California ISO | WESTERN ENERGY MARKETS

MSA Economics Symposium on Market Monitoring

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Overview

- Background on CAISO/WEIM market design
- Market power mitigation framework
- Measuring market power
- Role and impact of operator actions
- Bid cost recovery (BCR) payments
- Ancillary services
- Assessing congestion impacts on markets

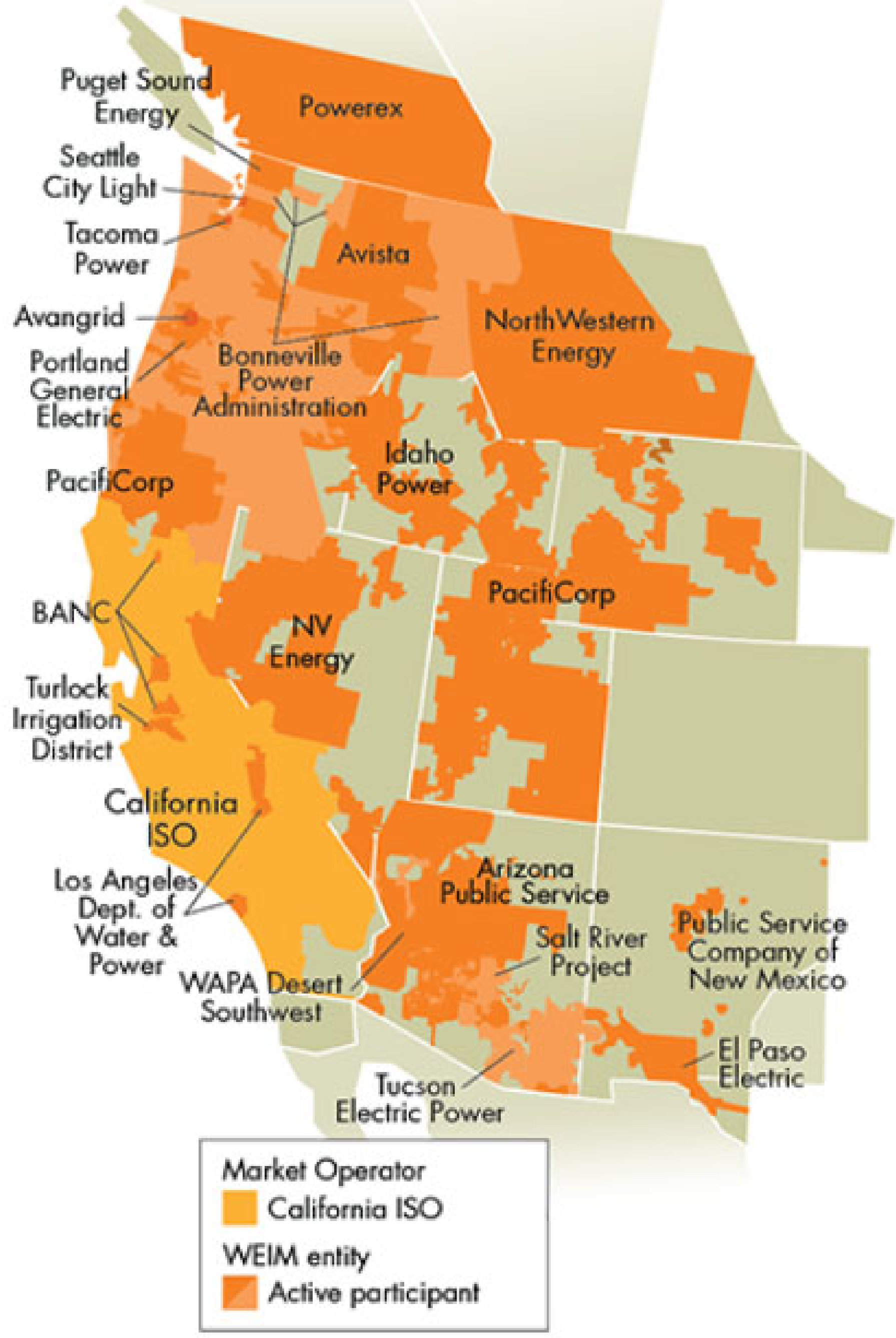
Please feel free to have questions and discussion as we go!

Western Energy Imbalance Market (WEIM)

- Allows balancing areas outside of the California ISO to participate in the real-time market (hour ahead, 15-minute and 5-minute)

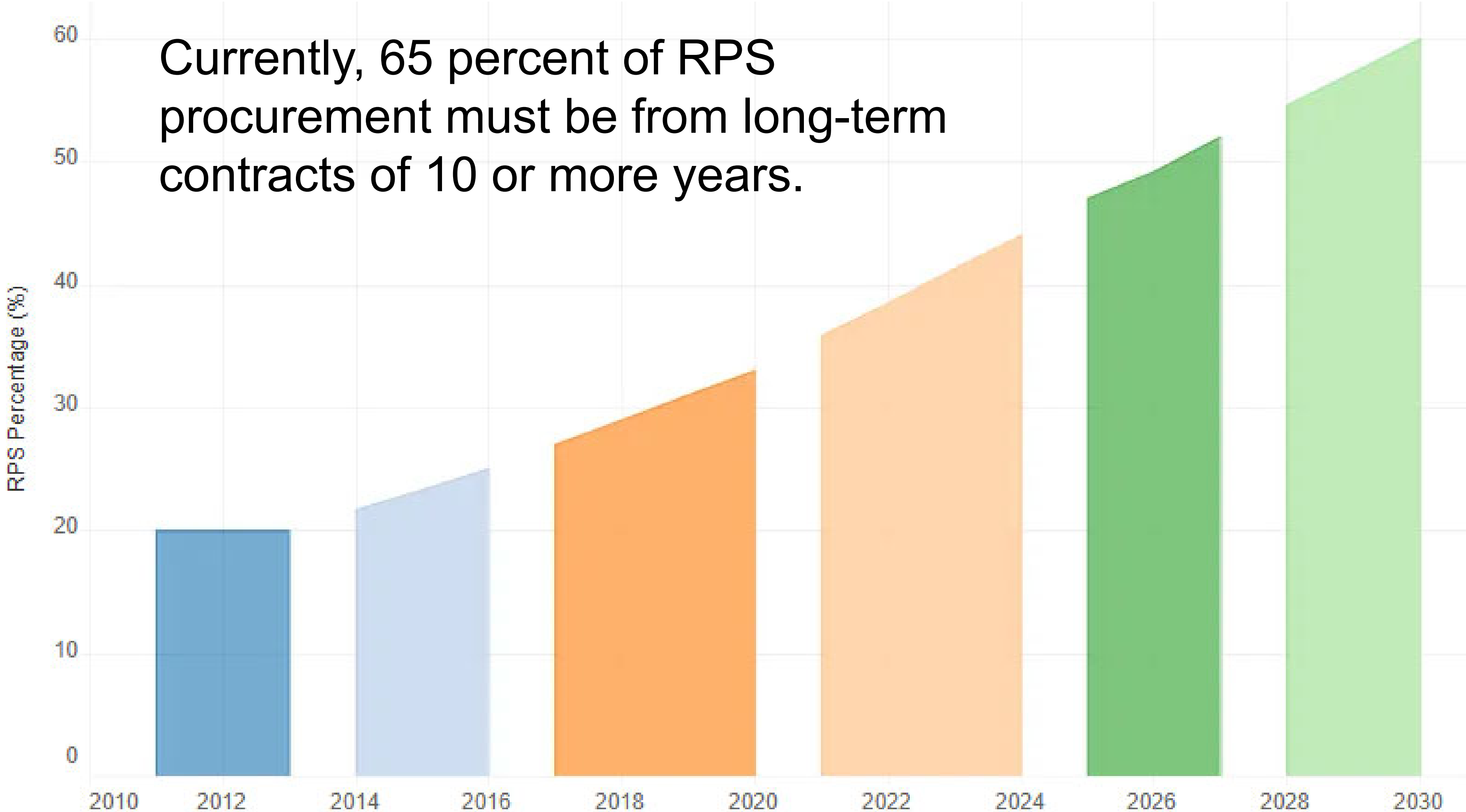
- Transmission capacity between areas allow market optimization to balance supply and demand across the footprint

- Dynamic transfers between BAAs in 15-minute and 5-minute market plays key role in balancing variable renewable energy sources

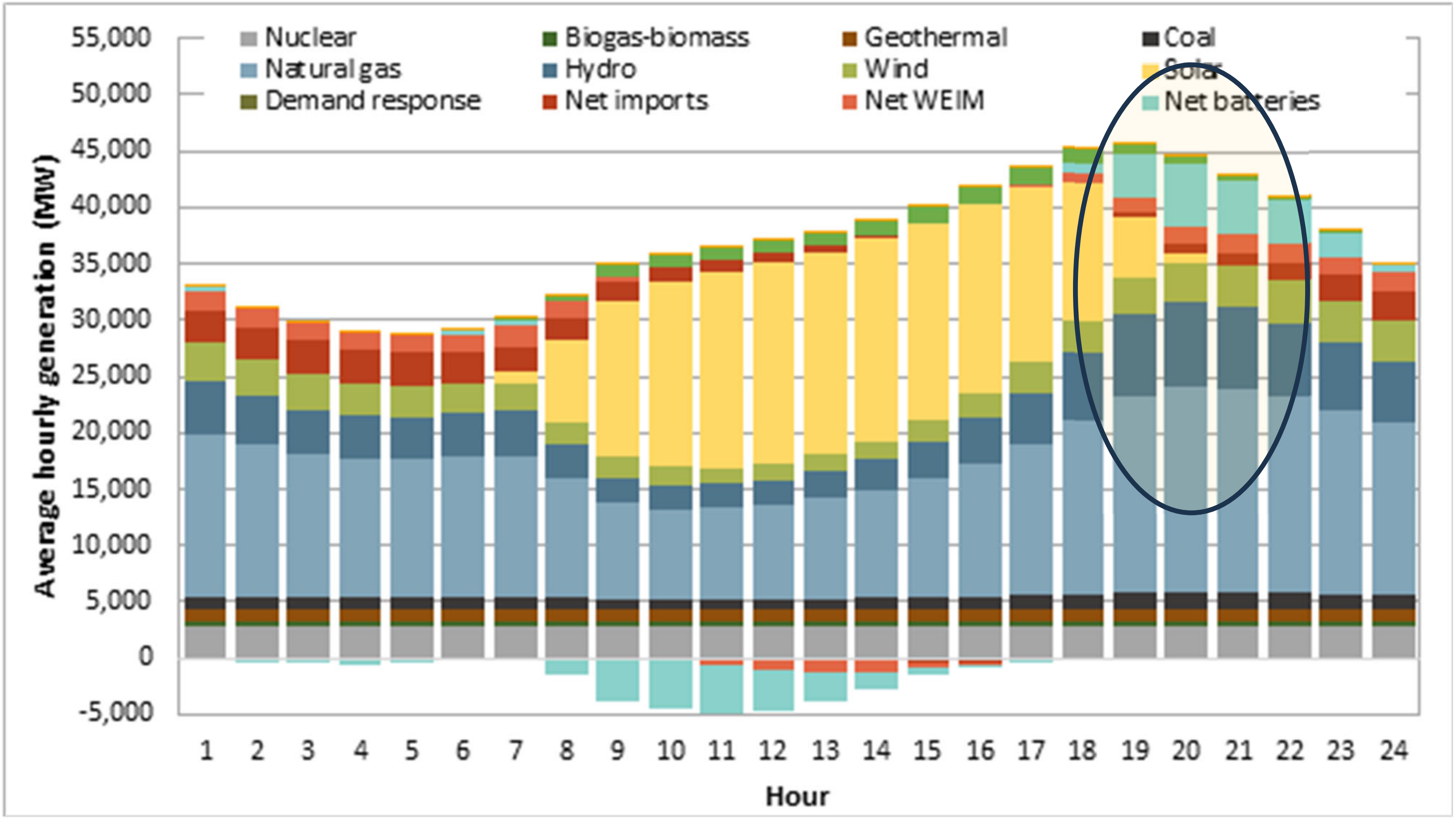


Renewable Portfolio Standards (RPS) have driven almost all new supply to be solar and battery storage.

Currently, 65 percent of RPS procurement must be from long-term contracts of 10 or more years.



Peak net load hours (18-22) now most important hours for reliability and market power issues



Average hourly generation in California (Q3 2024)

Supply planning and procurement

- California Public Utilities Commission (CPUC) set planning and procurement requirements for load serving entities (LSEs)
- California's Renewable Portfolio Standards (RPS) have driven almost all new supply to be wind, solar and battery storage.
- CPUC can authorize additional supply procurement activity needed in the following 1-3 years by a "central buyer"
- Shorter term capacity requirements met through California's Resource Adequacy (RA) program
  - LSE's capacity requirement = forecasted peak monthly load + 17% reliability reserve margin
  - Capacity self-provided or procured via bilateral contracts
  - Must offer requirement for all suppliers of Resource Adequacy capacity

Day-ahead and real-time market

	CAISO	WEIM
Day-ahead	Minimum Online Constraints (MOCs) Day-ahead Energy and Ancillary Services Market Residual Unit Commitment (RUC) Manual commitments	*Extended Day-Ahead Market* *Planned 2025*
Real-time	Manual energy dispatches Manual short-start commitments/ de-commitments Manual upward adjustment of system load used in market model	Manual actions by each BAA
	Resource Sufficiency Evaluation Hour-Ahead Scheduling Process (hourly imports/ exports) 15-minute market (including dynamic transfers) 5-minute market (including dynamic transfers)	Resource Sufficiency Evaluation Base Schedules (self-scheduled) 15-minute market 5-minute market

Market power mitigation framework

Market power mitigation framework

- Must-offer requirement for Resource Adequacy capacity
  - Mitigates physical withholding
  - Submitted bids subject to local market power mitigation procedures
- System wide bid cap
  - $1,000/MW “soft” bid cap normally in effect
- Local market power mitigation
  - Triggered when congestion occurs on structurally uncompetitive constraints (cost+10% or special *opportunity cost* bid caps)
- Bid caps for start-up and minimum load bids
  - Most gas units not owned or controlled by LSEs submit bids at the cap (125% of costs(125%)
- Mitigation for manual out-of-market dispatches
  - Mitigated depending on reason logged by grid operator

Local market power mitigation

- Automated approach day-ahead market and real-time markets
  - Run full market optimization with unmitigated bids
  - Test congested constraints for structural market power
  - Bids for resources that can relieve congestion on uncompetitive congestion are subject to bid mitigation
  - Run market optimization with mitigated bids
- Bid mitigation
  - Market bids capped using cost-based energy bids (plus 10% adder)
  - *Opportunity cost* bids for hydro, batteries, other limited use units
  - Competitive system price used as floor for mitigation

In practice, very few bids are actually lowered and impact of mitigation on dispatch is extremely limited

Conduct and impact test framework

- Used by ISO-NE, NYISO, MISO and SPP
- Conduct thresholds vary based on market power concerns:
  - $100 per MWh for constraints that are not chronic
  - $10 to $100 for chronically constrained areas
  - $25 per MWh for offers resulting in uplift
- Price impact of bids failing conduct estimated before market run:
  - Price impact thresholds same as the conduct thresholds for different constrained areas (eg $10 to $100/MW)
- DMM concerns with conduct and impact approach
  - Chronically constrained areas must be defined in advance (but congestion is very dynamic)
  - Suppliers can exercise market power up to conduct and impact test thresholds.
  - Calculating price impact with market software each real-time interval seems challenging?
  - Start-up and minimum load bids only mitigated *ex post,* which does not mitigate economic withholding of capacity that is not committed due to high bids

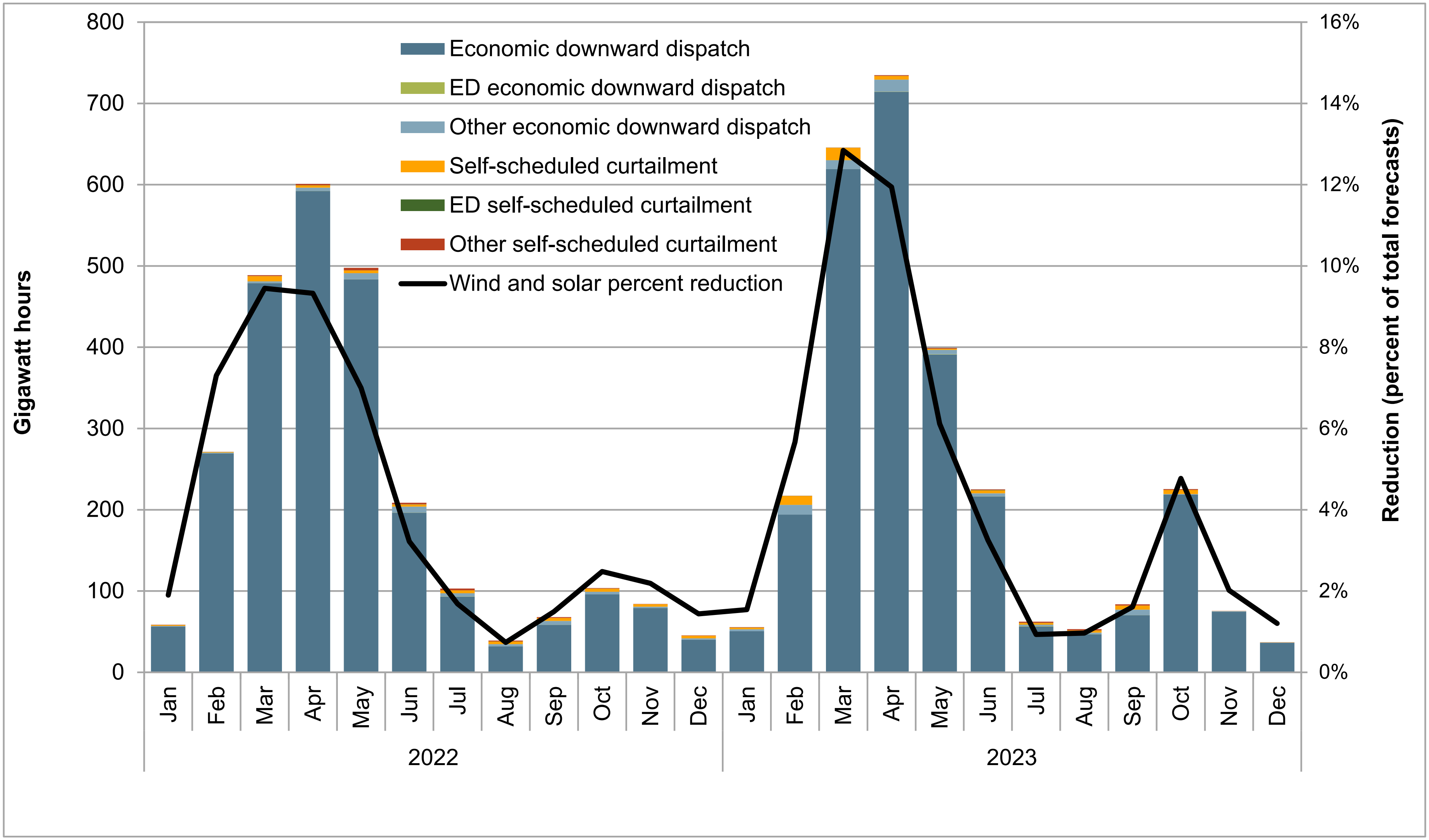
Gaming of bid cost recovery (BCR) payments

- Gaming opportunities stem from several market features:
  - Sequential day-ahead and real-time markets
  - Differences in day-ahead and real-time market models
  - Day-ahead and real-time BCR calcs are separate
    - profits in one market not netted off losses in other market
- Generators can profit by:
  - Getting committed in day-ahead (or “bridged” to stay on-line), and paid BCR to cover full commitment and minimum load costs (+25%)
  - Keep all net revenues from energy sold in real-time market
- Dec game
  - Getting scheduled in day-ahead and keeping those revenues
  - Getting dec’d out-of-sequence in real-time, and getting paid BCR for difference in LMP and very low bid price.

Mitigating decremental energy

- The “dec game” in California dates back to 1998 (Enron)
  - Self-schedule or bid low to get scheduled in day-ahead or hour-ahead market
  - Submit bid to “buy back” energy at $0 or negative price
- CAISO does not apply mitigation to decremental energy dispatches, but has -$150/MW bid floor
  - Value of various renewable energy tax credits and Renewable Energy Credits (RECs) = ~$30
- Beginning ~10 years ago, CAISO took actions to increase bidding of decremental energy by wind and solar
  - Required wind and solar projects to install necessary equipment
  - Worked with CPUC and LSEs to ensure bi-lateral contracts allow for economic curtailment (no *must-take* contracts)

Almost all solar and wind curtailment is now done based on economic bids (usually >= -$30/MW)

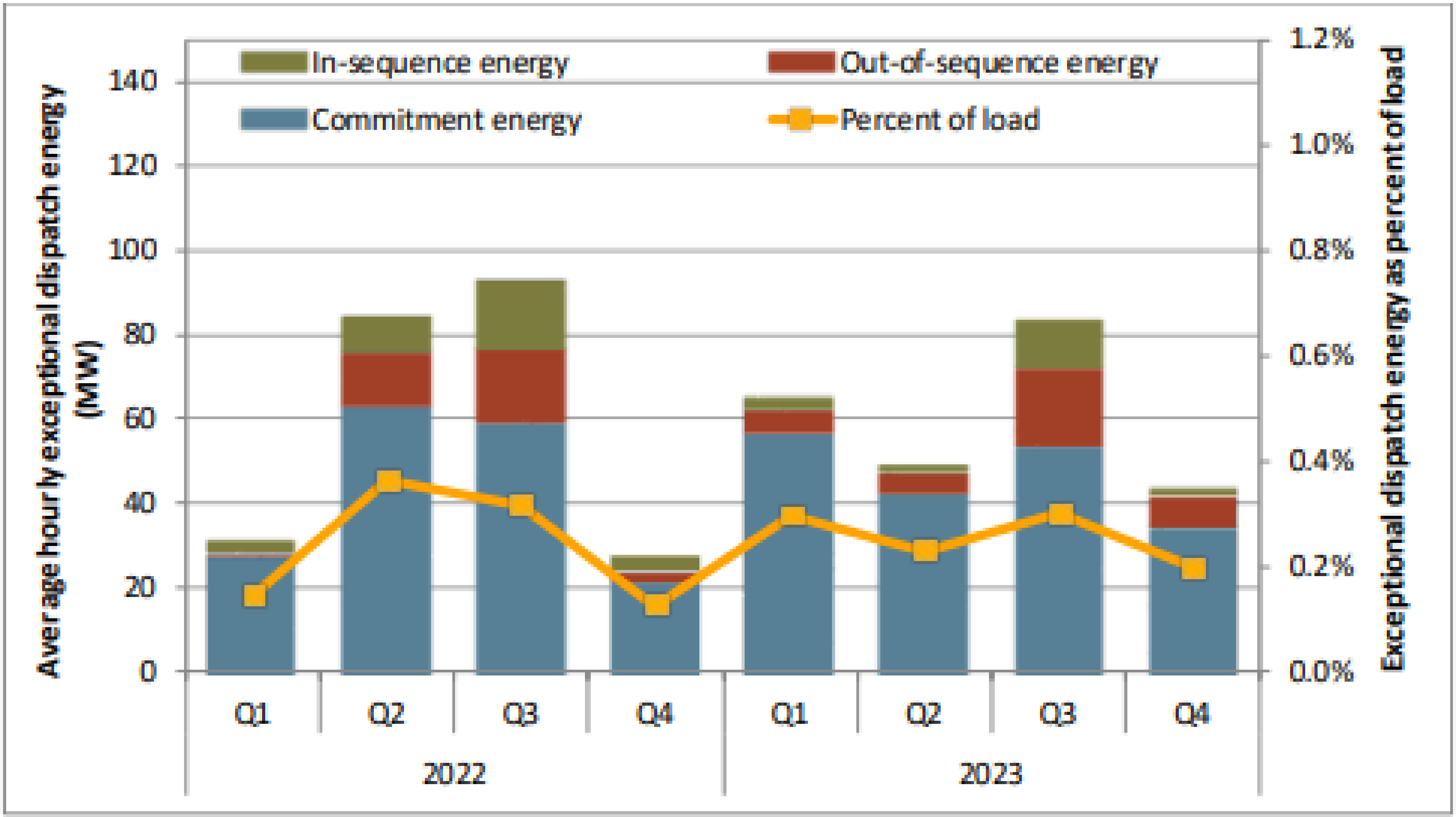


Mitigation of manual dispatches (out-of-merit order)

- DMM closely tracks manual dispatches for unit commitments and energy (aka “exceptional dispatches”)
- Monitoring of manual dispatches and costs serves several purposes:
  – Feedback to grid operators on trends, costs, etc.
  – Can be indicative of gaming or a market software or operational issue
  – *Ex post* mitigation of manual dispatches depends on how operators log the reasons for dispatches
- DMM has worked hard over the years to gain regulatory approval for mitigation of specific categories of dispatches, and to ensure correct logging tools and procedures.

DMM closely tracks manual dispatches (called “exceptional dispatches” by CAISO)

Figure 7.1 Average hourly energy from exceptional dispatch



Ex post mitigation of manual dispatches depends on how operators log the reasons for dispatches

Figure 7.2 Average minimum load energy from exceptional dispatch unit commitments

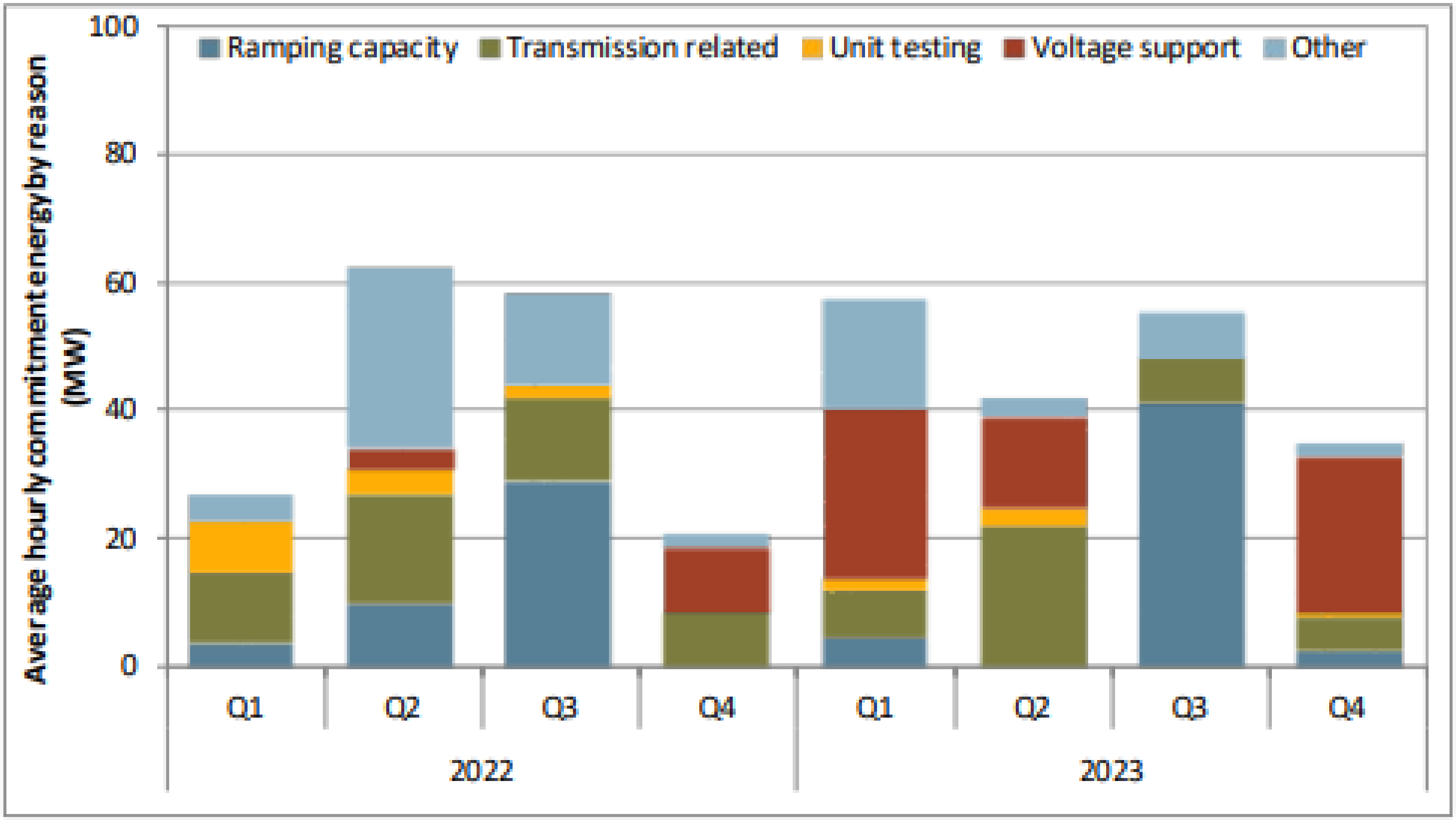
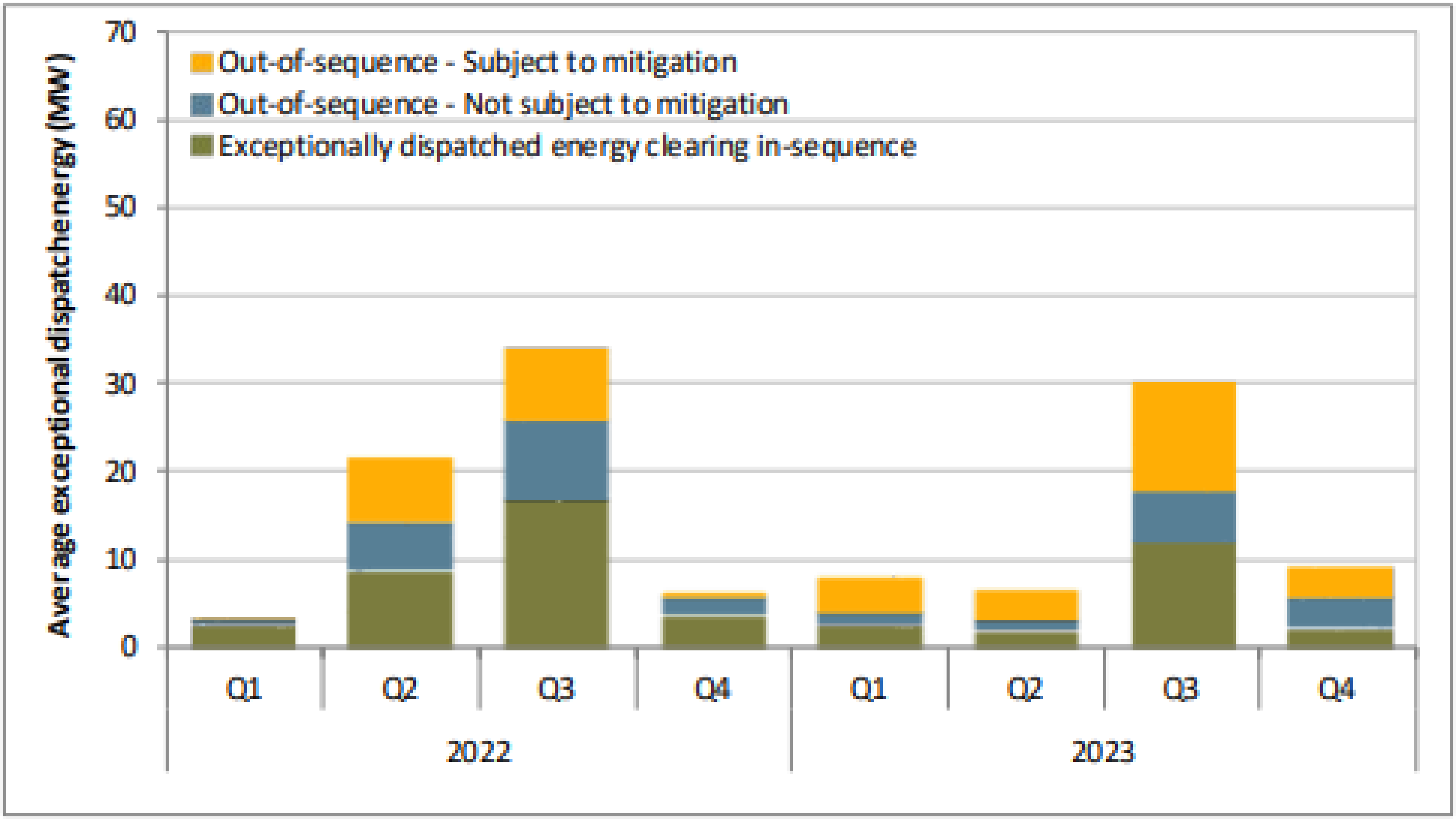


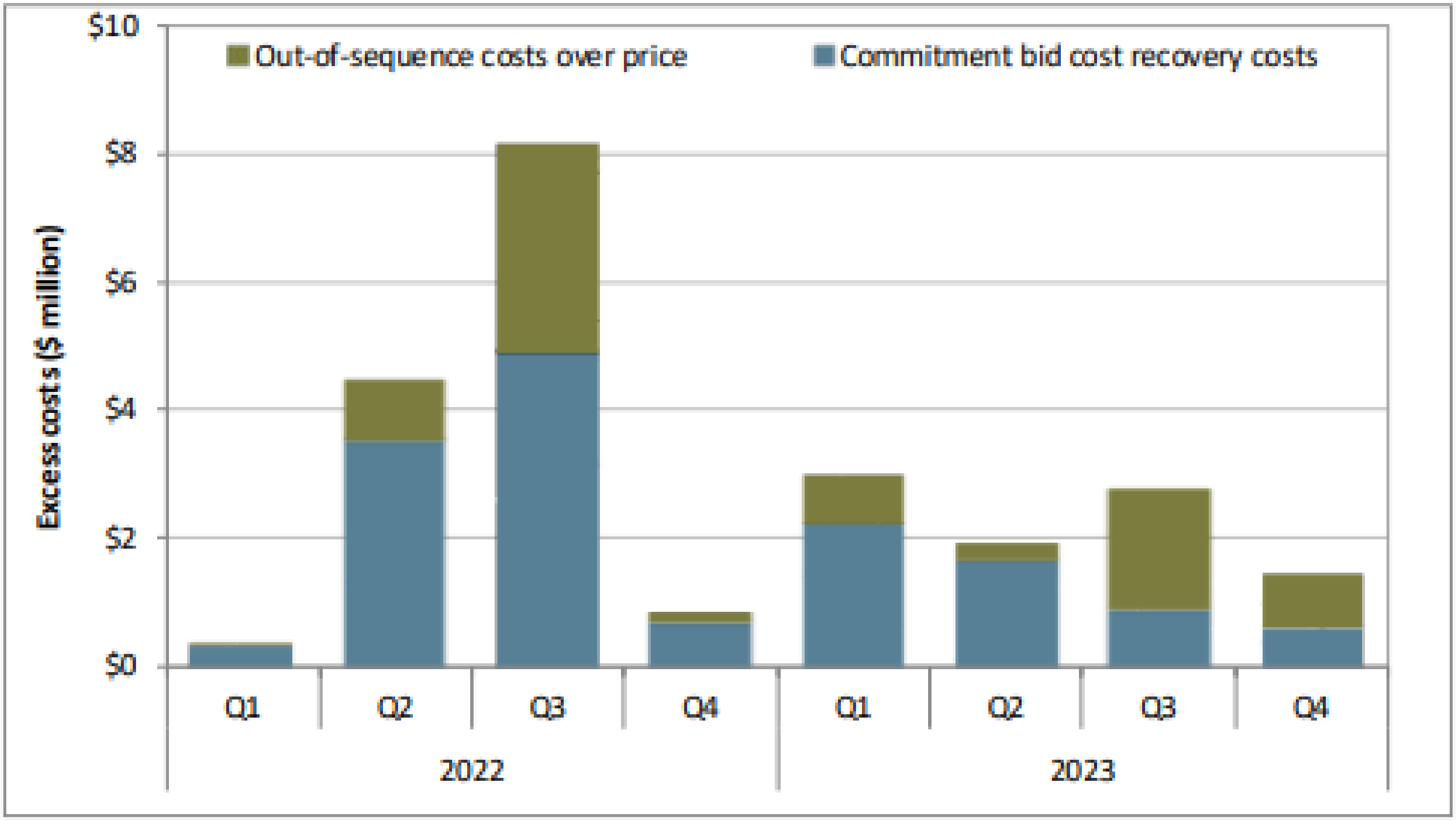
Figure 5.9 Exceptional dispatches subject to bid mitigation



DMM reports provide feedback to grid operators

If manual dispatch costs are high, grid ops reviews the cause, etc

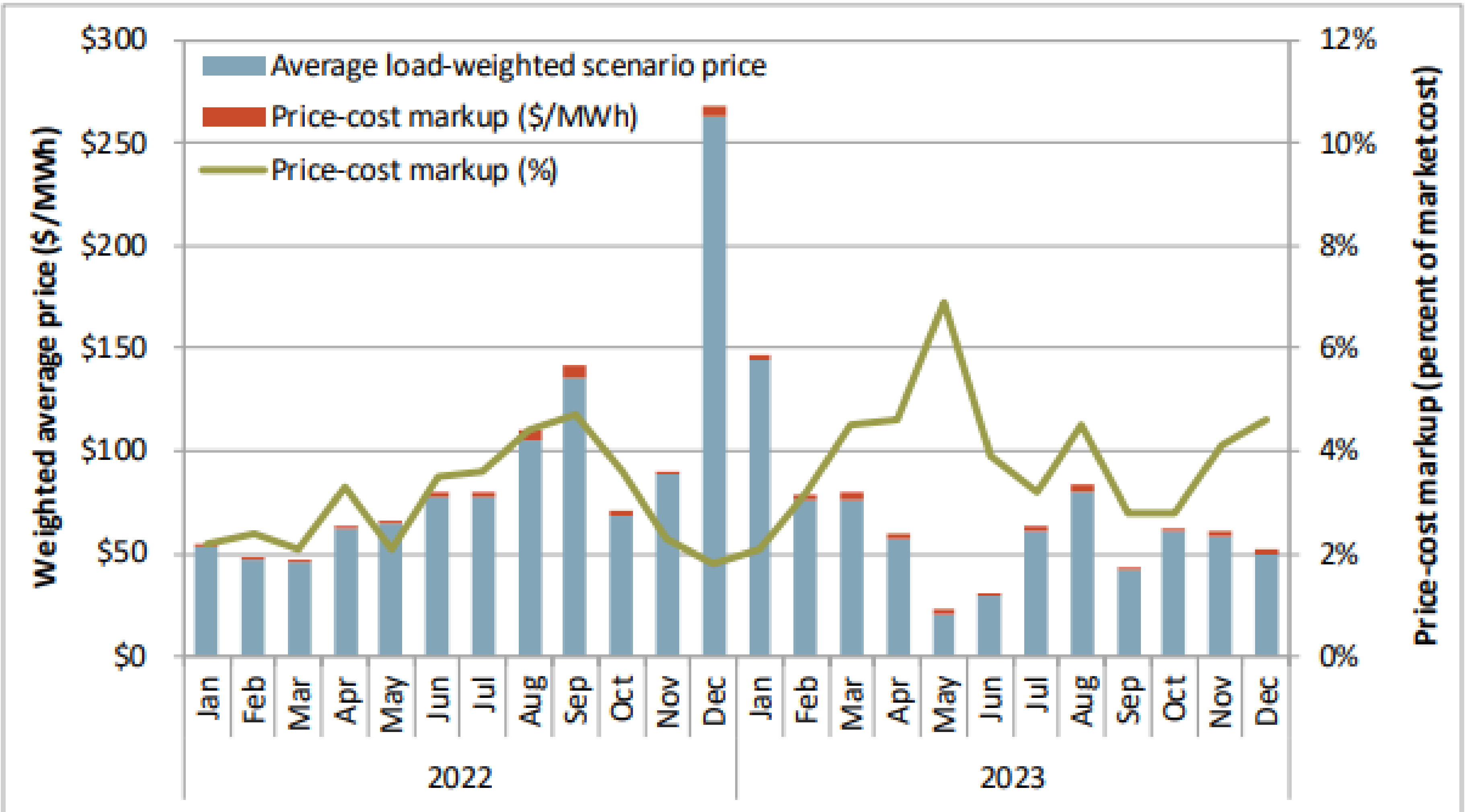
Figure 7.4 Excess exceptional dispatch cost by type



Assessing market power and performance

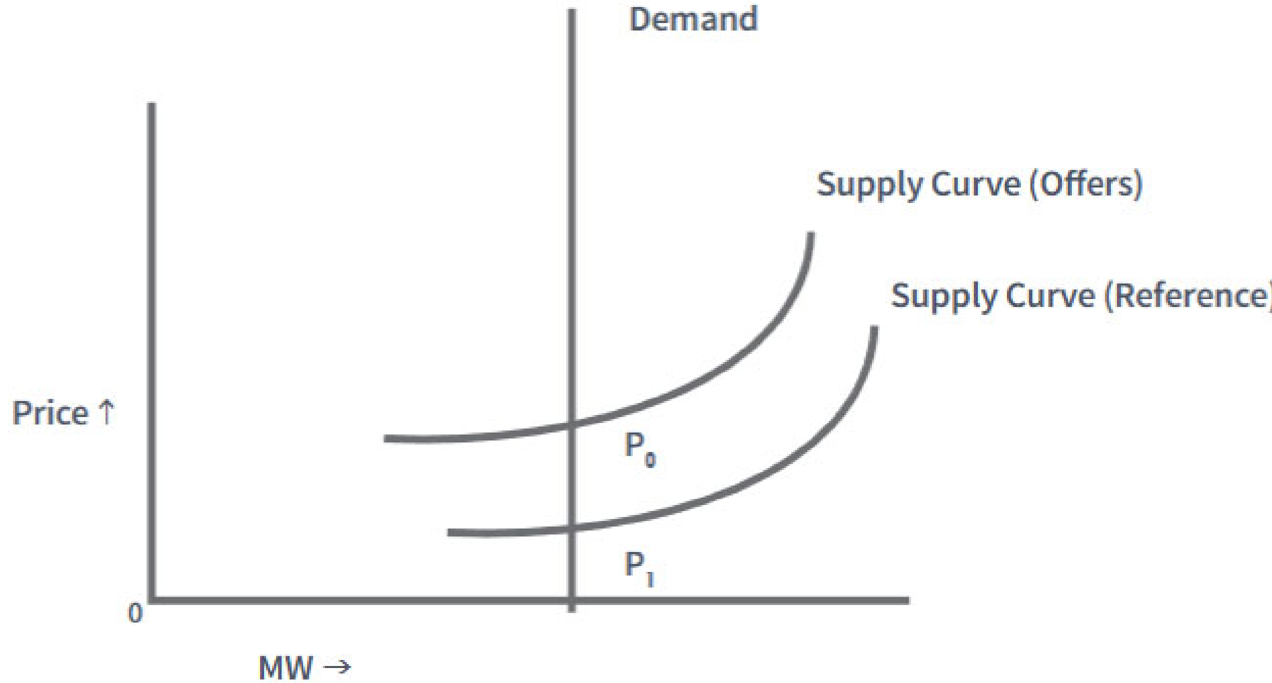
DMM has used cost-based run of day-ahead market model to assess price-cost markup -- this can be extremely complicated and has numerous problems (virtual supply/demand, renewable energy only scheduled in real-time, etc)

Figure 2.2 Day-ahead market price-cost markup – competitive baseline scenario[106]



Standard FERC price cost markup metric and its problems

- Uses real-time system supply stack only
- Includes undeliverable supply due to transmission constraints



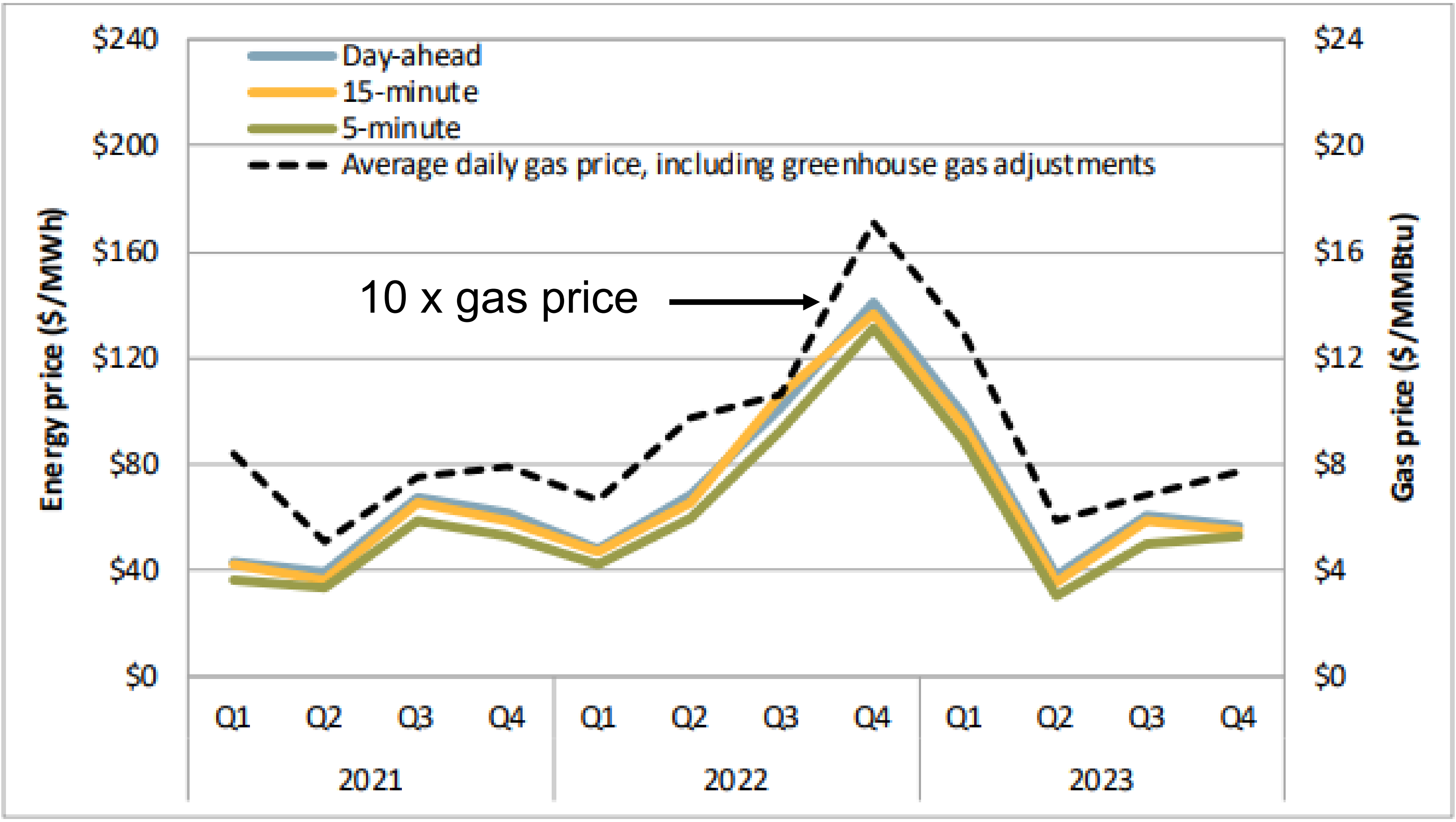
- If uses uncommitted units, may overestimate supply
- If only uses committed units, may underestimate
- Judgment needed for marginal cost and supply of numerous types of resources

Other price-cost markup metrics and their problems

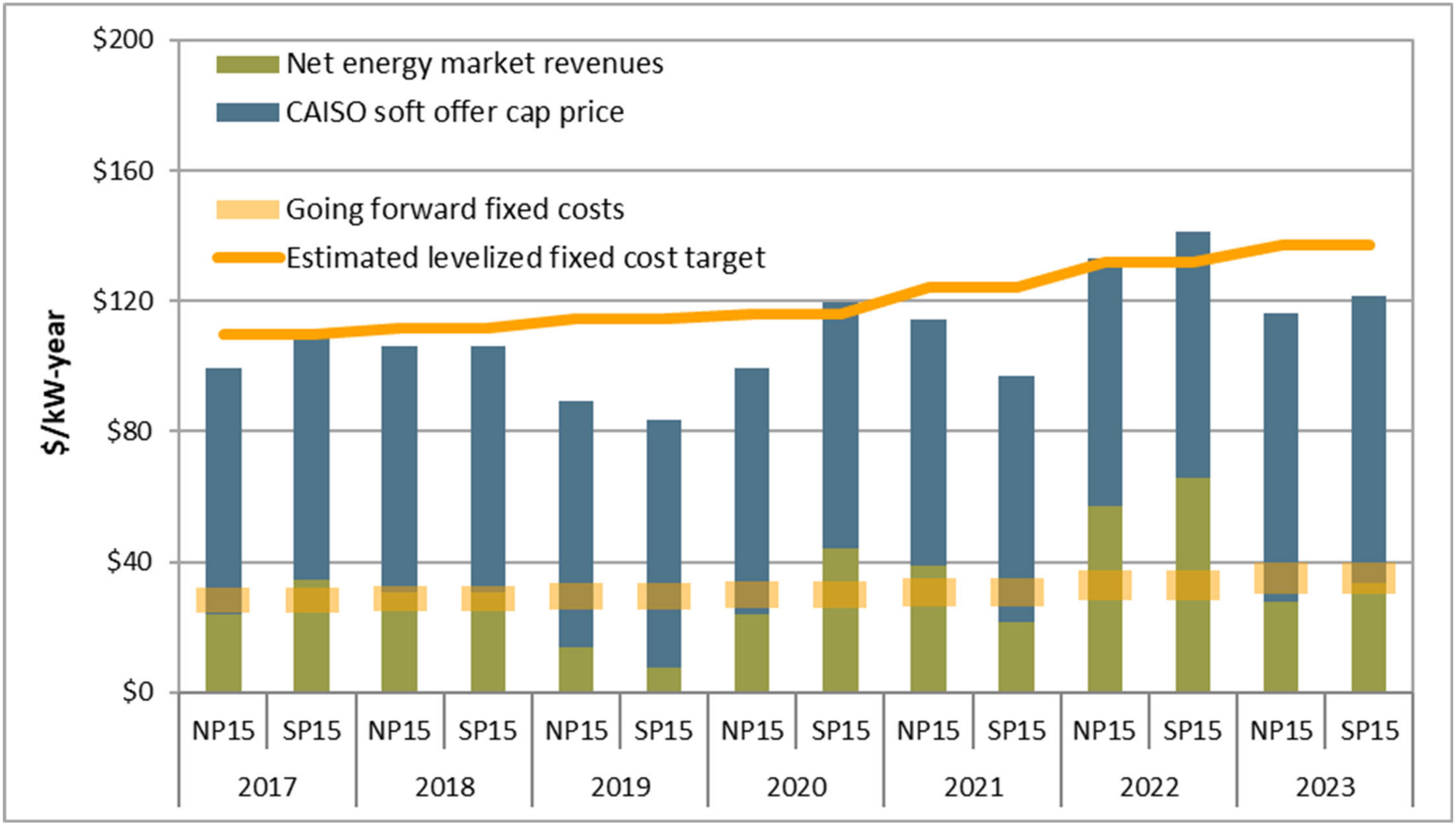
- ISO New England
  – Day-ahead: Simulation model…like CAISO?
  – Real-time: Seems to be standard FERC metric
- MISO
  – "Simulated" marginal price based on cost-based and offer-based bids…
- PJM and SPP
  – Price cost markup of just marginal unit(s)
    - Misses economic withholding of lower cost units to allow higher cost unit to set price
    - Hard to identify actual marginal units in LMP markets with many system and unit constraints

Overall average prices track closely with gas costs under most conditions – although batteries, imports and virtual supply are often marginal

Figure 2.4 Average quarterly prices (all hours) – load-weighted average energy prices

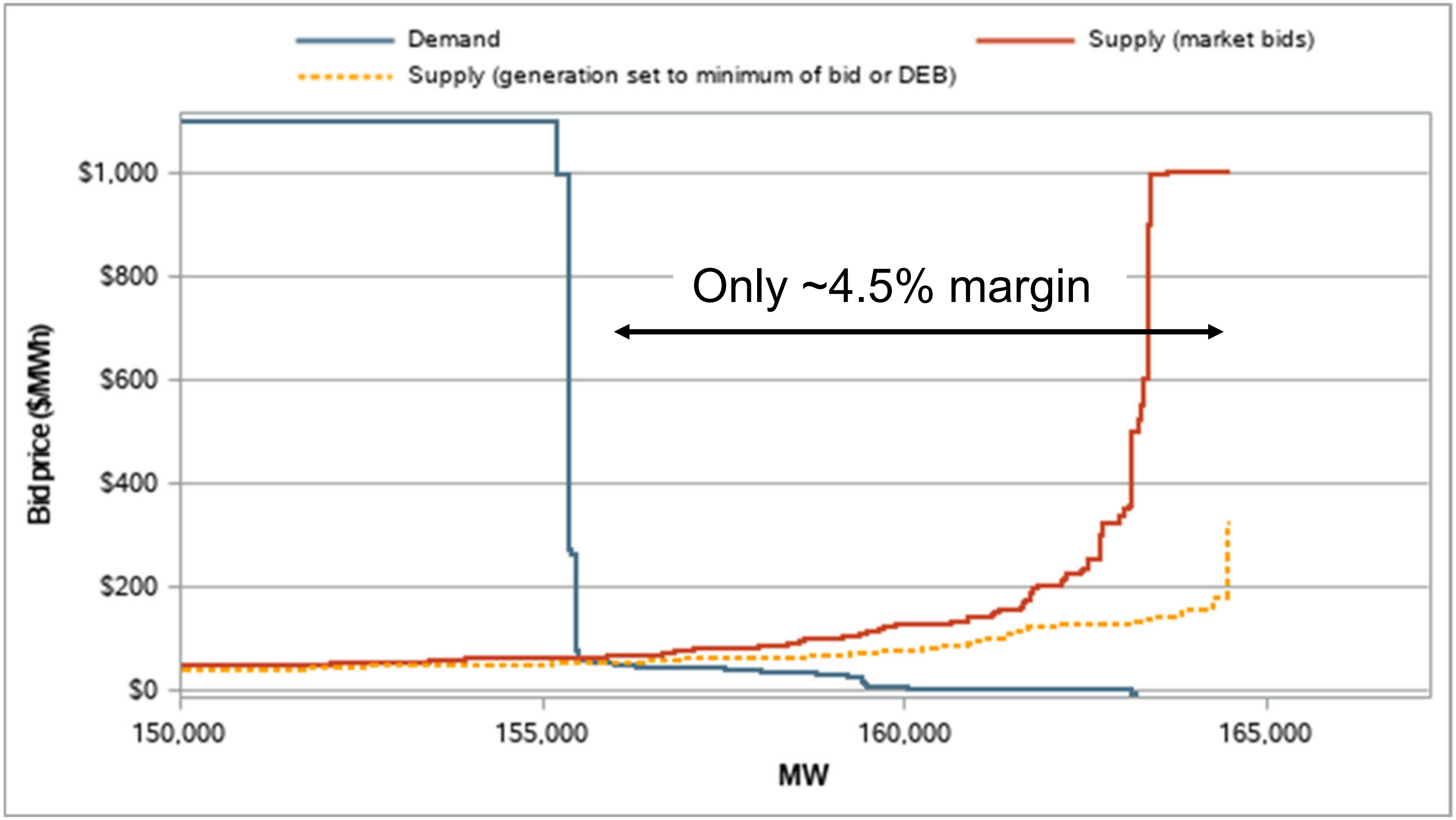


When prices are highly competitive, some kind of capacity payment or long-term contract is needed to cover fixed costs.

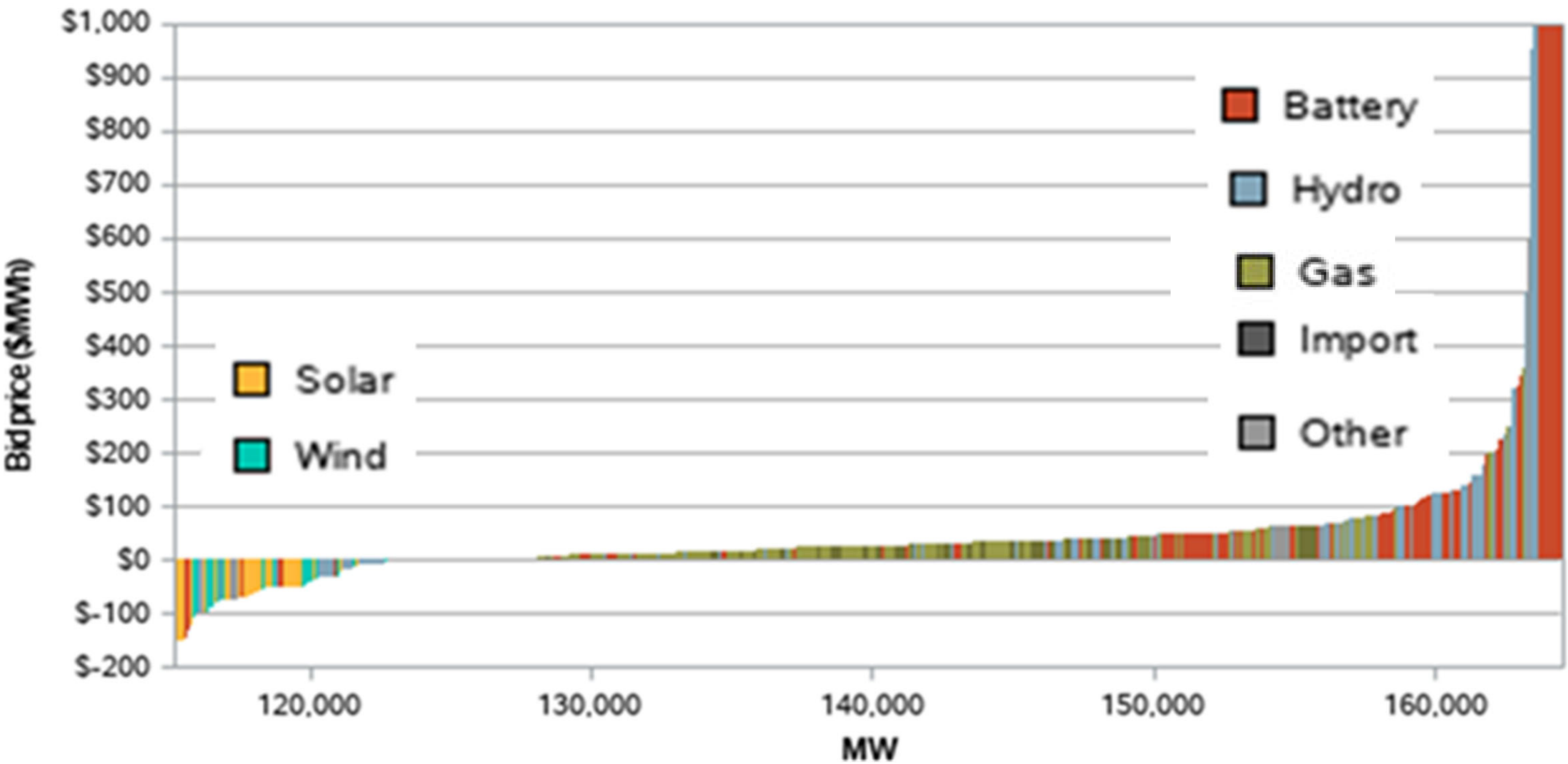


Prices can be competitive even at high load levels if there are many suppliers and regional competition

Total CAISO and WEIM 15-minute market supply and demand with generation at competitive reference levels (Sept 6, 2024 18:15)



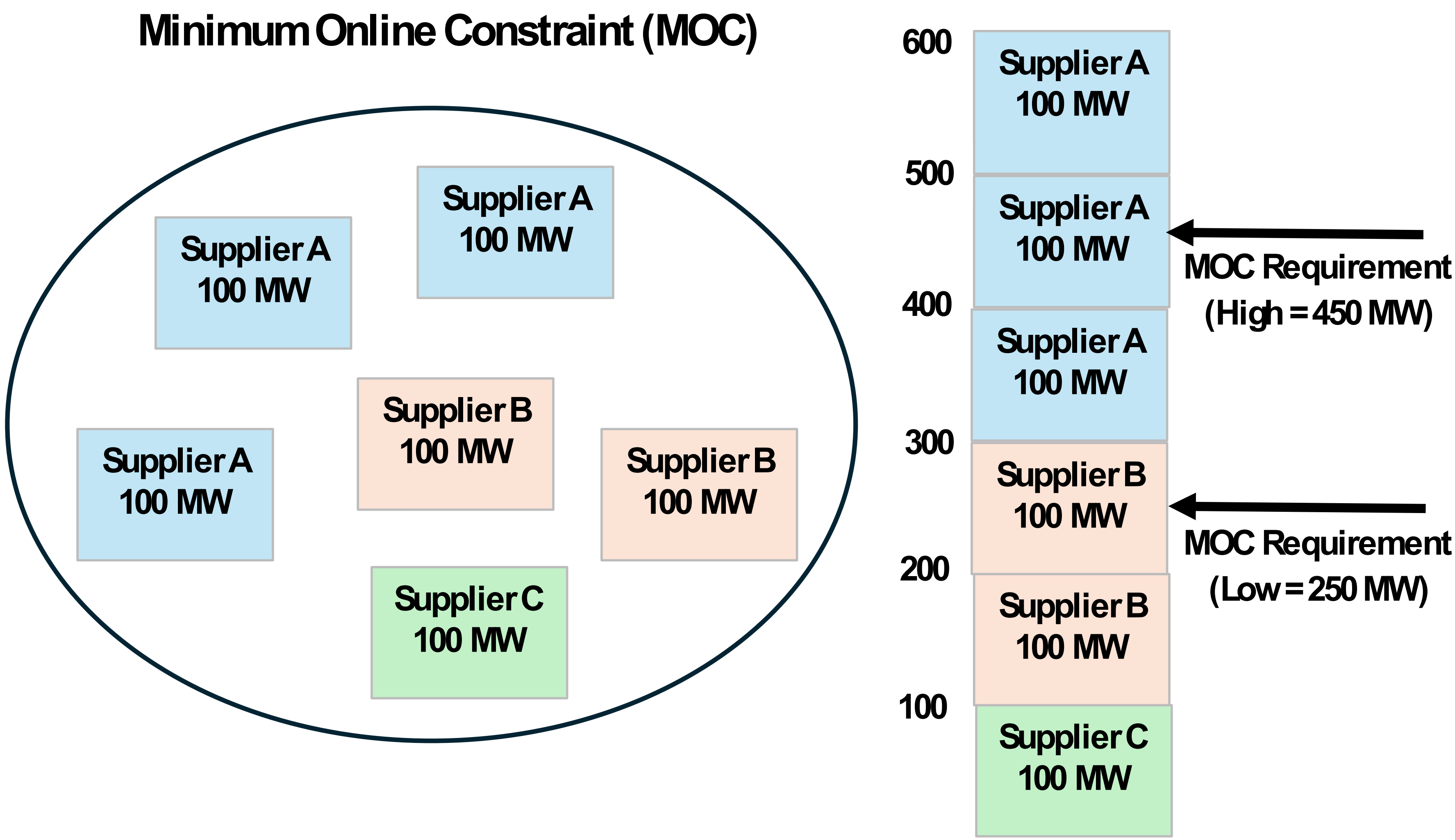
Batteries and hydro can be marginal under tight supply conditions --- and can be difficult to represent with competitive opportunity cost bids.



Pivotal supplier tests

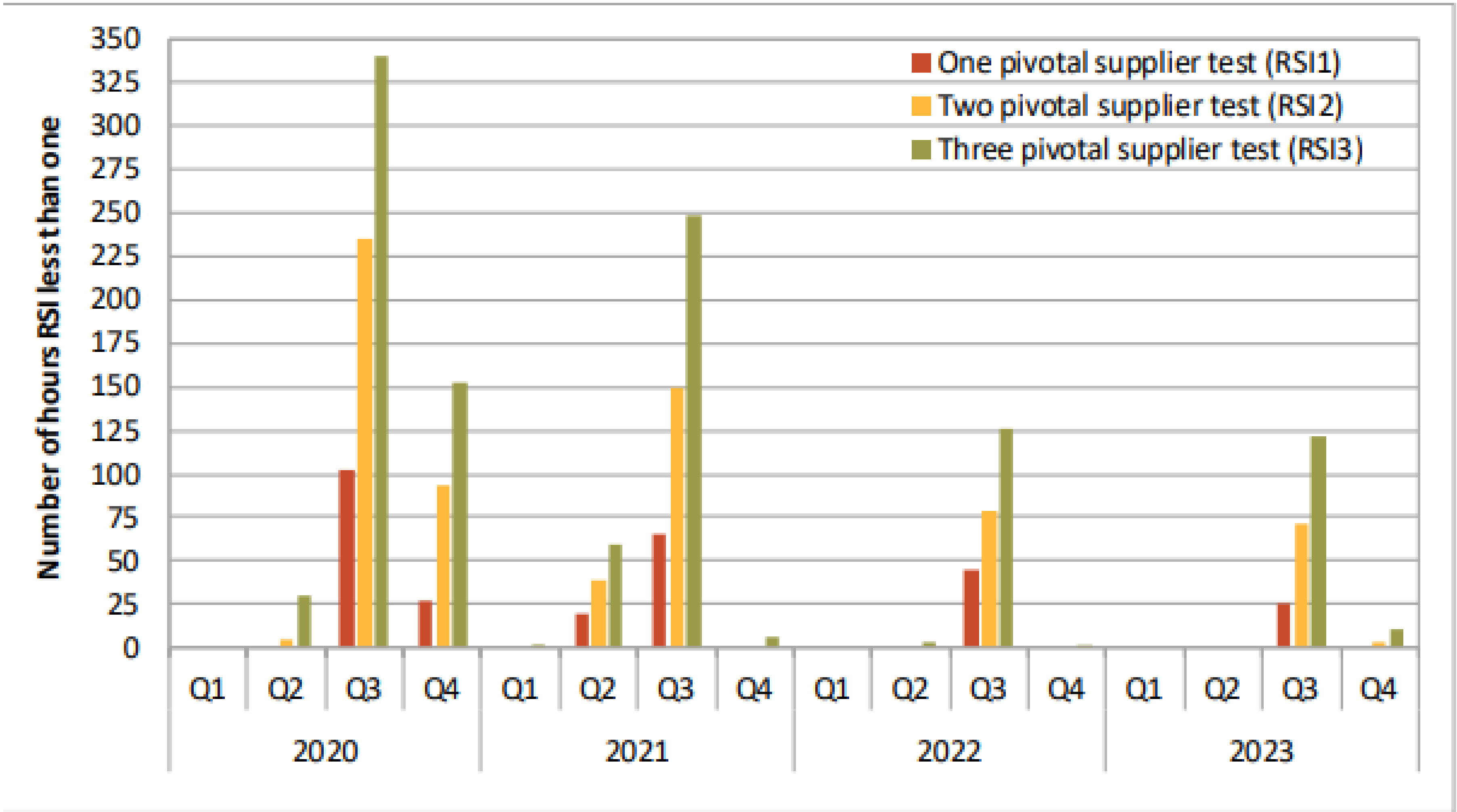
- Three pivotal supplier test may overestimate structural market power
- Residual Supply Index ($RSI_{1,}$ RSI_2 and $RSI_{3\,)}$ provide more information than pass/fail tests
- # of pivotal suppliers can be important
- Ideally, forward contracts (sales) and load obligations should be subtracted from supply of each seller
- Advantage of pivotal supplier test is that it can often be calculated before market run as part of automated *ex ante* mitigation
- CAISO considering using “less strict” test that three pivotal supplier
  - e.g. only mitigate suppliers that are pivotal vs, all participants

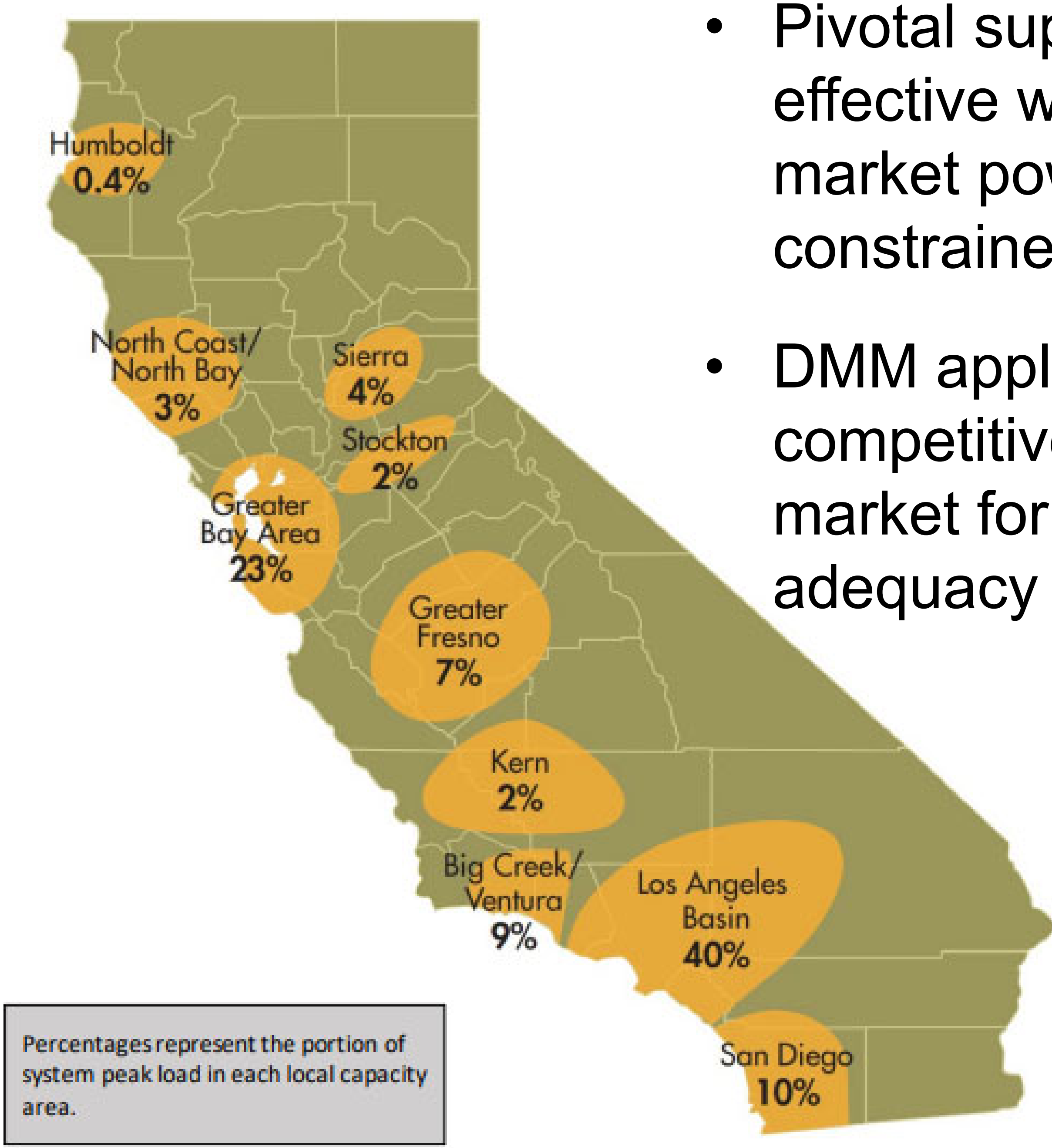
Pivotal supplier test can be very useful for capacity constraints and capacity requirements



Pivotal Supplier Tests and Residual Supply Index can provide way of tracking relative structural competitiveness

Figure 5.1 Hours with residual supply index less than one by quarter





- Pivotal supplier tests can be effective way to assess potential market power in transmission constrained local areas.
- DMM applies this test to assess competitiveness bi-lateral market for local resource adequacy capacity.

- CAISO defines capacity requirements under critical peak load conditions for various local areas.

Table 1.2 Load and supply within local capacity areas in 2023[39]

Local Capacity Area	LAP	Peak Load (1-in-10 year) MW	%	Dependable Generation (MW)	Local Capacity Requirement (MW)	Requirement as Percent of Generation
Greater Bay Area	PG&E	11,136	23%	7,770	7,312	94%
Greater Fresno	PG&E	3,288	7%	3,411	1,870	55%
Sierra	PG&E	1,812	4%	1,909	1,150	60%
North Coast/North Bay	PG&E	1,494	3%	911	857	94%
Stockton	PG&E	1,090	2%	579	579	100%
Kern	PG&E	940	2%	439	439	100%
Humboldt	PG&E	175	0.4%	178	141	79%
LA Basin	SCE	19,537	40%	9,661	7,529	78%
Big Creek/Ventura	SCE	4,427	9%	5,475	2,240	41%
San Diego	SDG&E	4,768	10%	5,358	3,332	62%
Total		**48,667**		**35,691**	**25,449**	

esource deficient LCA (or with sub-area that is deficient)—deficiency included in LCR. Resource deficient area implies that in order to comply with the criteria, at summer peak, load may be shed immediately after the first contingency.

- Available supply capacity in each area can be used to assess structural competitiveness, accounting for supply owned/controlled by “net buyers” (e.g. load serving entities)

Table 5.2 Residual supply index for local capacity areas based on net qualifying capacity

Local capacity area	Net non-LSE capacity requirement (MW)	Total non-LSE capacity (MW)	Total residual supply ratio	RSI_1	RSI_2	RSI_3	Number of individually pivotal suppliers
PG&E TAC area							
Greater Bay	4,732	5,156	1.09	0.44	0.11	0.07	2
Kern	327	304	0.93	0.00	0.00	0.00	3
North Coast/North Bay	708	826	1.17	0.00	0.00	0.00	1
Stockton	358	369	1.03	0.09	0.04	0.00	3
SCE TAC area							
LA Basin	1,828	3,553	1.94	0.74	0.27	0.18	1
San Diego/Imperial Valley	744	1,705	2.29	1.48	0.68	0.25	0

*Available capacity is insufficient to meet the LCA requirement; All supply is needed to contribute toward the LCA requirement

Operator actions and managing uncertainty

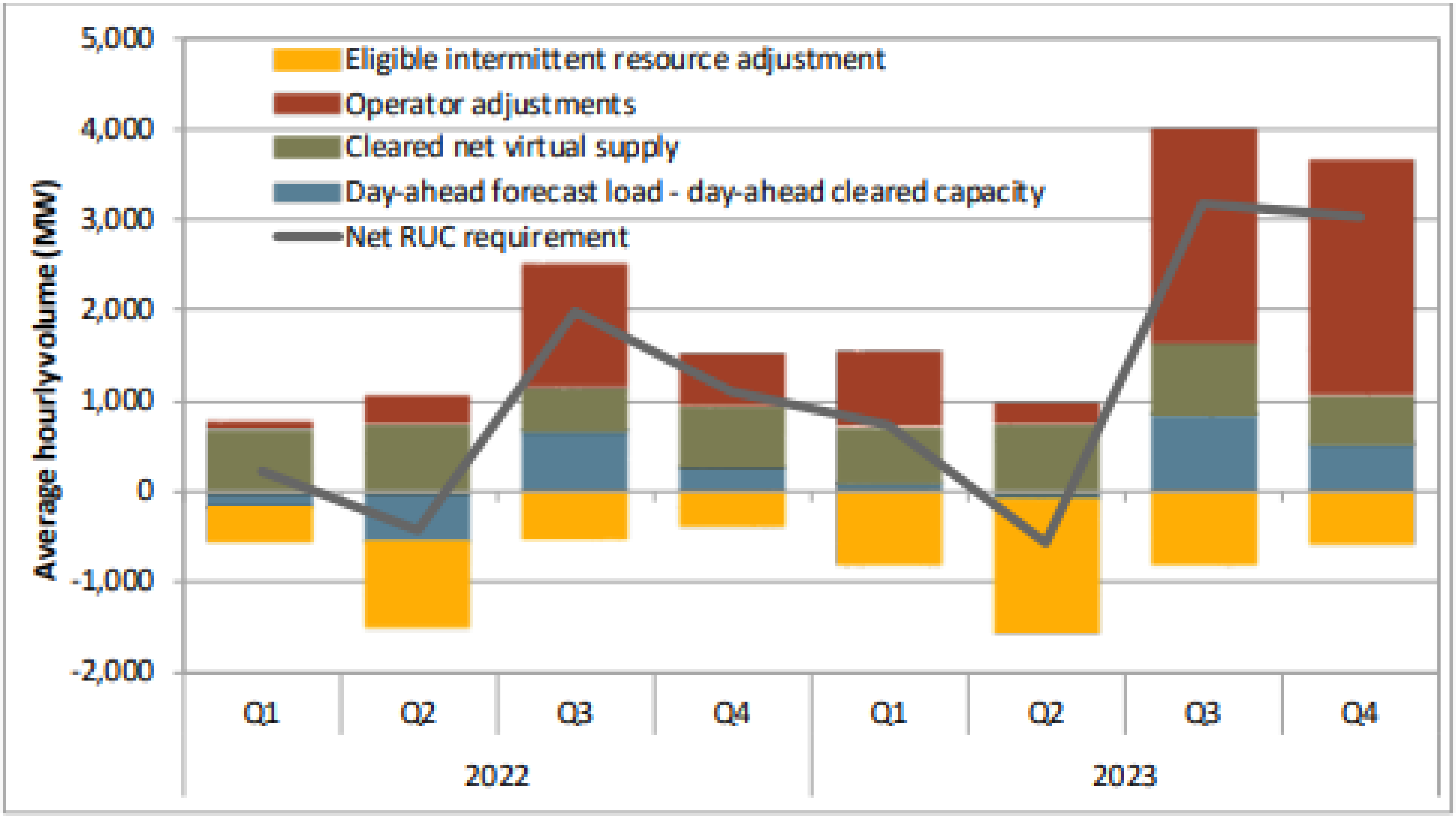
How does the CAISO manage net load uncertainty?

- Day-ahead
  - Upward adjustment of demand in residual unit commitment (RUC) process
  - Manual commitments for ramping and system reliability
  - New Imbalance Reserve product (with EDAM)
- Real-time
  - Manual dispatches for ramping energy
  - Large hour-ahead and 15-minute load bias
  - Flexible ramping product (FRP)

WEIM transfers in 15-minute and 5-minute markets have played a key role in helping CAISO to manage net load uncertainty,

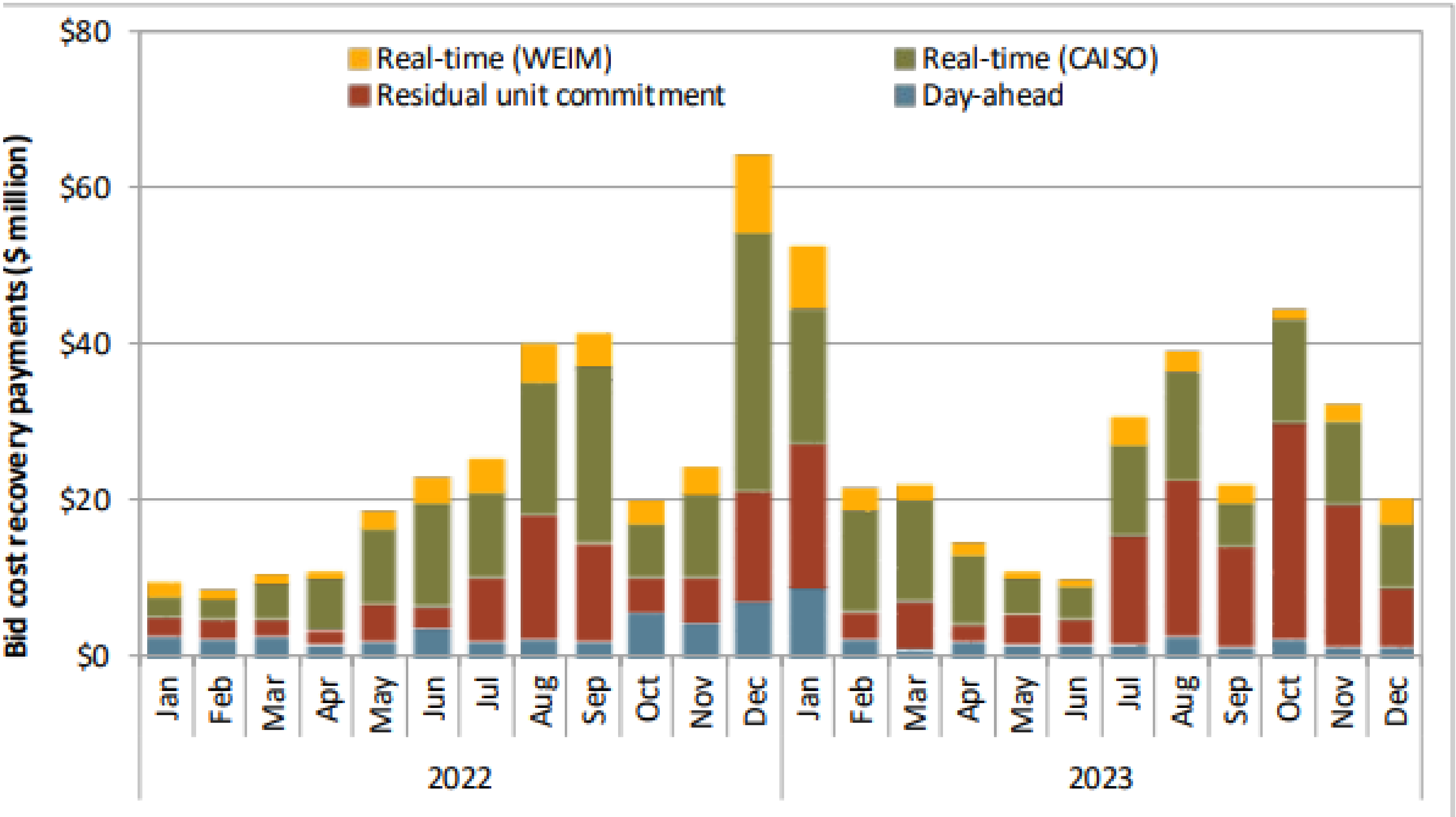
Operators routinely adjust load used in RUC process up to defend against uncertainty

Figure 7.12 Determinants of residual unit commitment procurement

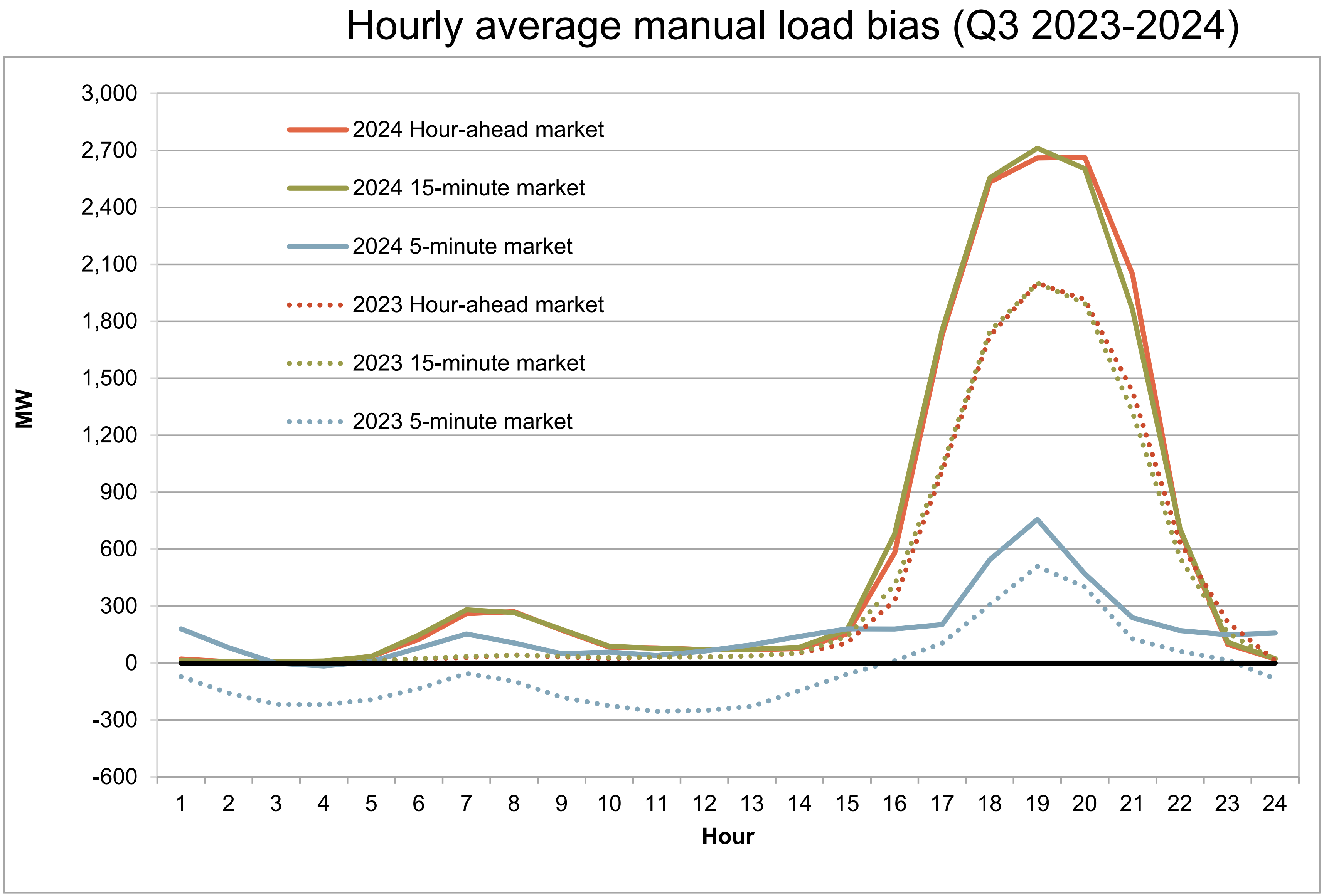


Manual adjustments to Residual Unit Commitment can be a major driver of Bid Cost Recovery payments

Figure 2.17 Bid cost recovery payments

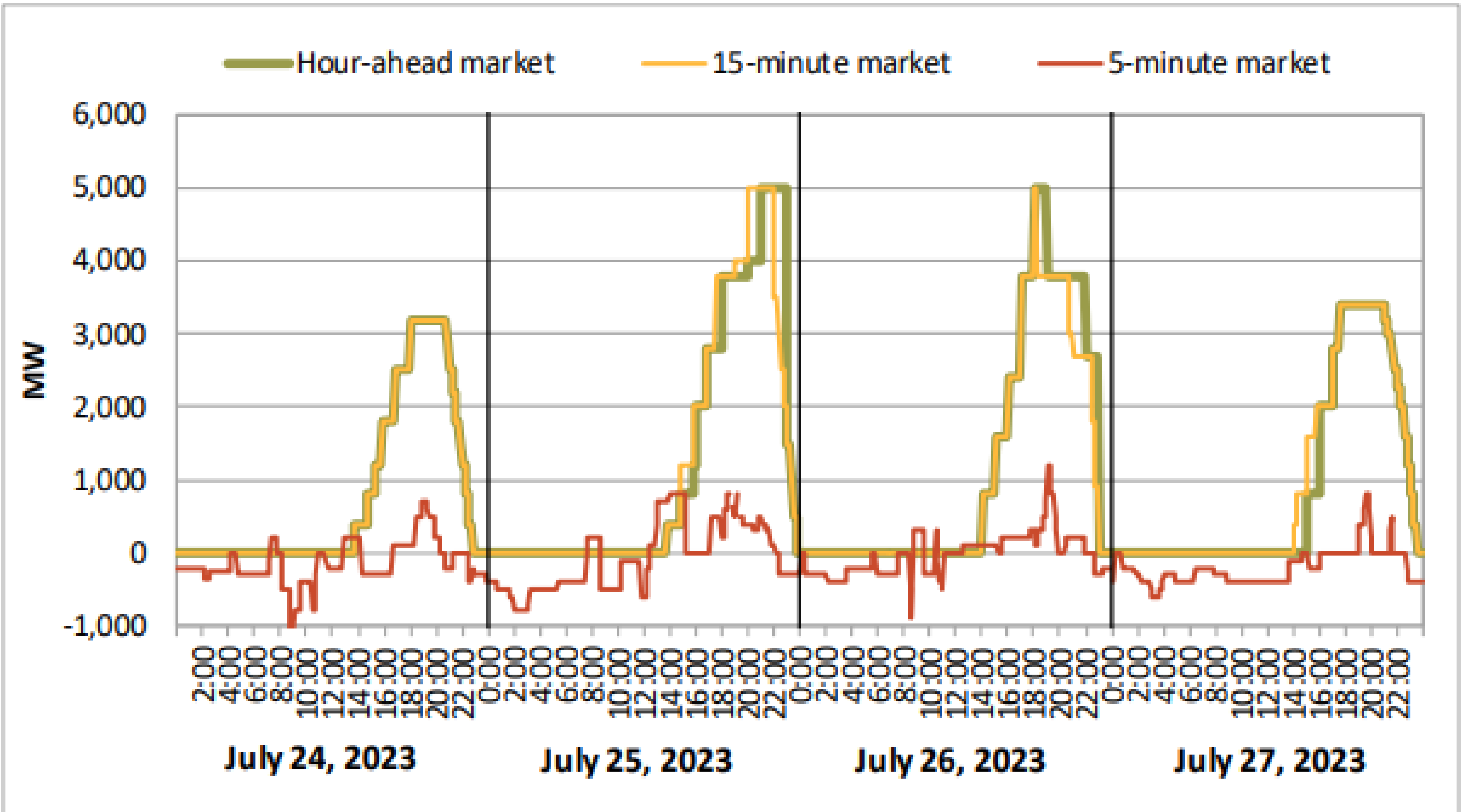


Manual load bias remains the main way the ISO creates extra upward capacity to manage ramping needs and net load uncertainty



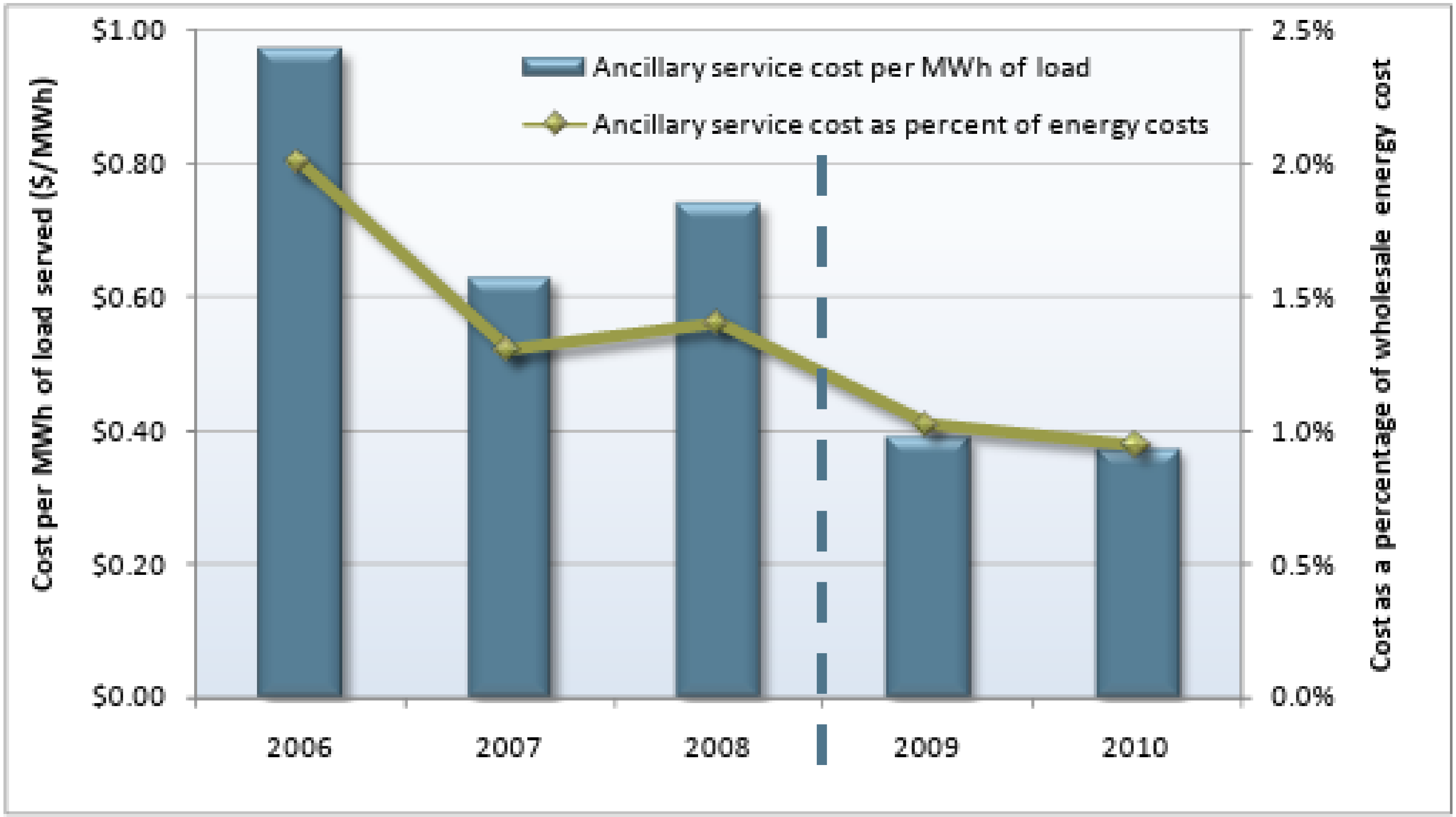
During most critical summer hours, manual load bias can reach 5,000 MW – or over 10% of net load.

Figure 3.9 ISO area load conformance adjustments (July 24–27)



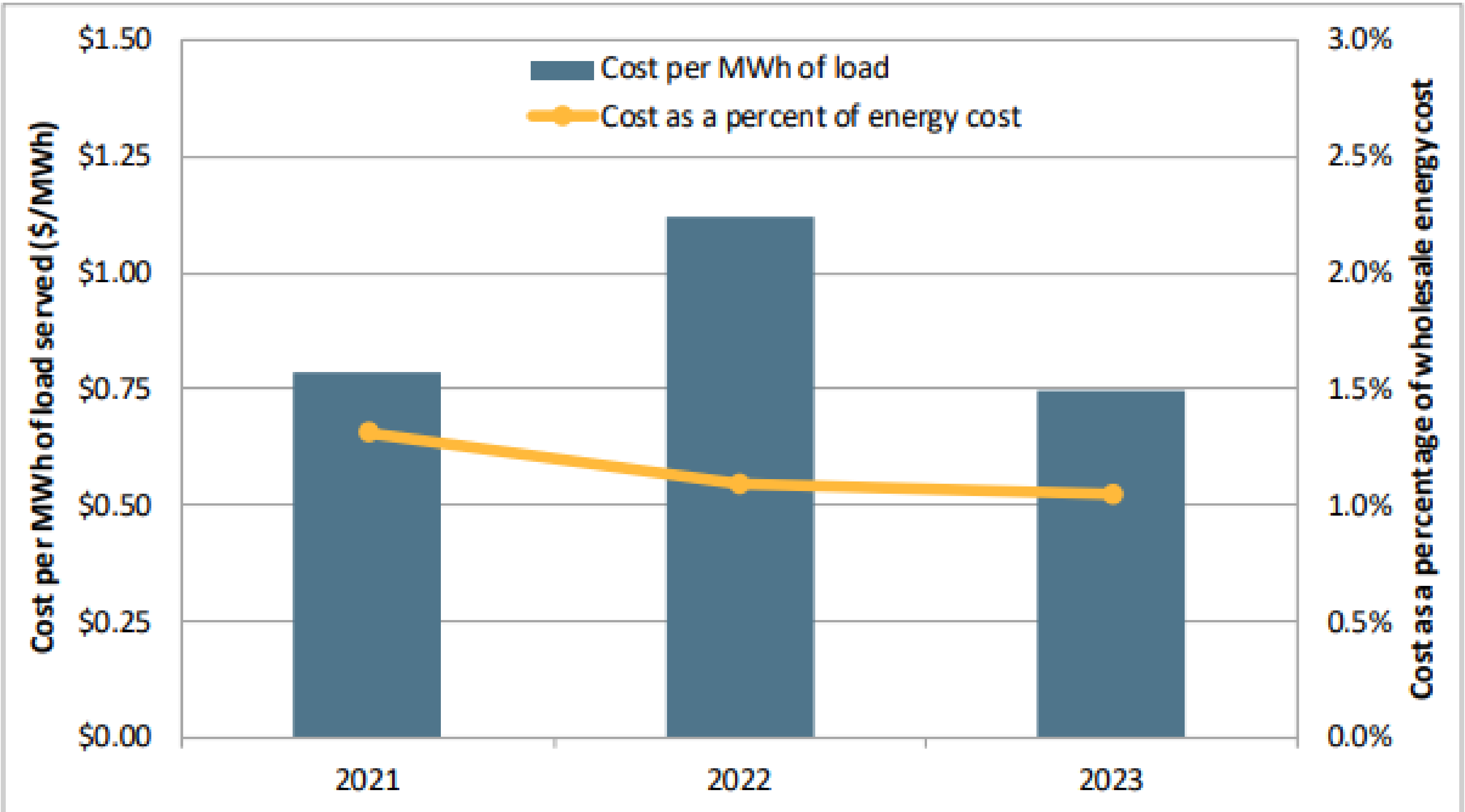
Ancillary service costs dropped after LMP market with day-ahead co-optimization was implemented in 2009.

Figure E.5 **Ancillary service cost as a percentage of wholesale energy cost (2006 – 2010)**



Ancillary service costs average about 1% of energy

Figure 4.1 Ancillary service cost as a percentage of wholesale energy costs (2021–2023)



Congestion Issues

Figure 6.3 Percent of hours with congestion impacting prices by load area

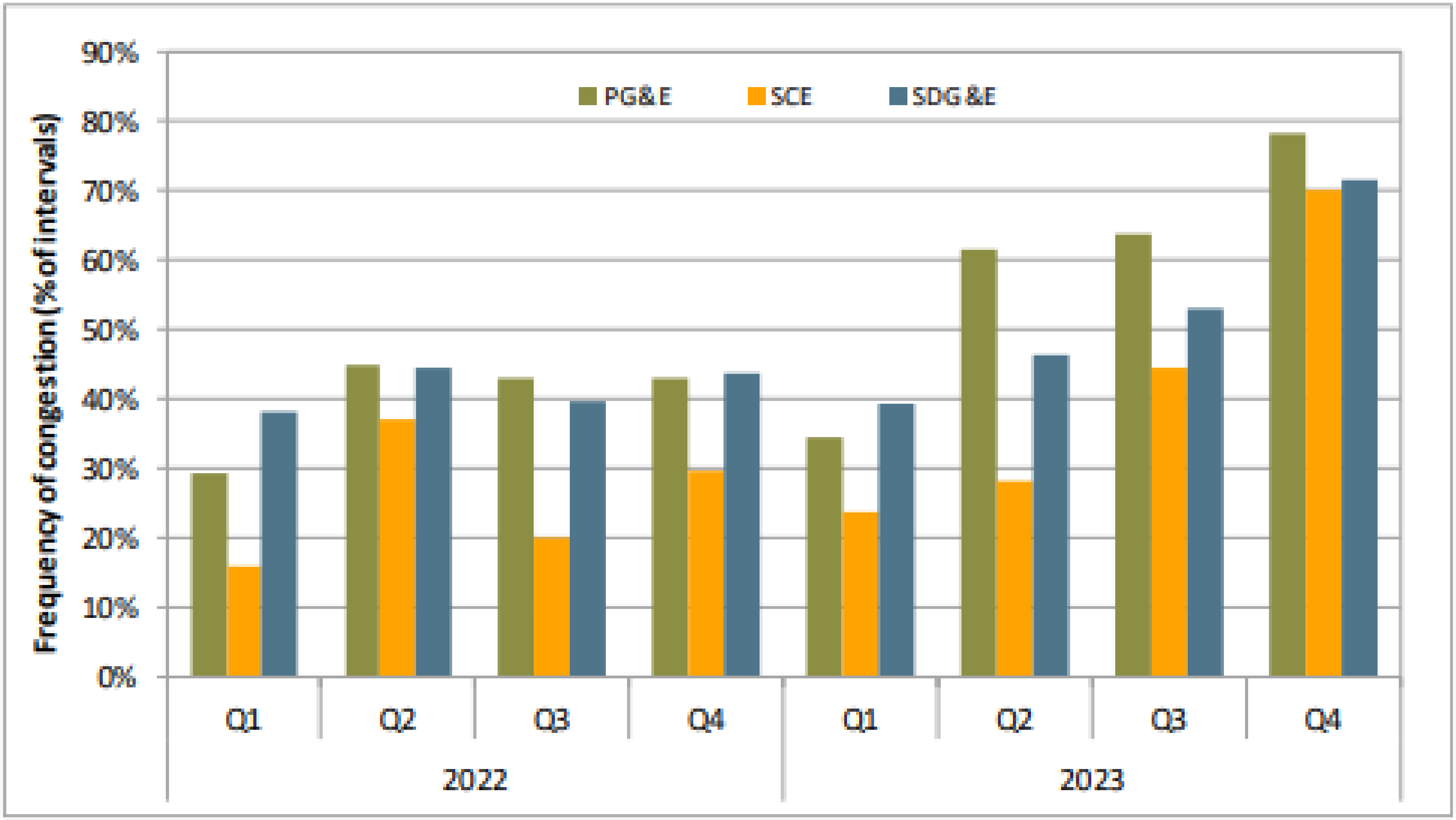
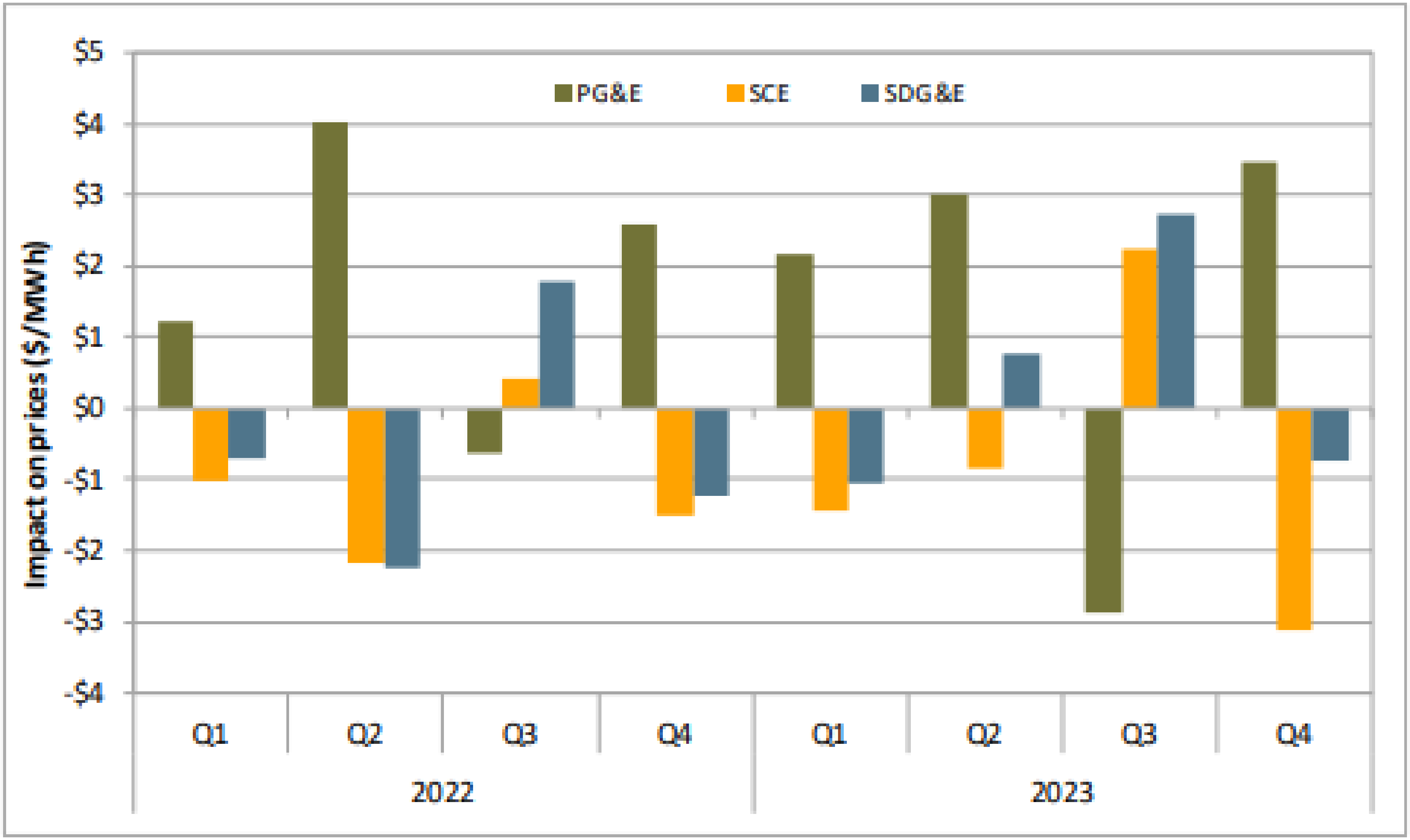


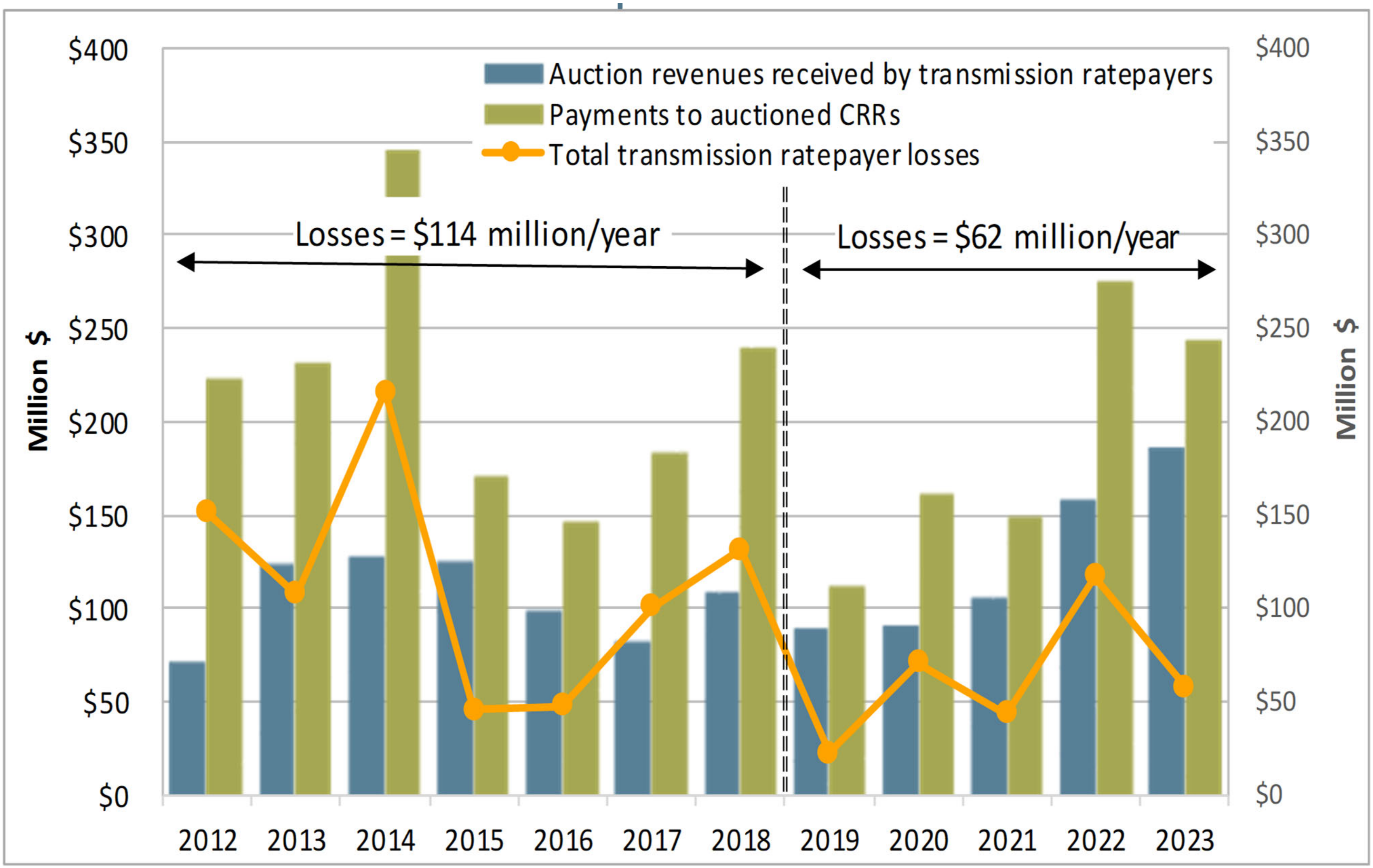
Figure 6.2 Overall impact of congestion on price separation in the day-ahead market



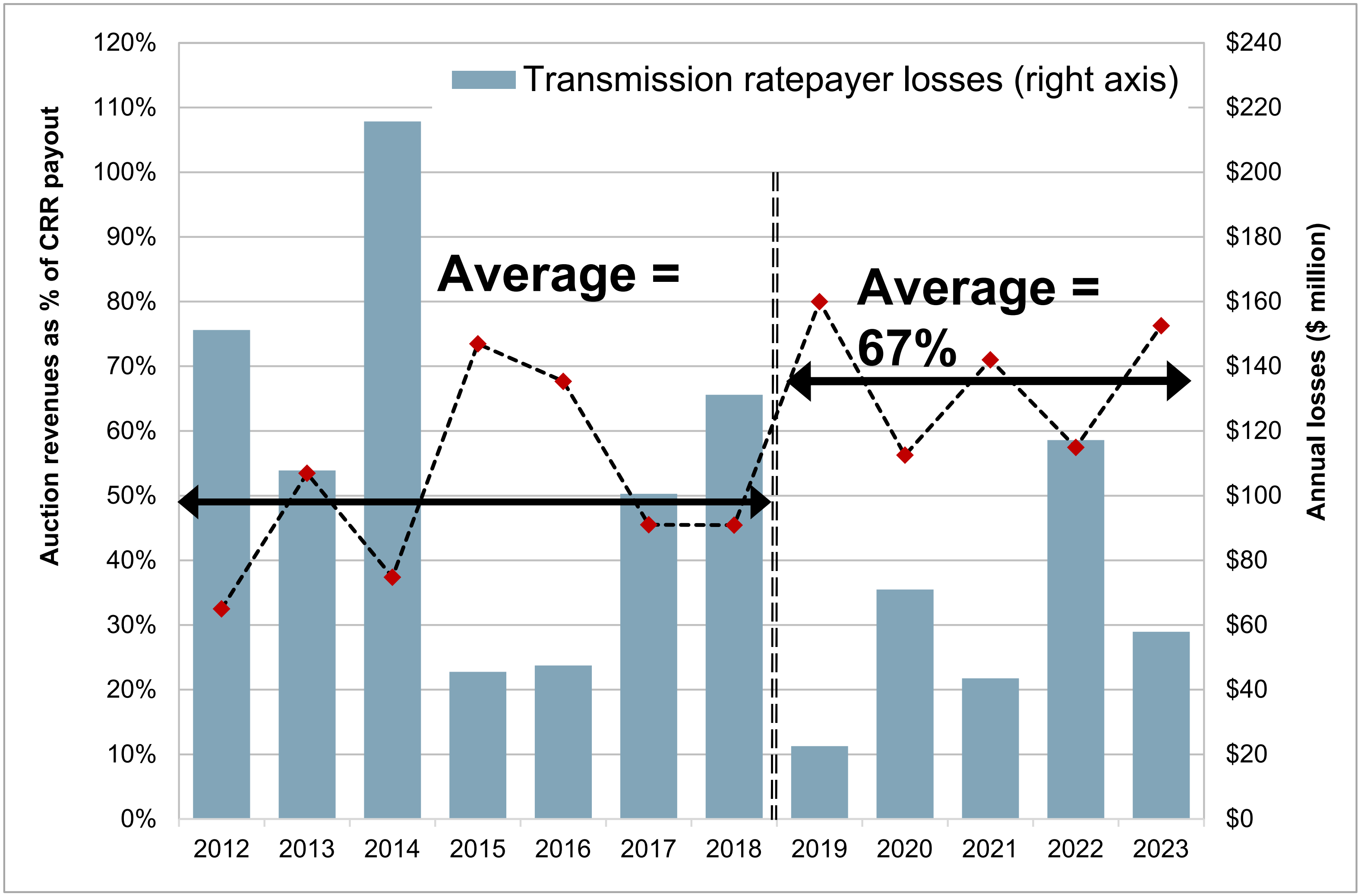
Financial congestion revenue rights (CRRs)

- Under LMP market, load serving entities <u>pay</u>:
  - Transmission access charge (TAC)
  - Congestion charges embedded in LMPs
- <u>Congestion surplus</u> results since LMPs <u>paid by LSEs</u> are greater than LMPs <u>paid to suppliers</u>
- CRRs are paid out of this congestion surplus, and remainder is refunded to LSEs *pro rata*
- CRRs are <u>allocated</u> to LSEs based on their historical load
- CAISO auctions off additional CRRs to whoever wants to bid on them (purely financial players, marketers, generators)

Transmission ratepayers still losing about $62 million per year from CRRs auctioned to non-LSEs since 2019



CRRs auctioned by CAISO to non-LSEs still selling for $.67 per $1 of payouts



All RTOs that auction financial congestion rights loose millions of dollars per year

	Auction Losses ($ millions)			
	MISO	ERCOT	PJM	SPP
2021	$932	$457	$1,060	$322
2022	$387	$969	$387	$443
2023	$184	$367	$232	$54
2024			$527	

Most auction losses (90%?) are from CRRs bought by financial entities that do no use them for hedging trades or sales of physical power