Extended Day-Ahead Market Performance June Report

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California Independent System Operator

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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 June report is the second in a series of customized monthly reports. It provides an assessment of market performance during EDAM's first two months 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 the first 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. Compared to the first month of operation, market outcomes were more consistent as market participants adapted to the new market framework. EDAM market outcomes have continued to stabilize, the market results are still in their early stages with ongoing participant learning, seasonal changes and settlement refinements.

Key takeaways:

Energy prices

June 2026 day-ahead energy prices remained moderate and reflected expected seasonal increases in demand, with CAISO and PACE prices rising across all hours while PACW prices were generally stable. Daily averages for energy were $17/MWh in PACE, $17/MWh in PACW, and $21/MWh in CAISO. Seasonal patterns remained evident, as prices increased from May to June but were generally lower than 2025 levels.

Price separation among the three BAAs narrowed significantly compared to May, particularly during solar hours, and daily average prices increasingly converged, indicating greater market stability in EDAM's second month of operation.

Day-ahead and real-time price convergence also improved across all BAAs, with June showing substantially smaller differences between IFM and FMM prices than observed immediately following EDAM go-live.

Analysis of price distributions showed a higher frequency of lower and negative prices in 2026 relative to 2025, while the occurrence of extreme high-price events declined in June, particularly in the PacifiCorp BAAs. Overall, results suggest improving price convergence and market stabilization under EDAM, with no observable increase in real-time price volatility or extreme price frequency.

Ancillary service and new capacity product prices

Ancillary service prices for CAISO remained within historical norms. Regulation up and regulation down prices decreased modestly from last month, while spinning and non-spinning reserve prices remained broadly consistent with pre-EDAM levels. Regulation up and regulation down prices in June decreased modestly from the previous month, while spinning and non-spinning reserve prices remained broadly consistent with pre-EDAM levels. Neither PACE nor PACW procure ancillary services through the centralized market.

Imbalance Reserve (IR) and Reliability Capacity (RC) markets both showed signs of stabilization in June 2026, reflecting improving EDAM market performance. IR prices declined and became more stable across all three BAAs compared to May, with the largest improvement observed in PACW. Price patterns generally aligned with morning and evening ramping periods, when operational flexibility is most valuable, while IR requirements remained consistent with underlying net-load uncertainty and seasonal system conditions. The broader EDAM footprint continued to provide diversity benefits by reducing total reserve requirements through geographic sharing of load and renewable forecast variability.

Reliability Capacity prices also declined significantly from May to June, suggesting improved supply-demand balance and reduced reliability procurement costs. While prices remained somewhat volatile in CAISO and PACW, average monthly prices fell across all BAAs. Reliability Capacity continued to function as designed, procuring both upward and downward capacity to address forecast deviations and maintain system reliability.

Total wholesale energy costs and market efficiency

Total wholesale energy costs in CAISO increased to $24/MWh in June from $19/MWh in May, but stayed below June of 2025 ($35/MWh). Bid cost recovery (BCR) payments decreased from May to June across all market runs and areas. In the CAISO, two issues identified on May 19 and 31 will be addressed in the next settlement cycle and will likely lower real-time market (RTM) BCR in May.

Along with energy transfers, EDAM included the procurement of two new directional capacity products, imbalance reserves and reliability capacity. Imbalance reserve procurement costs remained stable in the upward direction for the CAISO between May and June, at about $1.7 million each month, while imbalance reserve down costs declined from $1.25 million in May to $0.36 million in June. PacifiCorp West had large declines in both directions while PacifiCorp East went from $0.03 million in May to $0.5 million in June in the upward direction while the downward direction costs held steady.

For reliability capacity, procurement costs for upward capacity declined from May to June across all three regions while increasing in the downward direction. Procurement of reliability capacity down went from $0.861 million in May to $2.81 million in June in the CAISO area, for example.

Trends in transfer volumes

EDAM transfers reached 600 MW and were actively used to transfer 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, leveraging resource diversity among participating balancing authority areas. The pattern of trade in energy and capacity products is largely consistent with May, with some exceptions noted below for each commodity and region:

Energy

- **CAISO** remained a net exporter of energy in both May and June, with exports concentrated during midday and afternoon solar hours. PACE was its primary trading partner.
- **PACW** remained a net importer and significantly increased imports after June 3, driven by increased imports from PACE.
- **PACE** continued importing from CAISO but flipped to a net exporter to PACW after June 3, with daytime exports to PACW increasing substantially in June.

Imbalance reserves

- **CAISO** was a net exporter of imbalance reserves up, primarily to PACE. For imbalance reserves down, CAISO shifted from a net importer in May to a net exporter in June, largely due to reduced imports from and increased exports to PACE.
- **PACW** remained a net importer of both imbalance reserve products in May and June, with imports increasing in June, particularly from PACE.
- **PACE** remained a net importer of imbalance reserves up, mostly from CAISO, while beginning limited exports to PACW in June. For imbalance reserves

down, PACE shifted from predominantly exporting in May to a more balanced mix of imports and exports in June, mainly trading with CAISO.

Reliability capacity

- **CAISO** shifted from a mixed importer/exporter position in reliability capacity up during May to predominantly importing reliability capacity up in June. Conversely, CAISO moved from net reliability capacity down imports in May to net reliability capacity down exports in June.
- **PACW** remained a net exporter of reliability capacity up in both months, though imports increased in June. For reliability capacity down, PACW remained a net importer, with higher imports in June, particularly from PACE.
- **PACE** increased reliability capacity up exports in June, supplying more capacity to both PACW and CAISO. For reliability capacity down, PACE shifted from predominantly exporting in May to increased imports from CAISO in June as exports declined.

Congestion

Congestion revenue allocation payments in June were essentially on par with the volume of payments in May at about $1.3 million per month. Congestion revenue allocation returned similar volumes of payment of PacifiCorp in June as in May and were below levels projected prior to go-live. The largest amount of price impact from congestion continues to be in the CAISO internal constraints, which have resulted in price separation between Northern and Southern California. However, parallel flows originating from PACE had a meaningful impact on CAISO constraints. When expressed as the source of the constraint, CAISO constraints had a $-0.75/MWh average impact on prices in PACE in June and a $-0.94/MWh average impact on prices in PACW in June.

Other market performance areas

- EDAM results were posted before 1:00 p.m. in 76 percent of days in June, up from May (61 percent of the days) and at the same level in April prior to EDAM. This indicates a cautious approach to prioritizing quality during the initial month of the market roll out with additional validation steps for the new market operations.
- Resource sufficiency performance was strong across all participating areas in June. CAISO and PacifiCorp West (PACW) passed the resource sufficiency

evaluation in all intervals. PacifiCorp East (PACE) passed in 99.93 percent of intervals, failing the IRU test in a single interval.

- Convergence bidding activity was comparable to June 2025 levels, reflecting that EDAM implementation had little impact on convergence bidding behavior.
- The average monthly GHG price was $4.4/MWh in the day ahead market, slightly higher than real-time GHG prices. Prices followed similar intraday patterns, with higher values during the early morning and evening peak periods.
- Market issues continued to be tracked in this report and in forums with stakeholders.

Conclusion:

The second month of EDAM operations continued to demonstrate stable market performance across participating balancing authority areas. Compared to the initial implementation period, market outcomes were more consistent with expectations, with price formation, congestion management, and interregional transfers operating as expected, while market participants became more familiar with EDAM processes and market processes including settlement processes continued to improve. CAISO will continue to monitor market performance and report on key metrics as EDAM evolves and additional operating experience is gained.

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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 June report provides an overview of market performance during the first two months 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.

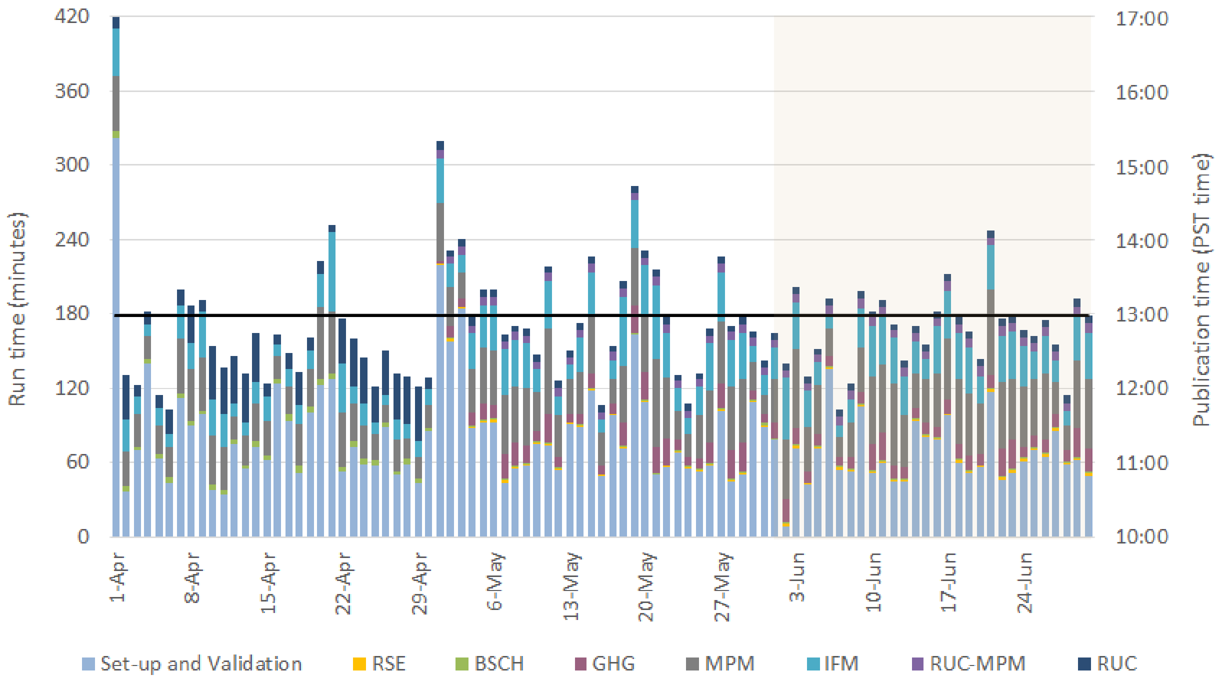
Day-Ahead Market Run

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. In June, EDAM results were posted before 1:00 p.m. in seven out of 30 days, an improvement from the posting of 19 out of 31 days in May. 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.

Table 1 shows the total monthly passing rate of each EDAM BAA for the IRU and IRD RSE tests for May and June. Aside from May 4 when PACW passed 16 out of the 24 hours and June 17 when PACE passed 23 out of the 24 hours, all three EDAM BAAs have passed both the IRU and IRD RSE tests across all hours of the day since EDAM go-live.

Table 1: RSE monthly passing rate by BAA for upward and down requirements

	IRU RSE Passing Rate (%)		***IRD RSE Passing Rate (%)***	
BAA	**May**	**June**	**May**	**June**
CAISO	100	100	100	100
PACE	100	99.86	100	100
PACW	98.92	100	99.87	100

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.

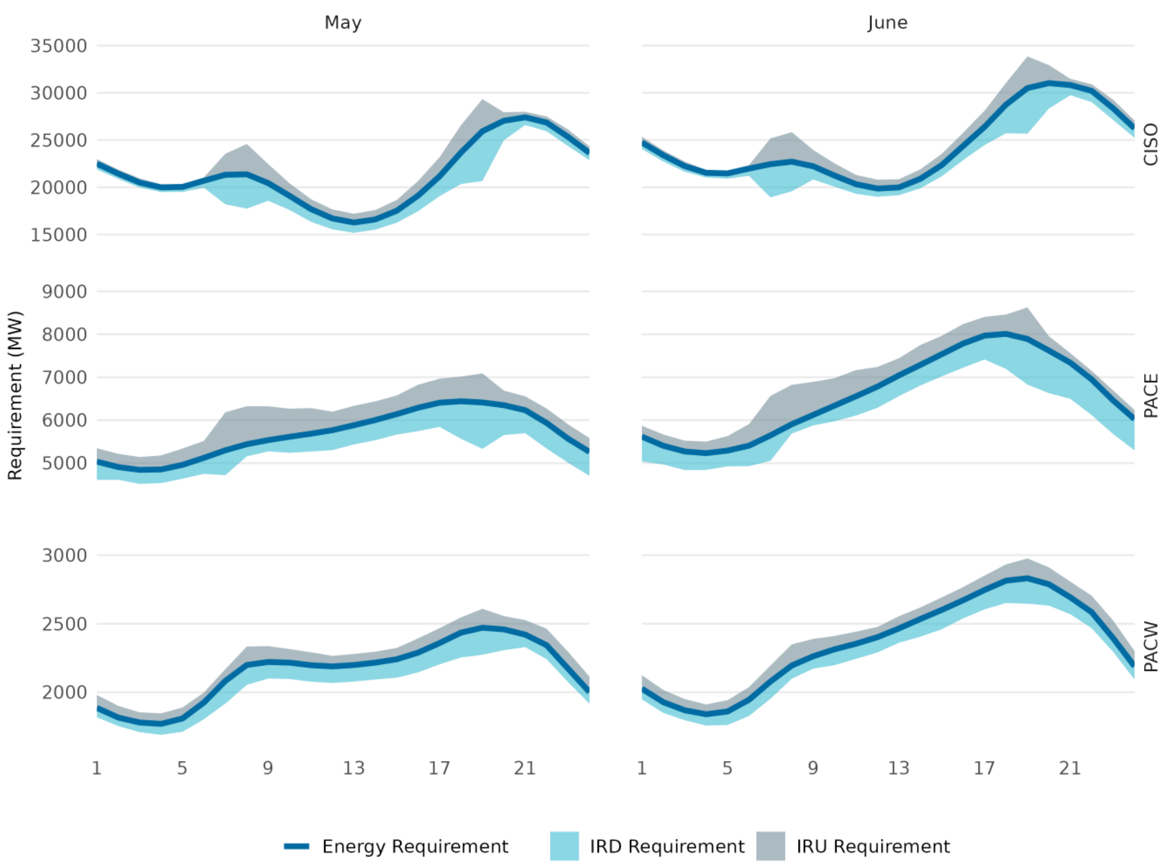
Figure 2 displays average hourly IRU and IRD requirements for each EDAM BAA over the months of May and June, with respect to the average energy requirement. The imbalance reserve requirements are calculated for each EDAM BAA separately. Requirements for IRU and IRD tend to be the largest for CAISO around 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. These trends remain consistent in May and June. PACE and PACW saw a larger evening peak in June compared to May. While the shape of hourly demand changed, the general shape of IRU and

IRD requirements remained relatively consistent. Table 2 gives the highest imbalance reserve upward and downward requirements for each BAA in May and June.

Table 2: Maximum imbalance reserve requirements by BAA

	Maximum IRU Requirement (MW)		Maximum IRD Requirement (MW)	
BAA	**May**	**June**	**May**	**June**
CAISO	3,629	3,486	5,320	5,487
PACE	1,028	1,028	1,099	1,125
PACW	225	228	241	259

Figure 2: Average upward and downward requirements by area and month



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 form the energy requirement.

Day-Ahead Market Products

Day-Ahead Demand

In IFM, bid-in supply is cleared to meet bid-in demand. However, bid-in demand does not necessarily match the day-ahead load forecast. Supply in RUC is cleared to meet the day-ahead demand forecast. Figure 3 shows the average day-ahead demand forecast and the average IFM schedule for each EDAM BAA in May and June 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. In May, the bid-in demand for PACE was almost always lower than the demand forecast, with the difference between the two largest during the evening peak. In June, however, this relationship flipped with the bid-in demand exceeding the forecast for much of the day, with the difference between the two being the smallest during the evening peak. Generally, the day-ahead demand forecast and the bid-in demand for PACW closely match, with June seeing a slightly higher bid-in demand compared to the day-ahead forecast.

The shape of the day-ahead demand forecast hourly profile changed significantly from May to June for all three BAAs. CAISO saw a smaller mid-day dip and higher evening peak, leading to a steeper afternoon ramp. Both PACE and PACW saw a significant increase in the evening peak demand with a steeper but also steadier increase in demand across daylight hours.

Figure 3: Bid-in demand vs. day-ahead demand

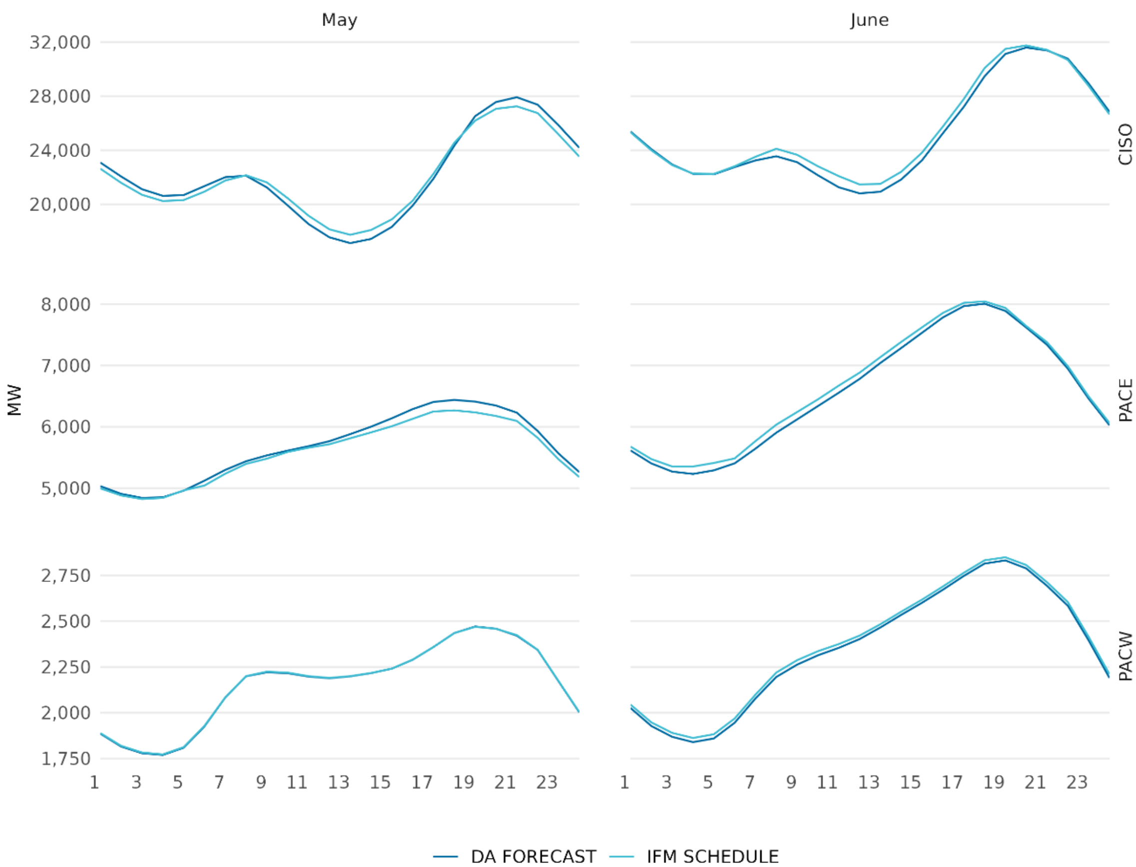


Table 3 shows the highest day-ahead demand forecast for a single hour for each EDAM BAA across May and June. All three BAAs saw an increase in the forecasted peak demand. The percent increases were 7.8, 16.3, and 25.6 percent for CAISO, PACE, PACW, respectively.

Table 3: Peak day-ahead demand forecasts

	Peak DA Demand Forecast (MW)	
BAA	**May**	**June**
CAISO	34,673	37,399
PACE	8,047	9,358
PACW	2,893	3,635

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:

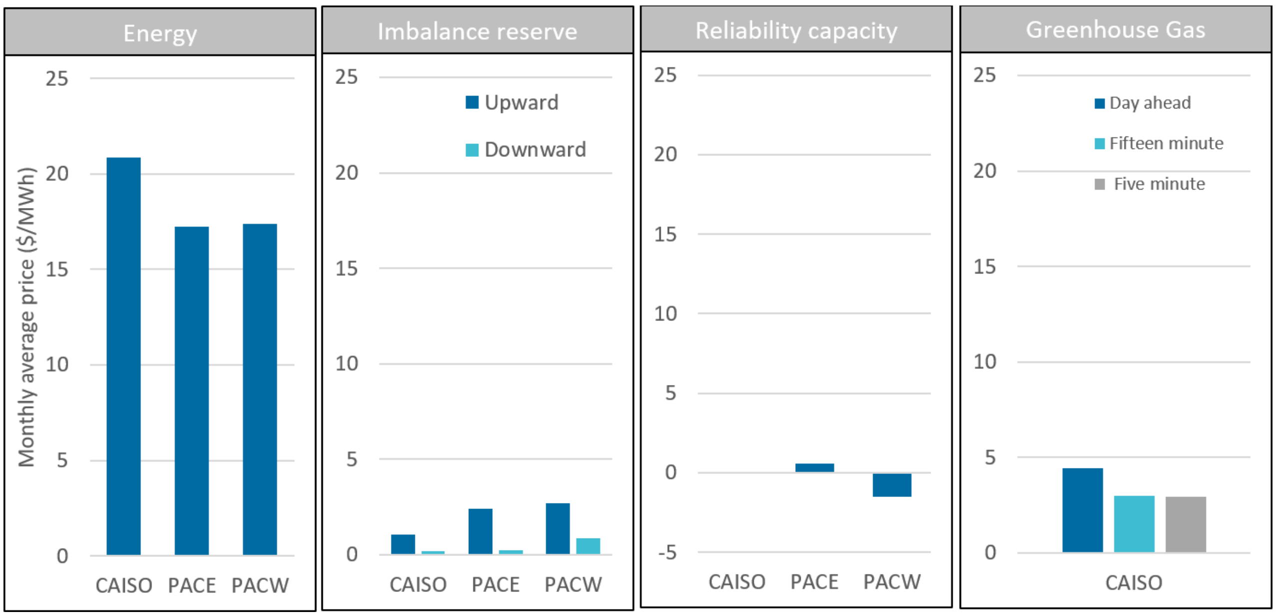
i) energy,
ii) ancillary services (regulation up and down, spinning reserves and non-spinning reserves),
iii) imbalance reserves up and down,
iv) reliability capacity up and down, and
v) greenhouse-gas emission allocation

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 form 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 and June compared to the CAISO average hourly IFM LMPs in April. The ELAP LMPS are used for PACE and PACW, while the load-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. Compared to May, June exhibited significantly less price separation between the three BAAs, particularly during solar hours. Prices in CAISO and PACE increased across all hours of the day compared to May. This is typical behavior, as summer months bring higher demands. PACW saw small decreases in IFM LMPS from May to June, except during the evening peak.

Figure 6 shows the daily average IFM LMPs across May and June. CAISO daily average IFM LMPs remained stable within normal ranges. Since mid-May, the average daily LMPs across the three BAAs have remained within $10/MWh of each other, with the exception of a few days like May 31 and June 10. In the first two weeks after EDAM go-live PACE frequently had negative daily average LMP, but in the month of June there was only one day when PACE saw a negative daily average LMP. These trends show that prices are stabilizing and converging in the second month of EDAM.

Figure 5: Hourly IFM LMP averaged by month

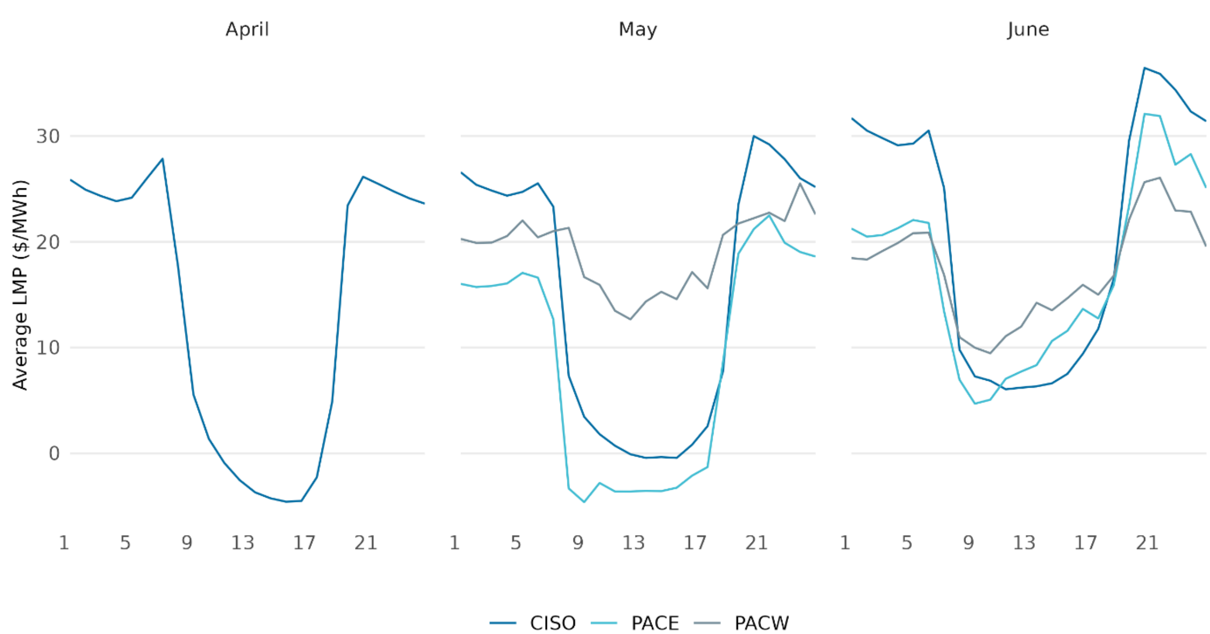
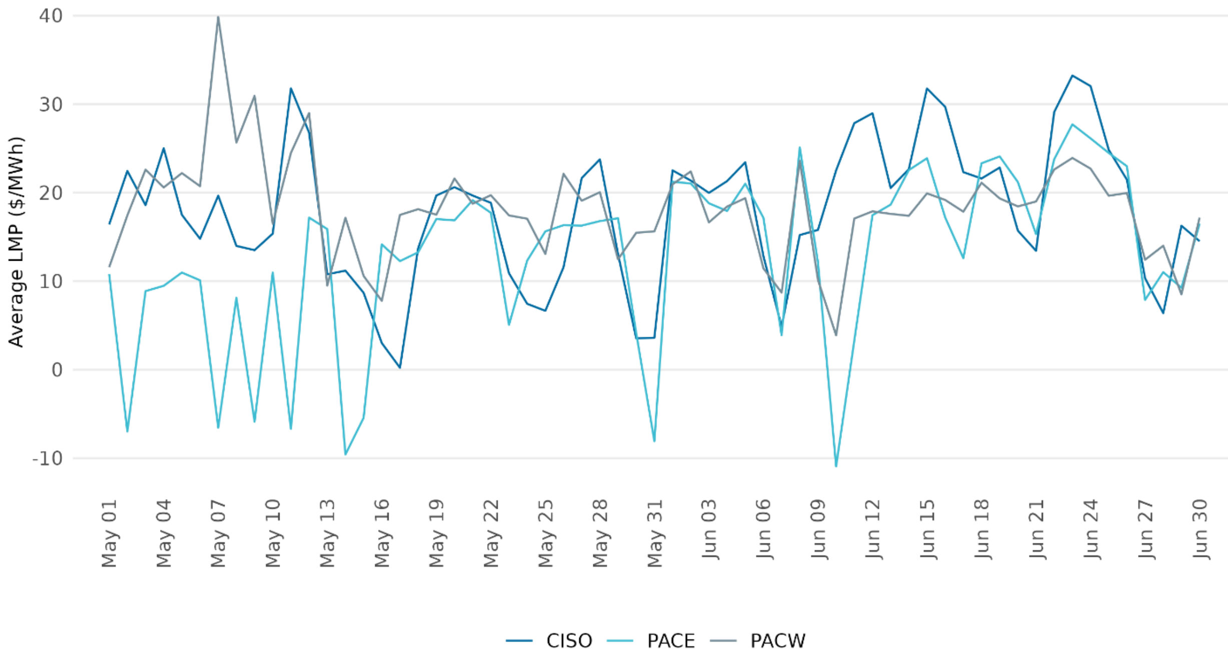
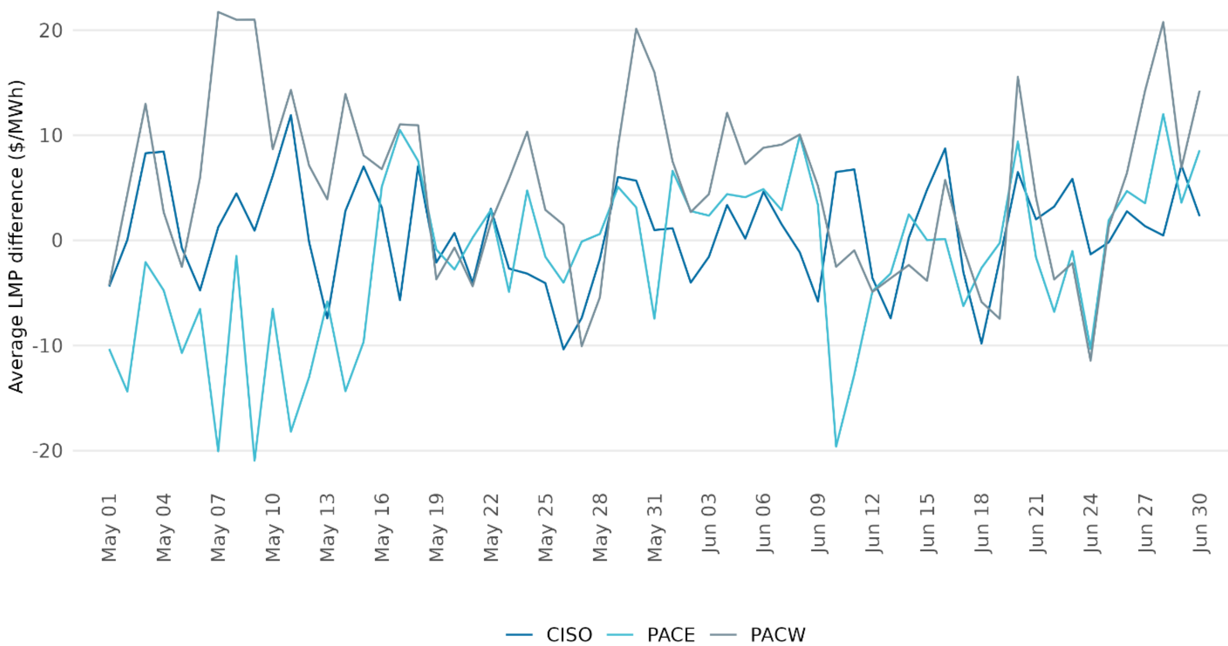


Figure 6: Daily average LMP by BAA



Ideally, day-ahead prices accurately represent the value of supply and demand realized in 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 compares prices from the day-ahead market (IFM) to the fifteen-minute market (FMM) for EDAM BAA in May and June 2026. Specifically, Figure 7 shows the daily average IFM LMP minus the daily average FMM LMP. A negative price reflects a higher real-time price compared to day-ahead price. A zero in the plot represents perfect convergence from day-ahead to real-time. In generally, price convergence improved from May to June. In May, PACE saw day-ahead prices that were frequently $10-$20 lower than the FMM prices and PACW frequently saw day-ahead prices that were $10-$20 higher than FMM prices. Except for June 10 for PACE and June 28 for PACW, the discrepancy between day-ahead and FMM prices was smaller in June.

Figure 7: Average difference between IFM LMP and FMM LMP



Prices tend to vary from day to day as conditions vary. Trends in price convergence are better understood over longer time spans. Figure 8, Figure 9, and Figure 10 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 8 illustrates that the price convergence observed in May and June between day-ahead and real-time for CAISO was like levels observed prior to EDAM implementation.

There is no day-ahead price data available for the PacifiCorp balancing authority areas prior to May 2026; therefore, historical convergence trends cannot be evaluated. However, the improved price convergence from May and June noted above is clear to see. Figure 9 shows that PACW had levels of price convergence similar to CAISO in June, a significant improvement from May. Figure 10 shows that PACE also saw improved price convergence in June compared to May, but also that IFM prices remain consistently higher than real-time prices. and only real-time price comparisons can be presented.

Figure 8, Figure 9, and Figure 10 also illustrate the seasonal trends in prices. Prices in 2026 have been overall lower compared to 2025. The increasing prices across May and June align with seasonal trends of increasing prices from May through September.

Figure 8: Monthly average price for CAISO area

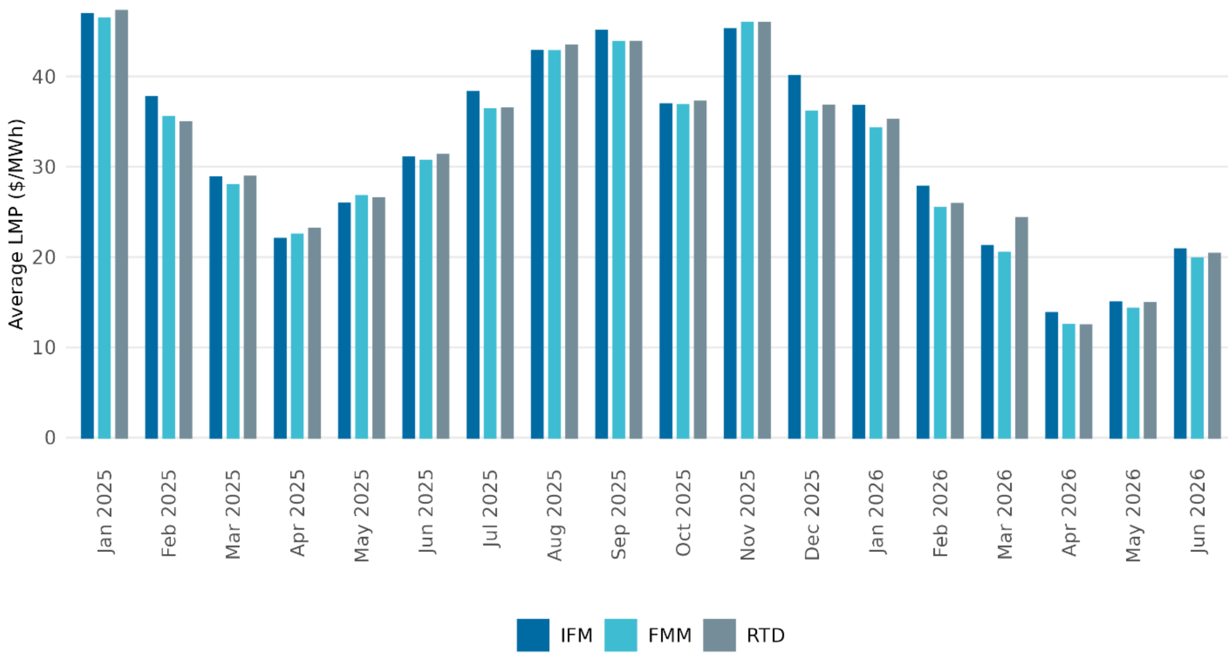


Figure 9: Monthly average price for PACW

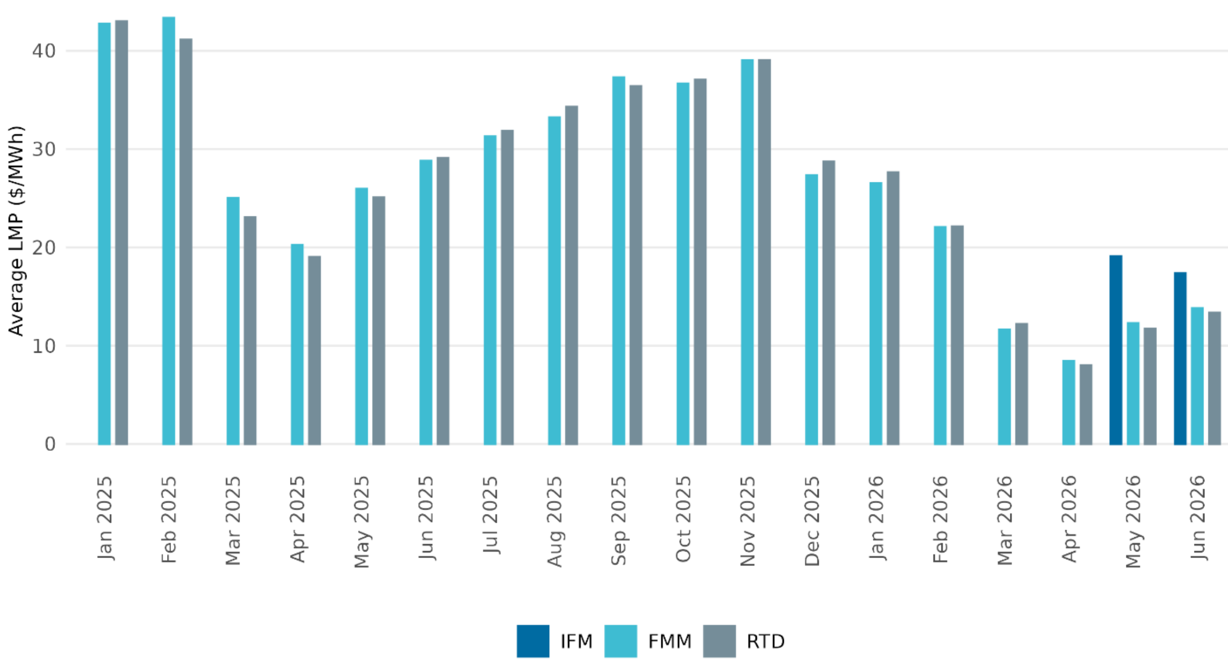


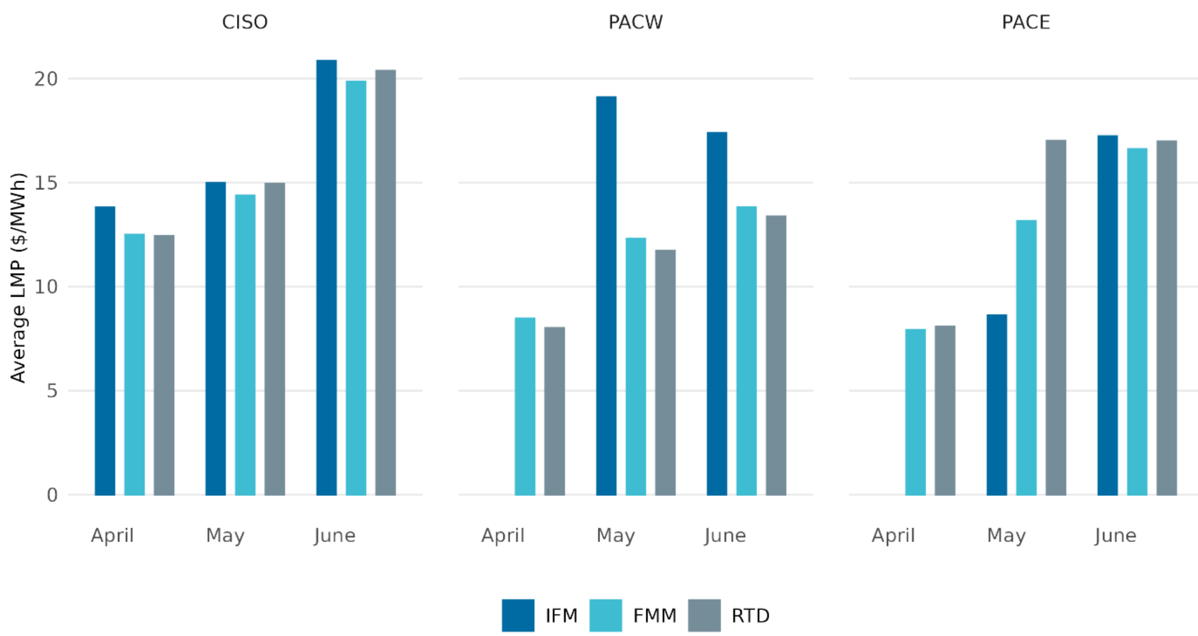
Figure 10: Monthly average price for PACE Average LMPs

Figure 11 presents the same monthly average LMPs for April, May, and June 2026 to ease the comparison among areas and months. Table 4 summarizes the average LMP across each month for each market and BAA.

Table 4: Monthly average LMP by BAA

	Average IFM LMP ($/MWh)			*Average FMM LMP ($/MWh)*			*Average RTD LMP ($/MWh)*		
BAA	April	May	June	April	May	June	April	May	June
CAISO	13.80	14.98	20.84	12.49	14.38	19.85	12.44	14.94	20.37
PACE		8.62	17.23	7.91	13.15	13.82	8.07	17.00	16.98
PACW		19.11	17.38	8.47	12.29	12.44	8.01	11.72	13.37

Figure 11: Monthly average LMPs



Price Volatility

Figure 12, Figure 13 and Figure 14 show the frequency of prices falling in predefined $/MWh ranges in the given month for each BAA. For example, in June 2026 the CAISO RTD LMP was between -50 and 0 $/MWh in less than 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 May, June CAISO saw more LMPs in the range of 20 to 40 $/MWh, making the 20 to 40 $/MWh range the most frequent for CAISO. Similar to May, the 0 to 20 $/MWh range was the most frequent range for PACE and PACW. PACW saw a small increase in the frequency of 40 to 100 $/MWh LMPs and PACE saw an increase in the frequency of 20 to 40 $/MWh LMPs.

Looking at last May and June suggests that this trend of the increasing frequency of higher LMPs is normal for this time of year. In general, the frequency of low and even negative LMPs has been much higher in 2026 compared to 2025. 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 $/MWh or above 100 $/MWh.

Figure 15 shows only the frequency of LMPs in the price ranges below -50 $/MWh and above 100 $/MWh. This more specific view shows that after EDAM go-live CAISO had no LMPs above 200 $/MWh and the frequency of LMPS between 100 and 200 $/MWh was within the normal range.

Figure 15 shows that PACW and PACE saw decreases in high LMPs in June compared to May. PACW had no LMPs above 100 $/MWh in June and PACE had no LMPs above 200 $/MWh in June.

Figure 12: CAISO RTD LMP range frequency

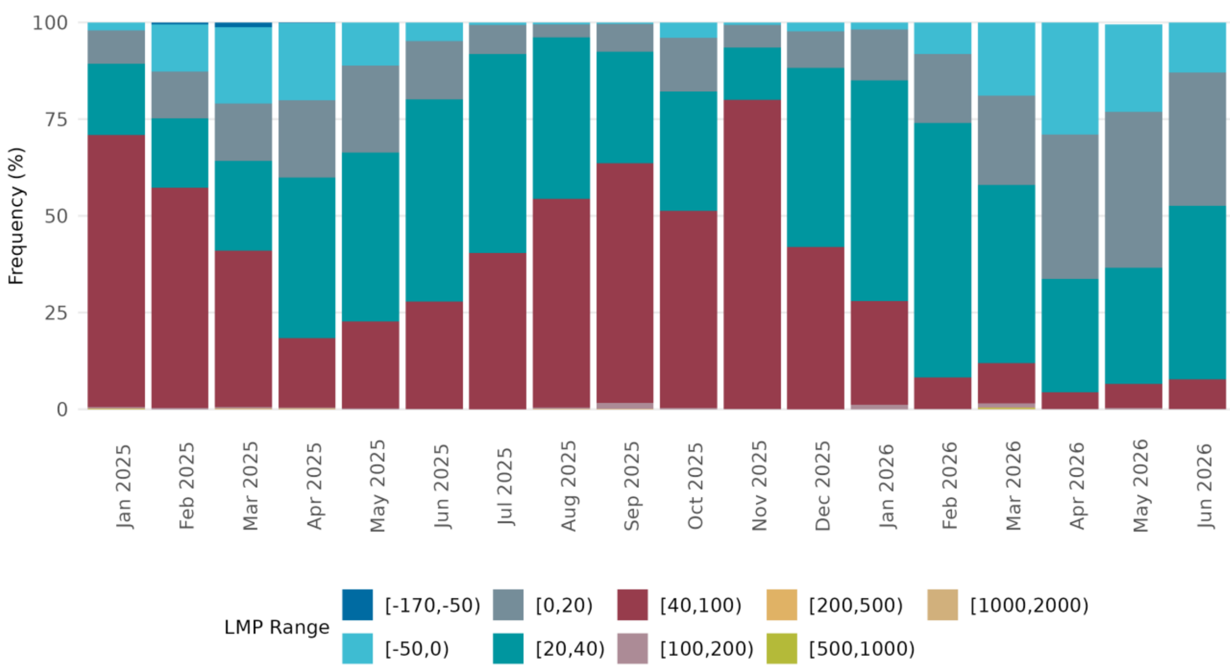


Figure 13: PACW RTD LMP range frequency

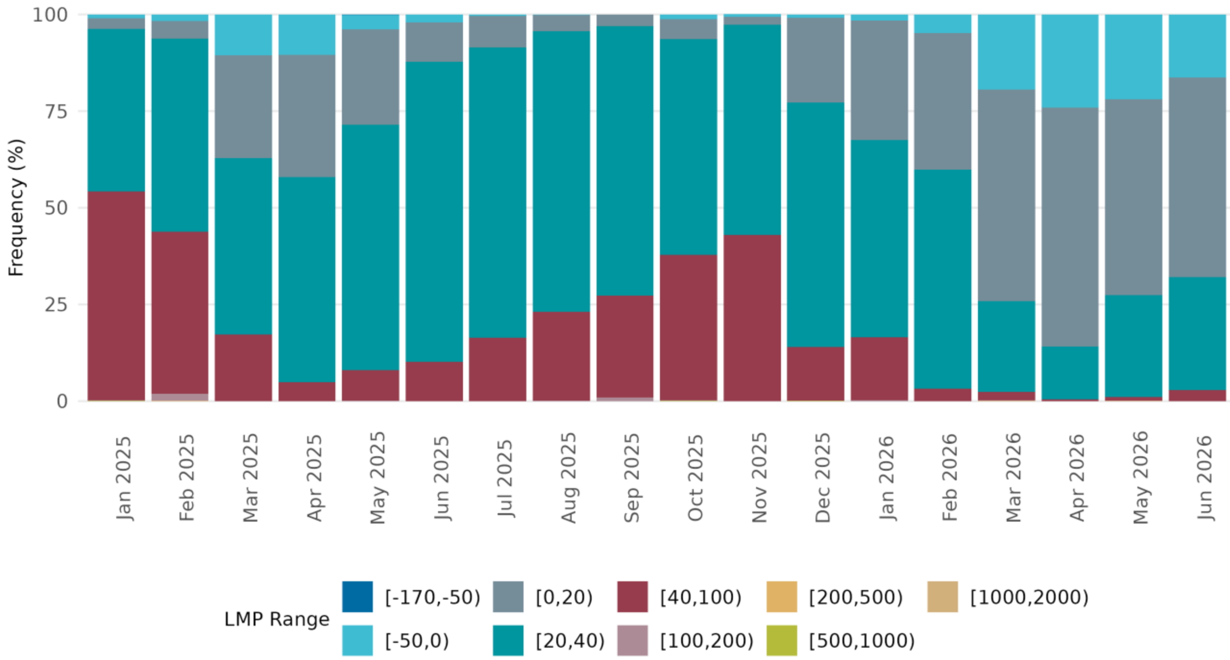


Figure 14: PACE RTD LMP Range Frequency

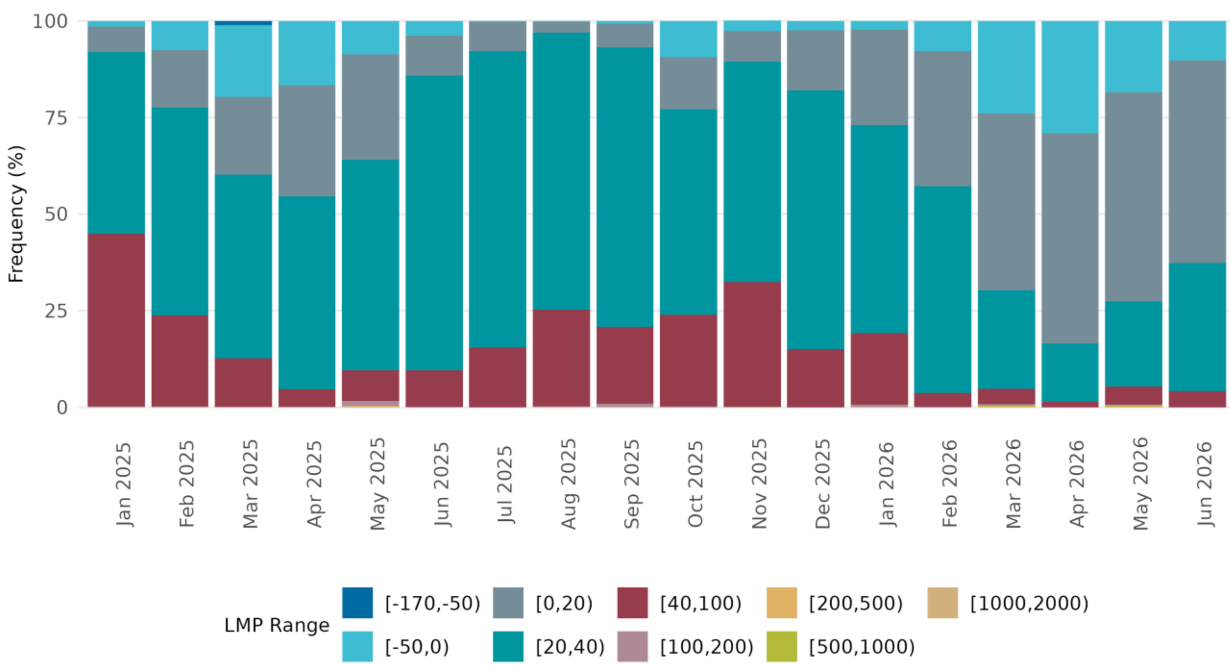
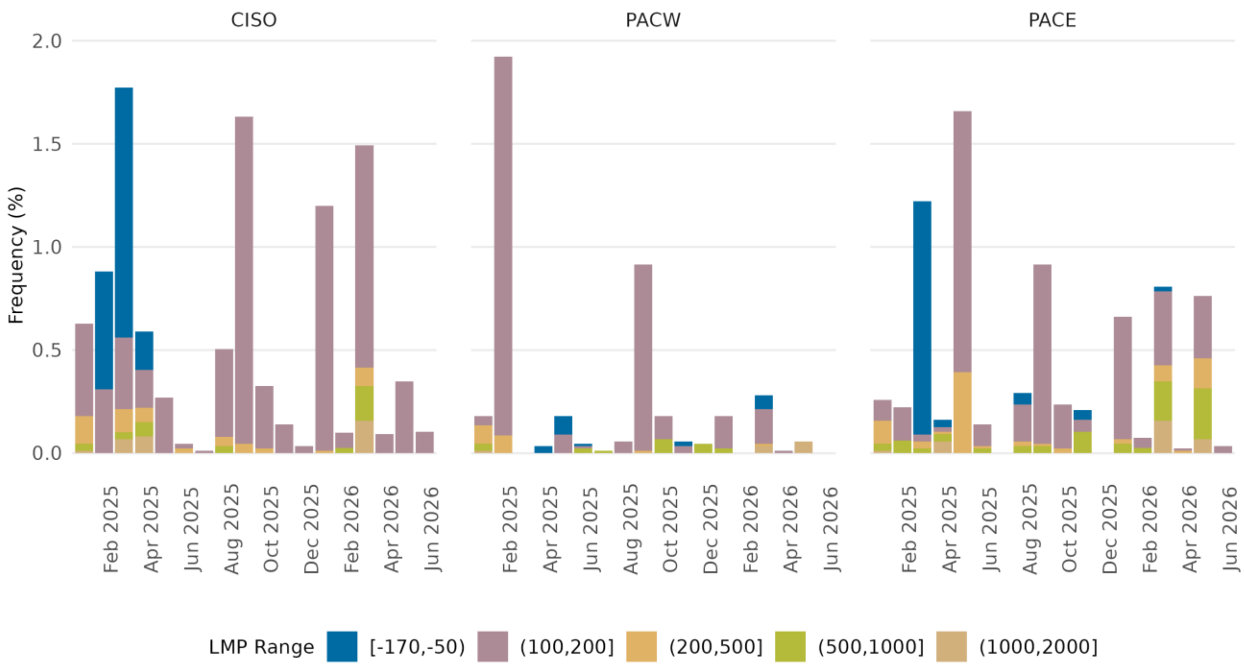


Figure 15: Frequency of extreme LMPs



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 16 for the LMP decomposition of any given node in a non-CAISO WEIM BAA:

Figure 16: LMP Decomposition for Non-CAISO WEIM BAA

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

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):

$$\lambda_j = \phi_j + \nu_j \; or \; \lambda_j = \phi_j + \xi_j$$

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:

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

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

$$\underline{T}_j \leq T_j \leq \overline{T}_j, \qquad \forall j \in EIM$$

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:

$$\lambda_j = \phi_j + \nu_j \; or \; \lambda_j = \phi_j + \xi_j$$

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 5: 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)

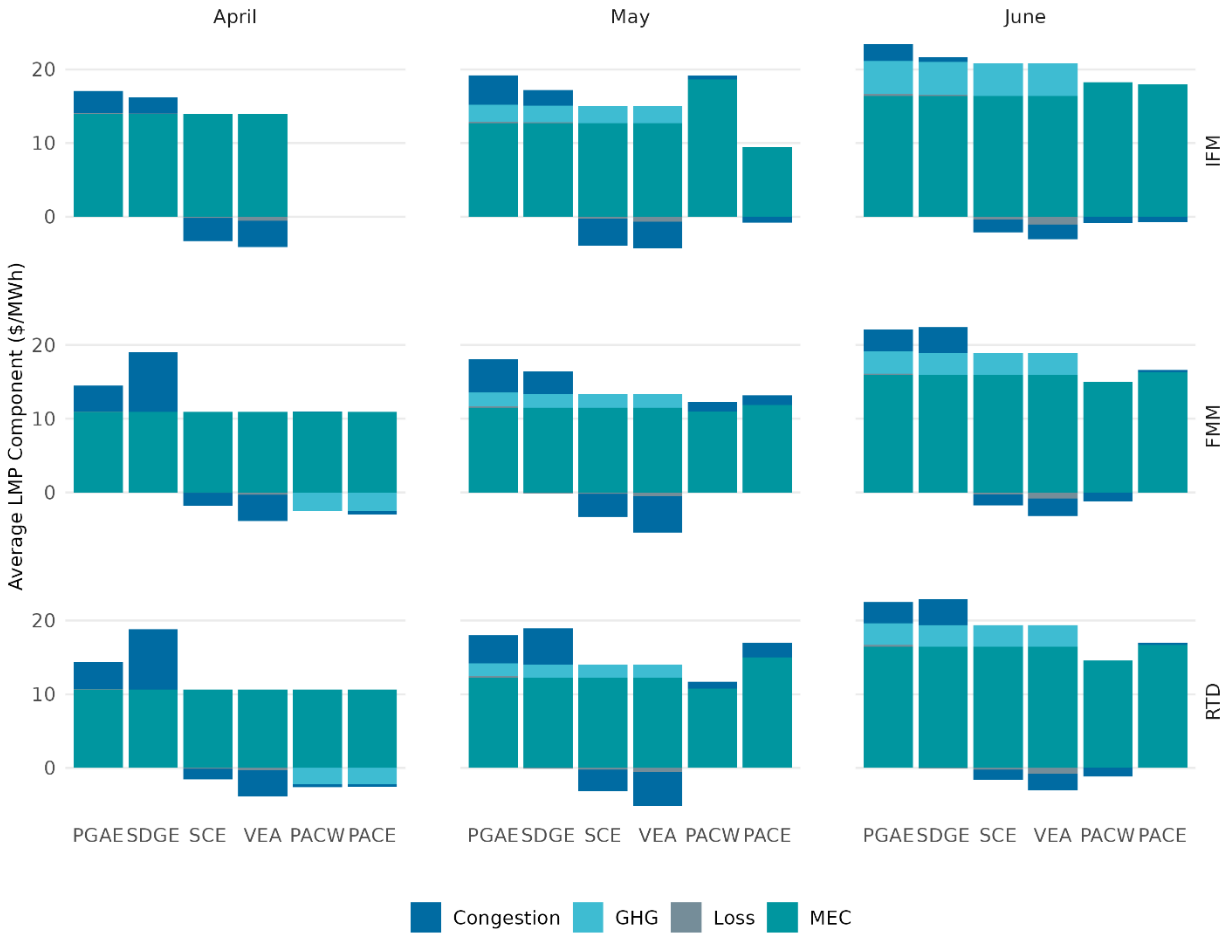
GHG prices

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 areas[1]. With EDAM/DAME the GHG component is positive and applied only to California-area locations.

Figure 17 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, May, and June. In April, the MEC was the same across all areas, reflecting the SMEC. In May and June, 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 17. 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. In general, the GHG component of the LMP increased across the four CAISO DLAPs. Excluding PACW IFM, the MEC increased across the market footprint from May to June. In June, PACE saw very little congestion impact on the LMP across all markets. The congestion component went from positive to negative in PACW from May to June, decreasing the overall effect of the higher MEC. The CAISO DLAPS also saw a small decrease in the congestion component from May to June.

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

Figure 17: Average monthly LMP components



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 18 and Figure 19 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 periods[2], 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 18 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 June. 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.

Figure 18: Daily average LMPs and bilateral power prices

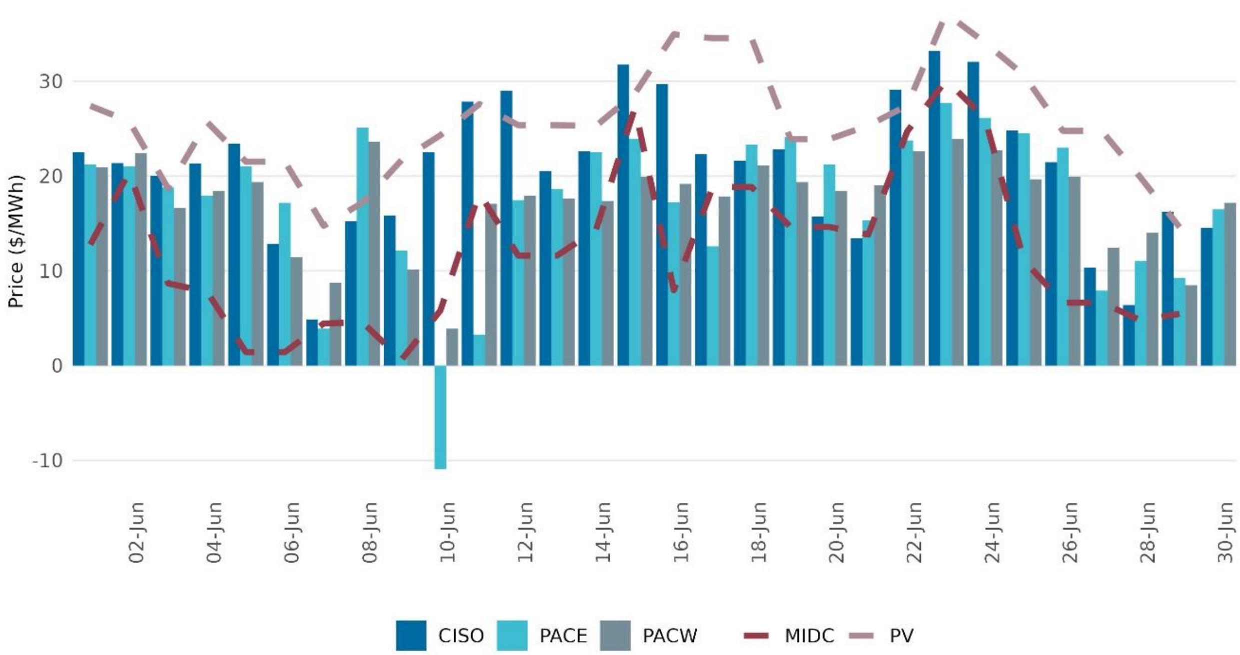


Figure 19 shows that CAISO day-ahead LMPs have historically shown some correlation with next-day bilateral power prices at MidC and PV. The high MidC price in February 2025 was due to a major Arctic cold snap. The first two months of EDAM appears to show some divergence between MidC and PV price and with CAISO day-ahead LMPs; However, historial trends also shoed this trend. A more robust assessment of this correlation will require observation over a longer period of EDAM operations.

[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 19: Monthly average LMPs and bilateral power prices

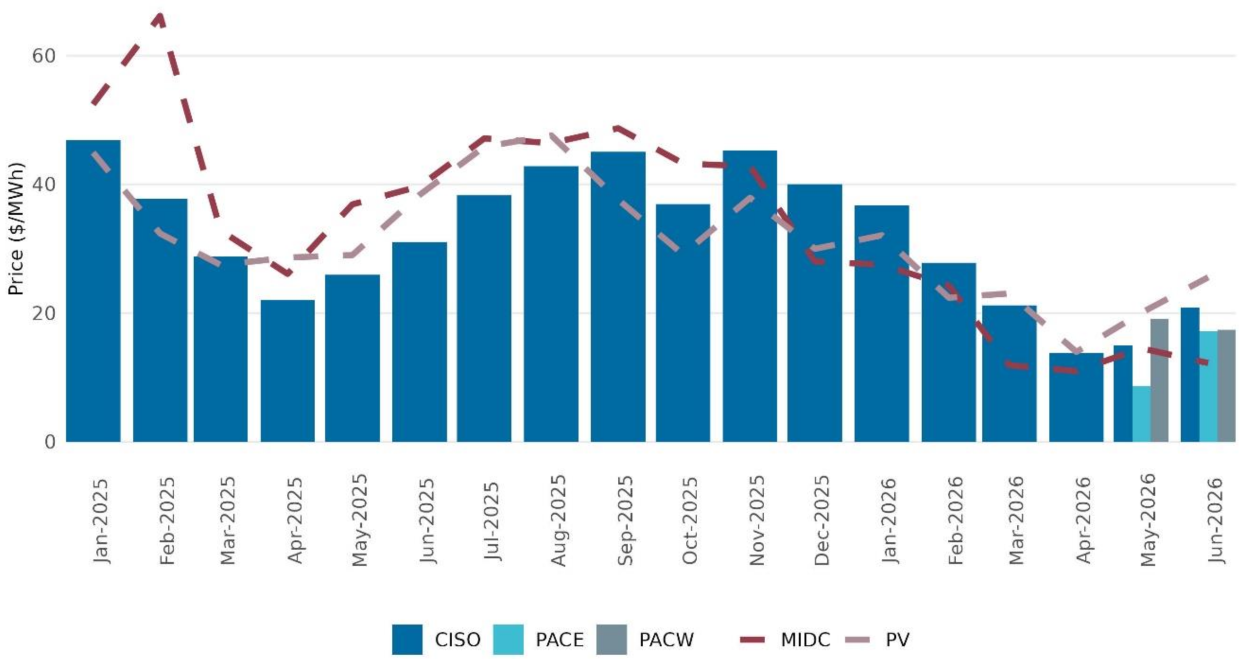


Figure 20 and Figure 21show the daily energy volume traded for bilateral next-day power at MidC and PV hubs from April to June. For on peak, no power is traded on Sundays, which is an off-peak day. For off-peak, volumes are lowest during the weekdays. For both on- and off-peak, volumes are usually highest 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 June.

Figure 22 and Figure 23 show the monthly average energy volume traded since January 2025. The volume traded in May and June 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 20: Total daily energy volume of bilateral trades (On-peak)

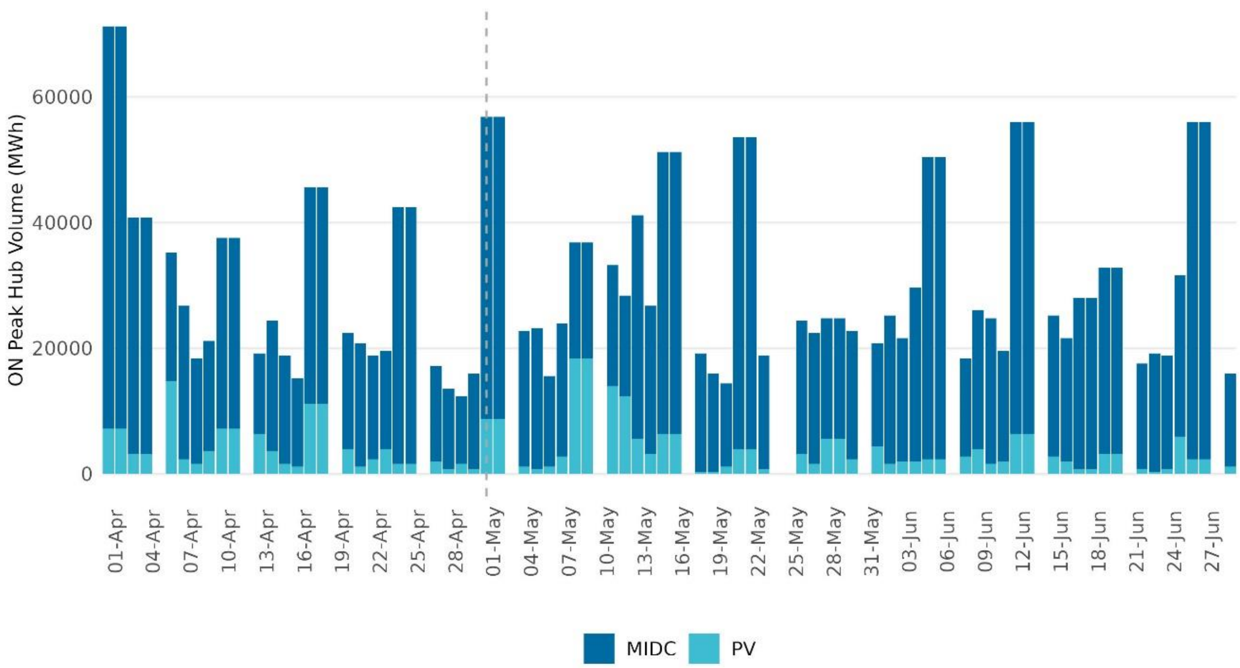


Figure 21: Total daily energy volume of bilateral trades (Off-peak)

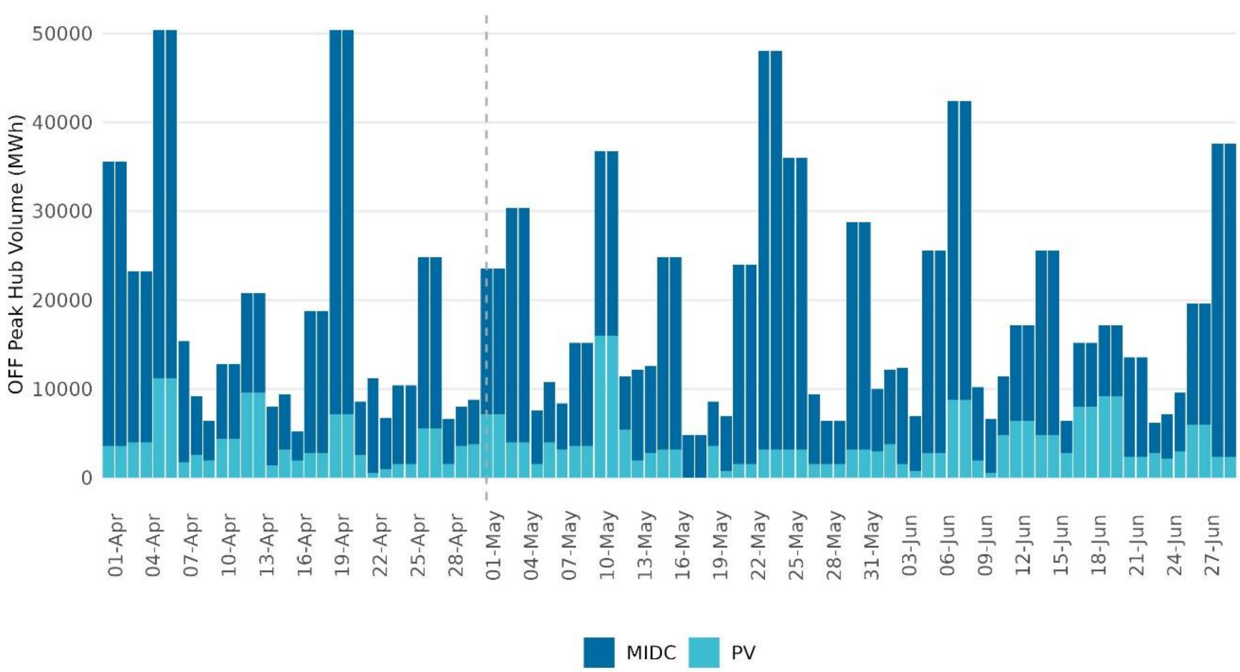


Figure 22: Total monthly energy volume of bilateral trades (On-peak)

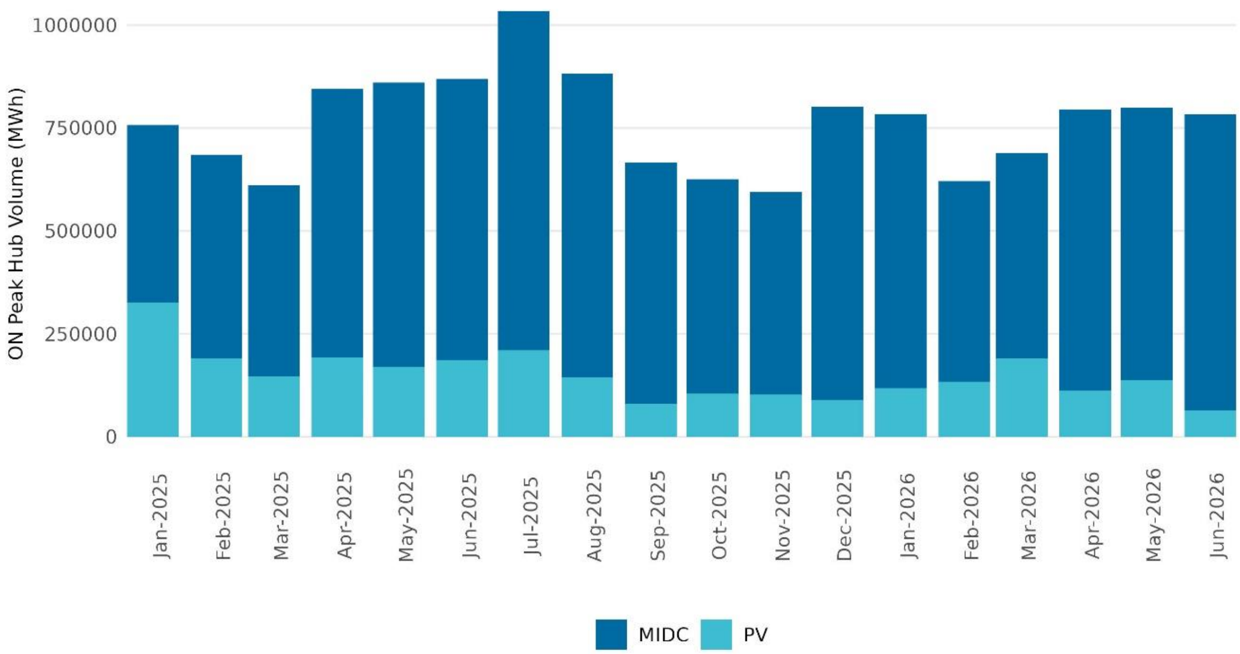
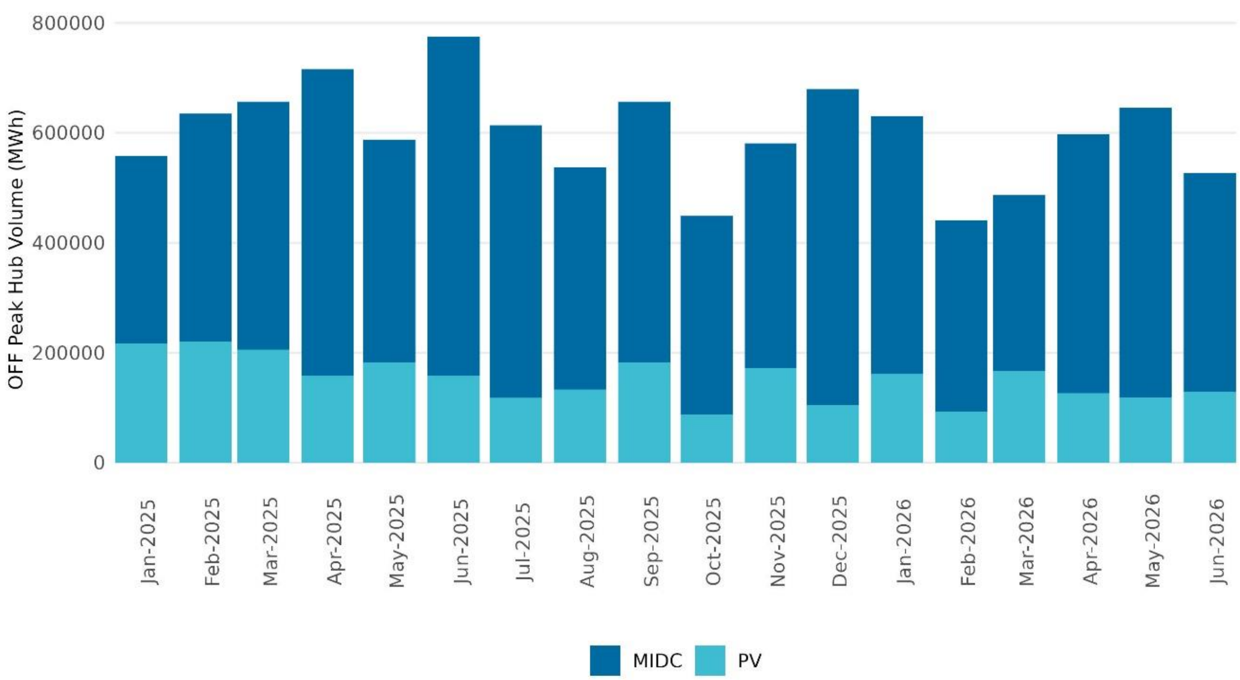


Figure 23: Monthly total energy volume of bilateral trades (Off-peak)



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 24 shows CAISO ancillary services prices in IFM from April 1st to June 30th. Overall, AS prices remained within typical ranges for all four commodities in June. Regulation up and down prices showed slight increase in May and trended downward in June. Spin and non-spin prices remained in similar ranges.

Figure 24: Daily average of CAISO ancillary services prices in IFM

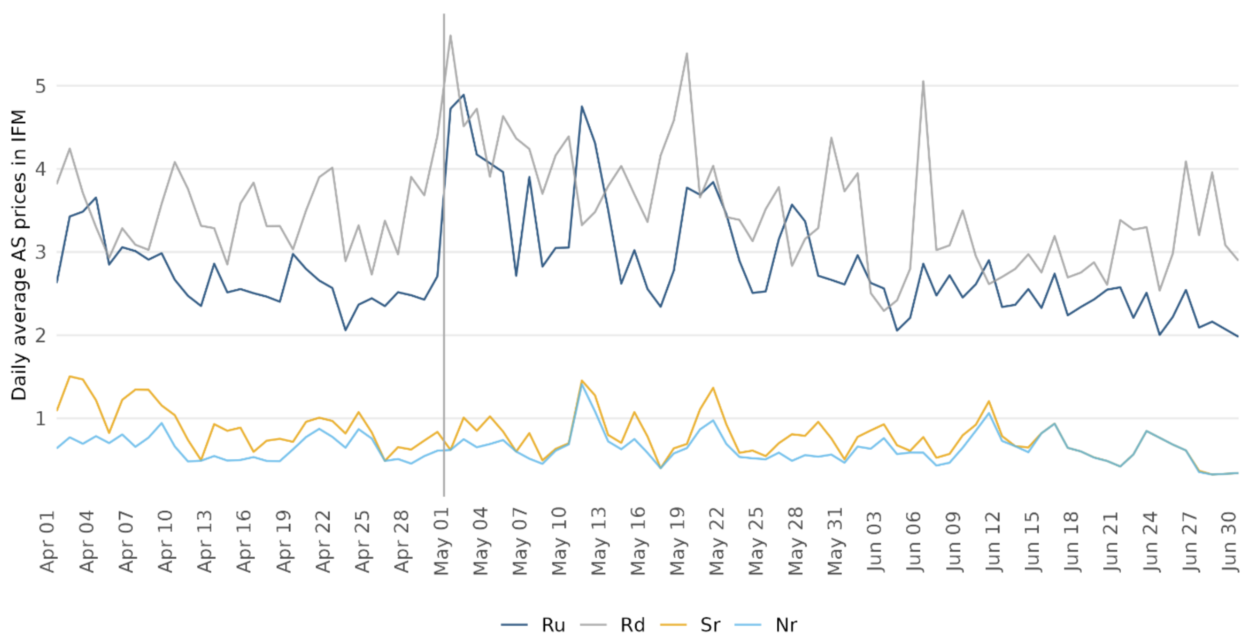
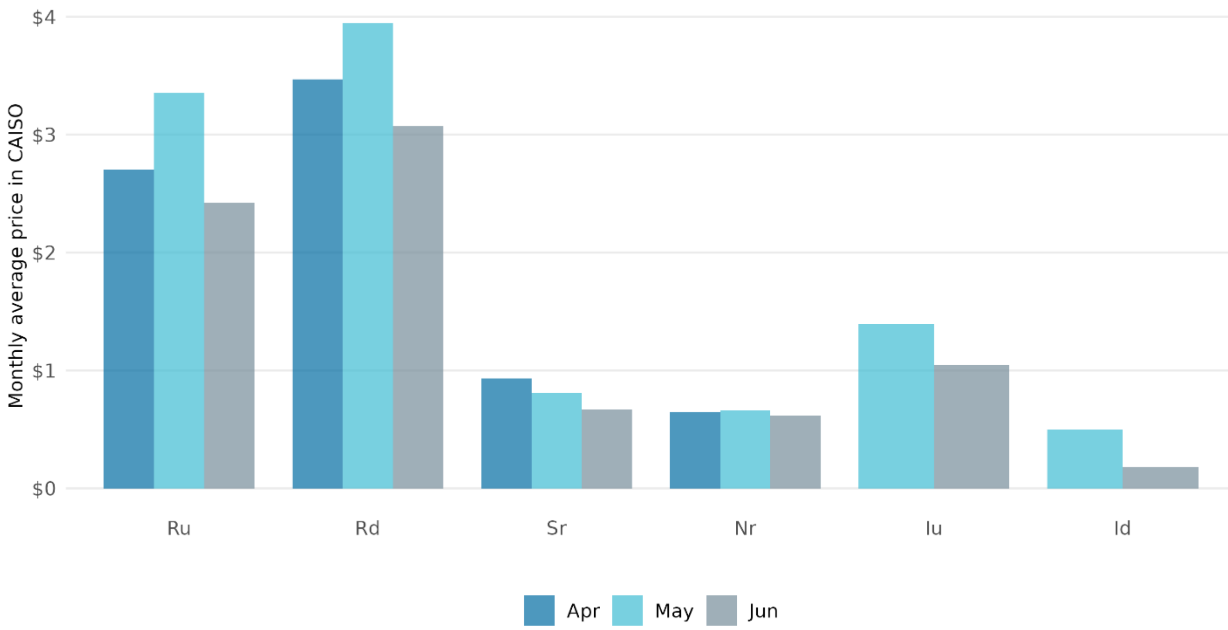


Figure 25 compares the monthly average AS prices in CAISO for the same period. Average regulation up and down prices showed slight decreases, while spin and non-spin prices generally remained in similar range. New imbalance reserve prices in CAISO in May and June are added for reference. Average price of imbalance reserve up fell between average prices of regulation up and spin.

Figure 25: 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.

Figure 26 compares the frequency of cascading in regulation up and spin across April, May, and June. The frequency of cascading in regulation up was 28.8% in April, decreased to 4.7% in May, and increased to 15.8% in June. The frequency of cascading in spin increased from 74.3% in April to 85.6% in May and 91.5% in June. The requirement for each AS is still fully met with the bids explicitly submitted for these services.

Figure 26: Frequency of cascading in Regulation and Spin reserves

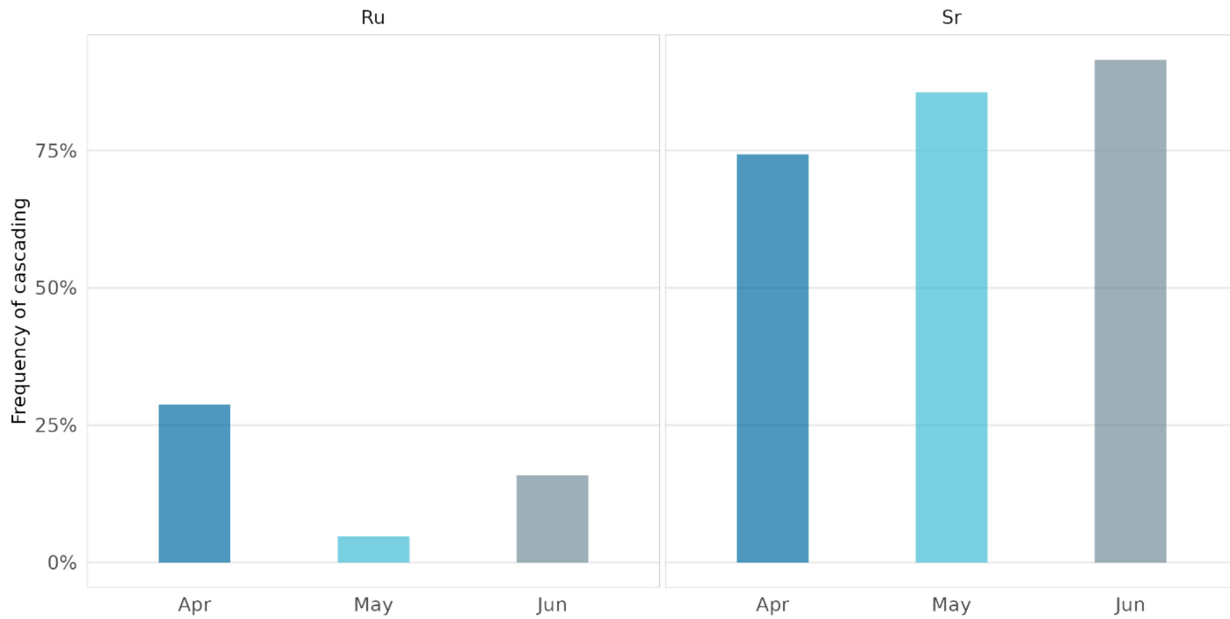


Figure 27 shows the percentage procurement for upward AS commodities in April, May, and June. Figure 28 shows the daily distributions of percentage procurement for regulation up for the same period. Percentage procurement is defined as procurement divided by the requirement for the corresponding product. 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. Percentage procurement of regulation up in June increased slightly from previous month with more outliers . Percentage procurement in spin showed an increase in overall distribution in June.

Figure 27: Comparison of monthly procurement in percentage

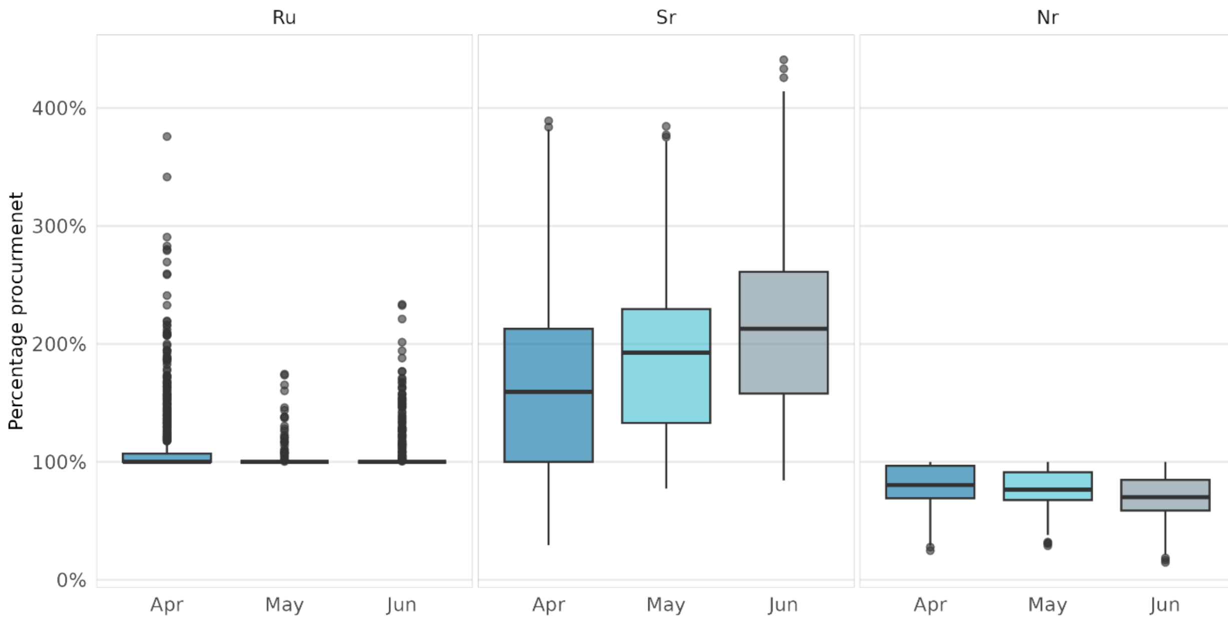


Figure 28: Daily distribution of regulation up percentage procurement in IFM

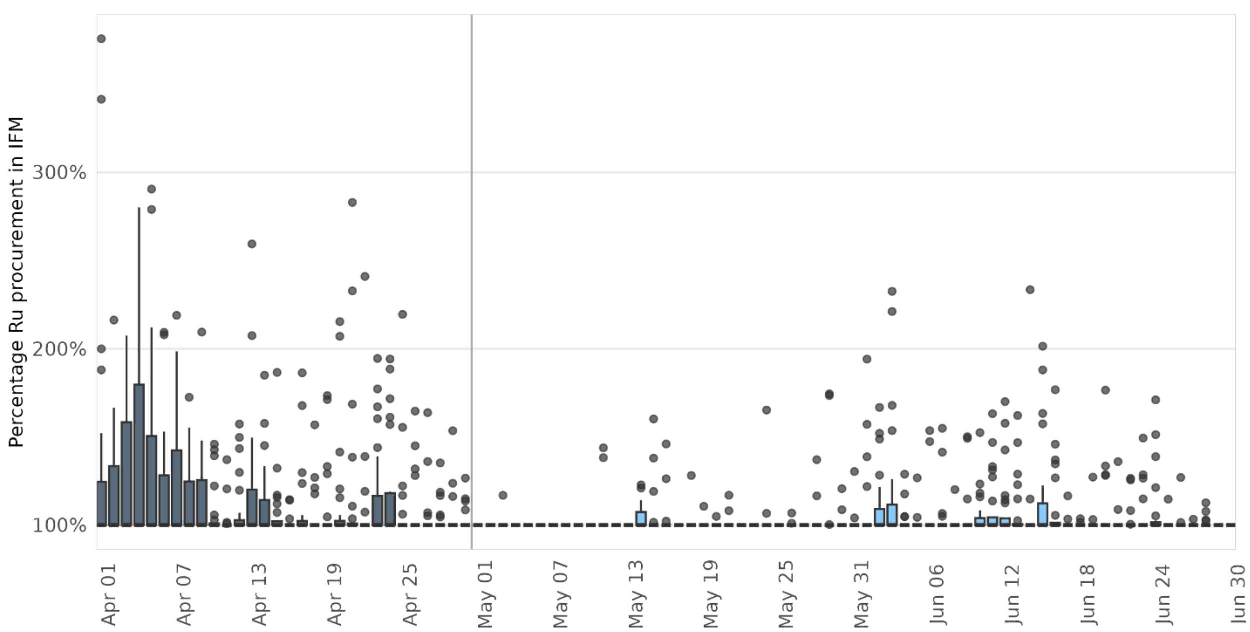
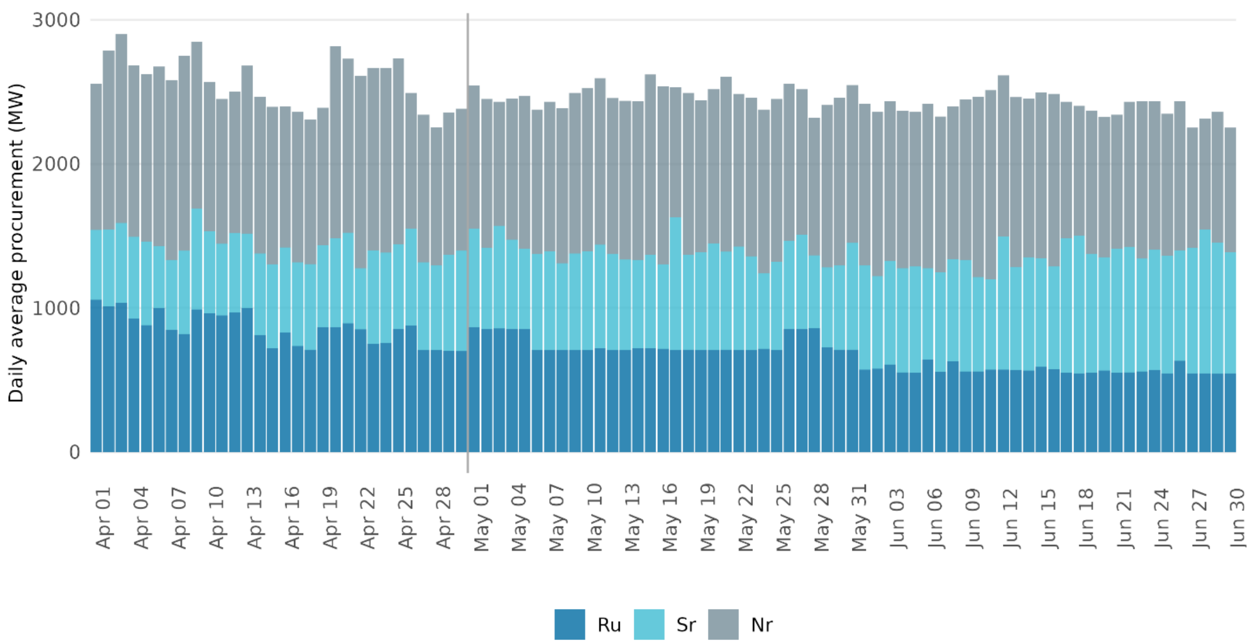


Figure 29 shows daily average procurement volume (MW) in upward AS commodities in IFM. After EDAM go-live, regulation up procurement showed slightly decrease while spin showed slightly increase.

Figure 29: 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 30 to Figure 32 show price comparisons in upward AS commodities, April through June. In June, the price trends for regulation up, spin, and non-spin retained the same hourly shape. Compared with previous months, regulation up prices decreased in June, to a level comparable to April, while average prices for spin and non-spin remained largely unchanged.

Figure 30: Regulation up prices for CAISO extended area

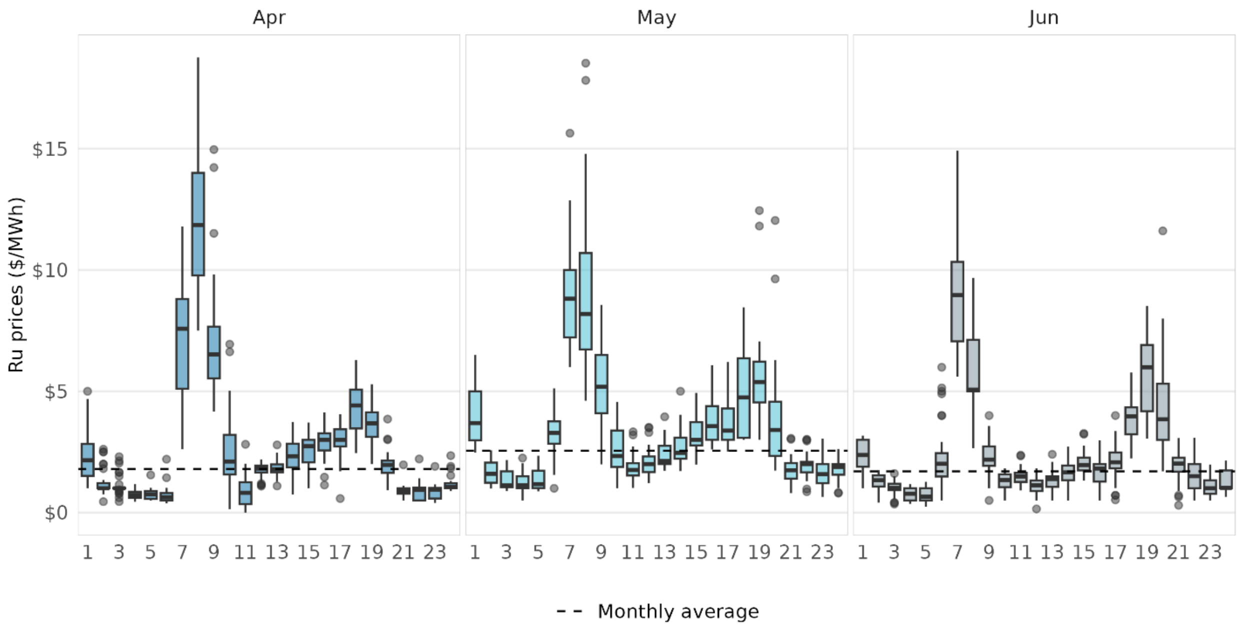


Figure 31: Spin prices for CAISO extended area

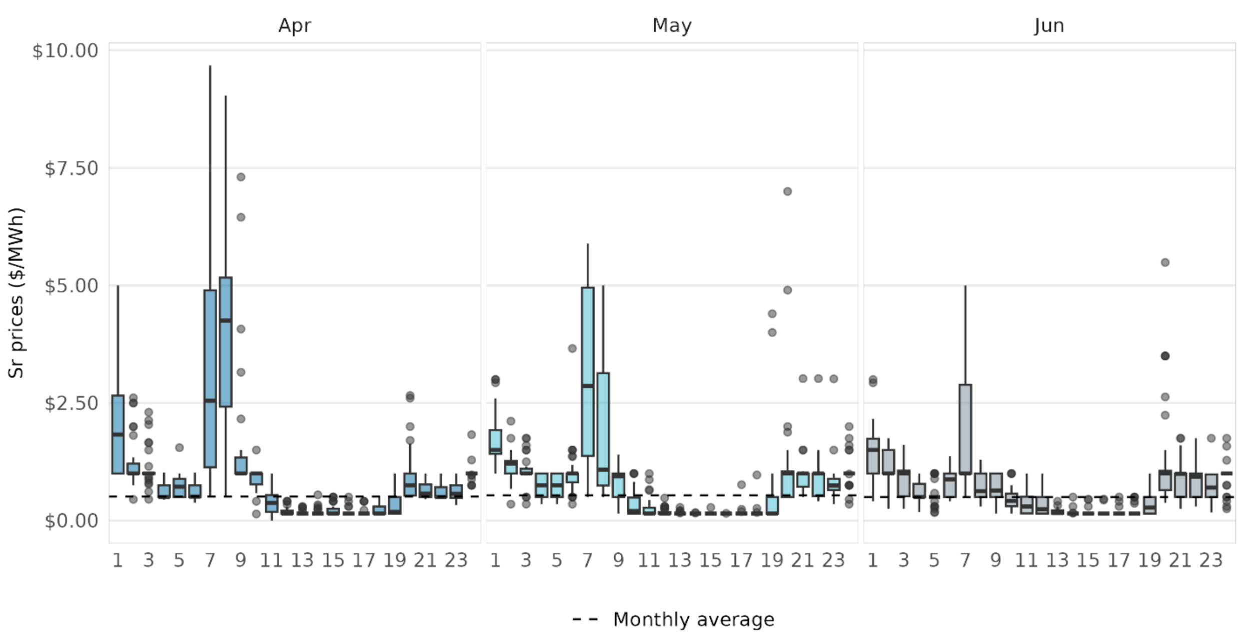
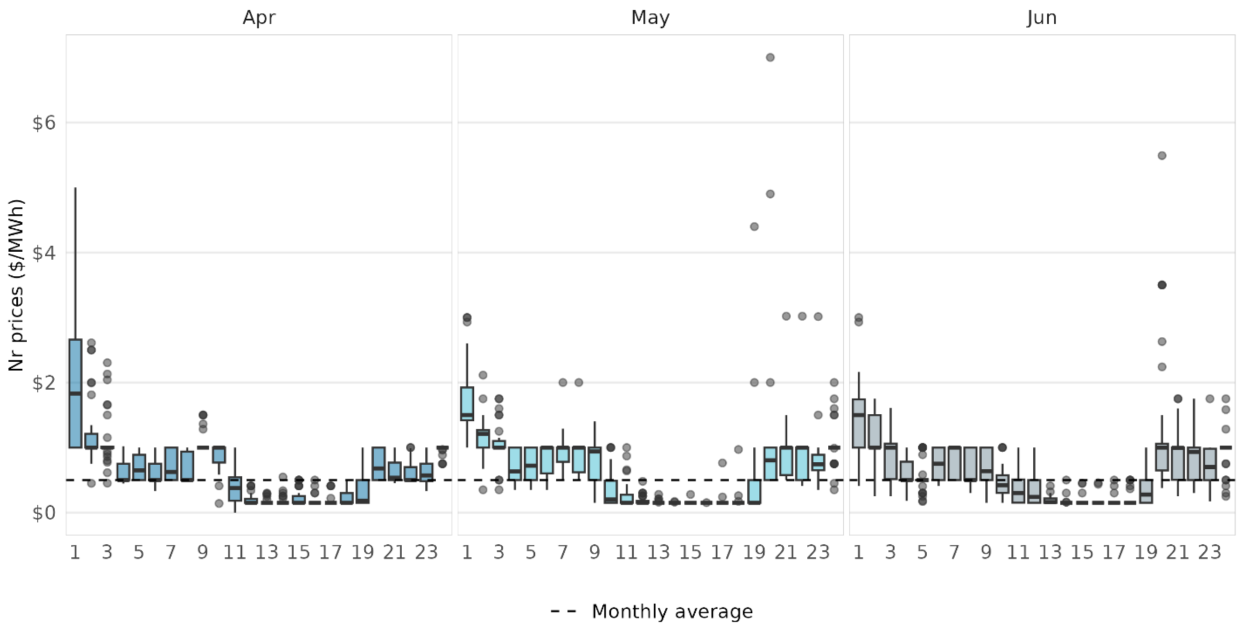


Figure 32: Non-spin prices for CAISO extended area



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. Imbalances also exist because real-time net load moves continuously and flat hourly schedules from the day-ahead market inherently cannot cover the fluctuation. 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 33 to Figure 36 below. The average daily profile is shown in Figure 33 and Figure 34, while the average hourly profile is shown Figure 35 and Figure 36. The mean monthly prices are shown in Table 6.

Overall, IR prices in June were stable and lower compared to May for all three BAAs, particularly for PACW. Figure 33 and Figure 34 show that prices stabilized in June, and Table 6 shows that monthly mean prices fell in June except for IRU for PACE which increased. The highest IR prices observed across June were for PACW, on average. The highest daily mean IRU price in June was 6.50 $/MWh in PACE on June 8th. For CAISO, the highest mean IRU price was 1.69 $/MWh on June 23rd. In PACW, the highest daily mean IRU price was 4.93 $/MWh reached on June 15th. PACW had the highest daily mean IRD price of 5.66 $/MWh also on June 15th. In both CAISO and PACE the IRD prices were low throughout the month with daily mean highs of 0.51 $/MWh on June 9th and 0.68 $/MWh on June 19th, respectively. The hourly average profiles for all BAAs showed the highest prices typically occurred during the morning and evening peak hours, coinciding with the hours having the highest IR requirements. The high prices in these hours indicates that the need for ramping is highest at these times if the net load forecast changes. 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 33: Daily average price of IRU

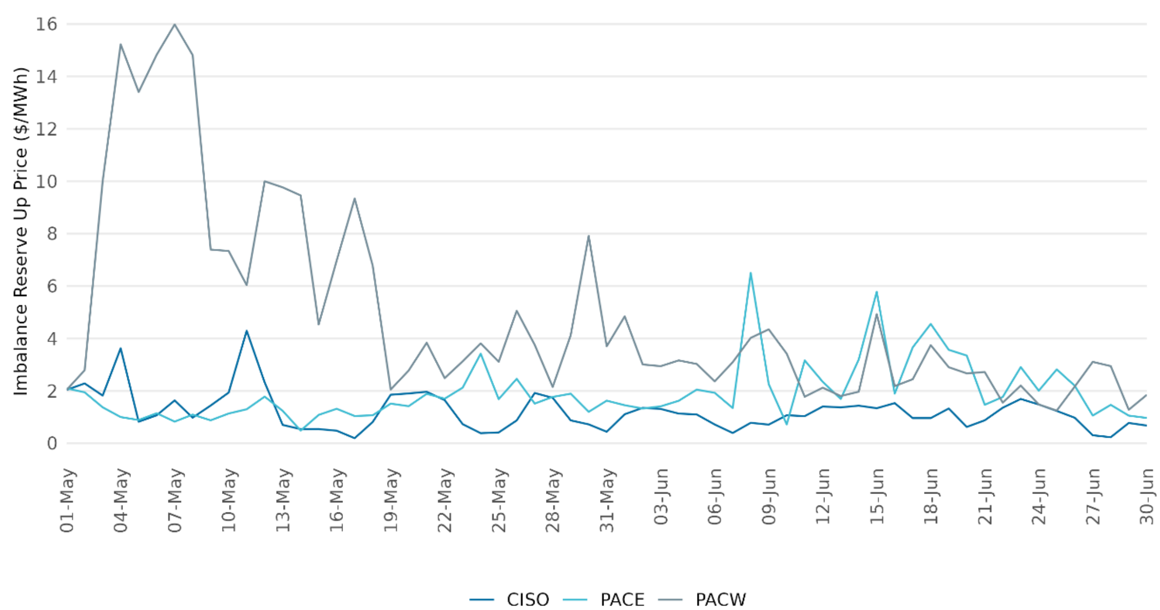


Figure 34: Daily average price of IRD

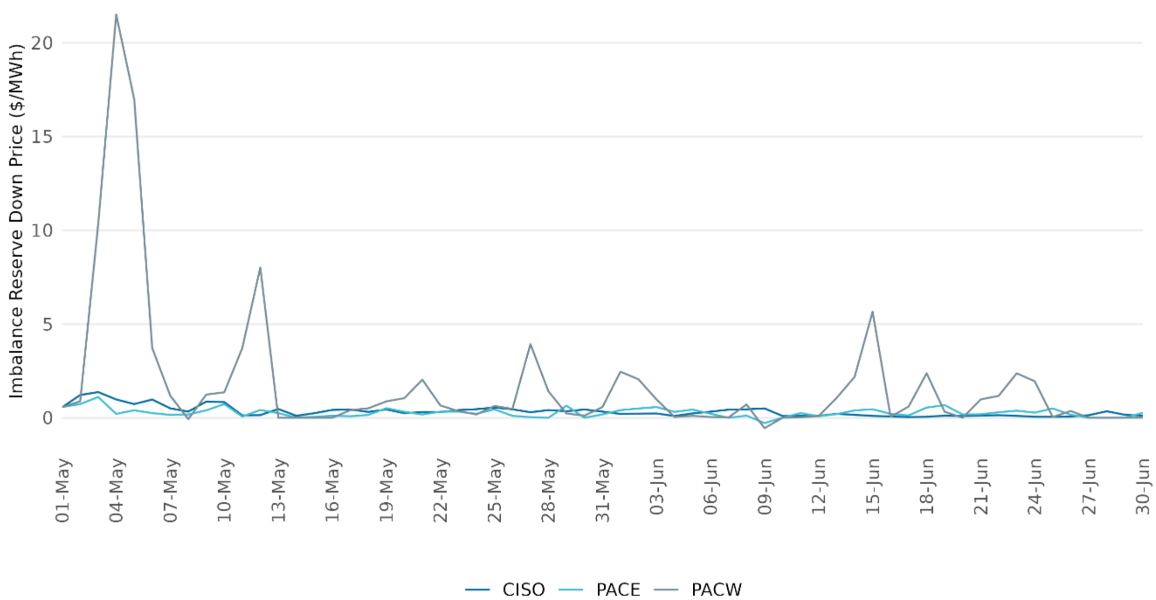


Figure 35: Hourly average price of IRU

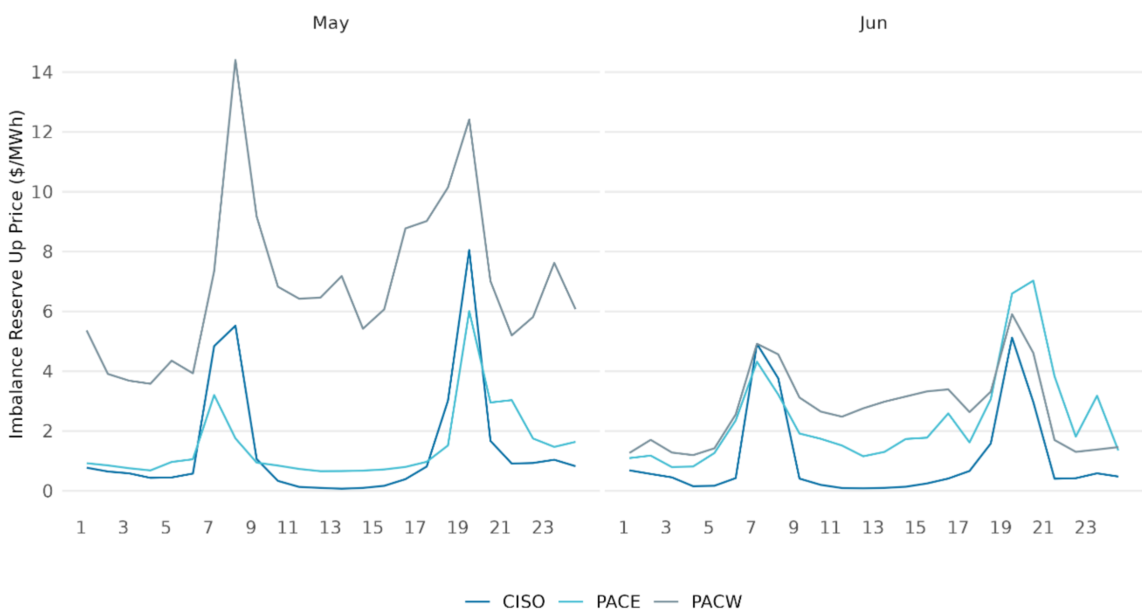


Figure 36: Hourly average price of IRD

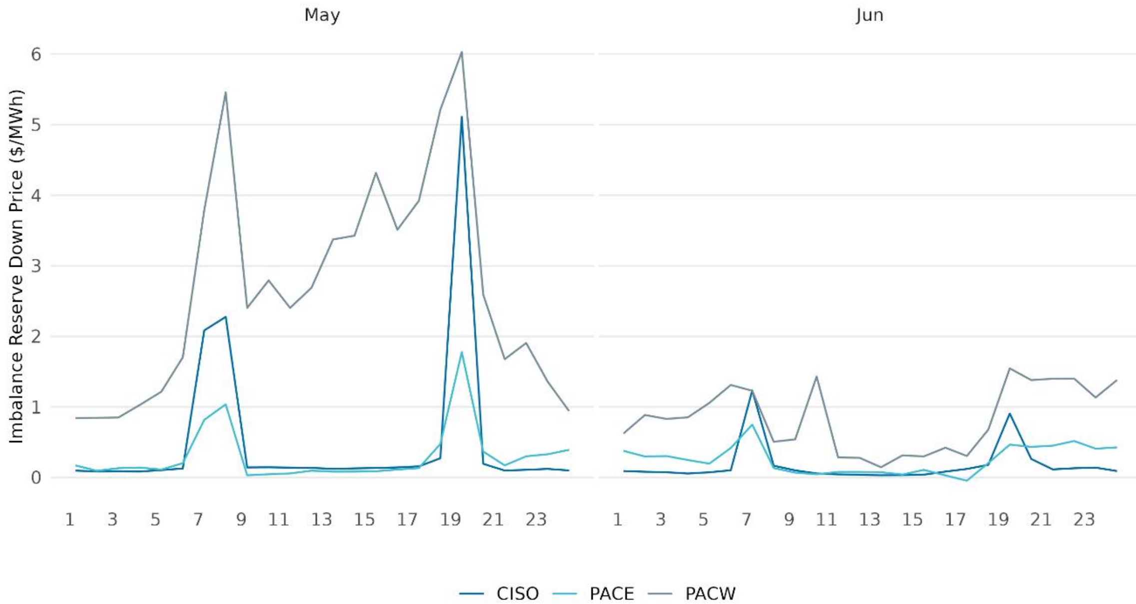


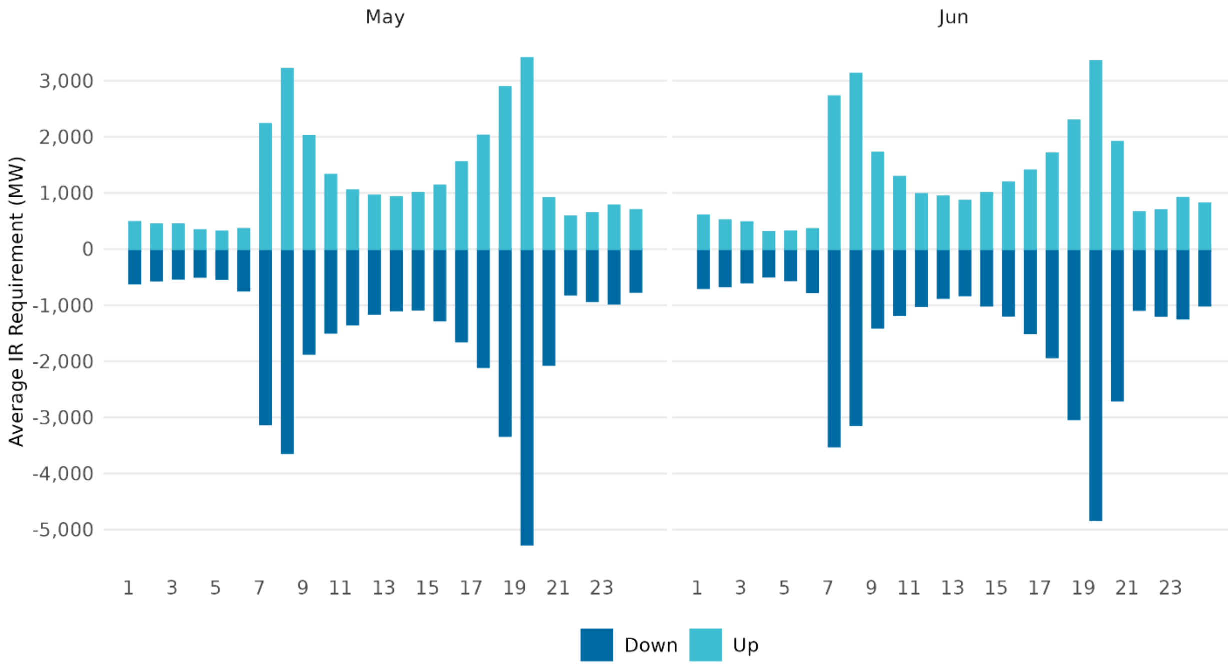
Table 6: Mean IR prices for May and June

	Mean IRU Price ($/MWh)		***Mean IRD Price ($/MWh)***	
BAA	**May**	**June**	**May**	**June**
CAISO	1.39	1.04	0.52	0.18
PACE	1.48	2.39	0.30	0.26
PACW	6.92	2.71	2.68	0.84

IR Requirements are calculated hourly for each BAA. Figure 37 to Figure 39 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.

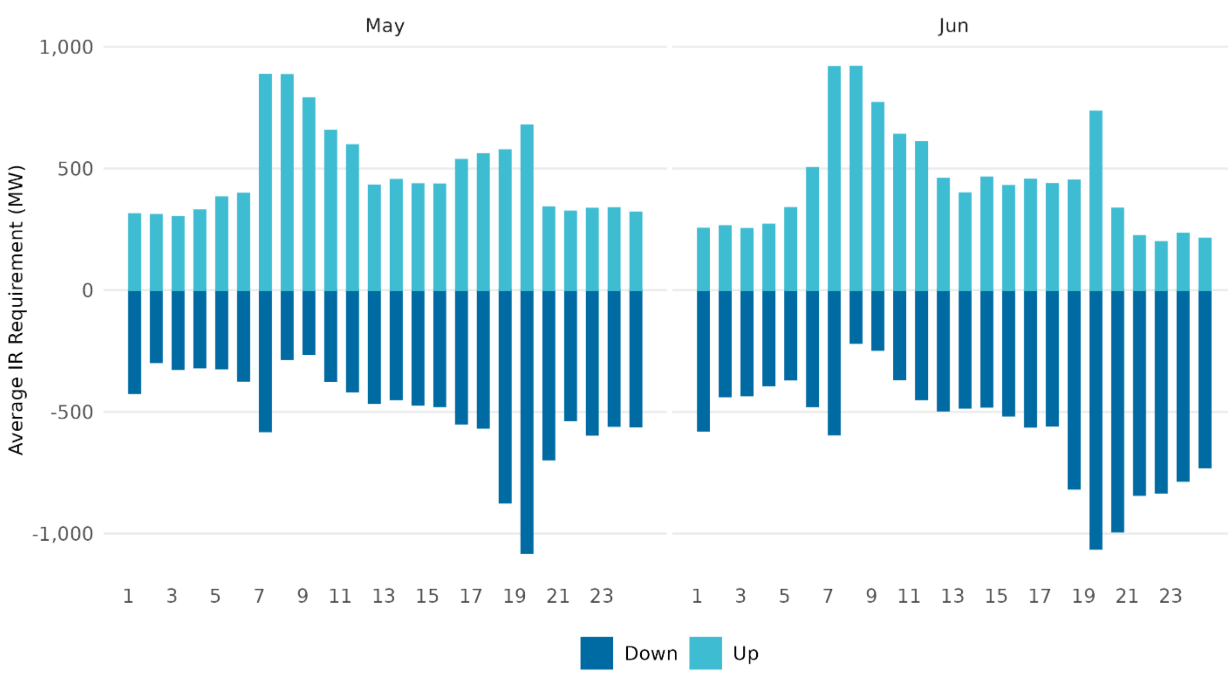
IR requirements for CAISO BAA were consistent in shape and magnitude across June and maintains a very similar shape to May. The highest requirements typically occur during the solar ramping hours where flexibility is required if the net load forecast changes.

Figure 37: Hourly average of IR requirements for CAISO



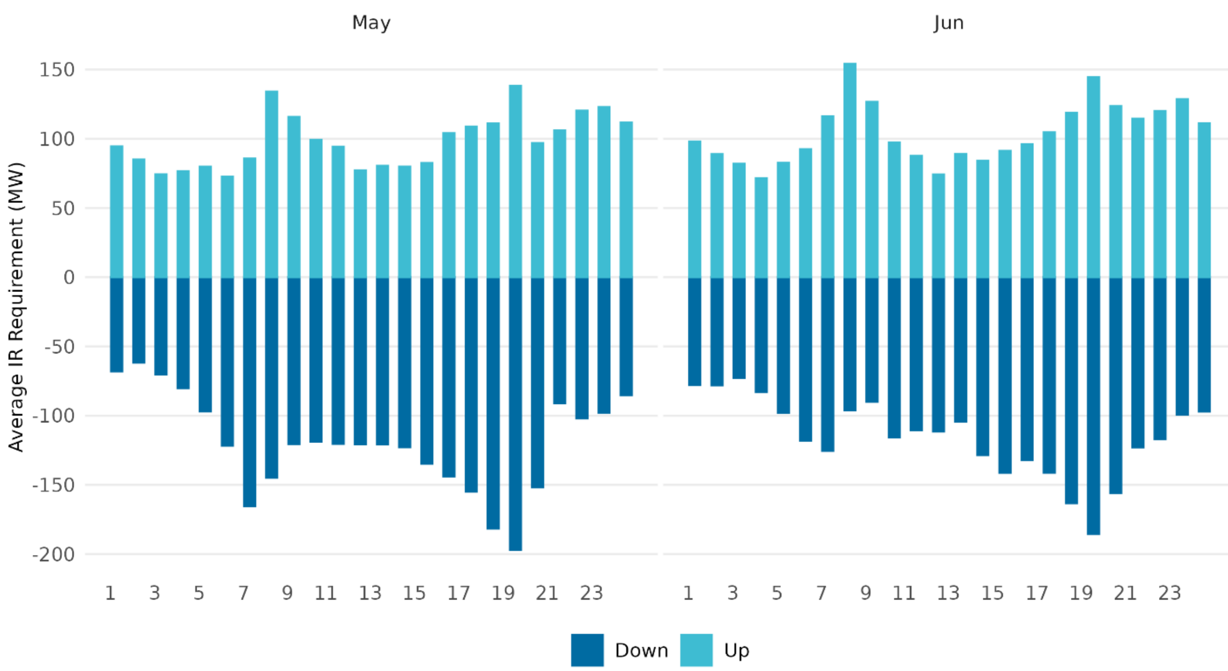
PACE IR requirements, on average, also saw the highest IRU requirements during the morning ramping hours and the highest IRD requirements during the evening peak. PACE IR requirements in June followed this same pattern and closely resembles the shape for May.

Figure 38: Hourly average of IR requirements for PACE



PACW IRU requirements were relatively consistent throughout the day on average for both IRU and IRD. In June, IRU averaged ~101 MW while IRD Averaged ~117MW with peaks in the morning and evening ramping hours. These numbers are consistent with the ~100 and ~120 in May.

Figure 39: 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 40 and Figure 41presents 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 June 2026, the average diversity benefit allocation is shown in Table 7.

Table 7 Average Diversity benefit allocation for June 2026

BAA	CISO		PACE		PACW	
IRU	351.4MW	66.3%	142.2MW	26.8%	36.7MW	6.9%
IRD	310.8MW	64.5%	142.2MW	29.5%	28.6MW	5.9%

Figure 40: Hourly average diversity benefit, IRU

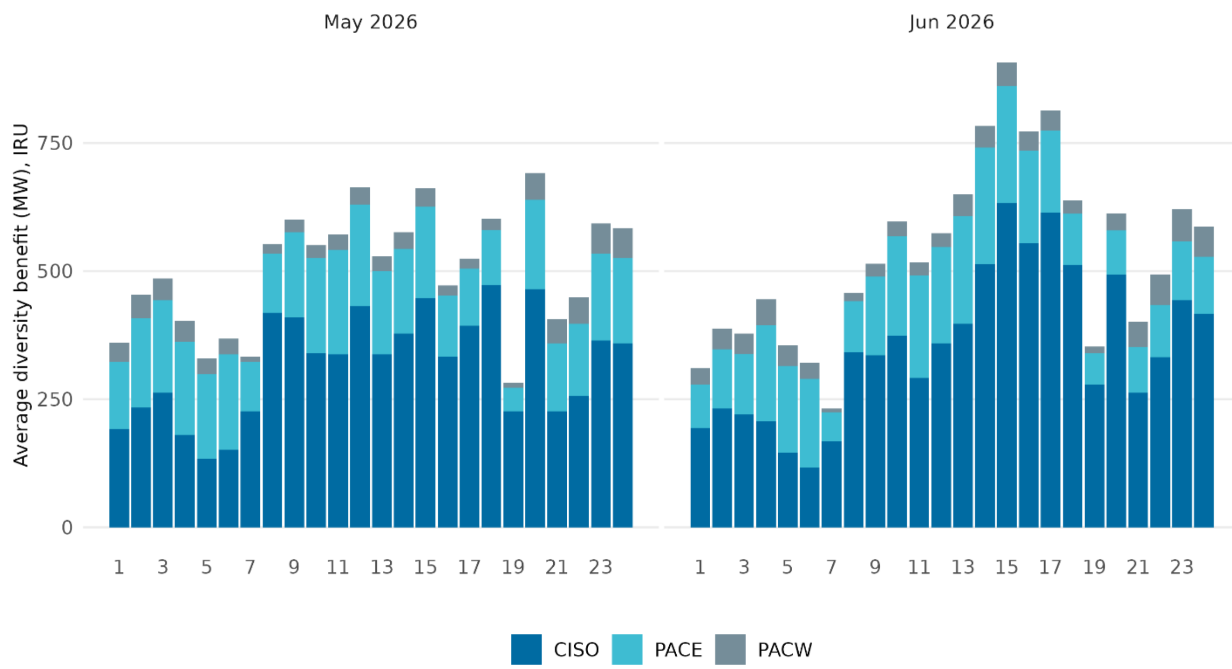


Figure 41 Hourly average diversity benefit, IRD

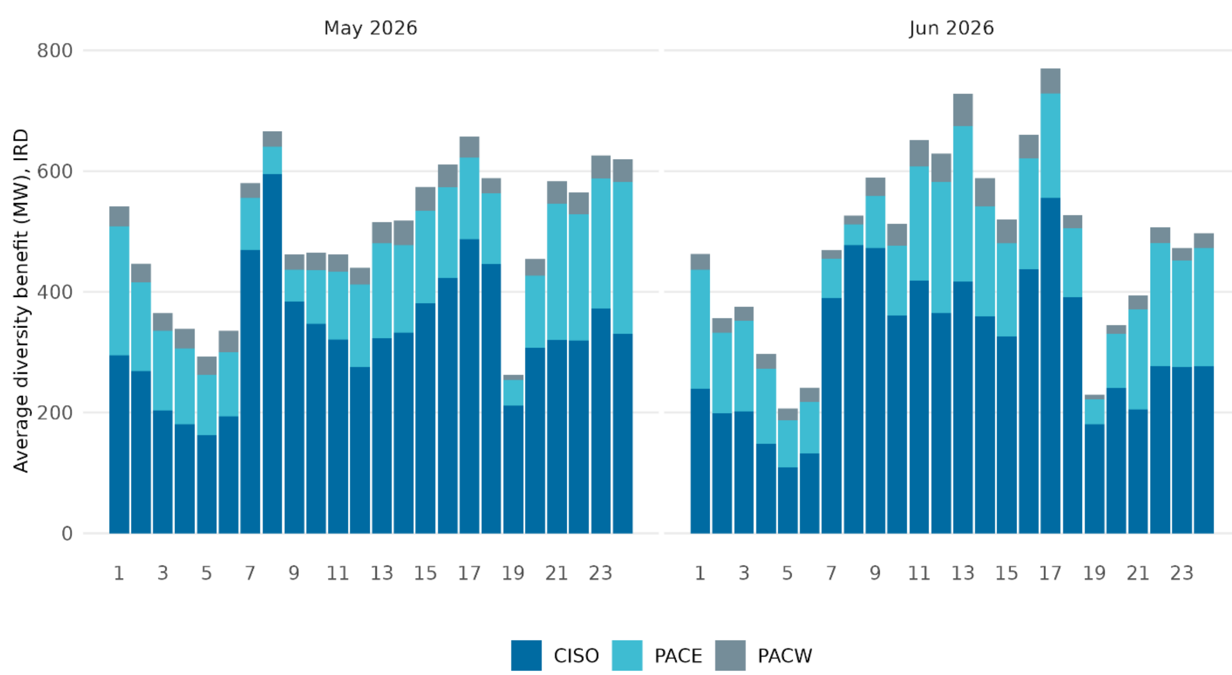


Figure 42 illustrates hourly average cleared IR by fuel type, positive direction indicates IRU and negative values indicate IRD, respectively. For the IRU direction, the resource mix exhibits a well-defined pattern, with gas resources providing the majority of IRU supply during overnight hours and remaining 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 42: Hourly average cleared IR by fuel type for CAISO

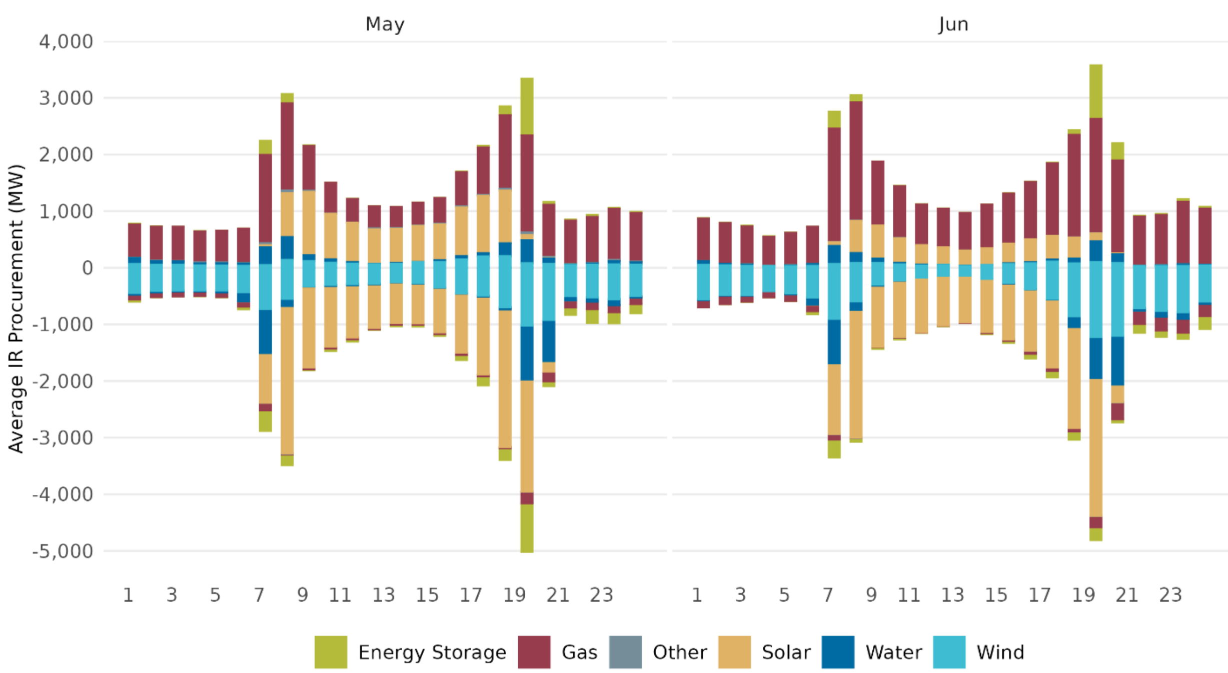


Figure 43 shows PACW's hourly average cleared IRU and IRD by fuel type, respectively. Unlike CAISO, the dominant resources in PACW are water and wind, while gas has minor contribution. Water resources provide nearly all the IRU supply, and wind resources contribute the most of IRD supply.

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

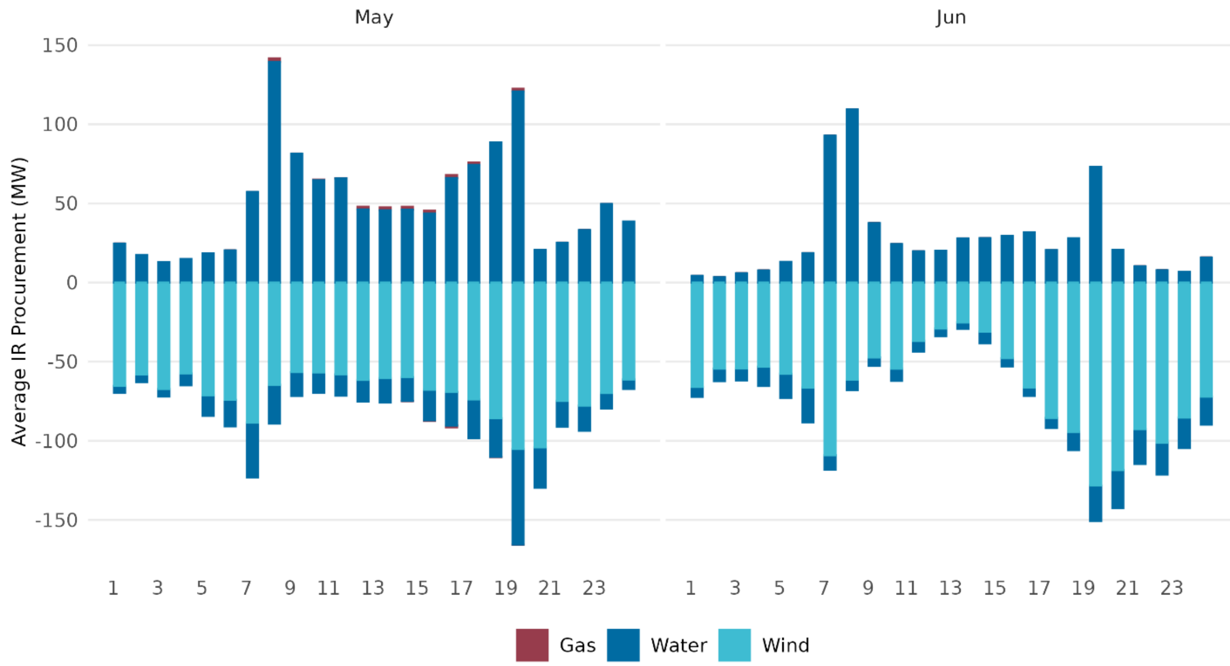
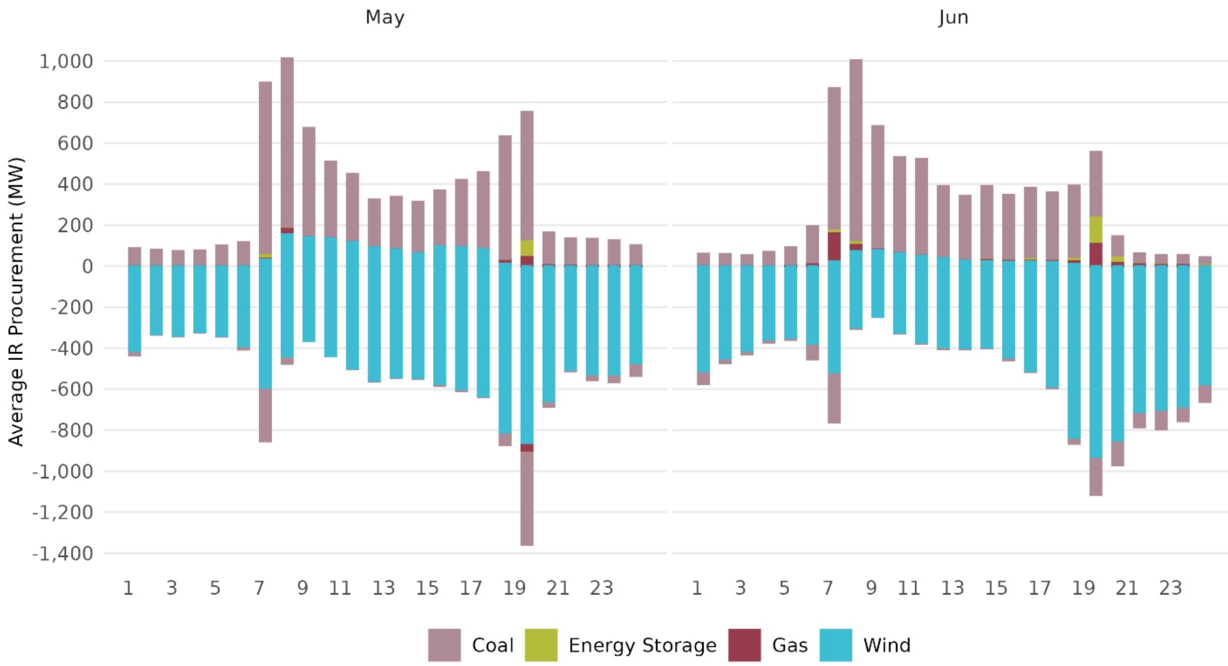


Figure 44 shows PACE's hourly average cleared IRU and IRD by fuel type, respectively. Unlike CAISO and PACW, the dominant resources in PACE are coal and wind, while gas and storage have minimal contribution. Coal resources provide the majority of the IRU supply, with wind resources contributing to the remaining during daylight hours. In IRD supply, wind resources contribute the most, with the morning and evening ramp requirements provided by coal resources.

Figure 44: 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 input bids

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 cap of 55 $/MWh.

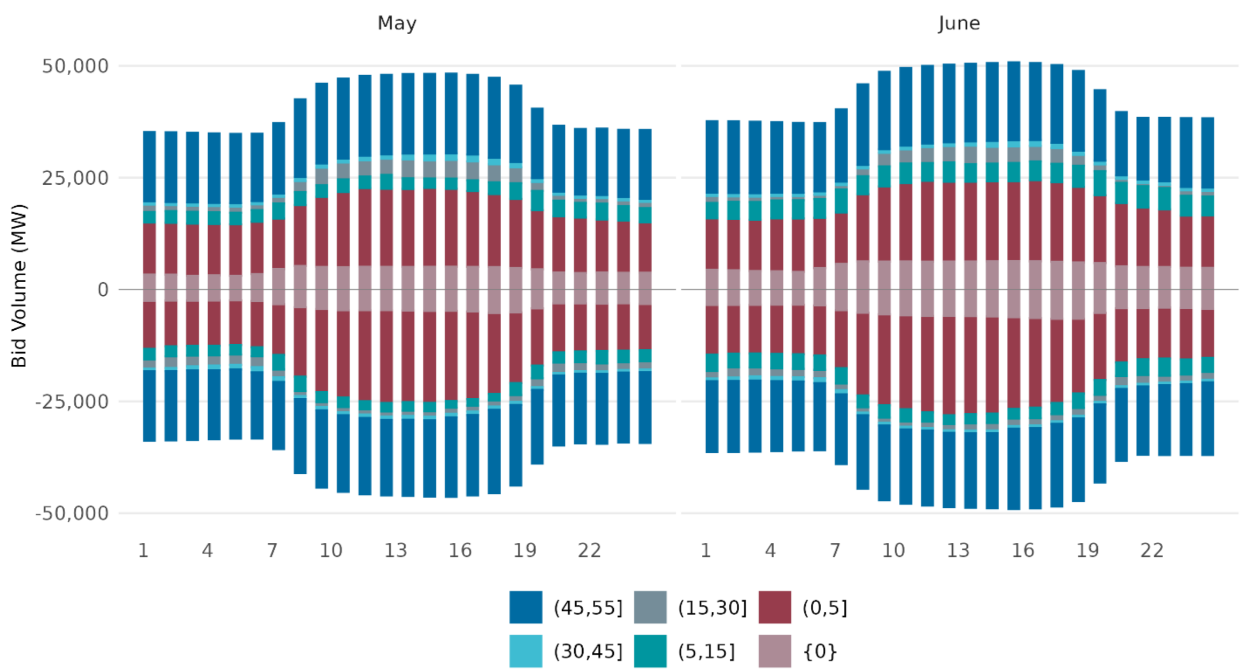
Figure 45 and Figure 46 illustrate CAISO's hourly and daily average IFM supply input bids for IR by bid price range, positive values represent up direction and negative represent down direction, respectively. Low-priced bids (0–5 $/MWh) and high-priced bids (45–55 $/MWh) consistently accounted for the largest share of submitted IR capacity throughout May and June with about 20,000 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, with only a few days exhibiting lower bid volumes. June shows the same bid pattern as May, with a very minimal increase in total bid volume. 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 and June. The volume of bids in the upward direction is very symmetrical to the volume for the downward direction.[3]

Figure 47 and Figure 48 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 May and June, followed by water, wind and hybrid resources.

Figure 45: 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 46: Daily average volume of IR bids organized by price for CAISO

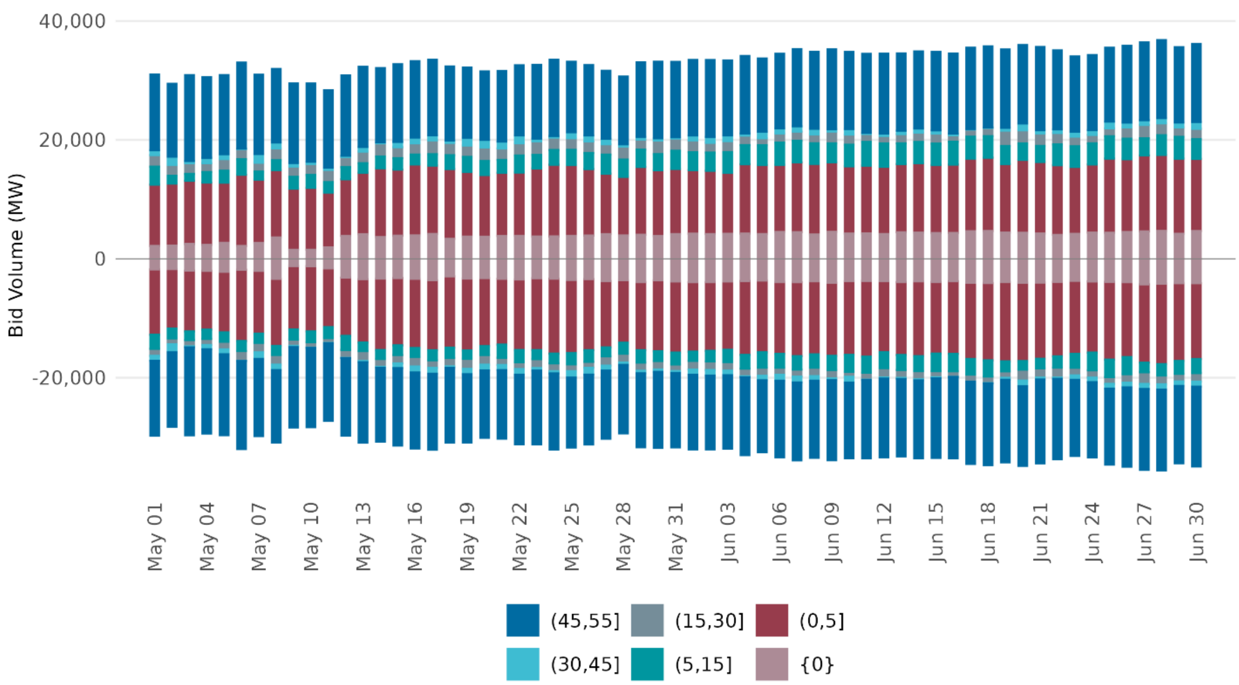


Figure 47: Hourly average volume of IR bids organized by fuel type for CAISO

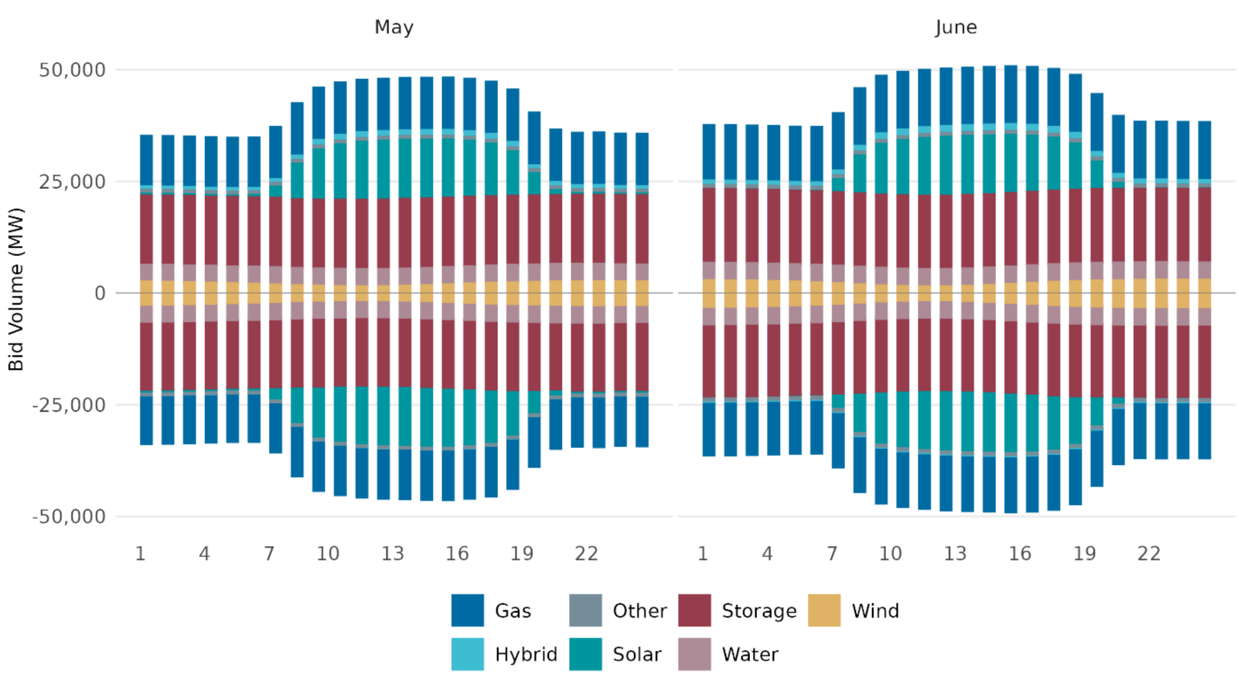


Figure 48: Daily average volume of IR bids organized by fuel type for CAISO

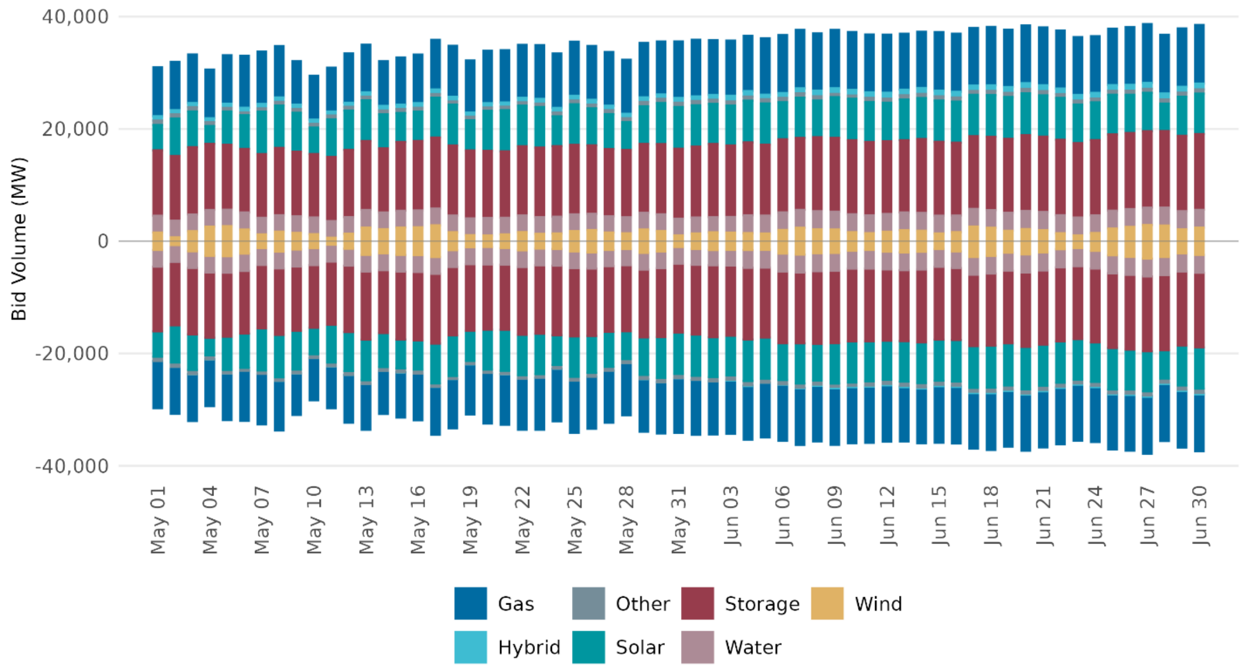


Figure 49 to Figure 52 illustrate the PACW's hourly and daily average IFM supply input bids for IR by bid price range and by fuel type. The price ranges are distributed across price ranges (0–5 $/MWh) and (5–15 $/MWh), and (45–55 $/MWh) with about 900 MW, and the remaining price range (15–30 $/MWh) represented a relatively small share of total submitted capacity. Water, gas, and wind accounted for the PACW's submitted IR capacity throughout May and June. 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 June.

Figure 49: Hourly average volume of IR bids organized by price for PACW

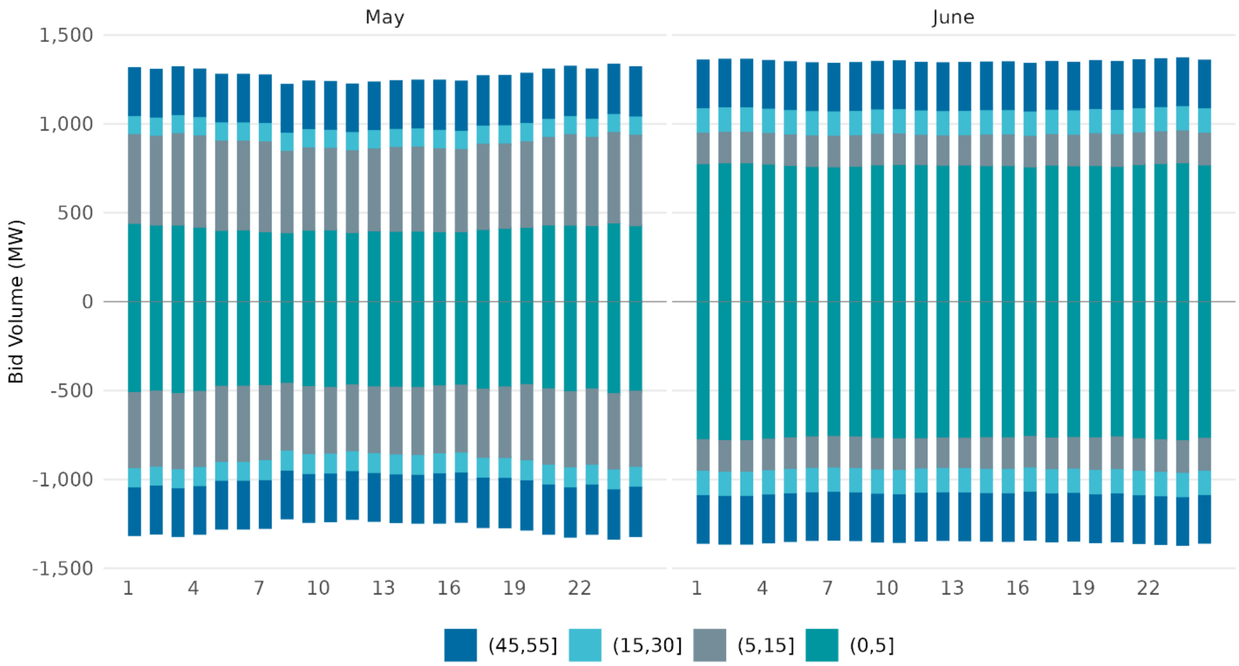


Figure 50: Hourly average volume of IR bids organized by fuel type for PACW

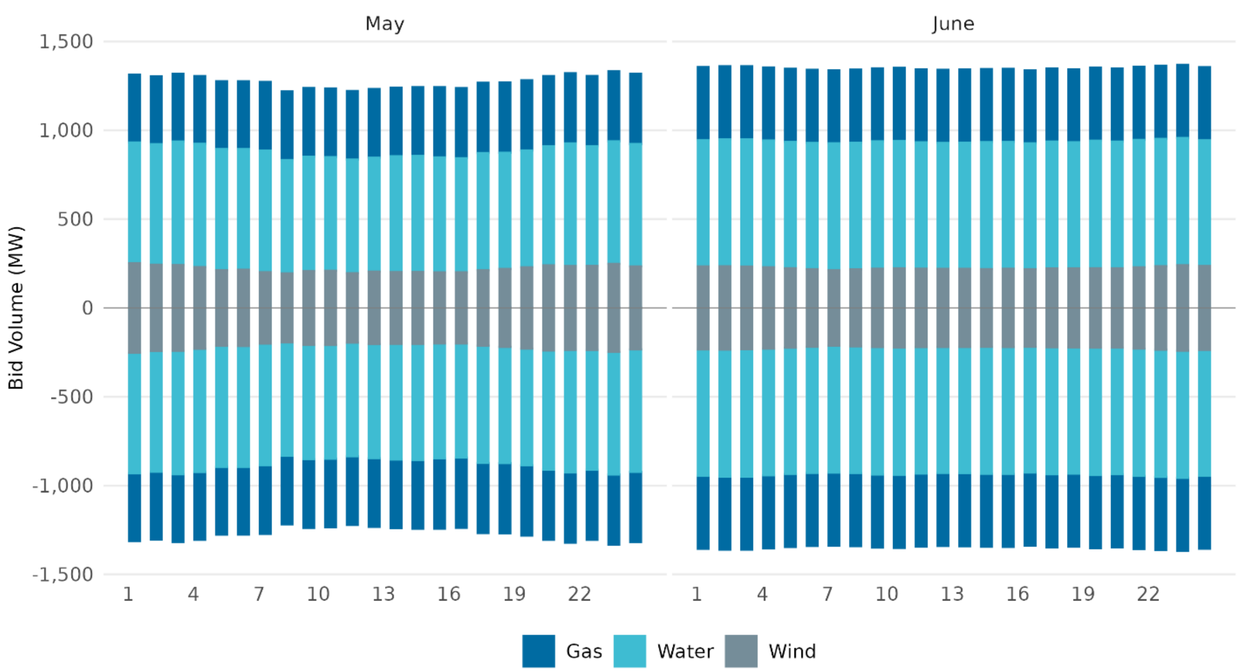


Figure 51: Daily average volume of IR bids organized by price by PACW

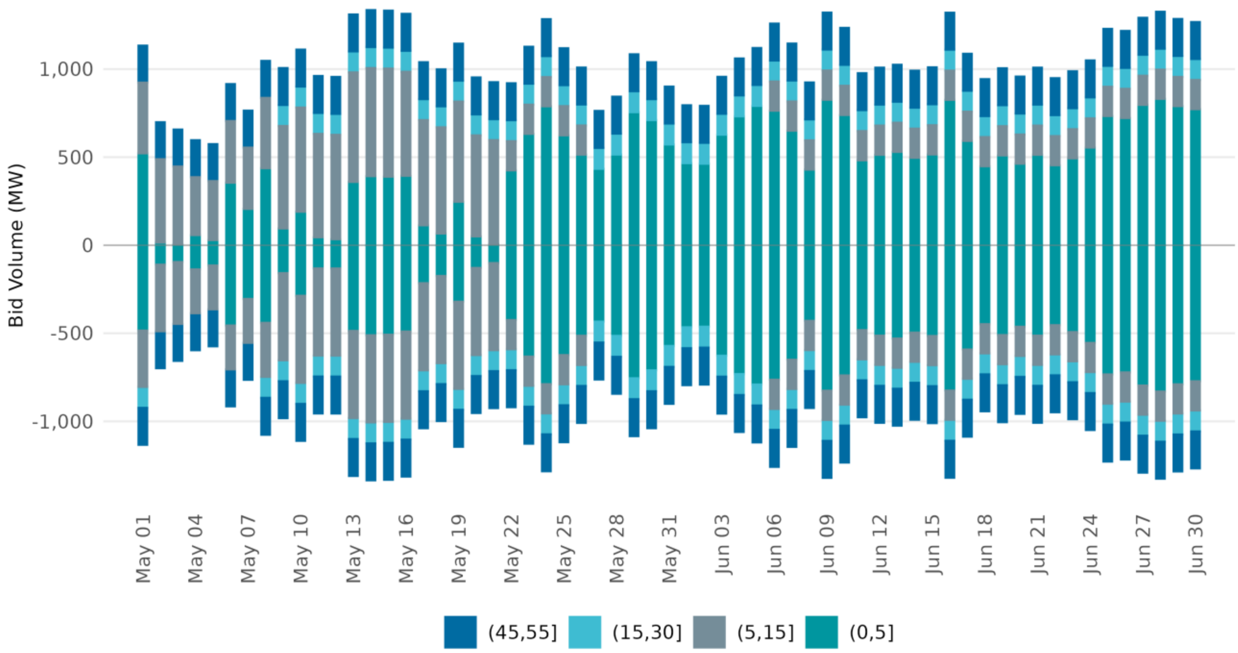


Figure 52: Daily average volume of IR bids organized by fuel type for PACW

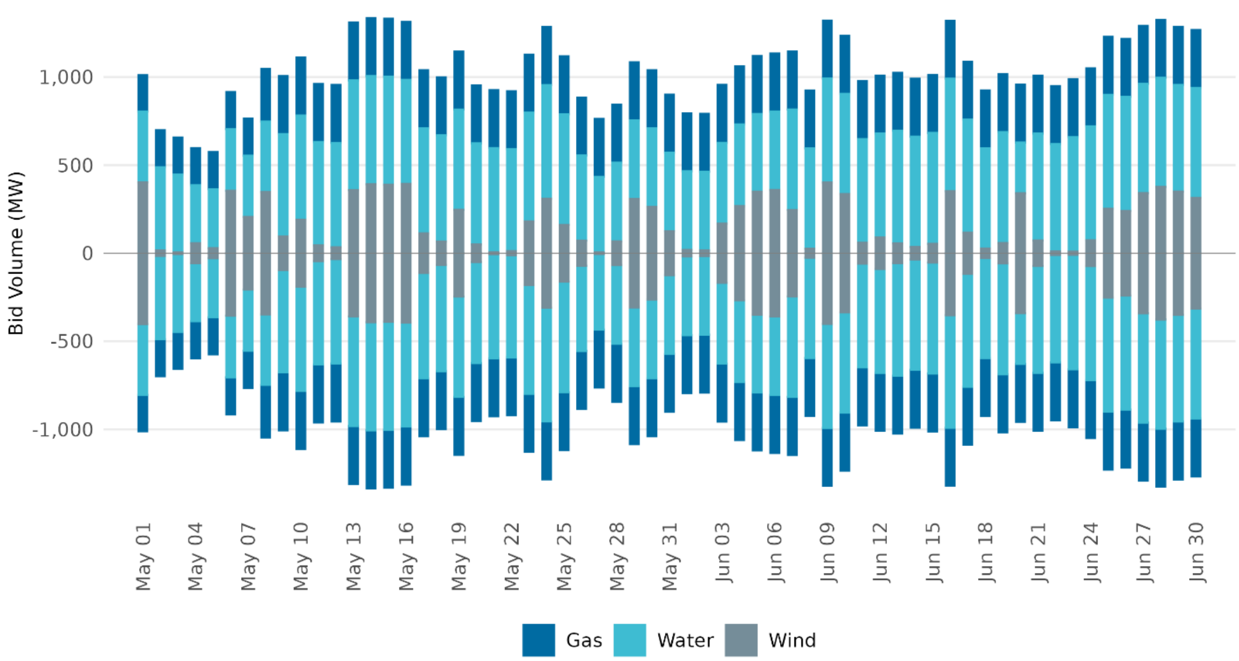


Figure 53 to Figure 56 illustrate the PACE's hourly and daily average IFM supply input bids for IR by bid price range. Low-priced bids ($0–5/MW) consistently accounted for the largest share of submitted IR capacity throughout the month with about 3,000 MW (or 90 percent), followed by bids in the 45–55 $/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 and June, 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 54 and Figure 56 illustrate PACE's hourly and daily average IFM supply input bids for IR by fuel type. Wind and coal accounted for the largest share of PACE's submitted IR capacity throughout May and June, followed by gas and storage resources.

Figure 53: Hourly average volume of IR bids by price for PACE

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

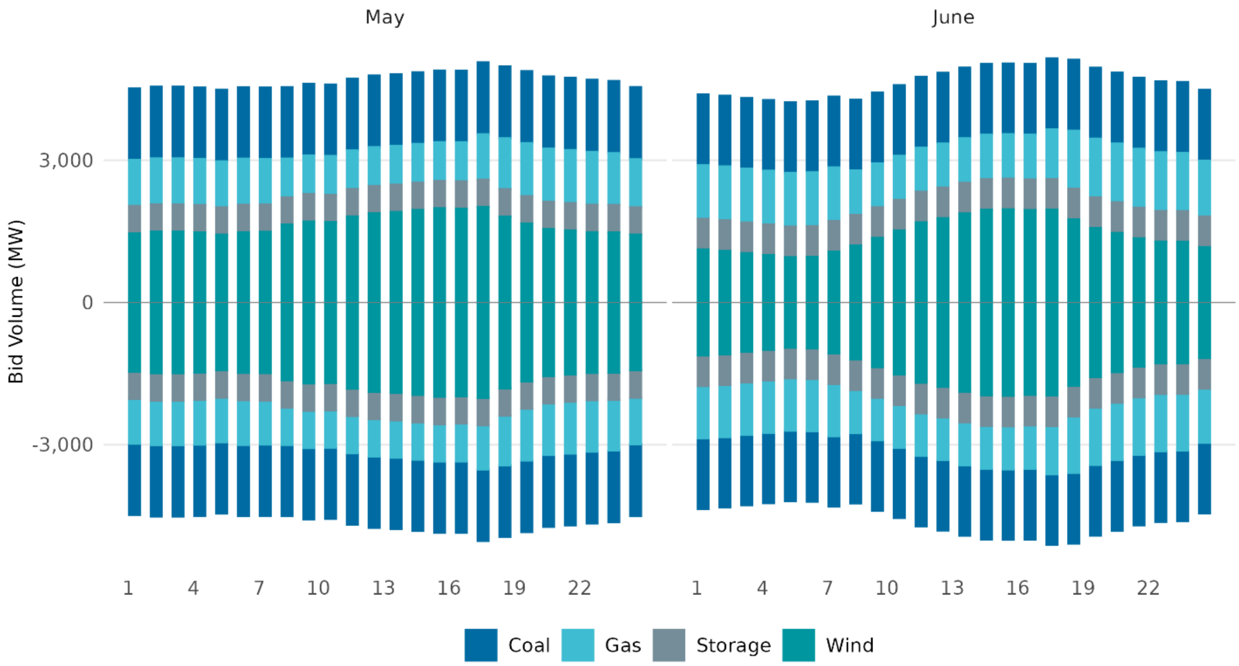


Figure 55: Daily average volume of IR bids by price for PACE

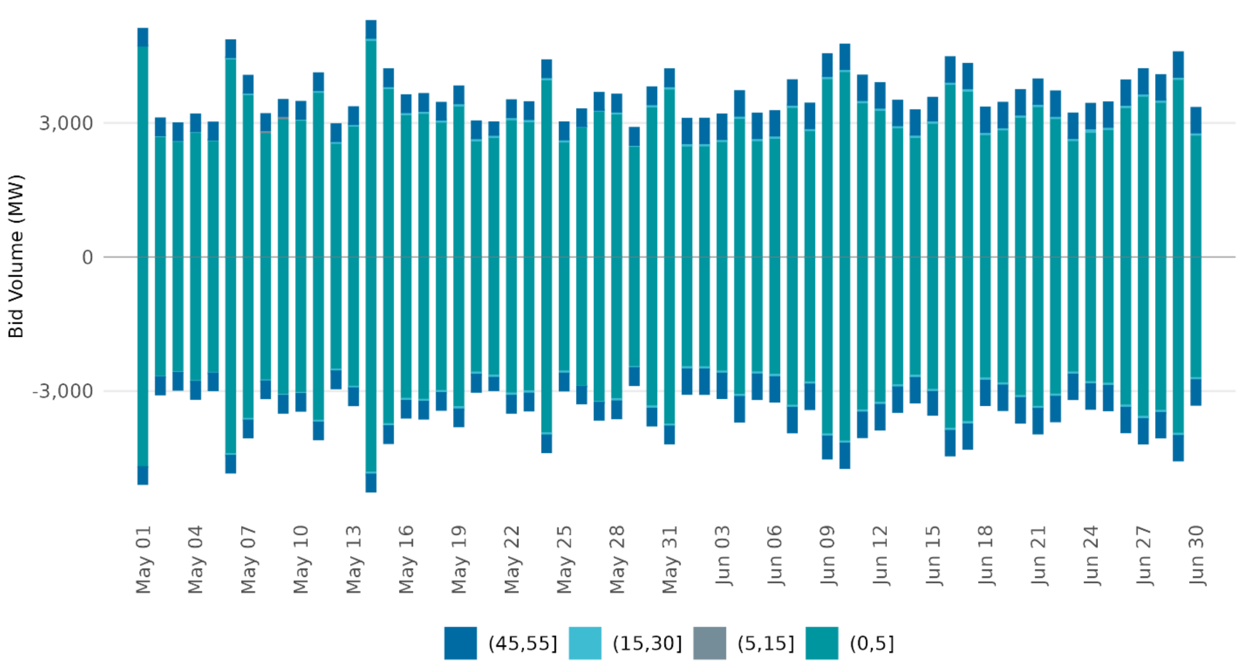
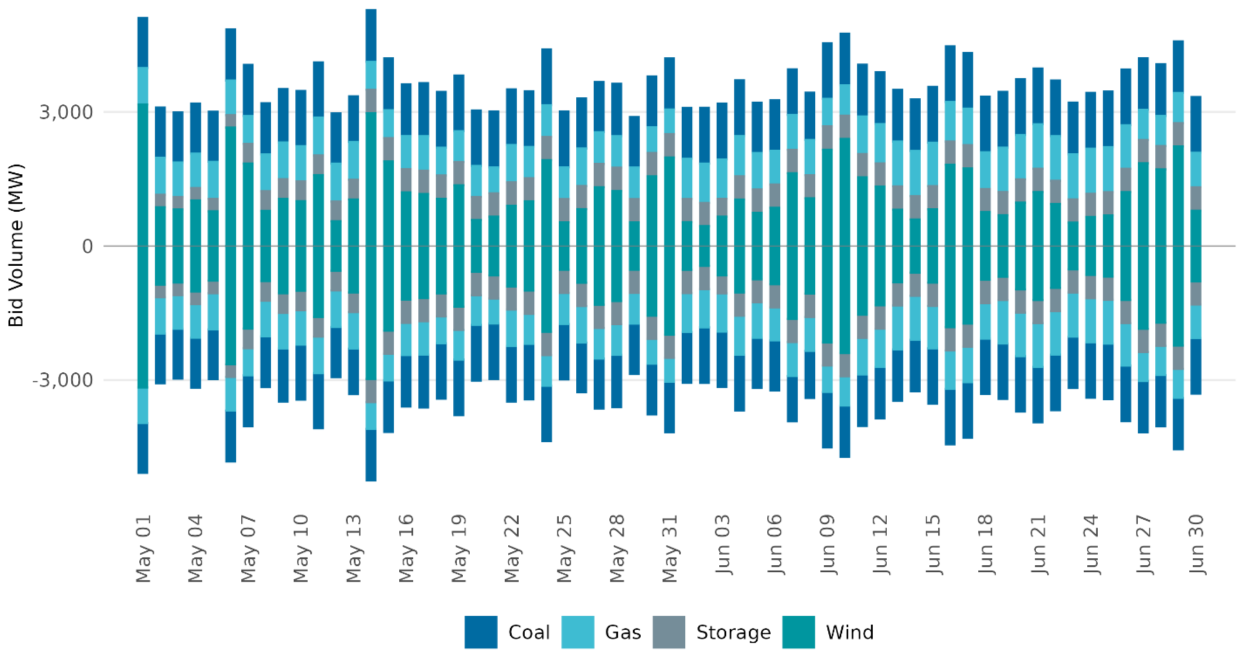


Figure 56: Daily average volume of IR bids by fuel type for PACE



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 June 2026, CAISO did not relax the IR requirements. PACE had demand curve procurement in the upward direction for 3 hours over two days. PACW had demand curve procurement in the downward direction for 1 hour on one day. Hourly averages of demand curve procurements are shown in Figure 57 and 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 57: Average imbalance reserve demand curve procurement, IRU

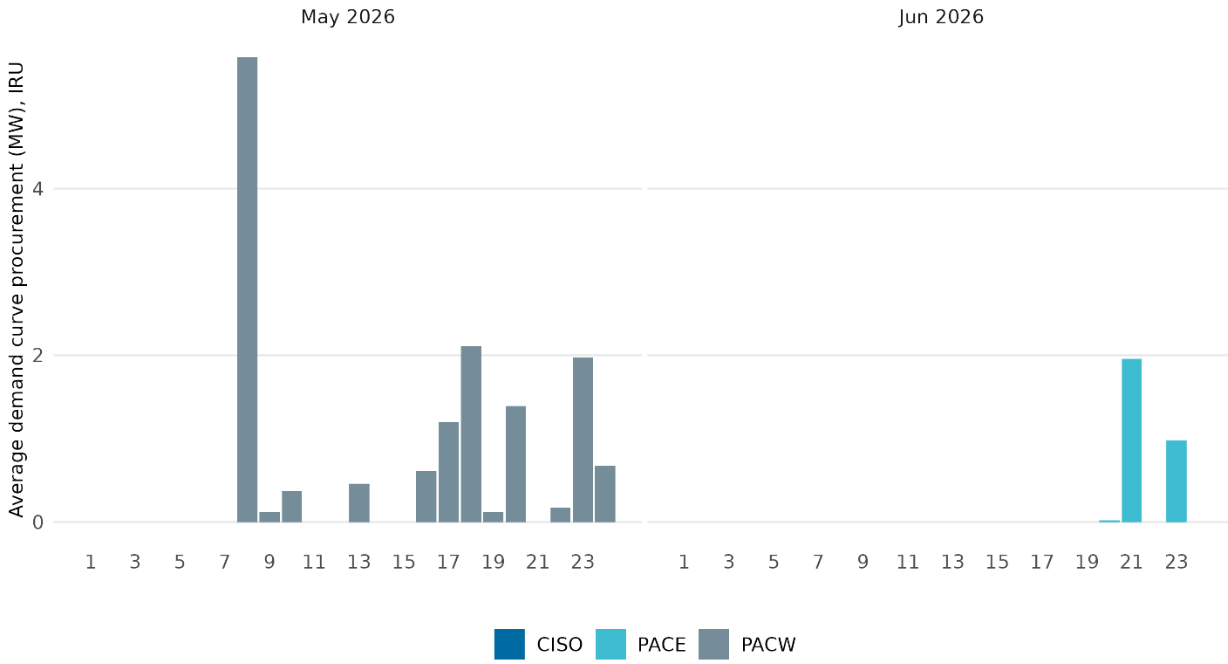


Figure 58 Average imbalance reserve demand curve procurement, IRD

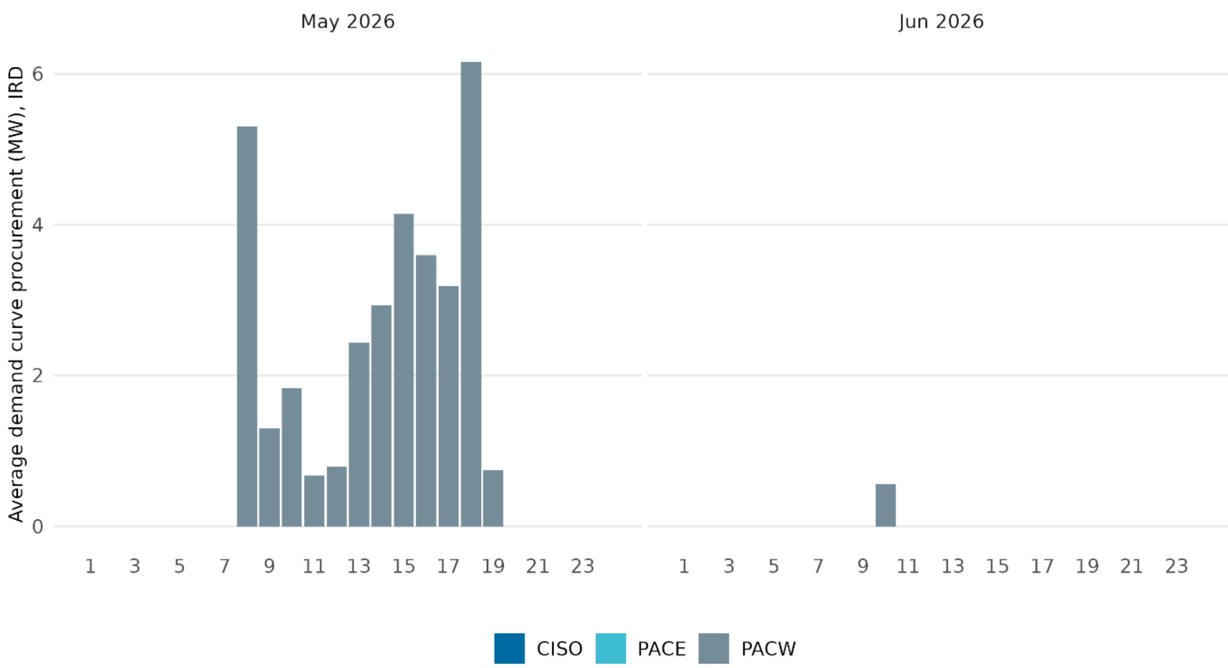


Figure 59 and Figure 61 show the hourly average net demand by EDAM BAA in May and June. Net demand is derived from demand forecast, net solar and wind forecast. The figures overlay hourly average IR procurement and requirement, for both up and down directions, and hourly average FMM net load uncertainty, on the net demand profile by BAA. Procurement reflects internal capacity procurement net BAA imbalance reserve transfer. 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. Overlaying the FMM net load certainty shows how the average uncertainty falls within the envelope of flexible capacity created by the imbalance reserve products.

Figure 59: Average net demand with imbalance reserve procurement, CISO

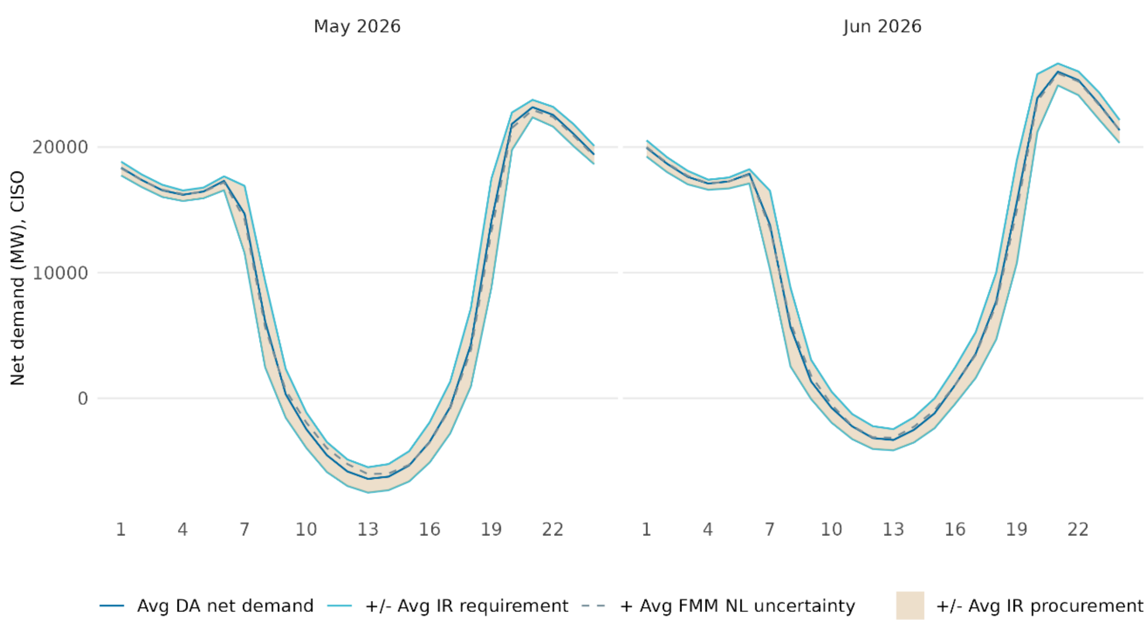


Figure 60: Average net demand with imbalance reserve procurement, PACE

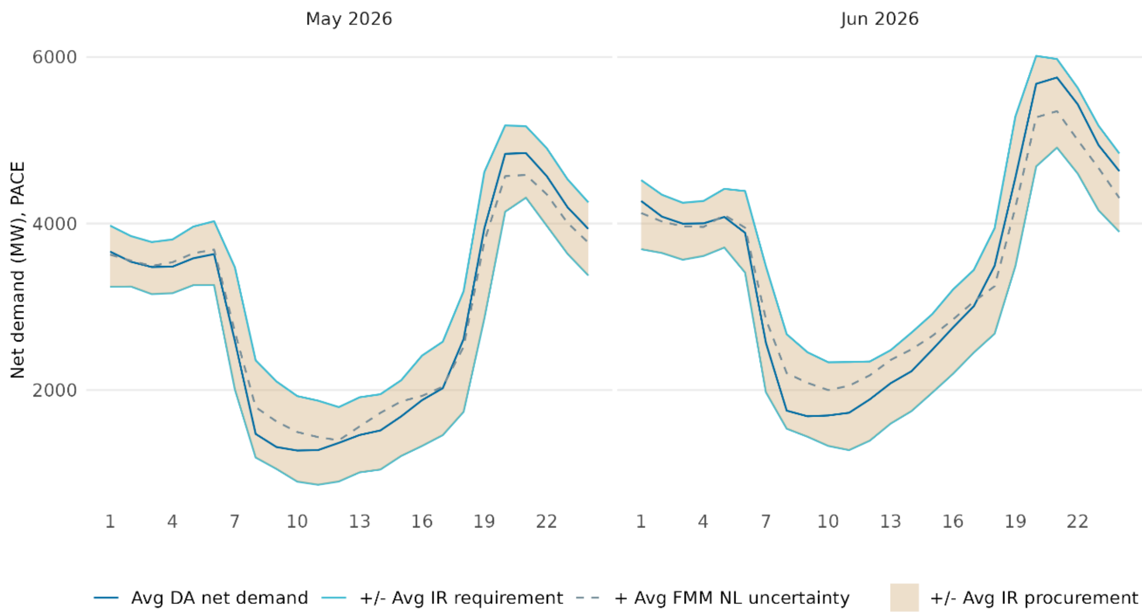


Figure 61: Average net demand with imbalance reserve procurement, PACW

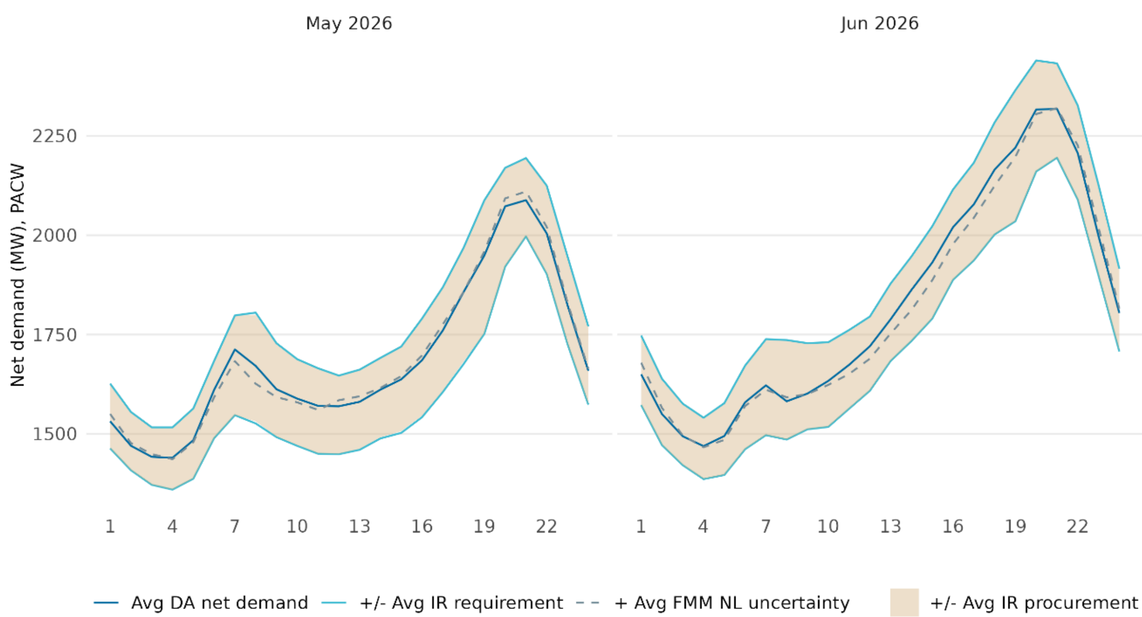


Figure 62 to
Figure 64 illustrate for each EDAM BAA, average available capacity in the fifteen-minute market corresponding to day-ahead imbalance reserve awards in stacked bar, breaking down by average utilized and un-utilized capacity in both upward and downward directions. Average day-ahead imbalance reserve requirements and procurements from internal

resources are included as reference. Internal procurement reflects the aggregated imbalance reserve awards within each BAA, to satisfy its own requirements and imbalance reserve transfer schedules. Hourly average upward and downward net load uncertainties are also included. Net load uncertainty is derived from the net load changes from day-ahead to fifteen-minute market. Real-time availability generally aligns with day-ahead procurement for all EDAM BAAs. Utilized capacity is relatively small comparing to available capacity and realized net load uncertainty, indicating that other resources in the system provided the capacity to meet the remaining uncertainty.

Figure 62: Hourly average IR requirement, procurement, and utilization, CISO

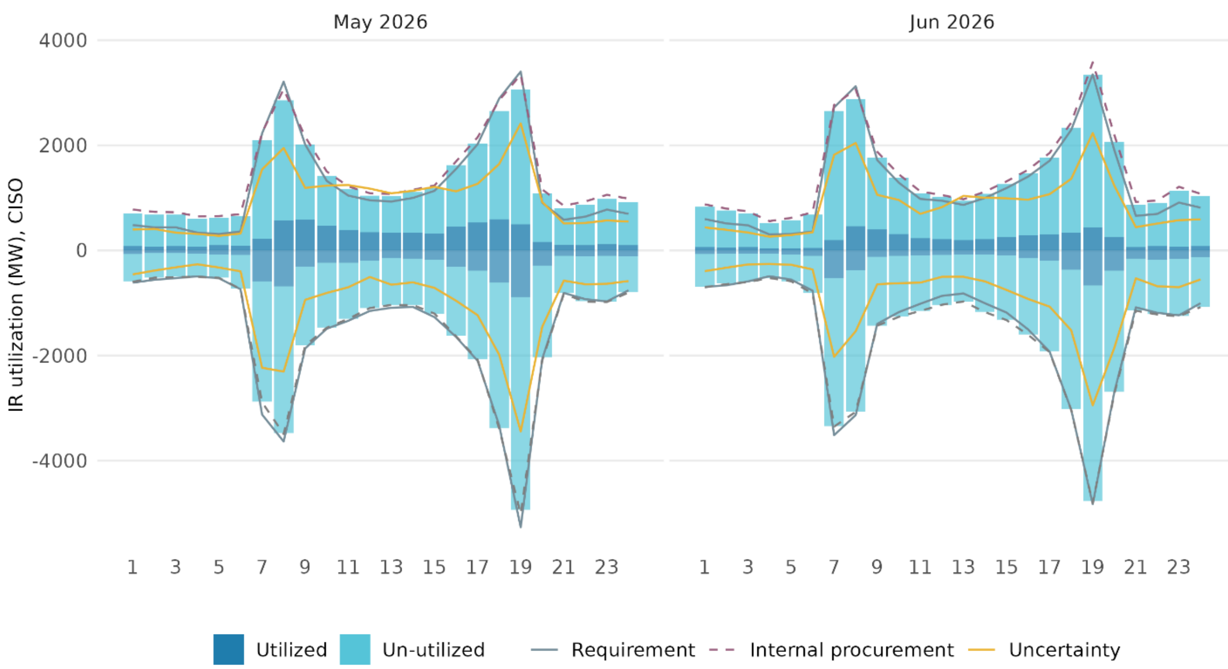


Figure 63: Hourly average IR requirement, procurement, and utilization, PACE

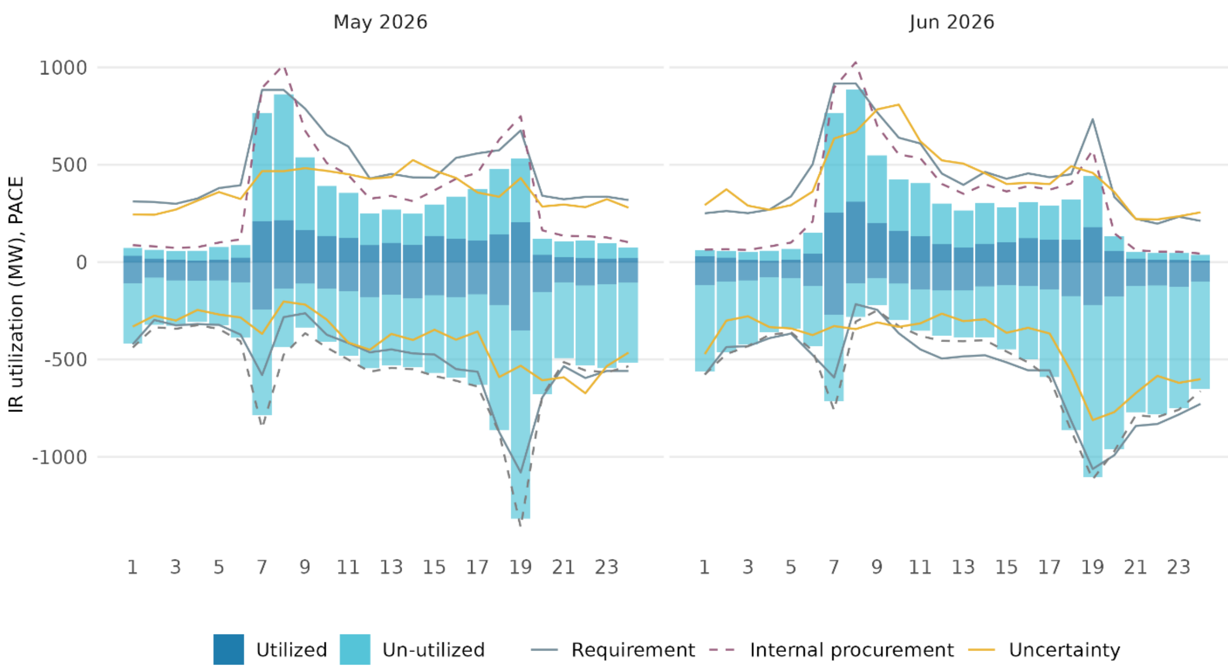
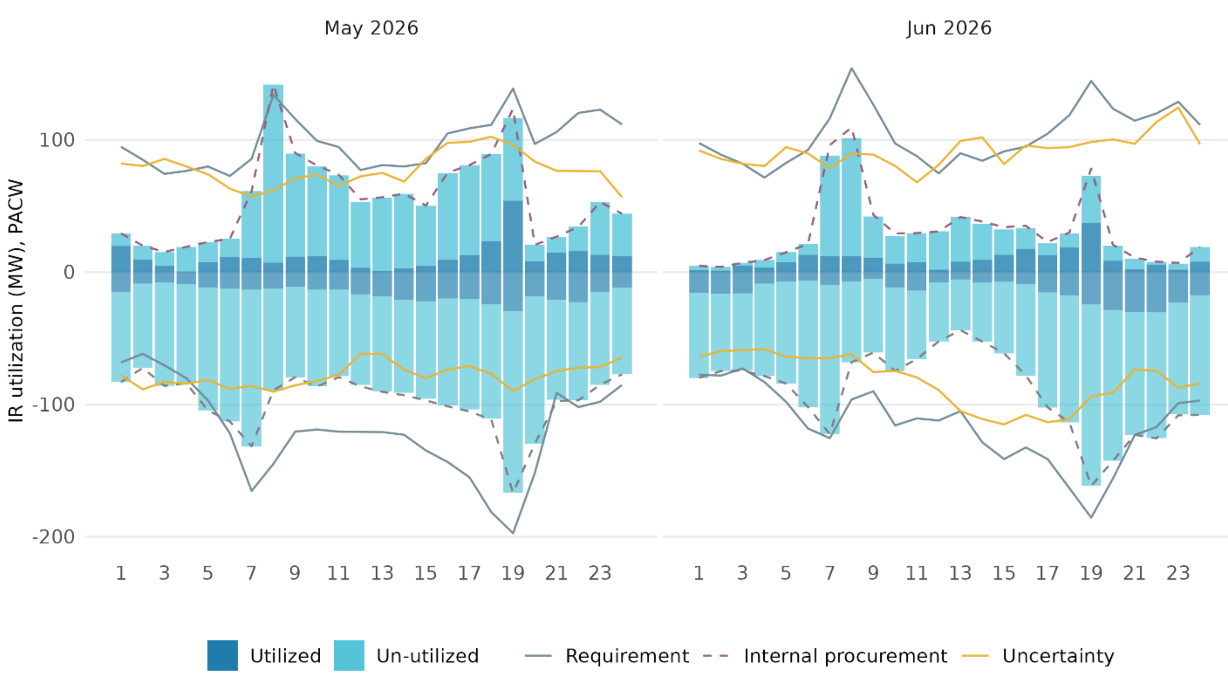


Figure 64: Hourly average IR requirement, procurement, and utilization, PACW



EDAM resources receiving imbalance reserve awards in the day-ahead market will have bidding obligations in the real time market. Figure 65 and

Figure 66 show real time available capacity corresponding to IR awards in the EDAM footprint, expressed as a percentage of imbalance reserve procurement. In the upward direction, over 80 percent of the IR capacity has been made available in the real time market in all hours. In the downward direction, the availability exceeds 95 percent majority of the time.

Figure 65: Percentage IRU availability in FMM for EDAM footprint

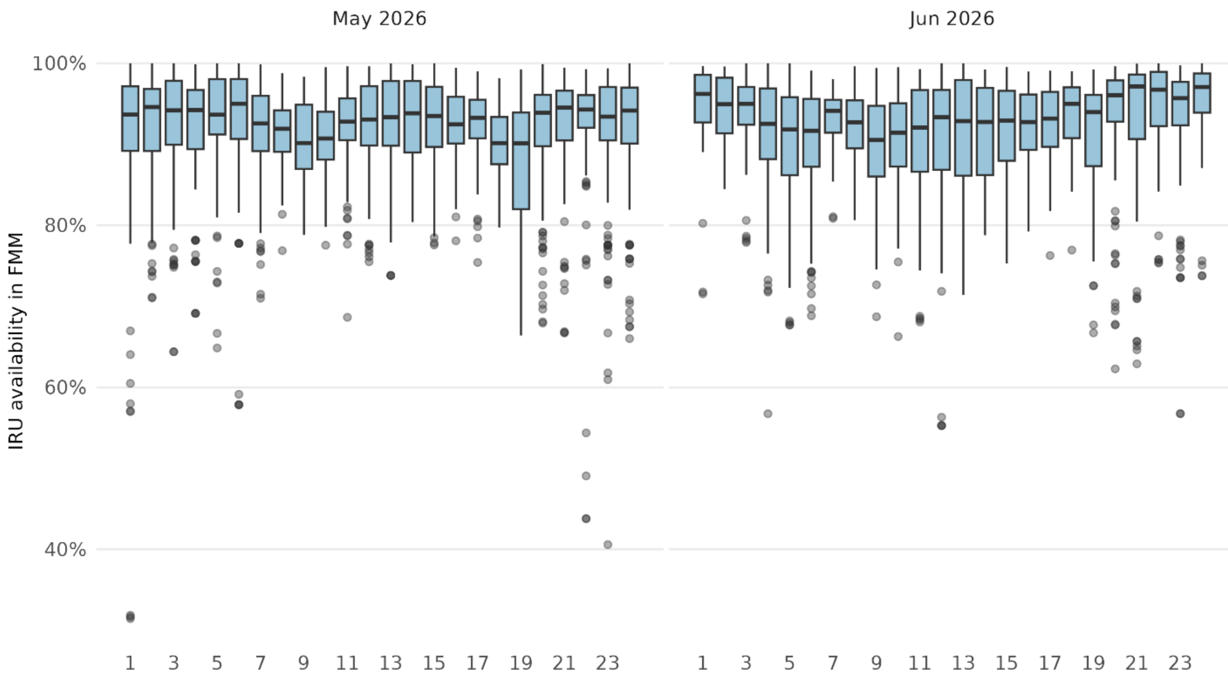


Figure 66: Percentage IRD availability in FMM for EDAM footprint

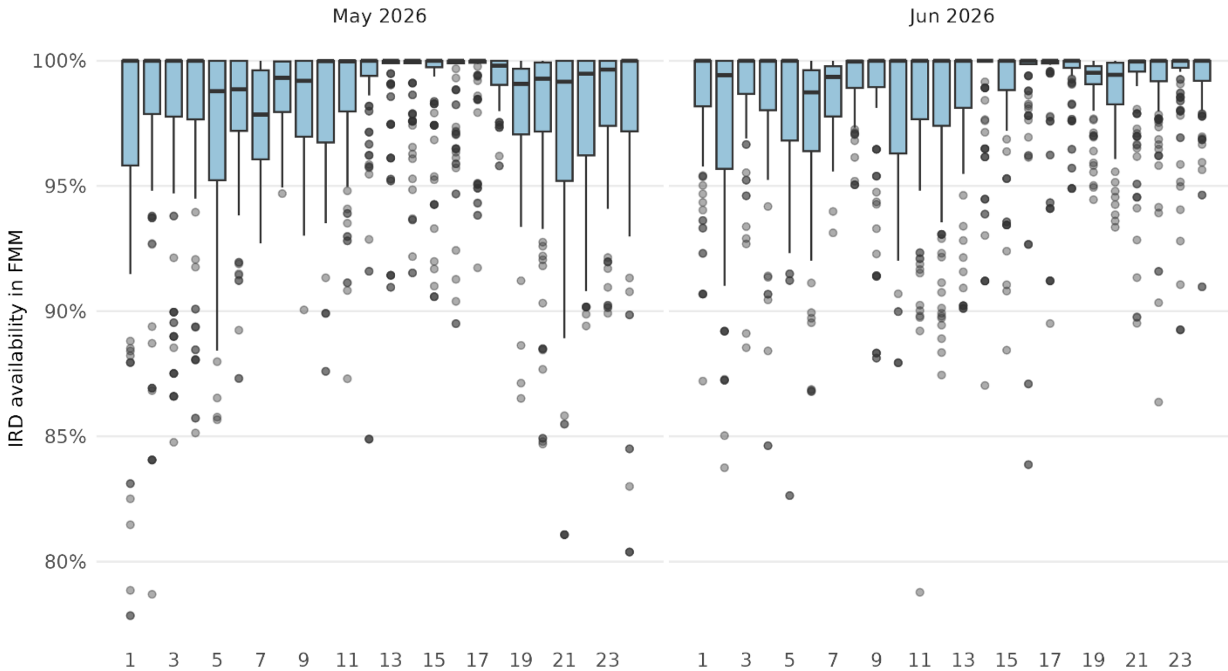


Figure 67 and Figure 68 show the hourly distributions of the utilized imbalance reserve up and down volumes, in the EDAM footprint in FMM. The utilization trends follow the shape of the imbalance reserve requirements, higher in the morning and evening peak hours for both up and down directions.

Figure 67: Hourly IR up utilization distribution in EDAM footprint

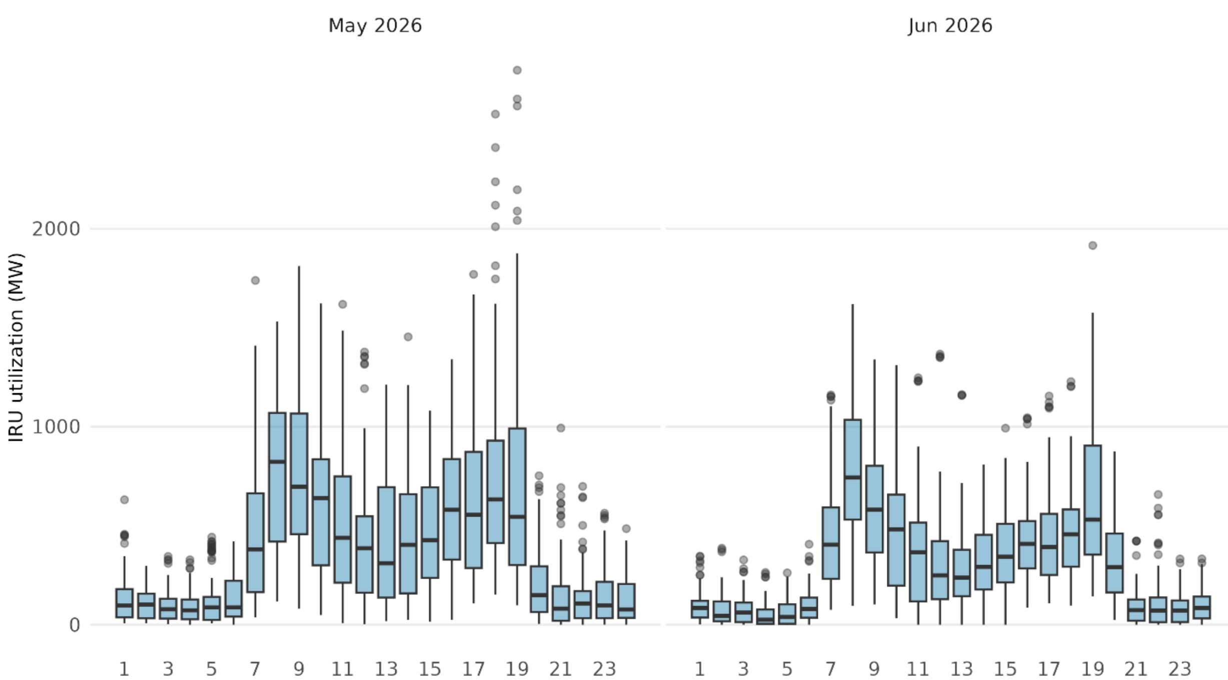
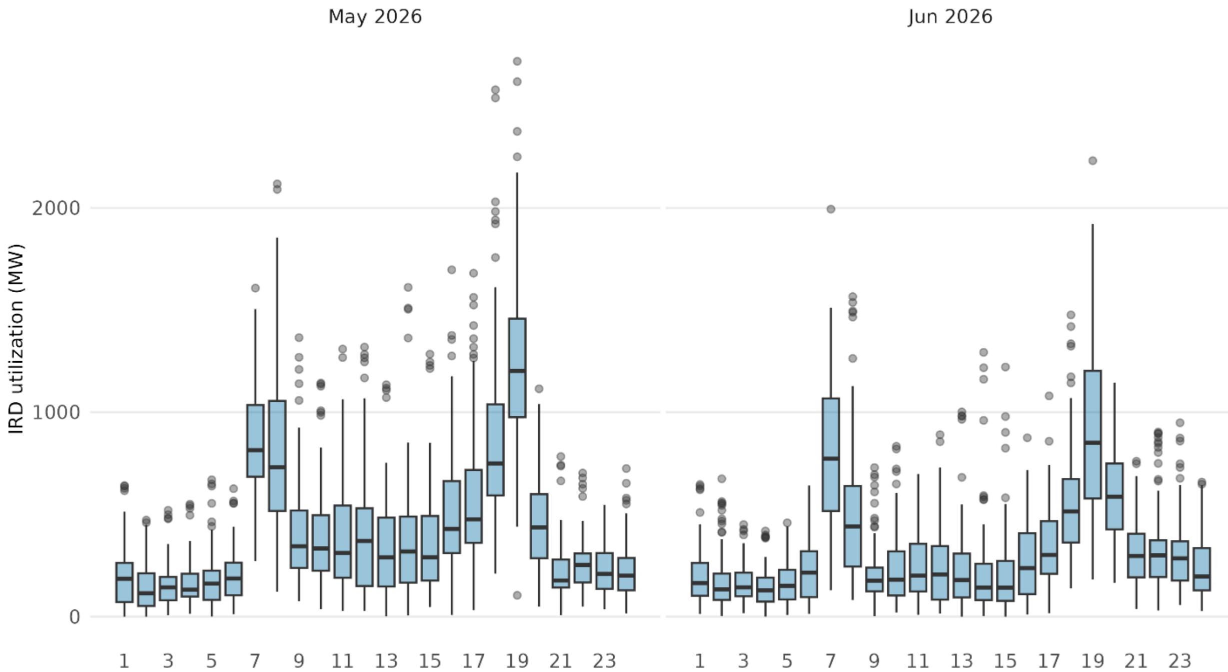


Figure 68: Hourly IR down utilization distribution in EDAM footprint



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 69 to Figure 70. The average daily profile is shown in Figure 69, while the average hourly profile is shown in Figure 70. The mean monthly prices are shown in

Table 8.

Overall, prices for reliability capacity decreased considerably in June compared to May as shown in

Table 8. For PACW, the mean monthly RCU price in June was negative. Prices for CAISO and PACW were more volatile than for PACE in June. In CAISO, the highest daily mean price for RCU was 12.37 \$/MWh on June 18th while the lowest was -42.53 \$/MWh on June 7th. In PACW, the highest daily mean RCU price was 4.11 \$/MWh on June 14th and the lowest was -12.46

$/MWh on June 15th. Meanwhile for PACE, the highest daily mean RCU price was 4.64 $/MWh on June 17th and the lowest was -0.48 $/MWh on June 15th. Negative reliability capacity prices have been observed on a few occasions as discussed in the Market Issues section. On June 7th the negative prices in CAISO occurred in hours ending 8 to 11. On an hourly basis, the trends were less consistent across BAAs. For CAISO and PACW, peak RCU prices on average occurred during the morning and evening peak hours. For PACE, the highest average hourly price was during the evening peak hour but not the morning 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 69: Daily average price of RCU

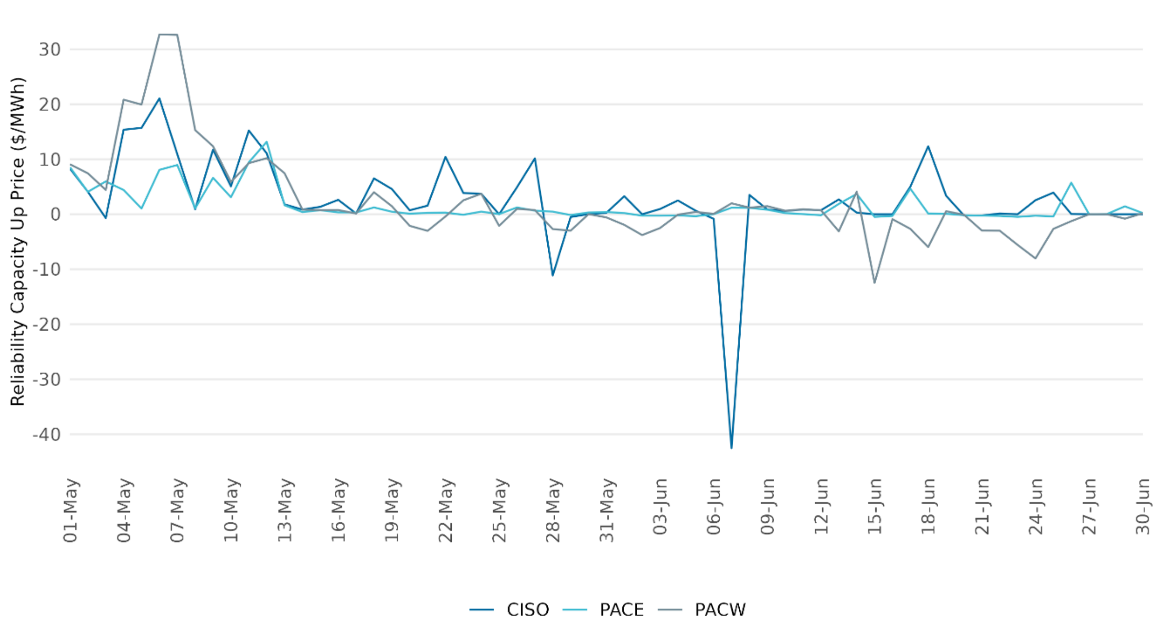


Figure 70: Hourly average price of RCU

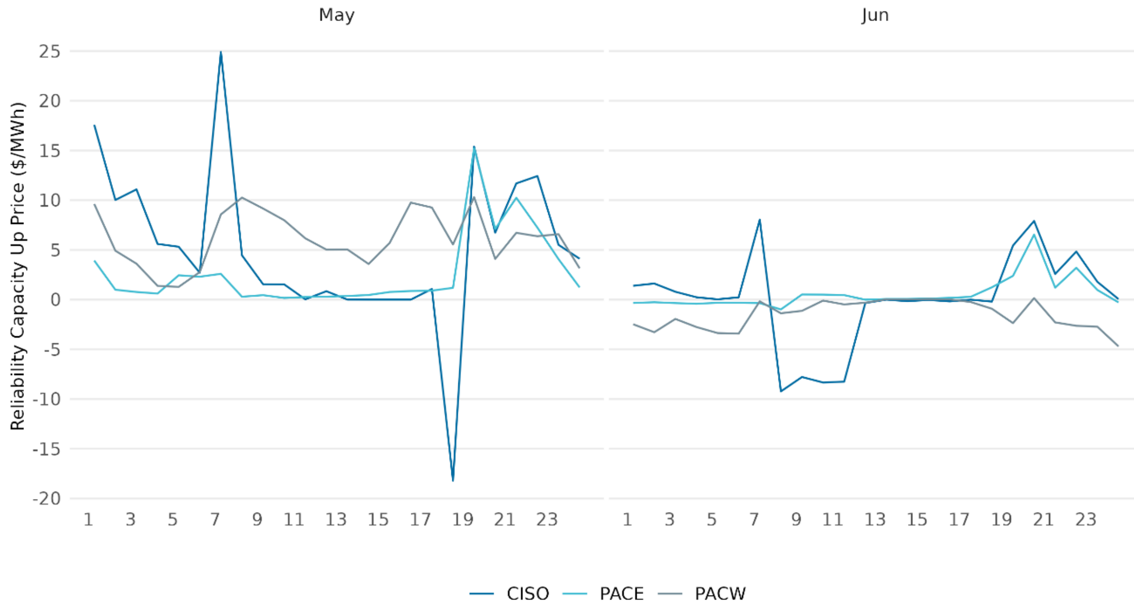


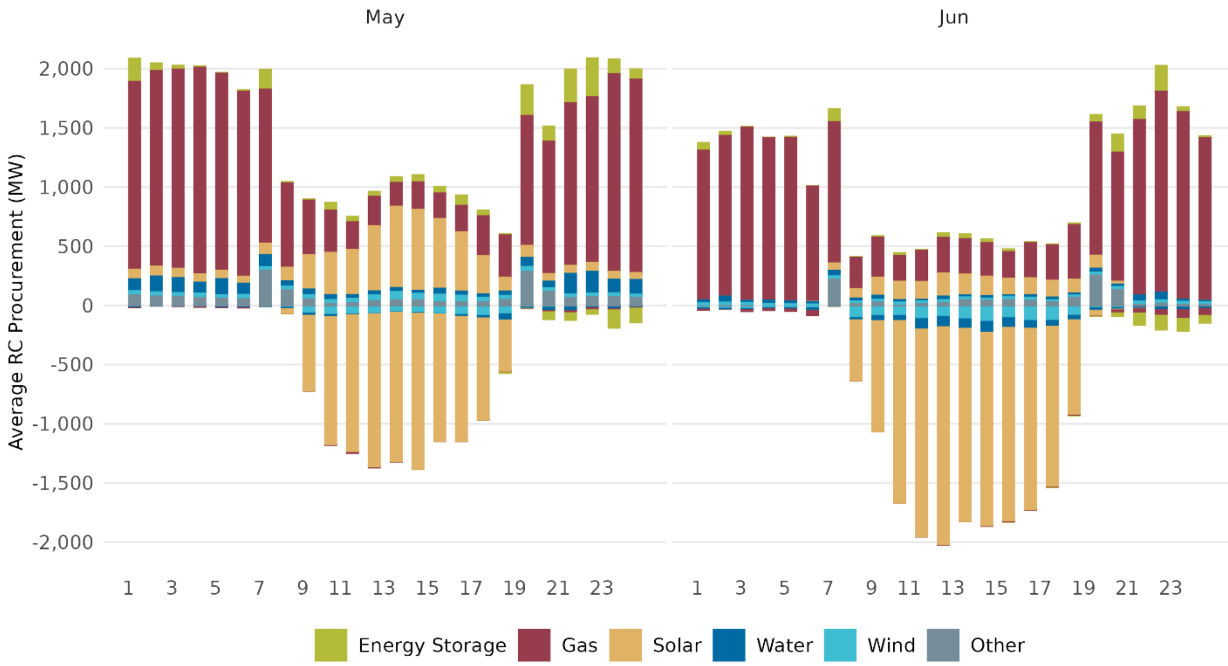
Table 8: Mean RCU prices for May and June

	Mean RCU Price ($/MWh)	
BAA	May	June
CAISO	5.19	0.02
PACE	2.70	0.59
PACW	6.12	-1.51

Figure 71 to Figure 73 illustrate the hourly average by technology supporting the procurement for each BAA.

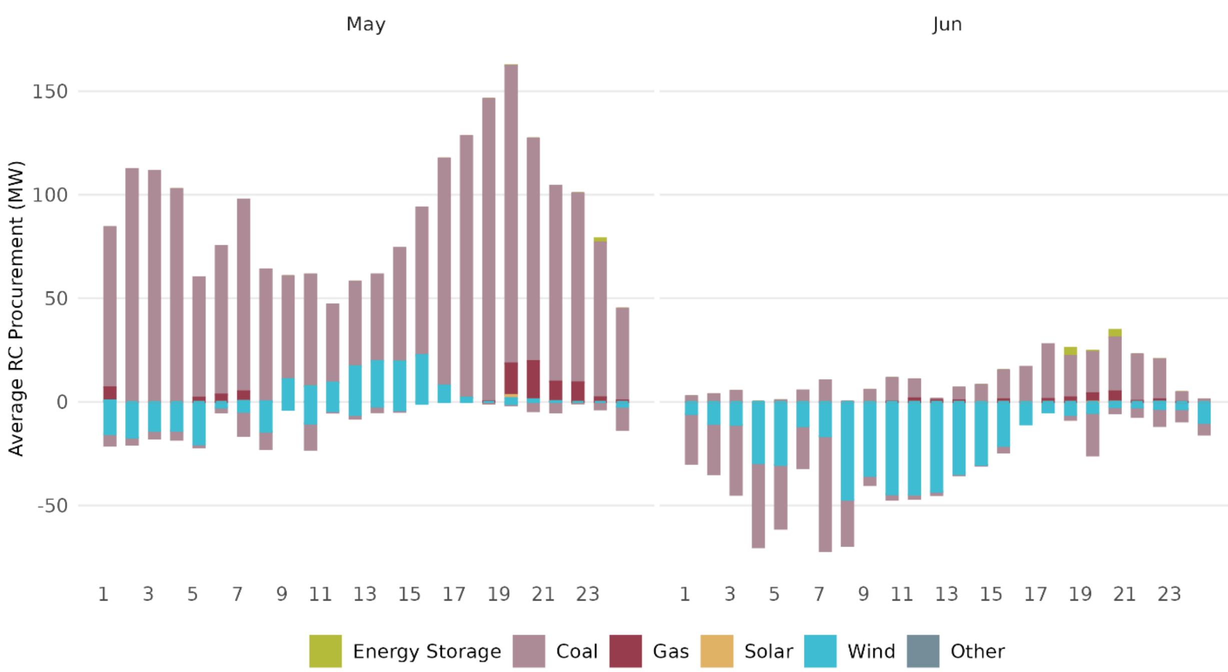
For CAISO, gas resources continue to make up the highest proportion (65 percent of the total) of RCU during non-solar hours. 87 percent of RCD is procured during solar hours by solar resources. The overall fuel mix for June was very similar to May, however the magnitude of RCU is down across the entire day with more RCD procured from solar on average.

Figure 71: Hourly average of RC procurement for CAISO



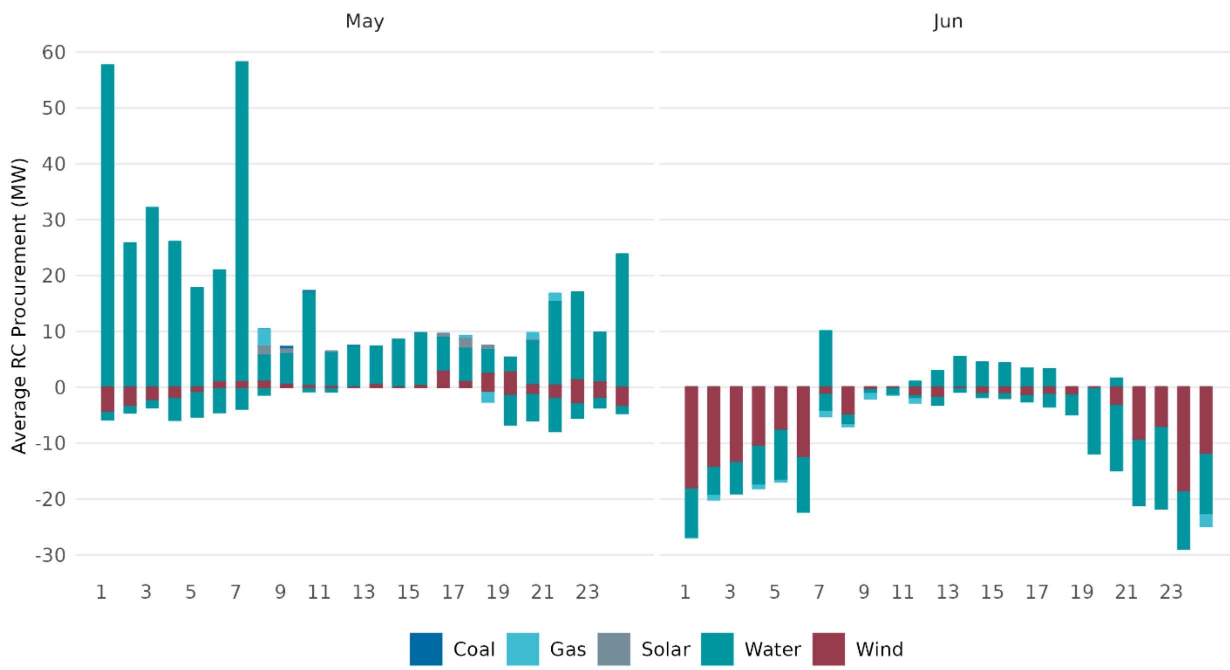
PACE reliability capacity is largely procured in the up direction and supplied primarily by coal and wind resources. In comparison to May, RCU procurement is down significantly. The average hourly RCU procurement for gas resources was 19MW in June in comparison to 72MW in May.

Figure 72: Hourly average of RC procurement for PACE



PACW RC is primarily supplied by hydro and wind resources. RCU procurement is down significantly from May with more RCD procurement, particularly in off-peak hours.

Figure 73: Hourly average of RC procurement for PACW



Reliability capacity input bids

Figure 74 and Figure 75 illustrate CAISO's hourly average volume of RC bids by bid price range and fuel type in May and June 2026, respectively. Zero-priced bids consistently accounted for the largest share of submitted RC capacity throughout May and June with about above 20,000 MW (or over 40 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 and solar resources accounted for approximately over 70 percent of the total. Generally, CAISO's submitted RC capacity remained slow growth from May to June, with only a few days exhibiting lower or higher bid volumes.

Figure 74: Hourly average volume of RC bids by price for CAISO

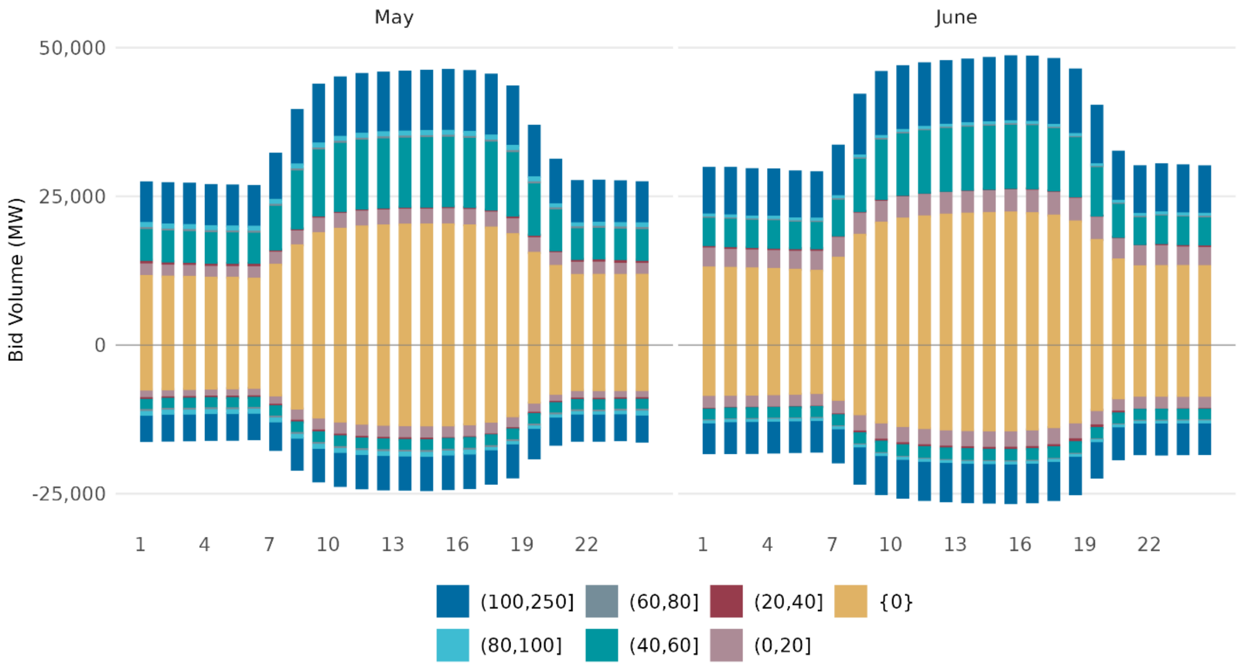


Figure 75: Hourly average volume of RC bids by fuel type by CAISO

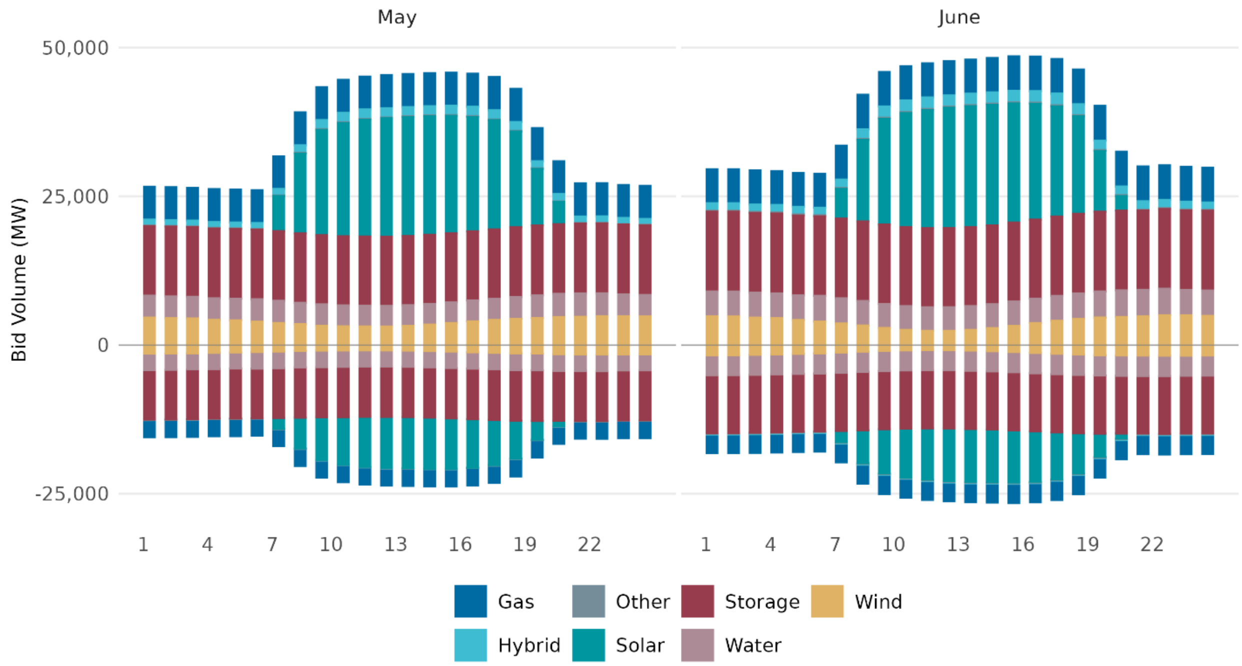


Figure 76 and and Figure 77 illustrate the CAISO's daily average volume of RC bids by bid price range and fuel type, respectively. Generally, CAISO's submitted RC capacity remained relatively stable during May and June, with only a few days exhibiting lower higher volumes. Gas, solar, and energy storage accounted for the largest share of RC bid volumes.

Figure 76: Daily average volume RC bids by price for CAISO

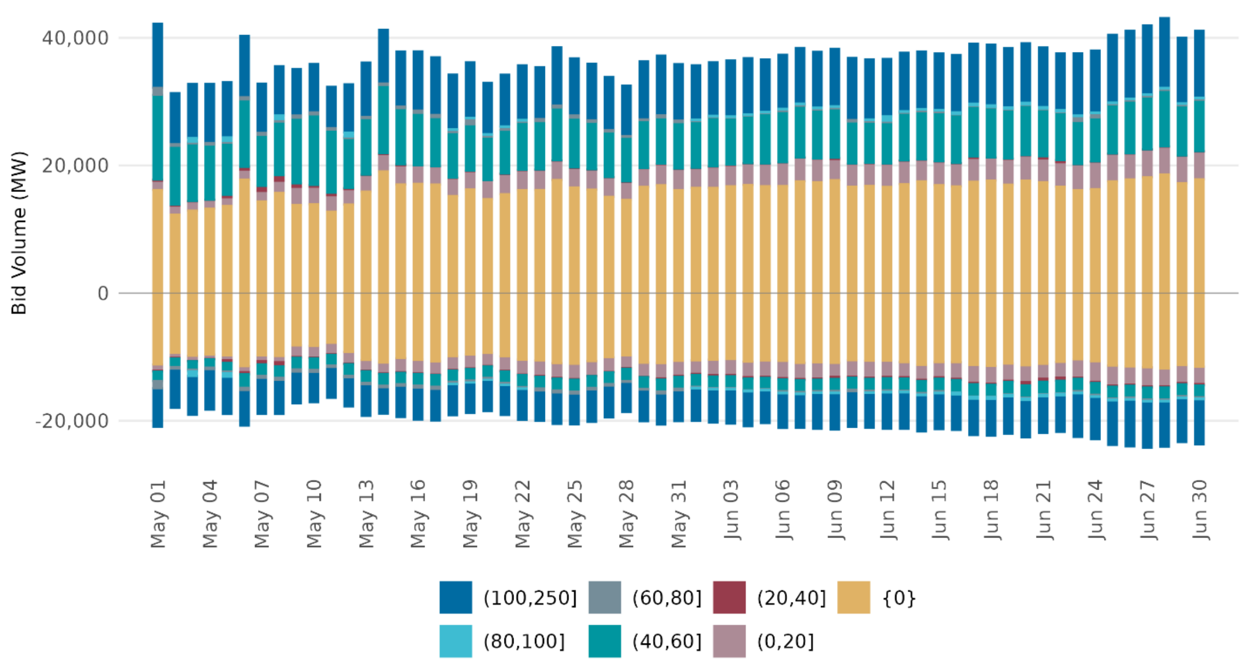


Figure 77: Daily average volume of RC bids by fuel type for CAISO

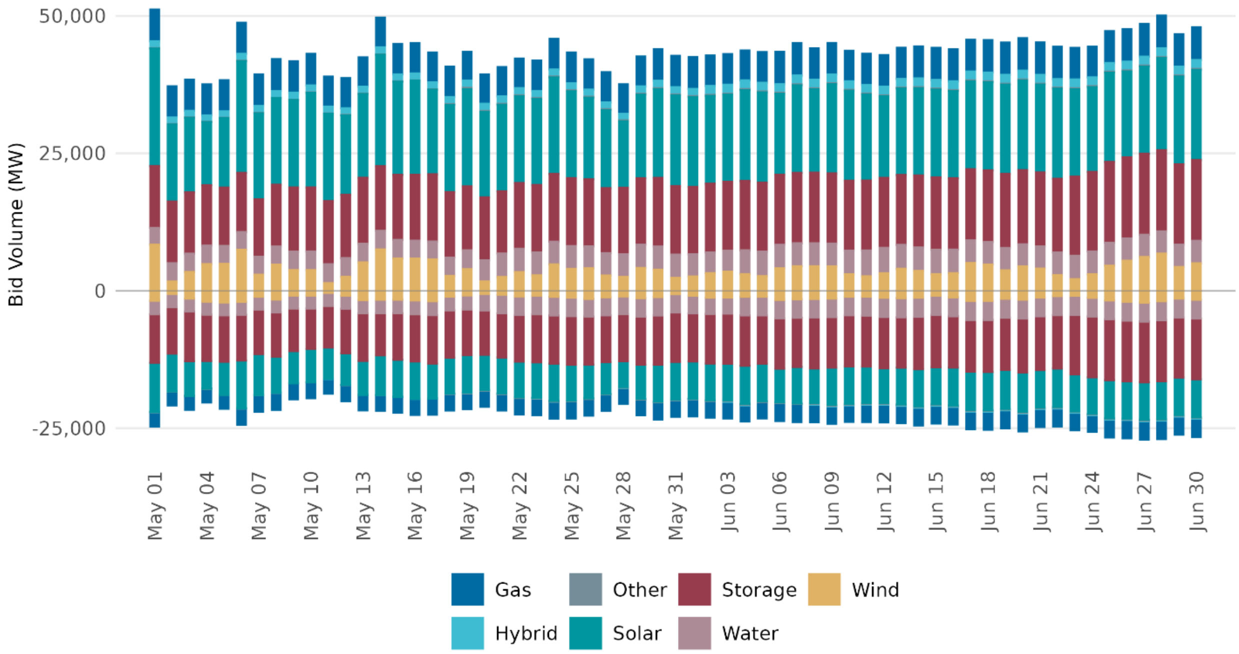


Figure 78 and Figure 79 illustrate PACW's hourly average volume of RC bids by price range and fuel type, respectively. Low-priced bids (0-20 $/MW) and moderate priced bids (40–60 $/MW) consistently accounted for the largest share of submitted RC capacity throughout the month with about 1,000 MW (or 90 percent of the total), followed by bids in the (100–250 $/MWh) range. It is noteworthy that in the down direction there are only low-priced bids submitted. Hourly bid volumes were slightly higher during daylight hours. Water and wind resources accounted for the largest share of submitted RC capacity, with some solar capacity bidding in RCU only. PACW's RCU bid volume is about 1,000 MW while RCD is only about 750 MW.

Figure 80 and Figure 81 illustrate PACW's daily average volume of RC bids. Generally, PACW's submitted RC capacity showed variations across both bid volumes and prices.

Figure 78: Hourly average volume of RC bids by price for PACW

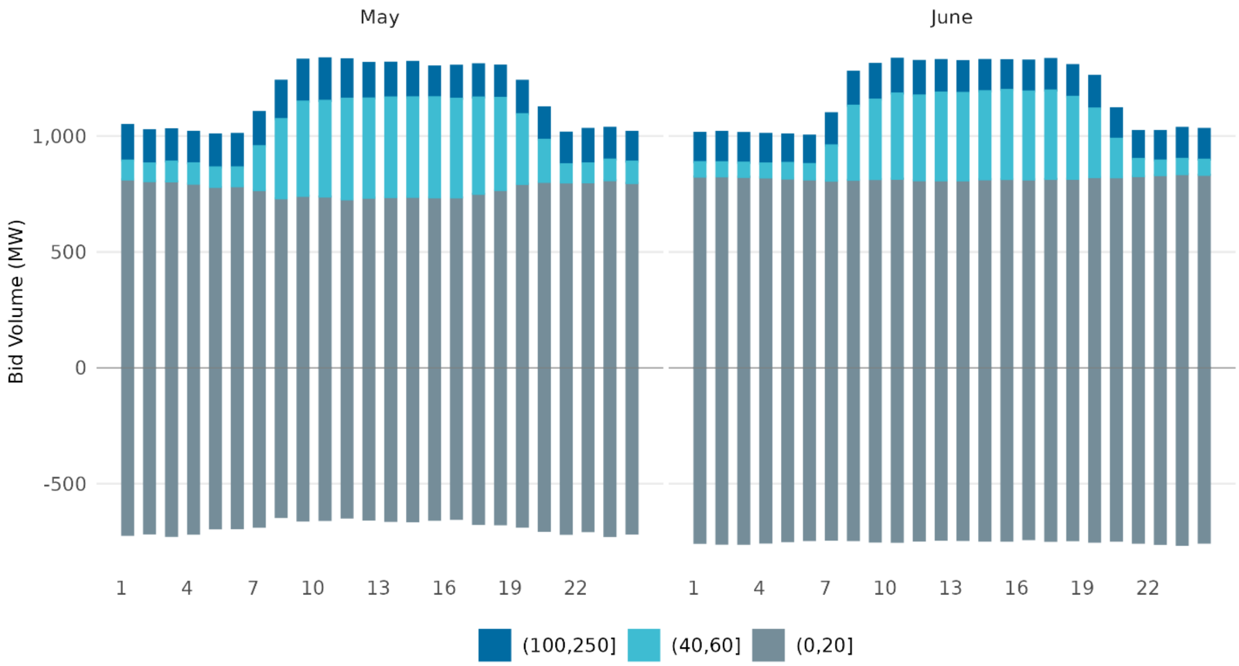


Figure 79: Hourly average volume of RC bids by fuel type for PACW

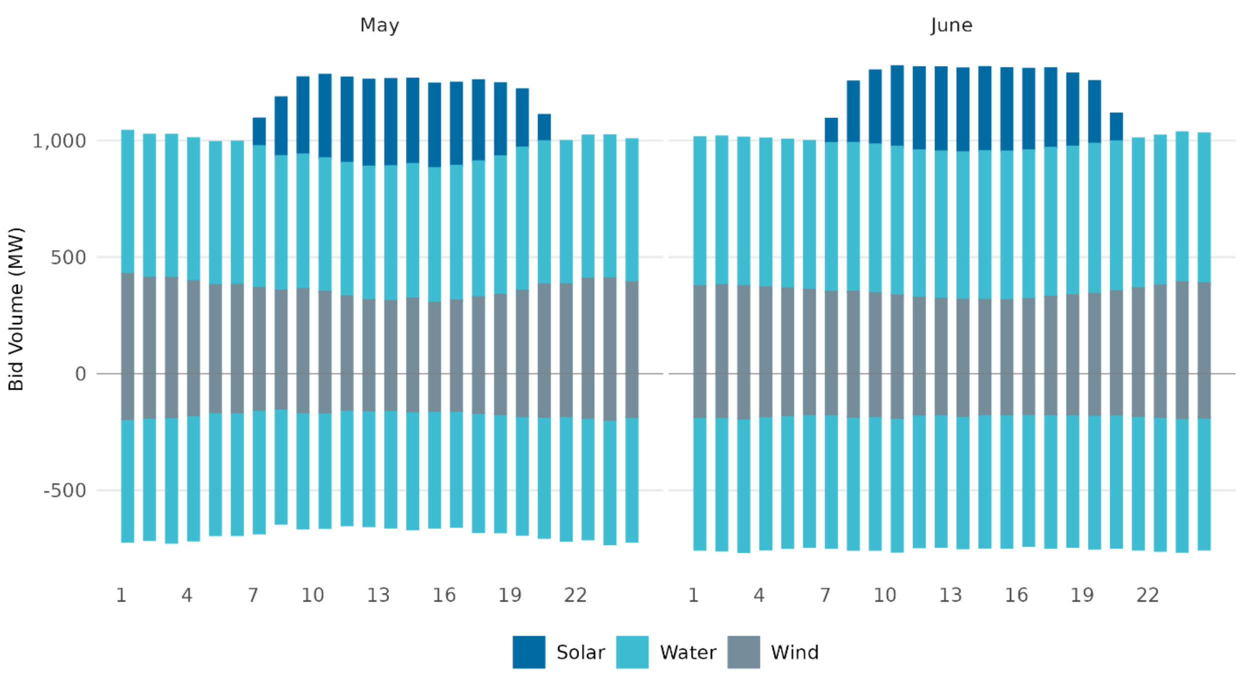


Figure 80: Daily average volume of RC bids by price for PACW

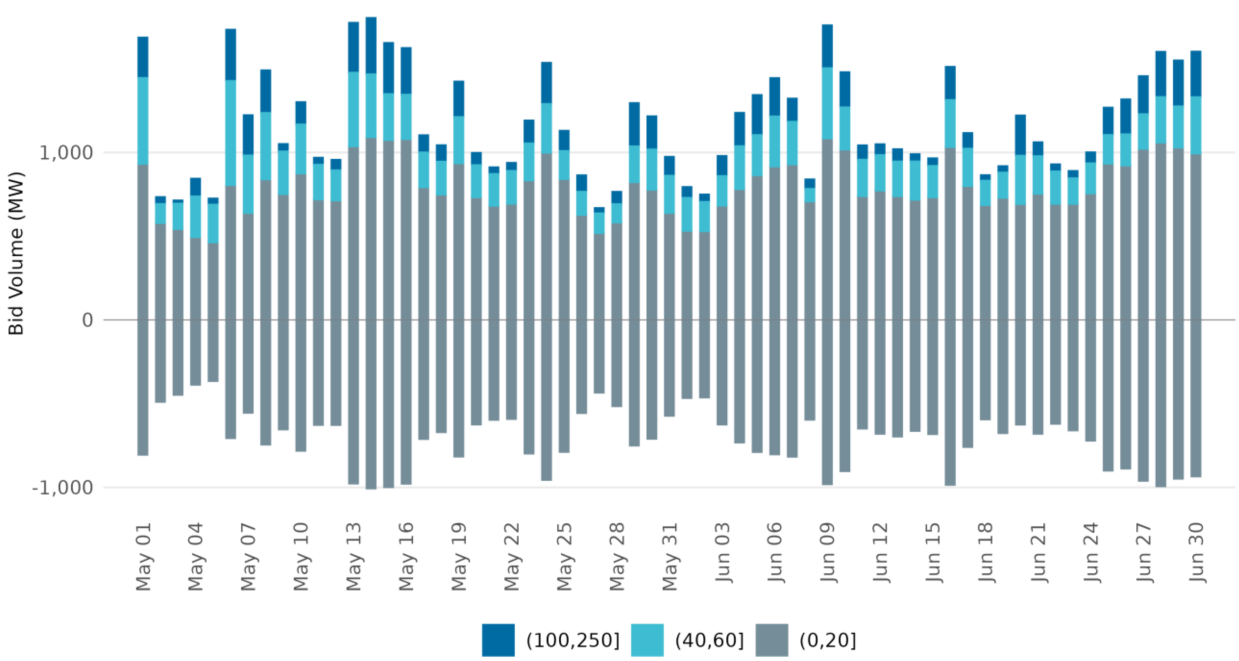


Figure 81: Daily average volume of RC bids by fuel type for PACW

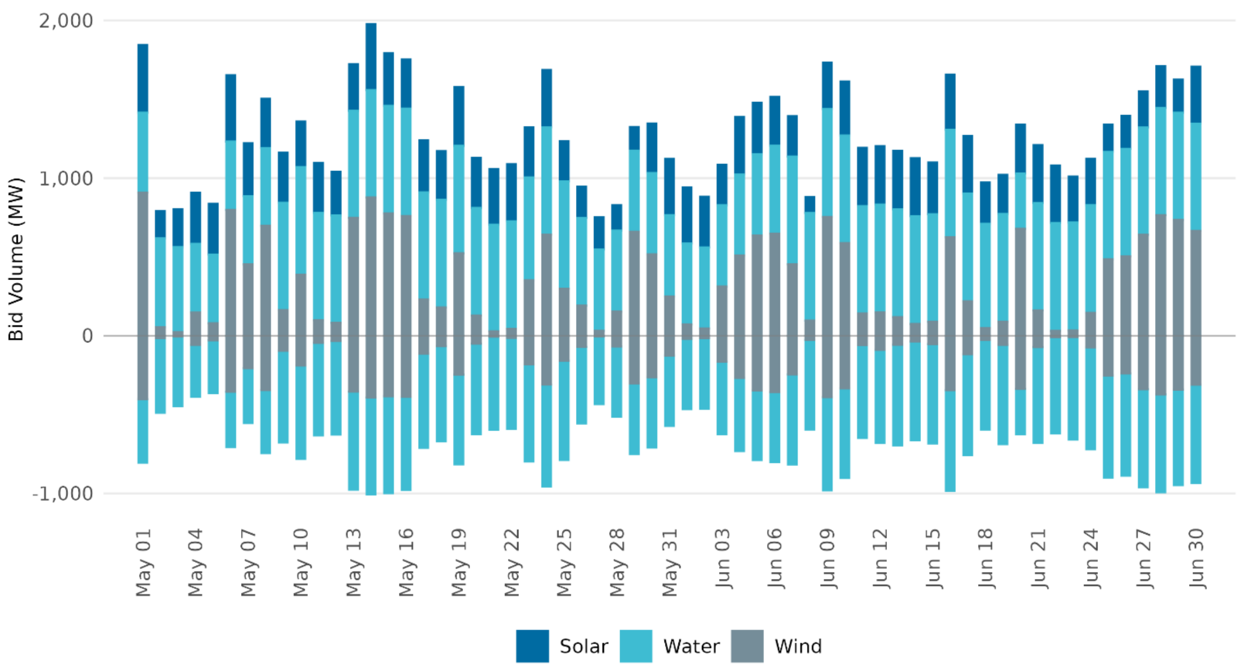


Figure 82 and Figure 83 illustrate the PACE's hourly and daily average volume of RC bids by bid price range and fuel type, respectively. Similarly, low-priced bids ($0–20/MW) and moderate priced bids (40–60 $/MWh) consistently accounted for almost all the share of submitted RC capacity throughout the month with about 90 percent, followed by some bids in the (100–250 $/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 6,000 MW while RCD is only about 2,000 MW.

Figure 82: Hourly average volume of RC bids by price for PACE

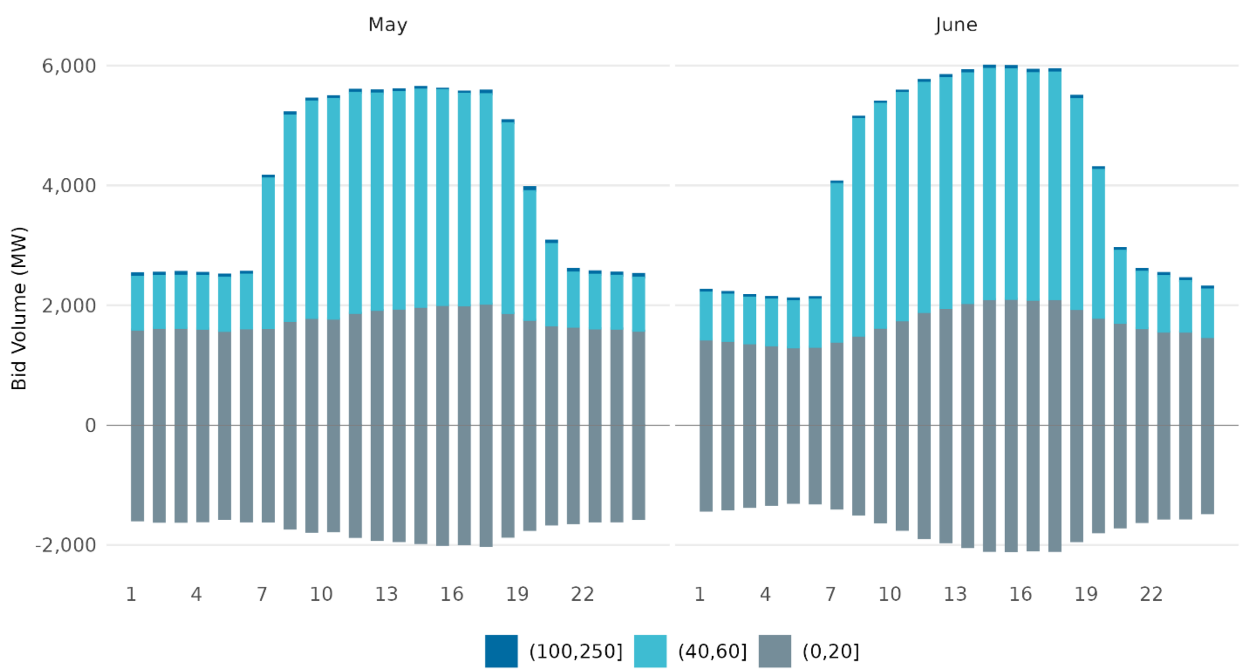


Figure 83: Hourly average volume of RC bids by fuel type for PACE

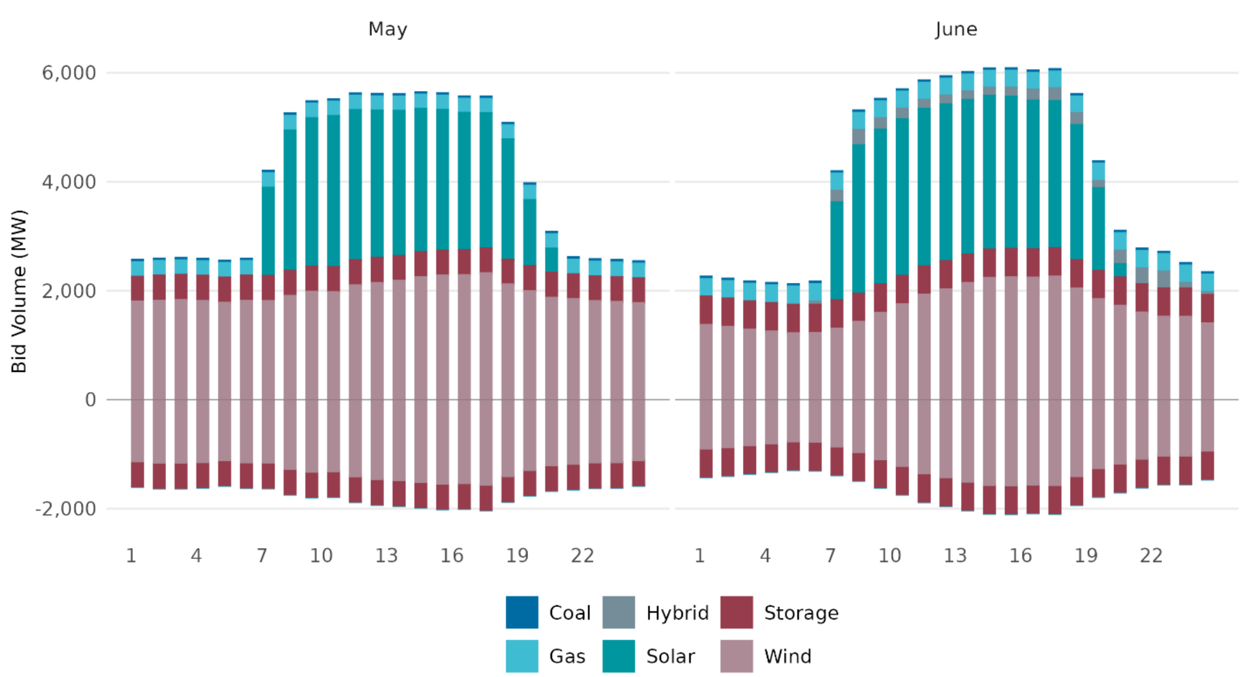


Figure 84: Daily average volume of RC bids by price by PACE

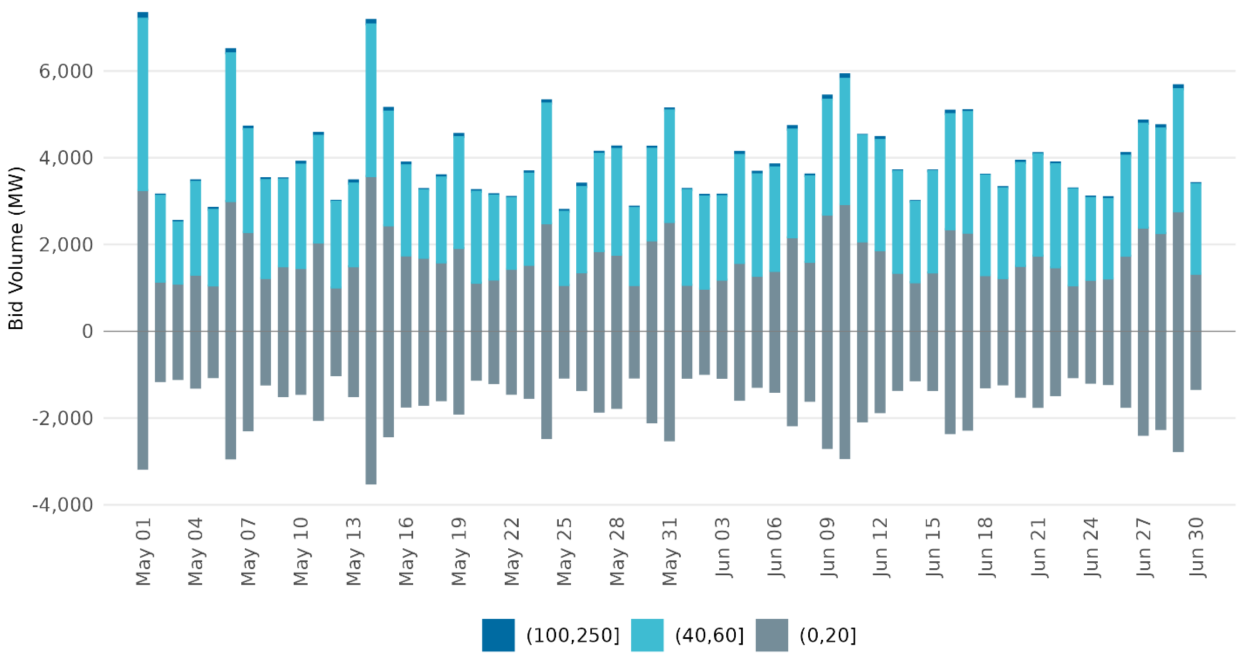
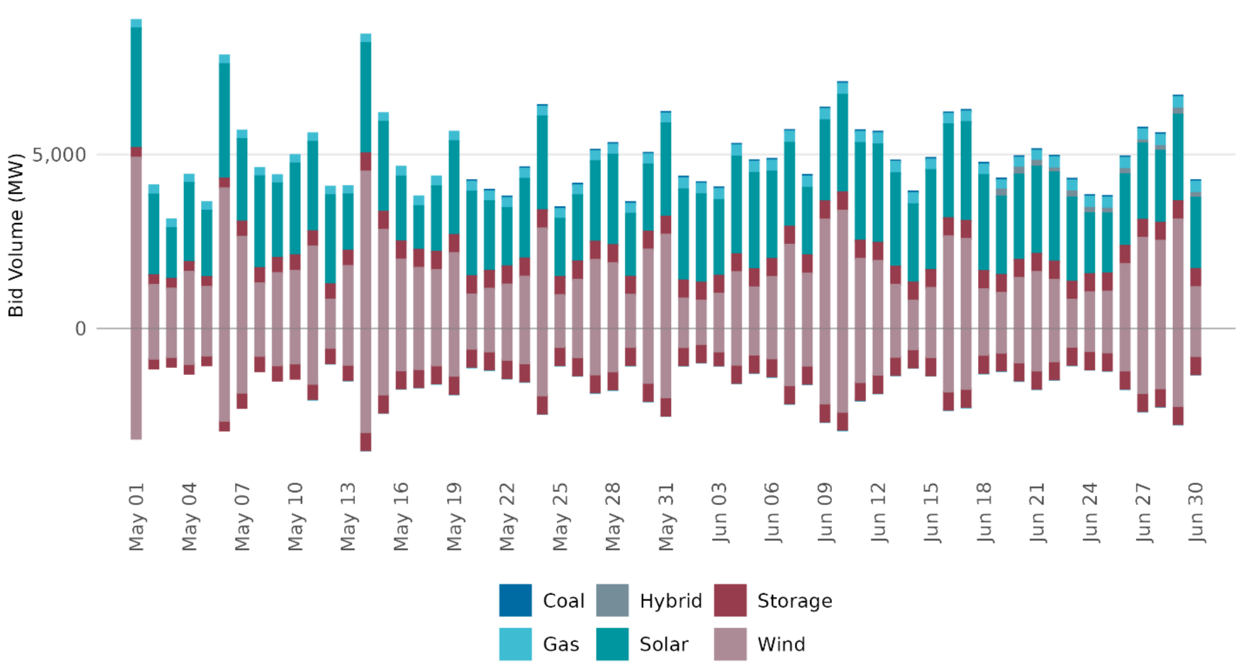


Figure 85: Daily average volume of RC bids by fuel type by PACE



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 86 shows the average hourly cleared virtual generation, virtual load, and the net virtual bids for each day in April, May, and June. The net cleared virtual bid 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 and lowest in June. There were multiple days in May and June where more virtual demand cleared compared to virtual generation. This reduction in net cleared virtual bids from April to May and then from May to June aligns with trends seen in prior years, suggesting that it is not a result of EDAM.

Figure 86: Average hourly cleared virtual bids

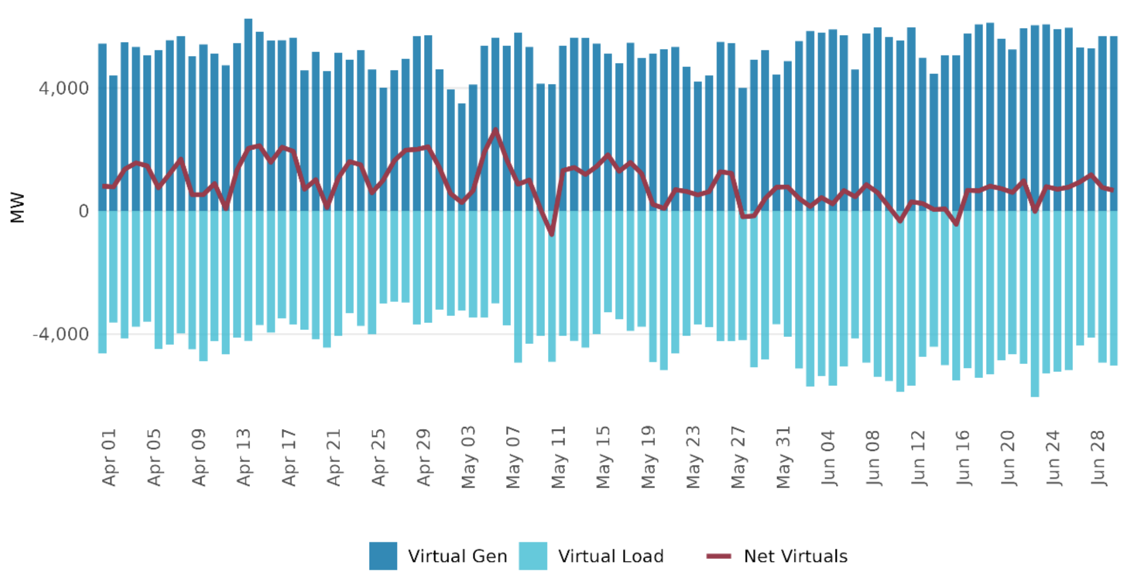


Figure 87 and Figure 88 show the hourly profile of average virtual supply and virtual demand, respectively, in April, May, and June. Figure 87 shows a decrease in cleared virtual supply during morning hours starting in May. Compared to April and May, June saw an increase in cleared virtual generation across solar hours and into the evening. Figure 88 shows a similar trend for cleared virtual load, with the exception being that June did not see smaller cleared virtual load in the morning hours. These complementary trends explain why the net virtual bids did not increase in June despite more cleared virtual bids overall. There was a similar increase in overall cleared virtual bids and a slight decrease in net virtual bids from April to June 2025.

Figure 89 shows the hourly profile of average net cleared virtual bids in April through June, 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 trends of reduced net cleared virtual bids in June compared to April and the higher virtual demand compared to virtual generation during solar hours also occurred in 2025. This means it is unlikely that EDAM led to the changes.

Figure 87: Average hourly cleared virtual supply

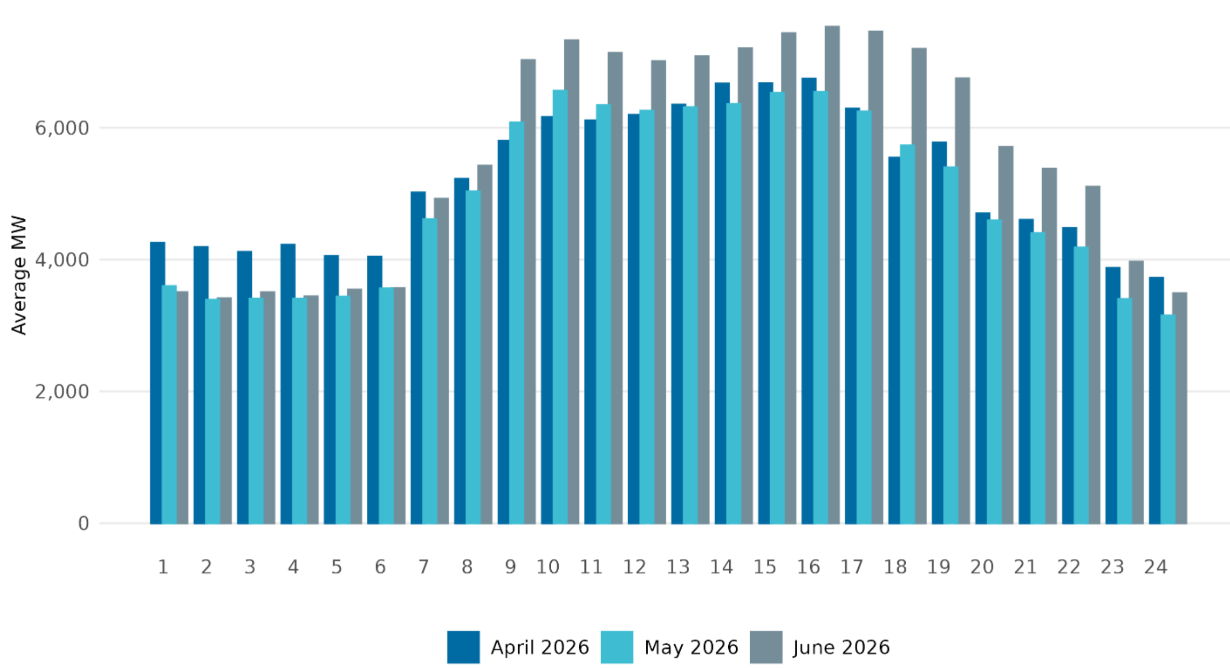


Figure 88: Average hourly cleared virtual demand

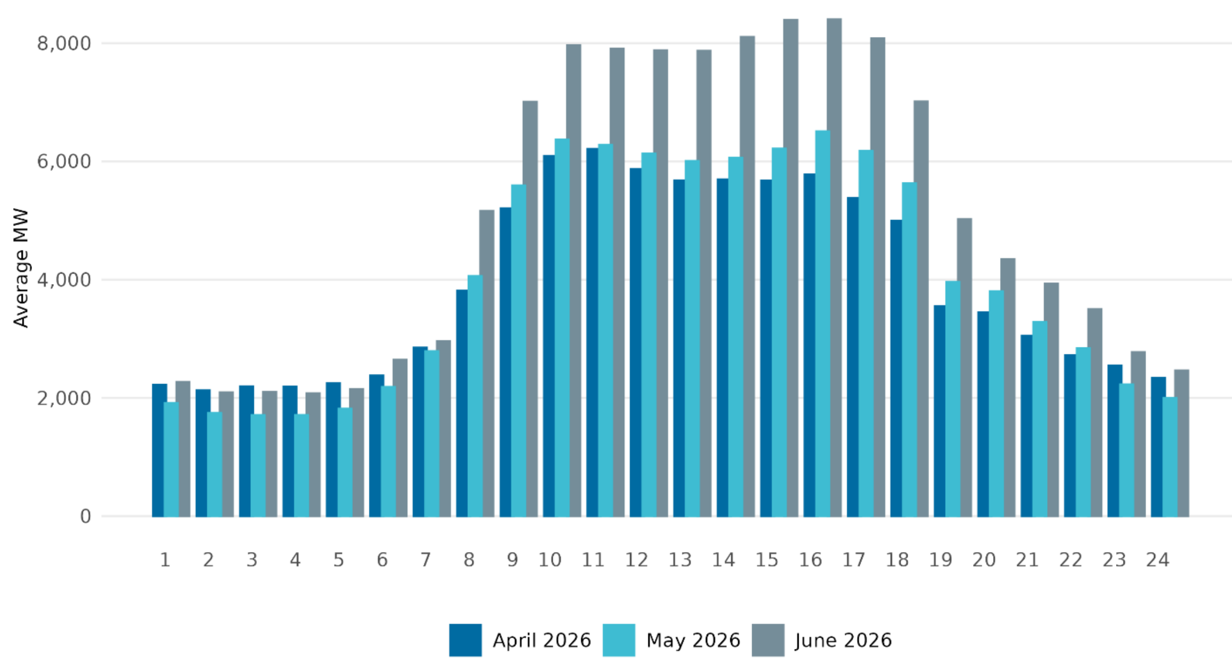
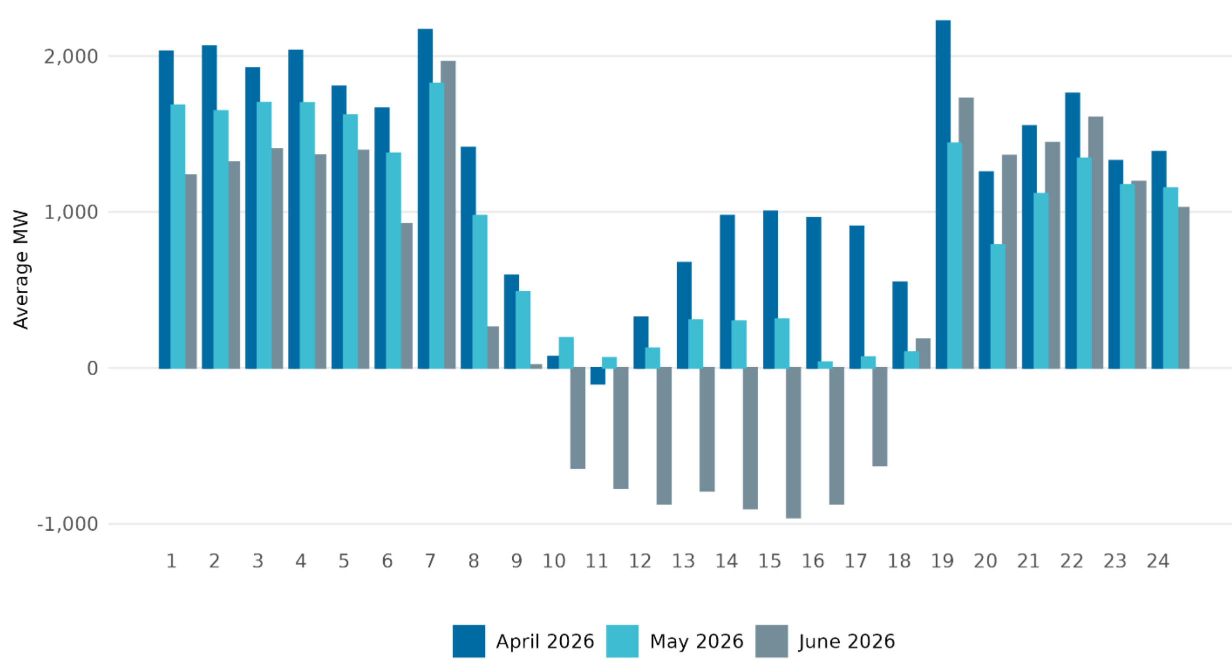


Figure 89: Average net hourly cleared virtual bids



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 June, the highest GHG price reached 30.4 $/MWh during Trade Hour 10 on June 29. The maximum hourly GHG allocation was 403 MW, occurring during Trade Hour 21 on June 16.

Figure 90 shows the daily average GHG allocation for both May and June. In June, the daily average GHG allocation reached highest levels near the middle of the month, peaking at 149 MW on June 16, followed by 102 MW on June 12. The average GHG allocations were substantially lower at the beginning and end of June. Overall, GHG allocations in June decreased compared with May.

Figure 90: Daily average GHG allocation

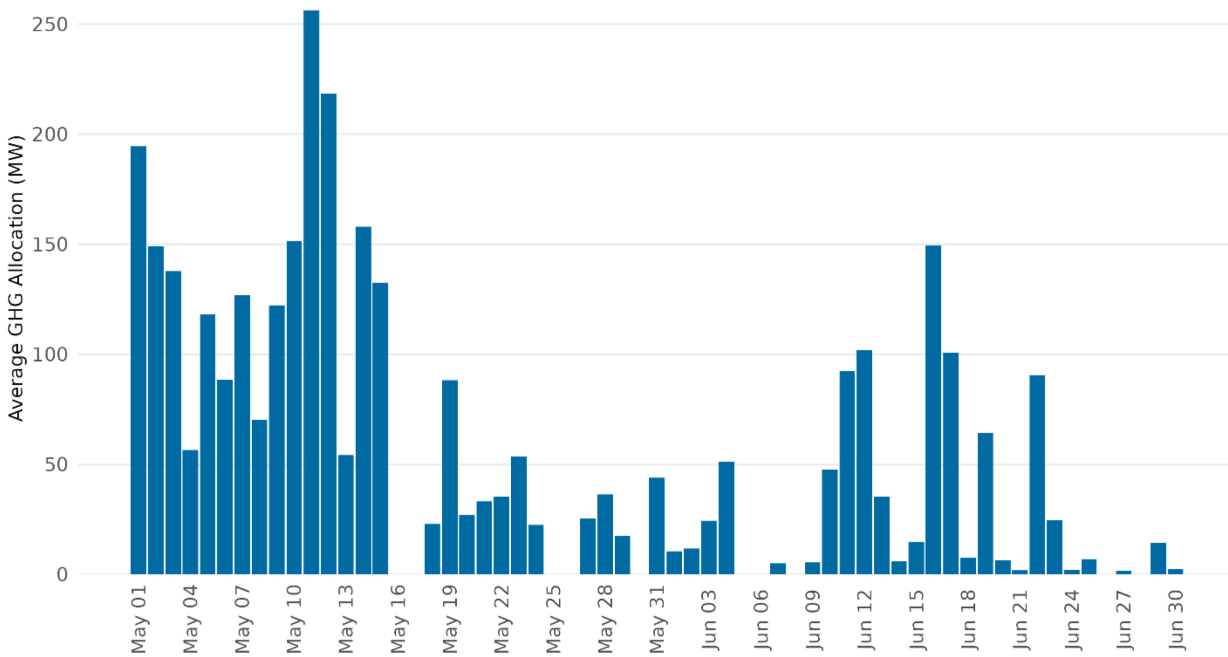


Figure 91 shows the daily average GHG prices in both May and June. In June, daily average GHG prices fluctuated throughout the month, with the highest daily average price reaching 11.7 $/MWh on June 10. Prices were generally higher during the middle of the month, and overall, GHG prices in June were higher than in May.

Figure 91: Daily average GHG price

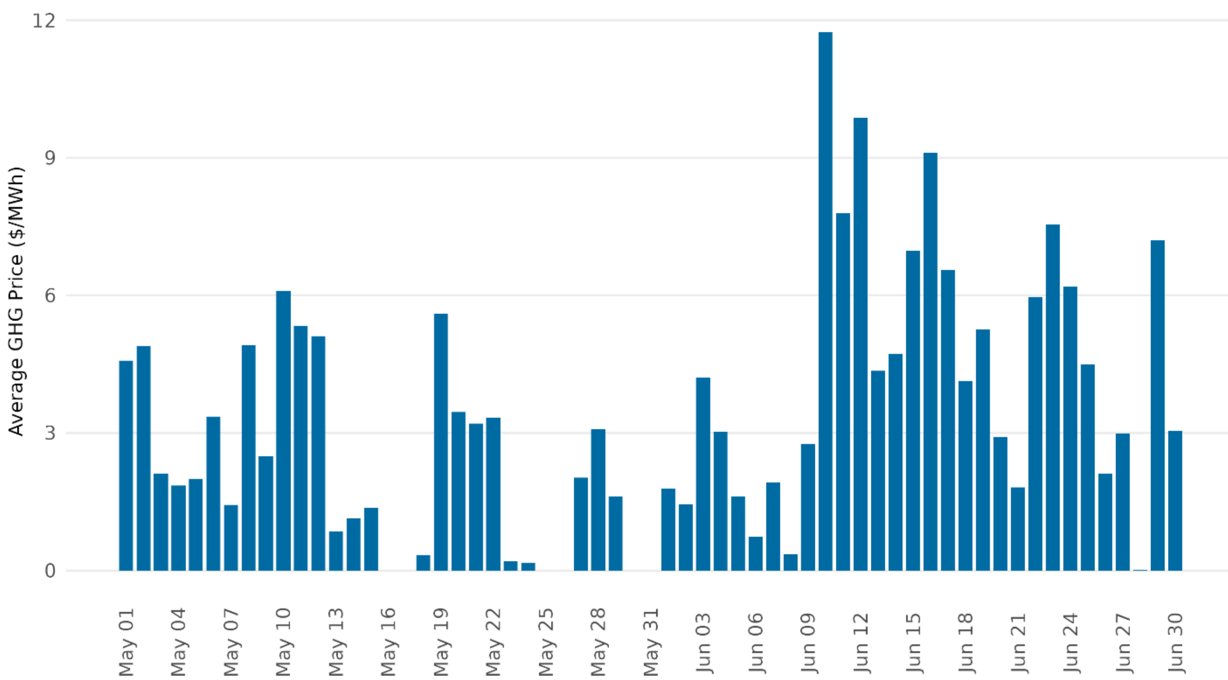
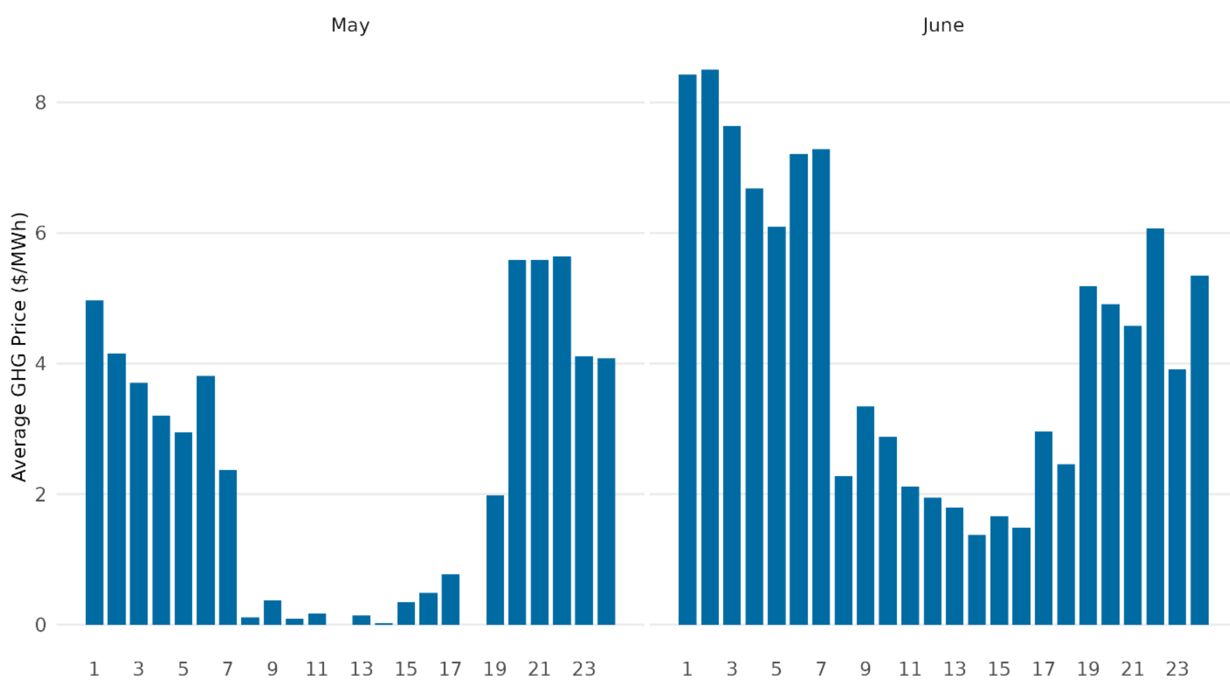


Figure 92 shows the hourly average GHG price by trade hour for May and June. In both months, GHG prices were generally higher during the early morning hours (Hours 1–7) and lower during the midday period (approximately Hours 10–17). In May, prices increased again during evening (Hours 19–24), whereas in June the evening increase was more moderate, with the highest prices remaining in the early morning hours. The lower midday prices coincided with periods when imports into the California area were reduced due to abundant solar generation within the CAISO area.

Figure 92: 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 93 illustrates CAISO daily average energy transfers in IFM in May and June 2026 on both export (+) and import (-) directions, and the breakdown for transfer paring entities. CAISO was a net exporter in both months, and the main transfer pairing BAA is PACE. 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 to end of June, while imports remained comparatively lower and more stable.

The hourly profile in Figure 94 exhibits a diurnal pattern, and both May and June show a very similar 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 93: Daily average energy transfers for CAISO

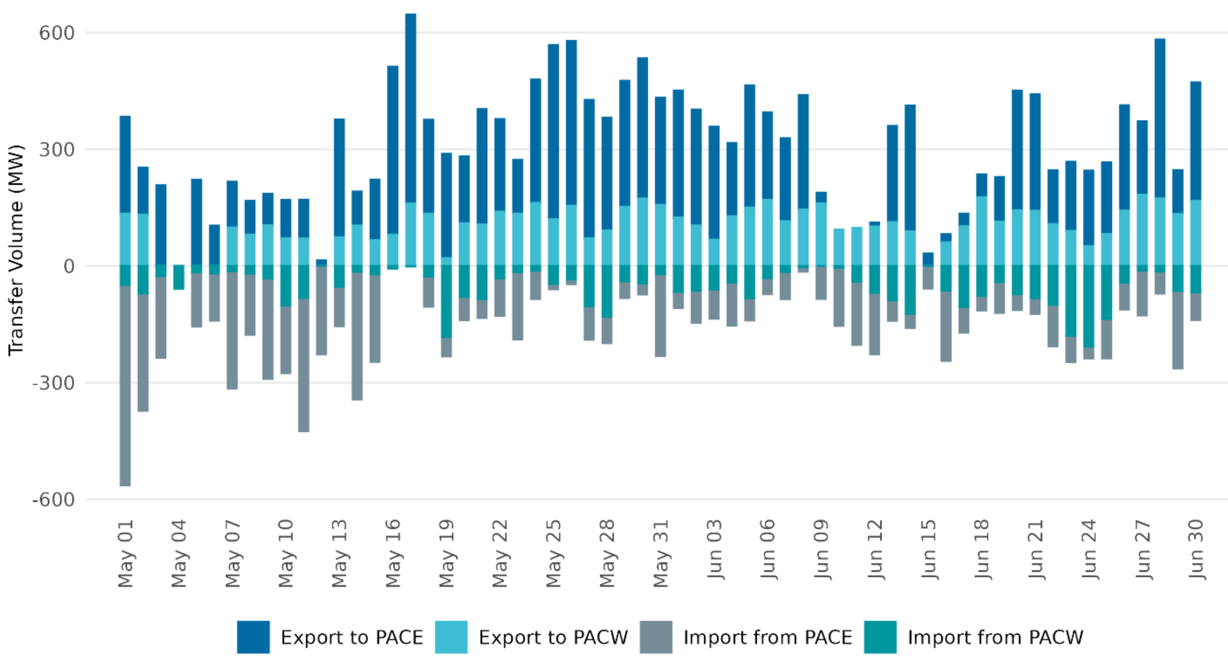


Figure 94: Hourly average energy transfers for CAISO

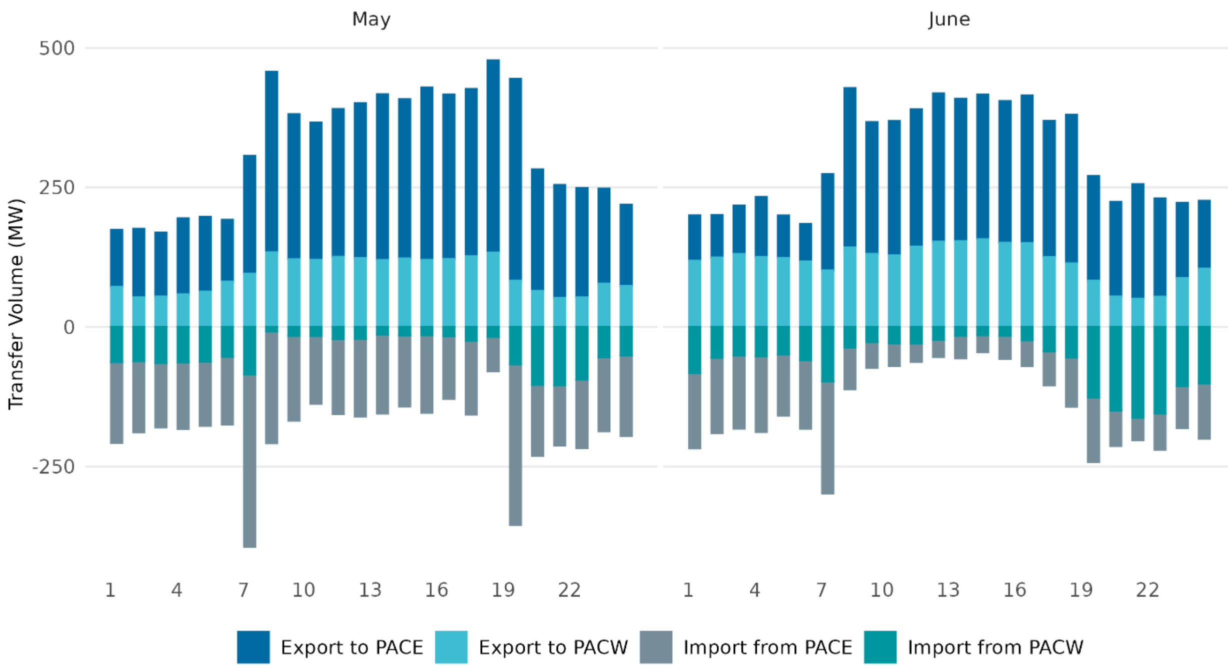


Figure 95 and Figure 96 show PACW's daily and hourly average energy transfers in May and June 2026 on both export (+) and import (-) directions. PACW remained a net importer in May and June. The average import volume significantly increased after June 3 and reached maximum daily average import volume of about 870 MW on June 19, and about 750 MW is imported from PACE.

The hourly profile exhibits a significant increase in average imports of over 300 MW from PACE in June compared with May, with the highest total average import reaching over 600 MW in HE 15-16. In contrast, exports stay the same in June, with peak is around HE 7 and HE 20-22 and a maximum average export of about 100 MW.

Figure 95: Daily average energy transfers for PACW

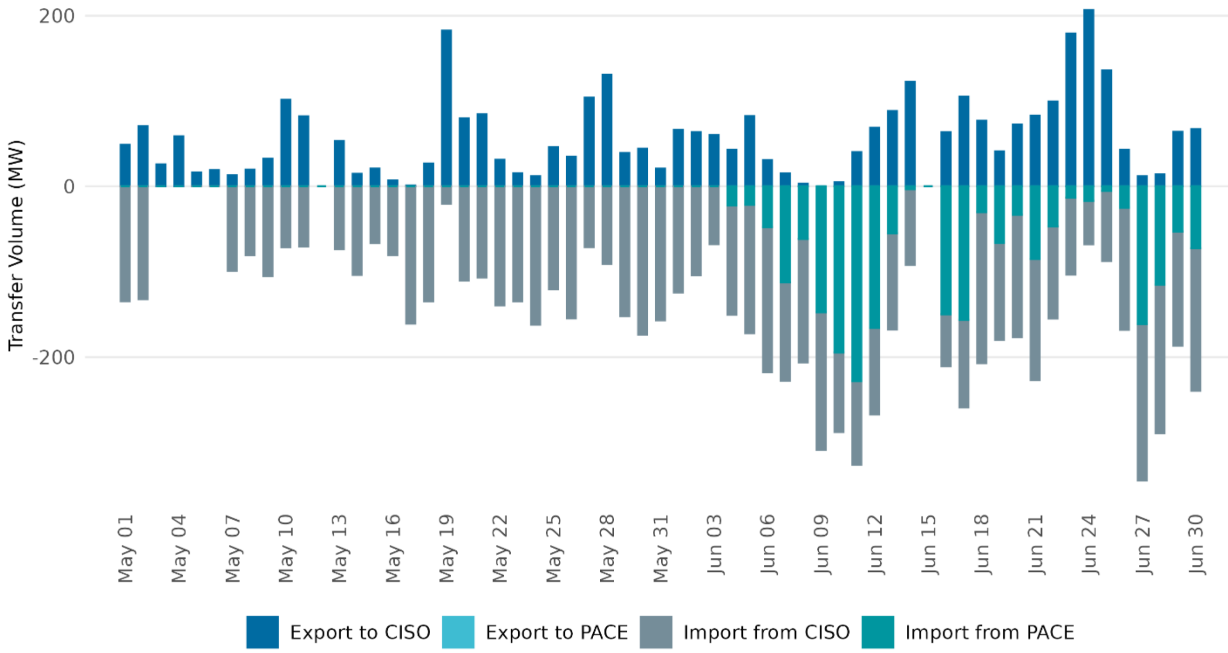


Figure 96: Hourly average energy transfers for PACW

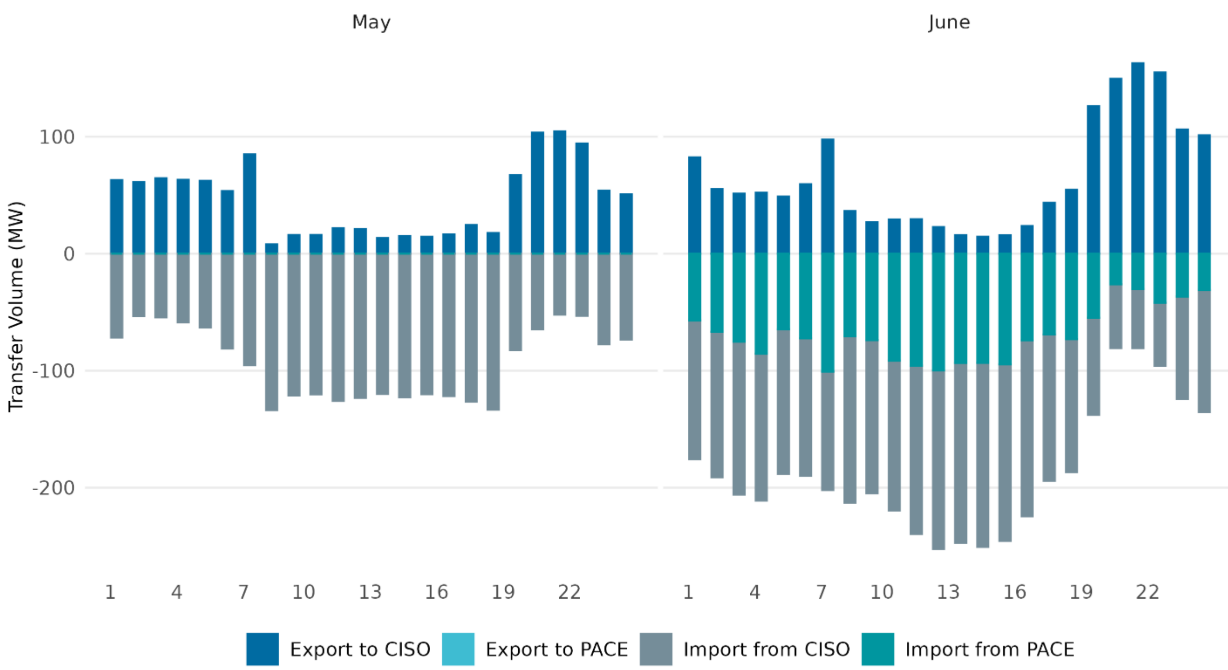


Figure 97 and Figure 98 show PACE's daily and hourly average energy transfers in May and Juen 2026 on both export (+) and import (-) directions. Generally, PACE remained an importer to CISO in May and June but changed to a net exported to PACW after June 3. The average daily exports reached the highest of over 850 MW on June 19. 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 exports to PACW during daylight hours in June, with peak imports of about 500 MW in HE18. In contrast, import from CISO peak hours pattern stayed the same as May but with a slightly lower value, which were HE 8 and 20 with a volume of about 300 MW.

Figure 97: Daily average energy transfers for PACE

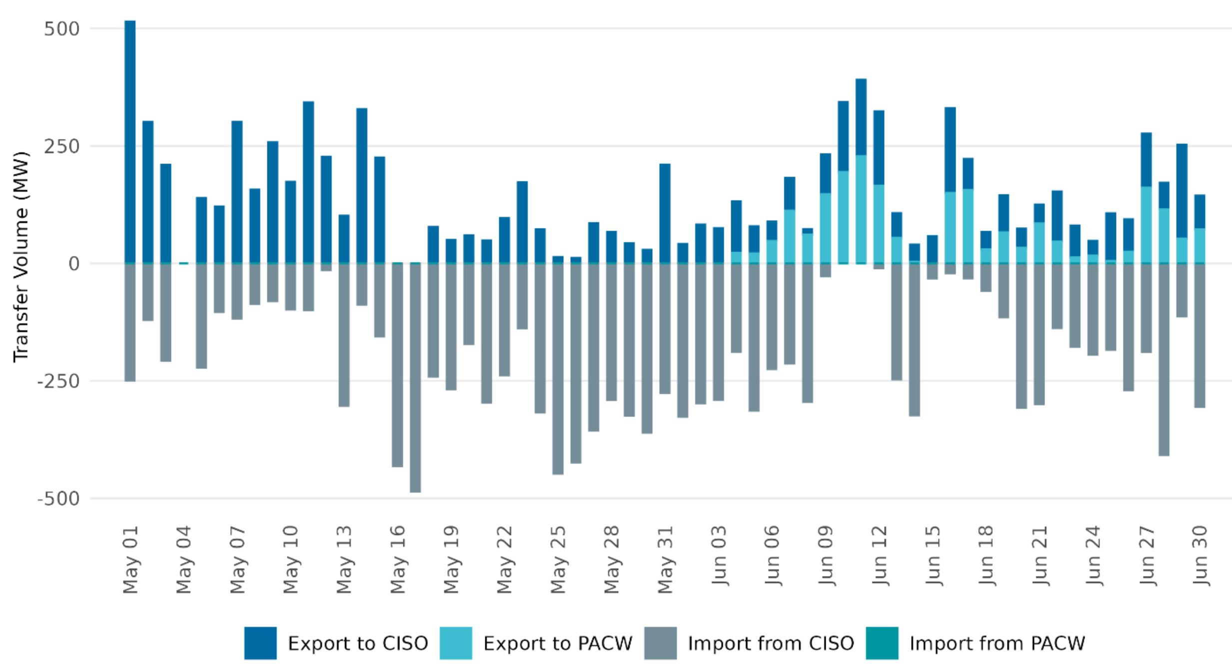


Figure 98: Hourly average energy transfers for PACE

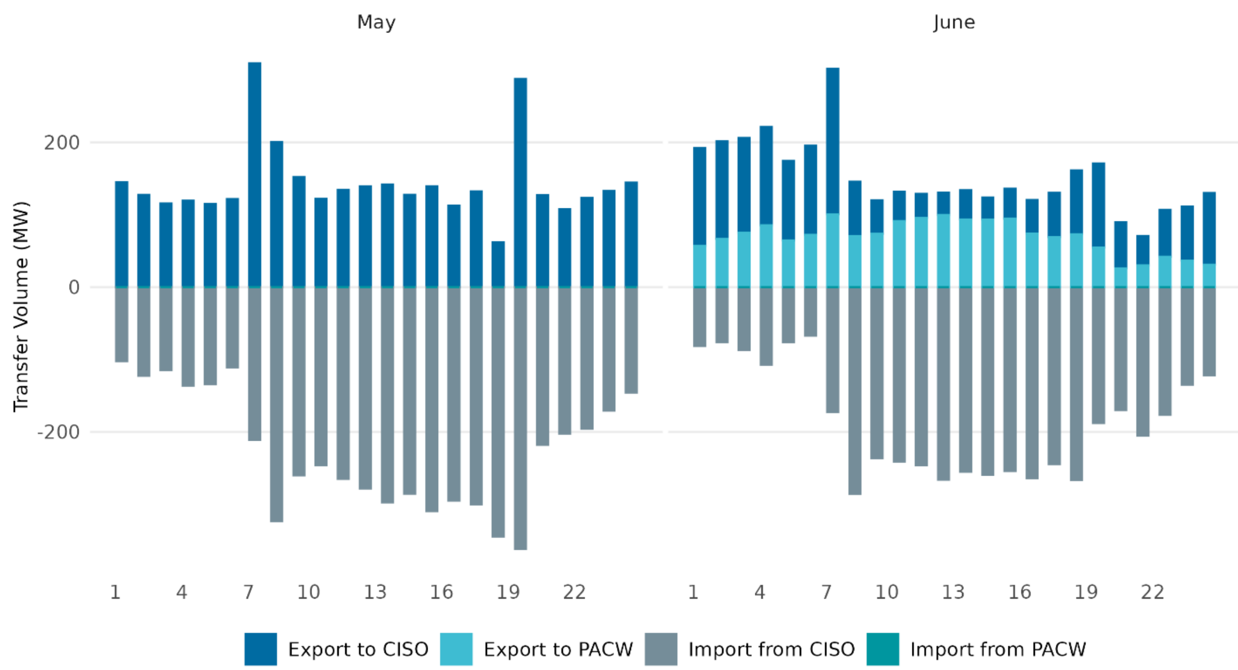
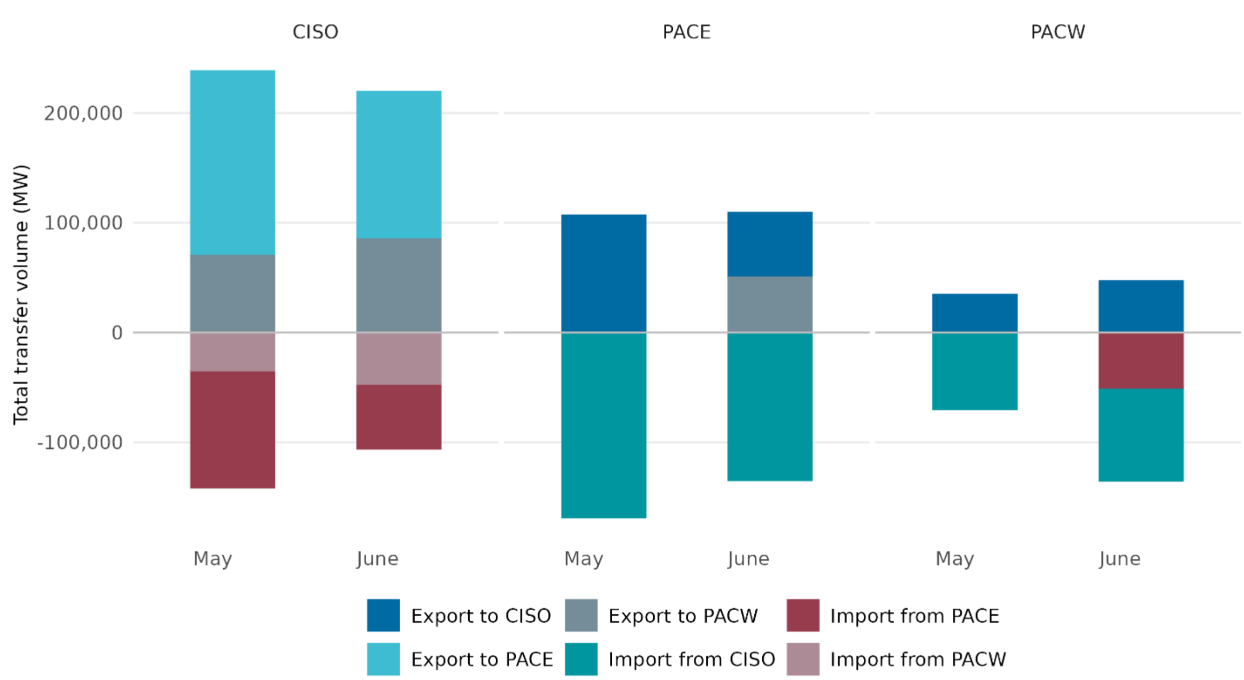


Figure 99 shows the summary of three BAAs' total energy transfer volumes in May and June in both export (+) and import (-) directions. For CISO, the total transfer volumes are almost the same in May and June, with only a slight increase in imports from PACE. However, the transfer between PACW and PACE increased a lot in June, compared with that there is almost no direct transfer between in May.

Figure 99: Total energy transfers volumes for 3 BAAs per month



Imbalance reserves

Imbalance reserves are a new day-ahead flexible reserve product introduced with EDAM to procure upward and downward reserve capacity for managing differences between day-ahead schedules and real-time conditions, including net load forecast uncertainty and real-time ramping needs. This section summarizes the patterns of imbalance reserves transfers among BAAs during May and June 2026.

EDAM enables the transfer of imbalance reserves between balancing authority areas, allowing available reserves to be shared where they are needed most. These transfers improve the efficient use of resources while supporting reliable system operations. The following sections summarize the overall transfer activity during the month and examine the underlying patterns and market outcomes in greater detail for both up and down direction.

Imbalance reserve up

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 100 and Figure 101 show CAISO's daily and hourly average IRU transfers in May and June 2026 on both export (+) and import (-) directions. Generally, in both May and June, CAISO exported IRU and most of the exports went to PACE. 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 in both May and June, with only a small proportion of imports in Hour 8 over 100 MW.

Figure 100: Daily average IRU transfers for CAISO

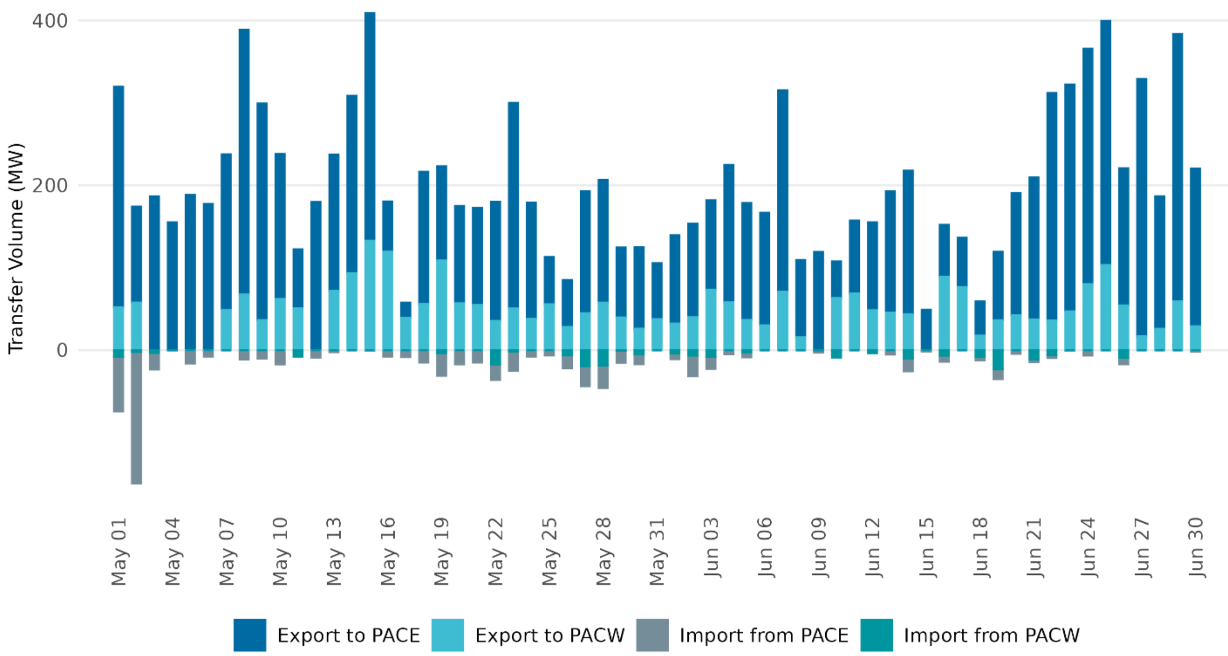


Figure 101: Hourly average IRU transfers for CAISO

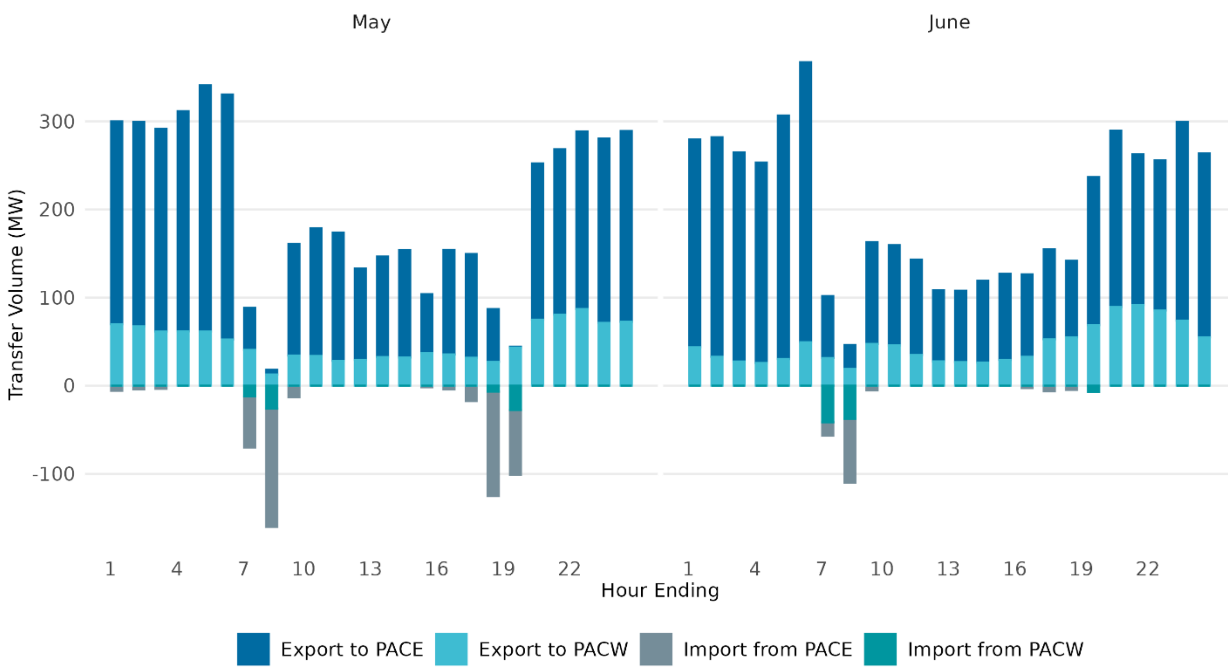


Figure 102 and **Error! Reference source not found.** Figure 103 show PACW's daily and hourly average IRU transfers in May and June 2026 on both export (+) and import (-) directions, respectively. Similar with energy transfer, PACW's IRU transfers were generally dominated by imports, and imports from PACE started to increase after June. The maximum import volume is about 130 MW on June 29. In the hourly profile, there is an obvious IRU imports increase in June compared with May. The peak hours for IRU import are nighttime hours, with Hours 20 – 23 over 100 MW in June. PACW exports less than 30 MW of IRU around Hours 7-8 and Hours 18-19.

Figure 102: Daily average IRU transfers for PACW

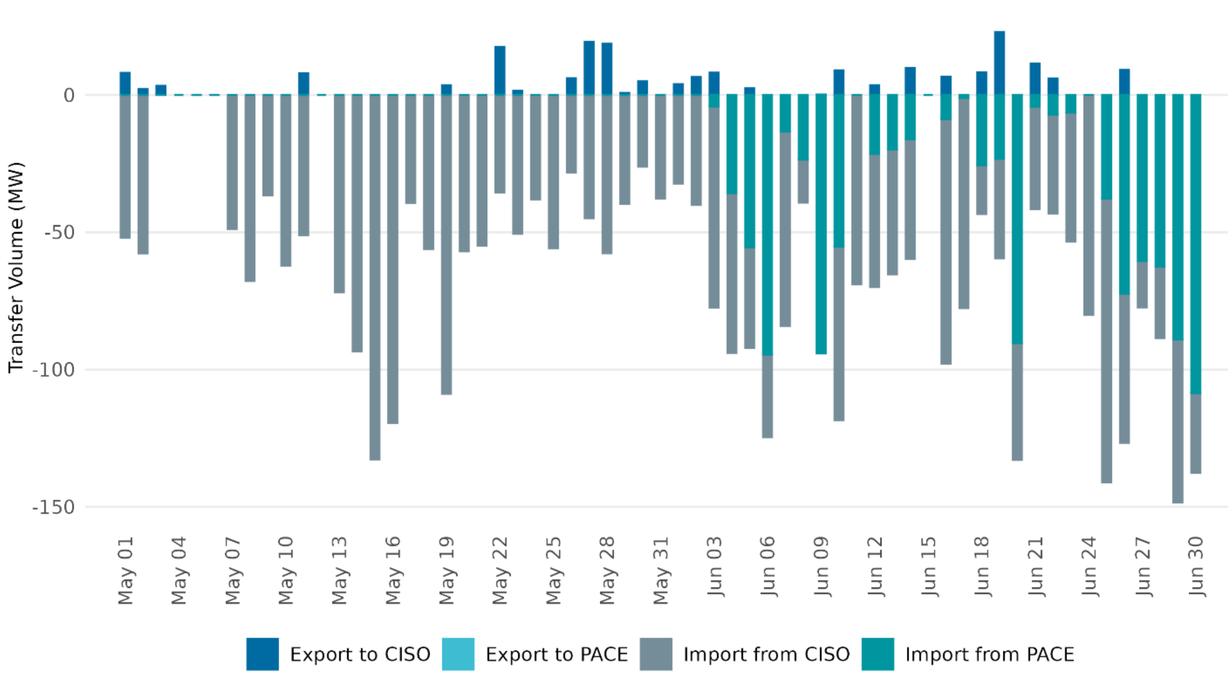
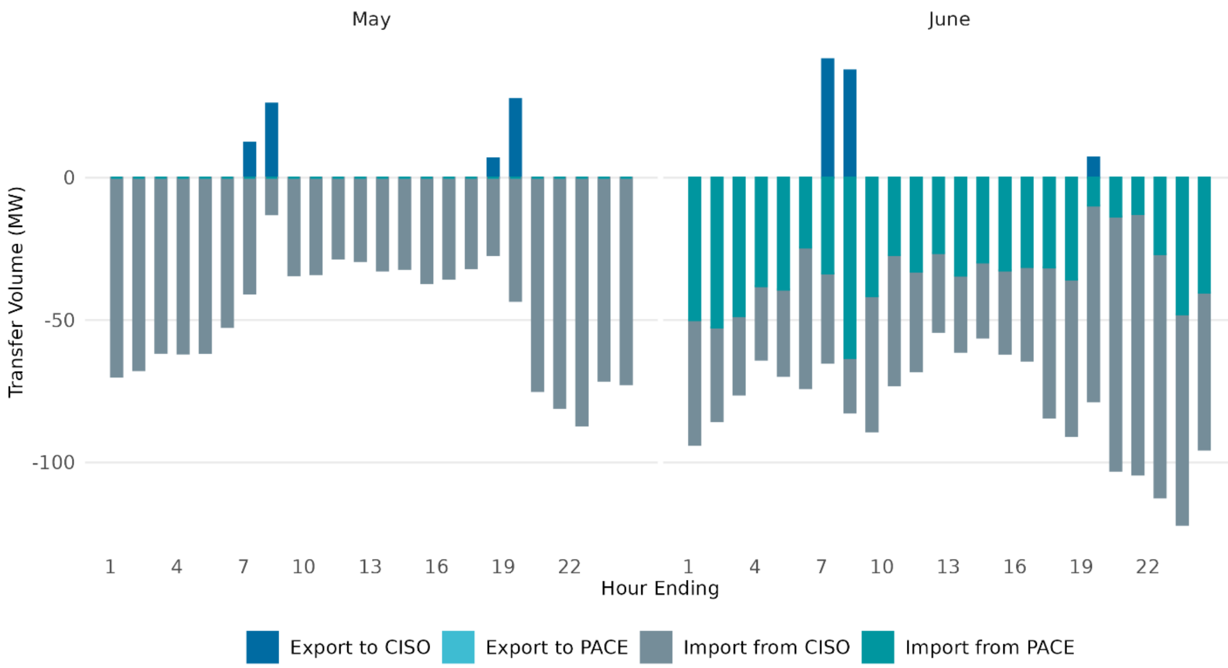


Figure 103: Hourly average IRU transfers for PACW



Error! Reference source not found. Figure 104 - Figure 105 show PACE's daily and hourly average IRU and IRD transfers in May and June 2026 on both export (+) and import (-) directions, respectively. For IRU products, PACE remained a net importer in both the months, and the main import is almost from CAISO. The maximum daily average is over 300 MW on May 8, June 27 and June 29. The hourly average import peak is around 270 MW mainly in Hours 5 – 6. However for the IRU exports, PACE started to export IRU to PACW from June, although only a small proportion of exports around 50 MW, and the export to CAISO during afternoon ramping hours decreased in June.

Figure 104: Daily average IRU transfers for PACE

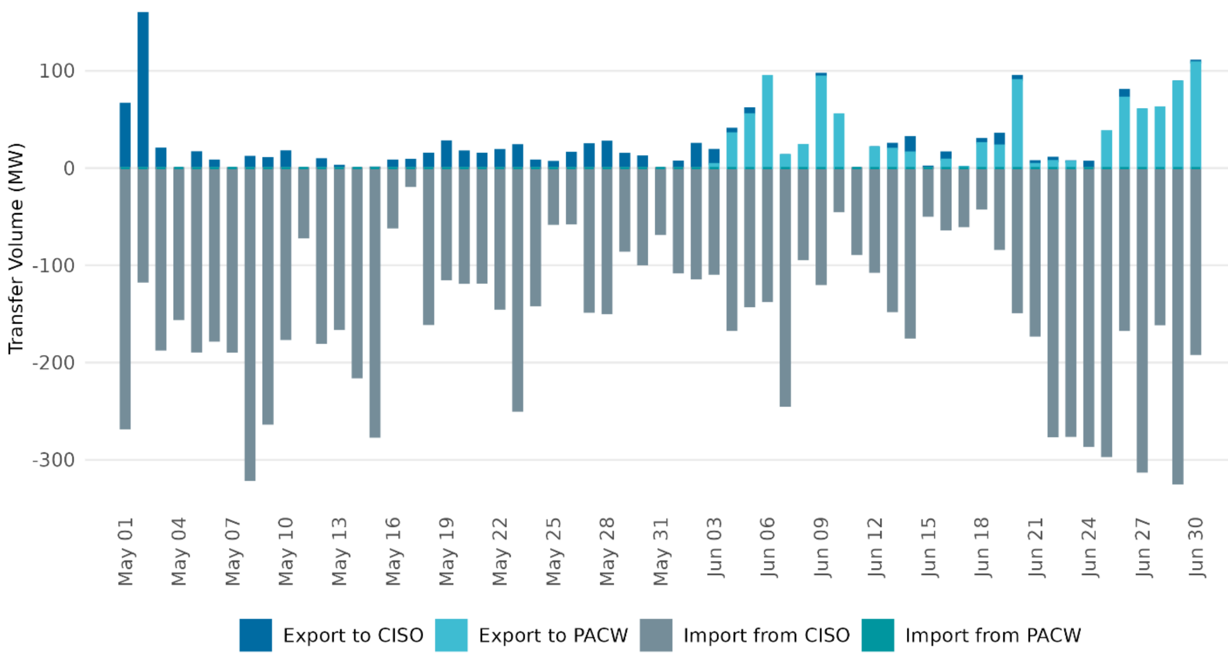


Figure 105: Hourly average IRU transfers for PACE

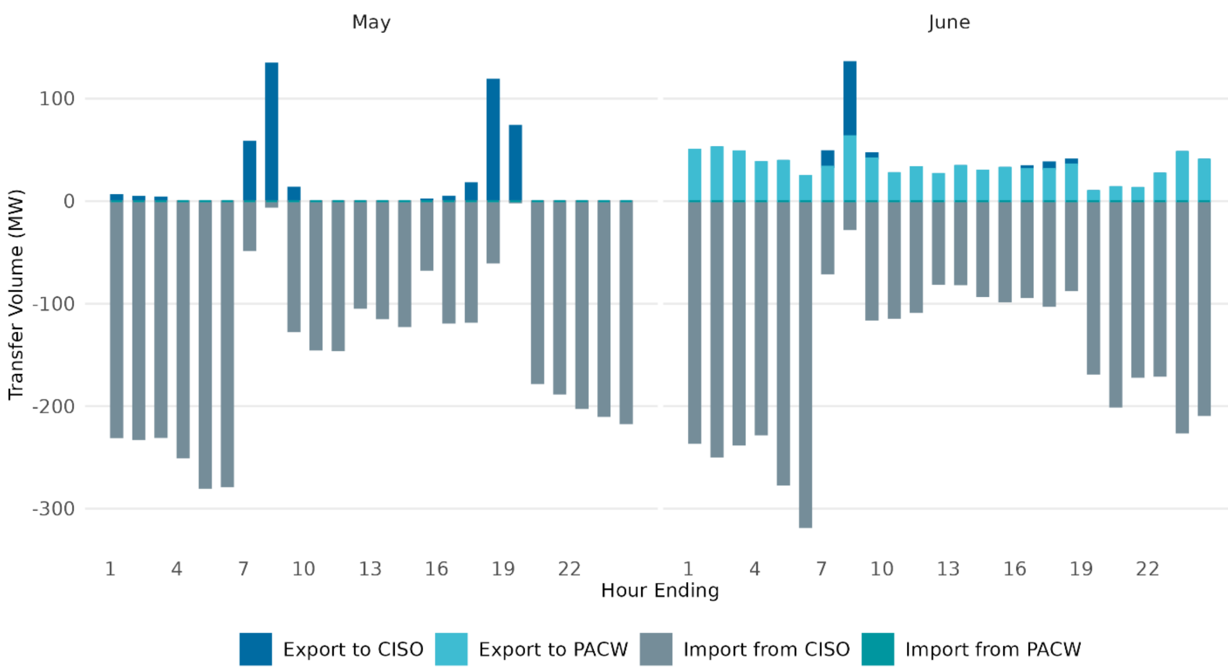
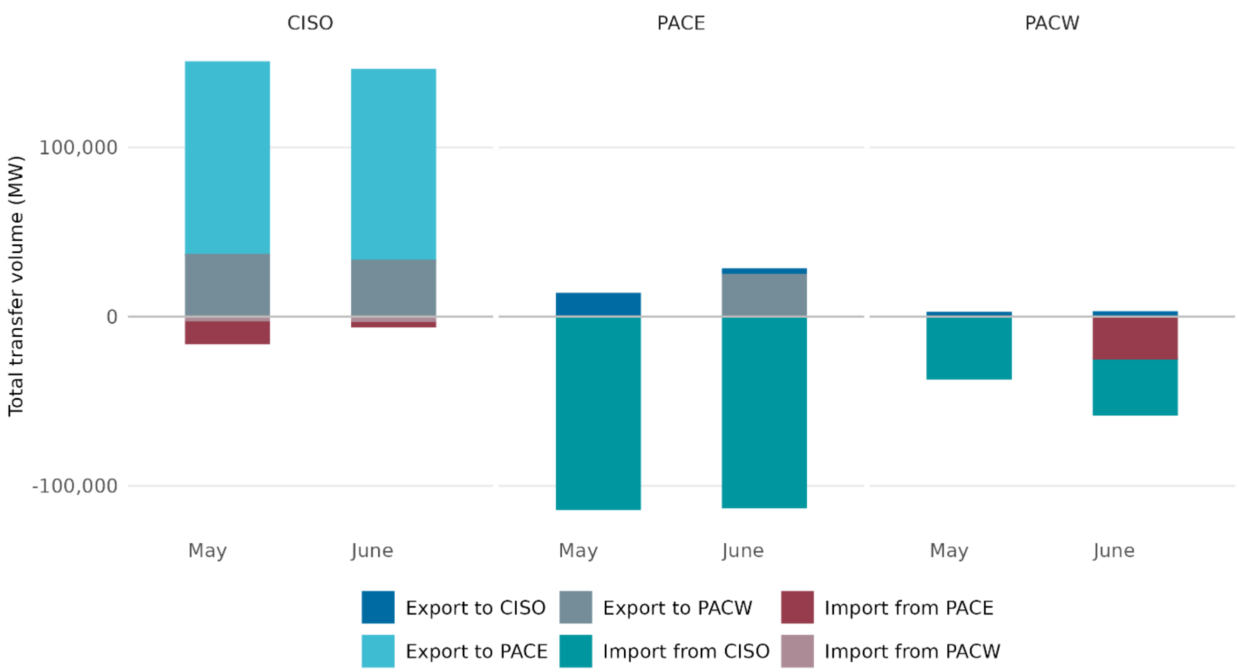


Figure 106 shows the summary of three BAAs' total IRU transfer volumes in May and June in both export (+) and import (-) directions. For CISO, the total transfer volumes are almost the same in May and June, with only a slight increase in imports from PACE. Similarly, the transfer between PACW and PACE increased a bit in June, compared with the fact that there is almost no direct transfer between in May.

Figure 106: Total IRU transfers volumes for 3 BAAs per month



Imbalance reserve down

For IRD products, as Figure 107 and **Error! Reference source not found.** Figure 108 show, CAISO's main IRD imports were from PACE, and the IRD imports realized mainly in May, reaching a daily maximum of about 300 MW on May 11. The IRD imports decreased in June while IRD exports to PACE increased in June, mainly in daylight hours. In May, Hours 7 and 19 had the highest average IRD imported volumes of about 300 MW, while these numbers decreased to 200 MW in June.

Figure 107: Daily average IRD transfers for CAISO

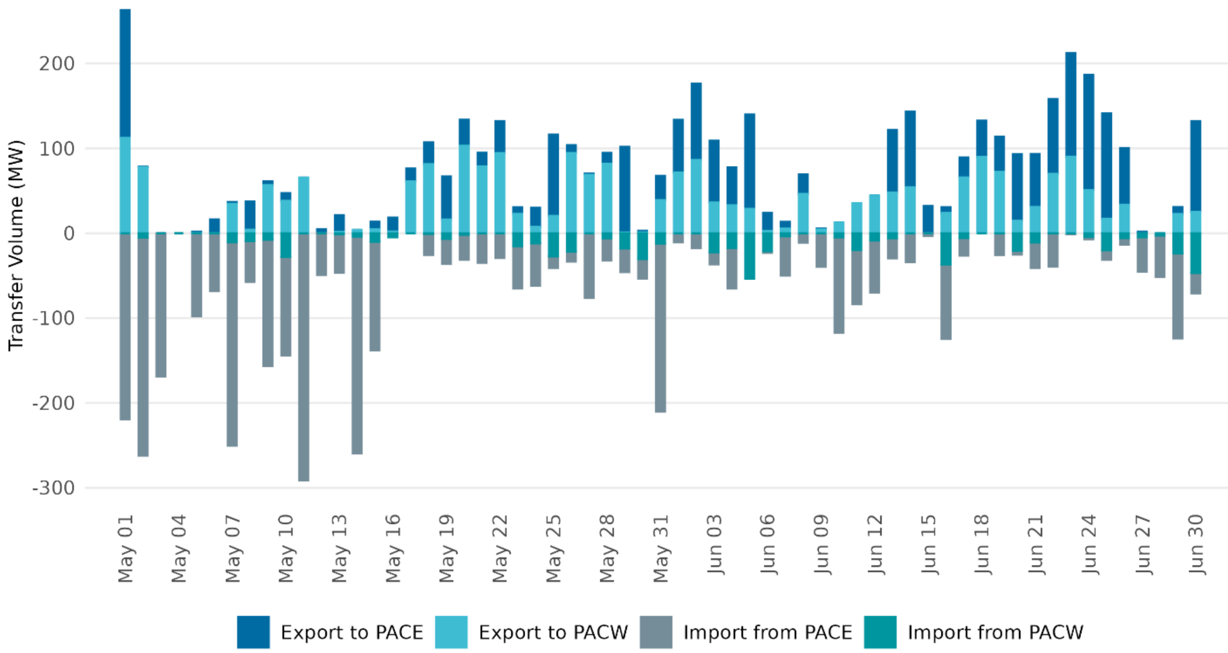
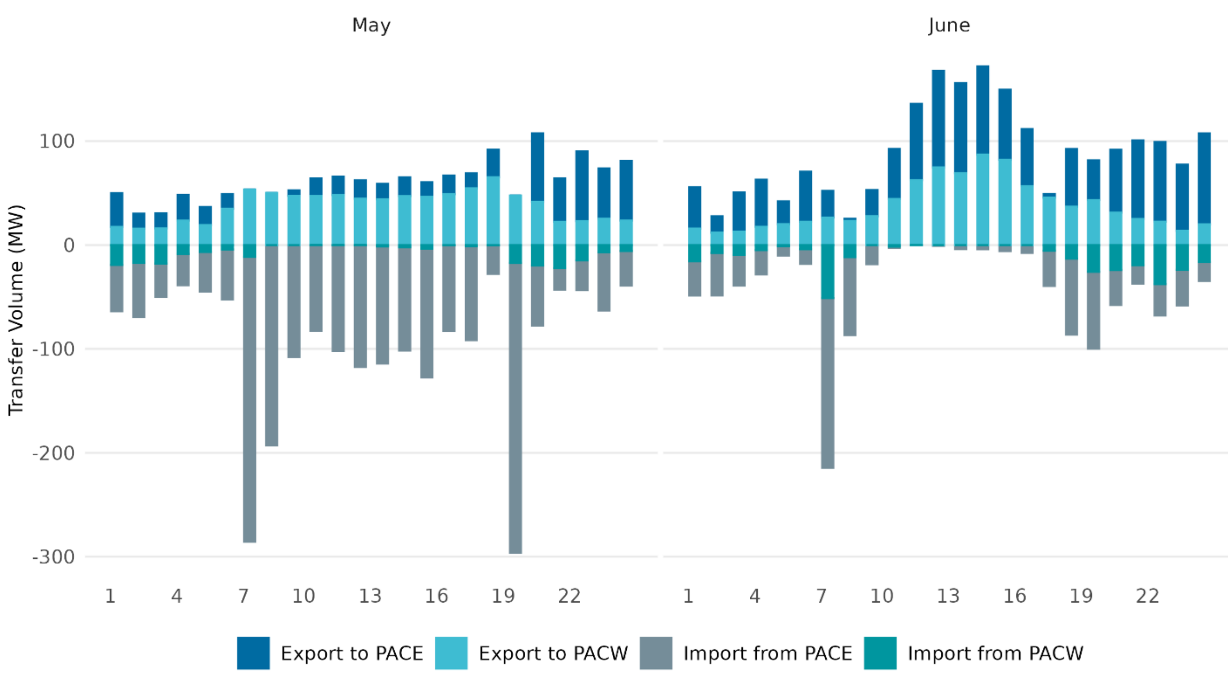


Figure 108: Hourly average IRD transfers for CAISO



For IRD products, PACW remained a net importer in the two months. In May 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. In June, PACW also increased the IRD export to CAISO in morning ramping hours. Besides, PACW started to import IRD from PACE in June during morning and afternoon ramping hours.

Figure 109: Daily average IRD transfers for PACW

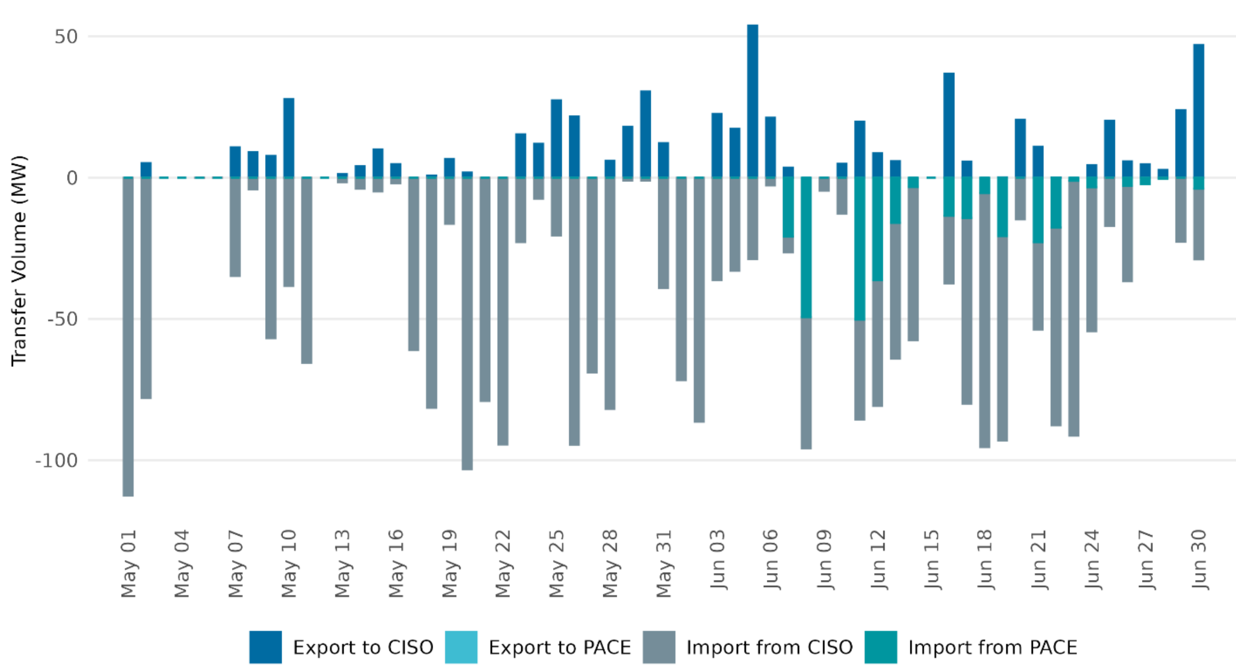
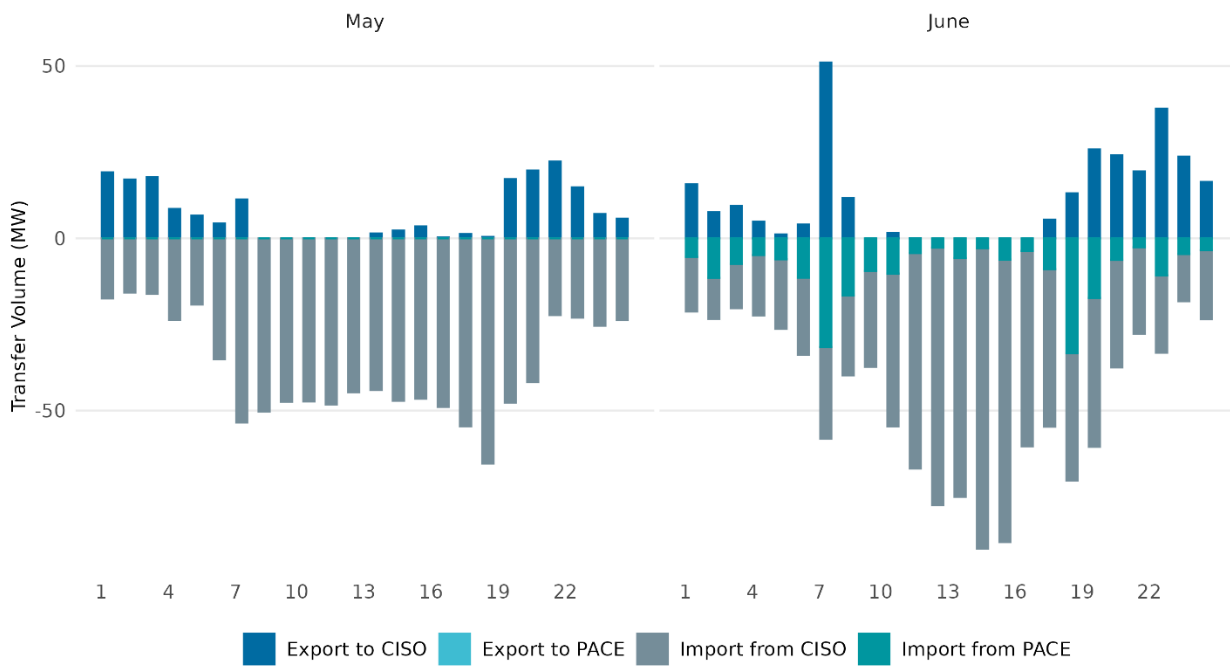


Figure 110: Hourly average IRD transfers for PACW



PACE's IRD transfer showed a more dynamic pattern in May and June. In May, 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. Then in June, PACE's IRD exports decreased while imports to increased, and the main transfer pairing entity is CAISO.

Figure 111: Daily average IRD transfers for PACE

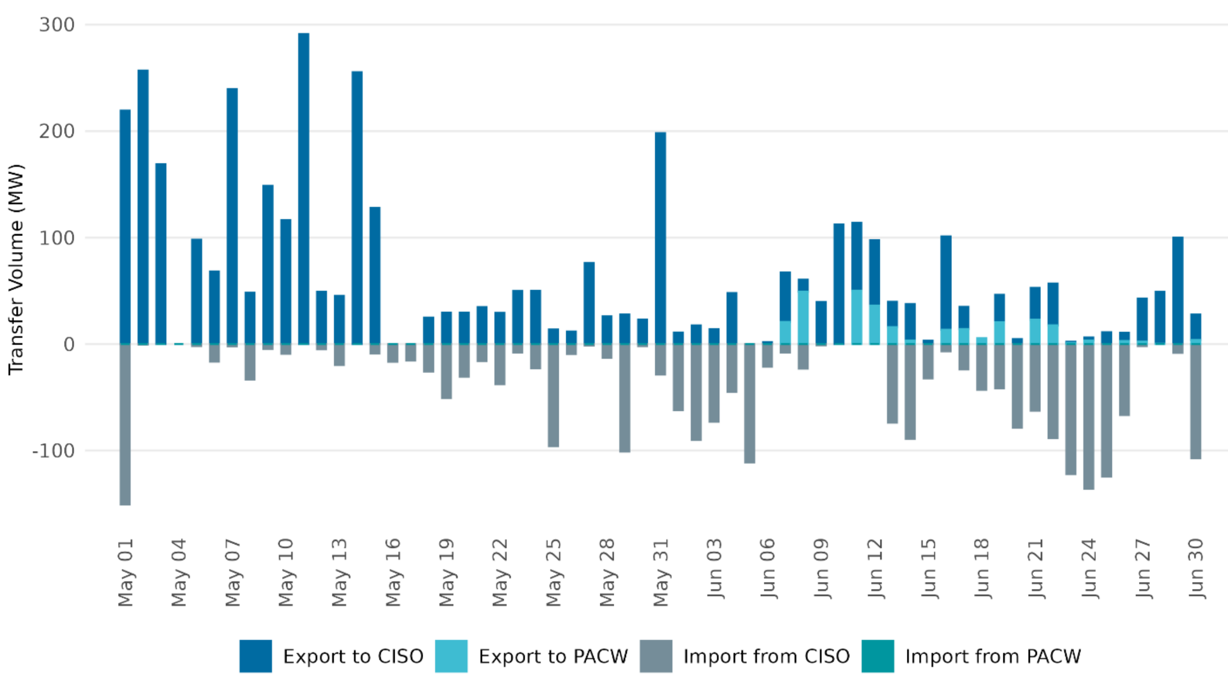


Figure 112: Hourly average IRD transfers for PACE

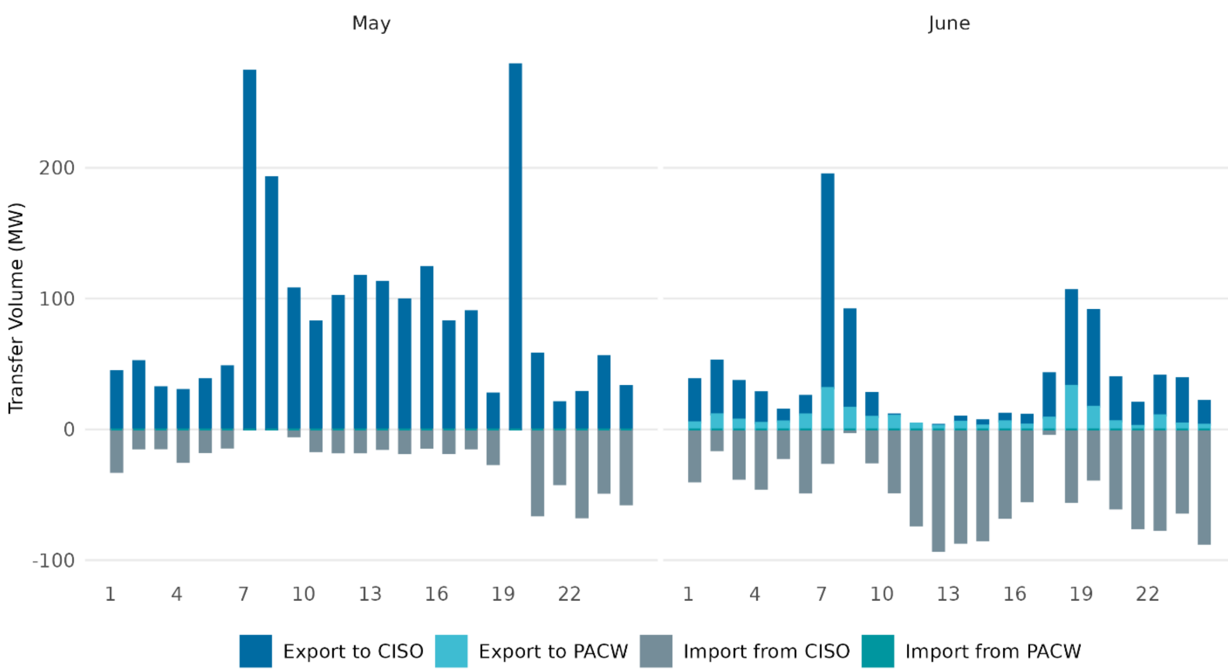
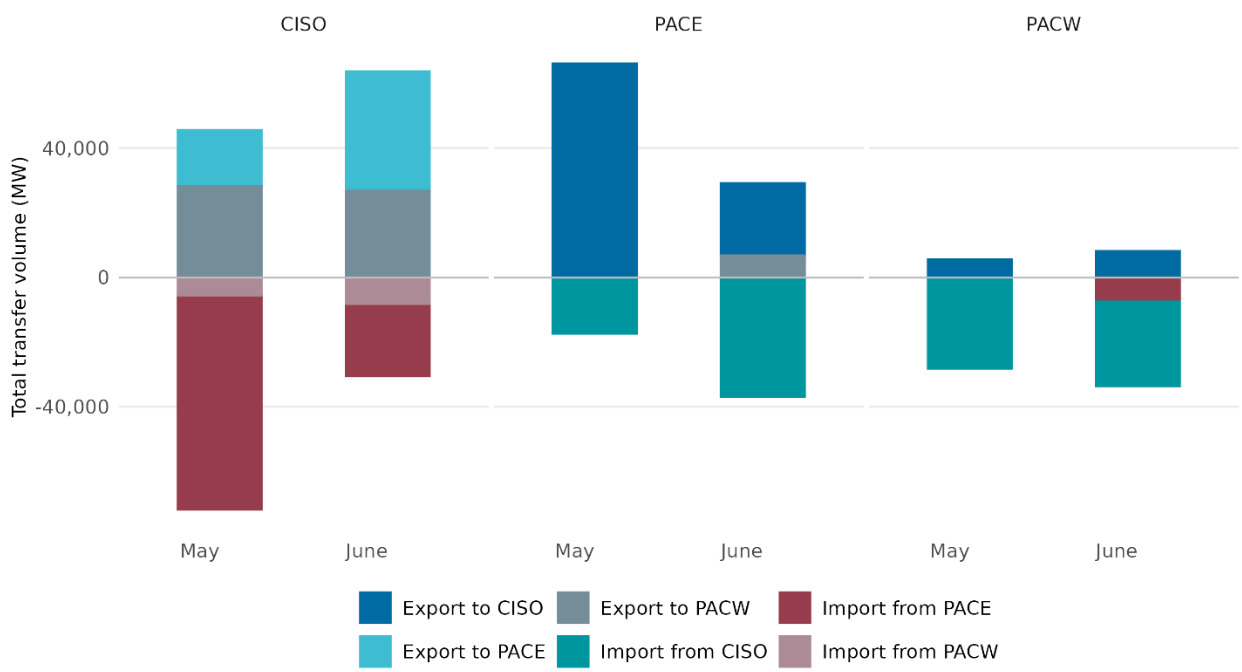


Figure 113 shows the summary of three BAAs' total IRD transfer volumes in May and June in both export (+) and import (-) directions. Compared with May, CAISO increased total IRD exports to PACE while decreased imports from PACE in June. PACE decreased IRD export to CAISO and increased imports from CAISO. While PACW showed slight increase in both IRD import and export volumes.

Figure 113: Total IRD transfers volumes for 3 BAAs per month



Reliability capacity transfers

Reliability capacity is a new day-ahead product introduced with EDAM to procure upward and downward capacity needed to balance differences between cleared day-ahead physical supply and the load forecast. Reliability capacity ensures sufficient capacity is available to address both supply shortfalls and oversupply. This section summarizes the patterns of reliability capacity transfers among BAAs during May and June 2026.

Reliability capacity up

Error! Reference source not found. Figure 114 to Figure 115 show CAISO's daily and hourly average RCU transfers in May and June 2026 on both export (+) and import (-) directions. Generally, CAISO remained a net importer for RCU in both May and June. The largest import volume at about 130 MW occurred on May 27, while net exports dominated much in the first two days half of May, with the maximum daily average export of about 180 MW on May 2. In June there were only limited RCU exports from CAISO and mainly June 14.

The hourly profile shows the largest imports over 100 MW occurring in Hours 2-4 and the largest export 50 MW in hour 20 in May, however, the RCU import peak hours were shifted to daylight hours in June.

Figure 114: Daily average RCU transfers for CAISO

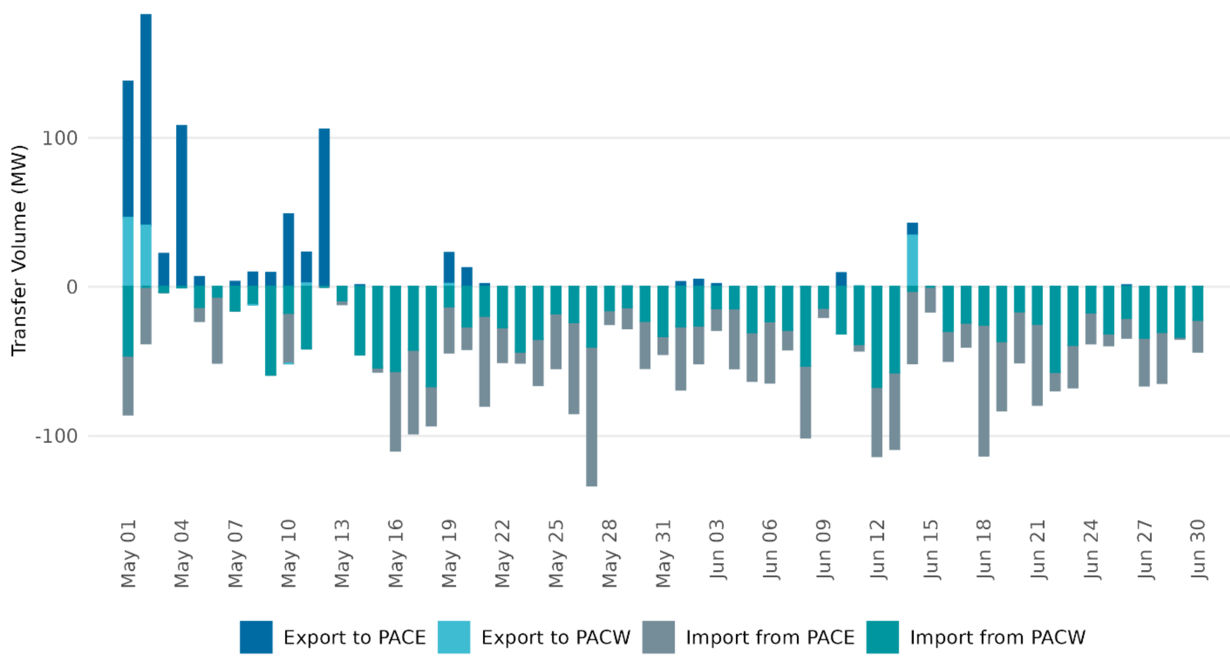
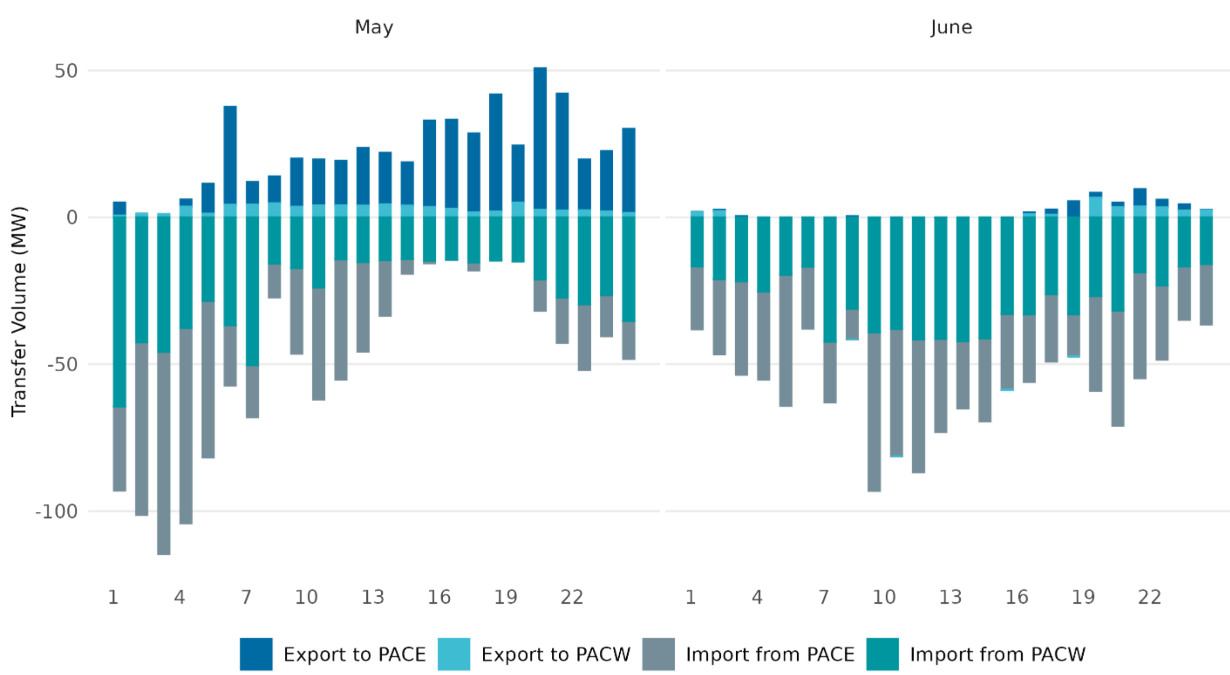


Figure 115: Hourly average RCU transfers for CAISO



Error! Reference source not found. Figure 122 Figure 116 to Figure 117 show PACW's daily and hourly average RCU transfers in May and June 2026 on both export (+) and import (-)

directions. Exports dominate PACW's RCU transfer volumes during most of the days, and the highest daily average is about 70 MW on May 18. The imports occurred at the beginning of May, then started to increase after mid of June, and the highest import is about 90 MW on June 14.

In May, the hourly profile shows a persistent net export pattern across all hours, with the largest export occurring during the overnight and early morning hours. But later in June, the RCU exports were more concentrated to daylight hours, and PACW increased imports from PACE across all hours.

Figure 116: Daily average RCU transfers for PACW

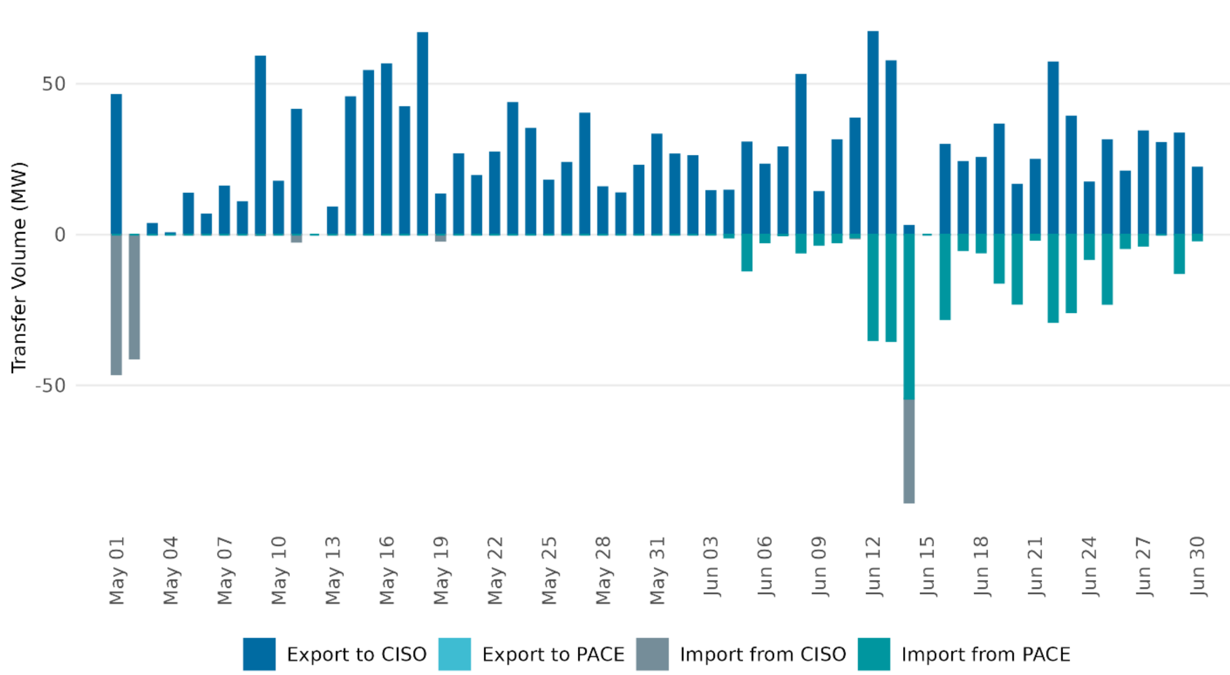
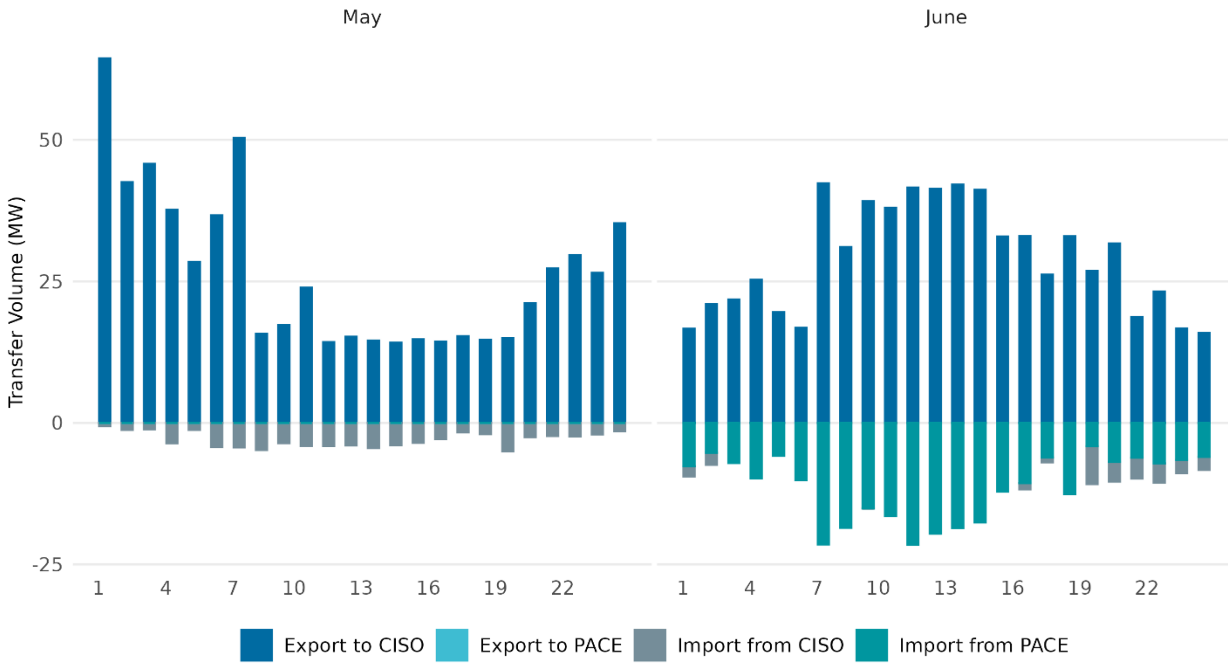


Figure 117: Hourly average RCU transfers for PACW



Error! Reference source not found. Figure 118 to Figure 119 show PACE's daily and hourly average RCU transfers in May and June 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 May then turns into a net exported. The daily average profile shows the maximum RCU import was about 140 MW on May 2 and maximum export volume over 100 MW on June 14. The hourly profile shows more exports in the first half of the day while more imports in the second half in May, then the imports were eliminated and exports to both PACW and CAISO were increased.

Figure 118: Daily average RCU transfers for PACE

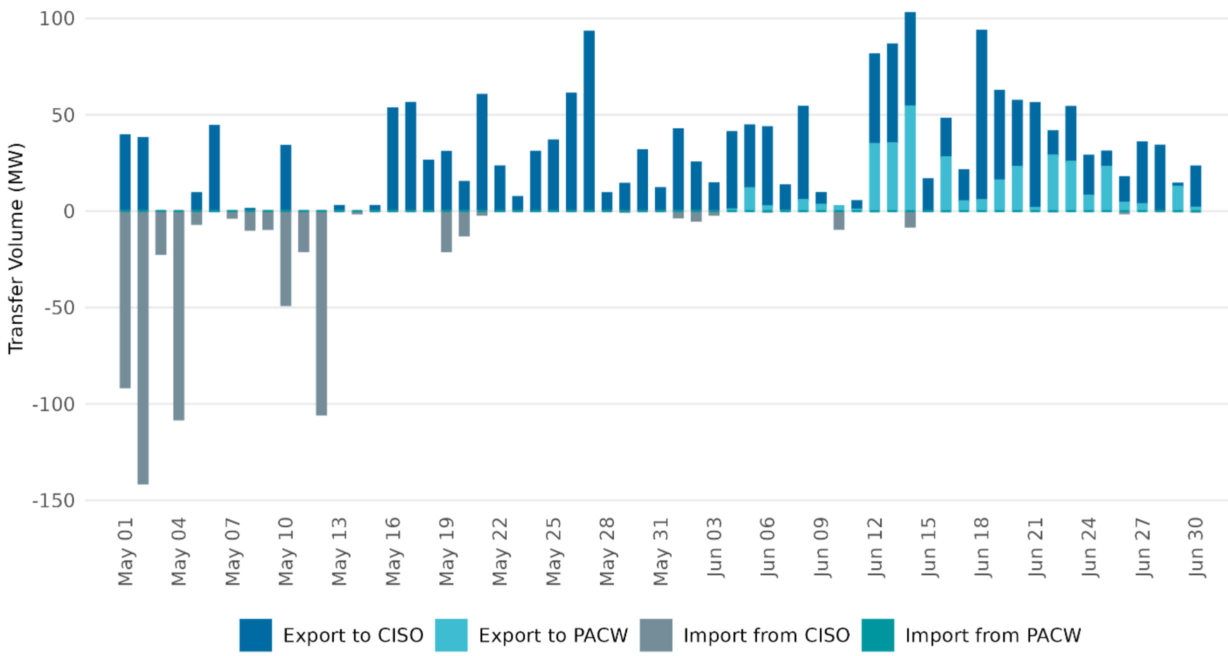


Figure 119: Hourly average RCU transfers for PACE

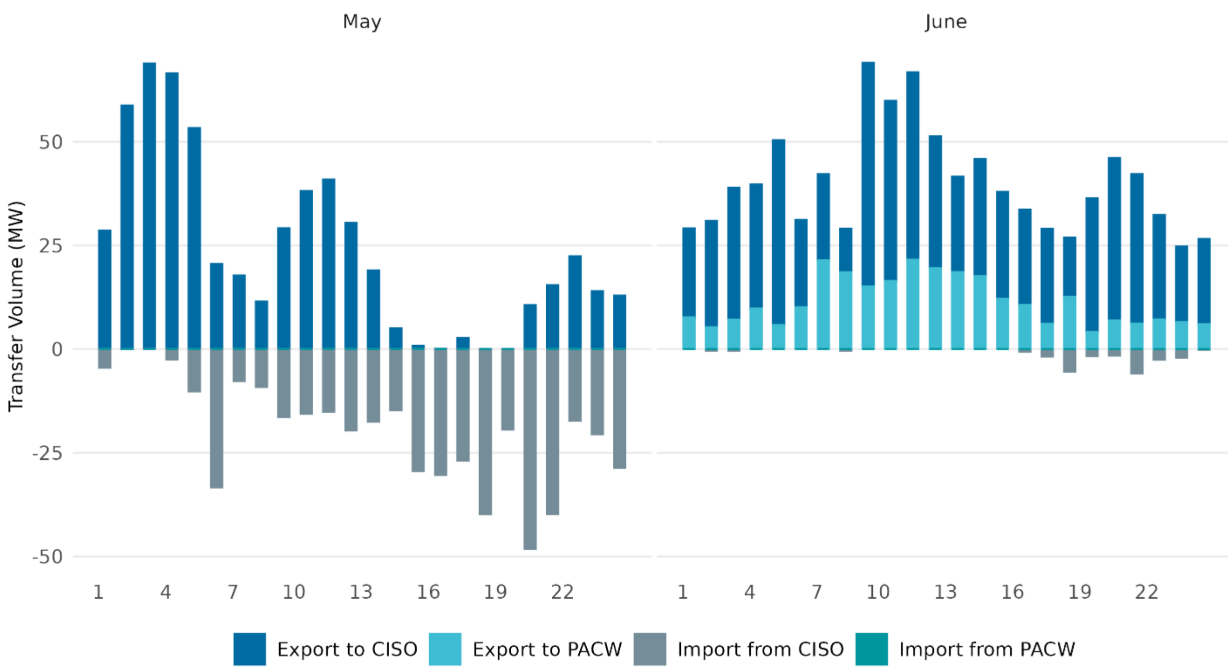
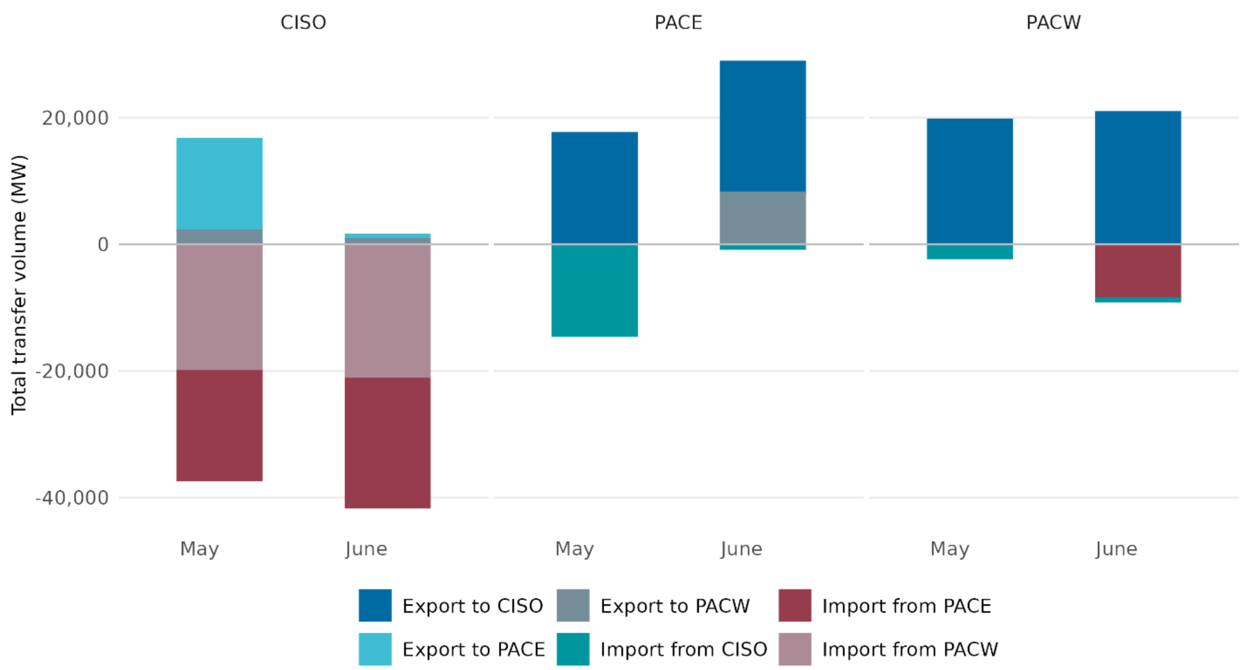


Figure 120 shows the summary of three BAAs' total RCU transfer volumes in May and June in both export (+) and import (-) directions. Compared with May, CAISO reduced significant RCU exports to PACE while imports from PACE and PACW stayed the same in June.

Accordingly, PACE decreased IRD imports from CAISO, while the IRD transfer between PACE and PACW showed slight increase.

Figure 120: Total RCU transfers volumes for 3 BAAs per month



Reliability capacity down

For CAISO's RCD transfers, 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 in May, with the highest volume over 30 MW in hour 24. In June, the CAISO's RCD imports during night hours decreased, while exports increased during morning peak hours.

Figure 121: Daily average RCD transfers for CAISO

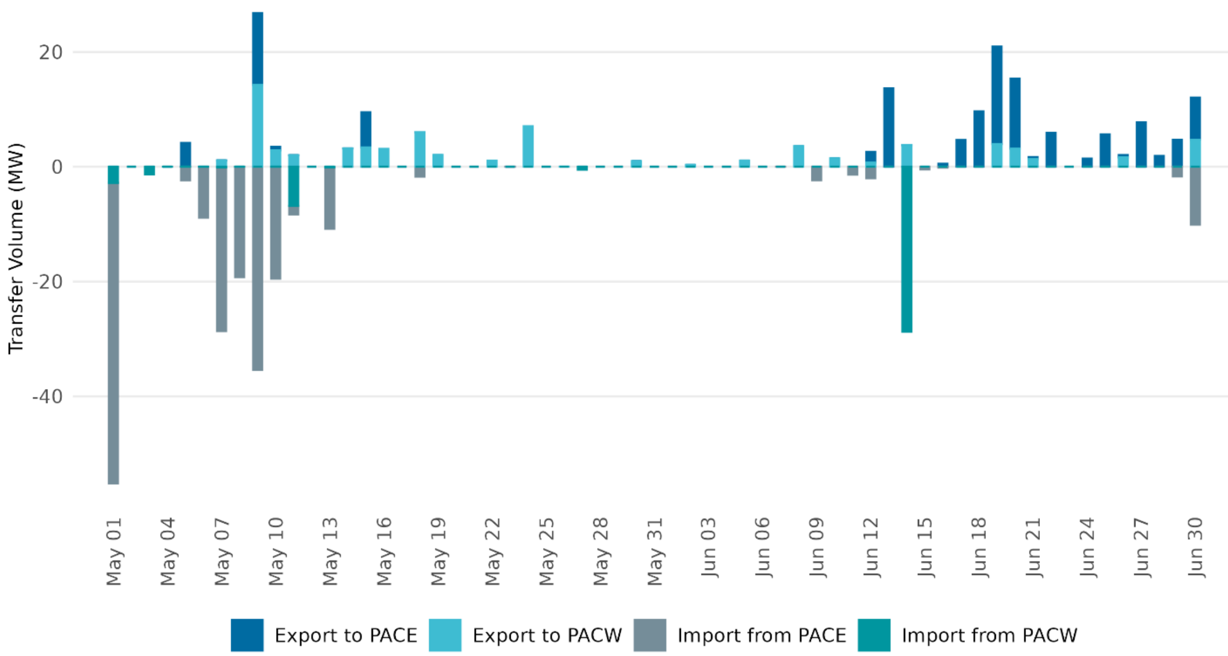
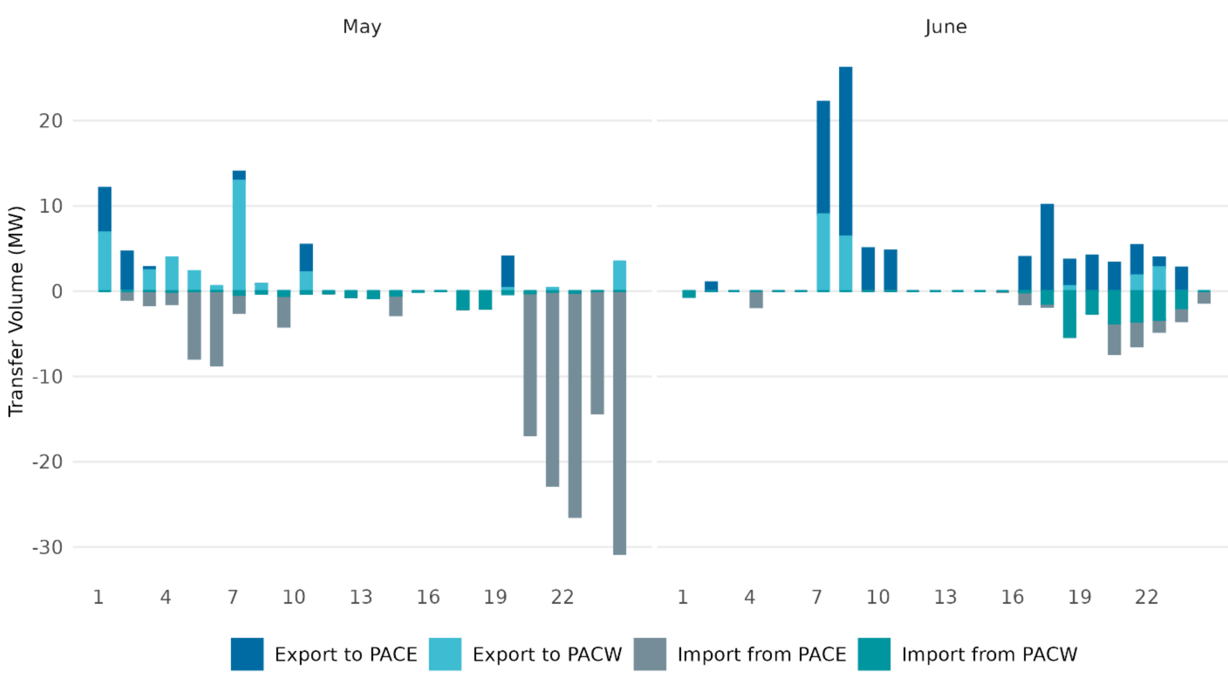


Figure 122: Hourly average RCD transfers for CAISO



As for RCD transfer in PACW, the average imports were more concentrated in June and the highest daily average was 20 MW on June 9. PACW also exported about 30 MW to CAISO on

June 14, while on other days were almost zero exports. The hourly RCD transfer profile showed the import peak is mainly at Hour 7 and the export peak was during night hours in June.

Figure 123: Daily average RCD transfers for PACW

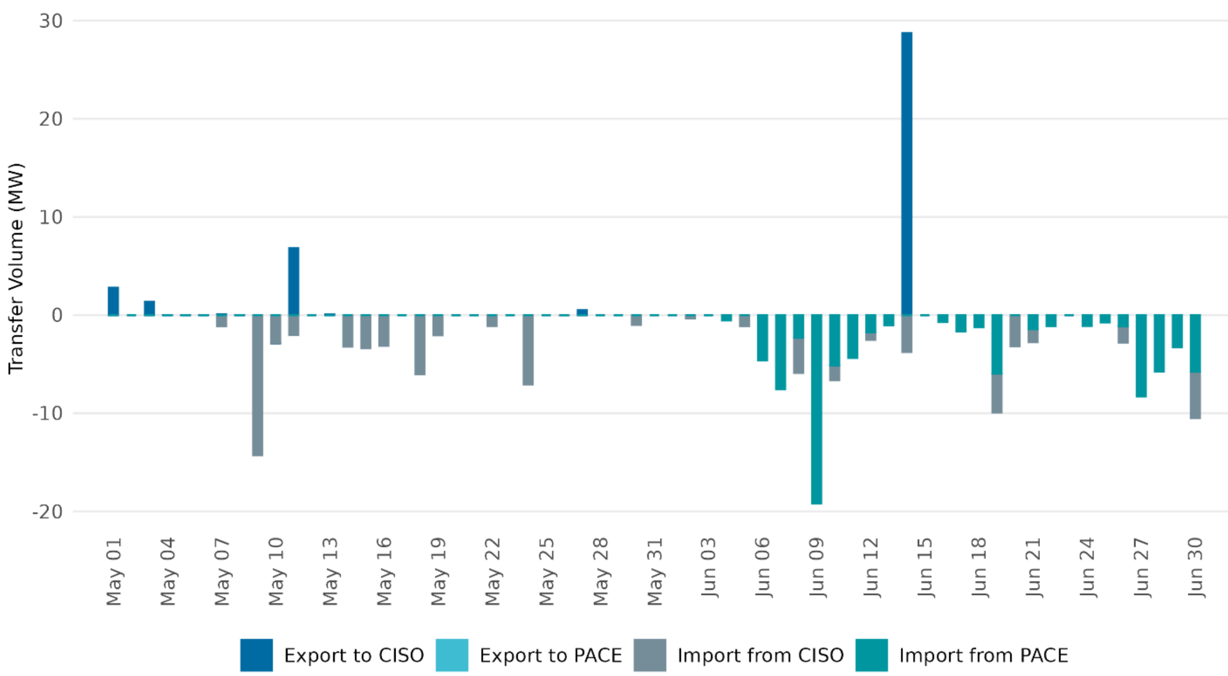
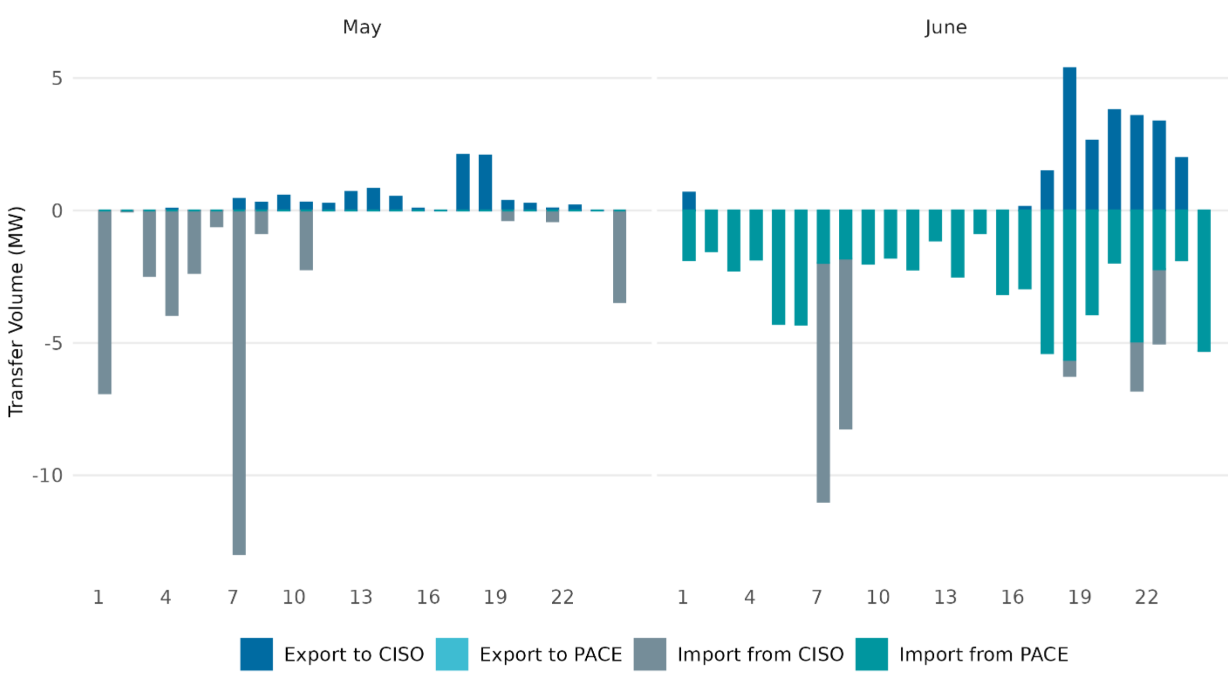


Figure 124: Hourly average RCD transfers for PACW



For RCD products, PACE's average transfer showed different patterns in May and June. RCD exports mainly occurred in the first half of May, and the maximum export was 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 in May. In June, the night hours RCD exports decreased while PACE increased its import from CAISO during morning and afternoon peak hours.

Figure 125: Daily average RCD transfers for PACE

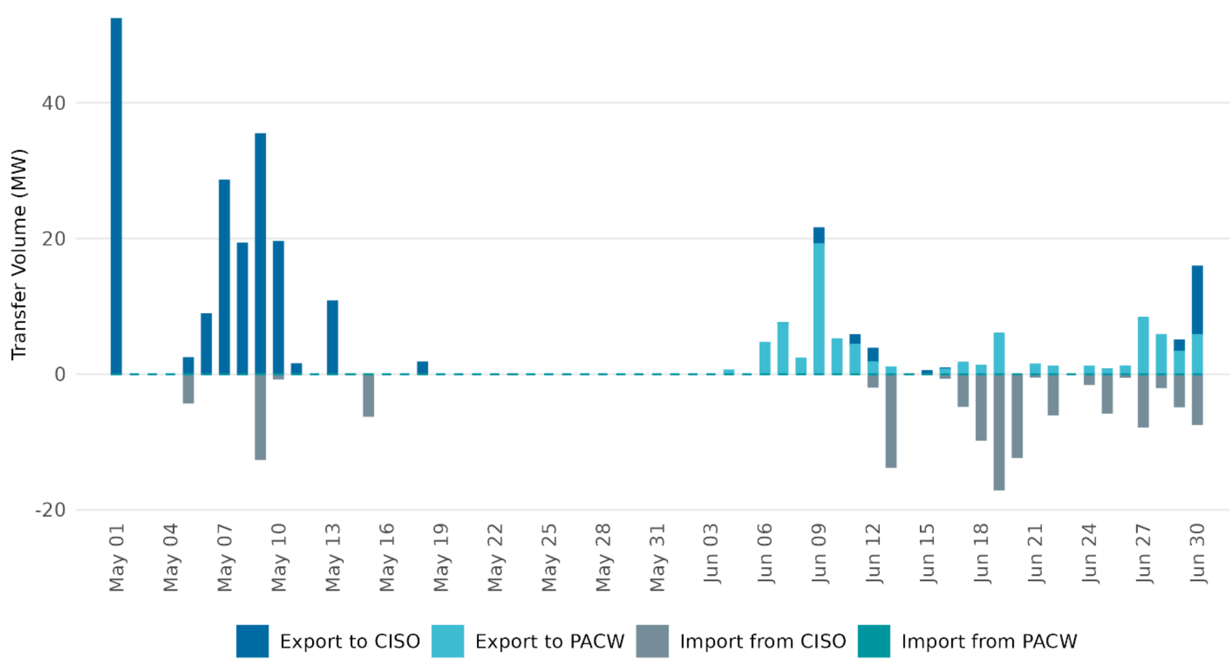


Figure 126: Hourly average RCD transfers for PACE

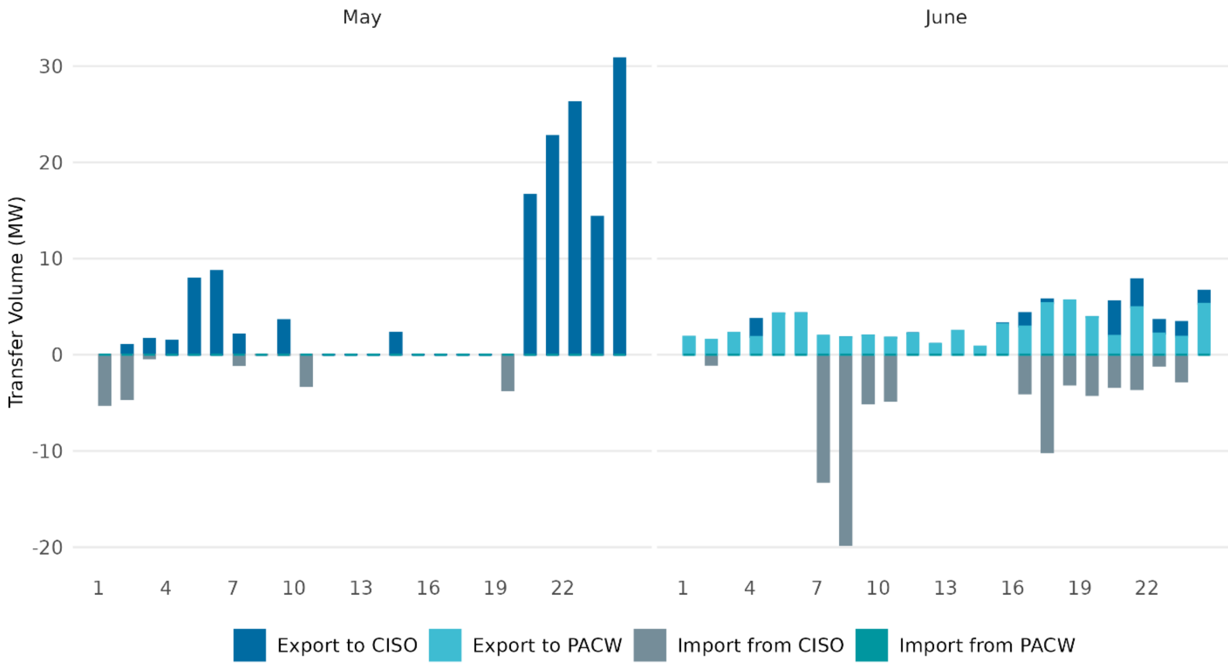
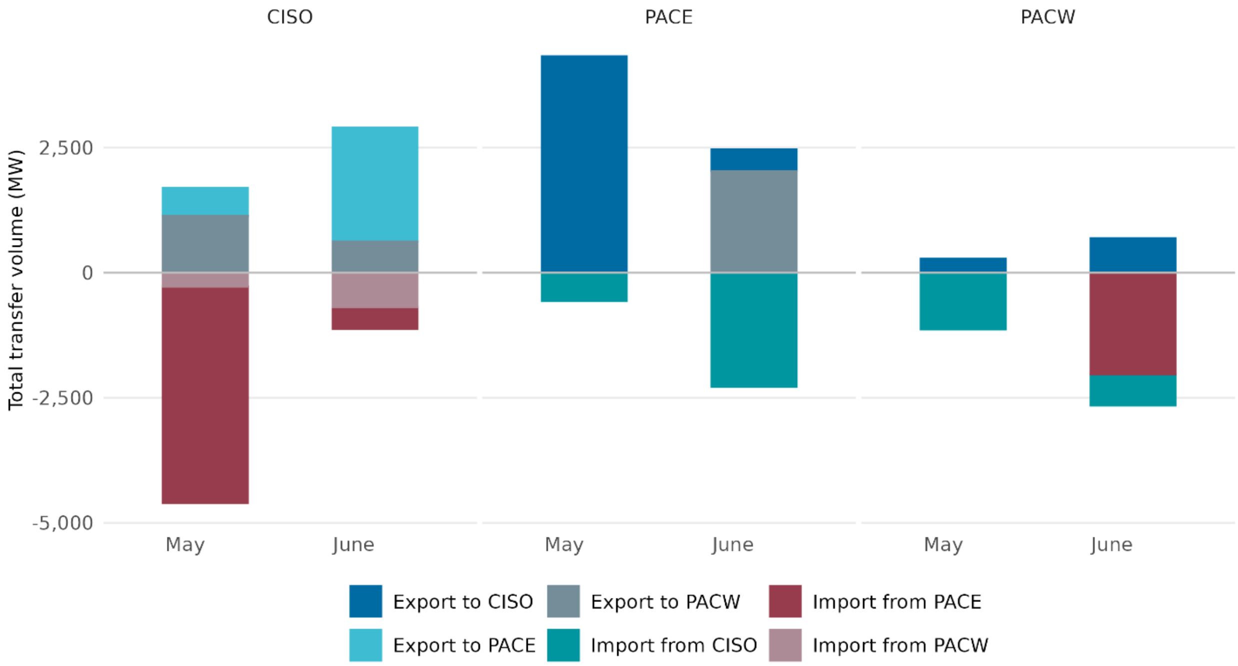


Figure 127 shows the summary of three BAAs' total RCD transfer volumes in May and June in both export (+) and import (-) directions. Compared with May, CAISO reduced RCD imports from PACE while increasing imports to PACE in June. Accordingly, PACE decreased IRD exports to CAISO but increased more imports from CAISO. PACW showed increase in both the imports and exports.

Figure 127: Total RCD transfers volumes for 3 BAAs per month



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 9 shows the average MCC for the month of May for the EDAM DLAP/ELAP APnodes[4]. 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 9: Average congestion costs

	Average MCC ($/MWh)	
DLAP/ELAP	May	June
PACE	-0.80	-0.75
PACW	0.48	-0.87
PGAE	4.04	2.29
SCE	-3.68	-1.76

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 June, congestion continues to have minimal impacts on PACE and PACW ELAP locational marginal prices, at -$0.75 and -$0.87, respectively. In contrast, within CAISO DLAPs, SCE MCC averaged -$1.76, while PG&E MCC averaged $2.29. 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 typically are like those of Northern California, however, average MCC values were negative in June due to ELAP price exposure to the 30005_ROUND MT_500_30015_TABLE MT_500_BR_1 _6 constraint. Average MCC prices at PACE were generally negative, mirroring congestion patterns in Southern California. For the month of June, both PAC BAAs saw lower prices from congestion on average. Like May, the magnitude of congestion observed at PACW and PACE was considerably lower than that seen within the CAISO areas.

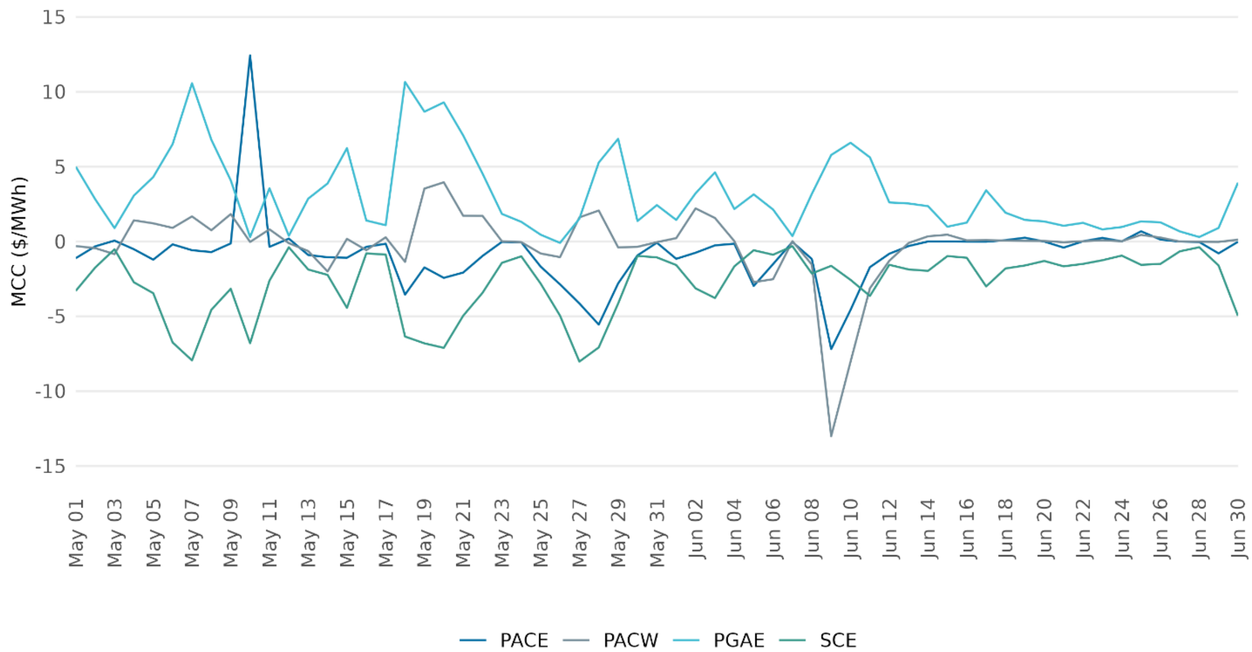
Table 10 provides an hourly average of congestion costs across areas with the blue gradient indicating larger positive MCC prices and the gradient of purple indicates larger negative MCC prices. The highest congestion costs occurred during solar generation hours, when renewable output was most concentrated on the grid, resulting in opposite congestion impacts between Northern and Southern California. Congestion price patterns at PACW were highest during solar hours like in May, but are down to under 1 dollar while congestion at PACE continues to generally follow the trends observed in Southern California. Both PAC areas generally saw deeper negative congestion prices during off-peak hours in June in comparison to May.

Table 10: Hourly average congestion costs

	May				June			
Trade Hour	PACE	PACW	PGAE	SCE	PACE	PACW	PGAE	SCE
1	-0.64	-0.63	-0.48	-0.37	-0.99	-1.46	0.32	0.16
2	-0.55	-1.37	-0.45	-0.08	-0.89	-1.61	0.35	0.10
3	-0.48	-0.43	-0.54	-0.35	-0.65	-1.00	0.23	0.10
4	-0.40	-0.97	-0.65	-0.05	-0.70	-1.33	0.32	0.11
5	-0.37	-0.34	-0.46	-0.36	-0.68	-1.00	0.28	-0.06
6	-0.50	-1.09	-0.60	-0.21	-0.87	-1.41	0.39	-0.01
7	-0.55	-0.32	0.24	-0.59	-0.33	-0.52	0.17	-0.08
8	-1.10	1.53	6.58	-6.39	-0.55	0.03	3.18	-3.04
9	-0.85	2.96	10.48	-9.80	-0.45	0.45	5.14	-4.69
10	-0.52	2.74	10.33	-9.29	-0.44	0.35	5.39	-4.73
11	-0.39	2.28	8.44	-7.45	-0.27	0.54	3.31	-3.85
12	-0.27	2.24	7.92	-6.77	-0.30	0.34	3.75	-3.41
13	-0.09	2.32	7.85	-6.53	-0.17	0.66	3.70	-3.39
14	-0.15	2.46	7.73	-6.46	-0.28	0.69	4.11	-3.56
15	-0.19	2.50	7.66	-6.34	-0.22	1.07	4.25	-3.91
16	-1.26	2.56	8.92	-6.80	-0.19	0.44	4.47	-4.04
17	-1.48	2.50	8.37	-6.79	-0.37	0.50	4.31	-3.91
18	-2.50	-0.38	8.03	-6.16	-0.65	-0.90	3.45	-2.80
19	-1.75	-1.35	3.18	-2.79	-1.23	-2.19	1.89	-0.87
20	-1.62	-1.92	2.14	-1.66	-2.16	-4.30	2.25	-0.58
21	-1.28	-1.01	1.62	-1.51	-1.56	-3.03	1.40	-0.27
22	-1.00	-1.21	0.71	-0.85	-1.58	-3.04	1.15	-0.05
23	-0.73	-0.81	0.02	-0.47	-1.19	-2.16	0.68	0.16
24	-0.48	-0.79	-0.19	-0.28	-1.16	-2.06	0.54	0.27

Figure 128 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. PAC BAA's daily averages were generally within a range of -2 \$/MWh to 2 \$/MWh with exception of June. 9th where daily averages for PACE and PACW were -7 \$/MWh and -13 \$/MWh, respectively. The negative congestion prices on this day were primarily driven by the 30005_ROUND MT_500_30015_TABLE MT_500_BR_1 _6 transmission constraint.

Figure 128: Daily average congestion cost by area



Parallel flows

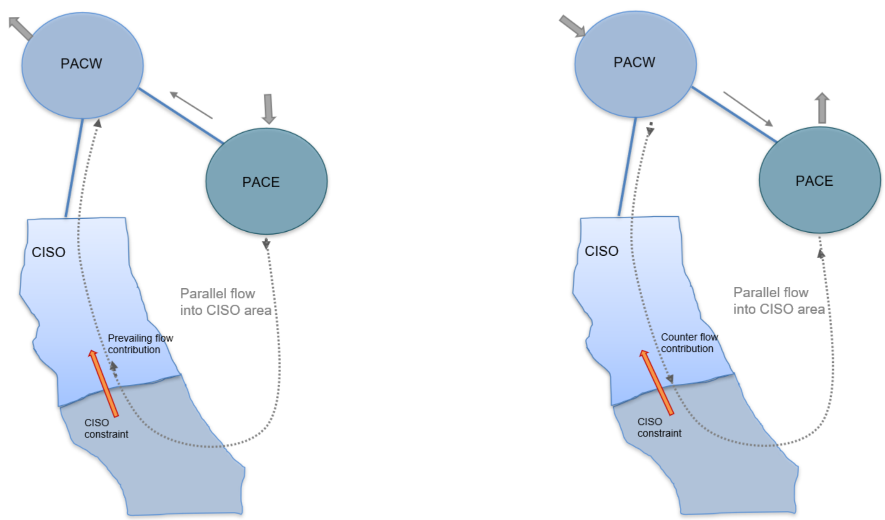
A more fundamental assessment of EDAM transaction effects is to examine their flow contributions on transmission constraints. Transactions in one BAA can contribute to flows on transmission constraints in another BAA; these are known as *parallel flow*. The data is presented in a matrix of transactions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

Figure 129: 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 129 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 130 illustrates the concepts of prevailing and counter flows from a transaction between PAC areas creating a parallel flow in CAISO BAA.

Figure 130: Illustration of parallel flows



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 11 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 11: MCC breakdown by source of congestion[5]

Congestion Price Impact ($/MWh)								
	May				June			
Source of Congestion	**PACE**	**PACW**	**PGAE**	**SCE**	**PACE**	**PACW**	**PGAE**	**SCE**
CISO	**-0.62**	**0.80**	**4.12**	**-3.00**	**-0.75**	**-0.94**	**2.15**	**-1.40**
Base	-0.60	0.74	3.92	-2.84	-0.66	-0.76	2.04	-1.34
IRD	-0.01	-0.02	0.08	-0.05	-0.02	-0.05	0.04	-0.05
IRU	-0.01	0.07	0.12	-0.10	-0.06	-0.13	0.07	-0.01
PACE	**0.42**		**-0.06**	**-0.18**	**0.08**	**0.03**	**-0.03**	**-0.06**
Base	0.41		-0.06	-0.17	0.02	0.01	-0.03	-0.03
IRD	0.00		0.00	0.00	0.01		0.00	0.00
IRU	0.01		0.00	0.00	0.04	0.03	0.00	-0.03

To summarize the table in terms of the relationship between the PacifiCorp and CAISO areas for the month of June, CAISO constraints across all deployment scenario constraint types, on average, had a -0.75 and -0.94 $/MWh MCC price impact on PACE and PACW, respectively. PACE constraints on average impacted PGAE and SCE DLAPS by -0.03 and -0.06 $/MWh respectively. PACW congestion was limited to ITC constraints; therefore, we do not see any direct parallel flow impacts to the MCC of other LAPs. Still, the most significant congestion impact was realized from CAISO constraints on CAISO area (internal flows). Table 12 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 *11* and the breakdown by transmission constraint.

Table 12: Congestion costs by constraint for June 2026

June 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	22440_MELROSE _69.0_22442_MELRSETP_69.0_BR_1 _1							0.00			0.00		
CISO	22464_MIGUEL _230_22468_MIGUEL _500_XF_81	-0.01						0.00			0.00		
CISO	22468_MIGUEL _500_22472_MIGUELMP_ 1.0_XF_80	-0.02		0.00				-0.01		0.00	0.00		
CISO	22773_BAY BLVD_69.0_22604_OTAY _69.0_BR_2 _1							0.00			0.00		
CISO	22831_SYCAMORE_138_22832_SYCAMORE_230_XF_1							-0.01			0.00		
CISO	22886_SUNCREST_230_22885_SUNCREST_500_XF_2 _P	-0.03			-0.01			-0.01			0.00		
CISO	22886_SUNCREST_230_92860_SUNC TP1_230_BR_1 _1	0.00		0.00				0.00		0.00	0.00		0.00
CISO	22886_SUNCREST_230_92861_SUNC TP2_230_BR_2 _1	0.00						0.00		0.00	0.00		0.00
CISO	24114_PARDEE _230_24147_SYLMAR S_230_BR_2 _1	-0.02						0.00			0.01		
CISO	24602_VICTOR _115_24607_ROADWAY _115_BR_1 _1										0.00		
CISO	24701_KRAMER _230_24601_VICTOR _230_BR_1 _1							0.00			0.00		
CISO	24701_KRAMER _230_24601_VICTOR _230_BR_2 _1							0.00		0.00	-0.02		0.00
CISO	24801_DEVERS _500_24804_DEVERS _230_XF_1 _P	-0.09						0.02			0.04		
CISO	30005_ROUND MT_500_30015_TABLE MT_500_BR_1 _6	-0.49	-0.02	-0.06	-1.00	-0.05	-0.13	0.29	0.02	0.04	0.11	0.01	0.01
CISO	30050_LOSBANOS_500_30055_GATES1 _500_BR_1 _3				0.04		0.01	0.03		0.00	-0.03		0.00
CISO	30055_GATES1 _500_30060_MIDWAY _500_BR_1 _1	0.00			0.02			0.02			-0.02		
CISO	30056_GATES2 _500_30060_MIDWAY _500_BR_2 _1	0.01			0.12			0.12			-0.12		
CISO	30060_MIDWAY _500_24156_VINCENT _500_BR_2 _3	0.00			0.00			0.00			0.00		
CISO	30105_COTTNWD _230_30245_ROUND MT_230_BR_2 _1	0.00			0.00			0.00			0.00		
CISO	30435_LAKEVILE_230_30460_VACA-DIX_230_BR_1 _1							0.01	0.00		0.00	0.00	
CISO	30440_TULUCAY _230_30460_VACA-DIX_230_BR_1 _1							0.03			-0.02		
CISO	30525_C.COSTA _230_30575_WND MSTR_230_BR_1 _1								0.00			0.00	
CISO	30640_TESLA C _230_30040_TESLA _500_XF_6H	-0.01		0.00	-0.01		0.00	0.01		0.00	-0.01		0.00
CISO	30750_MOSSLD _230_30797_LASAGUIL_230_BR_1 _1							1.10		0.02	-0.91		-0.01
CISO	30765_LOSBANOS_230_30766_PADR FLT_230_BR_1 _1							0.00		0.00	0.00		0.00
CISO	30765_LOSBANOS_230_30790_PANOCHE _230_BR_2 _1				0.07			0.07			-0.10		
CISO	30790_PANOCHE _230_30900_GATES _230_BR_1 _1				0.02			0.09			-0.08		
CISO	30790_PANOCHE _230_30900_GATES _230_BR_2 _1							0.05			-0.04		
CISO	30900_GATES _230_30889_CAFLTSSS_230_BR_1 _1							0.00			0.00		
CISO	32056_CORTINA _60.0_30451_CRTNA M_ 1.0_XF_1							0.00			0.00		
CISO	32754_OLEUM _115_32778_MRTNZJCT_115_BR_1 _1							0.00					
CISO	33020_MORAGA _115_32780_CLARMNT _115_BR_2 _1							0.02	0.00		-0.01		
CISO	33020_MORAGA _115_32790_STATIN X_115_BR_1 _1							0.00			0.00		
CISO	33020_MORAGA _115_32790_STATIN X_115_BR_4 _1							0.00			0.00		
CISO	33020_MORAGA _115_35101_SN LNDRO_115_BR_2 _1							0.00			0.00		
CISO	33200_LARKIN _115_33204_POTRERO _115_BR_2 _1							0.00					
CISO	33315_RAVENSWD_115_38028_PLO ALTO_115_BR_1 _1							0.00			0.00		
CISO	33315_RAVENSWD_115_38028_PLO ALTO_115_BR_2 _1							0.00			0.00		
CISO	33530_KASSONJ2_115_33548_TRACY _115_BR_1 _1							0.00					
CISO	33541_AEC_TP1 _115_33540_TESLA _115_BR_1 _1							0.00	0.01	0.00	0.00	0.00	0.00
CISO	33543_AEC_TP2 _115_33540_TESLA _115_BR_1 _1							0.00			0.00		
CISO	33724_LOCKEFRD_60.0_33726_VICTOR _60.0_BR_1 _1							0.00			0.00		
CISO	33932_MELONES _115_33936_MELNS JB_115_BR_1 _1							0.00					
CISO	33936_MELNS JB_115_33951_VLYHMTP1_115_BR_1 _1							0.00					
CISO	34101_CERTANJ2_115_34116_LE GRAND_115_BR_1 _1							0.00	0.00				
CISO	34116_LE GRAND_115_34115_ADRA TAP_115_BR_1 _1							0.01		0.00	0.00		0.00
CISO	34158_PANOCHE _115_34350_KAMM _115_BR_1 _1							0.00					
CISO	34162_ORO LOMA_115_34168_EL NIDO _115_BR_1 _1							0.00		0.00	0.00		0.00
CISO	34256_BORDEN _70.0_30805_BORDEN _230_XF_1								0.00				
CISO	34370_MC CALL _115_34385_KINGSJCT_115_BR_1 _1							0.00			0.00		
CISO	34385_KINGSJCT_115_34435_GUARD J2_115_BR_1 _1							0.00			0.00		
CISO	34418_KINGSBRG_115_34405_FRWT TAP_115_BR_1 _1							0.00					
CISO	34418_KINGSBRG_115_34428_CONTADNA_115_BR_1 _1							0.01			-0.01		
CISO	34427_ATWELL _115_34701_SMYRNA 1_115_BR_1 _1							0.00					
CISO	34540_HENRITTA_70.0_30881_HENRIETA_230_XF_4							-0.01		0.00			
CISO	34724_KRN OL J_115_34736_MAGUNDEN_115_BR_1 _1							0.00			0.00		
CISO	34880_SN BRNRD_70.0_39021_SC21ATP _70.0_BR_1 _1							0.00					
CISO	35352_WHISMAN _115_35356_MNTA VSA_115_BR_1 _1							0.00			0.00		
CISO	35353_MT VIEW _115_35356_MNTA VSA_115_BR_1 _1							0.00			0.00		
CISO	35616_SNJOSEB _115_35631_MARKHM J_115_BR_1 _1								0.00			0.00	
CISO	35618_SN JSE A_115_35616_SNJOSEB _115_BR_1 _1							0.09		0.00	-0.05		0.00
CISO	35621_IBM-HR J_115_35642_METCALF _115_BR_1 _1							0.00			0.00		
CISO	35631_MARKHM J_115_35636_EVRGREEN_115_BR_1 _1							0.03	0.00		-0.01	0.00	
CISO	35642_METCALF _115_30735_METCALF _230_XF_2							0.02			-0.01		
CISO	35642_METCALF _115_35645_EVRGRN J_115_BR_2 _2							0.01			-0.01		
CISO	36851_NORTHERN_115_36852_SCOTT _115_BR_2 _1							0.04			-0.03		
CISO	38206_COTTLE A_230_37563_MELONES _230_BR_1 _1										0.00		
CISO	38610_DELTAPMP_230_30580_ALTM MDW_230_BR_1 _1							0.00	0.01	0.00	0.00	-0.01	0.00
CISO	39021_SC21ATP _70.0_34888_ARVIN _70.0_BR_1 _1							0.00					
CISO	7320_CP6_NG								0.00				
CISO	7430_CP6_NG								0.00			0.00	
CISO	7690-CONTRL-INYOKN_EXP_NG										0.00	0.00	
CISO	7690-COOLWATER_KRAMER_IM_NG											0.00	
CISO	7820_TL 230S_OVERLOAD_NG		0.00			0.00			0.00			0.00	
CISO	AMR-SND 138							0.00			0.00		
CISO	HUMBOLDT_IMP_NG								0.00			0.00	
CISO	Line_Wilo-EOX_500KV	0.00						0.00			0.00		
CISO	Lugo AA bank outage Area EXP								0.00			0.00	
CISO	OMS_19695948_DEV_RDB_ALIS	0.00	0.00					0.00	0.00		0.00	0.00	
CISO	OMS20107865-CONTRL-INYOKN_EXP_NG											0.00	
CISO	OMS20108458-CONTRL-INYOKN_EXP_NG											-0.03	
CISO	OMS20246514-CONTRL-INYOKN_EXP_NG											-0.01	0.00
PACE	CAMPWILL_OQUIRRH_345_1	0.01		0.04	0.01		0.03	0.00		0.00	0.00		-0.03
PACE	DIMPLEDE_DUMAS_138	0.02						-0.03			-0.02		
PACE	MIDVALLY 345|138 T1	0.00	0.01					0.00	0.00		0.00	0.00	
PACE	TOTAL_WYOMING_EXPORT	0.00						0.00			0.00		

In summary, the preliminary assessment of May and June 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:

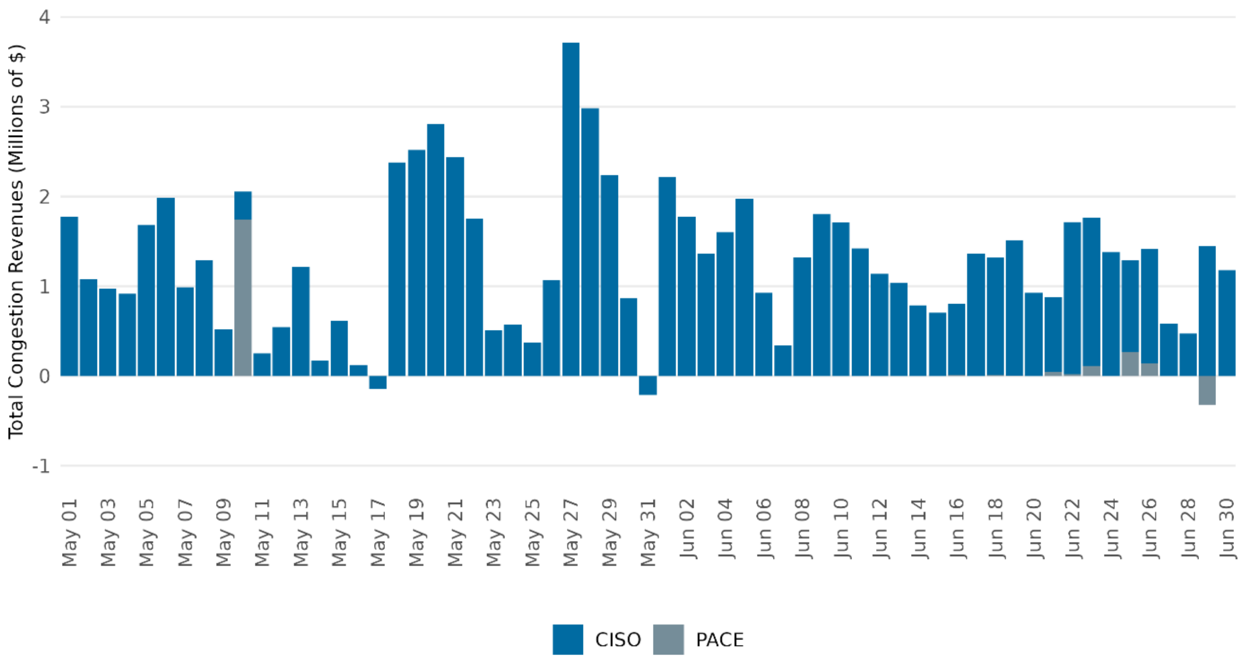
1. PAC transactions can have a sizable impact on CAISO constraints, and this is reflected with sizable MCC prices in PACE and PACW areas
2. CAISO transactions have negligible impact on PAC constraints, and this is reflected with minimal MCC prices in CAISO areas

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 131 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 131: Daily congestion total by BAA[7]



Total EDAM congestion revenues in June were $37.9M, with $37.6M sourced from the CAISO BAA and $285k from PACE. Negative congestion revenues are associated to constraints with net-flows in the non-prevailing direction like the PACE flowgate DIMPLEDE_DUMAS_138. There was no congestion sourced from PACW transmission constraints in June.

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 132 provides the breakdown of net-total congestion rents in the CISO area associated with parallel from PAC areas. In May, both PAC areas accounted for $598k or roughly 1.6% of overall congestion revenues associated with CISO constraints. In June, both areas accounted for $958k or 2.5% of the overall total.

[7] Negative daily totals are linked to an identified issues in the settlement of interties (IPP ITC) constraints and some flow reversal scenarios for PACE constraints. Additionally, the issue around the availability of shift factors has led to PACW ITC congestion to not be included int this total.

Figure 132: Net-Total CISO Congestion Revenues from PAC Flows

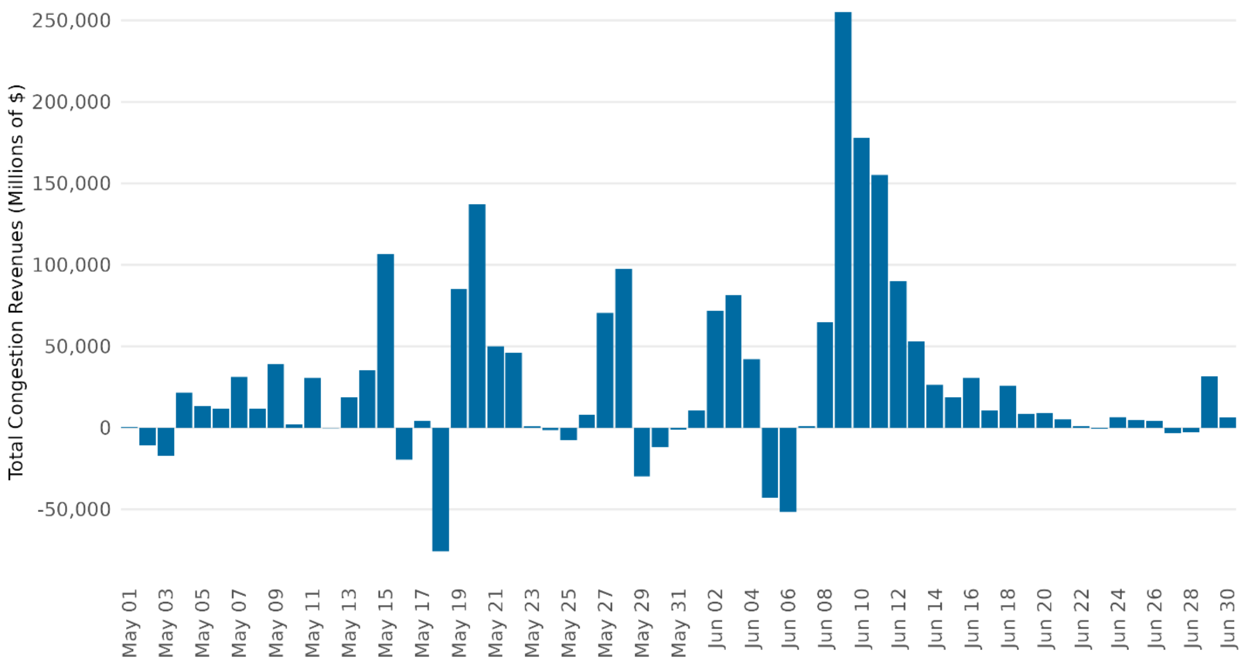


Figure 133 illustrates the daily total congestion revenues from CISO congestion that are returned to PAC areas given that they are associated with exercised rights. The congestion credit is the congestion revenue credit provided to holders of Open Access Transmission Tariff (OATT) transmission rights; 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. Returns to PAC areas from CISO congestion totaled $1.34M in May and $1.33M in June.

Figure 133: Total CRN Congestion Credit

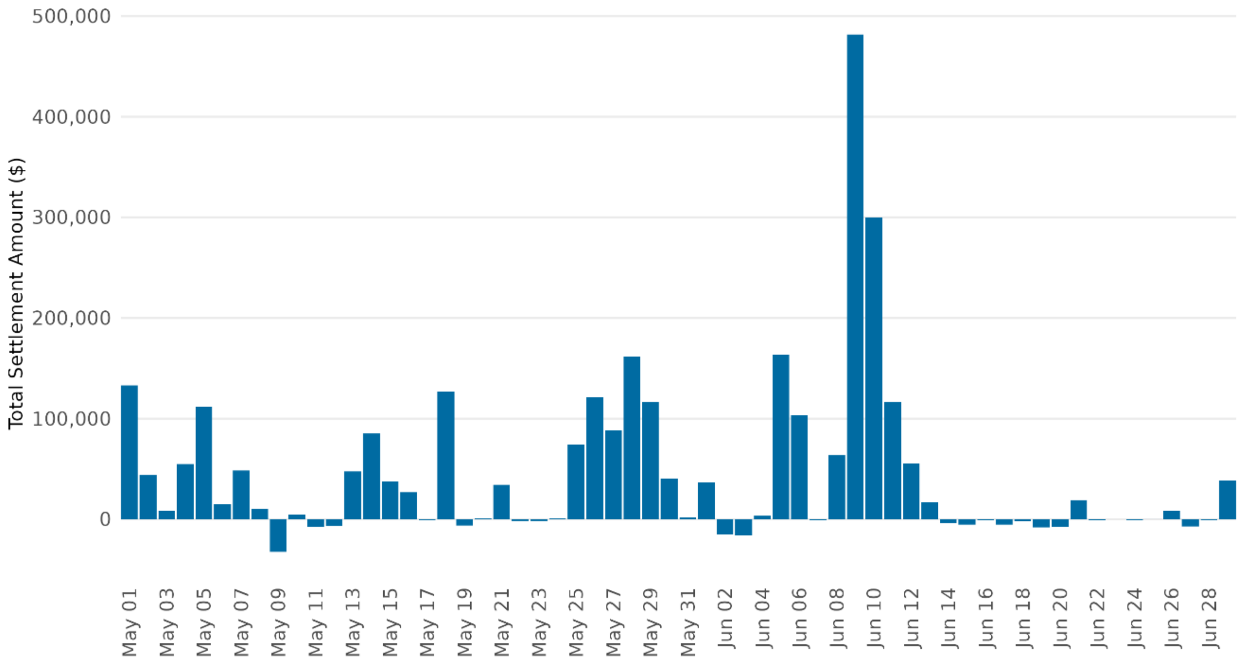


Figure 134 shows the volumes of OATT balanced self-schedules with respect to the total volume of all types of self-schedules for each PAC area. The proportions of OATT balanced self-schedules for PACE and PACW were 48% and 59% in May and 36% and 77% in June, respectively. Figure 135 provides the volumes of OATT balanced self-schedules for each PAC area. PACE averaged 1,835MWh in May and 1,516MWh in June. PACW averaged 1,509MWh in May and 1,826MWh in June.

Figure 134: Total self-schedules compared to OATT self-schedules by PAC Area

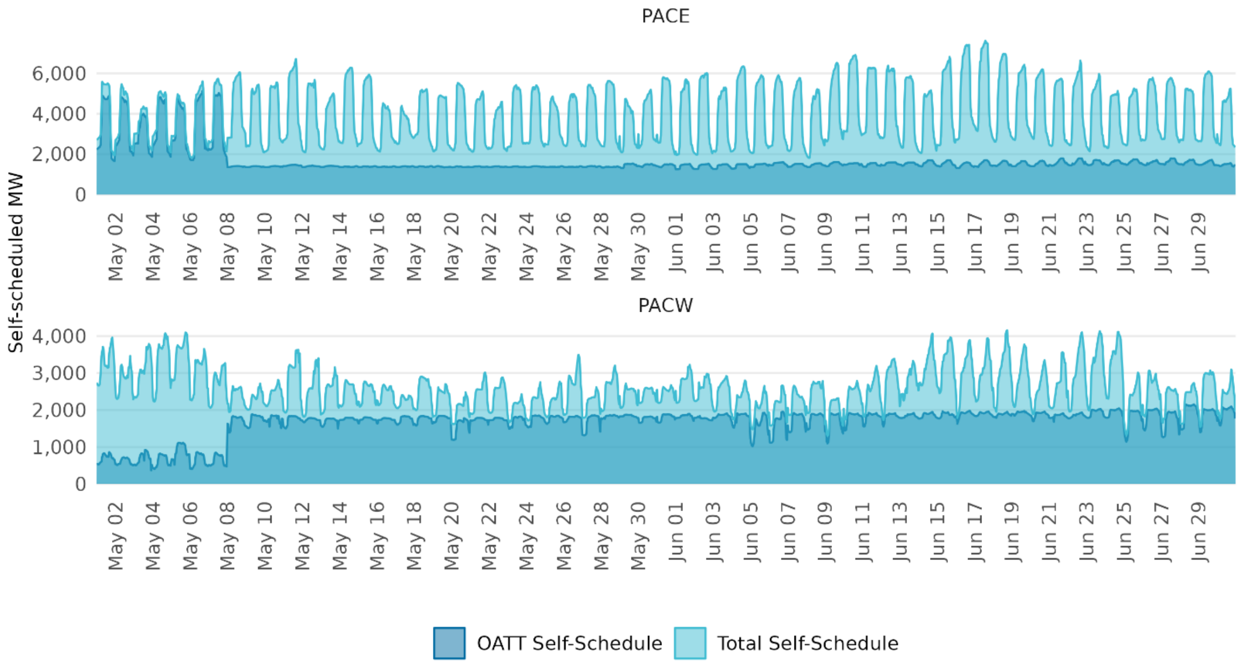
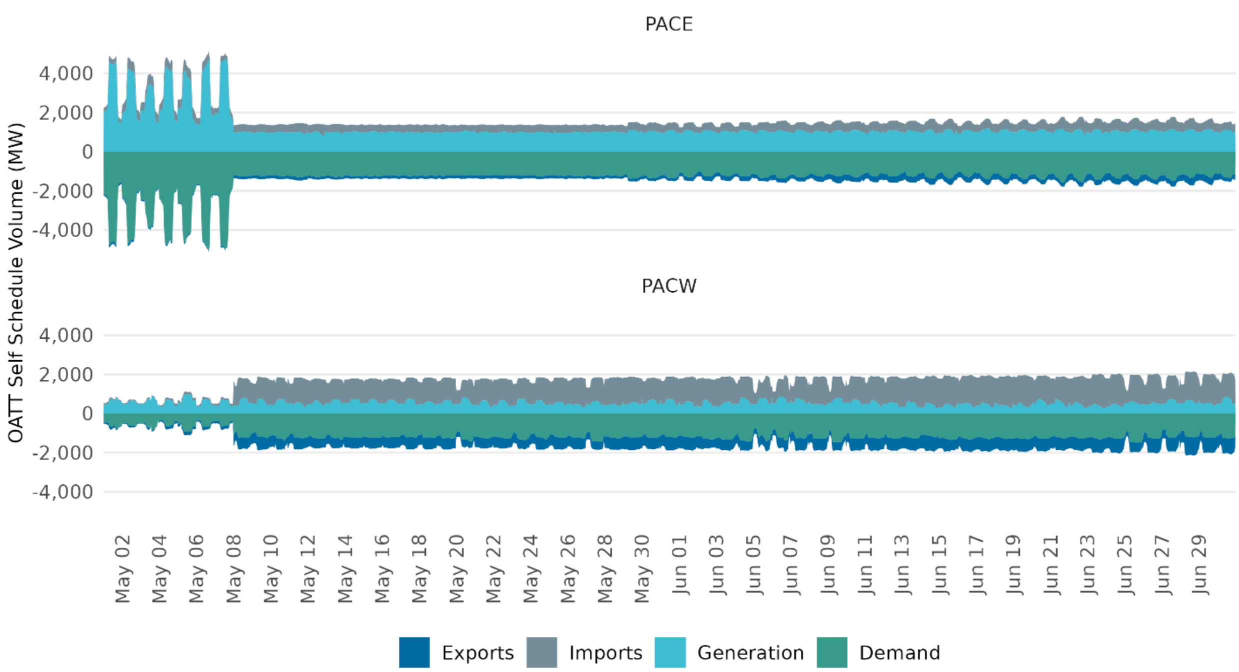


Figure 135: Total OATT Self Schedule Volumes by PAC Area



EDAM Net Export Constraints and RUC Adjustments

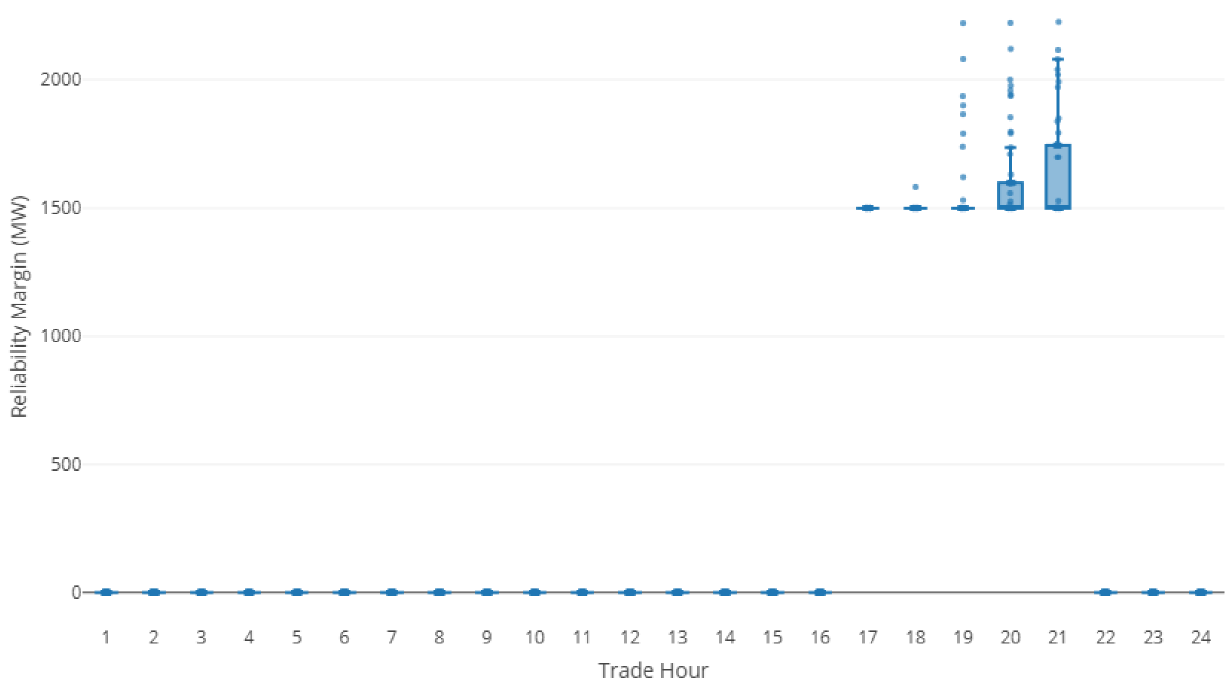
The EDAM export constraint and RUC adjustments are optional BA level constructs that help ensure sufficient procurement to support reliability going into the real-time market.

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 136: 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 both May and June, the CAISO did not see this constraint bind in any hour. Neither PACE nor PACW opted to enforce this constraint in May or June.

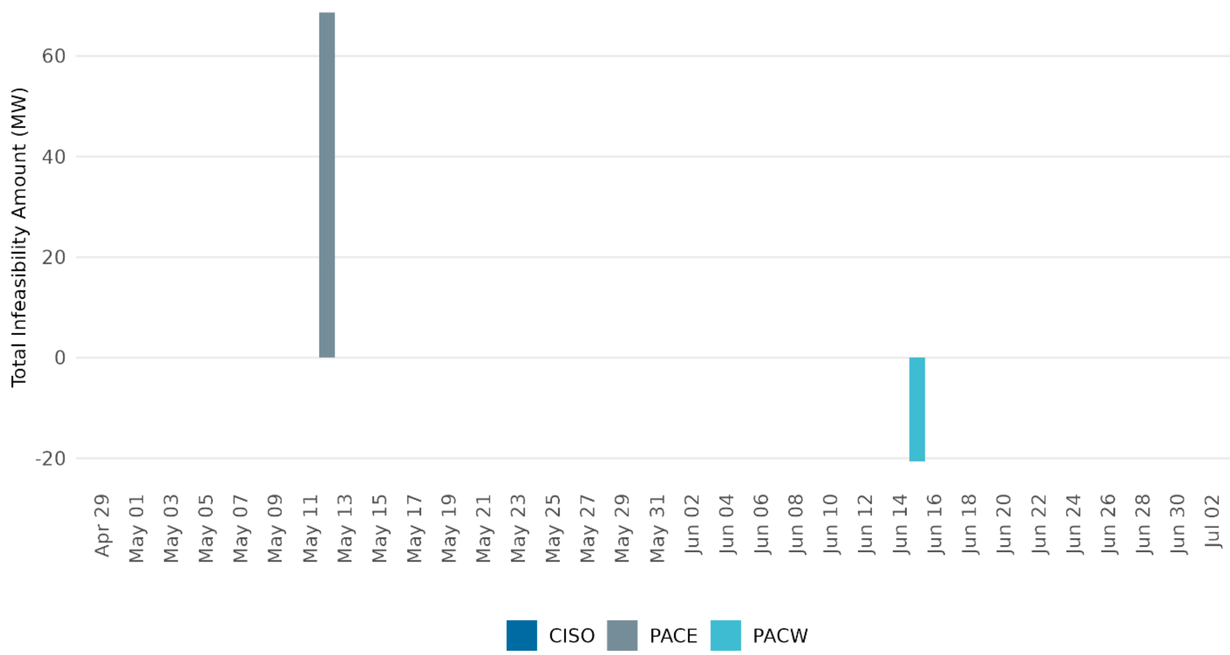
RUC adjustments

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. In June, RUC adjustments were applied for CAISO in 19 total hours across June 11 and June 12 up to a maximum of 810 MWs. No RUC adjustments were applied for PACE nor PACW.

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. The infeasibility may be in either the under-supply direction, which is indicated by a positive infeasibility, or the over-supply direction, which is indicated by a negative infeasibility. In May, PACE observed a RUC infeasibility in the peak hour of May 12, while CAISO and PACE did not observe any RUC infeasibilities in the month. In June, PACW had an over-generation infeasibility midday on June 15, while CISO and PACE did not observe any RUC infeasibilities.

Figure 137: RUC Infeasibilities



Market Power Mitigation

Bids submitted into CAISO markets are subject to market power mitigation (MPM) to maintain a competitive market. In the day-ahead market, MPM uses a competitive path assessment for binding transmission constraints to determine whether a path is competitive or not. If a path is non-competitive, MPM procedures identify any non-competitive contribution of those binding transmission constraints to locational marginal prices for energy and reliability capacity up prices. Bids from resources within that EDAM balancing authority area will be subject to mitigation if the net contribution from non-competitive binding transmission constraints for these prices is positive.

MPM for the IFM market is a market process that existed before EDAM. Before EDAM/DAME, separate bids were not submitted for RUC. Any bid considered in the RUC process before EDAM/DAME had already been subject to the IFM MPM. As part of EDAM/DAME and the introduction of reliability capacity products that require separate bids, a MPM pass was added to assess the competitiveness of RUC reliability capacity bids.

Figure 138 and Figure 139 show the total number of resources subject to mitigation as determined by the IFM MPM and RUC MPM passes on a daily basis, broken down by fuel type. Note, a resource is counted based on the number of day-ahead intervals it was subject to mitigation in, i.e., if a single resource was subject to mitigation in hours ending one through six then it will be counted six times. In Figure 138, the counts on dates before May first include only CAISO resources. After May first, the count includes all EDAM BAA resources. Gas and energy storage make up the majority of resources subject to mitigation in IFM. In RUC, there were almost no gas resources subject to mitigation. In general, there were many few resources subject to mitigation in RUC.

Figure 138: Resources subject to mitigation in IFM MPM, by fuel type

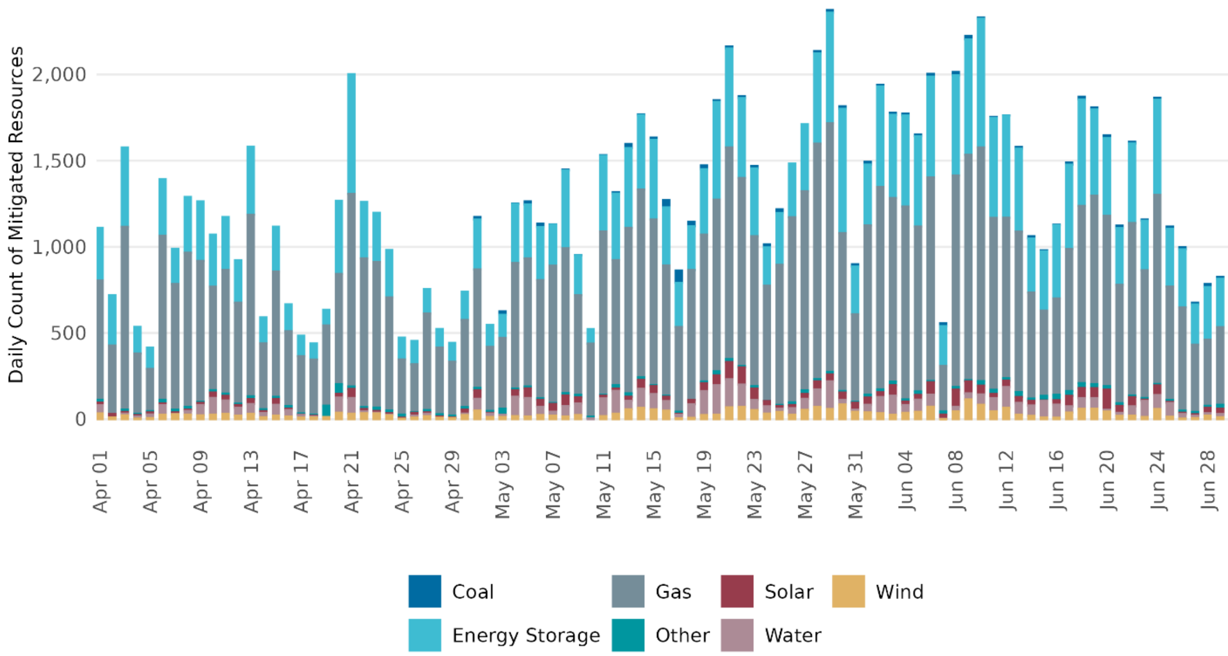


Figure 139: Resources subject to mitigation in RUC MPM, by fuel type

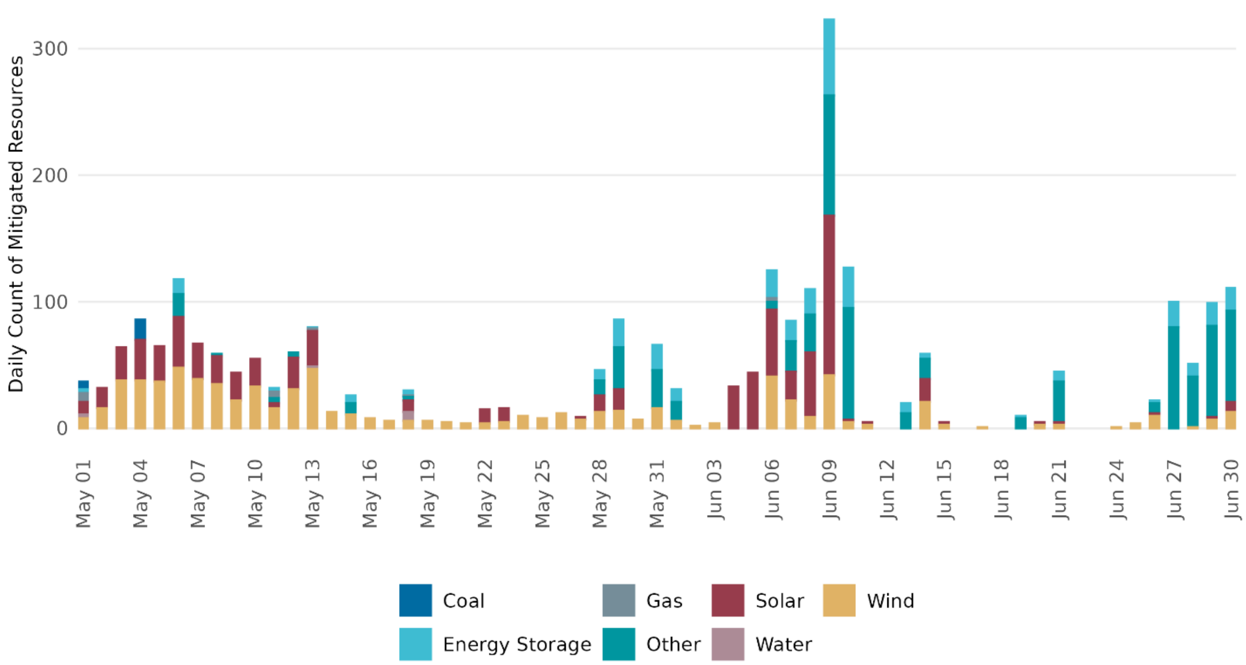


Figure 140 and Figure 141 show the same total counts as above but broken down by BAA. Figure 140 shows that after they joined the IFM market on May first, PACE and PACW, that collectively contain only about 9% of resources that can be subject to mitigation in EDAM, make up about 5.5 percent of the resources that were subject to mitigation in IFM during May and June. Relative to their fraction of the total resource pool, there were more resources subject to mitigation in RUC from PACE and PACW compared to CAISO. Specifically, CASIO resources accounted for about 55 percent of resources subject to mitigation in RUC, PACE resources accounted for about 14 percent, and PACW resources accounted for about 31 percent.

Figure 140: Resources subject to mitigation in IFM MPM, by BAA

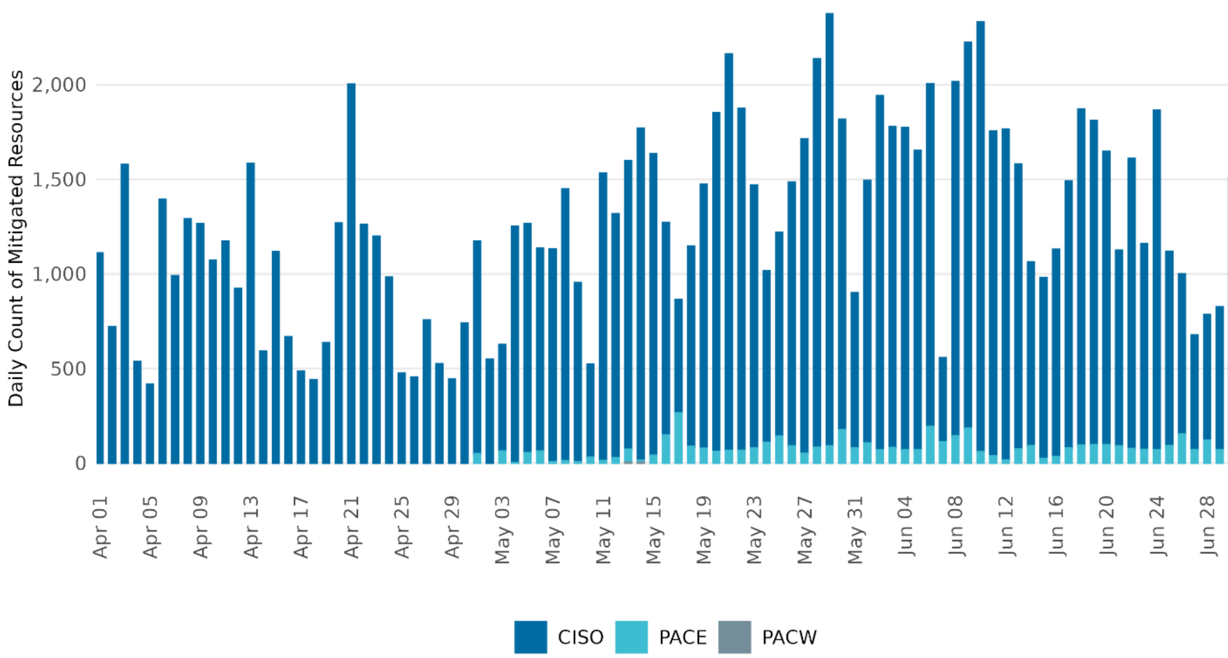


Figure 141: Resources subject to mitigation d in RUC MPM, by BAA

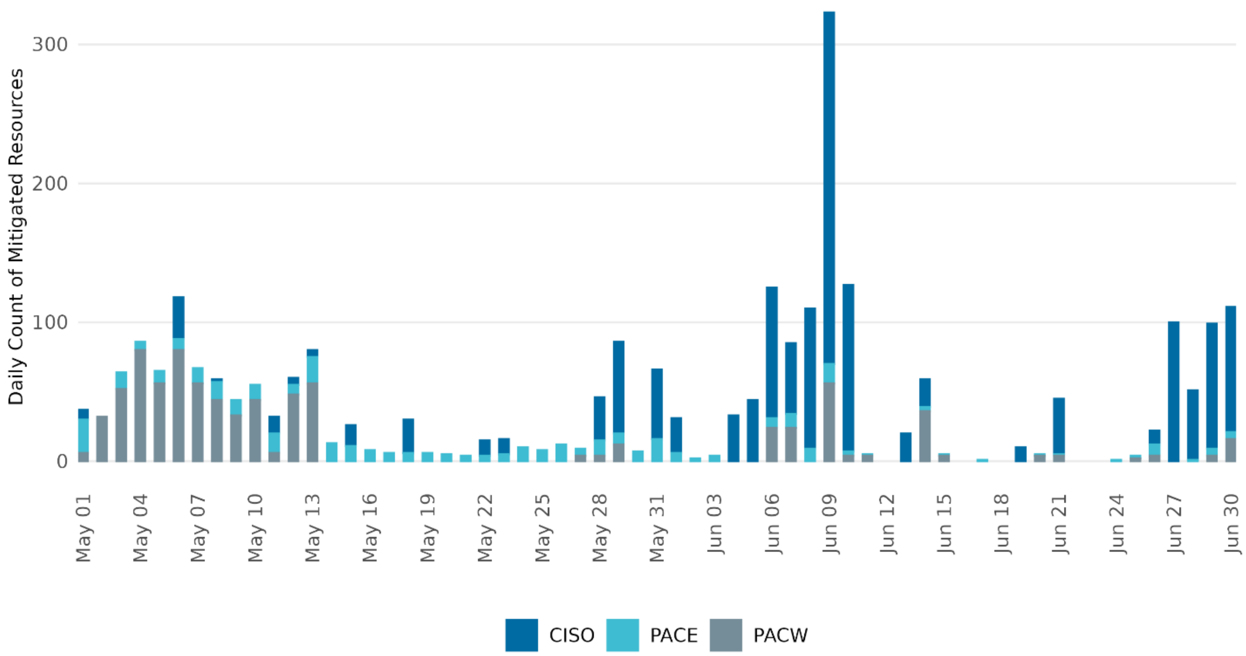


Figure 142 and Figure 143 show the average number of resources subject to mitigation in each hour of the day, averaged over April through June for IFM and May through June for RUC, broken down by fuel type. Figure 142 shows that mitigation in IFM is typically highest during the middle of the day when there is a lot of solar production. The middle of the day also sees the highest amounts of mitigation in RUC, but the overall hourly profile is not as symmetric.

Figure 142: Resources subject to mitigation in IFM MPM, by fuel type

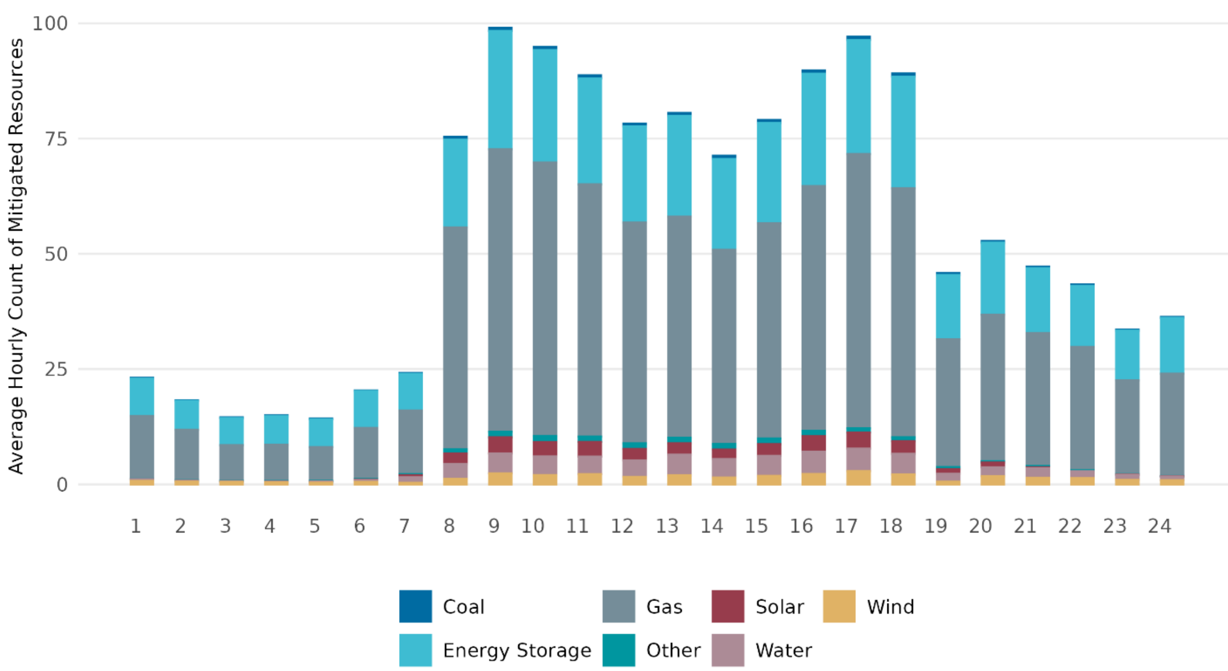
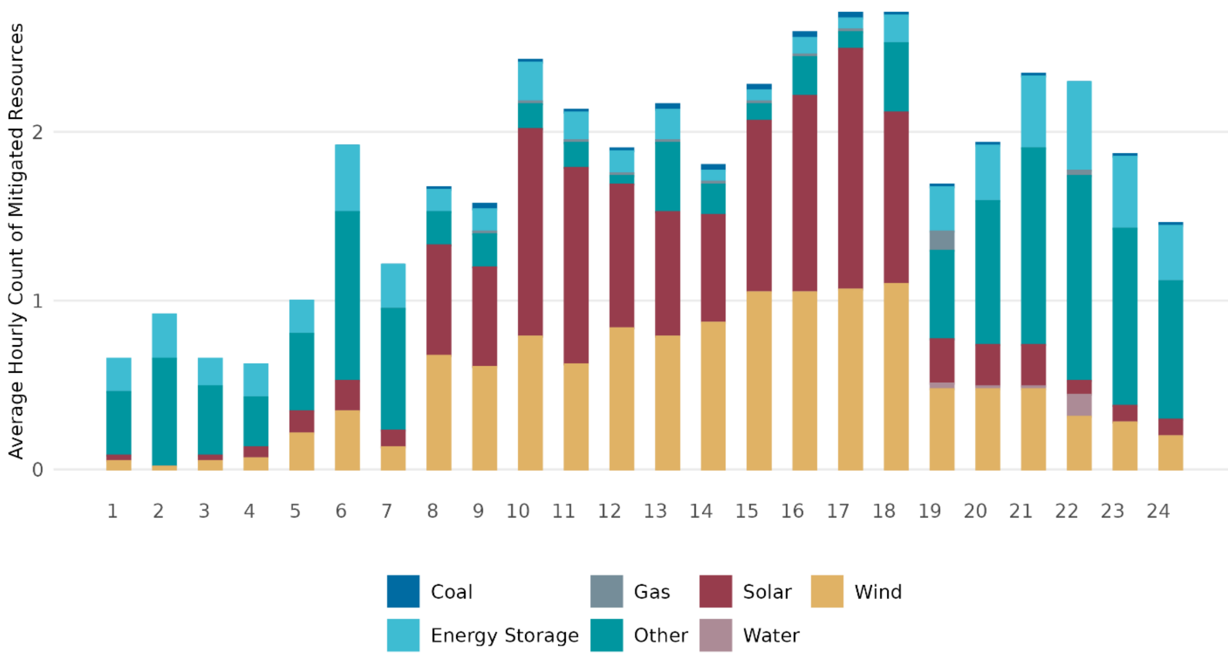


Figure 143: Resources subject to mitigation in RUC MPM, by fuel type



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 144 to Figure 146show the total wholesale costs for CAISO at a daily and monthly level. The average total cost per MWh is also shown in Figure 144 and Figure 145[8]. There is no notable change in total or average costs for CAISO after EDAM. Looking at the monthly level, the total costs for June continue the trend of lower total costs in 2026 relative to 2025.

[8] Total costs include 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.

Total costs in June 2026 increased from May, which is typical for this time of the year when demand increases as the weather gets hotter.

The total costs in April, May, and June 2026 were $283 million, $309 million, $426 million, respectively. This can be compared to $410 million, $518 million, and $622 million in 2025. The average costs per MWh in April, May and June 2026 were $19.14/MWh, $19.16/MWh, and $24.25/MWh, respectively, compared to $27.27/MWh, $31.36/MWh, and $35.02/MWh in 2025.

Figure 144: Total daily costs CAISO

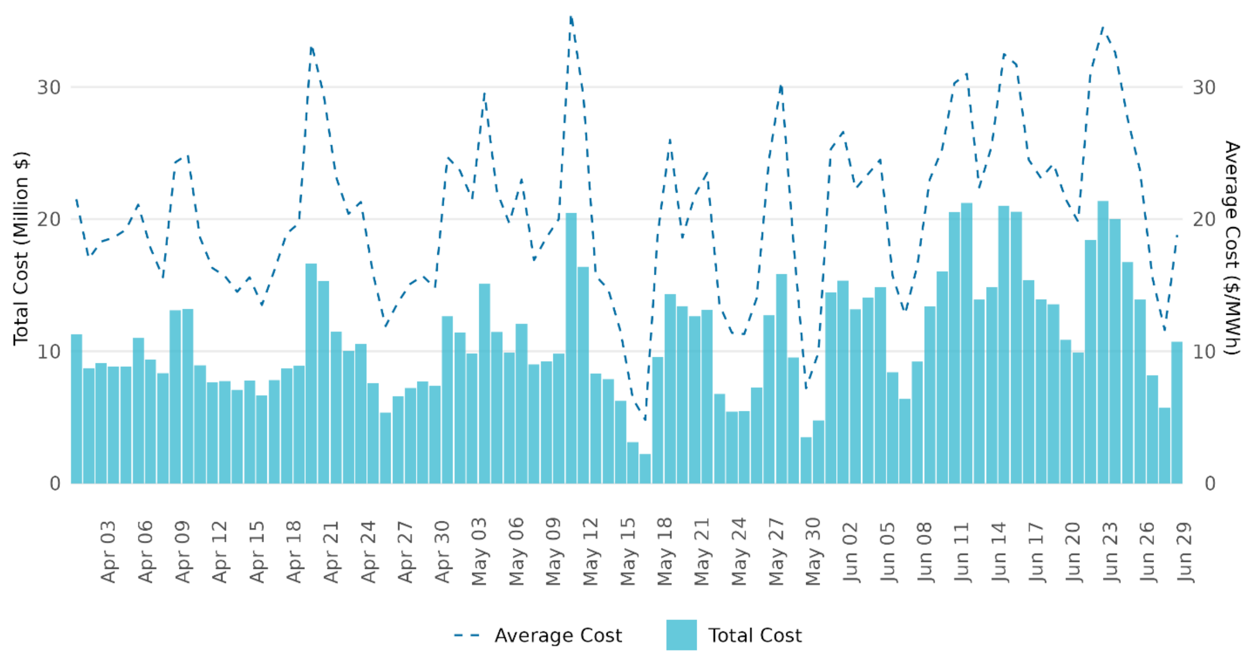


Figure 145: Monthly total costs CAISO

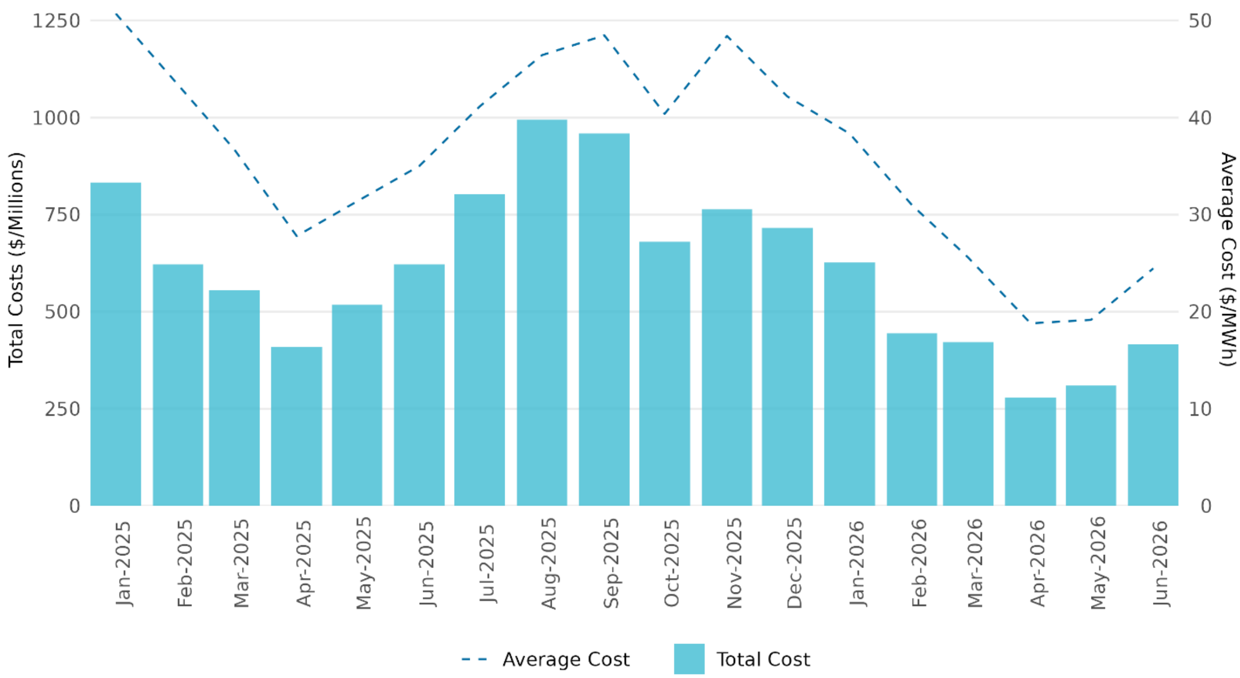
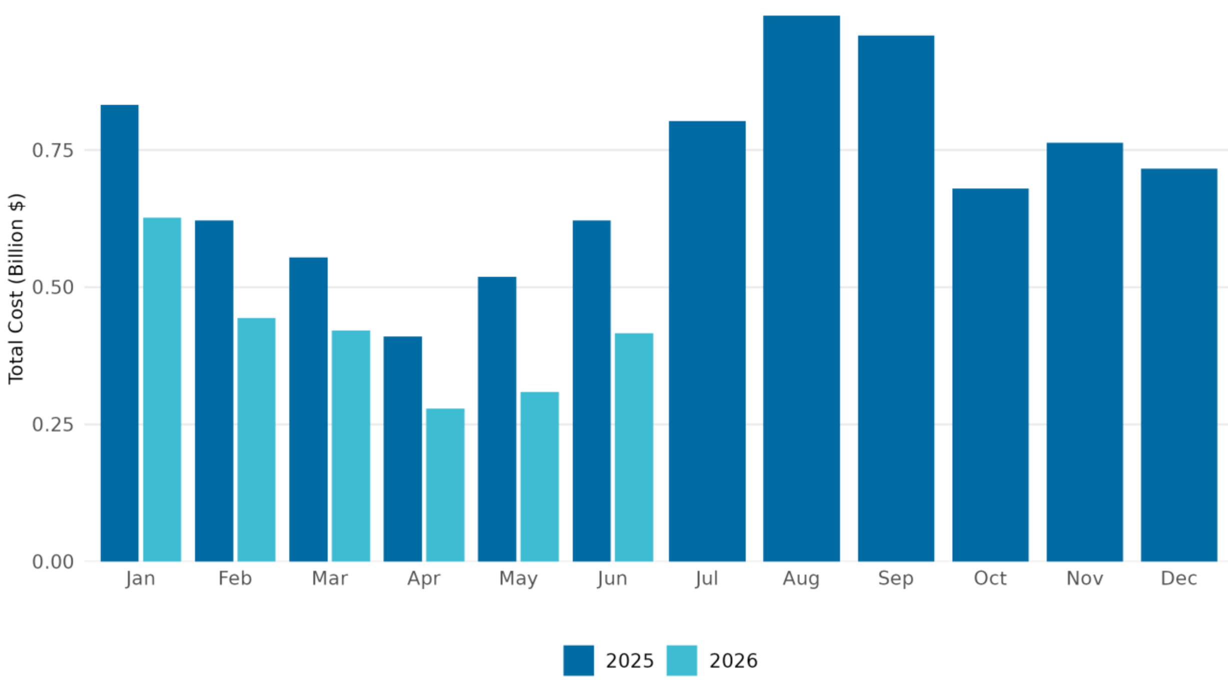


Figure 146: Monthly Total Costs CAISO, comparing 2025 to 2026



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 statement[9]. 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.

From Figure 147 to Figure 151 illustrate the Bid Cost Recovery (BCR) trends for CAISO, PACW, and PACE across April, May, and June. CAISO's IFM BCR increased from $1.64 million in April to $3.15 million in May and then declined to $2.21 million in June. CAISO's RTM BCR experienced a decline from $11.65 million to $8.24 million from April to May and then continued declining to $3.56 million in June. For PACW, May settlement data shows an IFM BCR of $0.097 million and June settlement data shows $0.005 million. PACW's RTM BCR rose from $0.019 million in April to $0.4 million in May then declined to $0.026 million in June. PACE saw an IFM BCR of $0.36 million in May and $0.11 million in June. PACE saw its RTM BCR increase significantly from $1,128.50 in April to $1.28 million in May but then decrease to $0.11 million in June. Figure 150 to Figure 151 compare BCR of three different BAAs in IFM and RTM.

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

Figure 147: BCR of CAISO by market

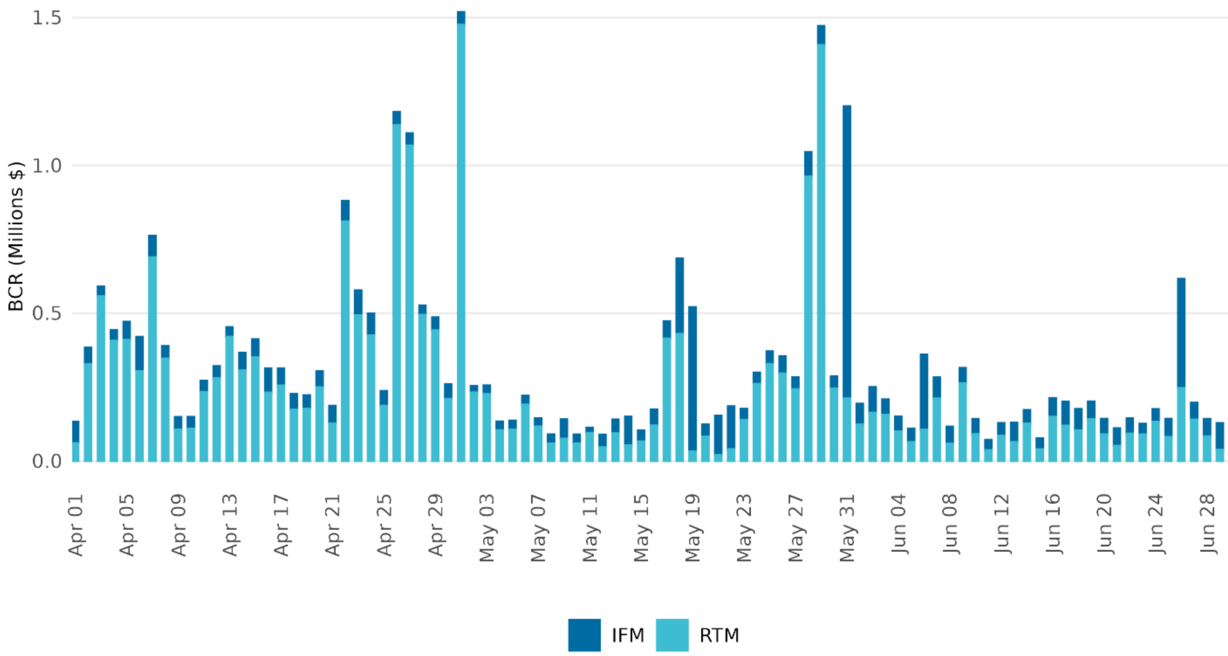


Figure 148: BCR of PACE by market

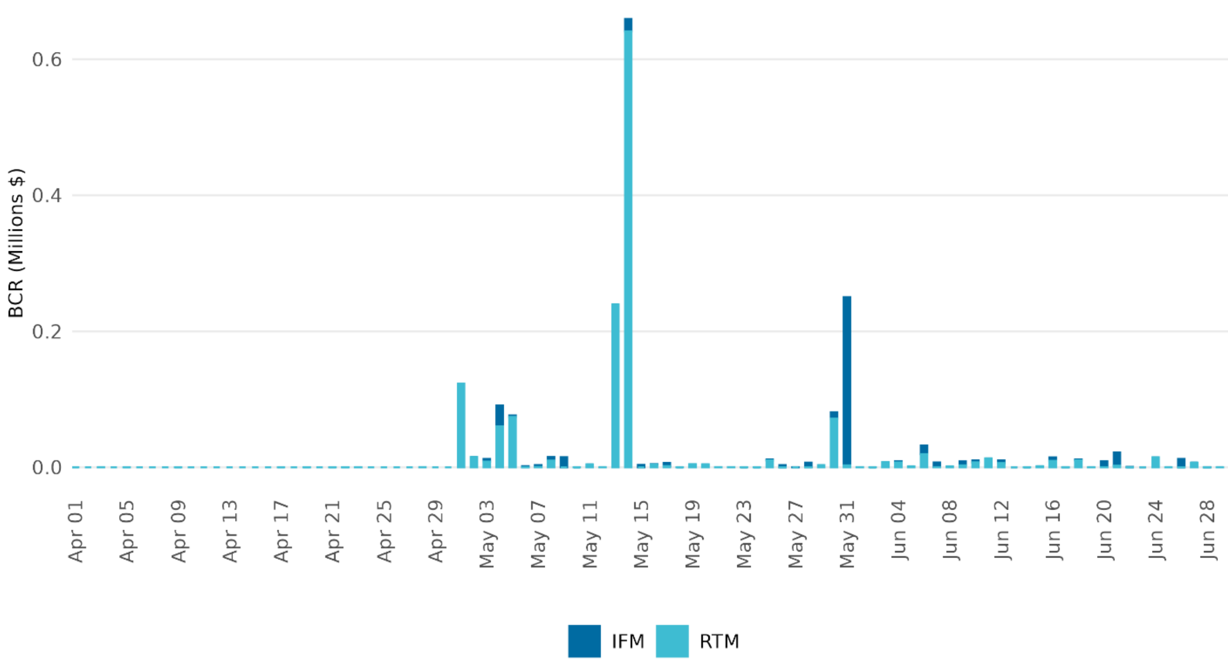


Figure 149: BCR of PACW by market

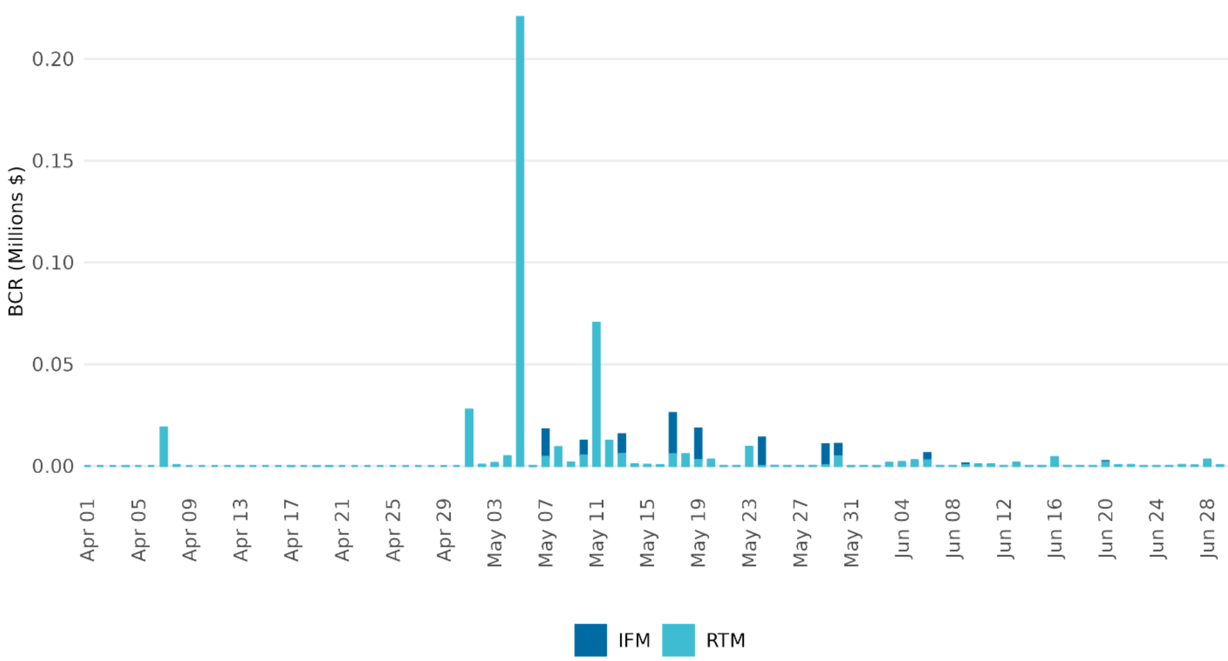


Figure 150: IFM BCR by BAA

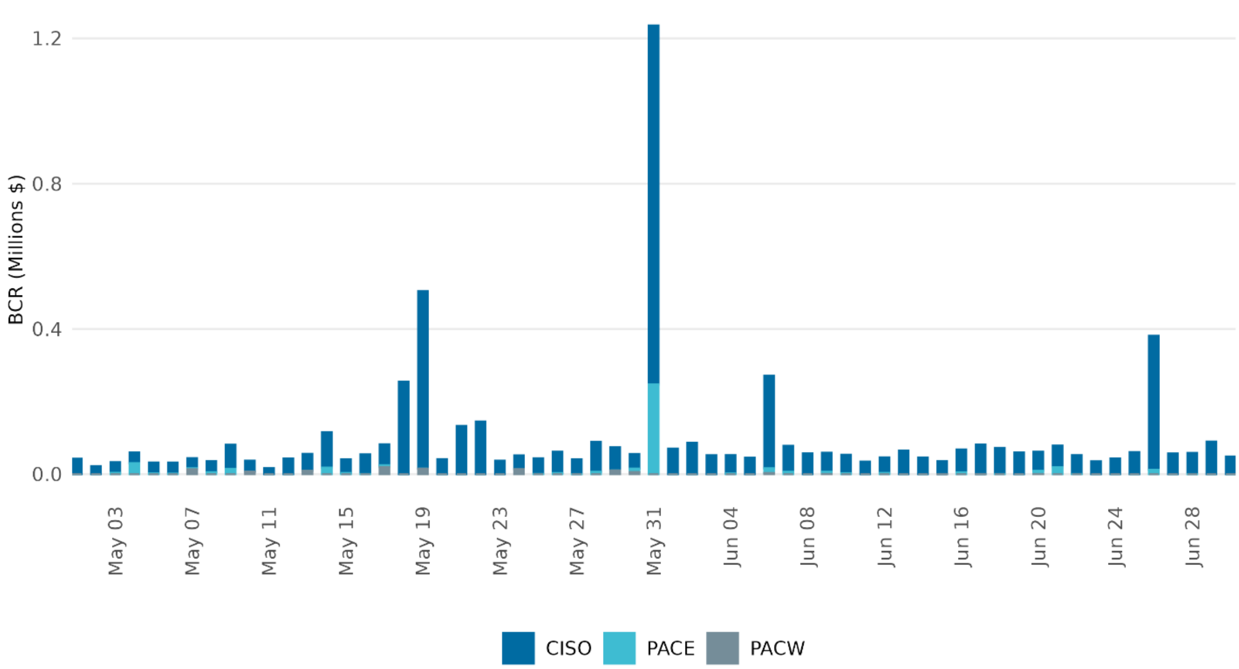
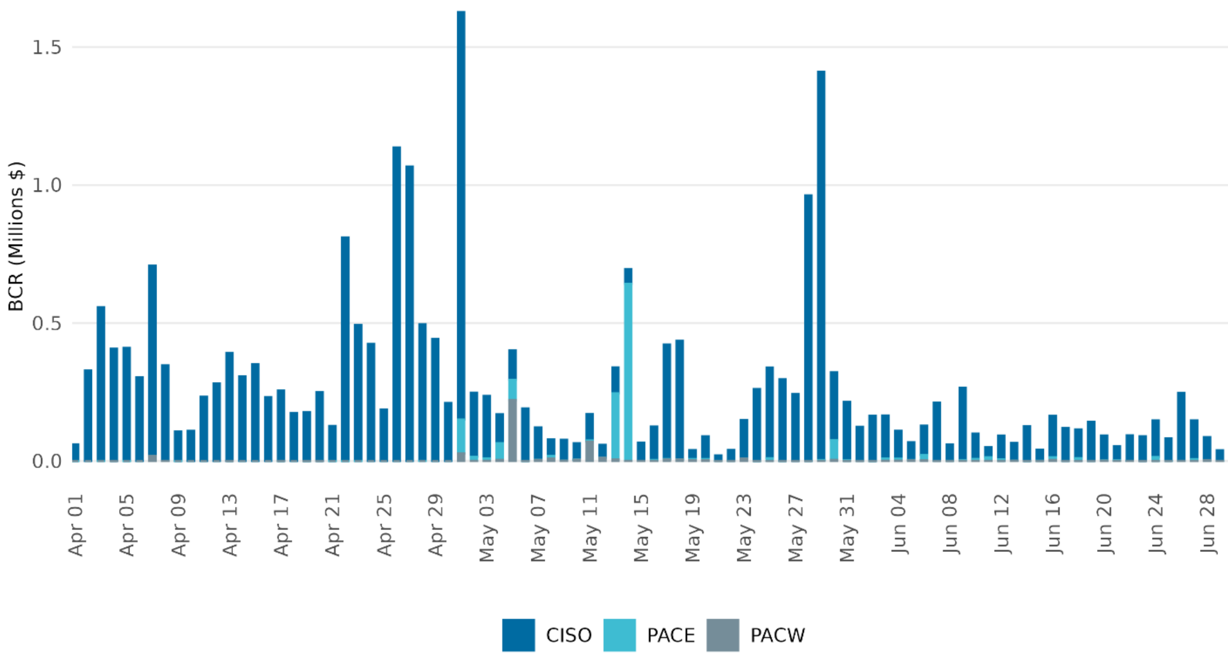


Figure 151: RTM BCR by BAA



Market offsets

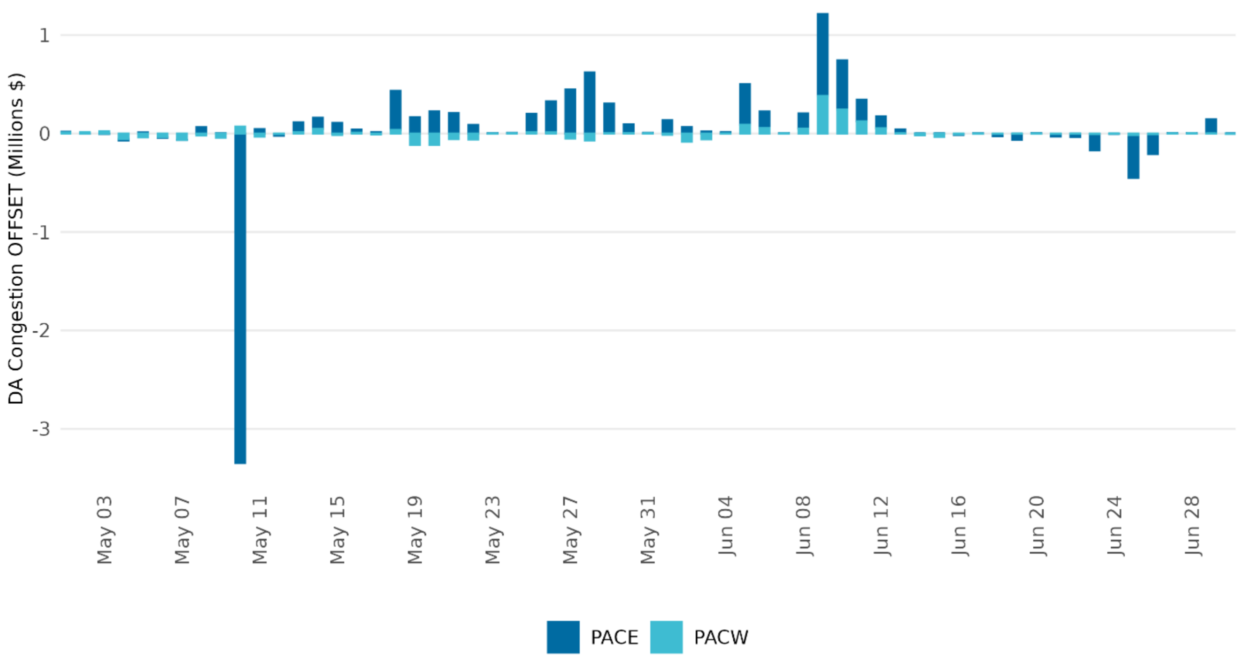
In CAISO's market settlements, participants are paid or charged. The money collected from some transactions is used to pay others. However, due to the multiple configurations of the various components of settlements such as different prices used to settle different components of energy, the total money 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 152, the total amount of PACE DACO in May is 0.18 million dollars and the corresponding value of PACW is -0.523 million dollars. The total amount of PACE DACO in May is $1.9 million and the corresponding value of PACW is $0.75 million. A negative amount reflects a payment to the entity. A spike in DACO indicated that congestion has a significant impact on the market dispatch during corresponding intervals. For example, the large DACO on May 10 was caused by congestion on the binding flowgate *CLOVER_SIGURD_345_2*.

Figure 152: DA Congestion Offset for PAC areas



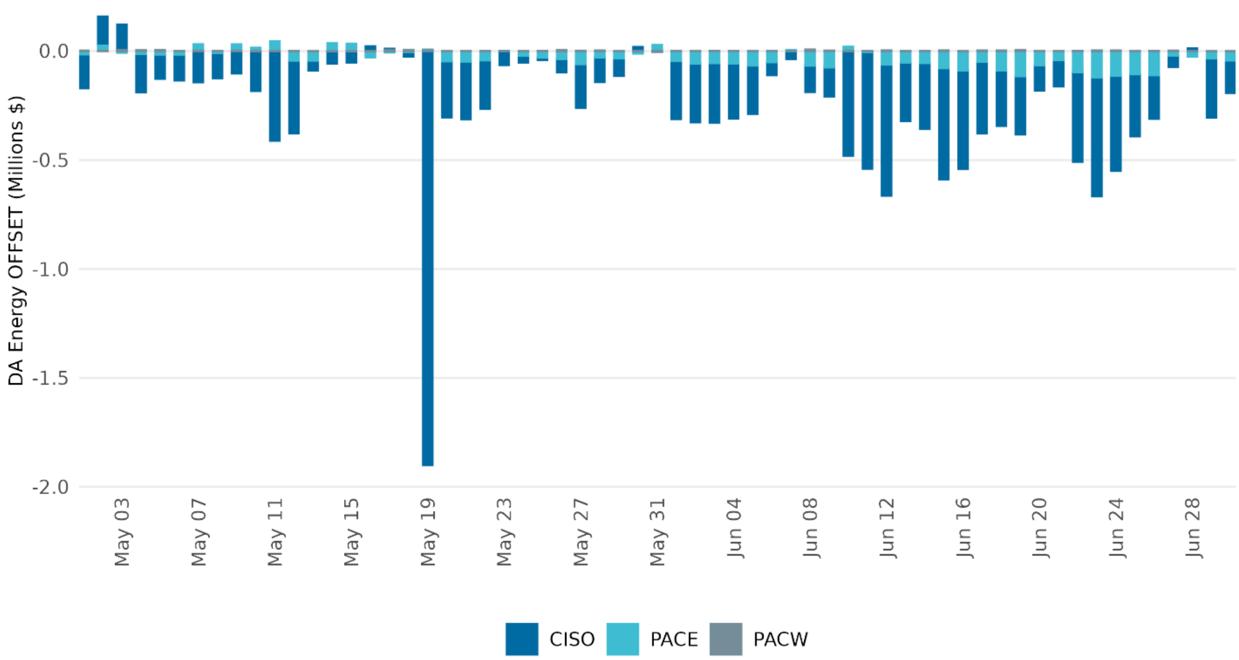
Day-Ahead energy offset

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 153, the total amount of CAISO DA energy offset in May and June is -$4.9 million and -$8.2 million, respectively. The totals for PACW are $0.076 million and $0.073 million in May and June, respectively. The totals for PACE are -$0.31 million and -$1.8 million in May and June, respectively. 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.

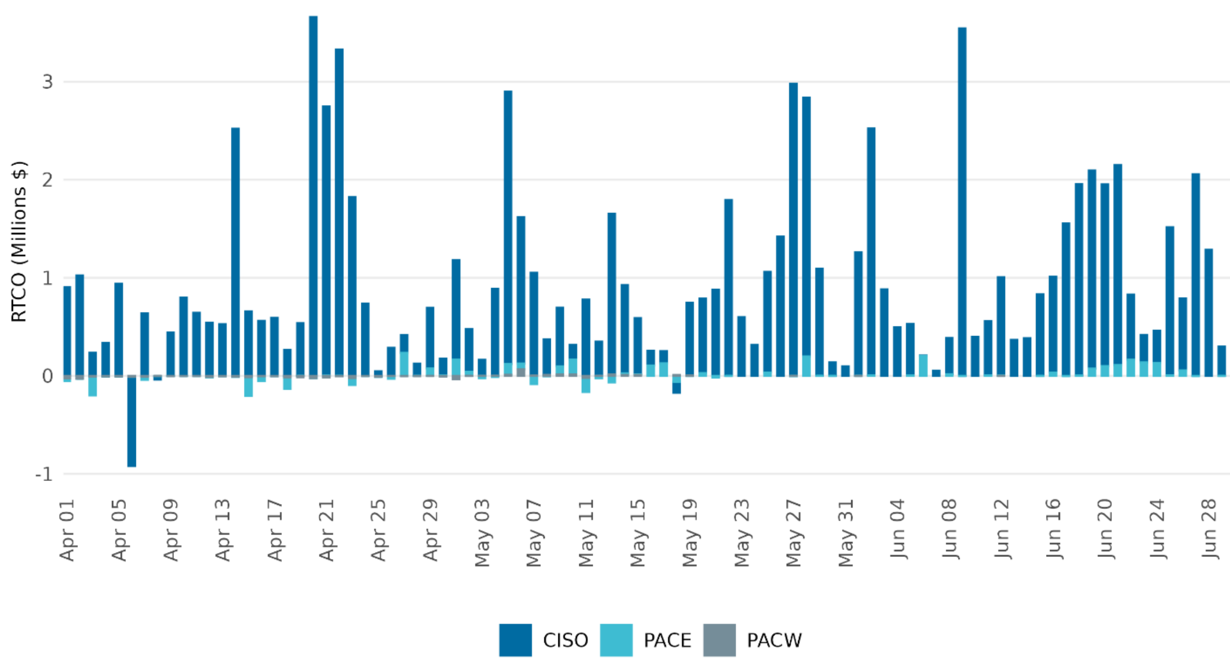
Figure 153: DA Energy Offset



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 154 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 to $32.0 million in June. 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. In June. PACE had total charges of $1.05 million while PACW saw a credit of $92.

Figure 154: 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 155 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 155 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. In June, CAISO's RTIEO resulted in a payment of $23.5 million. Conversely, PACW saw its charges rise from $1.16 million in April to $5.53 million in May and then decline to $2.17 million in June. PACE transitioned from a payment of $0.23 million in April to a charge of $2.96 million in May, and then saw another charge in June for $3.41 million.

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 155: Real-Time Imbalance Energy Offset

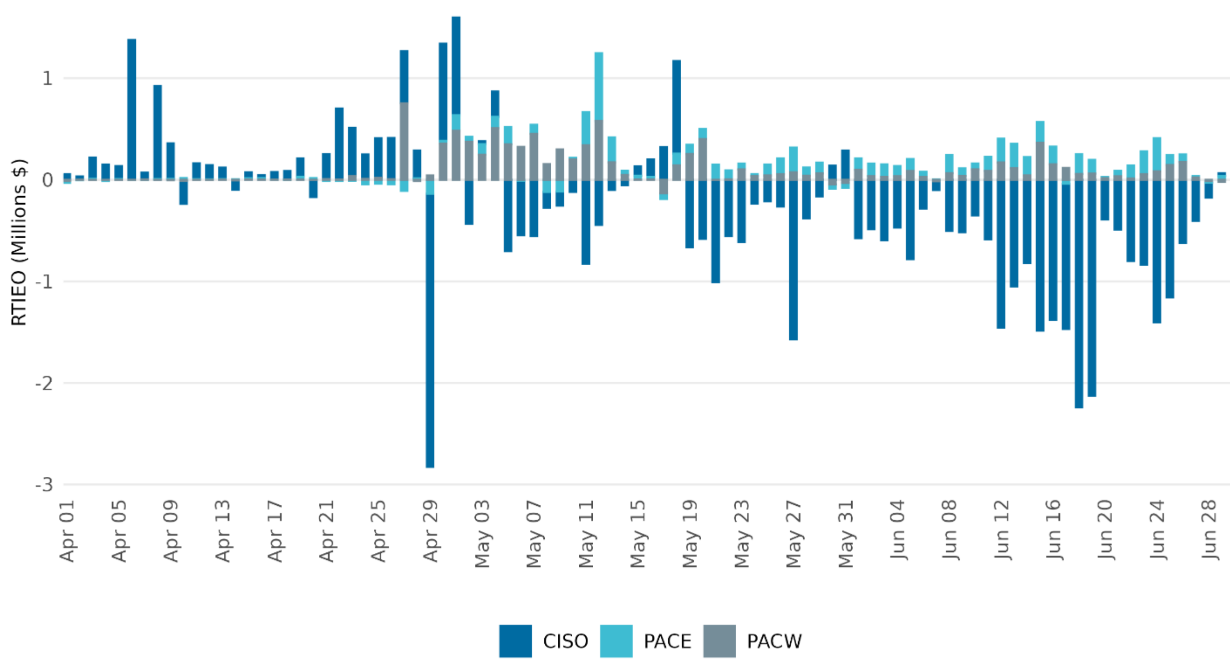
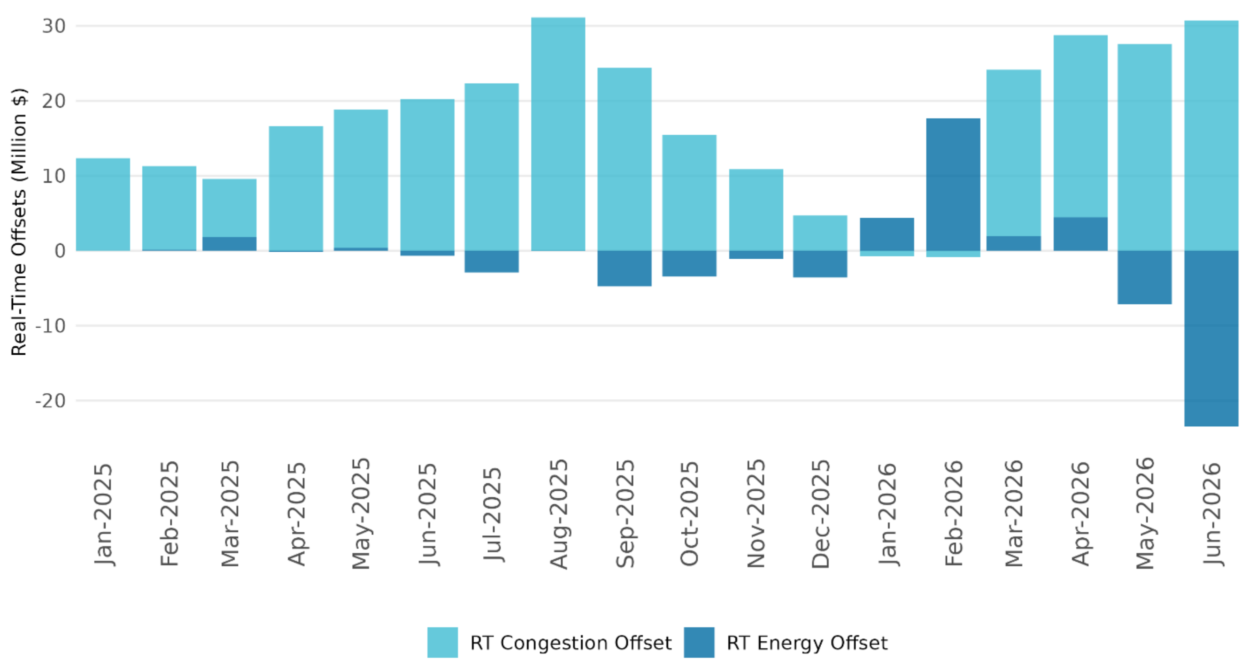


Figure 156 and Figure 157Figure 157 show the monthly real-time congestion and energy offsets for CAISO area and the WEIM excluding CAISO area, respectively. CAISO offsets remained within normal ranges, with an energy offset slightly more negative than seen in other months since the start of 2025. In June, the energy offset remained negative but got significantly larger. Figure 157 shows that in May and June, 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.

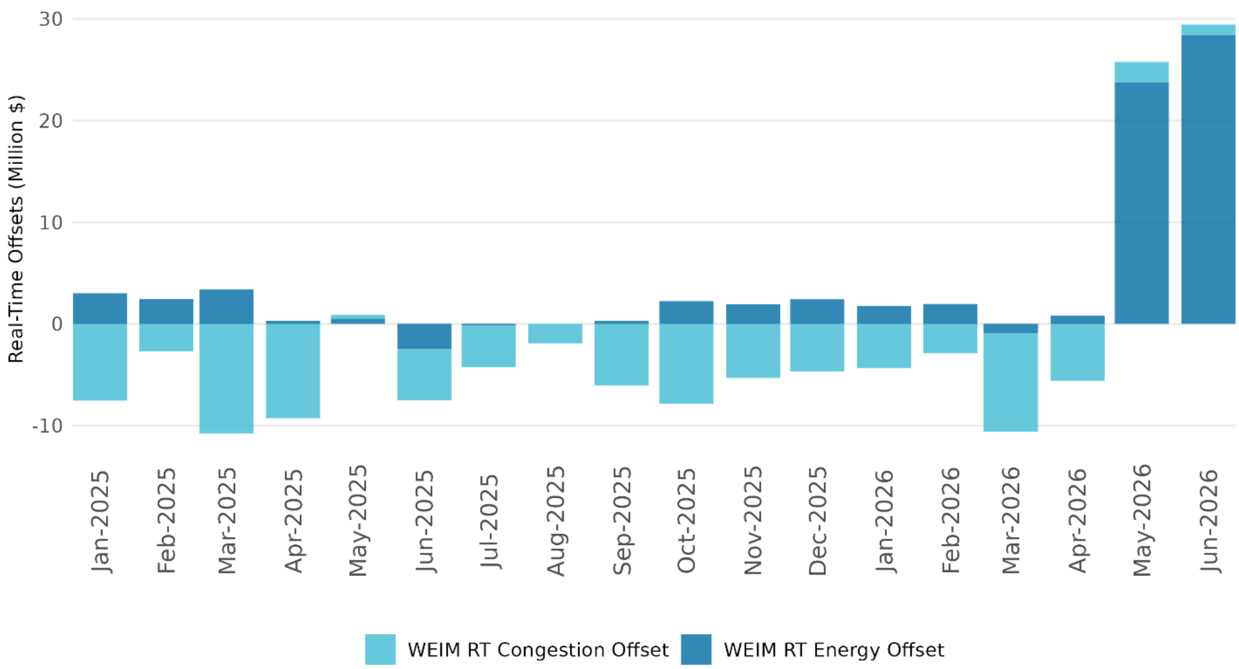
The magnitude of the real-time energy offsets for May and June are very high compared to historical offsets. First, it is important to note that the real-time imbalance energy offset (RTIEO) results observed after the May 1 EDAM go-live are not directly comparable to pre-EDAM outcomes. This is primarily 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 156: 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 157: Monthly Total Real-Time Offsets for WEIM



Imbalance reserves

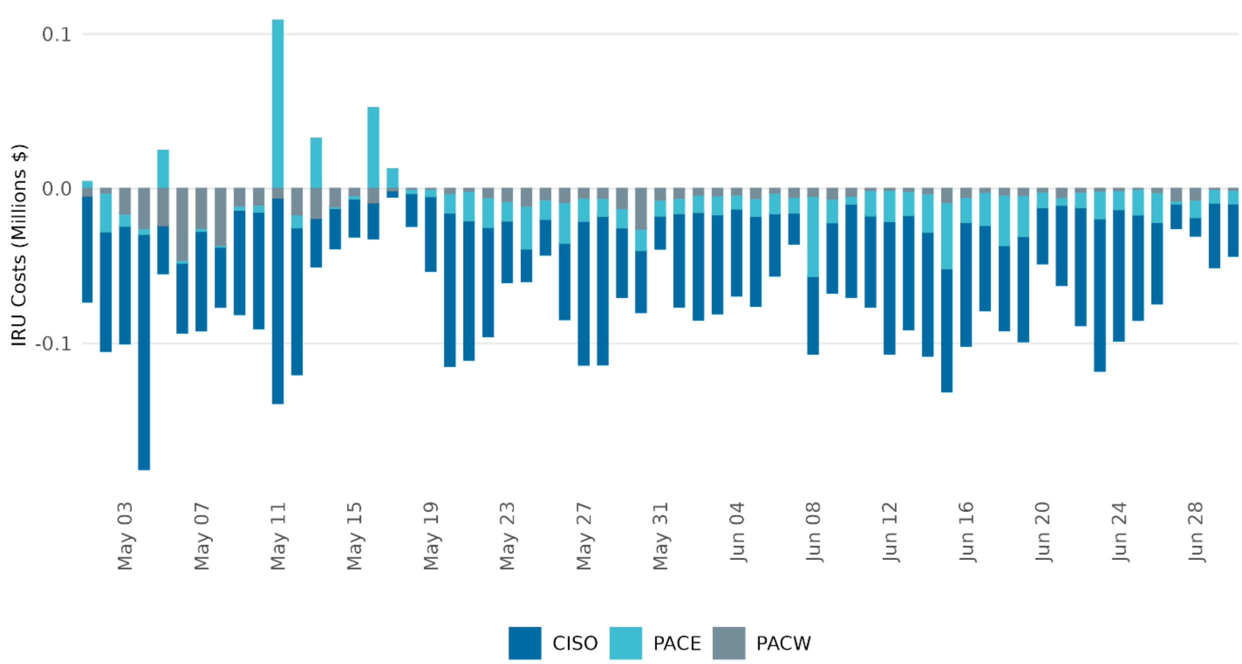
Imbalance reserve up/down are two components of the imbalance reserve product designed to provide upward/downward dispatch capability. Procured within the IFM, Imbalance Reserves up/down (IRU and IRD) is used to ensure that sufficient dispatchable capacity is available to meet positive/negative net load 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 158 shows the daily trend of IRU costs for May and June. IRU costs in May were -$1.79 million for CAISO area, -$0.365 million for PACW, and $0.03 million for PACE. IRU costs in

June were -$1.73 million for CAISO area, -$0.102 million for PACW, and -$0.493 million for PACE.

Figure 158: 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 159 shows the daily costs for procuring IRD in May and June. IRD costs in May for CAISO were -$1.25 million, while PACW and PACE had a cost of -$0.21 million -$0.135 million, respectively. In June, IRD costs were -$0.36 million for CAISO, -$0.055 million for PACW, and -$0.12 million for PACE.

Figure 159: IRD settlement costs

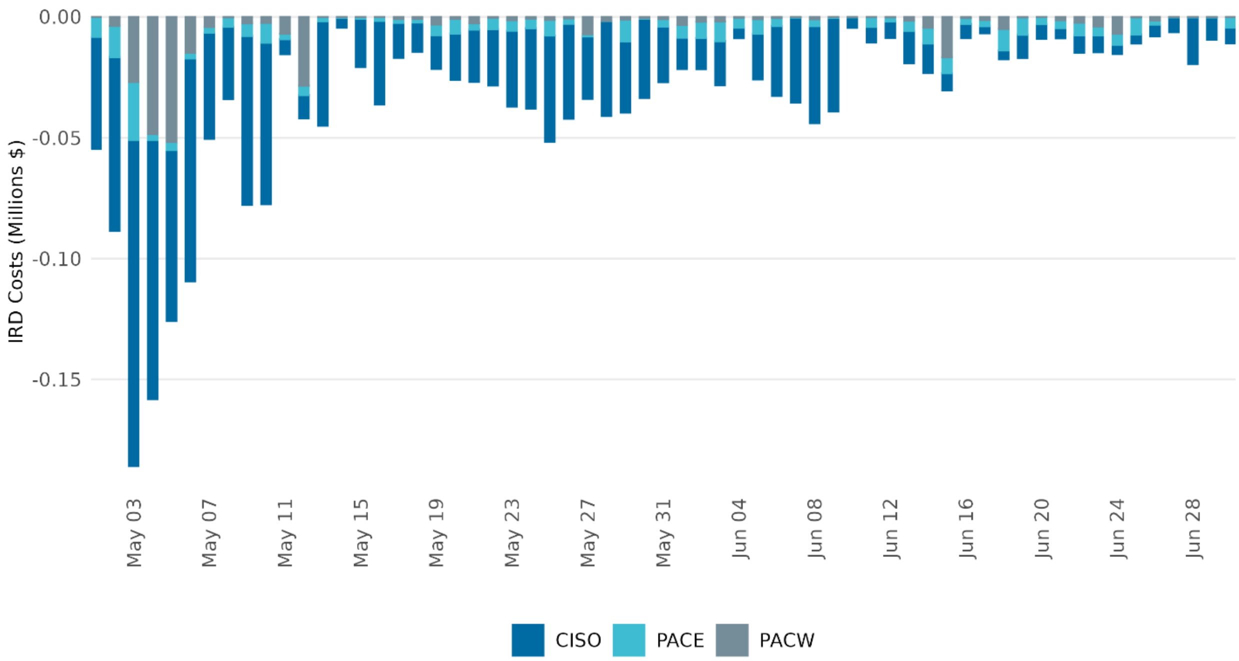


Table 13: Imbalance Reserves Total Monthly Settlement Costs

	IRU Total Costs ($million)		IRD Total Costs ($million)	
BAA	**May**	**June**	**May**	**June**
CAISO	-1.79	-1.73	-1.25	-0.360
PACW	-0.365	-0.102	-0.213	-0.0550
PACE	-0.0298	-0.493	-0.135	-0.115

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 160 shows the daily RCU costs organized by BAA in May and June. In May, the RCU costs for CAISO were -$4.05 million, while PACW and PACE costs were -$0.21 and -$0.23

million. For June, RCU costs for CAISO were -$1.53 million, while PACW and PACE costs were -$0.029 and -$0.011 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 161 provides the daily trend of RCD cost by BAA in May and June. In May, RCD costs were -$0.86 million, -$0.019 million and -$0.002 million for CAISO, PACW and PACE, respectively. In June, they were -$2.81 million, -$0.0496 million and -$0.0137 million for CAISO, PACW and PACE, respectively.

Figure 160: RCU settlement costs

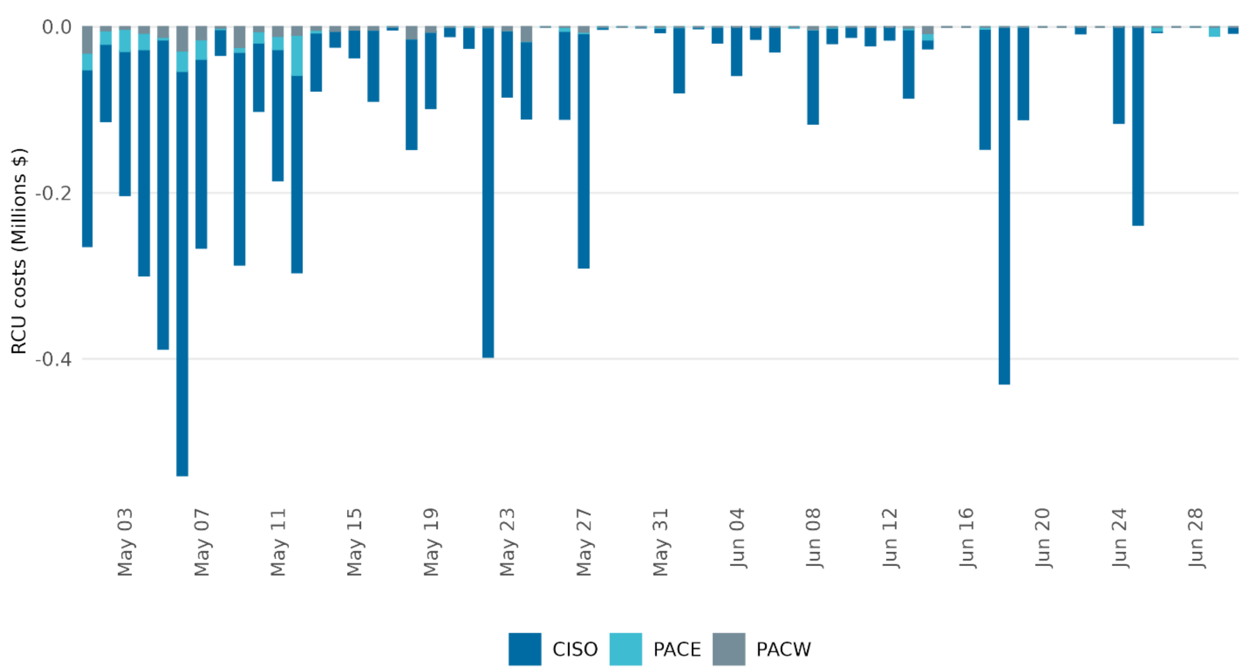
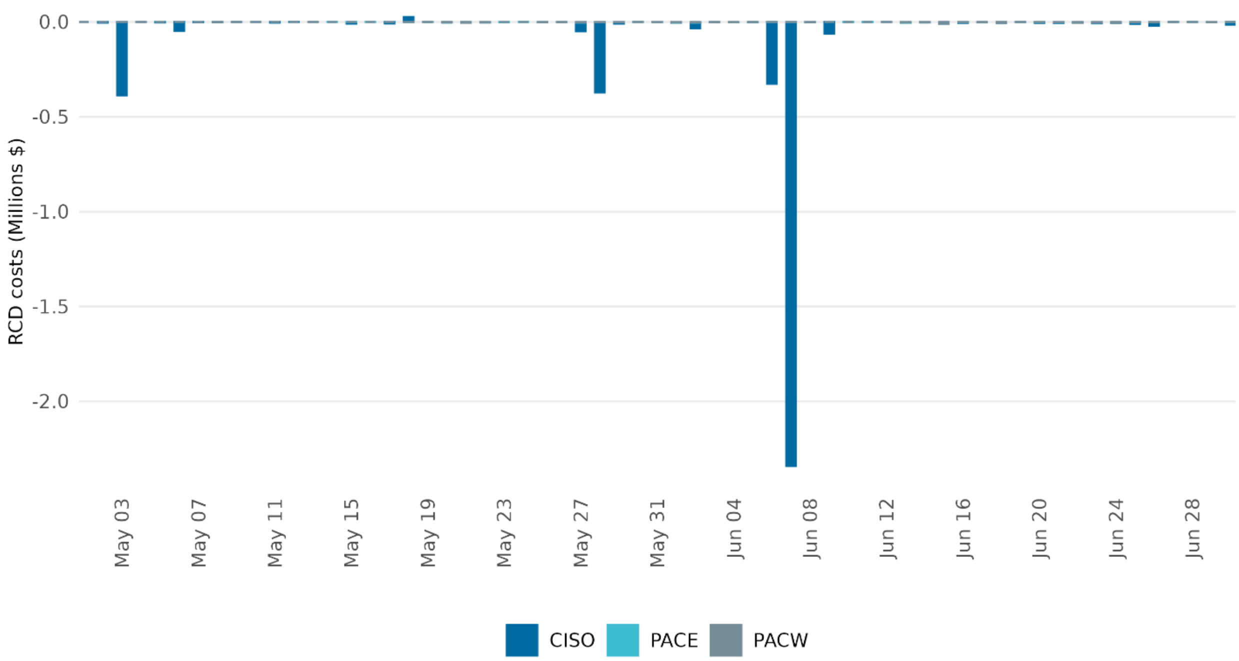


Figure 161: RCD settlement costs



Insert here a table that summarizes the cost for IRU/IRD/RCU/RCD all together showing totals of both months

Table 14: Reliability Capacity Total Monthly Settlement Costs

	RCU Total Costs ($million)		RCD Total Costs ($million)	
BAA	**May**	**June**	**May**	**June**
CAISO	-4.05	-1.53	-0.861	-2.81
PACW	-0.211	-0.0109	-0.0181	-0.0496
PACE	-0.233	-0.0297	-0.00197	-0.0137

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 CO_2-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 162 shows the GHG payments to EDAM entities that are supporting the energy imported into the GHG regulation area (California). Conversely, Figure 163 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. Table 15 summarizes the monthly total GHG costs for PACE and PACW.

Figure 162: Greenhouse Gas Settlement Costs in IFM

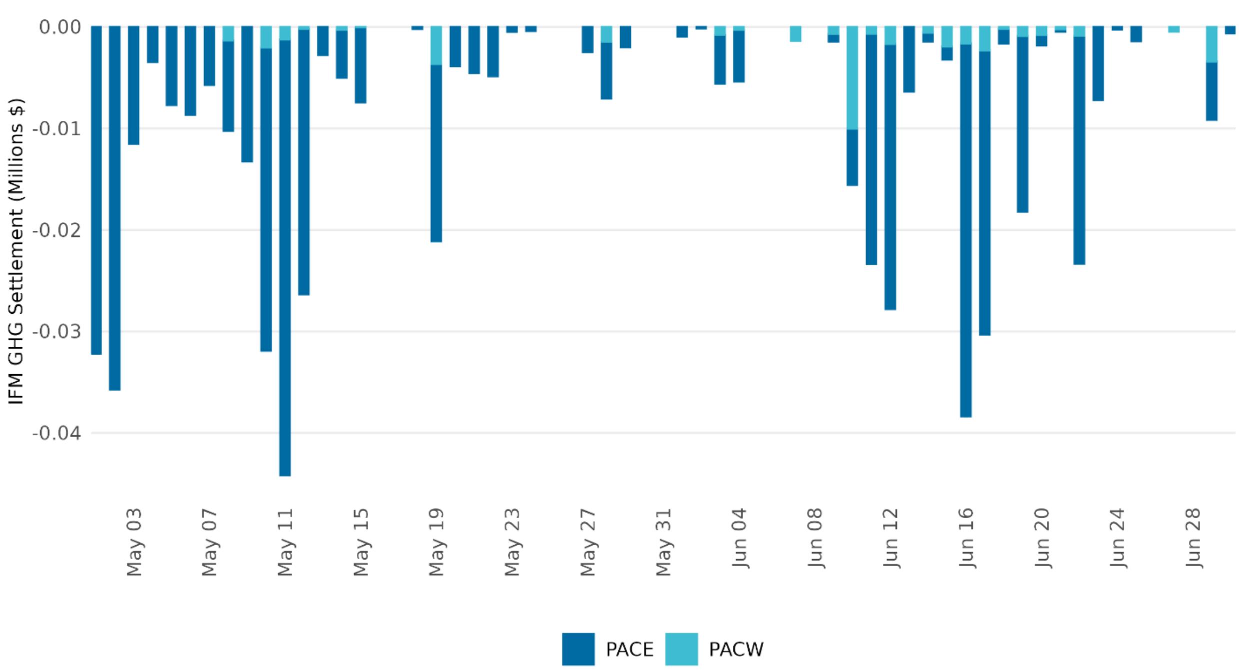


Figure 163: Greenhouse Gas Settlement Costs in RTM

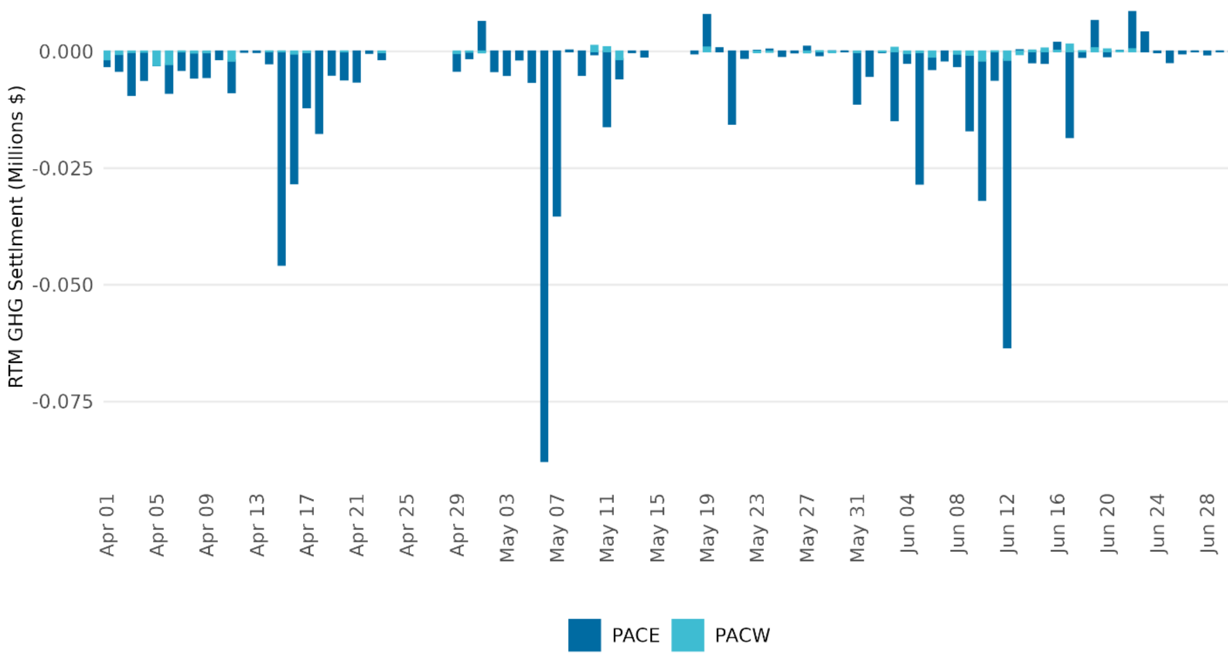


Table 15: IFM and RTM Monthly GHG Settlement Costs

	IFM GHG Costs ($ million)		RTM GHG Costs ($ million)	
BAA	May	June	May	June
PACW	-0.01	-0.029	0.0005	-0.002
PACE	-0.283	-0.197	-0.182	-0.18

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 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. Additionally, CAISO has identified a software issue impacting the congestion component for tie-generators that can drive the RC price negative. CAISO is working with its software vendor to address issues related to MSG transitions and SP-Tie pricing. CAISO did not correct RC prices for this issue because the impact is on the capacity awards and not the prices. Other negative RC 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.

- 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 was fixed on July 6, 2026.
- 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.
- 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.
- 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 Reliability Capacity Down prices due to solution limited by IFM commitment: Reliability Capacity Down can only be awarded to resources that are on-line and committed by the IFM. Additionally, down capacity range is limited by energy self-schedules, Ancillary Services and Imbalance Reserves awarded in IFM. This issue is not a software issue but due to the requirement to run RUC only after IFM is complete. CAISO will continue monitoring to ensure the new market functionality is working as intended.
- Ramping Interval for Imbalance Reserve: Imbalance Reserve awards were limited by 60-minute ramp capability rather than the expected 30-minute ramp capability due to an incorrect parameter setting in the market application. This issue was fixed on July 3, 2026.
- Commitment Costs in the day-ahead Resource Sufficiency Evaluation (RSE): The RSE test is considering non-zero minimum load costs and transition costs which economically prevents some resources from providing energy and Imbalance Reserve. CAISO is working with its software vendor to ensure that commitment costs are considered $0 in the RSE test only and this issue is expected to be fixed in an upcoming software patch.
- Missing MPM Results on OASIS: The Market Power Mitigation mechanism is working in the day-ahead market by identifying non-competitive constraints and mitigating applicable resources, however the results of the MPM are not fully published on OASIS on the MPM Nomogram/Branch Shadow Prices and MPM Nomogram/Branch Competitive Paths displays. This issue impacts May 1, 2026 and remains on-going. The issue is expected to be fixed in an upcoming software patch.

Stakeholder Feedback

The monthly EDAM Market Performance Report for May 2026 was published and presented during the monthly performance meeting on June 25, where stakeholders were invited to provide feedback. Stakeholders appreciated CAISO's efforts in developing the monthly EDAM Performance Report and recognized the detailed analysis and transparency it provides. They also valued CAISO's ongoing engagement with stakeholders and viewed the report as a useful tool for monitoring EDAM performance. Most of the feedback focused on adding new metrics, expanding the analysis, and providing more explanation of market results and design. A summary of the stakeholder feedback and CAISO's overall response is provided below.

SCE provided several suggestions to expand the EDAM Performance Report. Their feedback focused on adding more information about transfer capability and transfer utilization across EDAM and WEIM, the impact of GHG costs on market outcomes, and additional metrics on price differences and price convergence across EDAM balancing authority areas. They also requested more reporting on IR and RC, including bidding behavior, procurement levels, and how the procured quantities were used in real-time operations to better evaluate the performance of these new market products.

PG&E's feedback focused on improving transparency and expanding the information included in the EDAM Performance Report. They requested more visibility into settlement-related issues, including updates on known issues and their impacts, and suggested providing faster responses to stakeholder questions during the monthly performance meetings. PG&E also requested additional analysis of congestion, including the lack of congestion on PACW transmission constraints and more reporting on congestion across transmission constraints, energy, and imbalance reserves. They also suggested adding analysis on IR procurement compared to actual forecast changes, resource participation in the IR and RC products, and the frequency of high-price intervals to provide a better understanding of market performance.

WPTF recommended expanding the EDAM Performance Report with additional metrics and explanations to help stakeholders better understand how EDAM market design features are working. Their comments focused on providing more information about the impact of deployment scenarios on congestion and market outcomes, adding transparency around market power mitigation metrics in EDAM, and reporting additional details on negative RC prices and awarded quantities. WPTF also requested more explanation of the EDAM Net Export Constraint, including examples of how it affects market transfers and commercial transactions, and encouraged continued evaluation of market design elements to improve market efficiency and stakeholder understanding.

CAISO appreciates the feedback and recommendations provided by stakeholders. The comments highlight opportunities to further enhance the EDAM performance report by adding more transparency, metrics, and analysis. CAISO will review the suggested enhancements and consider incorporating additional information and analysis into future EDAM performance reports and stakeholder discussions, where appropriate and feasible based on available data and reporting priorities. The EDAM report for June has added new metrics and analysis on utilization of Imbalance reserves and also on market power mitigation. It has also improved and expanded the metrics and analysis of EDAM transfers. In subsequent monthly reports, the ISO will continue to expand the metrics and analysis.