



California ISO
Shaping a Renewed Future

Extended Day-Ahead Market Performance May Report

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Executive summary

On May 1, 2026, the California ISO, in partnership with PacifiCorp, successfully launched the Extended Day-Ahead Market (EDAM) alongside a suite of Day-Ahead Market Enhancements (DAME). This report is the first of series of customized monthly reports and provides an initial assessment of market performance during EDAM's first month of operation, focusing on price formation, reliability, new product performance, congestion, and settlement outcomes across participating balancing authority areas. These customized reports will be provided for six months after the entry of new EDAM entities.

Overall, market outcomes were robust and broadly aligned with expectations, reflecting a stable transition to expanded day-ahead market functionality. However, results should be viewed as preliminary, as May represents an early implementation phase with ongoing participant learning, evolving seasonal conditions, and settlement refinements still underway.

Key takeaways:

Market Operational Performance:

EDAM results were posted before 1:00 p.m. in 61 percent of days, down from April (77 percent of the days) reflecting additional validation steps needed due to the new market operations. This indicates a cautious approach to prioritizing accuracy during the initial month of the market roll out.

Resource Sufficiency and Reliability:

Resource sufficiency performance was strong across all participating areas. CAISO and PacifiCorp East (PACE) passed the resource sufficiency evaluation in all intervals, while PacifiCorp West (PACW) passed in 99.4 percent of intervals

Price Formation and Market Conditions:

Day-ahead energy prices remained moderate and seasonally consistent, with daily averages of \$8/MWh in PACE, \$19/MWh in PACW, and \$15/MWh in CAISO. The CAISO prices increased modestly from April 2026 (\$14/MWh) but remained significantly below the May 2025 prices (\$25/MWh).

Prices separated across the different balancing authority areas, reflecting underlying system conditions. PACE and PACW experienced some price volatility during the first days of EDAM operations, which subsided as market participants adapted to the new processes

and functionality. External bilateral indices appear largely unaffected by EDAM implementation.

Costs and Market Efficiency:

Total wholesale costs in CAISO remained stable (~\$19/MWh), continuing a broader trend of lower costs in 2026 compared to 2025. Wholesale cost metrics now incorporate new EDAM products, including imbalance reserves and reliability capacity as well as energy, ancillary services from both day-ahead and real-time markets, real-time offsets, and bid cost recovery.

CAISO's bid cost recovery (BCR) in the IFM increased from \$1.64 million in April to \$3.15 million in May, while RTM BCR declined from \$11.65 million to \$8.24 million. These preliminary CAISO BCR reflect two issues identified for May 19 and 31 dates, which will be addressed in the next settlement cycle and will reduce these volumes.

In PACW, IFM BCR totaled \$0.097 million in May, while RTM BCR increased from \$0.019 million in April to \$0.4 million. PACE recorded an IFM BCR of \$0.36 million in May, and RTM BCR, rising from approximately \$1,100 in April to \$1.28 million.

Ancillary Services and New Products:

Ancillary service prices for CAISO remained historical norms. Regulation up and regulation down prices increased modestly, while spinning and non-spinning reserve prices remained broadly consistent with pre-EDAM levels. PACE and PACW does not procure ancillary services through the centralized market.

The newly introduced imbalance reserve products performed as expected. Prices were stable in CAISO and PACE, averaging below \$1.5/MWh. PACW experienced some price volatility during the first days of operation, reflected in the higher monthly average price of \$7.5/MWh. In CAISO, average imbalance reserve prices remained below regulation prices but above operating reserve prices.

Imbalance reserve requirements were fully procured in CAISO and PACE throughout the month. PACW experienced seven days with procurement shortfalls in either direction, averaging up to 6 MW of unmet requirements. In CAISO, imbalance reserves were primarily supplied by natural gas and solar resources, with storage contributing limited volumes during morning and peak-demand hours. PACW relied primarily on hydro and wind resources, while PACE procured most imbalance reserves from coal and wind resources.

Reliability capacity prices were volatile during the initial days but stabilized over the remainder of the month. PACW recorded the highest average price at \$8/MWh, followed by CAISO at \$6/MWh and PACE at \$3.5/MWh.

Convergence bidding activity in was comparable to May 2025 levels, reflecting that EDAM implementation had little impact on convergence bidding behavior.

The average monthly GHG price was \$2.5/MWh in the day ahead market, and slightly higher than real-time GHG prices. Prices followed similar intraday patterns, with higher values during the early morning and evening peak periods.

Market Integration and Transfers:

EDAM transfers reached up to 600 MW and were actively used across energy and the new products (imbalance reserve and reliability capacity) in both import and export directions across all participating areas. These transfers enabled access to the most economic supply across the EDAM footprint and leveraged resource diversity among participating balancing authorities. Key trade patterns include:

- CAISO was a net exporter of energy and upward imbalance reserves, while importing downward imbalance reserves. Reliability capacity trading was more variable and occurred in smaller volumes, with exports of upward reliability capacity early the month, shifting to imports later. Downward reliability capacity began with imports, followed by reduced trading activity in the second half of the month.
- PACW was a net-importer energy and both upward and downward imbalance reserves. Reliability capacity patterns generally reflected exports of upward products and imports of downward products.
- PACE generally imported energy and upward imbalance reserves, while exporting downward imbalance reserves. Its reliability capacity trading pattern largely mirrored the CAISO BAA profile, with imports of upward reliability capacity in the first half before shifting to exports later in the month. For downward reliability capacity, PACE began the month exporting, with activity tapering off in the second half of the month.

Congestion Rents:

Congestion rents across the EDAM footprint totaled \$39.9 million, largely driven by CAISO constraints during solar-hour conditions, with \$1.7 million originating from PACE. Average congestion prices were -\$0.2/MWh in PACE and \$0.4/MWh in PACW, compared with \$4.1/MWh in Northern California and -\$3.0/MWh in Southern California.

Total congestion revenue allocation related to parallel flows across EDAM balancing authority areas and PAC own congestion were relatively small: PACE received \$886,000 and PACW received \$111,000.

Market Issues:

This report includes a summary of identified issues that affected market functionality, required price corrections, or have impacted settlement outcomes. Some issues remain under review and some of the results reported in this report are subject to change as settlements are updated with corrective actions.

Conclusion:

The first month of EDAM operations demonstrates a successful and stable market launch, with strong reliability performance, efficient price formation, and active interregional trade. While some early-stage volatility, timing delays, and settlement adjustments are evident, these are typical of initial implementation.

As market participants gain experience, system conditions tighten with the summer season, and enhancements mature, the full benefits of EDAM, including improved efficiency, enhanced reliability, and broader market integration, are expected to become more pronounced.

Contents

Executive summary..... 4

Figures 10

Tables 14

Introduction 16

Day-Ahead Market Run 17

Resource Sufficiency Evaluation 19

Day-Ahead Market Products 21

 Energy prices..... 23

 Changes in price formation with EDAM 30

 Marginal energy cost 30

 GHG prices..... 33

 Bilateral power price comparisons 37

 Ancillary services..... 42

 Imbalance reserves..... 48

 Reliability capacity..... 66

 Convergence bids 79

 Bid-in and forecasted demand 82

 Greenhouse gas emission product 83

EDAM Transfers 87

 Energy transfers 88

 Imbalance reserves..... 92

 Reliability capacity transfers..... 100

Congestion..... 107

 Parallel flows..... 110

 Congestion revenues 114

EDAM Net Export Constraints and RUC Adjustments 116

 EDAM net export constraints 116

 RUC adjustments 117

RUC infeasibilities.....	118
Market Costs.....	118
Wholesale costs.....	118
Bid cost recovery.....	120
Market offsets	123
Day-Ahead congestion offset	124
Day-Ahead energy offset	125
Real-Time congestion offset	126
Real-Time imbalance energy offset.....	126
Imbalance reserves.....	129
Reliability capacity.....	131
GHG settlement.....	133
Market Issues.....	135

Figures

- Figure 1: Run times for the extended day-ahead market 18
- Figure 2: RSE passing rate by BAA for upward and downward requirements 19
- Figure 3: Total upward and downward requirements by area 20
- Figure 4: Pricing of EDAM products 23
- Figure 5: Hourly IFM LMP averaged by month 24
- Figure 6: Daily average LMP by BAA 25
- Figure 7: CAISO’s area price convergence..... 26
- Figure 8: PACE’s area price convergence 26
- Figure 9: PACW’s area price convergence 27
- Figure 10: Monthly average price for CAISO area 28
- Figure 11: Monthly average price for PACW..... 28
- Figure 12: Monthly average price for PACE Average LMPs 29
- Figure 13: Monthly average LMPs 30
- Figure 14: LMP Decomposition for Non-CAISO WEIM BAA..... 31
- Figure 15: Average monthly LMP components 34
- Figure 16: CAISO RTD LMP range frequency 35
- Figure 17: PACW RTD LMP range frequency 35
- Figure 18: PACE RTD LMP Range Frequency..... 36
- Figure 19: Frequency of extreme LMPs 36
- Figure 20: Daily average LMPs and bilateral power prices 38
- Figure 21: Monthly average LMPs and bilateral power prices 39
- Figure 22: Total daily energy volume of bilateral trades (On-peak)..... 40
- Figure 23: Total daily energy volume of bilateral trades (Off-peak) 40
- Figure 24: Total monthly energy volume of bilateral trades (On-peak) 41
- Figure 25: Monthly total energy volume of bilateral trades (Off-peak)..... 41
- Figure 26: Daily average of CAISO ancillary services prices in IFM..... 42
- Figure 27: Monthly average AS prices in CAISO 43
- Figure 28: Frequency of cascading in Regulation and Spin reserves 44
- Figure 29: Comparison of monthly procurement in percentage 45
- Figure 30: Daily distribution of AS percentage procurement in IFM..... 45
- Figure 31: Daily average Upward AS procurement in IFM 46
- Figure 32: Regulation up prices for CAISO extended area 47
- Figure 33: Spin prices for CAISO extended area 47
- Figure 34: Non-spin prices for CAISO extended area 48
- Figure 35: Daily average price of IRU 49
- Figure 36: Daily average price of IRD 50

Figure 37: Hourly average price of IRU	50
Figure 38: Hourly average price of IRD	51
Figure 39: Hourly average of IR requirements for CAISO	52
Figure 40: Hourly average of IR requirements for PACE	52
Figure 41: Hourly average for IR requirements for PACW	53
Figure 42: Hourly average diversity benefit	54
Figure 43: Hourly average cleared IR by fuel type for CAISO	55
Figure 44: Hourly average cleared IR by fuel type for PACW	55
Figure 45: Hourly average cleared IR by fuel type for PACE	56
Figure 46: Hourly average volume of IR bids organized by price for CAISO	57
Figure 47: Hourly average volume of IR bids organized by fuel type for CAISO	58
Figure 48: Daily average volume of IR bids organized by price for CAISO	58
Figure 49: Daily average volume of IR bids organized by fuel type for CAISO	59
Figure 50: Hourly average volume of IR bids organized by price for PACW	60
Figure 51: Hourly average volume of IR bids organized by fuel type for PACW	60
Figure 52: Daily average volume of IR bids organized by price by PACW	61
Figure 53: Daily average volume of IR bids organized by fuel type for PACW	61
Figure 54: Hourly average volume of IR bids by price for PACE	62
Figure 55: Hourly average volume of IR bids by fuel type for PACE	63
Figure 56: Daily average volume of IR bids by price for PACE	63
Figure 57: Daily average volume of IR bids by fuel type for PACE	64
Figure 58: Average imbalance reserve demand curve procurement for PACW	65
Figure 59: Average net demand with imbalance reserve procurement	66
Figure 60: Daily average price of RCU	68
Figure 61: Hourly average price of RCU	68
Figure 62: Hourly average of RC procurement for CAISO	69
Figure 63: Hourly average of RC procurement for PACE	70
Figure 64: Hourly average of RC procurement for PACW	70
Figure 65: Hourly average volume of RC bids by price for CAISO	71
Figure 66: Hourly average volume of RC bids by fuel type by CAISO	72
Figure 67: Daily average volume RC bids by price for CAISO	73
Figure 68: Daily average volume of RC bids by fuel type for CAISO	73
Figure 69: Hourly average volume of RC bids by price for PACW	74
Figure 70: Hourly average volume of RC bids by fuel type for PACW	75
Figure 71: Daily average volume of RC bids by price for PACW	75
Figure 72: Daily average volume of RC bids by fuel type for PACW	76
Figure 73: Hourly average volume of RC bids by price for PACE	77
Figure 74: Hourly average volume of RC bids by fuel type for PACE	77

Figure 75: Daily average volume of RC bids by price by PACE	78
Figure 76: Daily average volume of RC bids by fuel type by PACE	78
Figure 77: Net cleared virtual bids	79
Figure 78: Daily average of hourly cleared virtual bids	80
Figure 79: Average hourly cleared virtual supply	81
Figure 80: Average hourly cleared virtual demand	81
Figure 81: Average net hourly cleared virtual bids	82
Figure 82: Bid-in demand vs. day-ahead demand forecast	83
Figure 83: Daily average GHG allocation	85
Figure 84: Daily average GHG price	86
Figure 85: Hourly average GHG price.....	87
Figure 86: Daily average energy transfers for CAISO	88
Figure 87: Hourly average energy transfers for CAISO	89
Figure 88: Daily average energy transfers for PACW	90
Figure 89: Hourly average energy transfers for PACW	90
Figure 90: Daily average energy transfers for PACE	91
Figure 91: Hourly average energy transfers for PACE	92
Figure 92: Daily average IRU transfers for CAISO	93
Figure 93: Hourly average IRU transfers for CAISO	93
Figure 94: Daily average IRD transfers for CAISO	94
Figure 95: Hourly average IRD transfers for CAISO	94
Figure 96: Daily average IRU transfers for PACW.....	95
Figure 97: Hourly average IRU transfers for PACW	96
Figure 98: Daily average IRD transfers for PACW.....	96
Figure 99: Hourly average IRD transfers for PACW	97
Figure 100: Daily average IRU transfers for PACE	98
Figure 101: Hourly average IRU transfers for PACE	98
Figure 102: Daily average IRD transfers for PACE	99
Figure 103: Hourly average IRD transfers for PACE	99
Figure 104: Daily average RCU transfers for CAISO	100
Figure 105: Hourly average RCU transfers for CAISO	101
Figure 106: Daily average RCD transfers for CAISO	101
Figure 107: Hourly average RCD transfers for CAISO	102
Figure 108: Daily average RCU transfers for PACW	103
Figure 109: Hourly average RCU transfers for PACW.....	103
Figure 110: Daily average RCD transfers for PACW	104
Figure 111: Hourly average RCD transfers for PACW.....	104
Figure 112: Daily average RCU transfers for PACE	105

Figure 113: Hourly average RCU transfers for PACE	106
Figure 114: Daily average RCD transfers for PACE	106
Figure 115: Hourly average RCD transfers for PACE	107
Figure 116: Daily average congestion cost by area	110
Figure 117: Parallel flow matrix example	110
Figure 118: Illustration of parallel flow on CAISO BAA due to transactions in PAC areas	111
Figure 119: Daily congestion total by BAA	115
Figure 120: Total CRN Congestion Credit	116
Figure 121: CAISO Reliability Margin	117
Figure 122: Total daily costs CAISO	119
Figure 123: Monthly total costs CAISO	119
Figure 124: Monthly Total Costs CAISO, comparing 2025 to 2026	120
Figure 125: BCR of CAISO by market	121
Figure 126: BCR of PACE by market	122
Figure 127: BCR of PACW by market	122
Figure 128: IFM BCR by BAA	123
Figure 129: RTM BCR by BAA	123
Figure 130: DA Congestion Offset for PAC areas	124
Figure 131: DA Energy Offset	125
Figure 132: Real-Time Congestion Offset	126
Figure 133: Real-Time Imbalance Energy Offset	127
Figure 134: Monthly Total Real-Time Offsets for CAISO	128
Figure 135: Monthly Total Real-Time Offsets for WEIM	129
Figure 136: IRU settlement costs	130
Figure 137: IRD settlement costs	131
Figure 138: RCU settlement costs	132
Figure 139: RCD settlement costs	132
Figure 140: Greenhouse Gas Settlement Costs in IFM	134
Figure 141: Greenhouse Gas Settlement Costs in RTM	134

Tables

Table 1: Comparison of LMP decomposition before and after May 1, 2026	32
Table 2: Average congestion costs	108
Table 3: Hourly average congestion costs	109
Table 4: MCC breakdown by source of congestion	112
Table 5: Congestion costs by constraint.....	113

Acronyms

AS	Ancillary service
EDAM	Extended day-ahead market
BAA	Balancing authority area
DAME	Day-ahead market enhancement
DLAP	Default load aggregation point
EDAM	Extended day-ahead market
ELAP	WEIM load aggregation point
GHG	Greenhouse gas
IFM	Integrated forward market
IRU/IRD	Imbalance reserve up/down
LMP	Locational marginal price
MCC	Marginal congestion component
MEC	Marginal energy component
PACE	Pacific Corporation East area
PACW	Pacific Corporation West area
RCU/RCD	Reliability capacity up/down
RSE	Resource sufficiency evaluation
RTM	Real-time market
RUC	Reliability unit commitment
SMEC	System energy marginal component
VER	Variable energy resource
WEIM	Western energy imbalance market

Introduction

The California ISO implemented Extended Day-Ahead Market (EDAM) operations on May 1, 2026, marking a significant transition from a single-BAA day-ahead market to a broader, multi-BAA EDAM footprint. Concurrently, new features were introduced as part of the day-ahead market enhancements (DAME). This report provides an overview of market performance during the first month of EDAM/DAME operations, focusing on price formation, resource sufficiency outcomes, congestion costs and settlement cost trends across participating balancing authority areas for EDAM. As with CAISO's prior monthly performance reports, the objective is to offer timely and transparent insights into market performance, particularly during the initial period of a major market design transition.

The implementation of EDAM/DAME introduced two new market products: imbalance reserves up and down (IRU/IRD) and reliability capacity up and down (RCU/RCD). The analysis includes a review of IRU/IRD and RCU/RCD prices, procurement volumes, requirements and cost allocation for the new market products. The report also provides a detailed assessment of energy prices, bilateral hub price comparisons, ancillary service procurement, imbalance reserve awards, reliability capacity procurement, and greenhouse gas (GHG) cost adders. The analysis also includes a review of convergence bidding in EDAM, highlighting changes in bid volumes and awards for virtual generation and virtual demand.

The report evaluates costs associated with congestion revenue allocation, and settlement cost trends across the EDAM footprint. This includes an assessment of congestion revenues, breakdown of marginal component of congestion (MCC) at the transmission constraint level among participating BAAs.

The CAISO will continue to monitor and evaluate market performance and will provide further analysis and reporting in upcoming monthly reports.

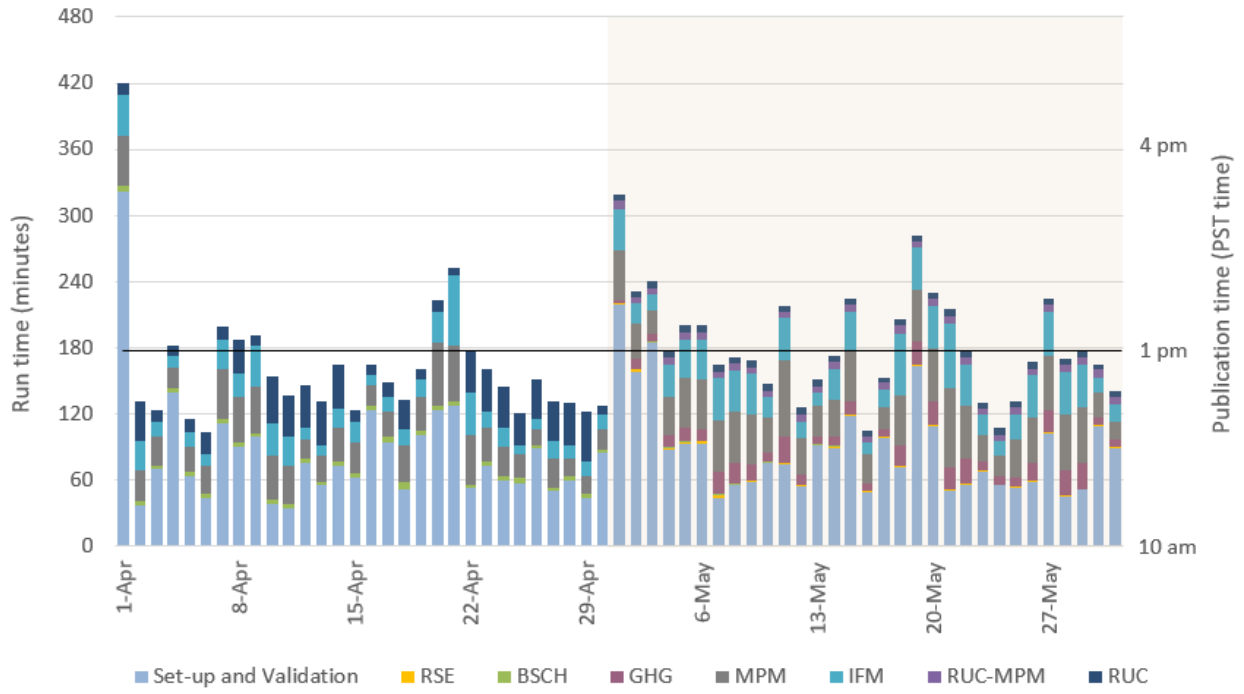
Day-Ahead Market Run

The Day-ahead (DA) market follows a daily schedule, unchanged by new market functionality. All bids submission is due by 10:00 a.m. Pacific Time, after which the CAISO runs multiple processes that comprise the day-ahead market. The standard window to run the day-ahead market is between 10:00 a.m. and 1:00 p.m., with the goal of publishing results by 1:00 p.m. To complete a day-ahead market run after the launch of the EDAM, multiple steps are performed, including:

- i) Market closing and setting up of inputs
- ii) running the binding resource sufficiency evaluation (RSE). New process
- iii) running the base schedule set up (BSCH)
- iv) running the green-house-gas emission market (GHG). New process
- v) running market power mitigation (MPM)
- vi) running the integrated forward market (IFM)
- vii) running market power mitigation for residual unit commitment (MPM-RUC). New process
- viii) running the residual unit commitment (RUC)
- ix) publishing market results
- x) validation of results after each run

In addition to running three new processes within the standard window, EDAM is inherently more complex because it solves for a wider market footprint and so has a larger optimization problem to solve multiple times. This has increased the overall computational workload. Despite the complexity, CAISO maintains the goal of a 1:00 p.m. publication time. Figure 1 illustrates the additional time the CAISO took in the first days of EDAM operations to ensure all processes and runs were properly executed and results could be closely assessed. This has taken longer to publish market results. After the first two weeks, CAISO gradually returned to more standard runs of the market and the market has been able to publish DA results before 1:00 p.m. EDAM results were posted before 1:00 p.m. in 19 out of 31 days. For a relative comparison, the day-ahead market published before 1:00 p.m. in 23 out of 30 days in April.

Figure 1: Run times for the extended day-ahead market

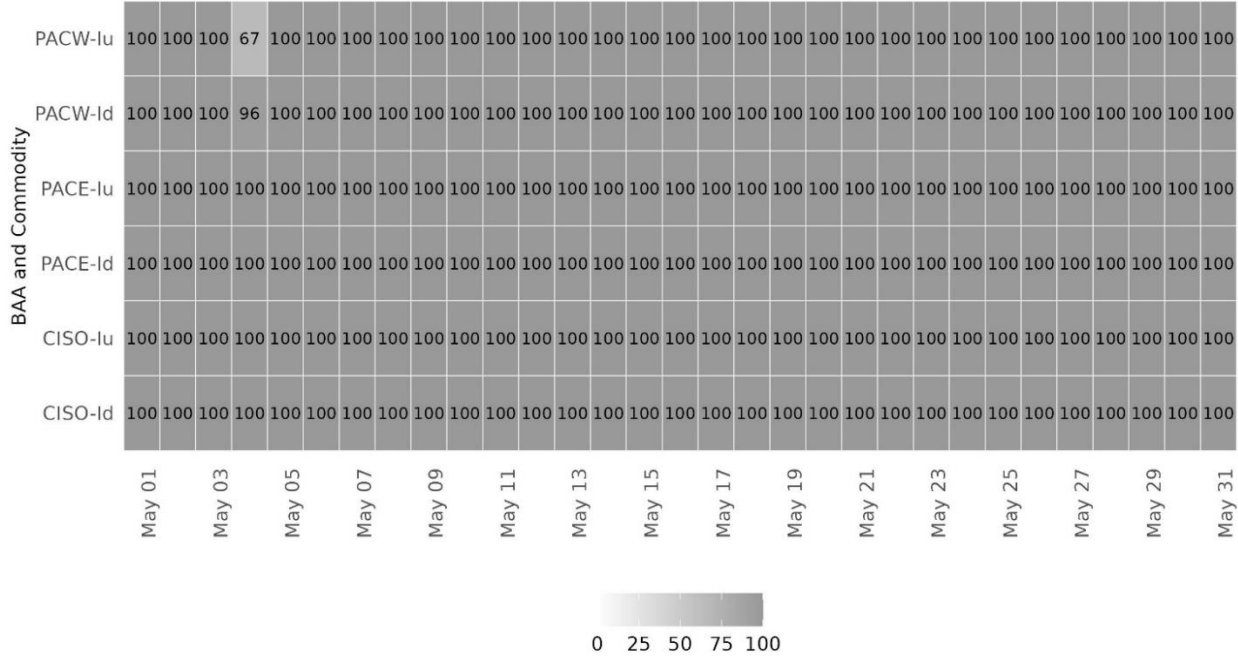


Resource Sufficiency Evaluation

The EDAM resource sufficiency evaluation (RSE) is a forward-looking test to ensure that each participating EDAM area has sufficient supply to meet their own forecasted demand, ancillary services, and uncertainty before engaging in economic transfers with other EDAM BAAs. Specifically, the RSE evaluates whether a unit-commitment optimization problem can be solved without relaxing (1) the power balance constraint, (2) the IRU/IRD procurement constraints, and (3) the ancillary services procurement constraints. These conditions are evaluated separately, and the entity passes the test without relaxing any of these constraints. This evaluation is performed on an hourly basis, in both upward and downward directions.

Figure 2 shows the daily passing rate of each EDAM BAA for the IRU and IRD RSE tests across the month of May. Aside from May 4 when PACW passed 16 out of the 24 hours, all three EDAM BAAs have passed both the IRU and IRD RSE tests across all hours of the day for the entire month of May.

Figure 2: RSE passing rate by BAA for upward and downward requirements

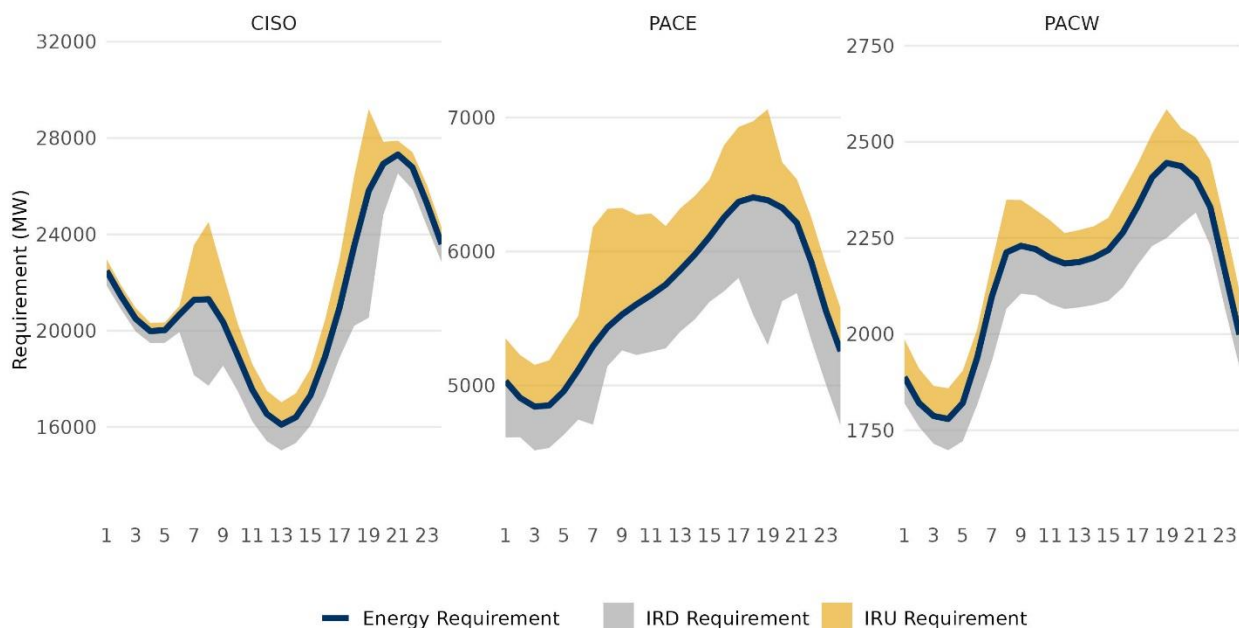


Imbalance reserves are used to address uncertainty between the day-ahead and real-time forecasts for load, wind and solar by providing upwards and downwards dispatch capability.

The requirements for IRU/IRD are based on historical load, wind, and solar forecast errors between day ahead and real time.

Figure 3 displays average hourly IRU and IRD requirements for each EDAM BAA over the month of May, with respect to the average energy requirement. The imbalance reserve requirements are calculated for each EDAM BAA separately. Requirements for IRU and IRD tend to be the largest for CAISO around the morning and evening peaks on the edges of solar hours. The IRD requirement during solar hours is higher than in the early morning and night hours, but noticeably smaller than in the morning and evening peaks. A similar trend exists in PACW for IRU requirements, but the IRD requirement remains relatively high through the middle of the day. The IRU requirement also peaks in the morning and evening hours in PACE, despite not having the midday dip in demand. The level of requirements for each area is different given the different size and generation composition of each area. While CAISO requirements can be as high as 3,500MW in the upward direction, PACE can exceed 1,000MW and PACW can be about 200 MW. CAISO and PACW tend to reach their peak upward requirement in hours ending 18 and 19 while PACE tends to hit its peak upward requirement between hours ending seven and nine.

Figure 3: Total upward and downward requirements by area



For an EDAM entity to pass the RSE, it must have at least enough supply to meet the requirement for each hour. For the upward direction the RSE requirement is the summation of the energy requirement and the upward IR requirements while for the downward direction the requirement is assessed by subtracting the IRD requirement from the energy requirement.

Day-Ahead Market Products

The EDAM launched on May 1, 2026. At the same time, the day-ahead market enhancements (DAME) were also introduced in this implementation. The market footprint encompasses the PacifiCorp balancing areas East and West together with the CAISO balancing area, all of which participate in a common day-ahead and real-time market framework. This integrated market structure supports more efficient coordination of resources across a broader geographic region, enhancing both operational reliability and economic efficiency.

As part of the day-ahead market enhancements, two new market products have been introduced: imbalance reserves and reliability capacity. These additions are designed to strengthen the market's ability to address evolving system needs while supporting reliable grid operations.

The imbalance reserve product enables the market to procure flexible capacity in advance to manage the uncertainty that exists between day-ahead scheduling and real-time operations. By securing this flexibility through a competitive market process, operators can ensure that sufficient resources are available to respond to changing system conditions while maintaining reliability.

The reliability capacity product represents supply procured in the residual unit commitment process in both the upward and downward direction to meet differences between market-cleared load schedules and demand forecast.

Procuring flexibility through the market promotes economic efficiency by identifying and securing the least-cost resources capable of providing these services. It also establishes transparent price signals that explicitly value flexibility, helping market participants better understand system needs and providing incentives to resources that can support reliable and efficient grid operations. Additionally, EDAM prices the greenhouse gas emissions associated with transfers between BAAs within the day-ahead market. This same formulation has been adapted for the real-time market.

Therefore, in the day-ahead market, different products are procured and priced explicitly:

- i) energy,

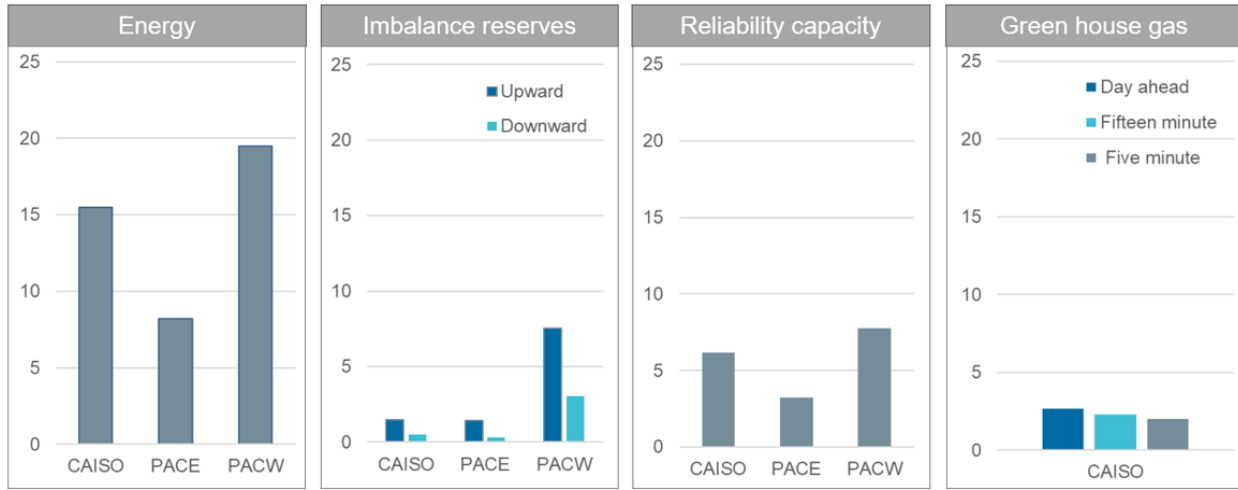
- ii) ancillary services (regulation up and down, spinning reserves and non-spinning reserves),
- iii) imbalance reserves up and down,
- iv) reliability capacity up and down, and
- v) greenhouse-gas emission allocation

Energy, ancillary services and imbalance reserves are all co-optimized in the integrated forward market, while reliability capacity are optimally procured in the residual unit commitment process that is run after the financial market. The residual unit commitment process considered as fixed the procurement of ancillary services, imbalance reserves, and only procures reliability capacity relative to the energy awards from IFM. This section provides an assessment of each of these market products during May. With more than a month of operational experience, the results offer an initial indication of how the EDAM/DAME functionality is performing. However, as the market continues to mature, participants gain experience operating under this new framework, and seasonal conditions transition toward summer patterns, the May results should be viewed as preliminary and may not yet fully reflect the extent of the changes introduced by EDAM/DAME.

The CAISO will continue to monitor and evaluate market performance and will provide further analysis in upcoming monthly reports.

Figure 4 compares prices across all EDAM products for the month of May. Prices across all commodities, including energy, imbalance reserves, and reliability capacity, remain within expected economic ranges. These results reflect underlying supply and demand fundamentals across the broader market footprint and demonstrate that the market is effectively valuing available resources while maintaining competitive and efficient outcomes.

Figure 4: Pricing of EDAM products



Seasonal conditions also play an important role in shaping price patterns observed in the first month. During the spring months, abundant renewable generation typically contributes to lower energy prices during midday hours. As solar production declines and demand increases during the morning and evening ramp periods, prices tend to rise, reflecting the changing balance between supply and demand. These recurring price dynamics underscore the market's ability to respond to evolving system conditions and provide transparent economic signals that support efficient resource utilization across the region.

Regional differences in supply and demand conditions are reflected in the pricing of all market products, including energy, imbalance reserves, and reliability capacity. As a result, prices exhibit expected regional variations, with PACE generally posting the lowest prices while PACW has tended to clear at higher price levels. These outcomes demonstrate that market prices properly reflect local system conditions and resource availability across the footprint when transfer capabilities are fully utilized.

The other pattern is that IR and RC products command lower prices than energy prices, which is expected given that these products provide services like flexibility.

Energy prices

Figure 5 shows the average hourly IFM LMPs for the three EDAM BAAs for May compared to the CAISO average hourly IFM LMPs in April. The ELAP LMPs are used for PACE and PACW, while the weighted average based on demand of the four DLAP LMPs is used for CAISO area.

Day-ahead prices for energy are moderate and responsive to system conditions and daily changes in supply and demand. Prices follow the profile of stronger morning and evening

peaks with a midday price decline. Prices between regions, however, have separated, with PACE typically having the lowest prices and PACW typically having the highest prices, with the CAISO area generally somewhere in between. CAISO's hourly prices remained within typical ranges and followed a normal profile for this time of year. PACE followed a similar profile, but with slightly lower LMPs across many hours of the day. PACW did not exhibit as significant of a dip in LMPs during solar hours, remaining close to \$20/MWh across all hours. For CAISO area, May prices tracked closely to the pattern and level of prices observed in April. For CAISO area, May prices in midday hours were higher than in April; this can represent a better economic outcome in EDAM since the surplus energy that can be realized in exports is valued at less negative prices.

Figure 5 and Figure 6 shows the daily average IFM LMPs across April and May. CAISO daily average IFM LMPs remained stable within normal ranges. PACW saw daily average LMPs like CAISO with a few days of higher but still normal prices. In the first two weeks after EDAM go-live PACE frequently had negative daily average LMP, but since then it has been trending towards prices like PACW and CAISO.

Figure 5: Hourly IFM LMP averaged by month

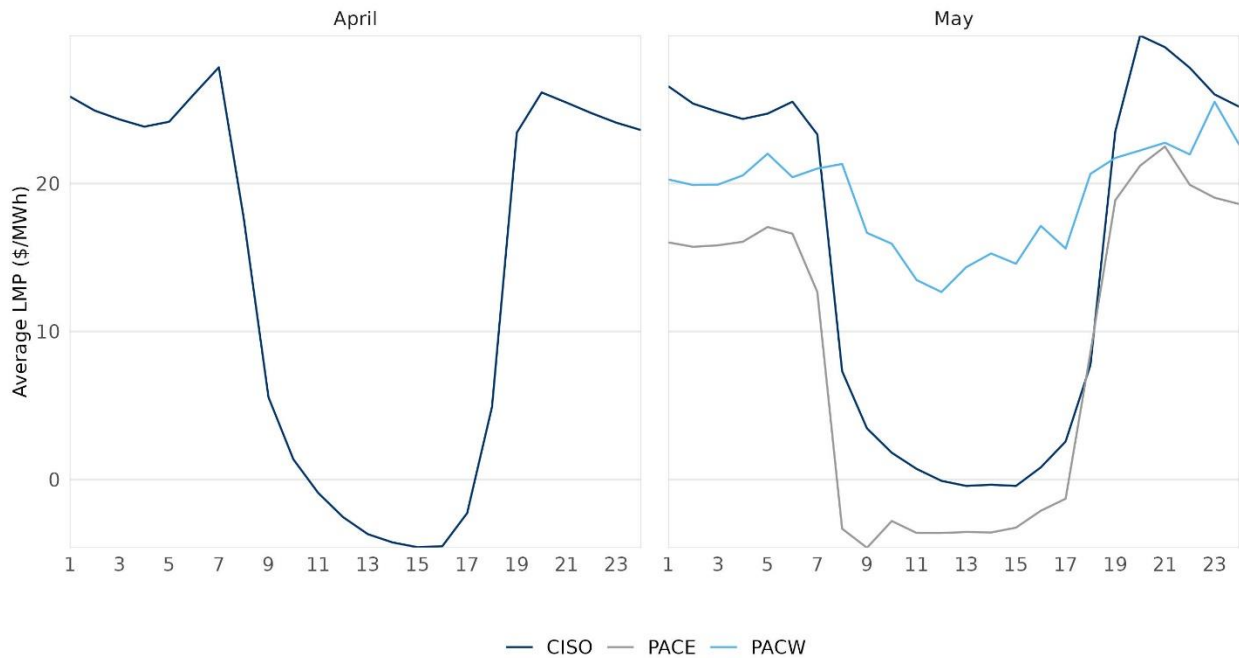
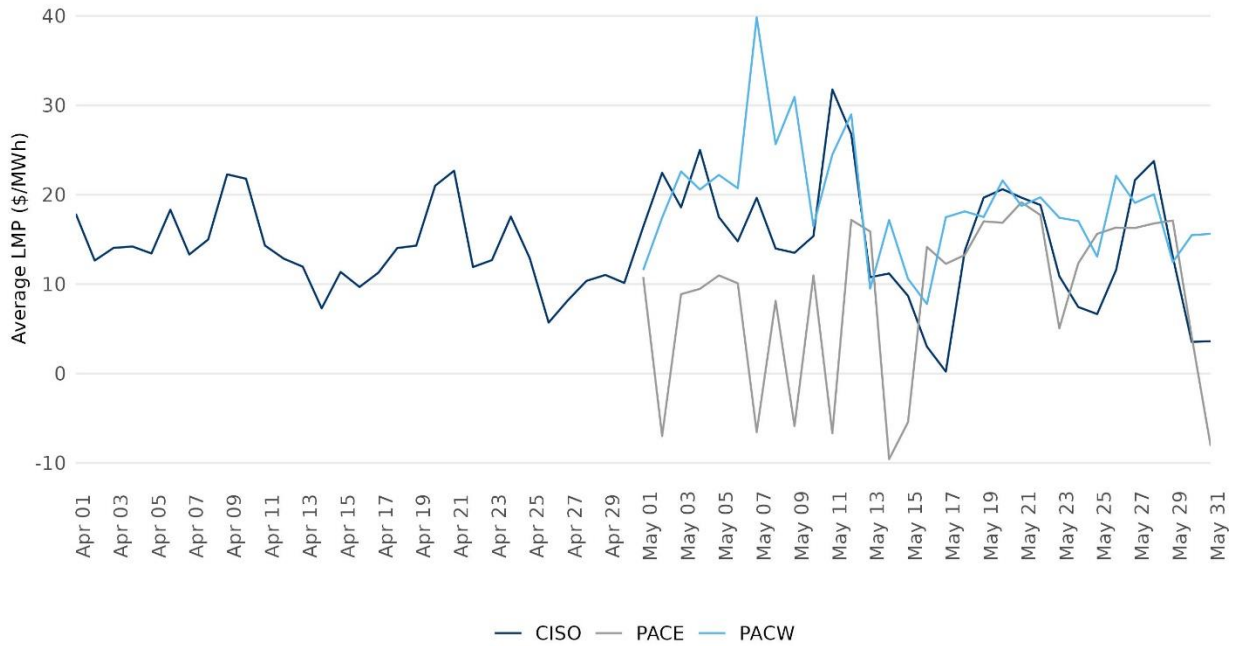


Figure 6: Daily average LMP by BAA



Ideally, day-ahead prices accurately represent the value of supply and demand realized in real time. Forecast errors, congestion, shifts in supply or demand, and available transfer capability can create differences between day-ahead and real-time prices. Figure 7, to Figure 9 compare prices across the day-ahead market (IFM), fifteen-minute market (FMM), and the real-time dispatch (RTD) for each EDAM BAA in May 2026.

For both CAISO and PACE, day-ahead prices tend to be lower than real-time prices. In the first two weeks of May, PACE had larger differences between day-ahead and real-time markets because the negative prices seen in IFM were not realized in FMM or RTD. In the second half of the month, the negative IFM prices were minimal and prices tracked closer. Particularly in the first half of the month, PACW frequently saw day-ahead prices higher than real-time prices, in part due to the difference on transfer capabilities available in real-time given the wider footprint relative to the more limited capability in day-ahead. Like PACE, PACW saw smaller price differences between day-ahead and real-time in the second half of May except for the last two days.

Figure 7: CAISO's area price convergence

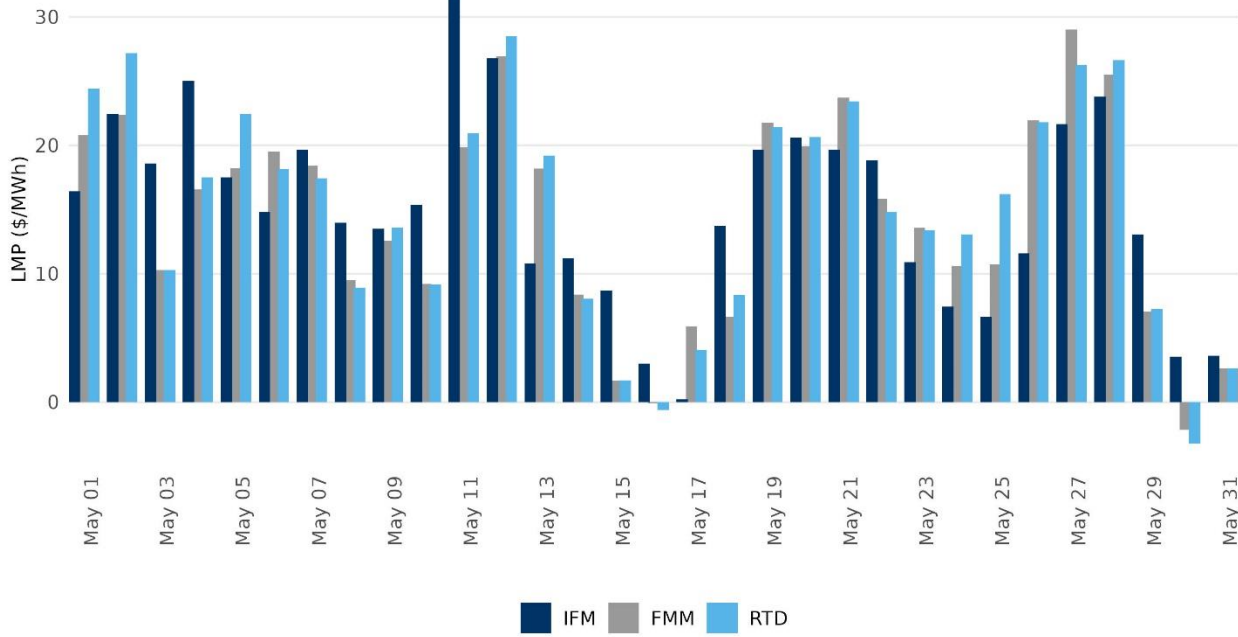


Figure 8: PACE's area price convergence

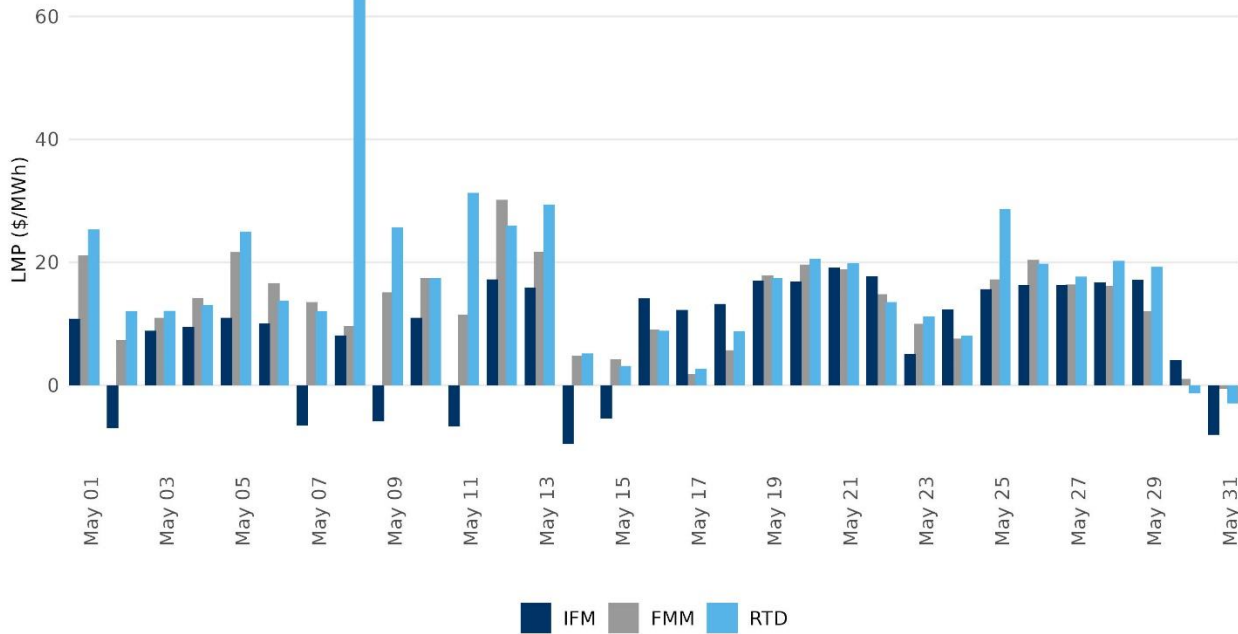
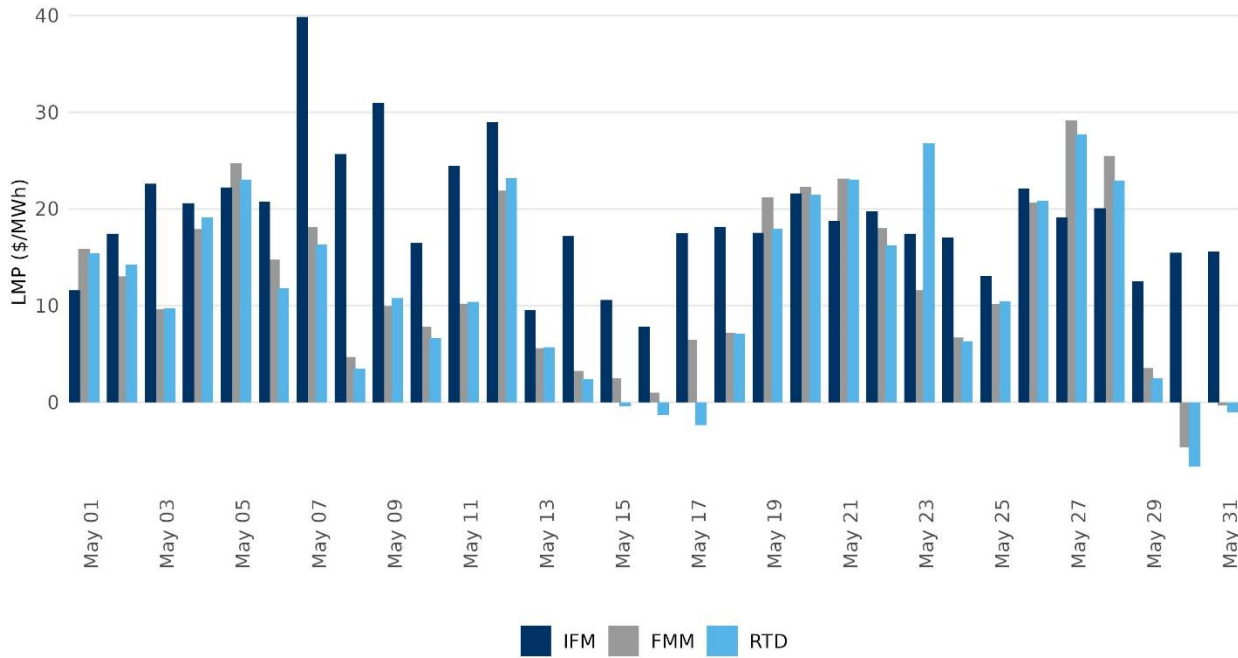


Figure 9: PACW's area price convergence



Prices tend to vary from day to day as conditions vary. Trends in price convergence are better understood over longer time spans. Figure 10 and Figure 11 show the average monthly LMPs across the three markets for the EDAM BAAs, with only CAISO having IFM prices prior to May 2026. Looking backwards to the beginning of 2025, Figure 10 illustrates that the price convergence observed in May between day-ahead and real-time was like levels observed prior to EDAM implementation.

There are no day-ahead price data available for the PacifiCorp balancing authority areas prior to May 2026; therefore, historical trends cannot be evaluated, and only real-time price comparisons can be presented. For the May price comparison in the PacifiCorp areas, notable differences are observed between the day-ahead and real-time markets. Day-ahead prices in PacifiCorp East generally tend to be lower than real-time prices, primarily for two reasons.

First, the level of transfer capability available in the day-ahead market is more limited. Within the three-area footprint, transfer capability is relatively modest compared to the significantly broader transfer opportunities available in the real-time market, which includes more than 20 interconnected areas. This expanded real-time transfer capability enables supply to be absorbed more efficiently across the broader market footprint.

Second, lower levels of demand bidding in the day-ahead market may result in lower quantities of demand being cleared compared to the demand ultimately realized in real time based on load forecasts. As a result, day-ahead prices may not price the demand levels that materialize during real-time operations.

Figure 10: Monthly average price for CAISO area

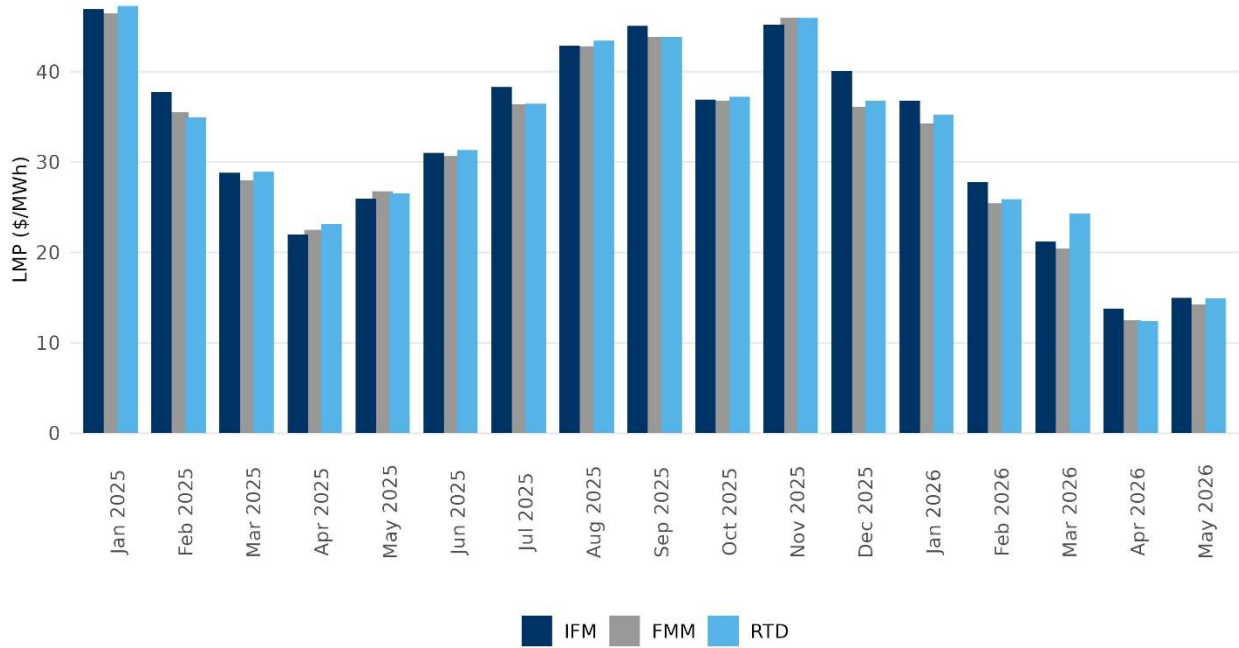


Figure 11: Monthly average price for PACW

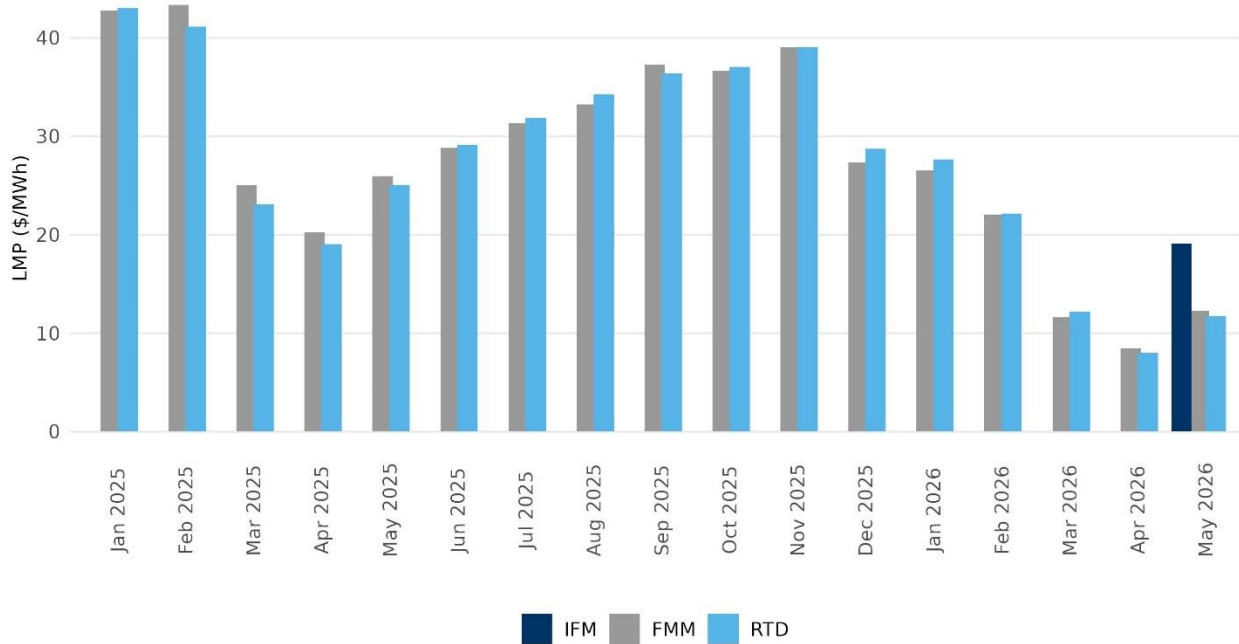


Figure 12: Monthly average price for PACE Average LMPs

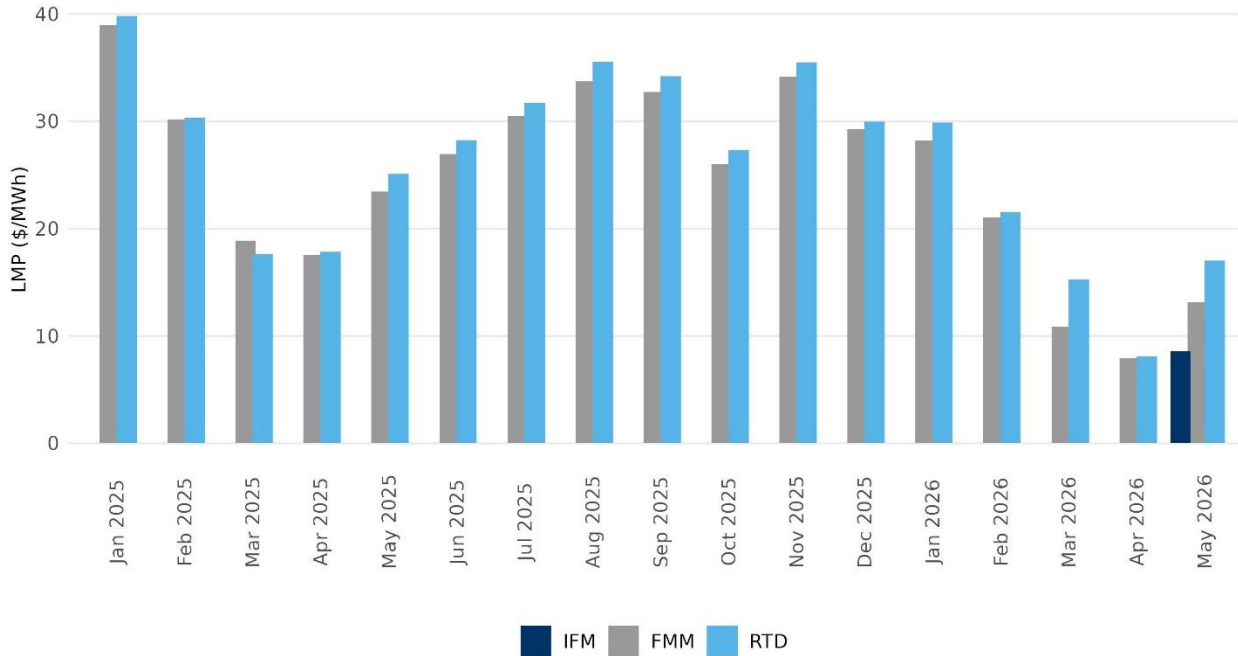
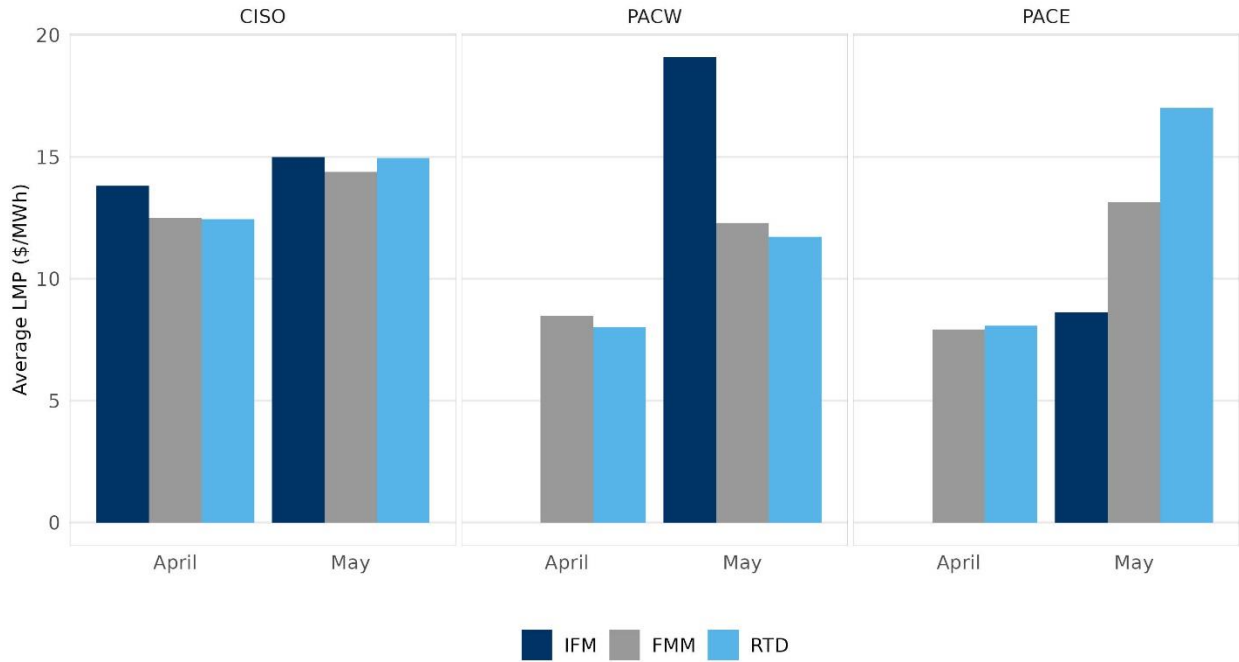


Figure 13 presents the same monthly average LMPs for April and May 2026 to ease the comparison among areas and months. The average IFM LMP for CAISO in April and May was \$13.80/MWh and \$14.98/MWh, respectively. The average IFM LMPs for the PACW and PACE areas in May were \$19.10/MWh and \$8.62, respectively. The average area FMM LMPs for CAISO, PACW and PACE were \$12.49/MWh, \$8.47/MWh, and \$7.91/MWh in April and \$14.38/MWh, \$12.29/MWh, and \$13.15/MWh in May. The average area RTD LMPs for CAISO, PACW and PACE were \$12.44/MWh, \$8.01/MWh, and \$8.07/MWh in April and \$14.94/MWh, \$11.72/MWh, and \$17.00/MWh in May.

Figure 13: Monthly average LMPs



Changes in price formation with EDAM

The previous assessment is based on the full locational marginal price (LMP). However, LMPs have different components:

- i) marginal energy cost (MEC),
- ii) marginal congestion cost (MCC),
- iii) marginal losses cost (MLC), and
- iv) marginal greenhouse gas emissions cost (MGHG).

With the introduction of EDAM/DAME, there are several significant changes to price formation in the day-ahead market.

Marginal energy cost

Before EDAM, there was a single system-level marginal energy cost (SMEC). After May 1, the marginal energy cost (MEC) is calculated separately for each BAA.

Before May 1, the day-ahead market enforced a power balance constraint (PBC) for only CAISO as there were no other BAAs in the day-ahead market. The real-time market, however, enforced two types of PBCs – a system-wide PBC and a BAA-specific PBC for every WEIM BAA except CAISO. The shadow price of the system-wide PBC (λ) served as the system marginal energy cost (SMEC) shared by all BAAs in the WEIM. On the other hand, the shadow price of the BAA-specific PBC (λ_j , where j denoted BAA j other than CAISO) was included in

the marginal congestion cost to drive price separation from the rest of the WEIM. See Figure 14 for the LMP decomposition of any given node in a non-CAISO WEIM BAA:

Figure 14: LMP Decomposition for Non-CAISO WEIM BAA

$$\left. \begin{aligned} SMEC &= \lambda \\ MLC_i &= (\lambda + \lambda_j - \psi) \left(\frac{1}{LPP_i} - 1 \right) \\ MCC_i &= \lambda_j - \sum_m \sum_{n \in N_m} a_{m,n} SF_{m,n,i} \mu_m \\ MGC_i &= -\psi \end{aligned} \right\}, \quad \forall i \in BAA_j \wedge j \in EIM \wedge j > 0$$

Note: i denotes node i , $j = 0$ denotes CAISO, and $j > 0$ denotes BAAs other than CAISO

The term λ_j itself consisted of multiple sub-components. Specifically, λ_j was the sum of the shadow price of the EIM Transfer Distribution Constraint for BAA j (ϕ_j) and the shadow price of either the upper EIM Transfer Scheduling Limit for BAA j (v_j) or the lower EIM Transfer Scheduling Limit for BAA j (ξ_j):

$$\lambda_j = \phi_j + v_j \text{ or } \lambda_j = \phi_j + \xi_j$$

First, the EIM Transfer Distribution Constraint ensured that the “WEIM Transfer for each WEIM BAA is distributed optimally to the applicable Energy Transfer Schedules” (Section 16.2.1.1.4 of the BPM for EIM). The WEIM Transfer for each WEIM BAA (T_j) was the sum of the schedules of all energy transfer system resources (ETSRs) defined for that BAA. $ET_{j,k,l}$ denoted an export ETSR l from BAA j to BAA k , and $IT_{j,k,l}$ denoted an import ETSR l to BAA j from BAA k :

$$\sum_{\substack{k \in EIM \\ k \neq j}} \sum_l (ET_{j,k,l} - IT_{j,k,l}) = T_j \quad \forall j \in EIM \wedge j > 0$$

The EIM Transfer Scheduling Limits constrained the total WEIM Transfer for a WEIM BAA to an upper limit \bar{T}_j and a lower limit \underline{T}_j . These limits were defined by the WEIM BAAs:

$$\underline{T}_j \leq T_j \leq \bar{T}_j, \quad \forall j \in EIM$$

In summary, prior to May 1, the shadow price of the system-wide PBC was applied uniformly to all WEIM BAAs via the SMEC. Price separation across the individual WEIM BAAs was

achieved via the MCC, which included the shadow price of the BAA-specific PBC which, in turn, consisted of the shadow prices of transfer constraints.

With the implementation of the extended day-ahead market, a new formulation of the energy component went into effect for both day-ahead and real-time markets. The formulation no longer uses a system-wide PBC; consequently, there is no longer the calculation of a system-wide SMEC. To facilitate the settlement of transfer revenues which arise when there is MEC separation between BAAs, EDAM and WEIM now only enforce BAA-specific power balance constraints for each EDAM or WEIM BAA. The shadow price of the BAA-specific PBC is the MEC for the BAA. The shadow price of the BAA-specific PBC (λ_j) still contains the shadow prices of the transfer constraints:

$$\lambda_j = \phi_j + v_j \text{ or } \lambda_j = \phi_j + \xi_j$$

The Transfer Distribution Constraint continues to be enforced for every WEIM BAA in the real-time market and is now enforced for every EDAM BAA in the day-ahead market. The Transfer Scheduling Limits continue to be enforced for every WEIM BAA in the real-time market and are now enforced for every EDAM BAA in the day-ahead market.

While the formulation of the transfer constraints did not change, the way their respective shadow prices feed into the LMP definition did change. Namely, the transfer constraint shadow prices are now part of the MEC and are no longer part of the MCC. The MCC now only reflects congestion from transmission elements (flow gates, nomograms and contingencies) and does not include any shadow price from a BAA-specific PBC.

Table 1: Comparison of LMP decomposition before and after May 1, 2026

Before 5/1/2026		5/1/2026 - Present	
SMEC Components	MCC Components	MEC Components	MCC Components
	ϕ_j	ϕ_j	μ_j
	v_j	v_j	
	ξ_j	ξ_j	
	μ_j		

Note: μ_j denotes shadow price of transmission constraint (e.g., flowgate, nomogram)

GHG prices

Before EDAM, the marginal cost of greenhouse gas (GHG) emissions was embedded into the SMEC and then subtracted from non-California BAA LMPs. With this formulation, the GHG component was applied only to non-California-area locations, and it was a negative component. After May 1, the marginal cost of GHG emissions is accounted for outside of the MEC and only applies within GHG regulation areas¹. With EDAM/DAME the GHG component is positive and applied only to California-area locations.

Figure 15 shows the average LMP composition in IFM, FMM, and RTD for the PACE and PACW ELAPs as well as the four CAISO default load aggregation points (DLAPs) across April and May. In April, the MEC was the same across all areas, reflecting the SMEC. In May, the MEC varied between BAAs. The variation in the MEC across BAAs was more pronounced in the IFM and RTD. The change in GHG cost accounting can also be seen in Figure 15. In April, the GHG component of the LMP was negative and only applied to PAC areas BAAs. After May 1, the GHG component of the LMP is positive and only applies to California-area LMPs.

¹ California is currently the only GHG regulation area active within the market footprint.

Figure 15: Average monthly LMP components

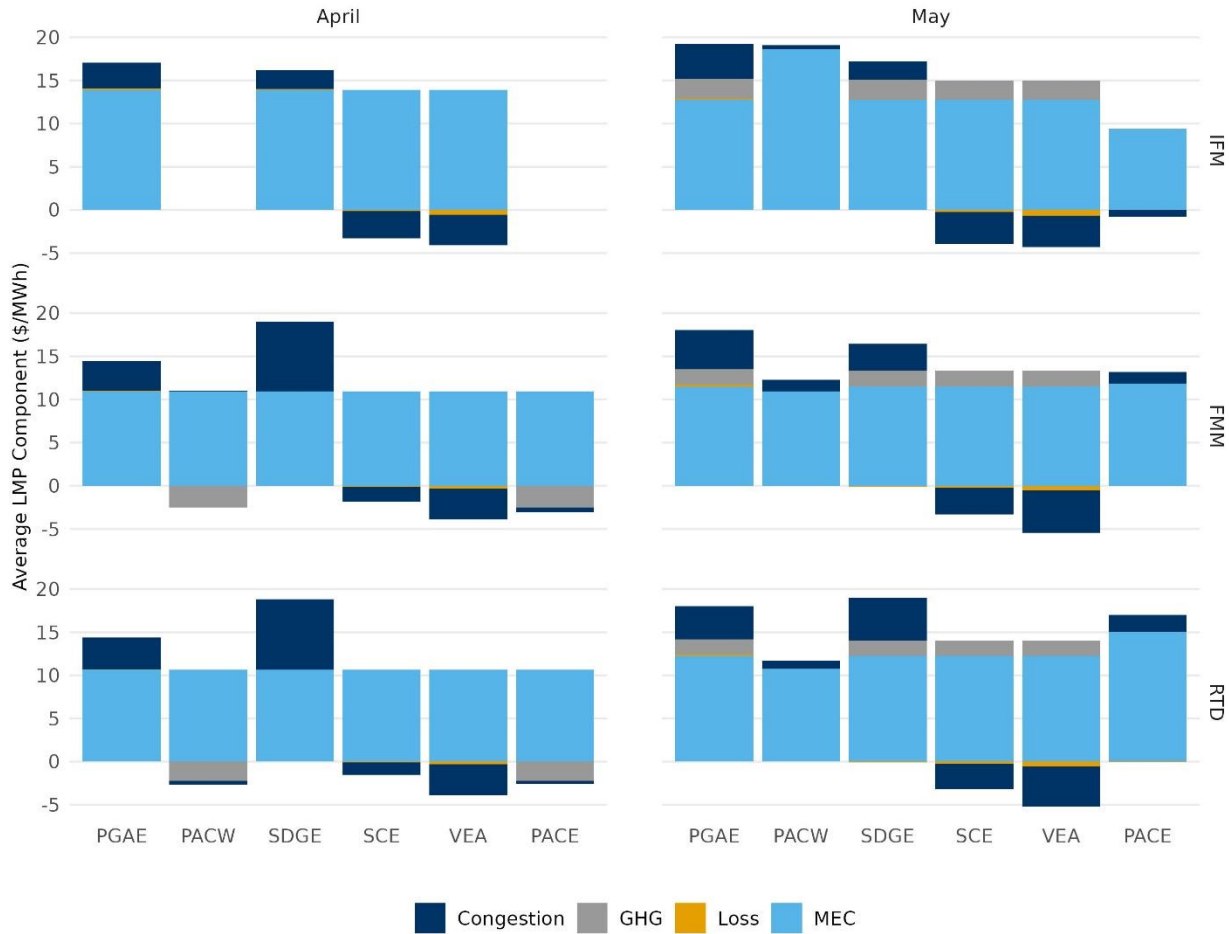


Figure 16, Figure 17, and Figure 18 show the frequency of prices falling in predefined \$/MWh ranges in the given month for each BAA. For example, in May 2026 the CAISO RTD LMP was between -50 and 0 \$/MWh in almost a quarter of all intervals in the month. For all three BAAs, the fraction of intervals with lower LMPs has increased compared to the same time last year.

Compared to April, May LMPs saw a slight increase in the frequency of LMPs in the 40 to 100 \$/MWh range for CAISO and 20 to 40 \$/MWh range for PACE and PACW. Looking at last April and May suggests that this is a normal trend for this time of year. These figures suggest that EDAM had no noticeable impact on the volatility of real-time prices. However, it is difficult to see any changes in the frequency of extreme prices, i.e. below -\$50 or above \$100.

Figure 19 shows only the frequency of LMPs in the price ranges below -\$50 and above \$100. This more specific view shows that CAISO had no LMPs above \$200 and the frequency of LMPs between 100 and 200 \$/MWh was within the normal range. Figure 19 shows that PACW had only five out of 8,928 intervals with LMPs reaching the \$1000 range. PACE saw the

greatest frequency of LMPs above \$100 out of the three EDAM BAAs, but PACE saw a similar frequency of high LMPs in March 2026.

Figure 16: CAISO RTD LMP range frequency

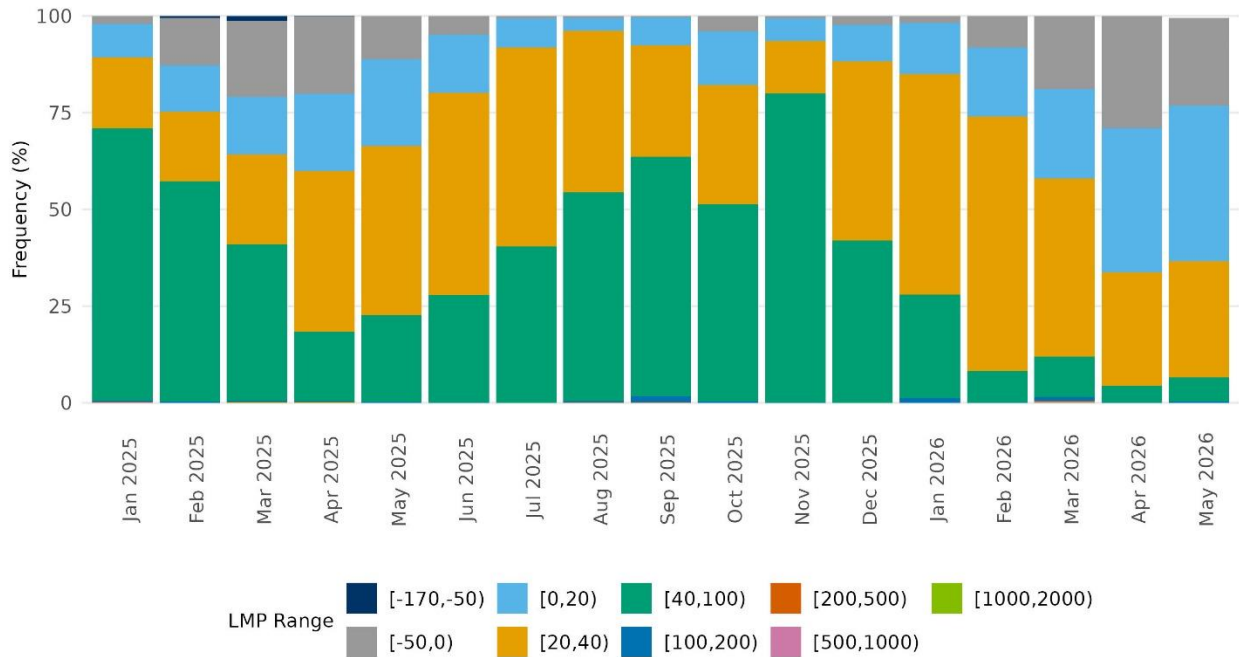


Figure 17: PACW RTD LMP range frequency

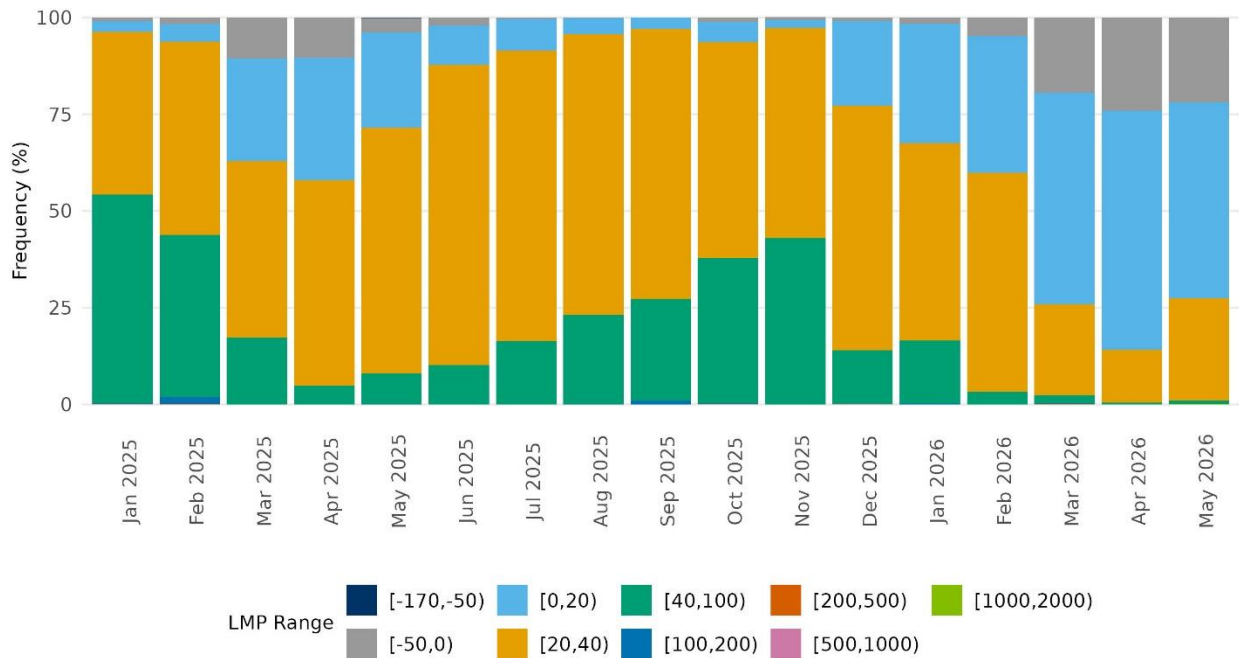


Figure 18: PACE RTD LMP Range Frequency

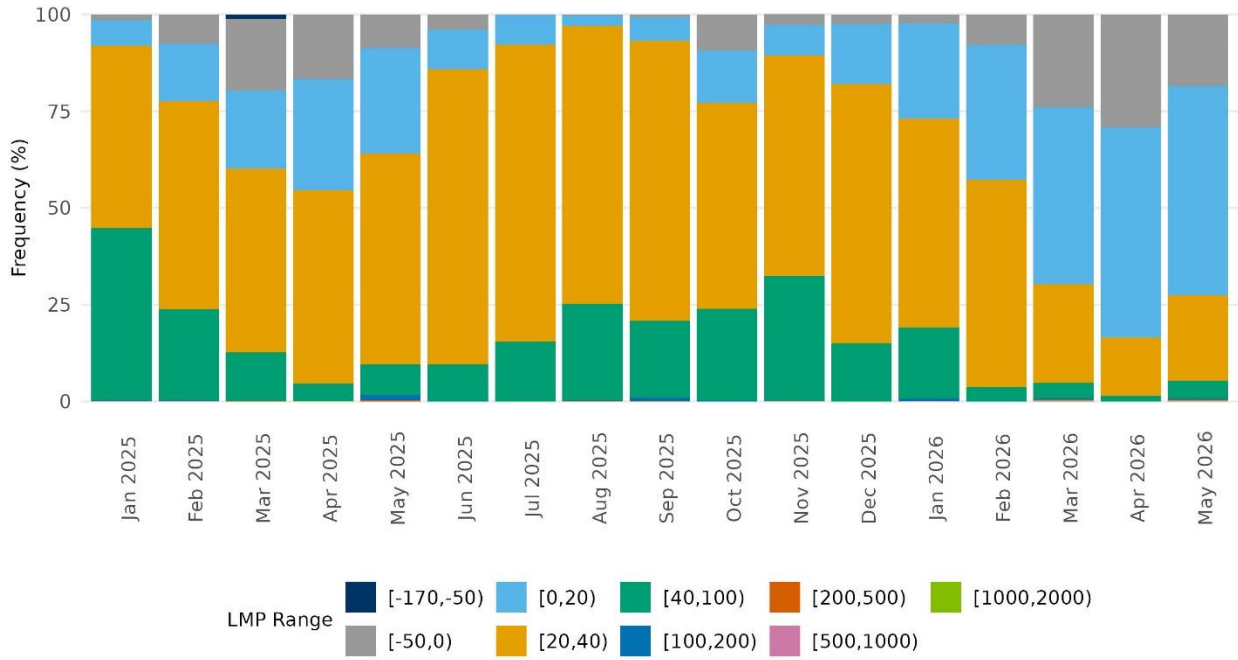
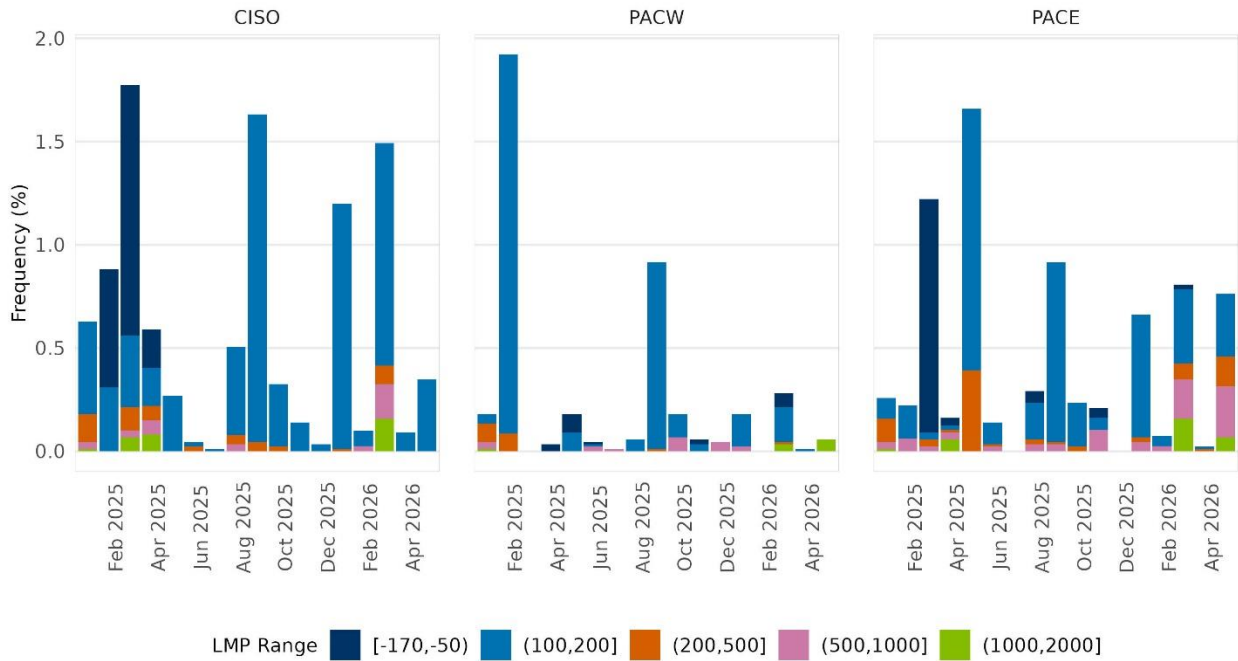


Figure 19: Frequency of extreme LMPs



Bilateral power price comparisons

Outside the CAISO's markets, power is historically traded through forward-looking transactions between buyers and sellers. The Intercontinental Exchange (ICE) is a bilateral power marketplace where power contracts can be bilaterally traded between two counterparties.

Comparing bilateral power prices from ICE to CAISO market prices is useful as both CAISO and ICE markets reflect the willingness of buyers and sellers to trade next-day power and can provide some reference of how the marketplace valued power in the West. The comparison of power prices and energy quantity traded is also useful to assess what impact the new EDAM market may have on bilateral next-day power trading.

Figure 20 and Figure 21 below show a comparison between EDAM BAA LMPs and next-day bilateral power prices at the Mid-Columbia (MidC) and Palo Verde (PV) hubs. These two hubs are highly liquid and geographically cover the north (MidC) and south (PV). While CAISO prices are hourly, next-day bilateral power trades in blocks for on-peak and off-peak periods², thus the bilateral prices shown are calculated as the average of hourly prices where each hour is assigned the applicable time of use price. The CAISO LMP is calculated as the load weighted average of its four DLAP LMPs.

Figure 20 shows that CAISO day-ahead LMP has a strong correlation with MidC and PV next-day bilateral power prices. CAISO LMPs were mostly lower than MidC and PV next-day prices but did converge on several days in May. There was also correlation between PACW day-ahead LMPs and next-day bilateral power prices, though not as strong as for CAISO. PACW LMPs were mostly lower than MidC and PV next-day prices and price convergence was observed on several days though fewer days than CAISO. Overall, PACE day-ahead LMPs were lower than MidC and PV next-day prices. This may relate to days with high level of renewables and low demand levels.

² Peak is typically defined as hours-ending 7-22 on weekdays and Saturdays; off-peak is typically defined as hours-ending 1-6 and 23-24 on weekdays and Saturdays, and hours-ending 1-24 on Sundays and holidays.

Figure 20: Daily average LMPs and bilateral power prices

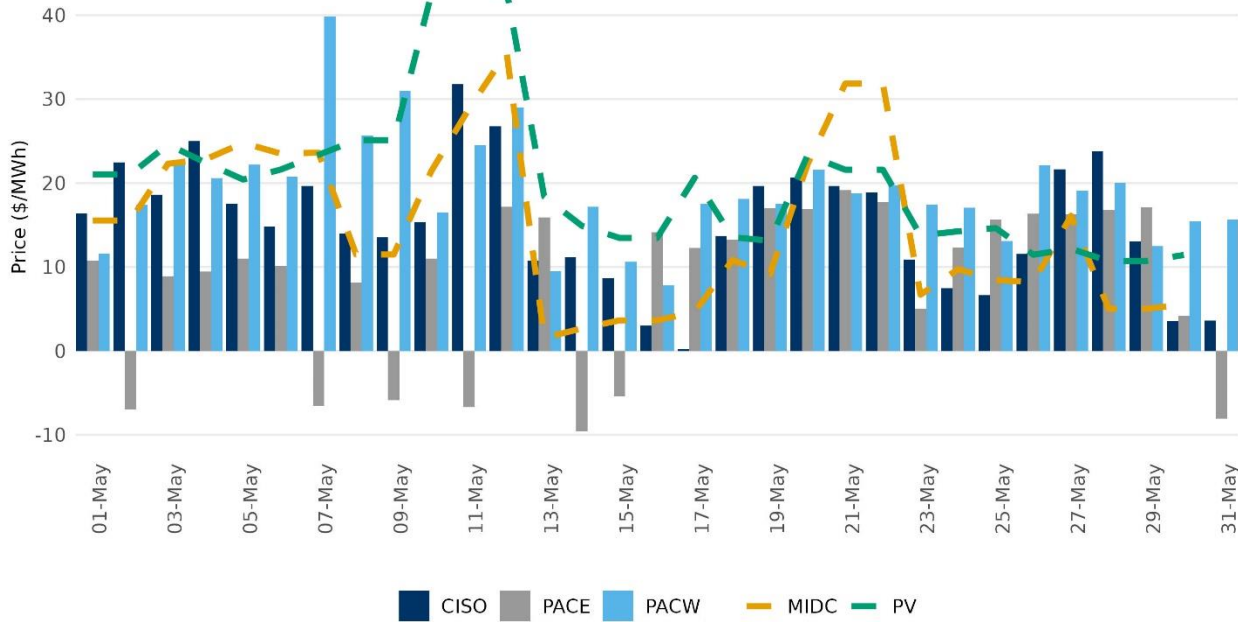


Figure 21 shows that CAISO day-ahead LMPs have historically shown some correlation with next-day bilateral power prices at MidC and PV. The high MidC price in February 2025 was due to a major Arctic cold snap. The first month of EDAM appears to show continued correlation in prices between CAISO day-ahead LMPs and next-day bilateral power prices at MidC and PV. For PACW and PACE, a more robust assessment of this correlation will require observation over a longer period of EDAM operations.

Figure 21: Monthly average LMPs and bilateral power prices

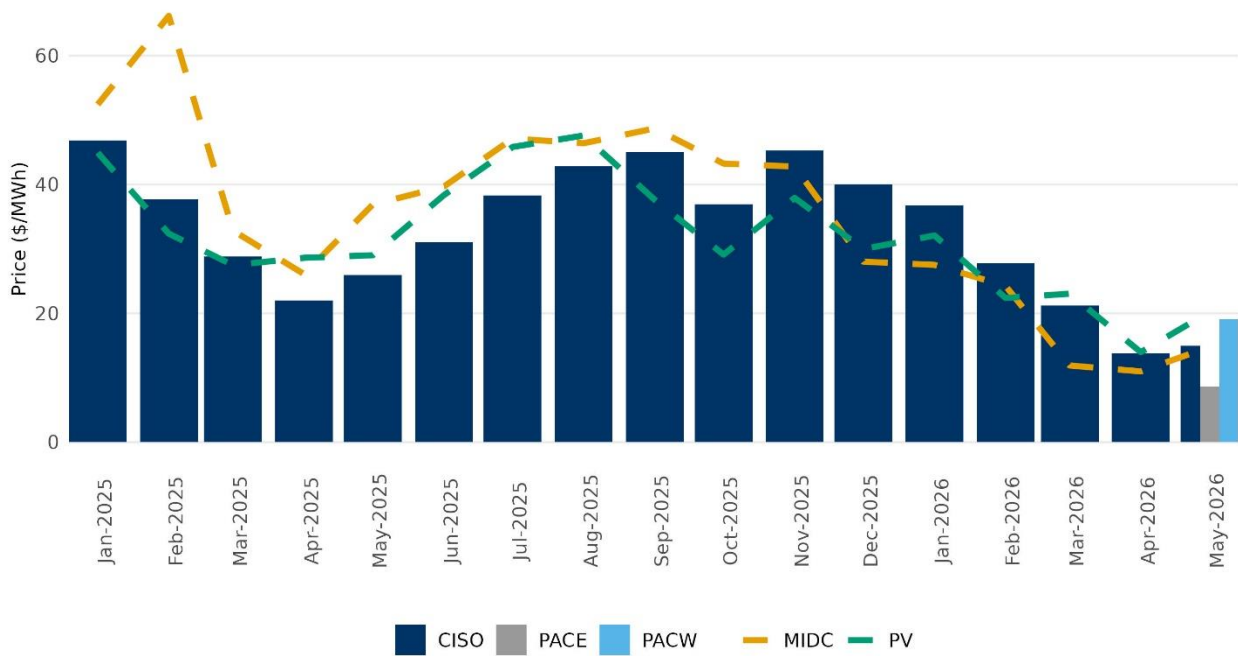


Figure 22 and Figure 23 show the daily energy volume traded for bilateral next-day power at MidC and PV hubs from April to May. For on peak, no power is traded on Sundays, which is an off-peak day. For off-peak, volumes are lowest during the weekdays. For both on- and off-peak, volumes are usually highest at the end of the week when power delivery is for Sunday and Monday. These figures show no observable change in the volume traded for on- or off-peak from April to May.

Figure 24 and Figure 25 show the monthly average energy volume traded since January 2025. The volume traded in May 2026 is like April 2026 and shows no marked deviation from historical patterns. Observing this metric after several months of EDAM operations will provide a better indication of any impact of the EDAM market on bilateral power trading.

Figure 22: Total daily energy volume of bilateral trades (On-peak)

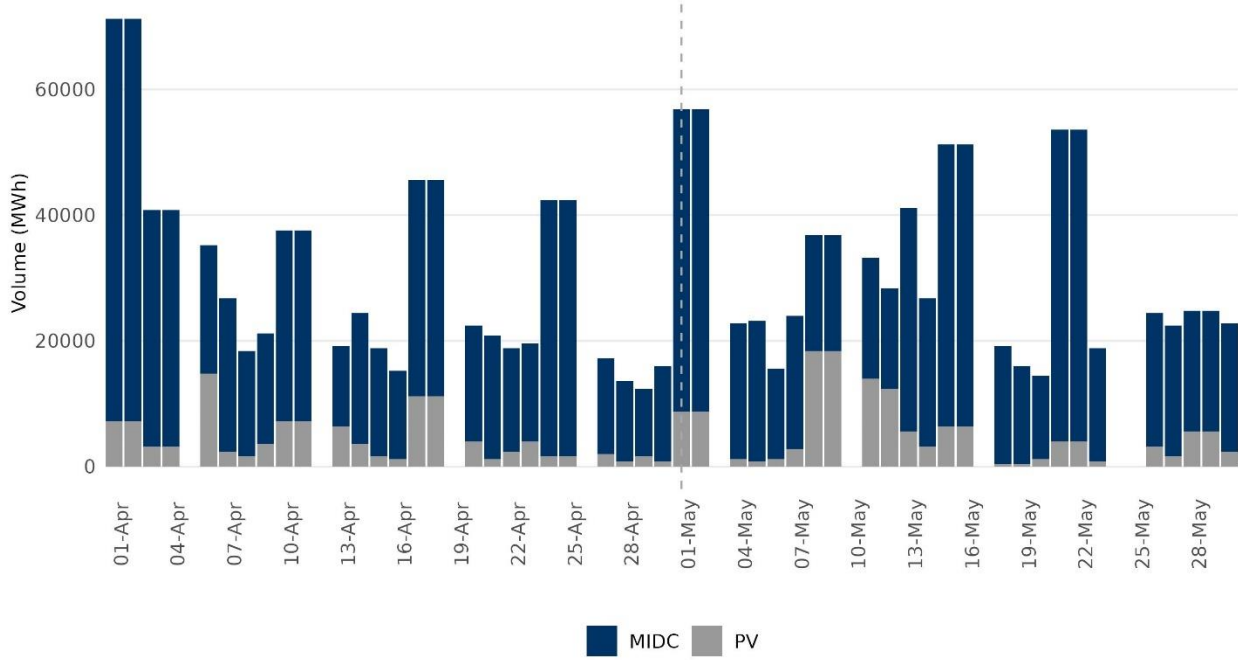


Figure 23: Total daily energy volume of bilateral trades (Off-peak)

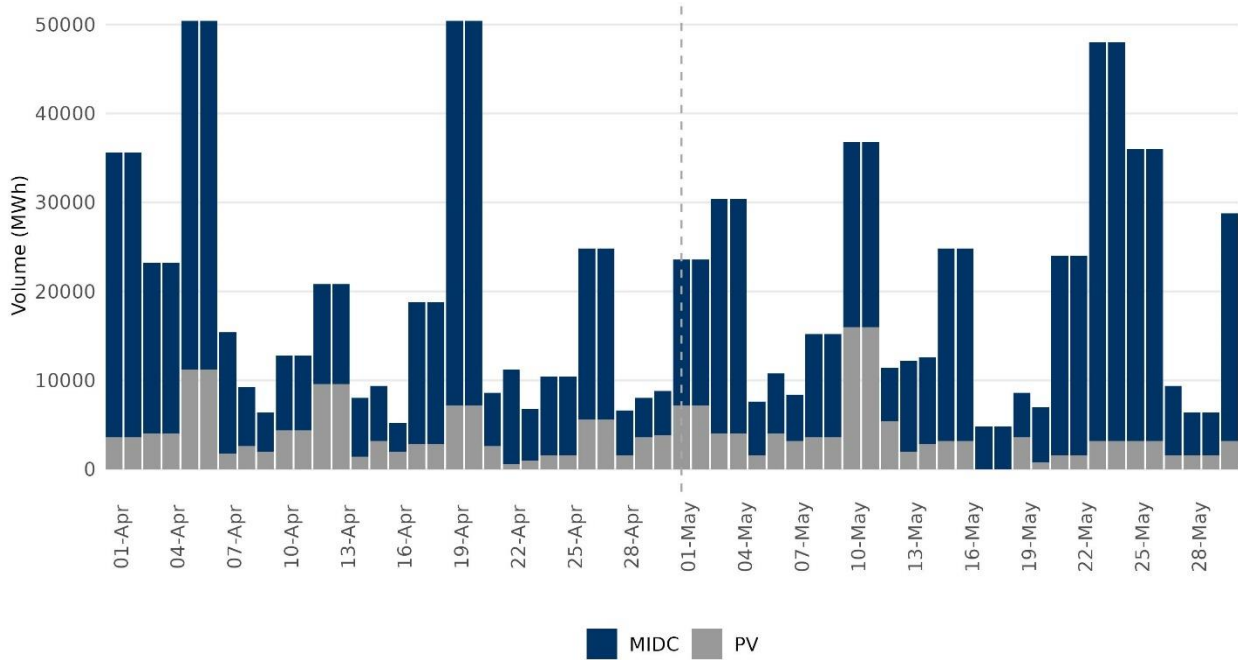


Figure 24: Total monthly energy volume of bilateral trades (On-peak)

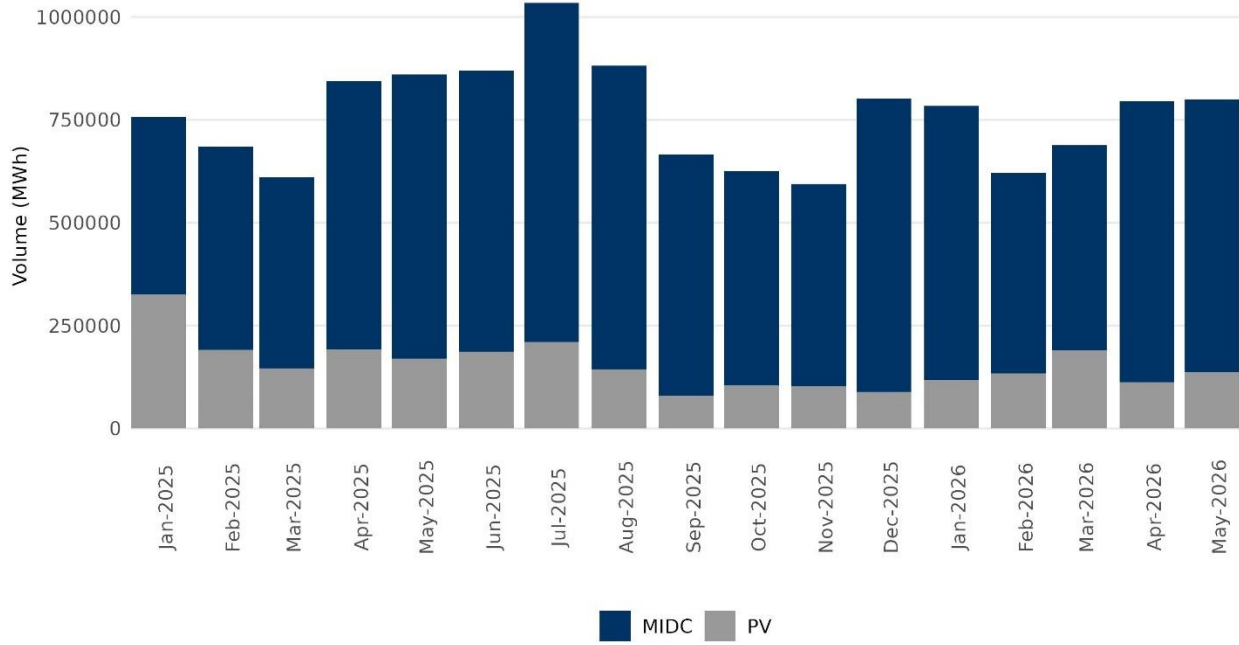
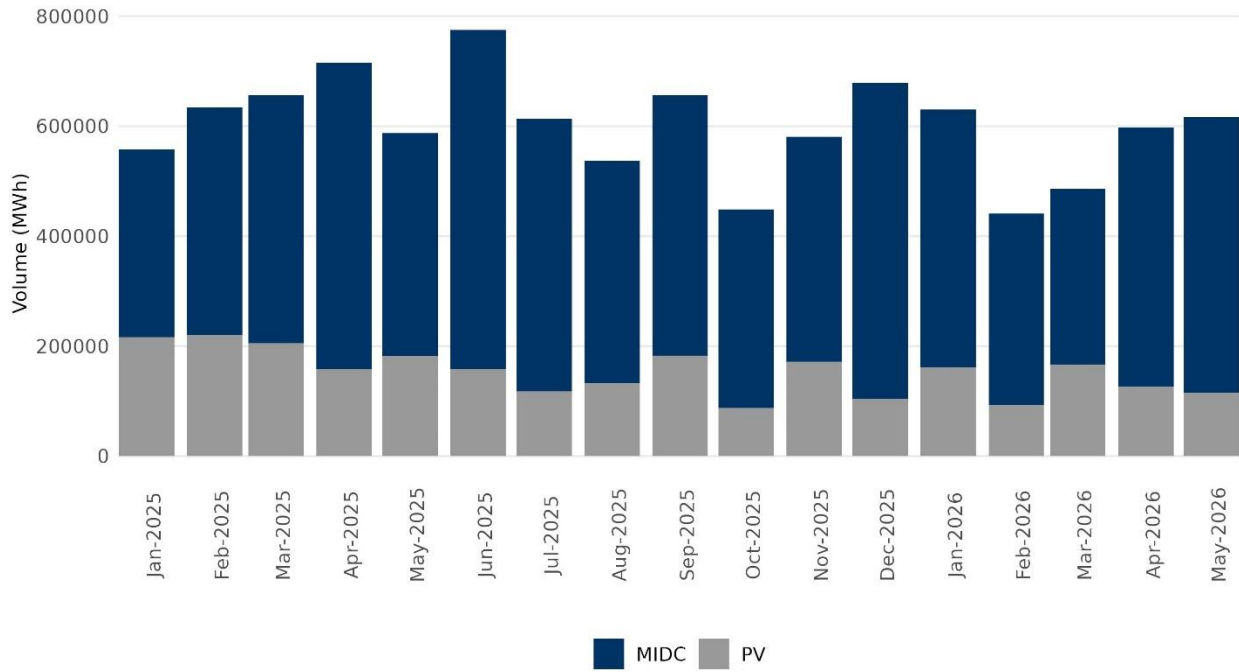


Figure 25: Monthly total energy volume of bilateral trades (Off-peak)



Ancillary services

EDAM go-live made few changes to ancillary service procurement market design. The one major change applies to battery storage resource type (LESR). For these resources, new commodities were added to the envelope constraint which models the impact on state of charge of various commodities, including regulation up and down for CAISO and the new commodities imbalance reserve and reliability capacity for resources in all EDAM BAAs.

Figure 26 shows CAISO ancillary services prices in IFM from April 1st to May 31st, spanning one month before to one month after EDAM go-live. Overall, AS prices remained within typical ranges for all four commodities in May. Regulation up and down prices showed slight increase while Spin and Non-spin prices remained in similar ranges.

Figure 26: Daily average of CAISO ancillary services prices in IFM

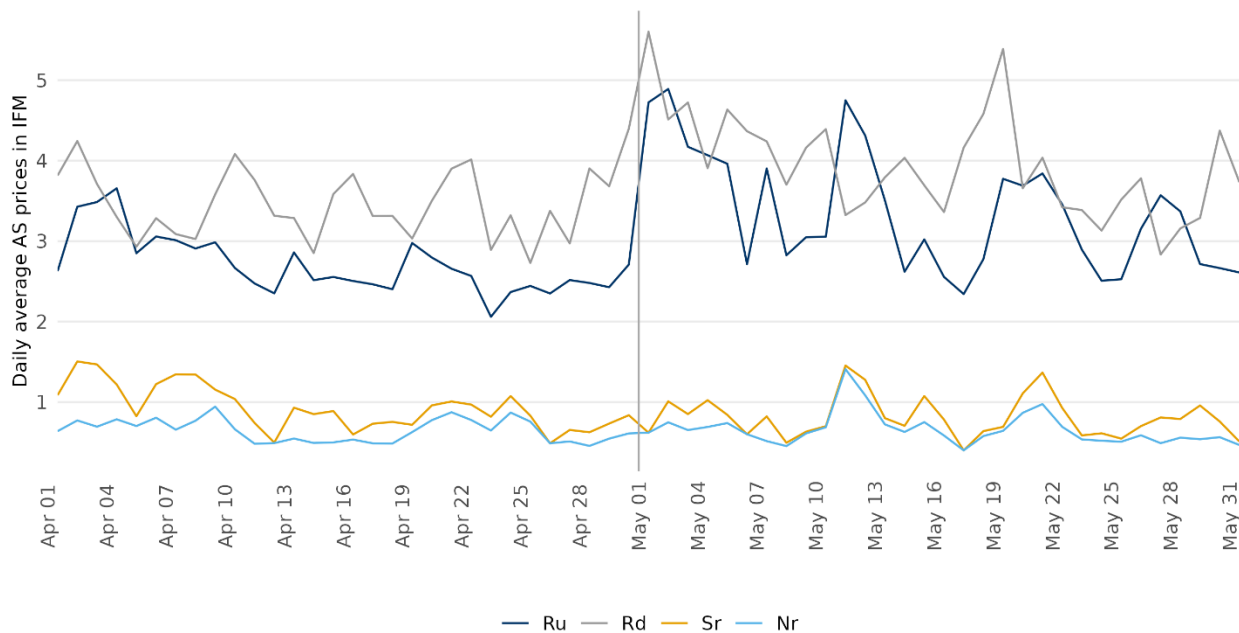
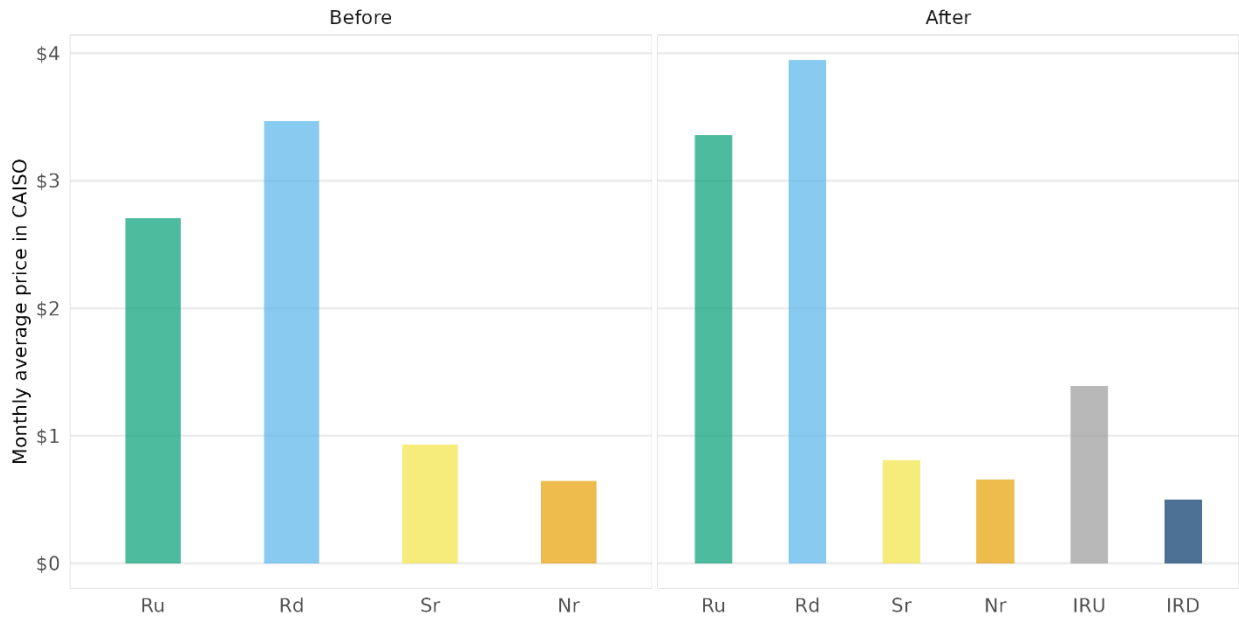


Figure 27 compares the monthly average AS prices in CAISO for the same period. Average regulation up and down prices showed slight increases, while spin and non-spin prices generally remained in similar range. New imbalance reserve prices in CAISO in May are added for reference. Average price of 1.4 \$/MWh for imbalance reserve up fell between average prices of 3.4 \$/MWh for regulation up and 0.8 \$/MWh for spin.

Figure 27: Monthly average AS prices in CAISO



A feature of CAISO’s market regarding provisions of AS is the flexibility to cascade procurement for upward AS commodities. Cascaded procurement is where capacity of a higher quality AS type can be counted towards meeting the requirements for a lower quality type. From highest to lowest quality, the upward AS product ranking is: regulation up, spin, non-spin. This cascading structure is embedded directly into the market clearing process, which simultaneously clears energy and ancillary services. In May after EDAM go-live, the frequency of AS cascading showed a change in pattern when procuring upward AS.

Figure 28 compares the frequency of cascading in regulation up and spin, one month before versus one month after go-live. The frequency of cascading in regulation up decreased from 28.8% in April to 4.7% in May. The frequency of cascading in spin increased from 74.3% in April to 85.6% in May. The requirement for each AS is still fully met with the bids explicitly submitted for these services.

Figure 28: Frequency of cascading in Regulation and Spin reserves

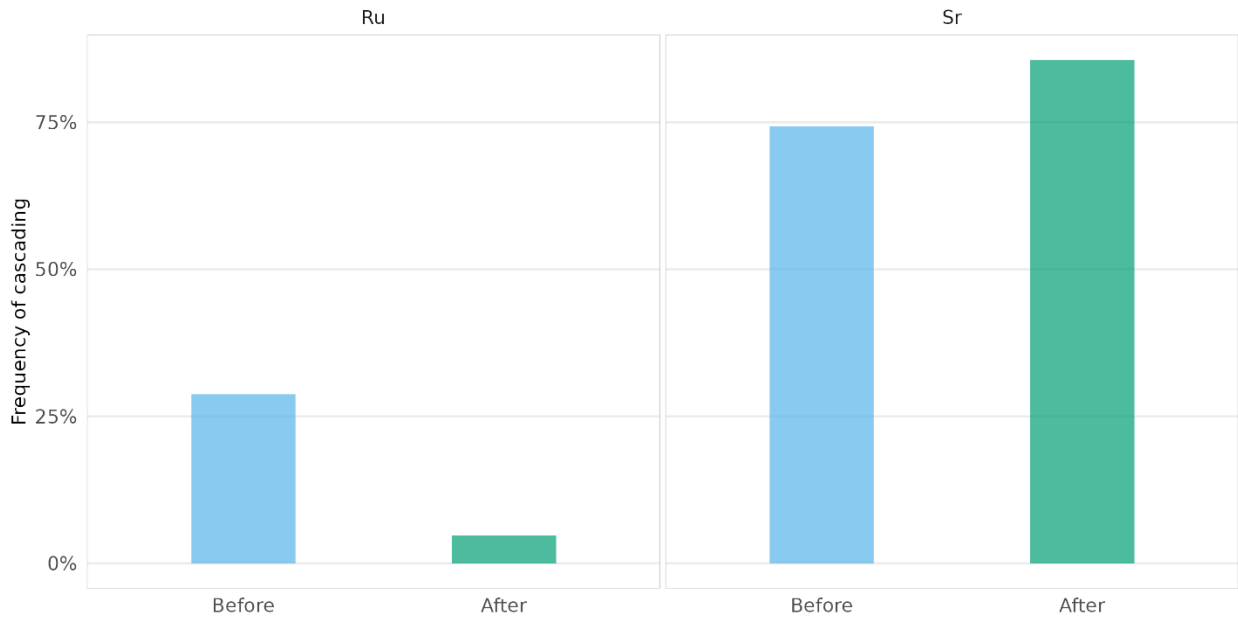


Figure 29 shows the percentage procurement one month before versus after EDAM go-live by AS commodity. Figure 30 shows the daily distributions of percentage procurement for the same period. Percentage procurement is defined as procurement divided by the requirement for the corresponding product. When cascading happens in one commodity, its percentage procurement will be higher than 100%, showing the extra capacity procured to fulfill the requirement of the lower quality commodity. After EDAM go-live, percentage procurement of regulation up is concentrated at 100%, with lower frequency of outliers. Percentage procurement in spin showed an increase in overall distribution.

Figure 29: Comparison of monthly procurement in percentage

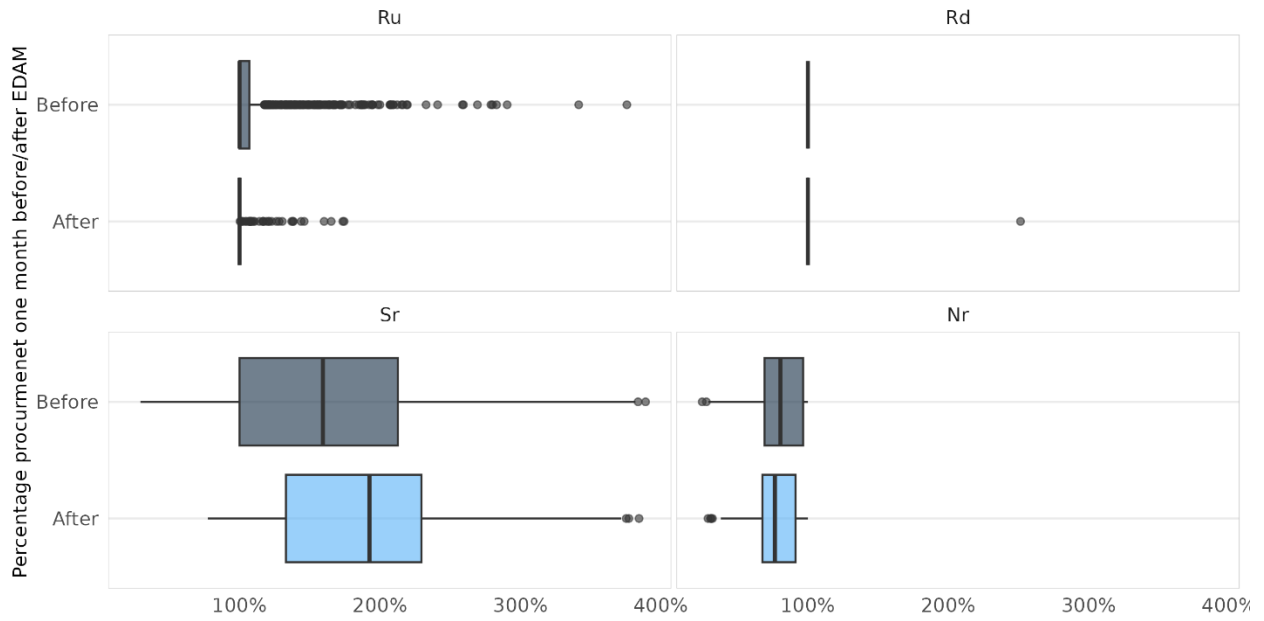


Figure 30: Daily distribution of AS percentage procurement in IFM

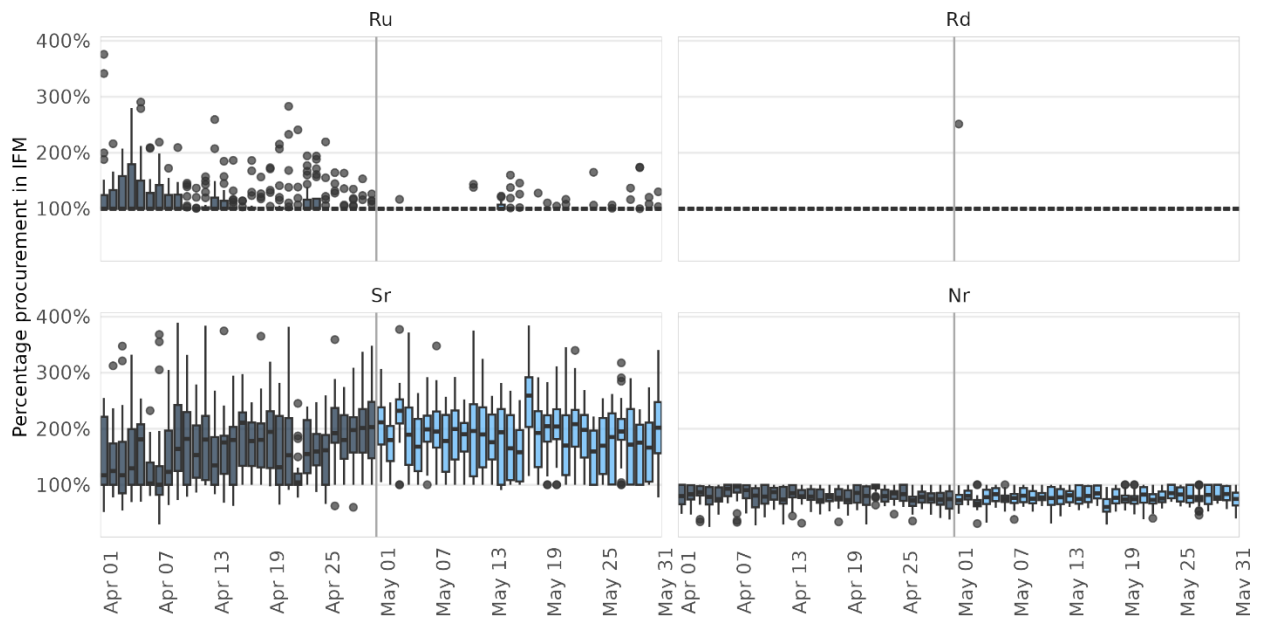
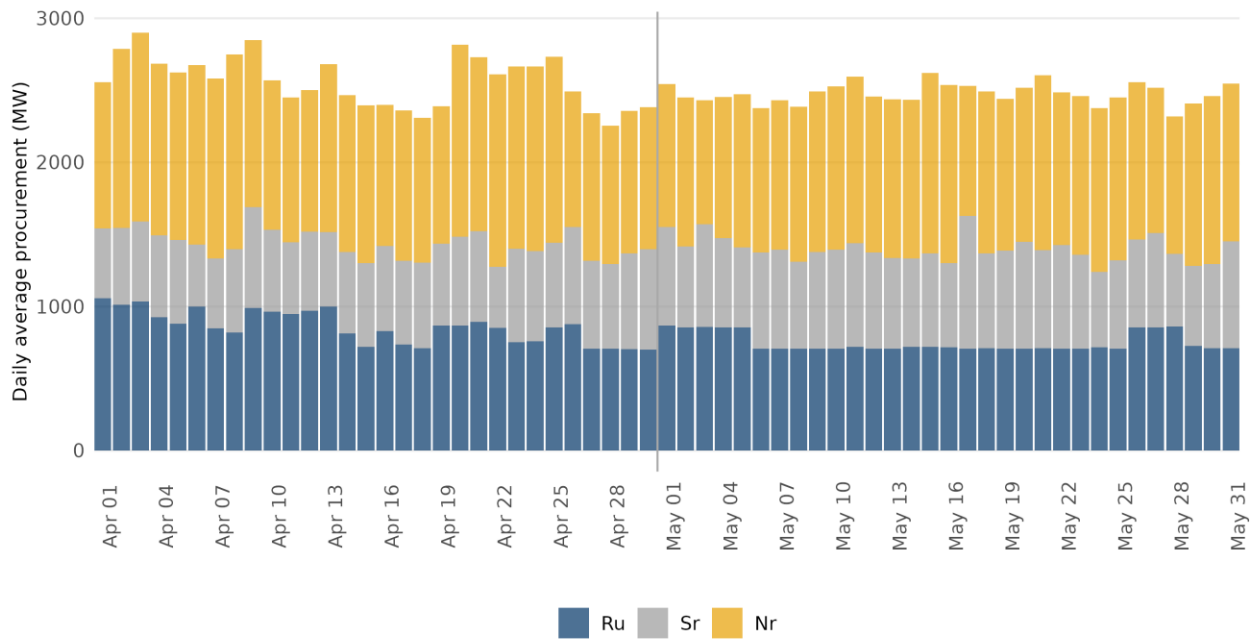


Figure 31 shows daily average procurement volume (MW) in upward AS commodities in IFM. In May, regulation up procurement showed slightly decrease while spin showed slightly increase.

Figure 31: Daily average Upward AS procurement in IFM



Cascading in upward AS is driven by AS prices and only happens when it is economical in the co-optimization process. Figure 32 to Figure 34 show price comparisons in upward AS commodities, one month before versus after EDAM go-live. In May, the price trends for regulation up, spin, and non-spin retained the same hourly shape. Compared to April, regulation up saw a 0.7 \$/MWh increase in average price in May, while average prices for spin and non-spin remained largely unchanged.

Figure 32: Regulation up prices for CAISO extended area

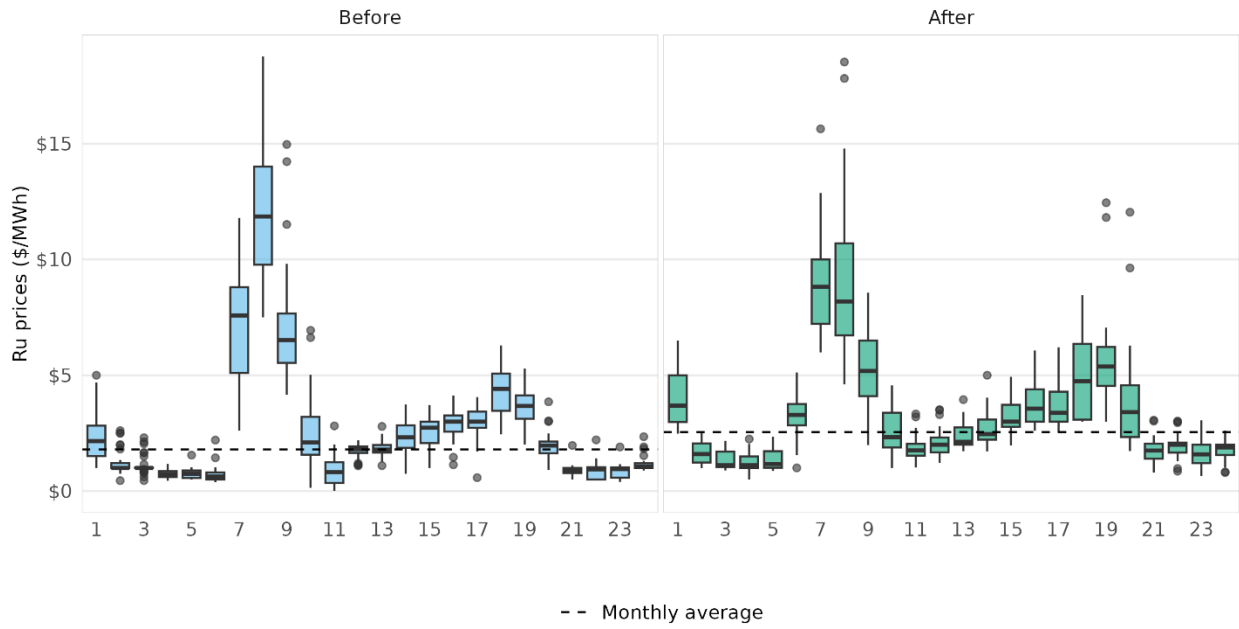


Figure 33: Spin prices for CAISO extended area

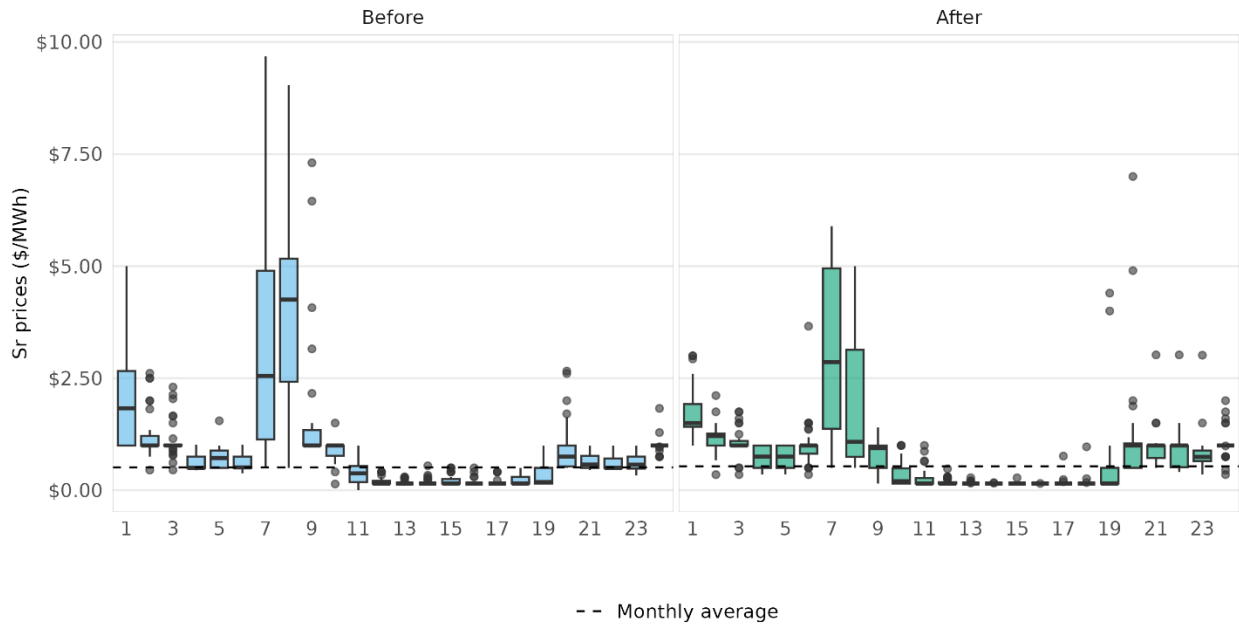
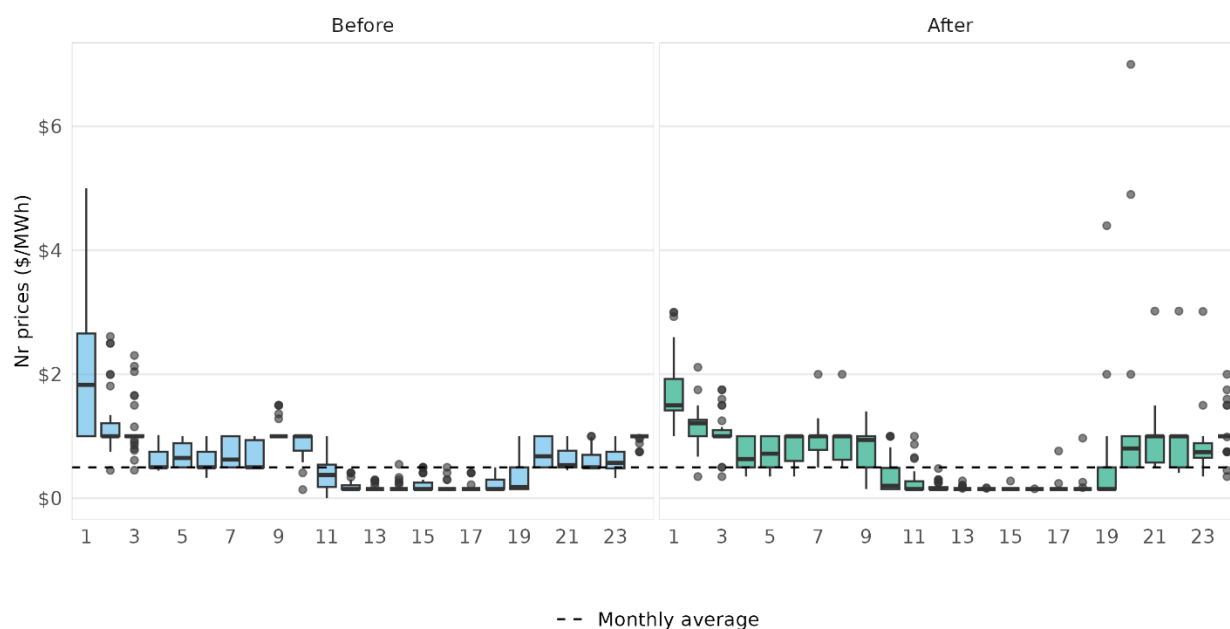


Figure 34: Non-spin prices for CAISO extended area



Imbalance reserves

Imbalance Reserves (IR) are a new flexible reserve day-ahead product introduced with the EDAM market. The IR product covers uncertainty that materializes between the day-ahead and the real-time net load forecast, and real-time ramping needs not covered by hourly day-ahead market schedules. Net load forecast uncertainty is driven by variability in variable energy resource production forecasts and load forecasts. Imbalances in the net load forecasts between the day-ahead and real-time markets have grown due to rapid growth in variable energy resource capacity on the CAISO grid and more extreme weather throughout the Western grid. The IR product ensures that each balancing authority area in EDAM has sufficient flexible capacity scheduled to meet net load imbalances between the day-ahead and real-time markets. The market procures imbalance reserves bi-directionally to ensure upward and downward net load imbalances are covered.

Imbalance reserve prices are shown in Figure 35 to Figure 38 below. The average daily price for May 2026 is shown in Figure 35 and Figure 36, while the average hourly price for May 2026 is shown Figure 37 and Figure 38.

Overall, IRU prices were higher than IRD prices for all three BAAs, which may be reflective of the lower demand conditions in May. Between BAAs, prices were consistently highest for PACW compared to CAISO and PACE. Daily average IRU prices for PACW reached over 15 \$/MWh at the beginning of May, with some hours exceeding 50 \$/MWh. Average daily IRD prices for PACW exceeded 20 \$/MWh on May 4, reaching 50 \$/MWh in certain hours. IRU and IRD prices in PACW stabilized in the second half of May. Meanwhile for CAISO and PACE prices were mild and stable throughout May, with IRU prices staying below 5 \$/MWh and IRD prices staying below 2 \$/MWh on average. Average hourly prices for all three BAAs tended to be highest during the morning and evening peaks. In general, the average hourly evening peak price was higher than the morning peak price. An exception was for IRU in PACW where the average hourly price during the morning peak was higher than the evening peak. The imbalance reserve price separation observed between the three BAAs reflects the economics of the wider EDAM market footprint and each BAA's imbalance reserve requirement, available supply mix and EDAM transfers.

Figure 35: Daily average price of IRU



Figure 36: Daily average price of IRD

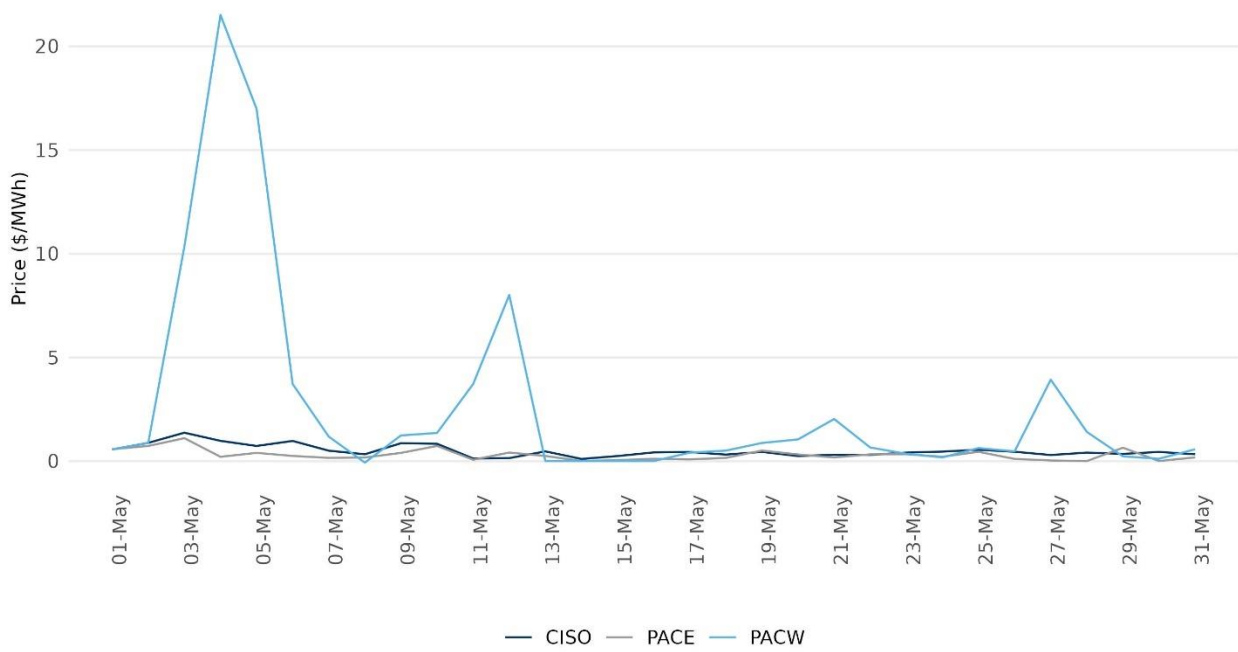


Figure 37: Hourly average price of IRU

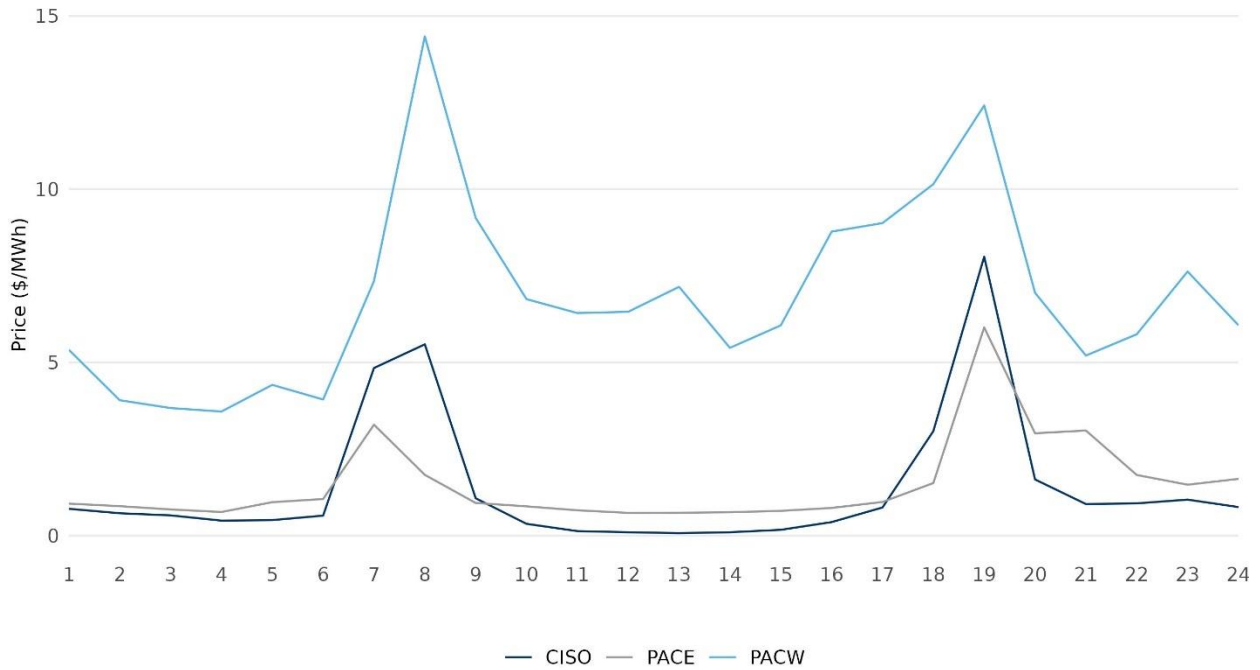
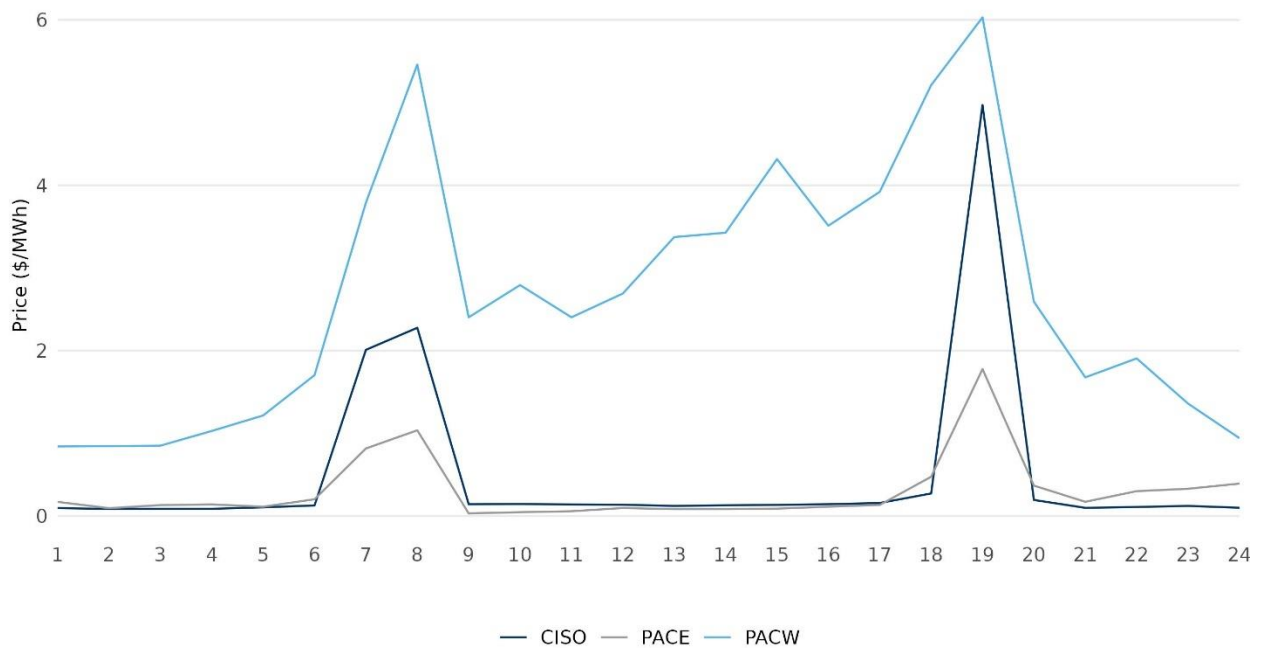


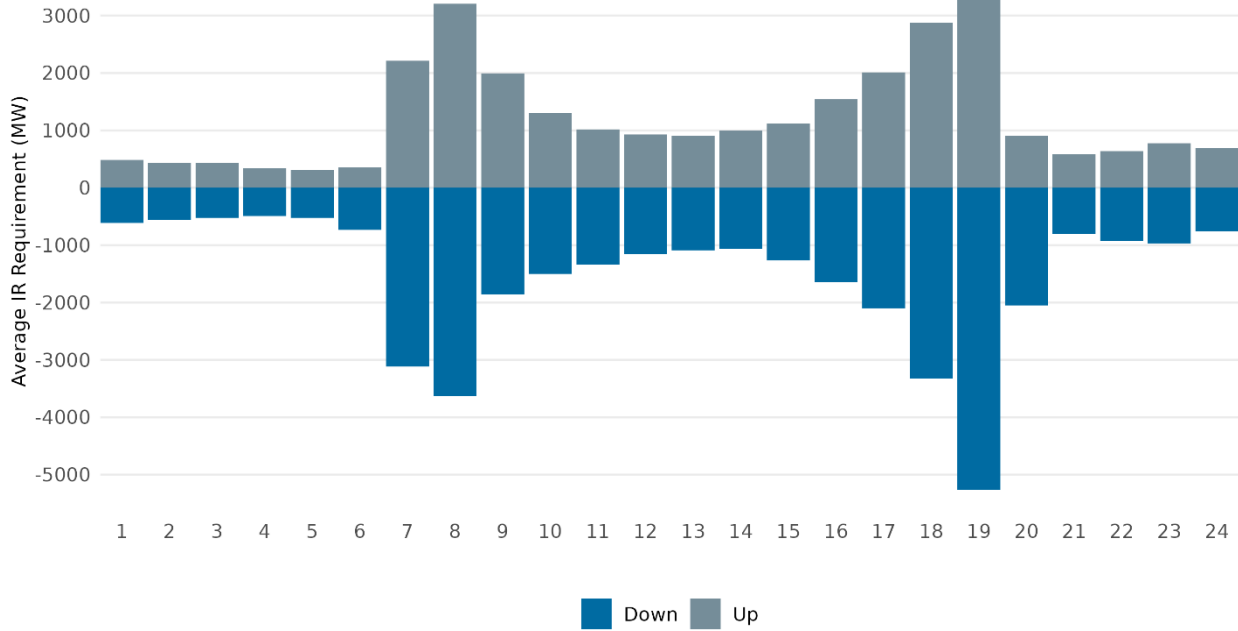
Figure 38: Hourly average price of IRD



IR Requirements are calculated hourly for each BAA. Figure 39 to Figure 41 illustrate average IR requirements for each BAA by direction. The magnitude of IR procured is proportional to the magnitude of net load uncertainty associated with that BAA. CAISO is the largest footprint in the EDAM with a large assortment of variable energy resources, so naturally it sees the highest amount of IR procurement.

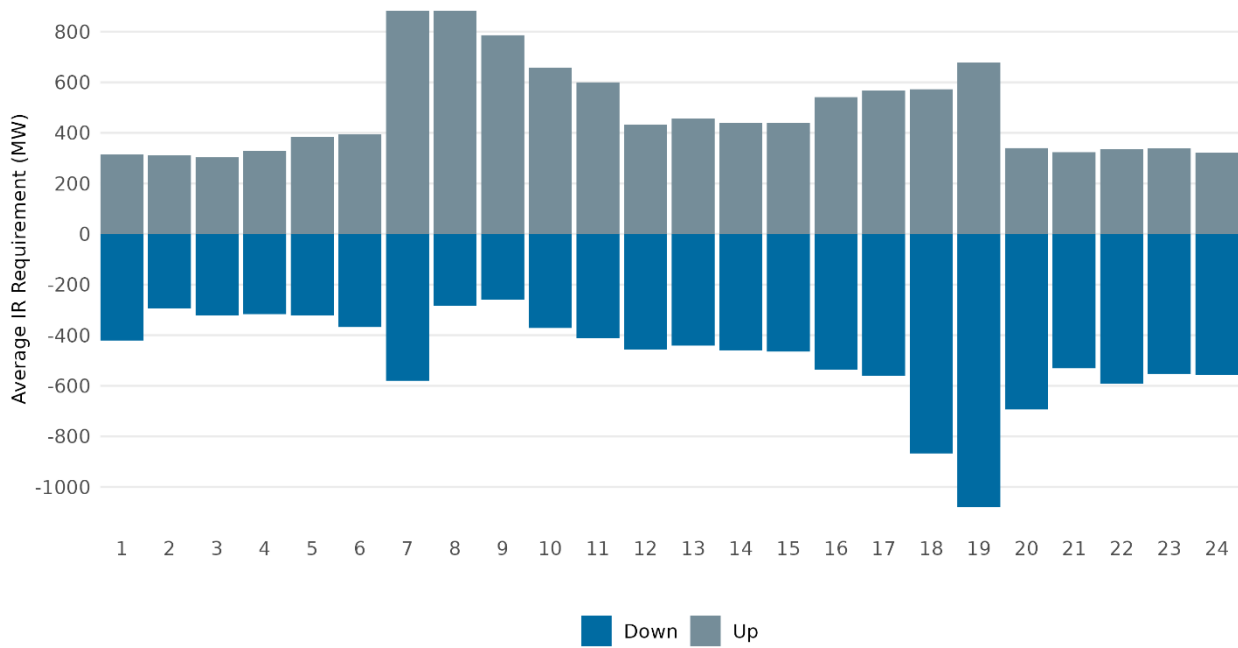
IR requirements for CAISO BAA were consistent in shape and magnitude across May. The highest requirements typically occur during the solar ramping hours where flexibility is required if the net load forecast changes.

Figure 39: Hourly average of IR requirements for CAISO



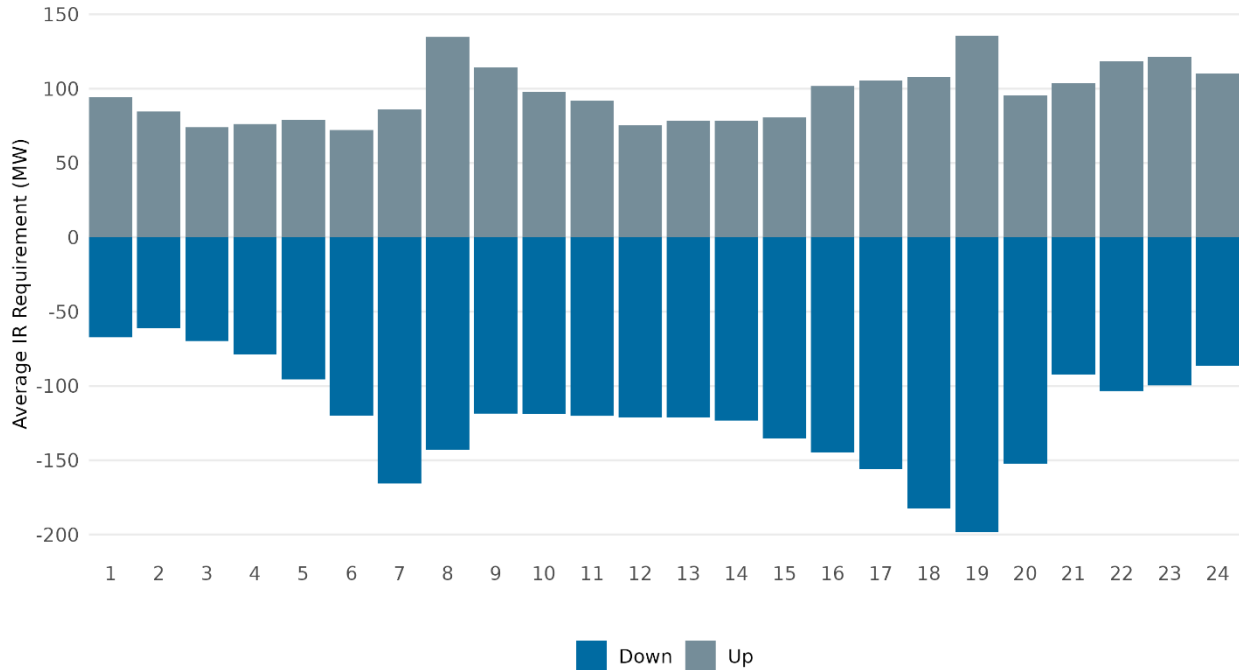
PACE IR requirements, on average, also saw the highest IRU requirements during the morning ramping hours and the highest IRD requirements during the evening peak.

Figure 40: Hourly average of IR requirements for PACE



PACW IRU requirements were relatively consistent throughout the day on average for both IRU and IRD. IRU averaged ~100 MW while IRD Averaged 120MW with peaks in the morning and evening ramping hours.

Figure 41: Hourly average for IR requirements for PACW



EDAM expands the day-ahead market footprint. Uncertainty in each area, due to load and renewable variability, does not usually occur at the same time. Sharing supply and demand variability across a broader footprint brings diversity benefit to the EDAM BAAs, by reducing the total requirement needed compared with the total requirements when assessing area needs separately. Figure 42 presents the hourly average diversity benefit by EDAM BAA by product. Diversity benefit is defined as the difference between the sum of individual BAA IR requirement and the IR requirement of the entire EDAM footprint. The reduction of requirements is then allocated pro-rata to each EDAM BAA based on its original individual BAA requirement. In May 2026, for the upward direction, the average diversity benefit allocation was 62.9% to CAISO, 30.4% to PACE, and 6.7% to PACW, corresponding to average volume of 316MW to CAISO, 153MW to PACE, and 34MW to PACW. For the downward direction, the average diversity benefit allocation was 66.4% to CAISO, 27.3% to PACE, and 6.3% to PACW, corresponding to average of 331MW to CAISO, 136MW to PACE, and 31MW to PACW.

Figure 42: Hourly average diversity benefit

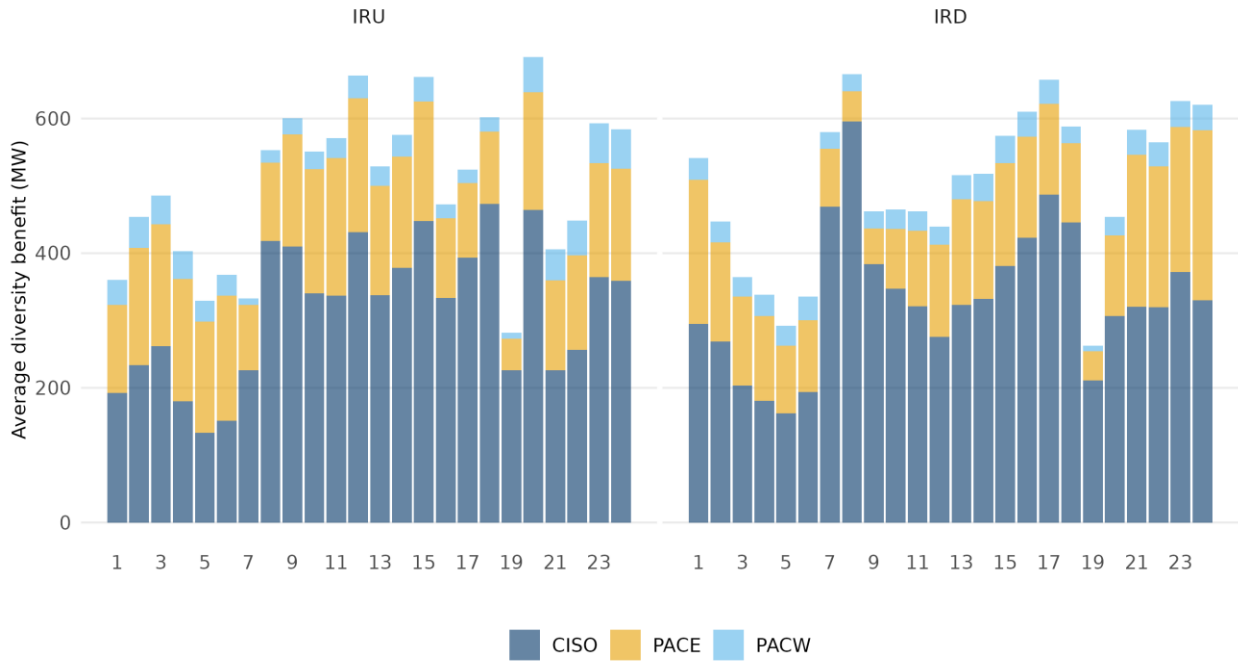


Figure 43 illustrates hourly average cleared IR by fuel type, positive direction indicates IRU and negative values indicate IRD, respectively. For the IRU direction, the resource mix exhibits a well-defined pattern, with gas resources providing the majority of IRU supply during overnight hours and remaining a significant contributor throughout the day. Solar resources become the dominant technology during daylight hours, and batteries show narrow procurement only during morning and evening ramp periods. As for IRD, solar resources show the greatest contribution during daylight hours, while wind resources become the main technology during night hours.

Figure 43: Hourly average cleared IR by fuel type for CAISO

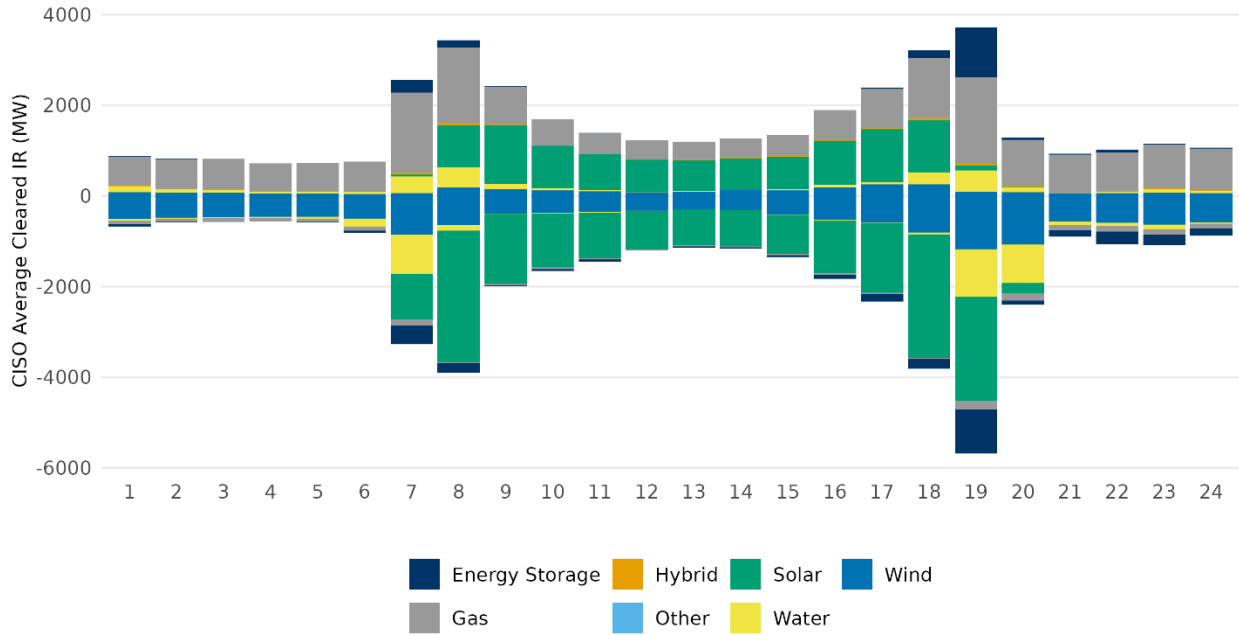


Figure 44 shows PACW’s hourly average cleared IRU and IRD by fuel type, respectively. Unlike CAISO, the dominant resources in PACW are water and wind, while gas has minor contribution. Water resources provide nearly all the IRU supply, and wind resources contribute the most of IRD supply.

Figure 44: Hourly average cleared IR by fuel type for PACW

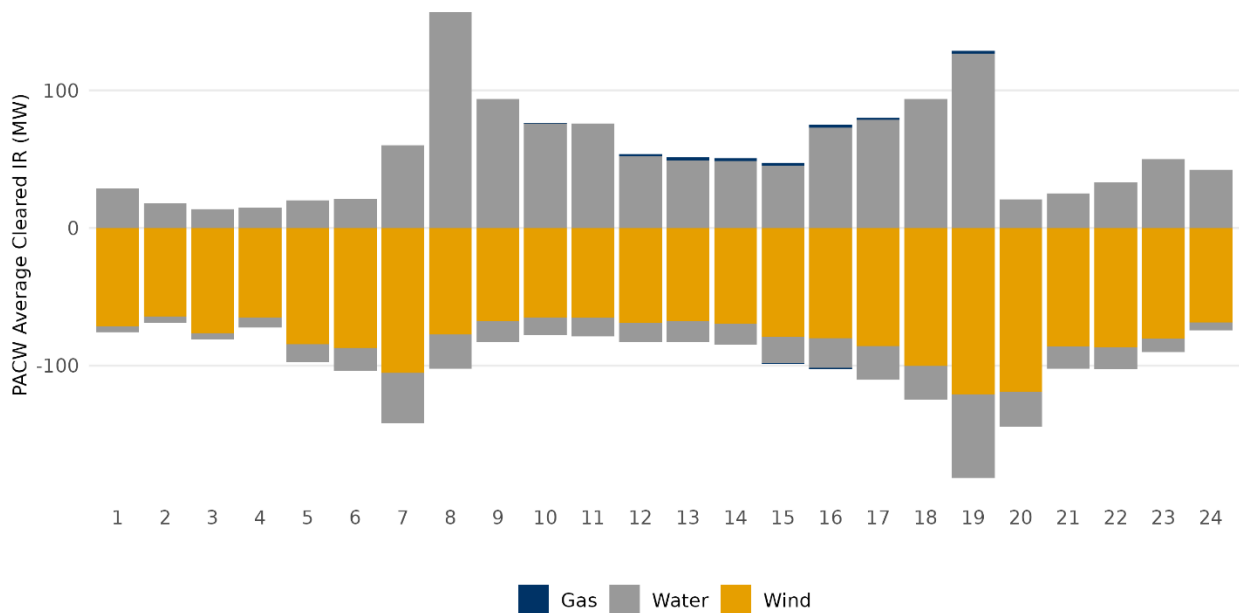
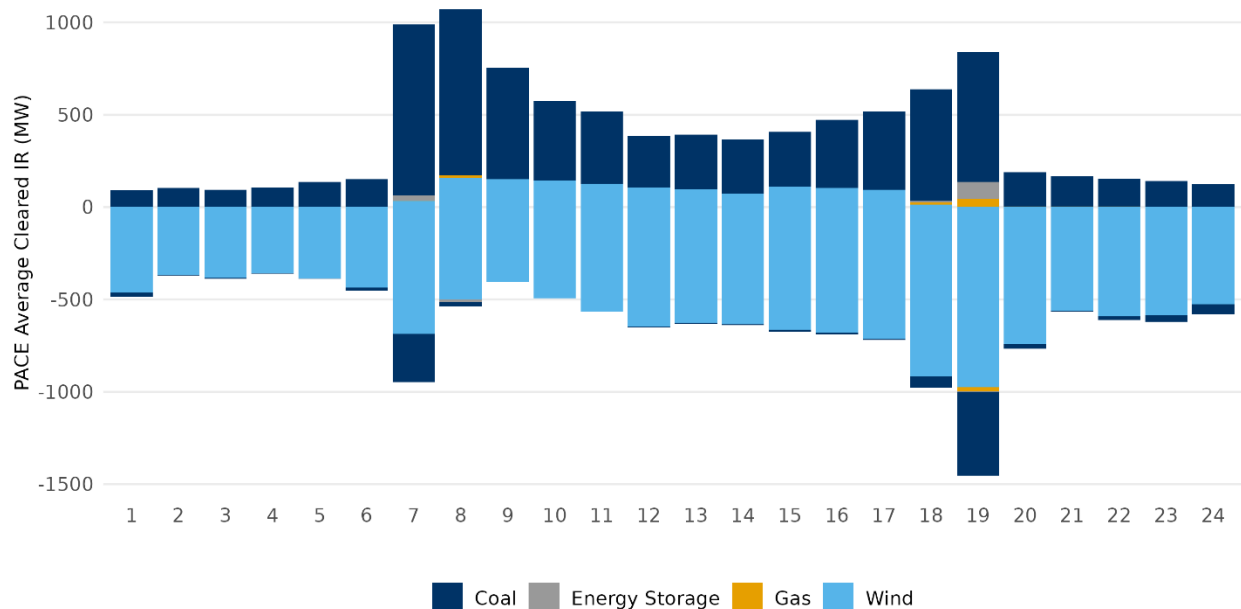


Figure 45: shows PACE’s hourly average cleared IRU and IRD by fuel type, respectively. Unlike CAISO and PACW, the dominant resources in PACE are coal and wind, while gas and storage have minimal contribution. Coal resources provide the majority of the IRU supply, with wind resources contributing to the remaining during daylight hours. In IRD supply, wind resources contribute the most, with the morning and evening ramp requirements provided by coal resources.

Figure 45: Hourly average cleared IR by fuel type for PACE



The technology supporting the procurement of IRU/IRD is organized by the host balancing area. However, as DAM enables economic transfers, a portion of the procured IR is indeed supported by areas transferring IR. These transfers are explicitly tracked and analyzed in subsequent.

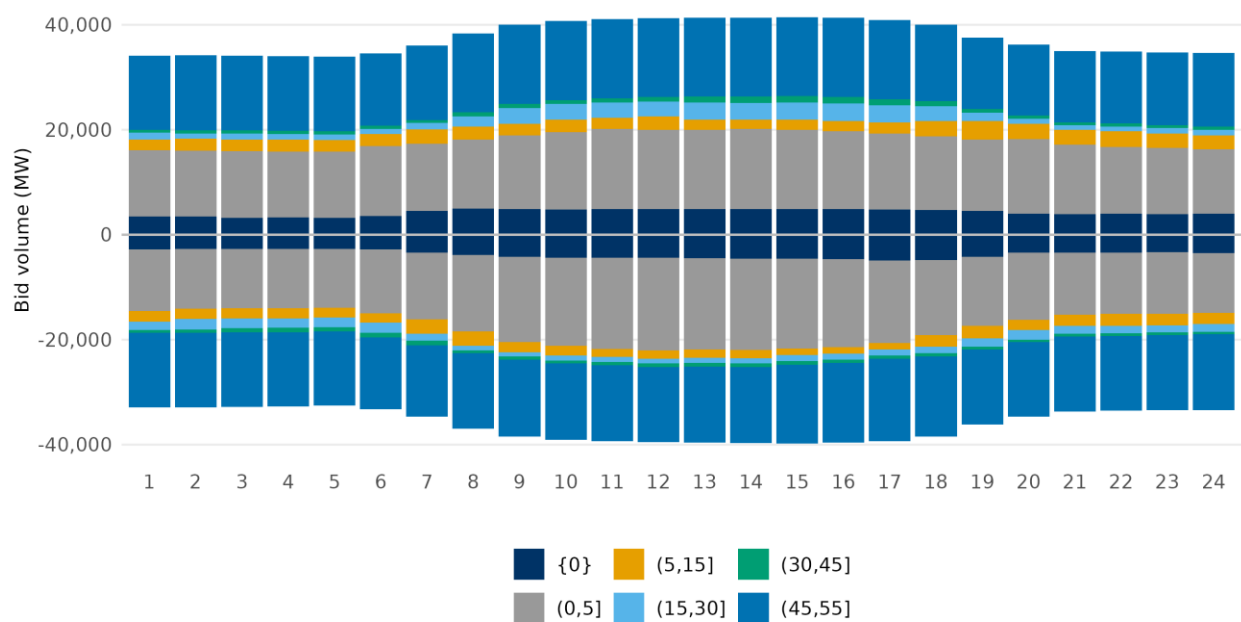
Imbalance reserves are co-optimized with energy and ancillary services in the IFM, therefore, resources need to submit economic energy bids for intervals in which imbalance reserve bids are submitted. The energy bid includes the portion that overlaps with the imbalance reserve bid. Imbalance reserve bids are subject to a \$55/MWh cap.

Figure 46 and Figure 48 illustrate CAISO’s hourly and daily average IFM supply input bids for IR by bid price range and by fuel type. Low-priced bids (0–5 \$/MWh) and high-priced bids (45–55 \$/MWh) consistently accounted for the largest share of submitted IR capacity throughout the month with about 30,000 MW (80 percent). The remaining price ranges, including zero prices, and mid-priced ranges (5–30 \$/MWh) represented a relatively small share of total submitted capacity. Hourly bid volumes were generally higher during daytime

hours and lower during overnight hours. Generally, CAISO’s submitted IR capacity remained relatively stable during May, with only a few days exhibiting lower bid volumes. The overall bid-price composition showed limited variation across both hourly and daily views, indicating a stable supply offer pattern for CAISO’s IR in May. The volume of bids in the upward direction is very symmetrical to the volume for the downward direction.³

Figure 47 and Figure 49 illustrate CAISO’s hourly and daily average IFM supply input bids for IR by fuel type. Energy storage, gas, and solar resources accounted for the largest share of submitted IR capacity throughout the month, followed by wind and hybrid resources.

Figure 46: Hourly average volume of IR bids organized by price for CAISO



³ This is a measure of the bid volume in the market that can be utilized to procure IR; however, much of that capacity can also be made available to meet energy needs. In the end, the market clearing process determines how to optimally allocate the supply available among the different market commodities.

Figure 47: Hourly average volume of IR bids organized by fuel type for CAISO

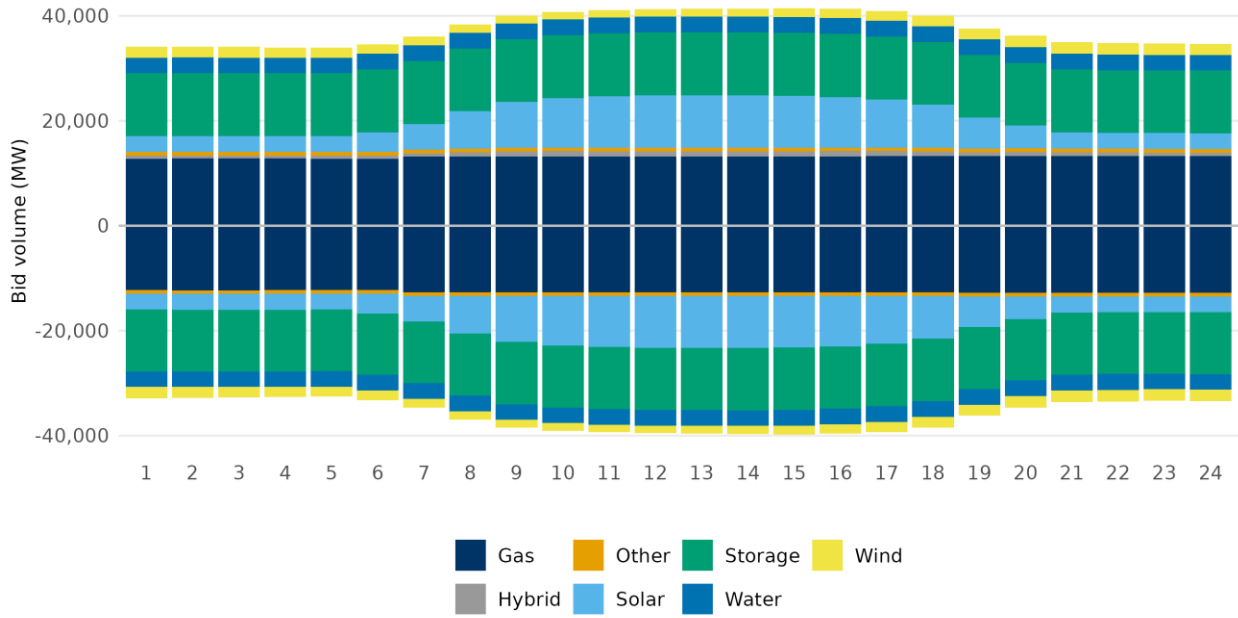


Figure 48: Daily average volume of IR bids organized by price for CAISO

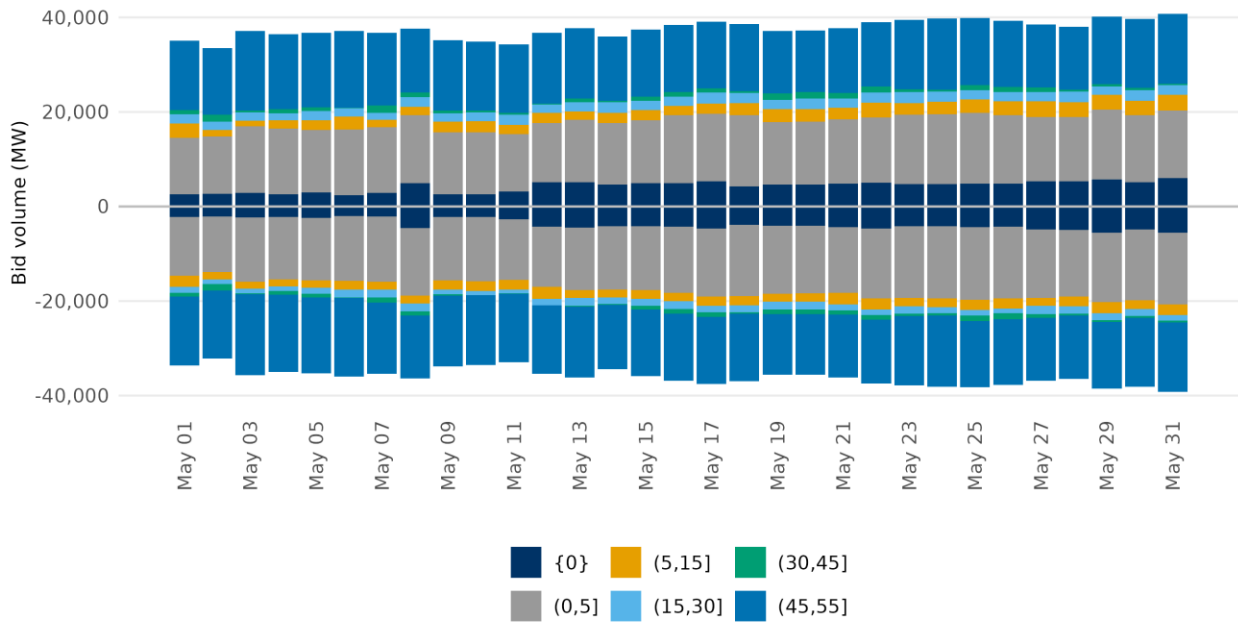


Figure 49: Daily average volume of IR bids organized by fuel type for CAISO

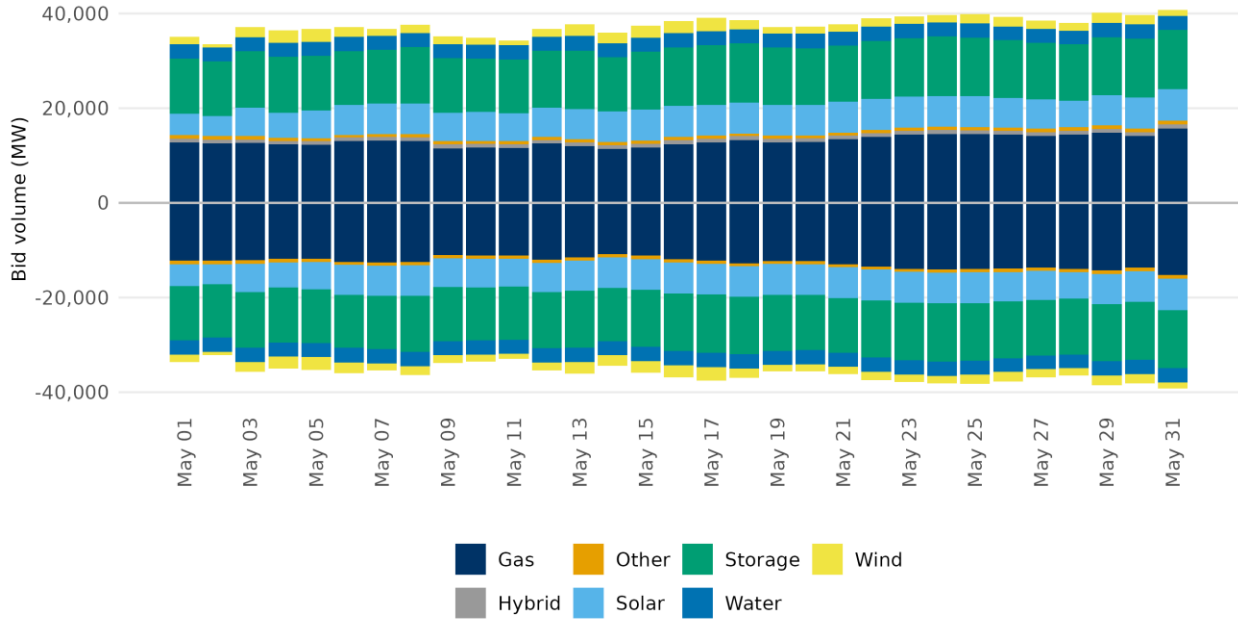


Figure 50 to Figure 53 illustrate the PACW’s hourly and daily average IFM supply input bids for IR by bid price range and by fuel type. The price ranges are distributed across price ranges (0–5 \$/MWh), (5–15 \$/MWh), and (45–55 \$/MWh) with about 1,200 MW, and the remaining price range (15–30 \$/MWh) represented a relatively small share of total submitted capacity. Hourly bid volumes were evenly distributed without any diurnal patterns. However, PACW’s submitted IR capacity exhibited a more variable pattern in both price ranges and volumes, as the overall bid-price composition showed variation across both the daily views. The IR bid volumes increased as EDAM launches, and prices slightly decreased as more bids fall in (0–5 \$/MWh) bucket at the end of May.

Figure 50: Hourly average volume of IR bids organized by price for PACW

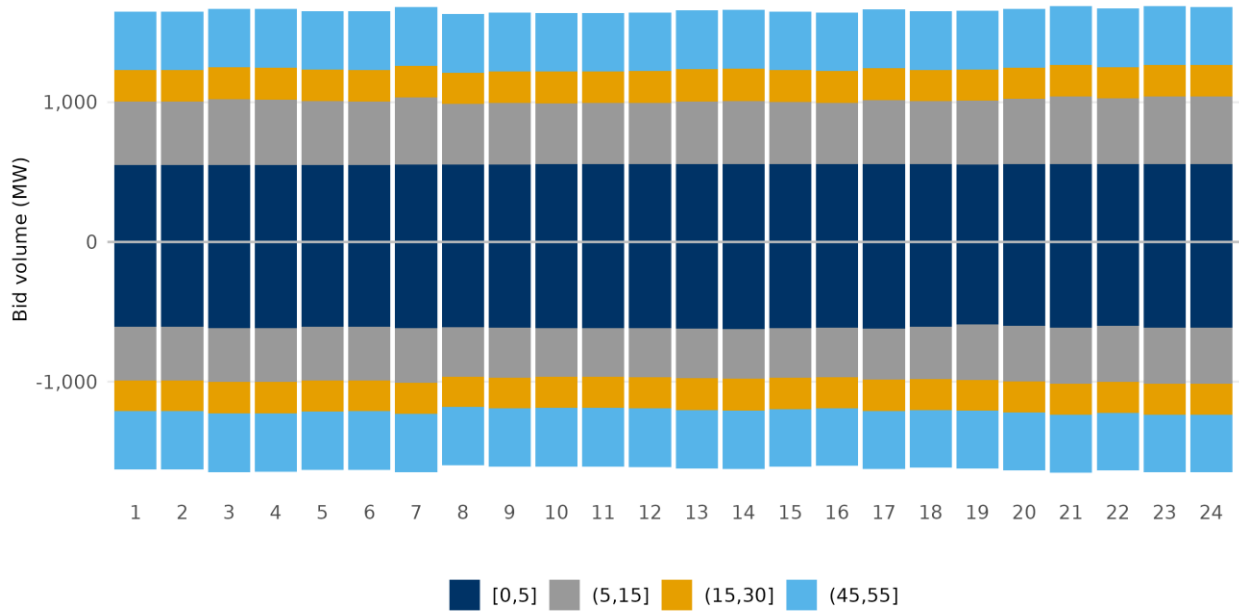


Figure 51: Hourly average volume of IR bids organized by fuel type for PACW

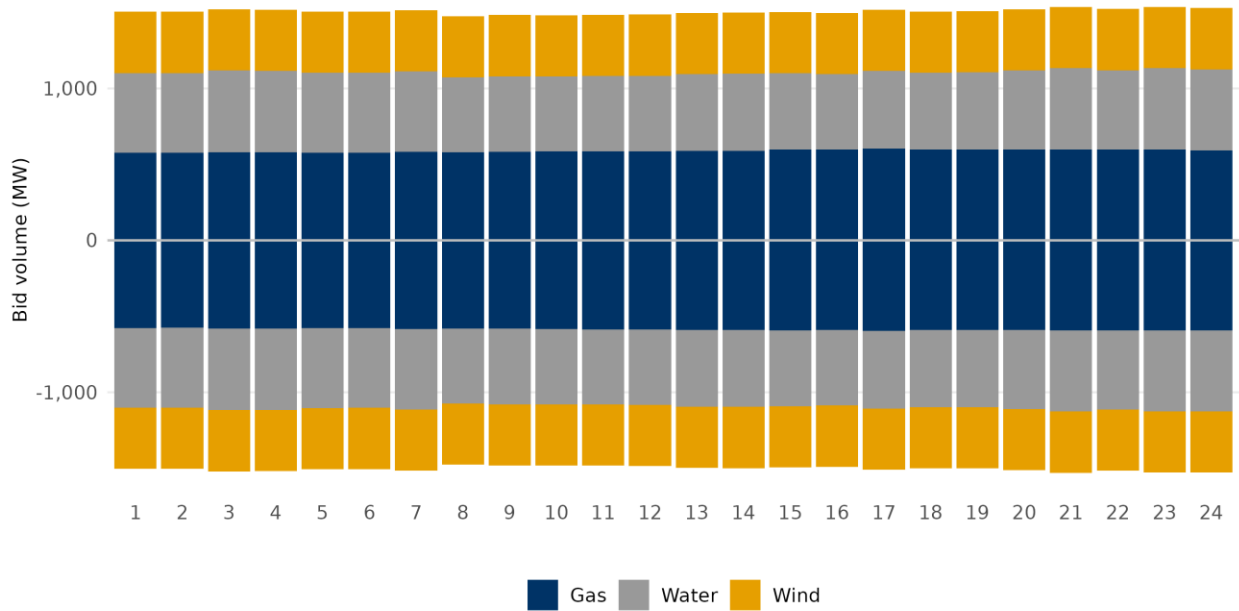


Figure 52: Daily average volume of IR bids organized by price by PACW

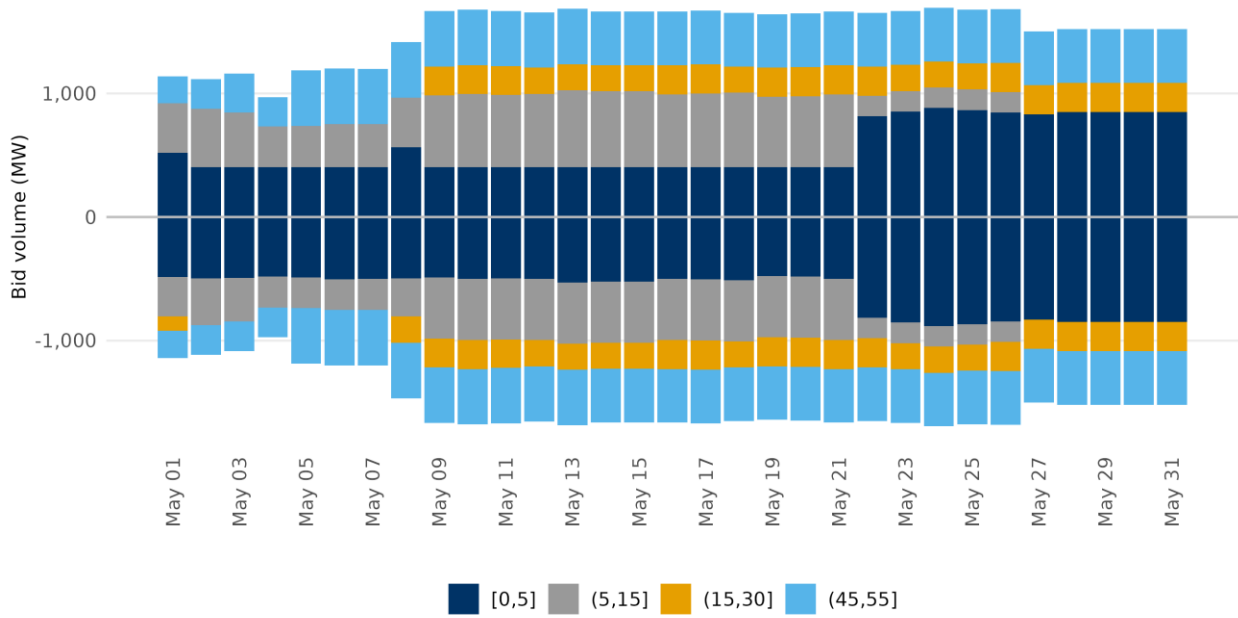


Figure 53: Daily average volume of IR bids organized by fuel type for PACW

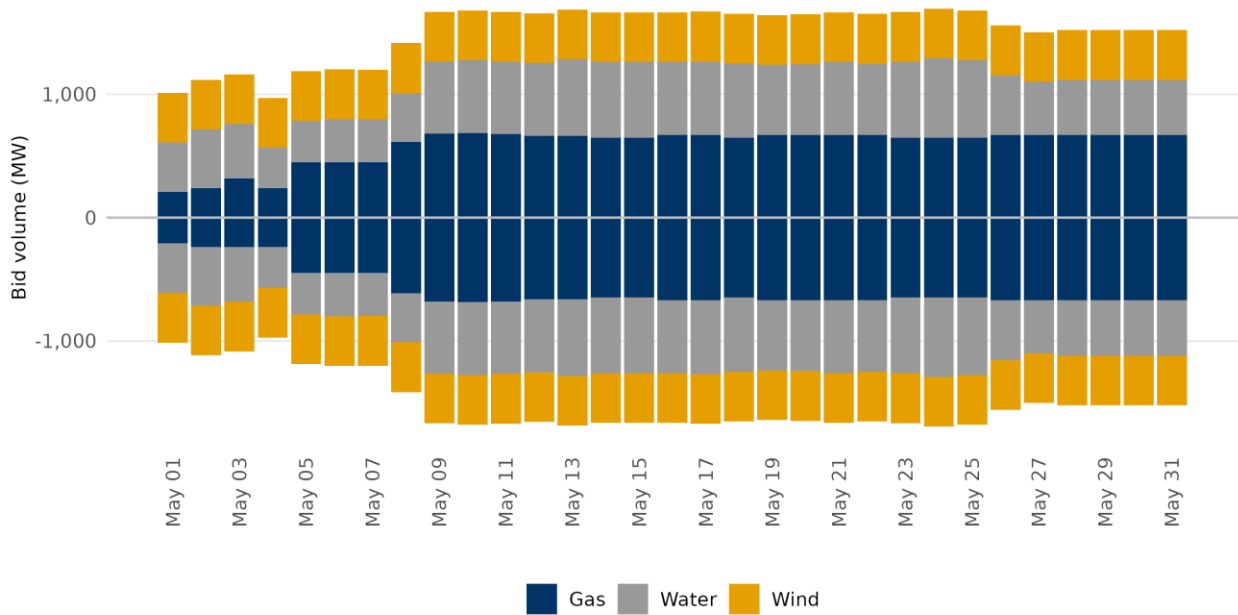


Figure 54 and Figure 56 illustrate the PACE’s hourly and daily average IFM supply input bids for IR by bid price range. Low-priced bids (\$0–5/MW) consistently accounted for the largest

share of submitted IR capacity throughout the month with about 5,000 MW (or 80 percent), followed by bids in the 45–55 \$/MWh range. The remaining price ranges represented a relatively small share of total submitted capacity. Hourly bid volumes were generally higher during daytime hours and lower during overnight hours. Generally, PACE’s submitted IR capacity remained relatively stable during May, with only a few days exhibiting lower bid volumes. The overall bid-price composition showed limited variation across both hourly and daily views, indicating a stable supply offer pattern for PACE’s IR during the month. Figure 55 and Figure 57 illustrate PACE’s hourly and daily average IFM supply input bids for IR by fuel type.

Figure 54: Hourly average volume of IR bids by price for PACE

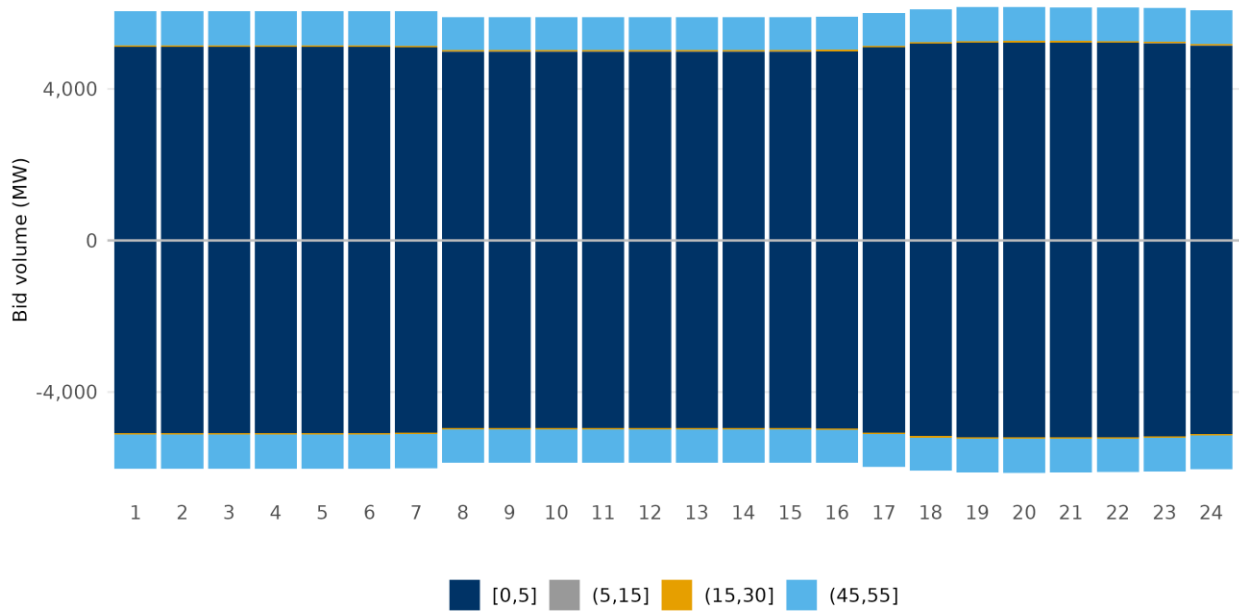


Figure 55: Hourly average volume of IR bids by fuel type for PACE

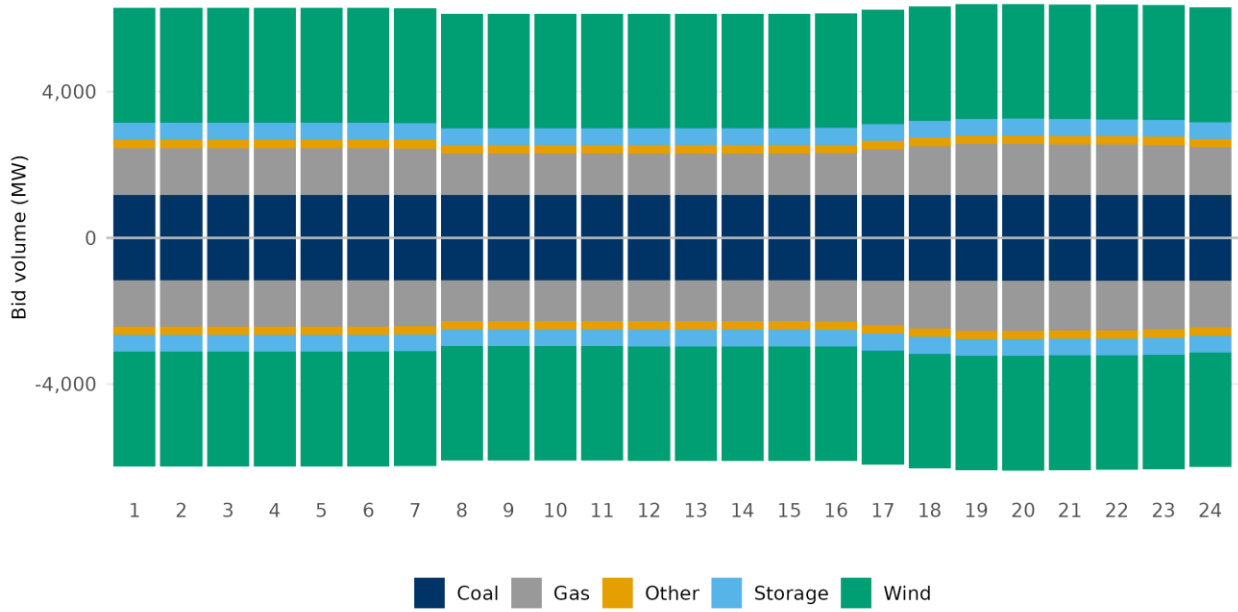


Figure 56: Daily average volume of IR bids by price for PACE

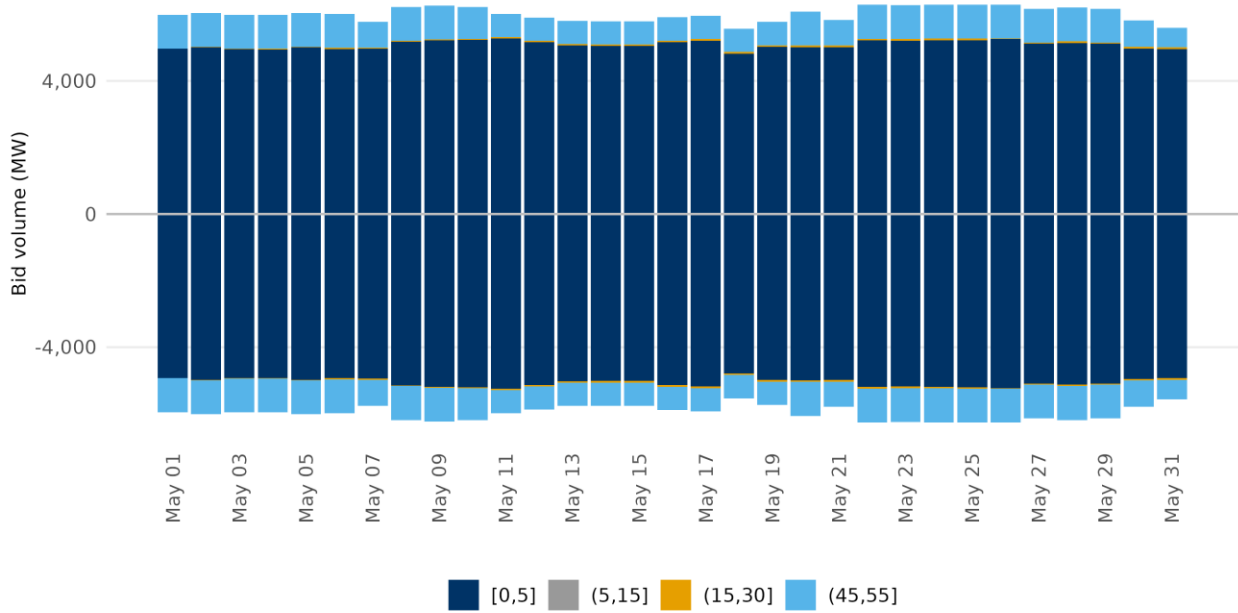
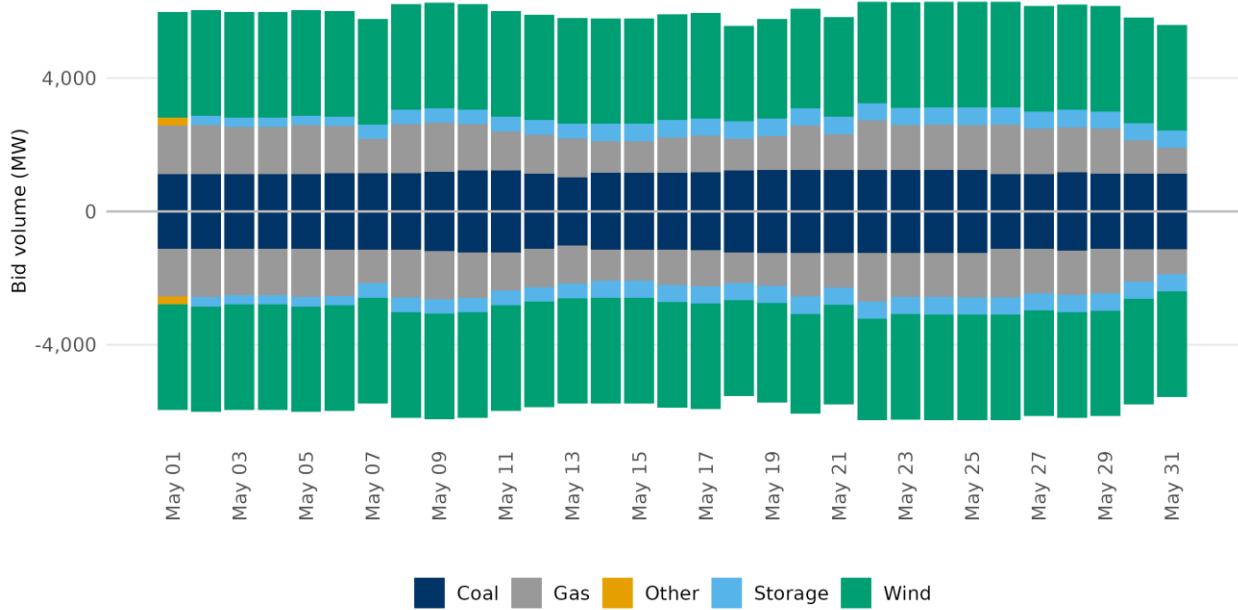


Figure 57: Daily average volume of IR bids by fuel type for PACE



When supply is tight, energy prices may rise to a level where IR is not procured. By design, the IR requirements may be relaxed at a cost. The IR demand curve represents the willingness to relax the IR requirement at certain price levels, capped to 55 \$/MWh, reflecting the tradeoff between meeting uncertainty needs and avoiding excessive system costs. In May 2026, CAISO and PACE did not relax the IR requirements. For PACW, demand curve procurement occurred in the upward direction for 20 hours over six days, and in the downward direction for 29 hours over four days, with hourly averages shown in Figure 58. Finally, some IR requirements for a BAA can be met with IR transfers from other BAAs or a BAA can also export IR transfers to other BAAs. These IR transfers are not shown explicitly in the previous metrics, and they are explicitly tracked in a subsequent section on transfers.

Figure 58: Average imbalance reserve demand curve procurement for PACW

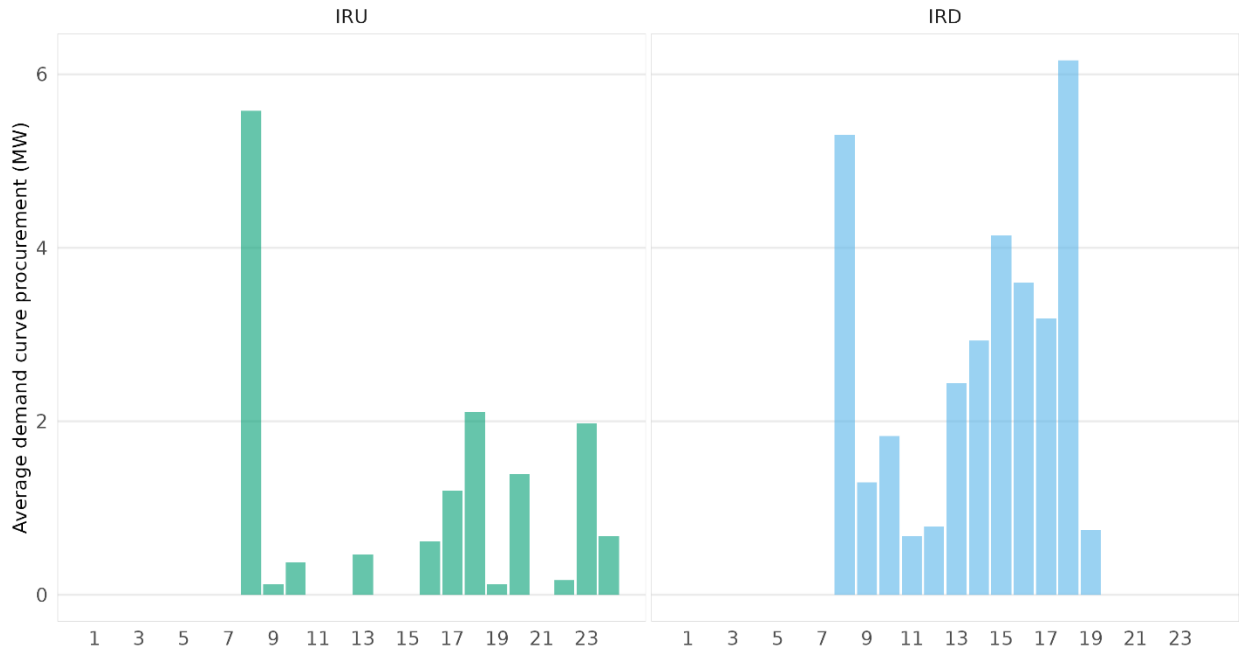
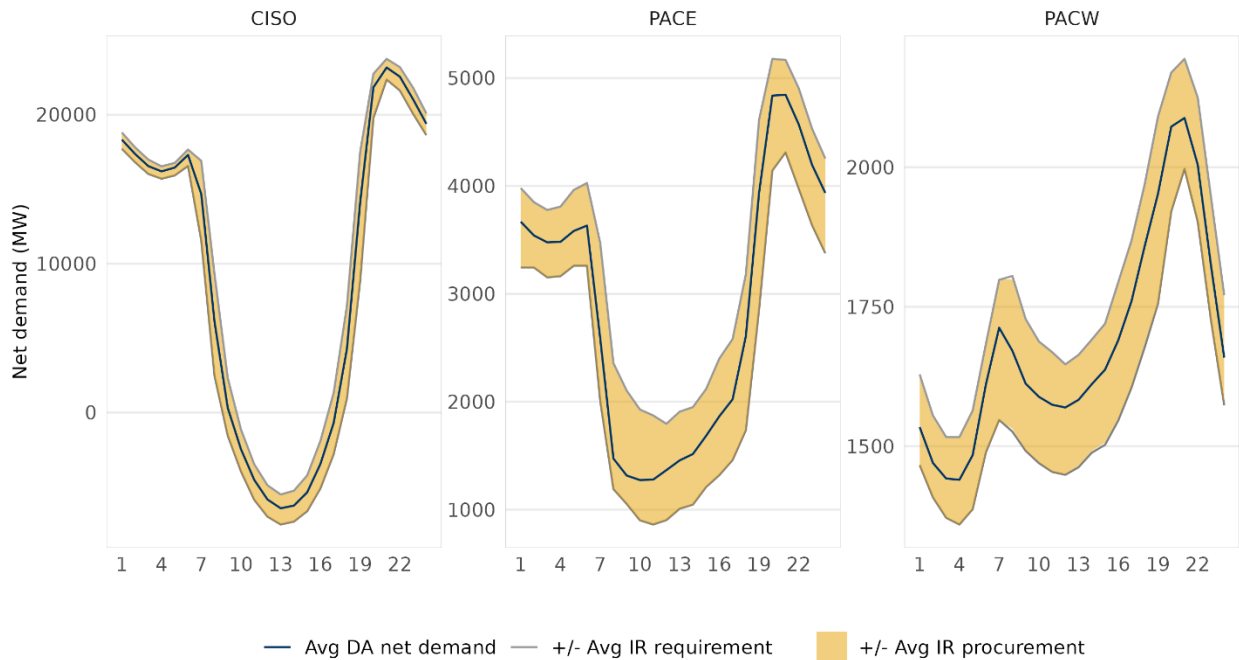


Figure 59 shows the hourly average net demand by EDAM BAA in May. Net demand is derived from demand forecast, net solar and wind forecast. The figure overlays hourly average IR procurement and requirement, for both up and down directions, on the net demand profile. Overlaying the IR requirements on the net demand profile visually shows how the imbalance reserves create an envelope of flexible capacity around the net demand.

Figure 59: Average net demand with imbalance reserve procurement



Reliability capacity

Reliability Capacity (RC) is the other new bi-directional day-ahead product introduced with the EDAM market. The reliability capacity product ensures there is enough capacity procured in the RUC process to meet the demand forecast. Like imbalance reserves, reliability capacity is procured in both upward and downward directions. The market procures reliability capacity to meet positive or negative differences between cleared physical supply in IFM and the load forecast. It is like the existing RUC capacity product, except RUC capacity is only procured when the forecast exceeds cleared physical supply. Reliability capacity up (RCU) covers supply shortfalls and reliability capacity down (RCD) accounts for over-supply.

Reliability capacity prices are shown in Figure 60 to Figure 61. The average daily price for May 2026 is shown in Figure 60, while the average hourly price for May 2026 is shown in Figure 61.

Daily average reliability capacity prices for all three BAAs were more volatile in the beginning of May. The highest daily average price was for PACW exceeding 30 \$/MWh, and CAISO's

highest daily average price exceeded 20 \$/MWh. Prices stabilized in the second half of the month, staying below 10 \$/MWh on average. Reliability capacity prices were lowest for PACE. There were a few days when average RCU prices for PACW and CAISO were negative. Hourly average RCU prices for May were mostly stable, staying below 10 \$/MWh, except for CAISO during the morning and evening peak. For CAISO the RCU price exceeded 20 \$/MWh in one hour of the morning peak and reached around -20 \$/MWh in one hour of the evening peak. Like imbalance reserves, the reliability capacity price separation observed between the three BAAs reflects the economics of the wider EDAM market footprint available supply mix and EDAM transfers.

A feature of the reliability capacity prices is that RCU and RCD prices are equal and opposite. This price symmetry is by design and a natural consequence of RUC optimization. The RUC process procures both reliability capacity up and down to address supply shortfalls or over-supply in different parts of the system. At the system level, however, there is either a net supply shortfall or over-supply. In a net supply shortfall for instance, the system needs RCU to balance the RUC optimization constraint, and the RCU price is set by the marginal resource. If conditions materialize such that one additional megawatt of RCU is needed, the value to the system of that incremental RCU is set by the price of the marginal resource. Conversely, if another resource moved downward in the opposite direction providing one additional megawatt of RCD, there is a cost to the system in the amount of the lost value of the additional RCU megawatt. Therefore, the RCD price must be equal to the opposite of the RCU price.

Figure 60: Daily average price of RCU

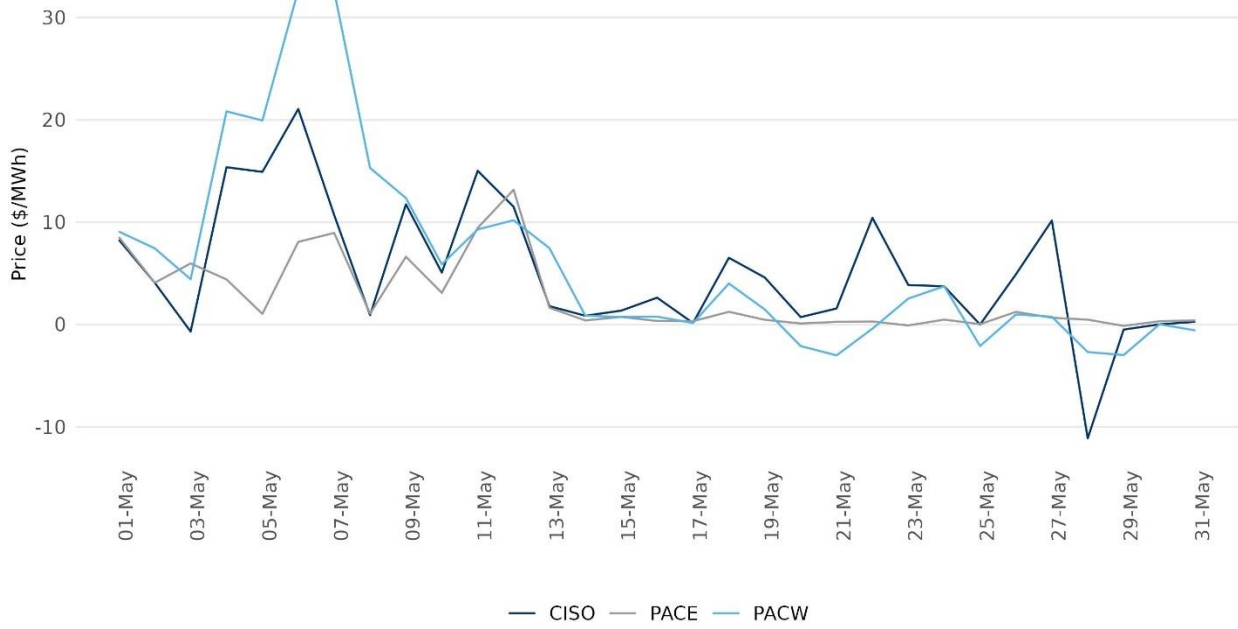


Figure 61: Hourly average price of RCU

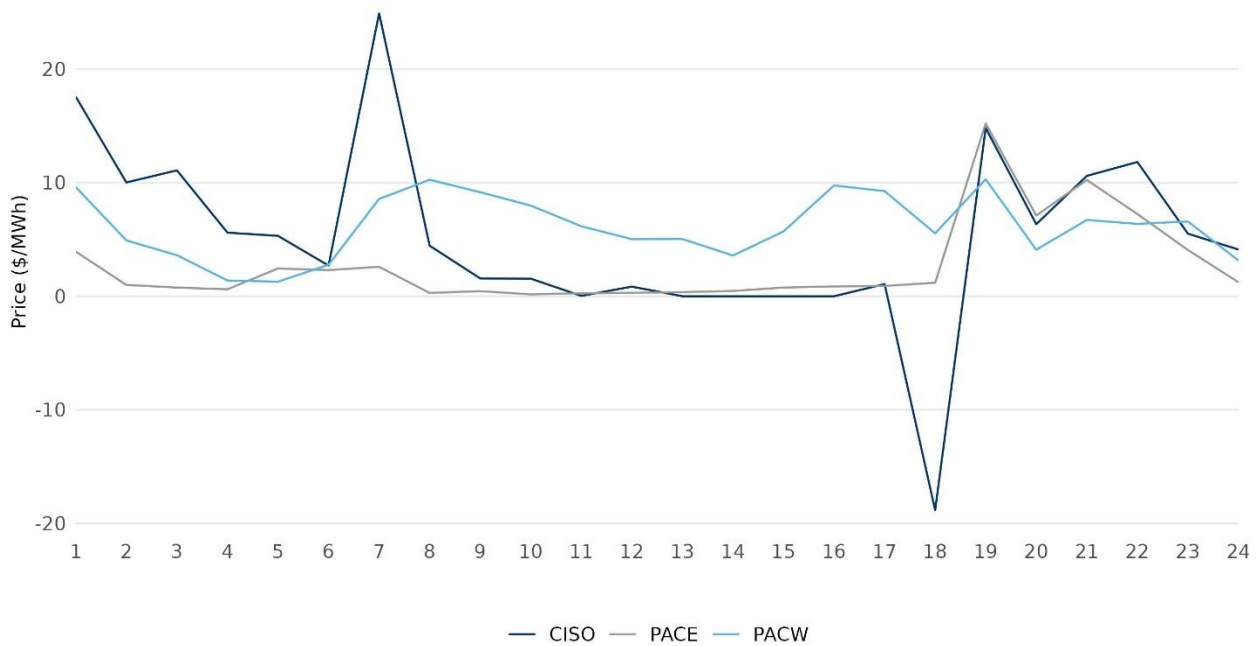
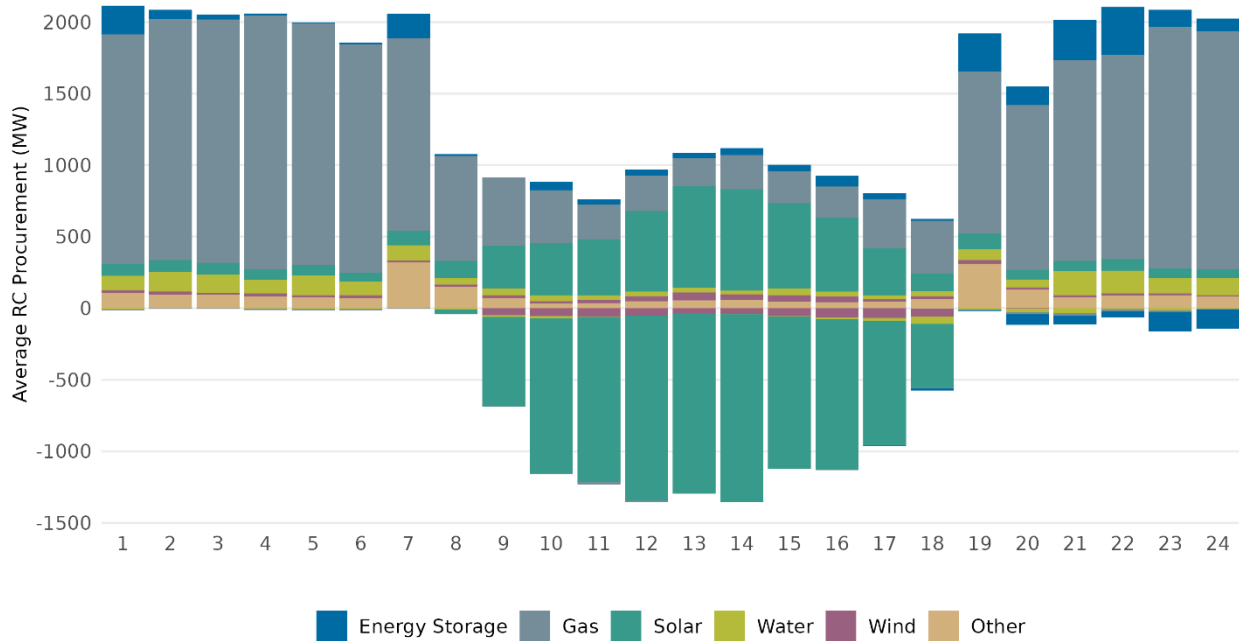


Figure 62 to Figure 64 illustrate the hourly average by technology supporting the procurement for each BAA.

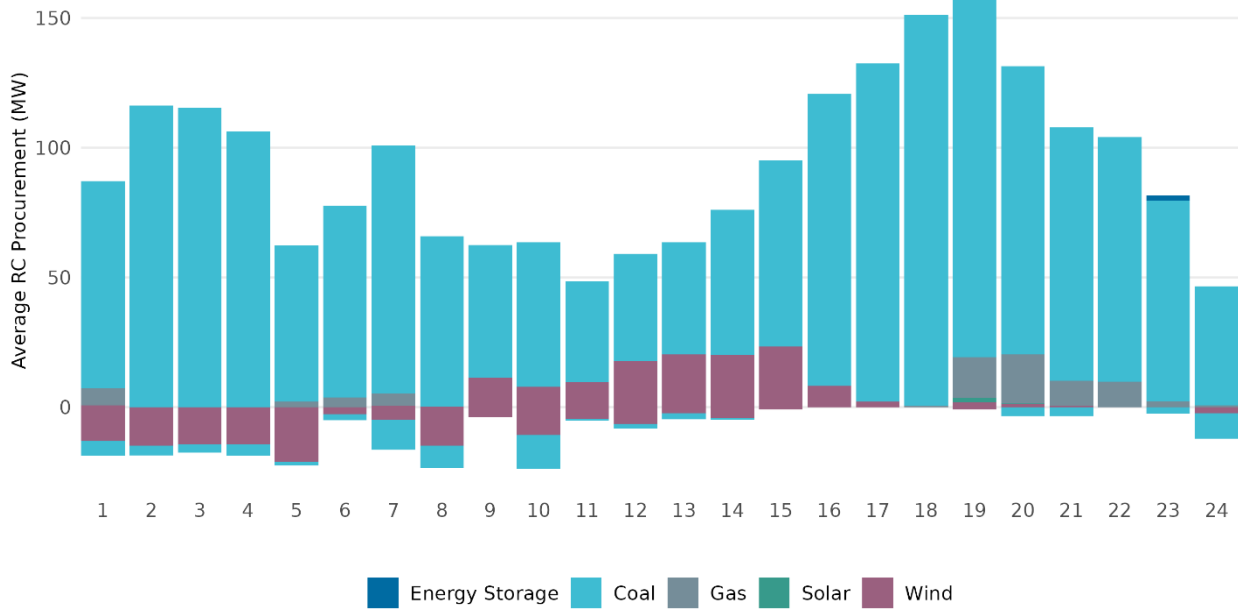
For CAISO, gas resources make up the highest proportion (65 percent of the total) of RCU during non-solar hours while solar procures during solar hours. RCD is primarily procured during solar hours by solar resources.

Figure 62: Hourly average of RC procurement for CAISO



PACE reliability capacity is largely procured in the up direction and supplied primarily by coal and wind resources. The highest levels of RCU procurement occurred during evening peak hours.

Figure 63: Hourly average of RC procurement for PACE



PACW reliability capacity is also primarily procured in the upward direction with the highest procurement occurring during the early morning. PACW RC is primarily supplied by hydro resources.

Figure 64: Hourly average of RC procurement for PACW

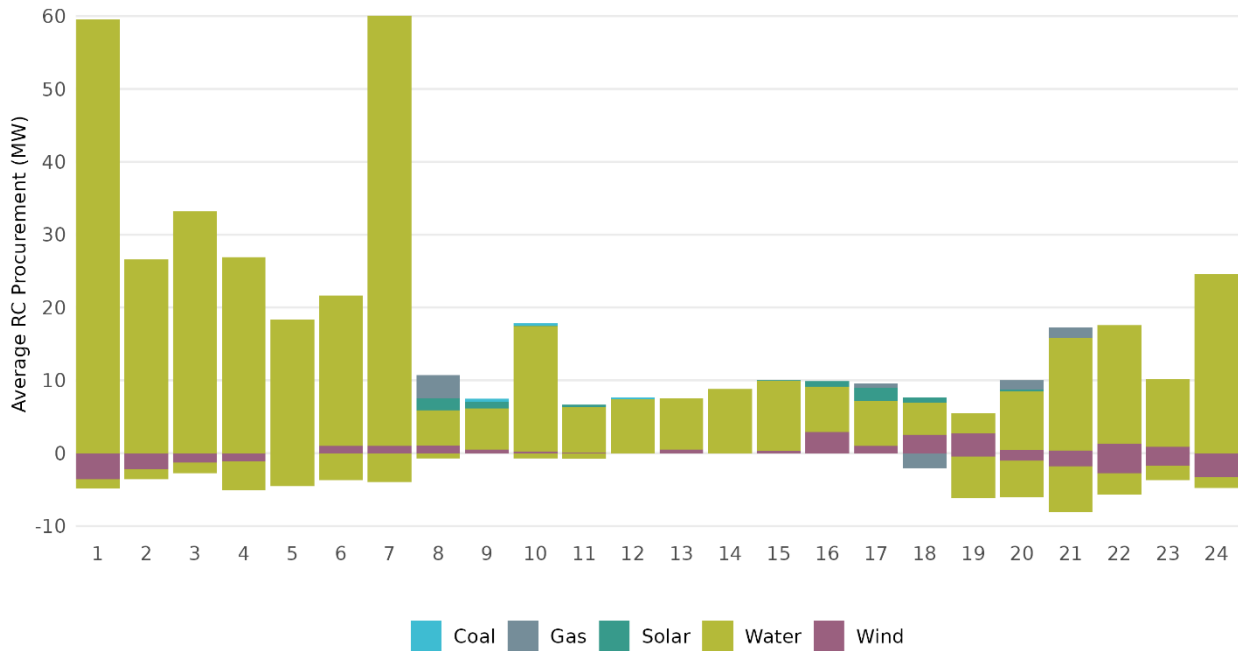


Figure 65 and Figure 66 illustrate CAISO’s hourly average volume of RC bids by bid price range and fuel type, respectively. Zero-priced bids consistently accounted for the largest share of submitted RCU capacity throughout the month with about above 25,000 MW (or over 35 percent of the total), followed by bids in the (40–60 \$/MWh) range. The remaining high-price ranges (100–250 \$/MWh) represented a small share of total submitted capacity. Hourly bid volumes were generally higher during daylight hours. Energy storage, gas, and solar resources accounted for approximately over 80 percent of the total. Generally, CAISO’s submitted RC capacity remained relatively stable during May, with only a few days exhibiting lower bid volumes.

Figure 65: Hourly average volume of RC bids by price for CAISO

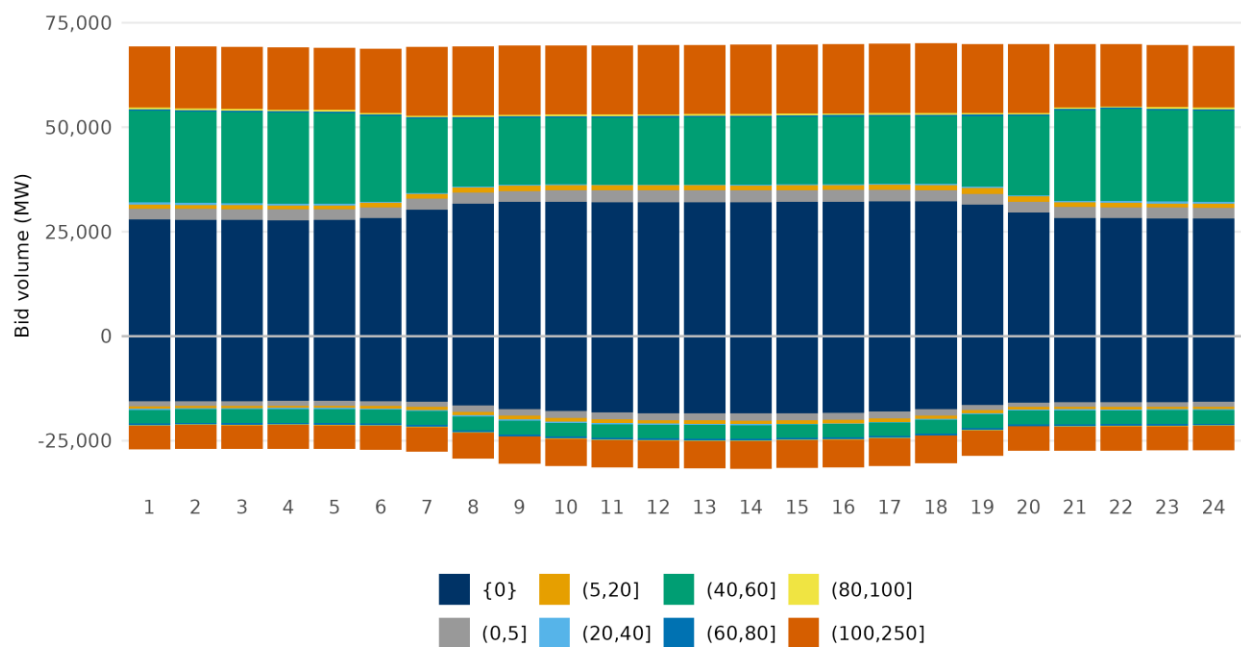


Figure 66: Hourly average volume of RC bids by fuel type by CAISO

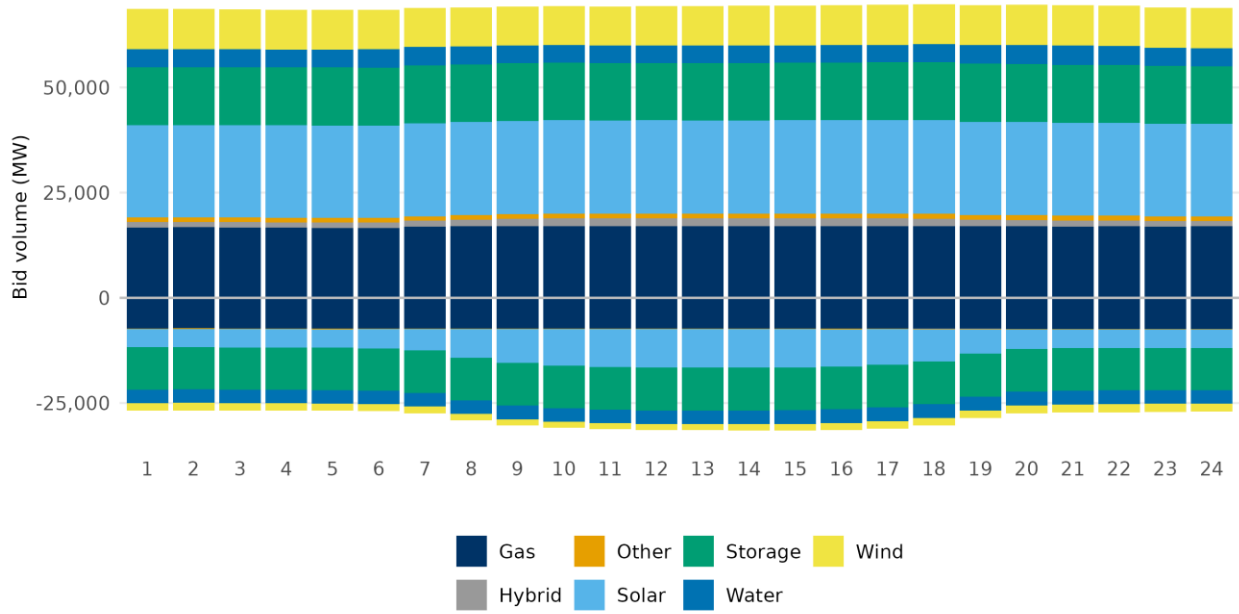


Figure 67 and and Figure 68 illustrate the CAISO’s daily average volume of RC bids by bid price range and fuel type, respectively. Generally, CAISO’s submitted RC capacity remained relatively stable during May, with only a few days exhibiting lower bid volumes. Gas, solar, and energy storage accounted for the largest share of RC bid volumes.

Figure 67: Daily average volume RC bids by price for CAISO

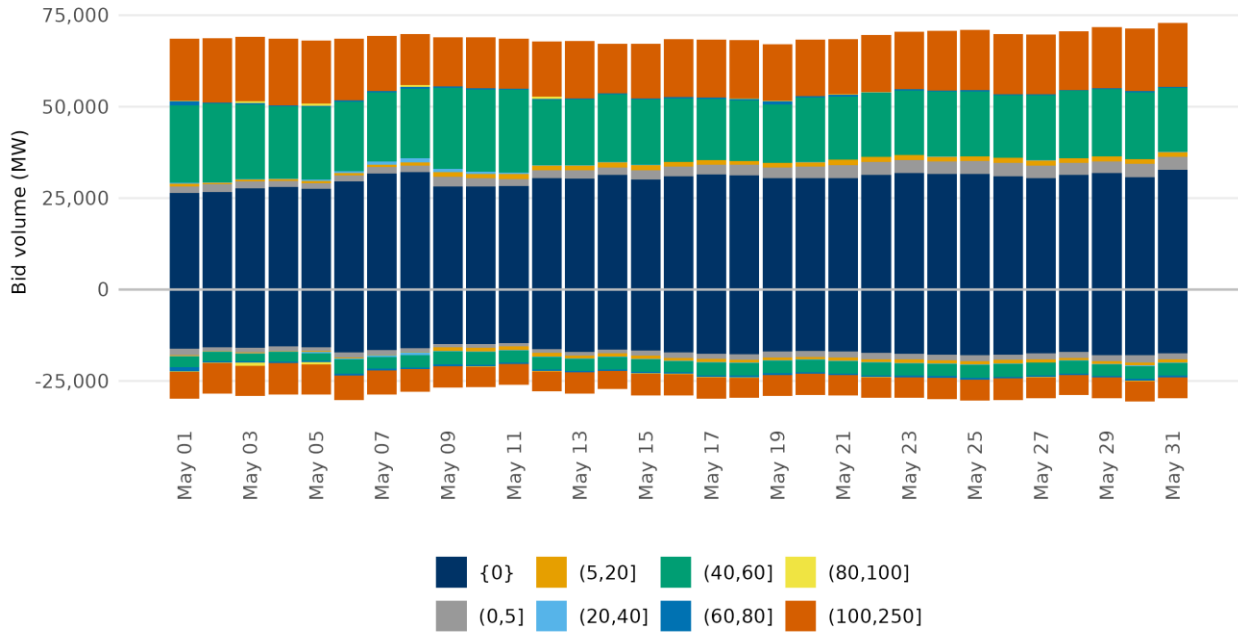


Figure 68: Daily average volume of RC bids by fuel type for CAISO

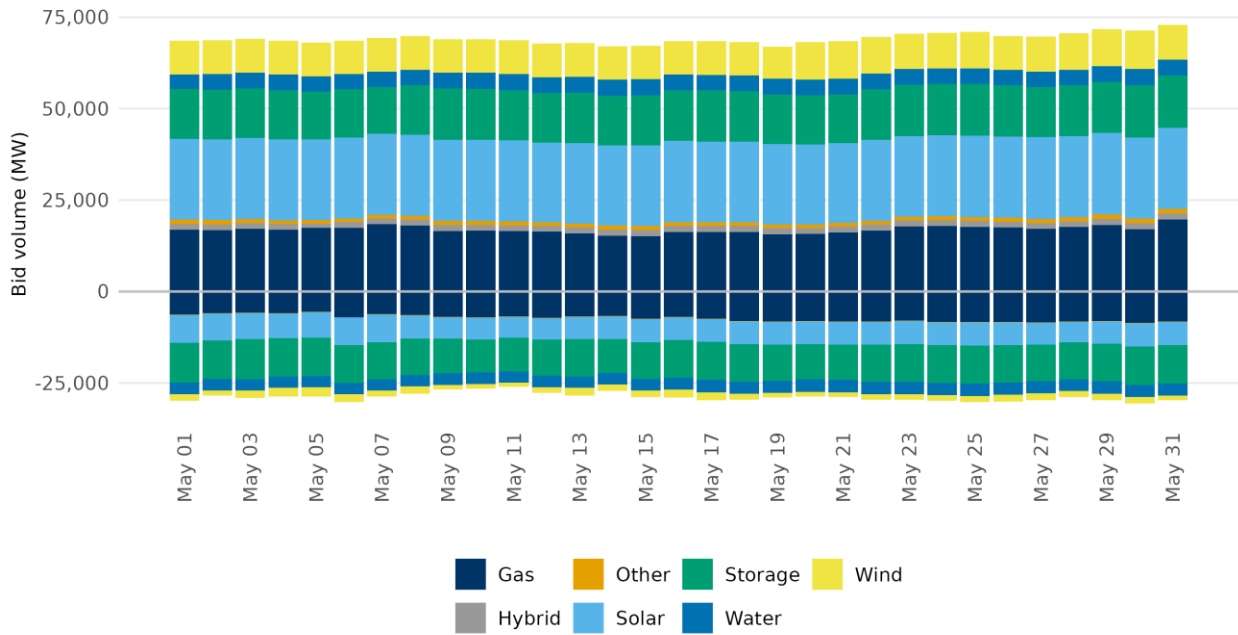


Figure 69 and Figure 70 illustrate PACW’s hourly average volume of RC bids by price range and fuel type, respectively. Low-priced bids (0–5 \$/MWh and 5-20 \$/MWh) and moderate priced bids (\$40–60/MW) consistently accounted for the largest share of submitted RC capacity throughout the month with about 2,500 MW (or 90 percent of the total), followed by bids in the (100–250 \$/MWh) range. Hourly bid volumes were slightly higher during daylight hours. Gas, water, and wind resources accounted for the largest share of submitted RC capacity, with some solar capacity bidding in RCU only. The PACW’s RCU bid volume is about 3,000 MW while RCD is only about 1,600 MW.

Figure 71 and Figure 72 illustrate PACW’s daily average volume of RC bids. Generally, PACW’s submitted RC capacity gradually increased in the first half of May and then became stable, with only a few days exhibiting lower bid volumes.

Figure 69: Hourly average volume of RC bids by price for PACW

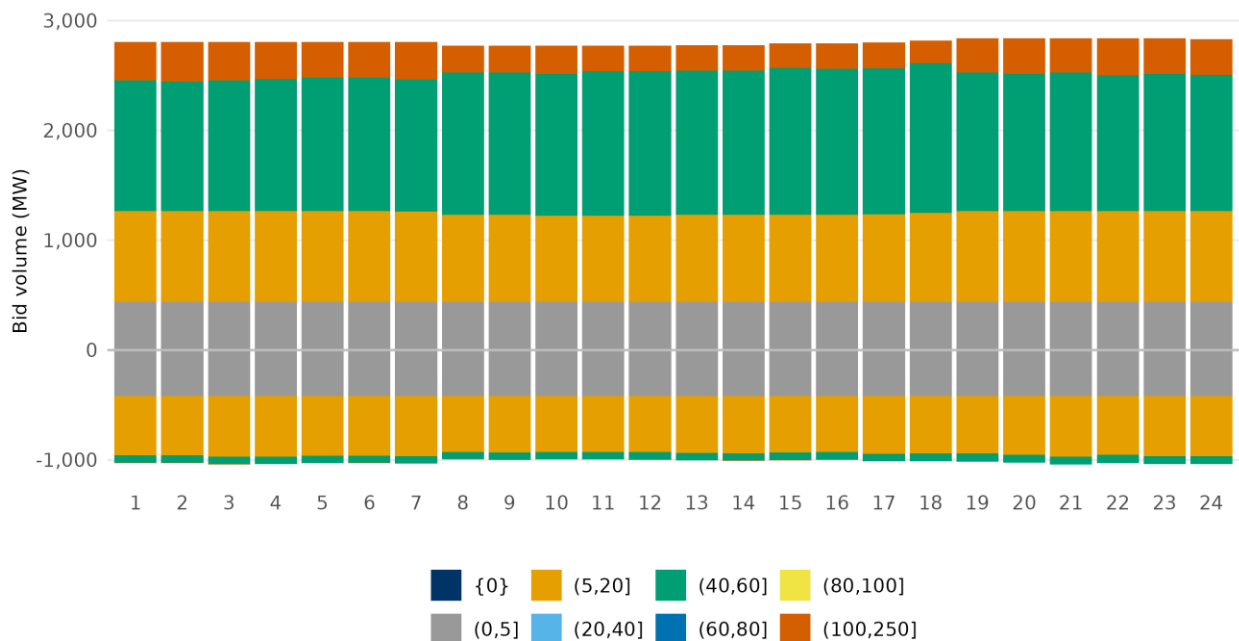


Figure 70: Hourly average volume of RC bids by fuel type for PACW

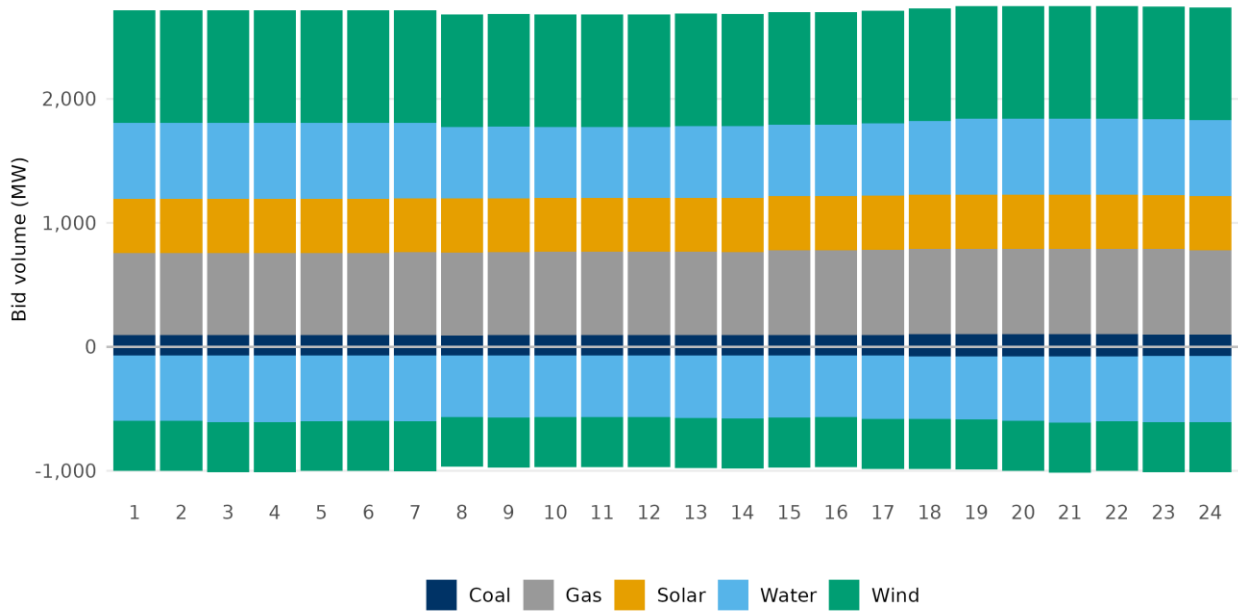


Figure 71: Daily average volume of RC bids by price for PACW

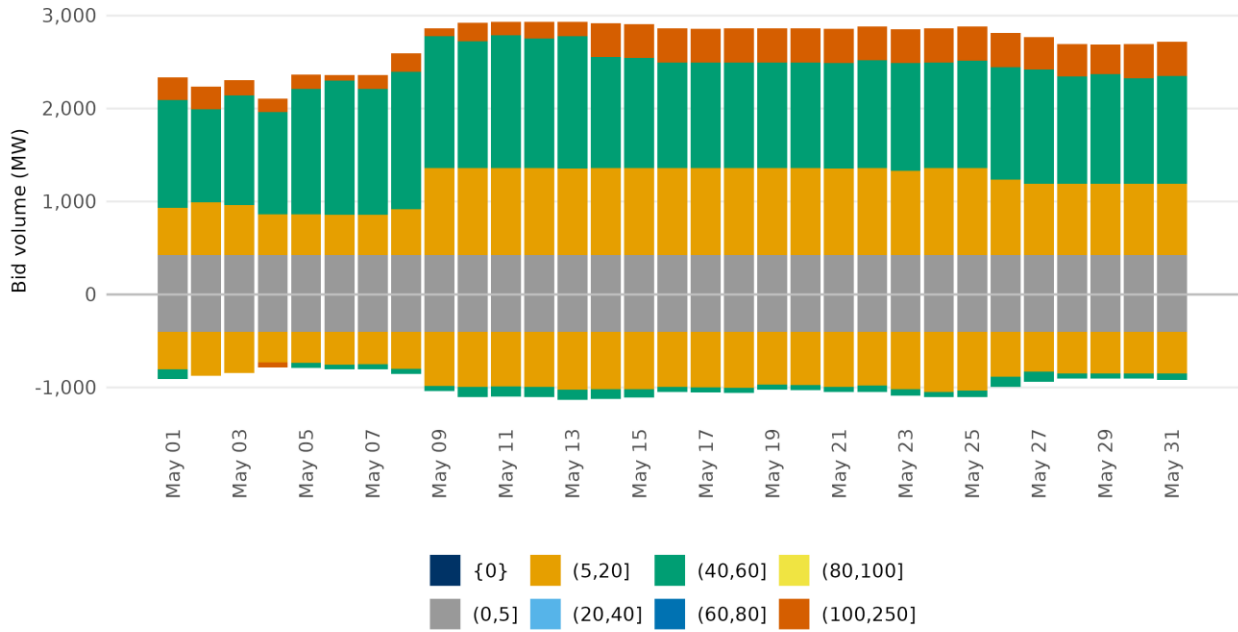


Figure 72: Daily average volume of RC bids by fuel type for PACW

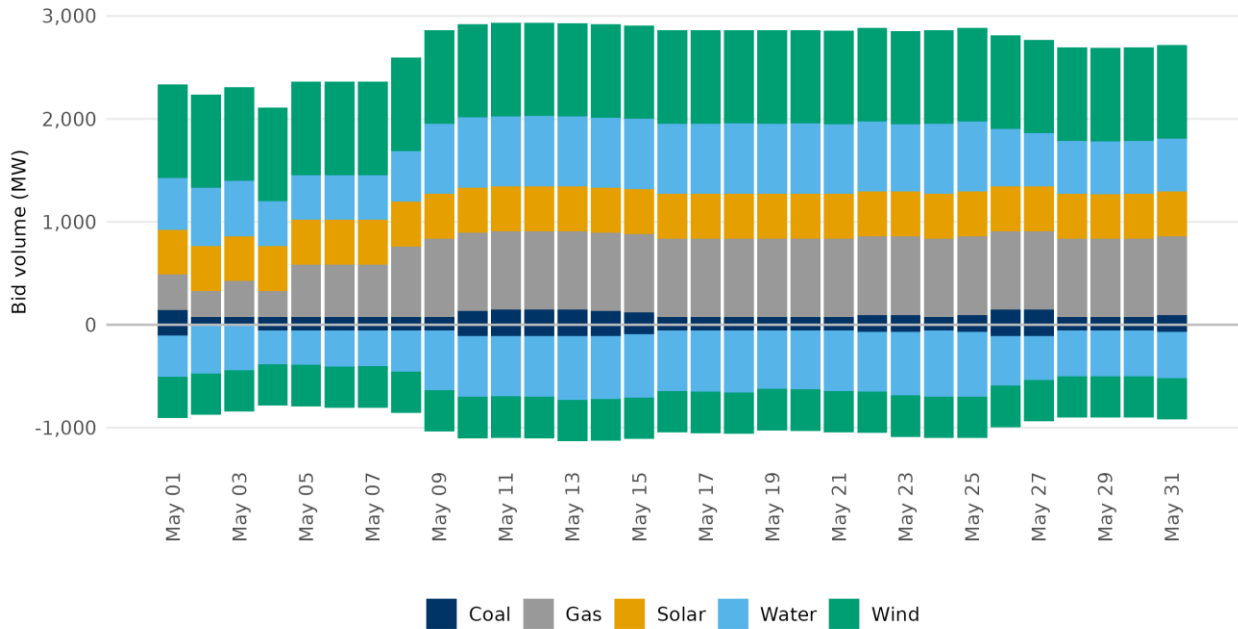


Figure 73 and Figure 74 illustrate the PACE’s hourly and daily average volume of RC bids by bid price range and fuel type, respectively. Similarly, low-priced bids (\$0–5/MW) and moderate priced bids (40–60 \$/MWh) consistently accounted for the largest share of submitted RC capacity throughout the month with about 90 percent, followed by bids in the (20–40 \$/MWh) range. Hourly bid volumes remained stable throughout the day but decreased slightly during daylight hours. Coal, gas, and wind resources accounted for the largest share of submitted RC capacity, with some solar capacity bidding in RCU only. The PACW’s RCU bid volume is about 12,000 MW while RCD is only about 5,500 MW.

PACE’s submitted RC capacity remained stable, with only a few days exhibiting lower bid volumes.

Figure 73: Hourly average volume of RC bids by price for PACE

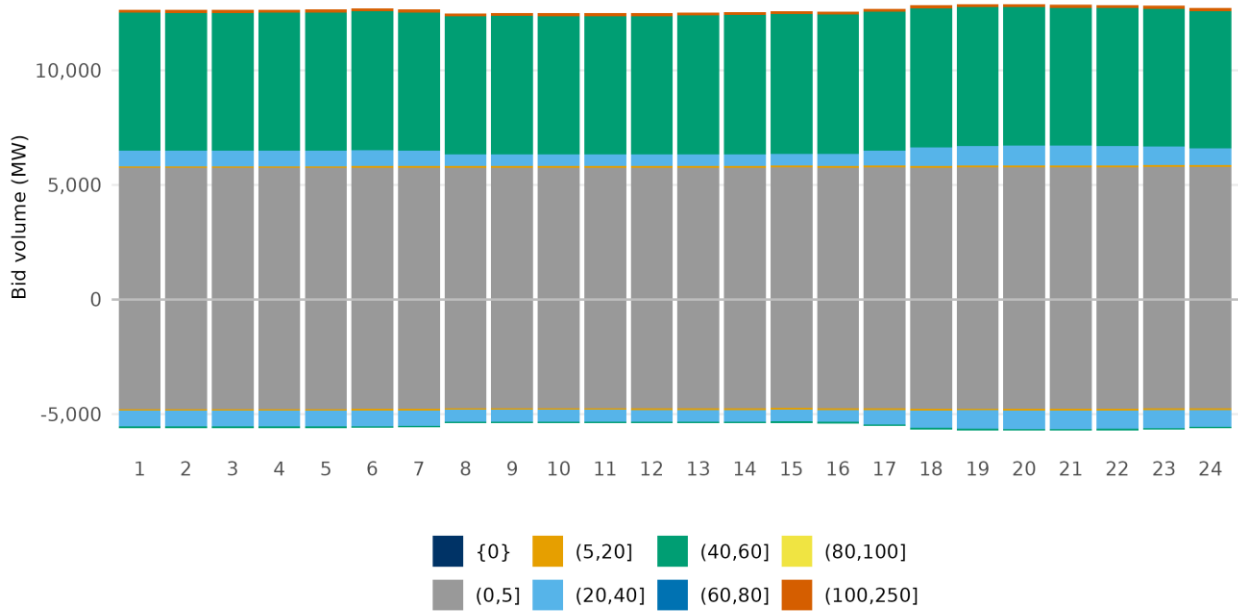


Figure 74: Hourly average volume of RC bids by fuel type for PACE

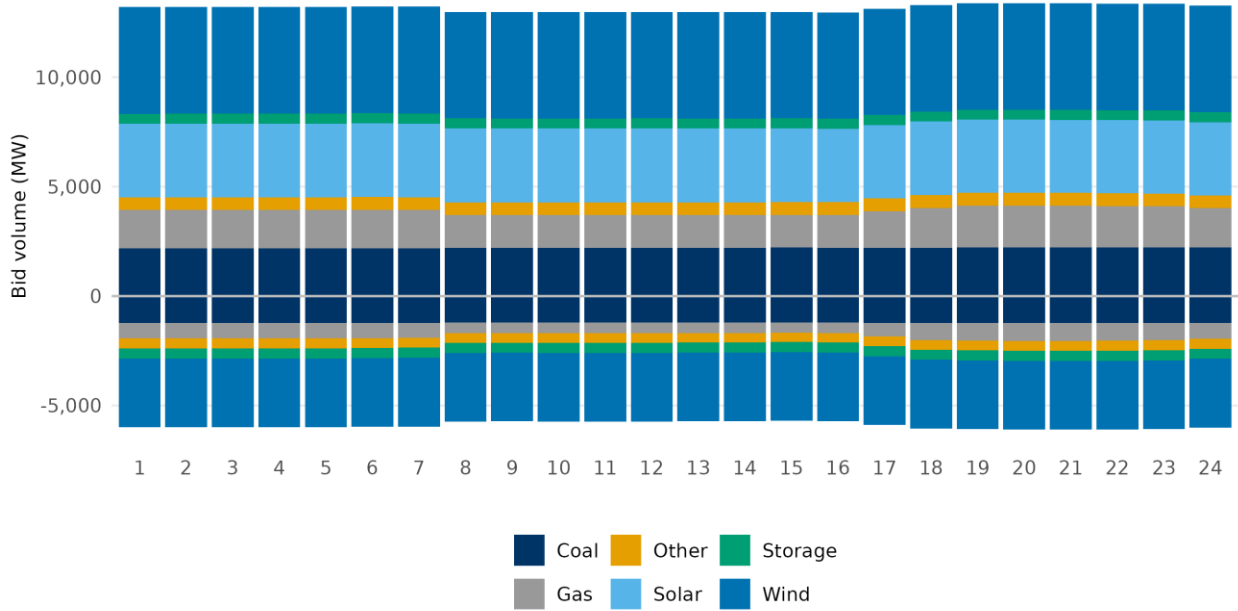


Figure 75: Daily average volume of RC bids by price by PACE

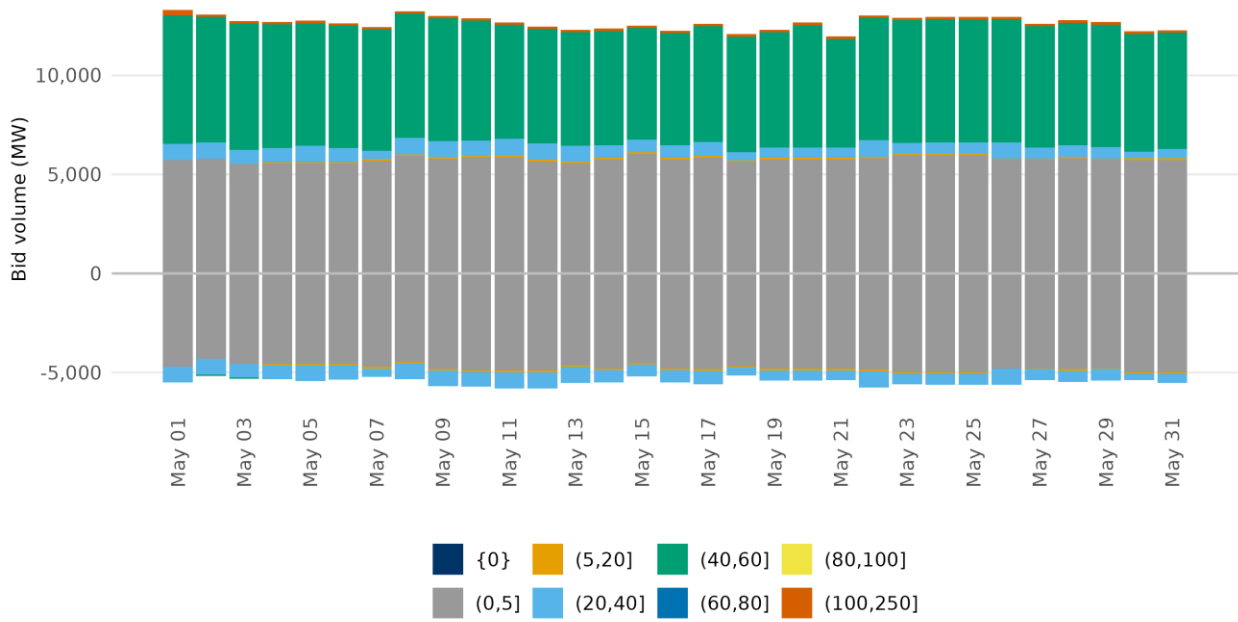
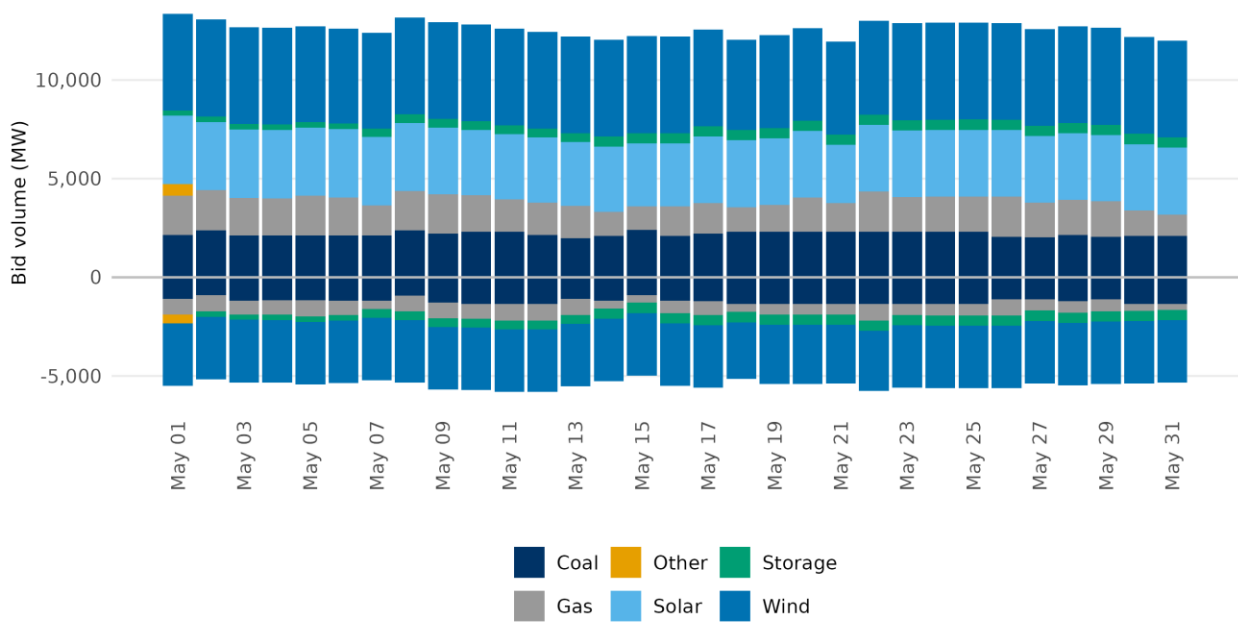


Figure 76: Daily average volume of RC bids by fuel type by PACE



Convergence bids

In addition to bids backed by physical resources, market participants within the CAISO area can submit virtual bids for generation or demand. Virtual generation and demand bids, also known as convergence bids, are intended to help convergence the day-ahead and real-time markets by arbitraging price differences between these two markets. Any virtual supply or demand cleared in the day-ahead market is liquidated in the real-time market.

Figure 77 shows the net of the total cleared virtual bids for each day in April and May, where the net is defined as the total cleared virtual generation minus the total cleared virtual demand. Generally, the net cleared virtual bids were lower in May than in April. There were even three days in May where more virtual demand cleared compared to virtual generation. This reduction in net cleared virtual bids from April to May aligns with trends seen in prior years, suggesting that it is not a result of EDAM.

Figure 77: Net cleared virtual bids

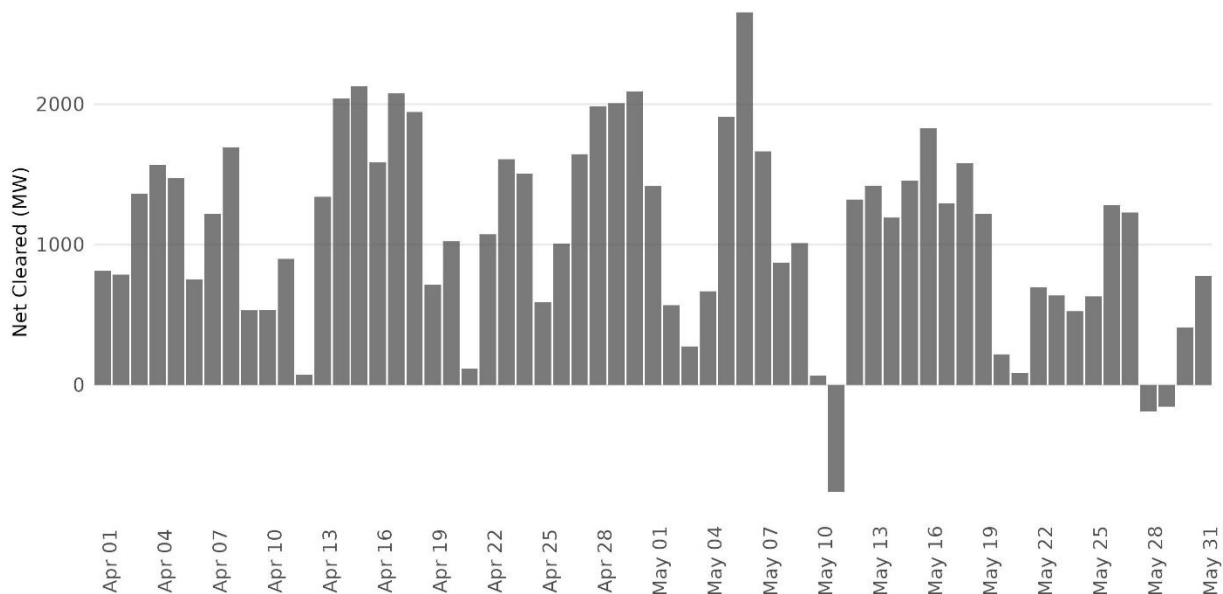


Figure 78 shows the average amount of virtual bids cleared per hour across April and May. There was no significant change from April to May.

Figure 79 and Figure 80 show the hourly profile of average virtual supply and virtual demand in April (Pre-EDAM) and May (EDAM), respectively. Figure 79 shows a slight decrease in cleared virtual supply outside of solar hours in May compared to April. Figure 80 shows a small increase in cleared virtual demand during solar hours in May compared to April.

Figure 81 shows the hourly profile of average net cleared virtual bids in April (Pre-EDAM) and May (EDAM), where the net is cleared virtual supply minus cleared virtual demand. In other words, a positive value represents net virtual supply while a negative value reflects net virtual demand.

The changes taken together led to generally lower net cleared virtual demand across all hours of day, except for hours ending 10 and 11, as shown in Figure 81. As mentioned above, this trend of reduced net cleared virtual bids in May compared to April also occurred in 2025, making it unlikely that EDAM led to the change.

Figure 78: Daily average of hourly cleared virtual bids

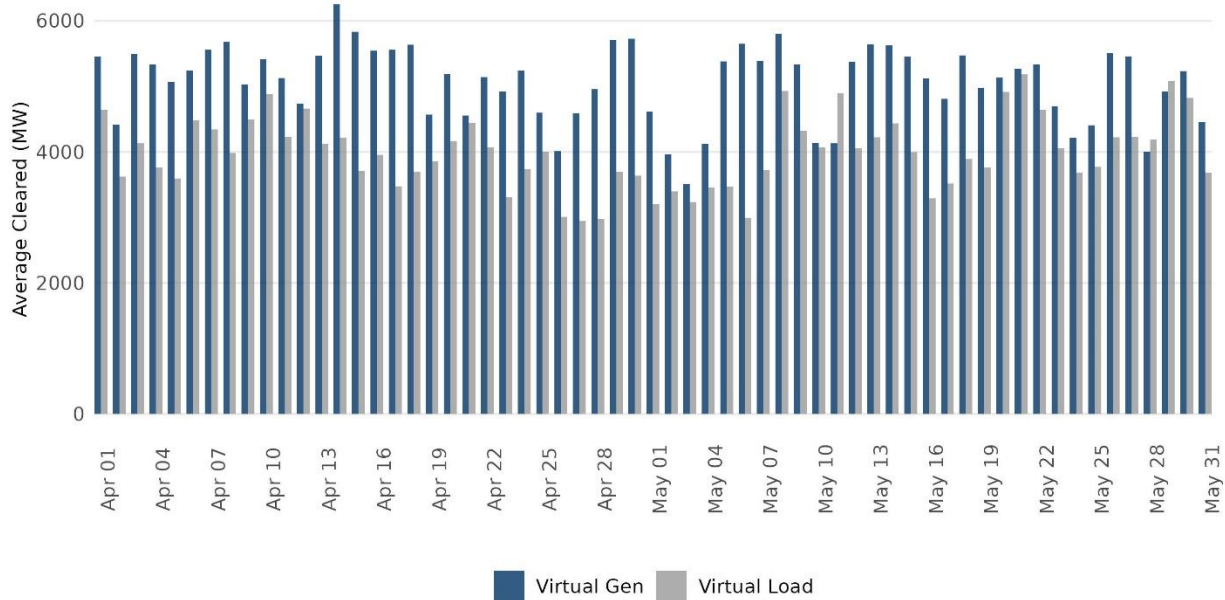


Figure 79: Average hourly cleared virtual supply

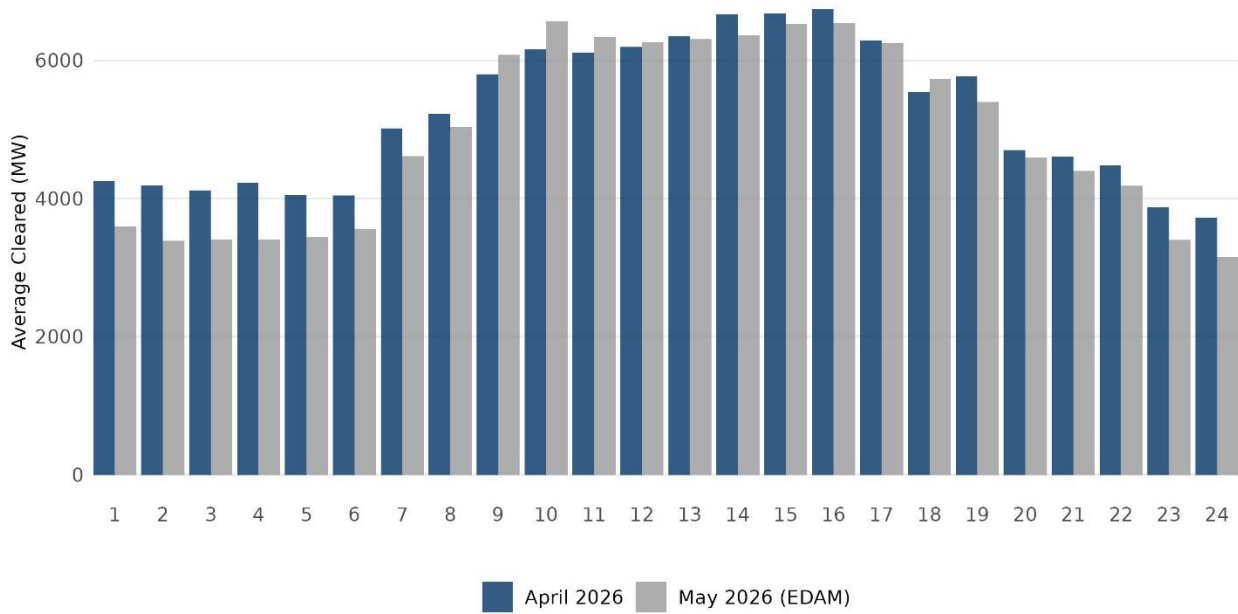


Figure 80: Average hourly cleared virtual demand

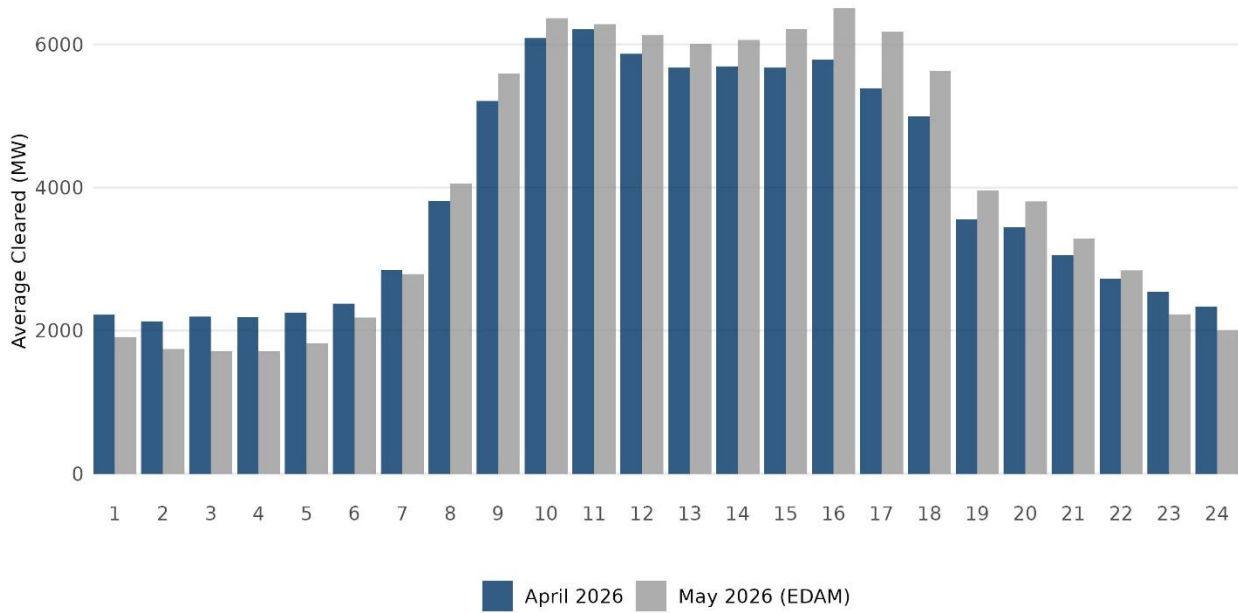
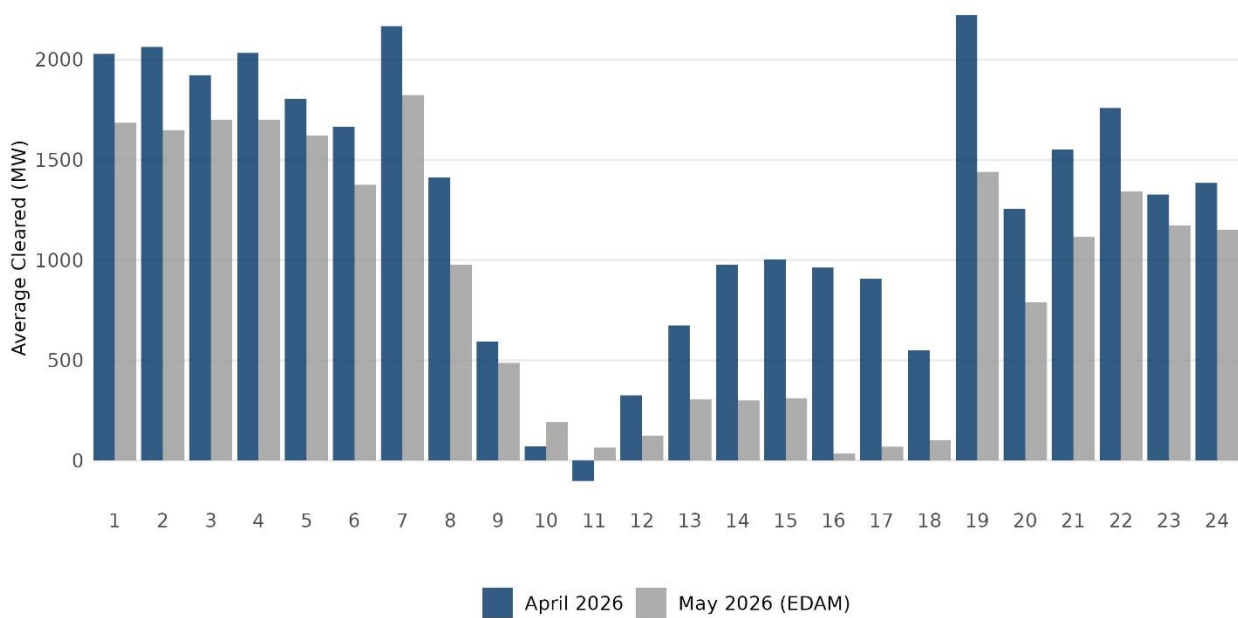


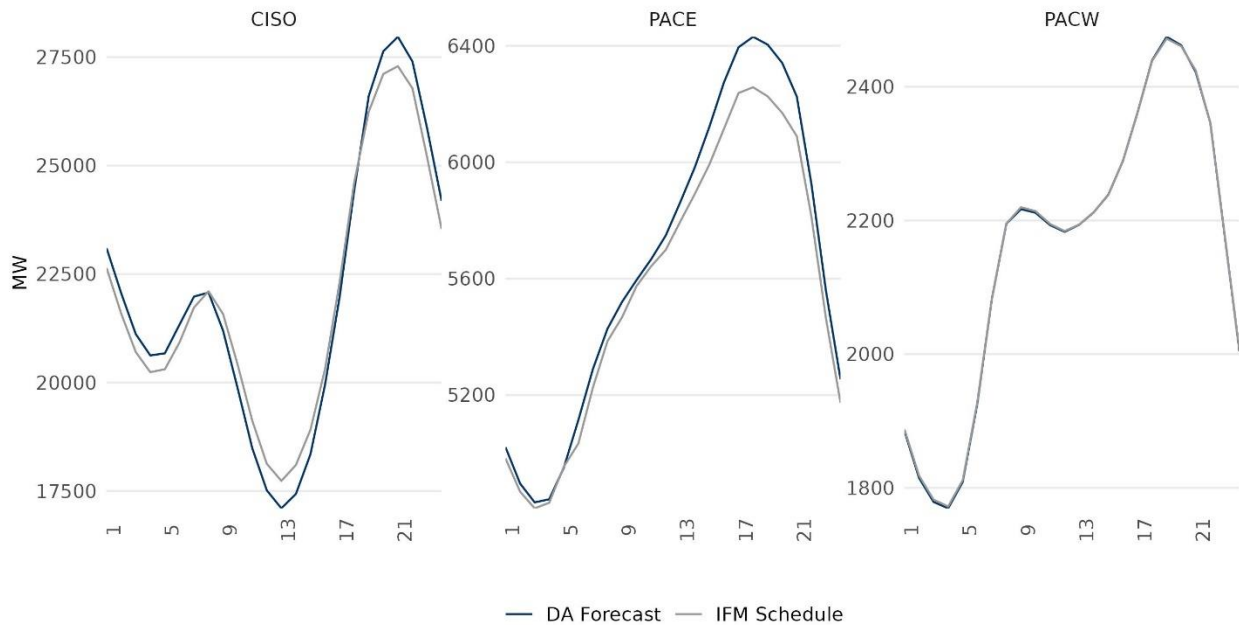
Figure 81: Average net hourly cleared virtual bids



Bid-in and forecasted demand

In IFM, bid-in supply is cleared to meet bid-in demand. However, bid-in demand is not necessarily matching the day-ahead load forecast. Supply in RUC is cleared to meet the day-ahead demand forecast. Figure 82 shows the average day-ahead demand forecast and the average IFM schedule for each EDAM BAA in May 2026. On average, the bid-in demand for CAISO is greater than the day-ahead demand forecast during solar hours but less than the forecast otherwise. The bid-in demand for PACE is almost always lower than the demand forecast, with the difference between the two largest during the evening peak. Generally, the day-ahead demand forecast and the bid-in demand for PACW closely match.

Figure 82: Bid-in demand vs. day-ahead demand forecast



The largest DA load forecast for the CAISO area in May was 34,763MW on May 11 at hour ending 20, or 8 PM. The IFM schedule for that same hour was 32,127MW, a 2,636MW difference. The largest DA load forecast for the PACE area was 8,047MW on May 12 at hour ending 18 and the bid-in demand was 402MW lower at 7,645MW. PACW also saw its largest DA load forecast of 2,893 MW on May 12. During the same hour, hour ending 19, the bid-in demand was only 63MW lower at 2,830MW. There were no RUC adjustments to the day-ahead forecast in all of May.

Greenhouse gas emission product

Greenhouse gas (GHG) regulations are designed to reduce carbon emissions associated with electricity generation and imports. In regions or states subject to GHG policies, such as California, imported electricity may incur additional costs when it is generated by resources located outside the regulated area. To ensure these environmental costs are properly reflected in market outcomes, the EDAM also incorporates the GHG model into the market optimization process.

Eligible resources located outside GHG regulation areas may voluntarily submit GHG bids in addition to their regular energy bids. The GHG model introduces GHG allocations as optimization variables that are assigned to generation outside (or across) GHG regulated

areas, representing the portion of their generation attributed to serving demand within a specific GHG regulated area.

The link between GHG allocations and net imports into the regulation area is enforced through the GHG import allocation constraint in the market optimization. The shadow price of this constraint defines the GHG price (or marginal GHG cost), which becomes part of the locational marginal price (LMP) within the regulated area, while remaining zero outside. Resources receiving GHG allocations are paid at the corresponding marginal GHG cost. This payment is separate from the regular energy schedule settlement and provides a mechanism for recovering the GHG regulation costs imposed on imports into the GHG regulation area.

Overall, the model incorporates GHG regulation costs into market optimization to ensure that dispatch decisions reflect both economic and environmental considerations. By accounting for the cost of emissions, the model prevents external resources from being dispatched solely based on energy costs while ignoring the associated GHG impacts. Throughout the month, the highest GHG price reached 22.15 \$/MWh during Trade Hour 20 on May 2. The maximum hourly GHG allocation was 483 MW, occurring during Trade Hour 24 on May 1.

Figure 83 shows the daily average GHG allocation. The daily average GHG allocation reached highest levels near the middle of the month, peaking at 256 MW on May 11, followed by allocations exceeding 200 MW on May 12. During the second half of the month, the average GHG allocations were substantially lower, with several days having average allocations below 50 MW.

Figure 83: Daily average GHG allocation

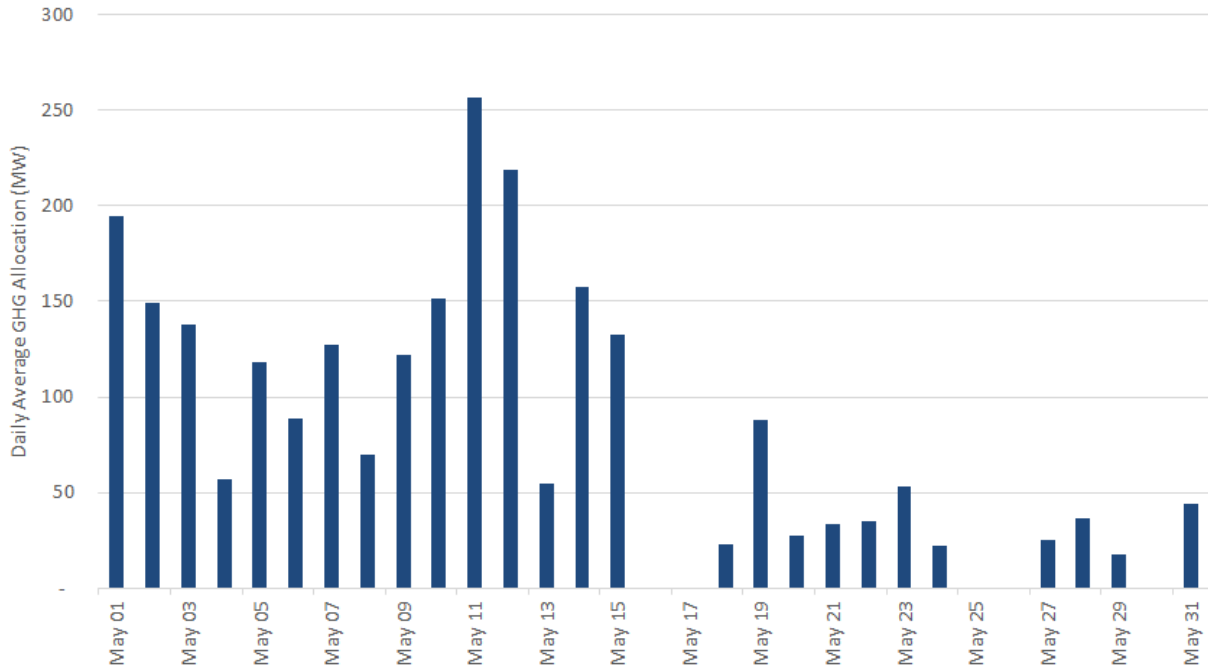


Figure 84 shows the daily average GHG price throughout the month. Daily average GHG prices varied considerably over the month, with the highest average price occurring on May 10 at 6.1\$/MWh. GHG prices generally trended downward during the second half of the month. The daily average GHG prices declined from 3.17 \$/MWh during the first half of the month to 1.44 \$/MWh during the second half, representing a decrease of approximately 55 percent.

Figure 84: Daily average GHG price

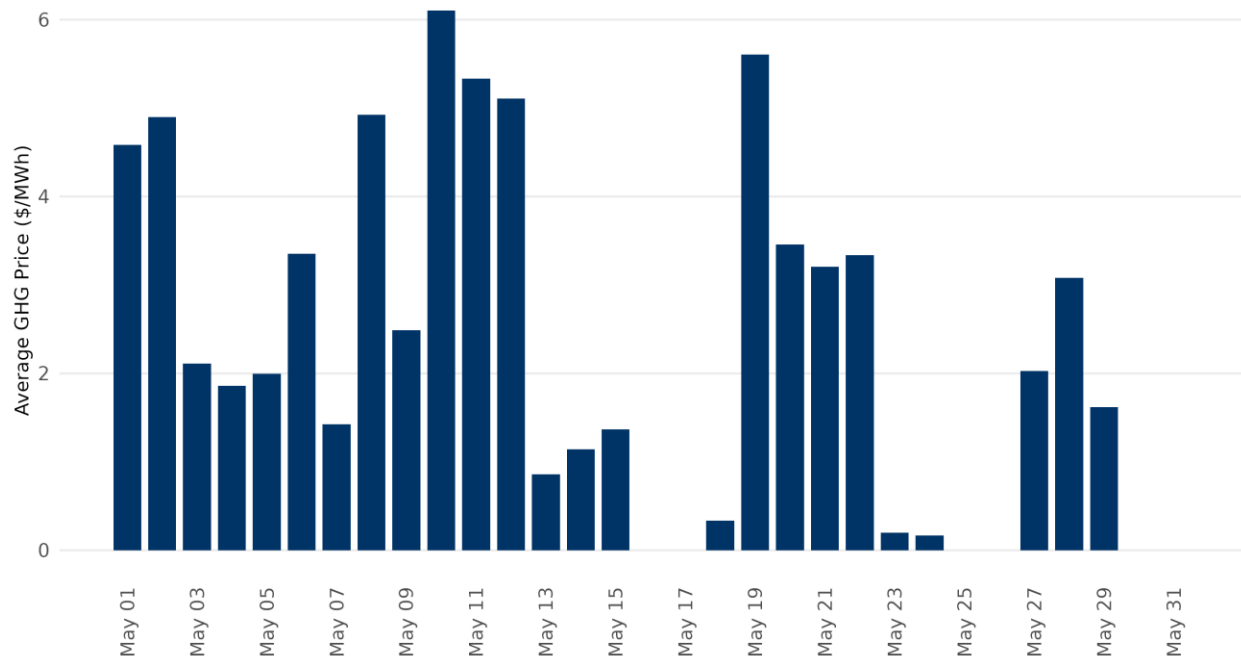
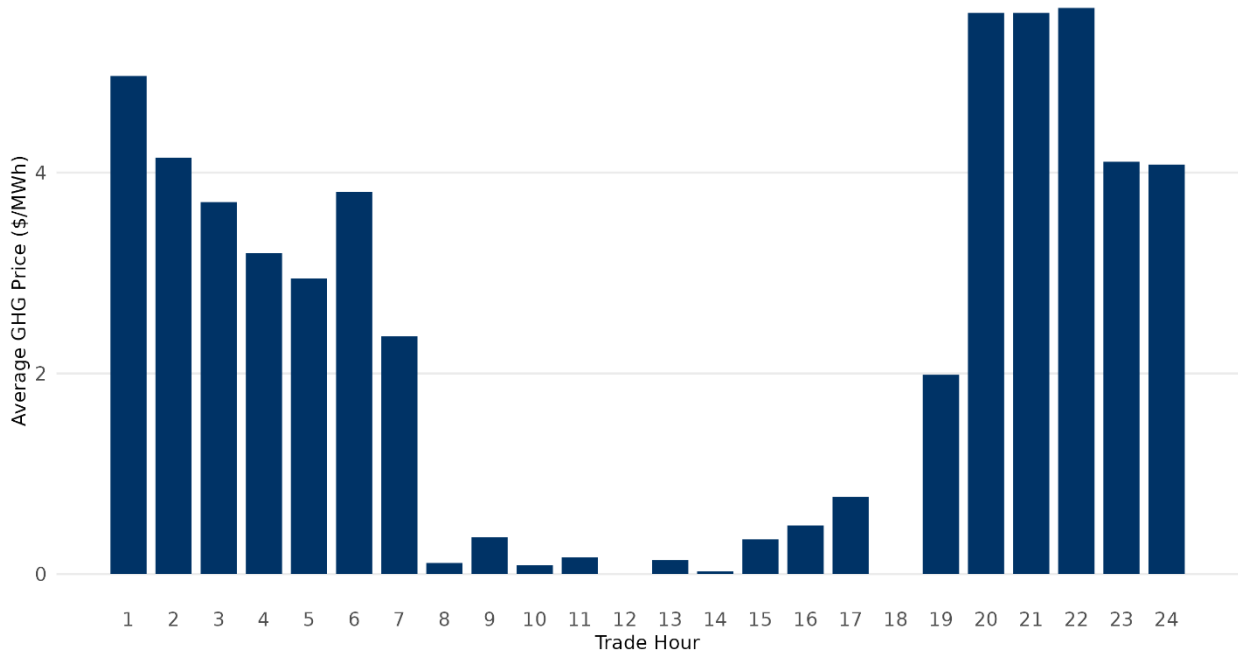


Figure 85 shows the hourly average GHG price by trade hour. GHG prices exhibited a distinct intraday pattern, with the highest prices occurring during early morning (Hours 1-7) and evening (Hours 19-24). In contrast, the prices remained relatively low for most midday hours. This is the time when imports to California area may be minimum given the plentiful solar production inside CAISO area. Notably, the periods of high GHG prices generally align with periods of higher GHG allocations, with both concentrated during early morning and evening peaks. This pattern is consistent with the underlying GHG model, as increased demand for GHG allocations requires resources with progressively higher marginal GHG costs to be selected and therefore increases the resulting GHG price.

Figure 85: Hourly average GHG price



EDAM Transfers

Available transfer capability among the three participating areas is enabling the market to capture the economic benefits of a larger, more integrated regional footprint. By facilitating the movement of cheaper supply across balancing areas, the market can more effectively access the most economical supply available while supporting reliable system operations.

Transfer flows are determined dynamically to these economic signals and can vary from hour to hour as market conditions evolve. Beyond supporting economic efficiency, transfers also enhance access to the geographic and fuel diversity available across the extended market footprint. This broader resource pool increases operational flexibility and improves the utilization of available generation.

Energy transfers

Figure 86 illustrates CAISO daily average energy transfers in IFM in May 2026 on both export (+) and import (-) directions. CAISO was a net exporter in the month. At the beginning of May, CAISO had more imported energy than exported. Then the average export volume generally increased during the second half of May, while imports remained comparatively lower and more stable. The hourly profile in Figure 87 exhibits a diurnal pattern, with exports increasing significantly during daylight hours and peaking in the late afternoon and early evening, with the highest average export volume of about 480 MW in Hour 18. In contrast, imports are concentrated during the morning and evening ramp periods, with notable spikes over 330 MW around Hours 7 and 19. This pattern is consistent with availability of solar generation during midday hours, enabling substantial exports to PAC areas.

Figure 86: Daily average energy transfers for CAISO

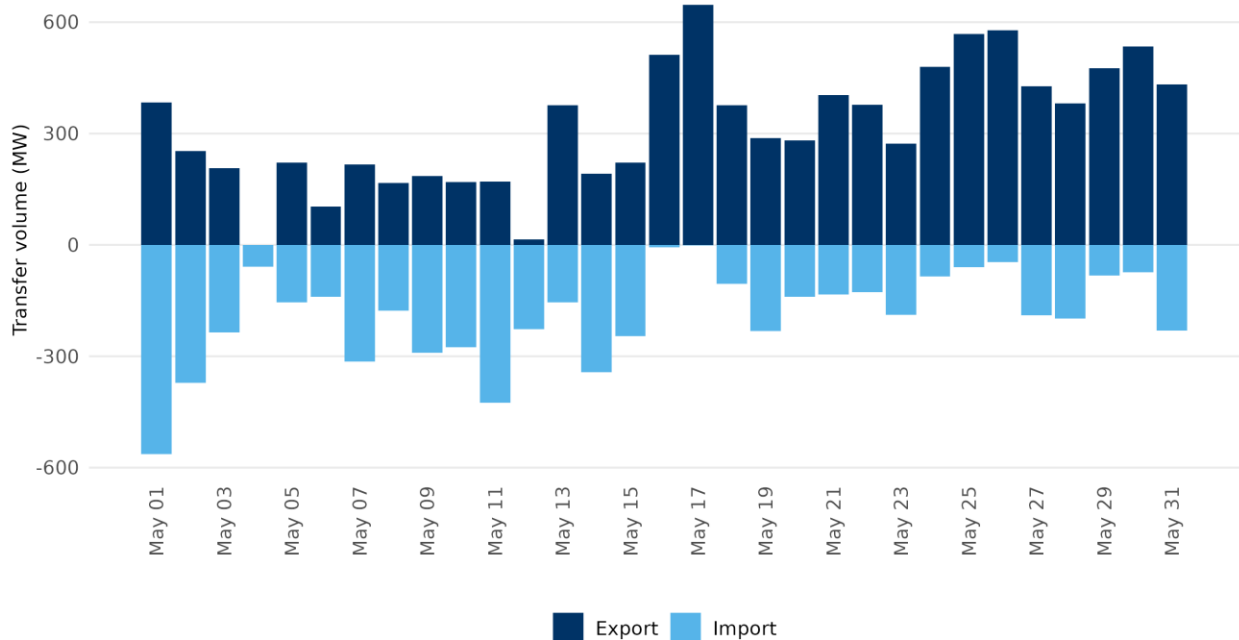


Figure 87: Hourly average energy transfers for CAISO

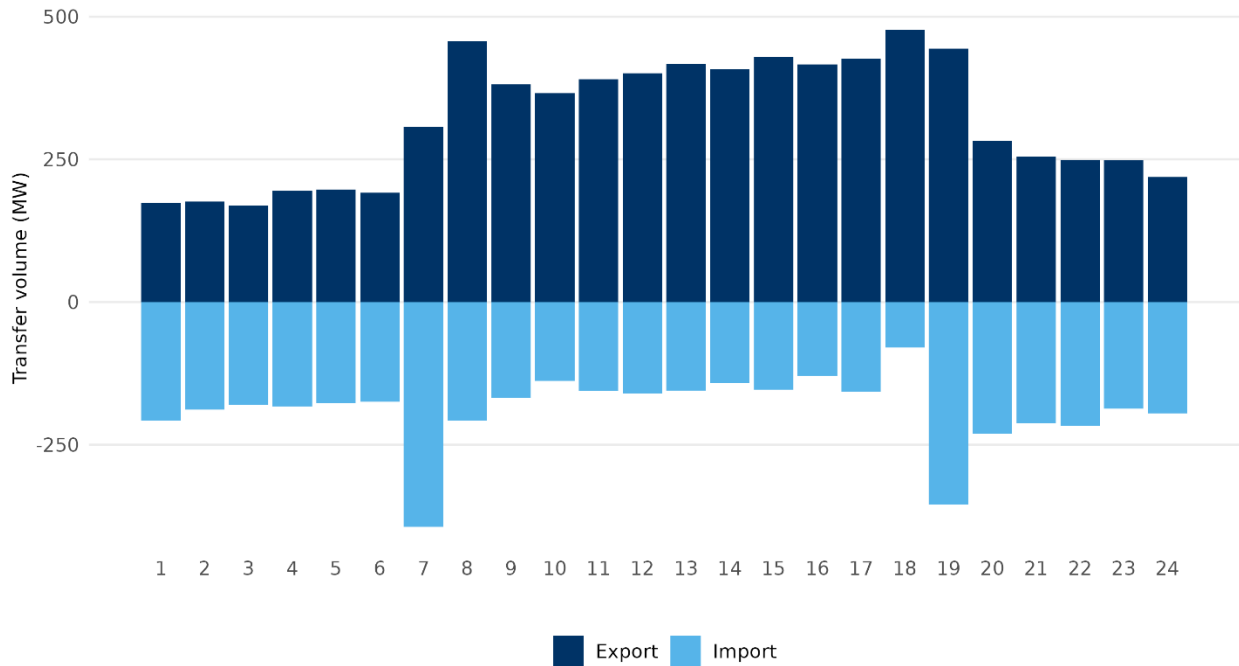


Figure 88 and Figure 89 show PACW’s daily and hourly average energy transfers in May 2026 on both export (+) and import (-) directions. PACW remained a net importer in the month. The average import volumes generally increased during the second half of May and reached maximum daily average import volume of about 170 MW on May 30. The highest daily average export volume was about 180 MW on May 19. The hourly profile exhibits a different pattern from CAISO, with increasing imports over 120 MW during daylight hours. In contrast, exports’ peak is around HE 7 and HE 20-22, with a maximum average export of about 100 MW.

Figure 88: Daily average energy transfers for PACW

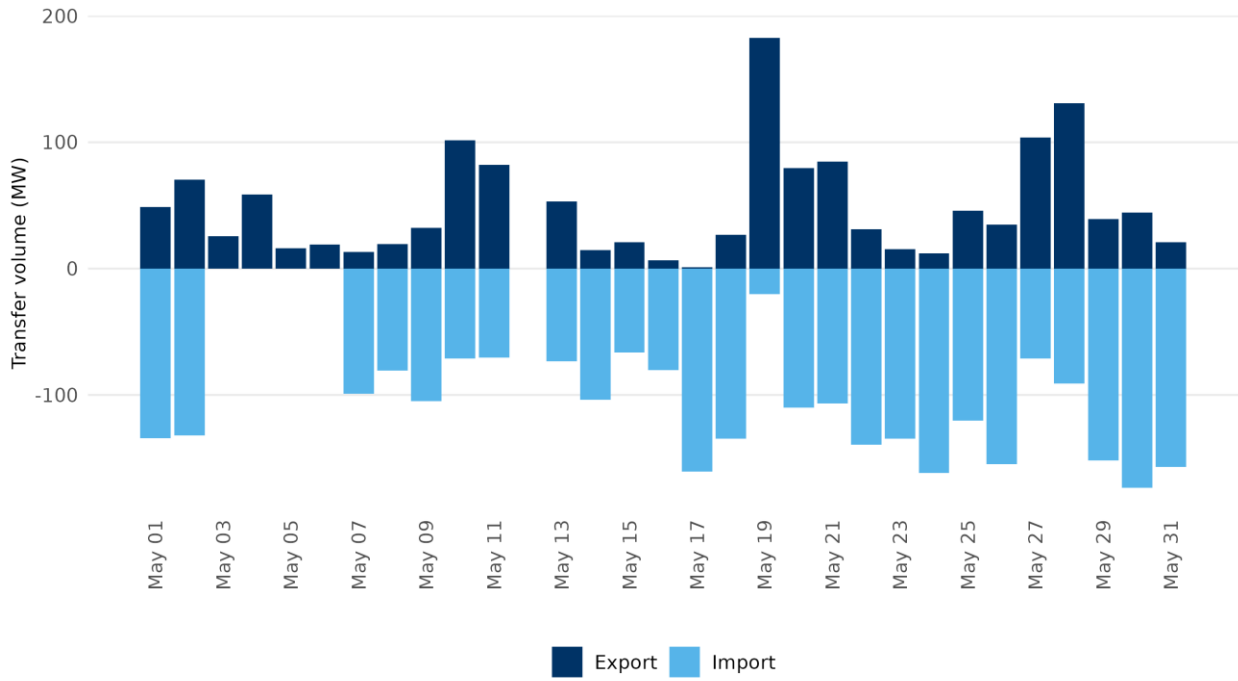


Figure 89: Hourly average energy transfers for PACW

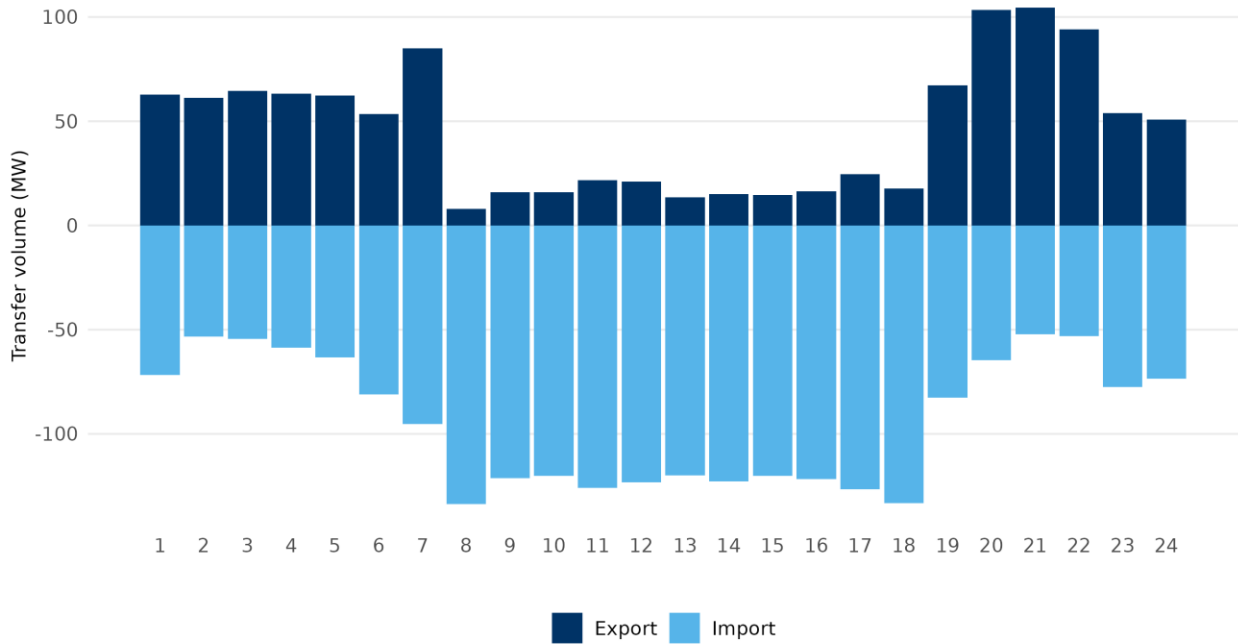


Figure 90 and Figure 91 show PACE’s daily and hourly average energy transfers in May 2026 on both export (+) and import (-) directions. Generally, PACE remained a net importer in May. The average daily exports reached the highest of over 500 MW on May 1, then decreased throughout the month. Import volumes increased during the second half of May and reached the highest volume of about 500 MW on May 17. The hourly profile shows PACE’s increasing imports during daylight hours, with peak imports of over 300 MW in HE8 and HE 18 - 19. In contrast, exports’ peak hours were HE 7 and 19 with a volume of about 300 MW.

Figure 90: Daily average energy transfers for PACE

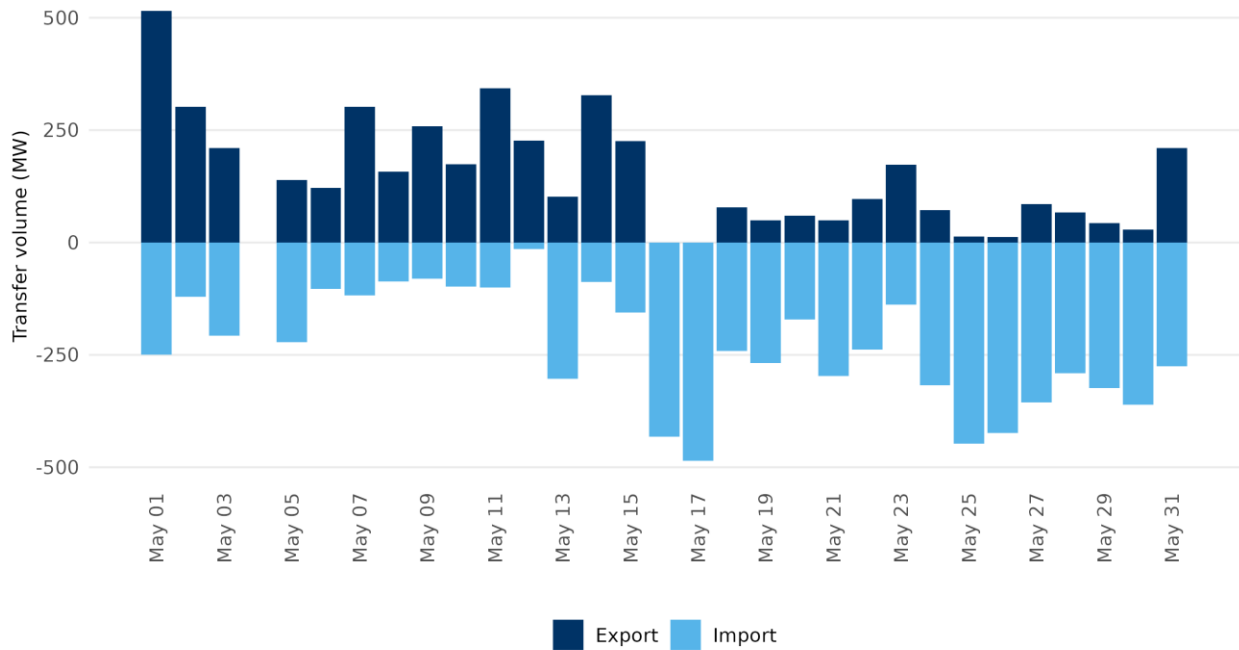
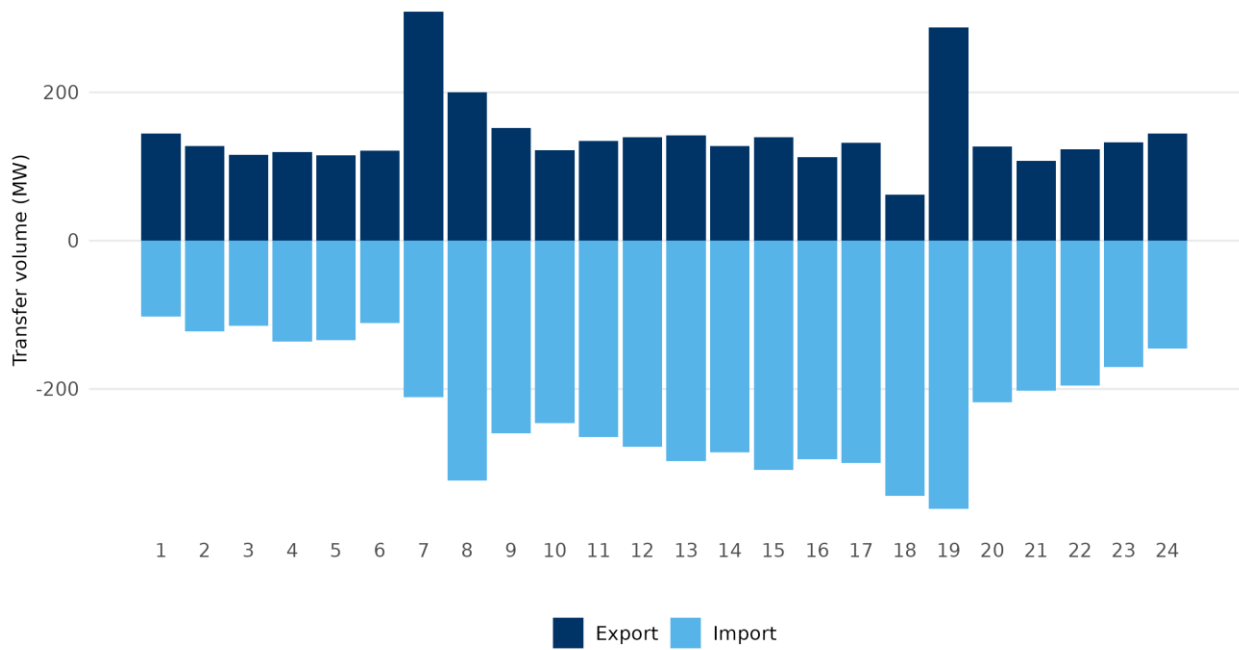


Figure 91: Hourly average energy transfers for PACE



Imbalance reserves

As with energy, the market can transfer imbalance reserves among BAAs, which provide revenue to exporting areas and lower costs capacity reserves to importing areas. Figure 92 and Figure 93 show CAISO’s daily and hourly average IRU transfers in May 2026 on both export (+) and import (-) directions. Generally, in May, CAISO exported IRU and imported IRD. Exports dominate the cleared IRU volume most of the time with the highest daily average export of over 400 MW on May 15. The peak IRU export occurs in early morning Hours 5-6 over 300 MW, with only a small proportion of imports in Hour 8 and Hours 18-19 over 100 MW.

As for IRD product, as Figure 94 and Figure 95 show, CAISO remained was net importer throughout the month. The IRD imports realized mainly in the first days of May, reaching a daily maximum of about 300 MW on May 11. Hours 7 and 19 had the highest average IRD imported volumes of about 300 MW. The maximum daily average export IRD was 250 MW on May 1.

Figure 92: Daily average IRU transfers for CAISO

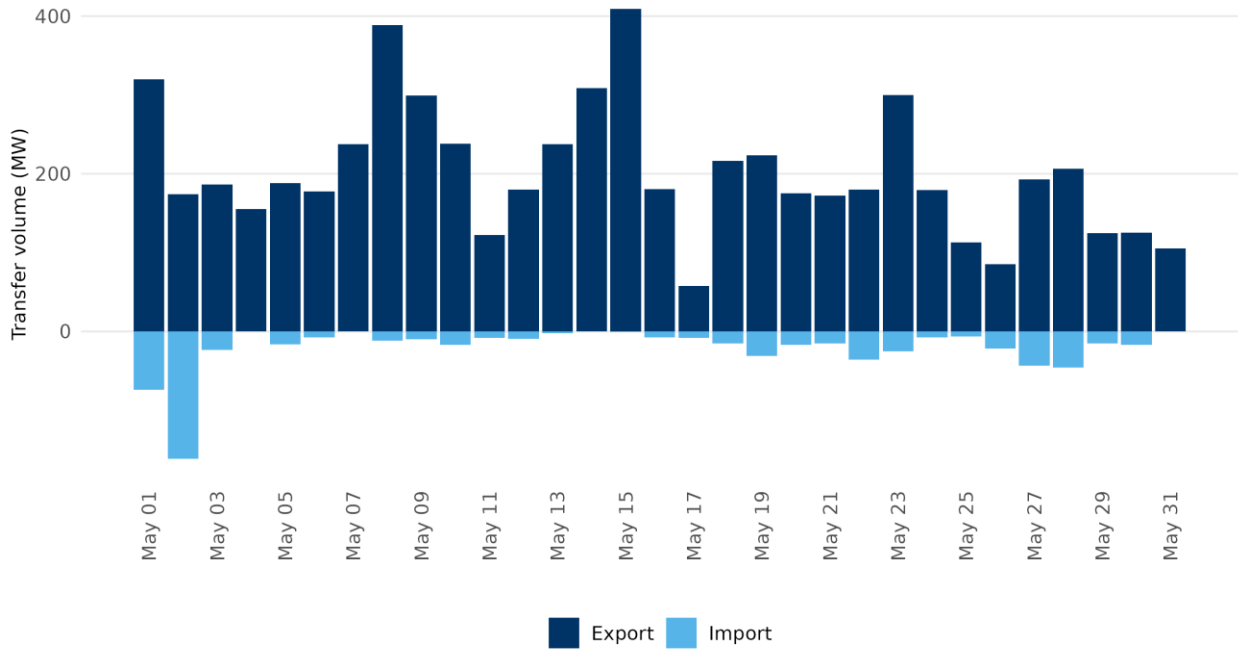


Figure 93: Hourly average IRU transfers for CAISO

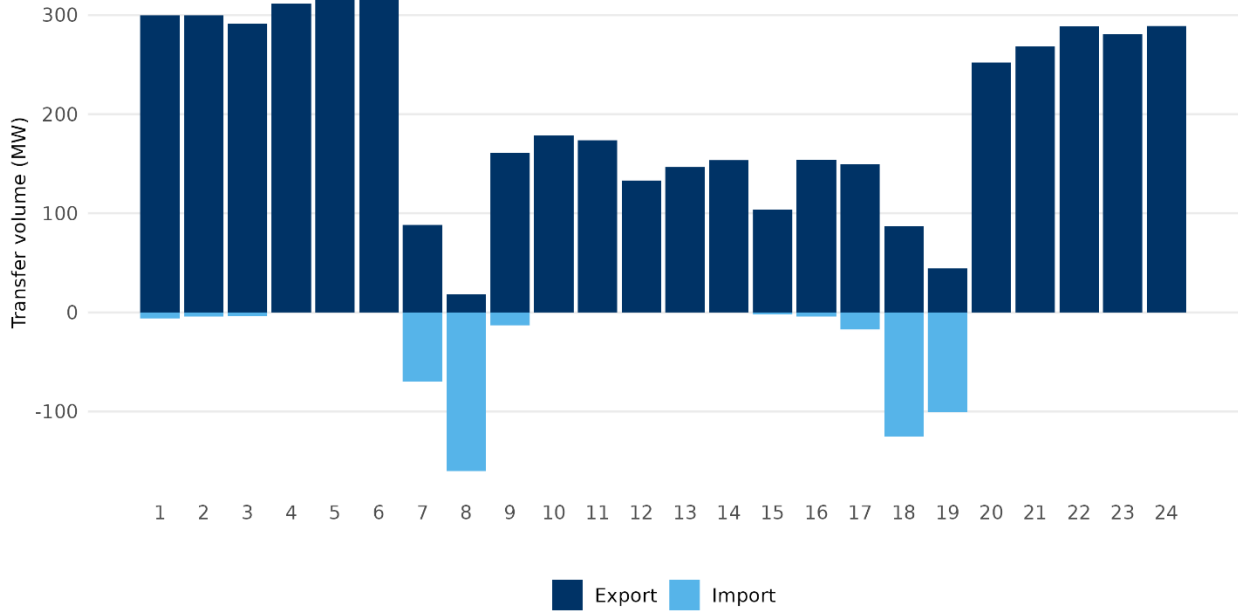


Figure 94: Daily average IRD transfers for CAISO

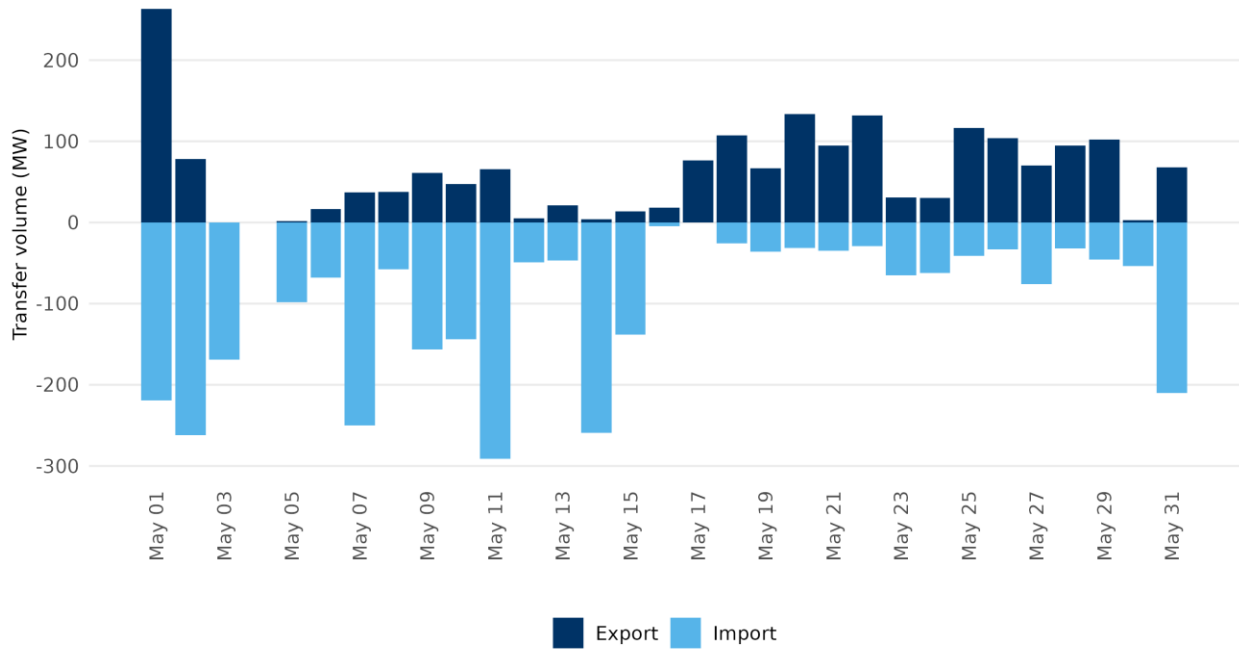


Figure 95: Hourly average IRD transfers for CAISO

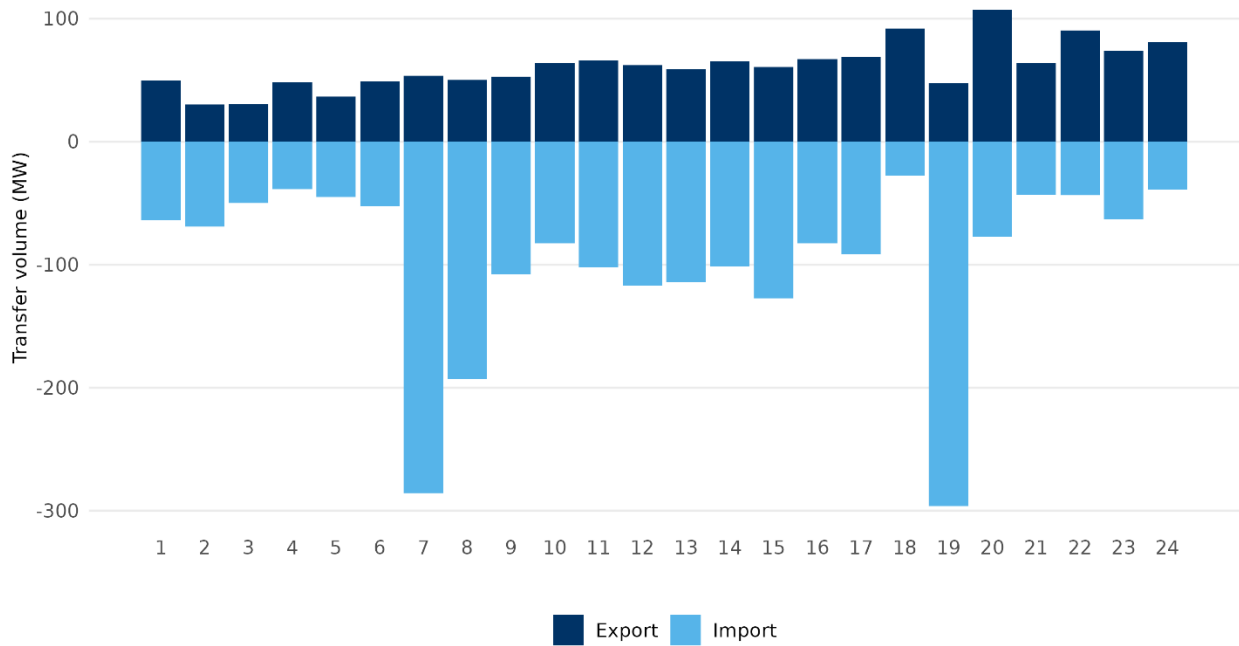


Figure 96 - Figure 99 show PACW’s daily and hourly average IRU and IRD transfers in May 2026 on both export (+) and import (-) directions, respectively. Unlike CAISO, the imbalance reserve transfers for PACW were generally dominated by imports in both directions.

For IRU, PACW remained a net importer in the month. Based on the average profile, imports dominate the cleared IRU volume most of the time. The maximum import volume is about 130 MW on May 15. The peak hours for IRU import are nighttime hours, with Hours 21 – 22 over 80 MW. PACW exports less than 30 MW of IRU around Hours 7-8 and Hours 18-19.

As for IRD product, PACW remained a net importer in the month too. The highest daily imported IRD is over 110 MW on May 1, and the highest hourly average import is Hour 18, with a volume of over 65 MW.

Figure 96: Daily average IRU transfers for PACW

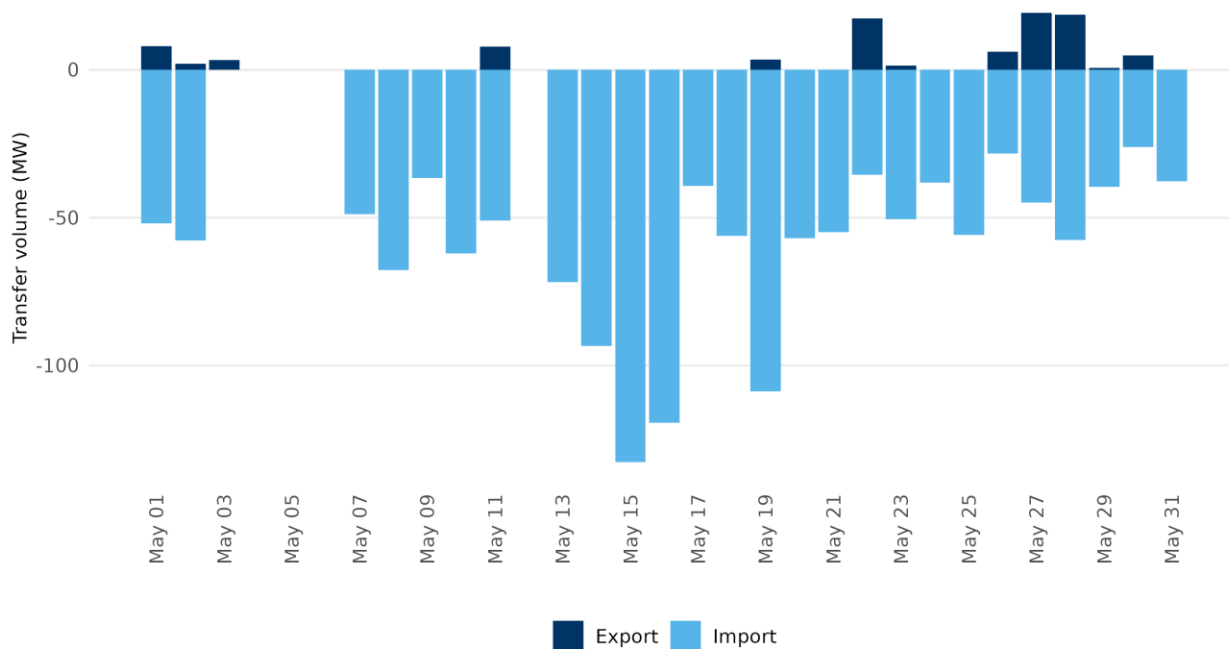


Figure 97: Hourly average IRU transfers for PACW

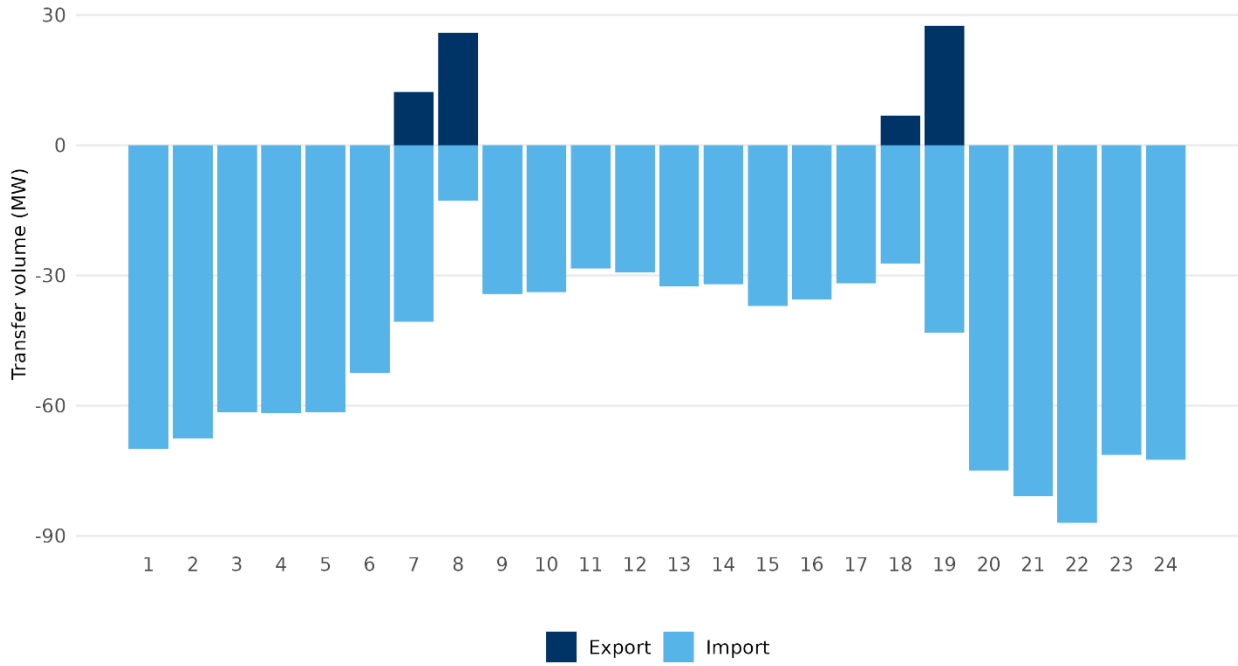


Figure 98: Daily average IRD transfers for PACW

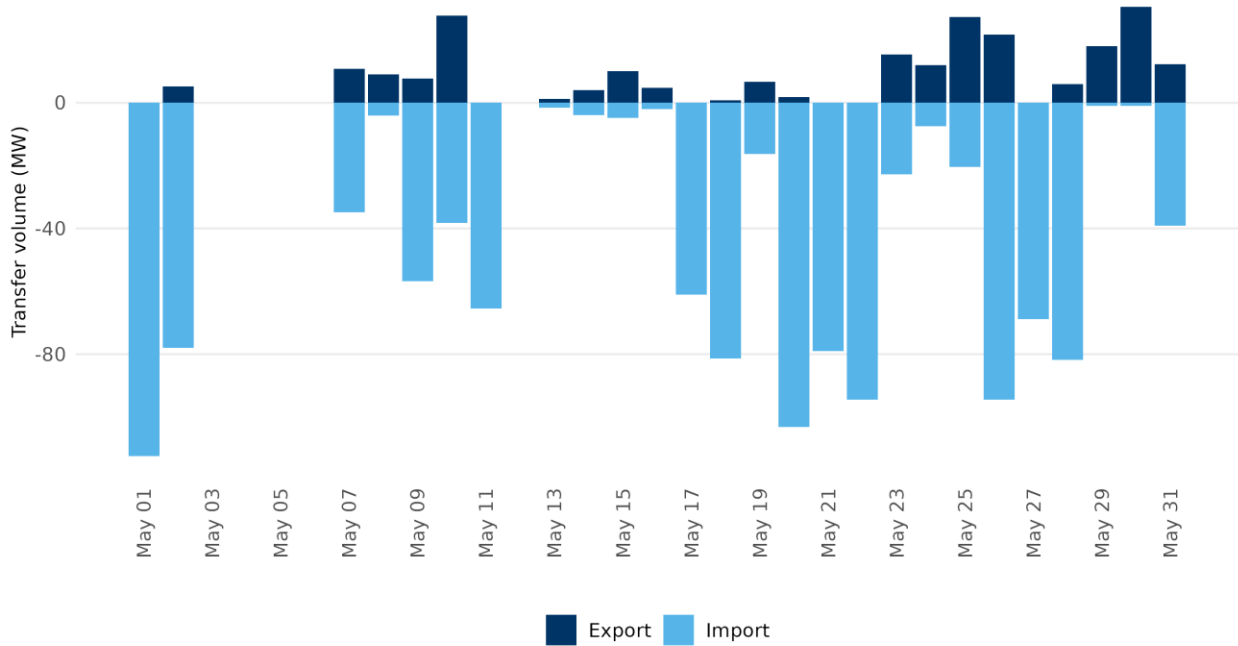


Figure 99: Hourly average IRD transfers for PACW

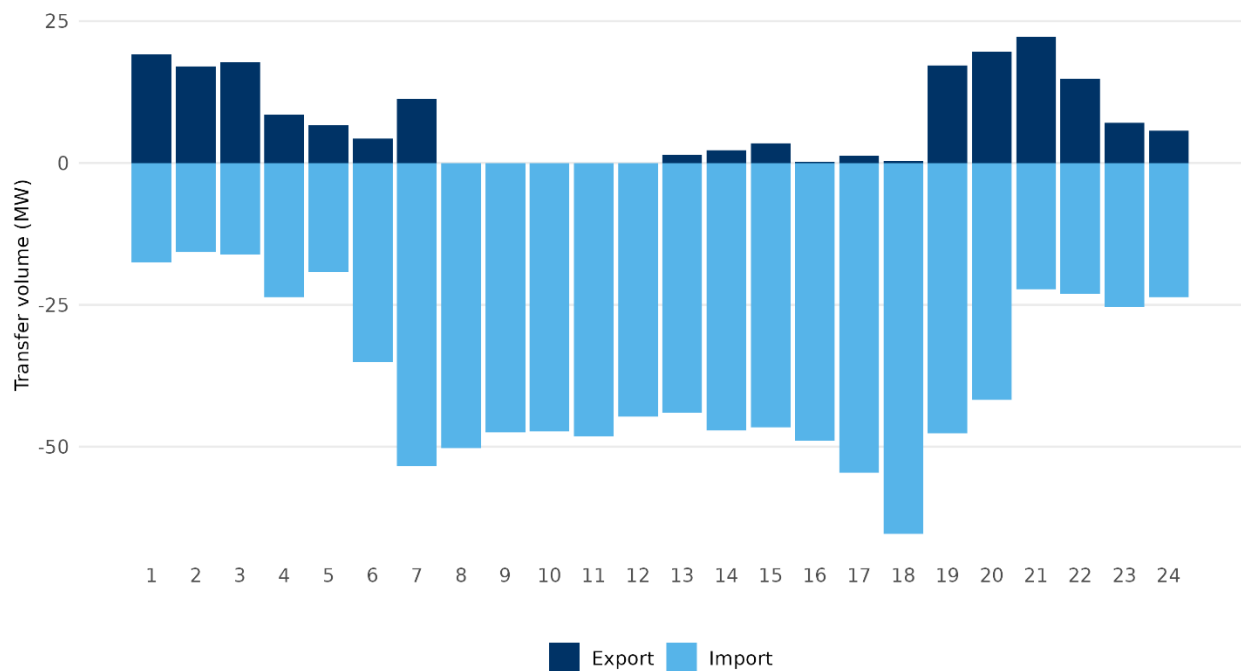


Figure 100 - Figure 103 show PACE’s daily and hourly average IRU and IRD transfers in May 2026 on both export (+) and import (-) directions, respectively. PACE generally imports upward reserves while exporting downward reserves.

For IRU products, PACE remained a net importer in the month. The daily average imports dominate PACE’s IRU volume most of the time, and the maximum daily average is over 300 MW on May 8. The hourly average import peak is around 270 MW mainly in Hours 5 – 6, with only a small proportion of exports over 100 MW in Hours 8 and 18.

PACE remained a net exporter of IRD throughout the month. The exported IRD products are concentrated in the first half of May with the highest daily average nearly 300 MW on May 11, and hourly average peak mainly in Hours 7 and 19 about 280 MW.

Figure 100: Daily average IRU transfers for PACE

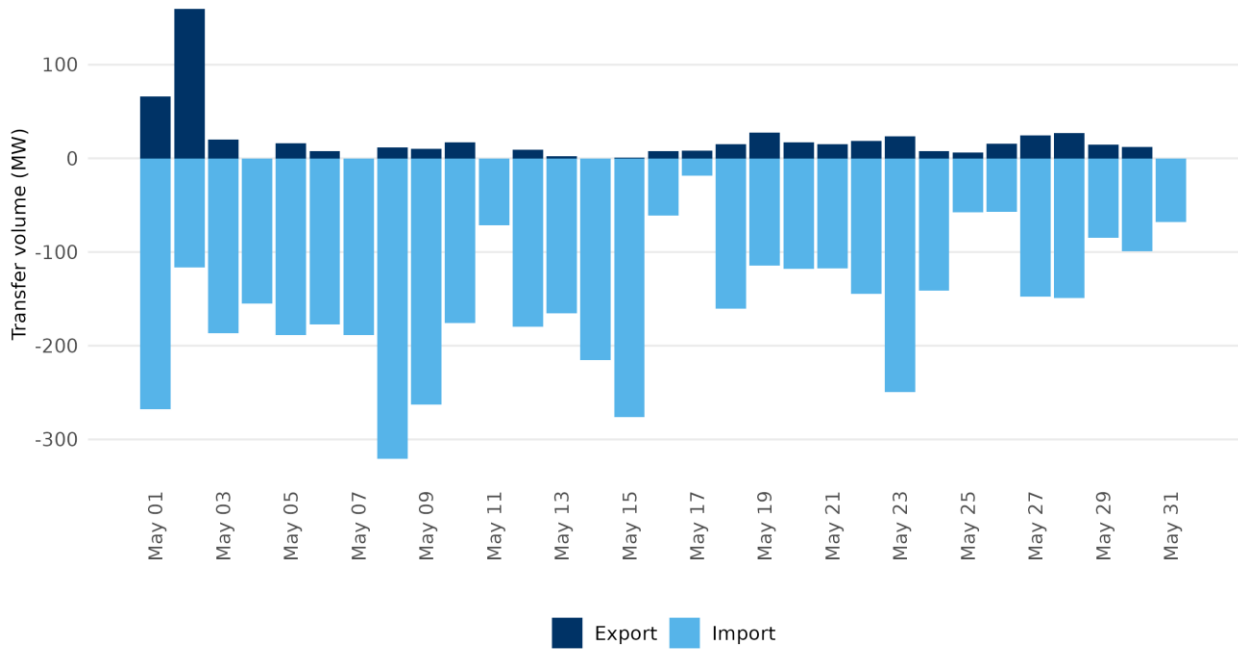


Figure 101: Hourly average IRU transfers for PACE

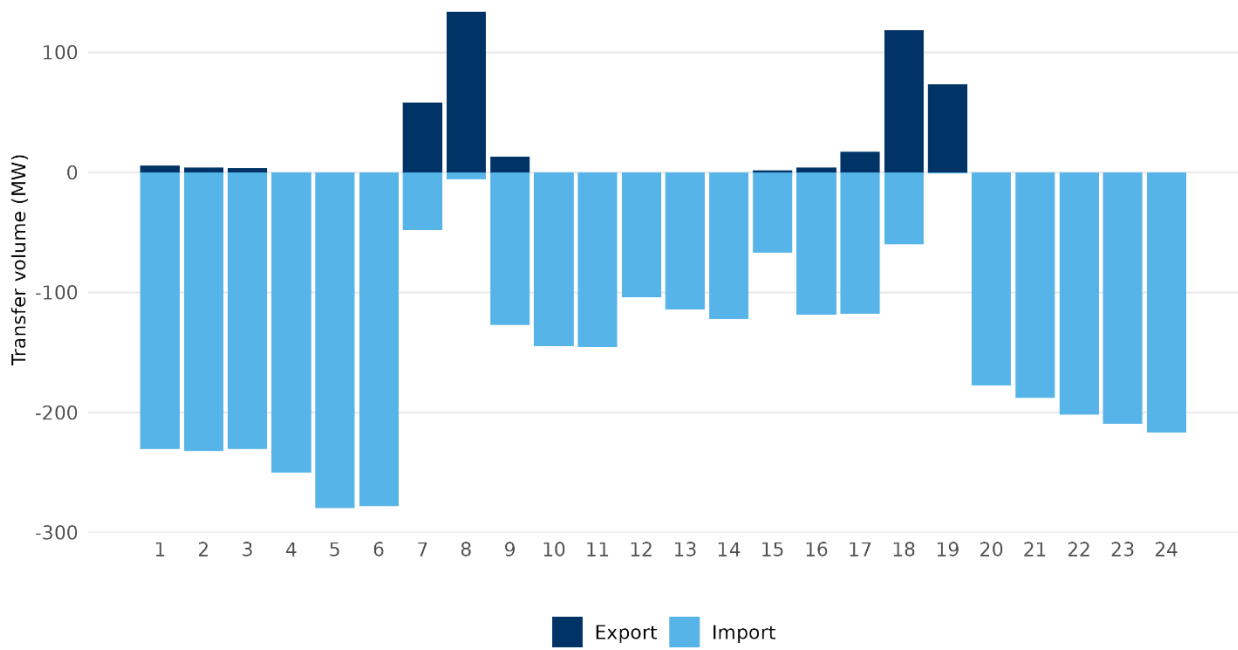


Figure 102: Daily average IRD transfers for PACE

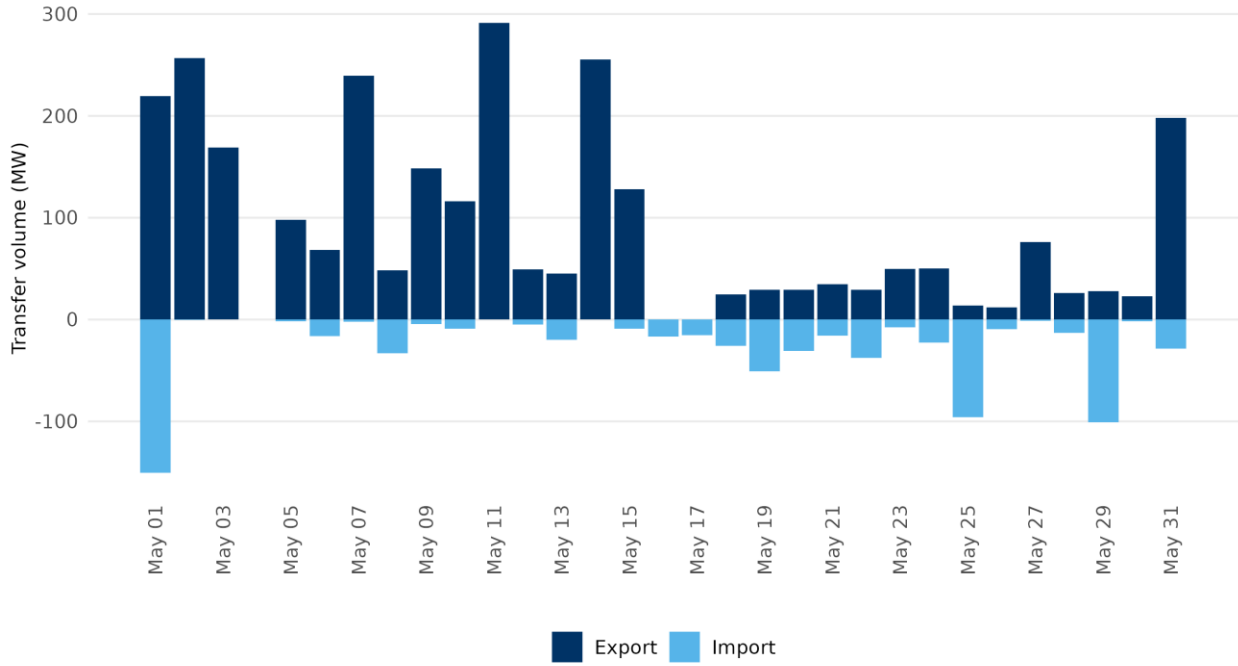
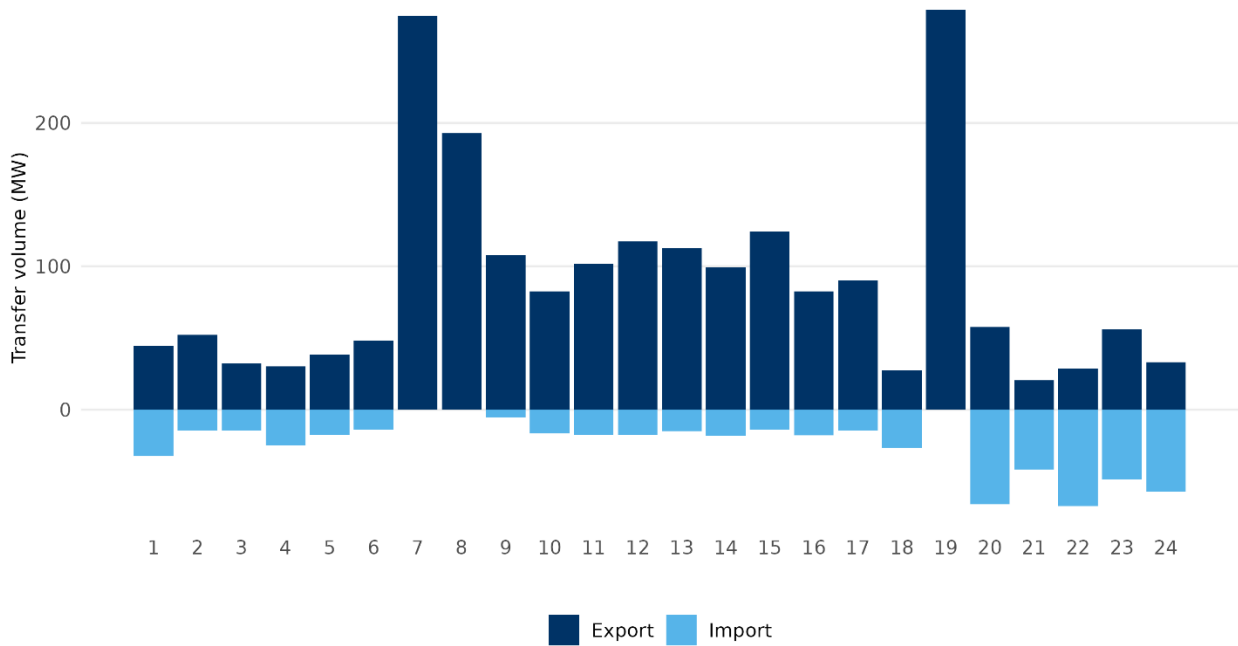


Figure 103: Hourly average IRD transfers for PACE



Reliability capacity transfers

Figure 104 to Figure 107 show CAISO’s daily and hourly average RCU and RCD transfers in May 2026 on both export (+) and import (-) directions. Figure 104 to Figure 107 show CAISO’s daily and hourly average RCU and RCD transfers in May 2026 on both export (+) and import (-) directions. Generally, CAISO remained a net importer for both RCU and RCD throughout the month.

For the RCU product, net imports were concentrated during the second half of May, with the largest import volume at about 120 MW occurring on May 27, while net exports dominated much in the first two days half of May, with the maximum daily average export about 180 MW on May 2. The hourly profile shows the largest imports over 100 MW occurring in Hours 2-4 and the largest export 50 MW in hour 20.

As for RCD, imports were concentrated during the first half of May with a maximum daily average over 50 MW on May 1. The hourly profile shows the average import peak is in evening hours, with the highest volume over 30 MW in hour 24.

Figure 104: Daily average RCU transfers for CAISO

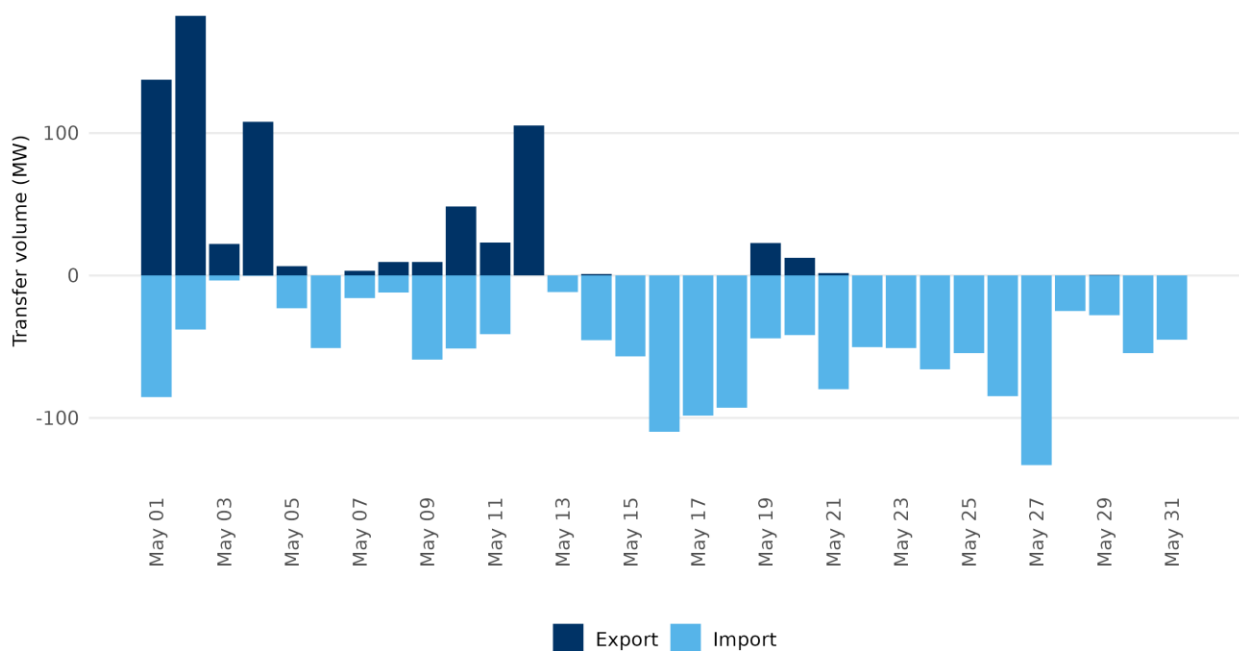


Figure 105: Hourly average RCU transfers for CAISO

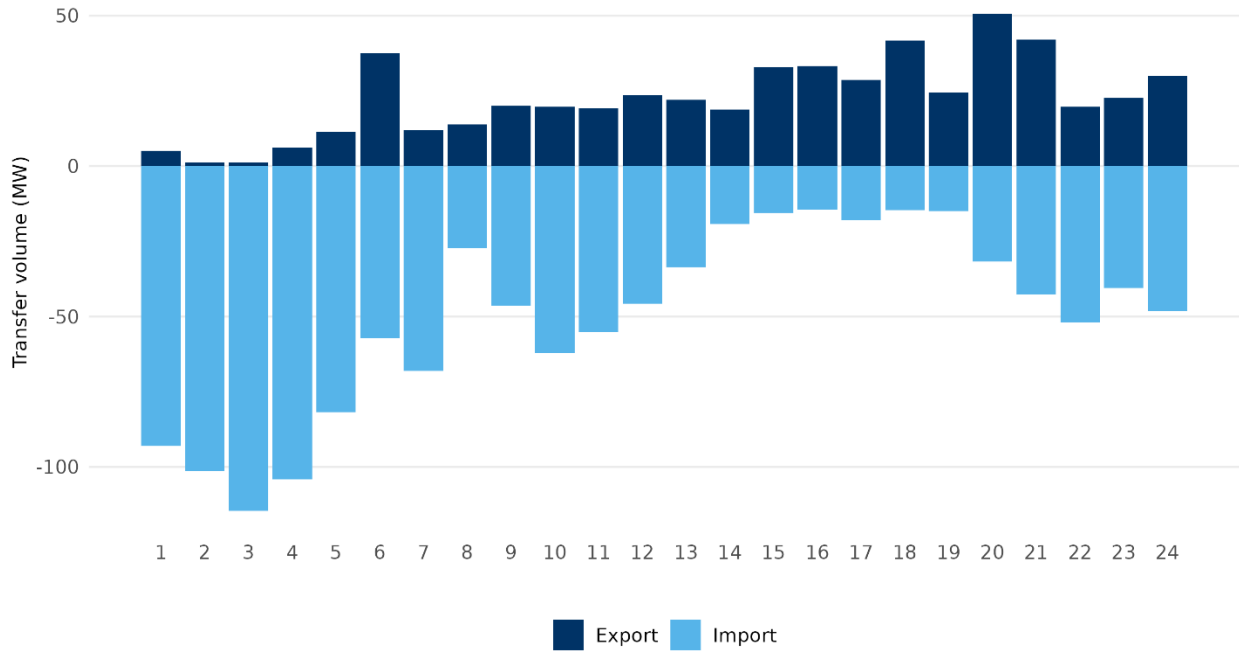


Figure 106: Daily average RCD transfers for CAISO

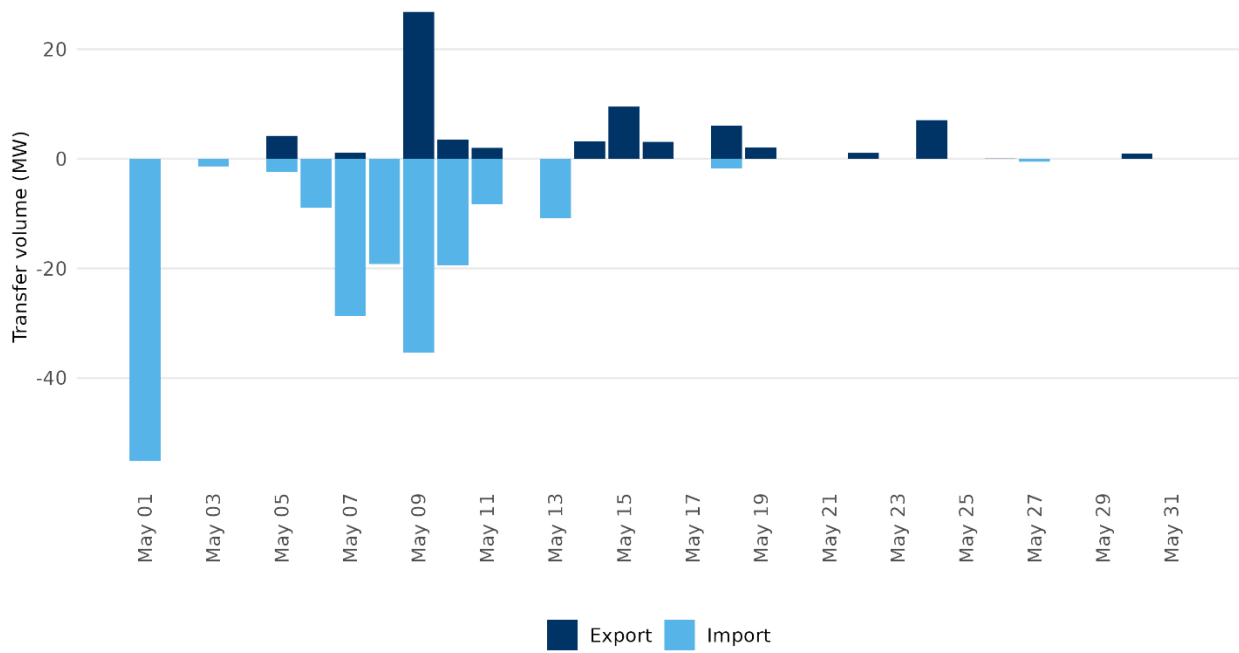


Figure 107: Hourly average RCD transfers for CAISO

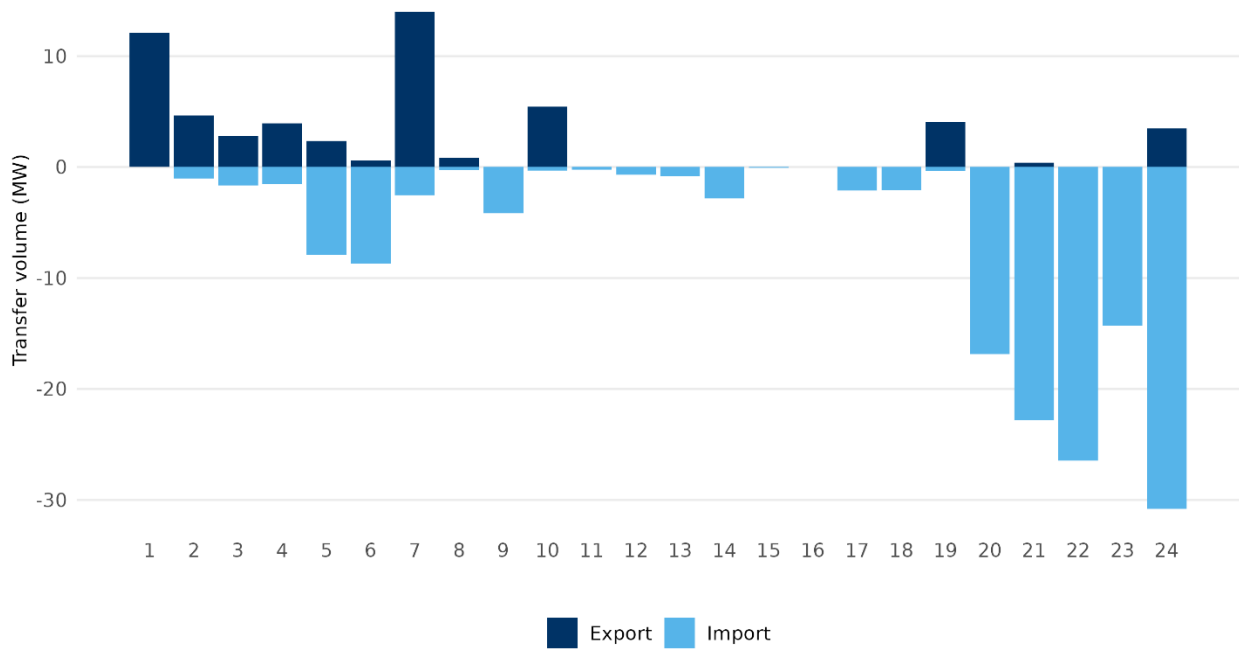


Figure 108 to Figure 111 show PACW’s daily and hourly average RCU and RCD transfers in May 2026 on both export (+) and import (-) directions. Exports dominate PACW’s RCU transfer volumes, and the highest daily average is about 70 MW on May 18. The imports occur only on several days, and the highest import on May 1. The hourly profile shows a persistent net export pattern across all hours, with the largest export occurring during the overnight and early morning hours. As for RCD, the average imports were concentrated during the mid of May and the highest daily average was 14 MW on May 9. The hourly RCD transfer profile showed the import peak is mainly at Hour 7 with 13 MW.

Figure 108: Daily average RCU transfers for PACW

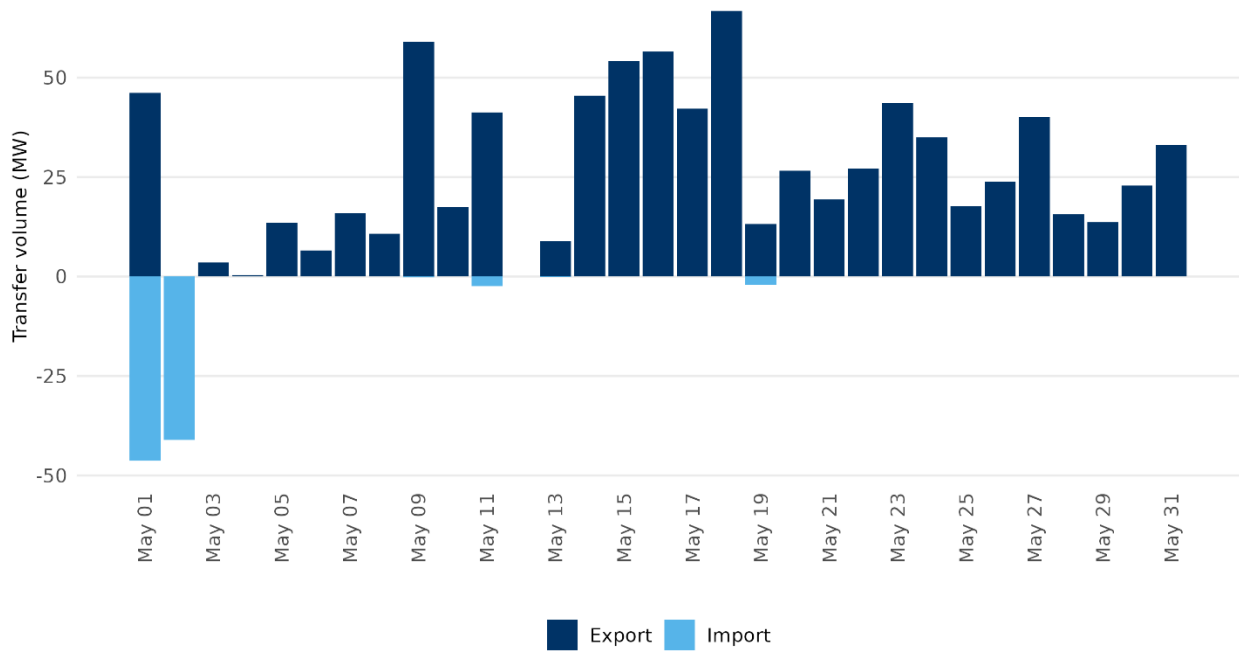


Figure 109: Hourly average RCU transfers for PACW

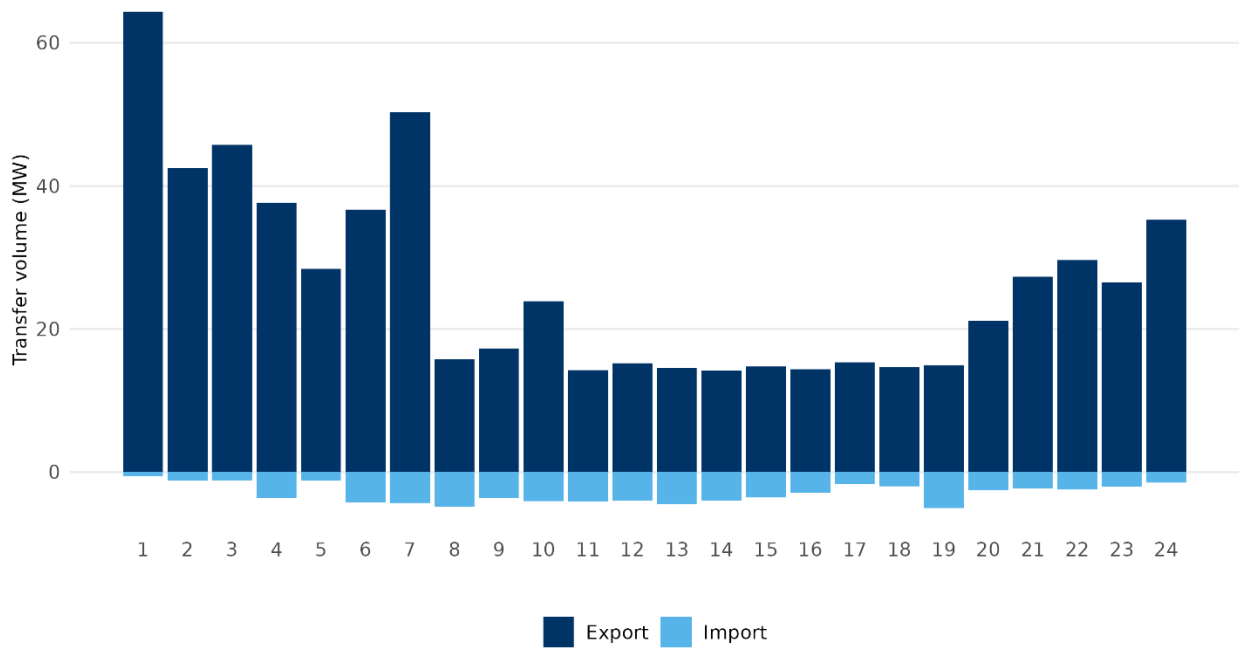


Figure 110: Daily average RCD transfers for PACW

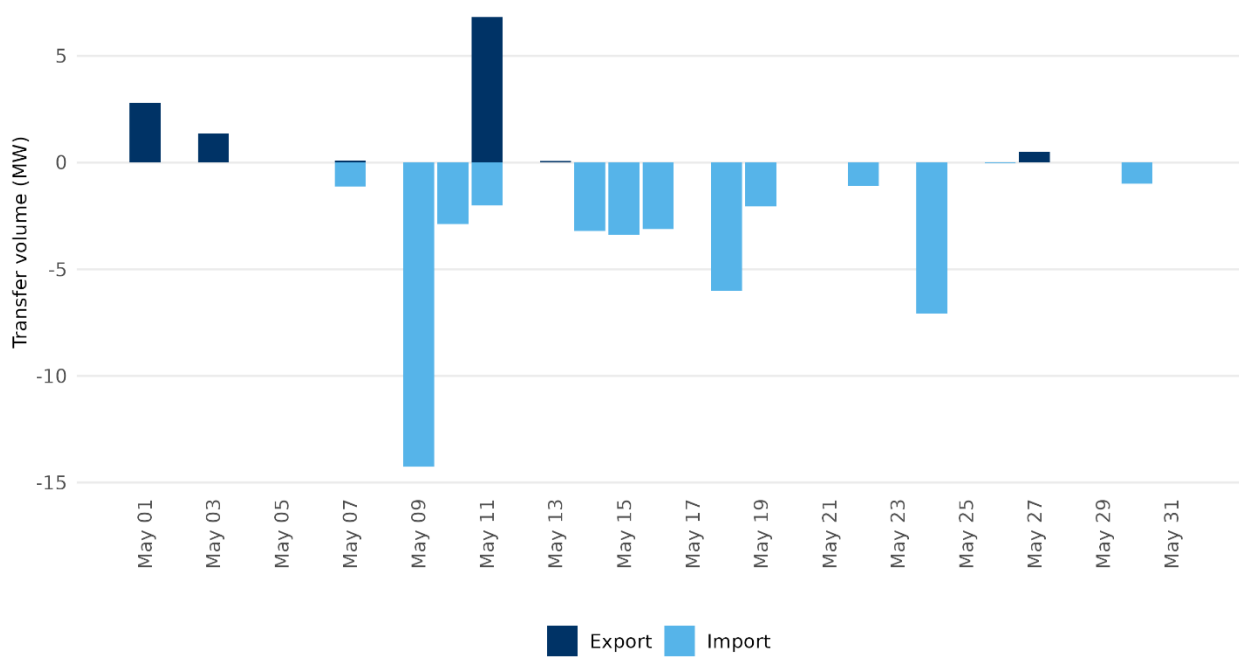


Figure 111: Hourly average RCD transfers for PACW

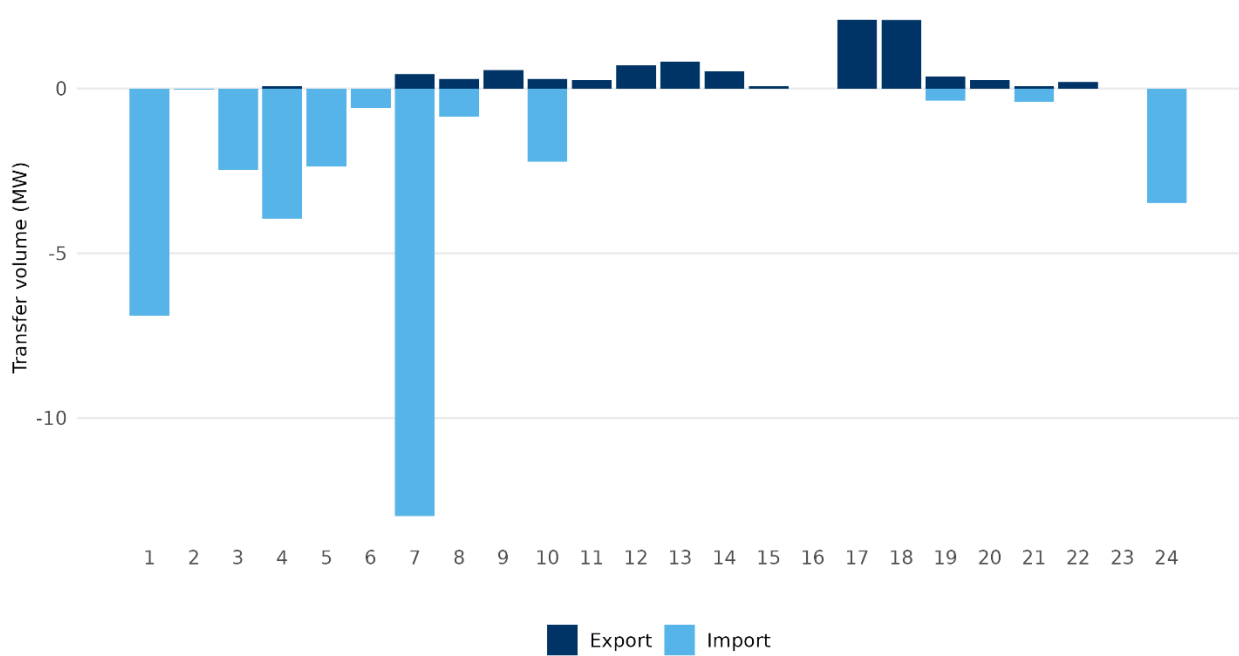


Figure 112 to Figure 115 show PACE’s daily and hourly average RCU and RCD transfers in May 2026 on both export (+) and import (-) directions. The RCU transfers in PACE show a more dynamic pattern, as a net imported at the first half of the month then turns to a net exported. The daily average profile shows the maximum RCU import was about 140 MW on May 2 and maximum export volume about 90 MW on May 27. The hourly profile shows more exports in the first half of the day while more imports in the second half.

As for RCD, PACE’s average transfer mainly occurred in the first half of May, and the maximum export is over 50 MW on May 1. The hourly profile shows that net exports dominated and the peak is in in Hours 20-24 with the highest export volume over 30 MW.

Figure 112: Daily average RCU transfers for PACE

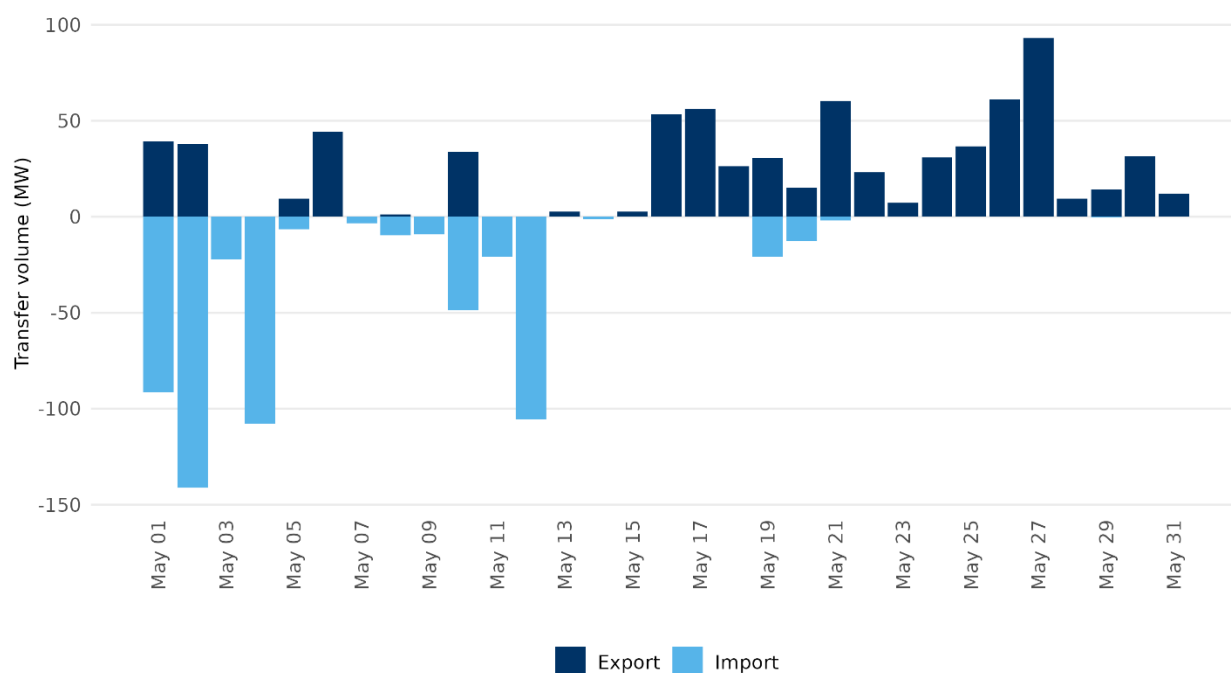


Figure 113: Hourly average RCU transfers for PACE

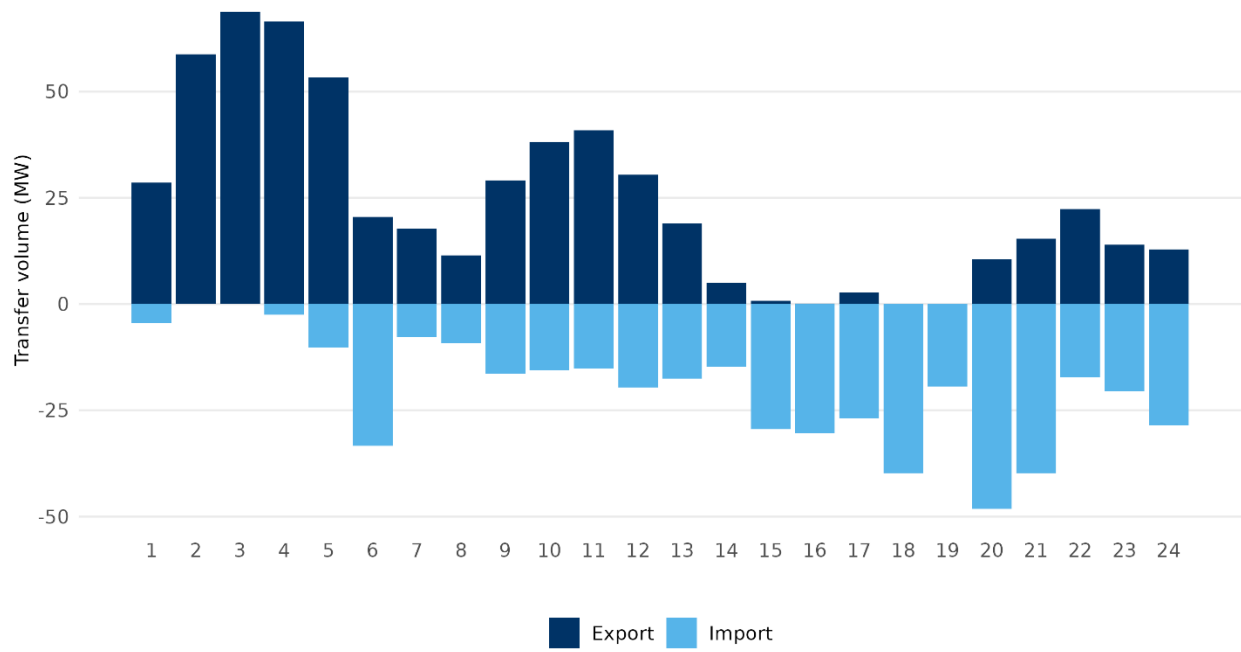


Figure 114: Daily average RCD transfers for PACE

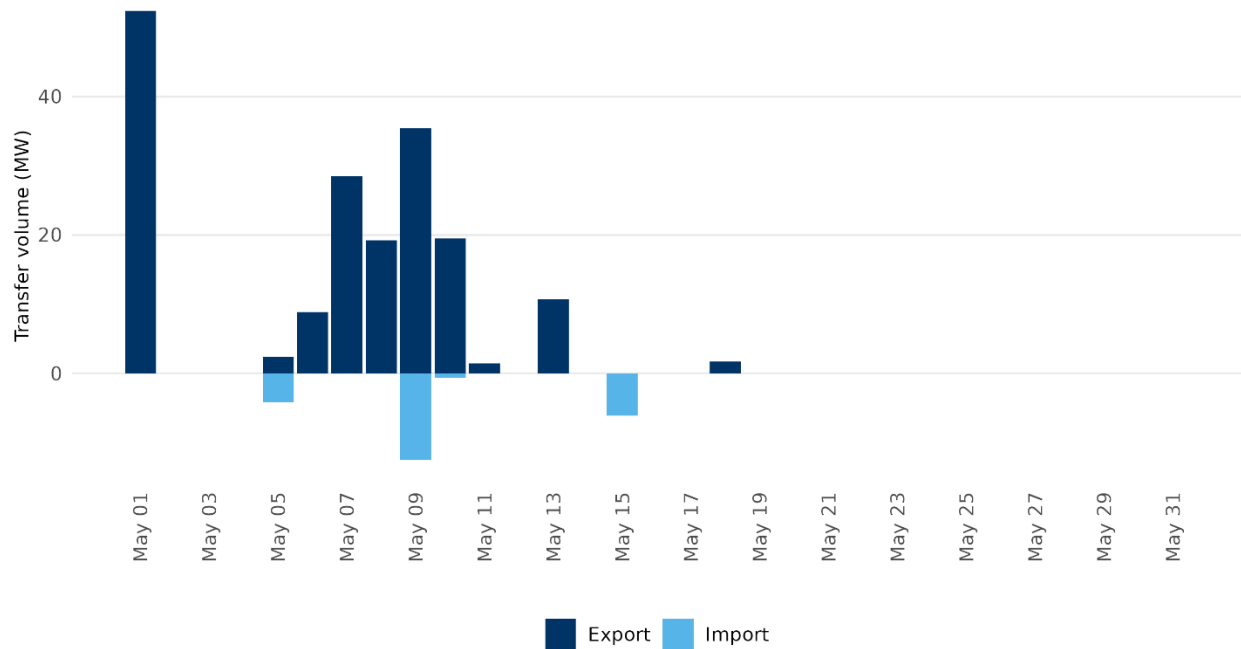
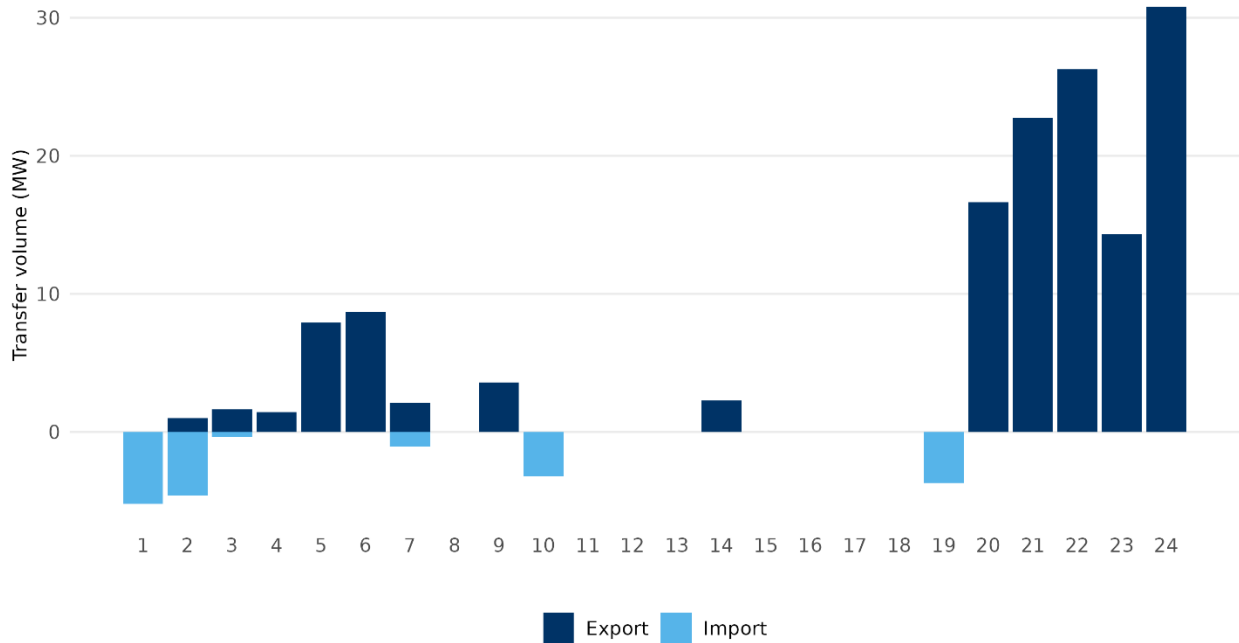


Figure 115: Hourly average RCD transfers for PACE



Congestion

Congestion can occur when the lowest cost energy cannot be transmitted to meet demand where it is needed due to a lack of transmission capacity. In that situation, higher cost, local resources must be used to meet that demand in a constrained area. The added cost of bringing on these resources is reflected in the Locational Marginal Price (LMP) through Marginal Cost of Congestion (MCC) component. In other words, the MCC is the cost of delivering one additional MW to that node/location due to congestion on the system.

Table 2 shows the average MCC for the month of May for the EDAM DLAP/ELAP APnodes⁴. Since congestion is defined at each location, using the DLAP/ELAP of the market areas is a simple and reasonable representation of the overall congestion in each area.

⁴ These results are preliminary and subject to revision. A known data issue is currently under investigation, which may result in discrepancies in the analysis.

Table 2: Average congestion costs

DLAP/ELAP	Average MCC (\$/MWh)
PACE	-0.80
PACW	0.48
PG&E	4.04
SCE	-3.68

A positive number for MCC represents an increase in DLAP/ELAP LMP due to system congestion while a negative number represents a decrease in LMP from congestion. A positive MCC for a DLAP/ELAP indicates a more constrained area where cheaper energy may not be able to flow. In May, congestion had minimal impacts on PACE and PACW ELAP locational marginal prices, at -\$0.80 and \$0.48, respectively. In contrast, within CAISO DLAPs, SCE averaged -\$3.68, while PG&E averaged \$4.04. CAISO DLAPs saw higher congestion costs due to most of the congestion occurring within the CAISO area, creating a notable price separation between Northern and Southern California. The SCE subarea experienced negative congestion prices, while the PG&E subarea in Northern California experienced positive congestion prices. This price separation is indicative of northbound transmission congestion.

Congestion prices at PACW closely tracked those in Northern California, with average MCC values remaining positive and contributing to higher total LMPs. In contrast, average MCC prices at PACE were generally negative, mirroring congestion patterns in Southern California. However, the magnitude of congestion observed at PACW and PACE was considerably lower than that seen within the CAISO are.

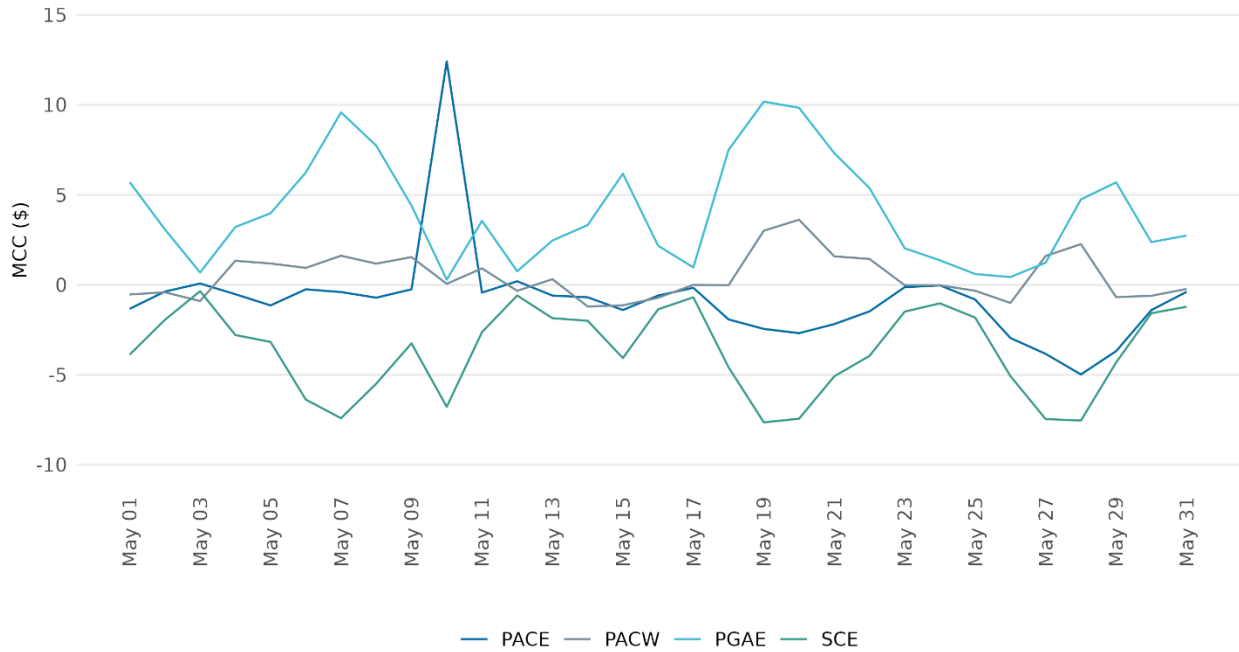
Table 3 provides an hourly average of congestion costs across areas with the blue gradient indicating larger positive MCC prices and the gradient of purple indicates larger negative MCC prices. The highest congestion costs occurred during solar generation hours, when renewable output was most concentrated on the grid, resulting in opposite congestion impacts between Northern and Southern California. Congestion patterns at PACW closely tracked those in the PG&E subarea of Northern California, while congestion at PACE generally followed the trends observed in Southern California. However, the magnitude of congestion in both PACW and PACE was significantly lower than that observed within California

Table 3: Hourly average congestion costs

Trade Hour	PACE	PACW	PGAE	SCE
1	-0.64	-0.63	-0.48	-0.37
2	-0.55	-1.37	-0.45	-0.08
3	-0.48	-0.43	-0.54	-0.35
4	-0.40	-0.97	-0.65	-0.05
5	-0.37	-0.34	-0.46	-0.36
6	-0.50	-1.09	-0.60	-0.21
7	-0.55	-0.32	0.24	-0.59
8	-1.10	1.53	6.58	-6.39
9	-0.85	2.96	10.48	-9.80
10	-0.52	2.74	10.33	-9.29
11	-0.39	2.28	8.44	-7.45
12	-0.27	2.24	7.92	-6.77
13	-0.09	2.32	7.85	-6.53
14	-0.15	2.46	7.73	-6.46
15	-0.19	2.50	7.66	-6.34
16	-1.26	2.56	8.92	-6.80
17	-1.48	2.50	8.37	-6.79
18	-2.50	-0.38	8.03	-6.16
19	-1.75	-1.35	3.18	-2.79
20	-1.62	-1.92	2.14	-1.66
21	-1.28	-1.01	1.62	-1.51
22	-1.00	-1.21	0.71	-0.85
23	-0.73	-0.81	0.02	-0.47
24	-0.48	-0.79	-0.19	-0.28

Figure 116 provides a daily trend of congestion costs across the month. CAISO areas saw the highest congestion costs as that is primarily where system congestion is sourced. PACE daily average MCC rose above \$10 on May 10th when the local Clover_Sigurd_345_2 flowgate bound for seven intervals during peak-solar hours.

Figure 116: Daily average congestion cost by area



Parallel flows

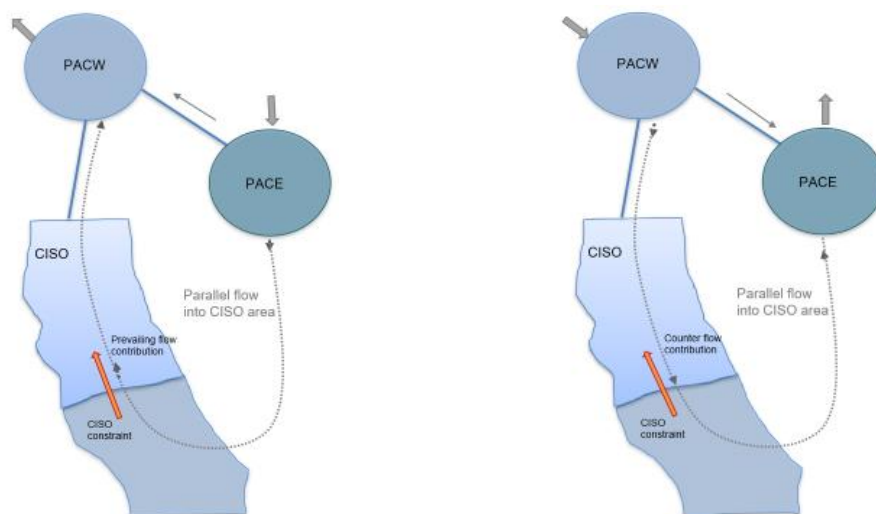
A more fundamental assessment of EDAM transaction effects is to examine their flow contributions on transmission constraints. Transactions in one BAA can contribute to flows on transmission constraints in another BAA; these are known as *parallel flow*. The data is presented in a matrix of transactions vs. constraints to highlight potential parallel flows across PAC and CAISO constraints due to transactions in these areas.

Figure 117: Parallel flow matrix example

	PACE transaction	PACW transaction	CISO transaction
PACE constraint	Internal flow on PACE	Parallel flow on PACE	Parallel flow on PACE
PACW constraint	Parallel flow on PACW	Internal flow on PACW	Parallel flow on PACW
CISO constraint	Parallel flow on CISO	Parallel flow on CISO	Internal flow on CISO

Figure 117 also highlights the impact of transactions on internal flows within each BAA, illustrating how CAISO transactions affect CAISO constraints. Parallel flows are a physical reality, independent of market constructs, economics, or contracts. They can either align with the prevailing direction of congestion or oppose it, creating counterflows. Transactions in the prevailing direction are charged for contributing to congestion, while transactions in the opposite direction are credited for relieving congestion. Figure 118 illustrates the concepts of prevailing and counter flows from a transaction between PAC areas creating a parallel flow in CAISO BAA.

Figure 118: Illustration of parallel flow in CAISO BAA due to transactions in PAC areas



In May, the impact of transactions in PAC areas over constraints in the CAISO area was meaningful, while the impact of CAISO transactions on PAC areas was minimal.

With the launch of EDAM/DAME, priced flows from one EDAM BAA can directly impact transmission constraints in another BAA based on current system topology. Table 4 goes a step further and breaks down the MCCs based on where the congestion is sourced. This is calculated by taking the shift factors of each DLAP/ELAP and applying them to across all binding transmission constraints and their shadow prices for each hour. Then, the hourly MCCs are aggregated and normalized to \$/MWh to reconstruct the monthly average MCC in the previous figure, but with a breakdown where the congestion is occurring.

With the inclusion of DAME, the table is also broken out to include constraints binding during imbalance reserve deployment scenarios, which ultimately contribute towards the total MCC.

Table 4: MCC breakdown by source of congestion⁵

Congestion Price Impact (\$/MWh)				
Source of Congestion	PACE	PACW	PGAE	SCE
CISO	-0.62	0.80	4.12	-3.00
Base	-0.60	0.74	3.92	-2.84
IRD	-0.01	-0.02	0.08	-0.05
IRU	-0.01	0.07	0.12	-0.10
PACE	0.42		-0.06	-0.18
Base	0.41		-0.06	-0.17
IRD	0.00		0.00	0.00
IRU	0.01		0.00	0.00

To summarize the table in terms of the relationship between the PacifiCorp and CAISO areas, CAISO constraints across all deployment scenario constraint types, on average, had a -\$0.62 and \$0.80 MCC price impact on PACE and PACW, respectively. PACE constraints on average impacted PGAE and SCE DLAPS by -\$0.06 and -\$0.18 respectively. There was no PACW congestion in May. Still, the most significant congestion impact realized from CAISO constraints on CAISO area (internal flows).

Table 5 takes this breakdown even further and attributes these MCC impacts to individual transmission constraints.

⁵ These results are preliminary. An identified data issue impacting the availability of shift factors will result in discrepancies between the total MCC reported in Table 4 and the breakdown by transmission constraint.

Table 5: Congestion costs by constraint

May 2026 Average Congestion Costs by Source of Congestion		PACE			PACW			PGAE			SCE		
BAA	Constraint Name	Base	IRD	IRU	Base	IRD	IRU	Base	IRD	IRU	Base	IRD	IRU
CISO	22604_OTAY_69.0_22616_OTAYLKP_69.0_BR_1_1							0.000			0.000		
CISO	24056_ETIWANDA_230_24132_SANBRDNO_230_BR_1_1							0.000			0.000		
CISO	24085_LUGO_230_24086_LUGO_500_XF_1_P							0.002			-0.002		
CISO	24114_PARDEE_230_24147_SYLMAR_S_230_BR_2_1	-0.007						0.002			0.003		
CISO	24254_WINDHUB_230_29401_WINDHUB_500_XF_4_P							0.001			-0.001		
CISO	24602_VICTOR_115_24607_ROADWAY_115_BR_1_1										-0.001		
CISO	24701_KRAMER_230_24601_VICTOR_230_BR_1_1							0.001	0.000		-0.009	0.000	
CISO	24701_KRAMER_230_24601_VICTOR_230_BR_2_1							0.002	0.000		-0.013	0.000	
CISO	24729_INYO_230_24998_INYO_SCE_230_BR_1_1										-0.005		
CISO	30005_ROUND MT_500_30015_TABLE MT_500_BR_1_6	-0.035			-0.117			0.027			0.011		
CISO	30040_TESLA_500_30050_LOSBANOS_500_BR_1_1				0.126			0.084			-0.092		
CISO	30050_LOSBANOS_500_30055_GATES1_500_BR_1_3				0.043		0.021	0.035	0.017		-0.035	-0.016	
CISO	30055_GATES1_500_30060_MIDWAY_500_BR_1_1	-0.029			0.181			0.206			-0.188		
CISO	30056_GATES2_500_30060_MIDWAY_500_BR_2_1	-0.034			0.300			0.306			-0.270		
CISO	30056_GATES2_500_30060_MIDWAY_500_BR_2_3	-0.018			0.148			0.146			-0.129		
CISO	30060_MIDWAY_500_24156_VINCEN_T_500_BR_2_3	-0.009			0.047			0.061			-0.051		
CISO	30060_MIDWAY_500_29402_WIRLWIND_500_BR_1_2	-0.030	0.000	-0.009	0.181	-0.002	0.049	0.245	-0.003	0.067	-0.214	0.003	-0.061
CISO	30440_TULUCAY_230_30460_VACA-DIX_230_BR_1_1				-0.004			0.004			-0.002		
CISO	30580_ALTMDW_230_30625_TESLA D_230_BR_1_1							0.003			-0.001		
CISO	30624_TESLA E_230_30670_WSTLYSMD_230_BR_1_1									0.001			-0.001
CISO	30640_TESLA C_230_30040_TESLA_500_XF_6H			0.000			0.000			0.000			0.000
CISO	30735_METCALF_230_30042_METCALF_500_XF_13	-0.400			-0.352			0.872			-0.438		
CISO	30750_MOSSLD_230_30797_LASAGUIL_230_BR_1_1							1.246	0.000		-0.940	0.000	
CISO	30765_LOSBANOS_230_30766_PADR FLT_230_BR_1_1				0.008			0.003	0.000		-0.006	-0.001	
CISO	30765_LOSBANOS_230_30790_PANOCH E_230_BR_2_1				0.139			0.071			-0.086		
CISO	30790_PANOCH E_230_30900_GATES_230_BR_1_1				0.040			0.055			-0.046		
CISO	30797_LASAGUIL_230_30790_PANOCH E_230_BR_1_1				0.002			0.279	0.000		-0.206	0.000	
CISO	31640_TRES VIS_60.0_31718_TBLE MTN_60.0_BR_1_1							0.000					
CISO	32056_CORTINA_60.0_30451_CRTNA M_1.0_XF_1							0.000			0.000		
CISO	32214_RIO OSO_115_32225_BRNSWKT1_115_BR_1_1							0.000					
CISO	32214_RIO OSO_115_32244_BRNSWKT2_115_BR_2_1							0.000					
CISO	32218_DRUM_115_32244_BRNSWKT2_115_BR_2_1							0.012	0.000			0.000	
CISO	32225_BRNSWKT1_115_32222_DTCH2TAP_115_BR_1_1							0.001			0.000		
CISO	32780_CLARMNT_115_32782_STATIN D_115_BR_1_1							0.007			-0.004		
CISO	33020_MORAGA_115_32780_CLARMNT_115_BR_1_1							0.004			-0.002		
CISO	33020_MORAGA_115_32780_CLARMNT_115_BR_2_1							0.022			-0.008		
CISO	35352_WHISMAN_115_35356_MNTA VSA_115_BR_1_1							0.030			-0.020		
CISO	35353_MT VIEW_115_35356_MNTA VSA_115_BR_1_1							0.000			0.000		
CISO	35371_AMES J1B_115_35352_WHISMAN_115_BR_1_1							0.001			-0.001		
CISO	35603_ZNKER J1_115_35612_TRIMBLE_115_BR_1_1							0.006			-0.002		
CISO	35612_TRIMBLE_115_35610_MONTAGUE_115_BR_1_1							0.051			-0.017		
CISO	35616_SNJOSEB_115_35612_TRIMBLE_115_BR_1_1							0.007			-0.002		
CISO	35618_SN JSE A_115_35616_SNJOSEB_115_BR_1_1							0.025	0.014	0.029	-0.016	-0.009	-0.019
CISO	35618_SN JSE A_115_35620_EL PATIO_115_BR_1_1							0.000			0.000		
CISO	35631_MARKHMJ_115_35636_EVRGREEN_115_BR_1_1							0.001			0.000		
CISO	35642_METCALF_115_30735_METCALF_230_XF_2							0.003			-0.002		
CISO	36850_KIFER_115_35615_FMC_115_BR_1_1							0.041	0.017	0.003	-0.035	-0.017	-0.003
CISO	36851_NORTHERN_115_36852_SCOTT_115_BR_2_1							0.037			-0.022		
CISO	38206_COTTLE A_230_37563_MELONES_230_BR_1_1									0.025	0.000		0.000
CISO	38610_DELTAPMP_230_30580_ALTMDW_230_BR_1_1												-0.015
CISO	39021_SC21ATP_70.0_34888_ARVIN_70.0_BR_1_1							0.000					0.000
CISO	7430_CP6_NG								0.000			0.000	
CISO	7690-CONTRL-INYOKN_EXP_NG										0.000	-0.001	0.000
CISO	7690-COOLWATER_KRAMER_IM_NG											0.000	
CISO	7760_DEV_RDB_ALIS_RT		0.000						0.000			0.000	
CISO	7820_TL 230S_OVERLOAD_NG		-0.001			-0.001			-0.001			0.000	
CISO	COL_DLN A 500KV							0.000			0.000		
CISO	HUMBOLDT_IMP_NG								0.012			-0.005	
CISO	Line_Wilo-EOX_500KV		-0.041					0.007			0.014		
CISO	Lugo AA bank outage Area EXP								0.000			0.000	
CISO	OMS_18894306_VACA-TSL		-0.005			-0.012			0.020			-0.008	
CISO	OMS_19695948_DEV_RDB_ALIS		0.000					0.000	0.000		0.000	0.000	
CISO	OMS_20219806_SDGE_RT_Import_NG		0.000			0.000			0.000			0.000	
CISO	SDGE_RT_Import_NG		0.000			0.000			0.000			0.000	
PACE	CLOVER_SIGURD_345_1			0.000						0.000			0.000
PACE	CLOVER_SIGURD_345_2	0.407	0.000	0.010				-0.059	0.000	-0.002	-0.172	0.000	-0.005

In summary, the preliminary assessment of May 2026 congestion under EDAM is in line with the projections provided in the CRA Phase 1 analysis that leveraged historical data from the Western Energy Imbalance (See figure below)⁶ That is:

1. PAC transactions can have a sizable impact on CAISO constraints, and this is reflected with sizable MCC prices in PACE and PACW areas
2. CAISO transactions have negligible impact on PAC constraints, and this is reflected with minimal MCC prices in CAISO areas

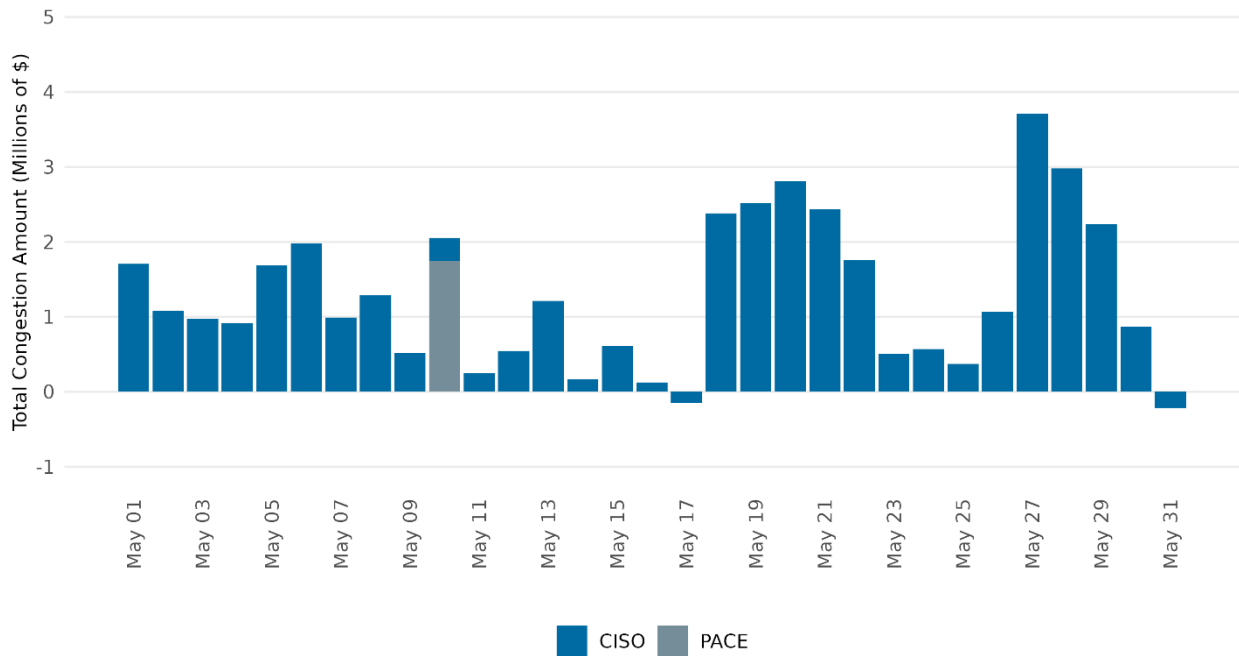
Congestion revenues

Congestion revenues are the financial surpluses based on the MCC resources are paid or getting charged when the transmission grid is constrained. This is the net total of congestion charges/credits for resources within each BAA. When a transaction at the resource level results in a charge, this is due to a generator having a negative MCC or a load resource with a positive MCC. These transactions are in aggregate contributing to congestion. Congestion credits occur in the opposite scenario where a generator resource has a positive MCC or a load resource has a negative MCC. This reflects the effect of relieving congestion.

Figure 119 provides the daily BAA totals for congestion revenues based on where the congestion is sourced.

⁶ <https://stakeholdercenter.caiso.com/InitiativeDocuments/Stage-1-Analysis-Extended-Day-Ahead-Market-Congestion-Revenue-Allocation-Dec-11-2025.pdf>

Figure 119: Daily congestion total by BAA⁷



Total EDAM congestion revenues in May were \$39.9M, with \$38.2M sourced from the CAISO BAA and \$1.7M from PACE. Most PACE congestion occurred on May 10th due to a binding internal constraint. There was also minor PACE congestion on May 12th, resulting in only \$1.5K. There was no congestion sourced from PACW transmission constraints in May.

The CAISO initiated an expedited stakeholder process with limited scope to revise the original methodology for congestion revenue allocation, which was approved by FERC in August 2025. The revised methodology currently implemented in EDAM allocates day-ahead congestion revenues, attributable to parallel flows, to the areas where market participants paid the congestion costs rather than to the areas where they were collected if they are associated with exercised transmission rights and self-scheduled transactions.

Figure 120 illustrates the daily total congestion revenues that are returned to PAC areas given that they are associated with exercised rights.

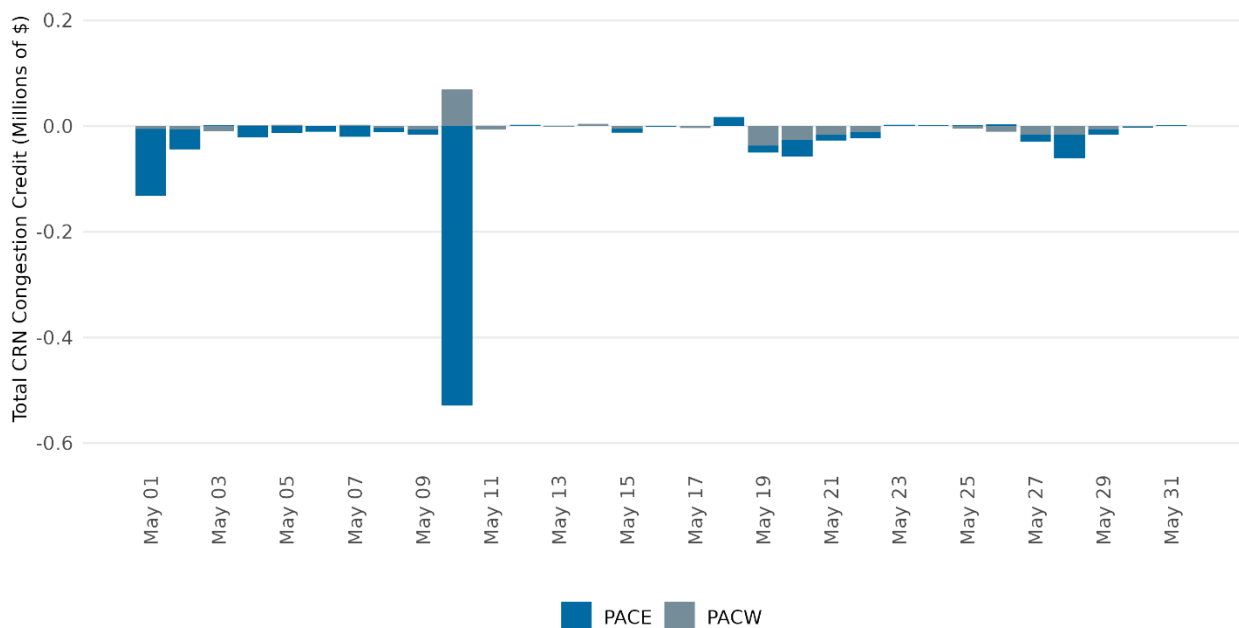
The congestion credit is the congestion revenue credit provided to holders of Open Access Transmission Tariff (OATT) transmission rights; these are from point-to-point rights but also for Network service (NITS). Those rights are exercised and can be tracked through balanced CRN self-schedules. Currently the congestion revenue allocation is tracked concurrently with PAC’s own internal congestion revenues. In future reports, the metric may be further developed to separate the congestion revenue allocation of parallel flows from congestion

⁷ Negative daily totals are linked to an identified issues in the settlement of interties (IPP ITC) constraints.

revenues from PAC’s own constraints. PACE saw the highest amount on May 10th when there was congestion in PACE. This was the congestion that was due mainly to an internal constraint binding in PACE. Across May, PACE totaled over \$886k while PACW totaled \$111k.

These levels of CRA returns are relatively low.

Figure 120: Total CRN Congestion Credit



EDAM Net Export Constraints and RUC Adjustments

The EDAM export constraint and RUC adjustments are optional BA level constructs that help ensure sufficient procurement to support reliability going into the real-time market.

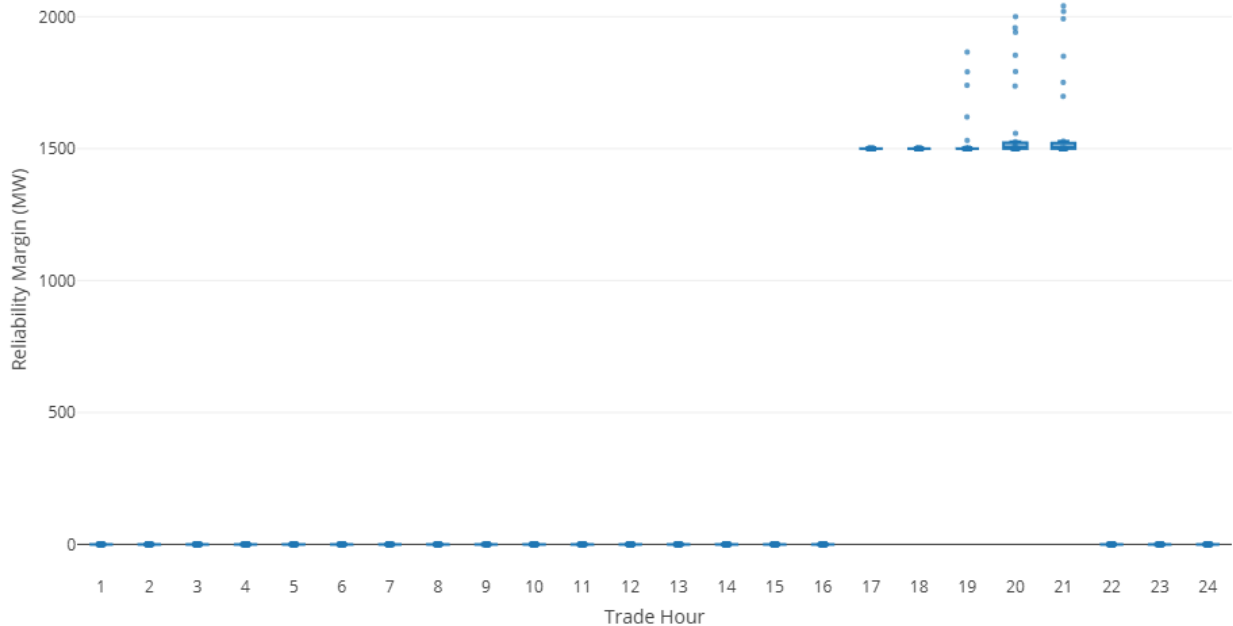
EDAM net export constraints

The EDAM net export constraint allows a BAA to limit the net exports on their TSRs to avoid exporting capacity on the TSRs that they may need for reliability. The constraint is optional and is enforced at the BA level. The constraint limits the net exports on the TSRs based on the total RSE eligible supply available above the RSE demand, with additional inputs to allow BAs to fine tune the constraint as needed.

There are two parameters that each BAA sets when the constraint is enforced: the confidence factor and the reliability margin. The confidence factor sets the percentage of

supply that is not eligible for the RSE that will count in the BAA’s supply that is eligible for export on the TSRs. The reliability margin is an additional buffer that the BAA may set to further limit the amount of supply that is eligible for export. The reliability margin is defined for each hour of the day as a specific MW value.

Figure 121: CAISO Reliability Margin



Based on stakeholder feedback, CAISO enforces the EDAM net export constraint on all days, with a 0% confidence factor and a reliability margin that tracks with the most severe single contingency. Full details of the CAISO implementation of the constraint are available in the Business Practice manual for EDAM. In May, the CAISO did not see this constraint bind in any hour. Neither PACE nor PACW opted to enforce this constraint in May.

RUC adjustments

The RUC load adjustment is an optional hourly MW value added to the forecasted load in RUC. It allows for manual adjustments to the forecast to provide extra capacity to a BAA to account for situations that aren’t fully captured in the day-ahead market forecast. With the

launch of the Imbalance Reserve product, there is now an additional option for a BAA to add RUC adjustments based off any Imbalance Reserve amount that did not clear in IFM, along with the peak load for the day. The exact formulation for how CAISO sets the RUC adjustment is defined in the EDAM BPM. No RUC adjustments were applied in May for any EDAM BAA.

RUC infeasibilities

As part of the market construct, the RUC process may not be able to balance supply with total demand, which may include any RUC adjustments. This condition is known as infeasibility or RUC shortfall. In May, PACW observed RUC infeasibility in peak hour of May 12, while CAISO and PACE did not observe any RUC infeasibilities in the month.

Market Costs

The CAISO markets are settled based on awards and prices derived from the markets through specific settlement charge codes; these include day-ahead and real-time energy, and ancillary services, among others. Most of the overall costs accrue on the day-ahead settlements.

The estimates presented in this section are from the first cycle (T-9 business days) of CAISO's market settlements. These numbers are subject to change in subsequent cycles given standard data updates, inclusion of price corrections within the extended price correction window, and the ongoing resolution of a series of issues impacting the inputs and calculations of settlements. Some of these issues are described in this report in the section for market issues.

Wholesale costs

Figure 122 to Figure 124 show the total wholesale costs for CAISO at a daily and monthly level. The average total cost per MWh is also shown in Figure 122 and Figure 123⁸. There is no notable change in total or average costs for CAISO after EDAM. Looking at the monthly level, the total costs for May continue the trend of lower total costs in 2026 relative to 2025. Total costs in April and May 2026 were the lowest monthly totals so far, which is typical for this time of the year when levels of demand and prices are low.

The total costs in April and May 2026 were \$283 million and \$309 million, respectively, compared to \$410 million and \$518 million in 2025. The average costs per MWh in April and

⁸ Total costs includes market costs for energy, ancillary services, for both day-ahead and real-time markets, real-time offsets, bid cost recovery. For May 2026 and onwards they now include IR and RC costs.

May 2026 were \$19.14/MWh and \$19.16/MWh, respectively, compared to \$27.27/MWh and \$31.36/MWh in 2025.

Figure 122: Total daily costs CAISO

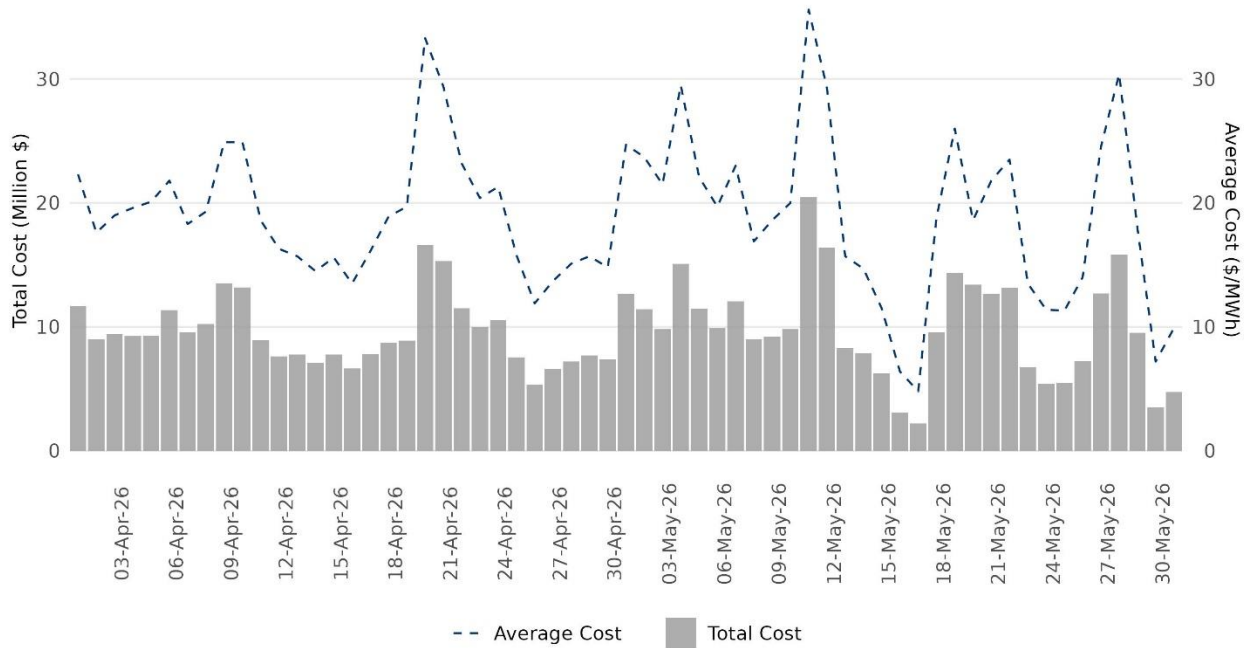


Figure 123: Monthly total costs CAISO

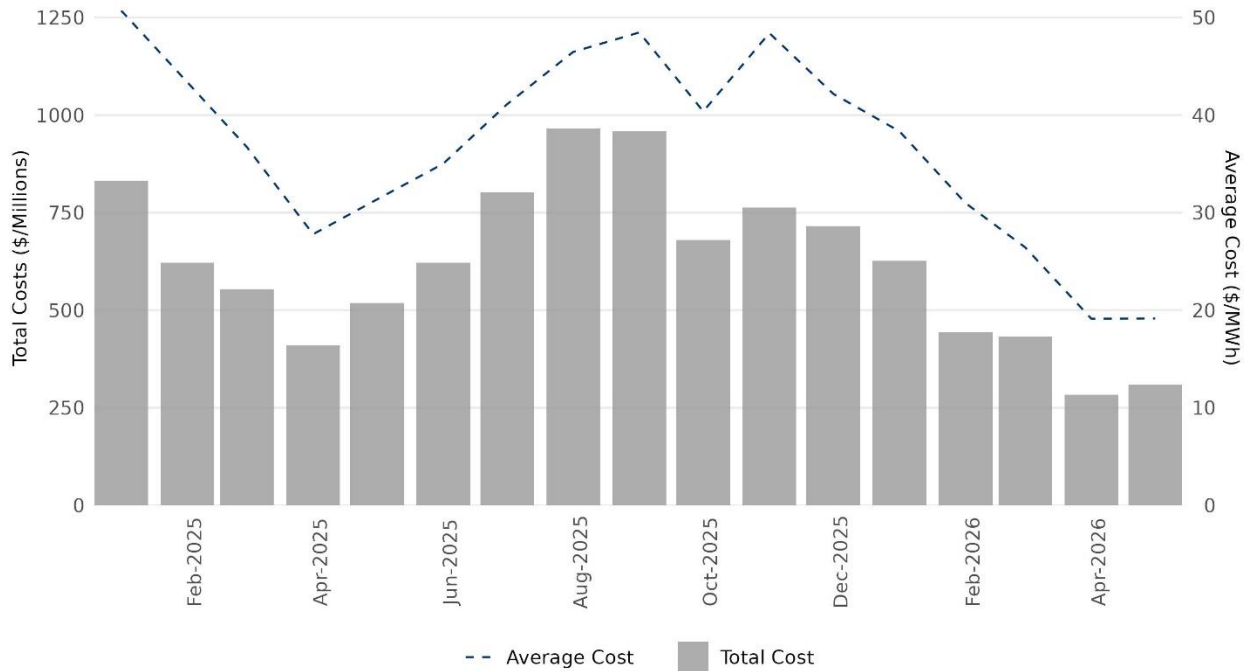
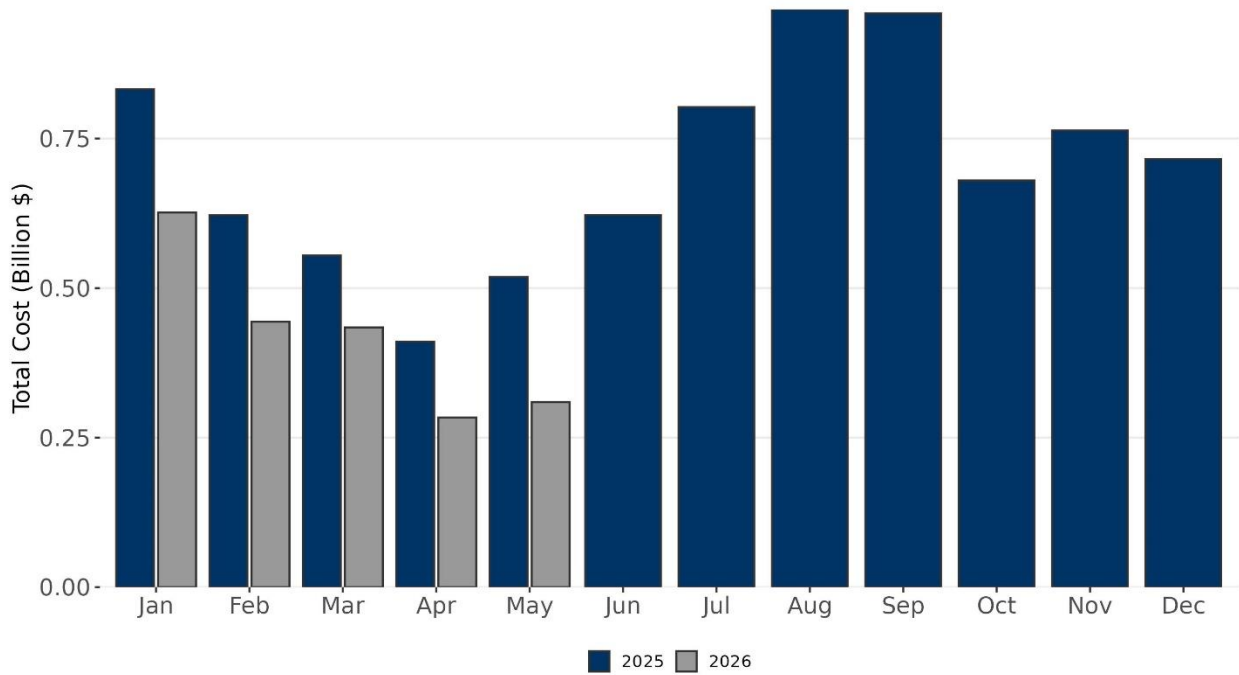


Figure 124: Monthly Total Costs CAISO, comparing 2025 to 2026



Bid cost recovery

Bid cost recovery (BCR) is a settlements mechanism in CAISO’s markets to ensure participating resources are made-whole when the revenues collected on participating in the market are not enough to cover their total costs. It is defined as the difference between total costs and market revenue when the revenue is less than the cost.

At this time, we are aware of data issues that are impacting the settlement statements, which in turn may be reflected in the BCR estimates. Therefore, the estimates provided here should be considered as preliminary and subject to change once the revised settlement statements are run. For example, IFM BCR for May 19 and 31, was high at approximately \$500k and \$1.2 million, respectively. Internal monitoring identified one bid cost calculation issue for each trade date that will be corrected and reflected in the T+72 settlement statement⁹. There were other issues identified for RTM BCR for May 1 and May 29 trade dates, which are expected to be corrected in T+70 settlement cycle. These corrections will impact the numbers reported below and we will update these in the next monthly report.

⁹ Refer to the section of Market Issues for more details.

From Figure 125 to Figure 129 illustrate the Bid Cost Recovery (BCR) trends for CAISO, PACW, and PACE across April and May. CAISO’s IFM BCR increased from \$1.64 million in April to \$3.15 million in May, while RTM BCR experienced a decline from \$11.65 million to \$8.24 million. For PACW, May settlement data shows an IFM BCR of \$0.097 million, alongside its RTM BCR rose from \$0.019 million in April to \$0.4 million in May. Meanwhile, PACE recorded an IFM BCR of \$0.36 million in May, with its RTM BCR increasing significantly from \$1,128.50 in April to \$1.28 million in May. Figure 125 to Figure 127 compare IFM BCR and RTM BCR in three different BAAs. Figure 128 to Figure 129 compare BCR of three different BAAs in IFM and RTM.

Figure 125: BCR of CAISO by market

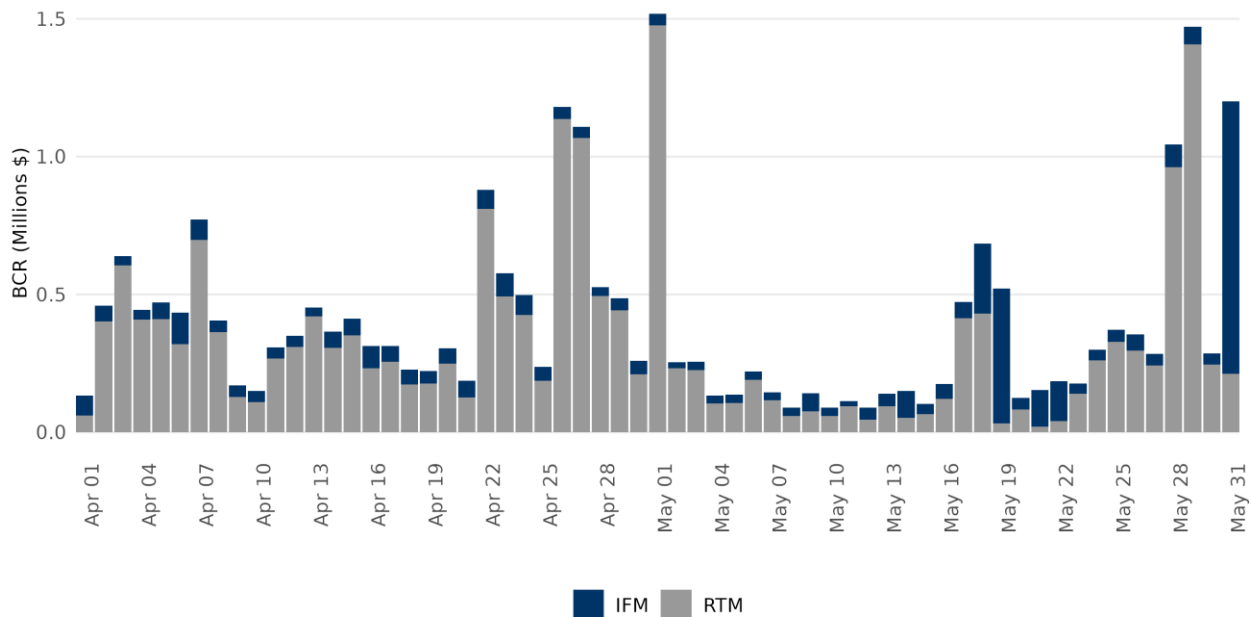


Figure 126: BCR of PACE by market

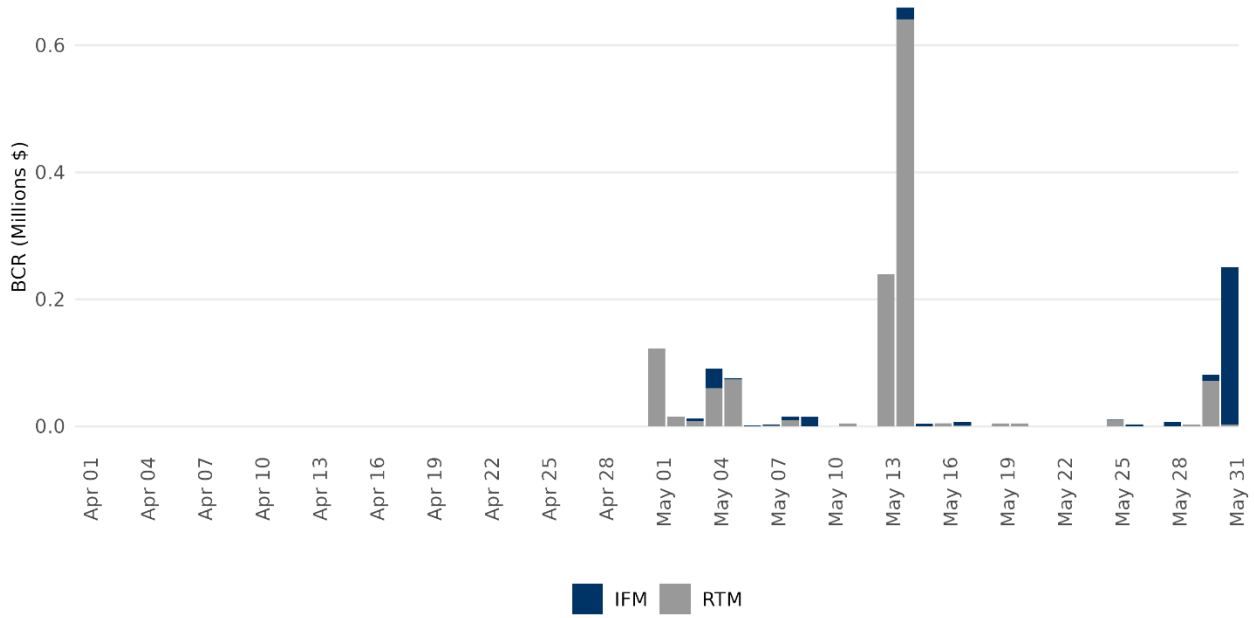


Figure 127: BCR of PACW by market

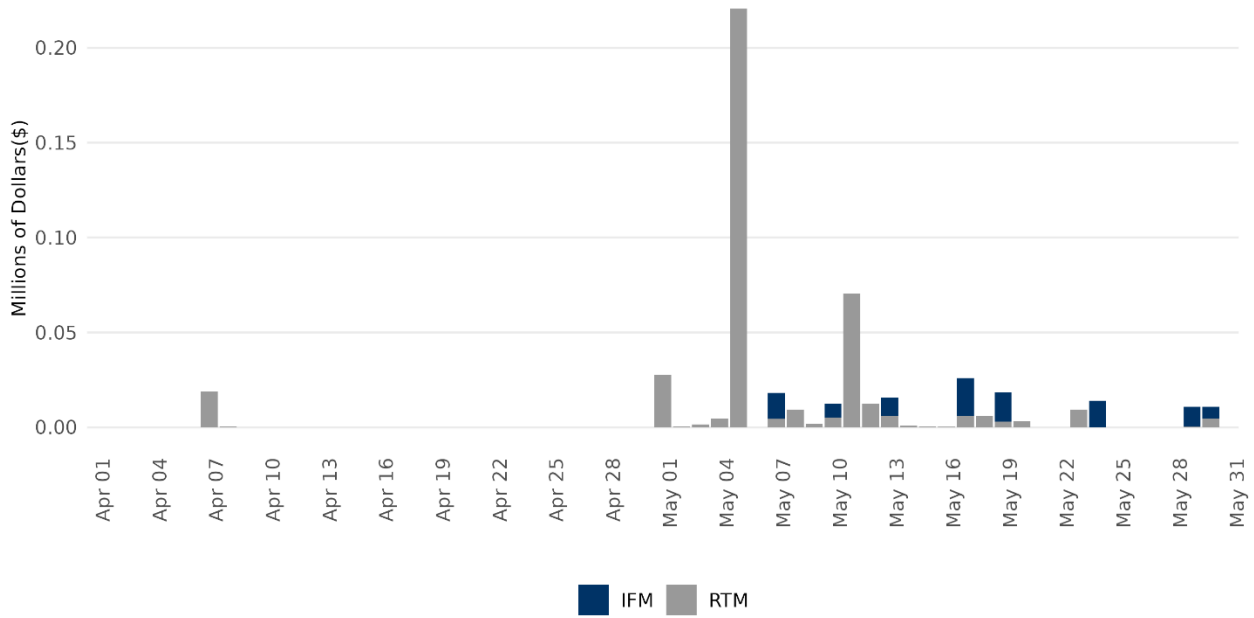


Figure 128: IFM BCR by BAA

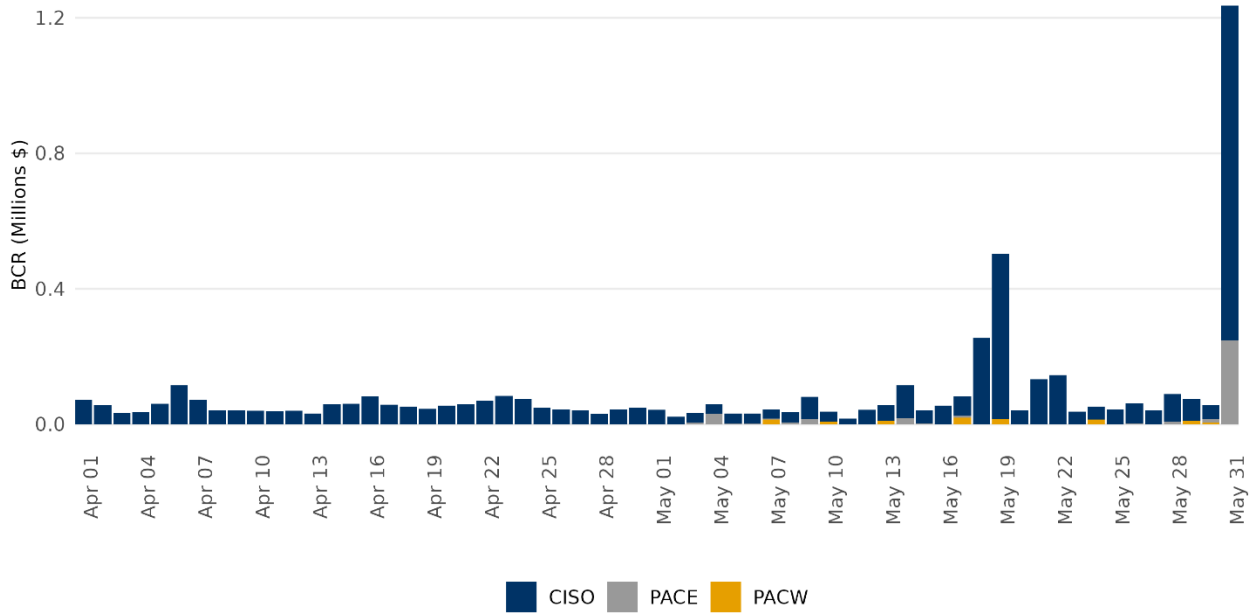
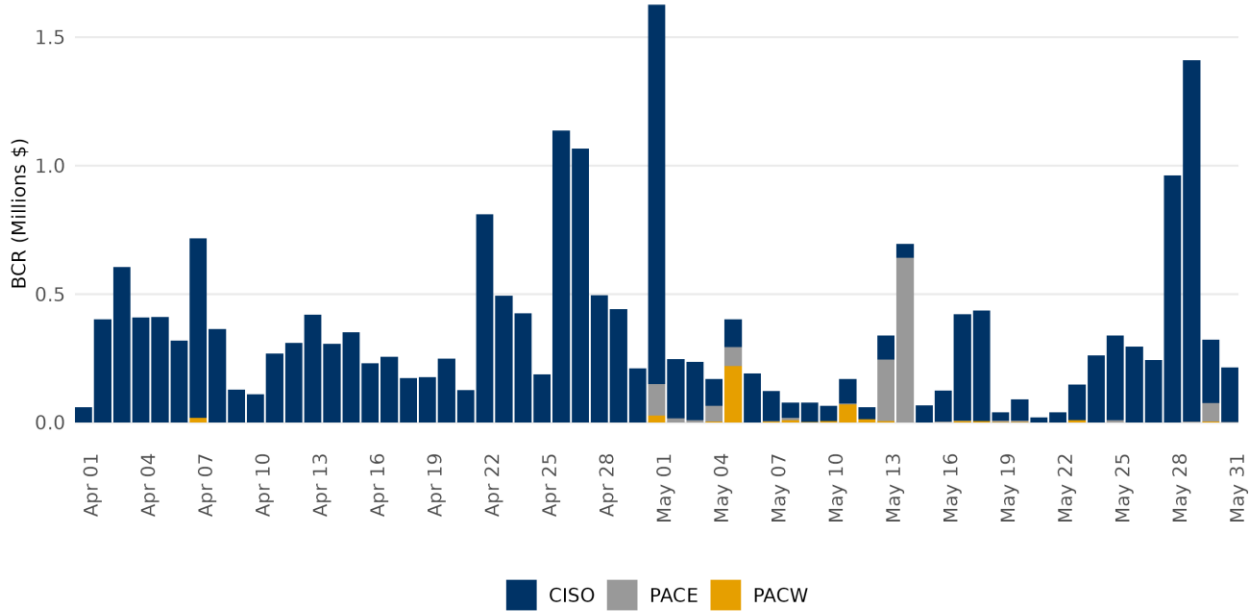


Figure 129: RTM BCR by BAA



Market offsets

In CAISO’s market settlements, participants are paid or charged. The money collected from some transactions is used to pay others. However, due to the multiple configurations of the

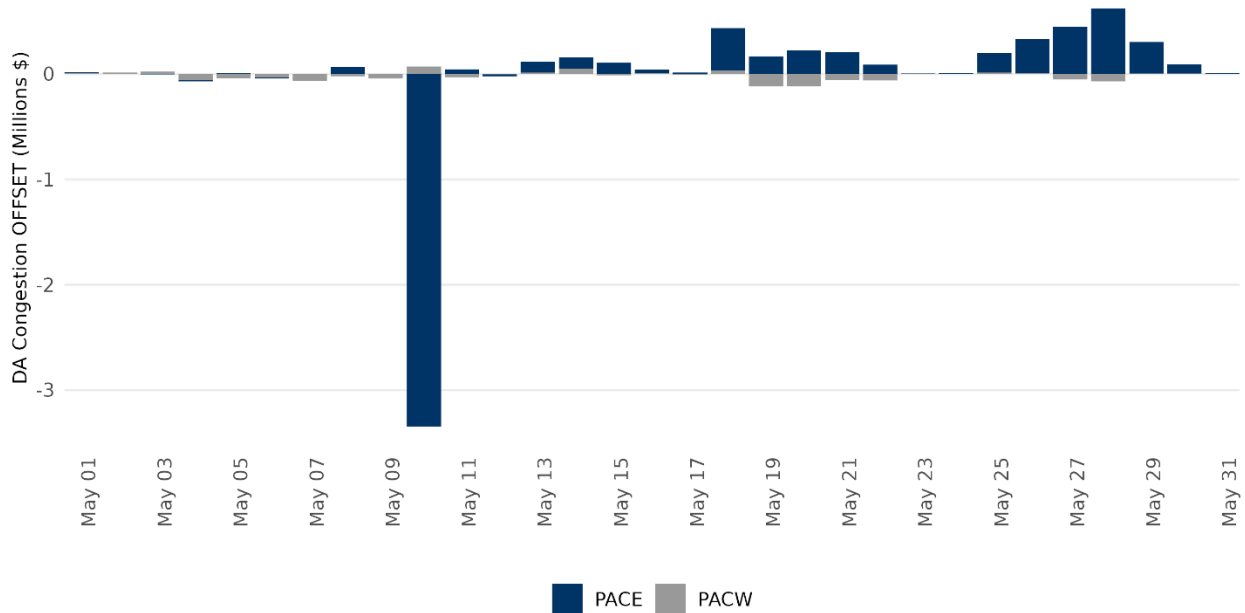
various components of settlements such as different prices used to settle different components of energy, the total money collected may not perfectly match the money paid out. The differences are balanced through settlements offsets. These offsets are the funds that CAISO needs to collect or redistribute to maintain revenue neutrality.

Day-Ahead congestion offset

This is a new settlements component introduced with the EDAM. Day ahead congestion offset (DACO) is a settlement charge code 8704. For more information on the calculation of DA congestion offset charge code, please refer to the BPM. CAISO does not have DACO because it has a specific CRR-based balancing mechanism, while PACW and PACE use DACO to handle the congestion refunds.

In Figure 130, the total amount of PACE DACO in May is 0.18 million dollars and the corresponding value of PACW is -0.523 million dollars. Negative amount is payment to the entity. When there is a spike in DACO, it means congestion has a great impact onto market dispatch at corresponding intervals. For example, the large DACO on May 10 was caused by congestion on the binding flowgate *CLOVER_SIGURD_345_2*.

Figure 130: DA Congestion Offset for PAC areas



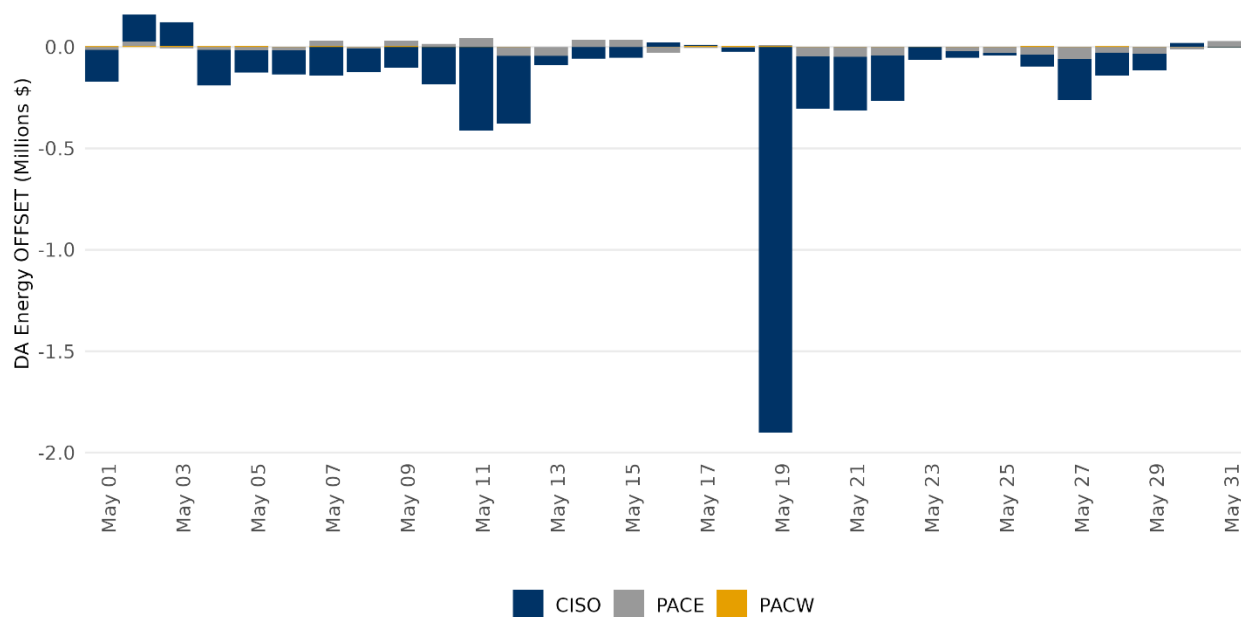
Day-Ahead energy offset

It captures the net financial difference between the total payments owed to supply-side resources (generation and imports) and the total revenues collected from demand-side participants (load and exports) for energy. It is an hourly accounting tool to make sure the day ahead energy market balances to zero. It adds up all the money collected from day energy schedules and convergence bidding at the marginal energy cost minus the congestion and GHG components. Any resulting imbalance within an external EDAM region is allocated directly to that specific EDAM entity's scheduling coordinator, whereas the imbalance within the CAISO region is allocated broadly to CAISO measured demand.

CAISO continues to investigate these instances on an ongoing basis, review the underlying components and will implement corrections in the T+70 cycle if any discrepancies are identified. Any corrections will impact the numbers reported below and we will update these in the next monthly report.

In Figure 131, the total amount of CAISO DA energy offset in May is -\$4.9 million, while PACW is 0.076 million dollars, and PACE is -0.313 million dollars. Positive DA energy offset means charge to the entity, while negative means additional payments needed to be sent out. The spike of May 19 for CAISO was related to slightly higher loads at higher marginal energy cost. It was accrued in the morning and evening hours.

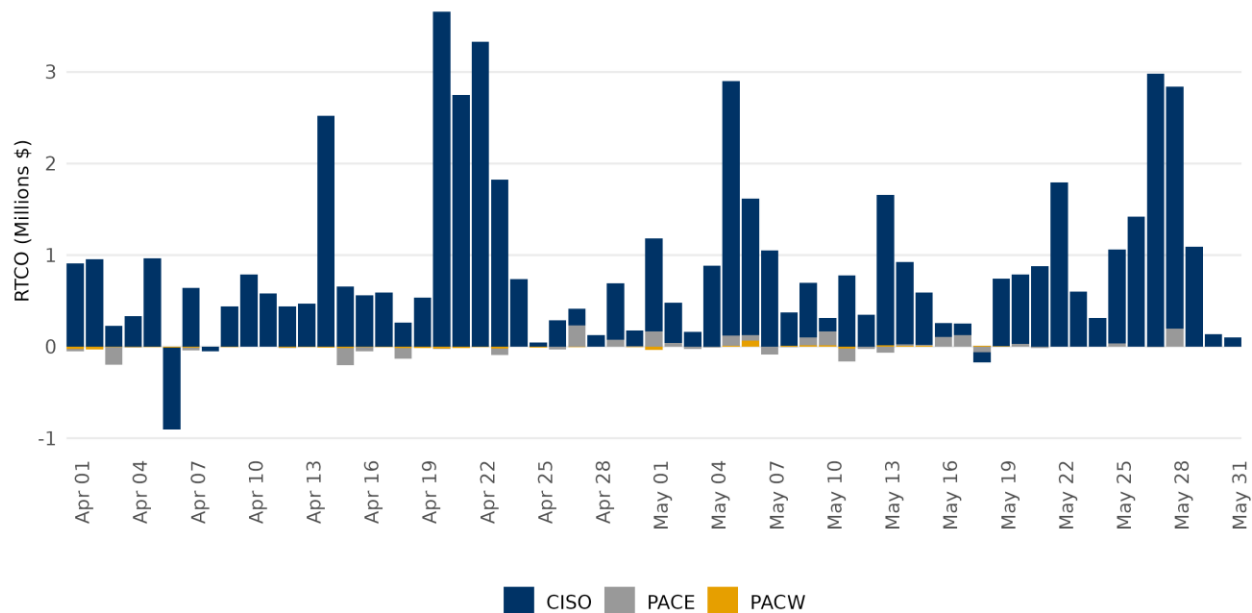
Figure 131: DA Energy Offset



Real-Time congestion offset

Real time congestion offset (RTCO) is very similar to DACO of external BAAs in IFM market. It is used to achieve revenue neutrality for congestion. An increase means the congestion in the corresponding intervals has large impact onto market dispatch. Figure 132 displays the Real-Time Congestion Offset (RTCO) for the three balancing areas, where a negative value denotes a payment to the BAA and a positive value denotes a charge. For CAISO, RTCO charges increased from \$24.66 million in April to \$27.8 million in May. Meanwhile, both PACW and PACE transitioned from a credit position in April (receiving payments of \$0.27 million and \$0.4 million, respectively) to a charge position in May, with costs of \$0.11 million and \$0.69 million.

Figure 132: Real-Time Congestion Offset



Real-Time imbalance energy offset

Real time imbalance energy offset (RTIEO) is very similar to DAEO. In settlements, RTIEO is a market neutrality charge code that ensures CAISO remains revenue neutral in the real time market. RTIEO is a residual amount due to an imbalance between real time energy payments and charges. RTIEO allocates this residual amount back to measured demand. Figure 133 illustrates a notable shift in RTIEO following the implementation of EDAM. While external BAAs, such as PACW and PACE, experienced an increase in RTIEO, there was a simultaneous reduction in CAISO's own offset.

CAISO is actively investigating several issues and disputes that may impact the T+9 settlement results. As these reviews are completed, CAISO will make appropriate corrections and adjustments as needed. These will be reflected in subsequent settlement recalculations, including at the T+70 settlement true-up. Any corrections will impact the numbers reported below and we will update these in the next monthly report.

Figure 133 illustrates the Real-Time Imbalance Energy Offset (RTIEO) for the three balancing areas, where a positive value indicates an additional charge collected from the BAA and a negative value indicates an additional payment sent out to them. CAISO’s RTIEO shifted from a charge of \$5.87 million in April to a payment of \$7.15 million in May. Conversely, PACW saw its charges rise from \$1.16 million in April to \$5.53 million in May, while PACE transitioned from a payment of \$0.23 million in April to a charge of \$2.96 million in May.

The real-time imbalance energy offset results observed after the May 1 EDAM go-live are not directly comparable to pre-EDAM outcomes. This is primarily due to fundamental design changes in the settlement calculations, including the transition from a single system marginal energy cost (SMEC) to individual area marginal energy cost references, as well as the incorporation of the GHG component within the GHG area framework. These structural differences inherently change how RTIEO values are calculated.

Figure 133: Real-Time Imbalance Energy Offset

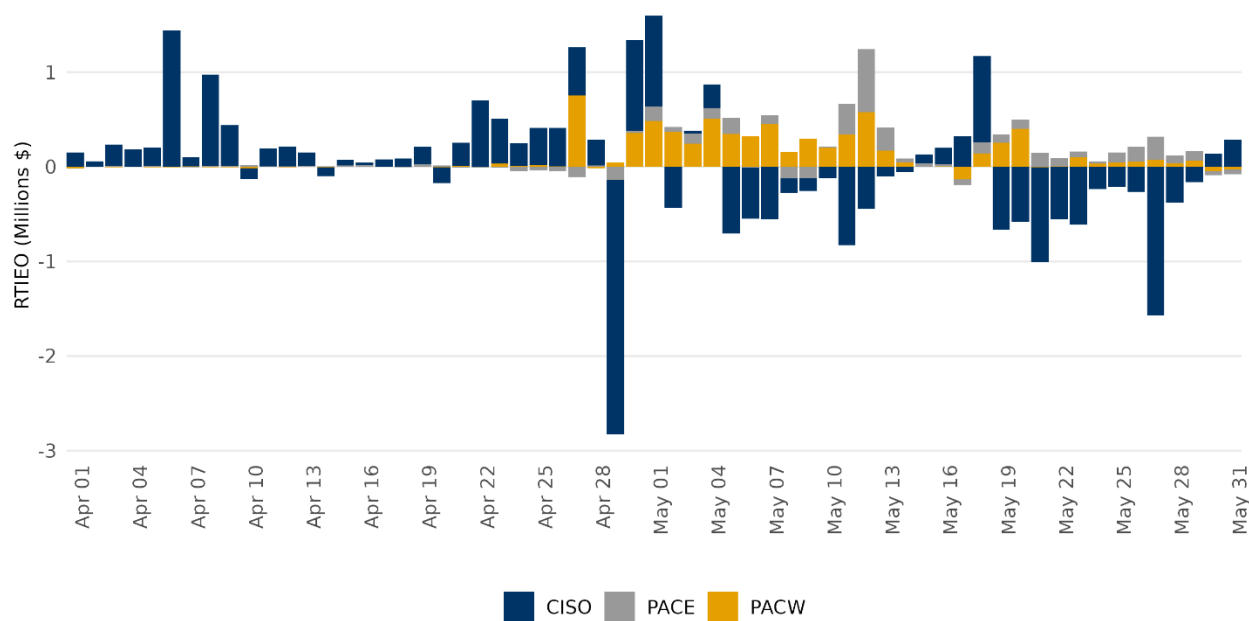
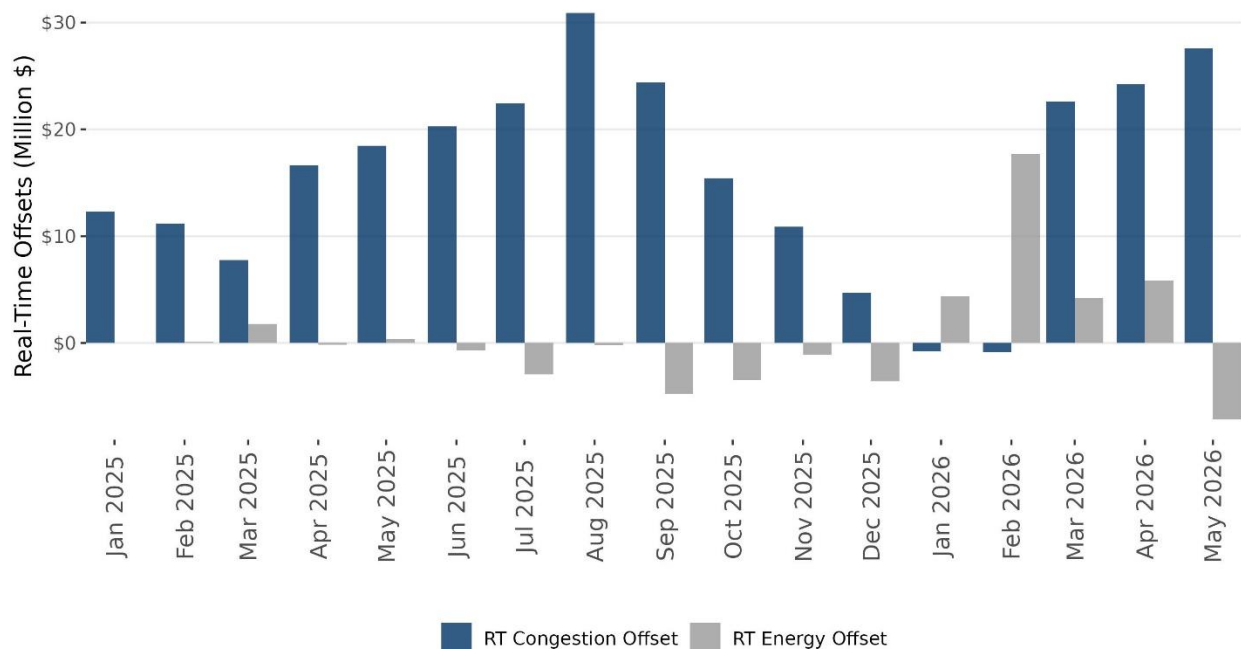


Figure 134 and Figure 135 show the monthly real-time congestion and energy offsets for CAISO area and the WEIM excluding CAISO area, respectively. CAISO offsets remained within normal ranges, with an energy offset slightly more negative than seen in other months since the start of 2025. shows that in May, the WEIM not including CAISO saw a positive congestion offset and a large, positive energy offset. The positive congestion offset is uncommon but not unheard of.

The magnitude of the real-time energy offset is higher compared to historical offsets. First, it is important to note that the real-time imbalance energy offset (RTIEO) results observed after the May 1 EDAM go-live are not directly comparable to pre-EDAM outcomes. This is primarily due to fundamental design changes, including the transition from a single system marginal energy cost (SMEC) to individual area marginal energy cost references, as well as the incorporation of the GHG component within the GHG area framework. These structural differences inherently change how RTIEO values are calculated

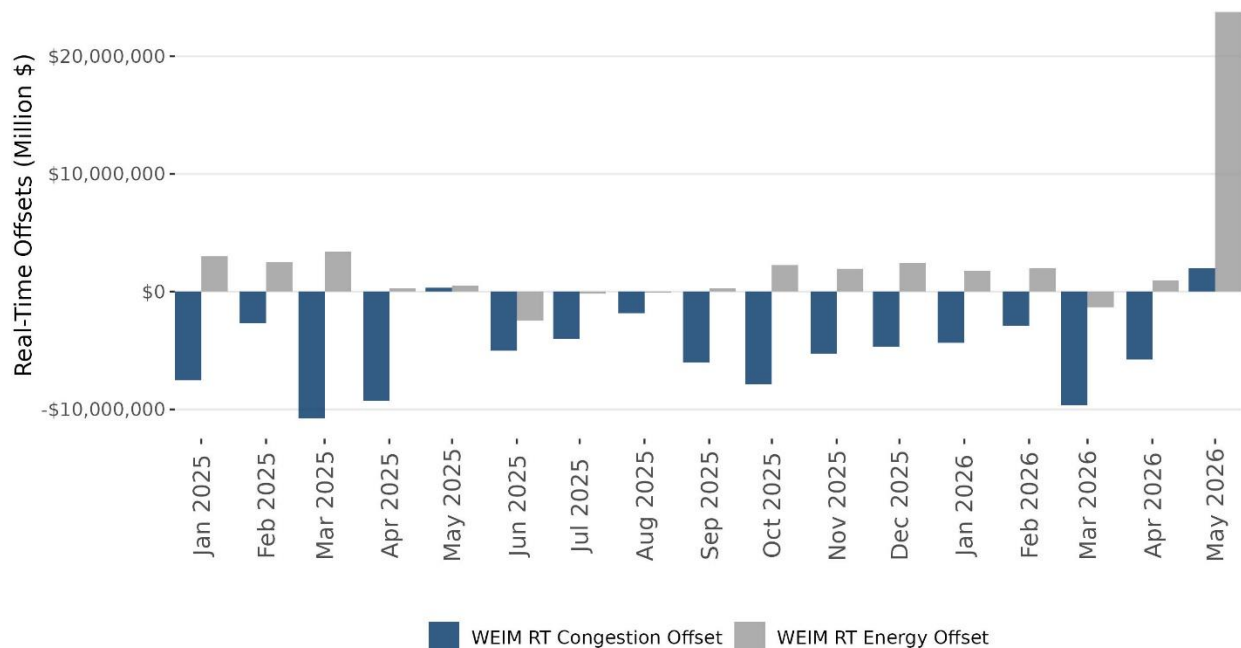
Figure 134: Monthly Total Real-Time Offsets for CAISO



While pre- and post-EDAM RTIEO results are not directly comparable, they should be explainable. The ISO has been focused on identifying the corresponding, counterbalancing sources associated with RTIEO charges. The ISO is actively investigating several issues and disputes that may affect and be reflected in the T+9 day real-time offsets settlement results. As these reviews are taking place, the ISO has and will continue to implement corrections and adjustments as needed. These will be reflected in subsequent settlement

recalculations, including at the T+70 true-up and future T+9 calculations. Any corrections will impact the numbers reported here and we will update these in the next monthly report.

Figure 135: Monthly Total Real-Time Offsets for WEIM



Imbalance reserves

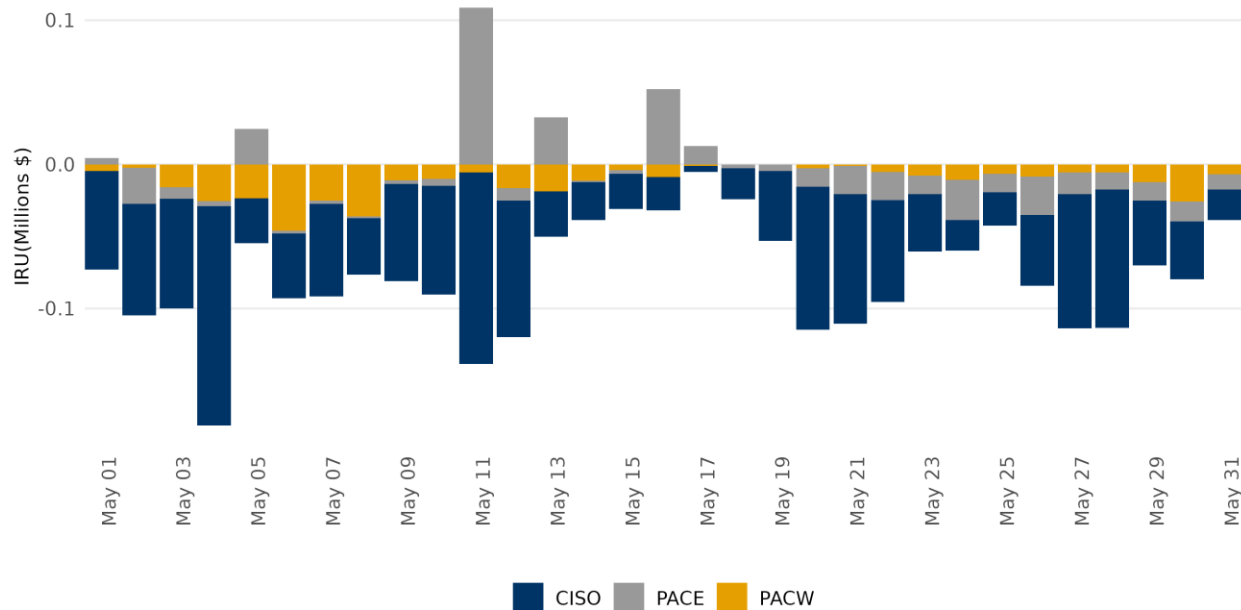
Imbalance reserve up/down are two components of the imbalance reserve product designed to provide upward/downward dispatch capability. Procured within the IFM, Imbalance Reserves up/down (IRU and IRD) is used to ensure that sufficient dispatchable capacity is available to meet positive/negative net load imbalance that occur between the EDAM and Real-Time markets. Only resources that can be dispatched in the 15-min market would be eligible to provide imbalance reserves and the maximum award capacity would be based on a resource’s 30-min ramp capability.

An IRU payment is calculated by multiplying the resources awarded IRU quantity by the locational IRU price. A negative Imbalance Reserve (IR) settlement indicates net payment to the scheduling coordinators (SC) of resources located in Balancing Authority Area (BAA). To enforce compliance, CAISO applies a no pay unavailability non-compliance charge if a resource fails to maintain its day-ahead flexible capability relative to its upper economic limit and five-minute ramp capability. Undelivered quantities are penalized using a resource-specific price equal to the higher of the real-time flexible ramp up price or the locational IRU price. PACE has five days with positive settlement values for IRU over five

different days. These are days impacted by some calculation issues currently being addressed.

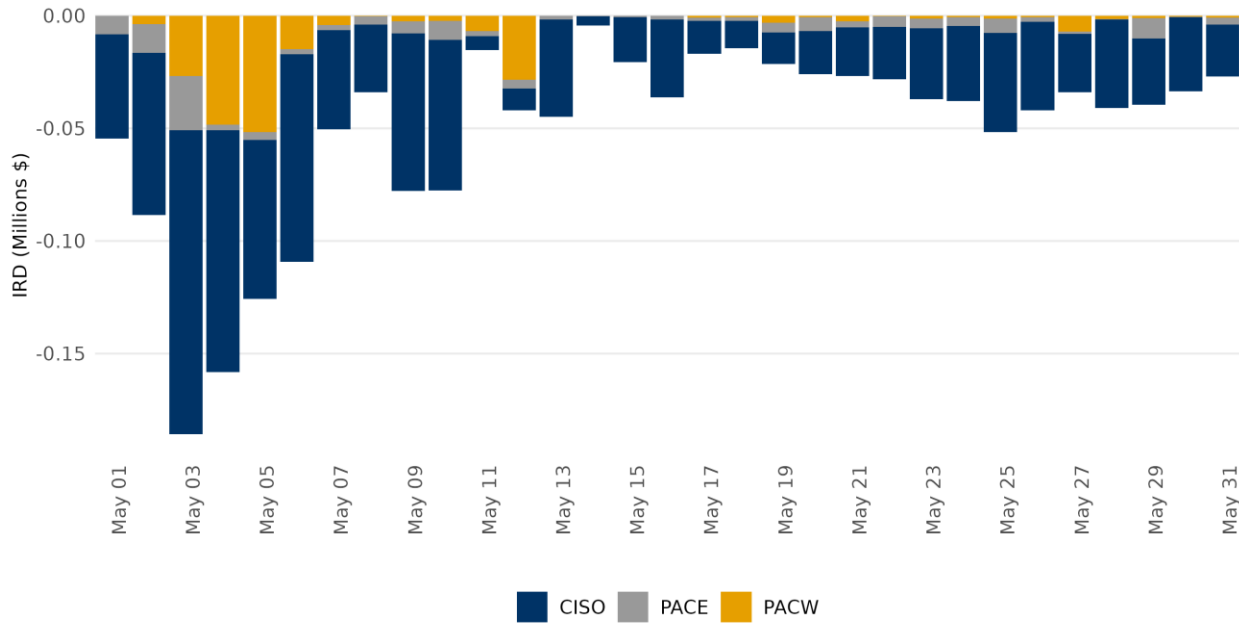
Figure 136 shows the daily trend of IRU costs for May. IRU cost was \$1.79 million for CAISO area, -\$0.365 million for PACW, and \$0.03 million for PACE.

Figure 136: IRU settlement costs



Similarly, The IRD payment charge code settles day-ahead market awards for resources and transfer resources on an hourly basis. The IRD payment for each resource is calculated by multiplying its hourly awarded IRD quantity by the resource's IRD price. The system tracks the resource's 5-minute ramp capable capacity portion along with IRD allocated capacity range in FMM, and If a resource fails to maintain its downward capability, it faces unavailability non-compliance charges at FMM flexible ramp down price. Figure 137 shows the daily costs for procuring IRD in May. IRD costs for CAISO were \$1.25 million, while PACW and PACE had a cost of \$0.21 million \$0.135 million, respectively.

Figure 137: IRD settlement costs



Reliability capacity

Reliability Capacity (RC), consisting of RCU and RCD, is procured in the Residual Unit Commitment (RUC) process. The RCU settlement costs is calculated on an hourly interval to manage day-ahead awards for resources. A negative value is indicated as a payment to the scheduling coordinator, while a charge is tracked as positive values. RC settlement is the hourly financial compensation provided to resources for awarded capacity, calculated as the product of the awarded quantity and the RUC Reliability capacity price. CAISO assesses a no-pay unavailability charge if a resource fails to keep its day-ahead reliability commitment available relative to its upper economic limit and real-time outages. This penalty is calculated as the product of the unavailable quantity and the resource's RCU price.

Figure 138 shows the daily RCU costs organized by BAA in May. The RCU cost for CAISO was \$4.05 million, while PACW and PACE costs were \$0.21 and \$0.23 million.

Similarly for RCD settlements, it is calculated by multiplying its hourly RCD quantity by the locational RCD price. While RCU checks resource's availability to ensure it has enough upward capability relative to its upper economic limit, RCD checks resource's downward flexibility to verify that its lower economic limit (including real-time outages) does not exceed its day-ahead energy schedule minus any downward regulations.

Figure 139 provides the daily trend of RCD cost by BAA in May. RCD costs were \$0.86 million, \$0.019 million and \$0.002 million for CAISO, PACW and PACE, respectively.

Figure 138: RCU settlement costs

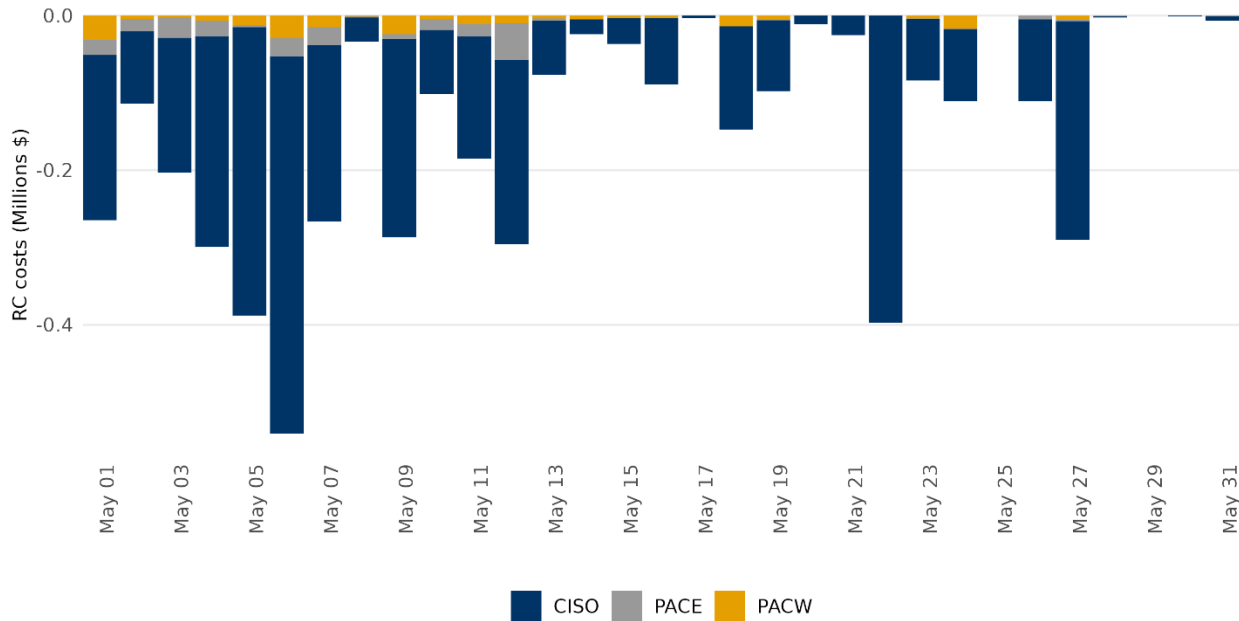
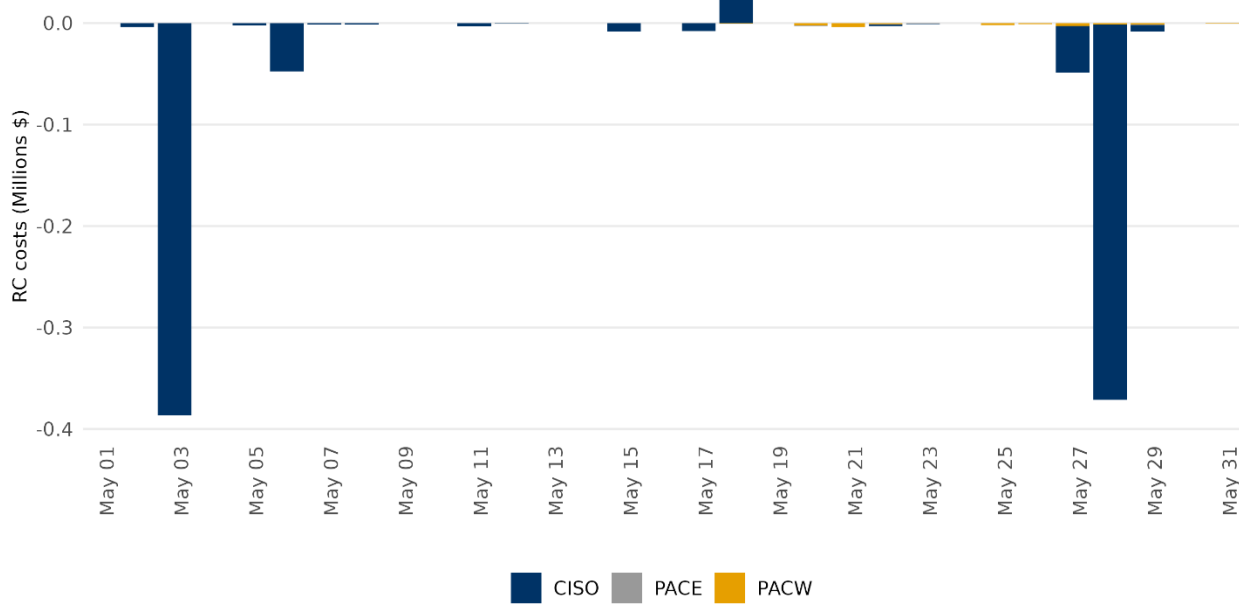


Figure 139: RCD settlement costs



GHG settlement

The California Cap and Trade regulation on greenhouse gas emissions requires market participants to surrender compliance instruments to the California Air Resources Board (CARB) for GHG emissions associated with energy generated from CO₂-emitting resources within California and energy imported into California. Energy generated outside California that is not imported into the state is not subject to this compliance obligation. To address these requirements, EDAM incorporates the cost of the GHG compliance obligation when dispatching generation within an EDAM entity area to serve load located in a GHG regulation area (in this case, California). This cost is not considered when the same generation is dispatched to serve load outside a GHG regulation area.

The GHG settlement mechanism is calculated on an hourly settlement interval basis. CAISO compensates the scheduling coordinator for energy deemed to have been imported into a GHG regulation area at the marginal GHG price. The settlement amount is calculated as the product of the deemed greenhouse gas quantity to the GHG regulation area and the applicable marginal GHG price. The marginal GHG price is included as a component of the LMP within the GHG regulation area. Figure 140 shows the GHG payments to EDAM entities that are supporting the energy imported into the GHG regulation area (California). Conversely, Figure 141 shows the Real Time GHG payment for the EDAM entities. Negative values indicate a payment to the Scheduling Coordinator and positive values, which will only occur in RTM, indicate a buyback amount. In the IFM market, PACE and PACW received payments of \$0.283 million and \$0.01 million, respectively. In RTM, PACE received a payment of \$0.182 million, while PACW had a charge in RTM of \$555.

Figure 140: Greenhouse Gas Settlement Costs in IFM

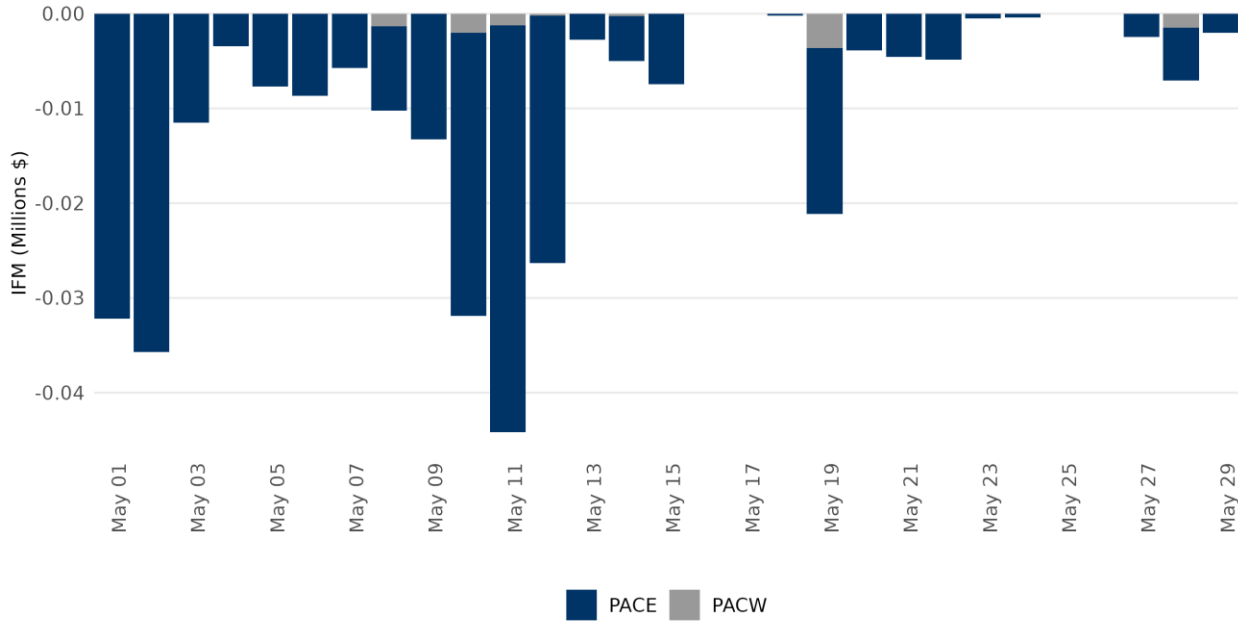
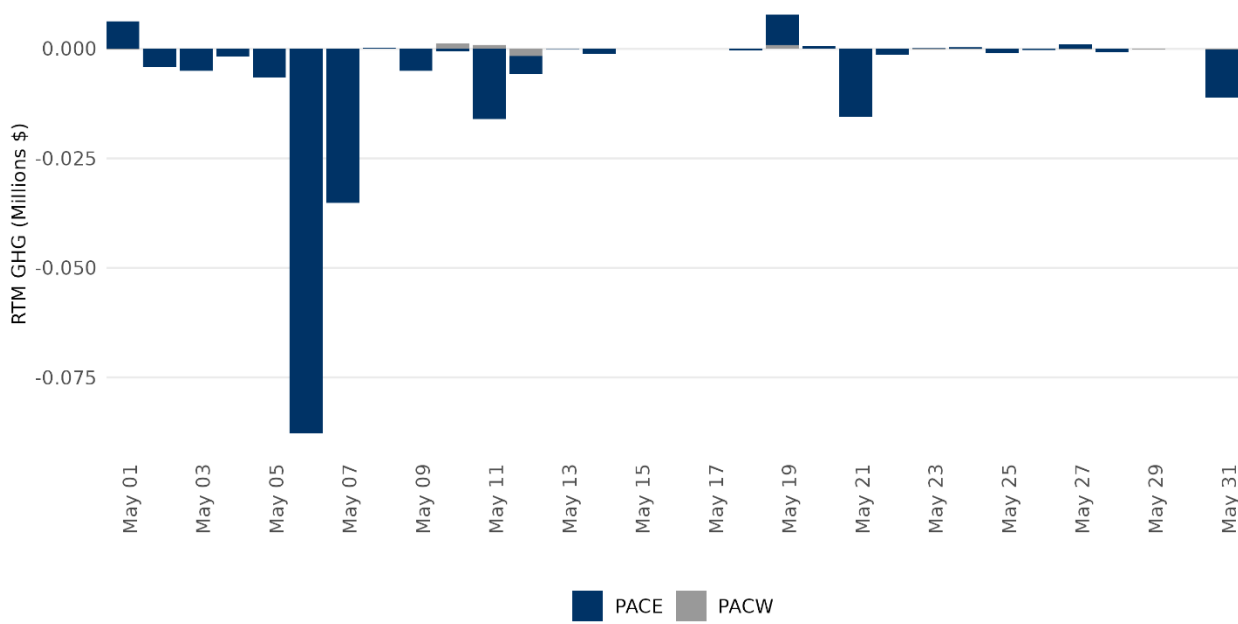


Figure 141: Greenhouse Gas Settlement Costs in RTM



Market Issues

Through the analysis of the market outcomes and performance and settlements, CAISO tracks any areas for improvements and identifies any market issues. Given the significant change in systems and processes with the implementation of the extended day-ahead market and the day-ahead market enhancements, the ISO identified several issues impacting the market outcomes in May. Several of the items listed in this section have been previously introduced and discussed in either EDAM implementation calls, the market update calls or the settlement user group calls. The ISO will continue to address the resolution of these issues as necessary.

- **Negative Reliability Capacity Down Prices:** Negative prices for RC awards have been observed due to several issues, including software issues with MSG transitions market-driven conditions related to optimality of solution and price formation. For price formation, negative marginal losses or congestion can drive prices below \$0. CAISO is working with its software vendor to address issues related to MSG transitions. CAISO did not correct RC prices for this issue because the impact is on the capacity awards and not the prices. Other negative RCD prices may simply reflect the optimality of solution or the effect of marginal losses. CAISO continues to monitor these market outcomes to ensure new products are functioning as intended.
- **Invalid Intertie Constraint (ITC) and Intertie Scheduling Limit (ISL) congestion shadow prices:** A software issue led to incorrect calculation of schedules on ITCs and ISLs constraints, resulting in invalid shadow prices. The constraints did not properly account for multiple commodities, including ancillary services, imbalance reserves, and reliability capacity. Invalid ITC congestion prices in the day-ahead market were corrected for trade date May 2 and May 3, 2026. Invalid MALIN500_ISL congestion was corrected in the day-ahead market from May 9-18, 2026. This issue was fixed on trade day May 19, 2026.
- **Negative Flex Ramp Product prices:** Incorrect low WEIM pool requirements for FRP lead to negative Flex Ramp Product prices. The real-time market consumed a value of 0.1 MW requirements for the WEIM up and down pool (previously called passing group), which drove negative pricing in the real-time market. This issue affected May 1-3, 2026 and real-time Flex Ramp Product prices were corrected for that period. The issue was fixed for trade date May 4, 2026.
- **Greenhouse Gas (GHG) Pricing issue:** Real-time GHG prices were affected by an inconsistency in the GHG area composition. On May 1-2, 2026, prices were impacted by a misalignment between BAA and GHG area definitions, with the GHG area

generally encompassing more demand than the BAA area. Real-time market prices are being corrected for this period. The issue was fixed for trade date May 3, 2026.

- Infeasible Solar Reliability Capacity Up Awards: This arises from the interaction between VER forecasts and Pmin re-rates, resulting in infeasible RCU awards to solar resources. This issue can lead to awards assigned during non-solar hours. The issue is expected to be resolved in a forthcoming software fix.
- In RUC when RCU and RCD bid prices are zero dollars; the optimization may procure both RCU and RCD in the same hour. Reliability Capacity consists of two distinct products that are procured when there is a difference between the CAISO forecast of CAISO demand and the cleared physical supply. Procuring both products in the same hour from different resources is not a software issue and reflects the complications of achieving an optimal solution when the upward and downward capacity have zero prices. CAISO will continue monitoring to ensure the new market functionality is working as intended.
- High Imbalance Reserve Settlement Charges: Elevated Imbalance Reserve charges occurred due to missing bill determinants. A software defect in the post-processing systems caused missing records for MSG Resources, resulting in incorrect quantities for Imbalance Reserve. This issue was resolved for trade date May 20, 2026. Trade dates from May 1-19 will be corrected on the T+70 BD settlement statement.
- Missing Shift Factors in the Market Participant Portal and in the CRR settlements system: Complete shift factor data is not available in the Market Participant Portal due to missing values in the payload transmitted from the market application. The CRR settlement system is also missing shift factors related to the IRU and IRD deployment scenarios. The omission has resulted in misallocation of congestion revenues. This issue affects trade dates from May 1, 2026 and onward and CAISO is working to correct it for T+70 BD settlement statements, and to backfill the data in the portal.
- Storage Resources and RCD: Storage resources are unable to provide RCD despite being economic and having sufficient state-of-charge headroom. When operating in a neutral state or charging state, the minimum energy bid limit is incorrectly constrained to 0 MWh or the IFM charging value. This issue is on-going and is expected to be resolved in an upcoming software patch.
- Self-Schedule Penalty Prices impacting Bid Cost Recovery: The day-ahead BCR mechanism is incorrectly including penalty prices of self-schedules into the bid cost calculations resulting in high BCR. This was corrected for trade date Jun 7, 2026. Prior trade dates will be corrected in the subsequent settlement statements.

- Flow Discrepancies for Intertie Constraints in the CRR system: Discrepancies in Intertie Constraint flows are impacting the CRR Settlement. When interties are mapped to multiple Intertie Constraints, the IFM flow calculation logic produces inaccurate results, leading to downstream misallocation of CRR revenues. This issue affects trade dates beginning May 1, 2026 and remains on-going. CAISO is working to correct this in the T+70 BD settlement statements.
- Missing IRU and IRD deployment scenarios in the CRR clawback mechanism: The CRR clawback calculation does not account for IRU and IRD deployment scenarios due to incomplete payload data from the market application to the CRR system. This issue impacts May 1, 2026 and remains on-going. CAISO is working to correct this in the T+70 BD settlement statements.
- High Bid Cost Recovery due to negative bid processing: The IFM BCR was relatively high on May 31, at \$1.2 million. There was a software issue related to processing negatively-priced bids where the bid costs are being set to zero. CAISO is reviewing for additional days impacted and expects to make corrections to be reflected in the T+70 BD settlement statements.