2019 Q3 Report on Market Issues and Performance

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Department of Market Monitoring, California ISO

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http://www.caiso.com/Documents/2019ThirdQuarterReportonMarketIssuesandPerformance.pdf

http://www.caiso.com/market/Pages/MarketMonitoring/AnnualQuarterlyReports/Default.aspx

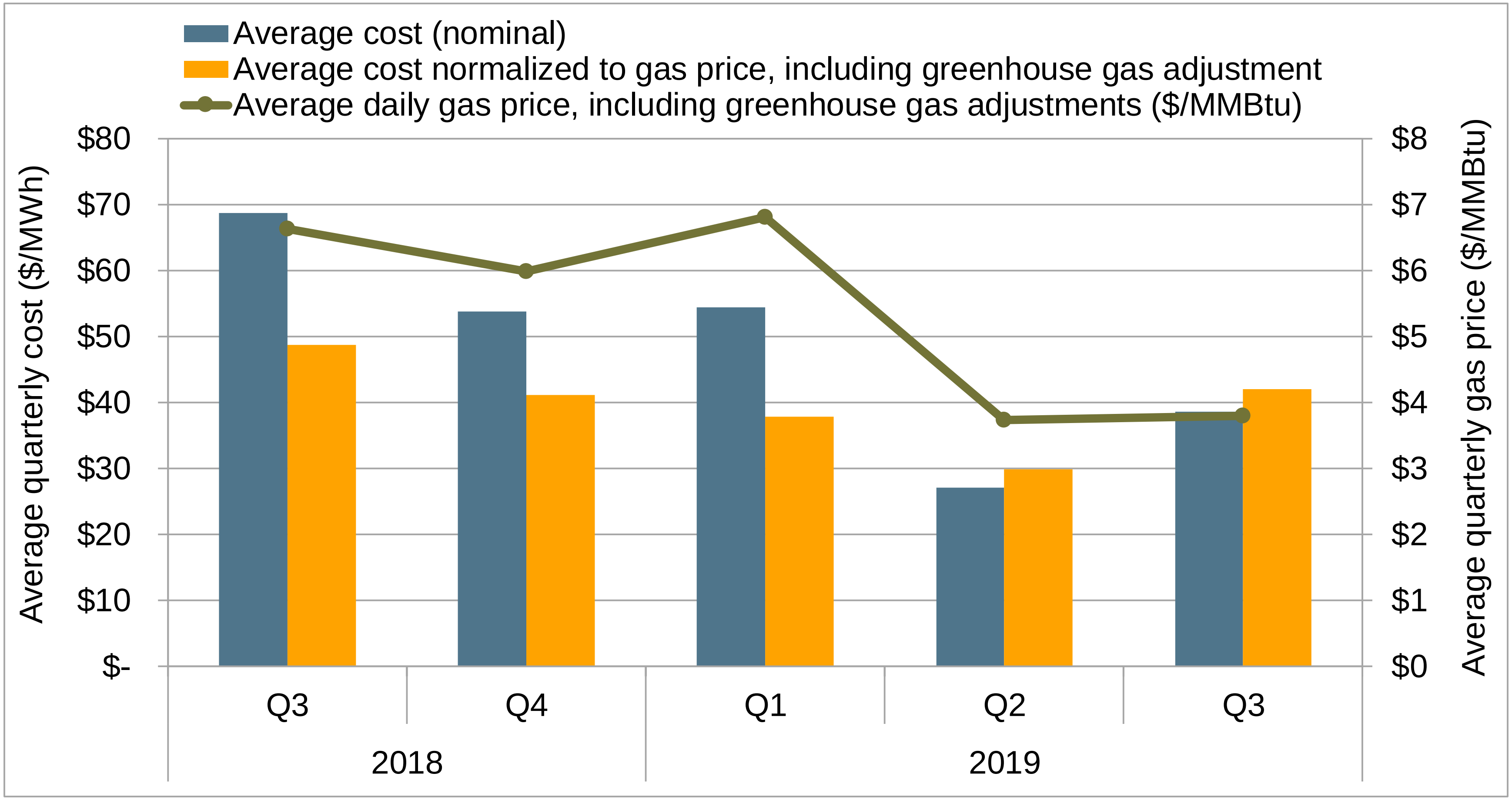
Highlights of Q3 market performance

- Market prices were low and highly competitive
  - Average gas prices down 44% from Q3 last year
  - Low load, high hydro/renewable, low congestion
  - Wholesale energy cost ($39/MWh) about 44% lower than Q3 2018
- Increase in market adjustments by operators including load conformance and exceptional dispatches
- Congestion revenue rights losses to ratepayers continued to fall due to recent changes and lower congestion

Special issues covered in Q3 market report

- Flexible ramping product
- Battery storage resources
- Participating demand response providing resource adequacy
- Exceptional dispatch
- System market power

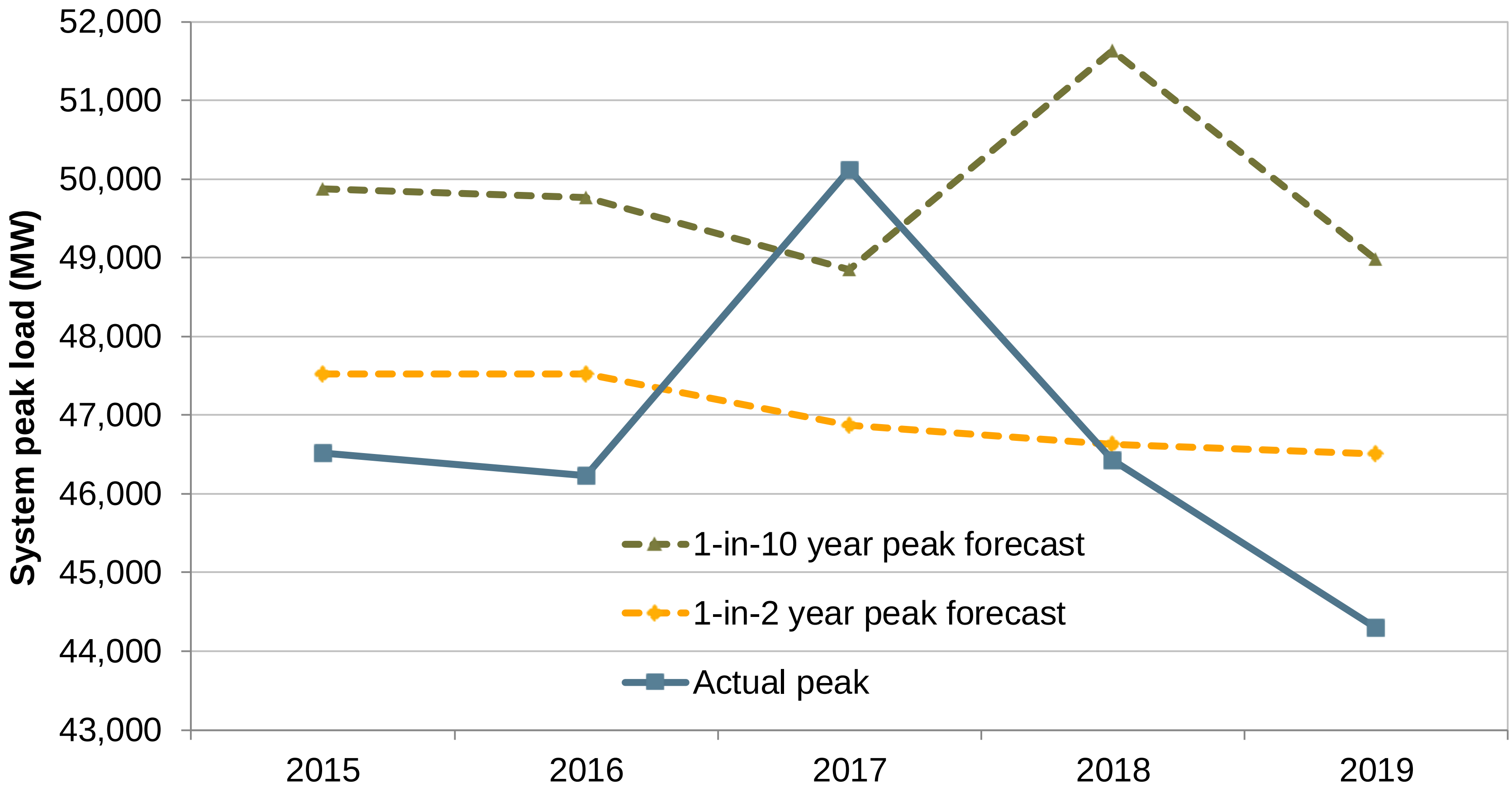
Total Q3 wholesale costs down 44% from Q3 2018, 14% after adjusting for gas and greenhouse gas costs.



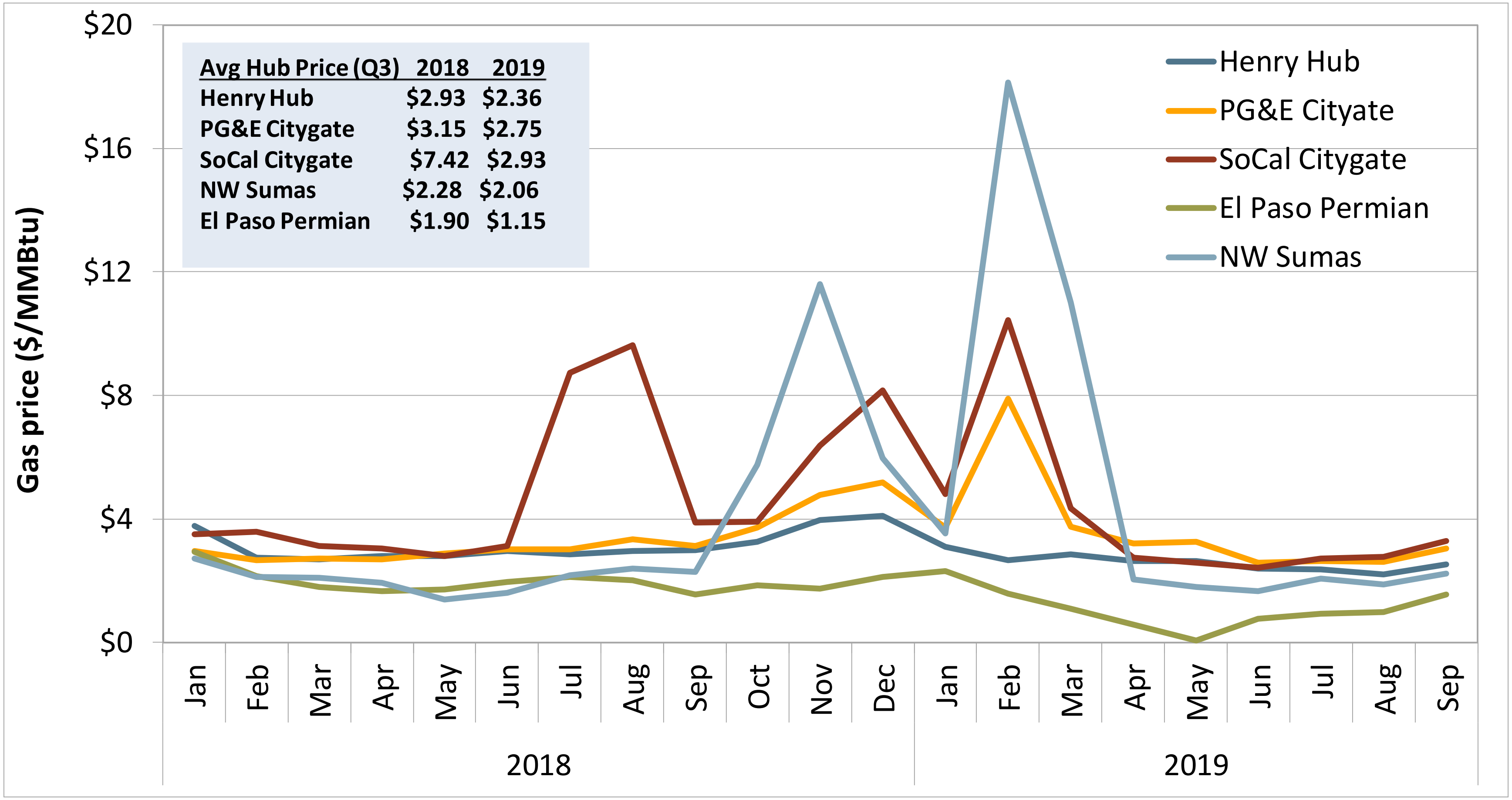
Q3 CAISO wholesale costs totaled $2.5 billion or about $39/MWh

	Q3 2018	Q4 2018	Q1 2019	Q2 2019	Q3 2019	Change Q3 2018-Q3 2019
Day-ahead energy costs	$ 64.52	$ 51.46	$ 52.24	$ 23.73	$ 36.01	$ (28.51)
Real-time energy costs (incl. flex ramp)	$ 0.69	$ 0.01	$ 0.25	$ 1.22	$ 0.95	$ 0.26
Grid management charge	$ 0.46	$ 0.48	$ 0.46	$ 0.46	$ 0.45	$ (0.01)
Bid cost recovery costs	$ 1.27	$ 0.48	$ 0.56	$ 0.49	$ 0.72	$ (0.56)
Reliability costs (RMR and CPM)	$ 0.63	$ 0.90	$ 0.06	$ 0.06	$ 0.04	$ (0.58)
Average total energy costs	**$ 67.57**	**$ 53.32**	**$ 53.56**	**$ 25.96**	**$ 38.17**	**$ (29.40)**
Reserve costs (AS and RUC)	$ 1.19	$ 0.53	$ 0.94	$ 1.14	$ 0.46	$ (0.72)
Average total costs of energy and reserve	**$ 68.76**	**$ 53.85**	**$ 54.50**	**$ 27.09**	**$ 38.64**	**$ (30.12)**

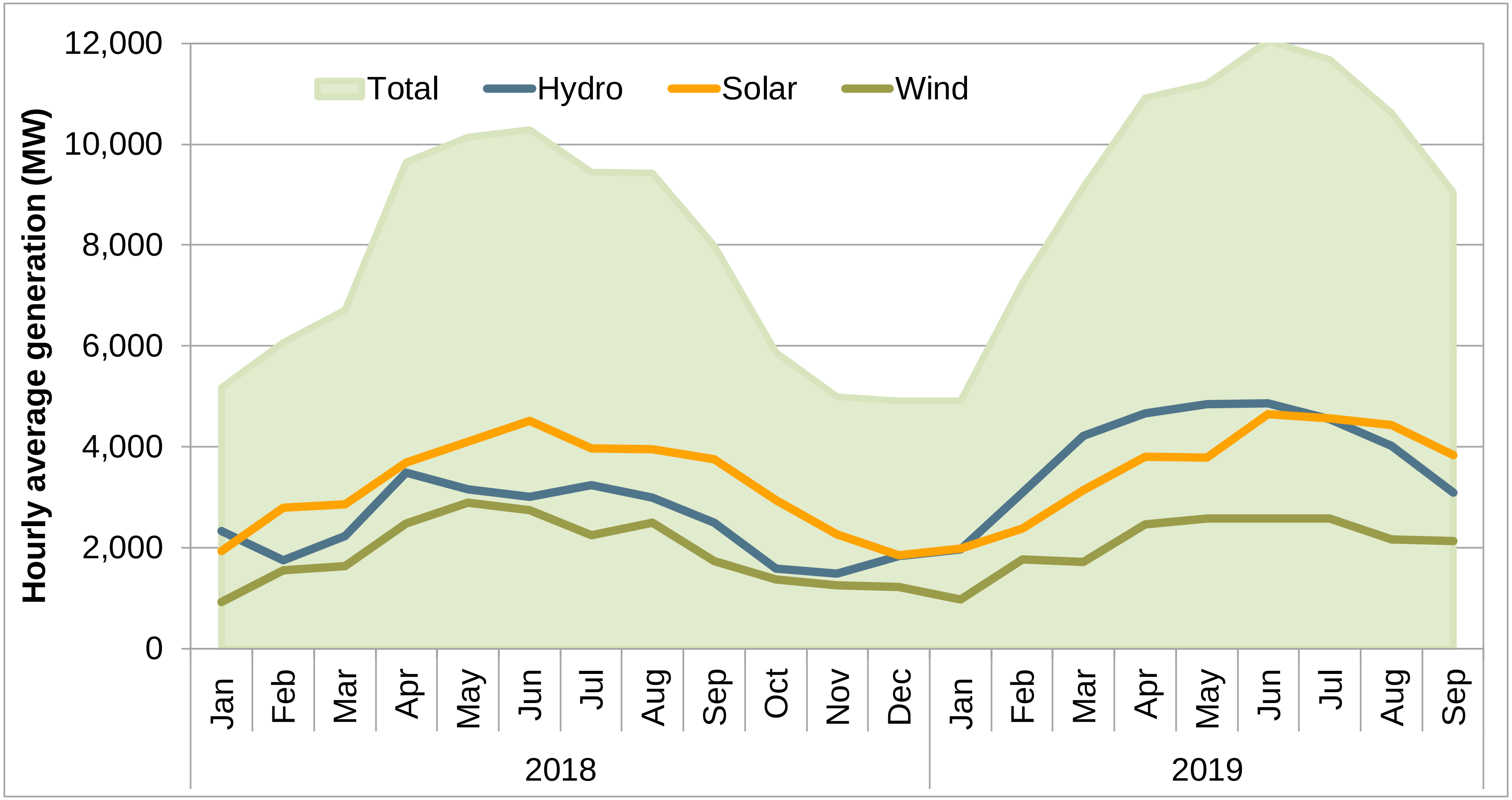
Lower load conditions contributed to lower wholesale energy costs



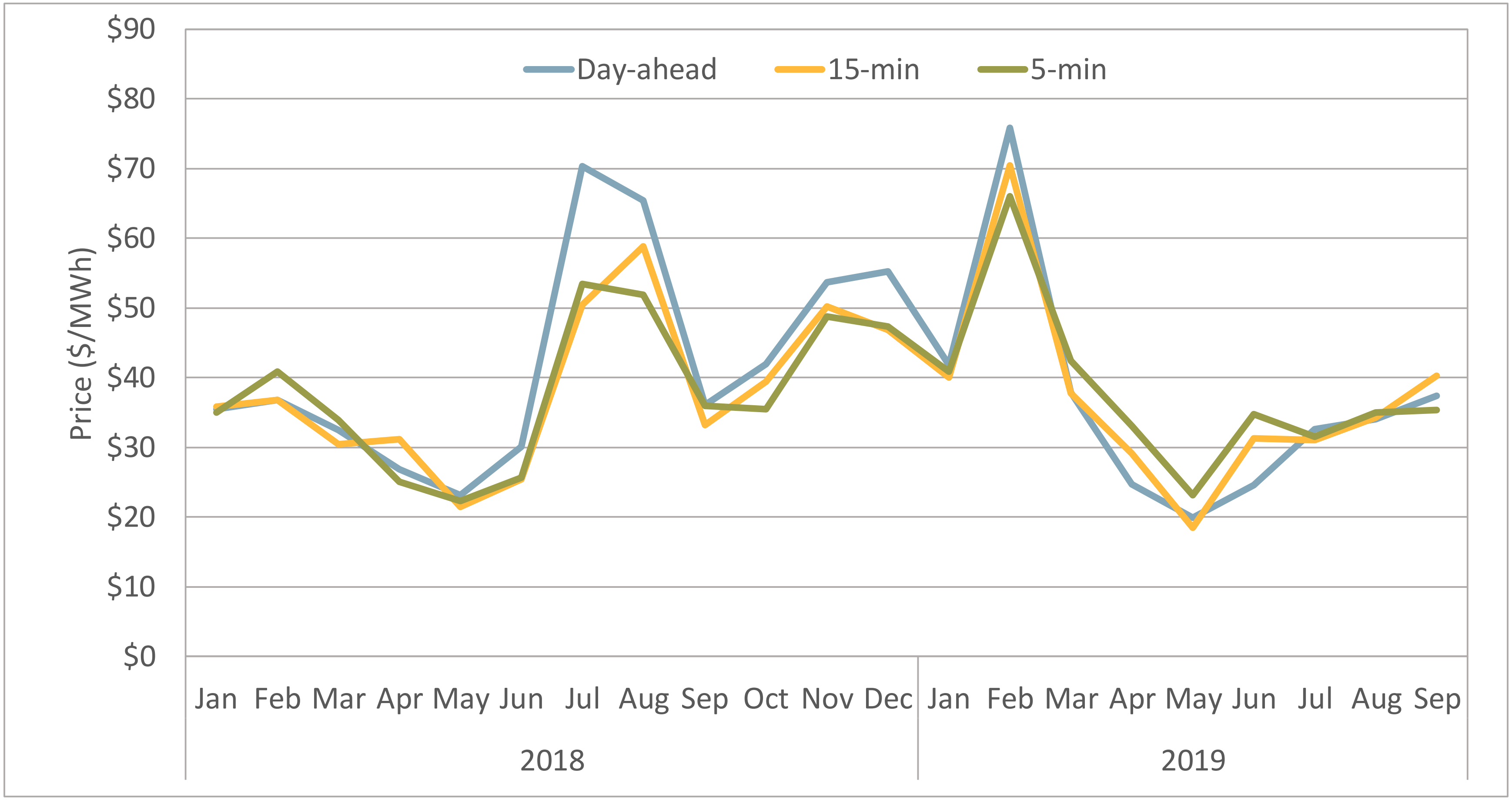
Average CAISO gas prices 45% less than Q3 2018



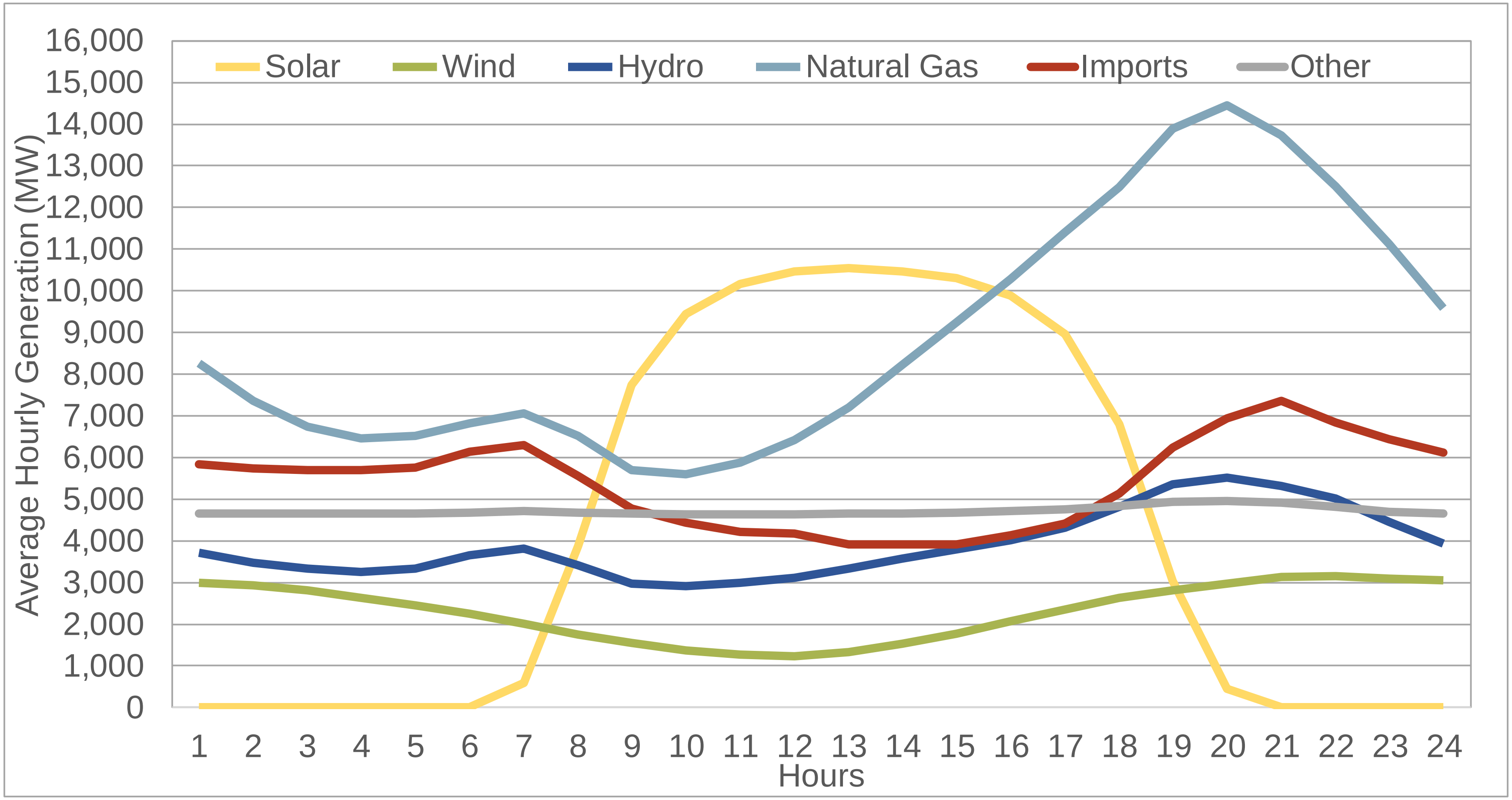
Renewable generation increases over Q3 2018 due to higher hydro



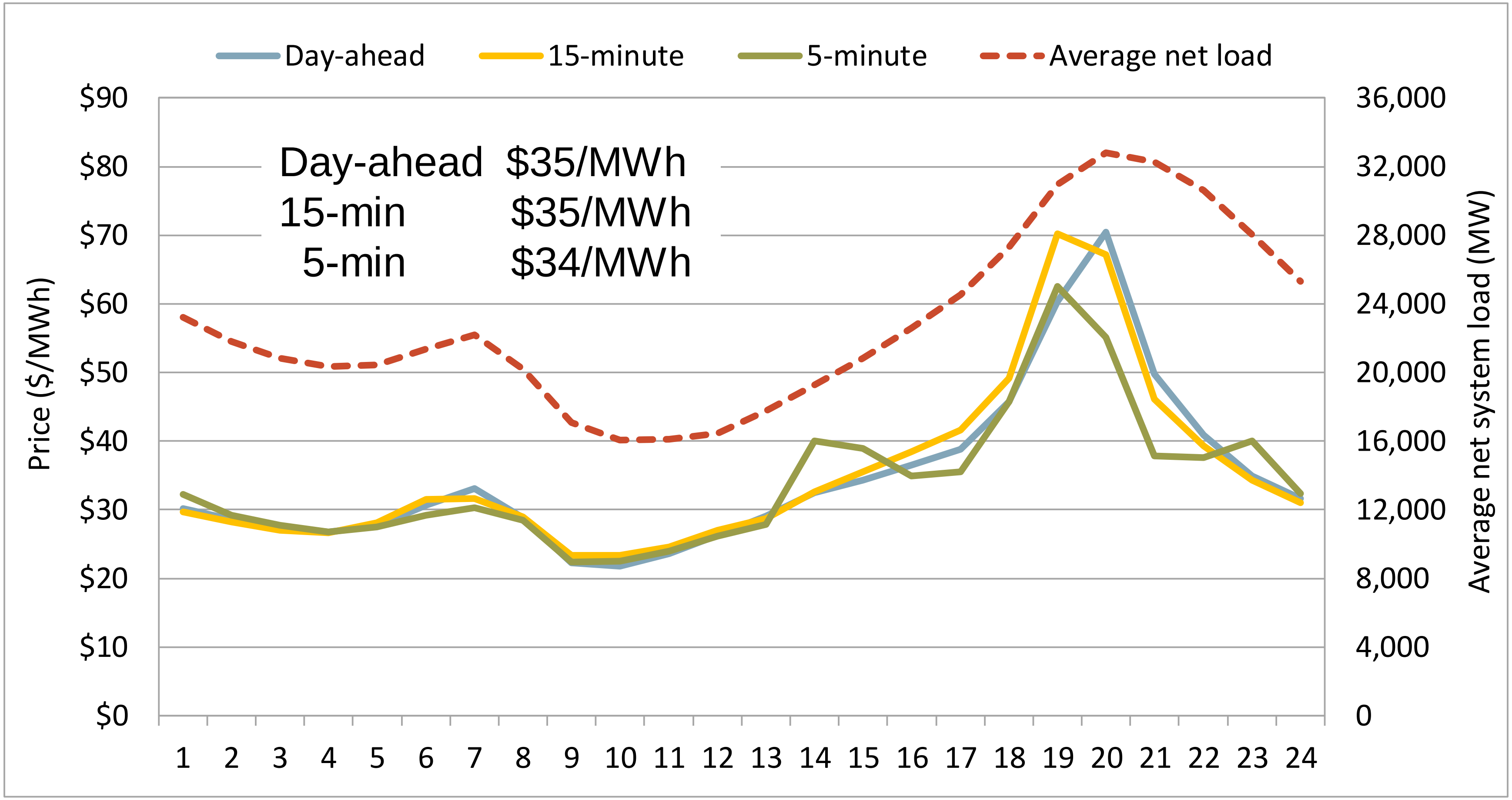
Energy prices decreased compared to the same quarter in 2018
Day-ahead and real-time prices closely aligned



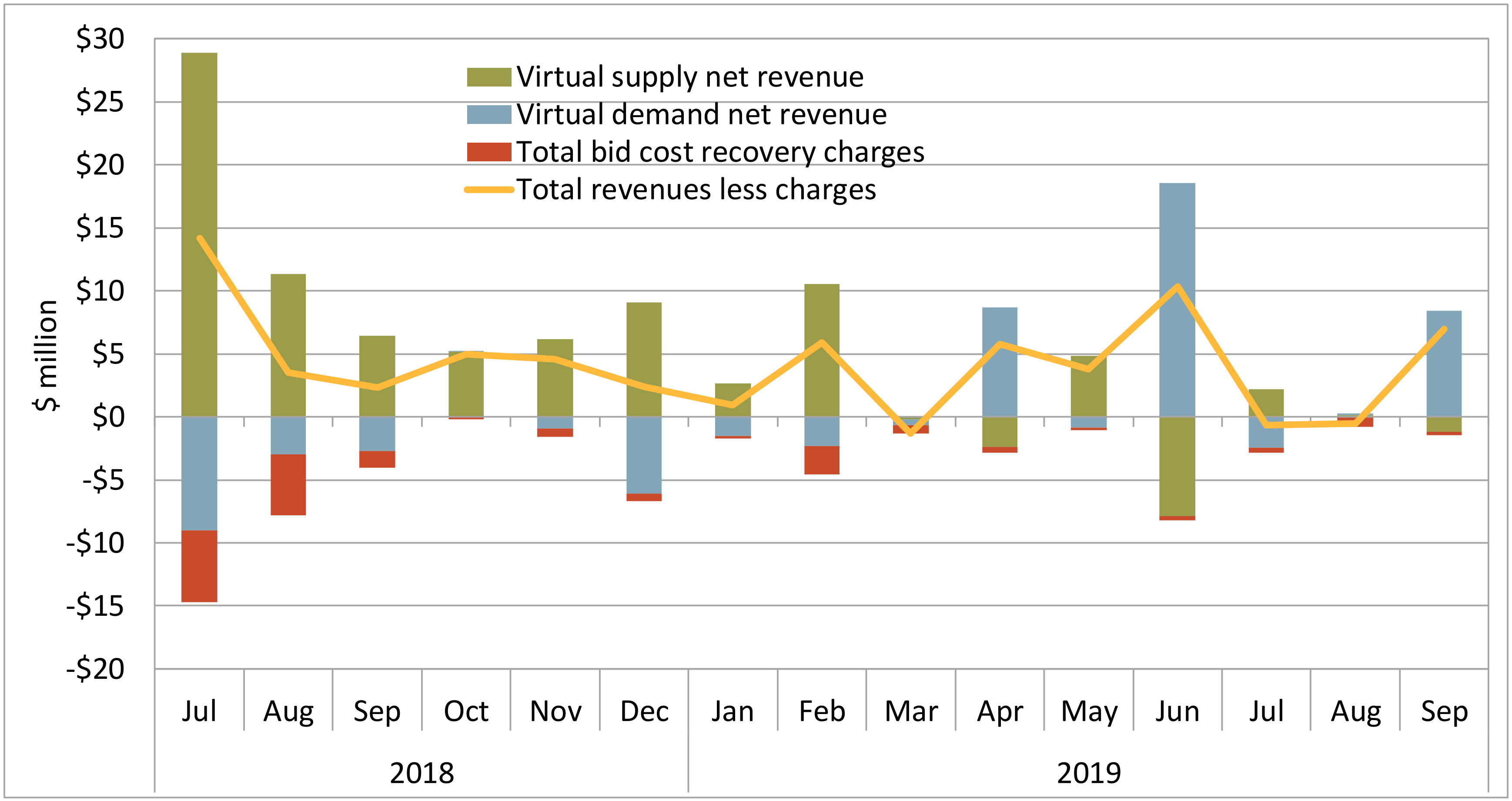
Variation in generation by fuel type, Q3 2019
Hourly variation driven by solar, increase in gas over Q2



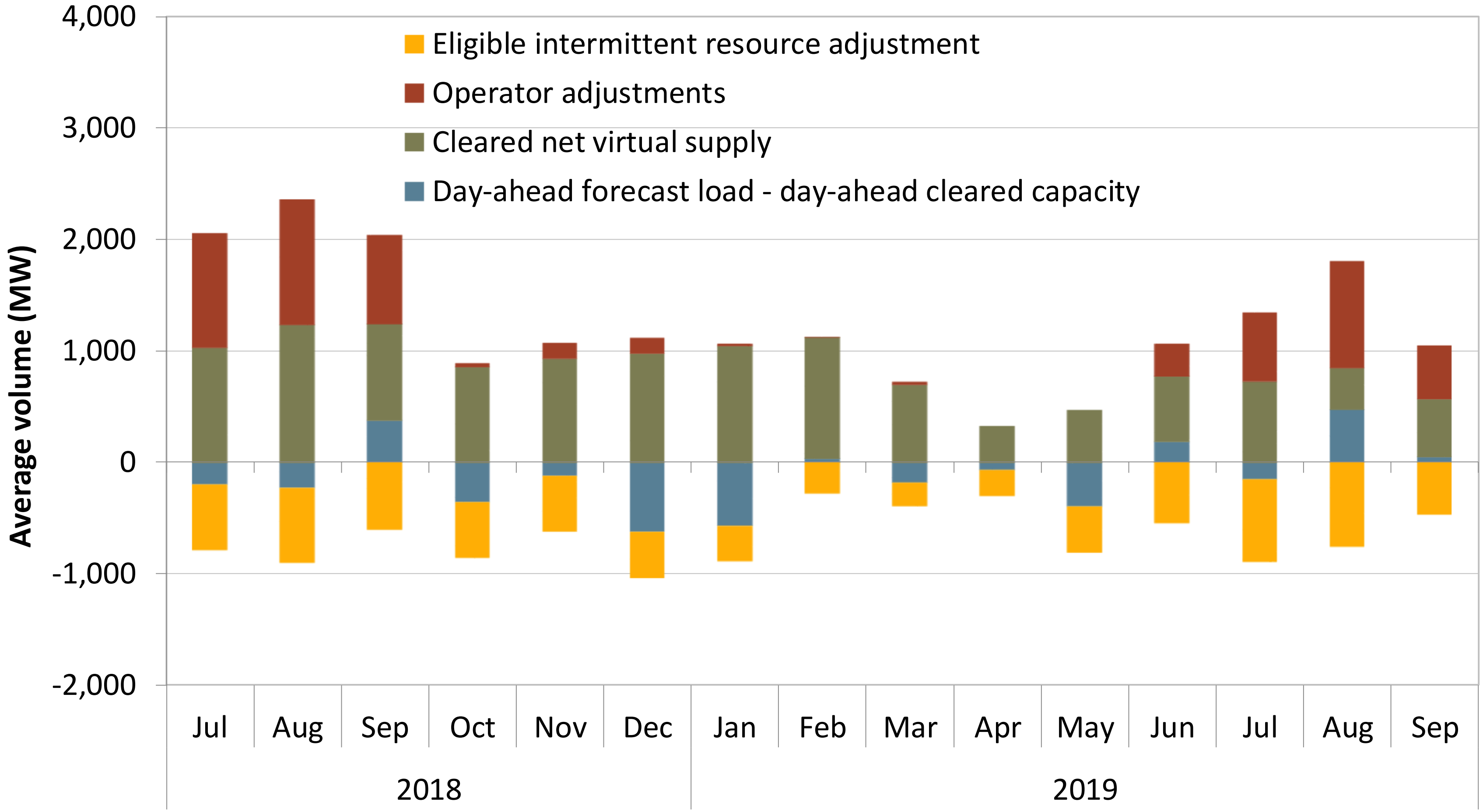
Average day-ahead prices down in Q3 2019 over Q3 2018



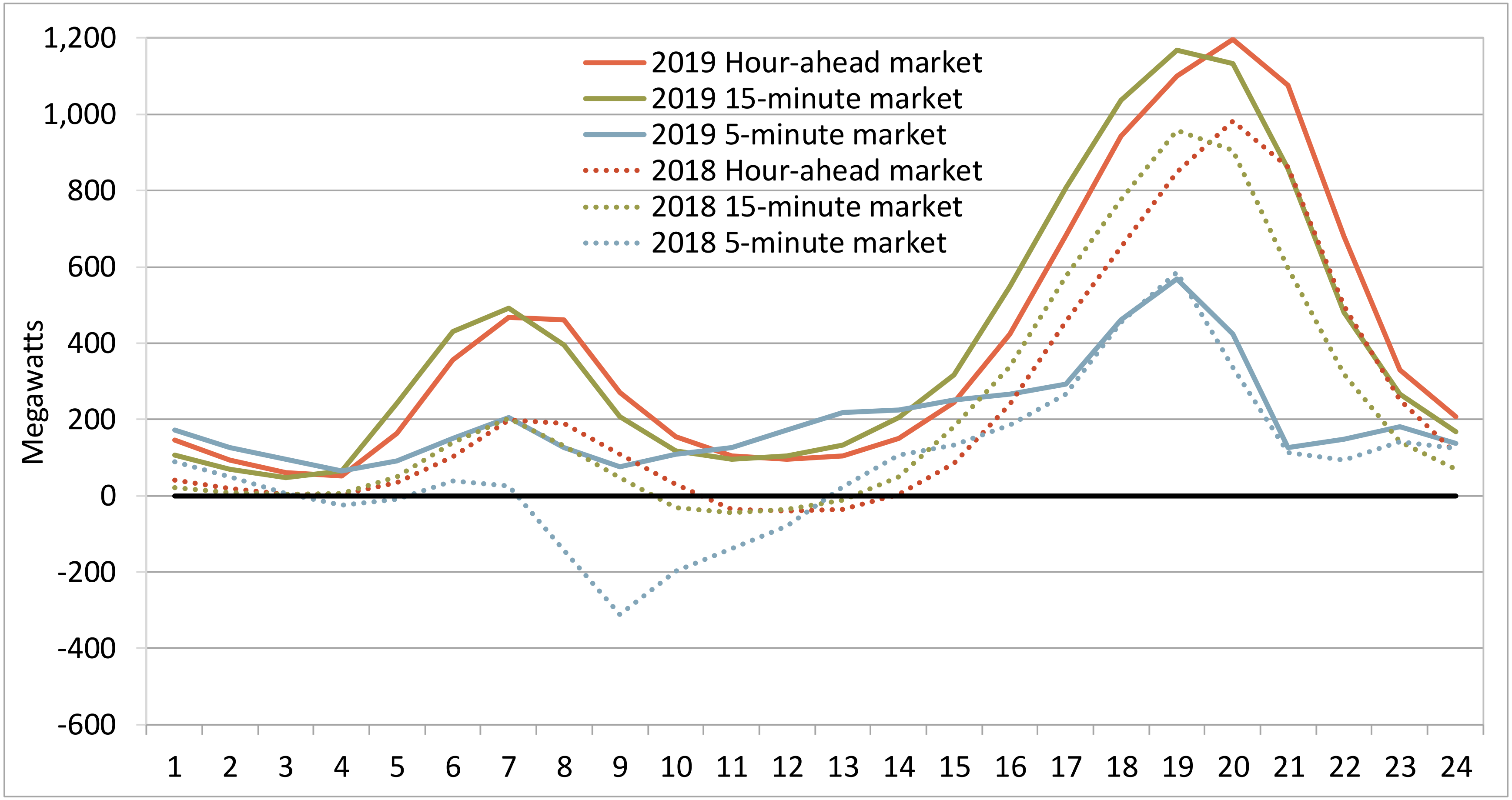
Convergence bidding revenue totaled $7.2 million in Q3



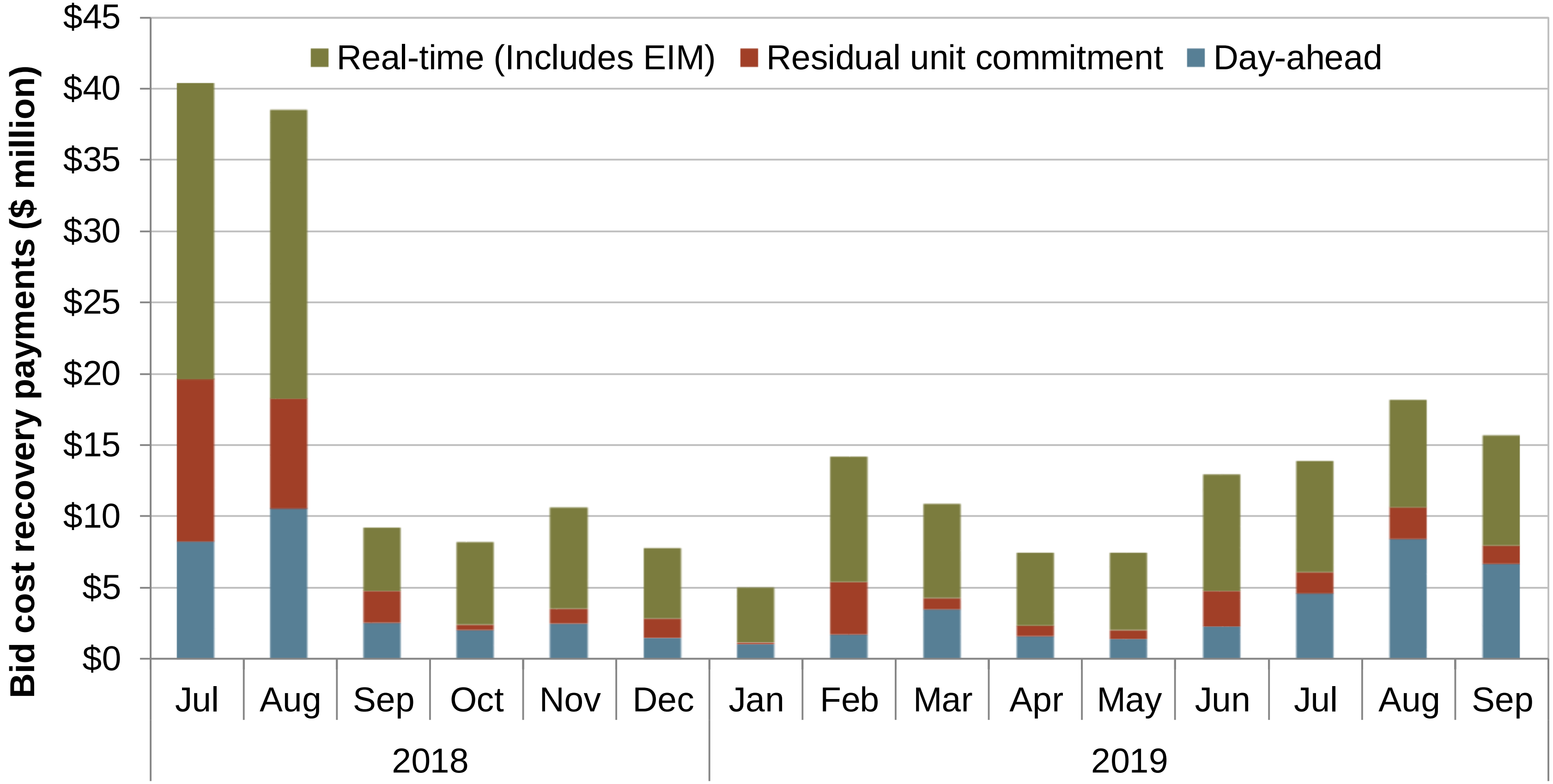
Operator adjustments increase residual unit commitment, but were lower than Q3 2018



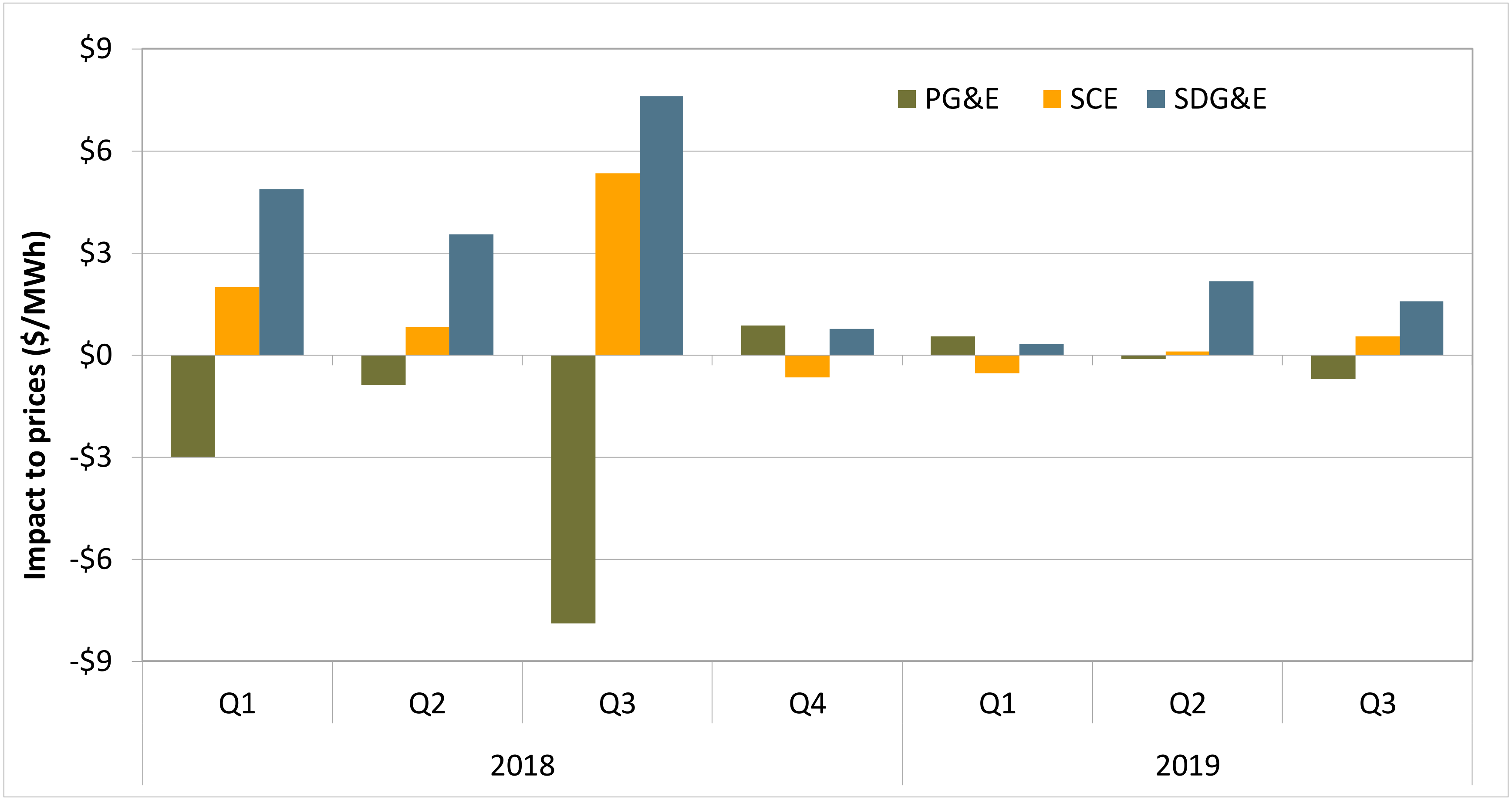
Average hourly load adjustment increase despite moderate system conditions (Q3 2018, Q3 2019)



Q3 bid cost recovery $48 million, $40 million less than Q3 2018



Overall impact of congestion on prices in the day-ahead market continues to be lower in 2019

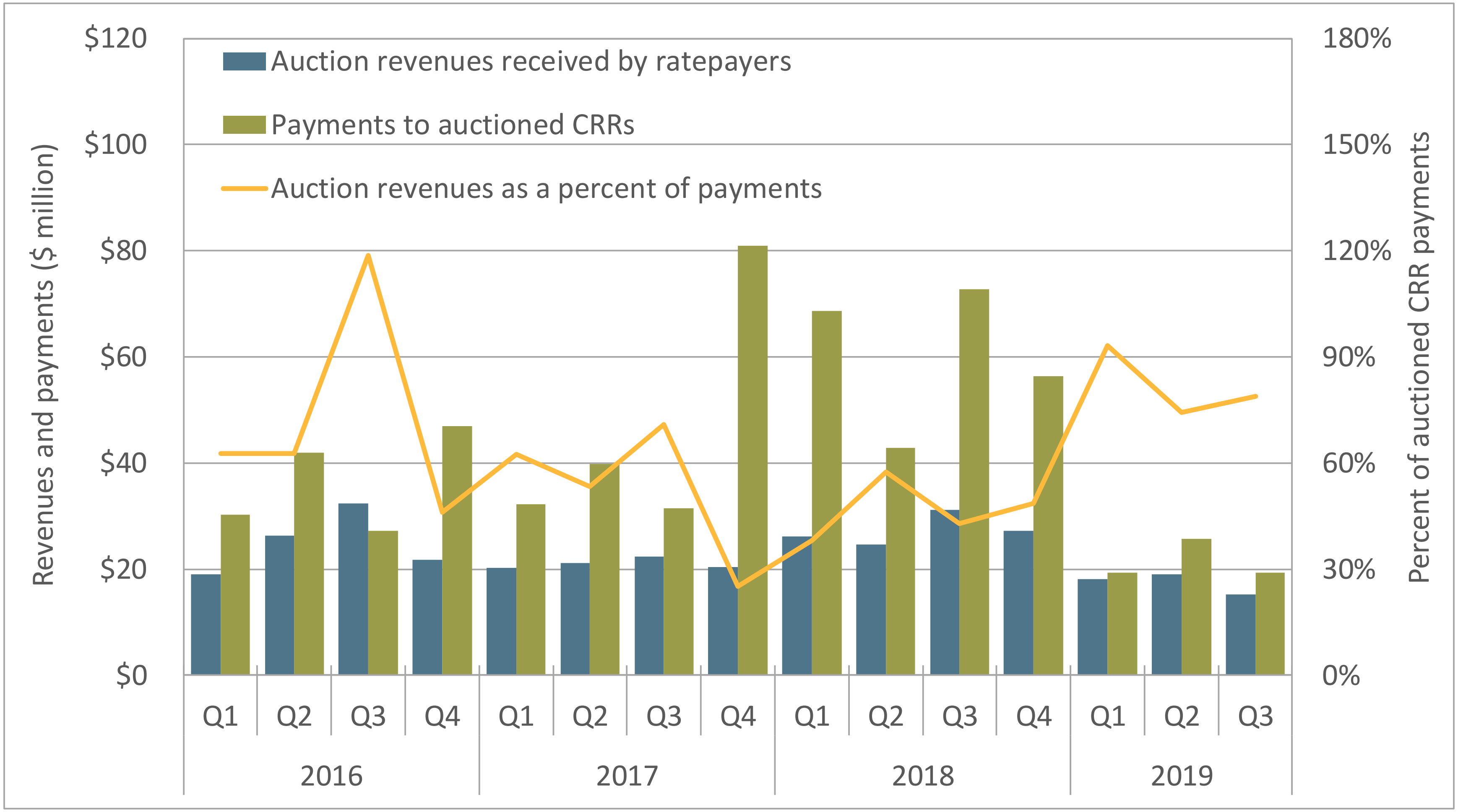


Congestion revenue right auction changes implemented January 2019

- **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.

Auction revenues and payments to non-load-serving entities
Q3 payments $4.1 million more than auction revenues



Track 1B changes ensure CRRs paid no more than congestion rent

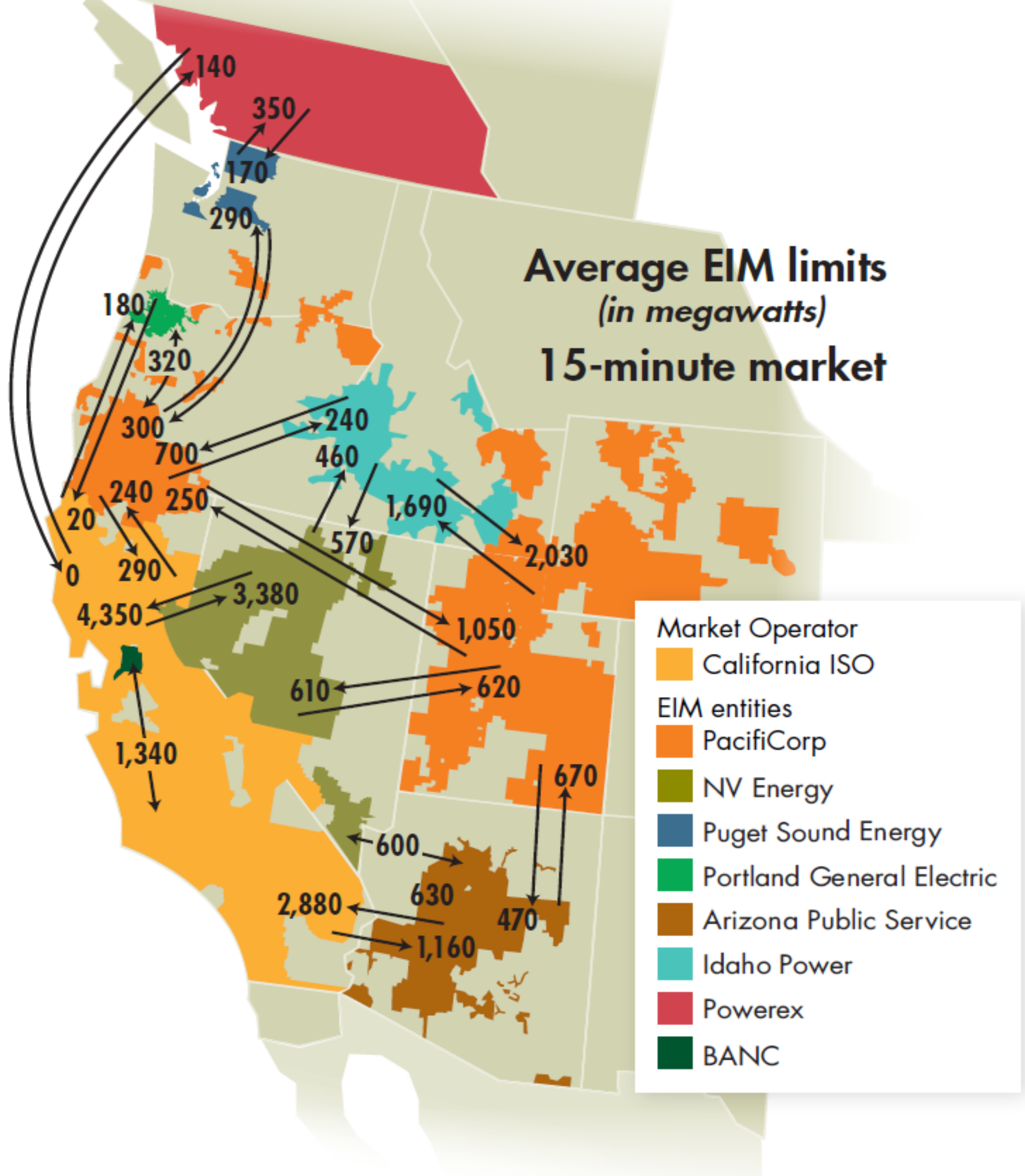
- Total CRR payments, netted by scheduling coordinator from each constraint, are calculated over the month.
- Total congestion rent is calculated by constraint.
- If all SC CRR payments on constraint > congestion rent:
  - Offset = CRR payment – congestion rent
  - Charged to SCs with net positive flows on constraint

DMM estimates track 1B reduced losses by ~$5.7 million

EIM highlights

- May 2019 sufficiency test enhancement decreases failure frequency.
- February load conformance limiter enhancement impacts prices Arizona Public Service and NV Energy
- During peak system load hours, prices in the Northwest region (PacifiCorp West, Puget Sound Energy, Portland General Electric, and Powerex) were low relative to other EIM areas due to limited transmission capacity.

Energy imbalance market transfer limits

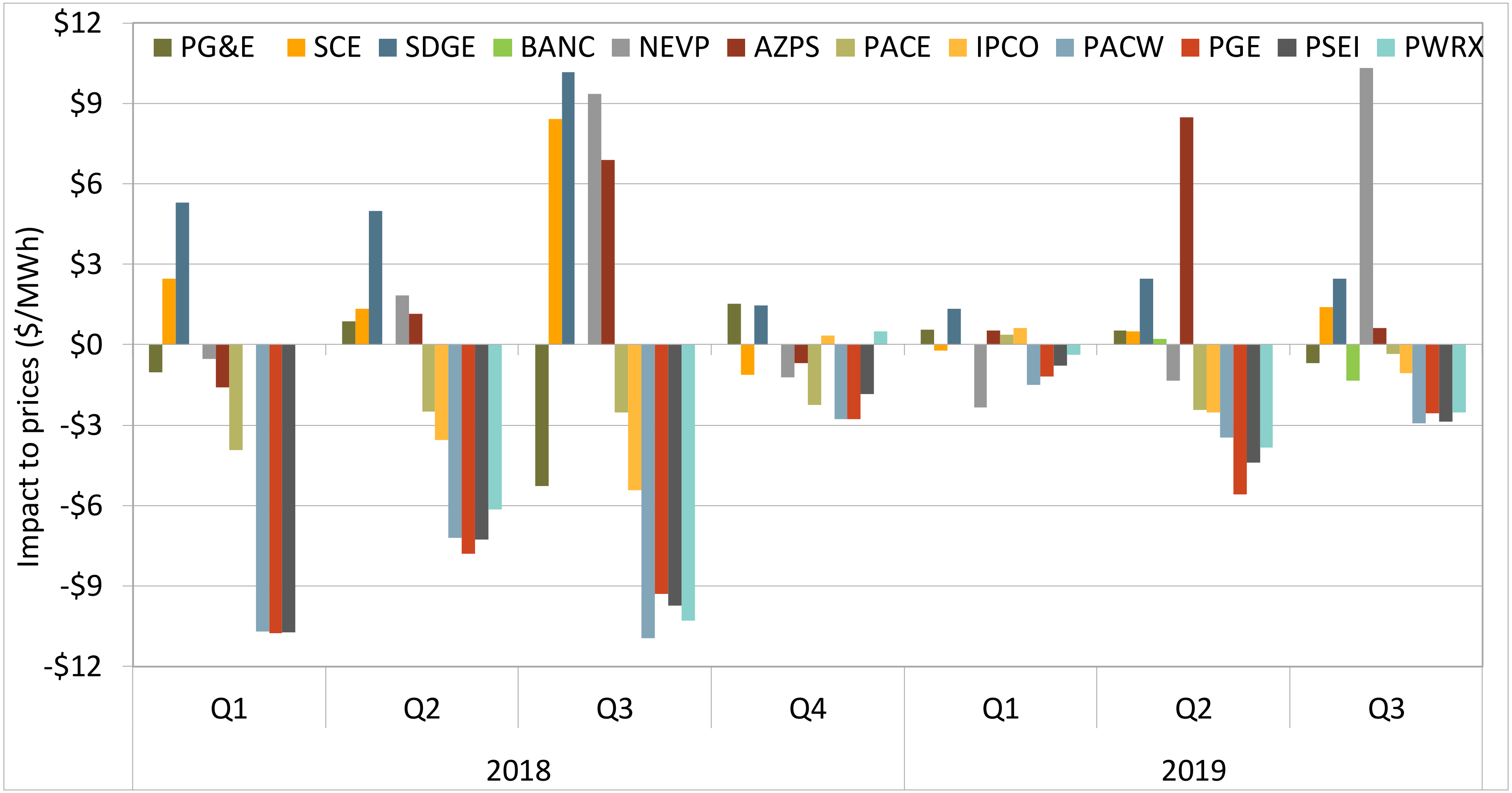


Califor

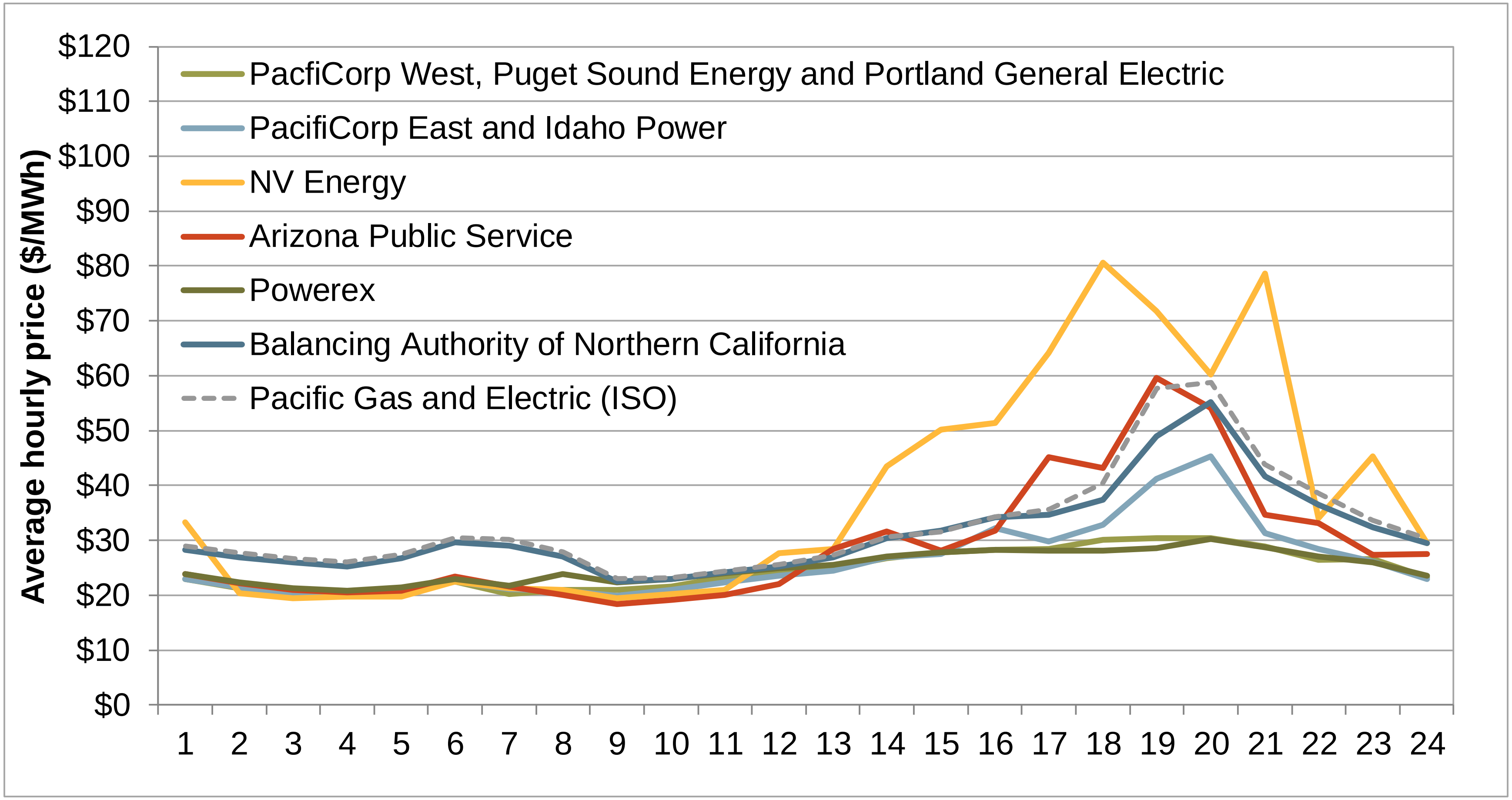
Frequency of congestion in the energy imbalance market (July – September)

	15-minute market		5-minute market	
	Congested toward ISO	Congested from ISO	Congested toward ISO	Congested from ISO
BANC	0%	0%	0%	0%
Arizona Public Service	0%	0%	0%	0%
PacifiCorp East	1%	1%	0%	1%
Idaho Power	0%	1%	0%	1%
NV Energy	2%	4%	1%	3%
PacifiCorp West	12%	2%	9%	2%
Portland General Electric	15%	5%	12%	2%
Puget Sound Energy	13%	5%	11%	5%
Powerex	13%	18%	13%	23%

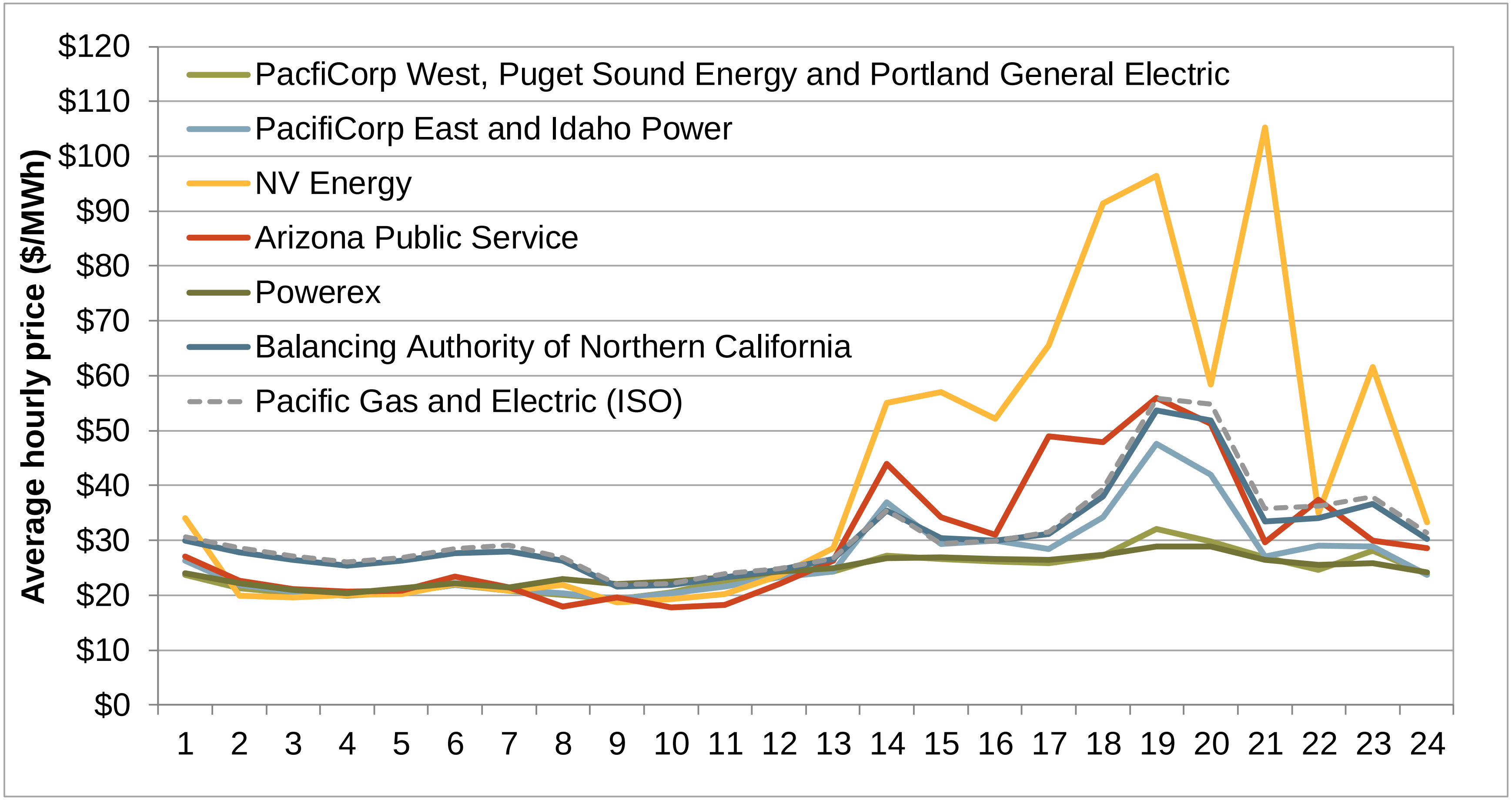
Impact of congestion on 15-minute prices



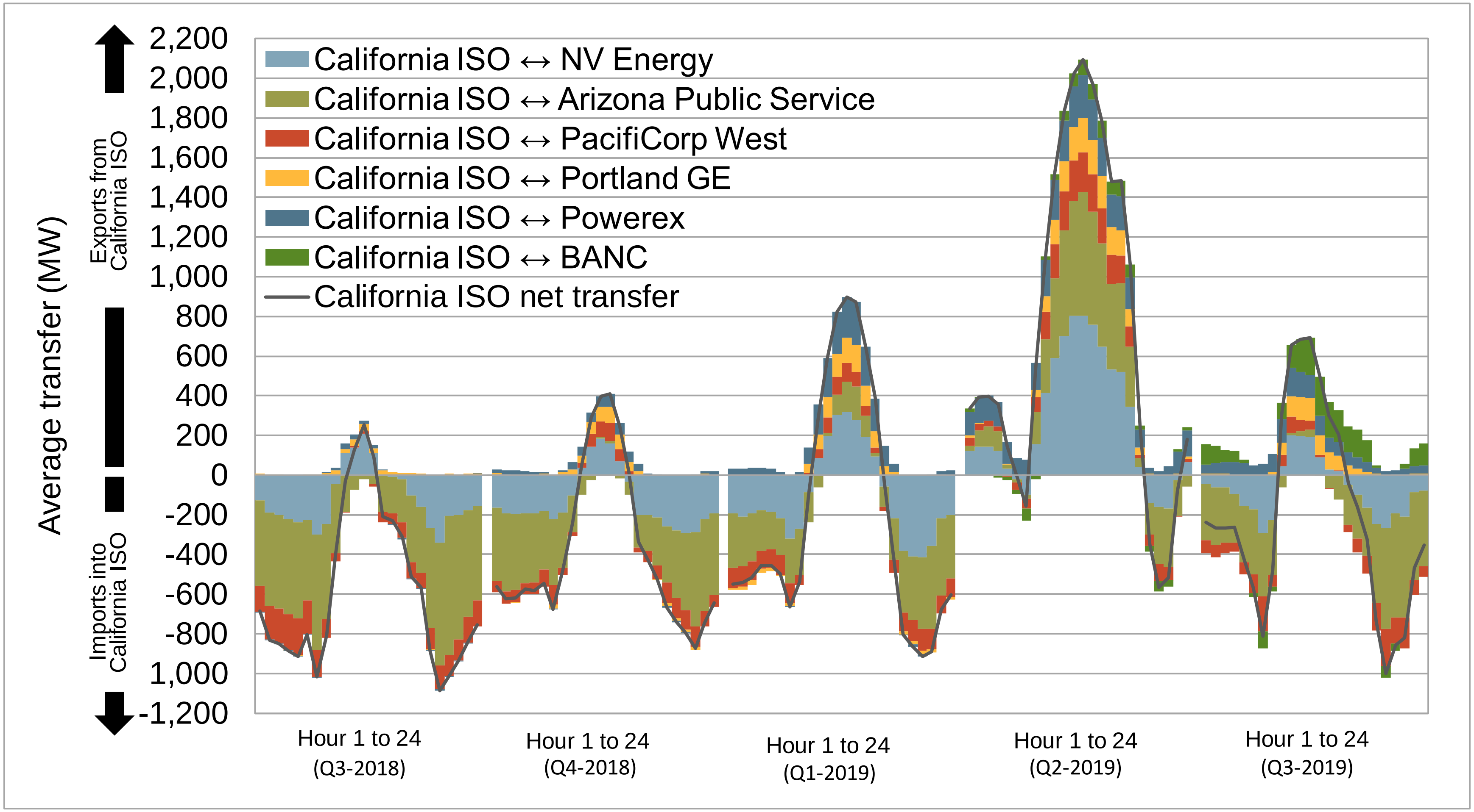
Hourly 15-minute market prices Q3 2019



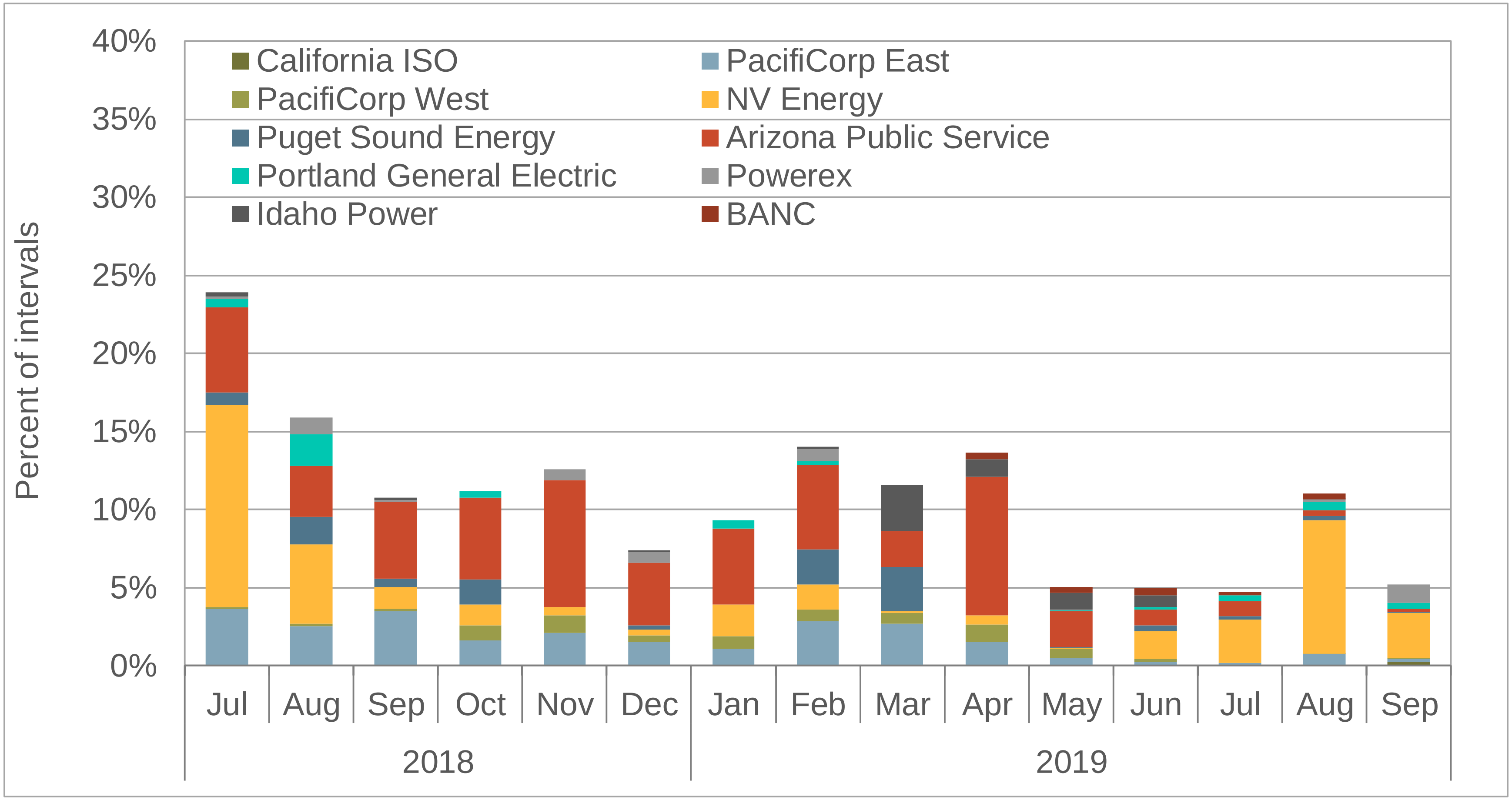
Hourly 5-minute market prices Q3 2019



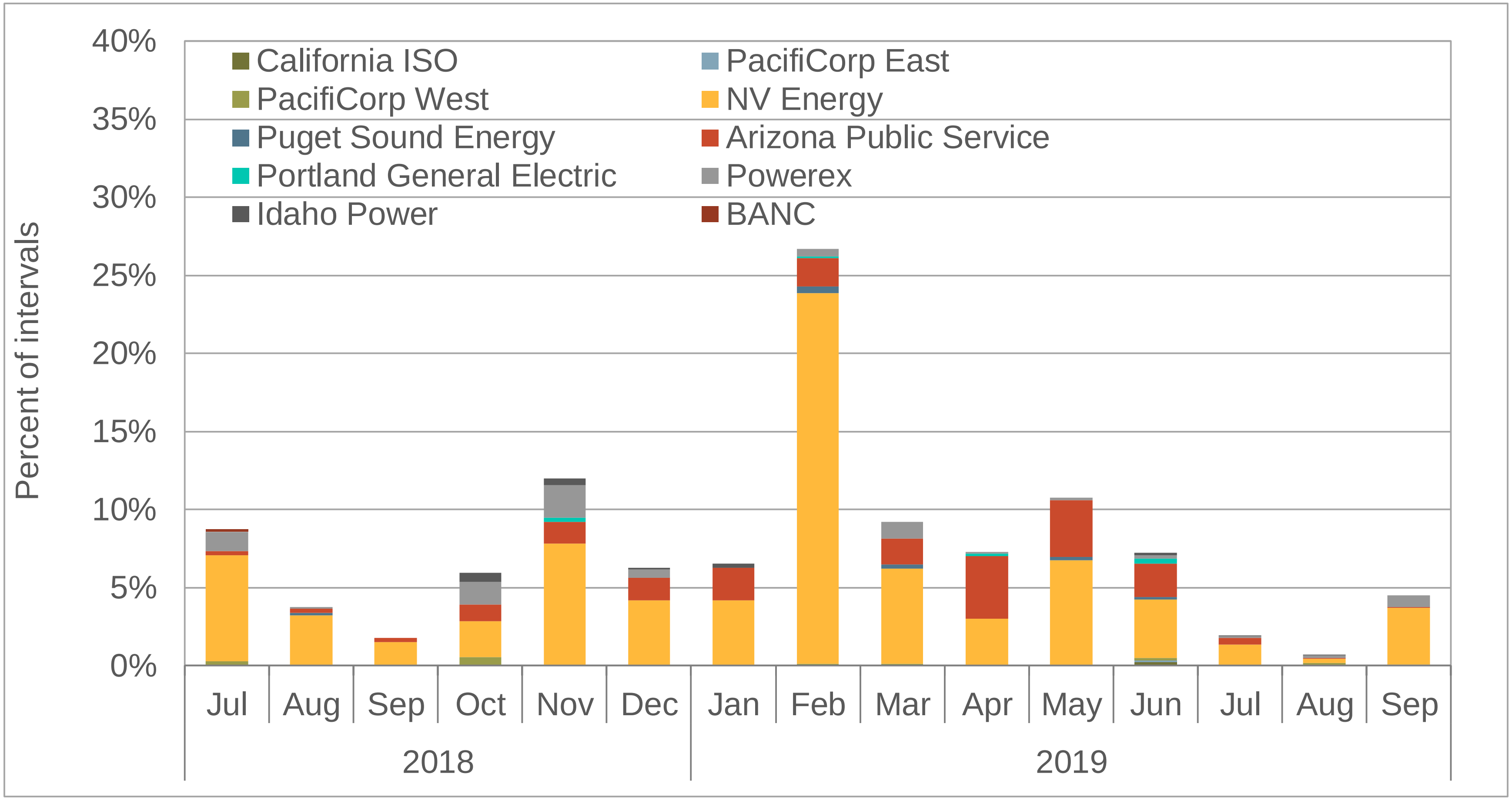
California ISO - average hourly 15-minute market transfer



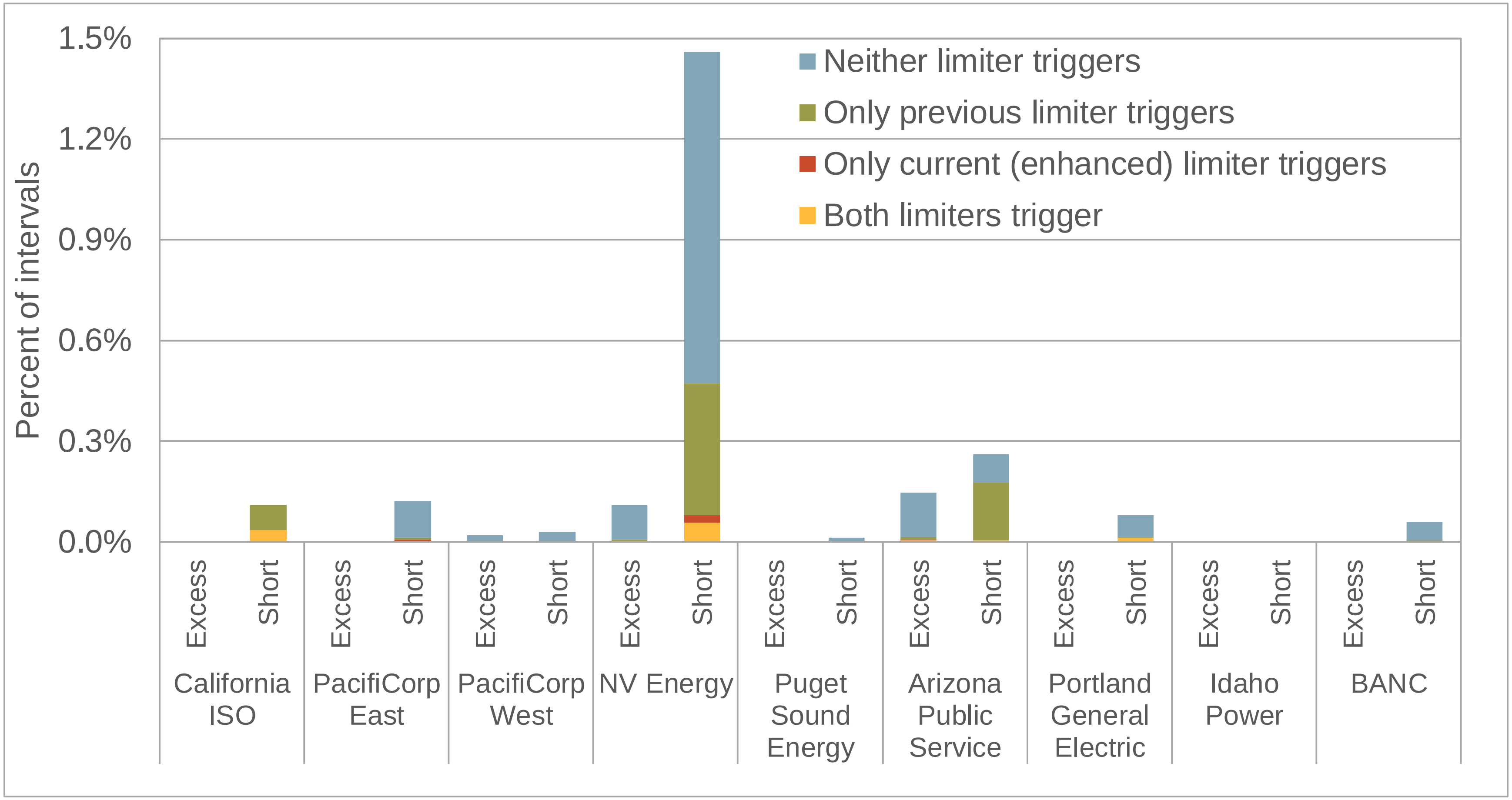
Frequency of upward failed sufficiency tests by month



Frequency of downward failed sufficiency tests by month



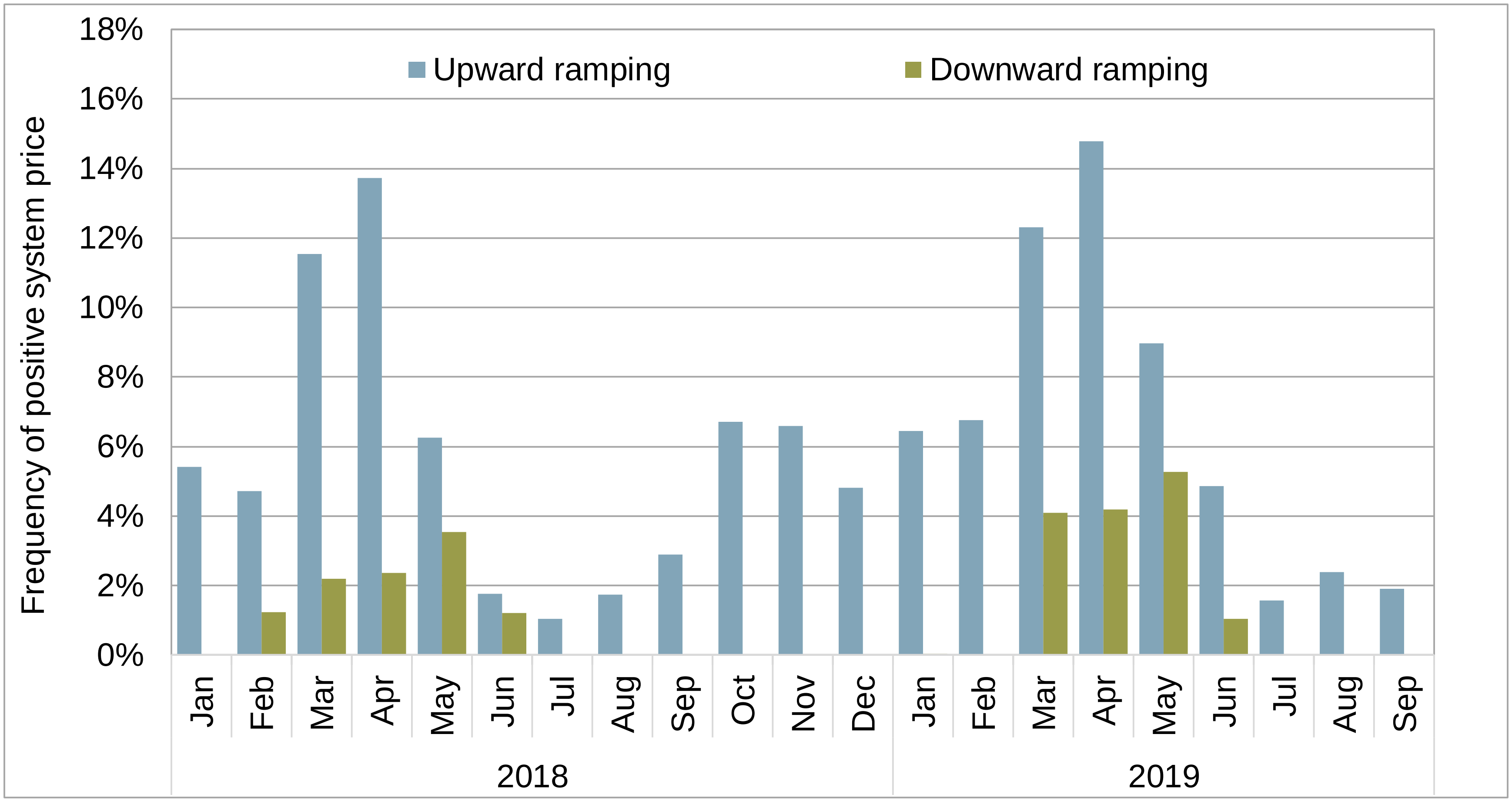
Frequency of load conformance limiter in the 5-minute market (July – September)



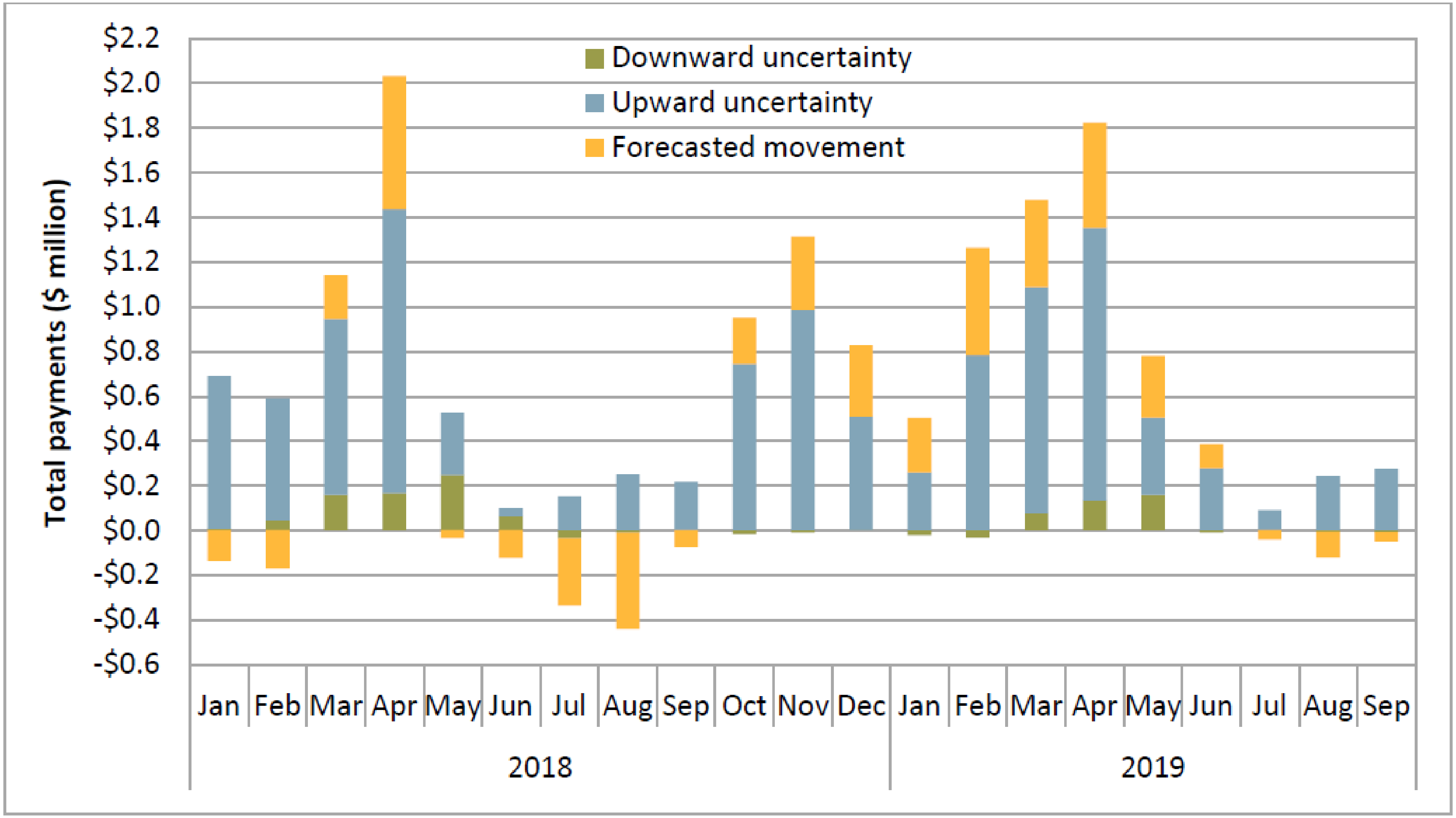
Flexible ramping capacity

- Flexible ramping prices were frequently zero
- Total uncertainty payments to generators were around $0.6 million, compared to around $2.1 million in Q2.
- A recent ISO report highlighted several issues with design and implementation including:
  - 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

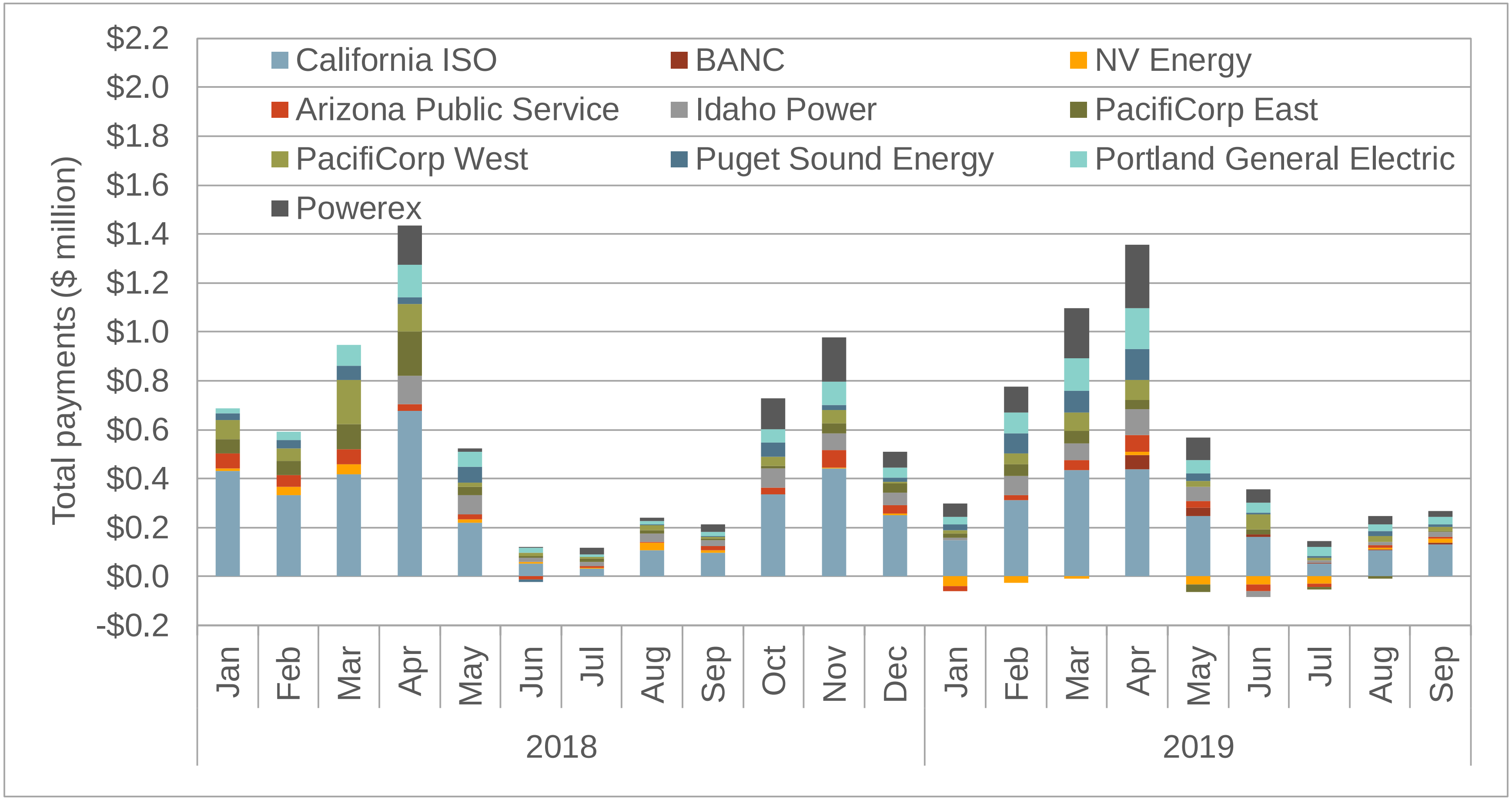
Monthly frequency of positive 15-minute market flexible ramping shadow price



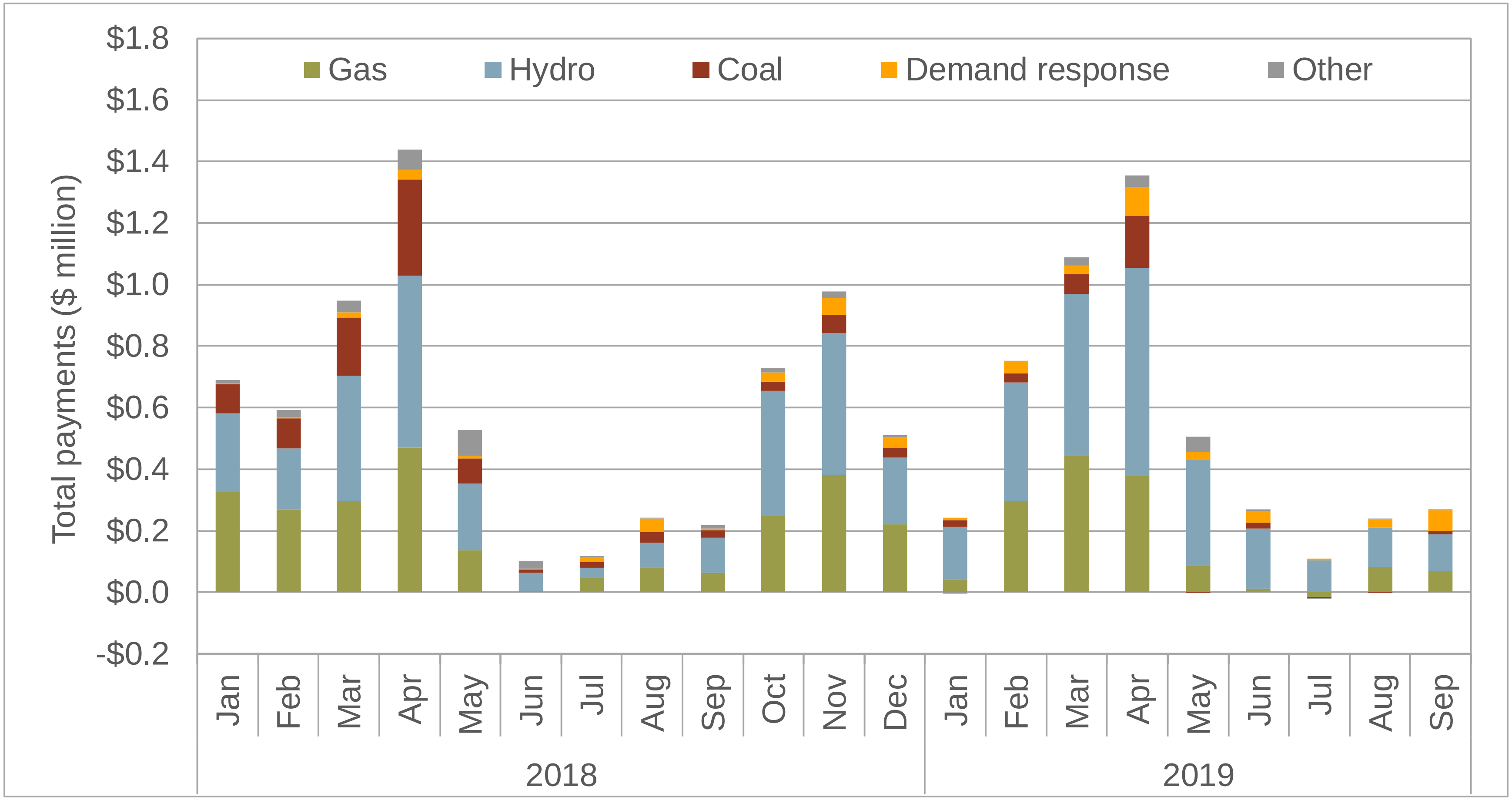
Monthly flexible ramping product payments by type



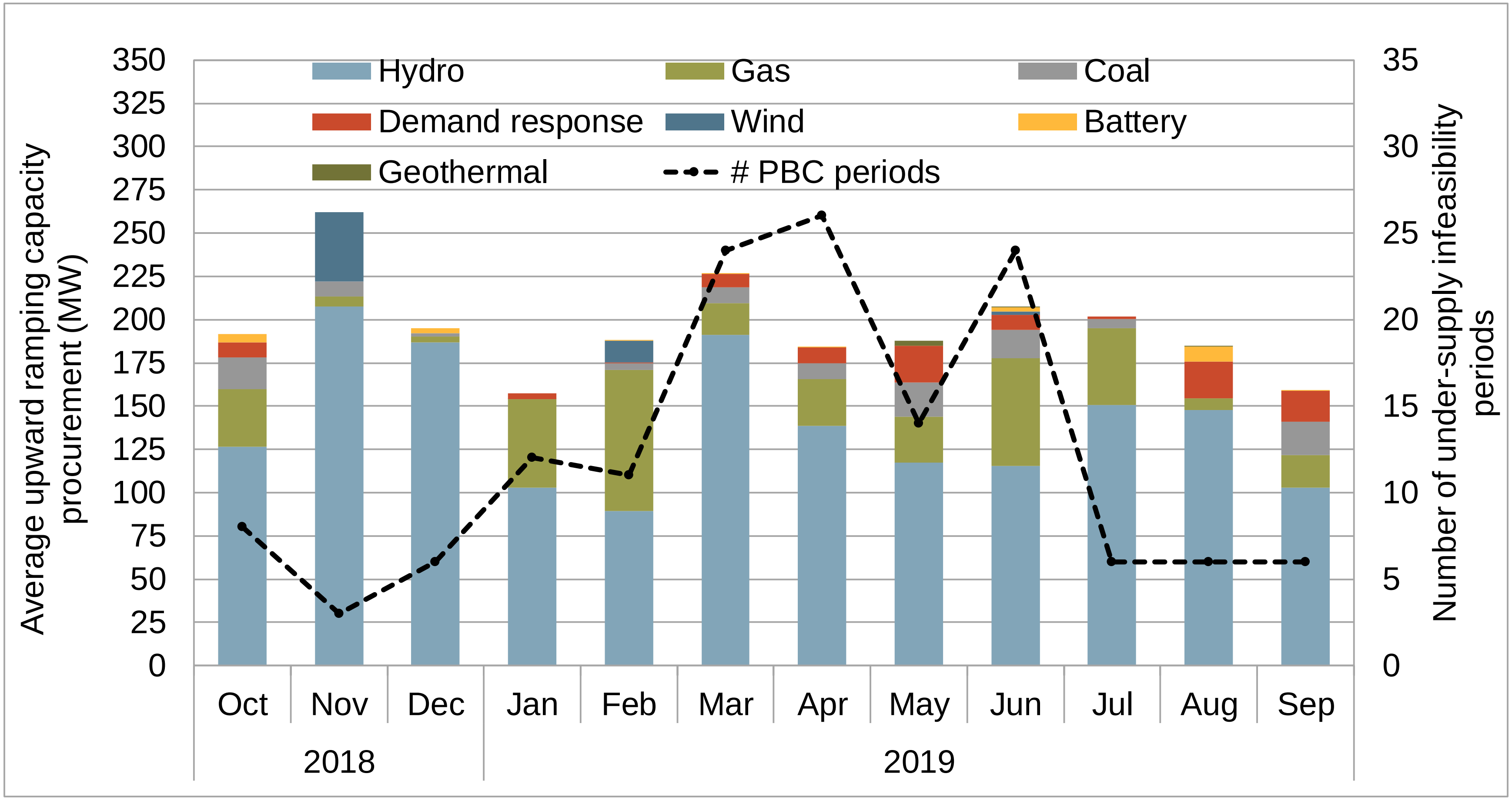
Monthly flexible ramping product uncertainty payments by area



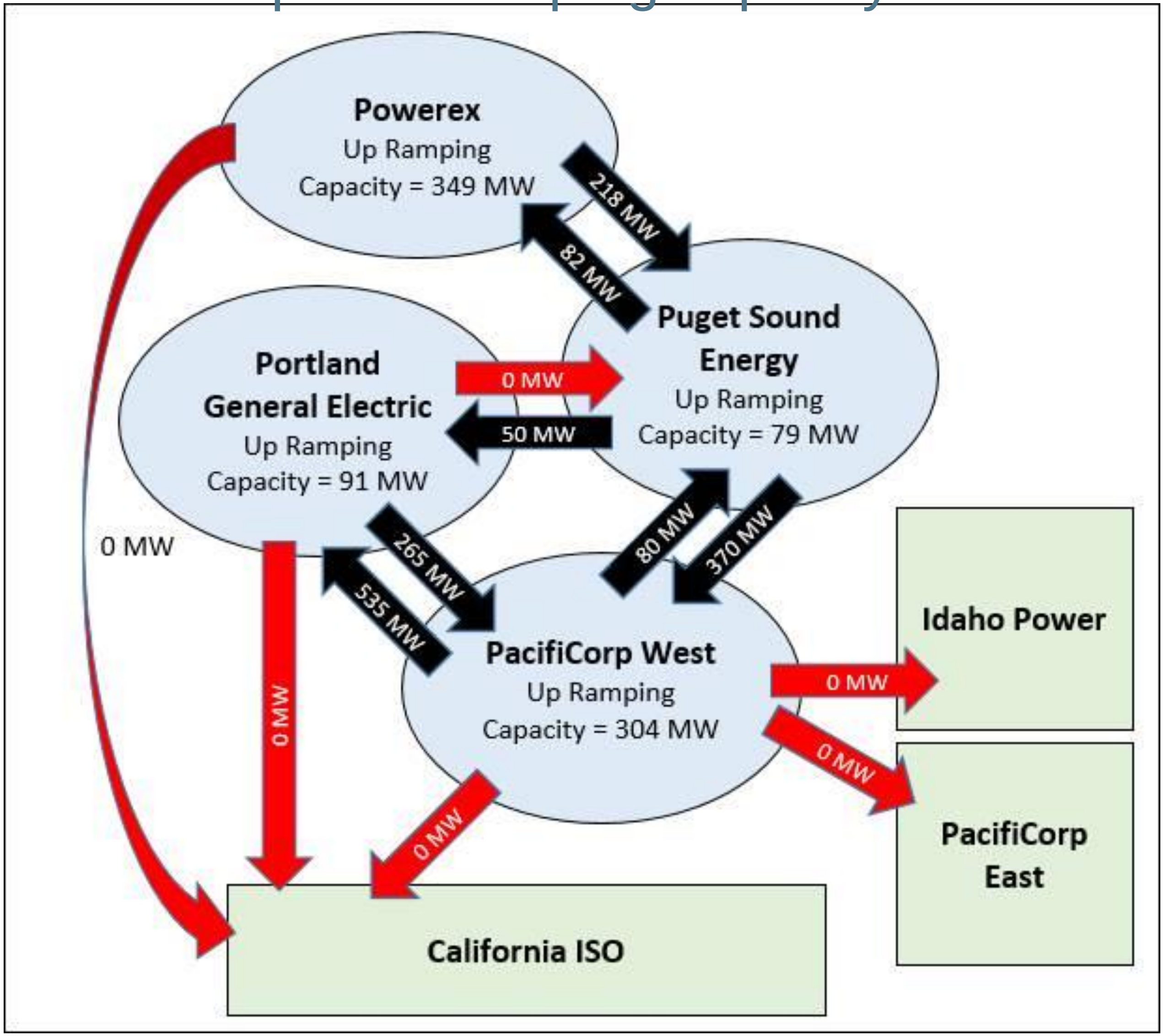
Monthly flexible ramping product uncertainty payments by fuel type



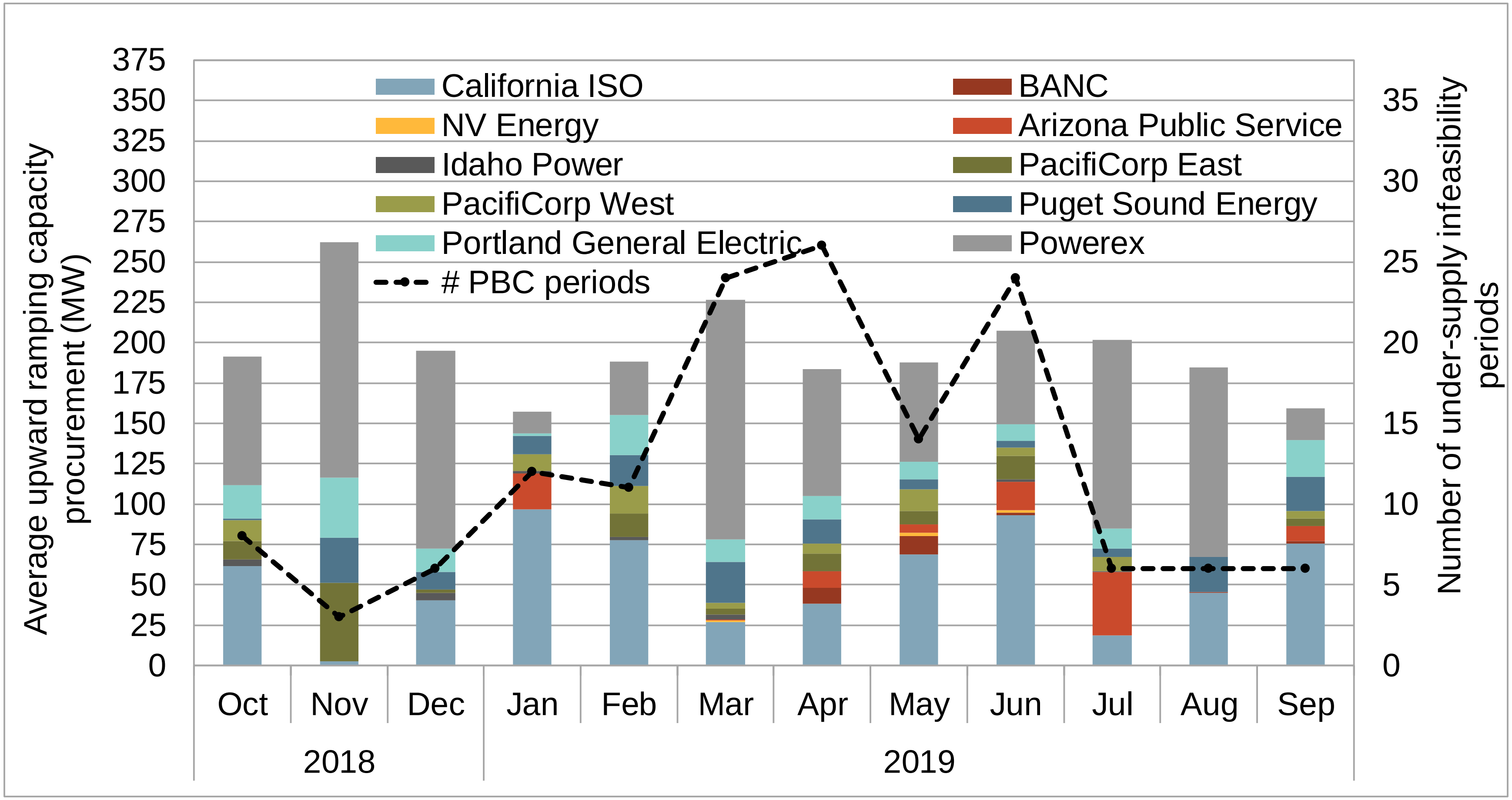
Average 5-minute market upward ramping capacity procurement prior to under-supply infeasibility periods - by fuel type



Example - Stranded upward ramping capacity in the Northwest



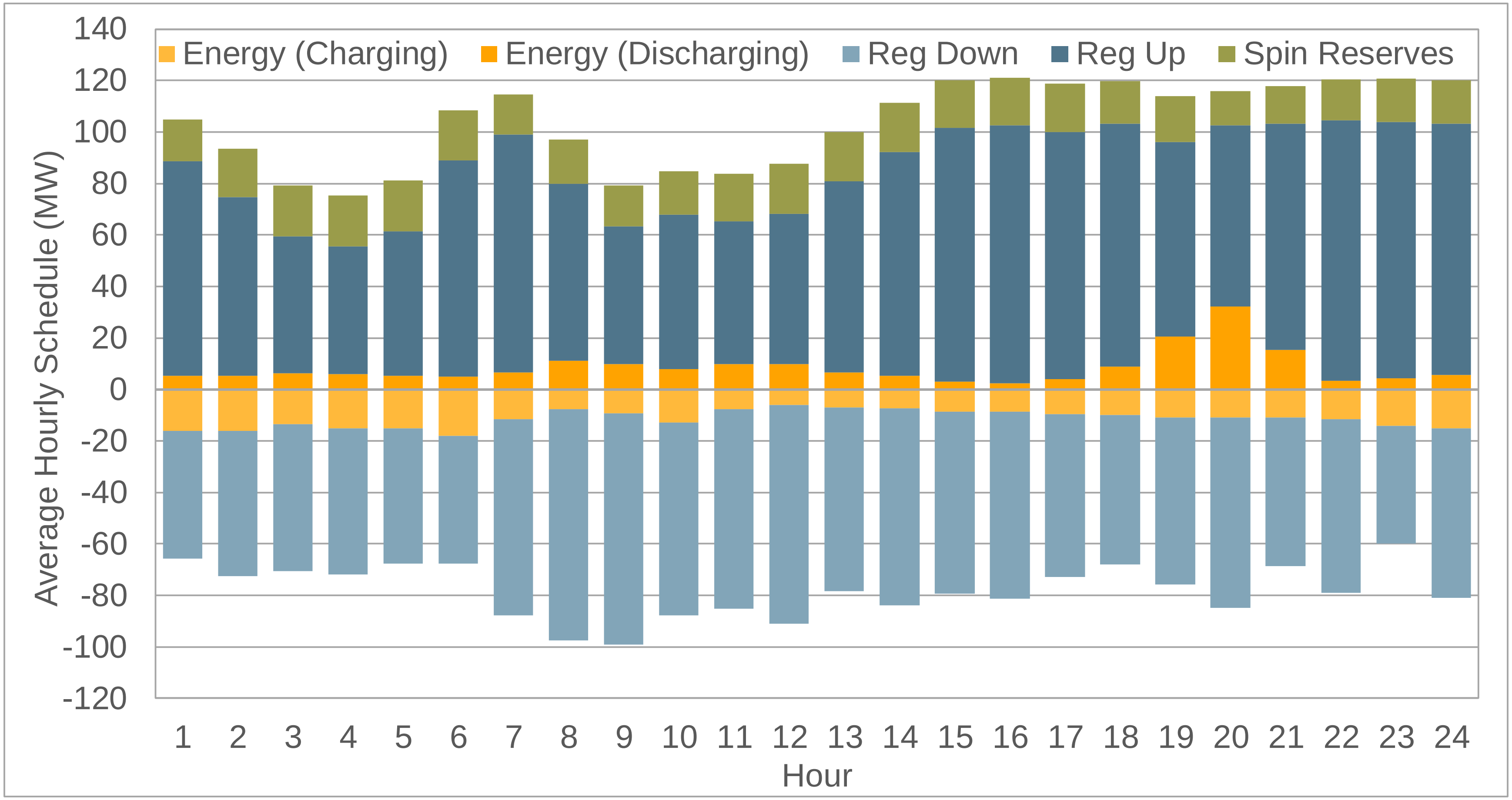
Average 5-minute market upward ramping capacity procurement prior to under-supply infeasibility periods - by area



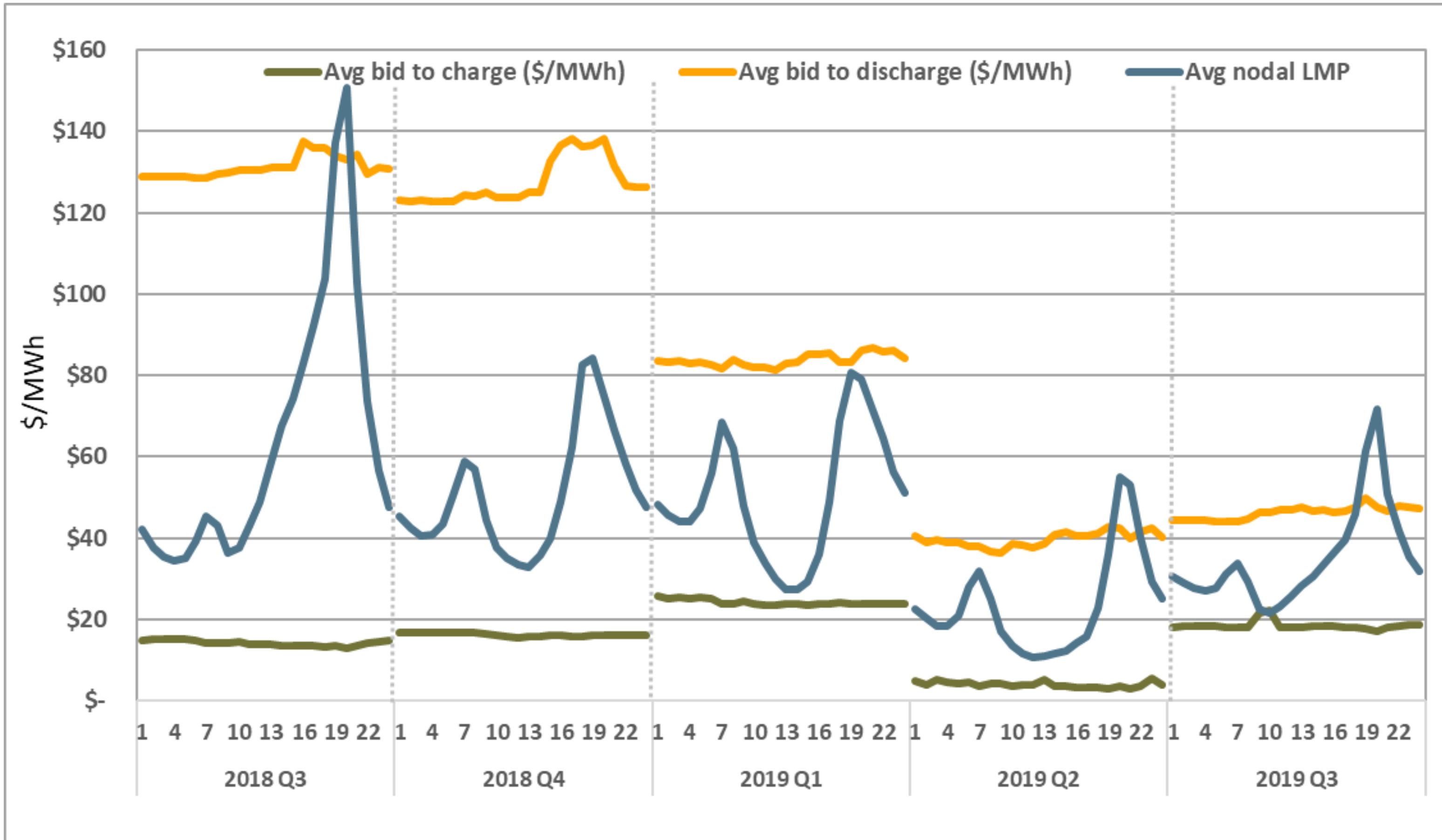
Flexible ramping product, need for longer time horizon

- 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 could reduce the need for manual load adjustments and more efficiently integrate distributed and variable energy resources by designing a real-time flexible ramping product that could procure and price the appropriate amount of ramping capability to account for uncertainty over longer time horizons than the current design considers

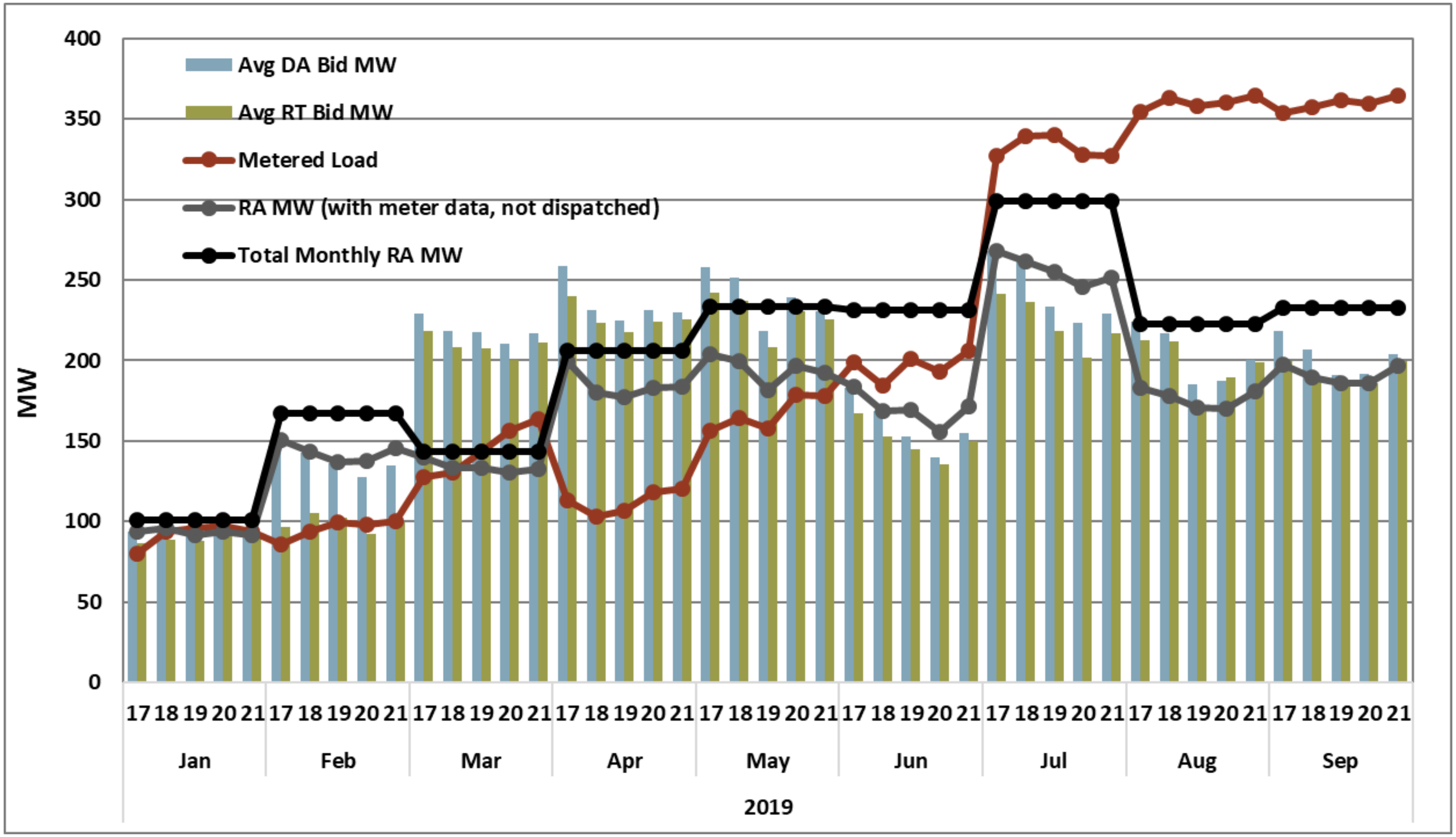
Average hourly battery schedules (2019 Q3)



Average hourly battery bids and nodal LMPs (2018 Q3 -2019 Q3)



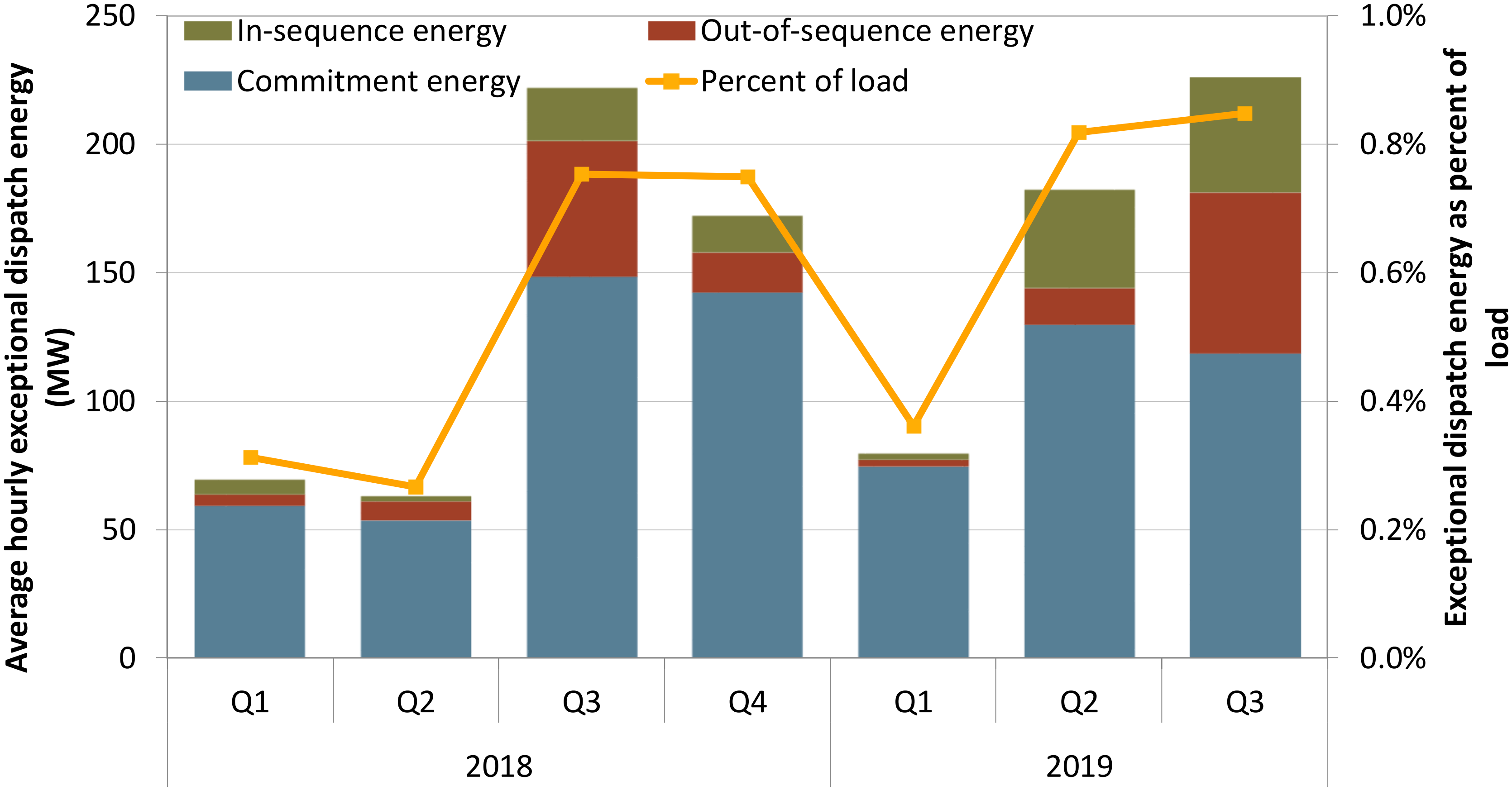
Average bids and metered load of PDR resources on RA supply plans



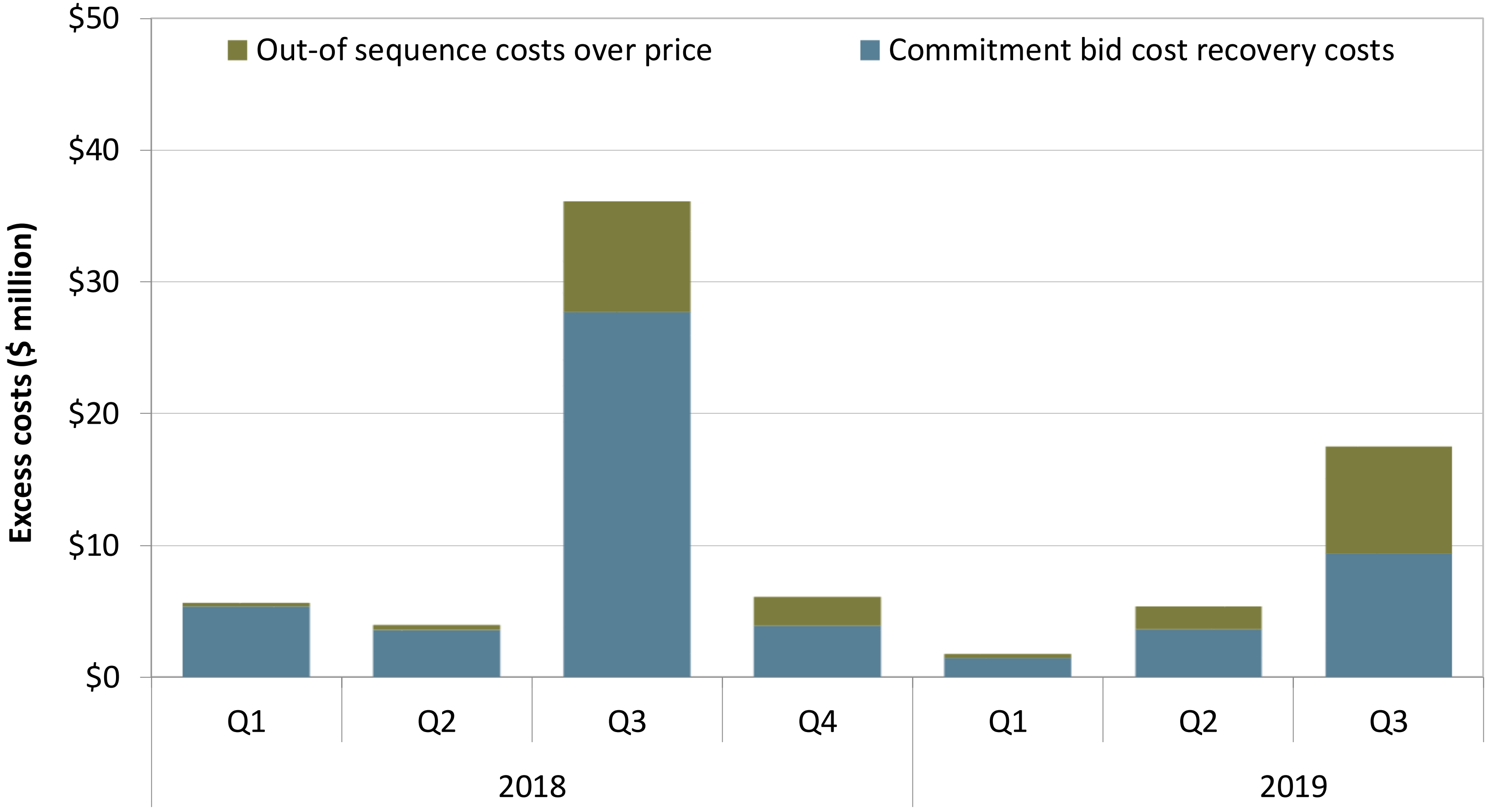
Exceptional dispatch

- Many exceptional dispatches were issued to commit and ramp up slower ramping gas units during the evening ramping hours in the third quarter.
- Exceptional dispatches to RA Max are not subject to energy bid mitigation, and are paid the higher of the unit’s energy bid or the market price.
- Total unmitigated RA Max exceptional dispatch energy costs were around $5.2 million, about $3.3 million above market prices in the third quarter.
- DMM is recommending that RA Max exceptional dispatch energy should be subject to mitigation.

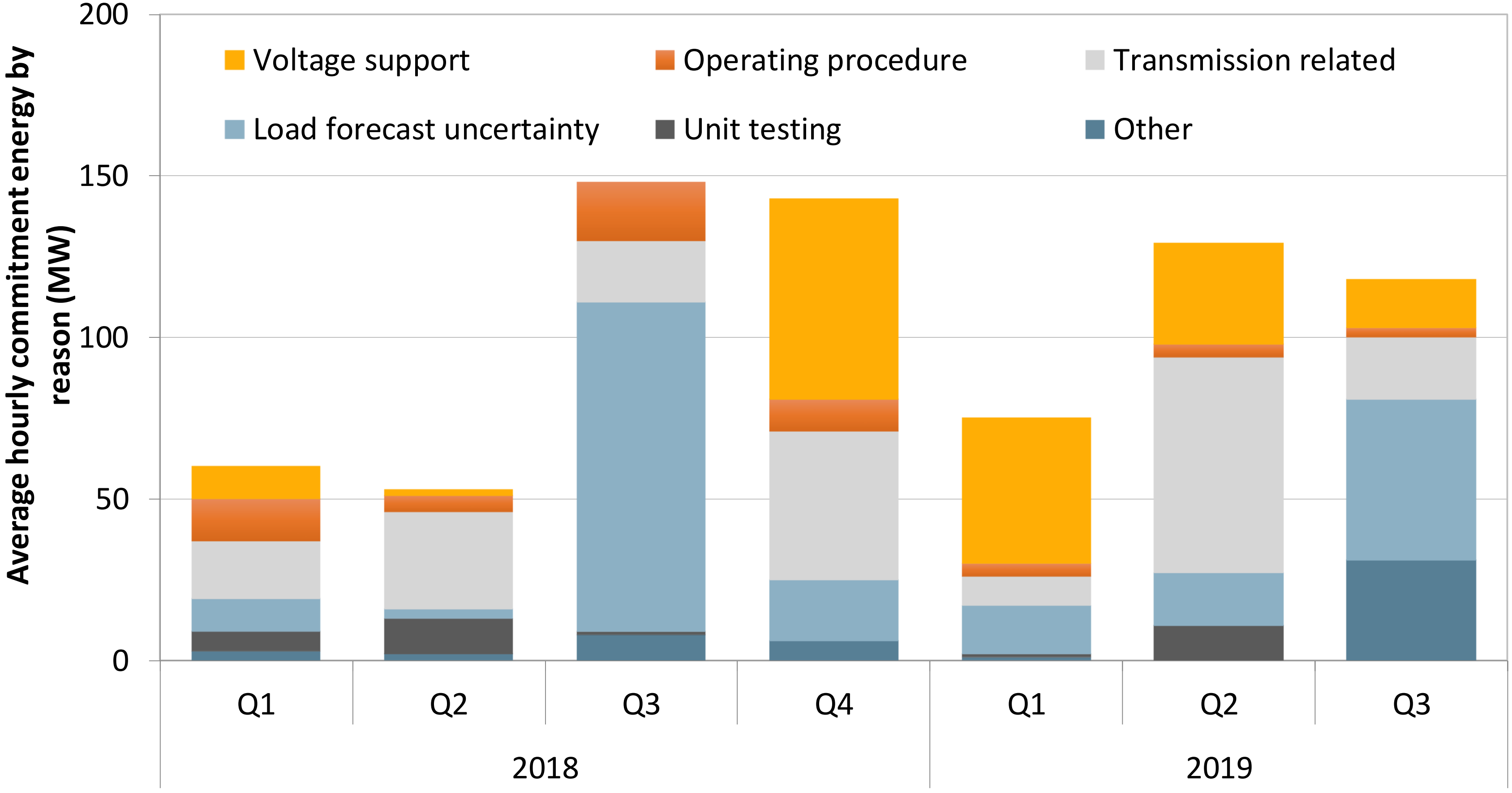
Average hourly energy from exceptional dispatch was comparable to Q3 2018 totaling 0.85% system load



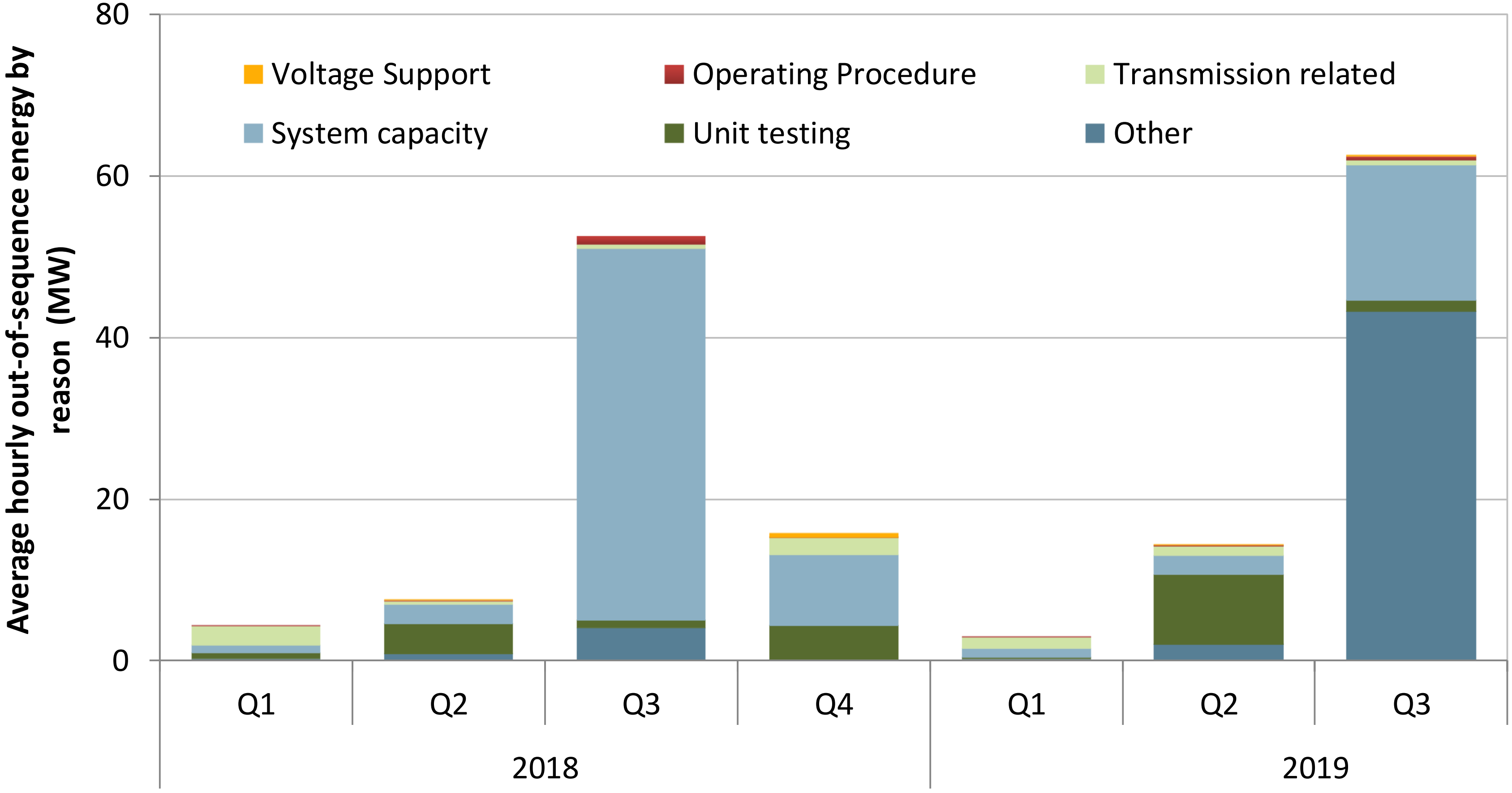
Excess exceptional dispatch cost total $17.4 million



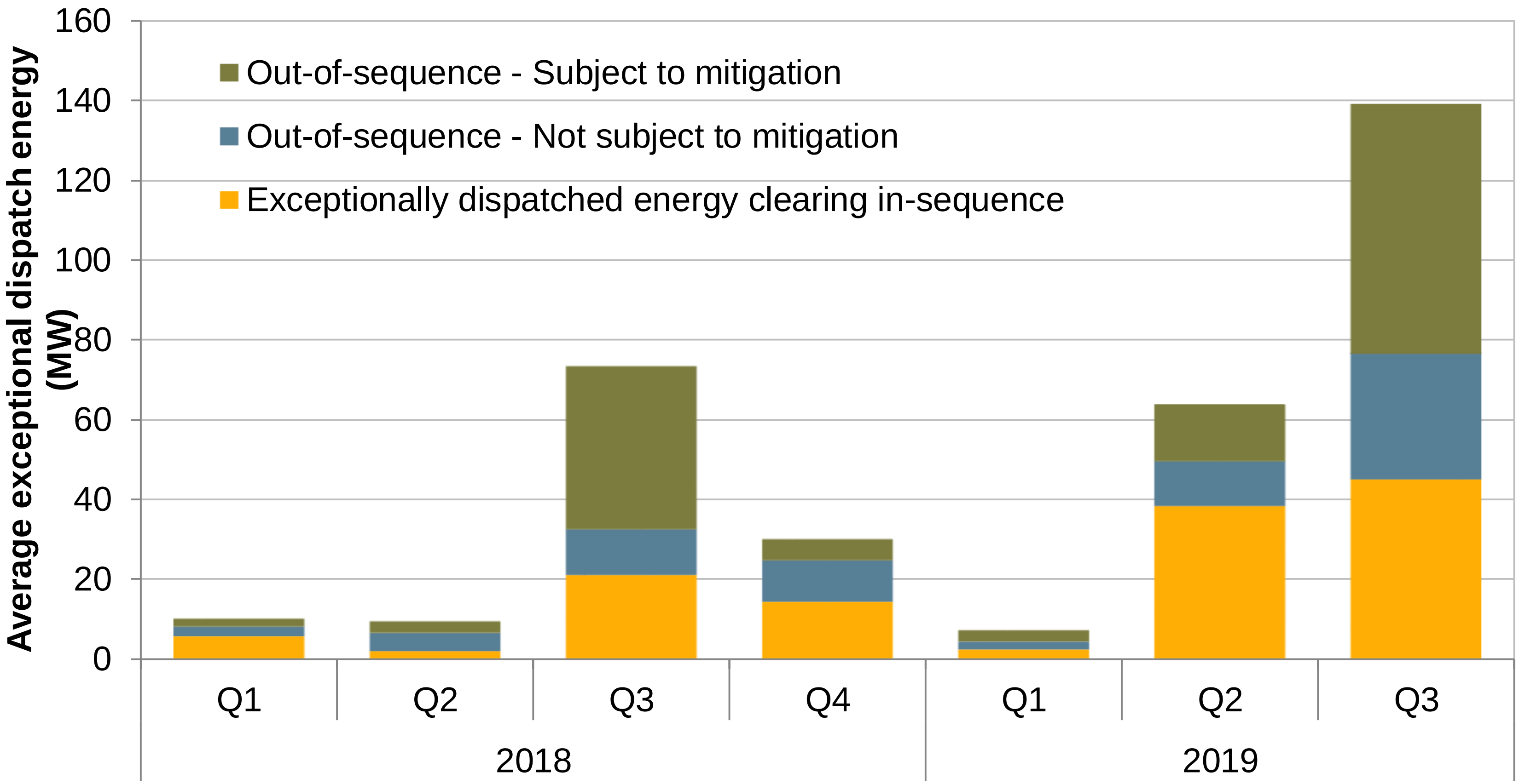
Average minimum load energy from exceptional dispatch unit commitments



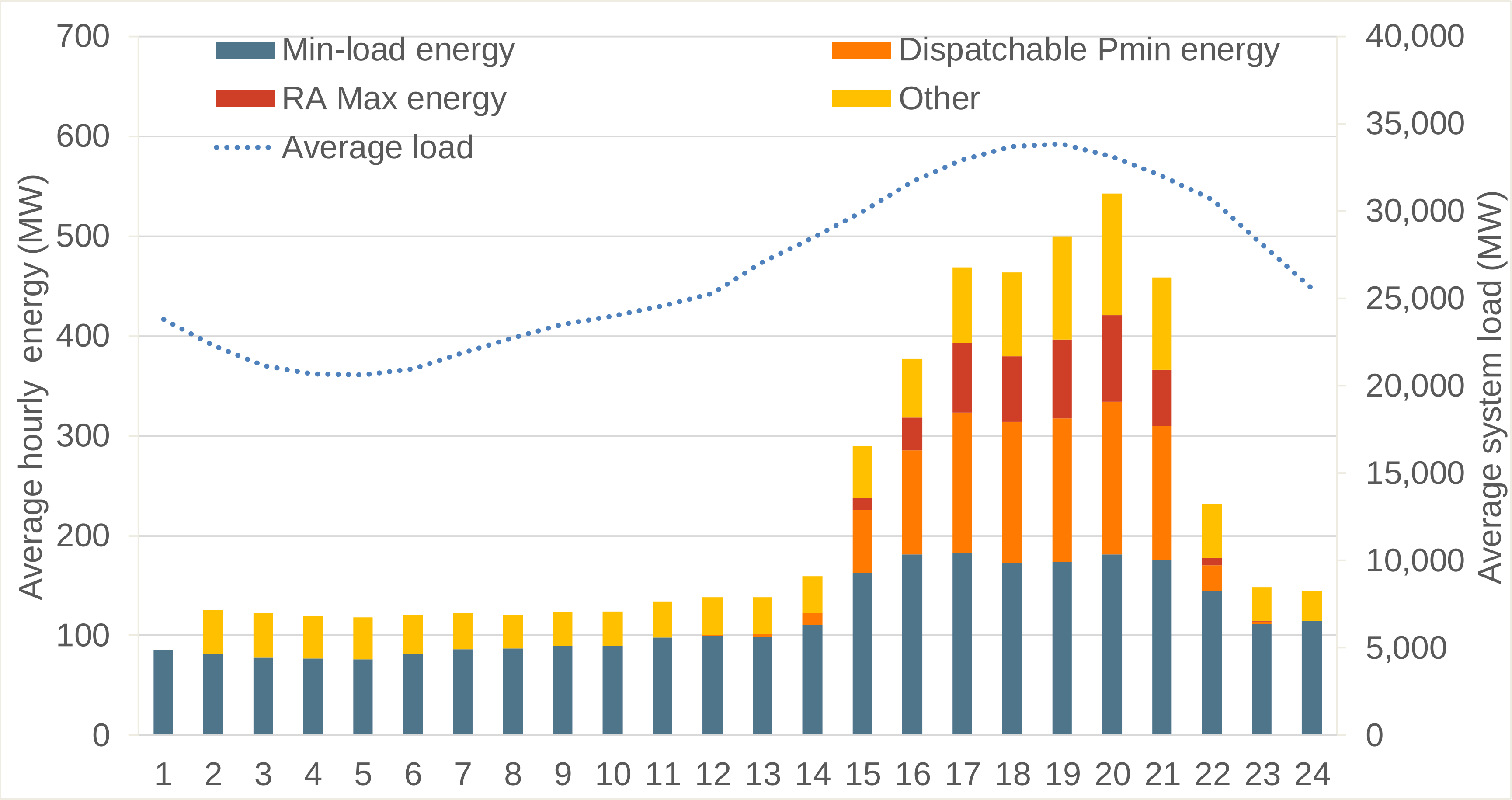
Out-of-sequence exceptional dispatch energy by reason



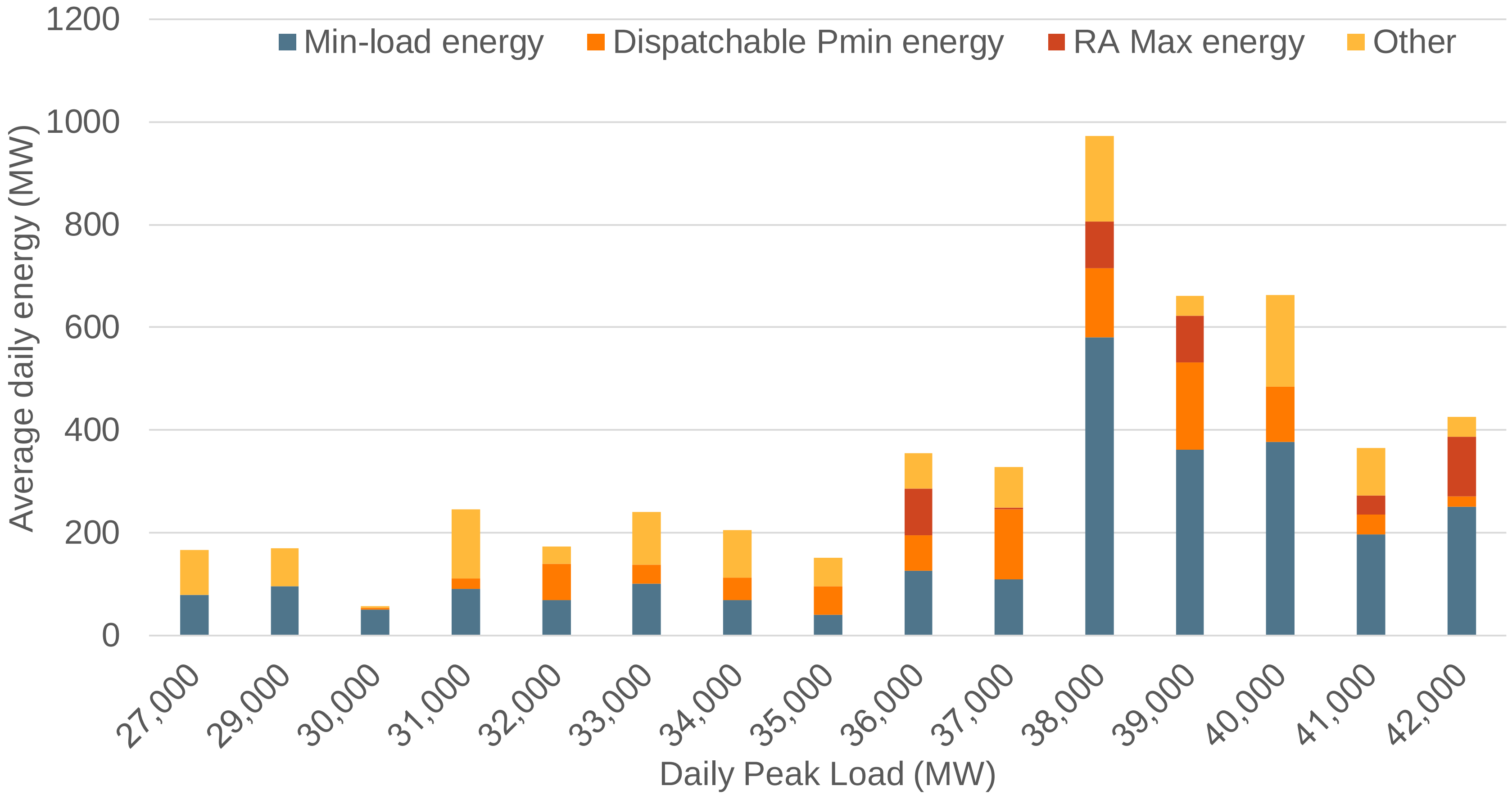
Exceptional dispatches subject to mitigation, should reduce costs by $15.4 million



Average hourly gas resource exceptional dispatch energy by type (July – September)



Average gas exceptional dispatch energy by peak load amount (July-September, hours ending 17-21)



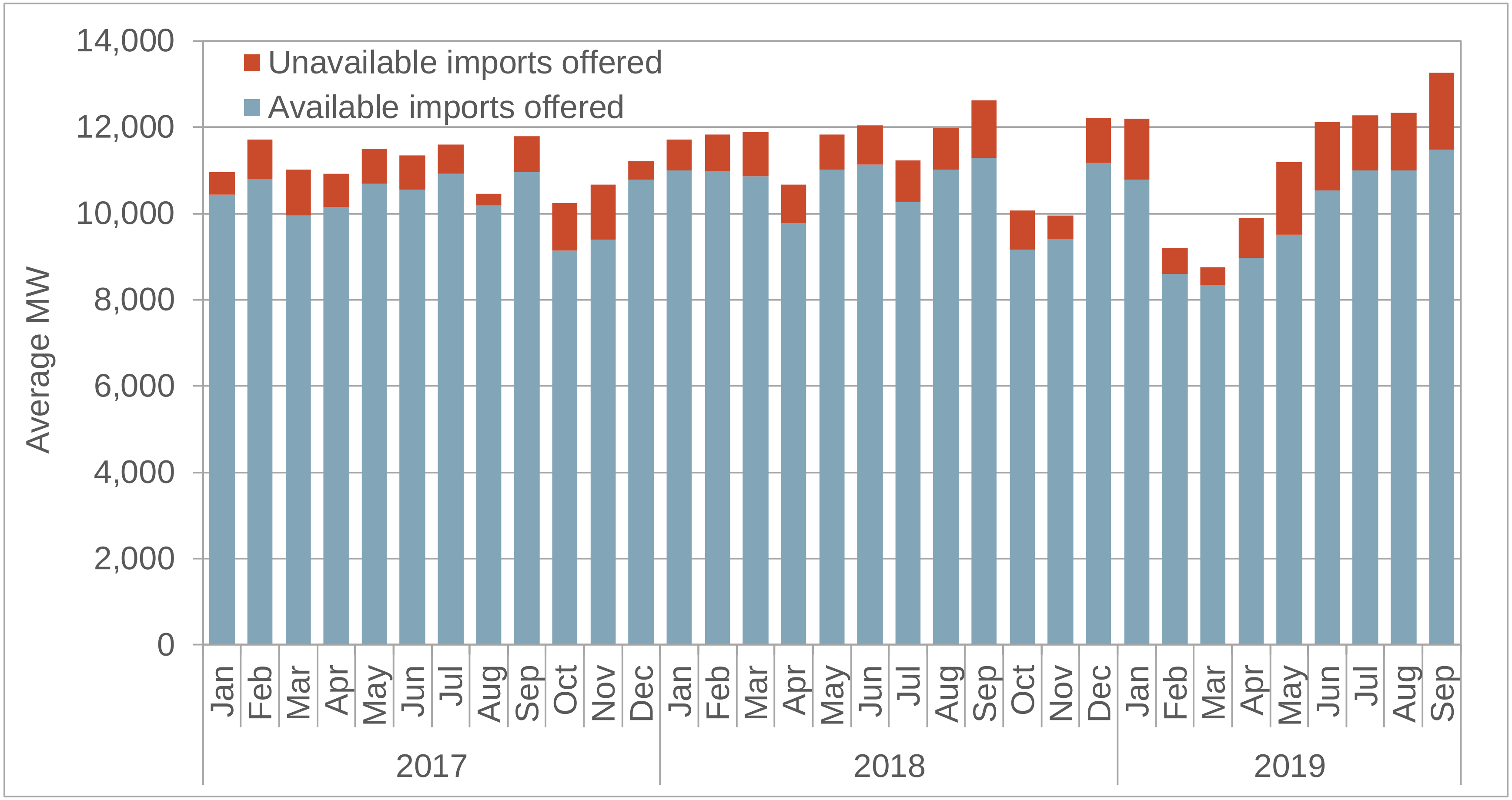
System market power

- Market power has had a very limited effect on system market prices even during hours when the ISO system was structurally uncompetitive
- However, DMM has expressed concern that market conditions may evolve in a way that will increase the potential for system-level market power
- DMM supports the ISO’s initiative as a an incremental improvement
- Continues to recommend other market design changes:
  - Increasing supply availability of RA imports
  - Ensure that import bids over $1,000/MWh are subject to ex ante cost verification
  - Avoid setting penalty prices at $2,000/MWh except when needed.

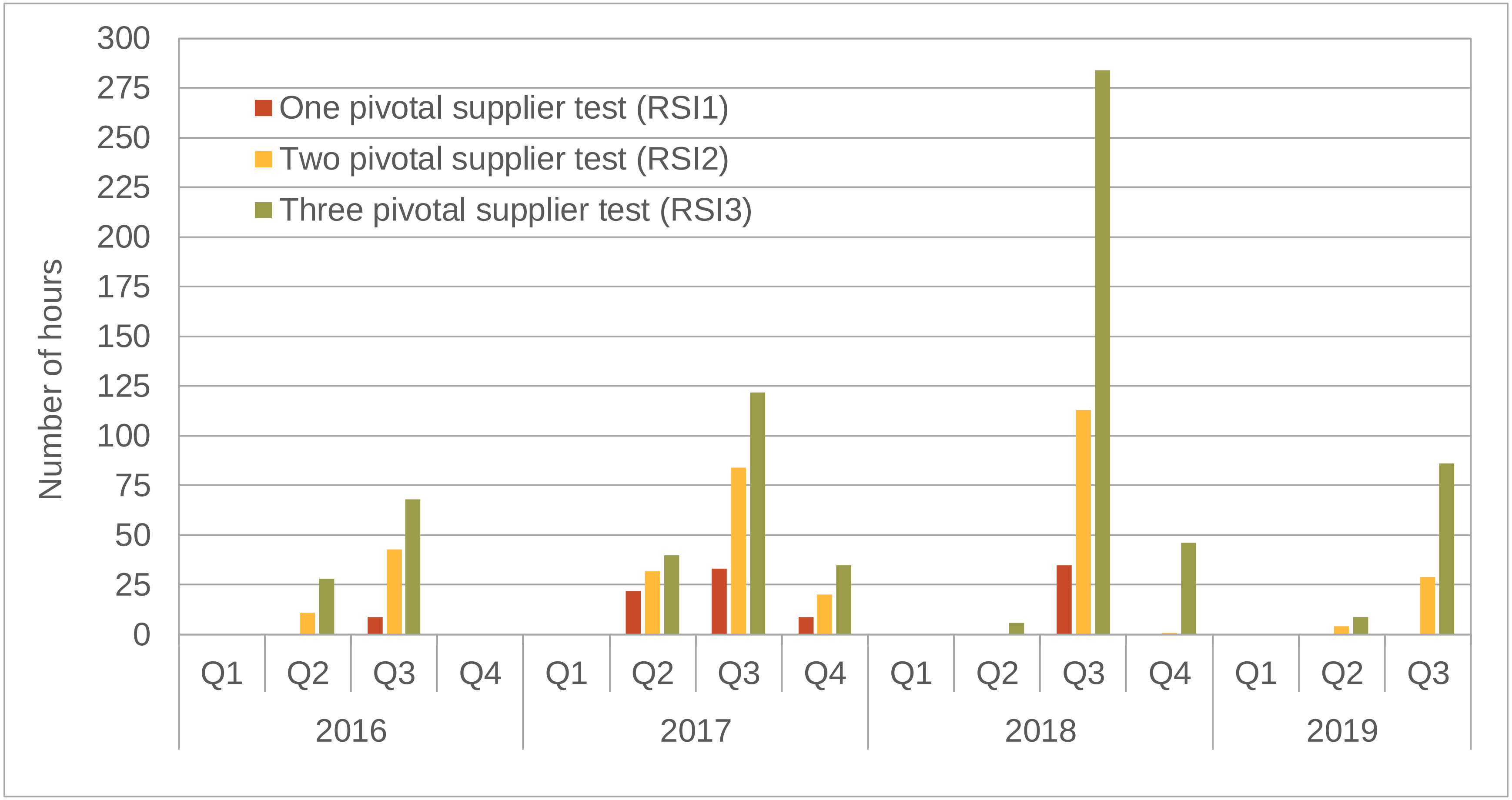
Residual supply index – calculation changes

- Use of day-ahead ***input bids*** for physical generating resources (adjusted for outages and de-rates) instead of post-processed bids used in the final market software optimization (or output bids)
- Accounting for losses (typically increasing demand by 2 or 3 %)
- Including self-scheduled exports as demand (combined with the day-ahead load forecast plus upward ancillary service requirements and transmission losses)
- Including ancillary services bids in excess of energy bids to account for this additional supply available to meet ancillary service requirements in the day-ahead market
- Exclusion of CPUC jurisdictional investor-owned utilities as potentially pivotal suppliers.
- Accounting for the maximum availability of non-pivotal imports offered relative to import transmission constraint limits.
- As in prior DMM analyses, virtual bids are excluded.

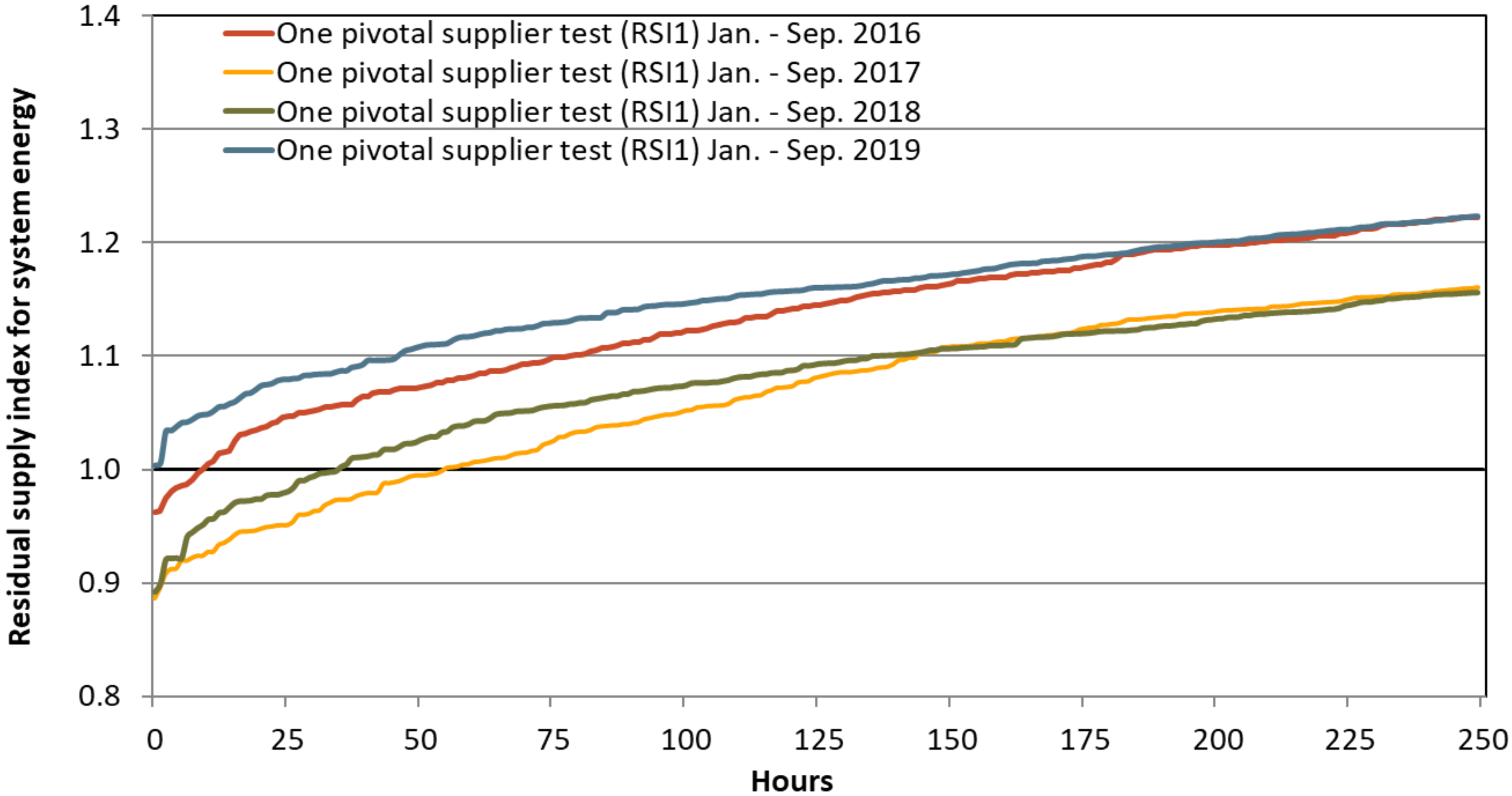
Day-ahead market imports offered and transmission availability



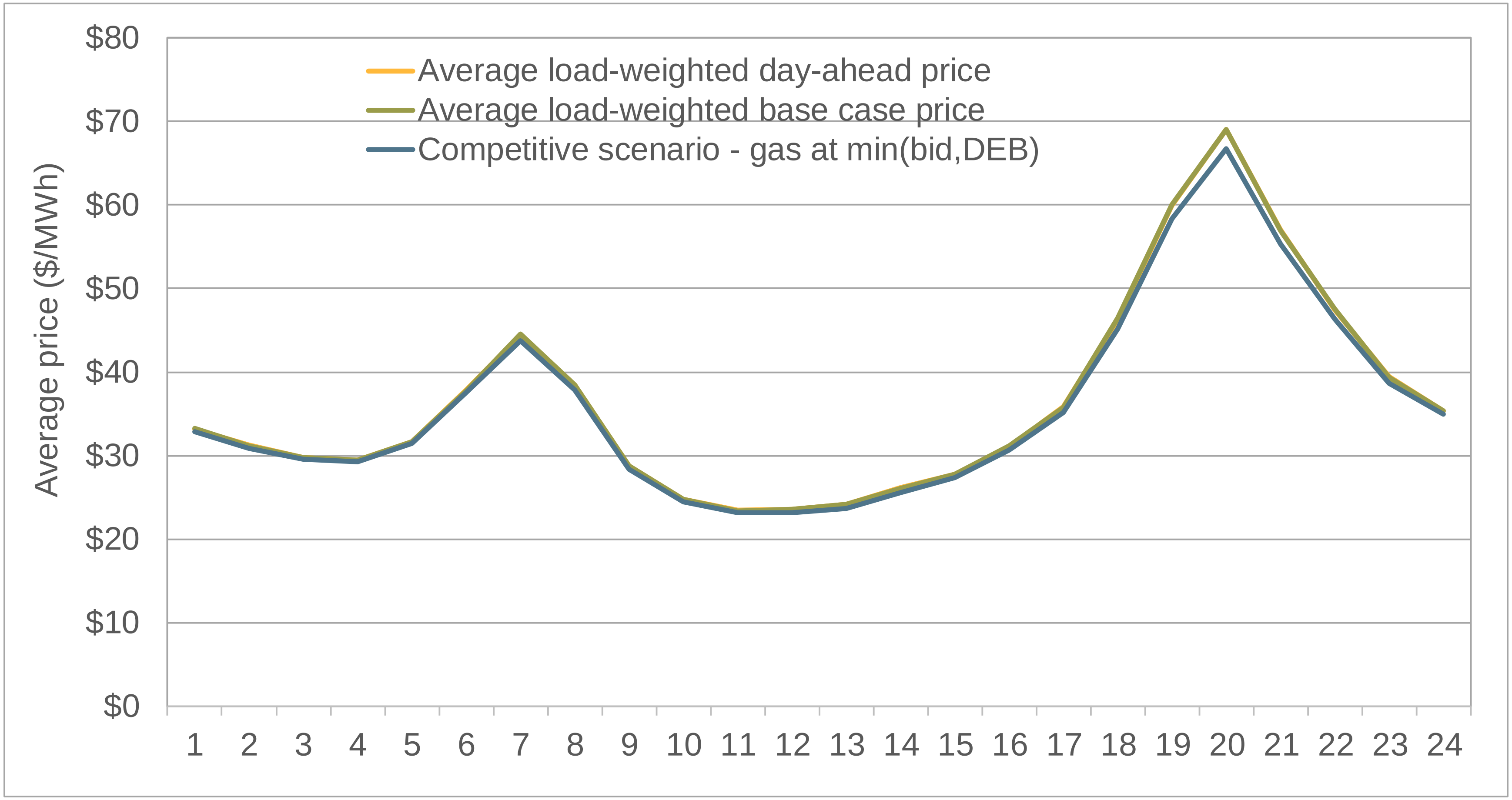
Hours with residual supply index less than one



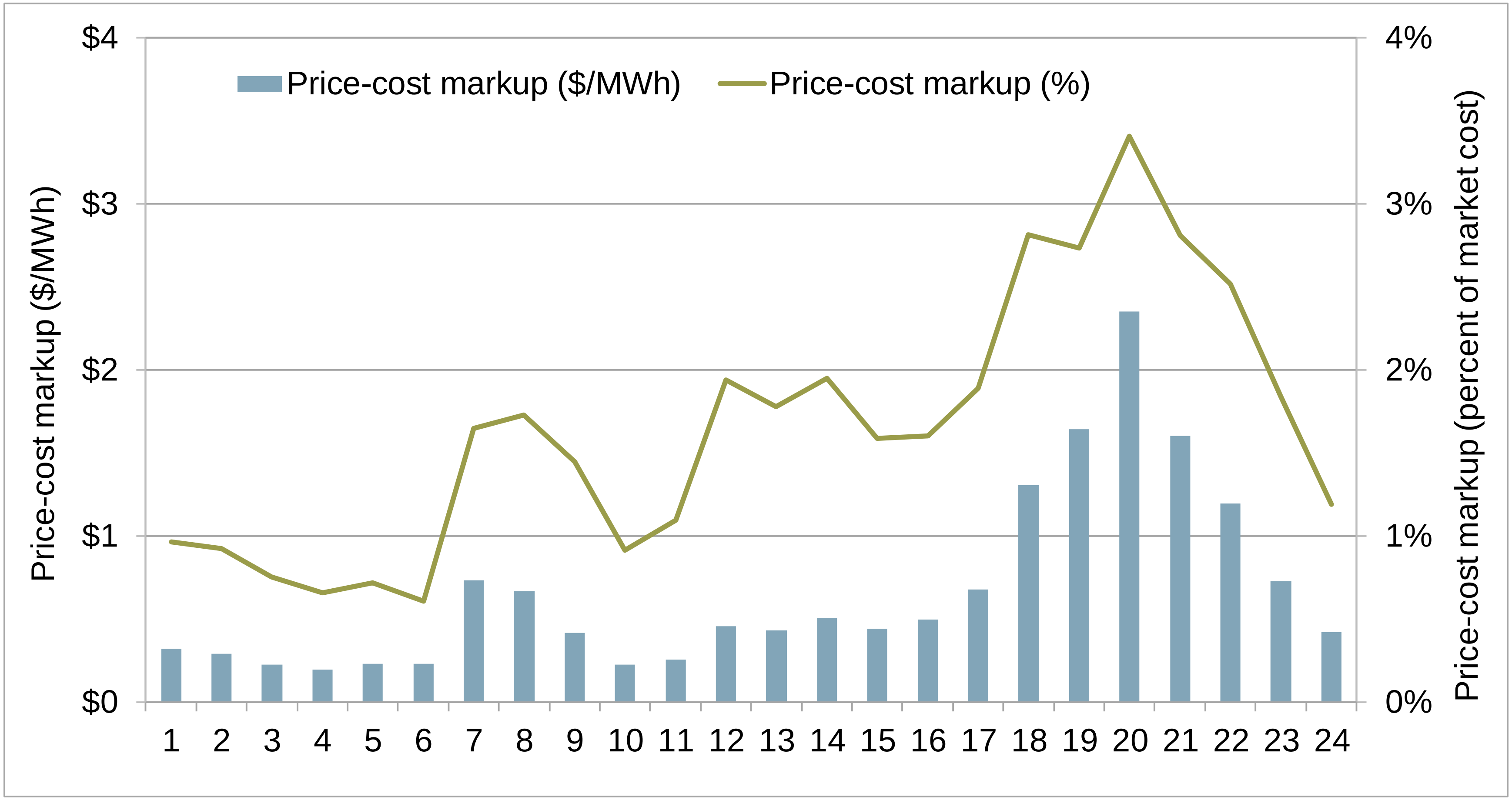
Residual supply index with largest supplier excluded (RSI_1) – lowest 250 hours (January to September)



Comparison of competitive baseline with hourly day-ahead prices (Jan – Sep)

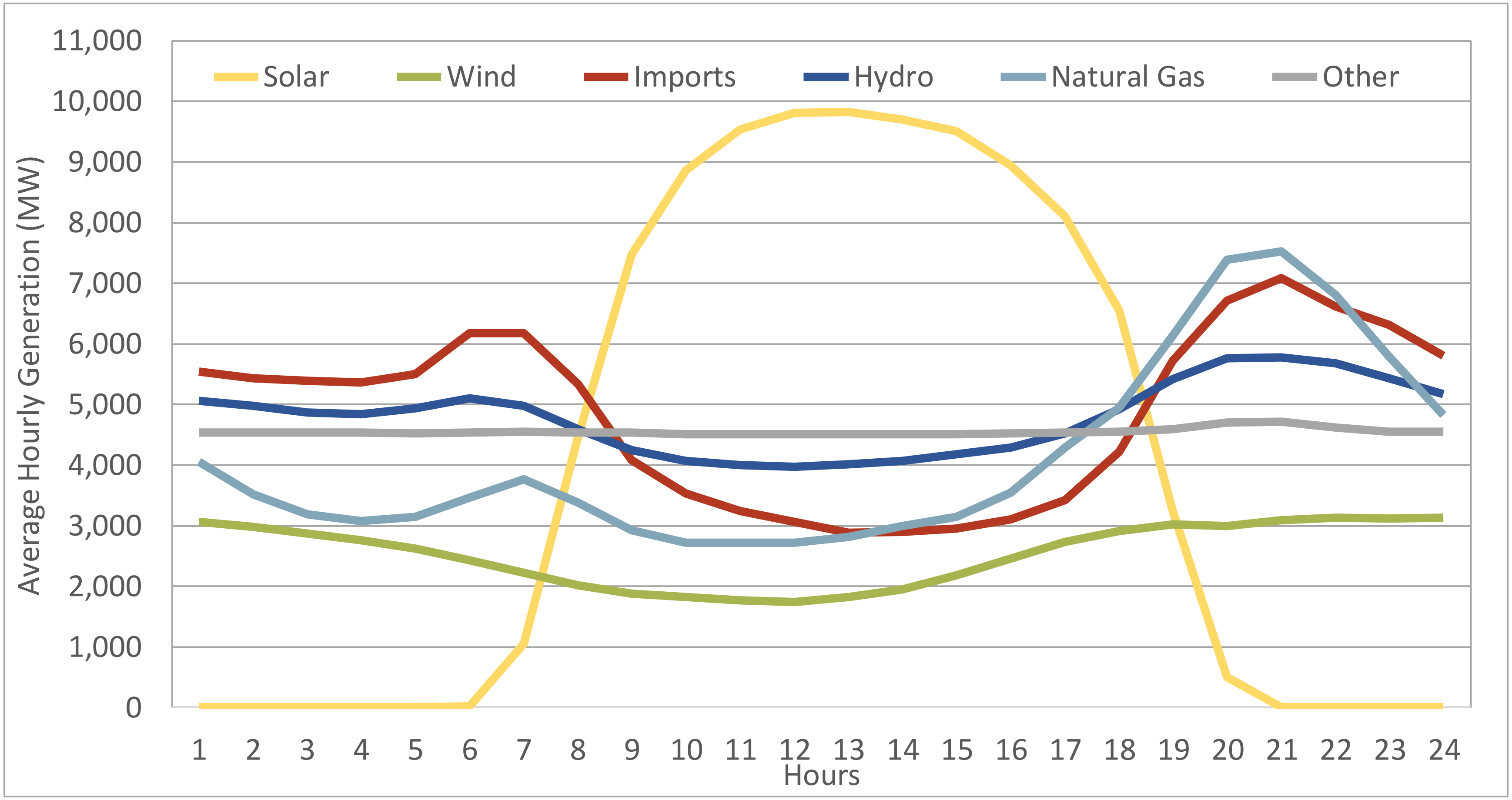


Hourly price-cost markup (Jan – Sep)

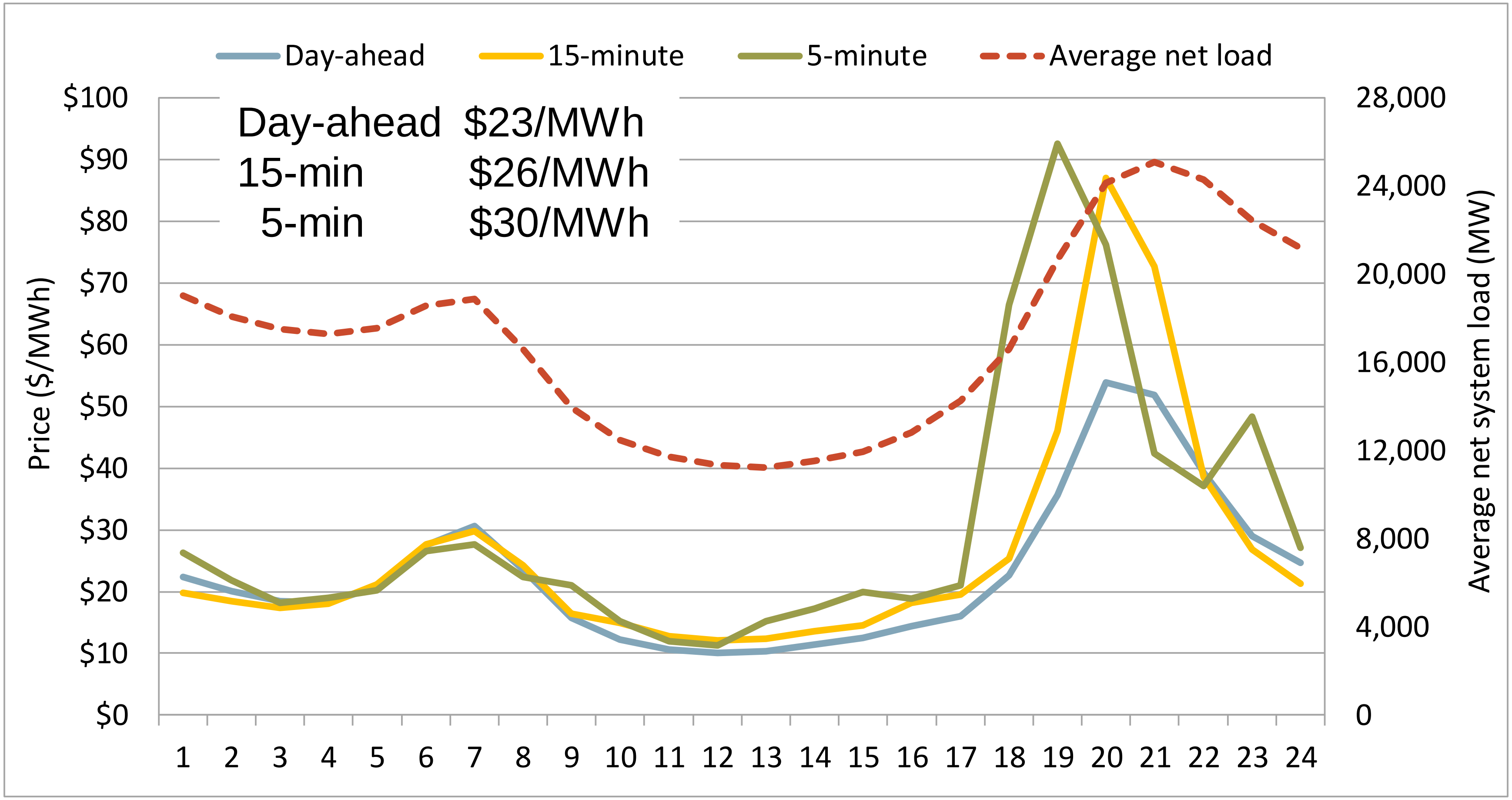


Appendix

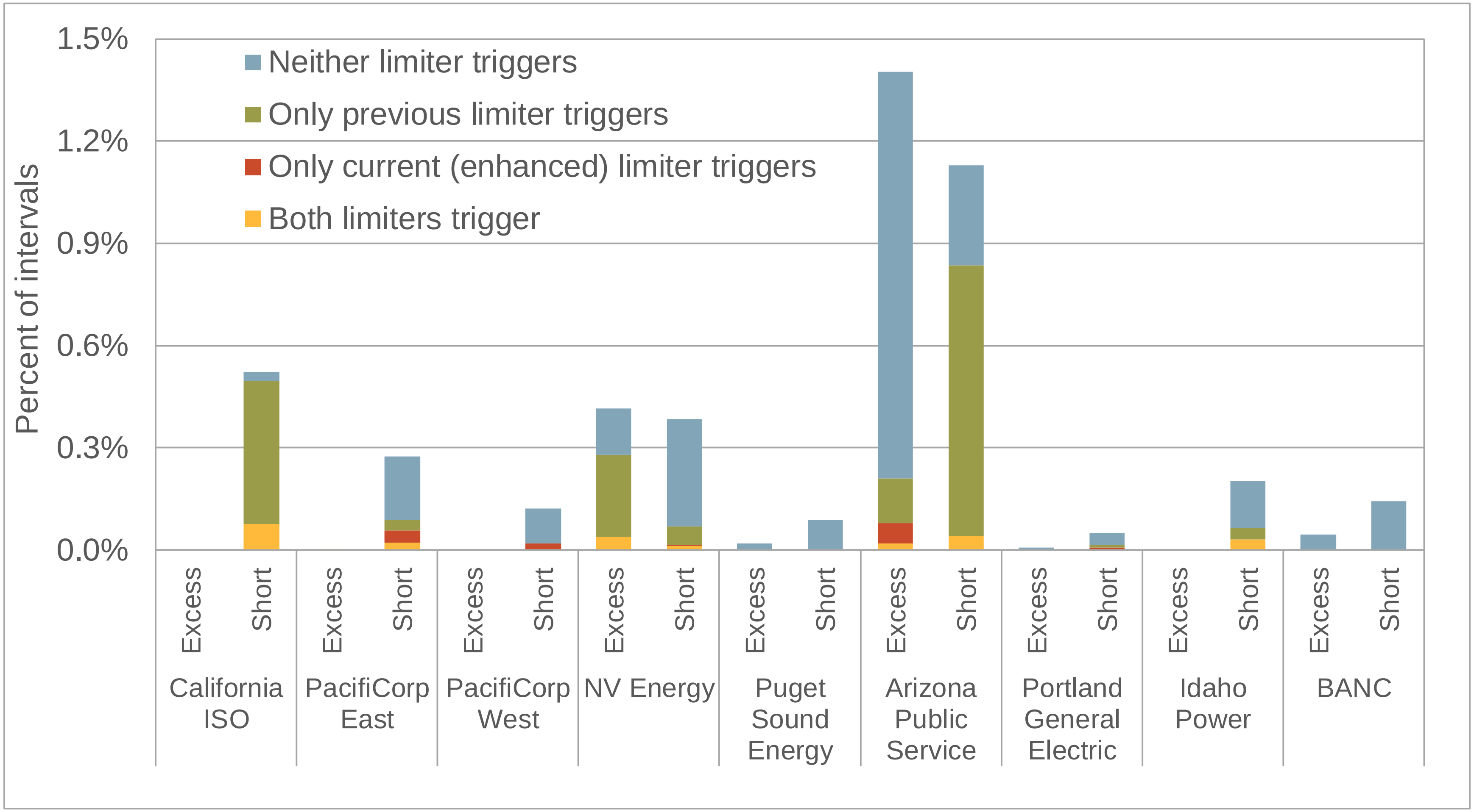
Variation in generation by fuel type, Q2 2019
Hourly variation driven by solar



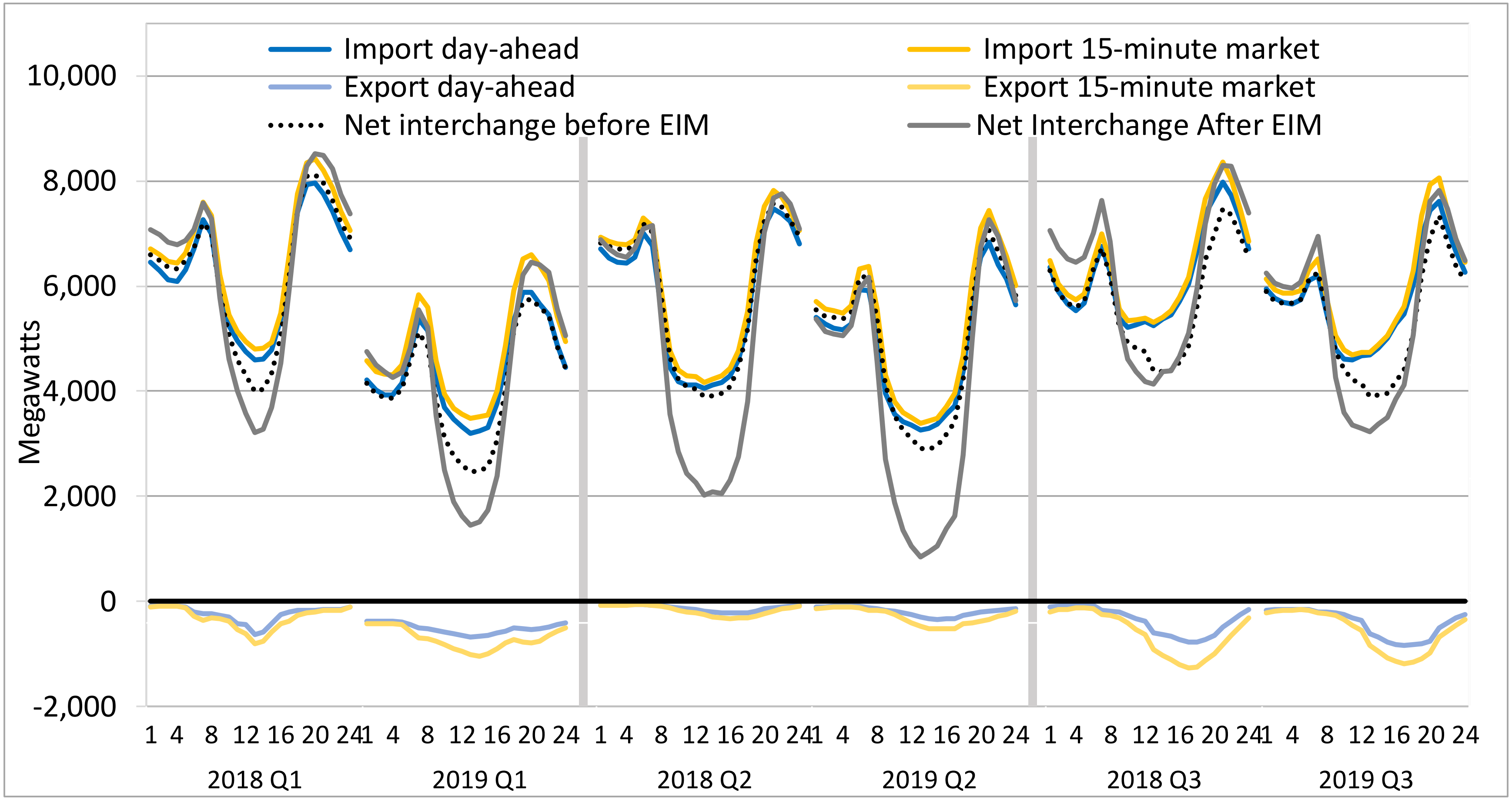
Average day-ahead prices down in Q2 2019 over Q2 2018



Frequency of load conformance limiter in the 5-minute market (April - June)

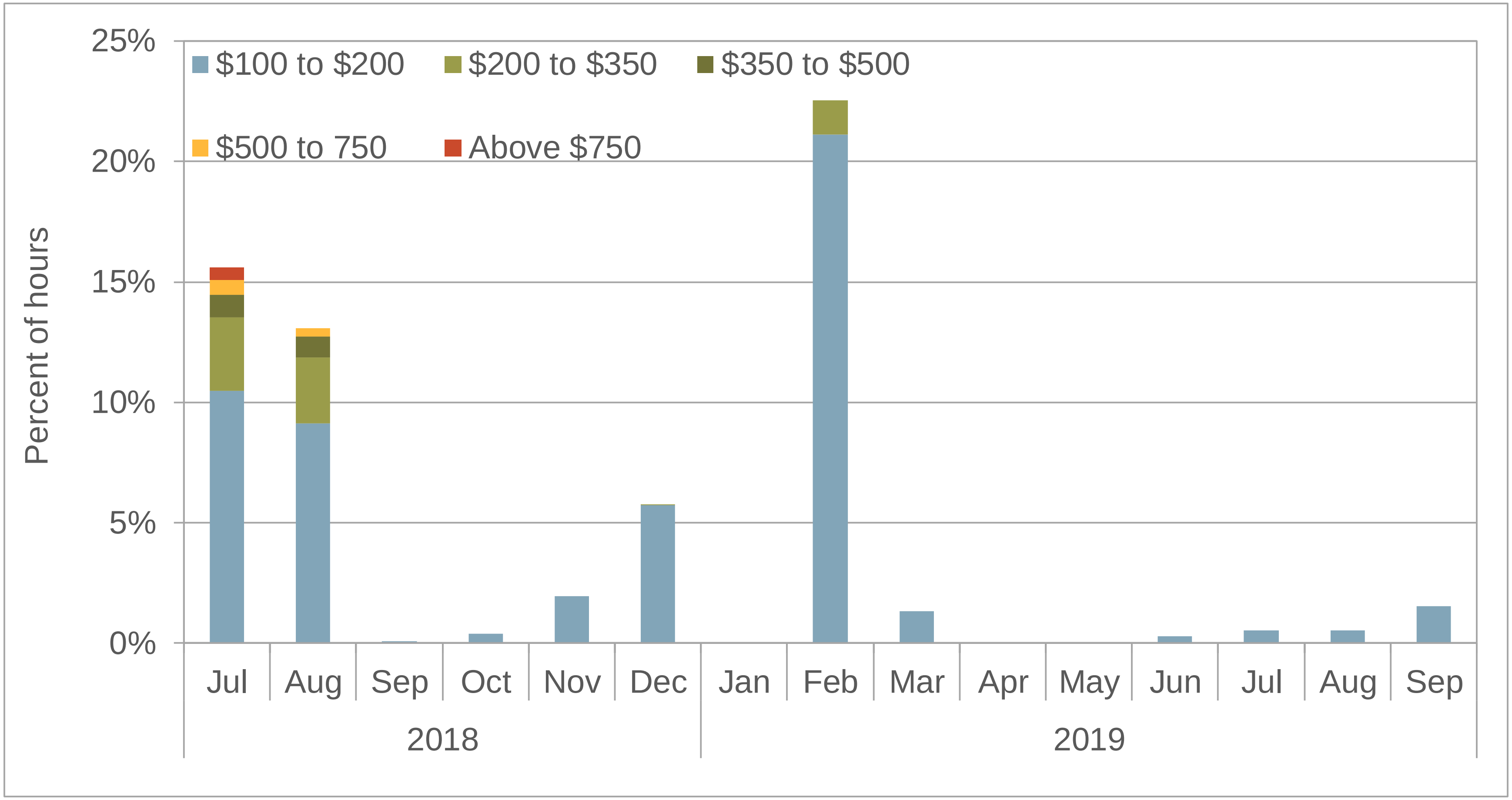


ISO continues to rely on imports to meet peak net load in ramping hours



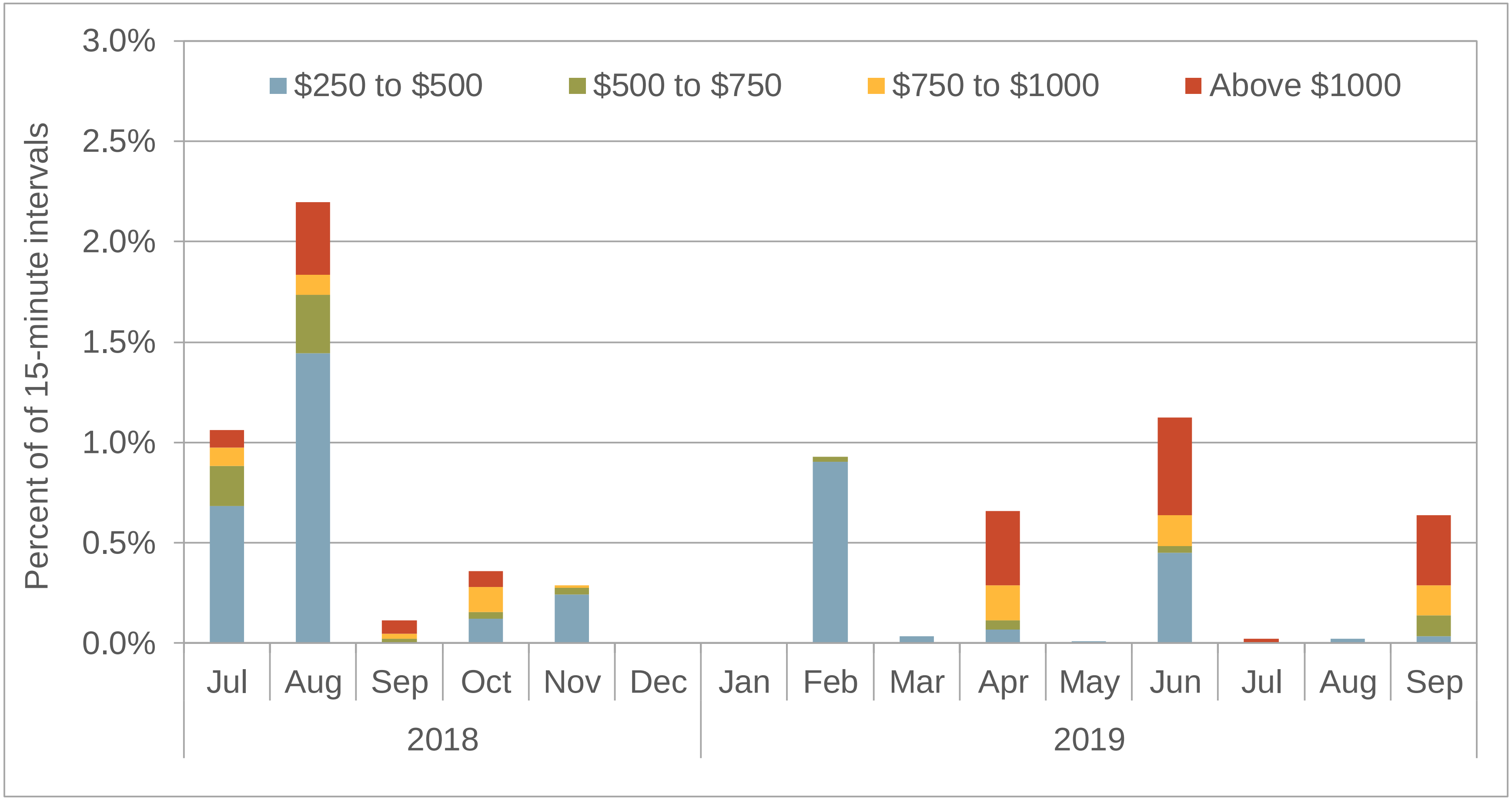
Very few high day-ahead prices in Q3 2019

Frequency of high day-ahead prices (MWh) by month

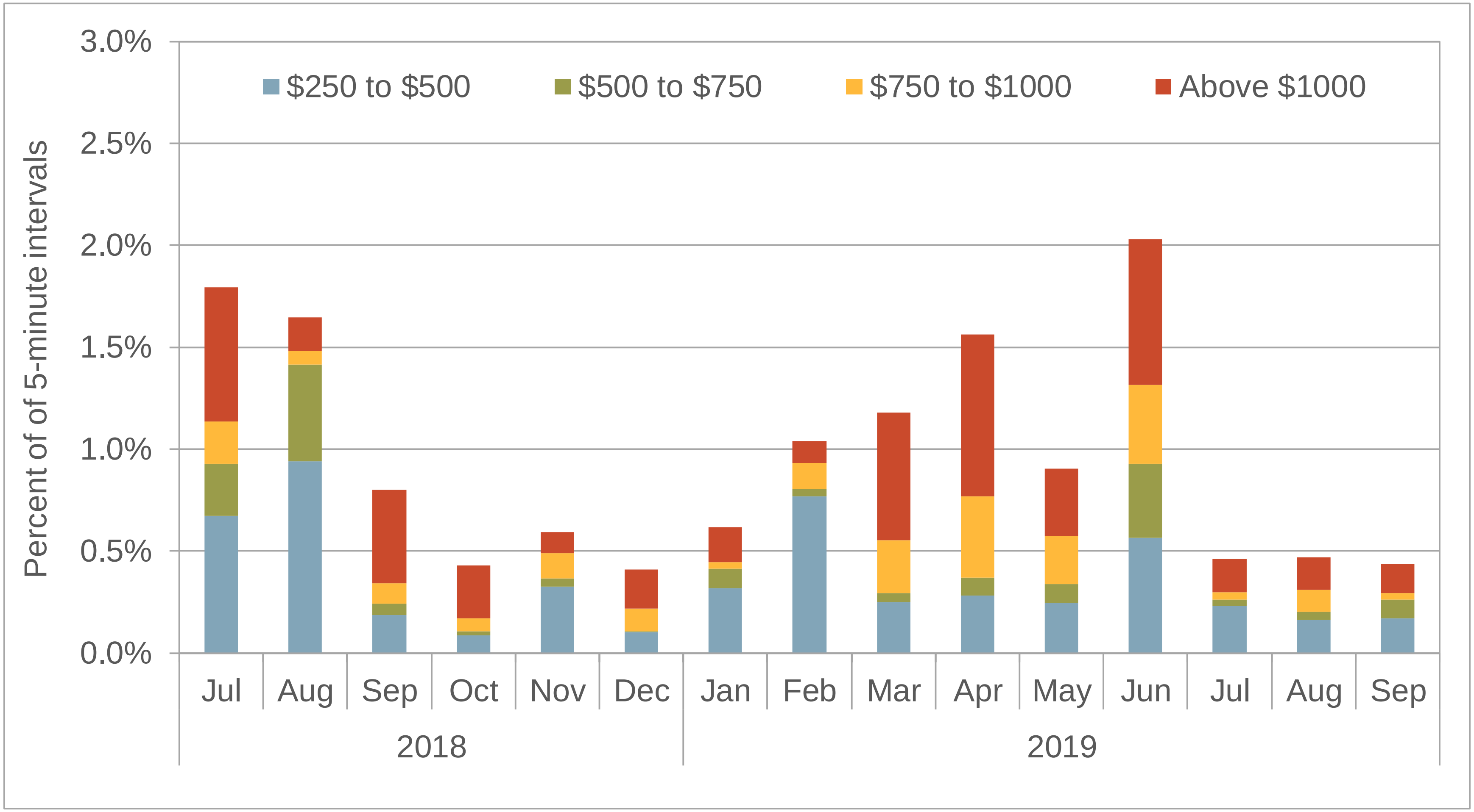


Few high 15-minute prices in Q3 2019

Frequency of high 15-minute prices by month (ISO LAP areas)

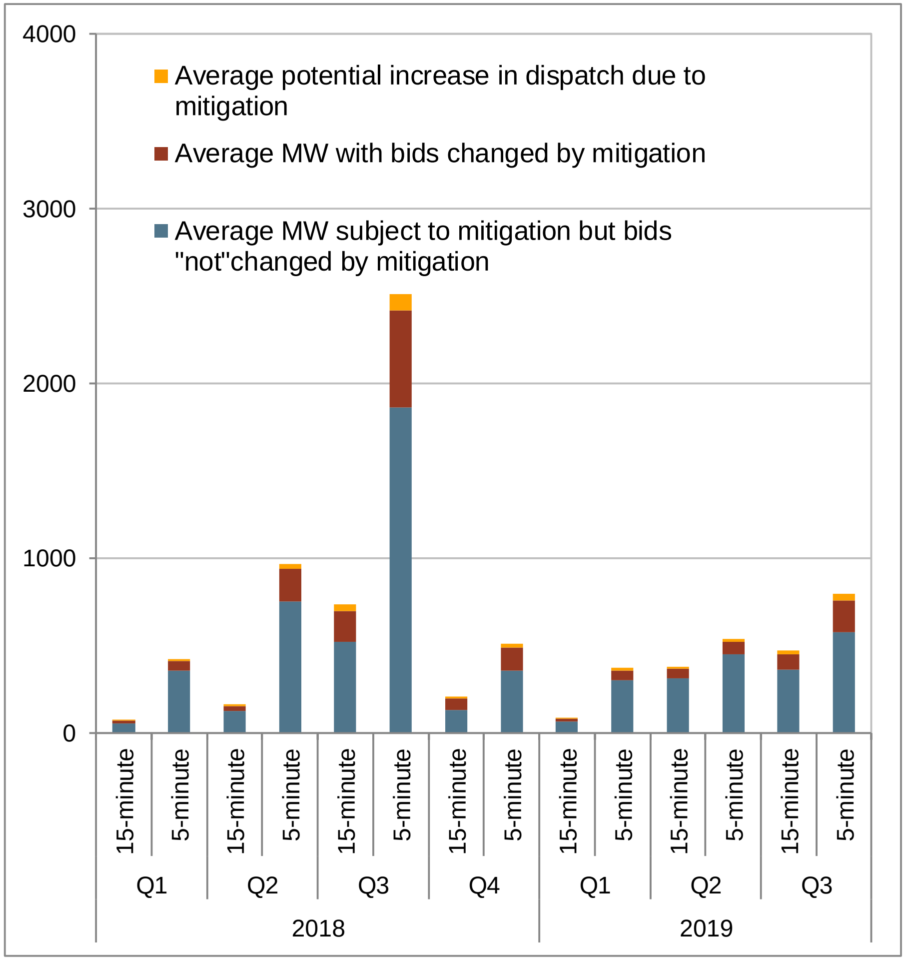


The ISO implemented changes to the load conformance limiter on February 27 which reduce impact of limiter

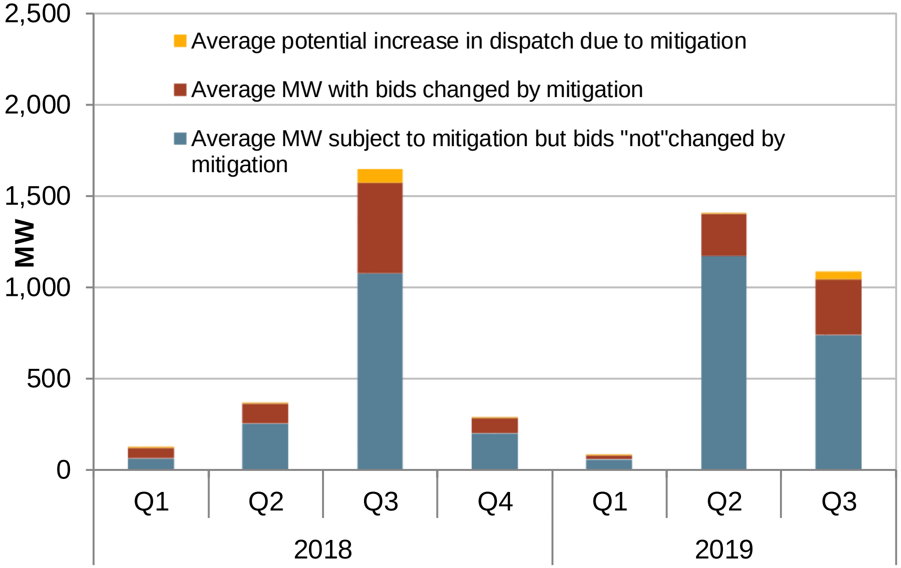


Energy bid mitigation had very minor overall impact on day-ahead and real-time energy dispatches

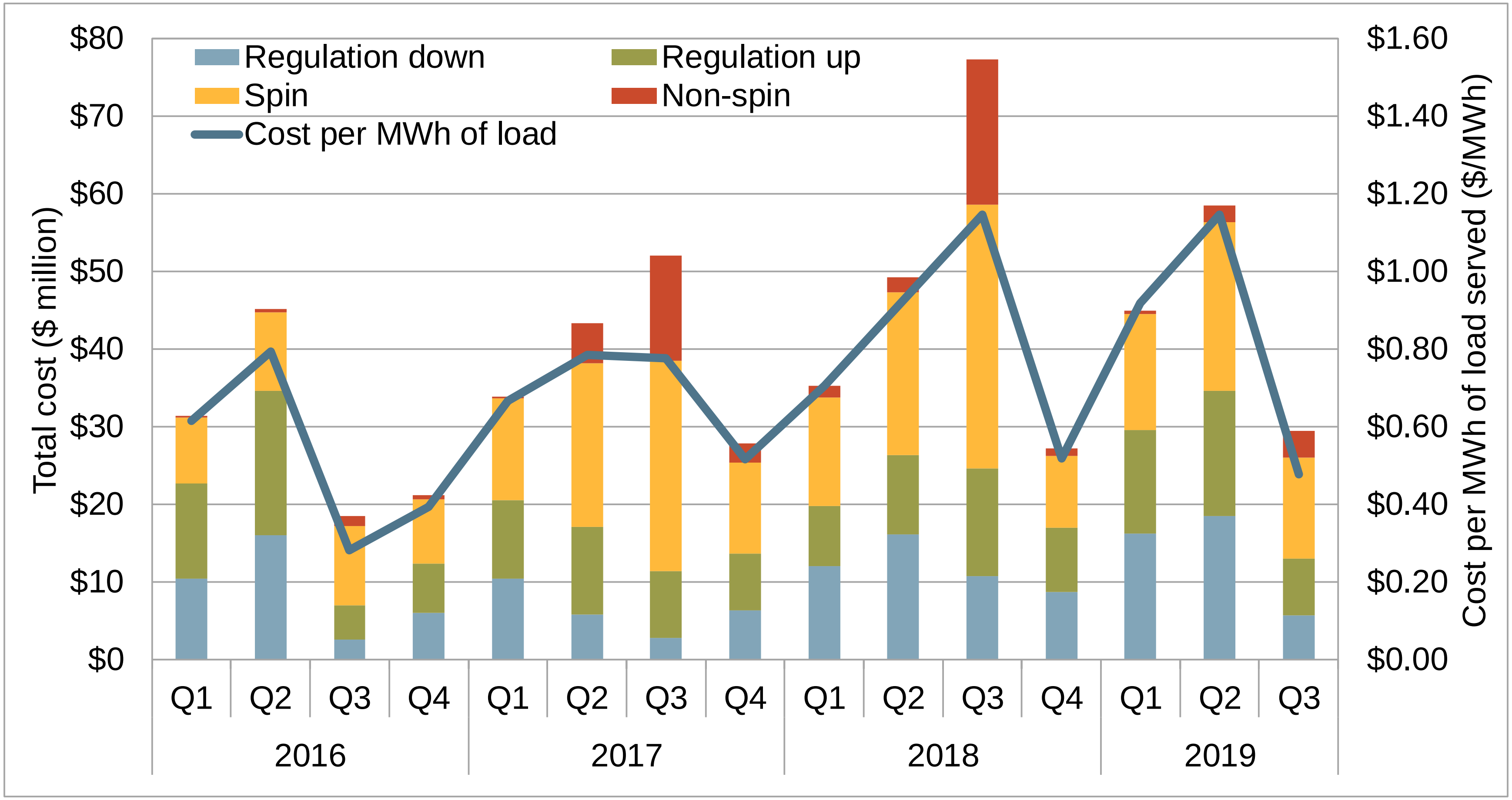
Real-time



Day-ahead



Ancillary service cost by product total $29 million



Average monthly day-ahead ancillary service requirements