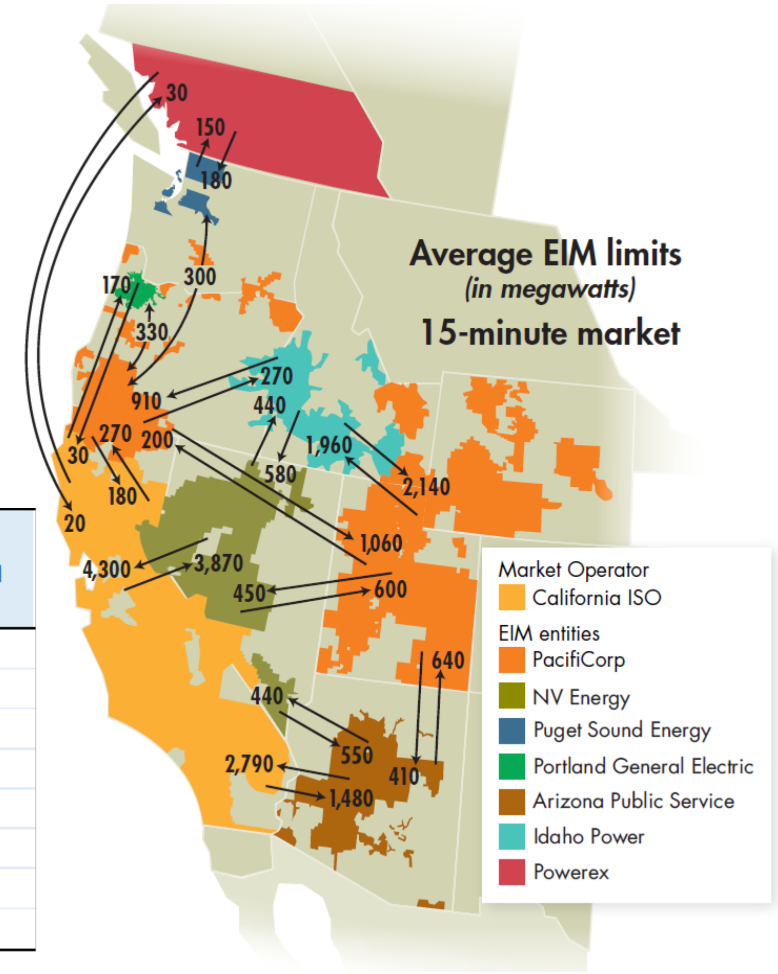


Congestion in the 15-minute market tended to lower prices in northwest EIM balancing areas relative to southern EIM balancing areas.

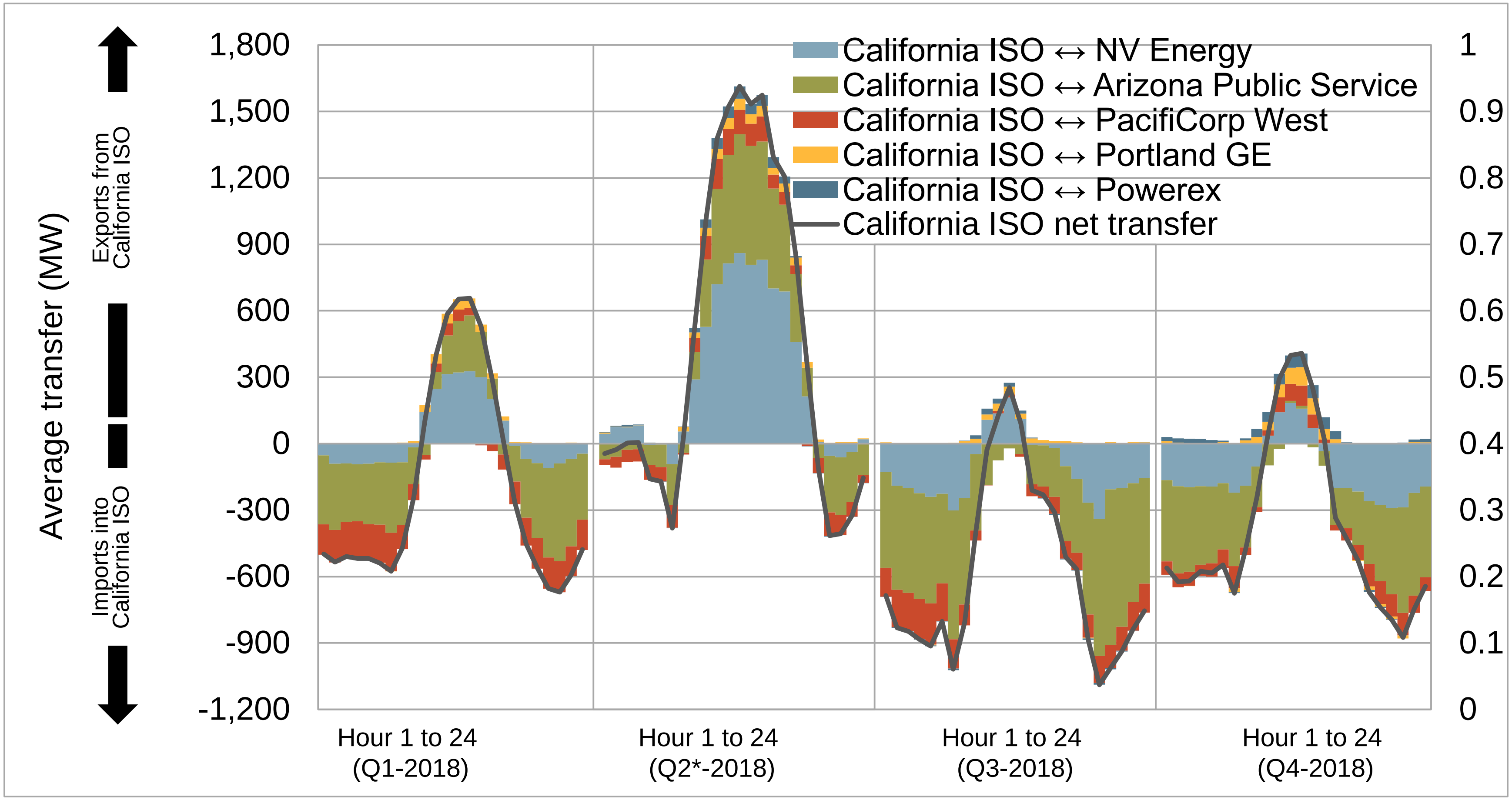


Energy imbalance market expansion improved performance of real-time market.

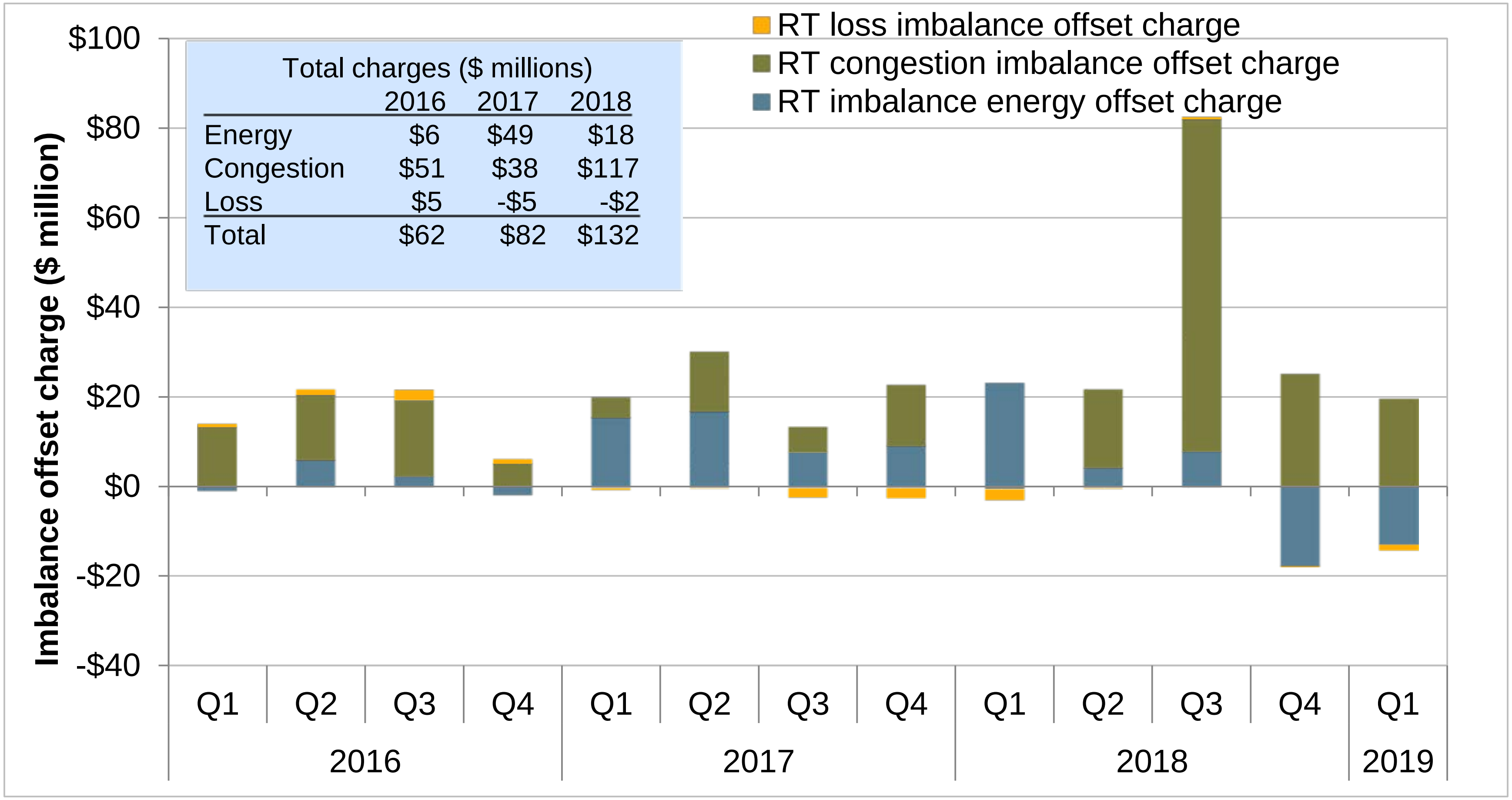
	15-minute market		5-minute market	
	Congested toward ISO	Congested from ISO	Congested toward ISO	Congested from ISO
NV Energy	3%	3%	3%	2%
Arizona Public Service	3%	3%	2%	3%
PacifiCorp East	10%	2%	8%	3%
Idaho Power*	6%	5%	3%	6%
PacifiCorp West	39%	3%	31%	6%
Portland General Electric	39%	4%	32%	7%
Puget Sound Energy	39%	7%	32%	9%
Powerex*	31%	30%	16%	24%



CAISO tends to export energy in EIM during peak solar hours, and import energy in other hours.



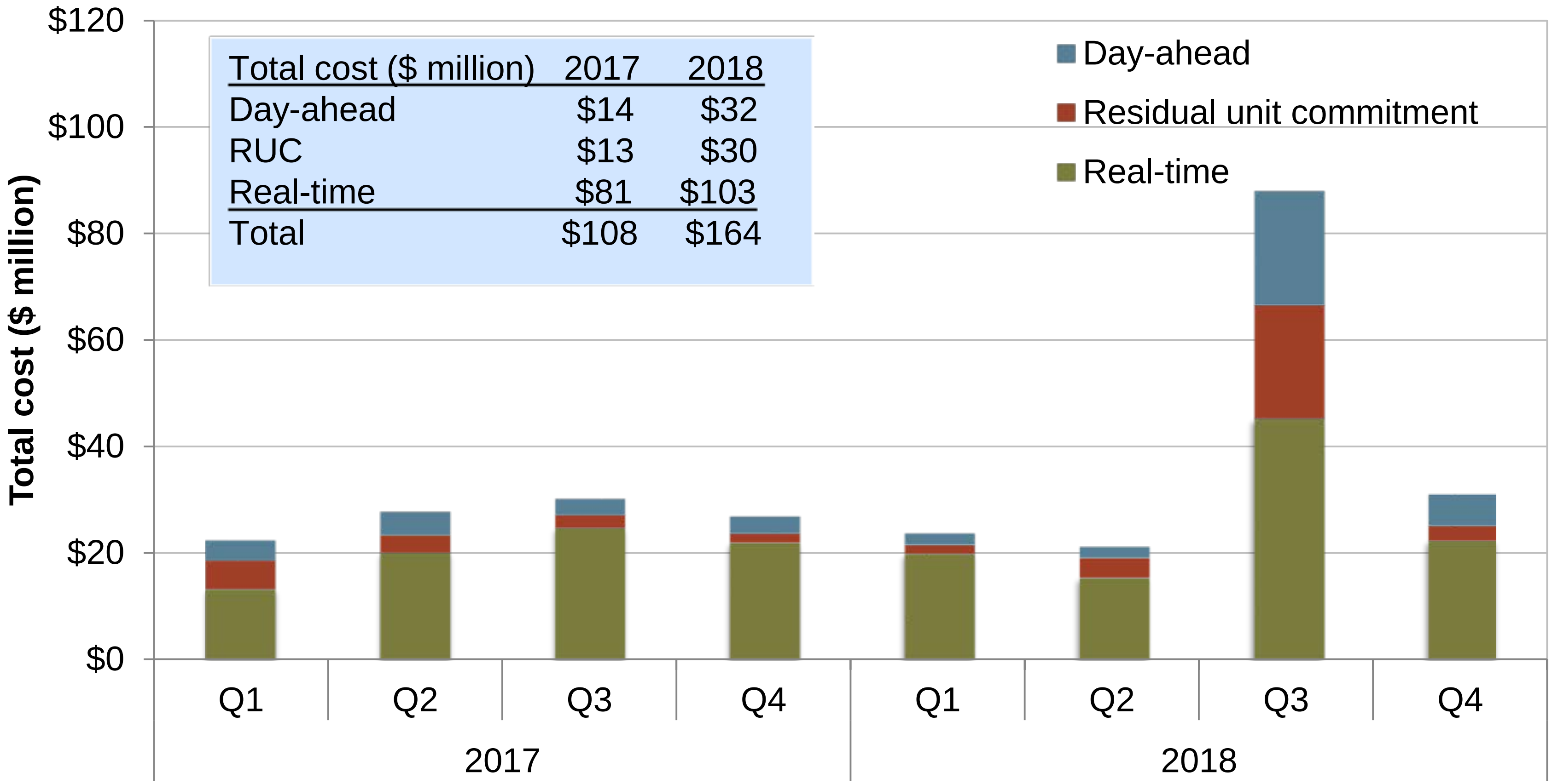
Real-time imbalance offset costs increased by 61% to $128 million.



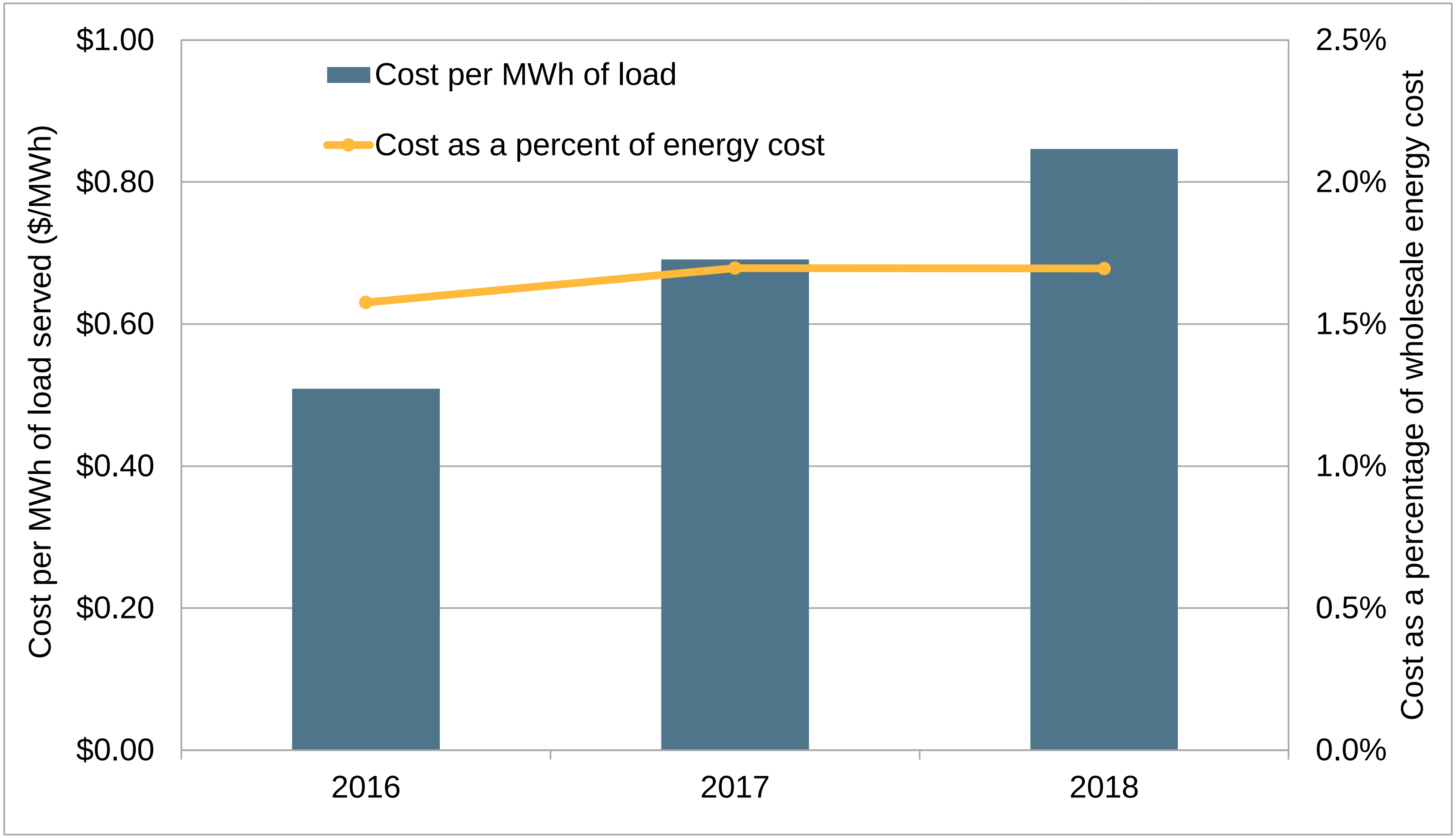
Total charges ($ millions)

	2016	2017	2018
Energy	$6	$49	$18
Congestion	$51	$38	$117
Loss	$5	-$5	-$2
Total	$62	$82	$132

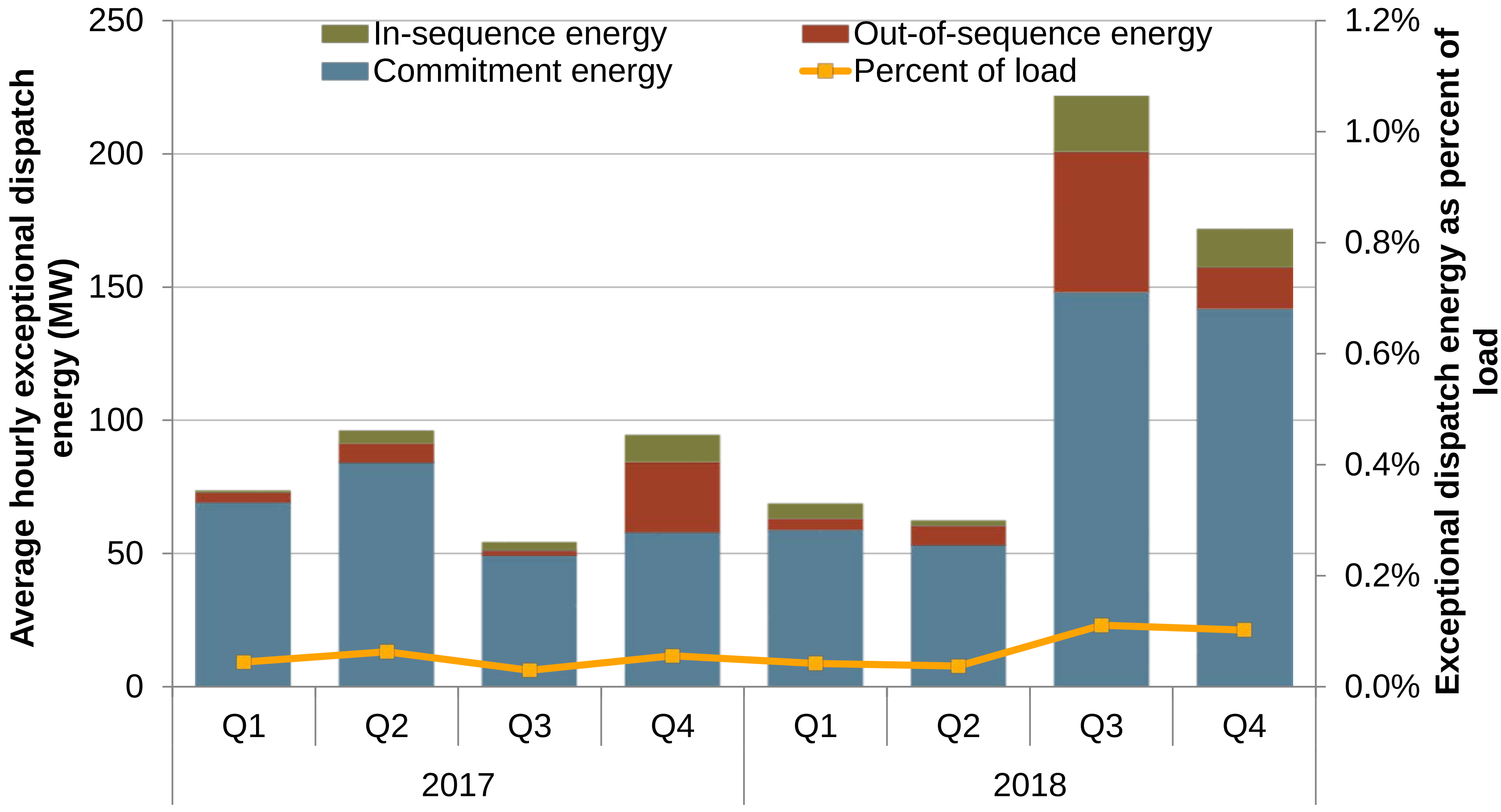
Bid cost recovery payments in the CAISO increased to $153 million or about 1.4 percent of total energy costs.



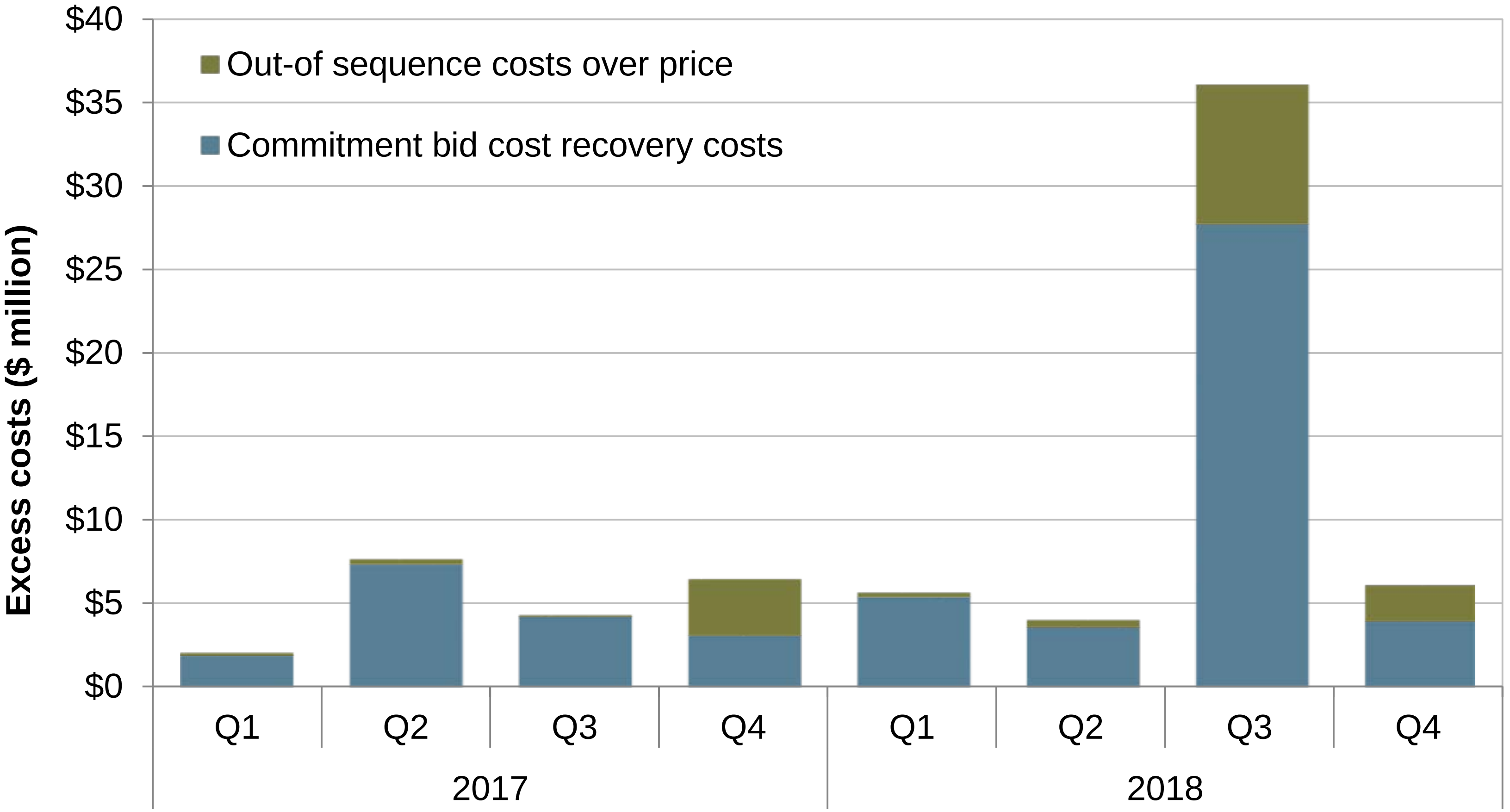
Ancillary service costs increased to $189 million, but remained at about 1.7% of wholesale energy costs.



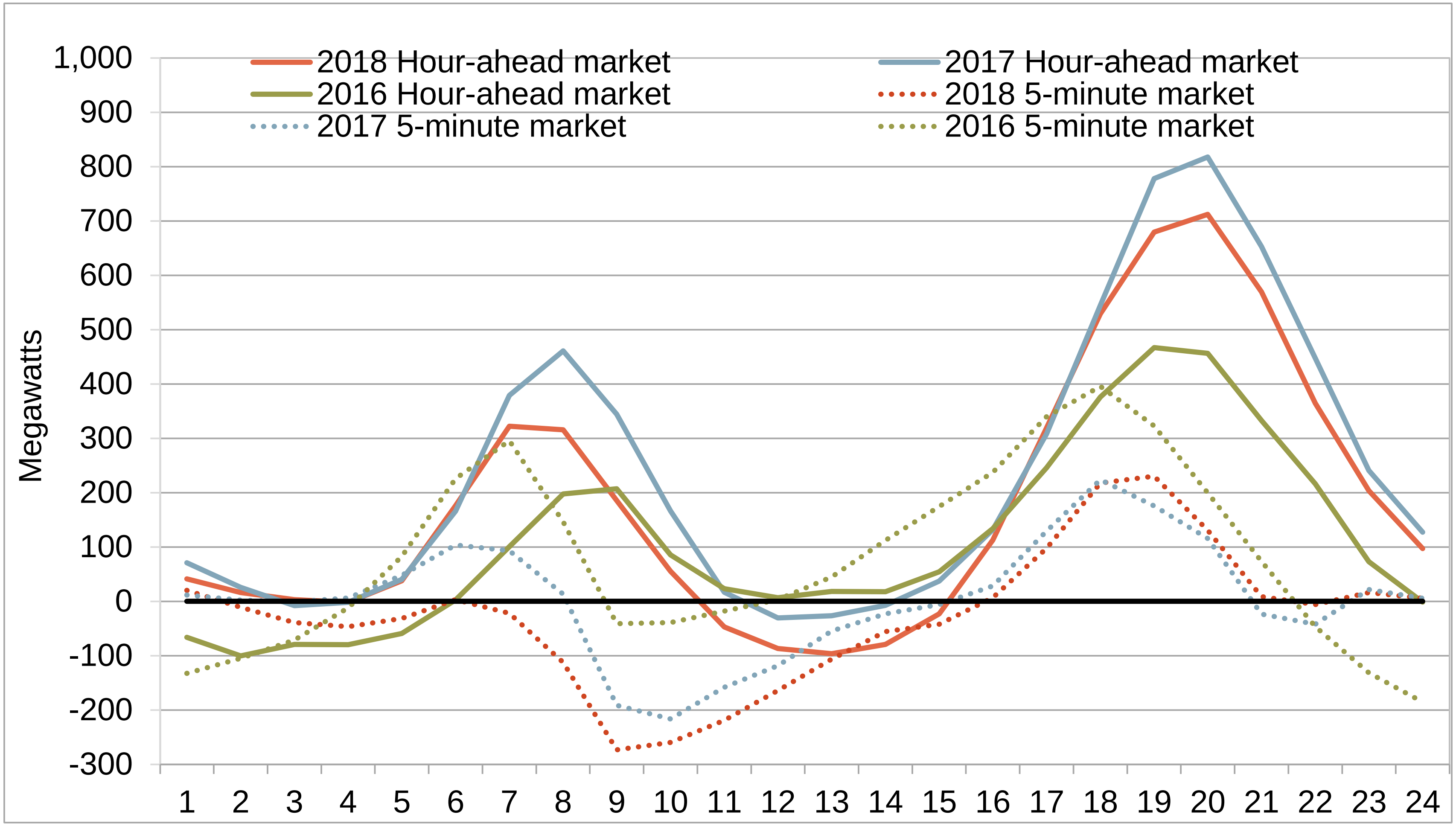
Total energy from exceptional dispatches increased in 2018 but account for a low portion of system load (.07%)



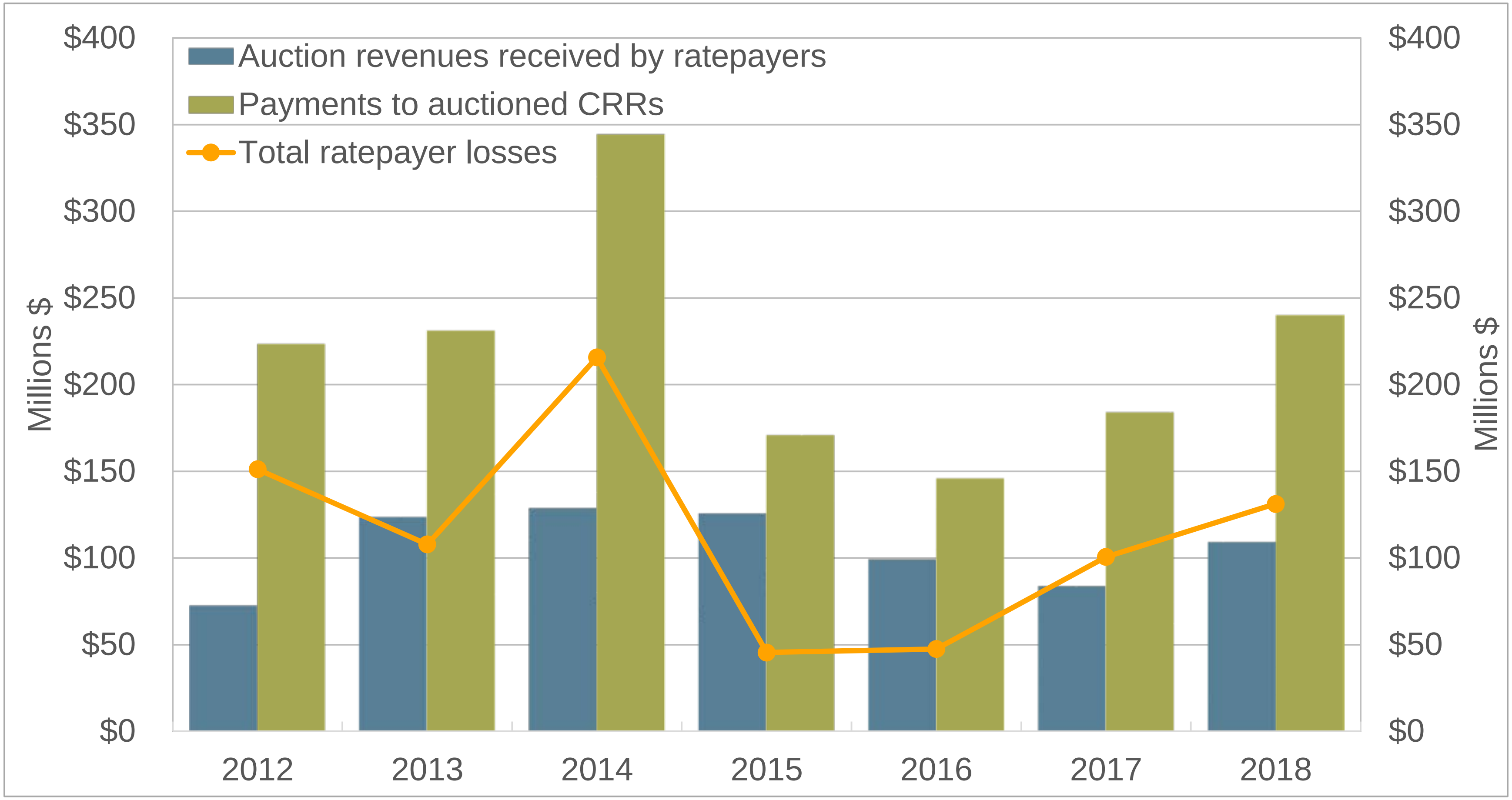
Above-market cost of exceptional dispatch increased over 150% to $52 million, but bid mitigation avoided about $18 million in “as bid” energy costs.



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



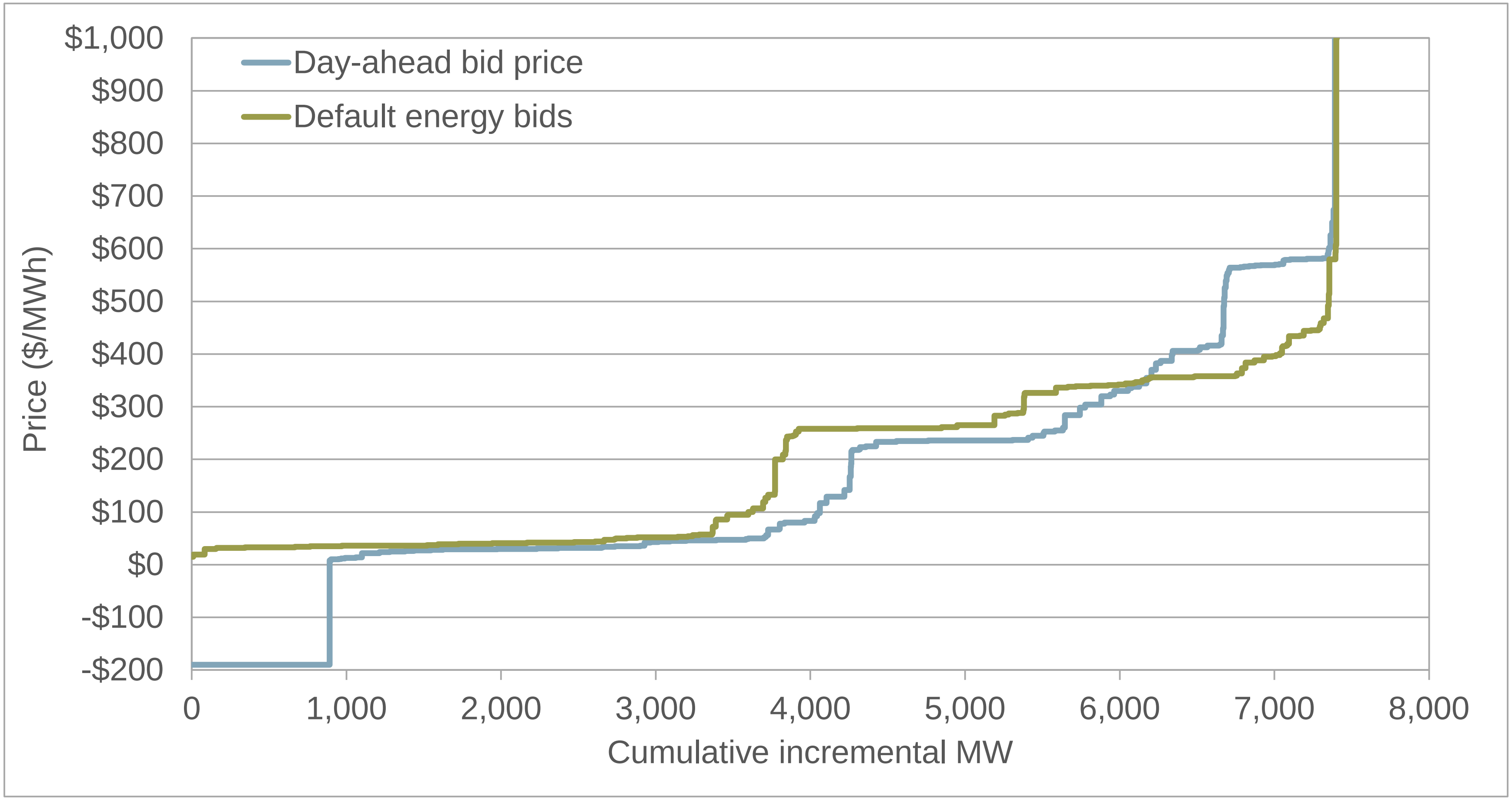
Transmission ratepayers lost over $131 million from auctioned CRRs in 2018 (>$866 million since 2009)



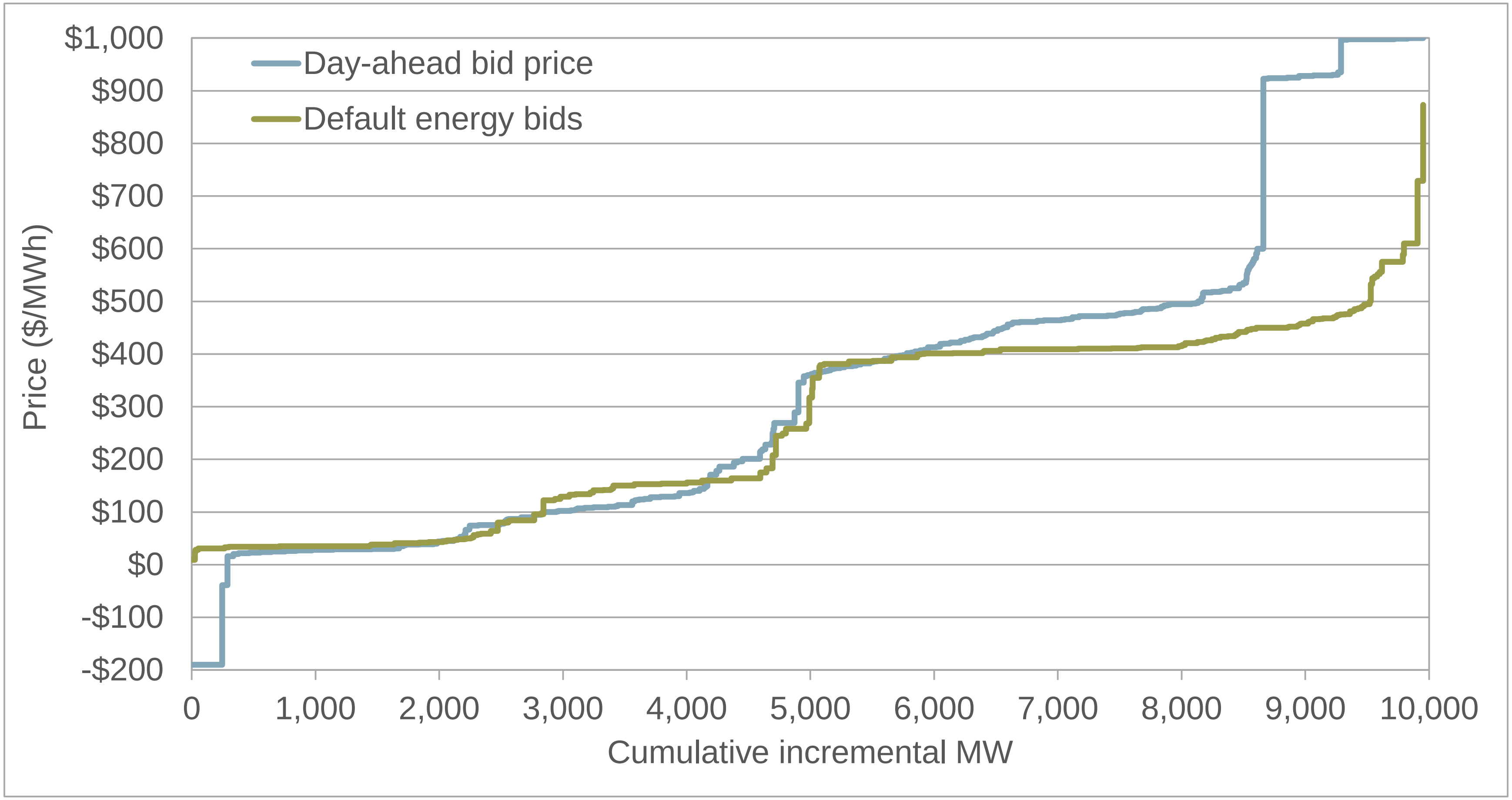
Market competitiveness

- CAISO's energy markets were generally competitive in 2018.
- Prices in the day-ahead market were significantly in excess of competitive levels in some hours when net load that must be met by gas-fired units is highest
  - Price cost markup
  - Highest cost of gas units dispatched
  - Day-ahead market software simulation
- Market for capacity needed to meet local requirements is structurally uncompetitive in almost all local areas.

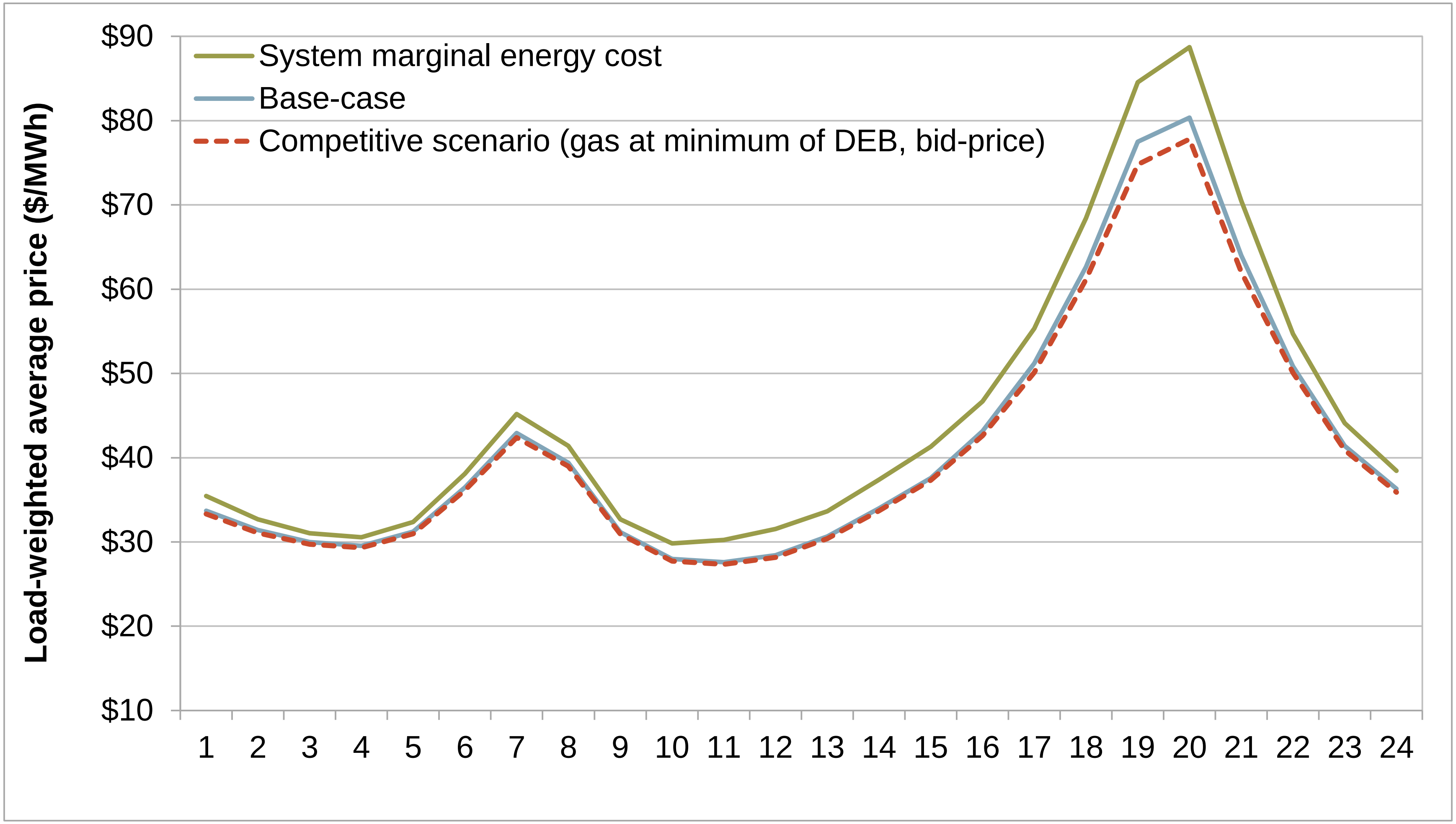
Net buyers' supply bids vs. default energy bids for gas units (July 24, 2018 hour 20).



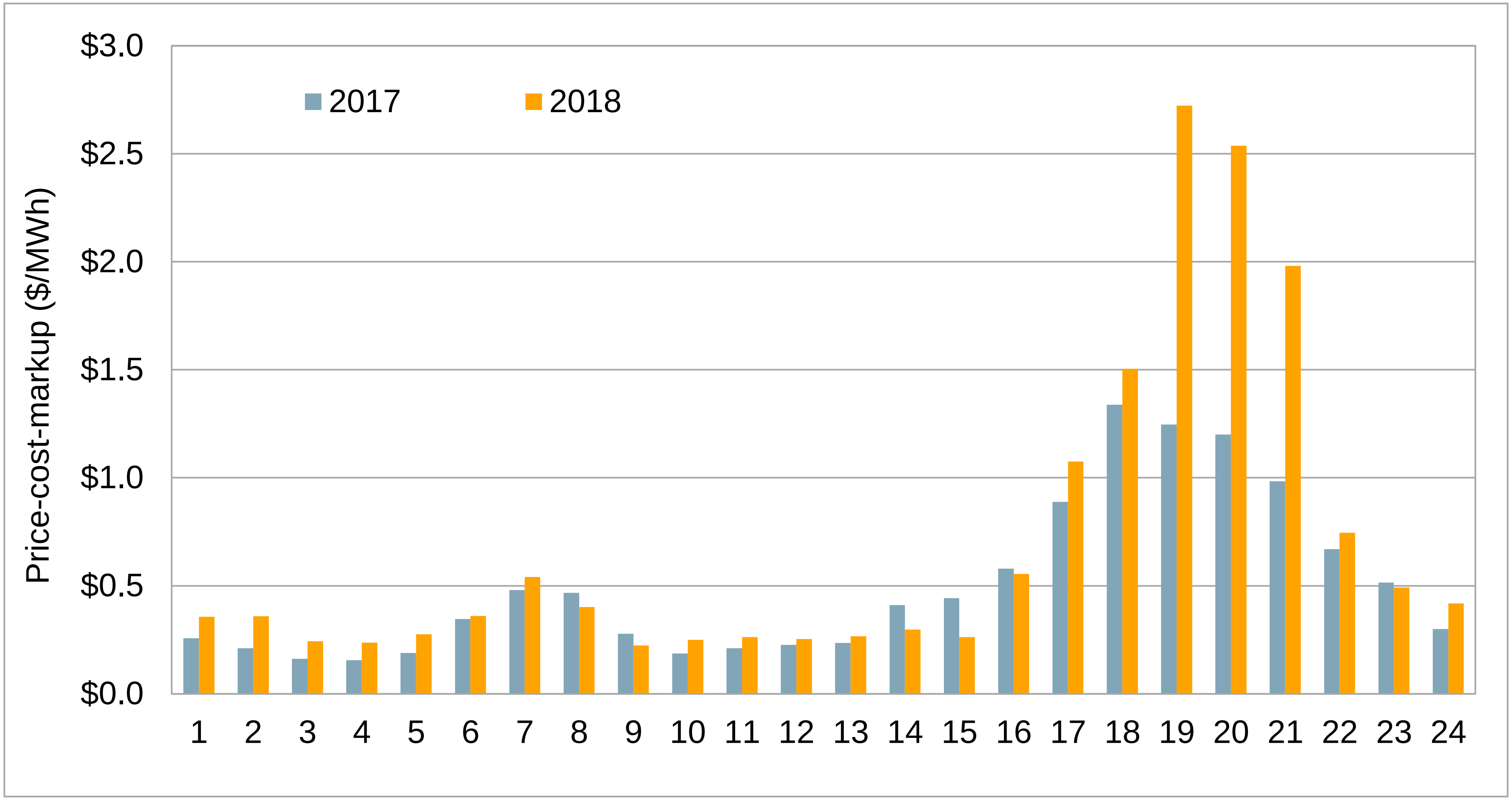
Net seller' supply bids vs. default energy bids for gas units (July 24, 2018 hour 20).



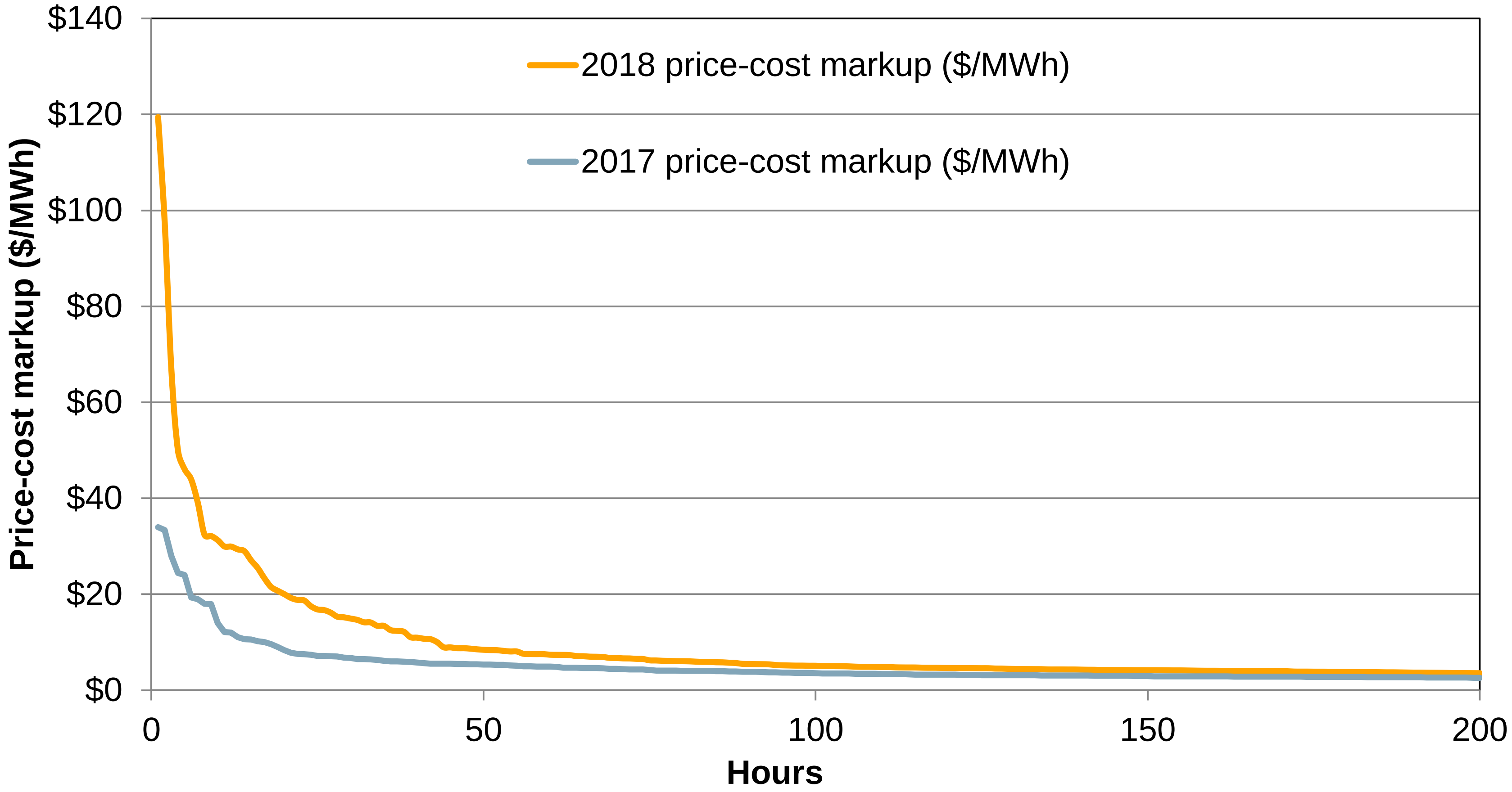
Average system marginal price compared to base case price and competitive scenario price (2018)



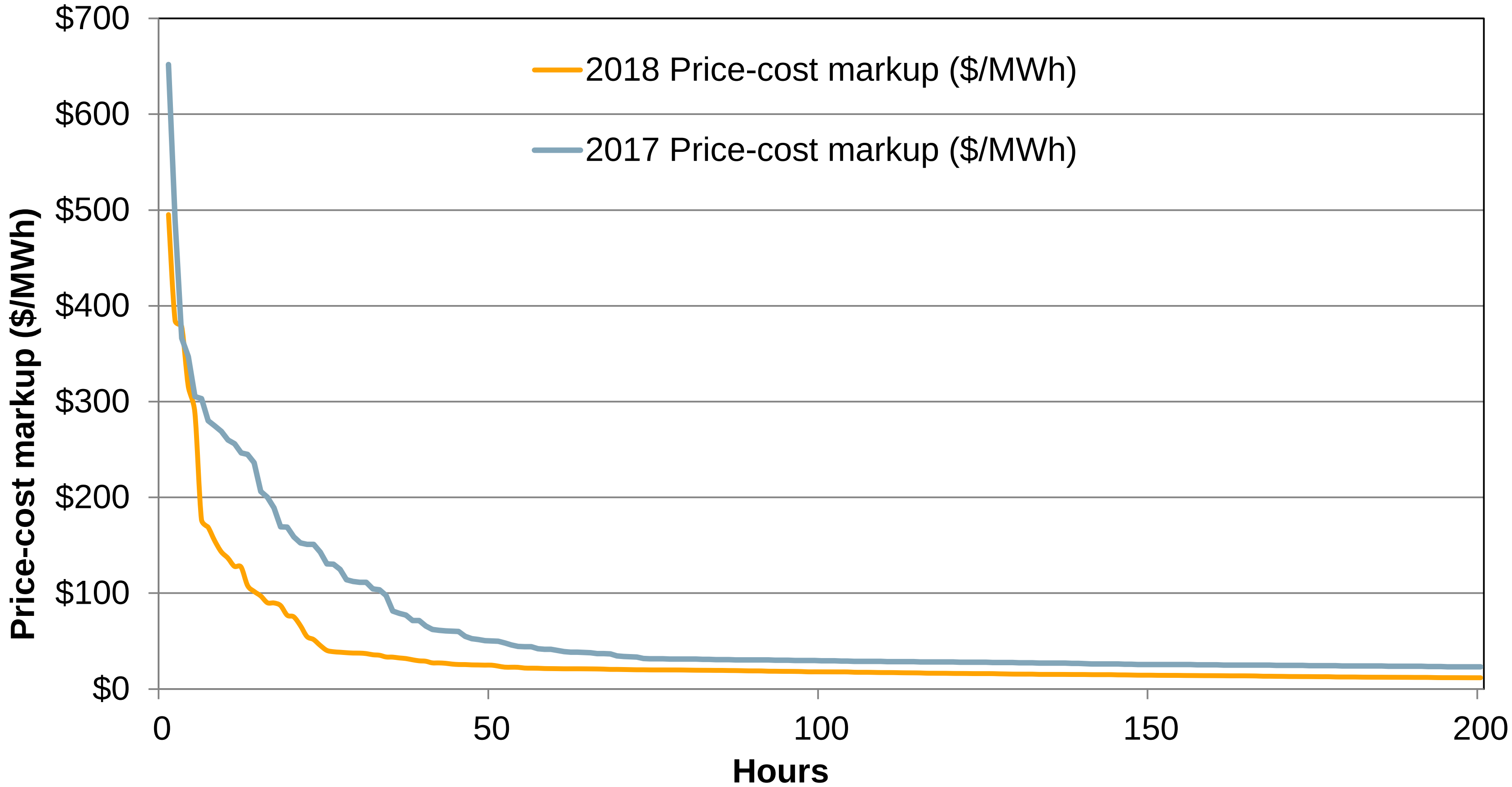
Average hourly price-cost markup is highest in evening ramping hours (HE 17-21).



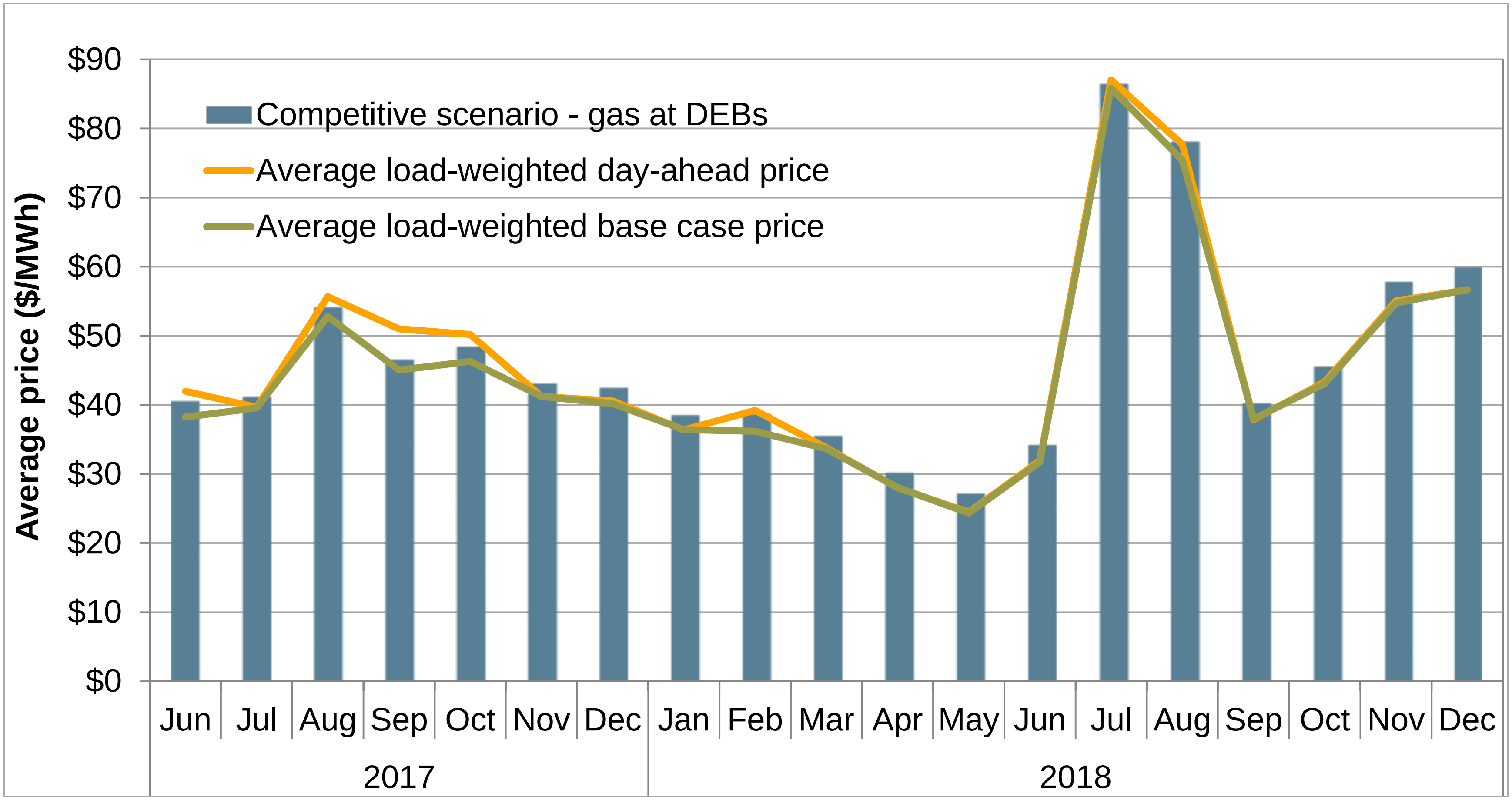
Duration curve of highest hourly price-cost markups



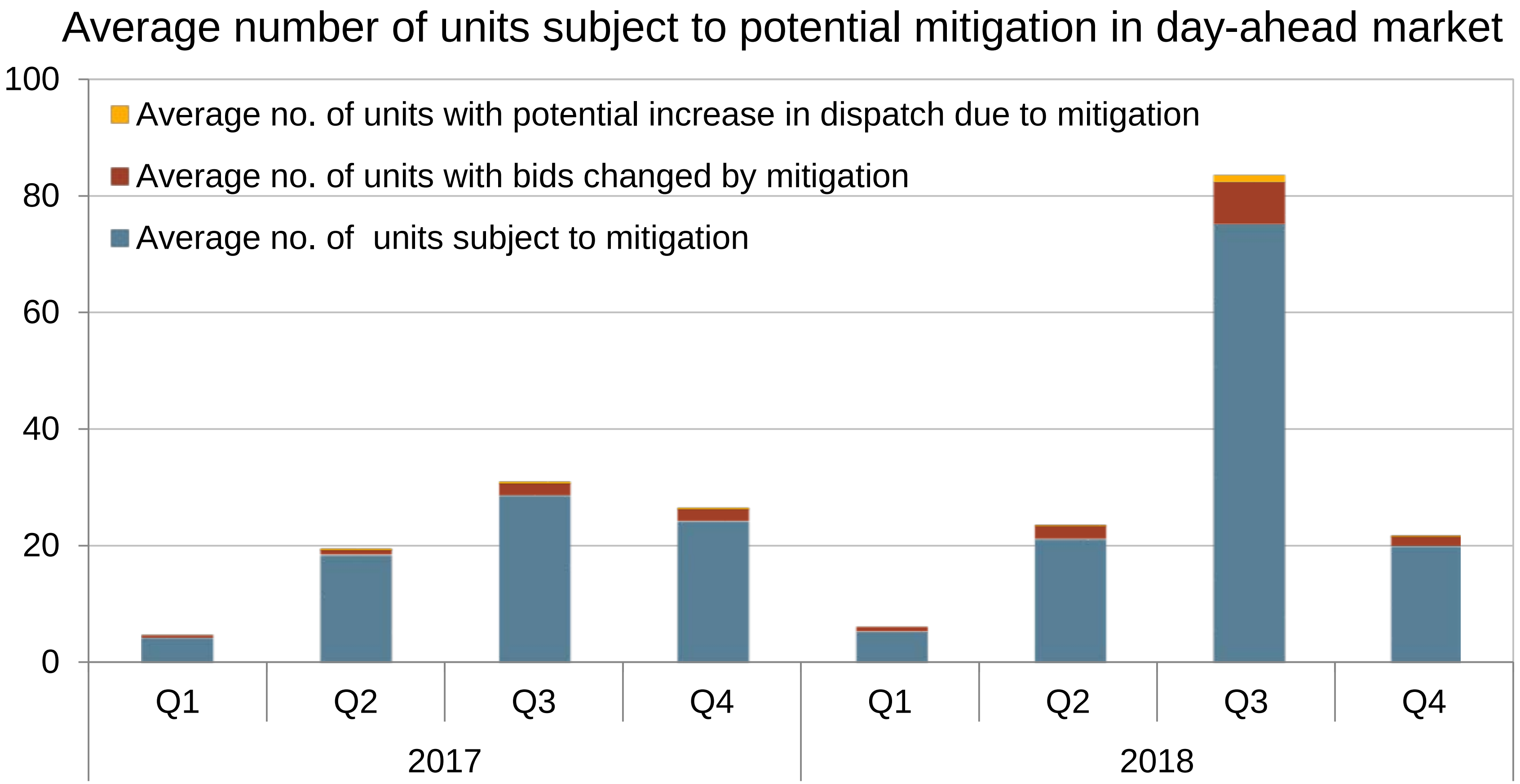
Price-cost markup based on highest cost gas-fired unit dispatched each hour (2017-2018).



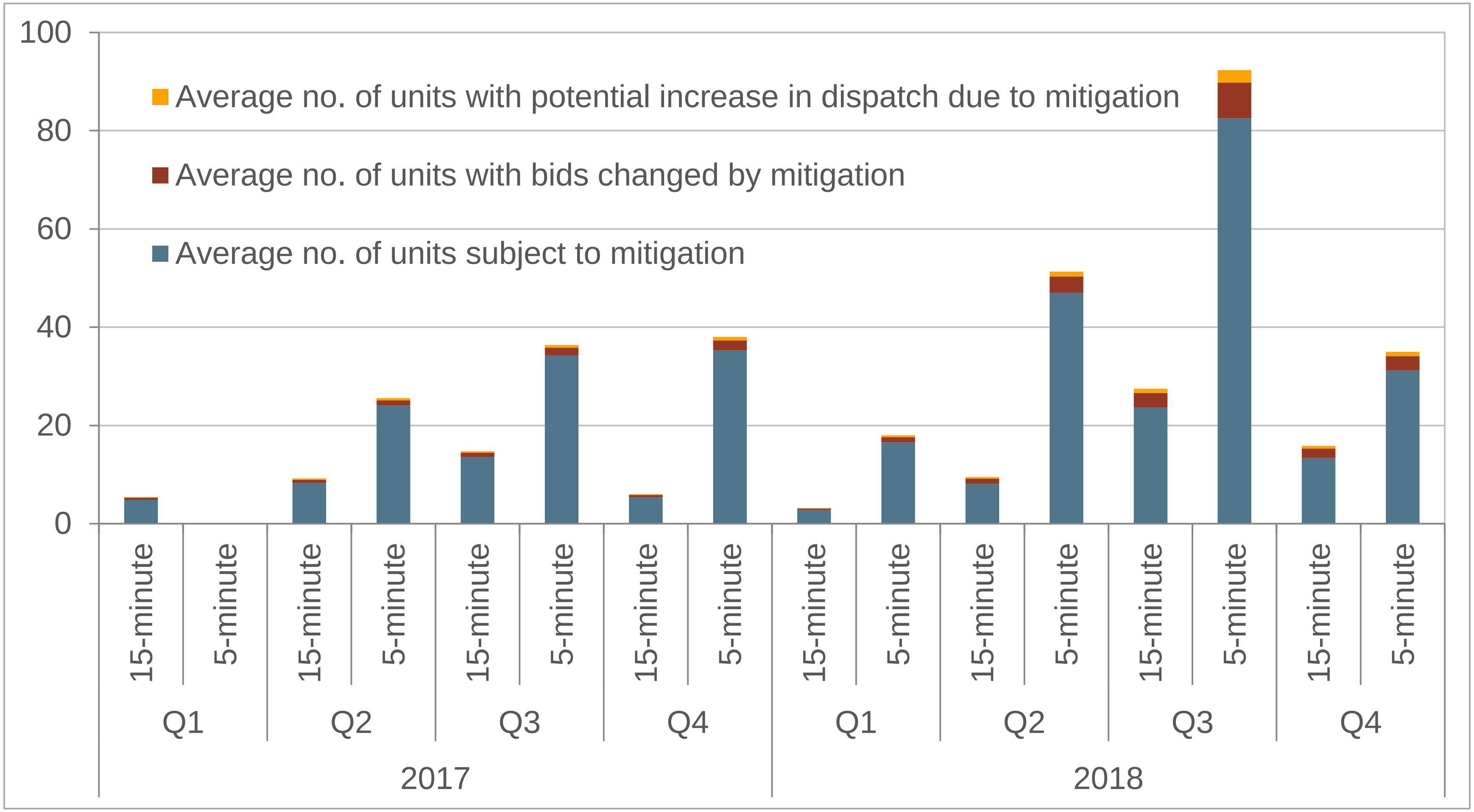
Comparison of competitive baseline price with day-ahead prices (using day-ahead market software).



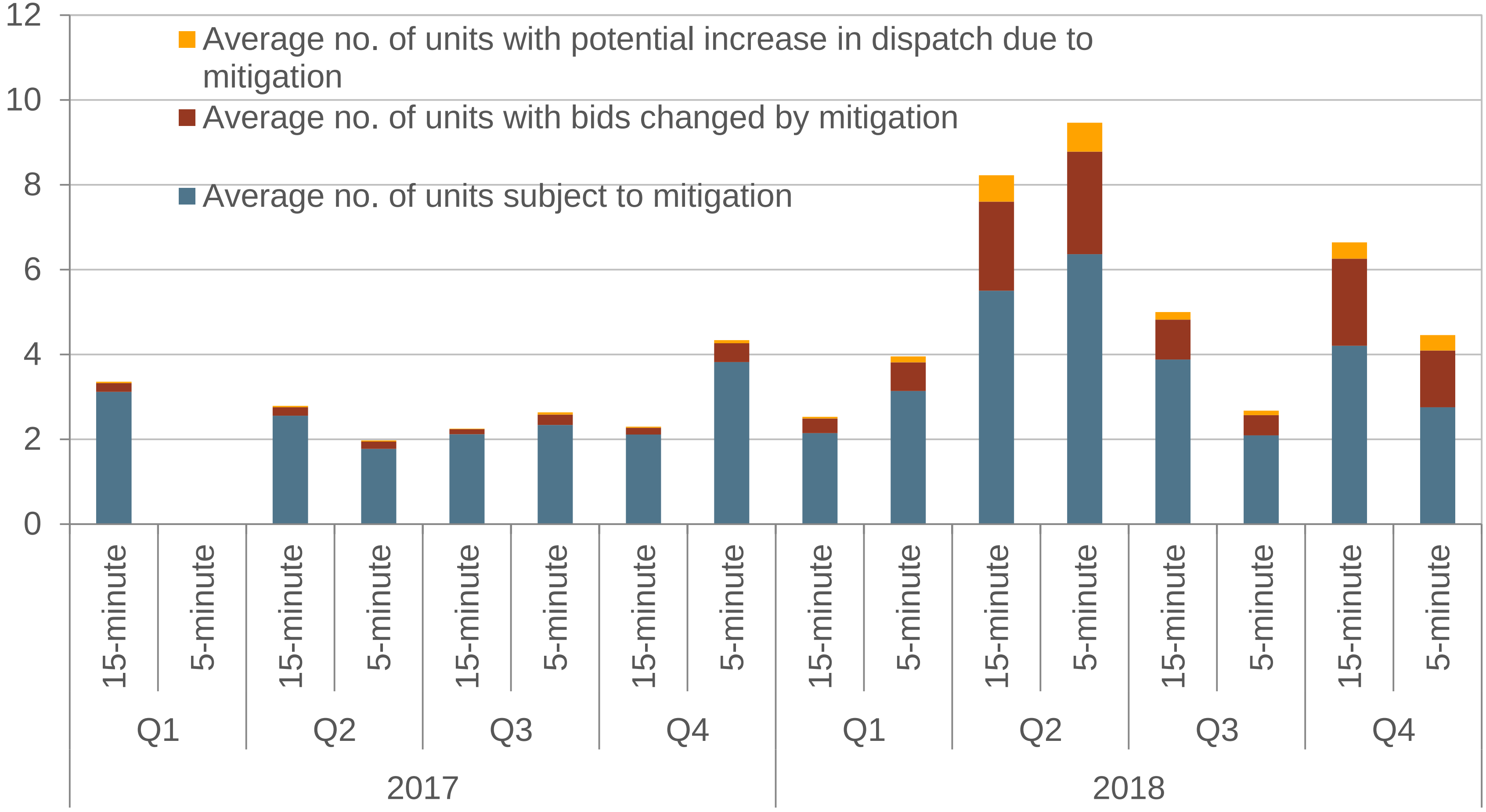
Frequency and impact of local market power bid mitigation provisions increased in 2018, but remained relatively low overall.



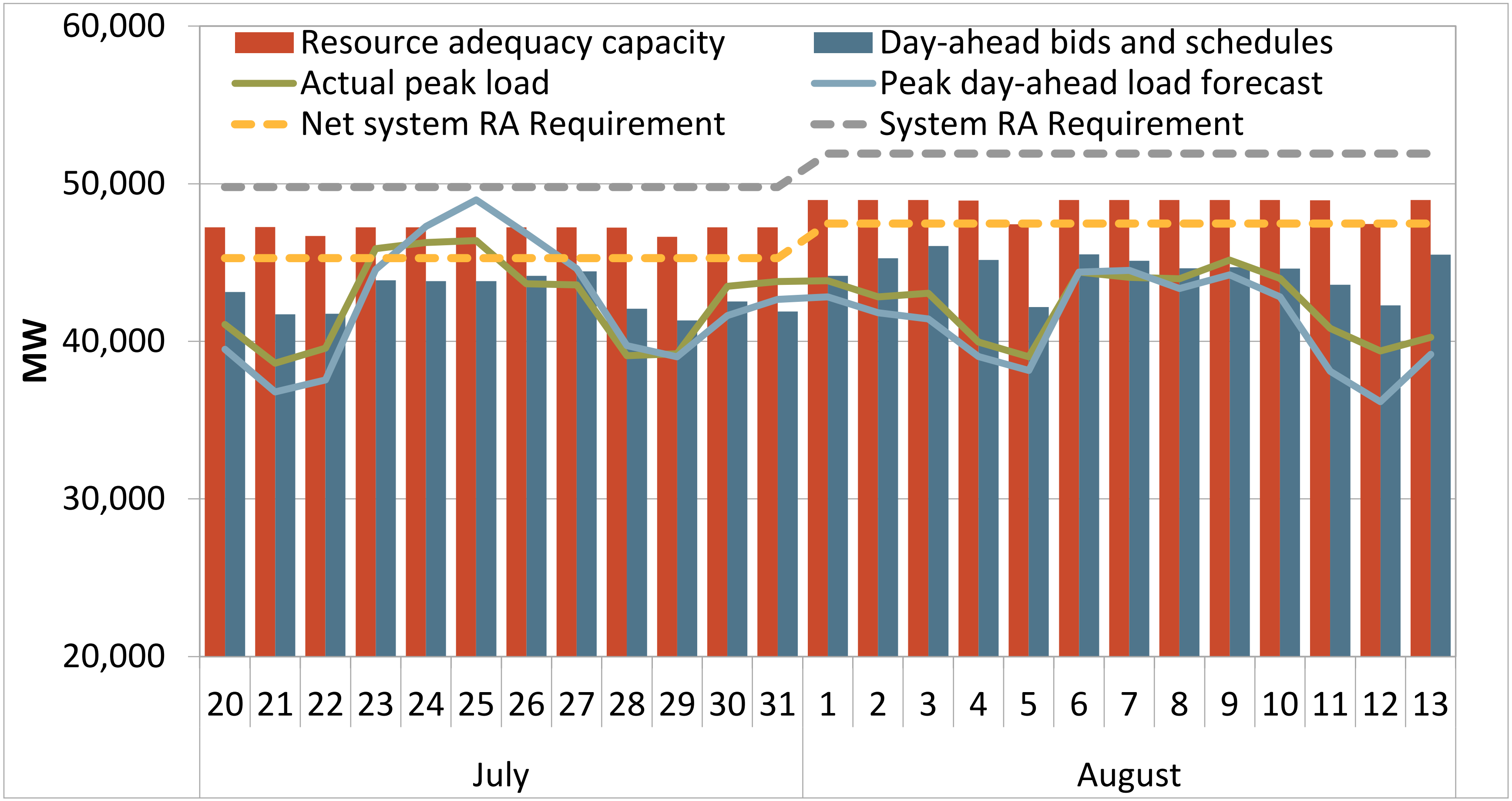
Average number of units subject to potential mitigation in 15-minute and 5-minute market (CAISO)



Average number of units subject to potential mitigation in 15-minute and 5-minute market (EIM)



Daily peak load, resource adequacy capacity, and planning forecast



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

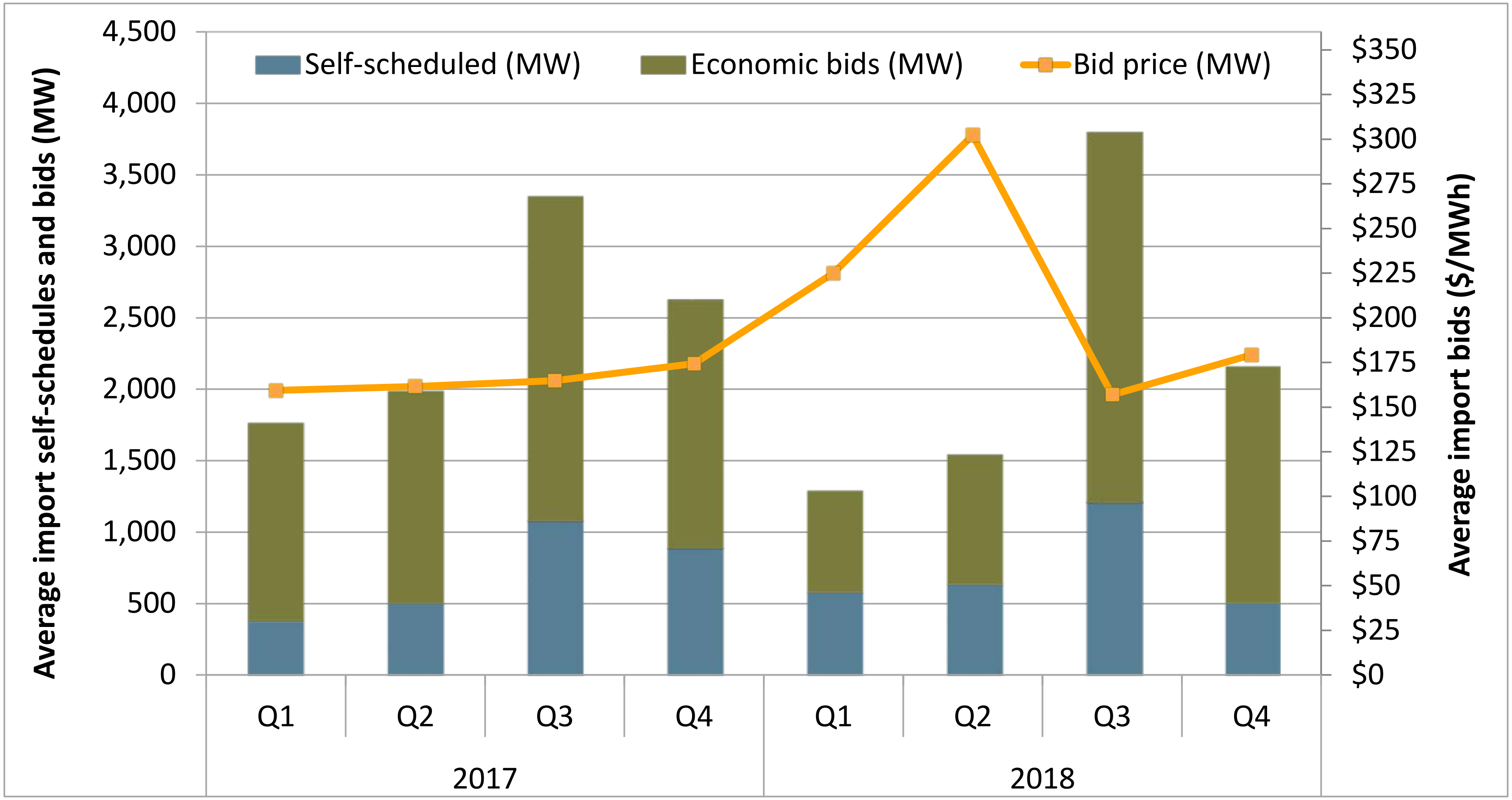
Resource type	Total resource adequacy capacity (MW)	Day-ahead market				Real-time market			
		Adjusted for outages		Bids and self-schedules		Adjusted for outages/availability		Bids and self-schedules	
		MW	% of total RA Cap.	MW	% of adjusted RA Cap	MW	% of total RA Cap.	MW	% of adjusted RA Cap
Must-Offer:									
Gas-fired generators	20,818	19,785	95%	19,785	100%	17,268	83%	16,835	97%
Other generators	1,672	1,543	92%	1,543	100%	1,543	92%	1,480	96%
Subtotal	**22,490**	**21,328**	**95%**	**21,328**	**100%**	**18,811**	**84%**	**18,315**	**97%**
Other:									
Imports	3,904	3,895	100%	3,732	96%	3,328	85%	2,725	82%
Use-limited gas units	5,043	4,900	97%	4,769	97%	4,799	95%	4,553	95%
Hydro generators	6,149	5,684	92%	5,242	92%	5,684	92%	5,249	92%
Nuclear generators	2,894	2,878	99%	2,875	100%	2,878	99%	2,814	98%
Solar generators	3,973	3,953	100%	2,611	66%	3,923	99%	2,738	70%
Wind generators	1,569	1,564	100%	1,008	64%	1,564	100%	1,158	74%
Qualifying facilities	1,403	1,375	98%	1,152	84%	1,292	92%	1,106	86%
Other non-dispatchable	494	487	99%	304	62%	465	94%	392	84%
Subtotal	**25,429**	**24,736**	**97%**	**21,693**	**88%**	**23,933**	**94%**	**20,735**	**87%**
Total	**47,919**	**46,064**	**96%**	**43,021**	**93%**	**42,744**	**89%**	**39,050**	**91%**

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

Load Type	Total resource adequacy capacity	Day-ahead				Real-time			
		Adjusted for outages		Bids and self-schedules		Adjusted for outages/availability		Bids and self-schedules	
		MW	% of total RA Cap.	MW	% of adjusted RA Cap.	MW	% of total RA Cap.	MW	% of adjusted RA Cap.
CCA	5,224	5,135	98%	4,670	91%	4,914	94%	4,516	92%
DA	3,509	3,435	98%	3,227	94%	3,071	88%	2,682	87%
IOU	34,100	32,576	96%	30,833	95%	30,005	88%	27,575	92%
Muni	4,209	4,042	96%	3,414	84%	3,942	94%	3,482	88%
Substituted capacity	878	878	100%	877	100%	813	93%	796	98%
Total	**47,919**	**46,065**	**96%**	**43,021**	**93%**	**42,744**	**89%**	**39,050**	**91%**

Resource adequacy import self-schedules and bids (peak hours)

http://www.caiso.com/Documents/ImportResourceAdequacySpecialReport-Sept102018.pdf



Average local resource adequacy capacity and availability (210 highest load hours)

Local capacity area	TAC area	Total resource adequacy capacity	Local requirement	Day-ahead				Real-time			
				Adjusted for outages		Bids and self-schedules		Adjusted for outages/availability		Bids and self-schedules	
				MW	% of local RA Req.	MW	% of total RA Net Adj	MW	% of local RA Req.	MW	% of total RA Net Adj
Greater Bay Area	PG&E	6,109	5,160	5,855	113%	5,693	97%	5,800	112%	5,582	96%
Greater Fresno	PG&E	3,073	2,081	2,966	143%	2,844	96%	2,916	140%	2,764	95%
Sierra	PG&E	1,968	2,113	1,686	80%	1,536	91%	1,619	77%	1,433	89%
North Coast/North Bay	PG&E	816	634	772	122%	671	87%	772	122%	752	97%
Stockton	PG&E	627	719	598	83%	539	90%	598	83%	580	97%
Kern	PG&E	470	453	448	99%	403	90%	448	99%	327	73%
Humboldt	PG&E	72	169	65	38%	52	80%	65	38%	45	69%
LA Basin	SCE	8,645	7,525	8,288	110%	8,013	97%	6,961	93%	6,562	94%
Big Creek/Ventura	SCE	4,141	2,321	3,808	164%	3,657	96%	3,035	131%	2,885	95%
San Diego	SDG&E	4,058	4,032	3,938	98%	3,671	93%	3,663	91%	3,388	92%
Total		**29,979**	**25,207**	**28,424**	**113%**	**27,079**	**95%**	**25,877**	**103%**	**24,318**	**94%**

Recommendations

- Update real-time market bid caps based on same-day gas market prices and conditions.
- Gas usage nomograms need improvement if CAISO plans on continued use of these constraints.
- Clarify/enhance rules for resource adequacy requirements met by import capacity.
- Consider options for reducing/mitigating potential system market power.
- Review/modify capacity procurement mechanism (CPM).
- Begin to develop mitigation rules for battery storage resources.