Extended Day-Ahead Market Performance October 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). On October 1, 2026, Portland General Electric Company (PGE) successfully joined the EDAM market. This October report is the sixth and last in a series of customized monthly reports assessing market performance during EDAM's initial months of operation. The report focuses on market outcomes across participating balancing authority areas (BAAs), including price formation, reliability, new product performance, congestion, transfers, and settlement outcomes.

EDAM continued to operate reliably in October while expanding from three to four balancing authority areas with the addition of Portland General Electric (PGE). Day-ahead market timing remained comparable to September, resource sufficiency remained high, and the expanded market coordinated energy and flexibility across a broader and more diverse resource footprint. October also included unusually high loads early in the month, providing an additional test of the new market functionality.

Day-ahead operations and resource sufficiency

Day-ahead market operations remained generally stable following PGE's October 1 entry. Results were published before the 1:00 p.m. target on 22 of 31 days, compared with 23 of 30 days in September. Resource sufficiency also remained strong: CAISO, PACE, and PGE passed the upward and downward imbalance reserve components of the Resource Sufficiency Evaluation in every hour, while PACW passed almost all (99.87 percent) hours in each direction.

Peak day-ahead demand declined from September in CAISO, PACE, and PACW as the region transitioned toward lower fall loads. PGE added a distinct resource portfolio to the market, with gas accounting for much of its energy awards and hydro and storage contributing more heavily during the evening peak. Across EDAM, the day-ahead market continued to coordinate substantially different combinations of solar, storage, gas, coal, wind, and hydro resources.

Regional transfers

PGE's entry expanded the network of energy and capacity transfers available to EDAM. PACE remained primarily an energy exporter in October, while PACW and PGE were net importers on average and CAISO experienced substantial two-way flows. Transfer activity was particularly strong around midday.

Transfer directions also differed by product. An area importing energy could simultaneously export imbalance reserves or reliability capacity when its resources were economic for those services. This illustrates an important feature of the broader EDAM footprint: energy, flexibility, and reliability capacity can be optimized separately and sourced from different resources and locations as regional conditions change.

Prices and new market products

Day-ahead energy prices increased from September to approximately $53/MWh in CAISO, $40/MWh in PACE, and $45/MWh in PACW, while PGE averaged approximately $45/MWh in its first month. PGE prices generally tracked PACW closely, while greater regional price separation occurred during overnight and evening hours. Day-ahead and real-time price convergence was somewhat weaker than in September, although the frequency of extreme real-time prices remained generally comparable.

Prices for the new imbalance reserve and reliability capacity products remained relatively low during most intervals, with higher prices concentrated around tighter system conditions in morning and evening ramps. PGE's addition also increased the diversity of supply available to meet flexibility needs. Because forecast uncertainty does not occur simultaneously or in the same direction across all areas, the broader footprint reduced the aggregate amount of imbalance reserves required relative to each area covering its uncertainty independently.

Congestion and congestion revenue allocation

Congestion continued to demonstrate the physical interaction among transactions across the EDAM footprint. Preliminary October analysis indicates that CAISO constraints accounted for most cross-area congestion effects, while constraints in the PacifiCorp and PGE areas had relatively little impact on aggregate EDAM-area prices. These results remain generally consistent with the parallel-flow relationships anticipated before EDAM implementation.

Under EDAM's congestion revenue allocation methodology, eligible congestion revenues associated with balanced self-schedules supported by exercised transmission rights are allocated back to the EDAM areas whose schedules incurred the congestion charges. In October, approximately $549K associated with CAISO constraints was allocated back to other EDAM areas, including about $511K to the PacifiCorp areas and $38K to PGE. Preliminary CRR revenue adequacy was approximately 93 percent, although congestion and settlement estimates remain subject to revision.

Reliability and market operations

The early-October period of unusually high loads provided an additional test of EDAM's reliability mechanisms. CAISO's optional net export constraint did not bind, including during these tighter conditions. CAISO did make greater use of RUC adjustments, with the maximum hourly average adjustment reaching 1,394 MW, compared with 521 MW in October 2025. CAISO also experienced RUC under-supply infeasibilities on October 5–7, while PACE, PACW, and PGE experienced no RUC infeasibilities during October.

These results illustrate the complementary roles of the new and existing reliability tools. Imbalance reserves procure flexibility for statistically expected day-ahead-to-real-time uncertainty, while RUC adjustments provide an additional mechanism for addressing operational needs not fully reflected in those requirements. Market power mitigation also continued to operate across the expanded footprint, with substantially less mitigation in RUC than in the Integrated Forward Market.

Wholesale market costs

CAISO wholesale market costs increased with higher October prices and tighter early-month conditions. Total costs were approximately $1.15 billion, up 14 percent from September, while average costs increased from $51.40/MWh to $61.80/MWh. The direct costs of the new capacity products remained small relative to overall wholesale market costs. October imbalance reserve payments across EDAM were approximately $3.0 million and reliability capacity payments approximately $4.5 million, with most costs concentrated in CAISO. Together, CAISO's imbalance reserve and reliability capacity costs represented less than 1 percent of total CAISO wholesale market costs.

Bid cost recovery was more concentrated in the real-time market in October. IFM BCR declined from September across the EDAM footprint, while CAISO real-time BCR increased from $4.48 million in September to $9.16 million in October. PGE recorded approximately $0.87 million in preliminary real-time BCR during its first month. Several identified settlement and BCR calculation issues remain under review, however, so these results should be considered preliminary and may change in subsequent settlement cycles.

Settlement offsets showed a more mixed pattern. CAISO's real-time congestion offset increased from $34.2 million in September to $54.5 million in October, reflecting in part the greater congestion experienced during the high-load conditions early in the month. In contrast, the combined real-time imbalance energy offset across EDAM was relatively small on a net basis in October at approximately -$0.3 million, although results differed by area. Day-ahead congestion offsets for the external EDAM areas were also relatively small, totaling approximately -$0.5 million in October. Because EDAM changed several

underlying settlement calculations and CAISO continues to investigate identified settlement issues, post-EDAM offset values are not always directly comparable with historical results and remain subject to revision.

Market issues and stakeholder feedback

CAISO continued to address implementation and settlement issues identified since EDAM launch, including issues affecting CRR settlements, bid cost recovery, RUC functionality, GHG treatment, and the real-time resupply test. The previously identified issue involving daily energy limits in the Resource Sufficiency Evaluation was resolved on November 3. Several remaining issues could affect financial results presented in this report, and settlement values may therefore change in subsequent cycles.

Stakeholder feedback also continued to shape EDAM performance reporting. Recent requests have focused on imbalance reserve utilization and pricing, reliability capacity procurement, negative prices, RUC adjustments, and settlement corrections. The October report expands analysis in several of these areas as operational experience with EDAM continues to accumulate.

Conclusion

Overall, October demonstrated both the progress and continuing maturation of EDAM. PGE's entry expanded the regional footprint without materially disrupting day-ahead operations, while the market increasingly shared energy and flexibility among four balancing areas with different resource mixes and system needs. At the same time, ongoing implementation and settlement issues underscore the importance of continued monitoring as experience with the new market design grows.

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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 October report provides an overview of market performance during the first six 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. On October 1, 2026, Portland General Electric Company (PGE) became the third western utility to successfully begin full participation in the EDAM market after PacifiCorp East (PACE) and PacifiCorp West (PACW). 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. CAISO will continue to monitor and evaluate market performance.

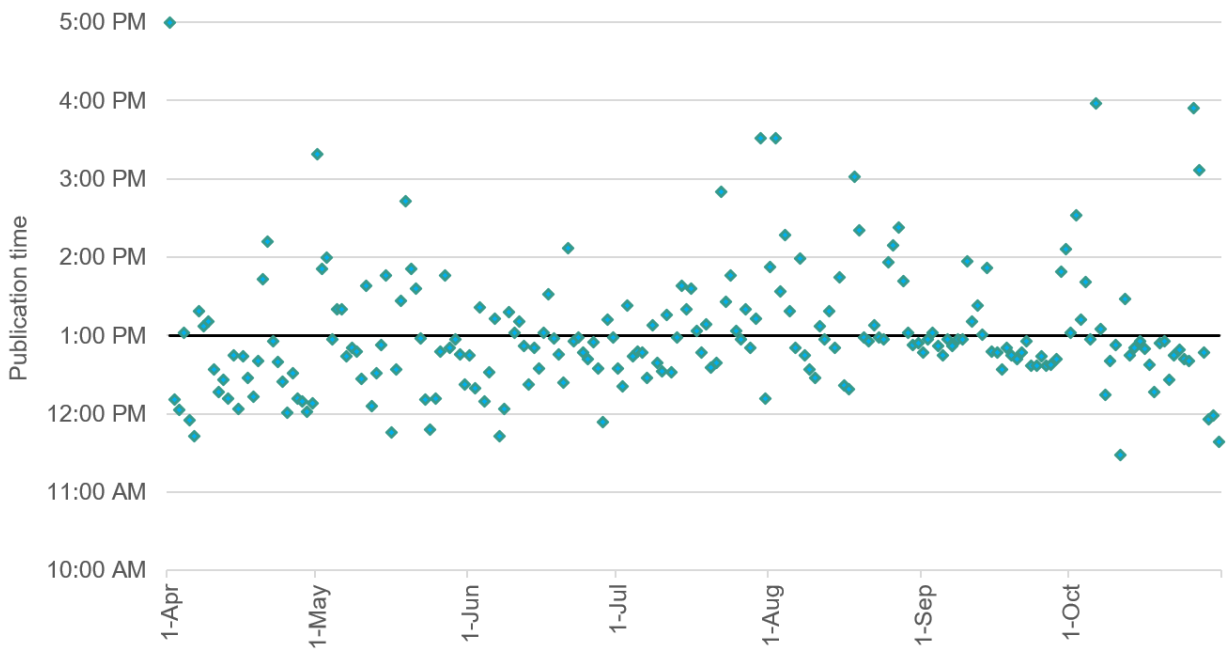
Day-Ahead Market Run

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 was able to publish DA results before 1:00 p.m. In October, EDAM results were posted before 1:00 p.m. in 22 out of 30 days (or 71 percent of the time), about the same frequency from the posting of 23 out of 30 days in September. This higher frequency of late posting was when the market was solving for the peak days so far in the year, which represent higher loads and more complex numerical problem to solve. For a relative comparison, the day-ahead market published before 1:00 p.m. in 23 out of 30 days in April prior to EDAM implementation.

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 from May to October.[1] On May 4, PACW passed the IRU RSE in 16 out of 24 hours and the IRD RSE in 23 out of 24 hours. On June 17, PACE observed an invalid RSE failure. This was due to the consideration of commitment costs in the RSE, and this issue was discussed as one of the market issues the ISO was pursuing a fix. Therefore, June's failure is not counted in the RSE statistics. In July, August, and September, there were no RSE failures for any EDAM BAA. On October 6, PACW passed the IRD RSE in 23 out of 24 hours. On October 20, PACW passed the IRU RSE in 23 out of 24 hours. The RSE failure for PACW for the month of October was due to additional export schedule changes from advisory to binding runs.

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

	IRU RSE Passing Rate (%)						IRD RSE Passing Rate (%)					
BAA	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**May**	**June**	**Jul**	**Aug**	**Sep**	**Oct**
CAISO	100	100	100	100	100	100	100	100	100	100	100	100
PACE	100	100	100	100	100	100	100	100	100	100	100	100
PACW	98.92	100	100	100	100	99.87	99.87	100	100	100	100	99.87
PGE	-	-	-	-	-	100	-	-	-	-	-	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.

[1] In addition to the IRU and IRD test, the RSE performs test for upward ancillary services. Ancillary services are not optimized nor procured in the extended day-ahead market for PAC areas.

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

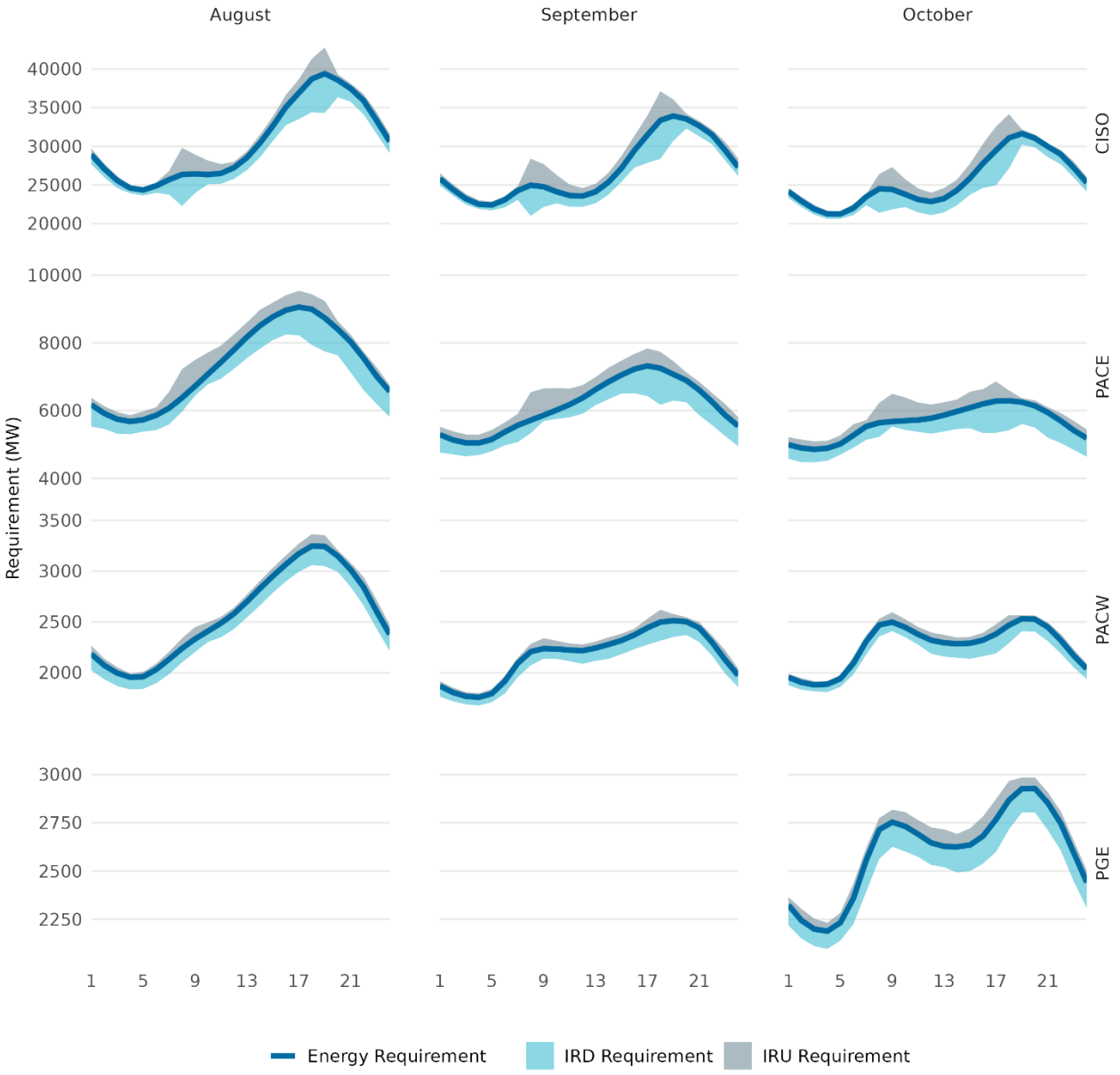


Table 2 gives the highest imbalance reserve upward and downward requirements for each BAA from May to October.

Table 2: Maximum imbalance reserve requirements by BAA

	Maximum IRU Requirement (MW)						Maximum IRD Requirement (MW)					
BAA	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**
CAISO	3629	3486	3536	3867	3900	3926	5320	5487	5985	5310	5245	5370
PACE	1028	1028	964	1045	989	1056	1100	1125	1125	1133	1185	1185
PACW	225	229	214	207	194	178	241	259	259	252	208	208
PGE	-	-	-	-	-	173	-	-	-	-	-	204

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 from July through September 2026. On average, the bid-in demand for CAISO is slightly greater than the day-ahead demand forecast during much of the day, while the two generally track closely. From July through September, the bid-in demand for PACE generally exceeded 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 July through September seeing a slightly higher bid-in demand compared to the day-ahead forecast.

The day-ahead demand forecast hourly profiles remained generally similar from July through September for all three BAAs. In September, all three BAAs experienced lower demand levels and lower evening peaks compared with August. CAISO continued to show a smaller mid-day dip and a steeper afternoon ramp, while PACE and PACW had more gradual and smoother changes through the day.

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

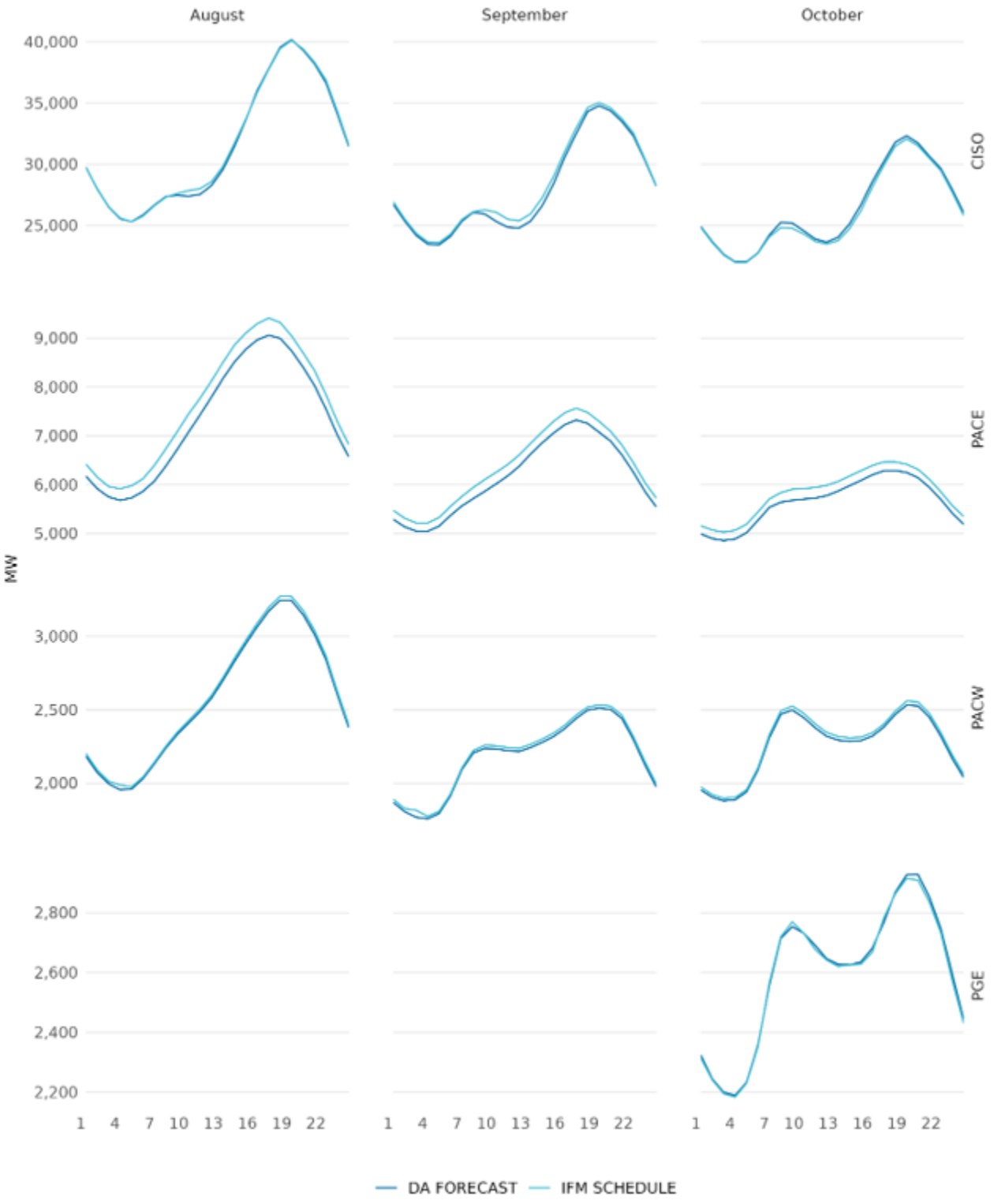


Table 3 shows the highest day-ahead demand forecast for a single hour for each EDAM BAA from May to October. From September to October, forecasted peak demand decreased for CAISO, PACE, and PACW. The changes were -1.9, -5, and -1 percent for CAISO, PACE, and PACW, respectively.

Table 3: Peak day-ahead demand forecasts

	Peak DA Demand Forecast (MW)					
BAA	**May**	**June**	**July**	**August**	**September**	**October**
CAISO	34674	37399	42928	46089	47741	46833
PACE	8047	9358	10527	10029	8351	7933
PACW	2893	3635	3866	3941	2998	2969
PGE	-	-	-	-	-	3219

Day-Ahead Supply

Figure 4 presents the hourly average energy awards by fuel type for CAISO from August through October. The results show a clear daily pattern driven largely by solar generation and energy storage. Solar awards increase substantially during daytime hours and peak in the afternoon before declining rapidly toward the evening. Storage generally shows negative energy awards during periods of high solar output, indicating charging, and transitions to positive awards during the late afternoon and evening as solar generation declines. Overall energy awards were higher in August, with higher peak levels observed over 40,000 MW in August, while September and October's peak demand was about 30,000 MW. Gas generation plays an important role in meeting evening demand. These patterns illustrate the complementary roles of solar, storage, and gas resources in supplying CAISO system demand throughout the day in the summer months.

Figure 4: Hourly average energy awards by fuel type for CAISO

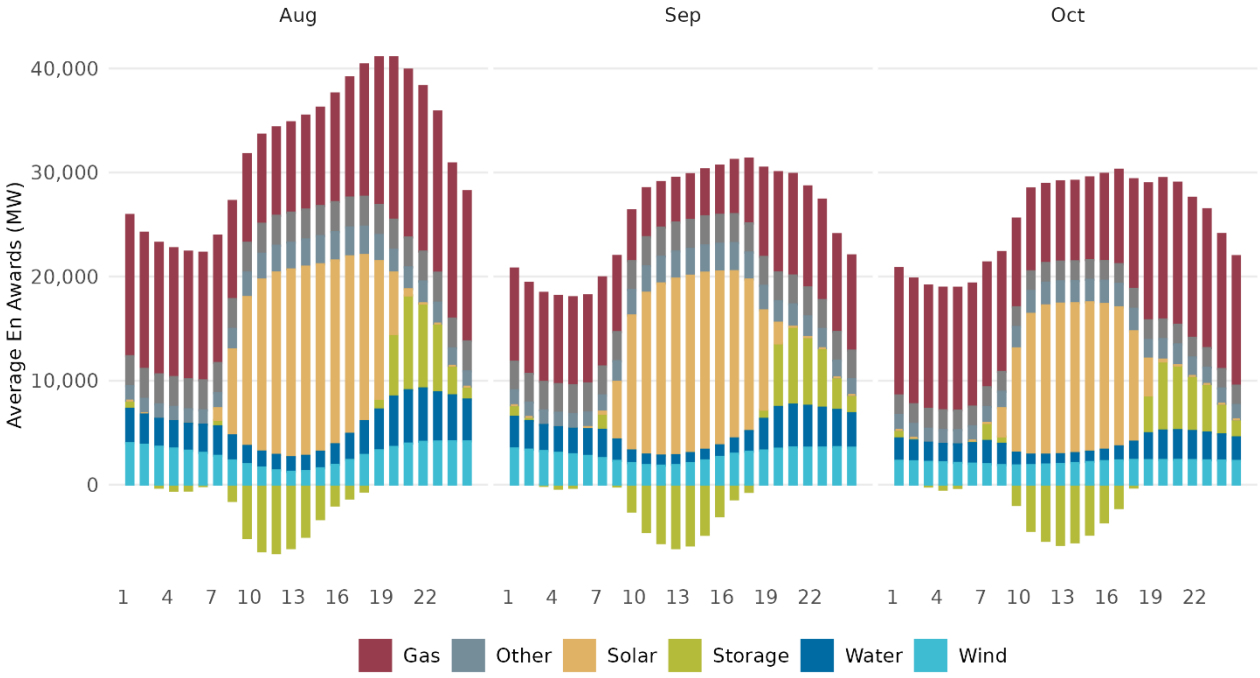


Figure 5 illustrates the hourly average energy awards by fuel type for PACE from August through October. The total cleared energy in September and October is lower than August, with peak at 9,000 MW. The results show distinct monthly and hourly patterns across the resource mix. Coal provides a relatively stable level of energy and becomes a main contributor to the overall PACE's resource mix. Solar awards follow a pronounced daytime profile. Gas awards generally increase as solar output declines, particularly during the evening hours, indicating their role in meeting system needs during the transition away from daytime solar generation. Wind awards are present throughout the day but vary across hours and months, while storage and other resources exhibit relatively small charging and discharging activity compared with CAISO.

Figure 5: Hourly average energy awards by fuel type for PACE

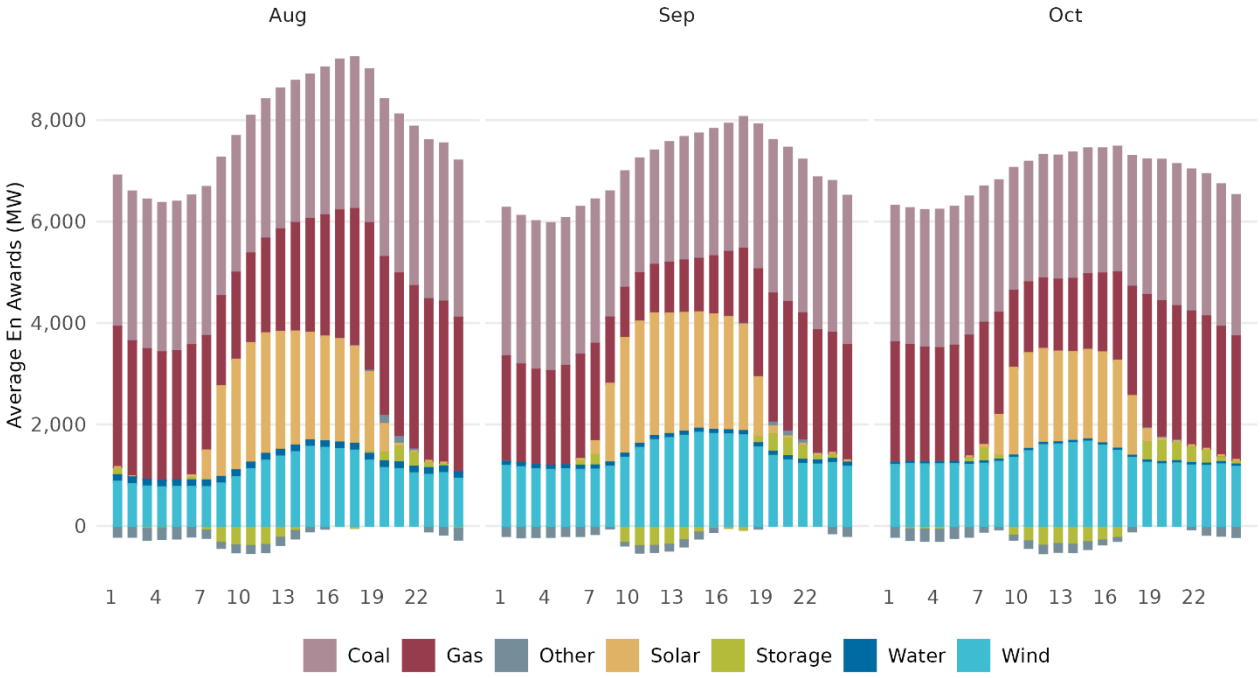


Figure 6 presents the hourly average energy awards by fuel type for PACW from August through October. Similar with CAISO and PACE, PACW's supply in October is lower than August and September. Gas, wind, and water resources still account for a substantial share of the energy awards throughout the period, and solar exhibits a clear daytime pattern. Hydro awards show relatively lower generation in September. Gas awards generally increase during periods of lower renewable output and contribute significantly to the higher evening awards. Coal and other resources represent relatively small portions of the overall resource mix. Total energy awards generally decreased from August, with the highest hourly levels around 1,600 MW occurring in HE 20.

Figure 6: Hourly average energy awards by fuel type for PACW

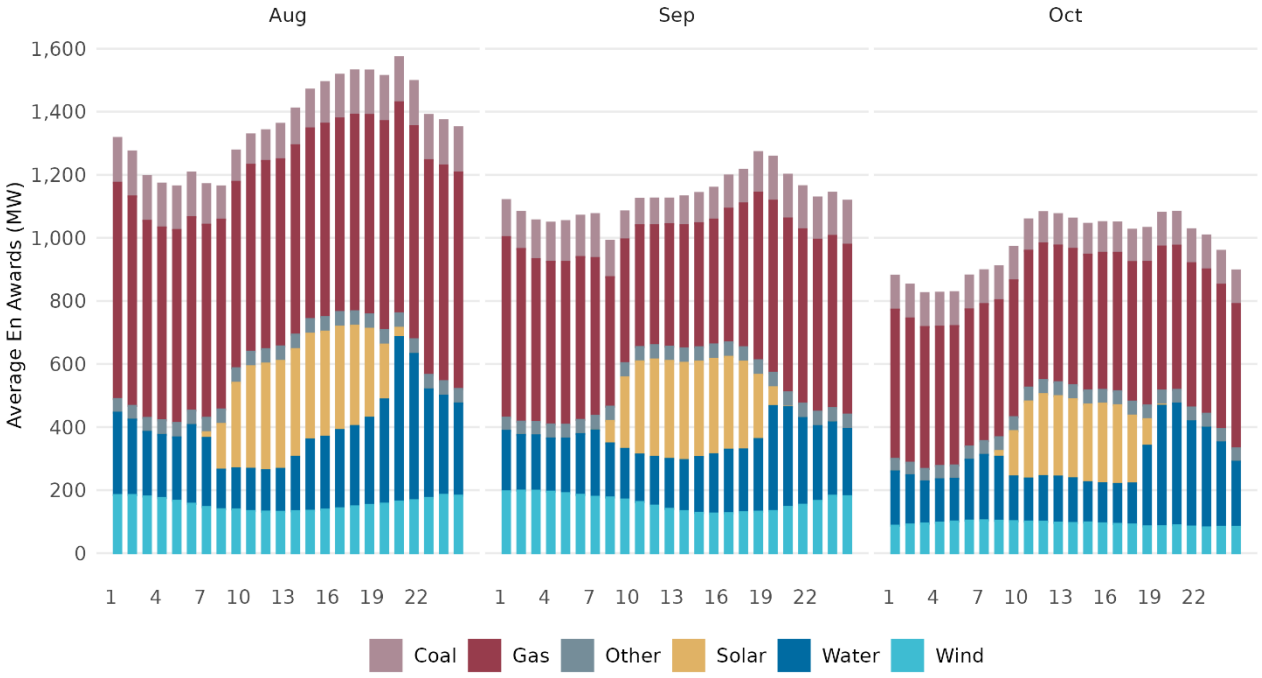
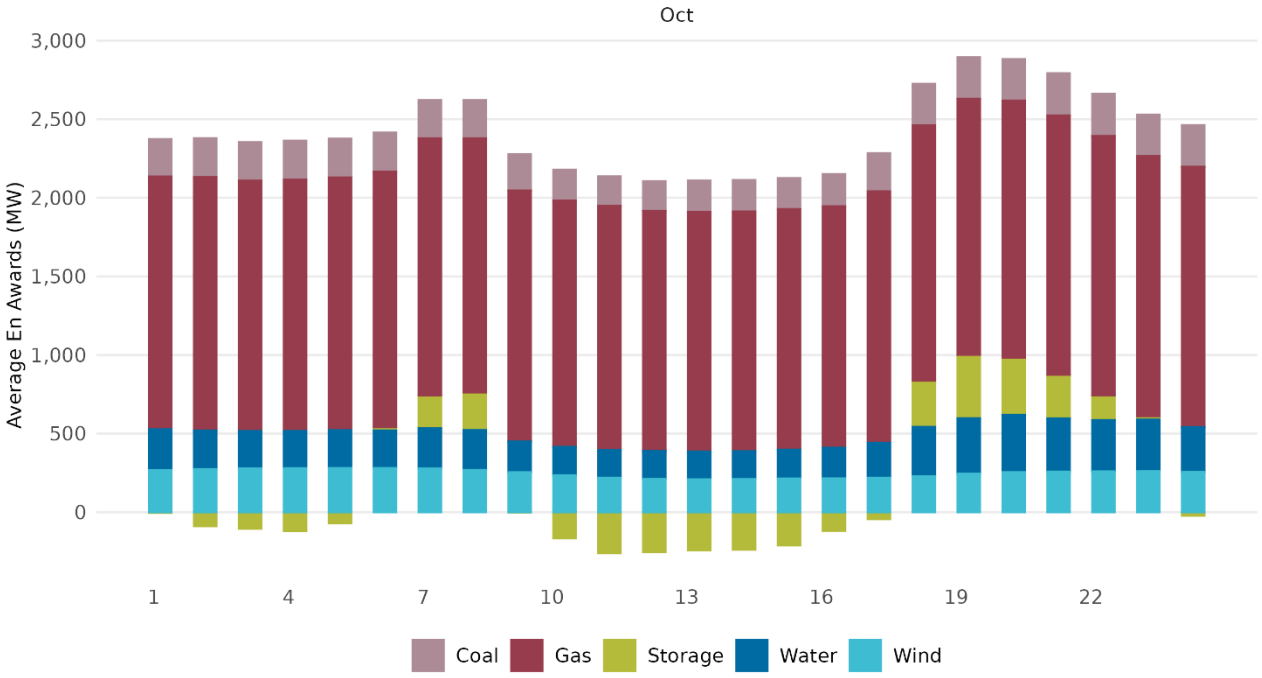


Figure 7 shows PGE's hourly average energy awards by fuel type in October, representing PGE's first month of participation in EDAM. Gas accounted for the majority of energy awards throughout the day, while wind and coal remained relatively stable. Water awards increased during the evening hours, particularly from HE18 through HE21. Storage showed the most pronounced hourly pattern, with negative awards during several off-peak and midday hours and positive awards during the evening peak. Overall, PGE's first month in EDAM shows a clear hourly pattern, with total energy awards increasing during the evening peak, supported by higher storage and water awards.

Figure 7: Hourly average energy awards by fuel type for PGE for October



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:

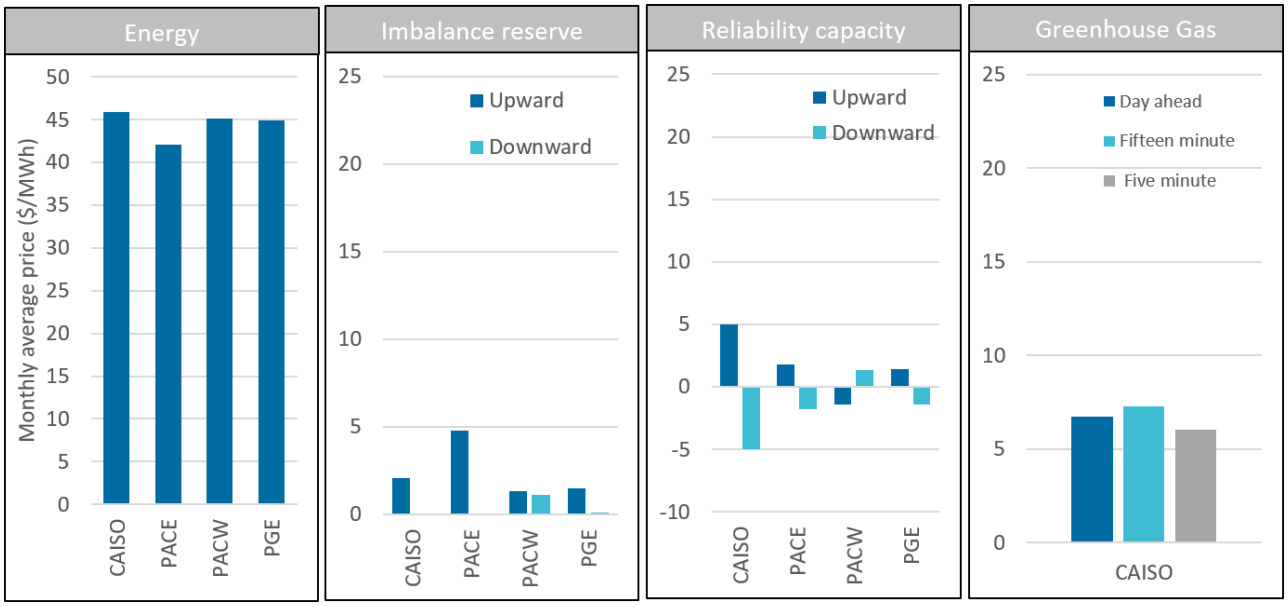
i) energy,

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 is 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 September. With about five months of operational experience, the results offer an initial indication of how EDAM/DAME functionality is performing. However, as the market continues to mature, participants gain experience operating under this new framework, and summer conditions exist, the results should be viewed as preliminary. The CAISO will continue to monitor and evaluate market performance and will provide further analysis in upcoming monthly reports.

Figure 8 compares prices across all EDAM products for the month of September. 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 8: Pricing of EDAM products for October 2026



Seasonal conditions also play an important role in shaping price patterns as observed in the month of October. During the summer months, due to higher load, typically sees higher energy prices as compared to spring months. 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 and PGE 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. Another pattern that appears in the pricing of the products shows that IR and RC products command lower prices than energy prices, which is expected given that these products provide services like flexibility.

Energy prices

Day-ahead energy prices measured using LMPs reflect expected market conditions and are influenced by changes in load, generation availability, imports, exports, and transmission constraints. Ideally, day-ahead prices accurately represent the value of supply and demand realized in in real time. Forecast uncertainty, congestion, shifts in supply or demand, and available transfer capability are some factors that can create differences between day-ahead and real-time price, commonly referred to as price convergence. Price convergence between BAAs also occurs, reflecting the diversity in conditions across the EDAM footprint. The figures in this section examine trends in energy prices and price convergence by showing average day-ahead and real-time LMPs for the three EDAM BAAs. The ELAP LMPs are used for PACE and PACW, while the load-weighted average of the four DLAP LMPs is used for the CAISO area.

Figure 9 shows monthly average LMPs for each EDAM BAA since EDAM implementation in May 2026. In October, day-ahead LMPs increased across all participating BAAs reflecting greater demand than in September. Compared to September, monthly average prices in October increased to $53/MWh from $45/MWh in CAISO, to $40/MWh from $31/MWh in PACE, and to $45/MWh from $36/MWh in PACW. Monthly average prices in PGE in October were $45/MWh. Price convergence across markets was weaker in October, with IFM LMPs being higher than FMM and RTD LMPs in CAISO, PACW and PGE. Across BAAs, CAISO LMPs were highest reflecting the highest demand. PACW LMPs continued to average higher than PACE despite having lower demand.

Figure 9: Monthly average LMP since May 2026



Figure 10, Figure 11 and Figure 12 show the average monthly LMPs since January 2025 and illustrate seasonal prices trends. IFM prices prior to May 2026 only exist for CAISO. Average prices are higher in the summer months in 2026 than in the spring months, consistent with seasonal trends observed in 2025. October 2026 prices deviated from those observed in 2025, coming in higher all summer months except for August.

Figure 10: Monthly average LMP for CAISO area since January 2025

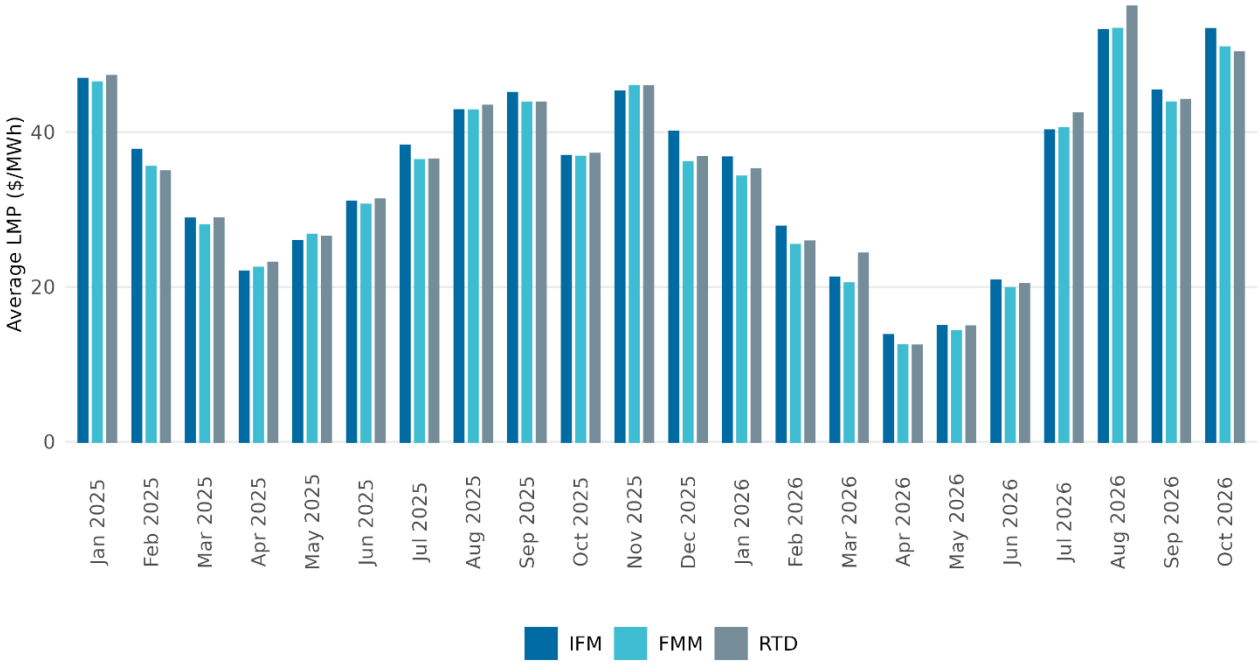


Figure 11: Monthly average LMP for PACW since January 2025

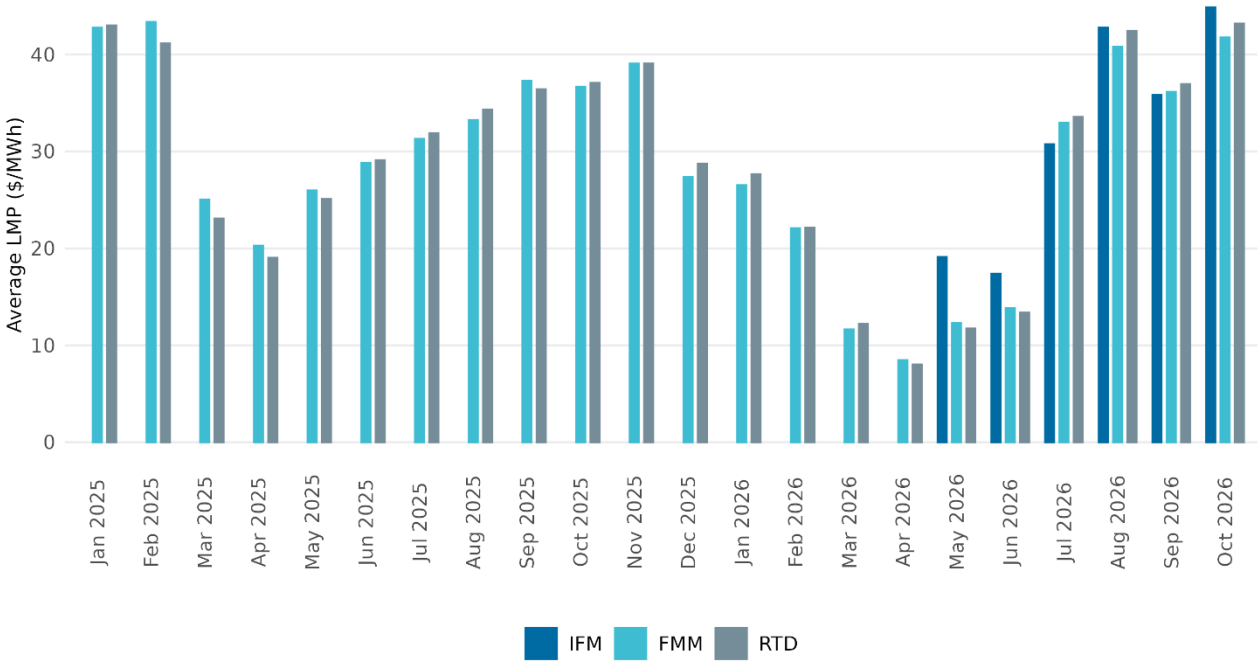


Figure 12: Monthly average LMP for PACE since January 2025

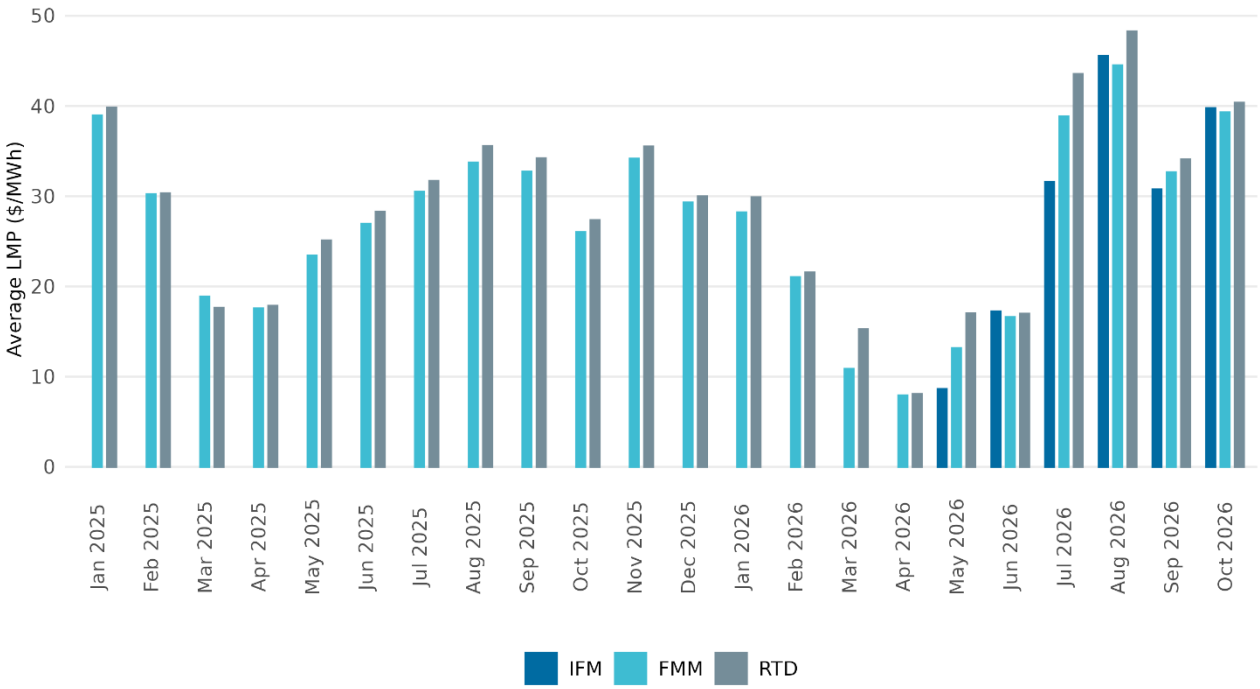


Figure 13: Monthly average LMP for PGE since January 2025

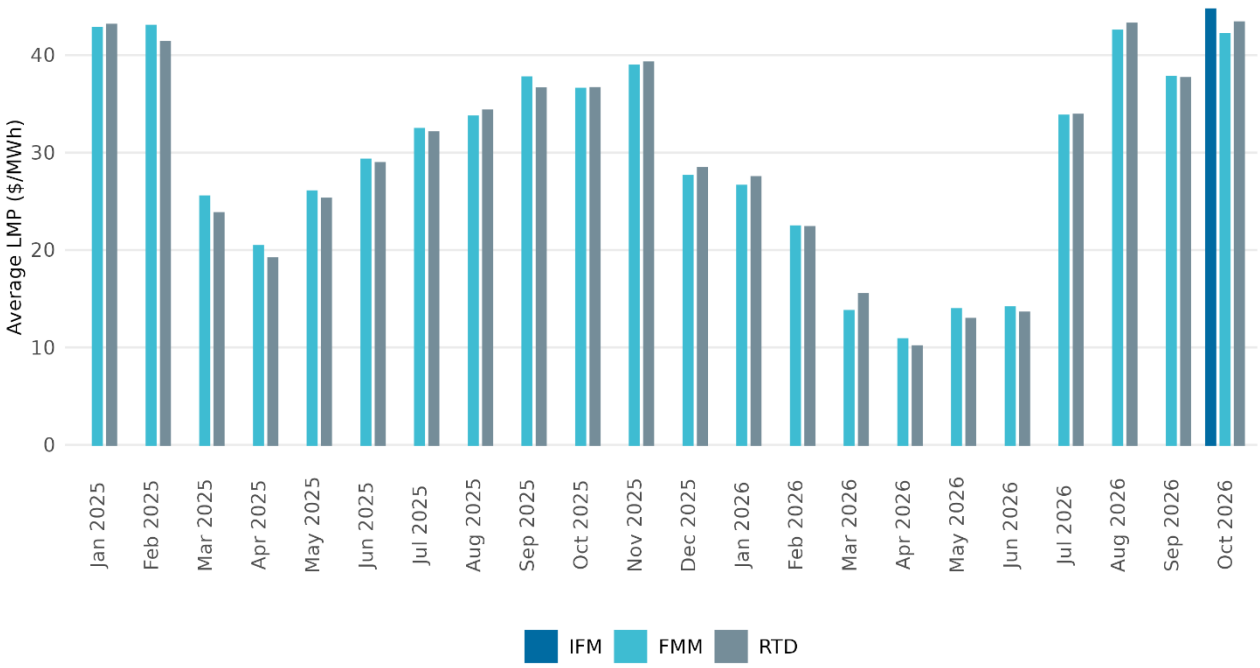


Figure 14 shows daily average LMPs for each EDAM BAA. Prices spiked on October 5th for CAISO averaging approximately $89/MWh.

Figure 14: Daily average IFM LMP by BAA

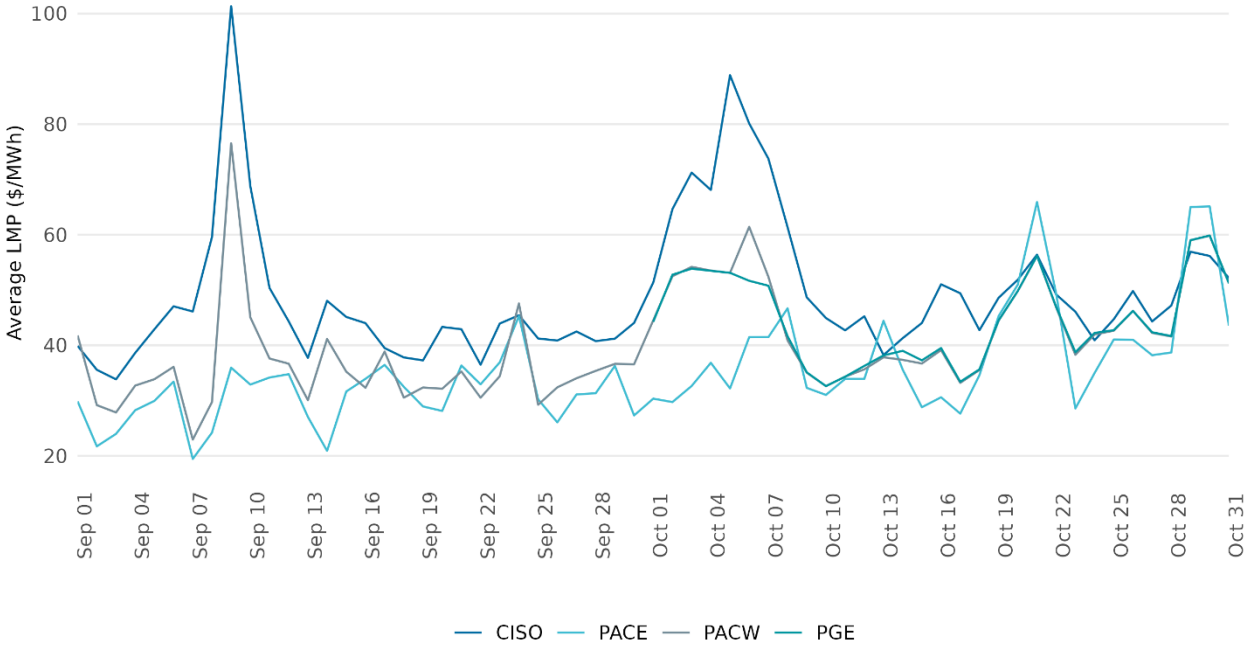


Figure 15 illustrates the price convergence between day-ahead and fifteen-minute market (FMM) prices for EDAM BAAs. A negative price reflects a higher FMM price compared to day-ahead. Price convergence was weaker in October such as from October 1 to 5 and October 20 to 22.

Figure 15: Average difference between IFM LMP and FMM LMP

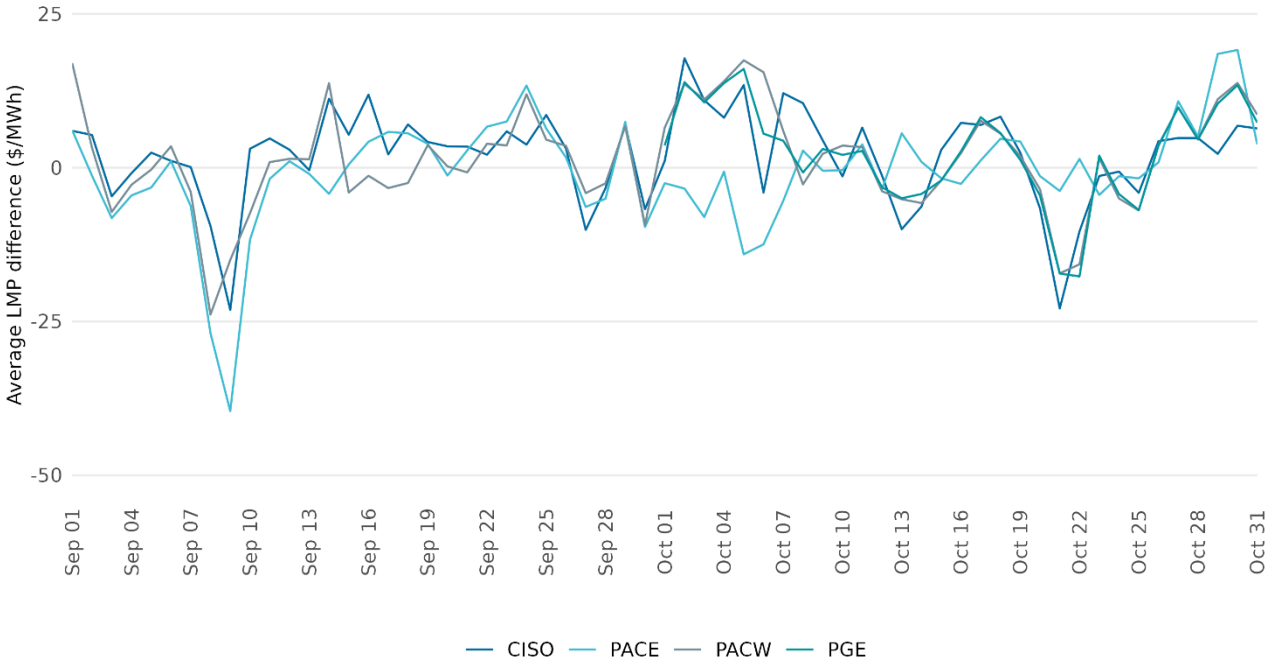
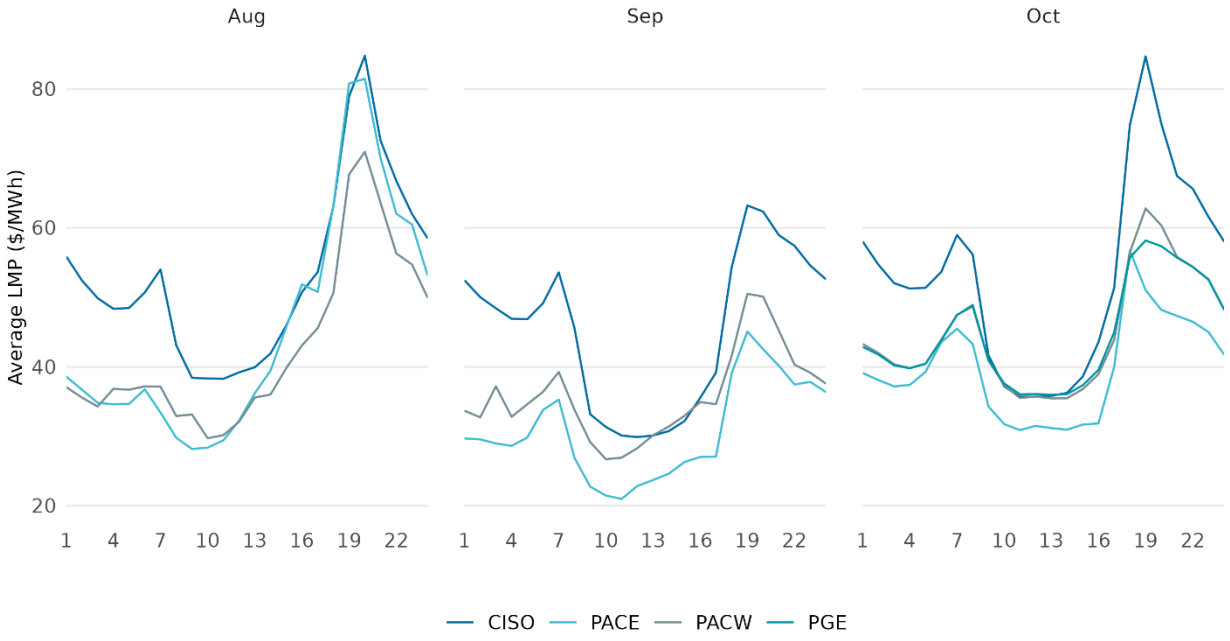


Figure 16 shows the average hourly IFM LMPs across the four EDAM BAAs. Average price separation between CAISO and both PACE, PACW, and PGE was greatest from HE 1 to HE 8 and from HE 18 to 24 in October. Price separation between PACE and PACW was higher after HE 18 compared to September. Prices in PGE mirrored PACW closely.

Figure 16: Hourly IFM LMP averaged by month



Price Volatility

Price volatility provides insight into the stability of market outcomes and changing system conditions. In this section, price volatility is measured using the frequency of extreme LMPs across the EDAM BAAs.

Figure 17, Figure 18 and Figure 19 and Figure 20 show the frequency of RTD LMPs falling in predefined $/MWh ranges in the given month for each BAA. Compared to September, the frequency of prices between $40/MWh and $100/MWh increased across all BAAs in October.

Figure 21 shows the frequency of extreme RTD LMPs in price ranges below -50 $/MWh and above 100 $/MWh. The frequency of very high and very low LMPs in October was similar compared to September. There was a slight uptick in the frequency of extreme LMPs for PGE lower than -$50/MWh and greater than $200/MWh.

Figure 17: CAISO RTD LMP range frequency

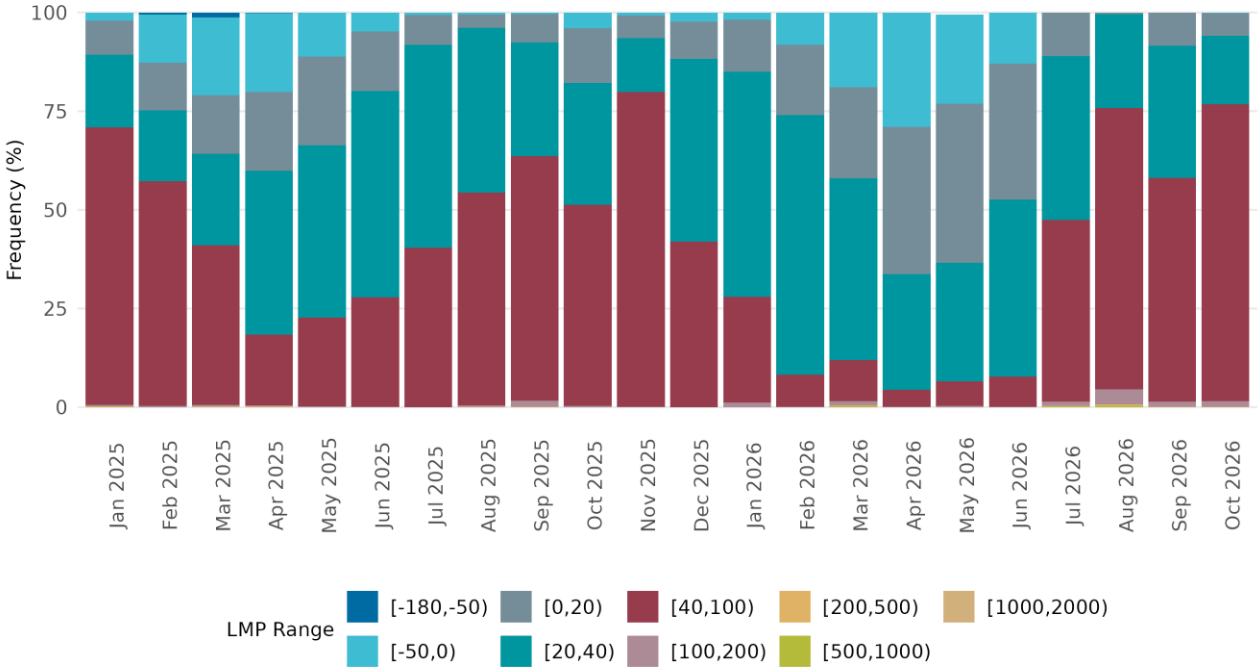


Figure 18: PACW RTD LMP range frequency

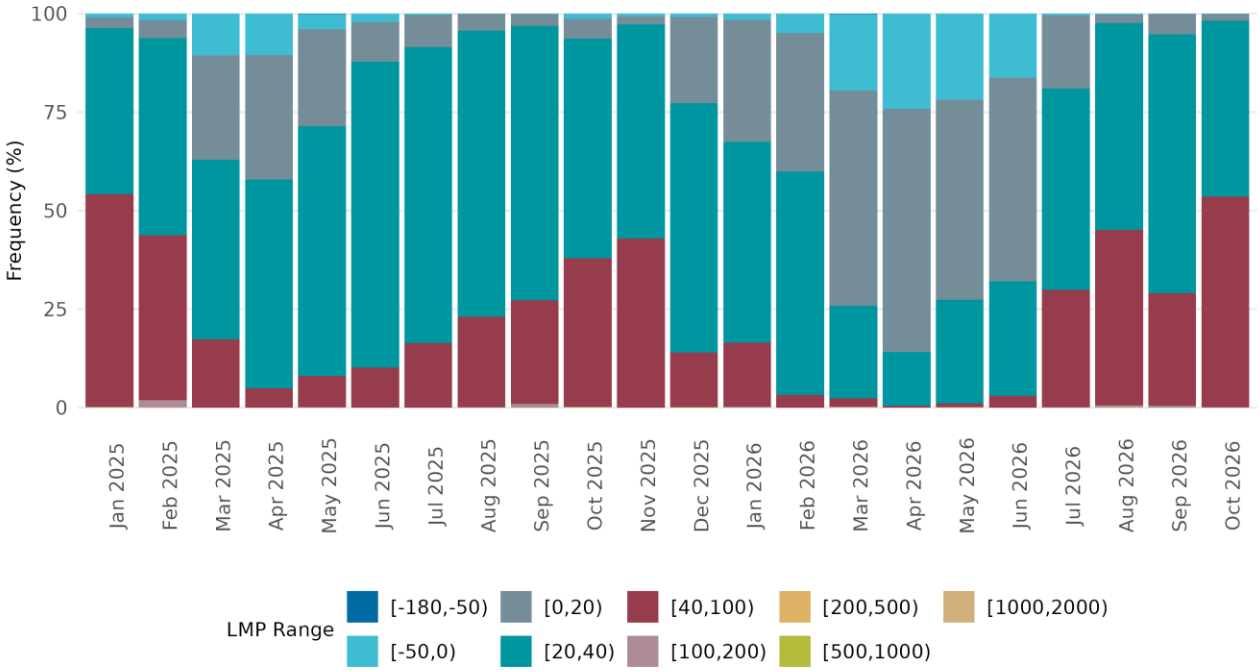


Figure 19: PACE RTD LMP Range Frequency

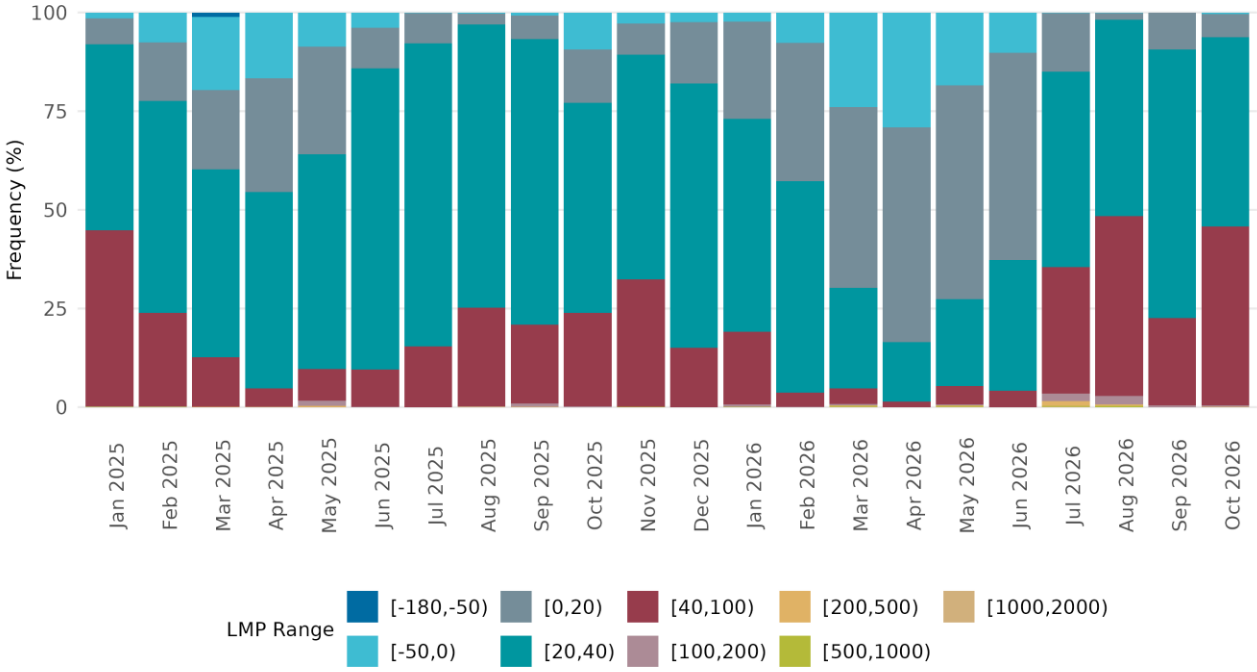


Figure 20: PGE RTD LMP Range Frequency

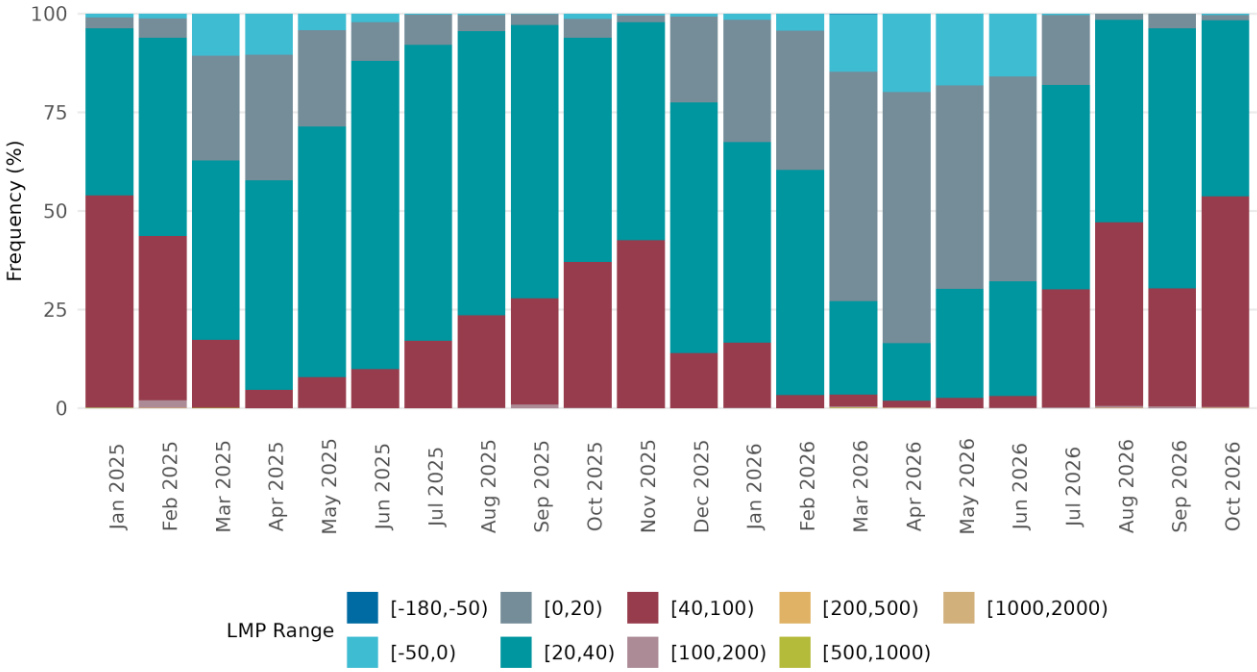
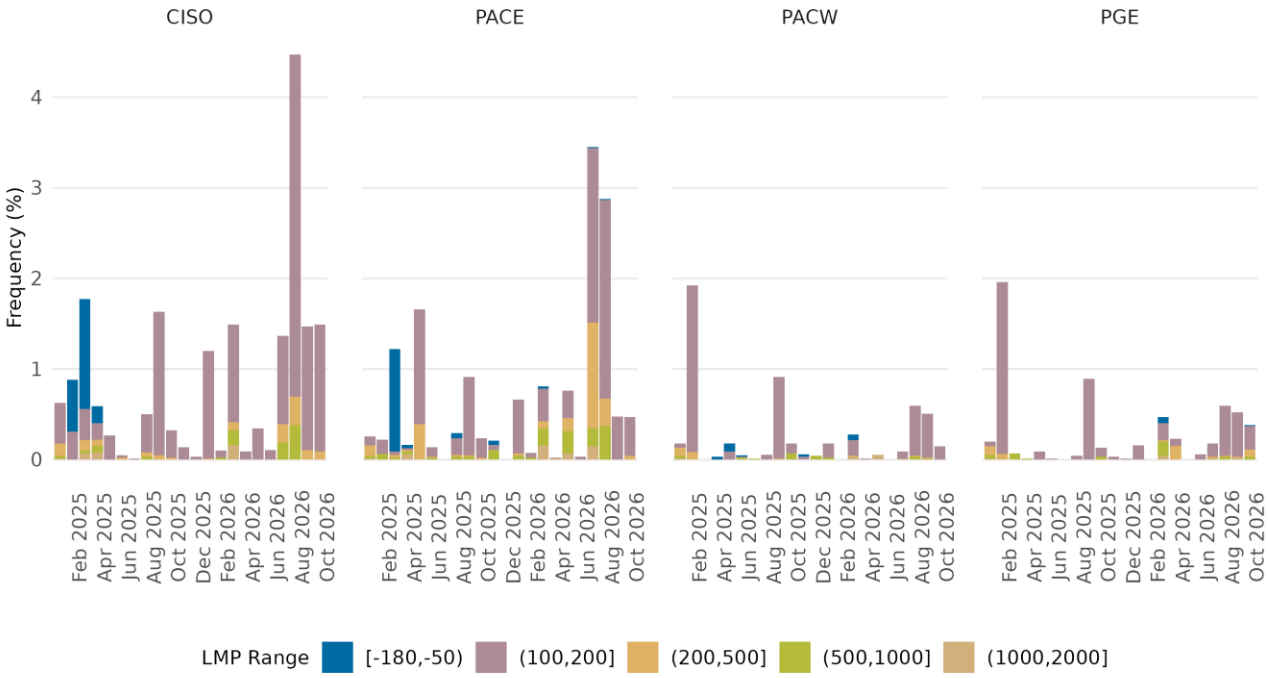


Figure 21: Frequency of low- and high-end RTD LMPs



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

Figure 22: 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):

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

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:

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

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 4: 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
	ν_j	ν_j	
	ξ_j	ξ_j	
	μ_j		

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

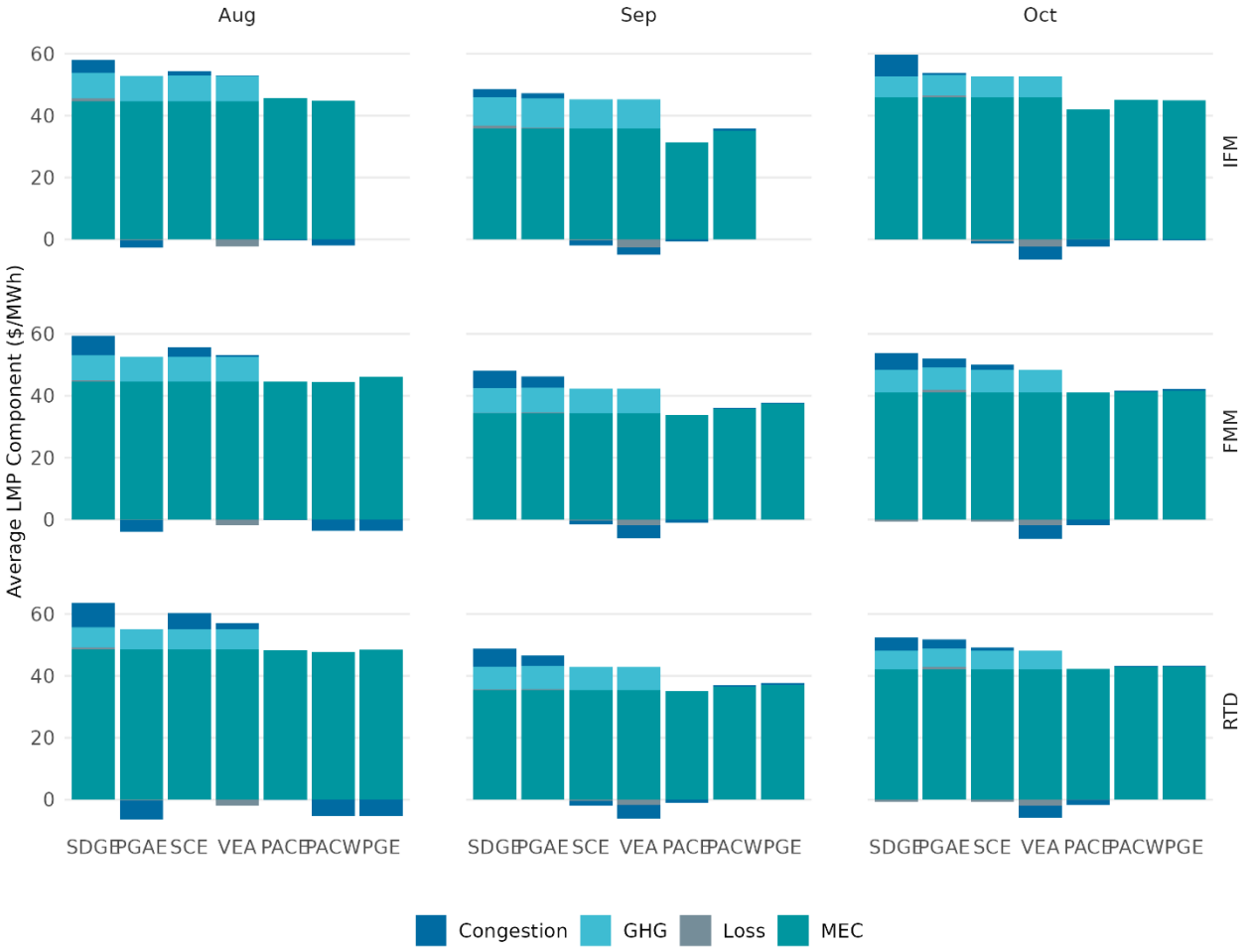
GHG prices

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. In EDAM the marginal cost of GHG emissions is accounted for outside of the MEC and only applies within GHG regulation areas[2]. The GHG component is positive and applies only to California-area locations.

Figure 23 shows the monthly average LMP composition in IFM, FMM, and RTD for the PACE, PACW and PGE ELAPs and CAISO's four default load aggregation points (DLAPs). The figure orders areas by how often they were the highest-priced area, from most to least frequent. A negative congestion component decreases the LMP. Overall, the monthly average MEC component increased from September to October for all BAAs. The area that was most frequently the highest priced area was SDG&E. There was similar separation across monthly average MECs in October compared to September as PACE MECs declined while MECs in the other areas remained similar. The monthly average congestion component remained in the same direction but increased in SDG&E, VEA and PACE particularly in IFM in October compared to September. The monthly average GHG component fell compared to September across all markets, with the largest drop in IFM from an average of $9.3/MWh in September to $6.7/MWh in October.

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

Figure 23: Average monthly LMP components



Bilateral power price comparisons

Outside CAISO's markets, power is historically traded through forward-looking bilateral transactions between buyers and sellers. The Intercontinental Exchange (ICE) is a marketplace where power contracts are 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 trends in 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. However, these trends need to be monitored over a sufficient time period to provide a more robust assessment of any correlations with EDAM operations.

Figure 24 and Figure 25 below shows a comparison between EDAM BAA LMPs and next-day bilateral power prices at the Mid-Columbia (MidC) and Palo Verde (PV) hubs on a monthly average and daily average basis, respectively. 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 time of use periods[3], 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.

Across BAAs, the daily trends in October were less clear than those observed on a monthly basis due to the influence of weather and short-term volatility. On a monthly average basis, CAISO day-ahead LMPs have historically tracked a blend of next-day bilateral power prices at MidC and PV, with the degree of alignment varying between the two hubs across months. On a day-to-day basis, CAISO day-ahead LMPs tracked with a blend of MidC and PV next-day bilateral power prices, but the correlation leaned towards PV more frequently. CAISO day-ahead LMPs are a load weighted average of the four DLAPs and thus the correlation fluctuates between MidC or PV based on which DLAPs had higher loads and congestion. PACE day-ahead LMPs have been more strongly correlated to PV than MidC on a monthly average basis, however on a daily basis the correlation is weaker with several days where correlation with MidC was stronger. PACW day-ahead LMPs were historically correlated with MidC prices more than PV prices on a monthly basis. In October, PGE's day-ahead LMPs were very close to PACW's during its first month in EDAM.

[3] 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 24: Monthly average LMPs and bilateral power prices

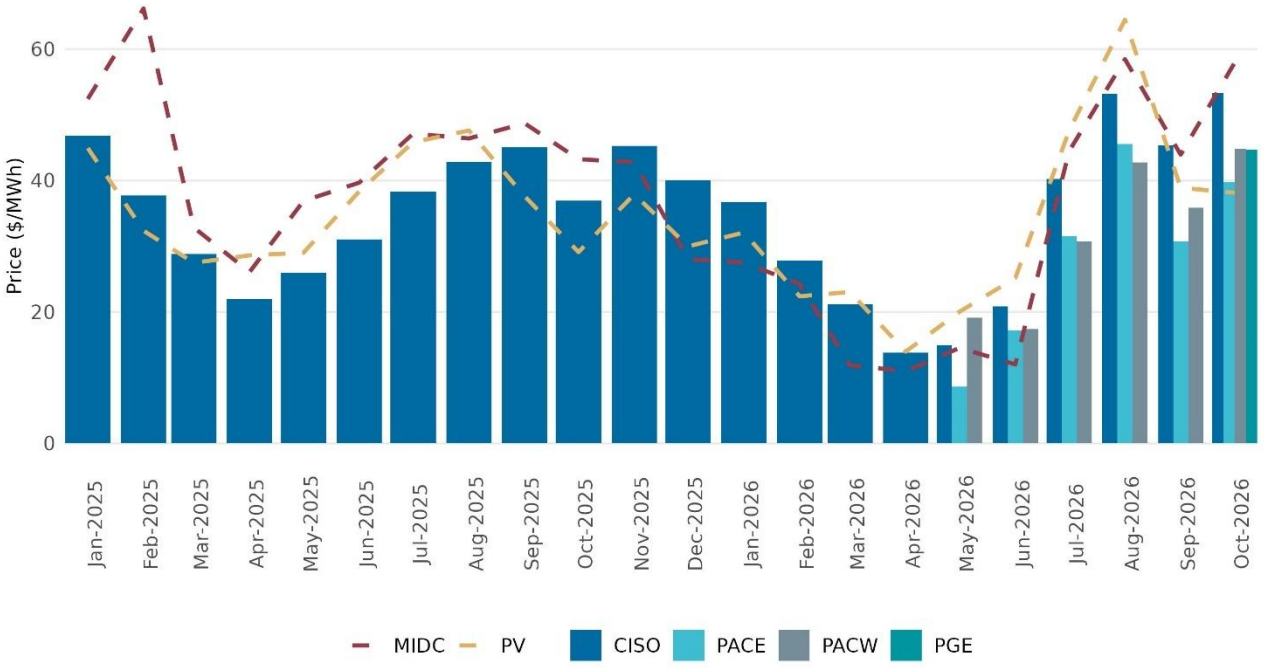
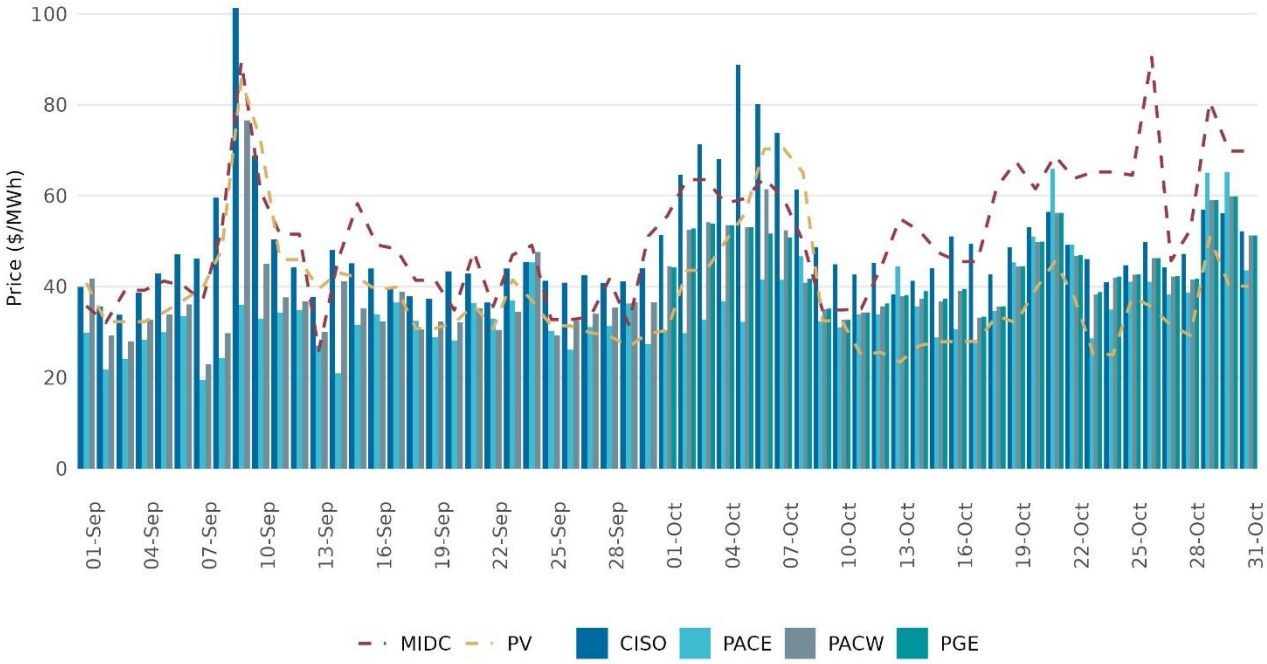


Figure 25: Daily average LMPs and bilateral power prices



Error! Reference source not found. and Figure 27 show monthly average energy volume traded since January 2025. On-peak volume declined in September 2026 but rebounded in October. Off-peak volumes fell in October 2026 compared to on-peak.

Figure 26: Total monthly energy volume of bilateral trades (On-peak)

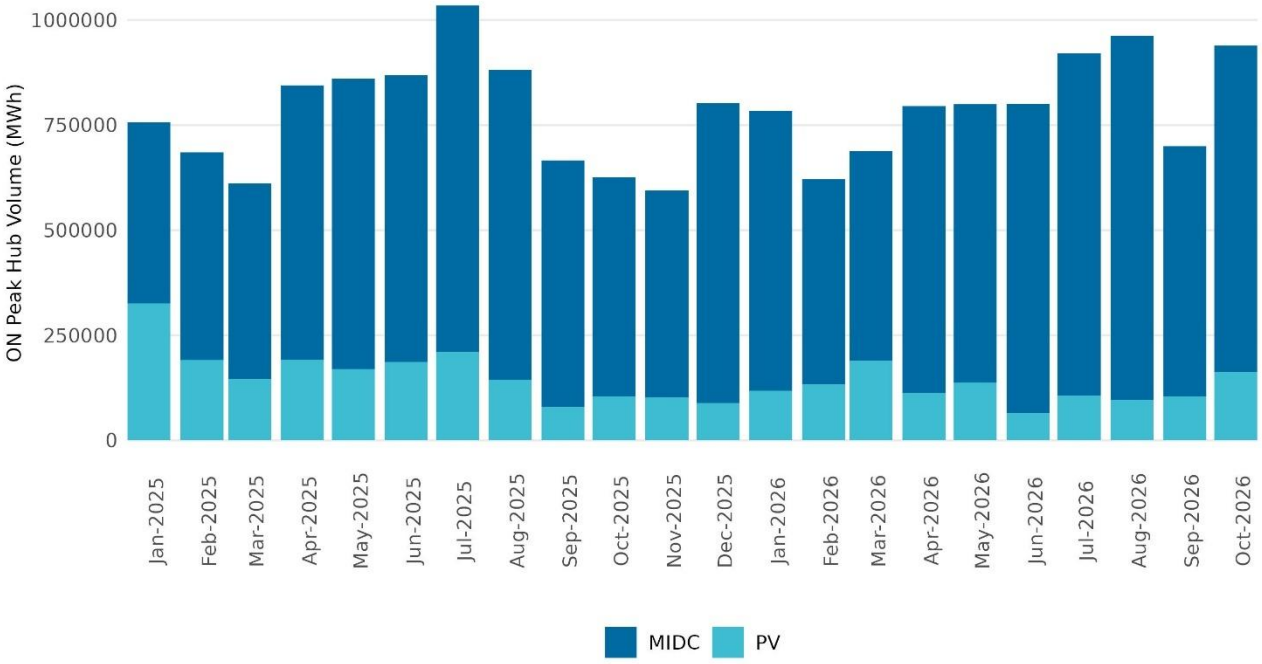


Figure 27: Monthly total energy volume of bilateral trades (Off-peak)

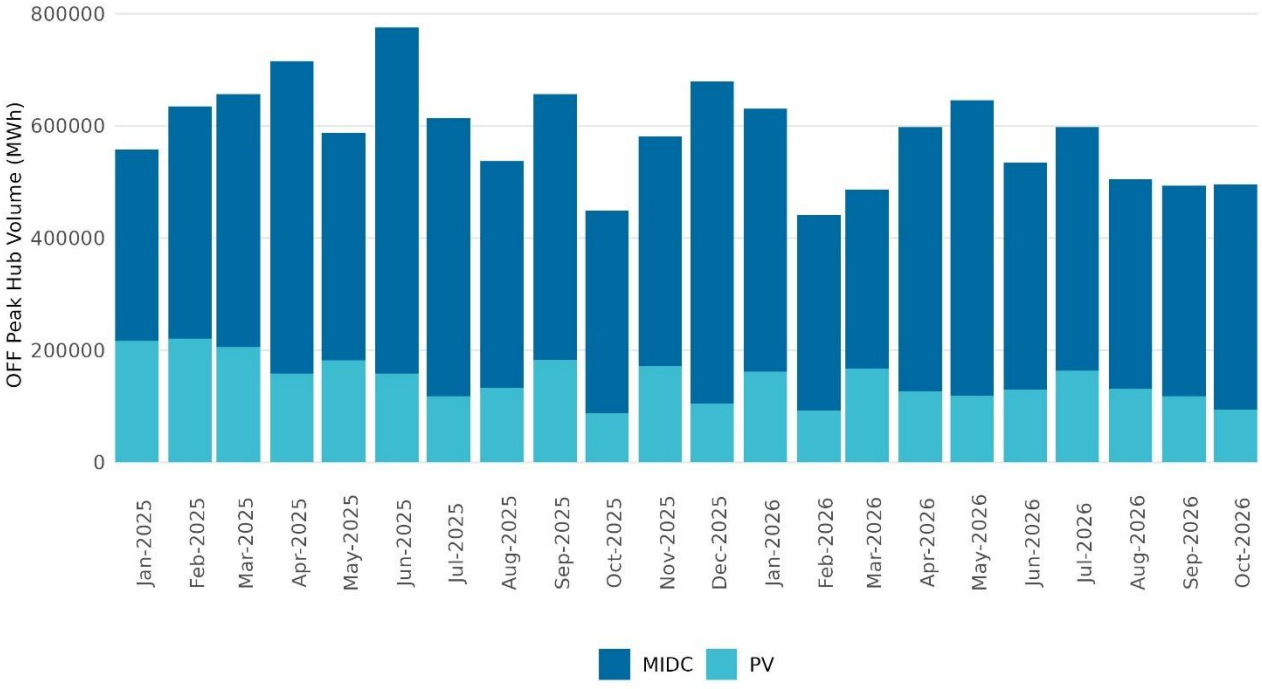


Figure 28 and Figure 29 show the daily energy volume traded for bilateral next-day power at MidC and PV hubs from April to October. For on peak, no power is traded on Sundays, which is an off-peak day. For off-peak, volumes are lowest during the weekdays. For both on- and off-peak, volumes are usually highest at the end of the week when power delivery is for Sunday and Monday. These figures show no observable change in patterns in the volume traded for on- or off-peak from pre-EDAM in April to EDAM operations from May through October. Volumes at Mid-C and PV showed several spikes in October, coinciding with high-heat events.

Figure 28: Total daily energy volume of bilateral trades (On-peak)

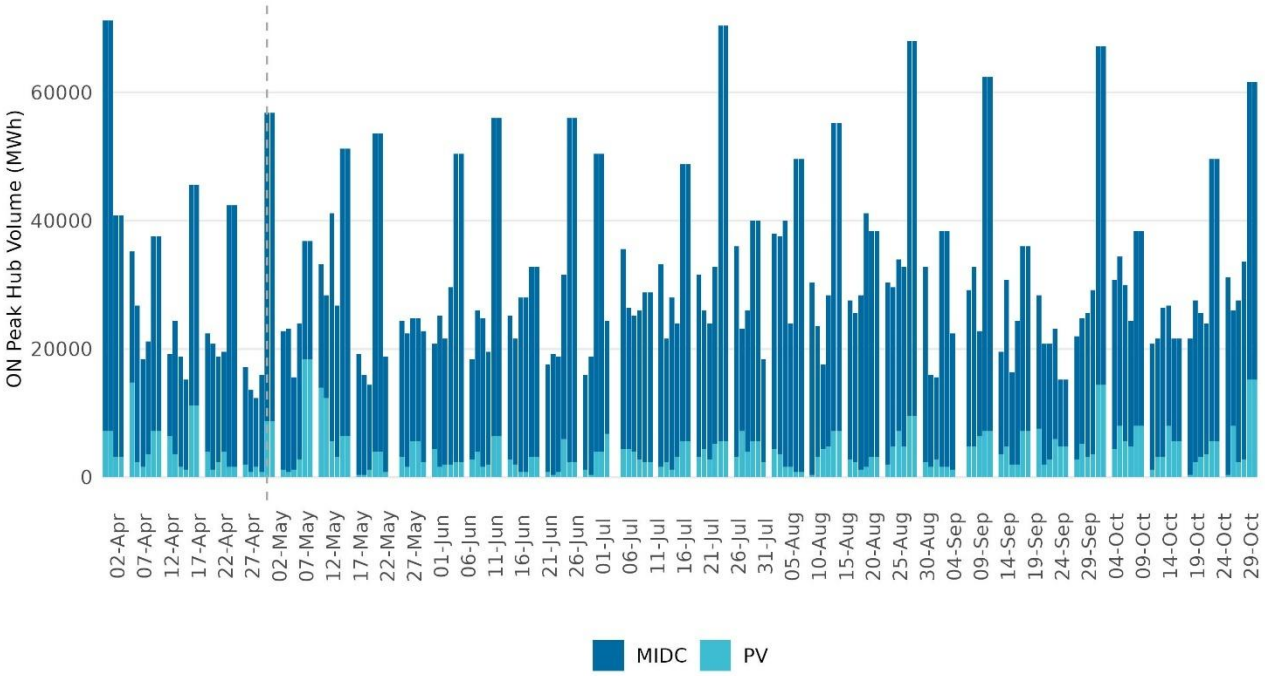
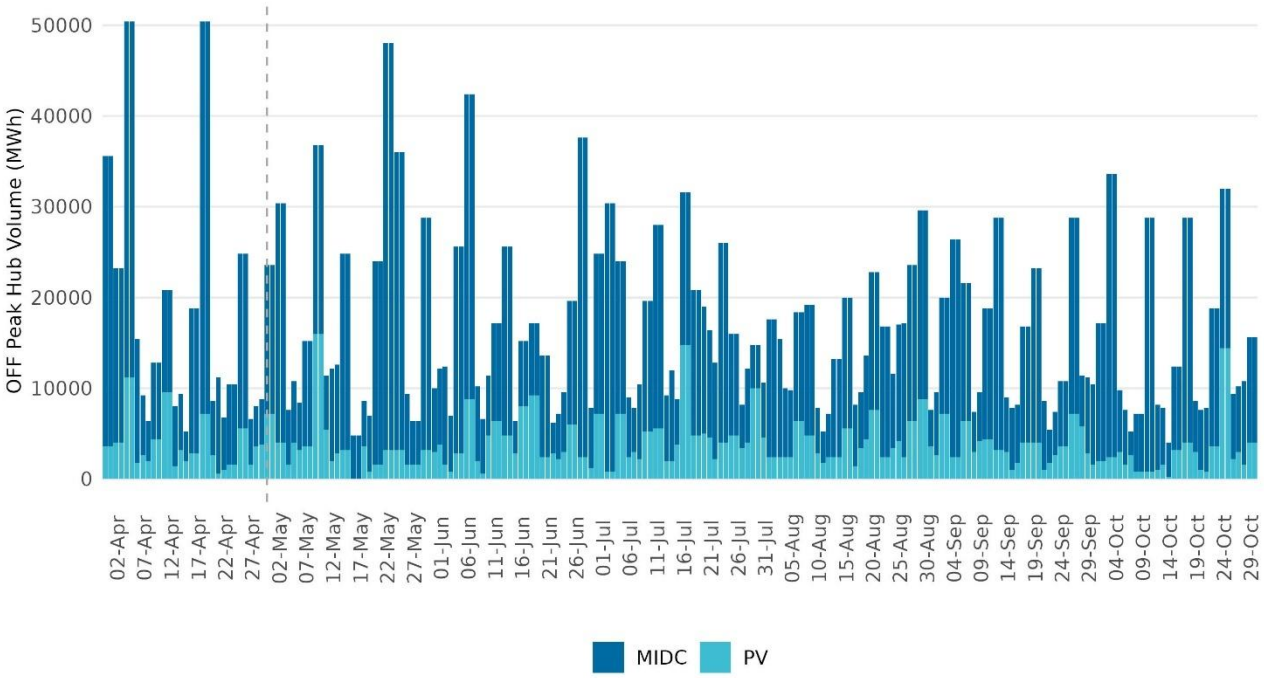


Figure 29: Total daily energy volume of bilateral trades (Off-peak)



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 30 shows CAISO ancillary services prices in IFM from August 1st to October 31st. Overall, AS prices remained within typical ranges for all four commodities in September, with slightly elevated prices for October 5 through 8 reflecting heatwave conditions.

Figure 30: Daily average of CAISO ancillary services prices in IFM

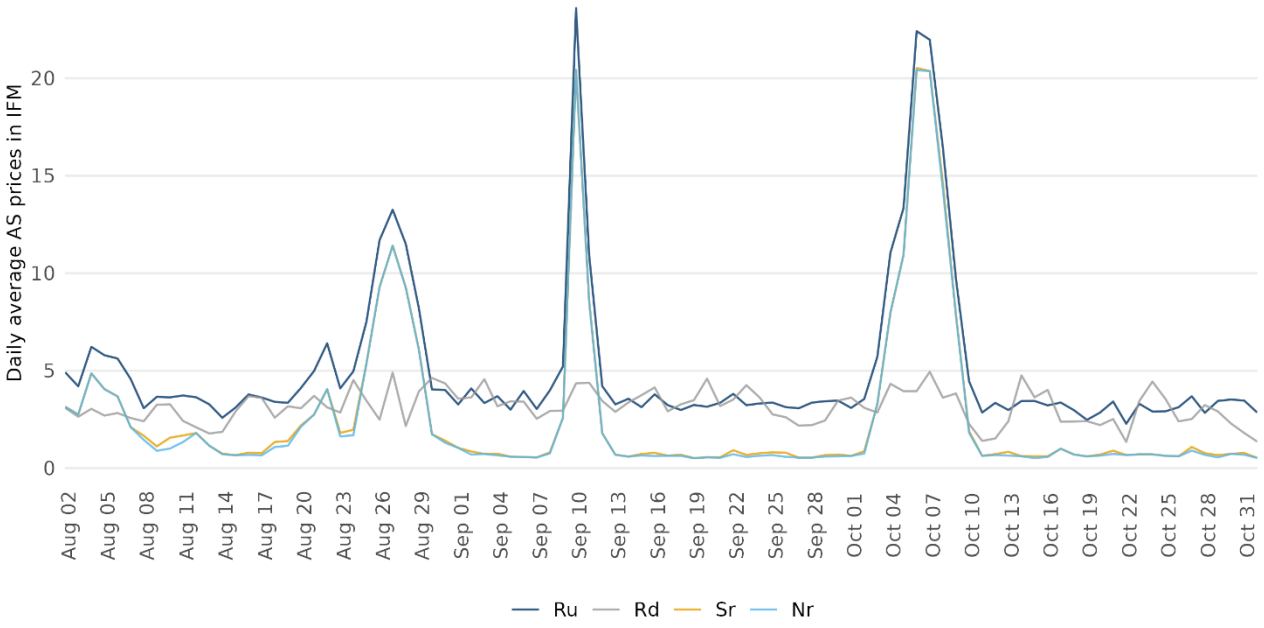
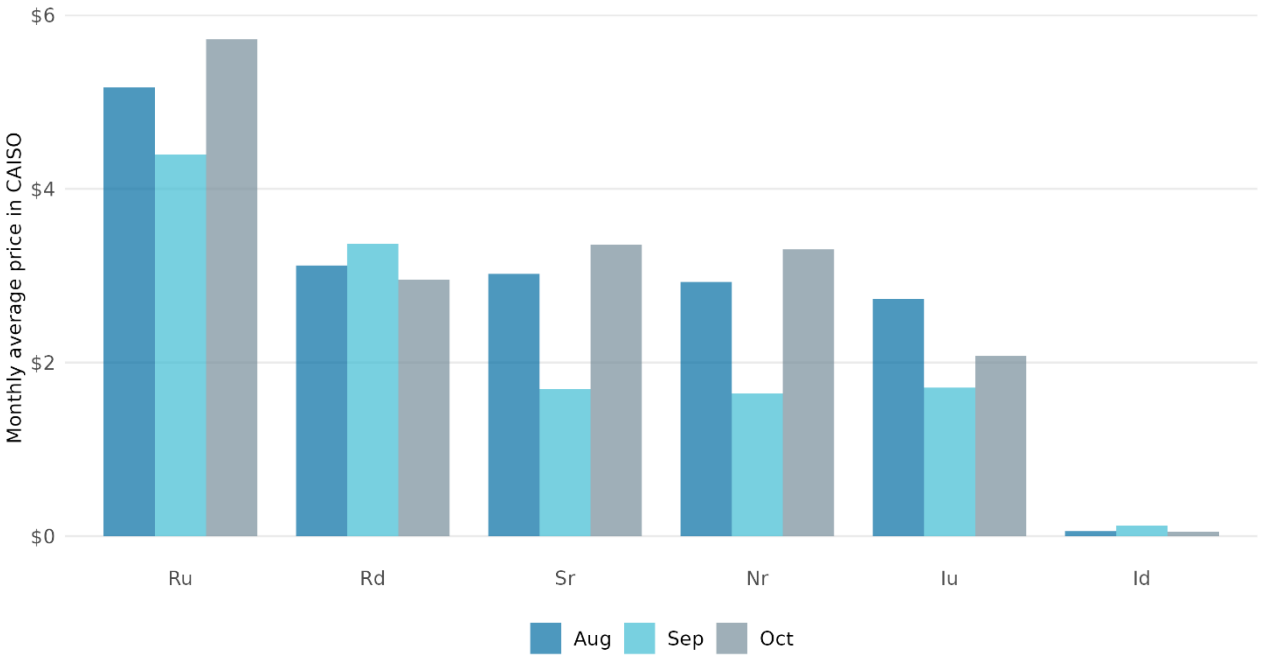


Figure 31 compares the monthly average AS prices in CAISO for August through October. Average regulation up, spin, and non-spin prices showed slight increases, while regulation down prices remained in similar ranges. New imbalance reserve prices in CAISO are added for reference. Average price of imbalance reserve up remained in similar ranges in October, lower than the average prices of spin and non-spin.

Figure 31: Monthly average AS prices in CAISO



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

Figure 32 shows that IRU prices in October increased compared to September for CAISO and PACE but fell for PACW. PACE recorded the highest monthly average IRU price in October at $4.76/MWh, up from $2.37/MWh in September. CAISO followed at $2.07/MWh, with lower monthly average

prices in PGE ($1.51/MWh) and PACW ($1.33/MWh). Monthly average IRD prices across BAAs in October remained highest for PACW. However, compared to September monthly average IRD prices for PACW decreased in October, falling from $1.78/MWh to $1.13/MWh. For PACE and CAISO, monthly average IRD prices remained low in October. Monthly average IRD prices for PGE were also low in October.

Figure 32: Monthly average IR prices



Figure 33 and Figure 34 show the frequency of IRU and IRD price ranges from May to October. IRU prices in October ranged from $0/MWh to $5/MWh for approximately 90% of intervals in CAISO, 96% in PACW and 94% in PGE. For PACE, IRU prices ranged from $0/MWh to $5/MWh for approximately 65% of intervals in October, compared to 83% in September. For IRD, prices ranged from $0/MWh to $5/MWh in 100% of intervals in October for CAISO and PGE. For PACE, IRD prices fell between -$5/MWh and $5/MWh in 100% of intervals and 94% for PACW.

Figure 33: Frequency of IRU price ranges

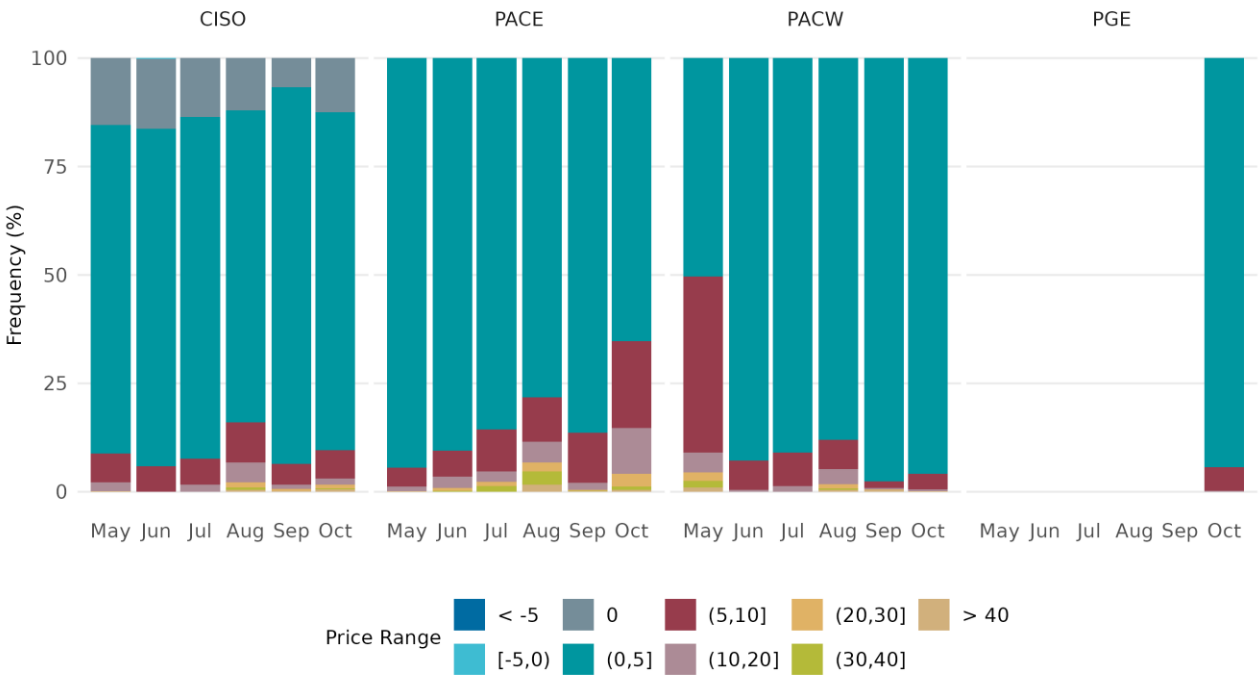


Figure 34: Frequency of IRD price ranges

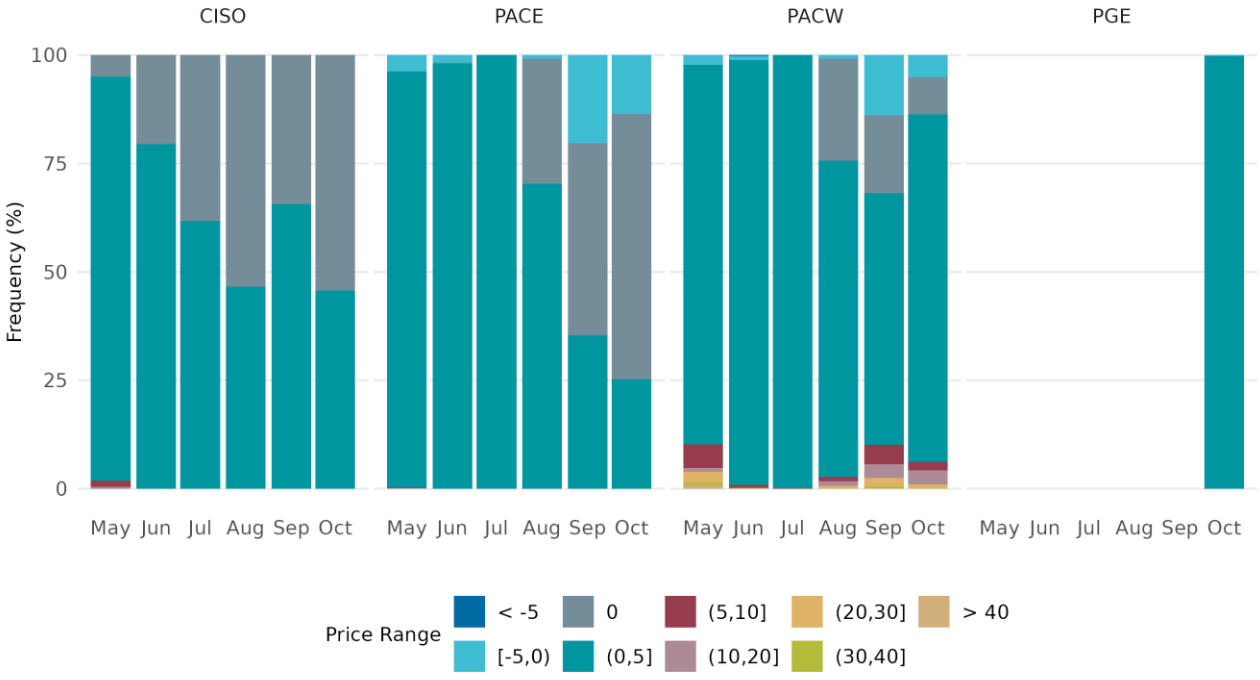


Figure 35 and Figure 36 show the daily average IR prices in October. Daily average IRU prices were more volatile compared to September for CAISO and PACE, but less volatile for PACW. The highest daily average IRU prices occurred in PACE on October 21 and 29 of $14.57/MWh and $13.75/MWh, respectively. CAISO experienced high IRU prices on October 5 with a daily average price of

$10.47/MWh. Daily average IRU prices in PACW and PGE remained low. Daily average IRD prices remained stable in October except for PACW which experienced price volatility, though PACW IRD prices were less volatile than in September. PACW experienced multiple IRD price spikes at the beginning of the month, with the highest daily average IRD price occurring on October 2 at $11.19/MWh.

Figure 35: Daily average price of IRU

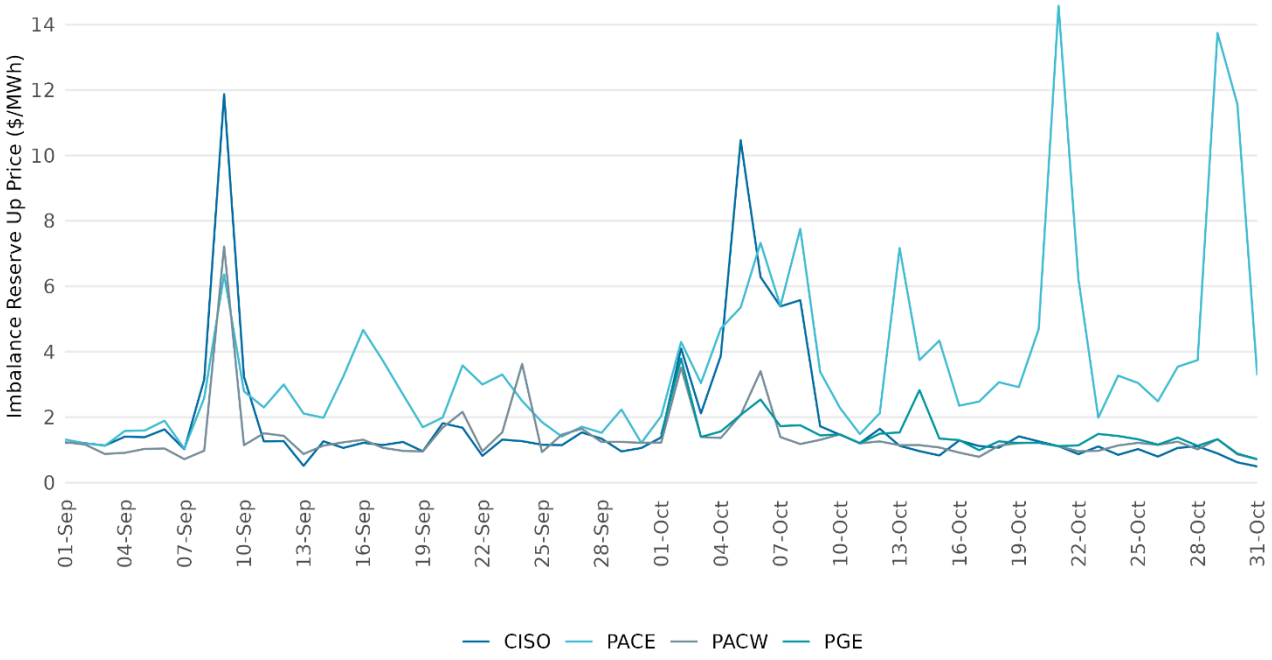


Figure 36: Daily average price of IRD

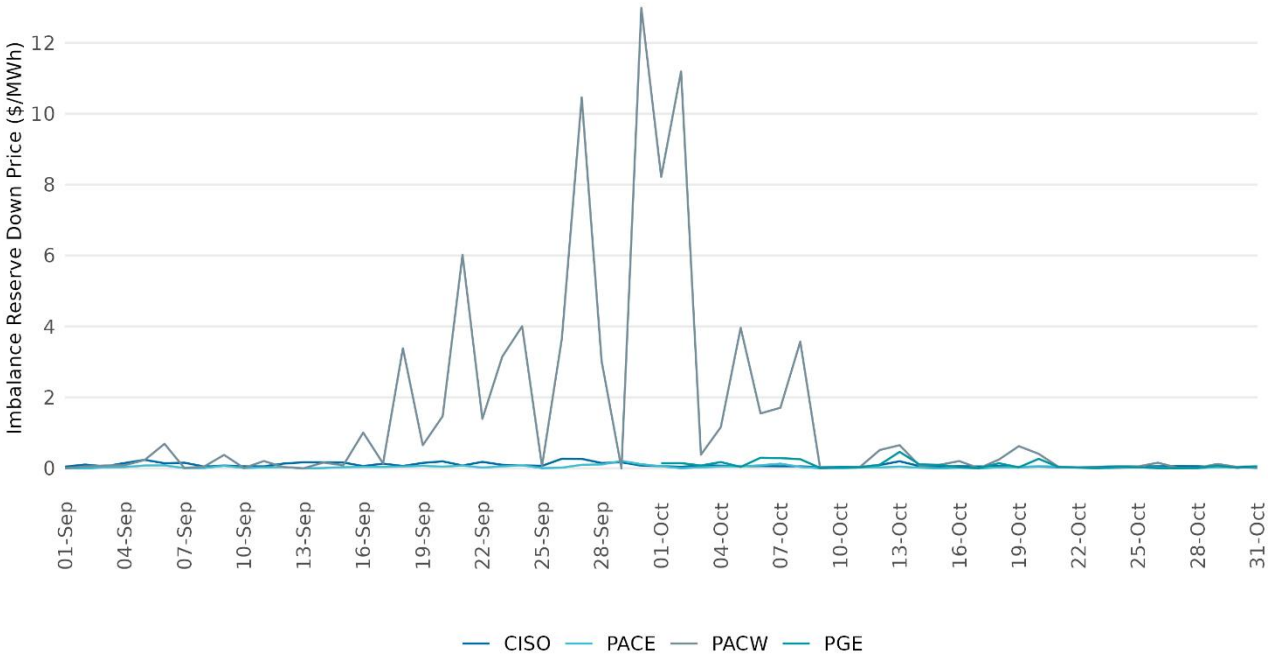


Figure 37 and Figure 38 show the hourly average IR price profiles for all BAAs in October. The highest hourly average IRU prices occurred during the morning and evening ramping periods, consistent with trends observed in prior months. This coincides with the hours of highest day-ahead demand, indicating that ramping needs are greatest when net load forecasts change during these periods. Hourly average IRD prices also peaked in these hours for all three BAAs. In particular, PACW IRD prices were highest from hours ending 13 to 18.

Figure 37: Hourly average price of IRU

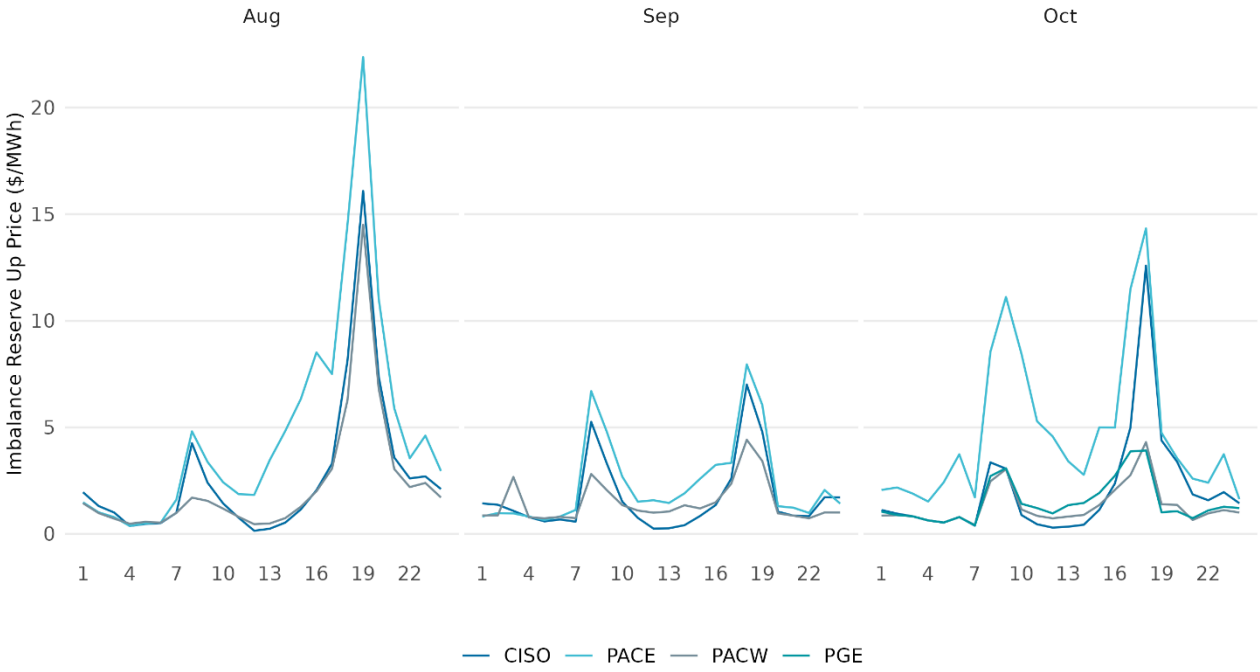


Figure 38: Hourly average price of IRD

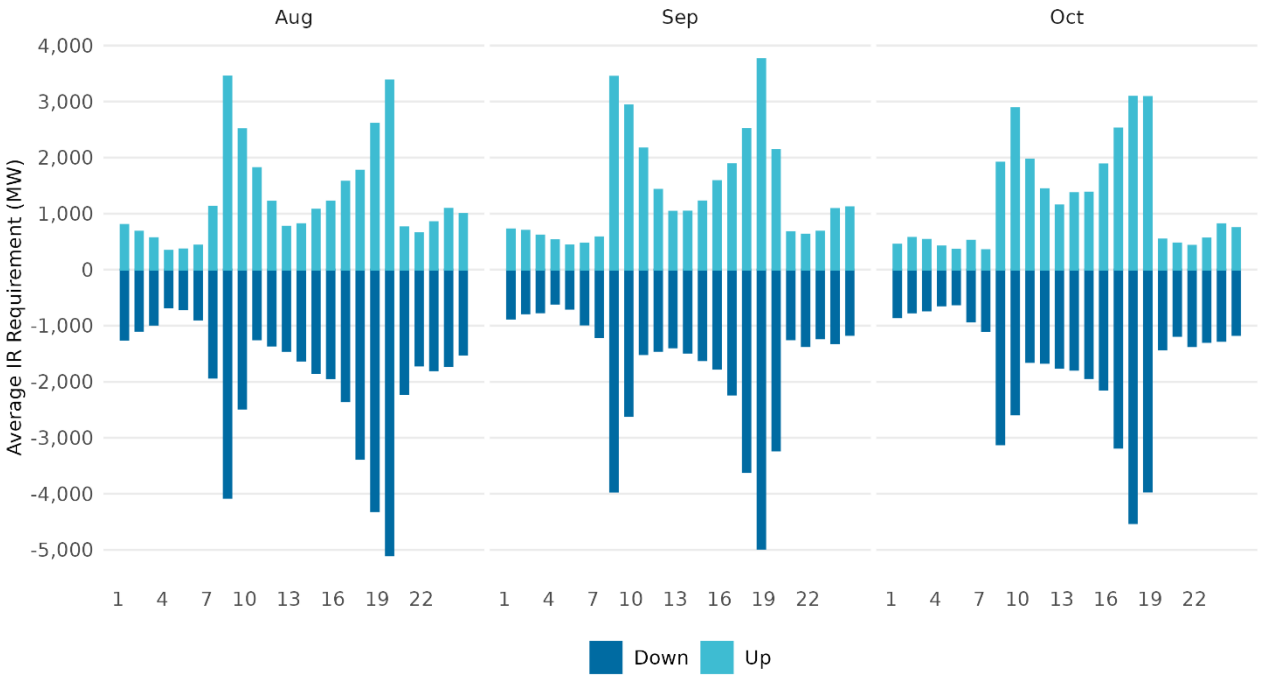


The imbalance reserve price separation observed between the three BAAs reflects the economics of the wider EDAM market footprint and each BAA's imbalance reserve requirement, available supply mix and EDAM transfers.

Imbalance reserve requirements

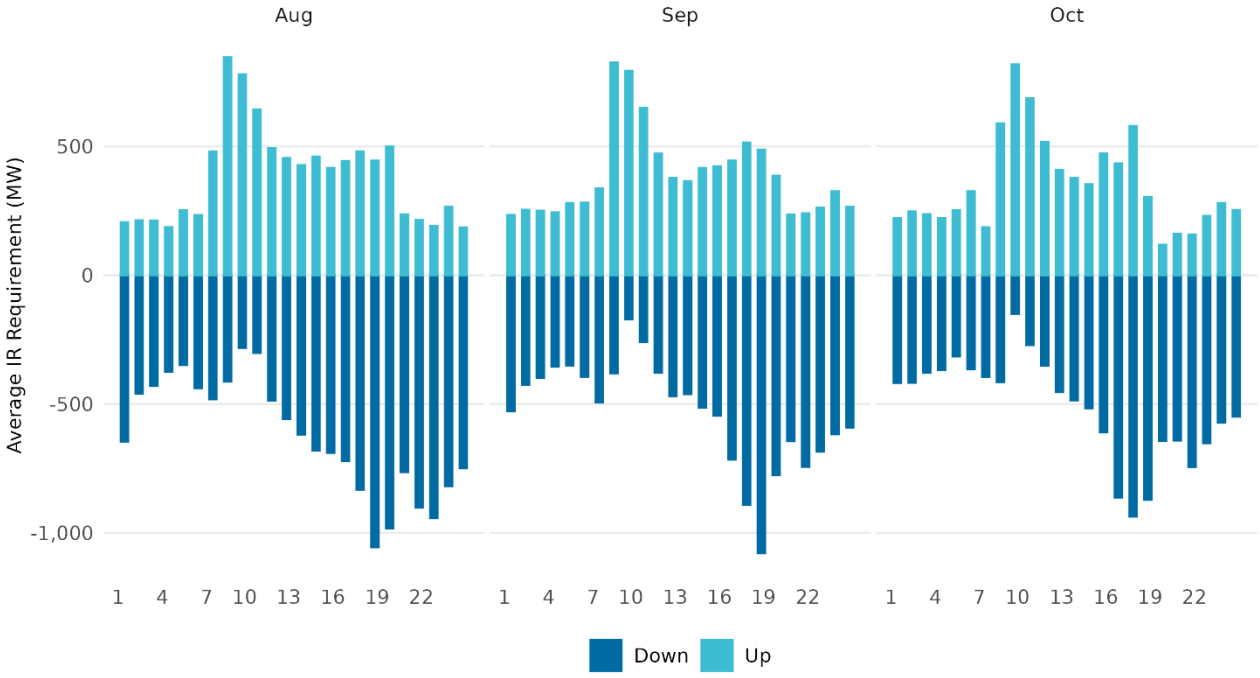
IR Requirements are calculated hourly for each BAA. Figure 39 to Figure 41 illustrate average IR requirements for each BAA by direction. The magnitude of IR procured is proportional to the magnitude of net load uncertainty associated with that BAA. CAISO is the largest footprint in the EDAM with a large assortment of variable energy resources, so naturally it sees the highest amount of IR procurement.IR requirements for CAISO BAA are consistent in shape and magnitude since August. The highest requirements typically occur during the solar ramping hours where flexibility is required if the net load forecast changes.

Figure 39: Hourly average of IR requirements for CAISO



PACE IR requirements, on average, also saw the highest IRU requirements during the morning ramping hours and the highest IRD requirements during the evening peak. PACE IR requirements shape and magnitude also are stable since August.

Figure 40: Hourly average of IR requirements for PACE



PACW IR requirements are relatively consistent throughout the day on average for both IRU and IRD. However, there was a noticeable decrease in the requirement in September and October compared with August in both upward and downward directions.

Figure 41: Hourly average for IR requirements for PACW

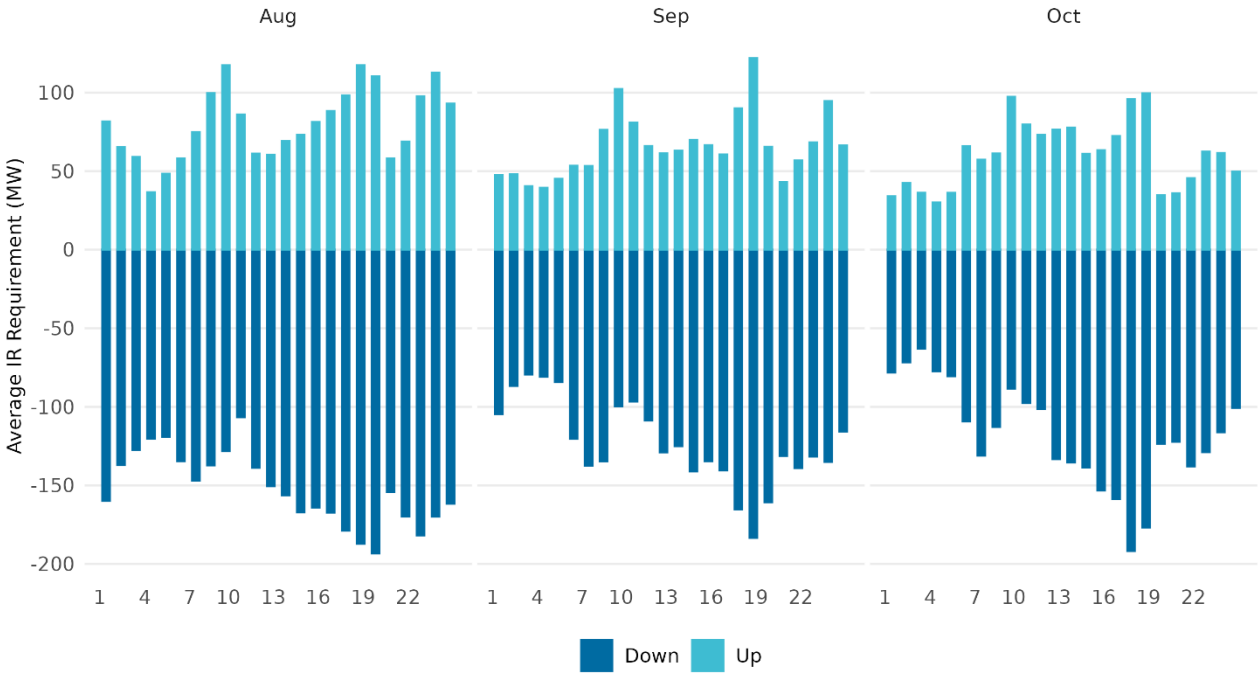
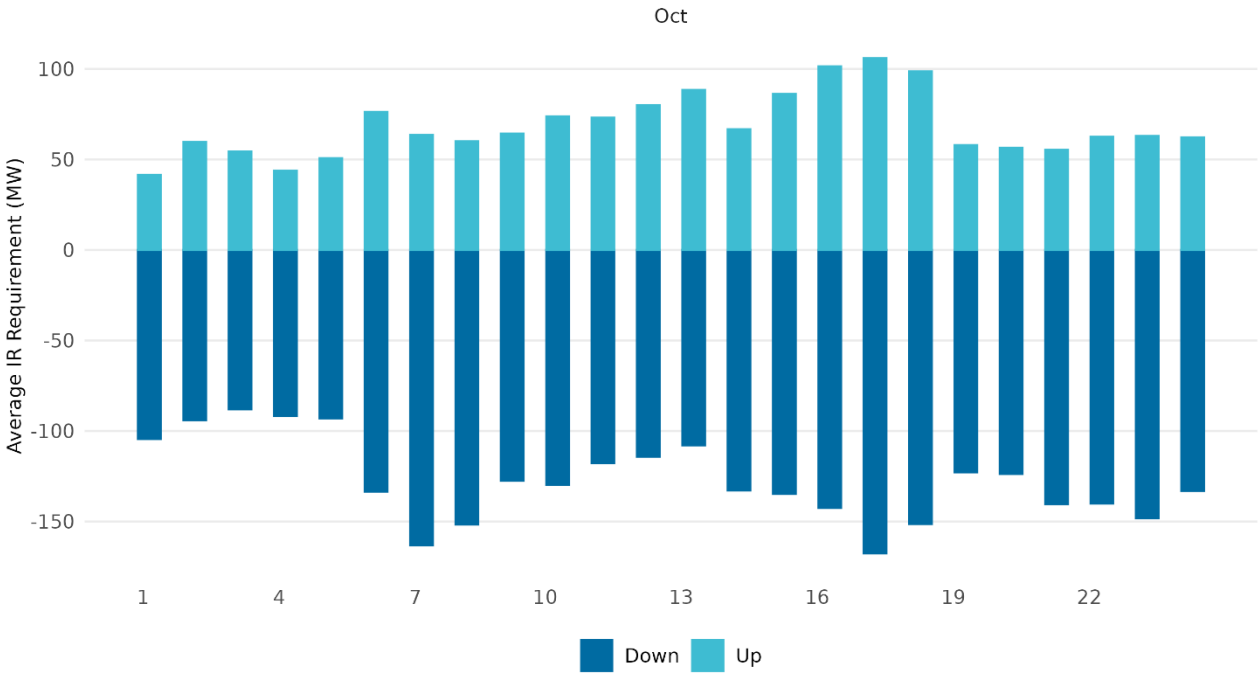


Figure 48 shows PGE's hourly average requirements in October, representing PGE's first month of participation in EDAM. Both upward and downward IR requirements varied throughout the day, with upward requirements generally ranging from approximately 40 to 105 MW and downward requirements ranging from approximately 90 to 170 MW in magnitude.

Figure 42: Hourly average for IR requirements for PGE for October



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 43 and Figure 44 presents the hourly average diversity benefit by EDAM BAA by product. Diversity benefit is defined as the difference between the sum of individual BAA IR requirement and the IR requirement of the entire EDAM footprint. The reduction of requirements is then allocated pro-rata to each EDAM BAA based on its original individual BAA requirement. In October2026, the average diversity benefit allocation is shown in Table 5.

Table 5 Average Diversity benefit allocation

BAA	CISO		PACE		PACW		PGE	
IRU	400	68.3%	133	22.7%	24.1	4.1%	28.7	4.9%
IRD	346	66.2%	120	22.9%	27.5	5.3%	29.5	5.6%

Figure 43: Hourly average diversity benefit, IRU

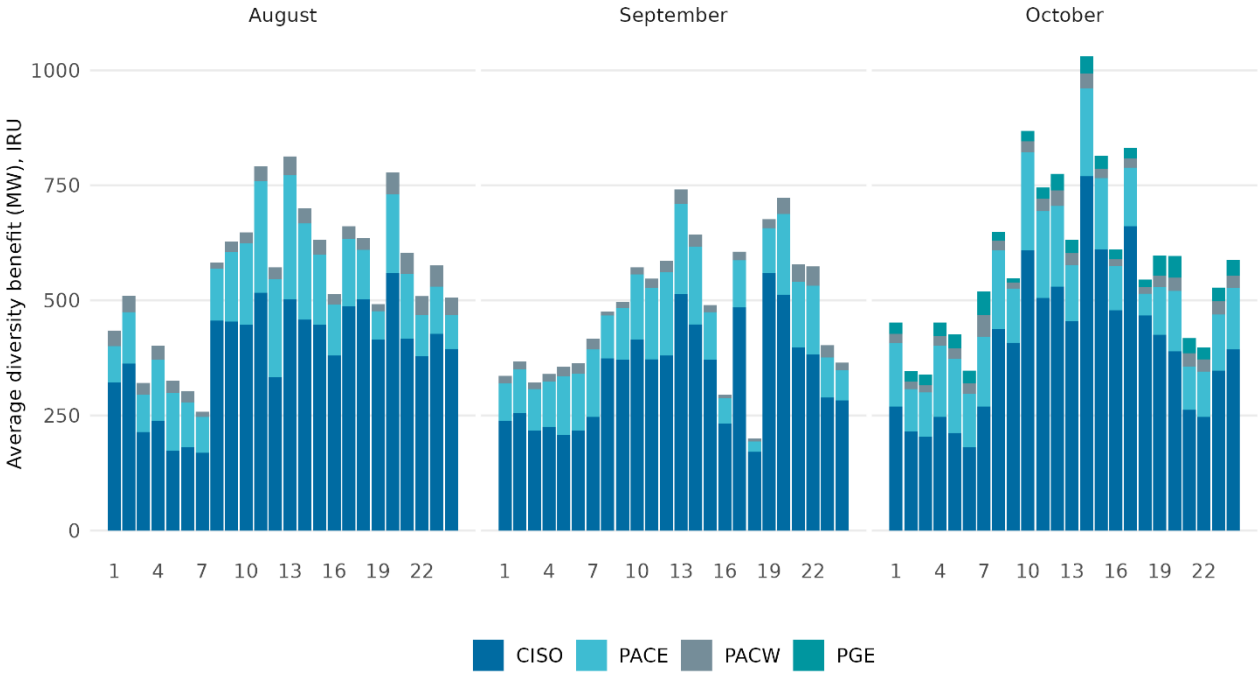
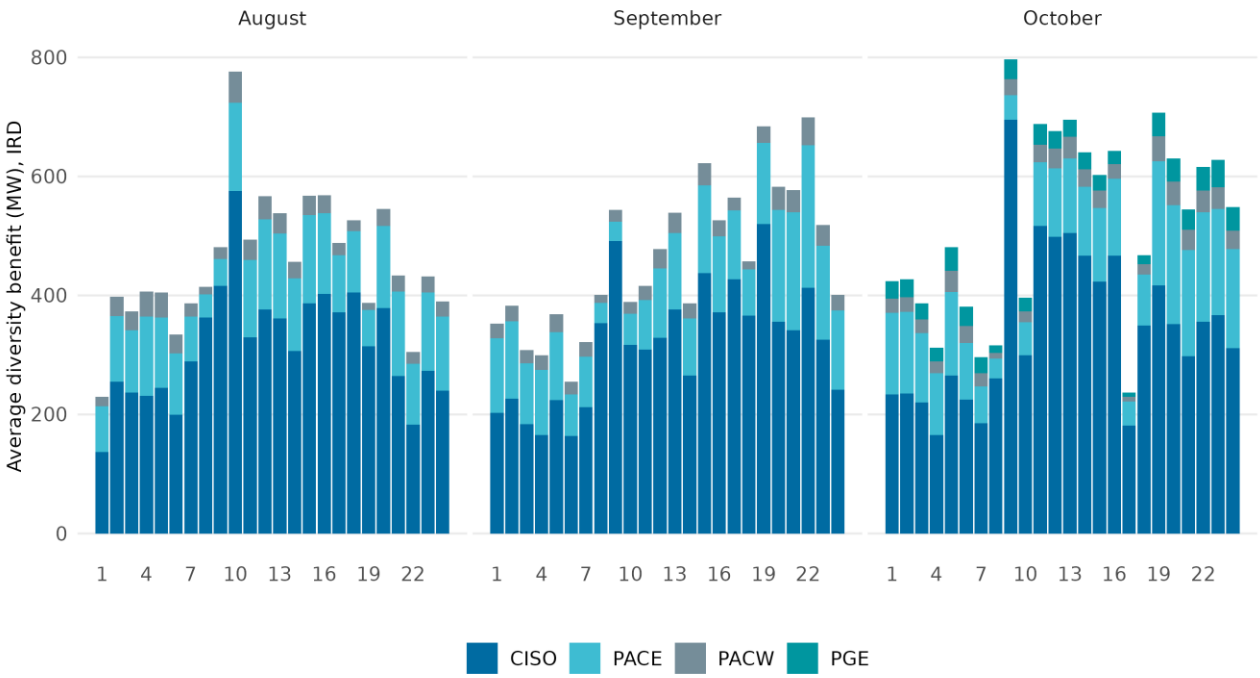


Figure 44 Hourly average diversity benefit, IRD



Imbalance reserve awards

Figure 45 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 non-solar hours. The CAISO's IR procurement is stable across three months. October shows a similar pattern: The largest ramp-period movements occur around HE 17–19, with positive procurement around 3,000 MW and negative procurement reaching roughly -4,500 MW

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

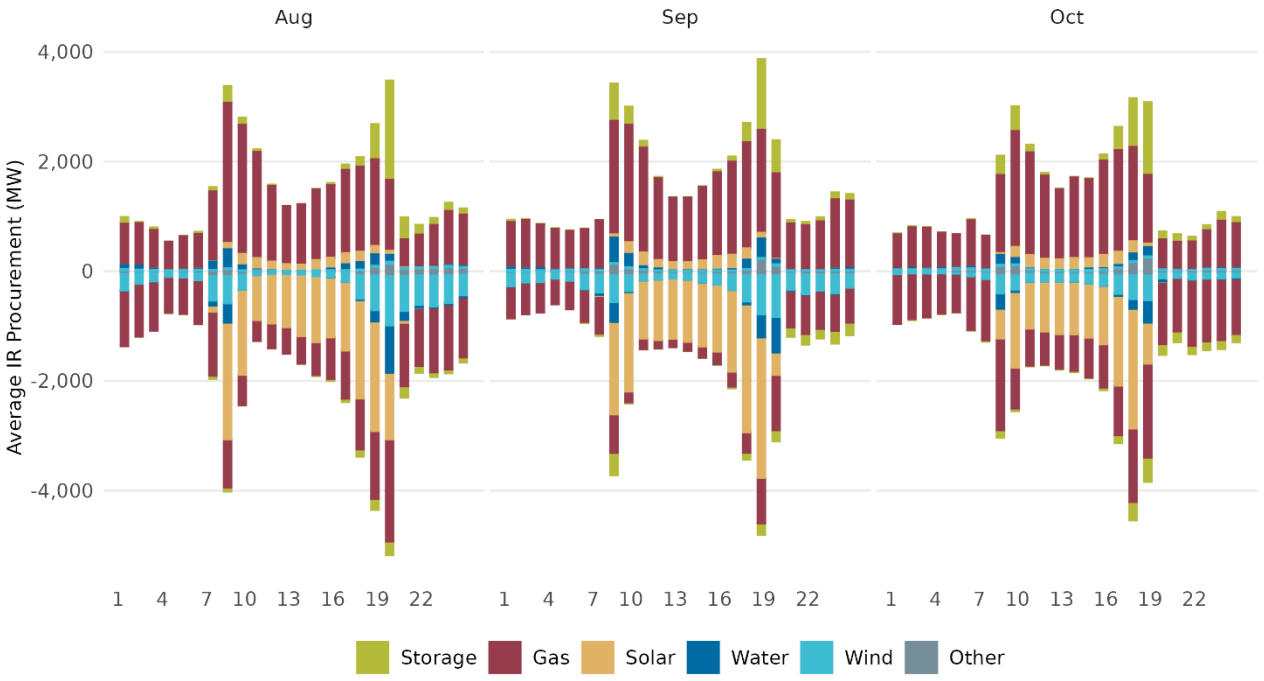


Figure 46 shows PACE's hourly average cleared IRU and IRD by fuel type, respectively. The dominant resources in PACE are coal and wind, followed by gas resources. Solar and storage have minimal contribution, with storage only during peak hours and solar during daytime hours and for IRD only. The overall IR procurement of PACE is stable throughout the three months.

Figure 46: Hourly average cleared IR by fuel type for PACE

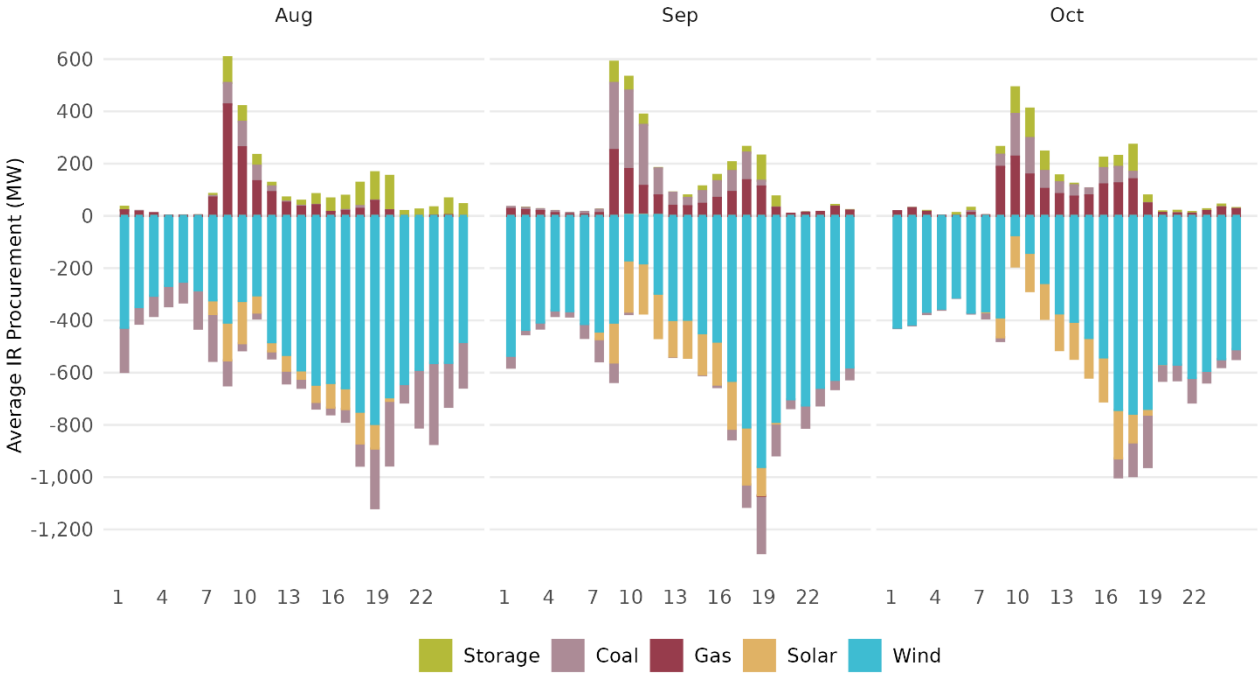
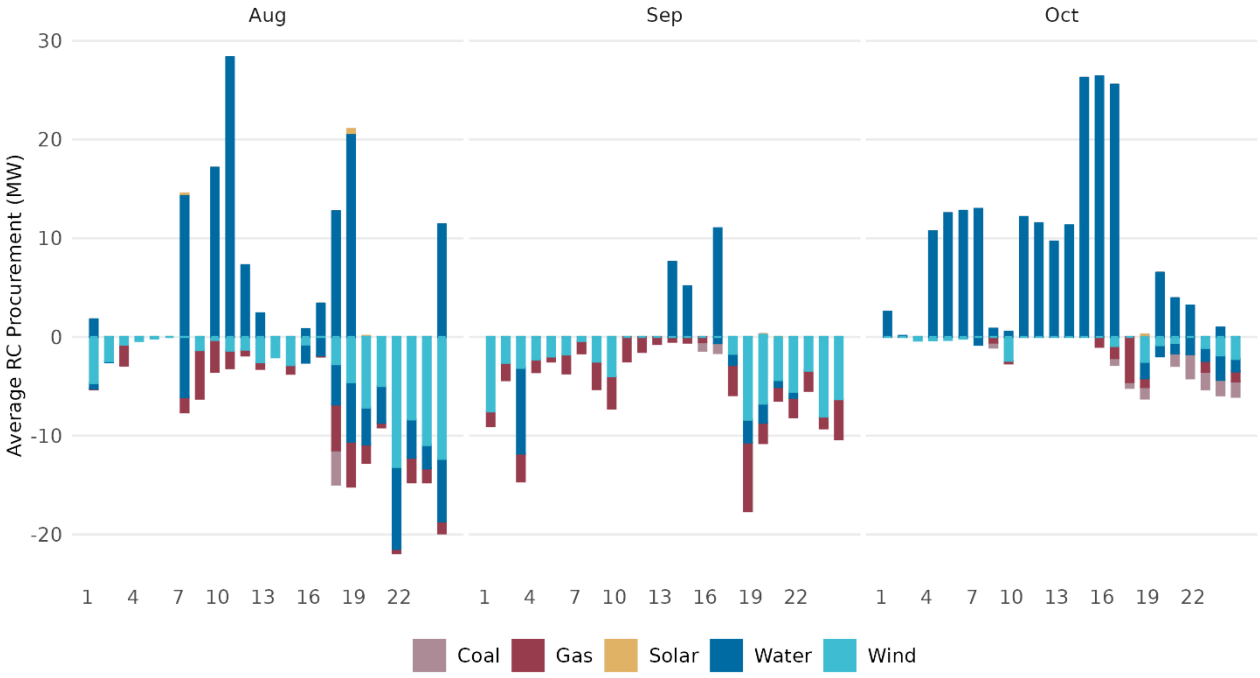


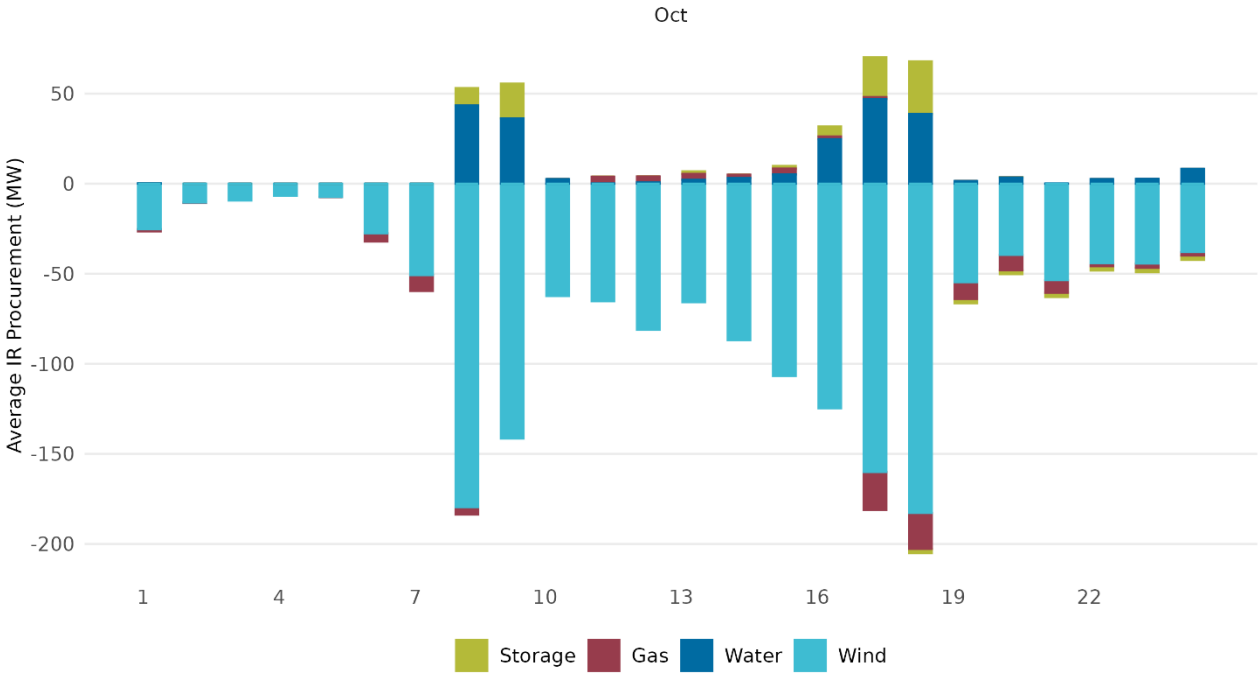
Figure 47 shows PACW's hourly average cleared IRU and IRD by fuel type, respectively. Unlike CAISO, the dominant resources in PACW are water and wind. Water resources provided nearly all the IRU supply and increased significantly in August and September. And October shows stronger hydro IRU procurement during daytime and afternoon hours, peaking at approximately 25–26 MW around HE 15–17. Wind resources contribute the most of IRD supply, and there were some gas resources providing IRD.

Figure 47: Hourly average cleared IR by fuel type for PACW



PGE's IR procurement in October was dominated by wind resources on the IRD side, with the largest procurement occurring around HE 18 at approximately 200 MW. Water and storage resources accounted for most of the IRU procurement, with notable increases around HE 8–9 and HE 17–18. Overall, PGE's profile shows pronounced morning and evening movements, with wind resources providing the majority of IRD procurement during PGE's first month in EDAM.

Figure 48: Hourly average cleared IR by fuel type for PGE



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 49 and Figure 50 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 August and October with about 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. The overall bid-price composition showed limited variation across both hourly and daily views, indicating a stable supply

offer pattern for CAISO's IR throughout August to October. The volume of bids in the upward direction is symmetrical to the volume for the downward direction.[4]

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

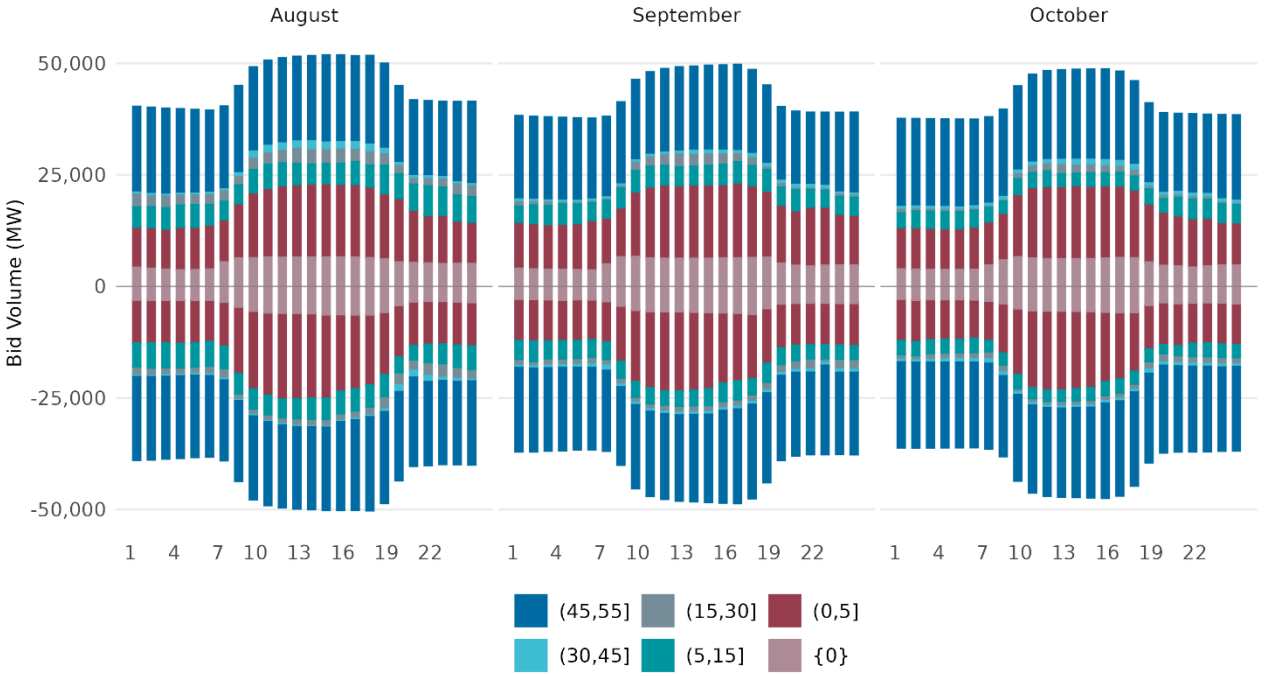
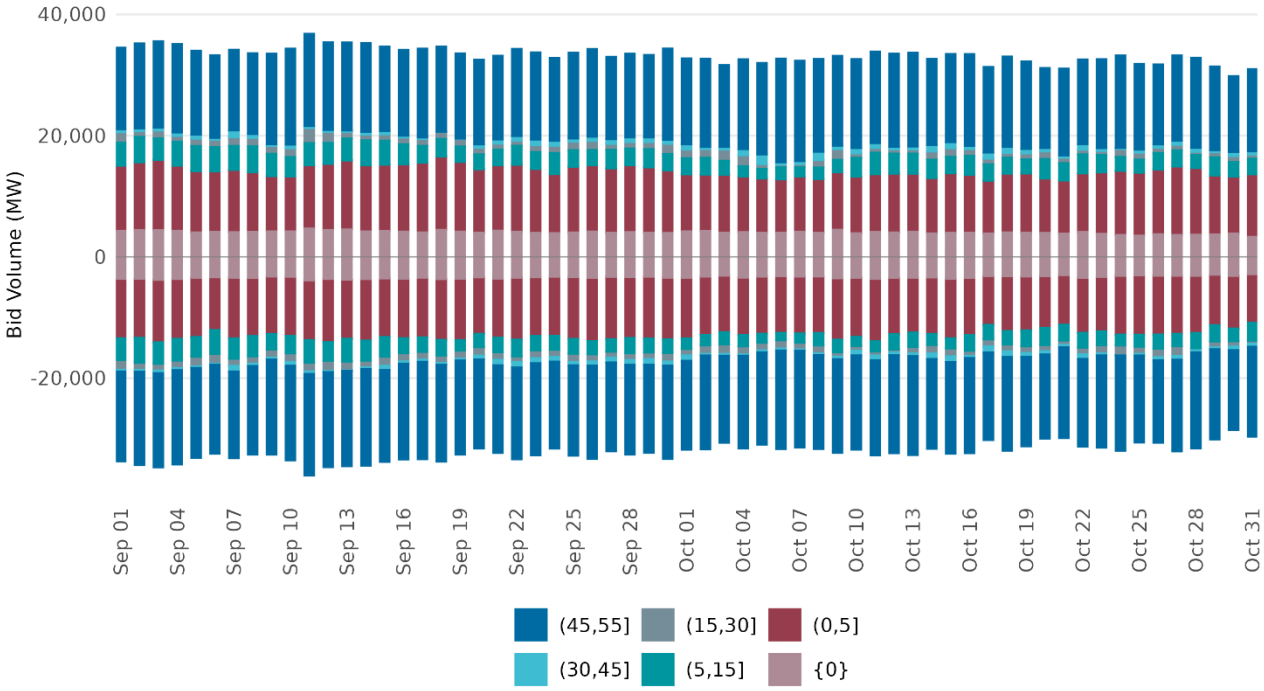


Figure 50: Daily average volume of IR bids organized by price for CAISO



[4] 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 51 and Figure 52 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 August to October, followed by water and wind resources.

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

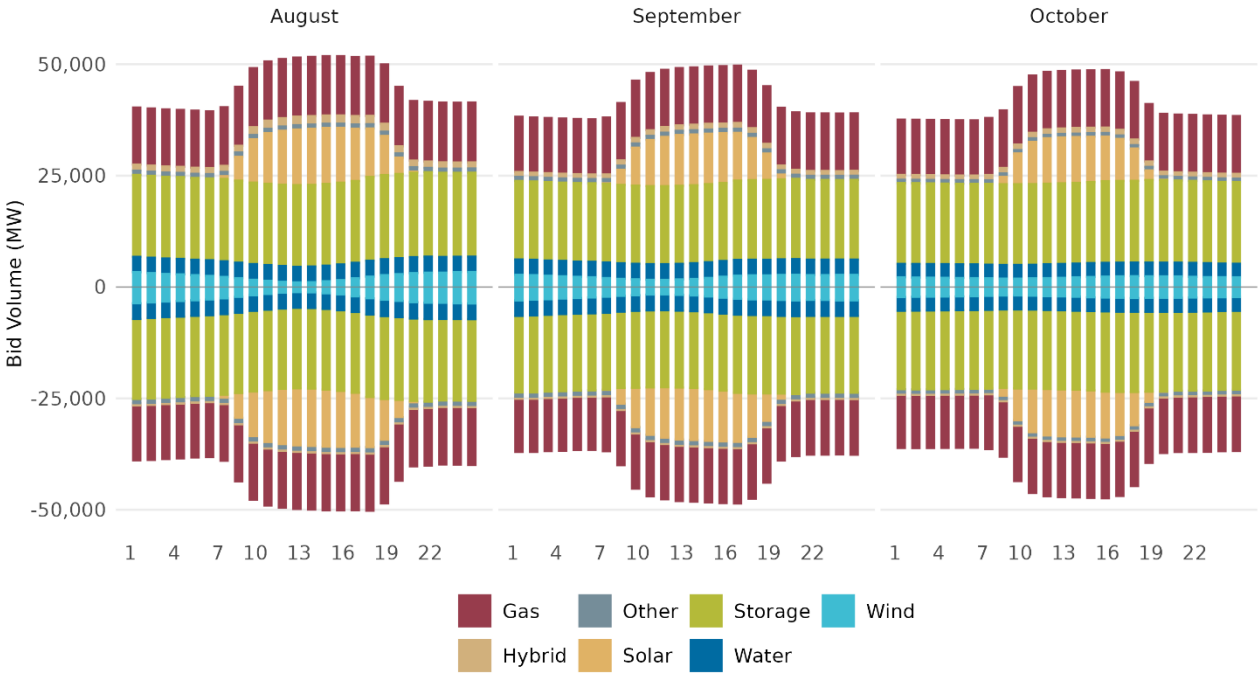


Figure 52: Daily average volume of IR bids organized by fuel type for CAISO

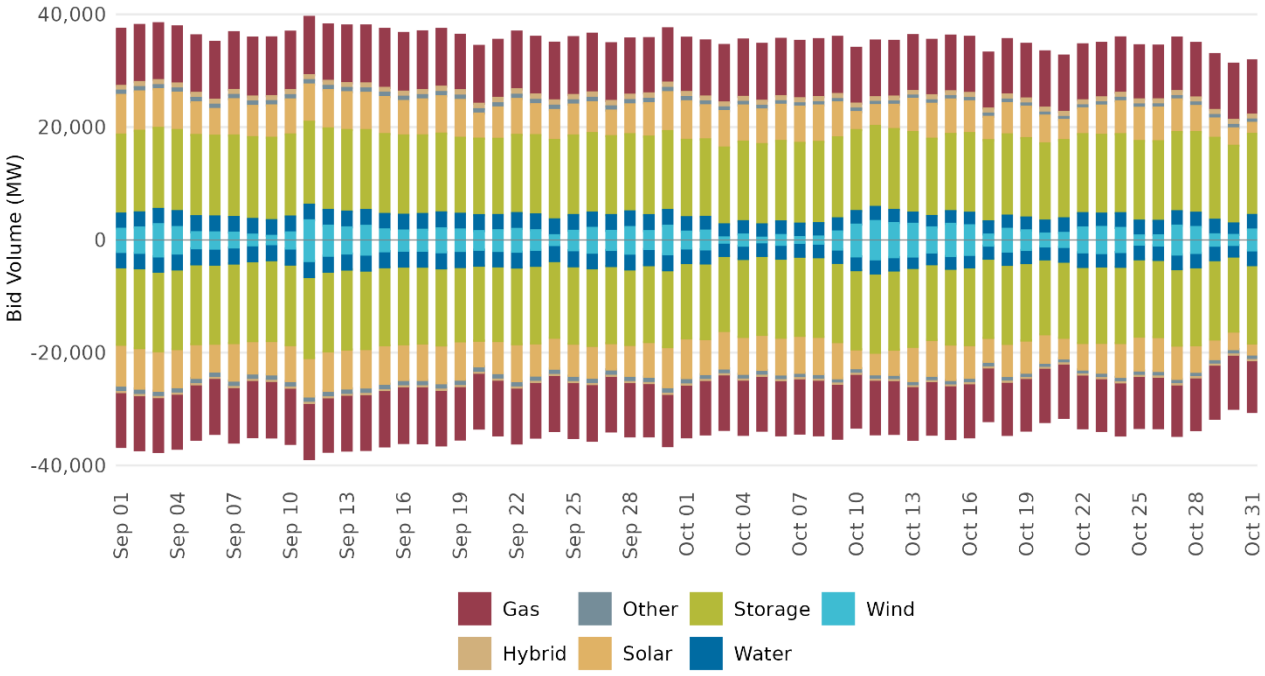


Figure 53 to Figure 55 illustrate the PACE's hourly and daily average IFM supply input bids for IR by bid price range. Low-priced bids ($0–5/MW) consistently accounted for the largest share of submitted IR capacity throughout the months with about 3,500 MW (or 80 percent), followed by bids in the 45–55 $/MWh range. The remaining price ranges represented a relatively small share of total submitted capacity. Hourly bid volumes were generally higher during daytime hours and lower during overnight hours, capped by renewable outputs. Starting in August, PACE gradually shifted a portion of its bids from ($0–5/MW) to ($0/MW), with this trend becoming more pronounced in September and October.

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

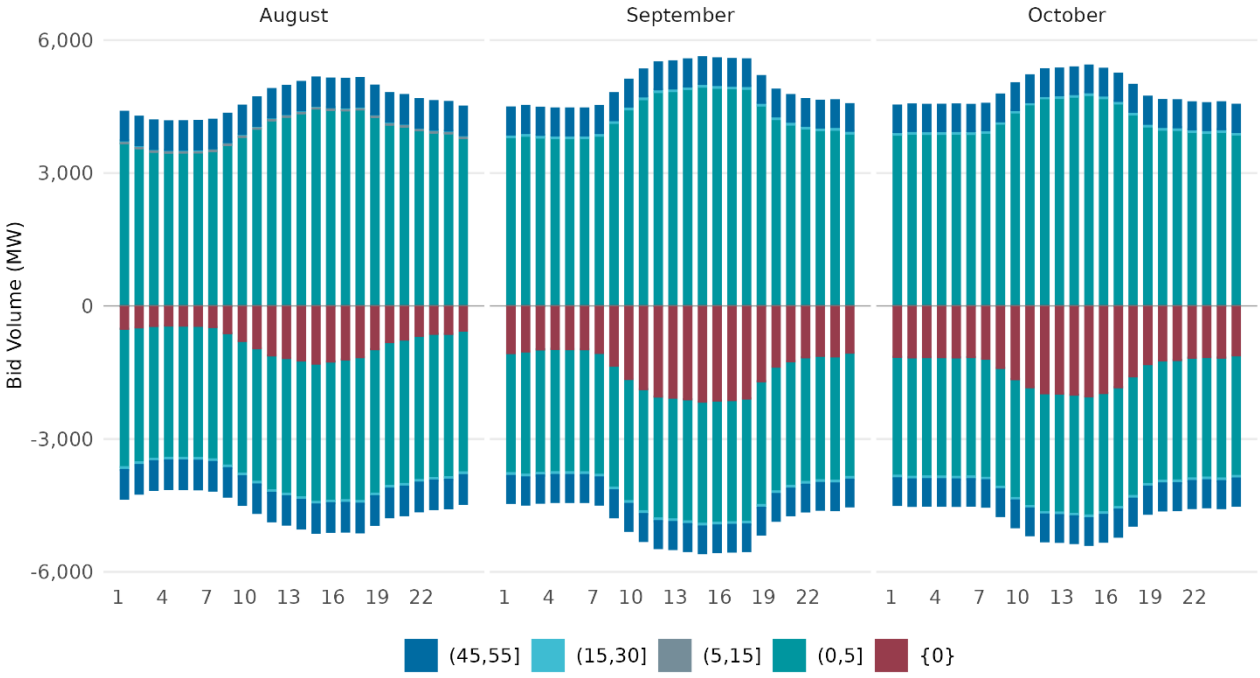


Figure 54: Daily average volume of IR bids by price for PACE

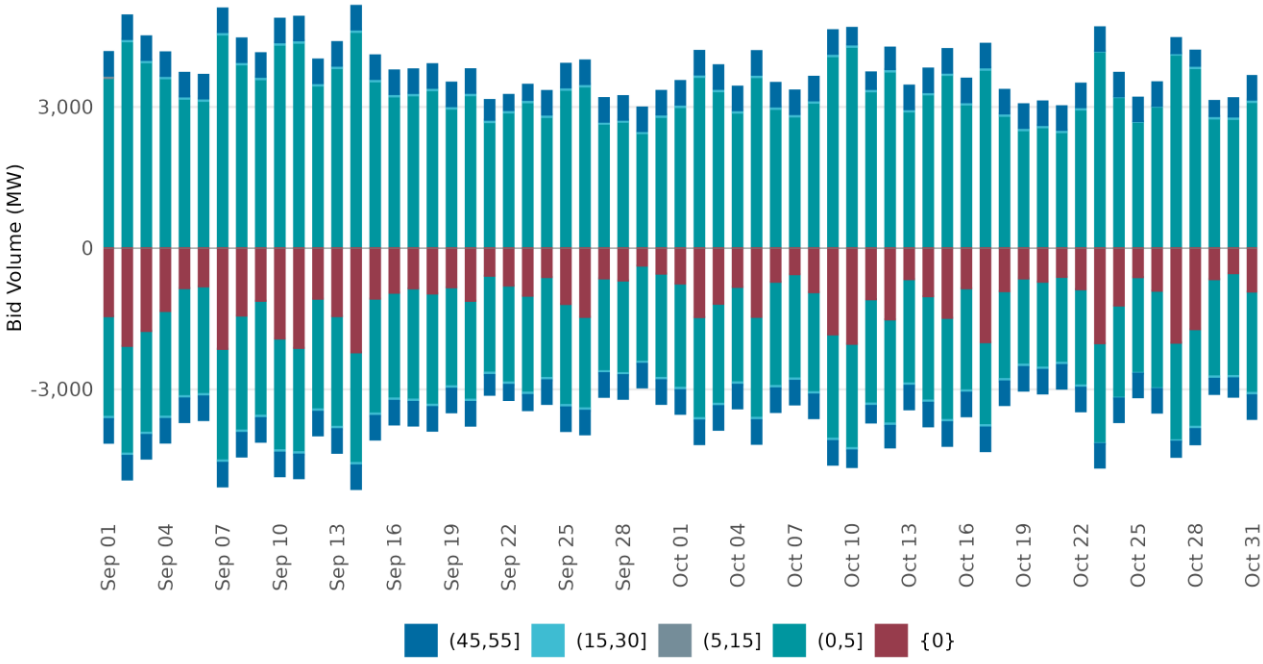


Figure 55 to Figure 56 illustrate PACE's hourly and daily average IFM supply input bids for IR by fuel type. Wind and coal accounted for the largest share of PACE's submitted IR capacity throughout August and October, followed by gas and storage resources. Wind resources' capacities were capped by renewable forecasts, causing variations in total bid volumes across the three months.

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

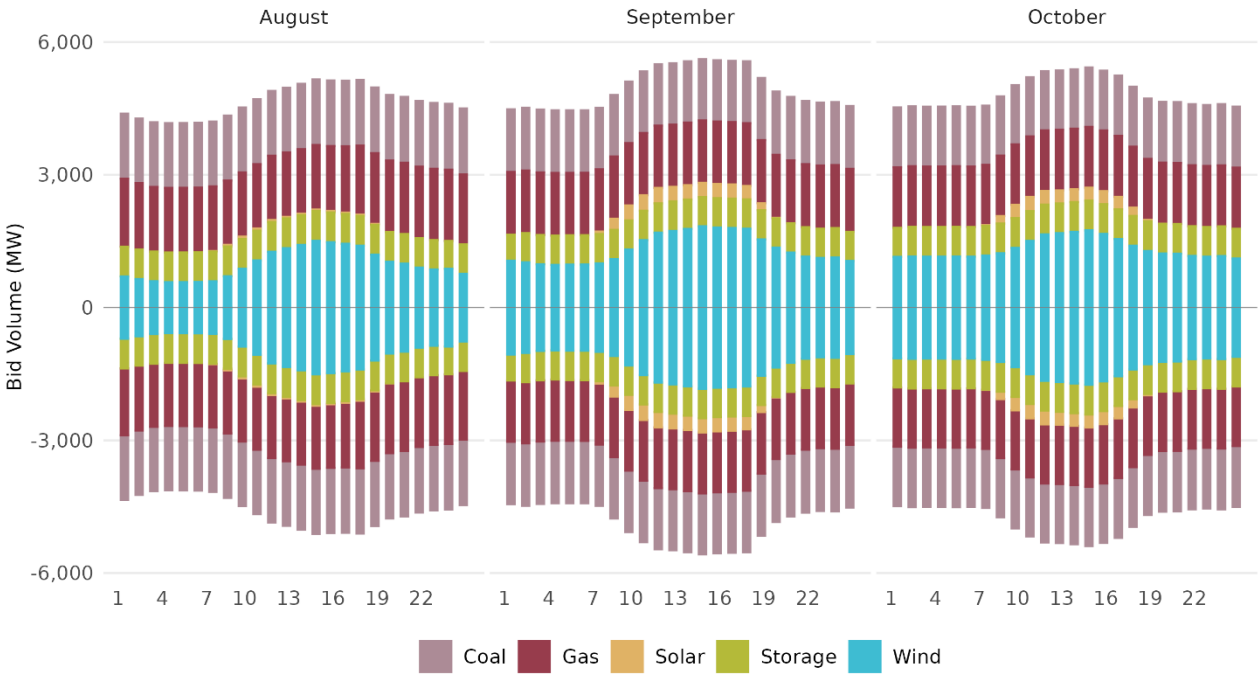


Figure 56: Daily average volume of IR bids by fuel type for PACE

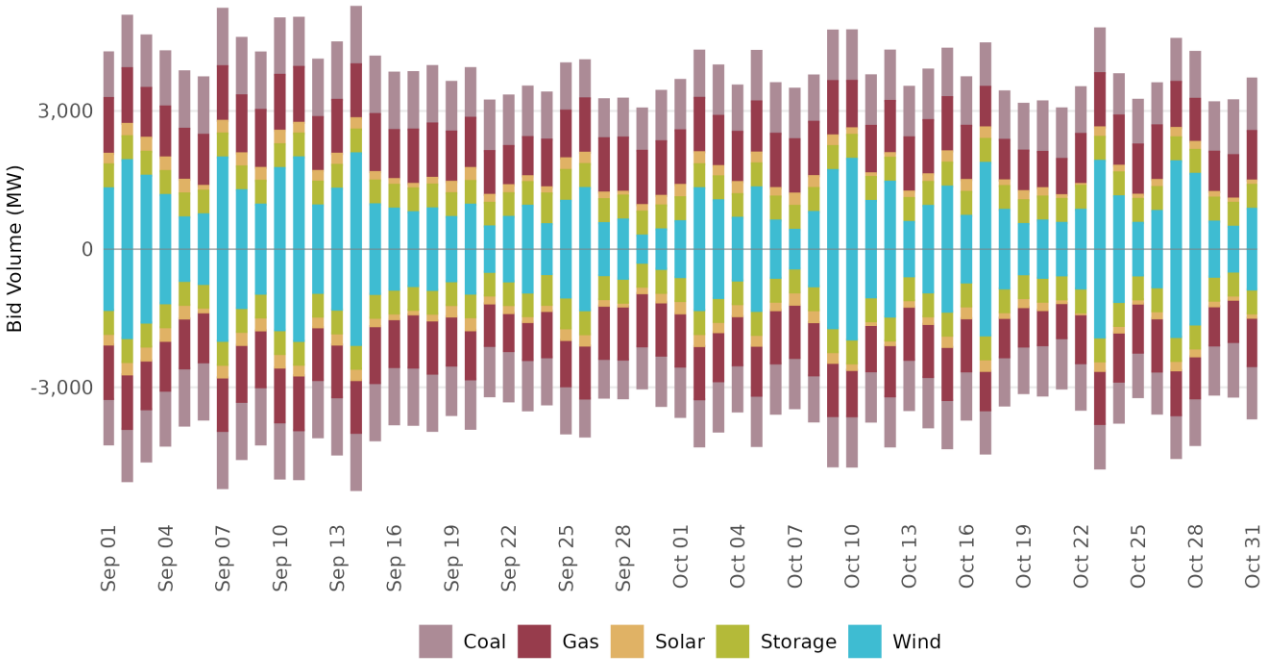


Figure 57 to Figure 60 illustrate the PACW's hourly and daily average IFM supply input bids for IR by bid price range and by fuel type. The price ranges are almost distributed across price ranges (0–5 $/MWh) and (5–15 $/MWh), and (45–55 $/MWh), and the remaining price range (15–30 $/MWh) represented a relatively small share of total submitted capacity. Water, gas, and wind accounted for the PACW's submitted IR capacity throughout August to October. 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 and hourly views.

Figure 57 and Figure 58 show the hourly and daily variations by price buckets, respectively. The IR bid volumes increased while prices went down during the three months. August had the highest and relatively stable hourly bid volumes, while September and October showed progressively lower volumes and greater intraday variation. Across all three months, most IR bids were concentrated in the $0–$5/MWh price range, with a smaller but persistent share in the $45–$55/MWh range.

Figure 57: Hourly average volume of IR bids organized by price for PACW

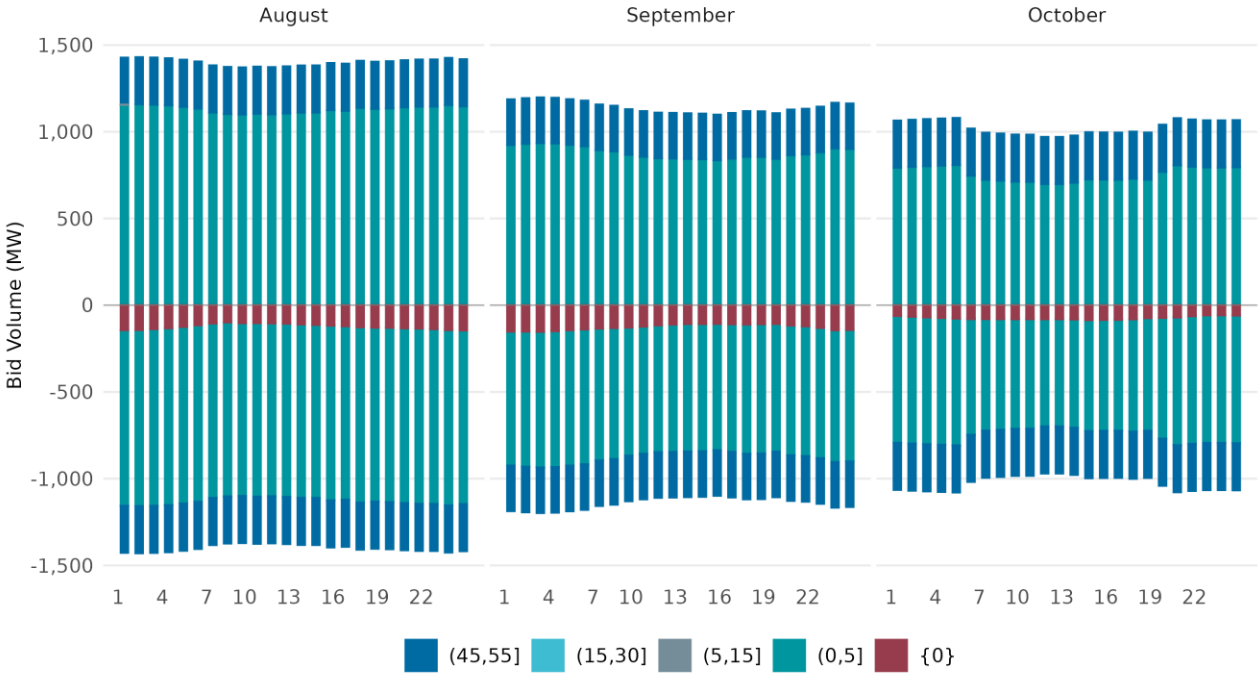


Figure 58: Daily average volume of IR bids organized by price by PACW

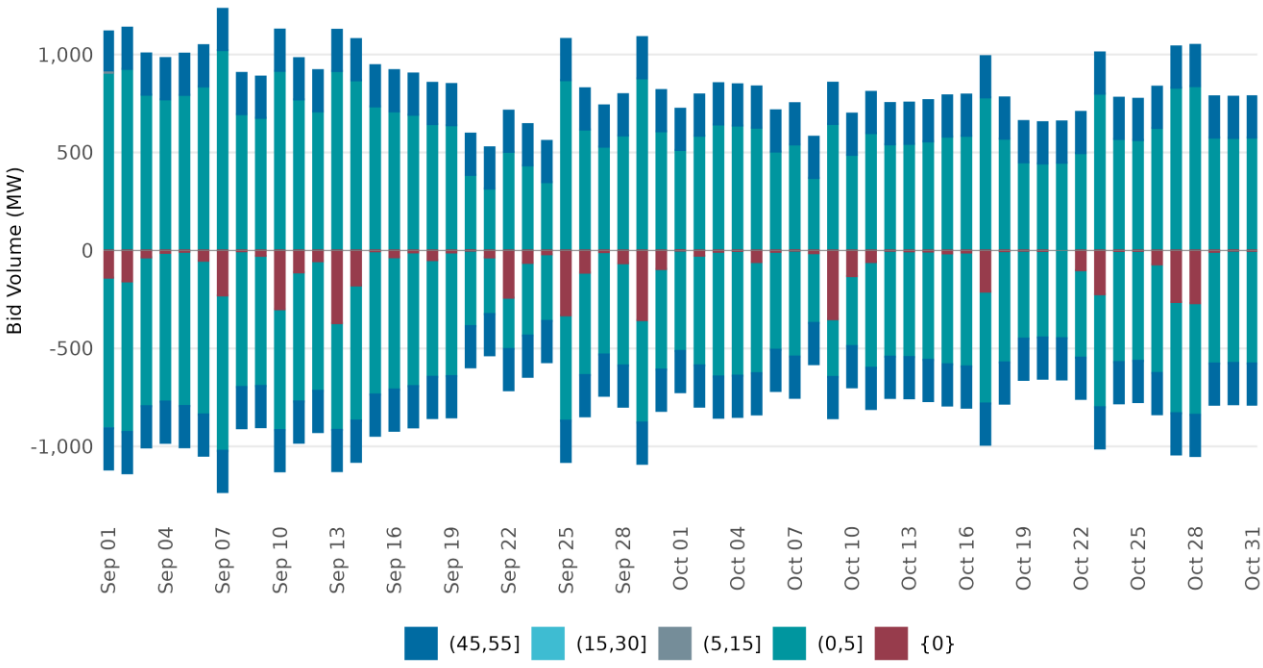


Figure 59 and Figure 60 show the hourly and daily variations by fuel type, respectively. PACW only has three fuel types bidding in IR products, i.e., gas, wind, and water. The bid volumes were highly dependent on wind forecasts, causing volume variations in both hourly and daily charts. Similarly, in October, there was noticeable decrease in the total bid volume.

Figure 59: Hourly average volume of IR bids organized by fuel type for PACW

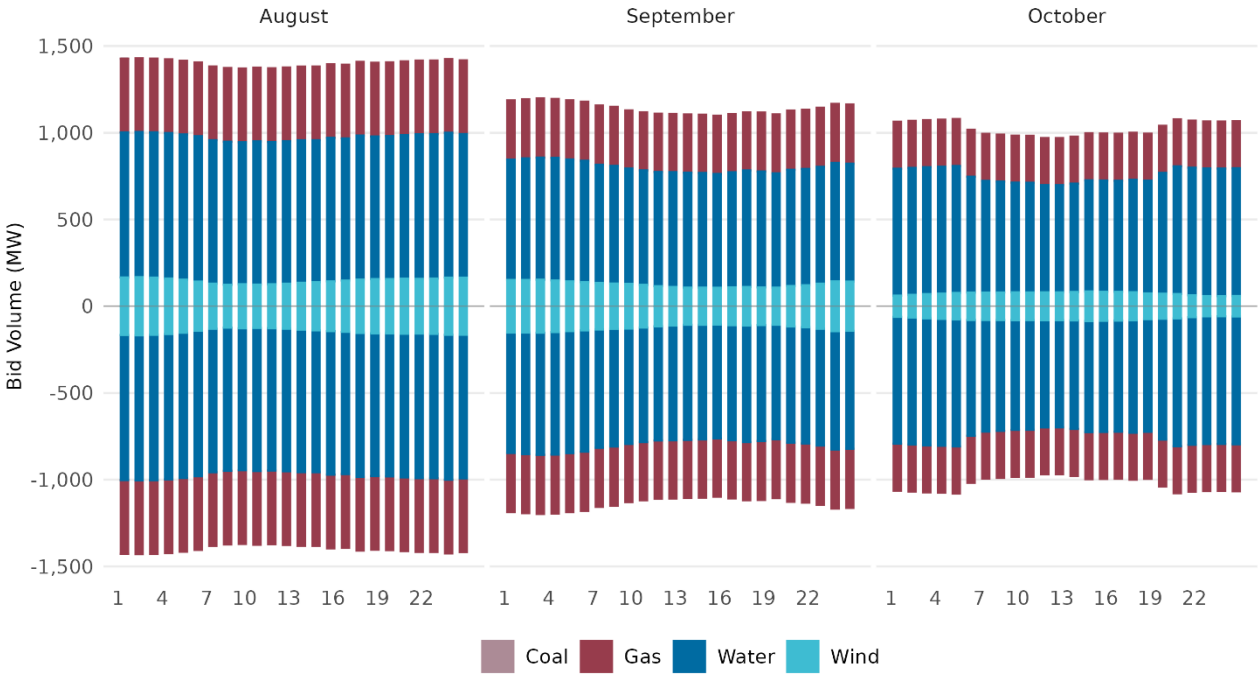


Figure 60: Daily average volume of IR bids organized by fuel type for PACW

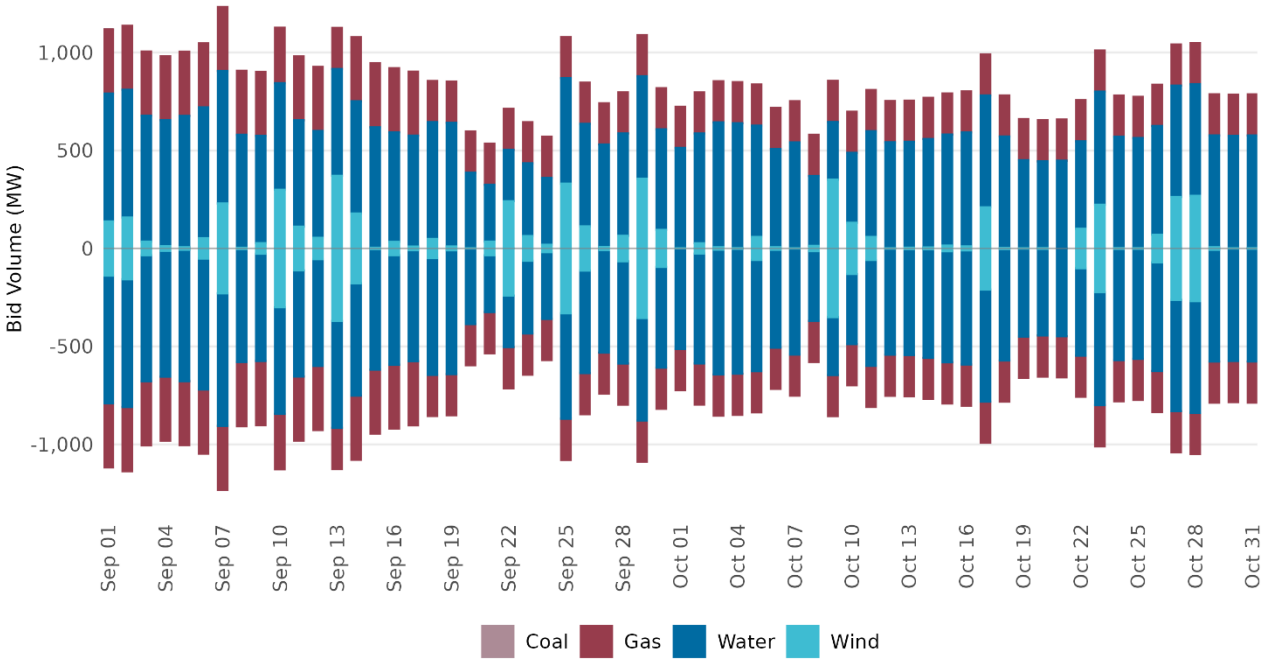


Figure 61 to Figure 64 illustrate the PGE's hourly and daily average IFM supply input bids for IR by bid price range and by fuel type. October is PGE's first month of joining EDAM, its IR bids were relatively stable across both hours and days, with the vast majority of bid volume concentrated in the $0–$5/MWh price range. Limited volumes shifted into the $5–$15/MWh range, and the overall bid volume remained broadly consistent throughout the month.

PGE's October IR bid volume was relatively stable throughout the day and was primarily supplied by water, followed by gas and storage. While the hourly fuel mix remained consistent, the daily analysis shows that wind has higher variation in IR bid volume as it follows the forecasts.

Figure 61: Hourly average volume of IR bids organized by price for PGE

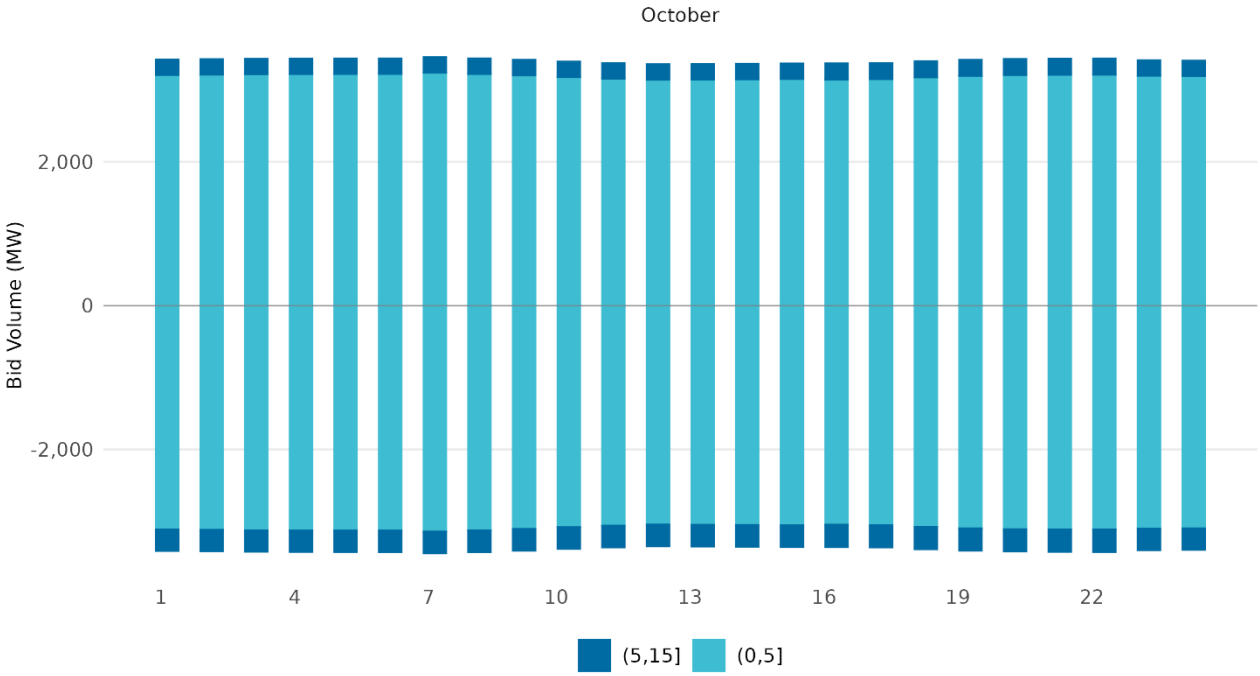


Figure 62: Daily average volume of IR bids organized by price by PGE

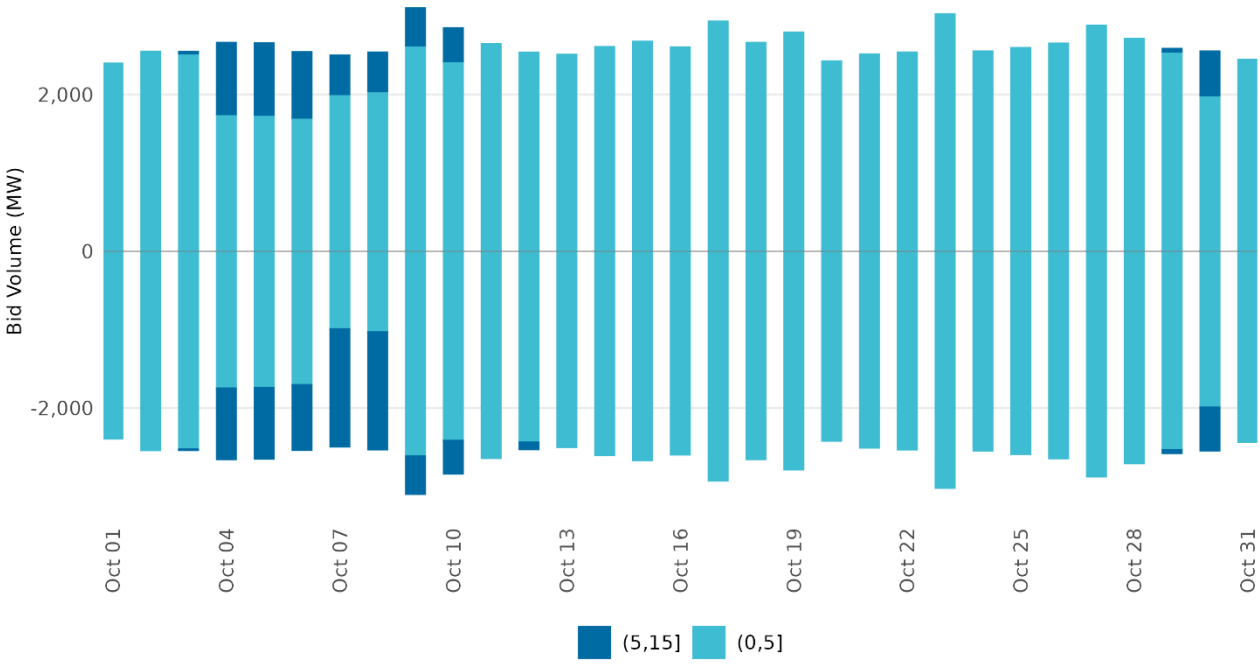


Figure 63: Hourly average volume of IR bids organized by fuel type for PGE

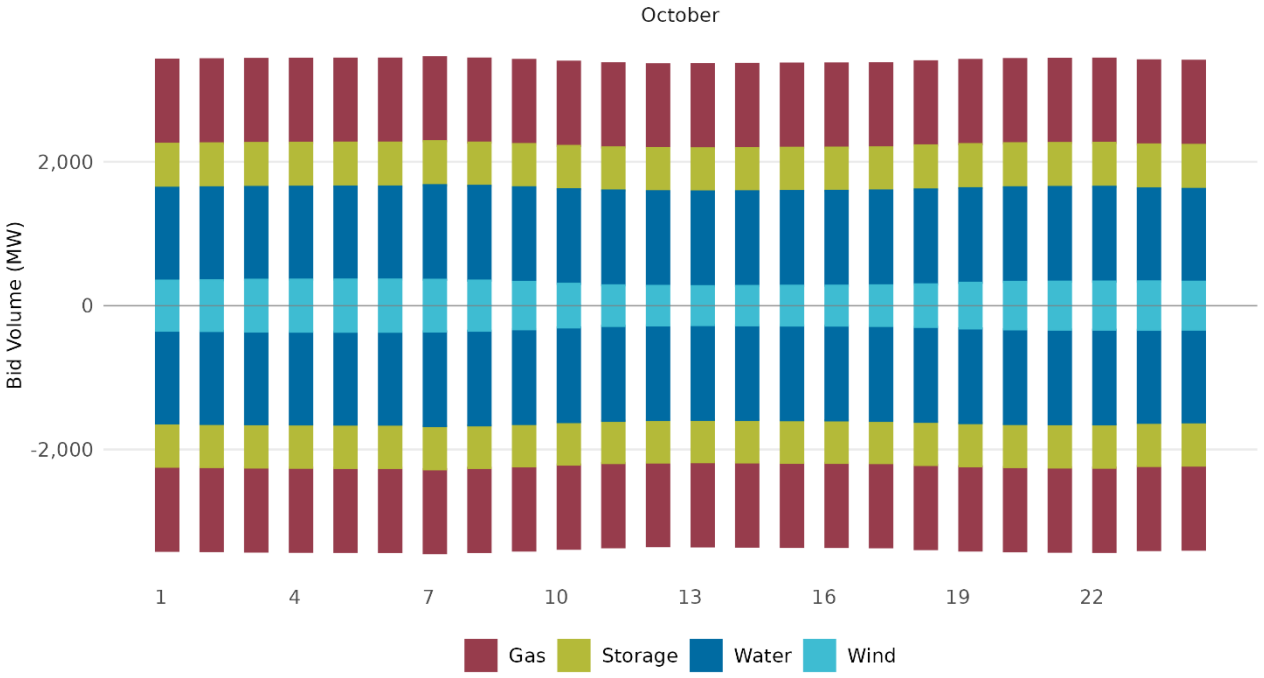
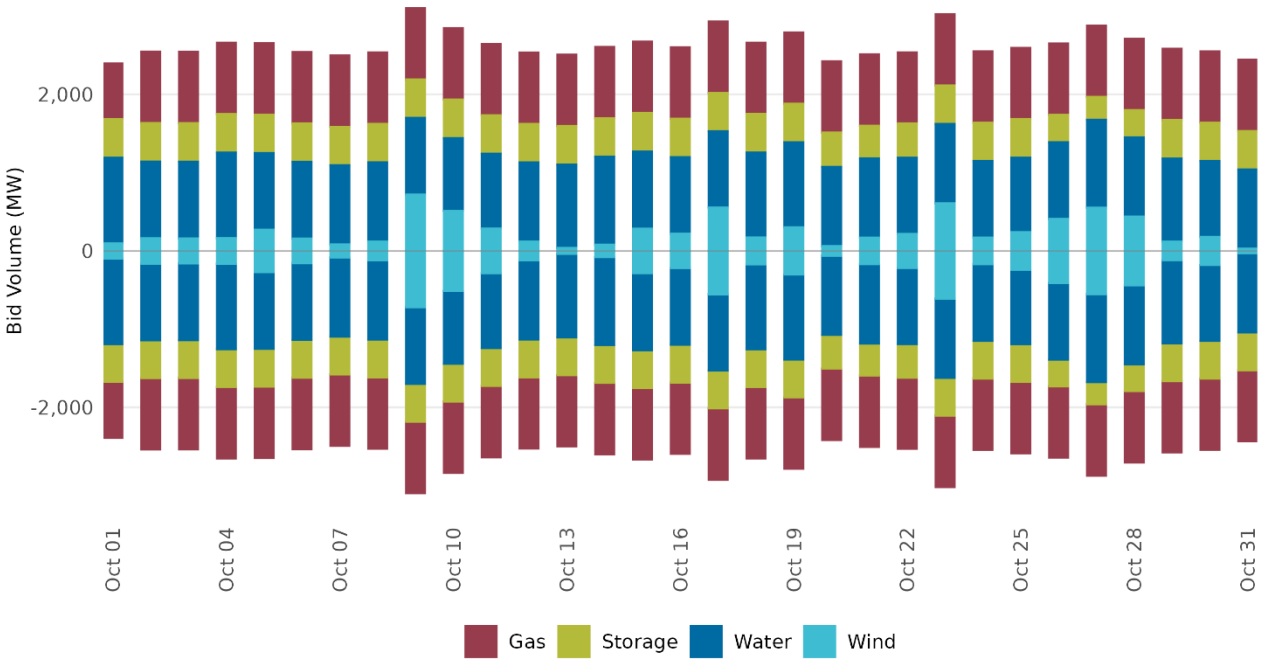


Figure 64: Daily average volume of IR bids organized by fuel type for PGE



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 October2026, CAISO had demand curve procurement in the upward direction for 6 hour over four days. PACE had demand curve procurement in the upward direction for 5 hours over five days. PACW had demand curve procurement in downward direction for 4 hours over four days. Hourly averages of demand curve procurements are shown in Figure 65 and Figure 66. 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 65: Average imbalance reserve demand curve procurement, IRU

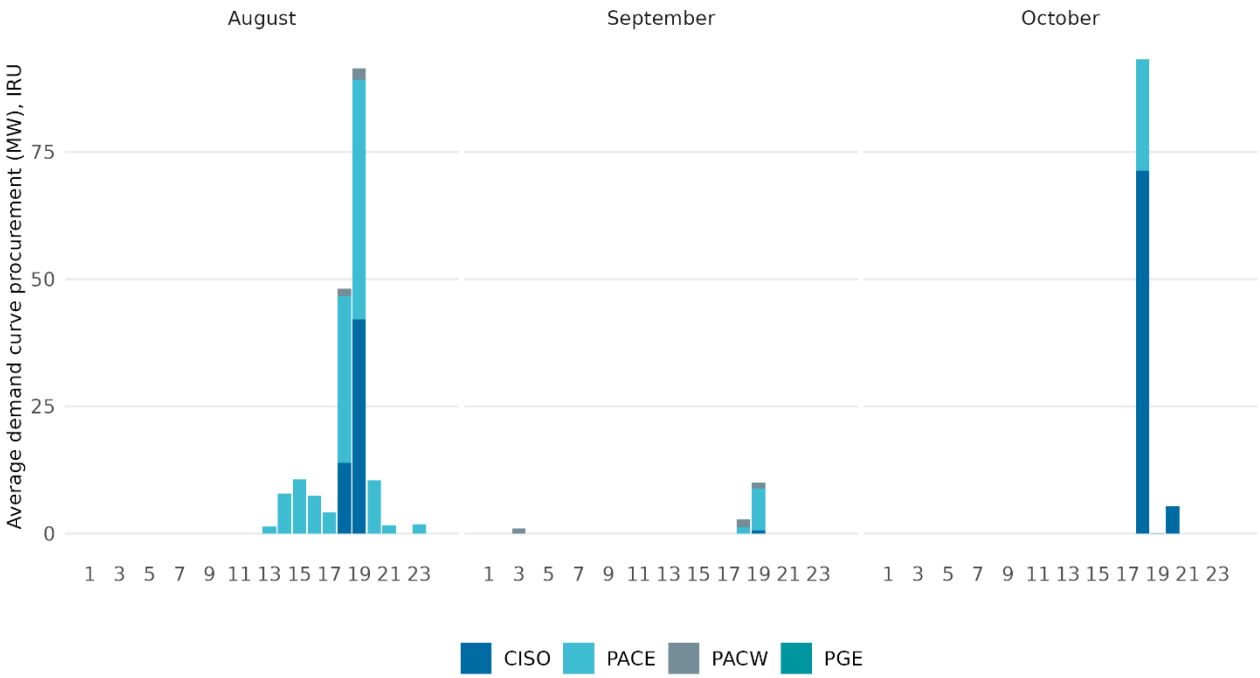


Figure 66: Average imbalance reserve demand curve procurement, IRD

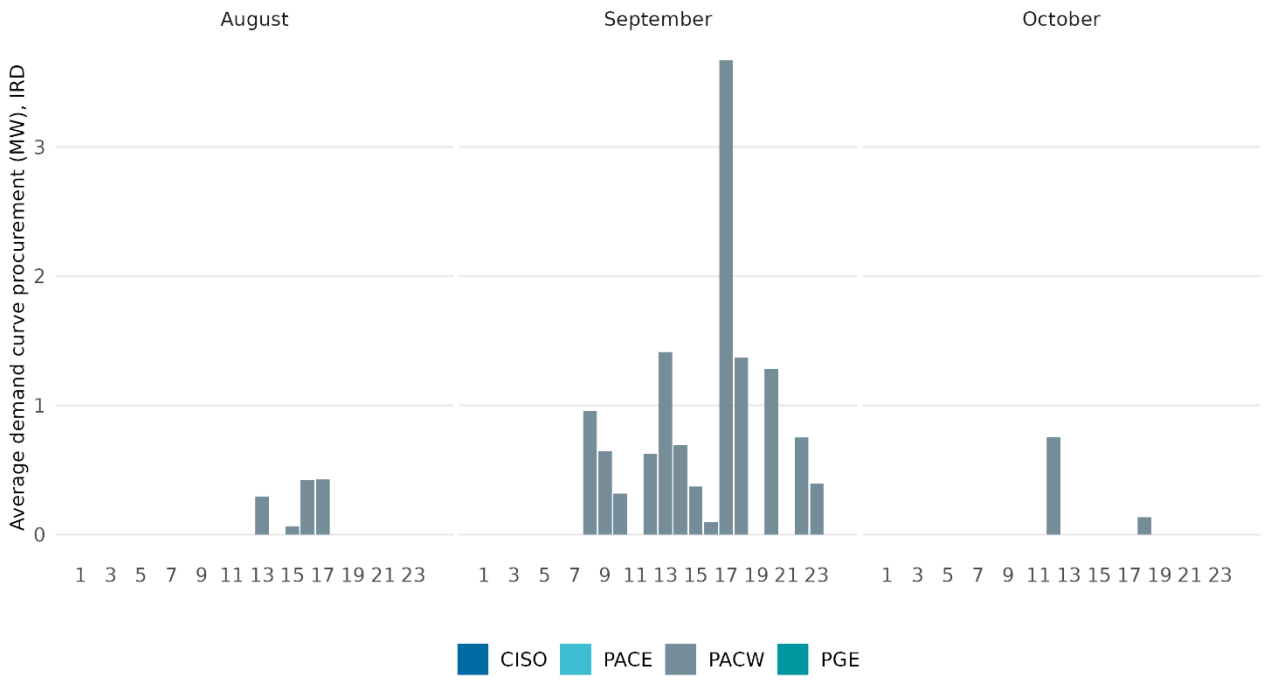


Figure 67 and Figure 69 show the hourly average net demand by EDAM BAA in July through September. Net demand is derived from demand forecast, net solar and wind forecast. The figures overlay hourly average IR procurement and requirement, for both up and down directions, and hourly average FMM net load 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 uncertainty shows how average uncertainty falls within the envelope of flexible capacity created by the imbalance reserve products.

Figure 67: Average net demand with imbalance reserve procurement, CISO

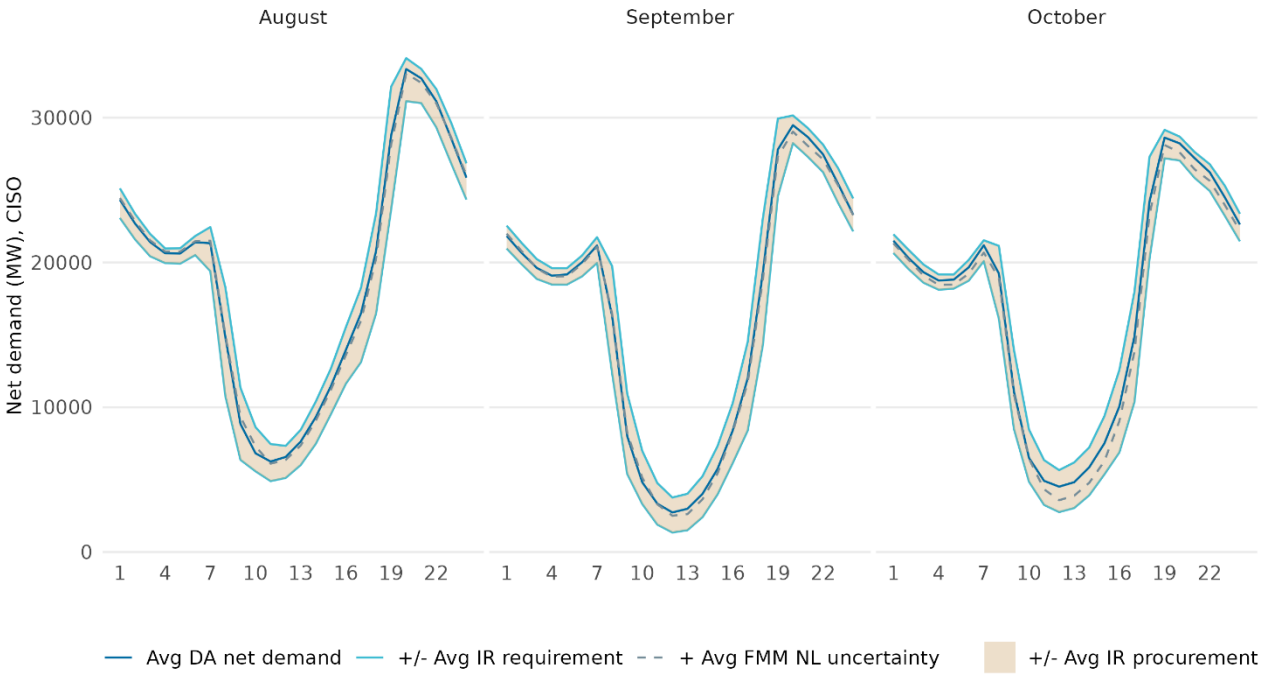


Figure 68: Average net demand with imbalance reserve procurement, PACE

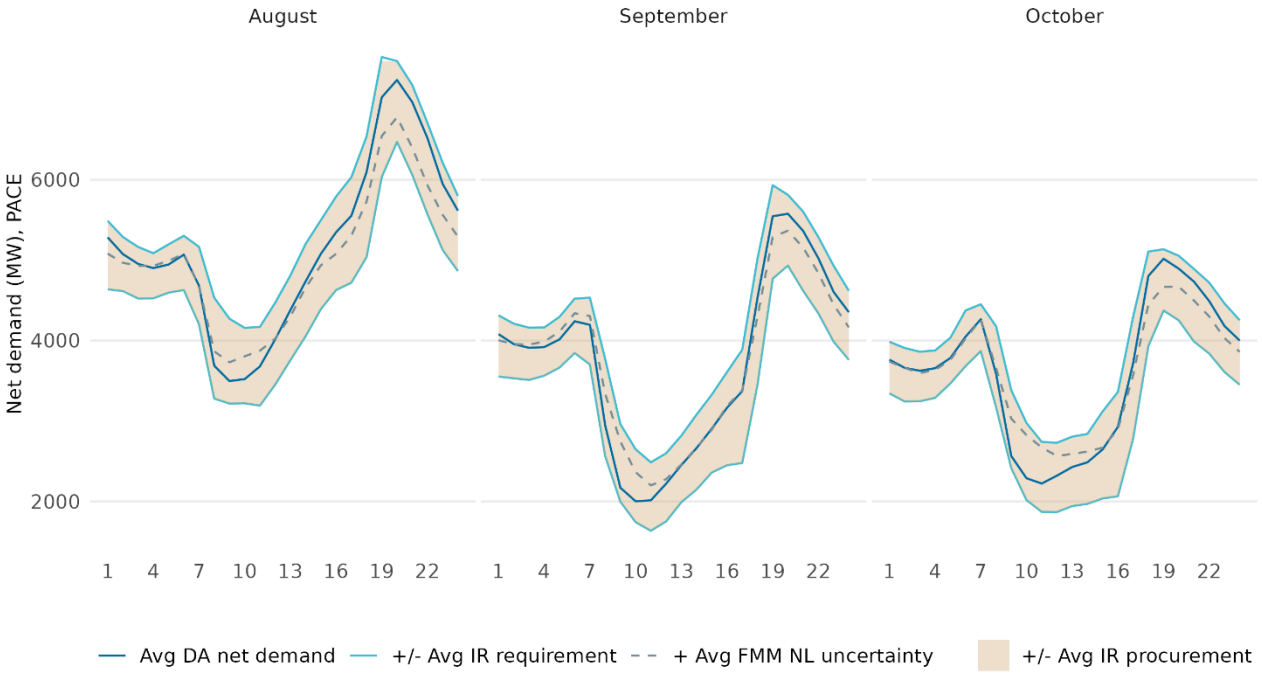


Figure 69: Average net demand with imbalance reserve procurement, PACW

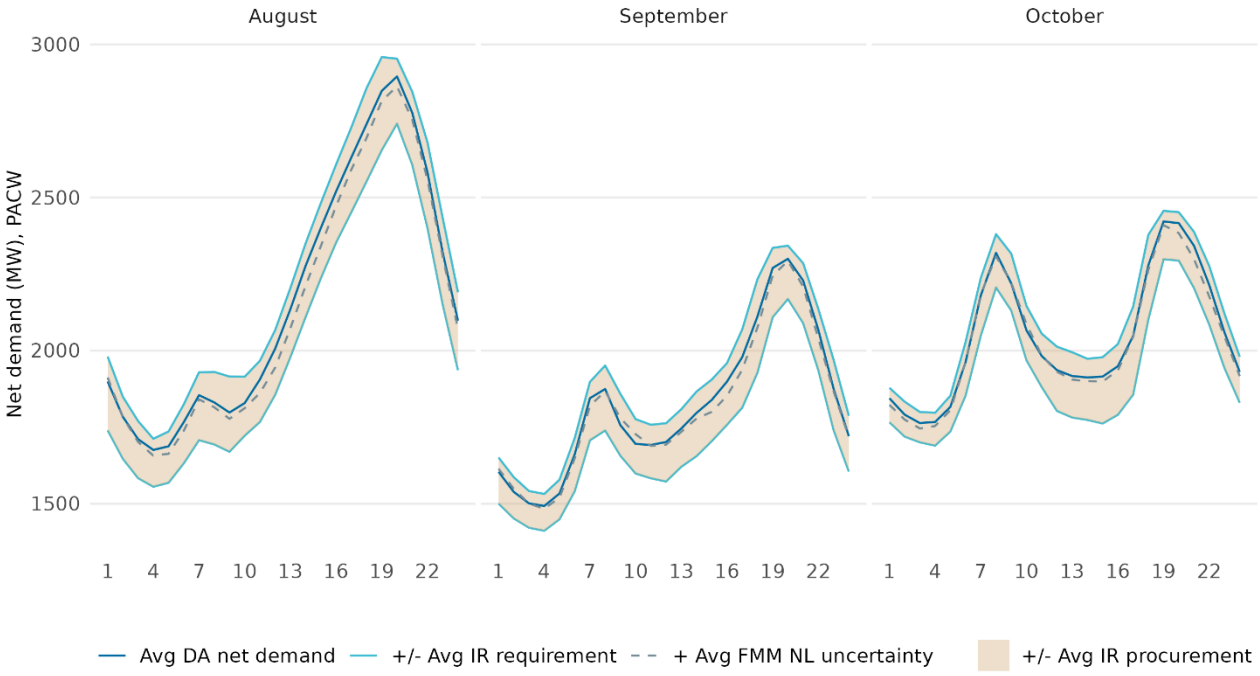
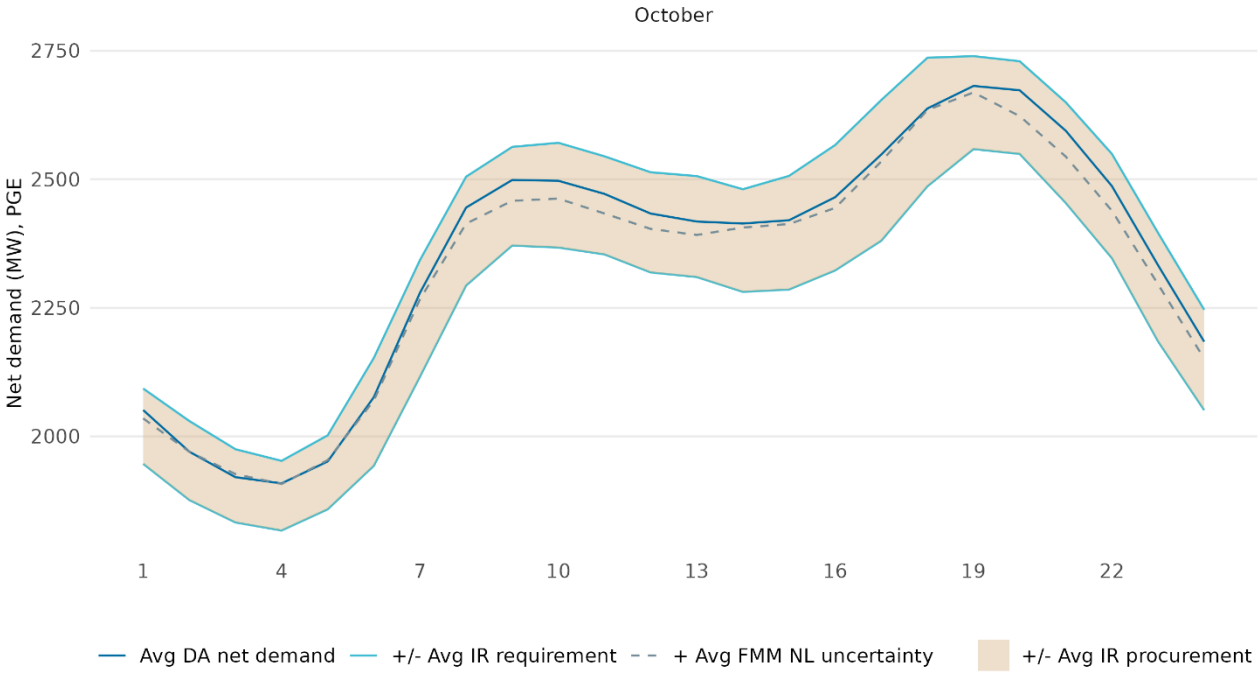


Figure 70: Average net demand with imbalance reserve procurement, PGE



Imbalance reserve utilization

Figure 71 to Figure 73 illustrate for each EDAM BAA, average available capacity in the fifteen-minute market for the capacity awards of day-ahead imbalance reserves represented in stacked bar. These bars grouped the imbalance reserves into two groups, capacity that is utilized (deployed) in the FMM market, and the second group is imbalance reserve awards that were not utilized in the FMM market. This is showing for both upward (positive) and downward (negative) directions. Average day-ahead imbalance reserve requirements and procurements from internal resources are included as reference with line trends. 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 that is realized in FMM is also shown as a reference with the line in yellow. Realized net- load uncertainty is derived from the net load differences from day-ahead to fifteen-minute market. Utilized capacity over the reported period has been relatively small compared to available capacity and realized net load uncertainty for CAISO area. Utilized capacity for PACE, PACW, and PGE on average are relatively higher in certain hours. The average percentages utilized IR relative to the awarded IR in the day-ahead market are shown in Table 6.

Table 6 Monthly average utilized imbalance reserve per EDAM BAA

	August		September		October	
	IRU	IRD	IRU	IRD	IRU	IRD
CISO	18.40%	12.40%	13.00%	12.80%	18.1%	12.5%
PACE	43.20%	23.00%	59.00%	24.00%	42.5%	22.4%
PACW	21.70%	17.80%	19.10%	24.70%	39.4%	23.5%
PGE					27.4%	16.9%

If the level of utilized IR in real-time is lower than the actual realized uncertainty, it means that other resources increased generation to meet that realized uncertainty, but they were not awarded IR. The larger pool of such resources is from the balancing areas participating in WEIM and that are not part of EDAM and were, therefore, not awarded IR in the day-ahead market.

Figure 71: Hourly average IR requirement, procurement and utilization. CISO

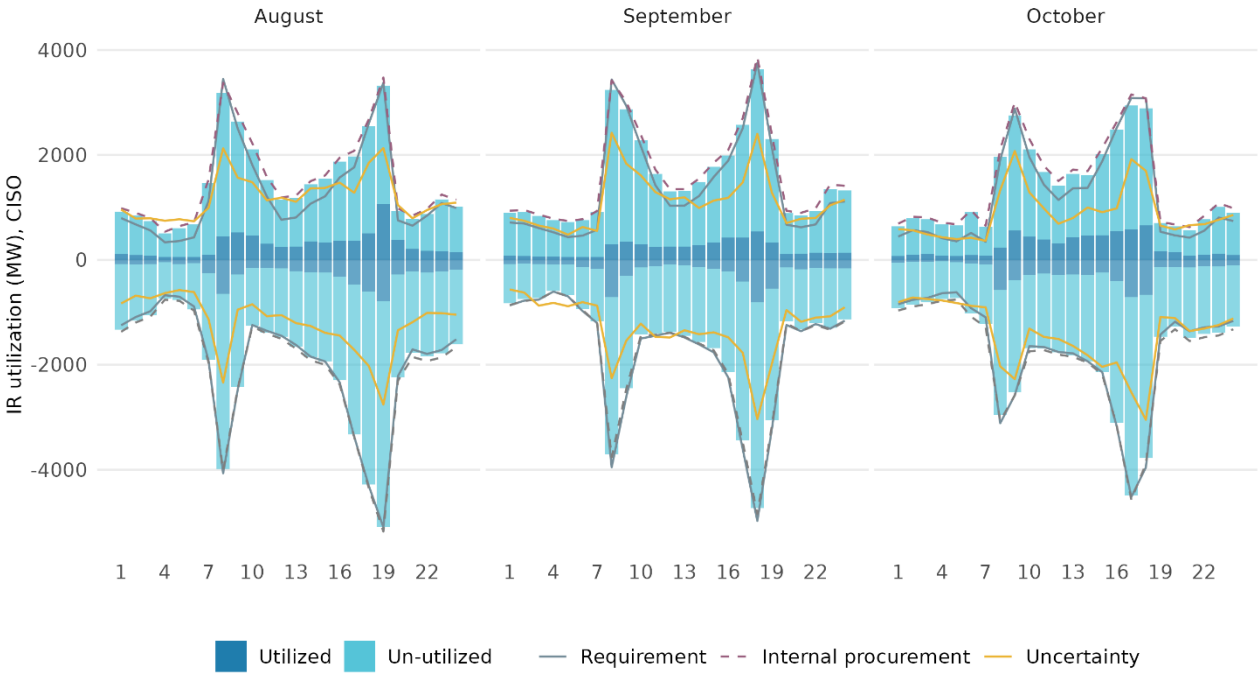


Figure 72: Hourly average IR requirement, procurement and utilization. PACE

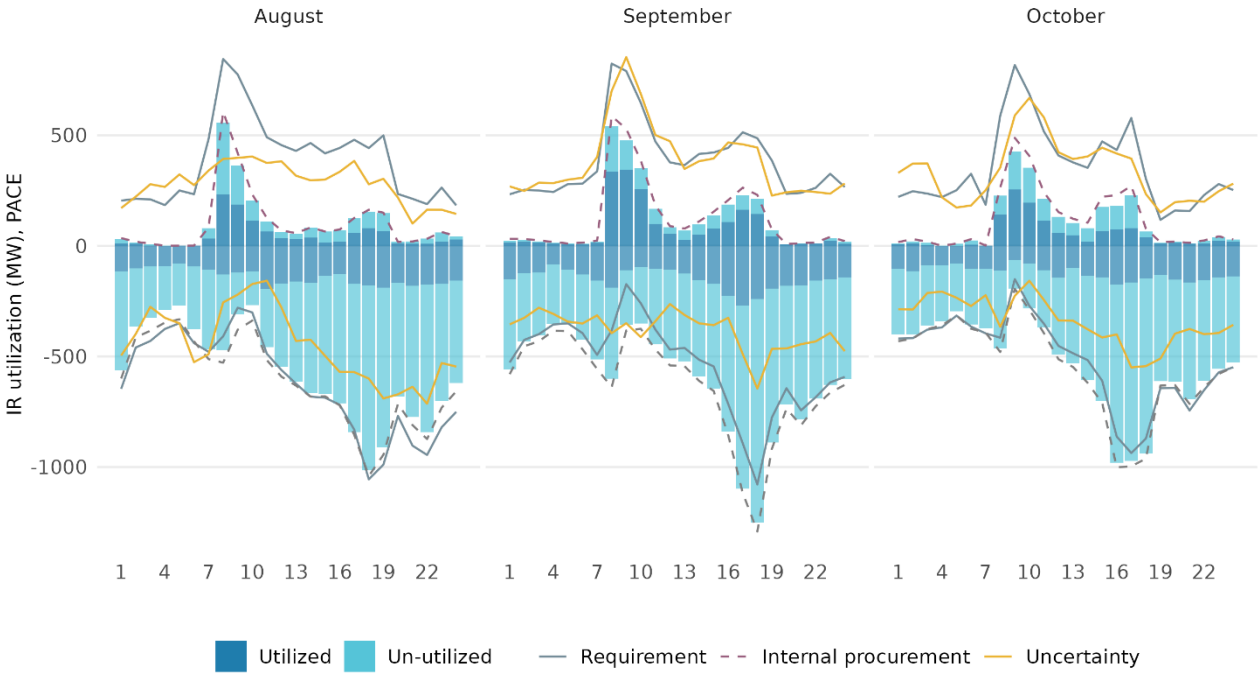


Figure 73: Hourly average IR requirement, procurement, and utilization, PACW

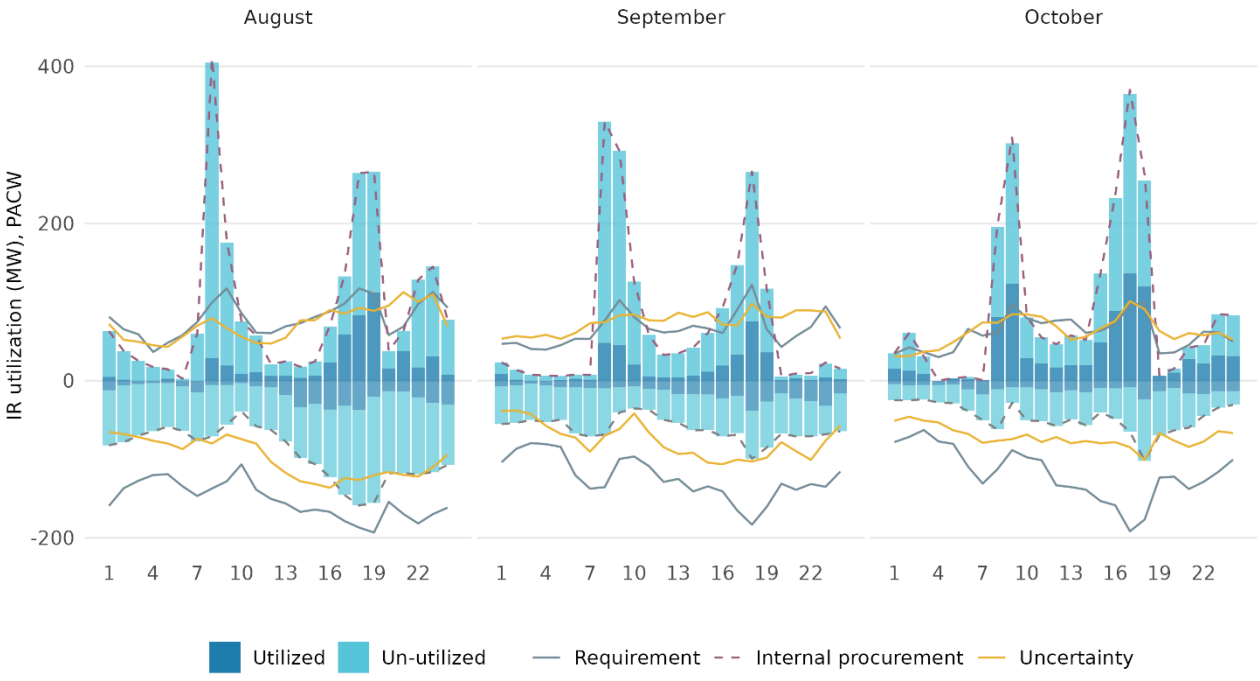


Figure 74 Hourly average IR requirement, procurement, and utilization, PGE

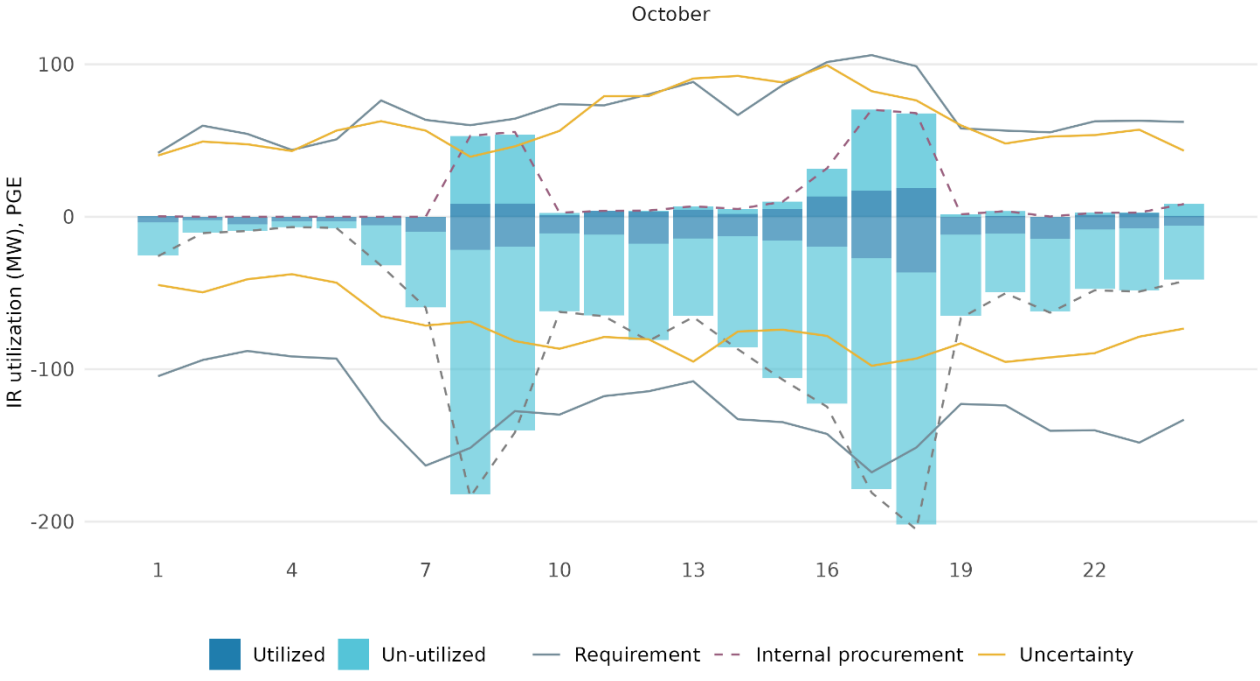


Figure 75 to Figure 77 evaluate the real-time performance of imbalance reserve up awards, by showing the estimated percentage breakdown of awarded capacity. The evaluation is estimated

based on observed real time conditions, schedules and prices. The attribution of unutilized IRU awards assumes that additional utilization would not materially alter system conditions, economics, or prices.

Utilization is measured at the resource level. Specifically, the change in a resource's energy schedule between the day-ahead market and the fifteen-minute market is compared against the corresponding imbalance reserve up awards. The portion of this schedule change that falls within the awarded capacity range is considered utilized.

From the capacity made available in real time, the portion not utilized is classified as unutilized capacity. Available capacity may remain unutilized for different reasons, including economics, congestion, among other factors. Unutilized capacity is further broken down by different categories. For CAISO BAA, approximately 51% of October IRU awards were unutilized because gas units received IRU awards but remained offline in real time. These resources were available to provide capacity but were not economical to start and operate based on their commitment costs and real-time market conditions. The second largest category of unutilized awards is economics for online resources. These resources are already online and may have utilized a portion of their awarded IRU capacity. Some awarded capacity remained unutilized because it is not economic to fully utilize the reserved capacity while other cheaper supply can be dispatched. For PACE, PACW, and PGE, economics for online resources represented the largest share of unutilized capacity, at 36%, 58%, and 60%, respectively.

Figure 75: IRU awards: real time breakdown, CAISO

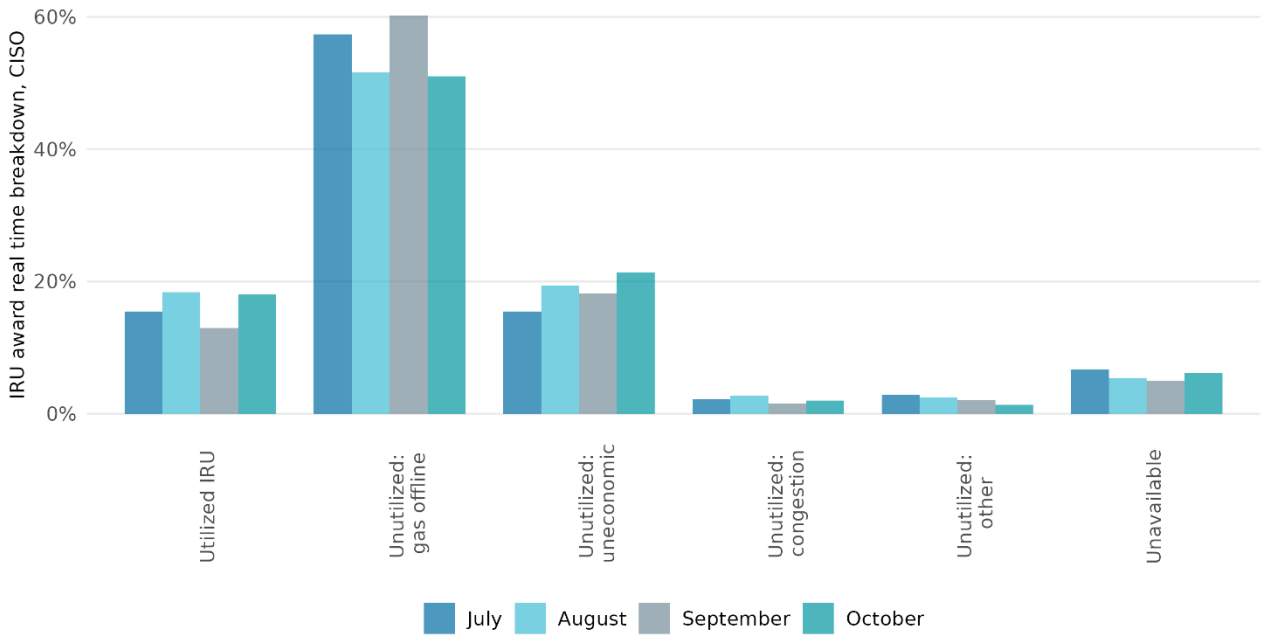


Figure 76 IRU awards: real time breakdown, PACE

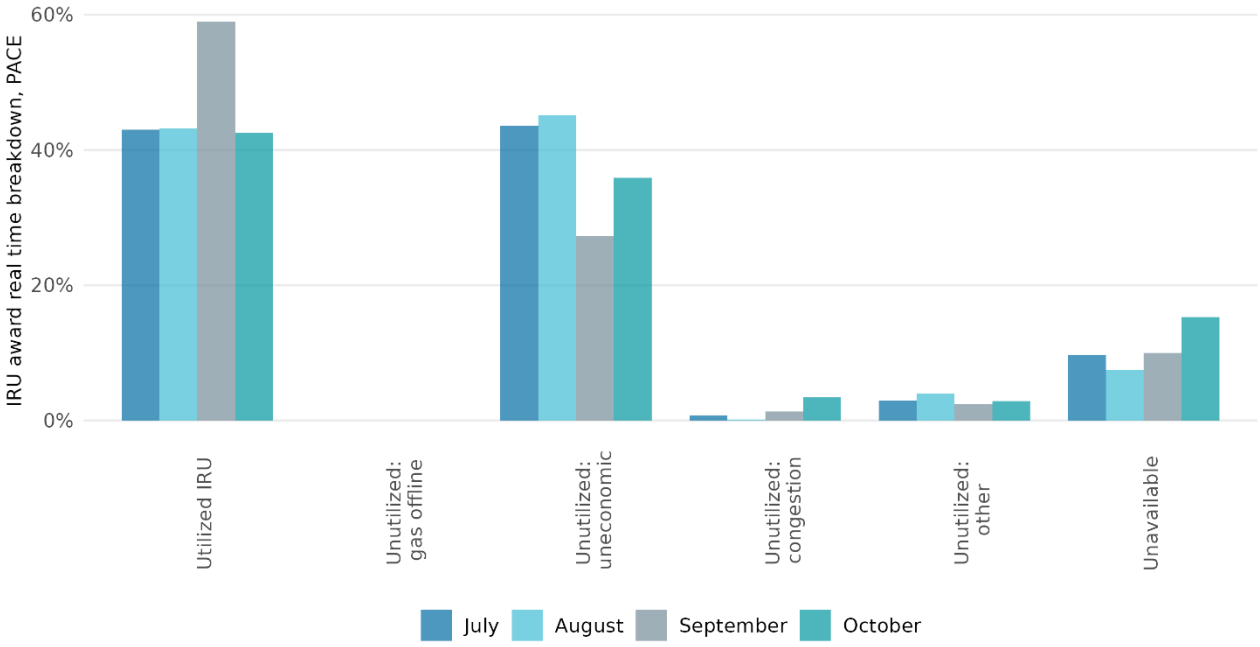


Figure 77. IRU awards: real time breakdown, PACW

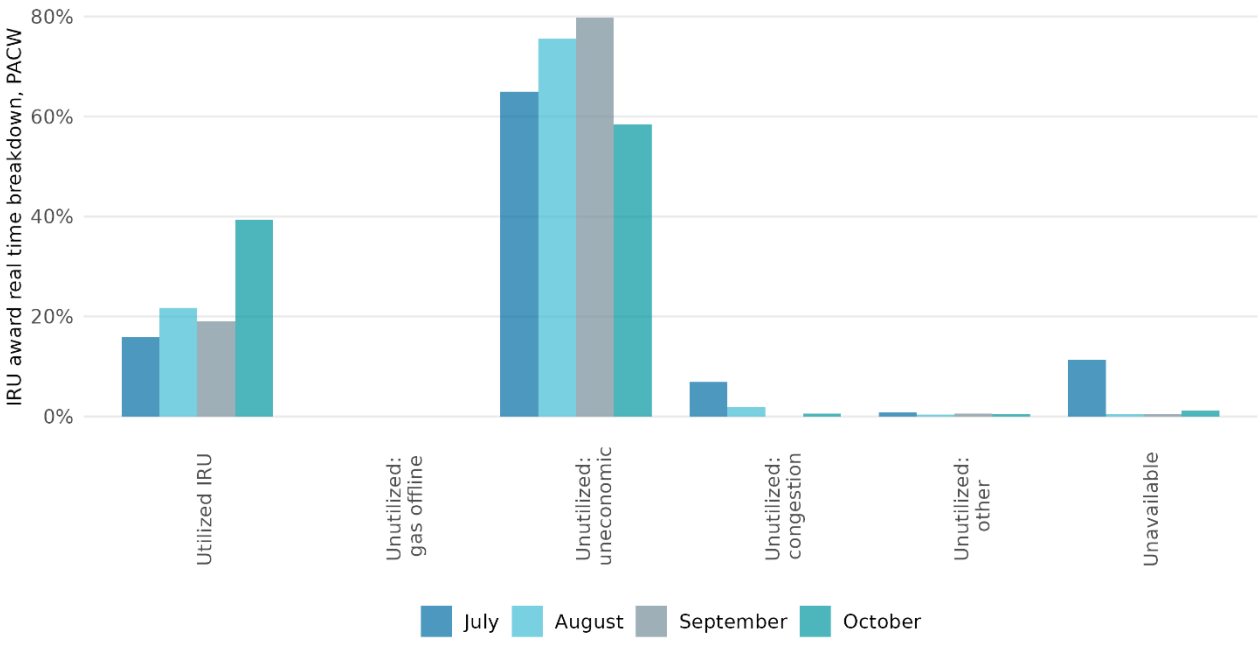
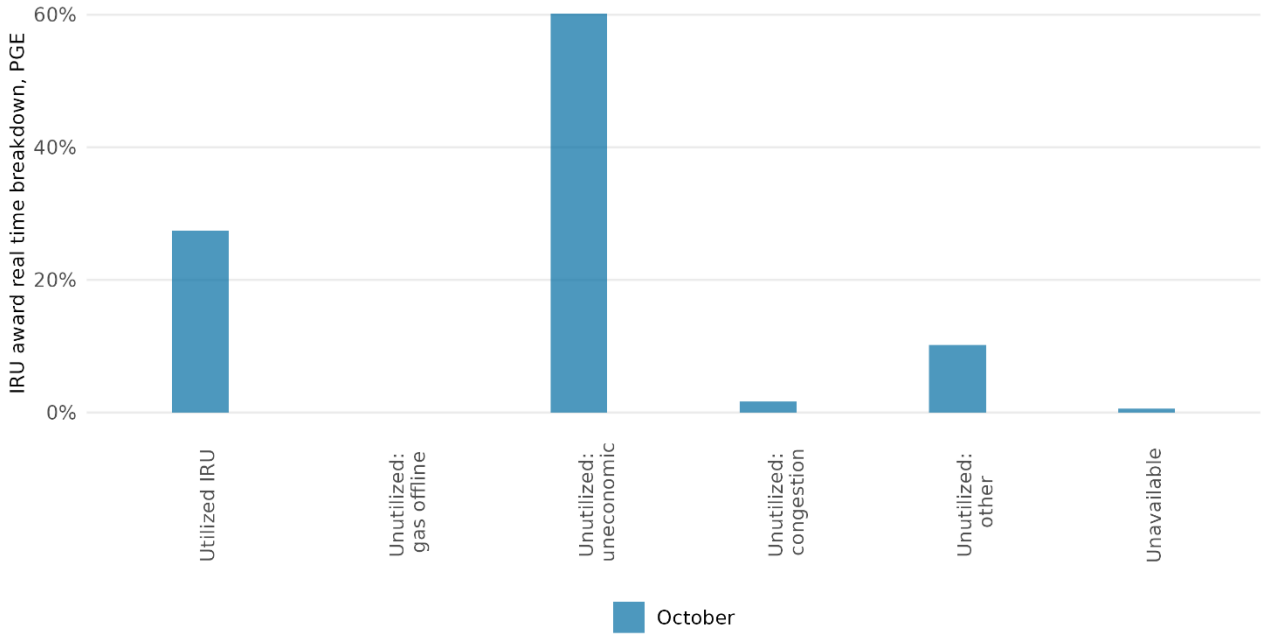


Figure 78 IRU awards: real time breakdown, PGE



EDAM resources receiving imbalance reserve awards in the day-ahead market will have bidding obligations in the real time market. Figure 79 and Figure 80 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 90 percent majority of the time.

Figure 79: Percentage IRU availability in FMM for EDAM footprint

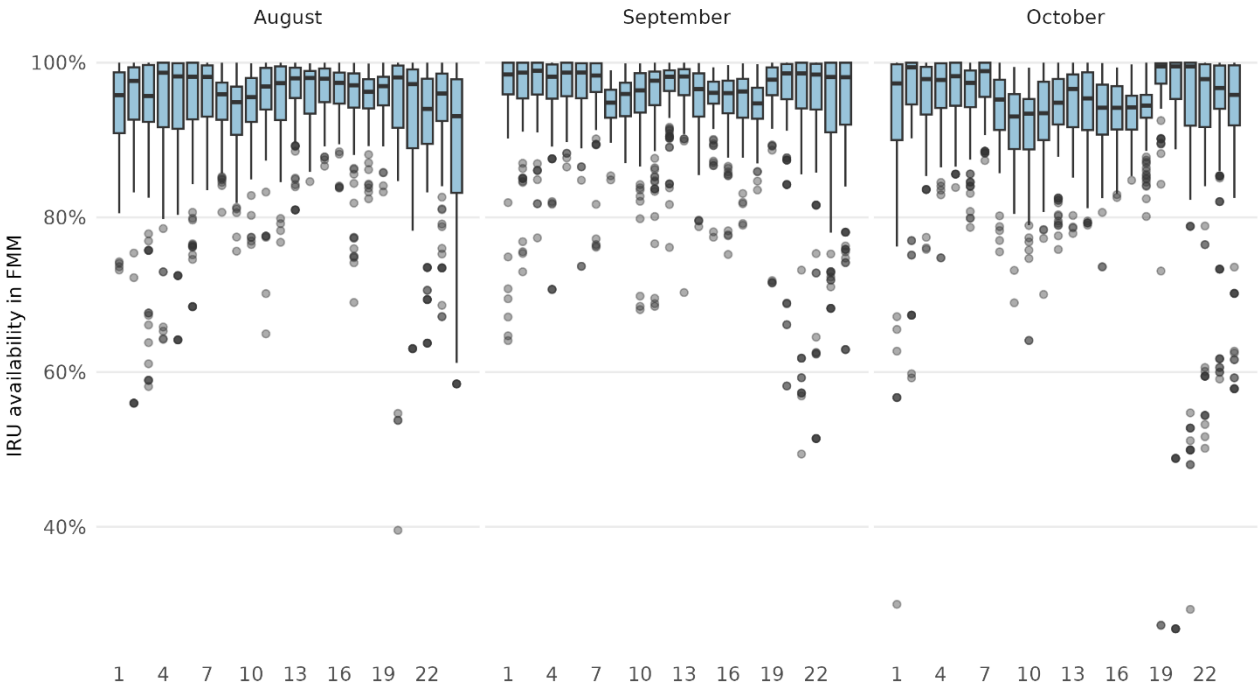


Figure 80: Percentage IRD availability in FMM for EDAM footprint

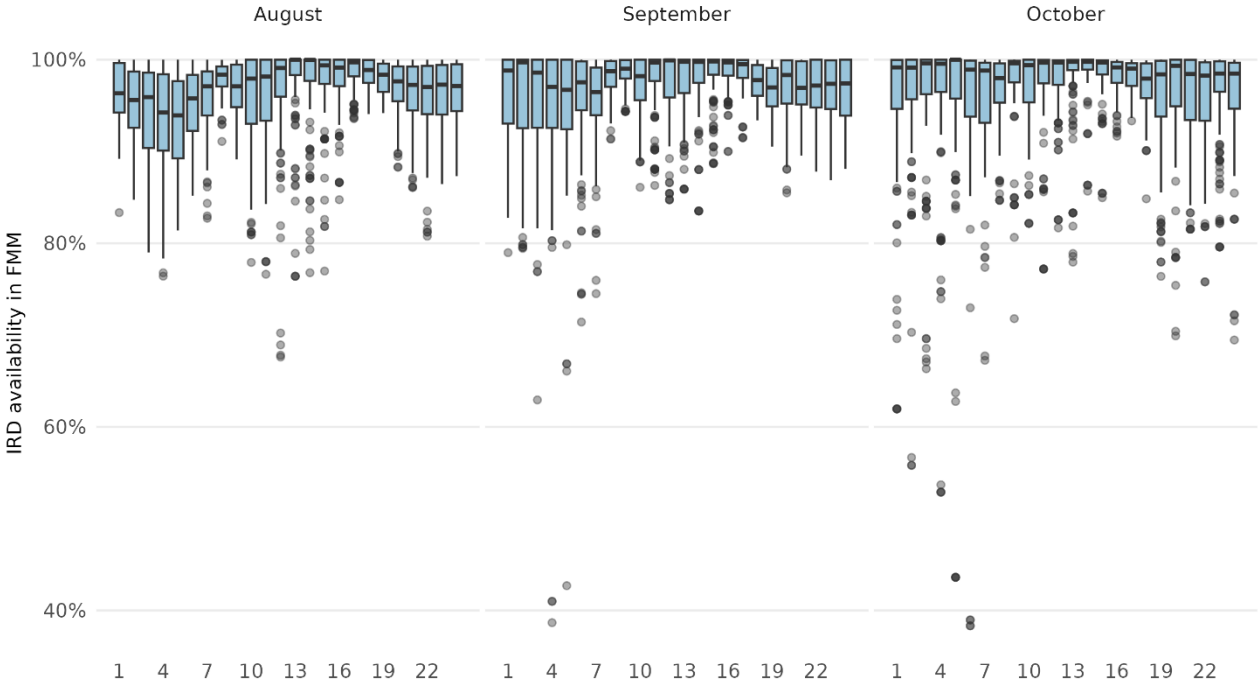


Figure 81 and Figure 82 show the hourly distributions of the utilized imbalance reserve up and down volumes, in the EDAM footprint in FMM. The utilization trends follow the shape of the imbalance reserve requirements, higher in the morning and evening peak hours for both up and down directions.

Figure 81: Hourly IR up utilization distribution in EDAM footprint

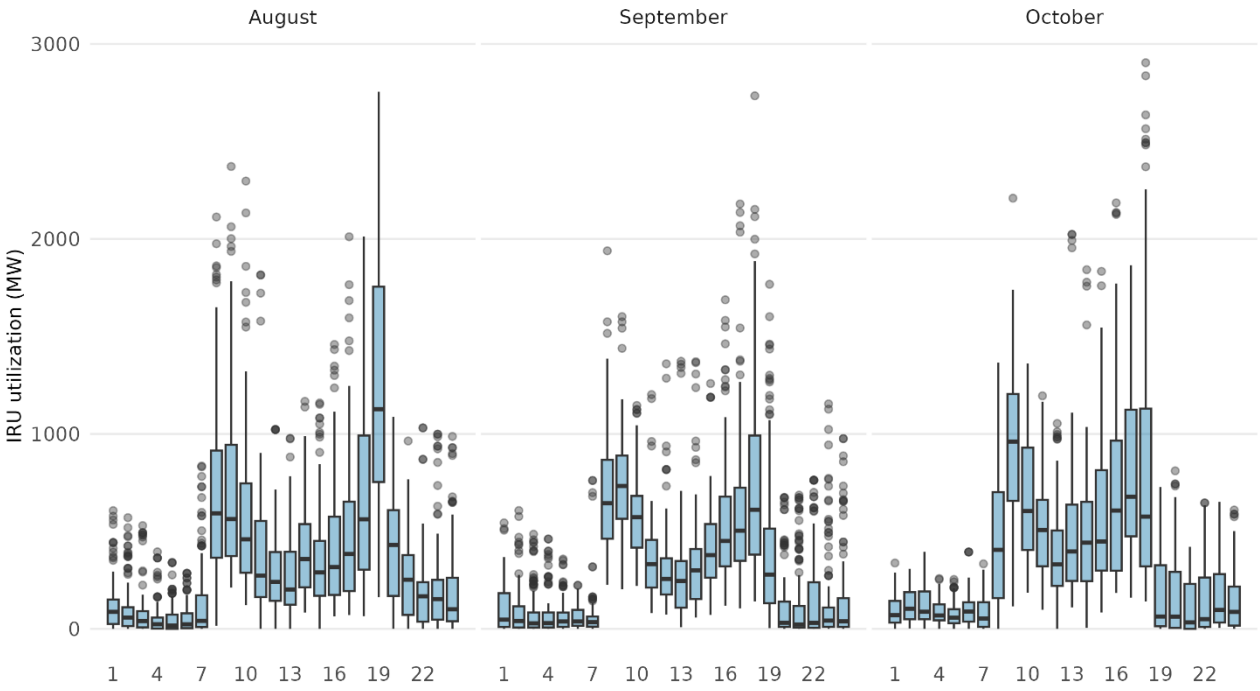
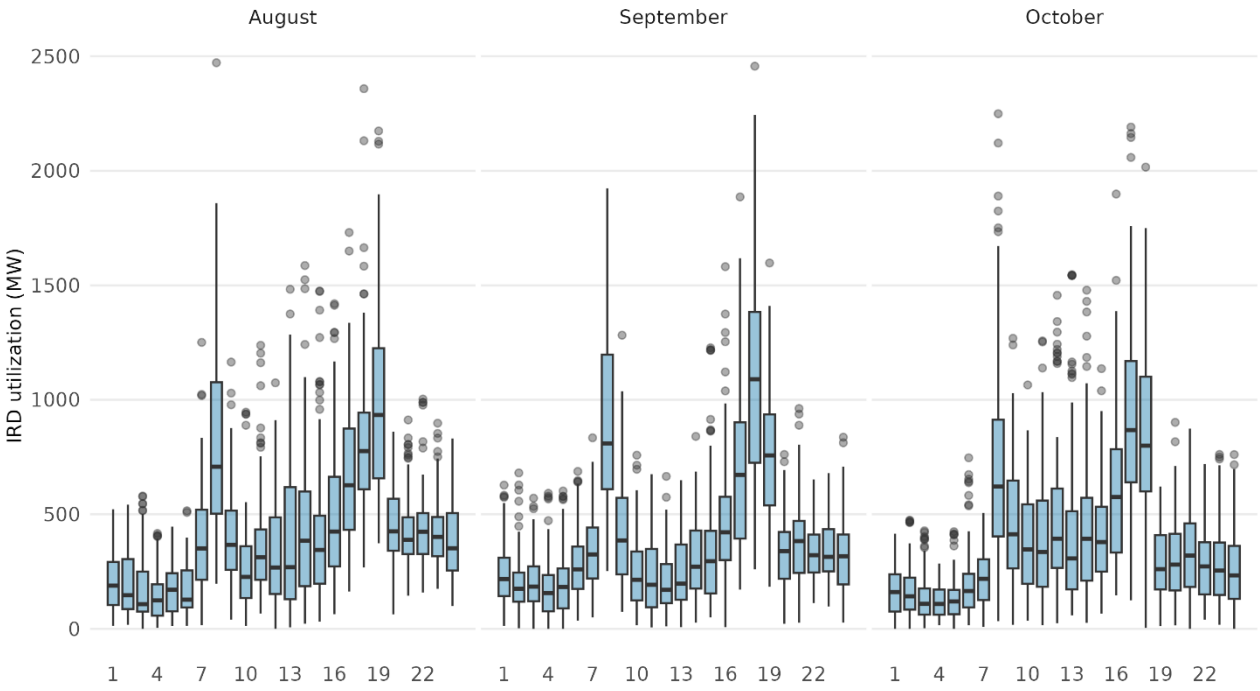


Figure 82: Hourly IR down utilization distribution in EDAM footprint



The congestion component of IRU/IRD marginal prices is impacted only by the transmission constraints enforced for IRU and IRD deployment scenarios and its trend is an estimate of how much congestion is impacting IRU/IRD marginal pricing. Figure 83 and Figure 84 show the nodal congestion components of the imbalance reserve marginal prices in upward and downward directions. For the months of August through October, the imbalance reserve congestion is minimal and centered around $0/MWh. When analyzing the outliers for IRU in the month of October, there is positive congestion in the SDGE region. When analyzing the outliers for IRD in the month of October, there is negative congestion in the SDGE region. The MCC breakdown for monthly average IR congestion is provided in Table 11.

Figure 83: Nodal IRU congestion component of the IRU marginal price

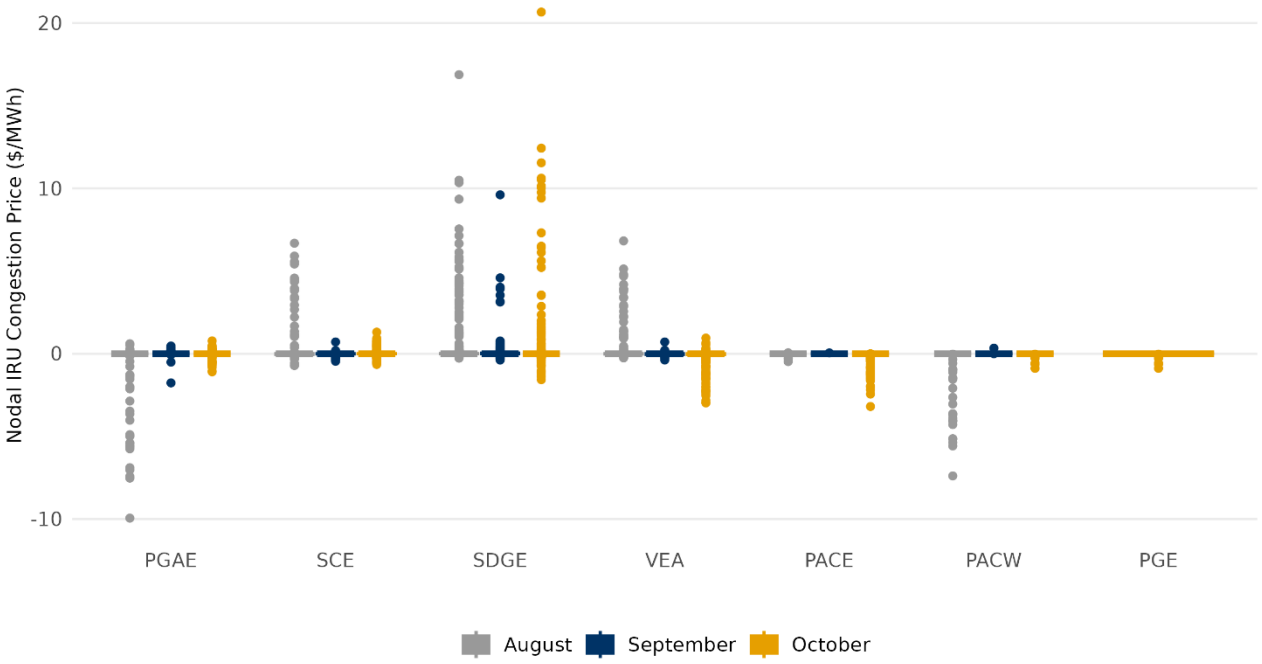
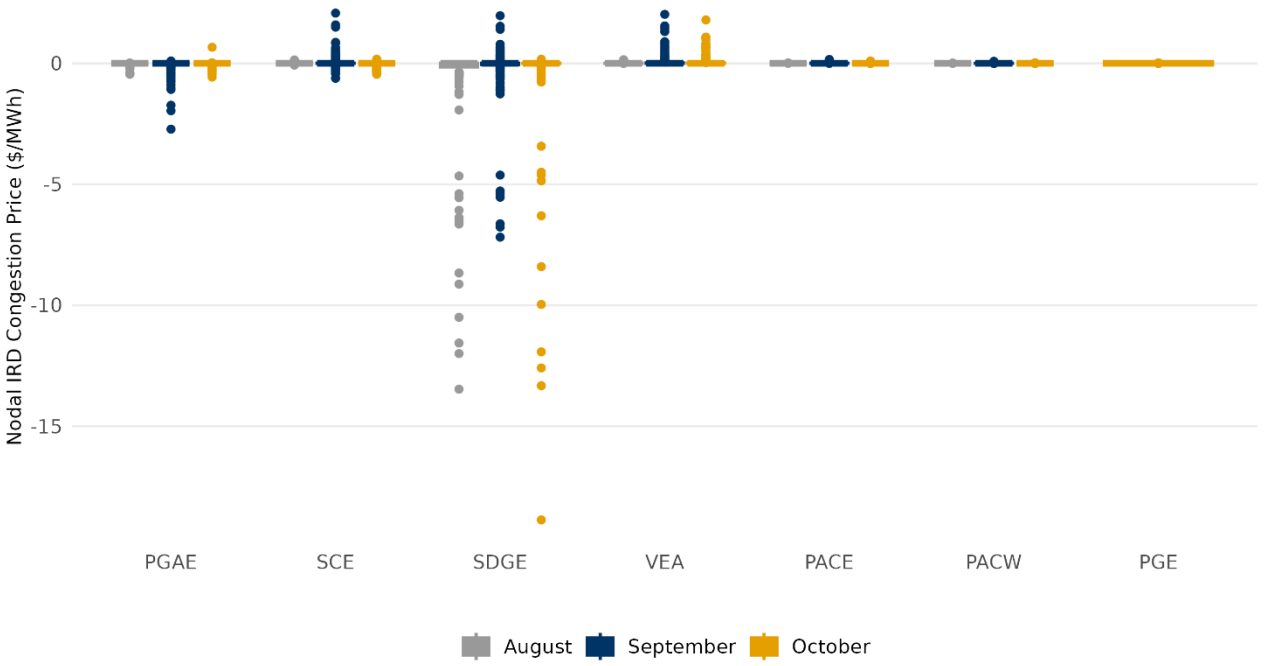


Figure 84: Nodal IRD congestion component of the IRD marginal price



Contingencies are currently not enforced in the IR scenarios for EDAM. This was a decision made through the DAME configurable parameters initiative before the launch of EDAM. Table 7 provides the constraints with the highest average congestion costs across EDAM (base and IRU) and FMM. As contingencies are not enforced in the IR scenarios, there is a possibility that contingency-related congestion could materialize in FMM and get IR stranded. This is the case for the all the CISO related contingencies in the following table.

Table 7: October 2026 average congestion costs by constraint across day-ahead and FMM

October 2026 Average Congestion Costs by Constraint		Contingency	PACE			PACW			PGE			PGAE			SCE		
BAA	Constraint Name		Base	IRU	FMM	Base	IRU	FMM	Base	IRU	FMM	Base	IRU	FMM	Base	IRU	FMM
CISO	7760_DEV_RDB_ALIS	N	(0.54)	(0.01)	(0.93)							0.02		1.08	0.29	0.00	2.23
CISO	8610_SylmarBNK_N-S_Import_NG	N	(0.44)	(0.08)	(0.23)			0.26			0.25	0.10	0.02	0.47	0.23	0.04	0.57
CISO	30056_GATES2 _500_30060_MIDWAY _500_BR_2 _1	Y			(0.11)			0.56			0.56			0.55			(0.79)
CISO	30060_MIDWAY _500_24156_VINCENT _500_BR_2 _3	Y	0.08		0.05	(0.25)		(0.22)	(0.25)		(0.22)	(0.35)		(0.30)	0.27		0.23
CISO	24091_MESA CAL_230_24076_LAGUBELL_230_BR_2_1	Y	(0.03)			(0.05)		(0.27)	(0.05)		(0.27)	(0.05)		(0.32)	0.06		0.57
CISO	7820_TL23040_IV_SPS_NG	N	(0.58)	(0.06)	(0.00)	(0.00)			(0.01)			(0.26)	(0.02)	0.01	(0.01)	(0.00)	0.04
CISO	7430_CP6_NG	N										0.17	0.02	0.22	(0.21)	(0.02)	(0.34)
CISO	38615_DS AMIGO_230_30790_PANOCHE _230_BR_1 _1	Y										(0.00)		(0.24)	(0.30)		(0.37)
CISO	30750_MOSSLD _230_30797_LASAGUIL_230_BR_1 _1	Y										0.33		0.15	(0.28)		(0.17)
CISO	30040_TESLA _500_30050_LOSBANOS_500_BR_1 _1	Y			(0.02)			0.18			0.18			0.09			(0.22)
CISO	30055_GATES1 _500_30060_MIDWAY _500_BR_1 _1	Y	(0.01)		(0.02)	0.08		0.06	0.08		0.06	0.11		0.07	(0.11)		(0.07)
CISO	7820_TL 230S_OVERLOAD_NG	N	(0.09)	(0.00)	(0.22)	(0.04)	(0.00)		(0.04)	(0.00)		(0.05)	(0.00)	0.02	(0.02)	(0.00)	0.11
CISO	30790_PANOCHE _230_30900_GATES _230_BR_1 _1	Y				0.01		0.04	0.01		0.04	0.12		0.11	(0.11)		(0.11)
CISO	34418_KINGSBRG_115_34428_CONTADNA_115_BR_1 _1	Y										0.11		0.21	(0.06)		(0.09)
CISO	35618_SN JSE A_115_35616_SNJOSEB _115_BR_1 _1	Y										0.18		0.06	(0.17)		(0.03)

Figure 85: CISO IRU award concentration based on IFM and FMM participation

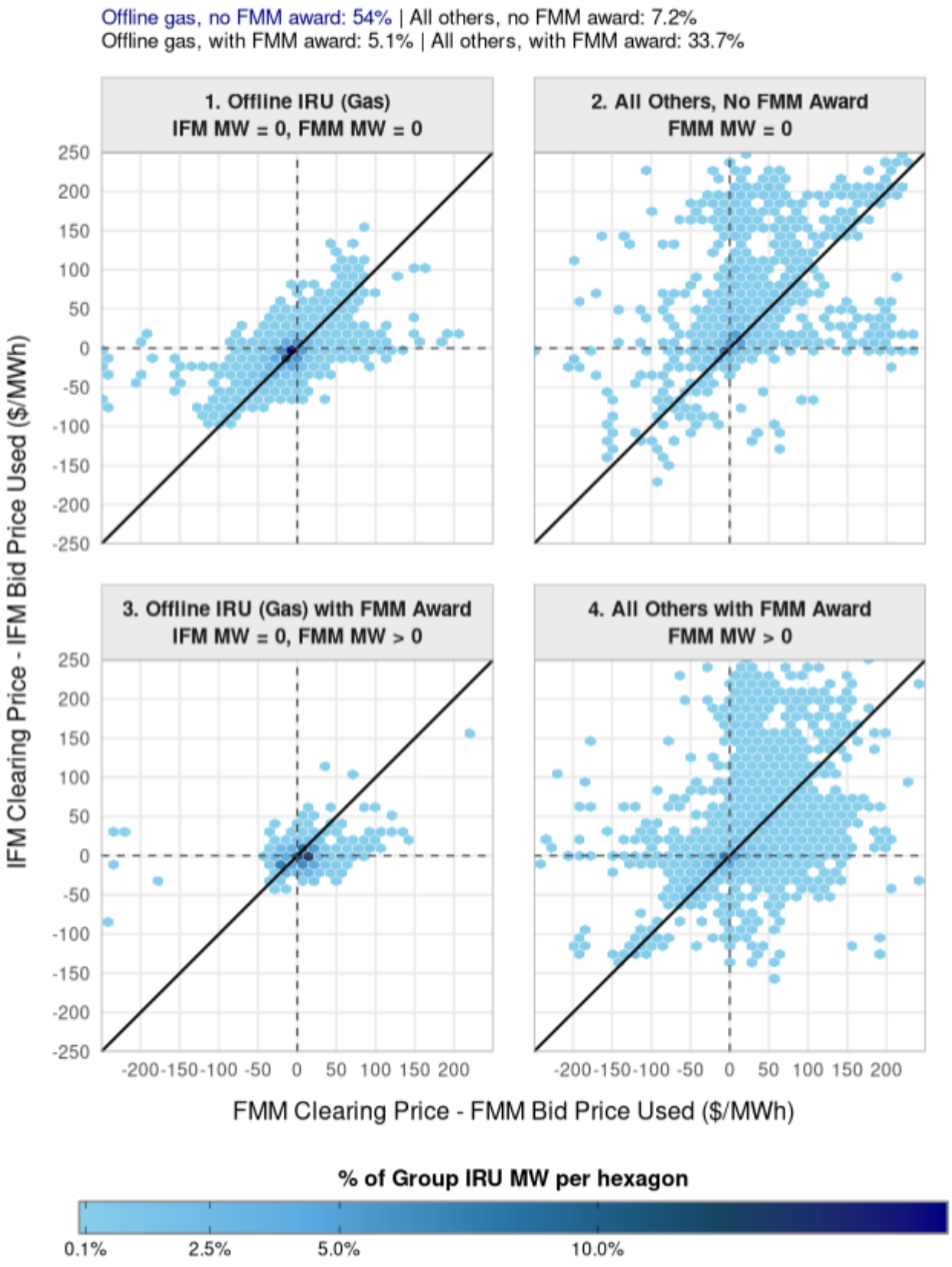


Figure 85 shows the concentration of CISO IRU awards across EDAM and FMM. The bid price used in the chart uses the following assumptions:

1) Use no load cost over Pmin if the resource is offline (ignore Pmin less than 1 MW)
2) Use the first segment of the price curve if the resource is cleared at Pmin
3) Startup, transition costs, outages, ramp rate restrictions, SOC and other inter temporal constraints do influence the final FMM commitment but are not captured by the input bid price.

As covered earlier in Figure 75 thru Figure 77, IRU awards can be procured from quick-start resources having startup time less than 15 mins. These resources are quick and less expensive to start; however, they are expensive to operate. A large percentage of IRU is procured from resources that are never started up in FMM due to the higher cost of operation. This is also evident from the presence of darker coloring in the upper left panel. The upper right panel includes resource with IRU that were not awarded in real-time due to other constraints mentioned as part of the assumptions.

For units that are economic in FMM, data points are concentrated in the first quadrant. The utilization percentage is based on whether the awarded IRU realizes in FMM as an energy award and the highest FMM award for that hour is used. The percentages are slightly different as not all data points are shown in this chart for clarity, the data points are limited to IFM and FMM spreads under $250.

Based on the concentration of IRU awards with IFM and FMM spreads, congestion differences between IFM and FMM do not significantly impact the deliverability of IRU awards, the largest contributor is the set of offline resources with high commitment cost.

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

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 86 shows the monthly average prices for RCU and RCD for all BAAs. Overall, prices for RC increased indicating that RCU needs in October were higher than RCD on average. The monthly average RCU price for PGE was $1.4/MWh, while CAISO saw an average RCU price of $5.0/MWh.

Figure 86: Monthly average price of RCU and RCD

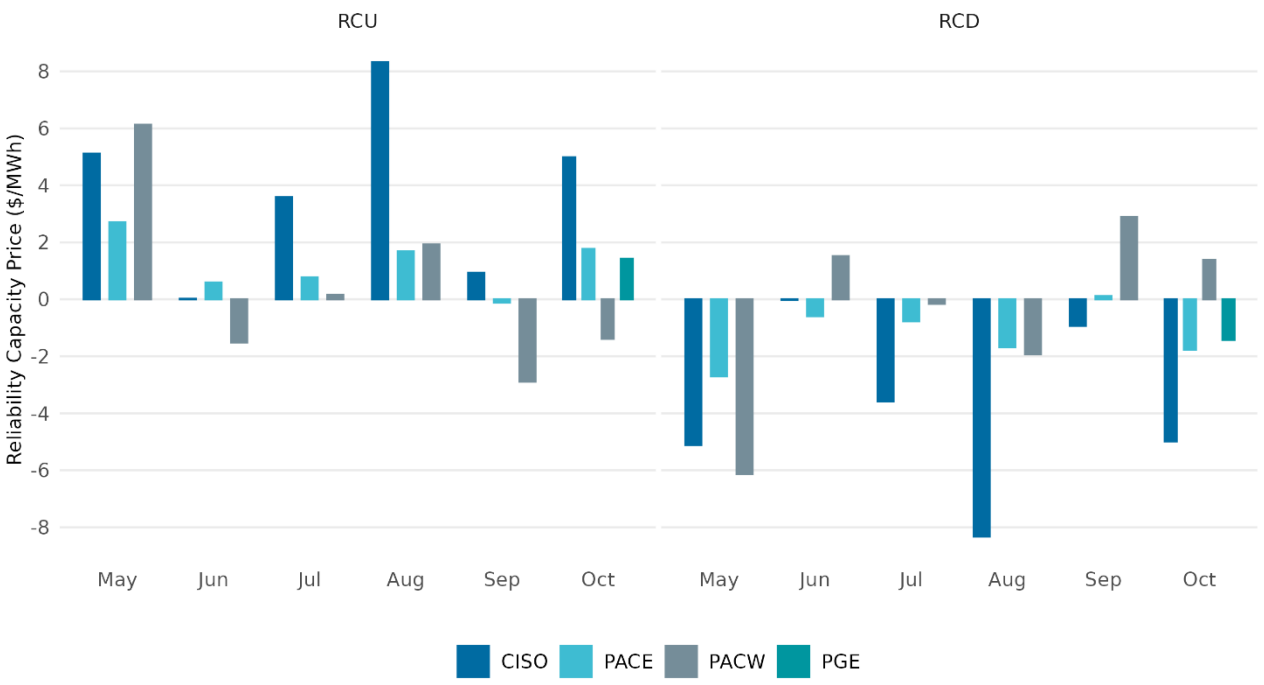


Figure 87 and Figure 88 shows the frequency of reliability capacity up and down price ranges for each BAA from May to October. Reliability capacity prices for CAISO were near $0/MWh in over

89% of intervals in October. For PACE, reliability capacity prices fell between $0/MWh and $5/MWh over 95% of the time, and over 86% of the time for PACW. Reliability capacity prices in PGE fell between -$5/MWh and $5/MWh in PGE over 94% of the time.

Figure 87: Frequency of RCU price ranges

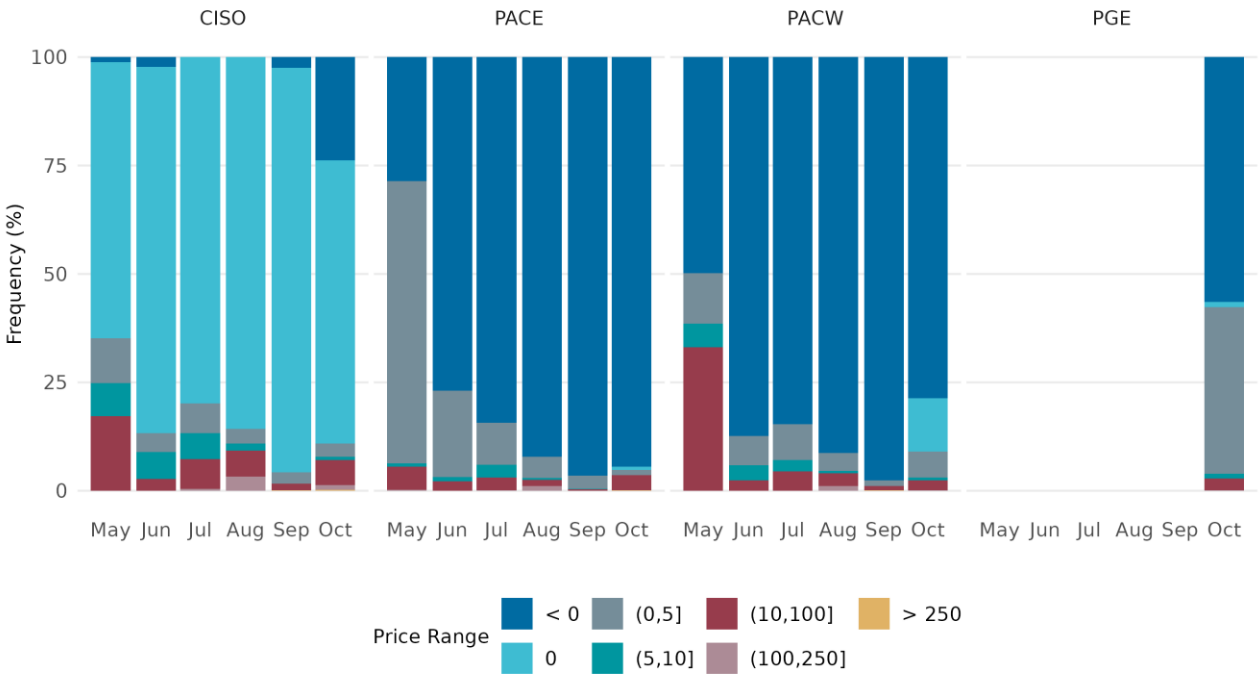


Figure 88: Frequency of RCD price ranges

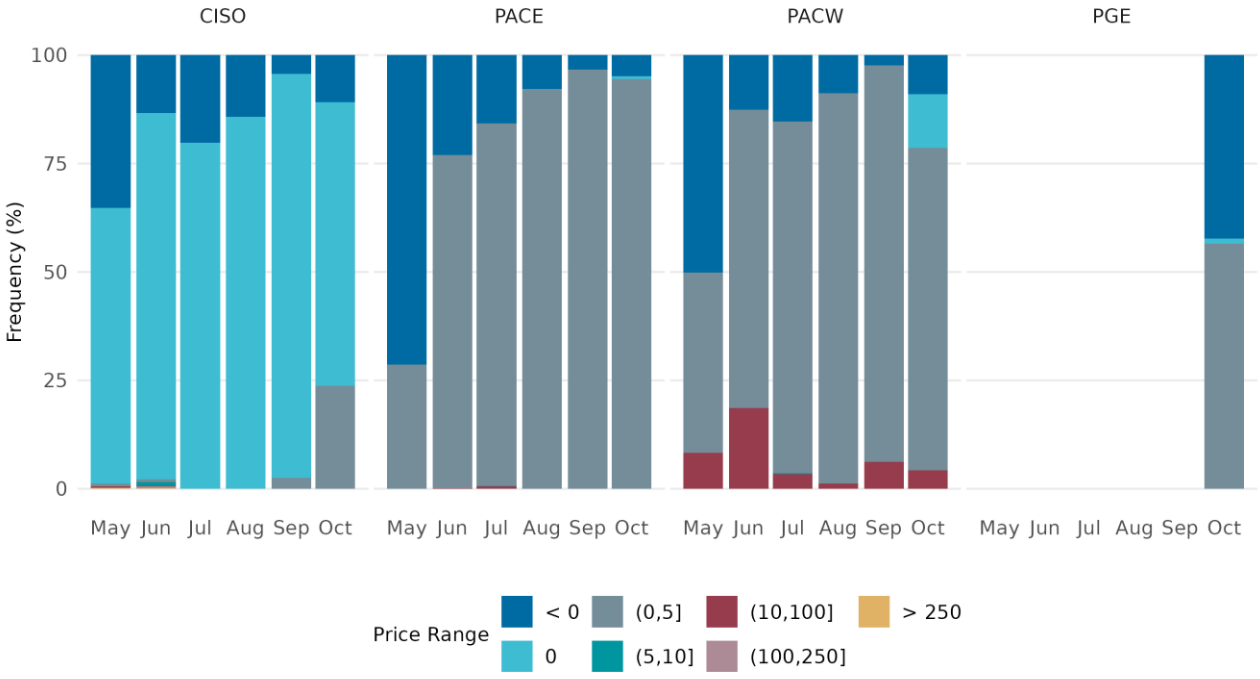


Figure 89 and Figure 90 show the daily average RCU and RCD prices. Prices were more volatile in October due to price spikes at the beginning of the month. October 7 saw an RCU price spike for CAISO with a daily average price of $44.5/MWh. Daily average RCU prices in PGE on October 4 reaching $21.6/MWh.

Figure 89: Daily average price of RCU

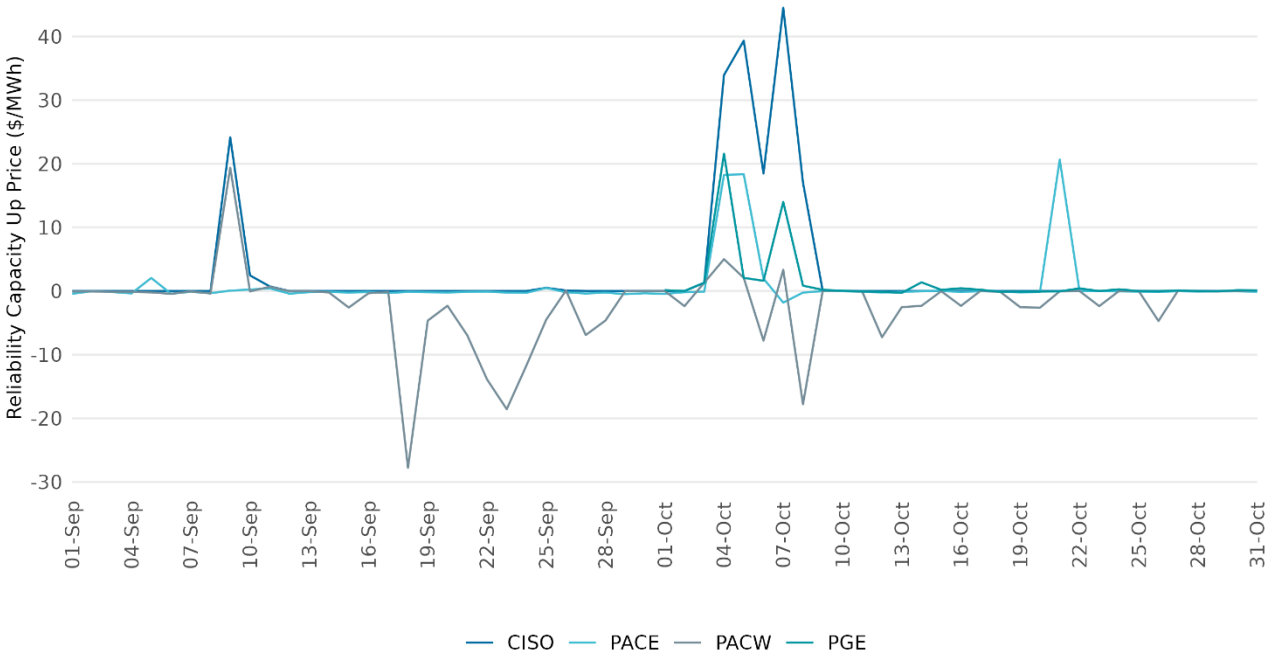


Figure 90: Daily average price of RCD

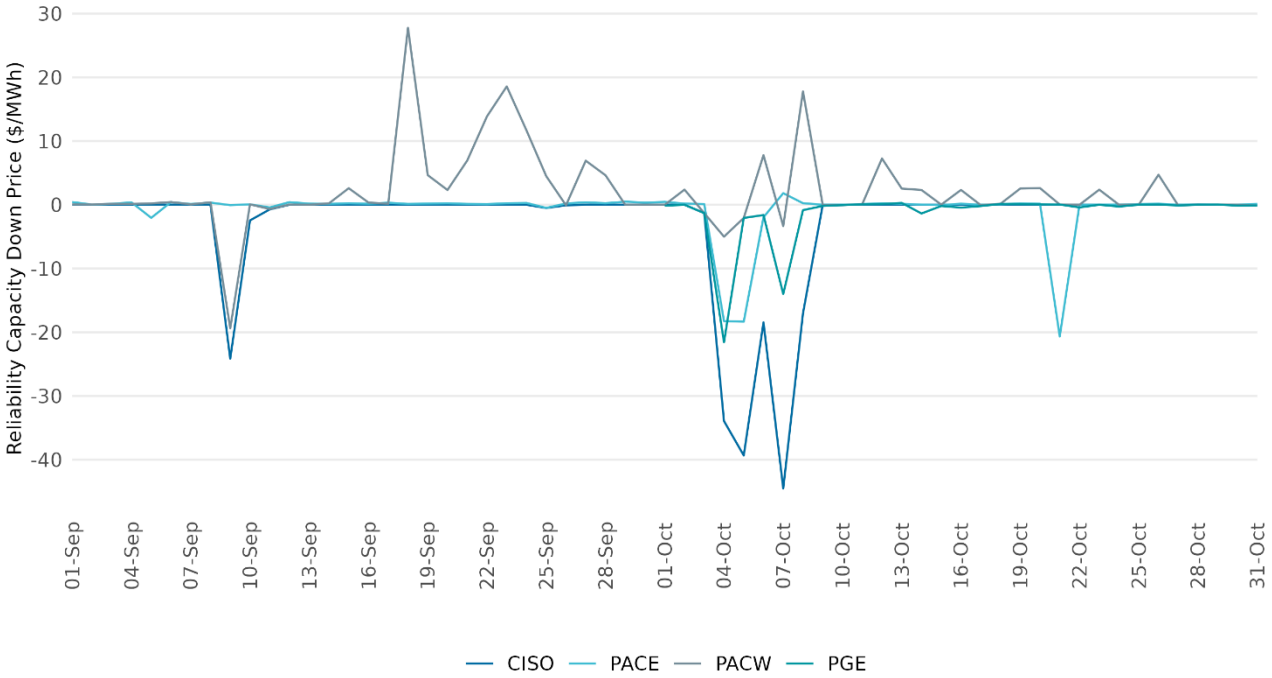


Figure 91 and Figure 92 show the hourly average RCU and RCD prices. On average prices were highest during the evening peak period across hours ending 17 and 20 in October. The highest hourly average RCU price was $43.8/MWh for CAISO in hour ending 19 and $11.8/MWh for PACE in hour ending 18. PACW saw the highest hourly average RCD price in hour ending 17 of $11.8/MWh.

Figure 91: Hourly average price of RCU

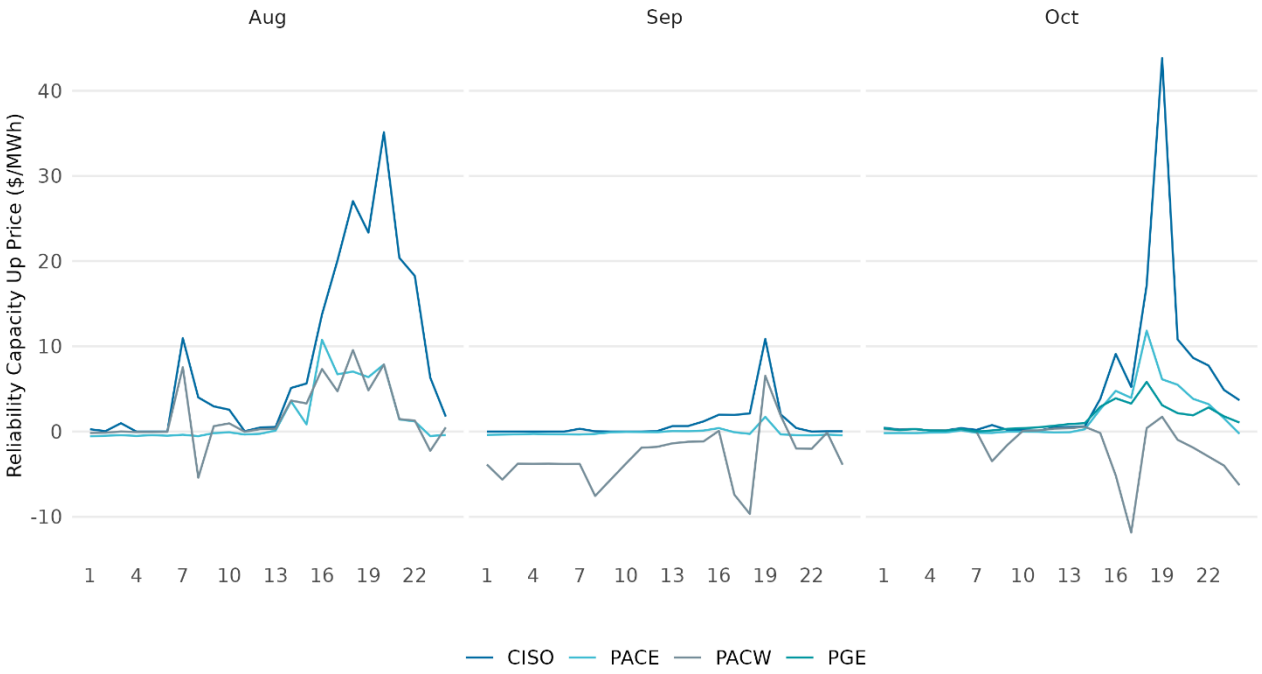
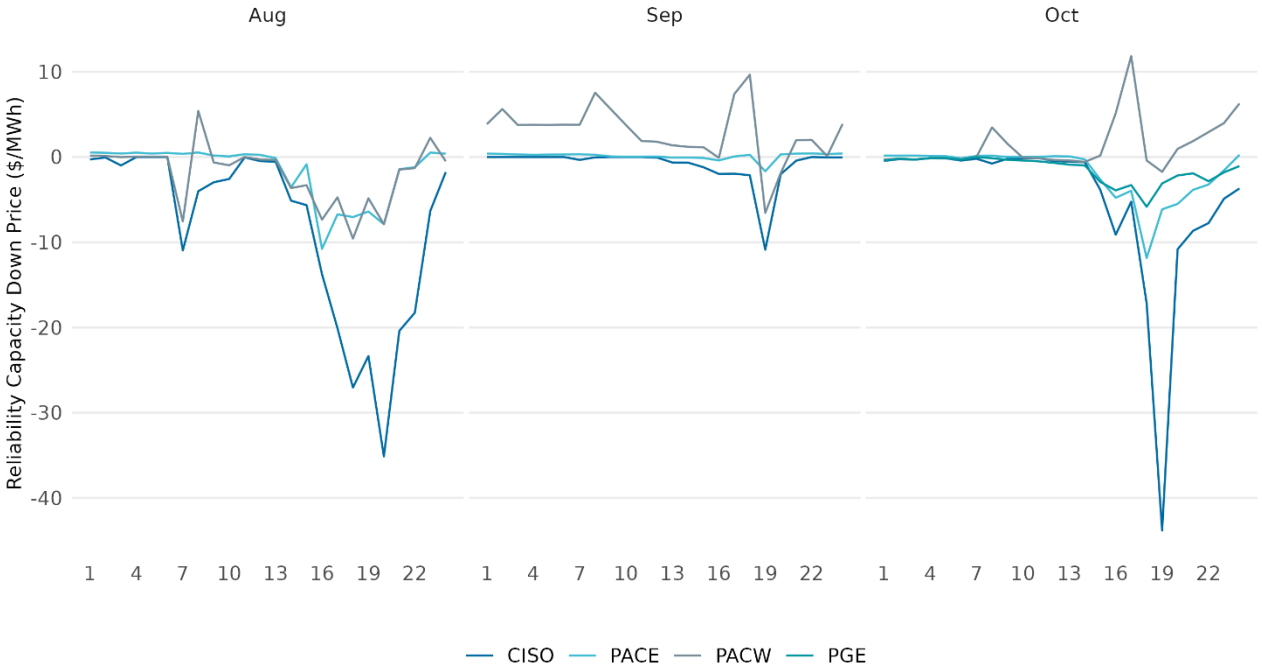


Figure 92: Hourly average price of RCD



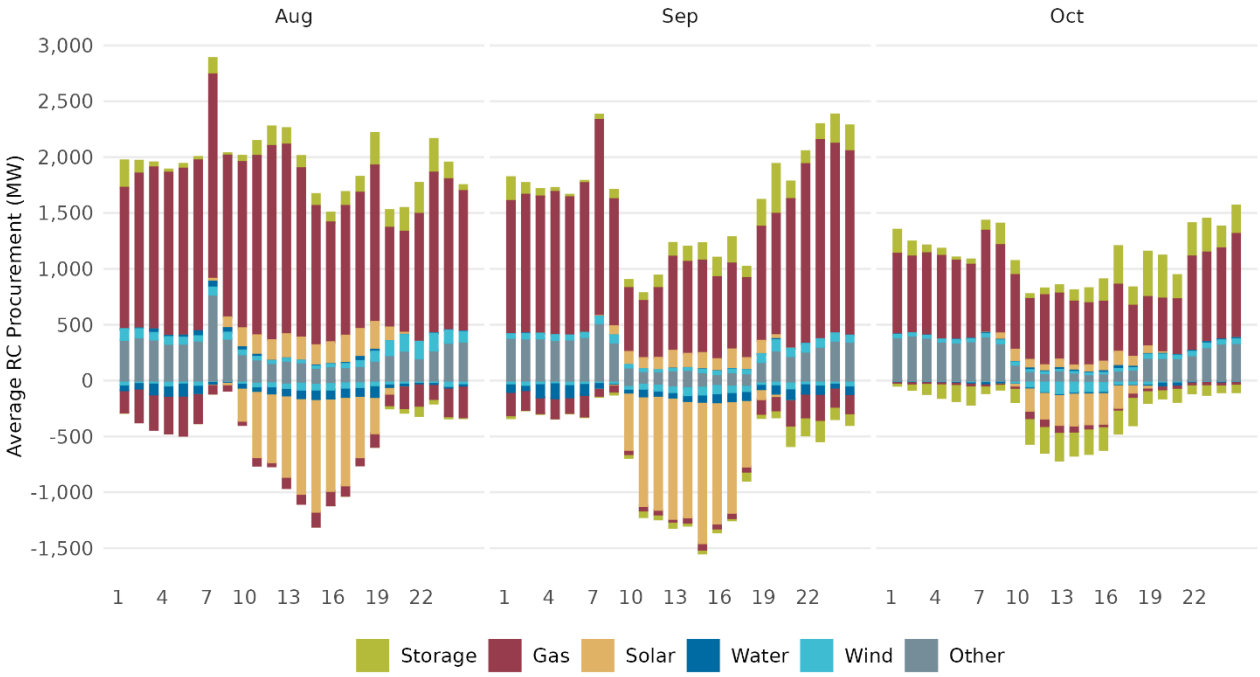
The reliability capacity price separation observed between the three BAAs reflects the economics of the wider EDAM market footprint, available supply mix and EDAM transfers.

Reliability capacity procurement

Figure 93 to Figure 95 Figure 96 illustrate the hourly average by technology supporting the procurement for each BAA.

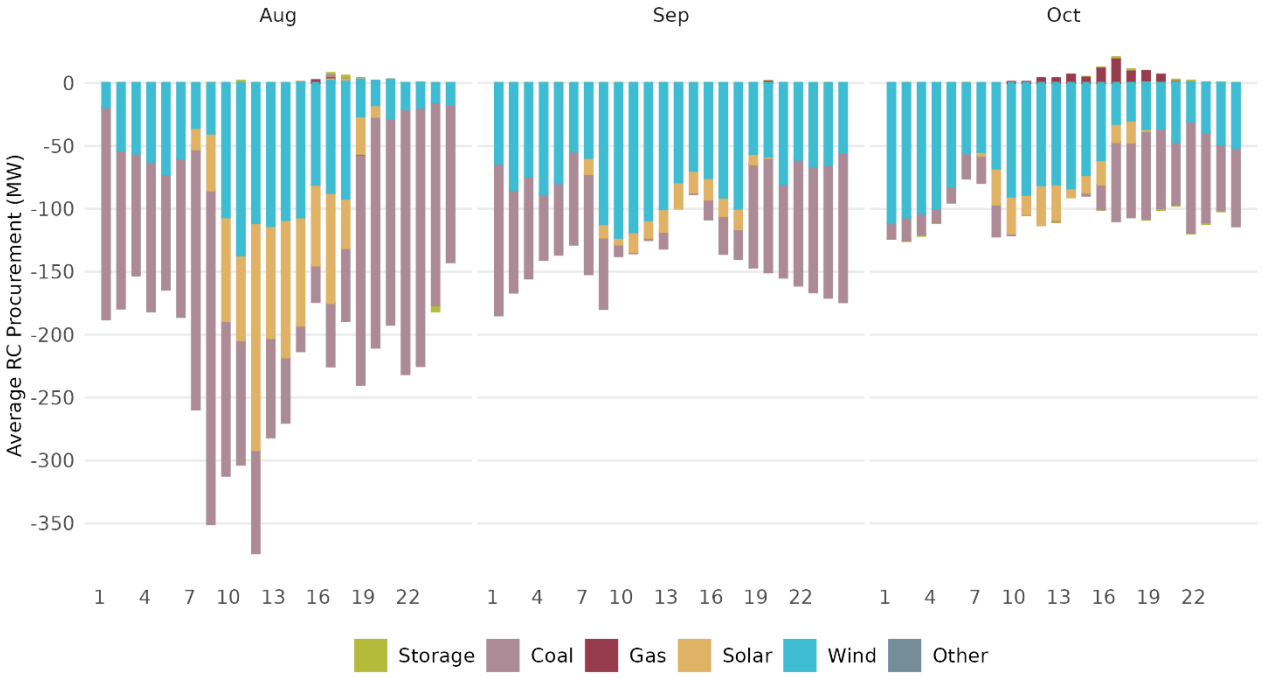
For CAISO in the past three months, gas resources continue to make up the highest proportion of RCU, mostly during non-solar hours. The majority of RCD is procured during solar hours by solar resources. September procured the same pattern of RCU on average as August, however, with an obvious decrease in the total procurement amount. By October, both RCU and RCD procurement had decreased substantially, indicating a less pronounced overall procurement requirement compared with the prior two months.

Figure 93: Hourly average of RC procurement for CAISO



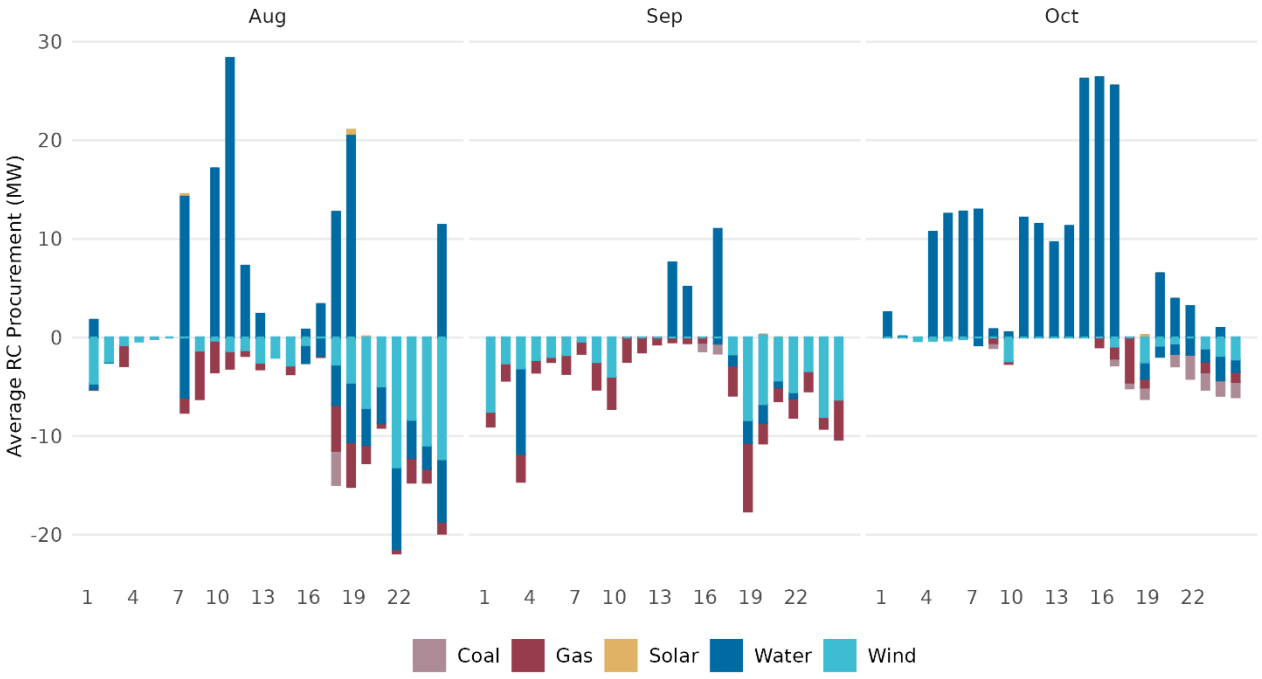
PACE reliability capacity is largely procured in the down direction and supplied primarily by coal and wind resources. RCD procurement has increased significantly, primarily from coal, wind, and solar in August. The RCD procurement decreased substantially in September and October, and by October, a small amount of RCU procurement emerged during the afternoon hours, primarily from gas resources.

Figure 94: Hourly average of RC procurement for PACE



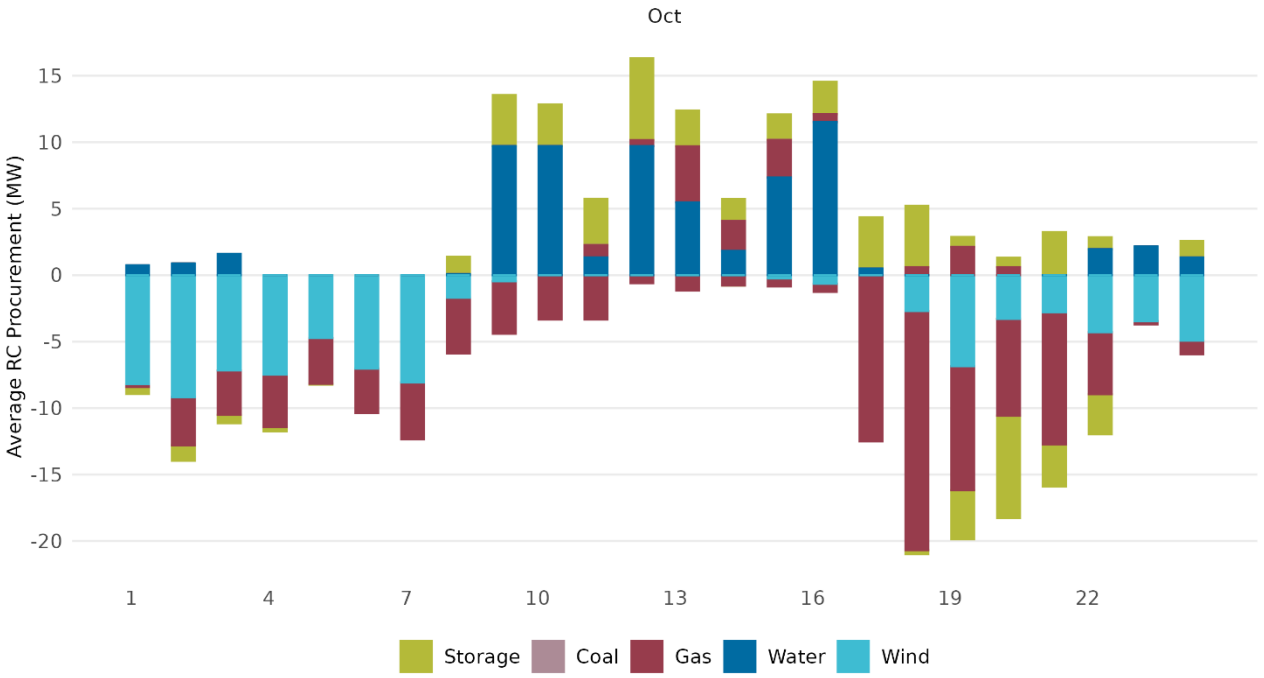
PACW's RC is primarily supplied by hydro and wind resources, followed by gas resources. In October, RCU procurement was pronounced more across all hours, mainly supplied from hydro resources.

Figure 95: Hourly average of RC procurement for PACW



PGE's October RC procurement showed a clear intraday pattern. RCU procurement peaked at approximately 16 MW around HE 12 and was primarily supplied by water and storage, while the largest RCD procurement, approximately -21 MW around HE 18, was mainly associated with gas and storage. Overall, PGE's RC procurement volume was relatively small but exhibited a distinct hourly pattern and changing fuel mix.

Figure 96: Hourly average of RC procurement for PGE



Reliability capacity input bids

Figure 97 and Figure 98 illustrate CAISO's hourly average volume of RC bids by bid price range and fuel type throughout August to October 2026, respectively. Zero-priced bids consistently accounted for the largest share of submitted RC capacity with about 50,000 MW (or about 60 percent of the total), followed by bids in the (40–60 $/MWh) and high-price ranges (100–250 $/MWh). Hourly bid volumes were generally higher during daylight hours as solar resources submitted bids in RC products.

Gas, storage and solar resources accounted for approximately 90 percent of the total. Generally, CAISO's submitted RC capacity remained stable from August to October.

Figure 97: Hourly average volume of RC bids by price for CAISO

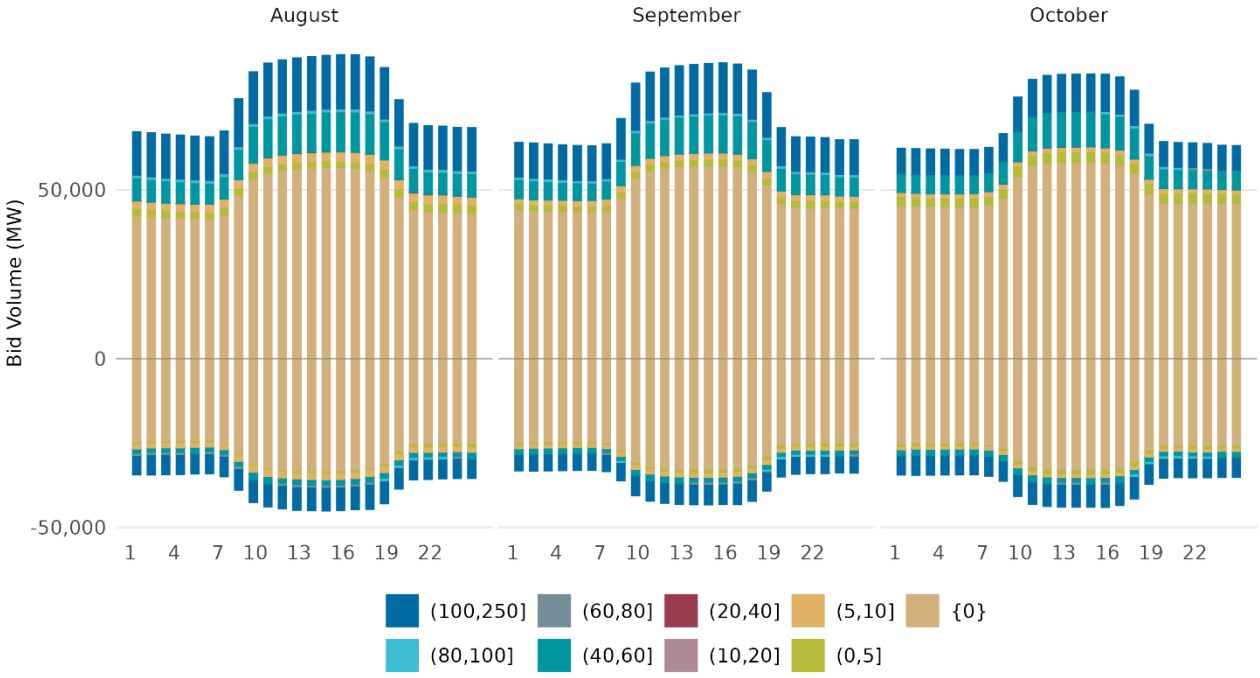


Figure 98: Hourly average volume of RC bids by fuel type by CAISO

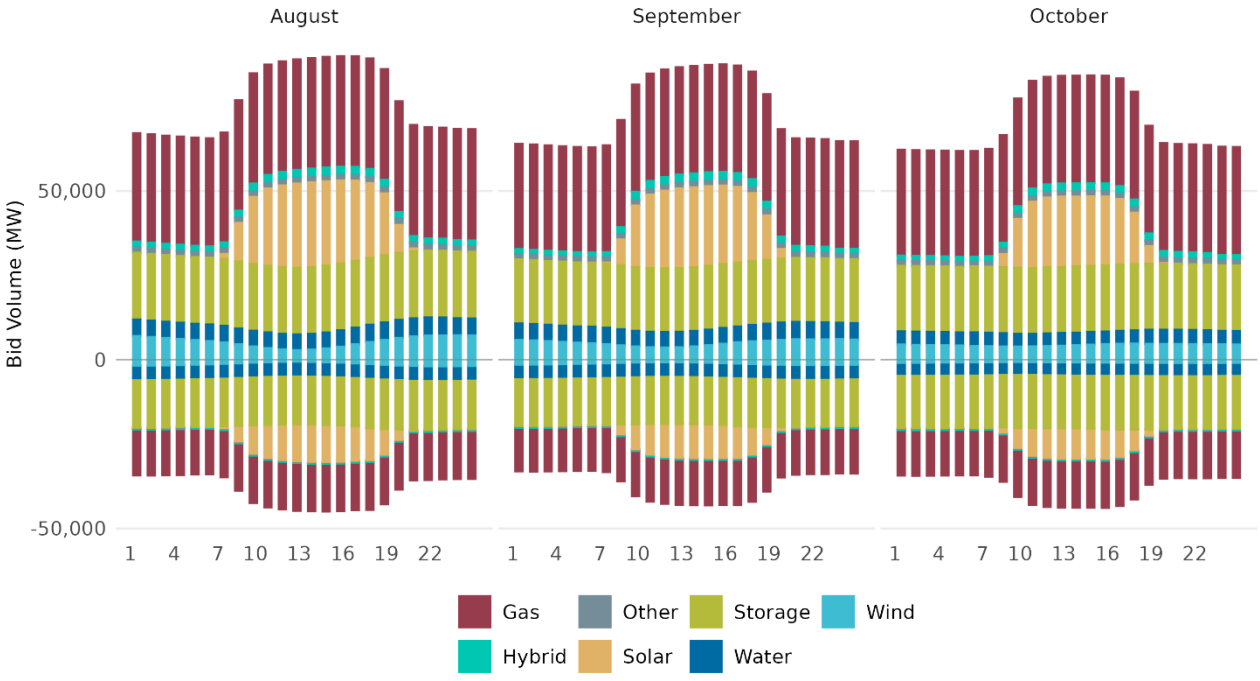


Figure 99 and Figure 100 illustrate the CAISO's daily average volume of RC bids by bid price range and fuel type, respectively. Total RC bid volume declined modestly toward the end of October, but the overall price composition remained largely unchanged.

Gas, solar, and energy storage accounted for the largest share of RC bid volumes.

Figure 99: Daily average volume RC bids by price for CAISO

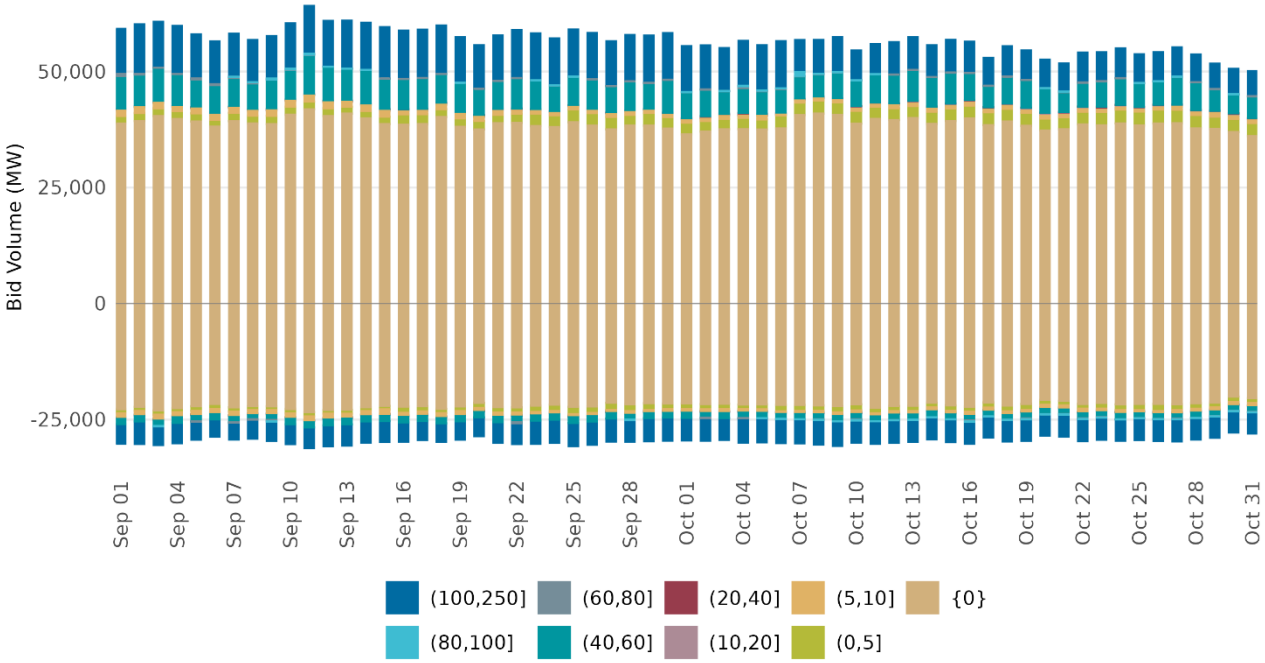


Figure 100: Daily average volume of RC bids by fuel type for CAISO

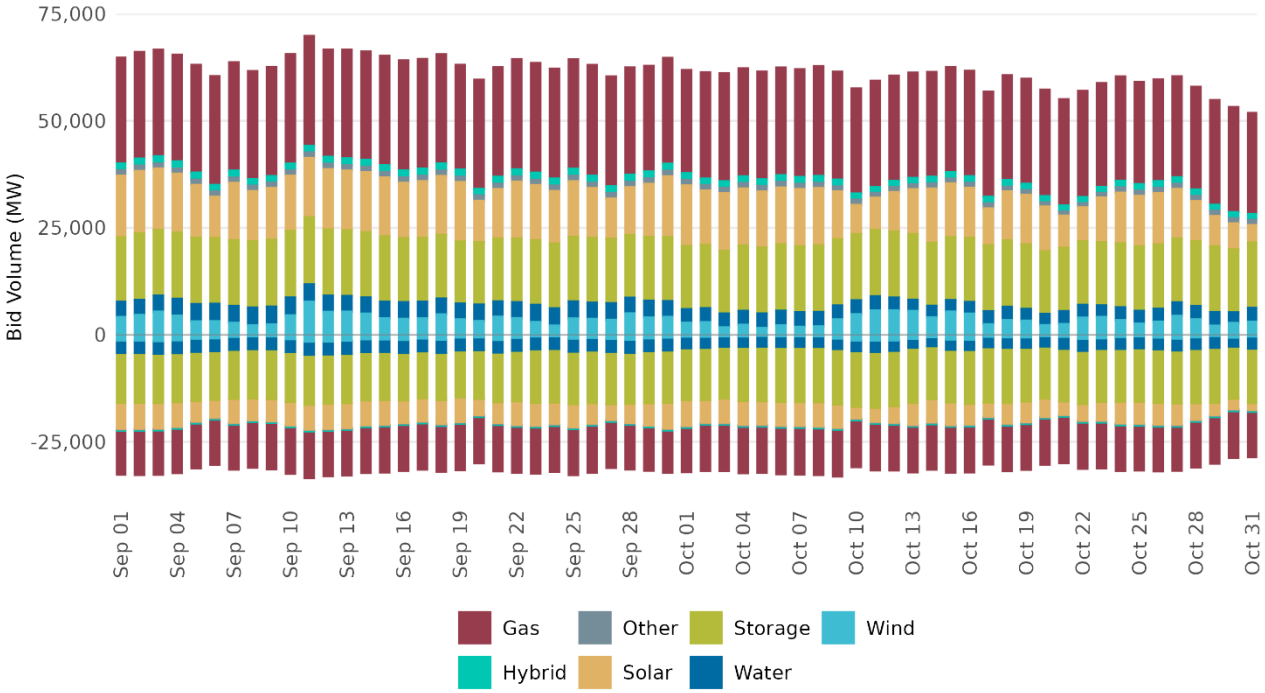


Figure 101 and Figure 102 illustrate the PACE's hourly average volume of RC bids by bid price range and fuel type, respectively. Low-priced bids ($0–5/MW) and moderate priced bids (40–60 $/MWh) consistently accounted for almost all the share of submitted RC capacity throughout the months. Coal, gas, and wind resources accounted for the largest share of submitted RC capacity, with some solar capacity bidding in RCU only.

Figure 101: Hourly average volume of RC bids by price for PACE



Figure 102: Hourly average volume of RC bids by fuel type for PACE

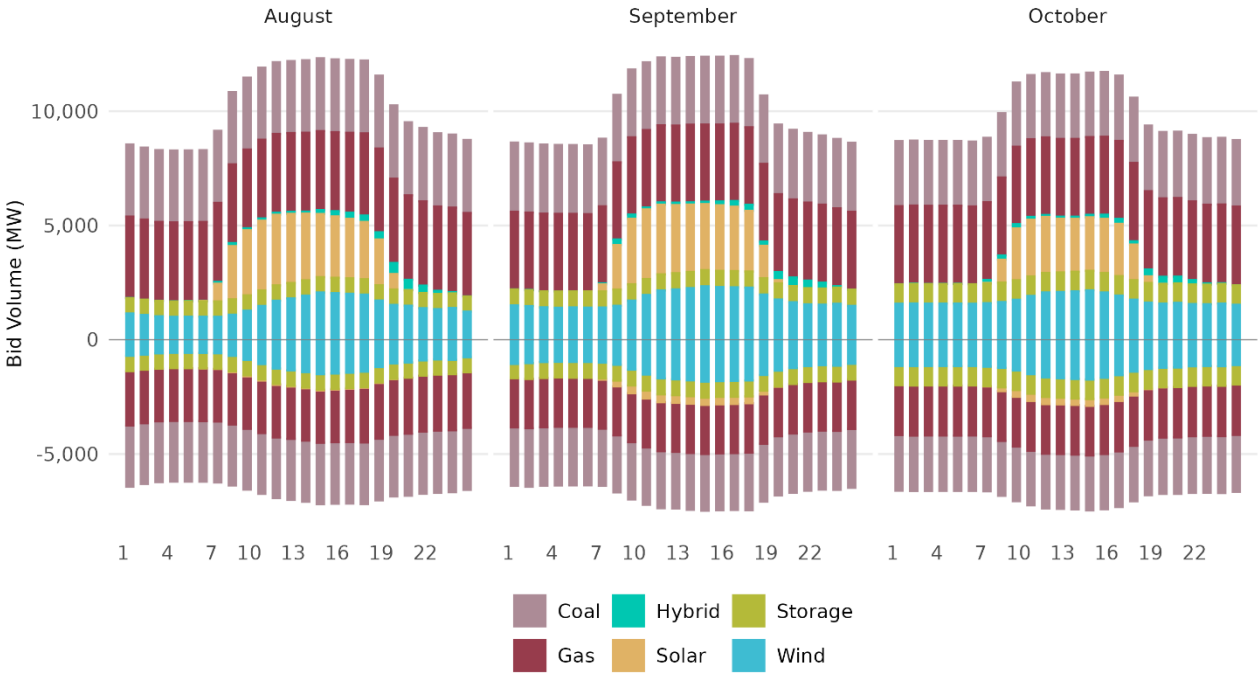


Figure 103 and Figure 104 plotted the daily average volume of PACE's RC products by price and fuel type, respectively. As for the bid volume, it is dependent on renewable forecasts, and solar resources only submitted bids in RCU, leaving an asymmetrical bid volume with RCU up to 10,000 MW and RCD only about 5,000 MW.

Figure 103: Daily average volume of RC bids by price by PACE

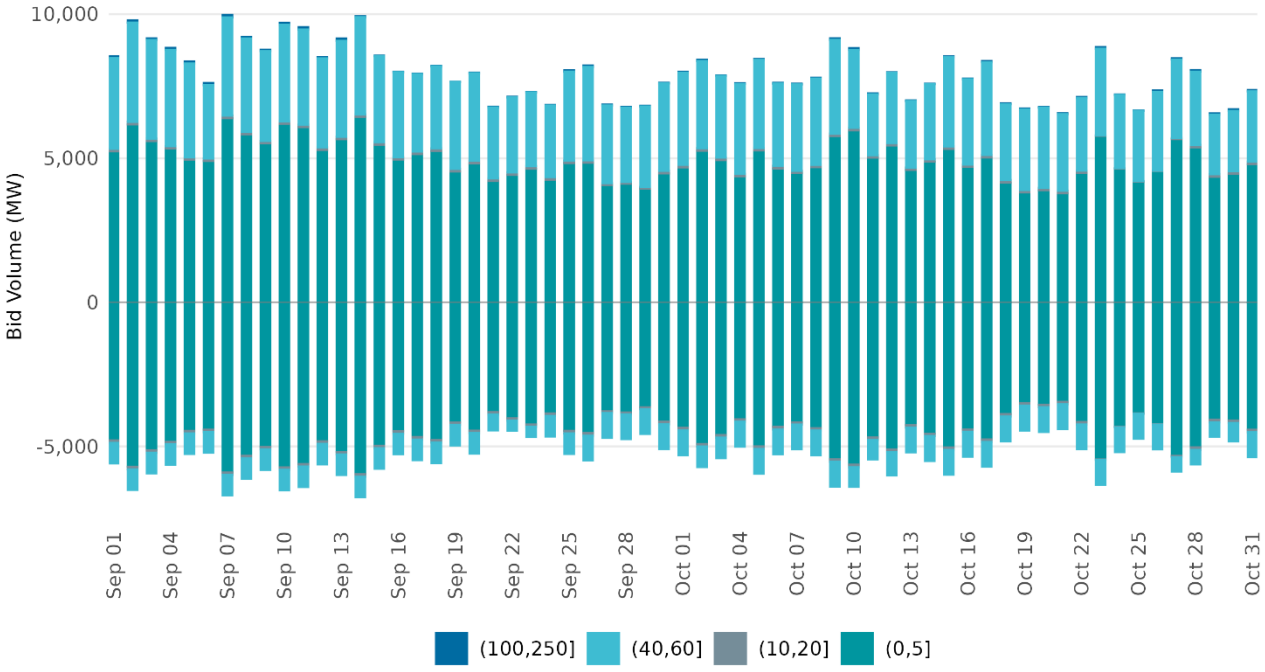


Figure 104: Daily average volume of RC bids by fuel type by PACE

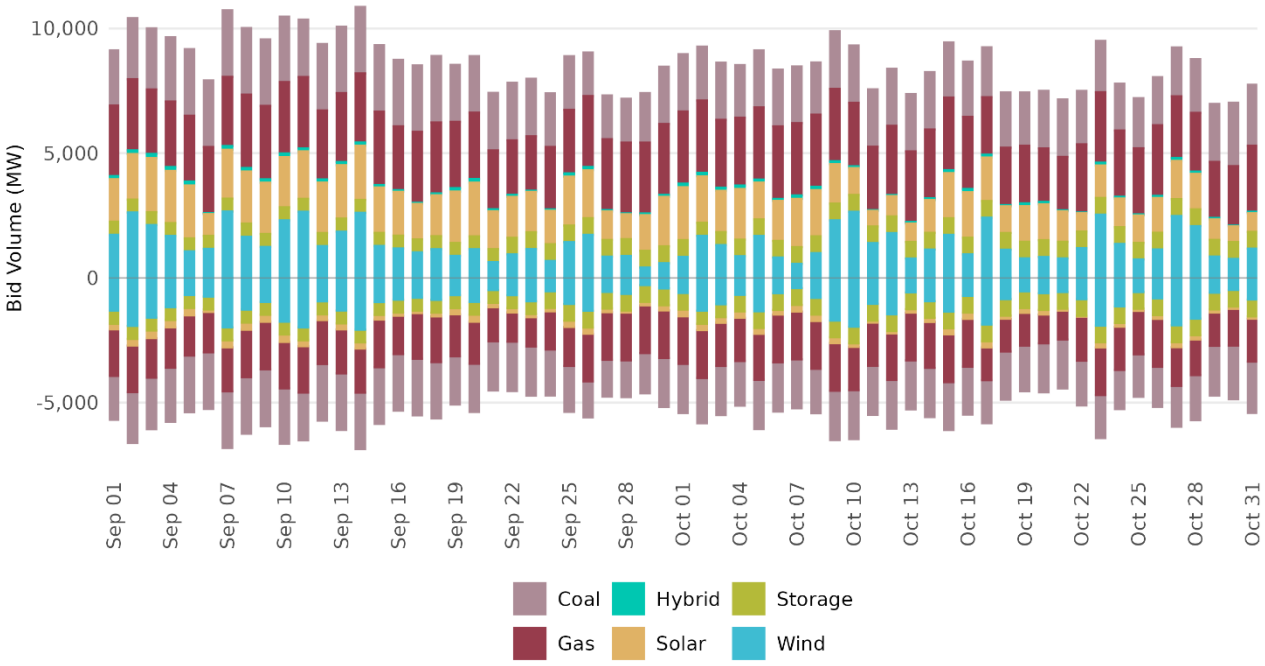


Figure 105 and Figure 106 illustrate PACW's hourly average volume of RC bids by price range and fuel type, respectively. Low-priced bids (0-5 $/MW) and moderate priced bids (40–60 $/MW) consistently accounted for the largest share of submitted RC capacity throughout the month, followed by bids in the high (100–250 $/MWh) range. It is noteworthy that in the down direction there are only low- and mid-priced bids submitted. Hourly bid volumes were slightly higher during daylight hours. Gas, water and wind resources accounted for the largest share of submitted RC capacity, with extra solar capacity bidding in RCU only. Despite the decline in overall volume, the hourly bid profile remained relatively consistent, with higher RCU bid volumes during the daytime hours.

Figure 105: Hourly average volume of RC bids by price for PACW

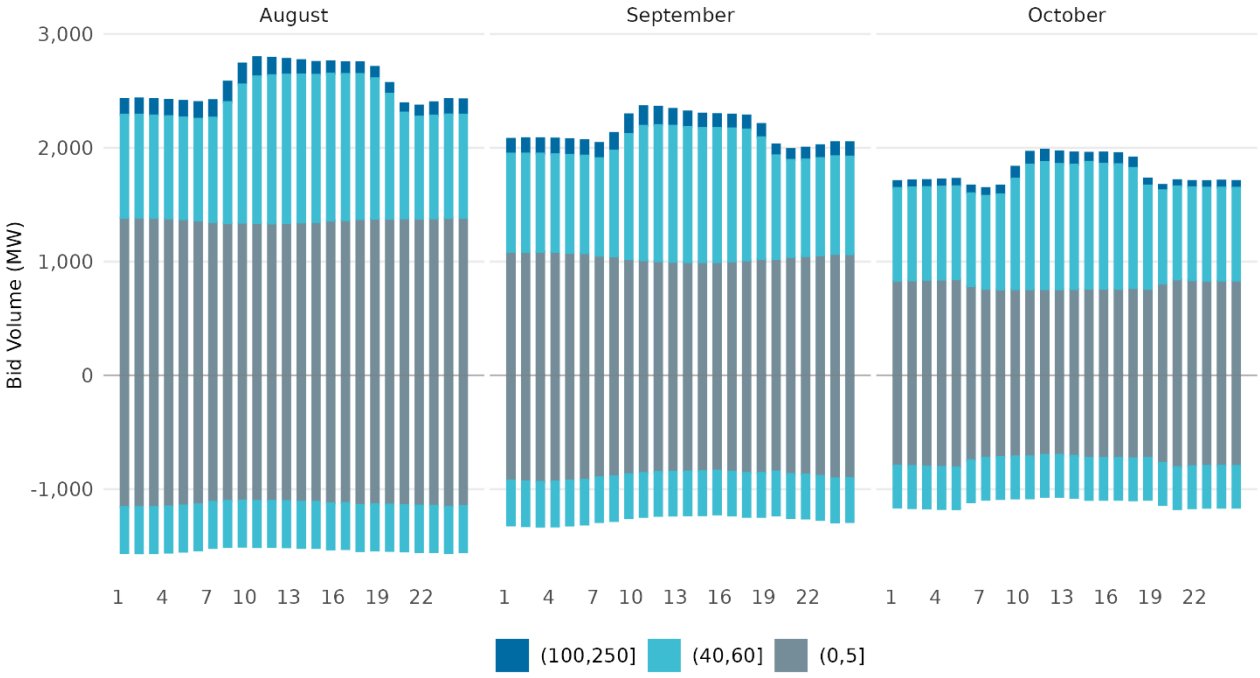


Figure 106: Hourly average volume of RC bids by fuel type for PACW

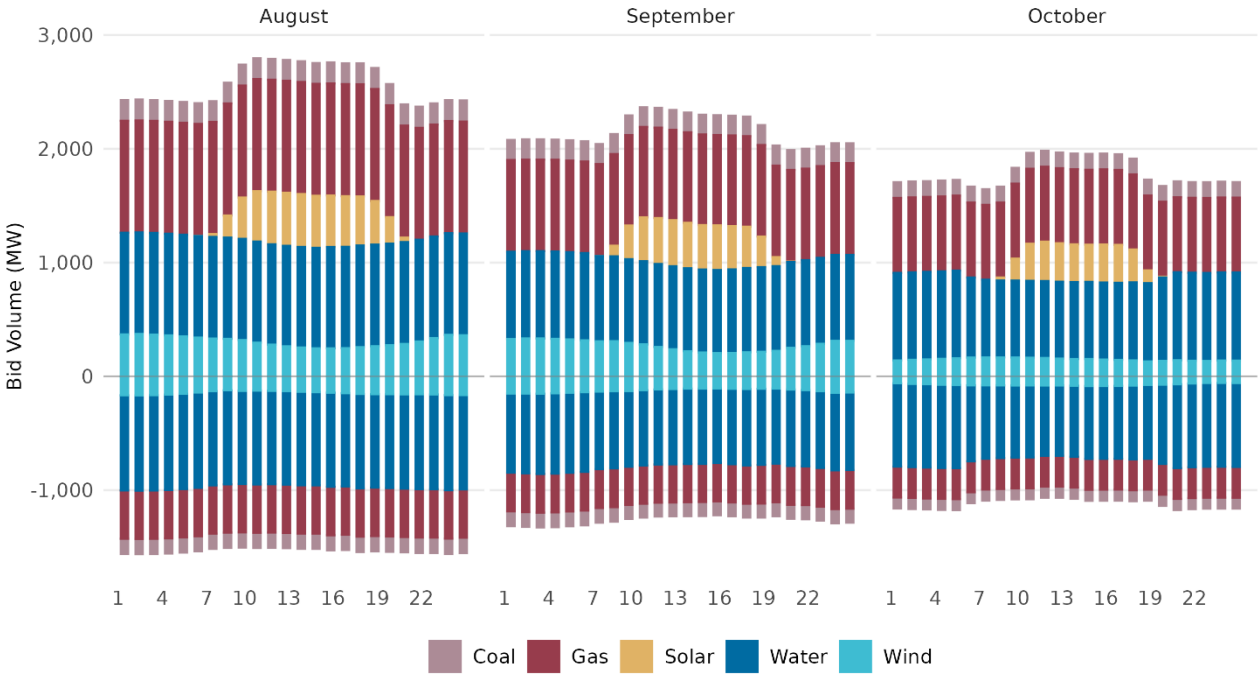


Figure 107 and Figure 108 illustrate PACW's daily average volume of RC bids. Generally, PACW's submitted RC capacity showed variations across both bid volumes and prices due to its dependency on its available renewable outputs.

Figure 107: Daily average volume of RC bids by price for PACW

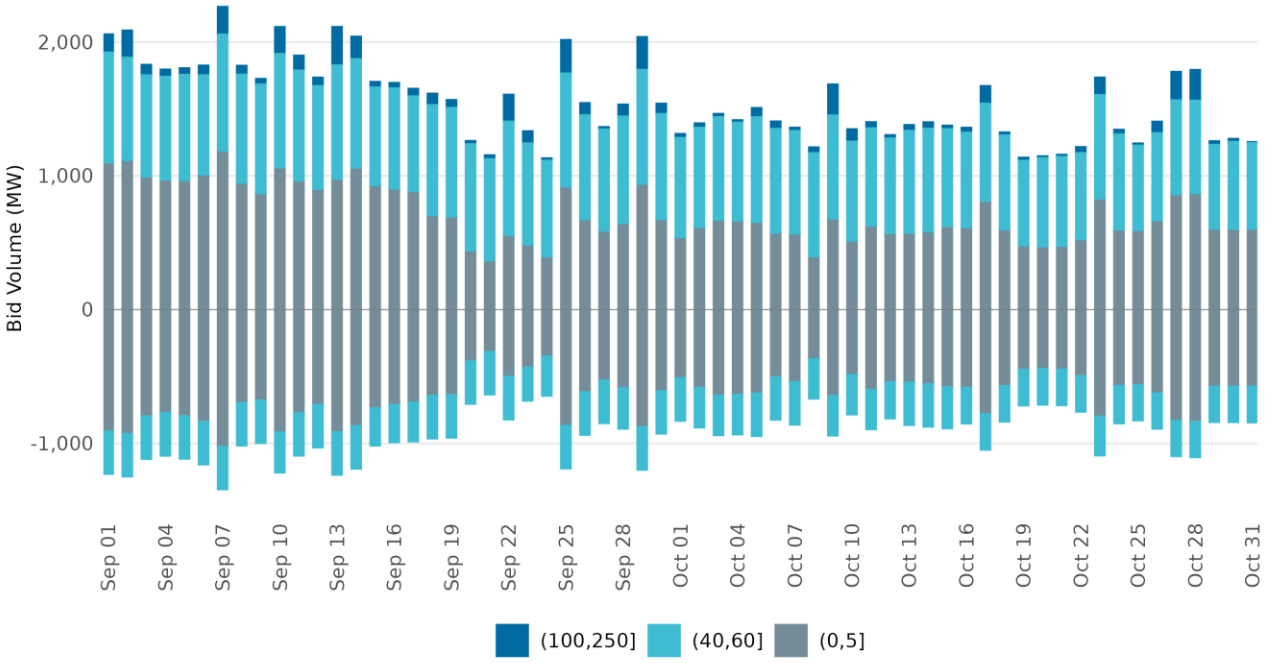
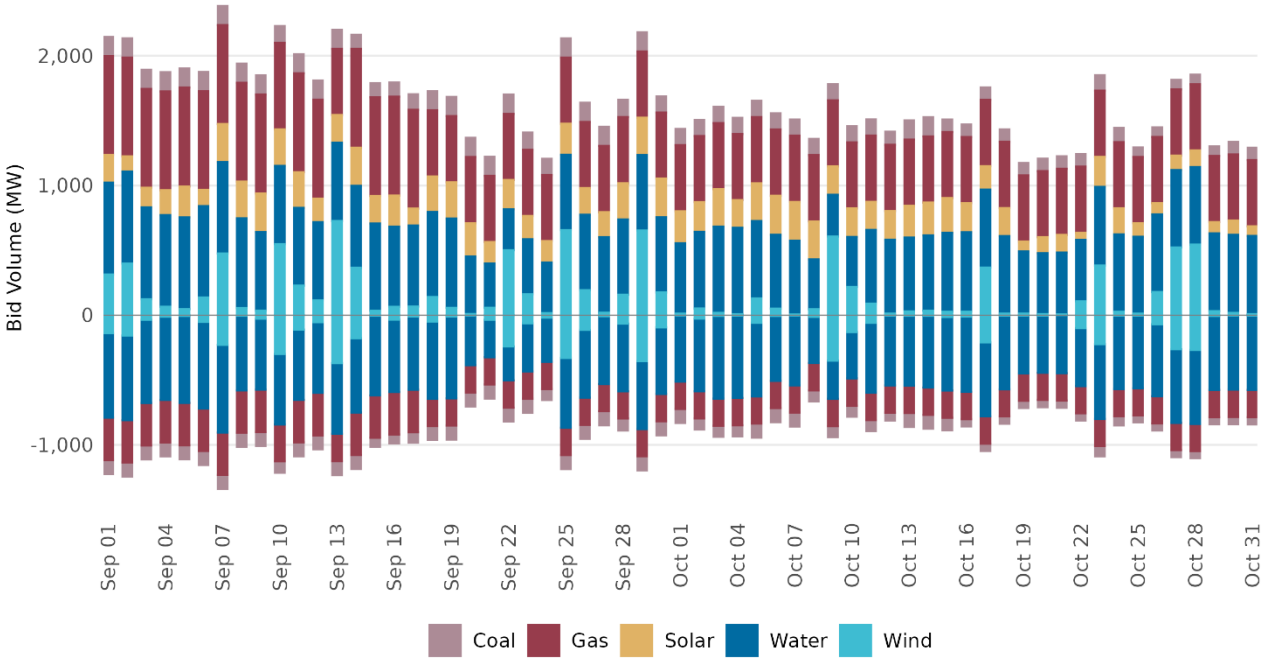


Figure 108: Daily average volume of RC bids by fuel type for PACW



PGE's October RC bid volume was highly stable throughout the day, with approximately 5,000 MW of RCU bids and 3,700–3,800 MW of RCD bids available in most hours. The majority of bids were offered in the $0–$5/MWh range, indicating strong concentration at relatively low bid prices. Gas and water accounted for the largest shares of RC bid volume, while storage, wind, and coal made smaller contributions. Both the price and fuel-type composition showed minimal hourly variation.

Figure 109: Hourly average volume of RC bids organized by price for PGE

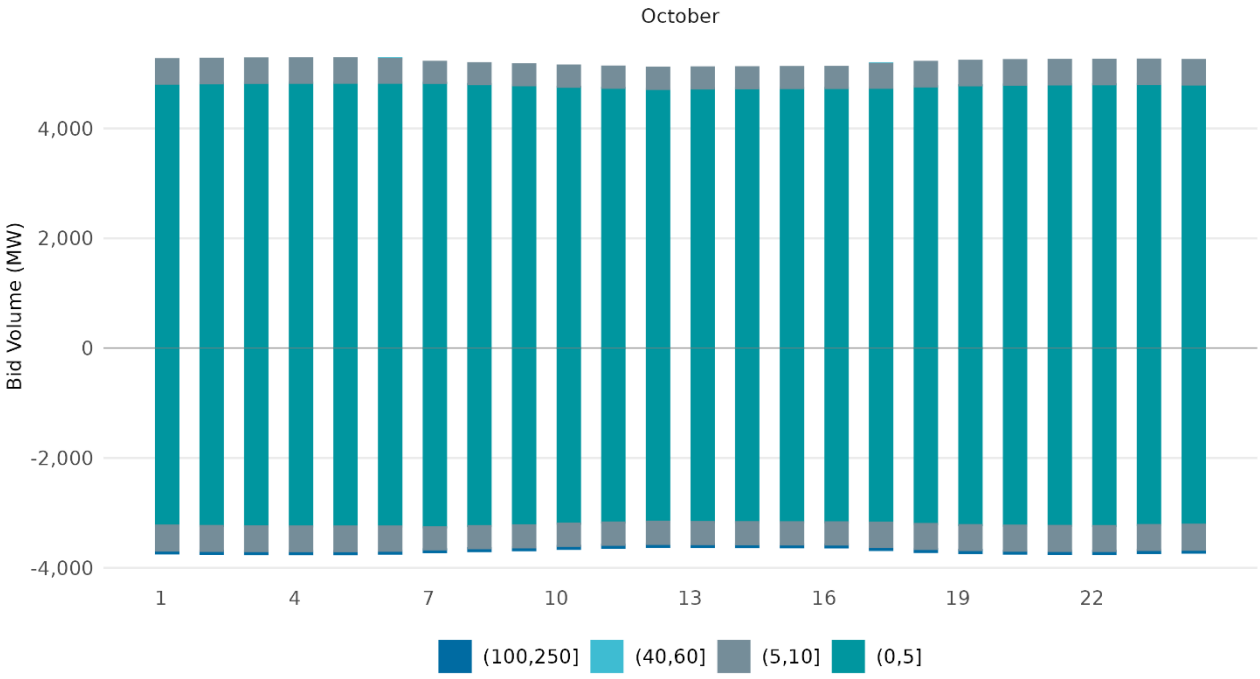
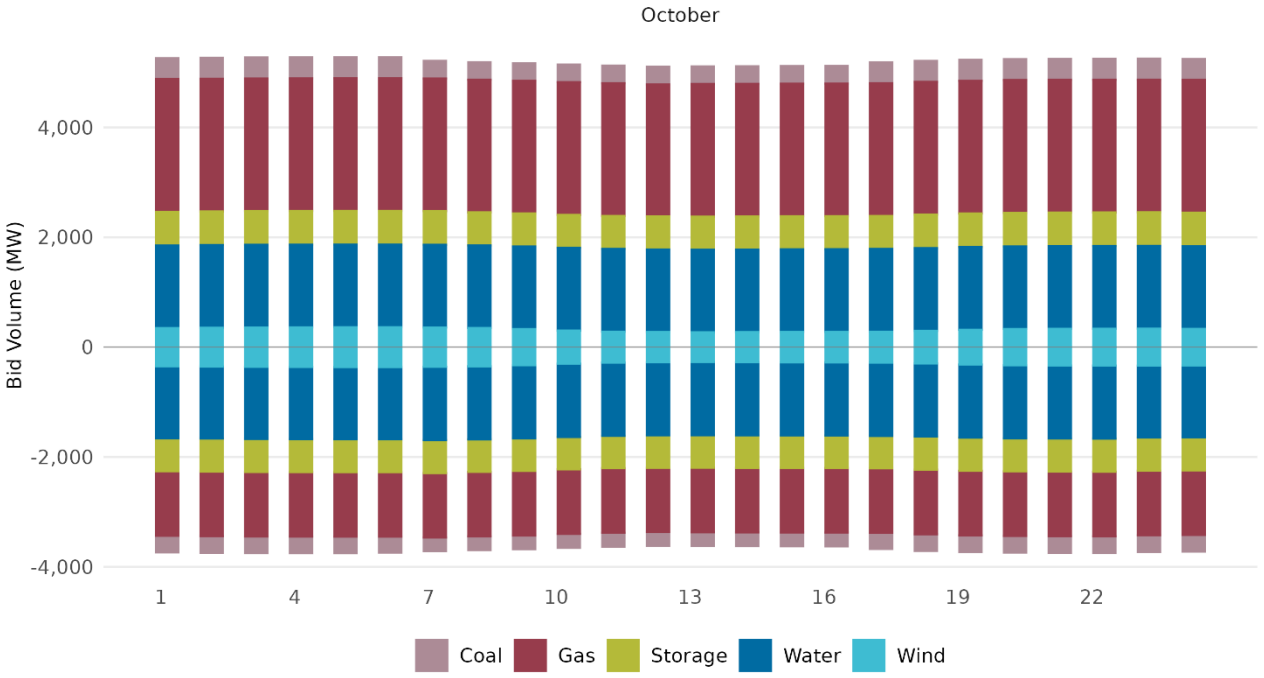


Figure 110: Hourly average volume of RC bids organized by fuel type for PGE



PGE's RC bid volume remained relatively stable throughout October, both across hours and across days. Daily variation was primarily associated with changes in wind bid volume, while a noticeable increase in higher-priced RCD bids occurred around Oct. 20–22.

Figure 111: Daily average volume of RC bids organized by price by PGE

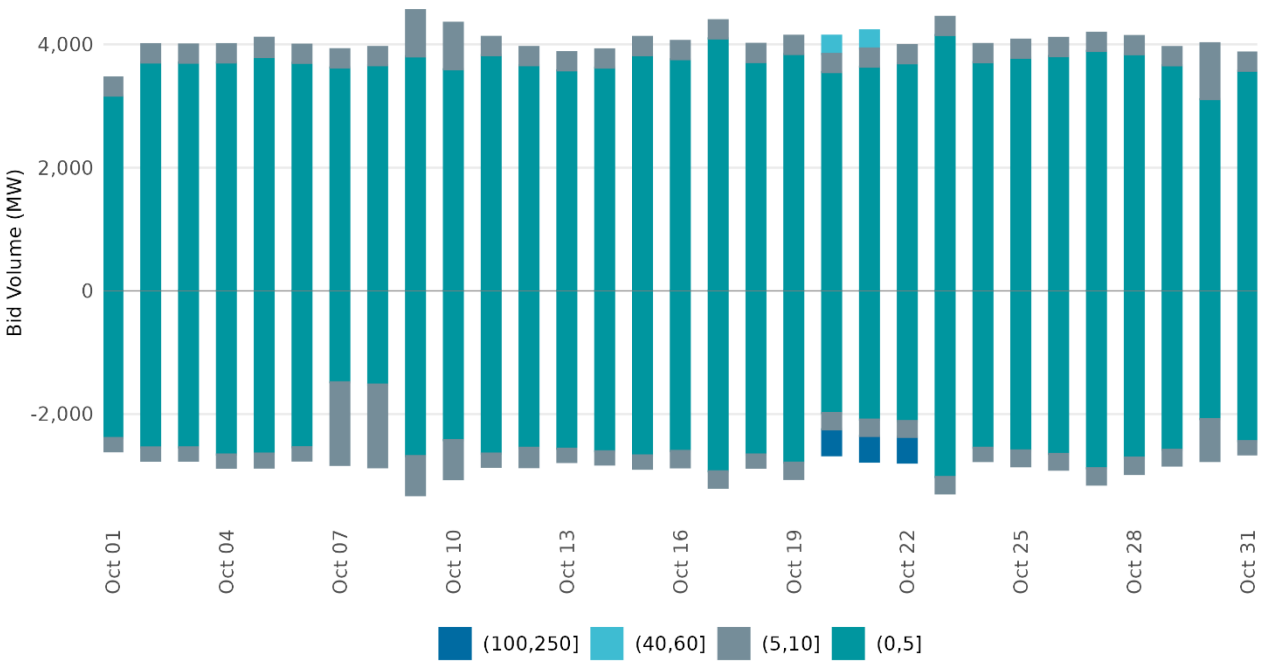
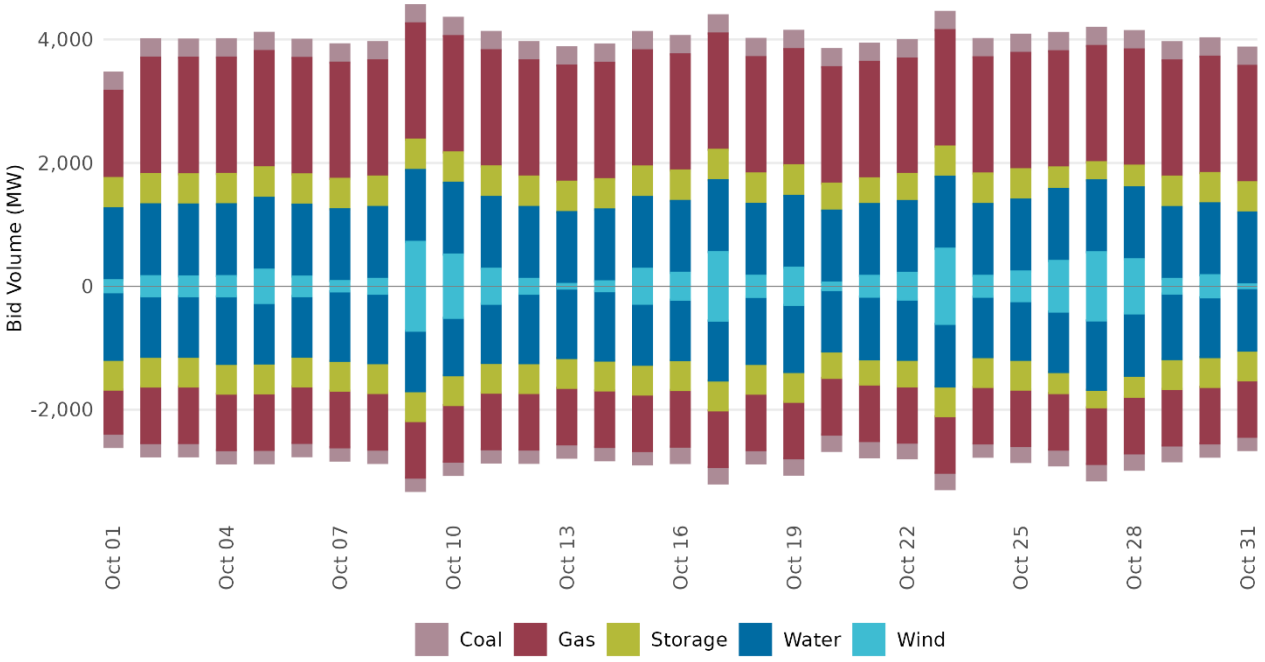


Figure 112: Daily average volume of RC bids organized by fuel type for PGE



Export reduction

In the month of October, there were instances of economic and low priority export reductions in the RUC process, shown in Figure 113. Exports can still participate in the real-time market by rebidding relative to the DAM solution, or directly into the real-time market with either high or low priority, as well as with economical bids. Figure 114 shows the instances when the real-time market reduced exports in October, with the largest reduction happening on October 2 for low priority exports.

Figure 113: RUC export reduction

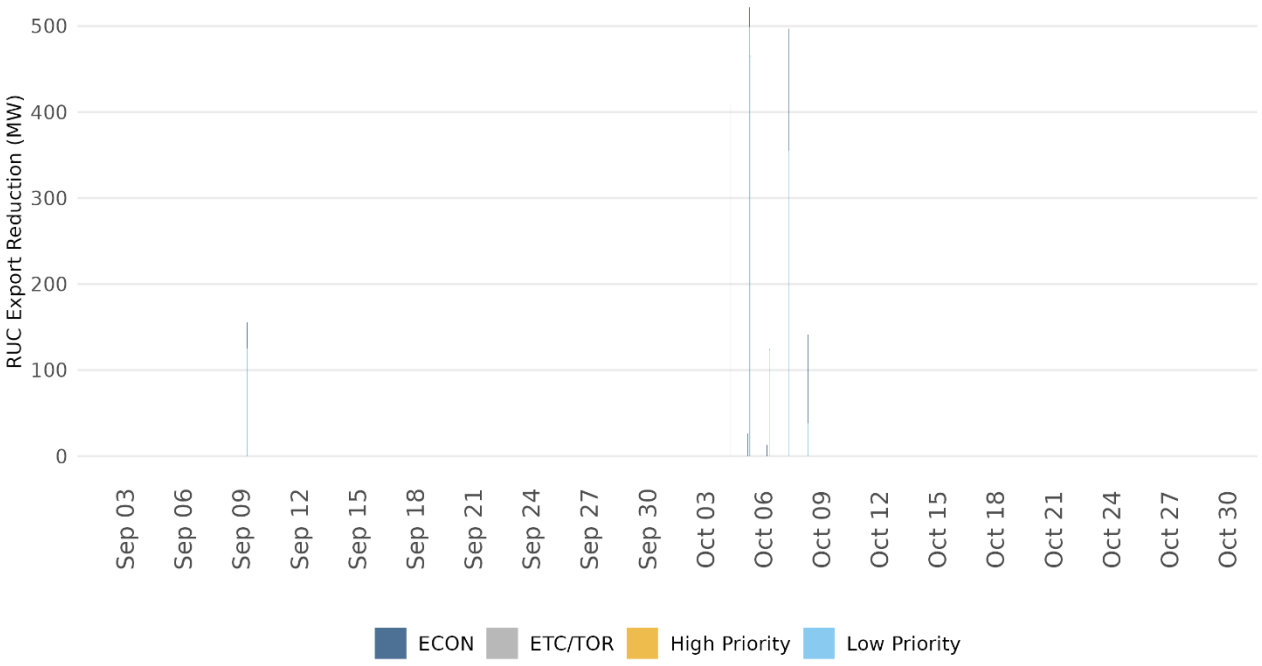
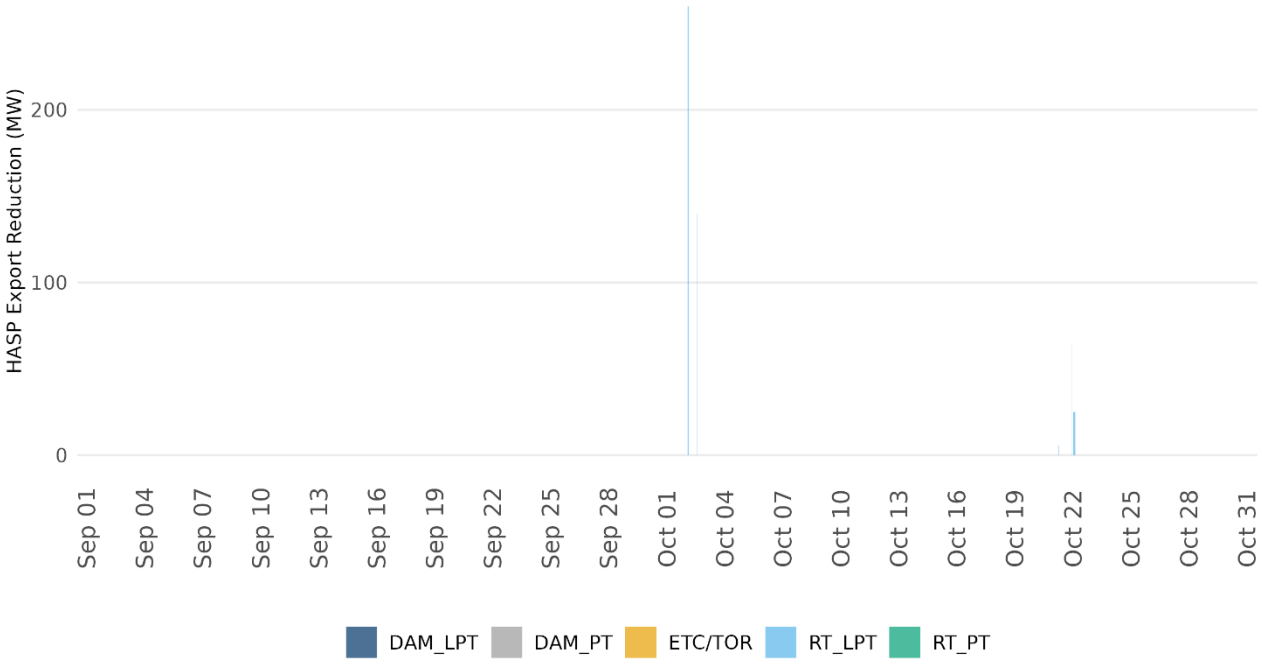


Figure 114: Exports reductions in HASP



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 price convergence between 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 115 shows the average monthly cleared virtual supply and demand bids. From August to October, average Virtual Gen volumes remained higher than Virtual Load volumes. Virtual Gen increased from approximately 4,750 MW in August to 5,250 MW in September before declining slightly to around 5,000 MW in October. In comparison, Virtual Load increased steadily from approximately 3,850 MW in August to 4,650 MW in October.

Figure 115: Average monthly cleared virtual bids

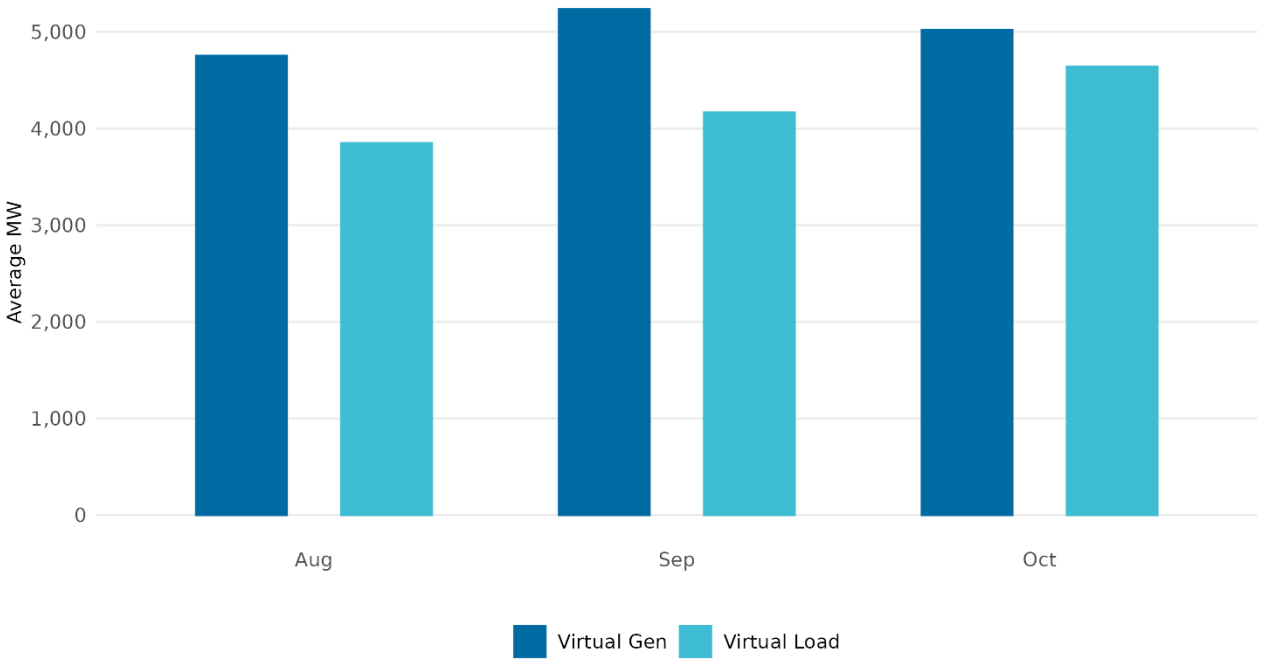


Figure 116 shows the average hourly cleared virtual generation, virtual load, and the net virtual bids for each day in September and October in the day-ahead market. The net cleared virtual bid is defined as the total cleared virtual generation minus the total cleared virtual demand. Cleared virtual bids in September were net supply except from October 1 to 5 and October 29 to 31.

Figure 116: Average hourly cleared virtual bids

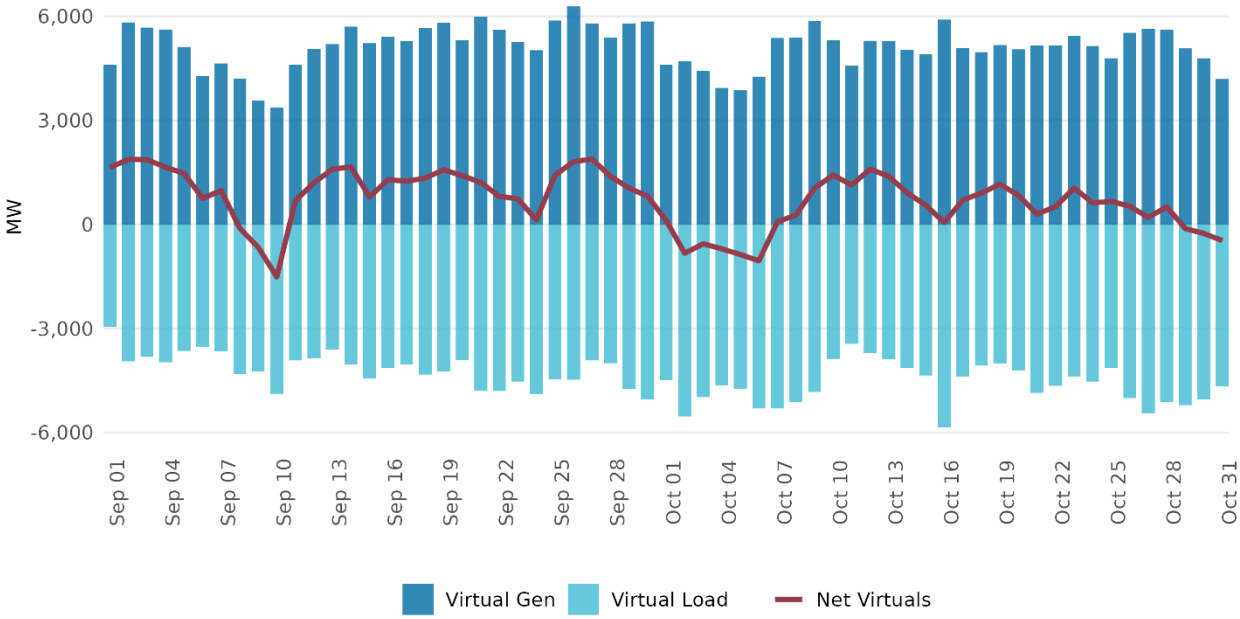


Figure 117 and Figure 118 show the hourly profile of average virtual supply and virtual demand, respectively, throughout August to October. Hourly average volumes of cleared virtual supply bids rose through the day, peaked around HE16–HE18, and then declined. September generally had the highest volumes, while October moderated but remained above August during many off-peak hours. Hourly volumes of cleared virtual demand bids followed a consistent daily pattern, rising through the morning, peaking around HE15–HE17, and declining thereafter. October generally recorded the highest volumes across most hours, followed by September and August.

Figure 117: Average hourly cleared virtual supply

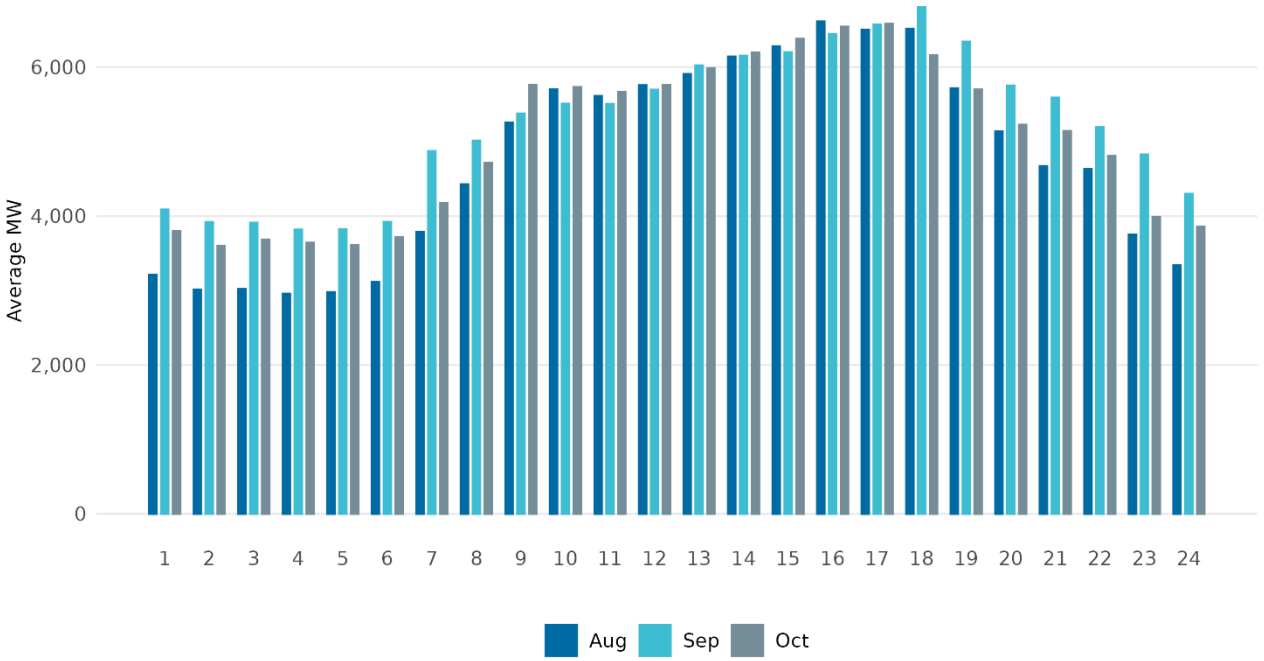


Figure 118: Average hourly cleared virtual demand

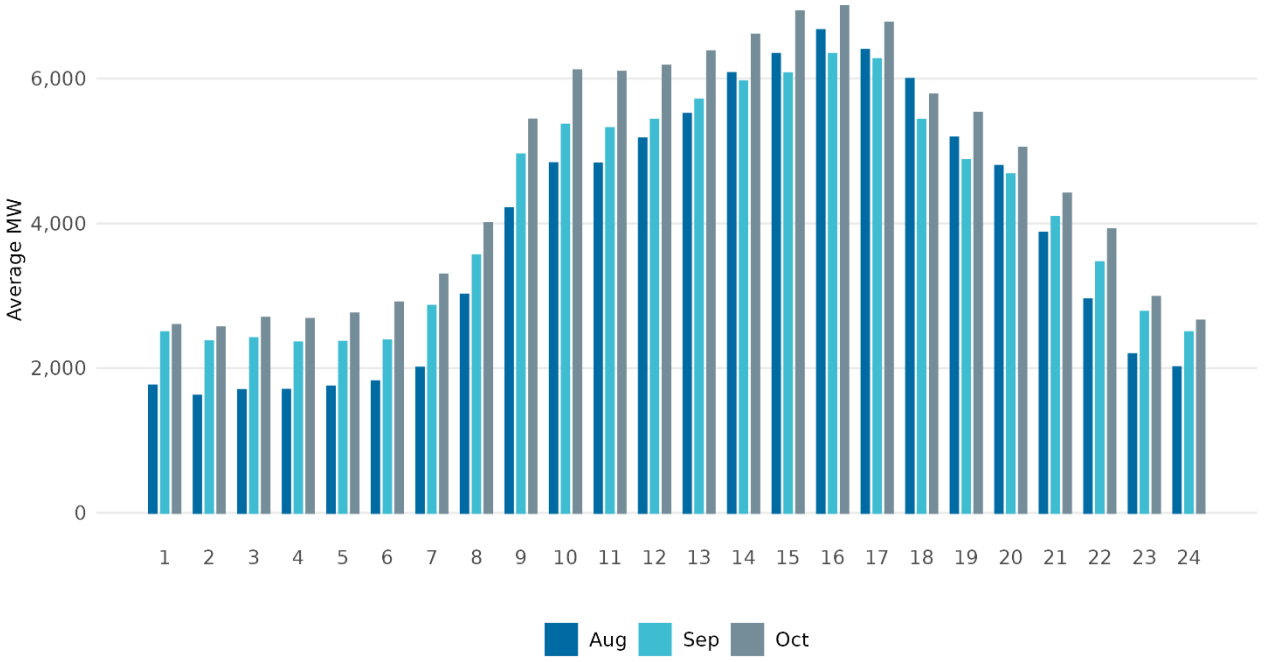
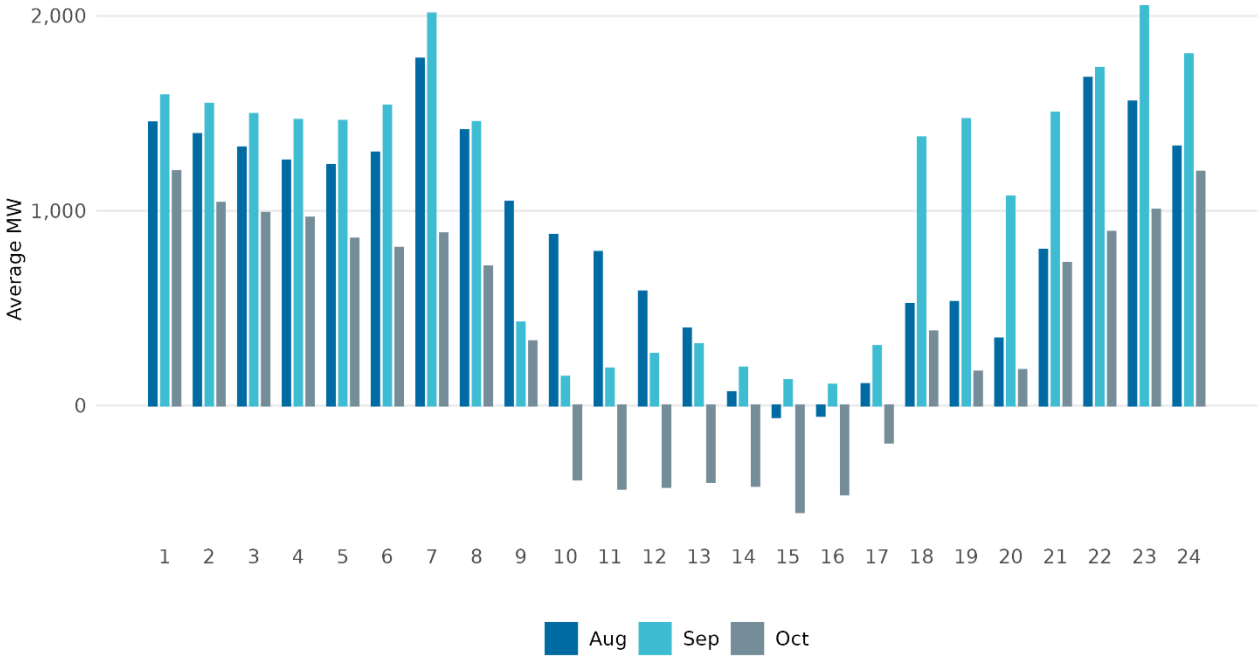


Figure 119 shows the hourly profile of average net cleared virtual bids from August through October, calculated as cleared virtual supply minus cleared virtual demand. Positive values indicate

net virtual supply, while negative values indicate net virtual demand. October volumes of net virtual bids were lower than August and September across most hours, with net virtual demand from approximately HE10 to HE17. September generally recorded the highest volumes of net virtual bids, particularly during the evening peak.

Figure 119: 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 October, the highest GHG price reached 71.58 $/MWh during Trade Hour 20 on October 2. The maximum hourly GHG allocation was 515 MW, occurring on multiple days in September.

Figure 120 shows the daily average GHG allocation by fuel type for both September and October. During the period covered, GHG allocation was distributed among Gas, Coal, Hydro, and Wind resources, with Gas resources receiving the majority of the allocation. In October, the daily average GHG allocation reached its highest level on October 6, peaking at 194 MW, followed by 170 MW on October 5. Overall, the level of GHG allocation in October was lower than that in September.

Figure 120: Daily average GHG allocation by fuel type

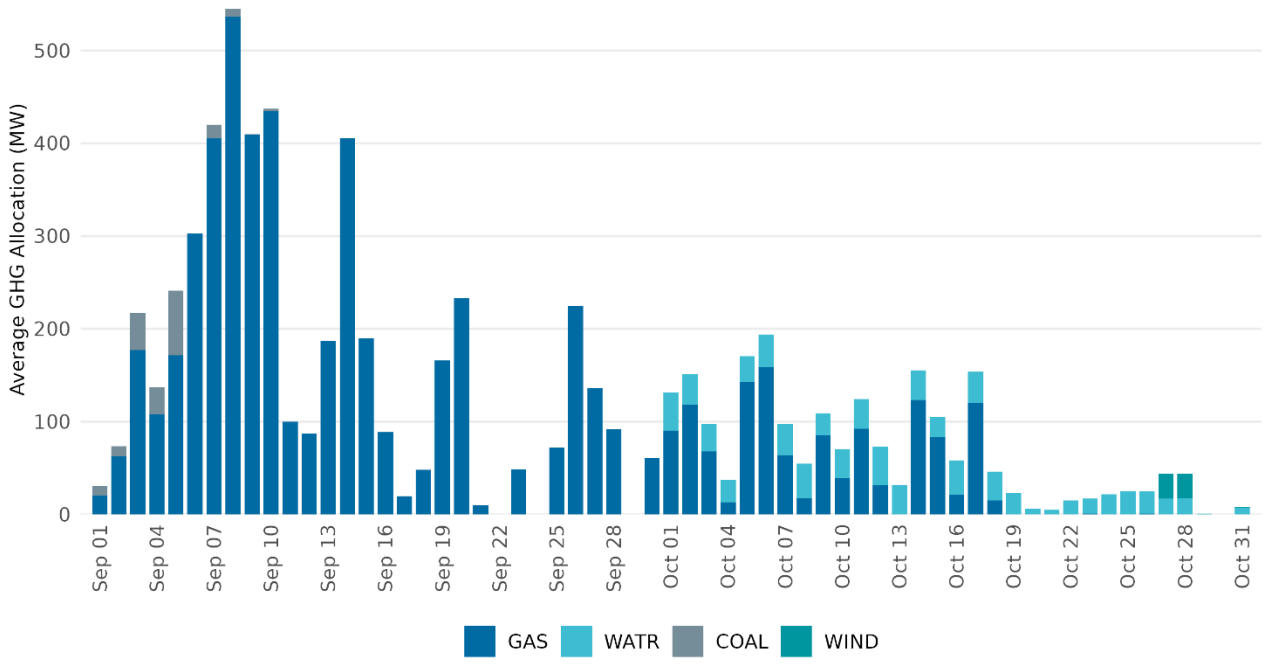


Figure 121 shows the hourly average GHG allocation by fuel type for October. GHG allocation was generally higher during the early morning and evening hours and lower during the midday hours, when solar generation within the CAISO area is typically abundant.

Figure 121: Hourly average GHG allocation by fuel type

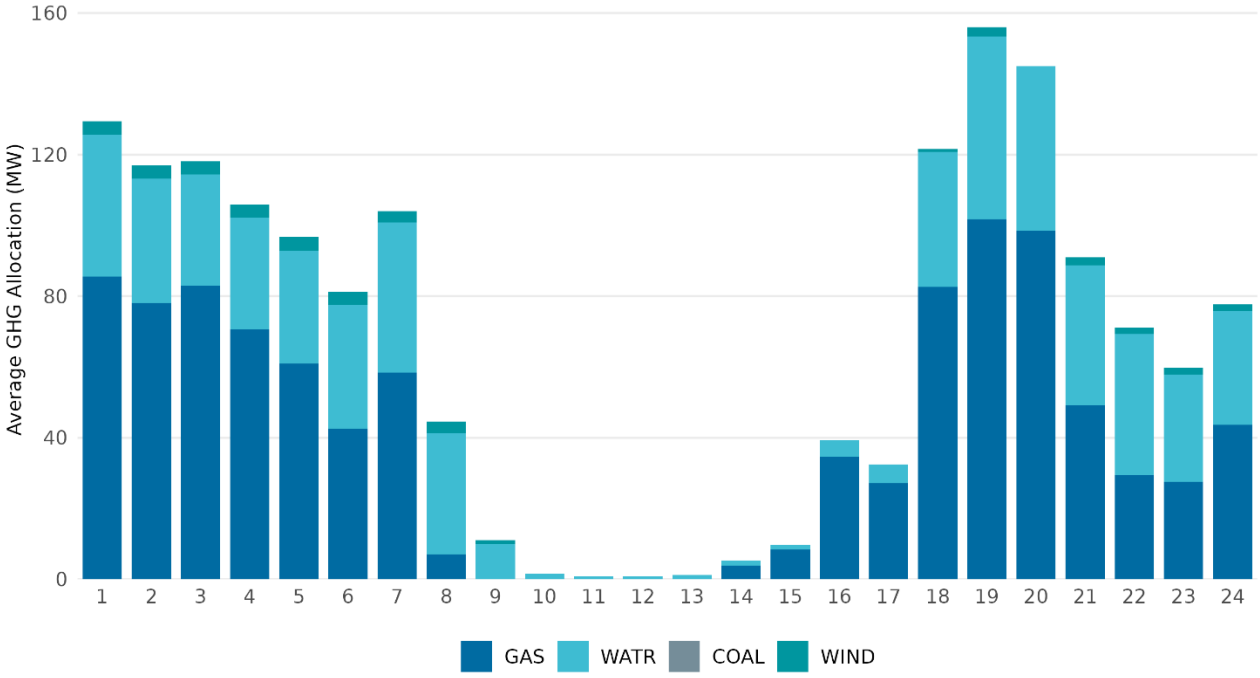


Figure 122 shows the daily average GHG prices in both September and October. In October, daily average GHG prices fluctuated throughout the month, with the highest daily average price reaching 16.20 $/MWh on October 17. Overall, the range of daily average GHG prices in October was lower than that observed in September.

Figure 122: Daily average GHG price

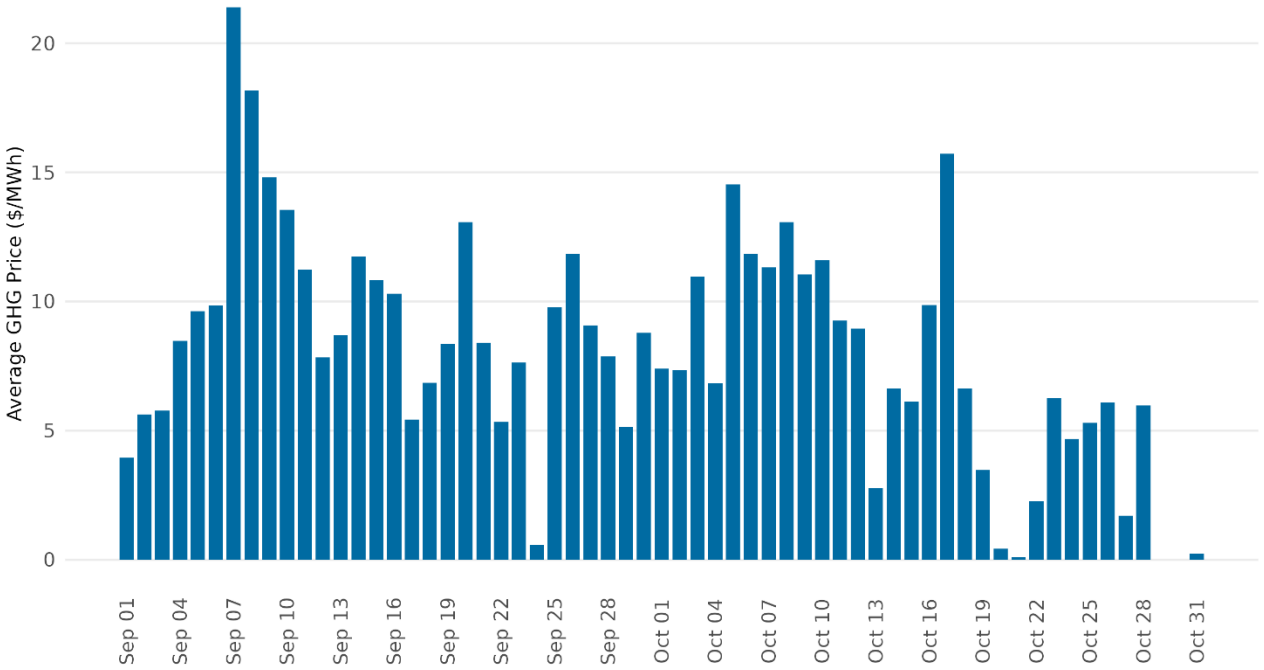


Figure 123 shows the hourly average GHG price by trade hour for August, September, and October. GHG prices were generally higher during the early morning hours (Hours 1-7), declined during the midday period (approximately Hours 10-17), and showed a modest increase again during the evening hours (Hours 19-24). 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 123: Hourly average GHG price

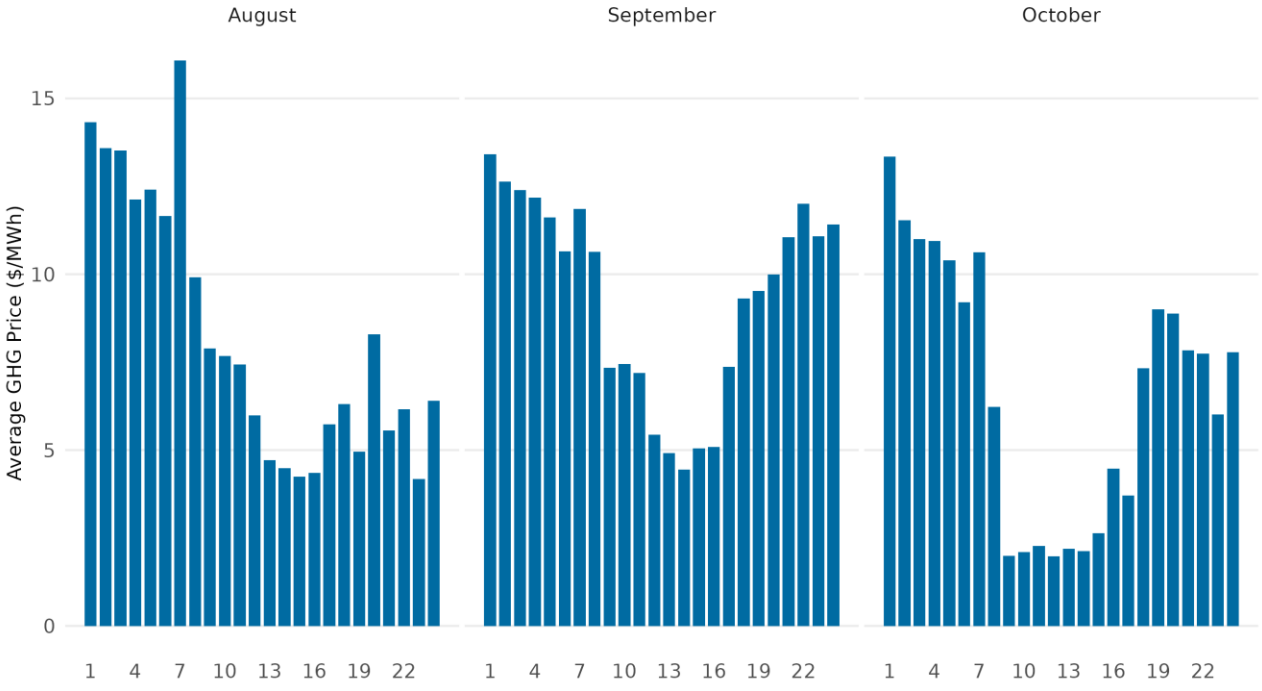
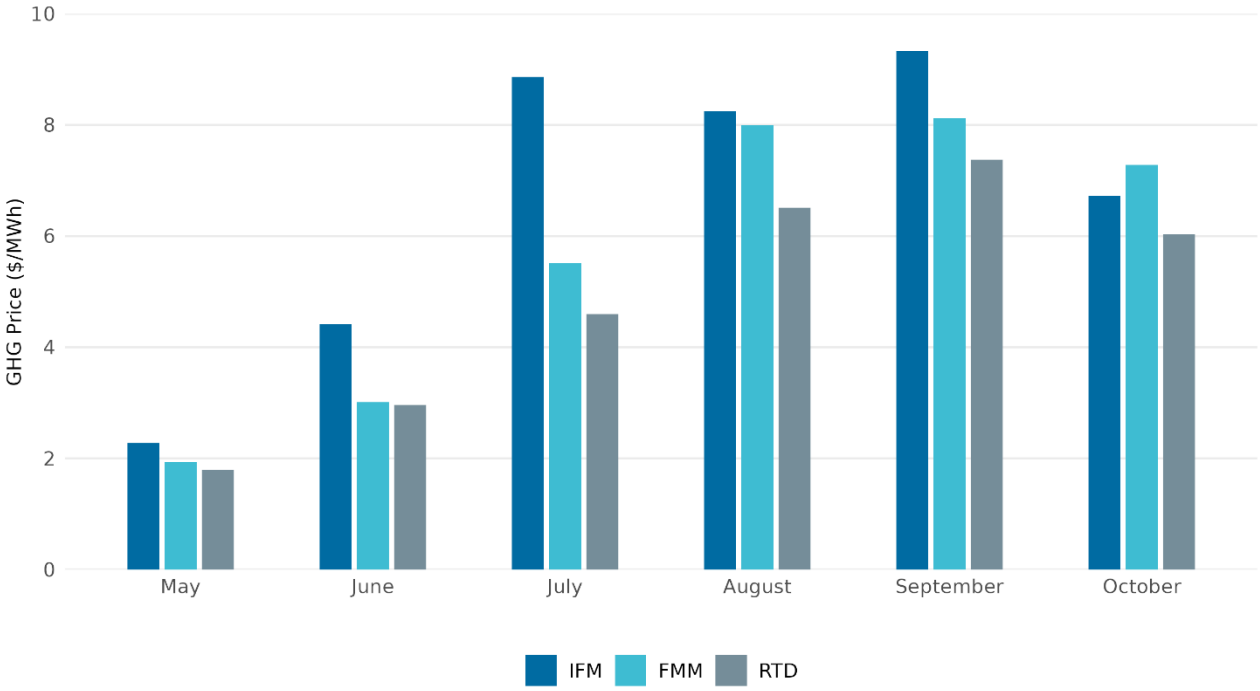


Figure 124 shows the monthly average GHG prices in the IFM, FMM, and RTD markets from May to October. GHG prices increased until its peak in September before declining in October, with exceptions in IFM reaching its peak and remaining high across August to October. IFM prices remained higher than real-time prices from August to October and lowered to real-time levels in October. Notably, the increase in GHG prices coincided with the summer months, when higher system loads can increase reliance on energy transfers and imports across BAAs in both EDAM and WEIM. Higher levels of energy transfers during these periods can increase the volume of GHG allocation, which may in turn contribute to higher GHG prices.

Figure 124: Monthly average GHG price by market



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.

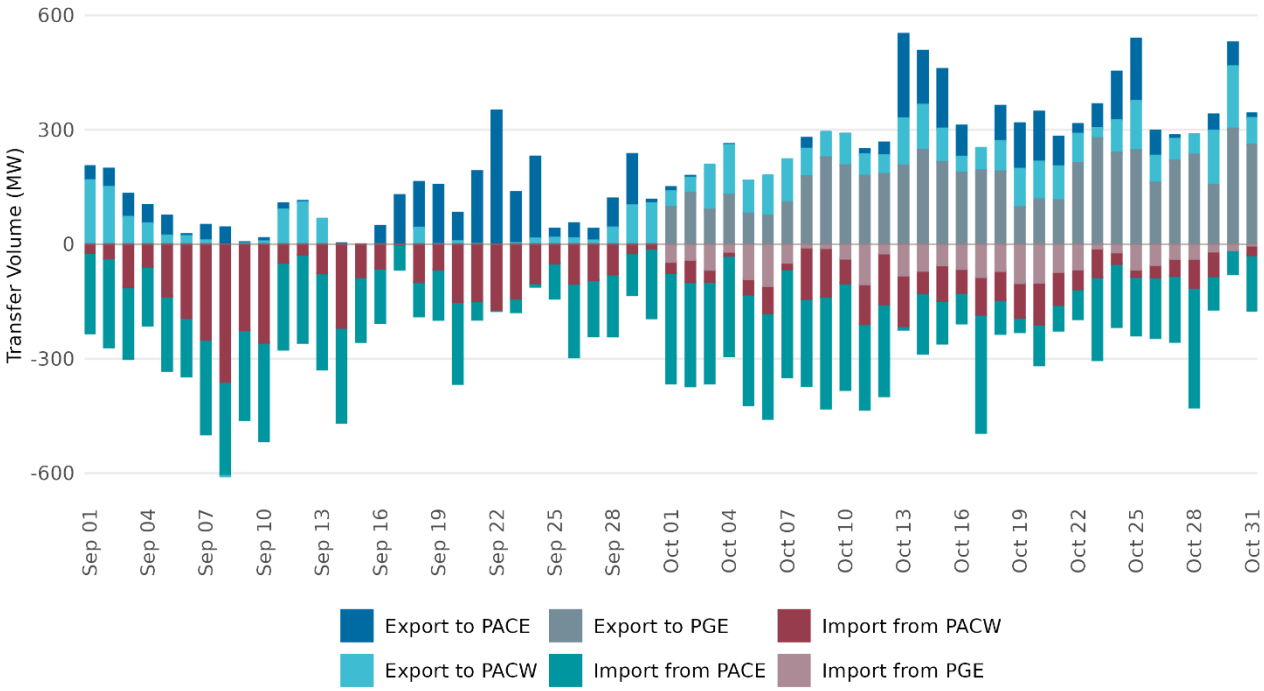
Transfer flows are determined dynamically to these economic signals and can vary from hour to hour as market conditions evolve. Beyond supporting economic efficiency, transfers also enhance access to the geographic and fuel diversity available across the extended market footprint. This broader resource pool increases operational flexibility and improves the utilization of available generation. With PGE joining EDAM on October 1, an additional transfer pairing has been introduced, for CAISO and PAC BAAs, representing either exports to PGE or imports from PGE.

Energy transfers

Figure 125 illustrates CAISO daily average energy transfers in IFM in September and October 2026 on both export (+) and import (-) directions, and the breakdown for transfer paring entities. CAISO was a net importer in both months, and the main transfer pairing BAA is PACE, however, on a few days in September, CAISO had more imported energy from PACW. Following PGE's entry into EDAM on October 1, an additional transfer pairing was introduced between CAISO and PGE. The October

results show that PGE has become a meaningful component of CAISO's daily energy transfers, particularly on the export side.

Figure 125: Daily average energy transfers for CAISO



The hourly profile in Figure 126 exhibits variations in daily transfer volumes through August to October. CAISO's average hourly transfers increased notably in October, particularly during the midday hours. The addition of PGE as a transfer pairing contributed substantially to the higher export volume, with total exports exceeding 500 MW during several midday hours.

Figure 126: Hourly average energy transfers for CAISO

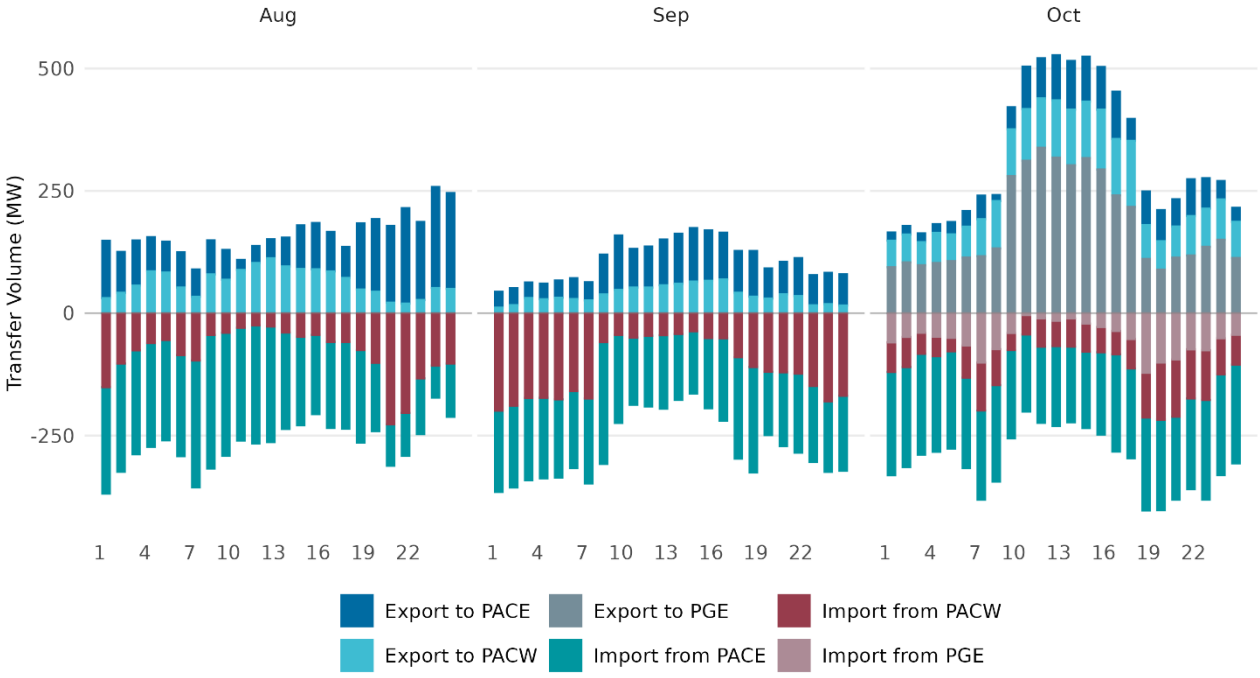


Figure 127 show PACE's daily average energy transfers throughout September to October 2026 in both export (+) and import (-) directions. Generally, PACE remained a net exporter in September and October. In October, the daily exports reached highest of about 580 MW on October 17 . Since PACE is not directly connected to PGE, there is no direct transfer between.

The Figure 128 hourly profile also shows PACE's increasing energy exports as market evolves in the past three months. Hourly transfers were primarily driven by exports across all three months. August recorded the highest export volumes, particularly during the morning hours, while September and October showed more moderate and stable transfer patterns.

Figure 127: Daily average energy transfers for PACE

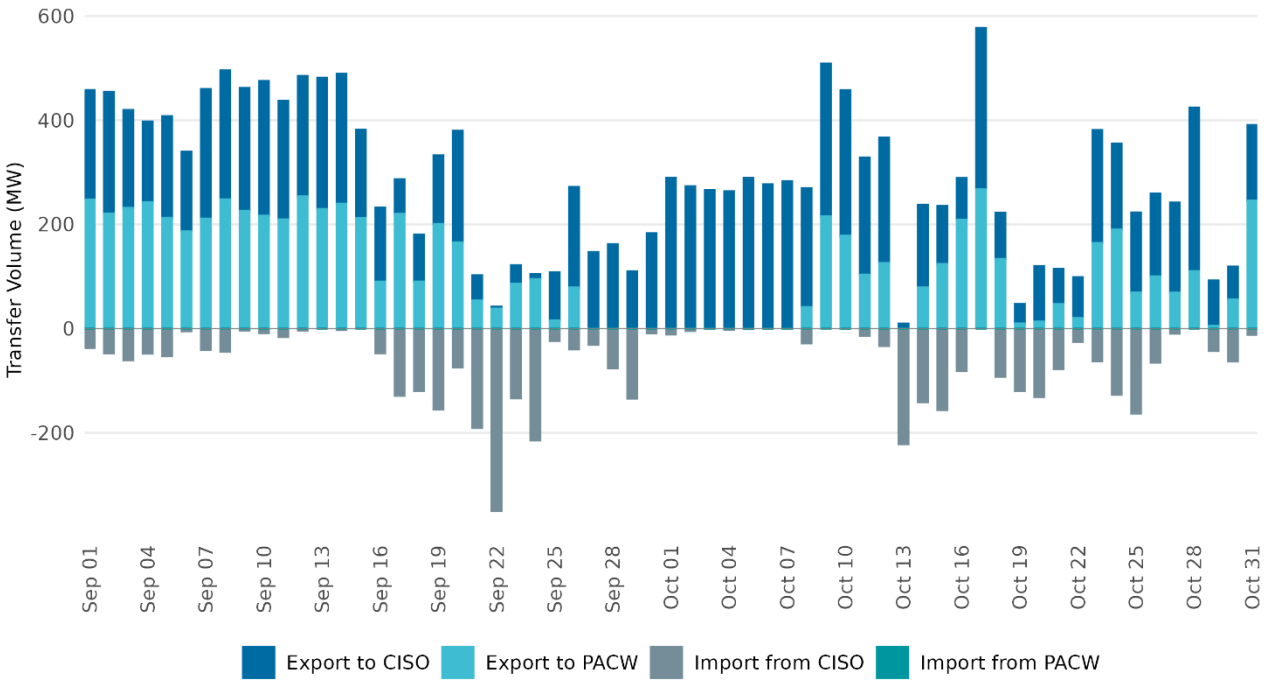


Figure 128: Hourly average energy transfers for PACE

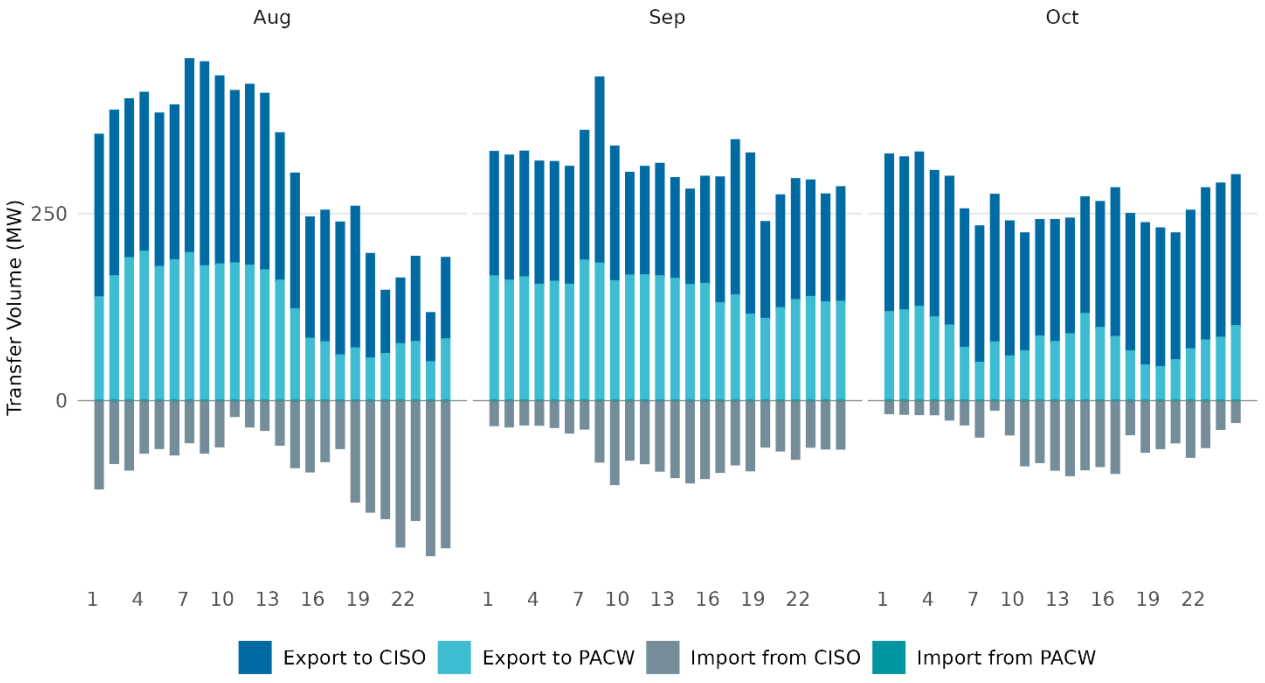


Figure 129 and Figure 130 show PACW's daily and hourly average energy transfers throughout September to October 2026 on both export (+) and import (-) directions. PACW continued to experience significant two-way energy transfers in September and October, with imports generally

dominating on many days. The addition of PGE in October introduced another transfer pairing, although PACW's transfer activity remained primarily driven by CAISO and PACE.

Figure 129: Daily average energy transfers for PACW

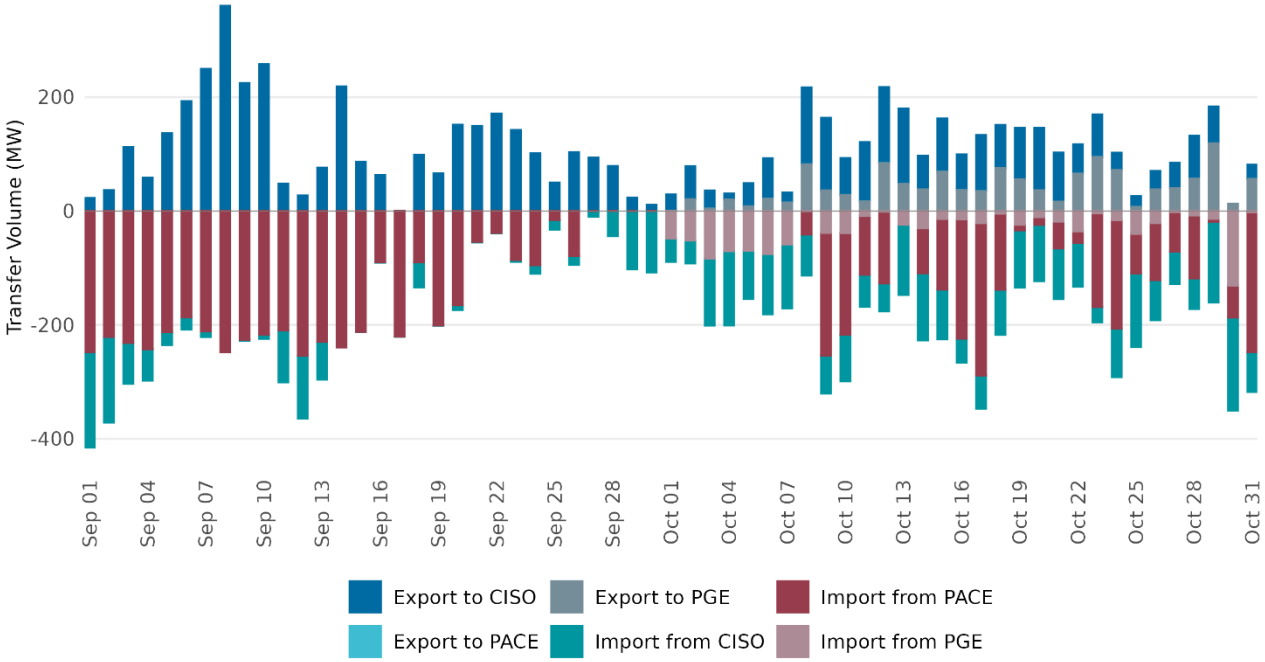


Figure 130: Hourly average energy transfers for PACW

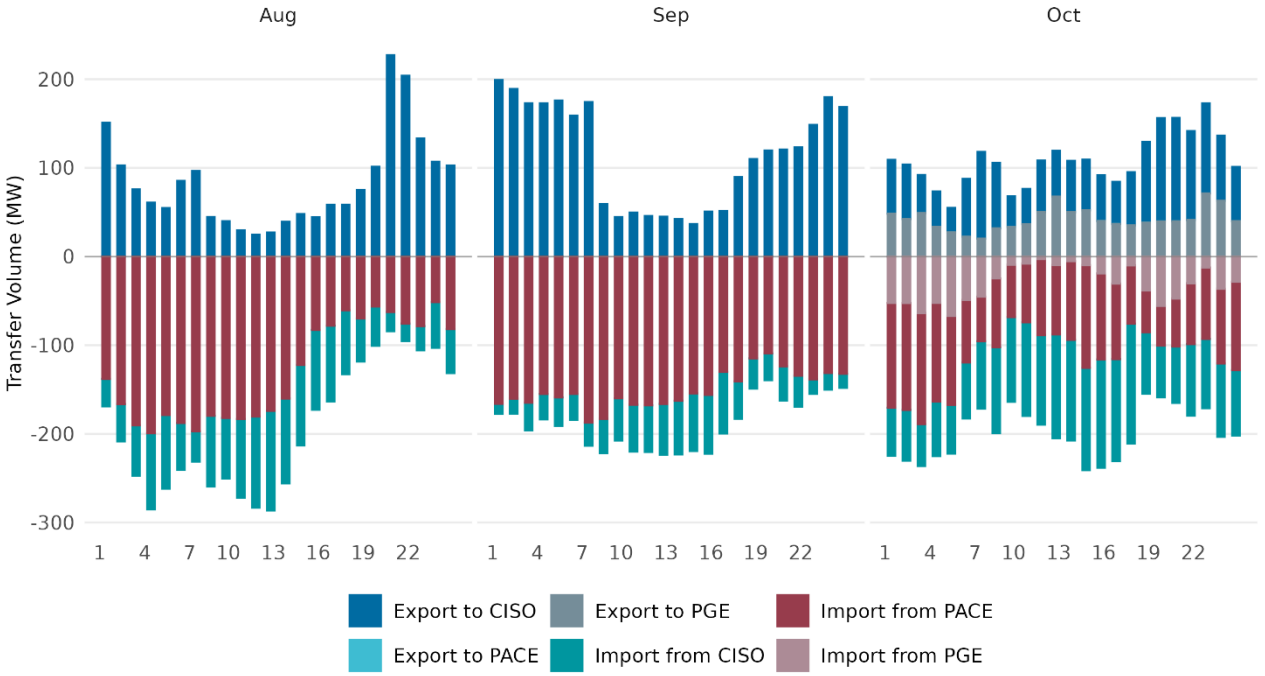


Figure 131: Daily average energy transfers for PGE

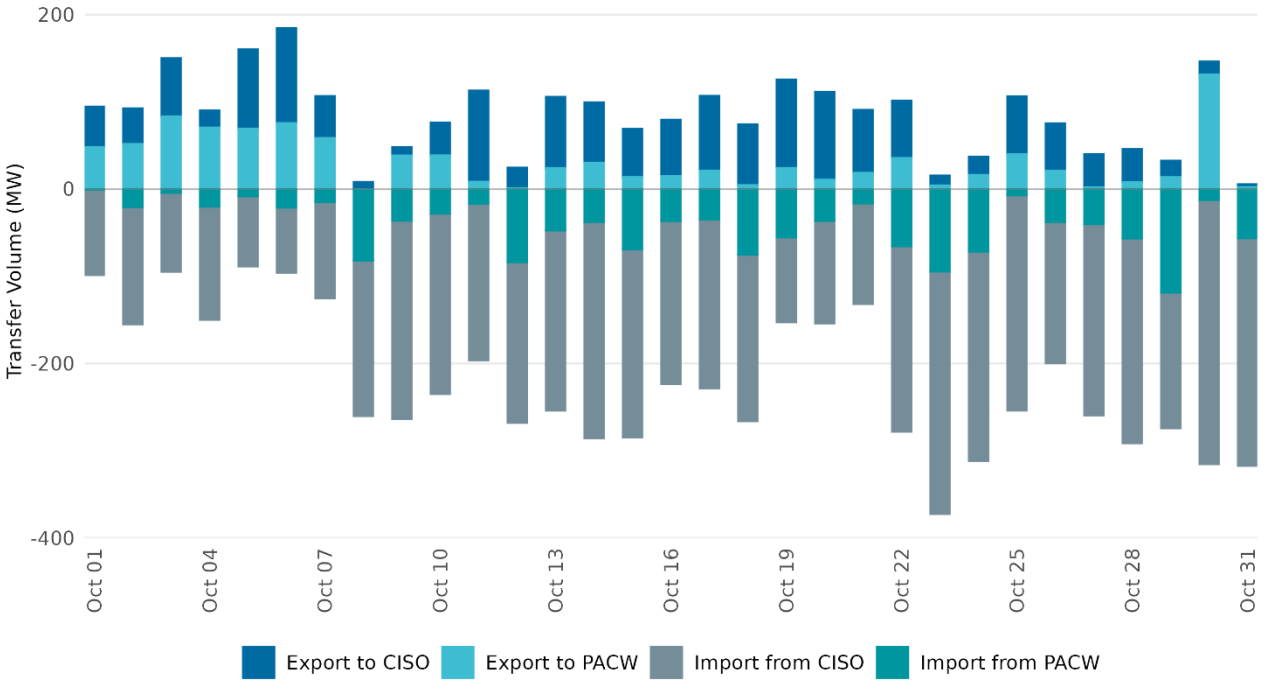


Figure 132: Hourly average energy transfers for PGE

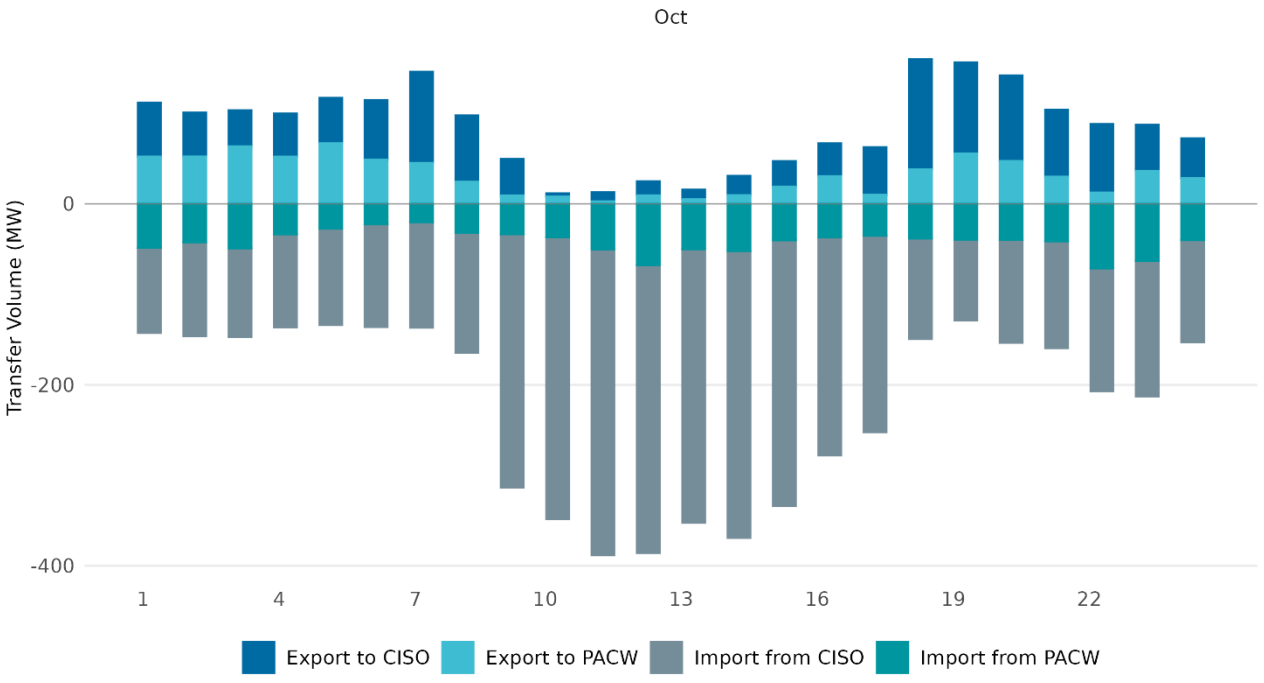
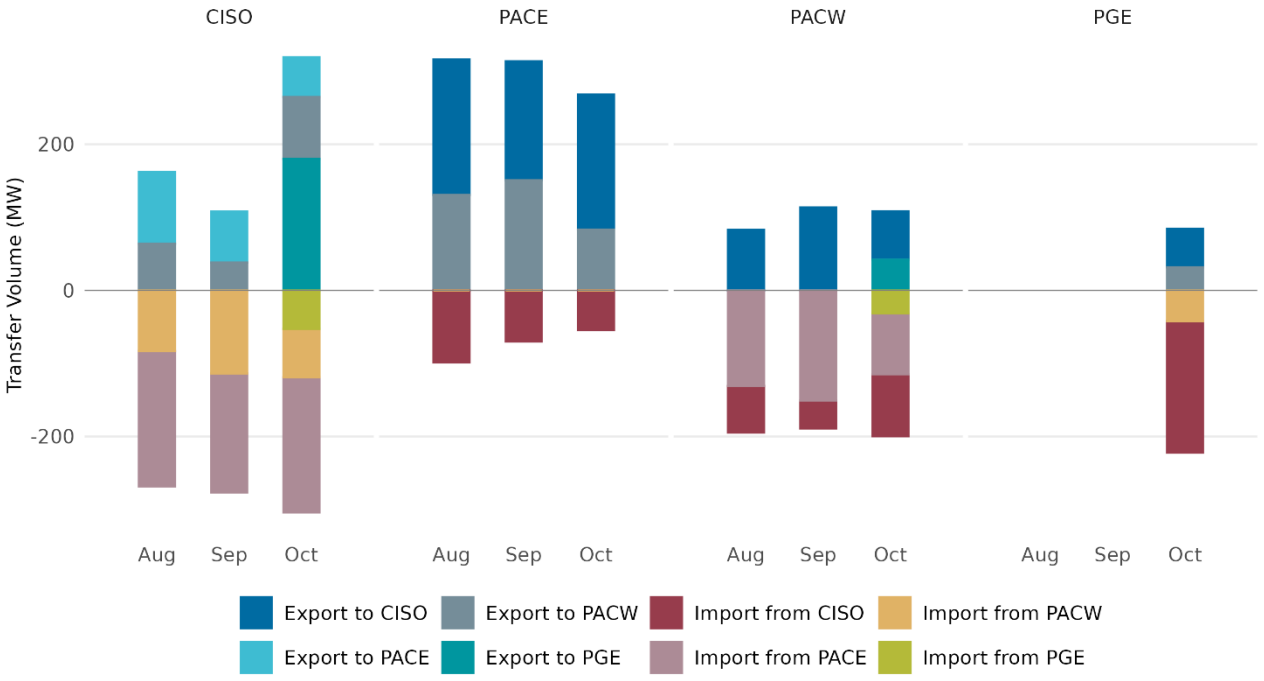


Figure 133 shows the summary of four BAAs' total energy transfer volumes throughout August to October in both export (+) and import (-) directions. EDAM energy transfers became more

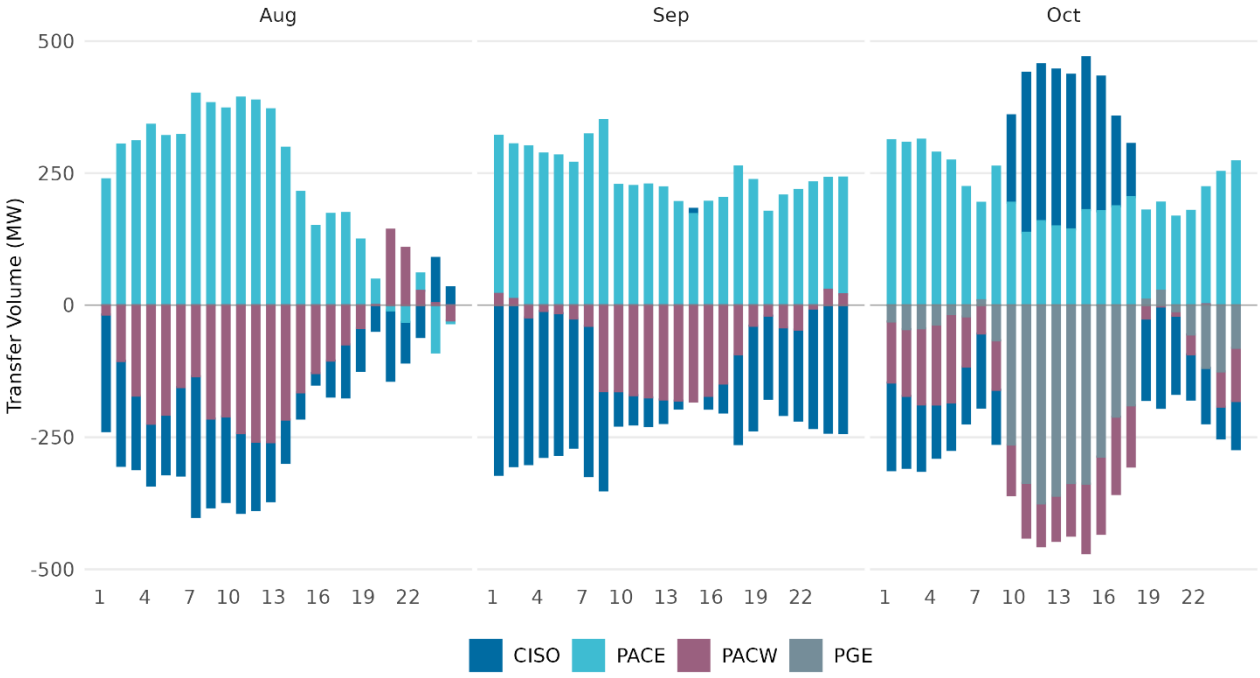
interconnected in October, with PGE adding new transfer paths to the existing network. PACE remained primarily an exporter throughout the period, while PACW remained a net importer. CAISO continued to facilitate substantial two-way transfers, with both imports and exports increasing in October. PGE's first month in the transfer network was characterized by larger imports than exports, making PGE a net importer on average in October.

Figure 133: Hourly average energy transfers volumes in EDAM



Net EDAM energy transfers in Figure 134 exhibited a clear hourly pattern across the three months, with PACE generally contributing to export transfers and CAISO and PACW contributing more heavily to import transfers. October showed the largest change in the transfer profile, as the addition of PGE increased transfer activity, particularly during the midday hours. Both export and import transfer volumes peaked around midday in October, indicating greater two-way transfer activity and a more interconnected EDAM footprint following PGE's entry.

Figure 134: Hourly average net energy transfers volumes in EDAM



Imbalance reserves transfers

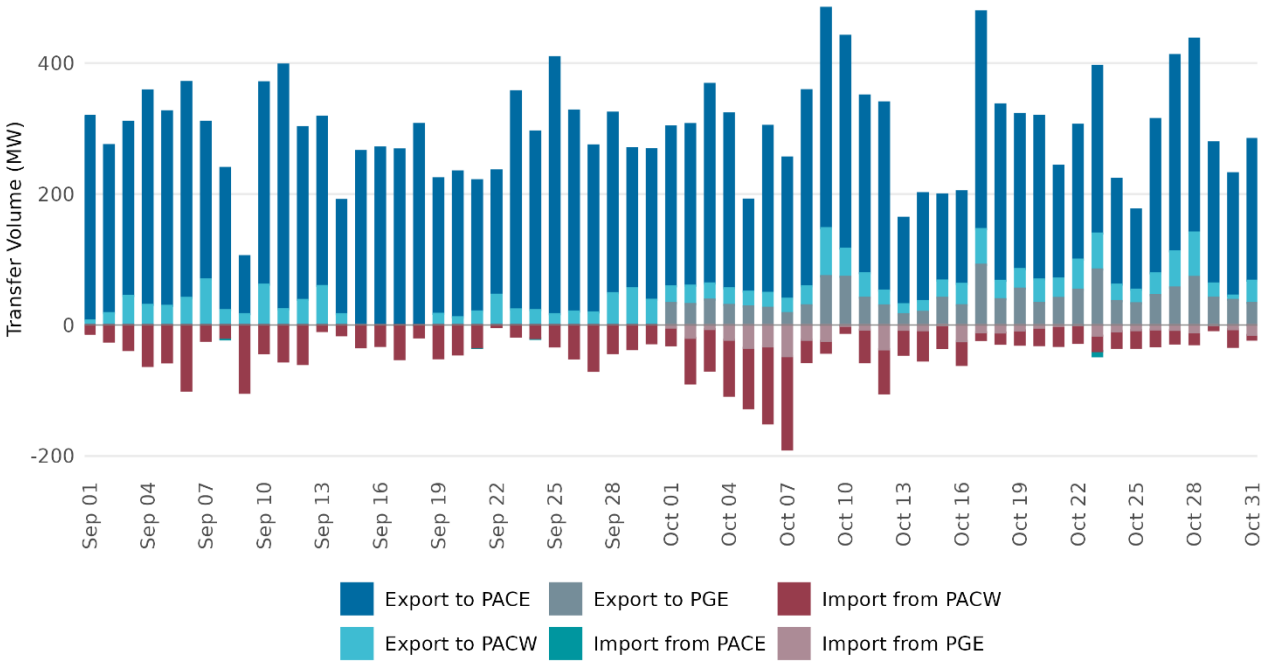
Imbalance reserves are a new day-ahead flexible reserve product introduced with EDAM to procure upward and downward reserve capacity for managing differences between day-ahead schedules and real-time conditions, including net load forecast uncertainty and real-time ramping needs. This section summarizes the patterns of imbalance reserves transfers among BAAs throughout September to October 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 export and import directions. With PGE joining EDAM on October 1, an additional transfer pairing has been introduced.

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 135 and Figure 136 show CAISO's daily and hourly average IRU transfers throughout September to October on both export (+) and import (-) directions. CAISO's IRU transfers were predominantly exports to PACE throughout September and October, with daily export volumes generally ranging from approximately 200 to 400 MW and occasionally approaching 500 MW. October showed greater variability and a more diversified transfer mix, including the addition of PGE-related transfers. Imports remained considerably smaller than exports overall, although imports from PACW increased notably during several days in early October, particularly around October 6–8.

Figure 135: Daily average IRU transfers for CAISO



CAISO's hourly IRU transfers were dominated by exports to PACE across August through October, with export volumes generally increasing during daytime hours. Imports were smaller and more variable, primarily from PACW, with notable increases during the morning and evening periods. In October, PGE introduced additional import and export transfer paths, resulting in a more diversified transfer mix, although PACE continued to account for the majority of CAISO's outward IRU transfers.

Figure 136: Hourly average IRU transfers for CAISO

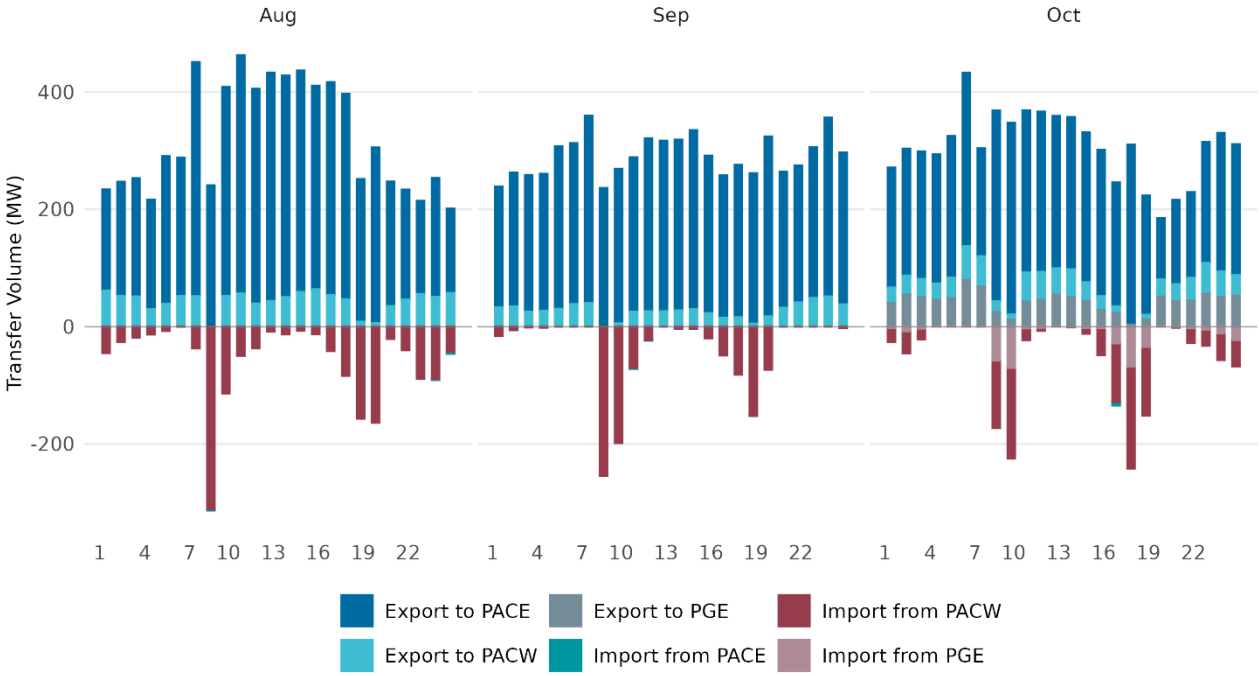


Figure 137 - Figure 138 show PACE's daily and hourly average IRU transfers throughout September to October 2026 on both export (+) and import (-) directions, respectively. Generally, PACE remained a net importer in both the months, and the imports are almost all from CAISO, with a peak import around 400 MW on September 25. There were only a few days that PACE also exported IRU to PACW or CAISO.

The hourly charts showed that PACE's IRU shared the same pattern in the last three months, with peak imports over 300 MW and only limited exports throughout the whole day.

Figure 137: Daily average IRU transfers for PACE

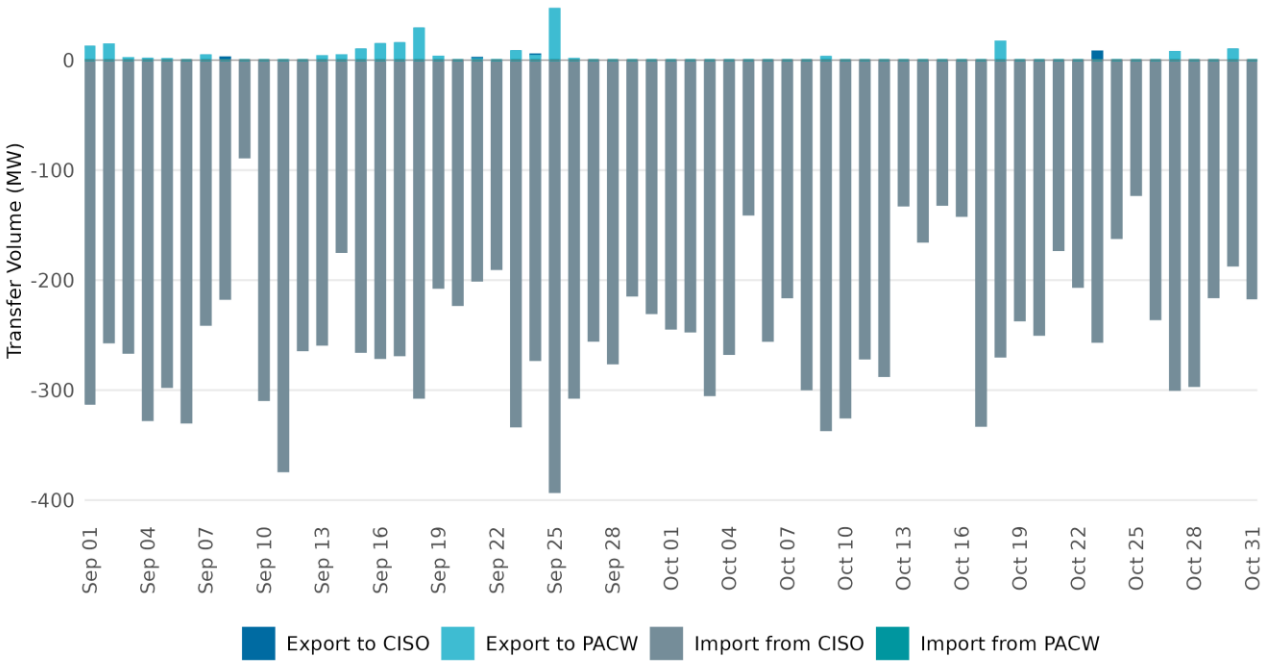


Figure 138: Hourly average IRU transfers for PACE

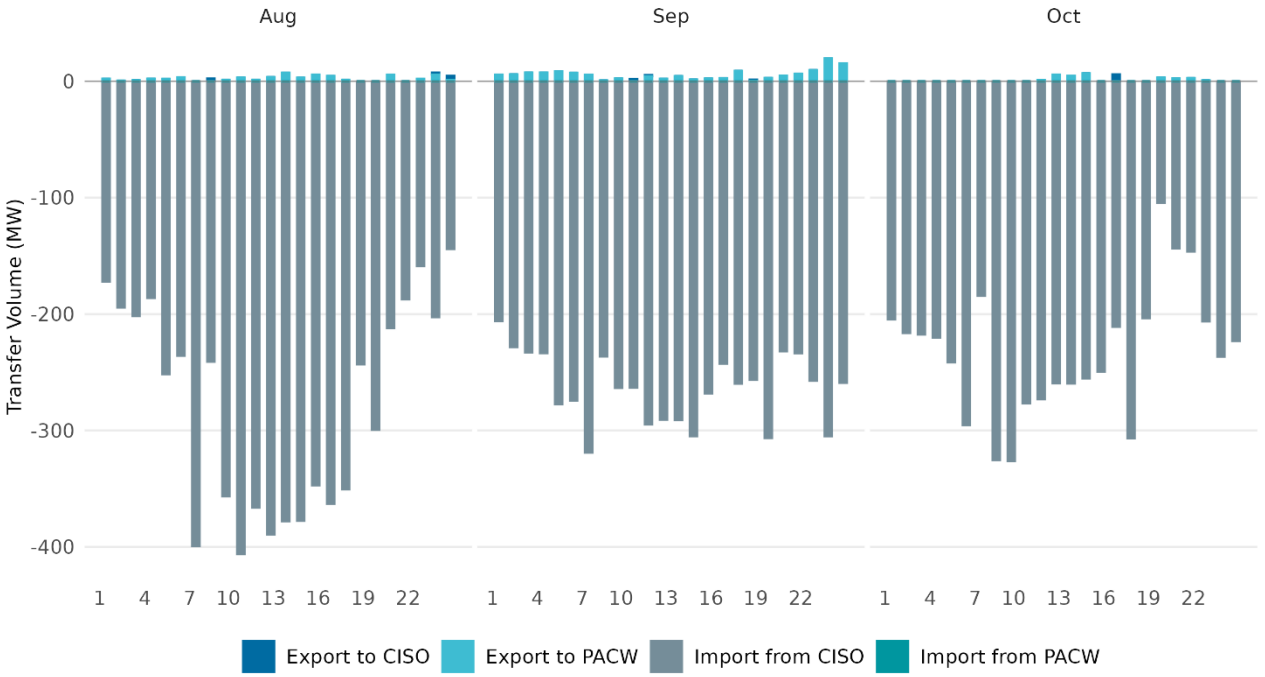


Figure 139 and Figure 140 show PACW's daily and hourly average IRU transfers throughout September to October 2026 on both export (+) and import (-) directions, respectively. Daily average IRU transfers showed an overall increase in PACW's exports to CAISO and PGE. Export volumes were relatively higher in October, with several pronounced peaks about 200 MW, and generally increased after October 1. Meanwhile, imports from CAISO remained persistent throughout the period but did not exhibit a clear trend. Transfers between PACW and PACE were comparatively limited.

PACW's IRU transfers were primarily driven by transfers with CAISO and exhibited strong hourly variation. Exports to CAISO increased sharply during selected morning hours across all three months, while October also showed substantial export activity during the evening hours. Imports from CAISO were generally smaller and more stable throughout the day. With the addition of PGE-related transfers in October, PACW's IRU transfer mix became more diversified, although CAISO remained the dominant transfer counterpart.

Figure 139: Daily average IRU transfers for PACW

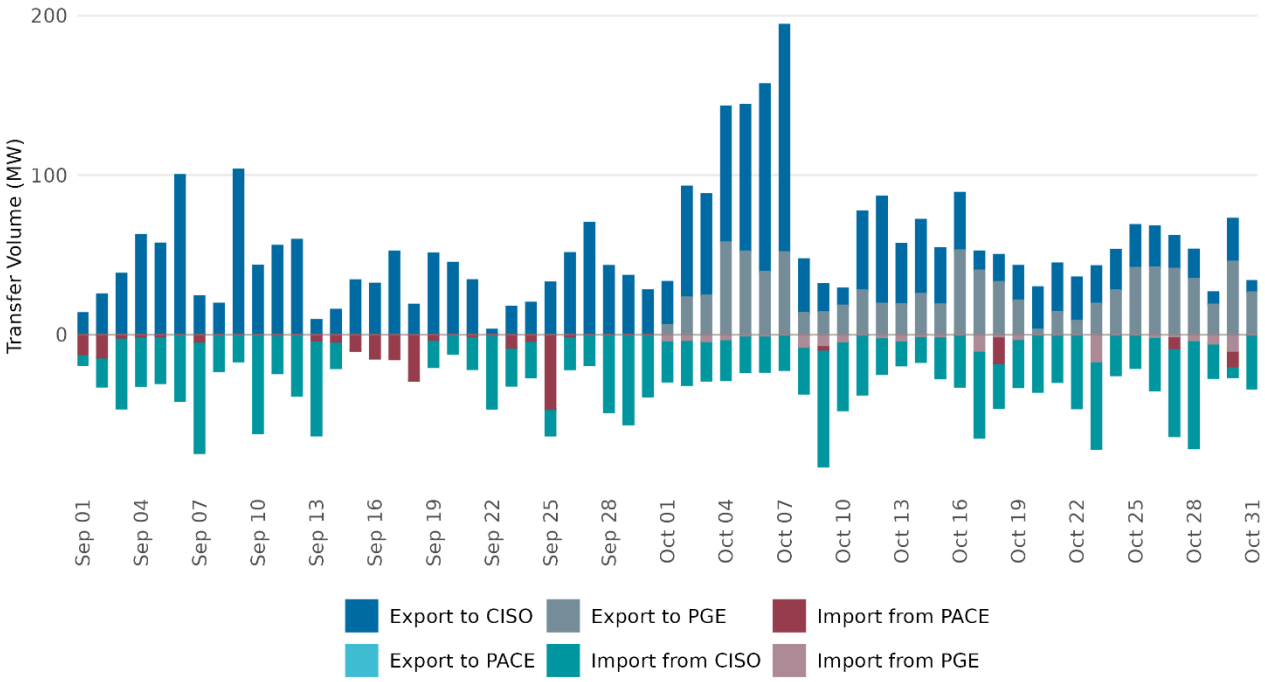


Figure 140: Hourly average IRU transfers for PACW

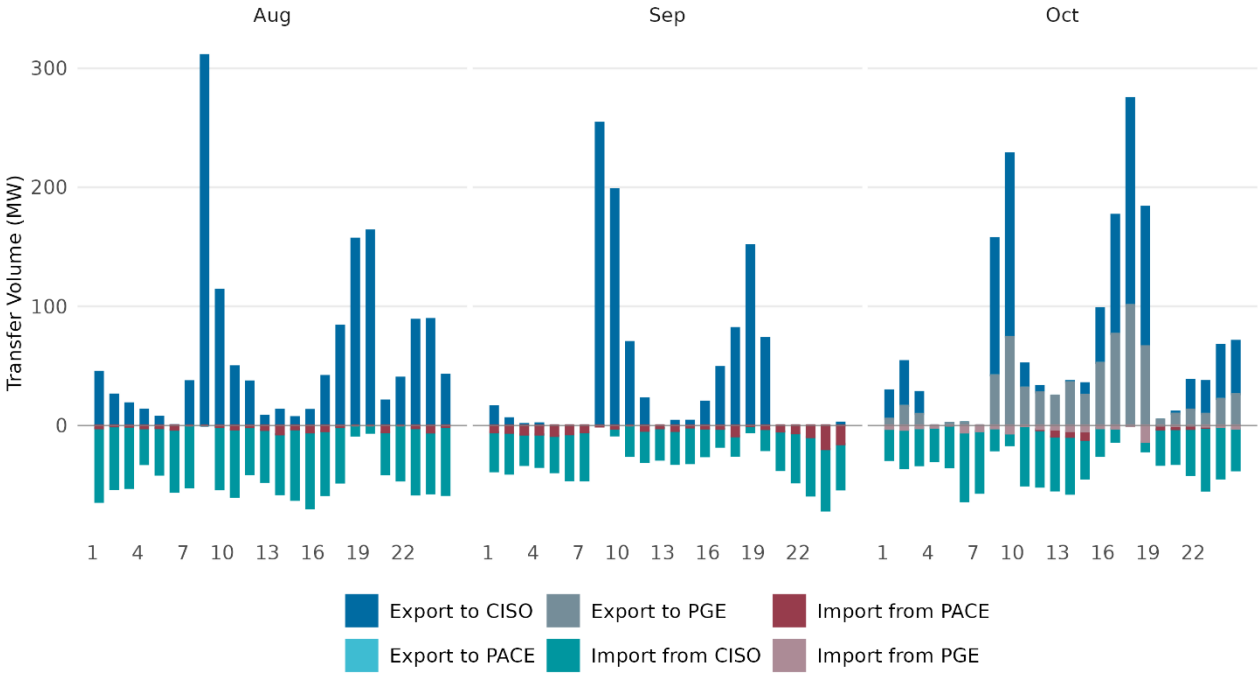


Figure 141 and Figure 142 show PGE's October IRU transfers were predominantly imports, with CAISO accounting for most import volume and PACW contributing significantly during the late afternoon hours. Transfer direction varied considerably by hour: PGE showed notable exports to CAISO during the morning and late afternoon, while imports increased substantially around HE 16–18. Daily transfer volumes were also variable, with no clear trend across the month.

Figure 141: Daily average IRU transfers for PGE

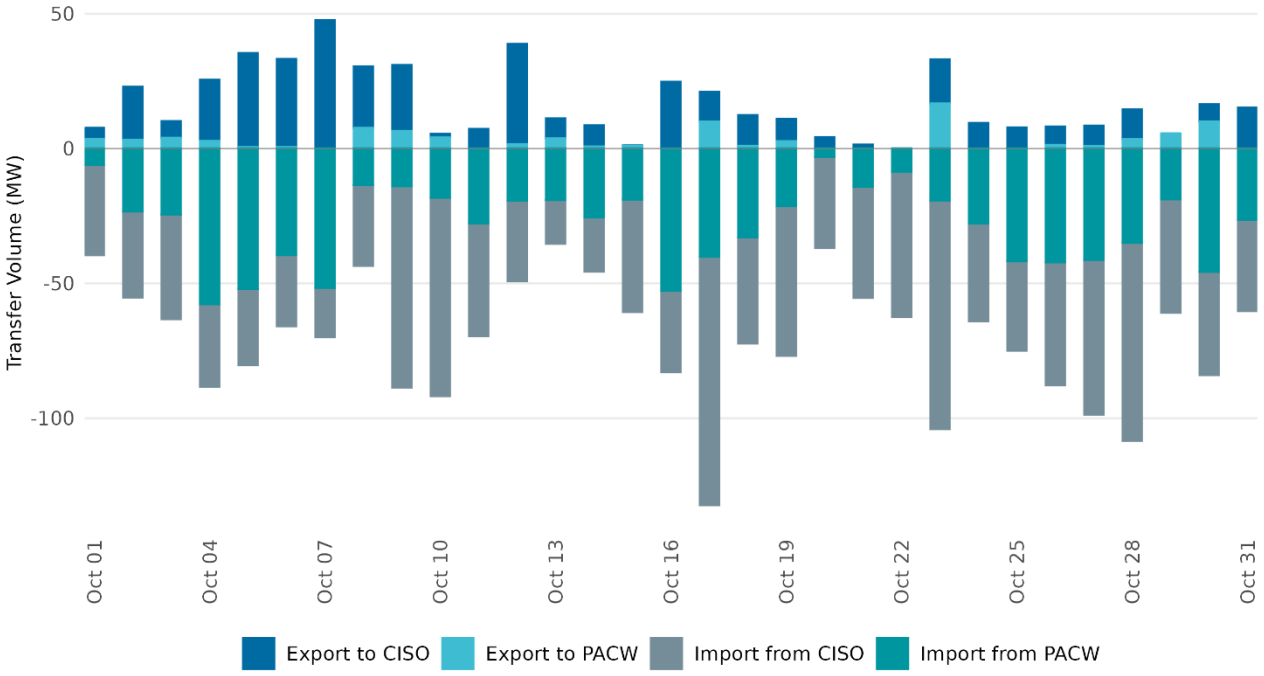


Figure 142: Hourly average IRU transfers for PGE

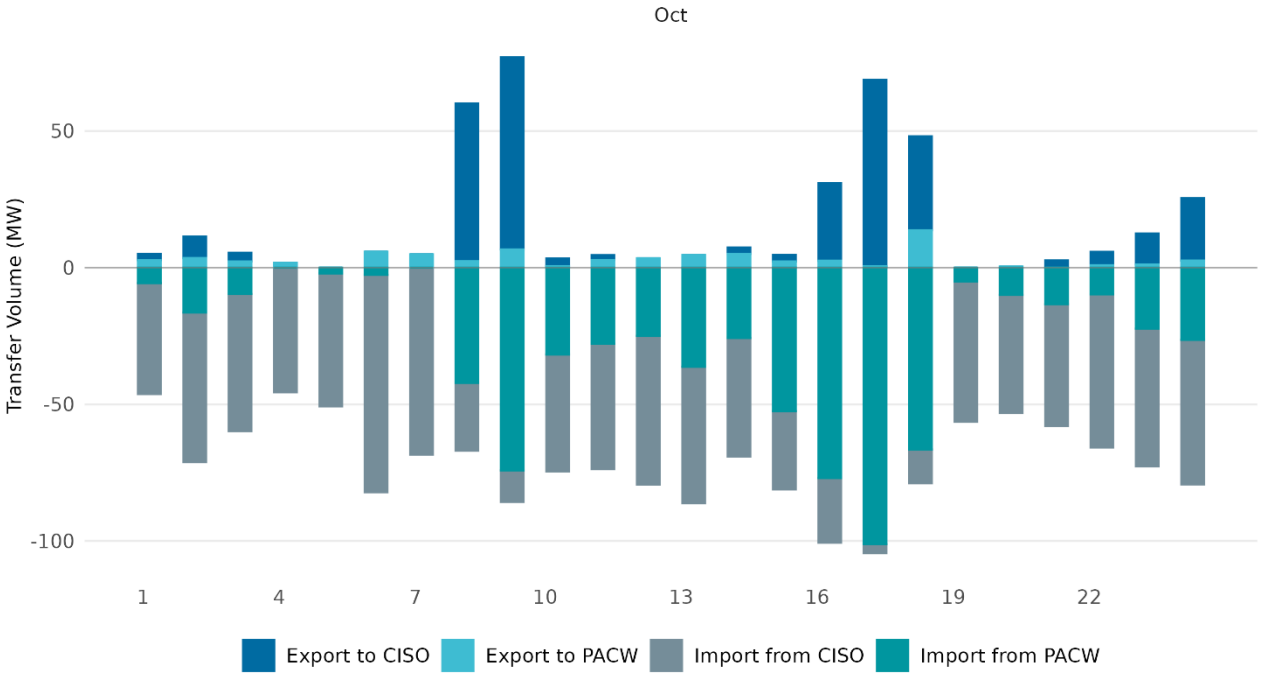
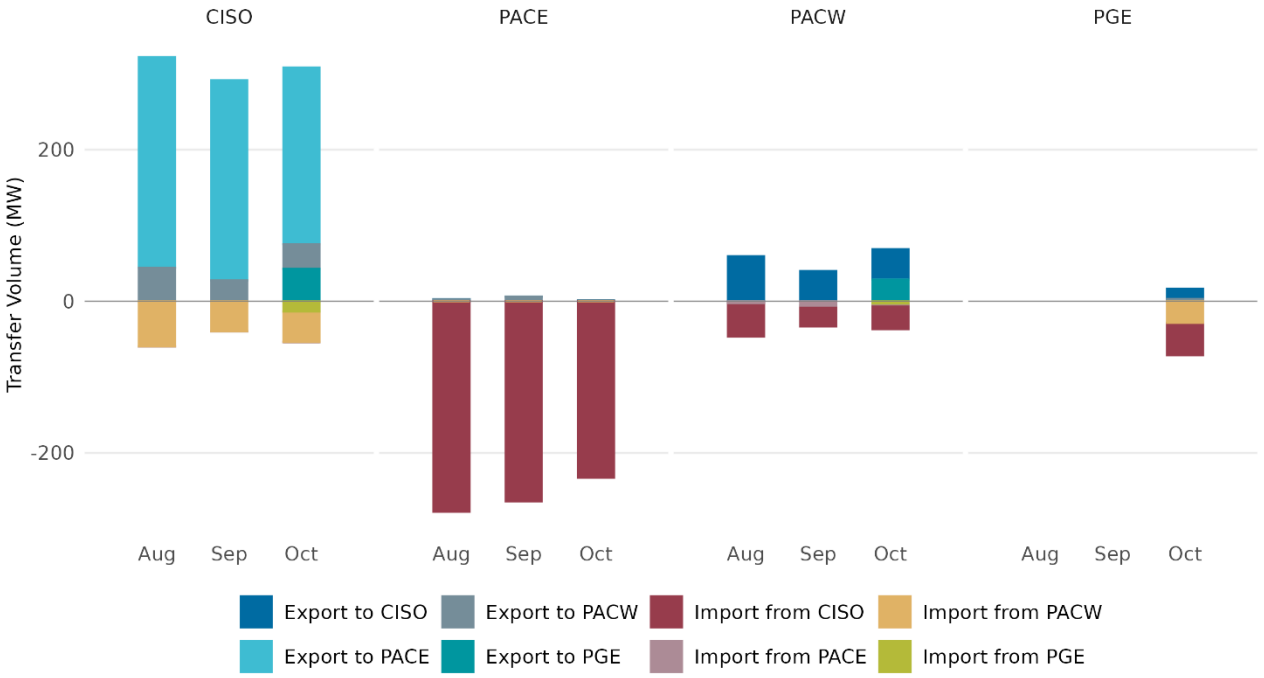


Figure 143 shows the summary of four BAAs' total IRU transfer volumes throughout August to October in both export (+) and import (-) directions. Overall transfer volumes on this path decreased modestly by October. With PGE joining the transfer network in October, additional

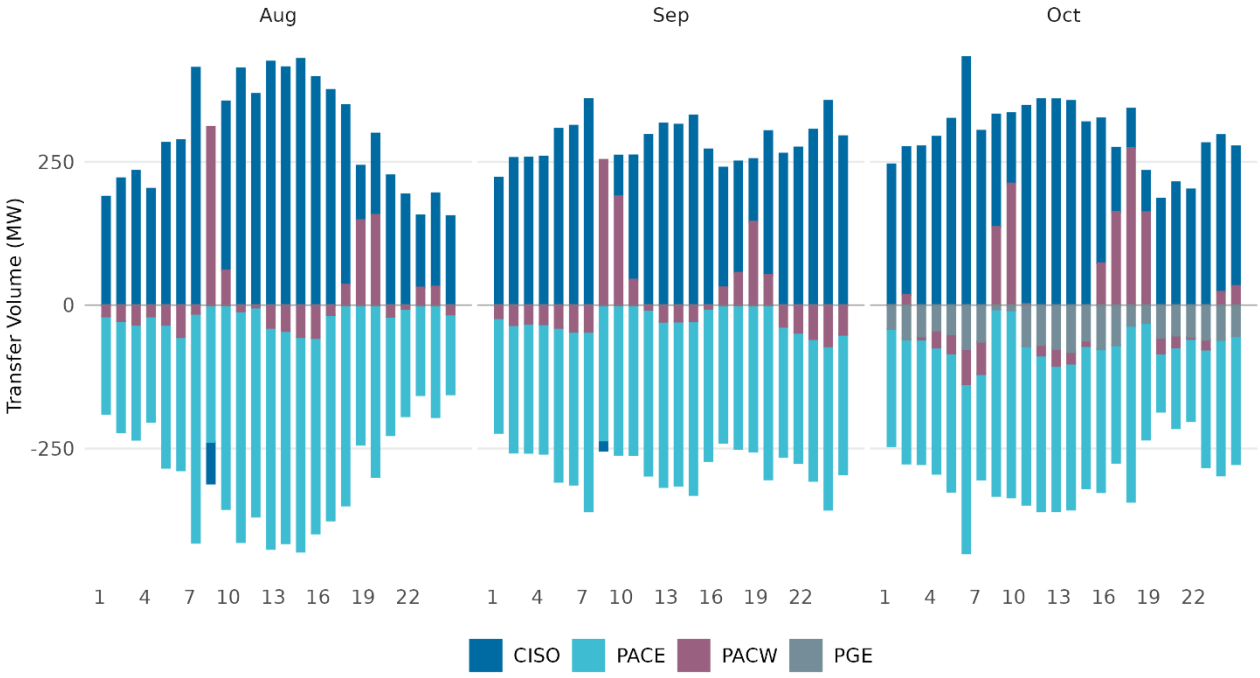
transfer paths emerged among CAISO, PACW, and PGE, although PGE-related IRU transfer volumes remained relatively small compared with the existing CAISO–PACE transfers.

Figure 143: Hourly average IRU transfers volumes in EDAM



CAISO is predominantly an exporter across all three months, while PACE is predominantly an importer. PACW switches between imports and exports depending on the hour, with notable export increases during the morning and evening periods. In October, PGE enters the EDAM footprint and is primarily an importer, adding another component to the overall IRU transfer pattern.

Figure 144: Hourly average net IRU transfers volumes in EDAM



Imbalance reserve down

For IRD products, as Figure 145 shows, CAISO's daily average IRD transfers fluctuated significantly throughout September to October. CAISO's IRD transfer activity increased substantially in October compared with September, with a clear shift toward higher export volumes. September was characterized by relatively small transfers and frequent imports from PACE, while October saw larger exports to PACE and PACW, along with the addition of PGE-related transfers. Export volumes generally increased through October and reached their highest levels toward the end of the month, while imports remained more episodic and were primarily associated with PACE and PACW.

Figure 145: Daily average IRD transfers for CAISO

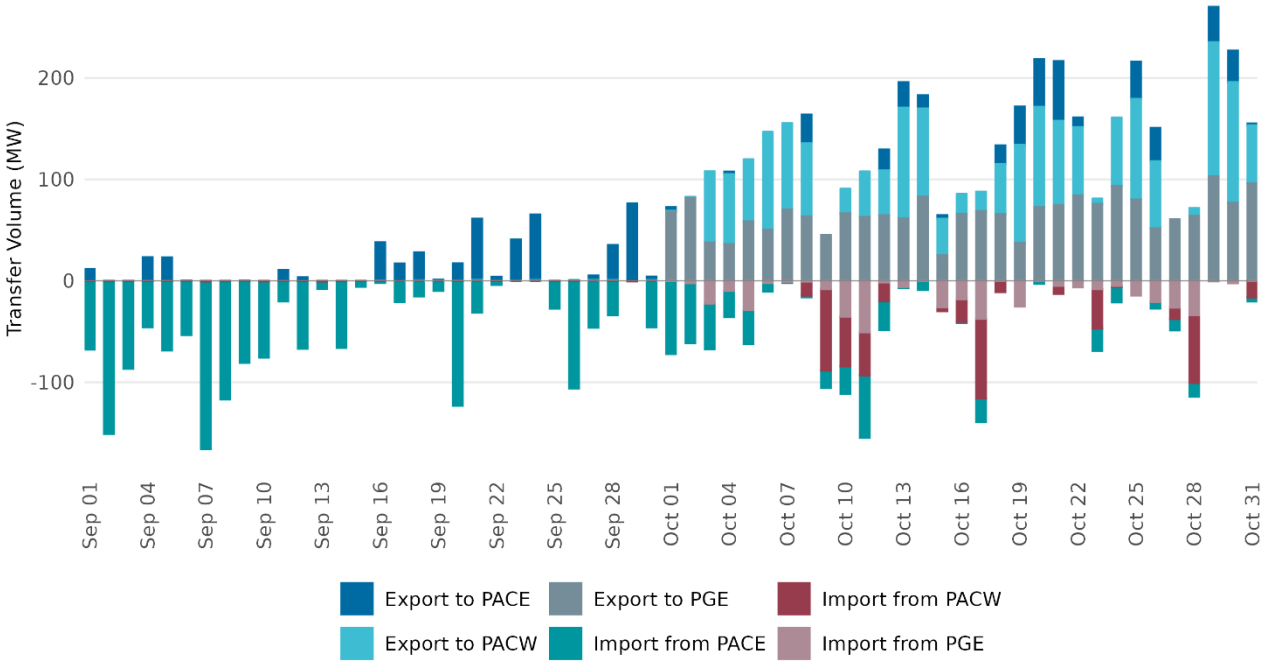
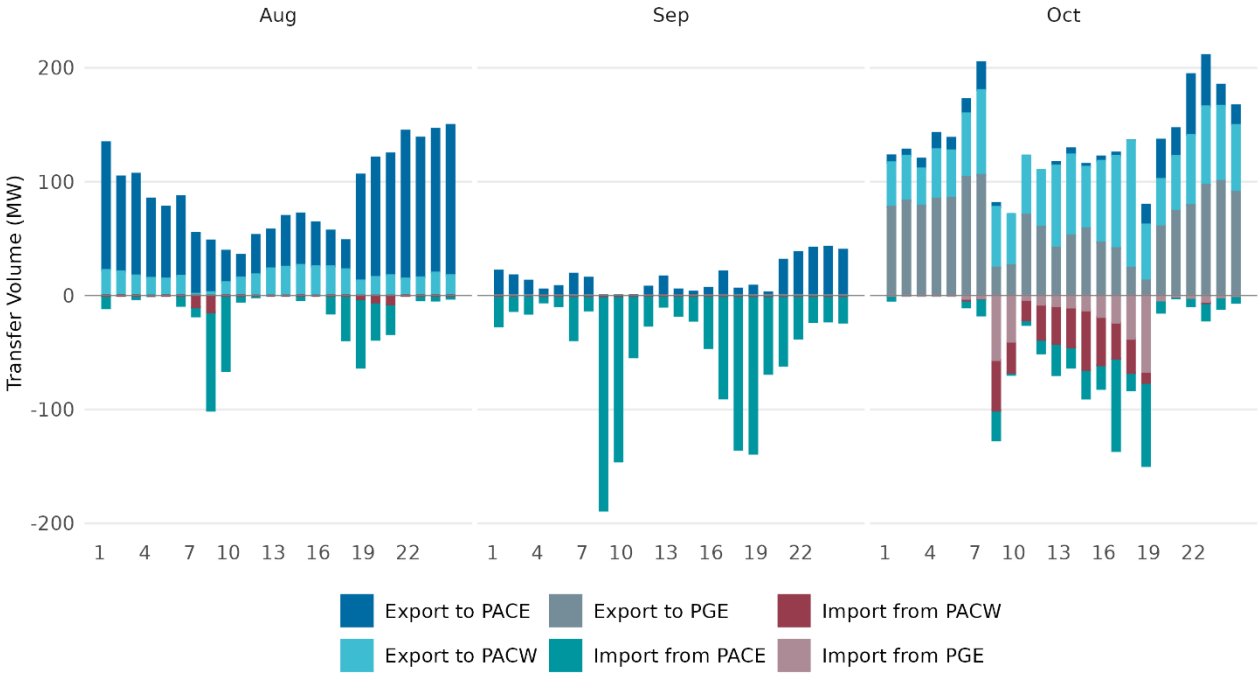


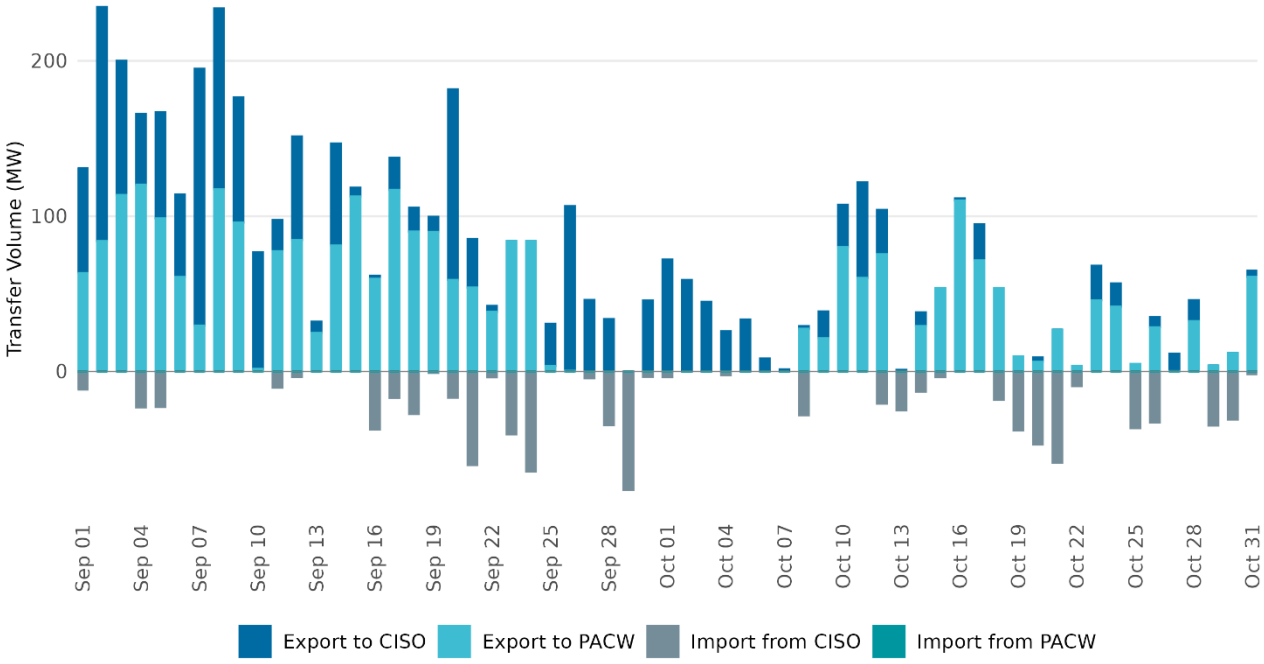
Figure 146 shows CAISO's hourly IRD transfer profile changed substantially from August through October. August was characterized primarily by exports to PACE, while September experienced considerably lower export volumes and stronger imports from PACE, particularly during the morning and evening hours. In October, CAISO's export activity increased significantly and became more diversified across PACE, PACW, and PGE. At the same time, imports remained significant during the midday and evening hours, with PACW accounting for a larger share of the import volume. Overall, October exhibited both higher IRD transfer activity and a broader set of transfer relationships following PGE's entry.

Figure 146: Hourly average IRD transfers for CAISO



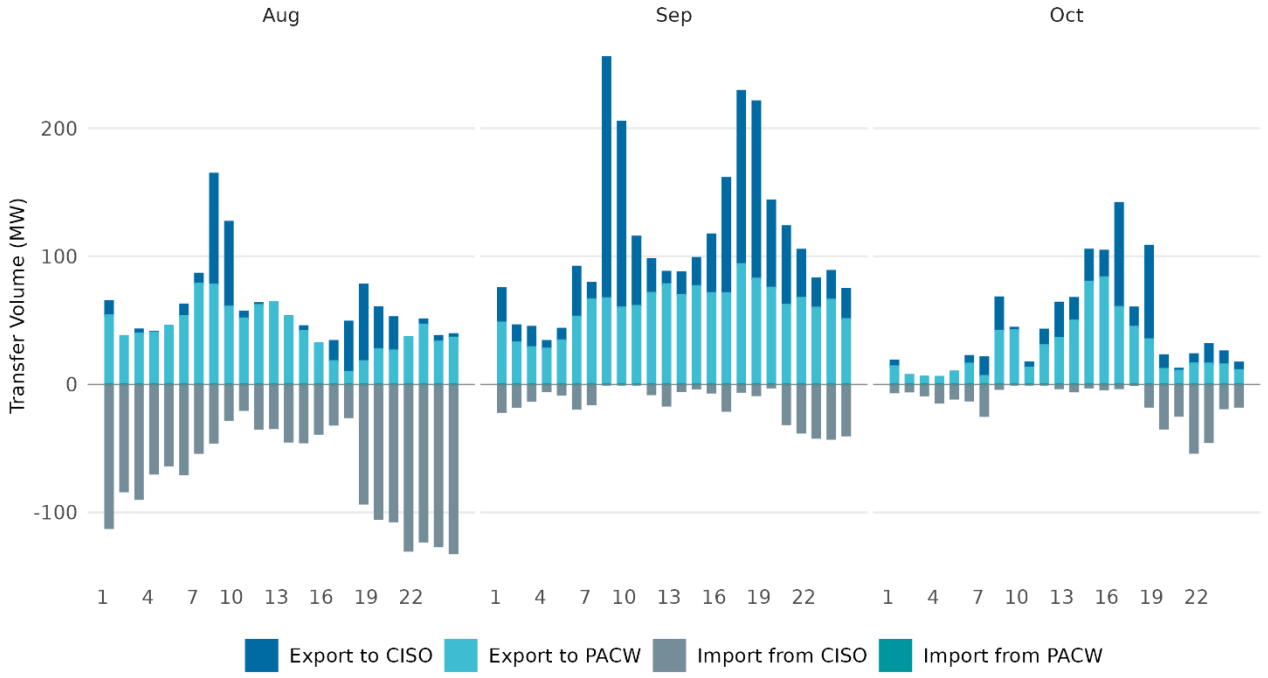
As Figure 147 shows, PACE's IRD transfers were predominantly exports during September and October, with exports directed to both CAISO and PACW. Export volumes were substantially higher in September, particularly during the first half of the month, before declining and becoming more variable in October. Imports remained smaller overall but became more pronounced on selected October days, particularly around Oct. 19–21.

Figure 147: Daily average IRD transfers for PACE



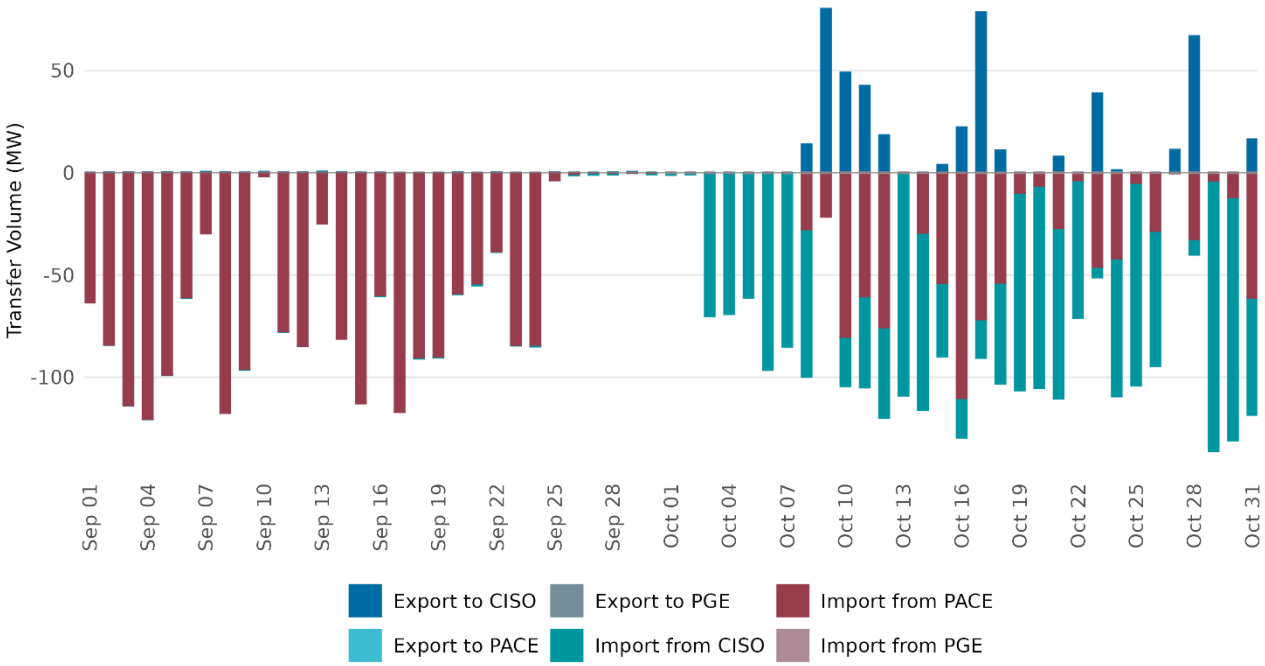
The hourly profile Figure 148 showed PACE's substantial variation from August through October. September recorded the highest IRD export activity, with pronounced export peaks to CAISO during the morning and late-afternoon hours, while exports to PACW provided a more consistent contribution throughout the day. By October, PACE's overall IRD transfer activity declined considerably, with exports concentrated primarily during the afternoon and imports becoming more noticeable during the late-evening hours.

Figure 148: Hourly average IRD transfers for PACE



In Figure 149 PACW's IRD transfers were predominantly imports during both September and October, but the transfer mix changed substantially between the two months. September imports were primarily from PACE, with very limited export activity. In October, imports from CAISO became the dominant component, while PACW also exhibited more frequent exports to CAISO. Overall, October showed substantially greater two-way IRD transfer activity for PACW and greater day-to-day variability than September.

Figure 149: Daily average IRD transfers for PACW



In October, PACW's imports from CAISO increased substantially during the daytime and afternoon hours, with total PACW imports reaching their highest levels around HE 15–17. PACW also exported to CAISO during many of these hours, indicating a more active and variable IRD transfer relationship in October.

Figure 150: Hourly average IRD transfers for PACW

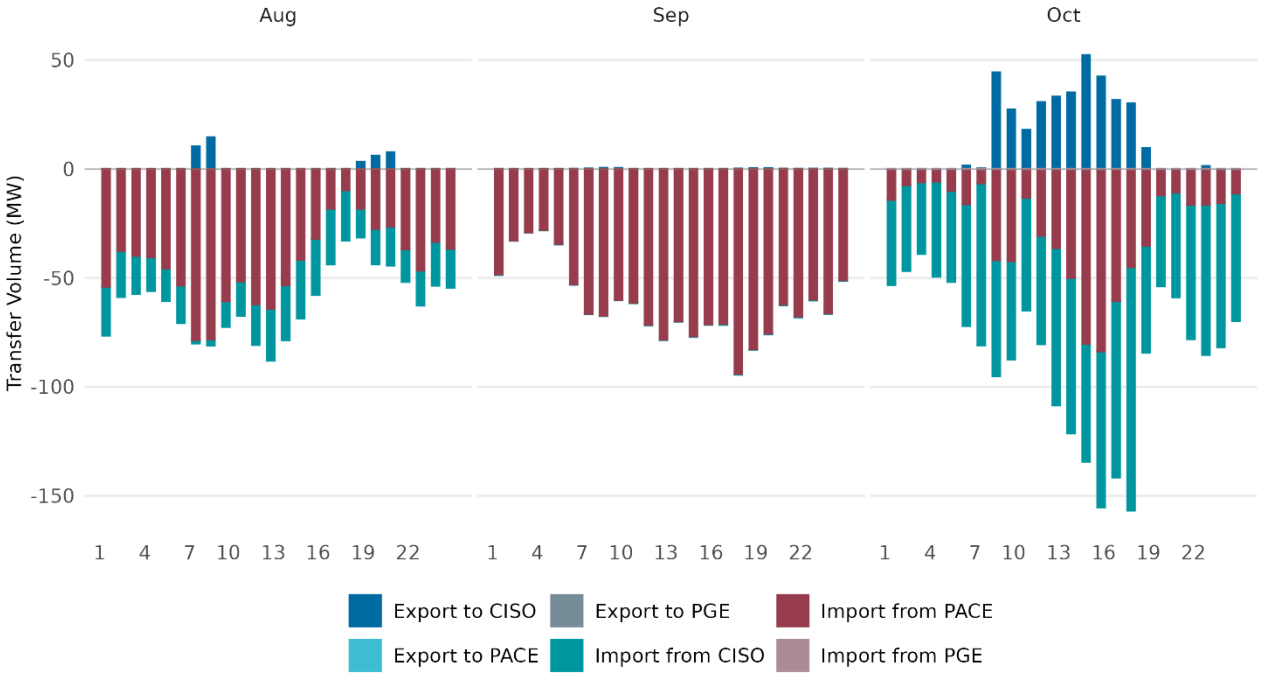


Figure 151: Daily average IRD transfers for PGE

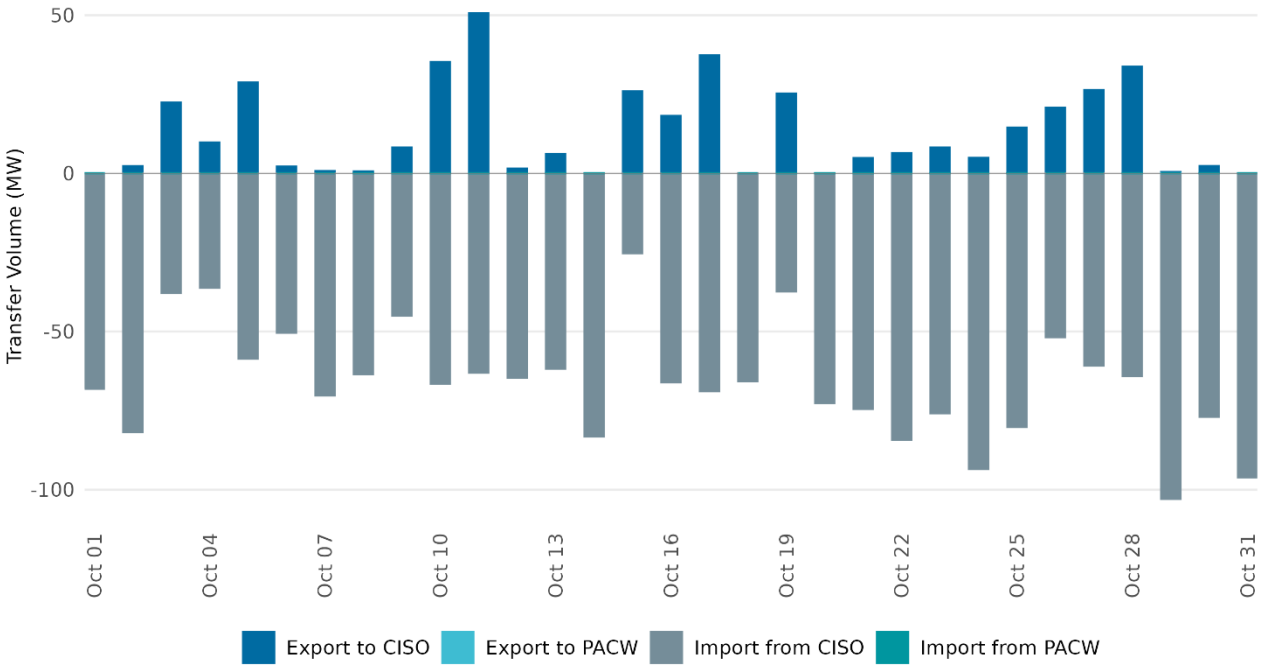
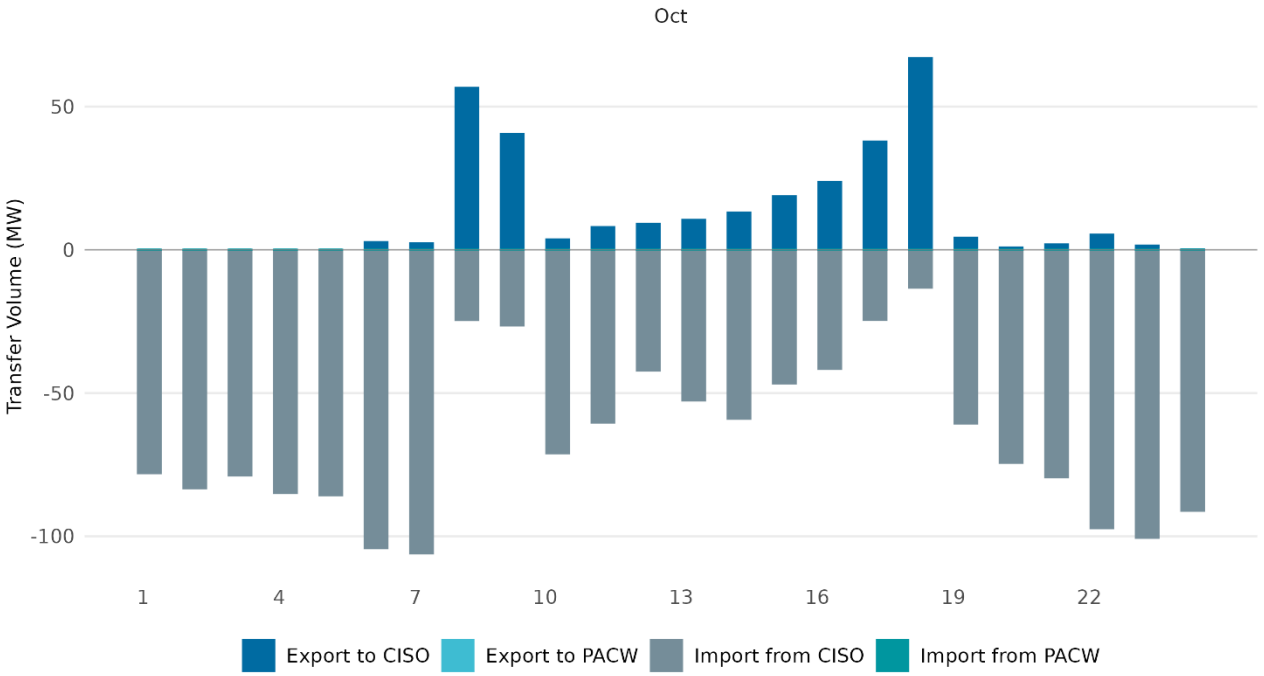


Figure 152: Hourly average IRD transfers for PGE



In PGE's first month of joining EDAM, it was predominantly an IRD importer during October, with most imports coming from CAISO. The hourly profile showed distinct directional shifts, with PGE transitioning from imports during the overnight hours to exports around HE 8–9, returning to imports during much of the daytime, and reaching its strongest export levels around HE 17–18 before shifting back to imports during the late evening.

Figure 153 illustrates average EDAM IRD transfers changed materially from August through October. PACE recorded the highest average export activity in September, while CAISO's export activity increased substantially in October and expanded across PACE, PACW, and the newly participated PGE. PACW remained a net importer throughout the period, although its primary import source shifted from PACE in August and September toward CAISO in October. PGE entered the EDAM in October as a net importer, with most of its IRD imports coming from CAISO.

Figure 153: Hourly average IRD transfers volumes in EDAM

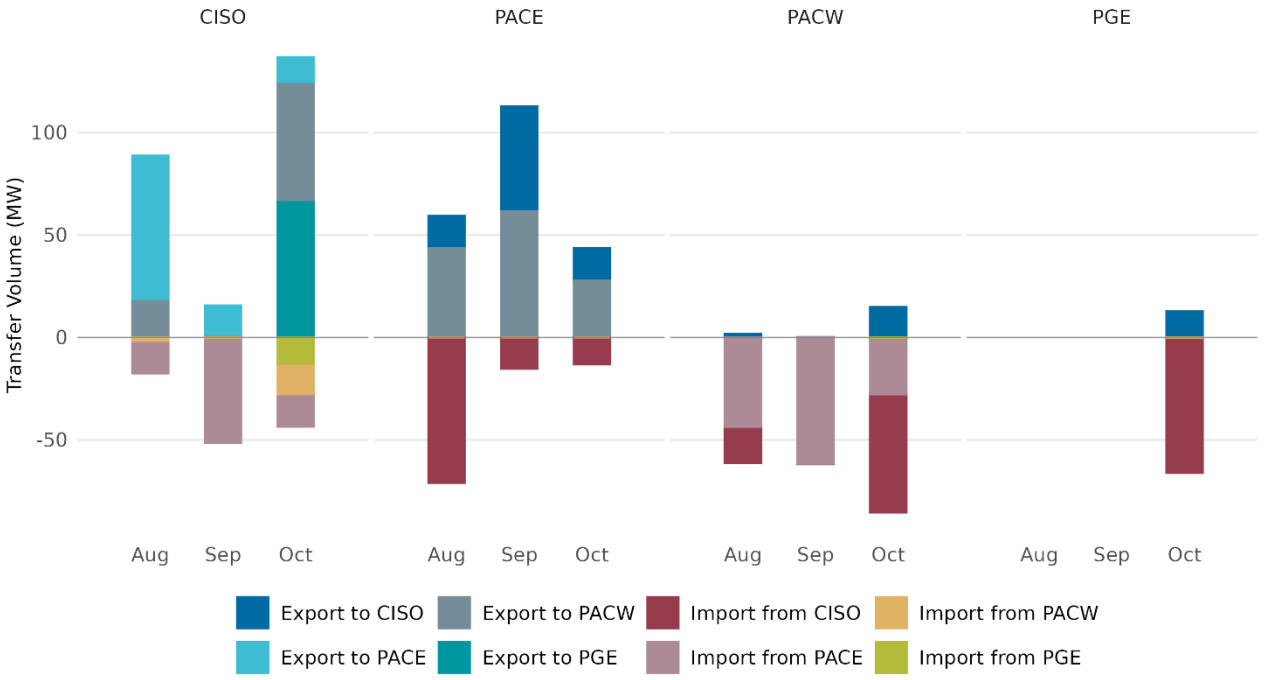
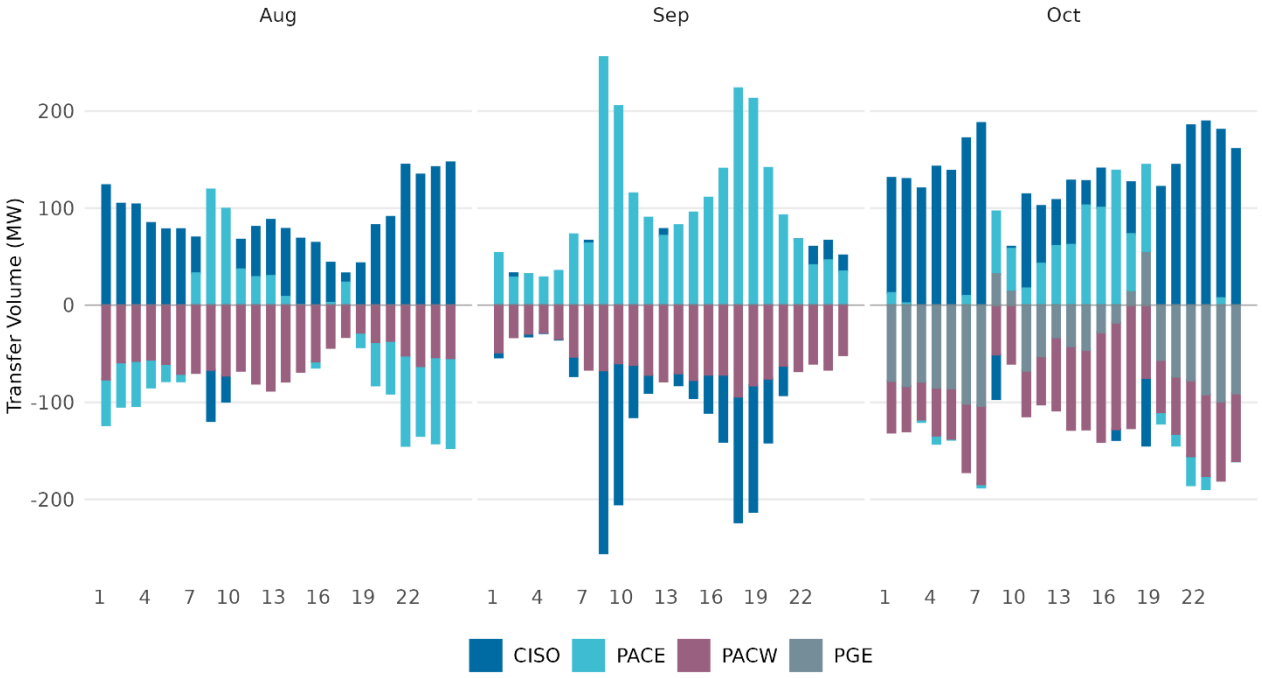


Figure 154 shows net IRD transfer patterns shifted substantially from August through October. September was characterized by strong PACE net exports and corresponding CAISO net imports, particularly during the morning and late afternoon hours. In October, CAISO shifted back to being the dominant net exporter, while PACW remained predominantly a net importer and PGE entered EDAM as an additional net-importing entity.

Figure 154: Hourly average net IRD transfers volumes in EDAM



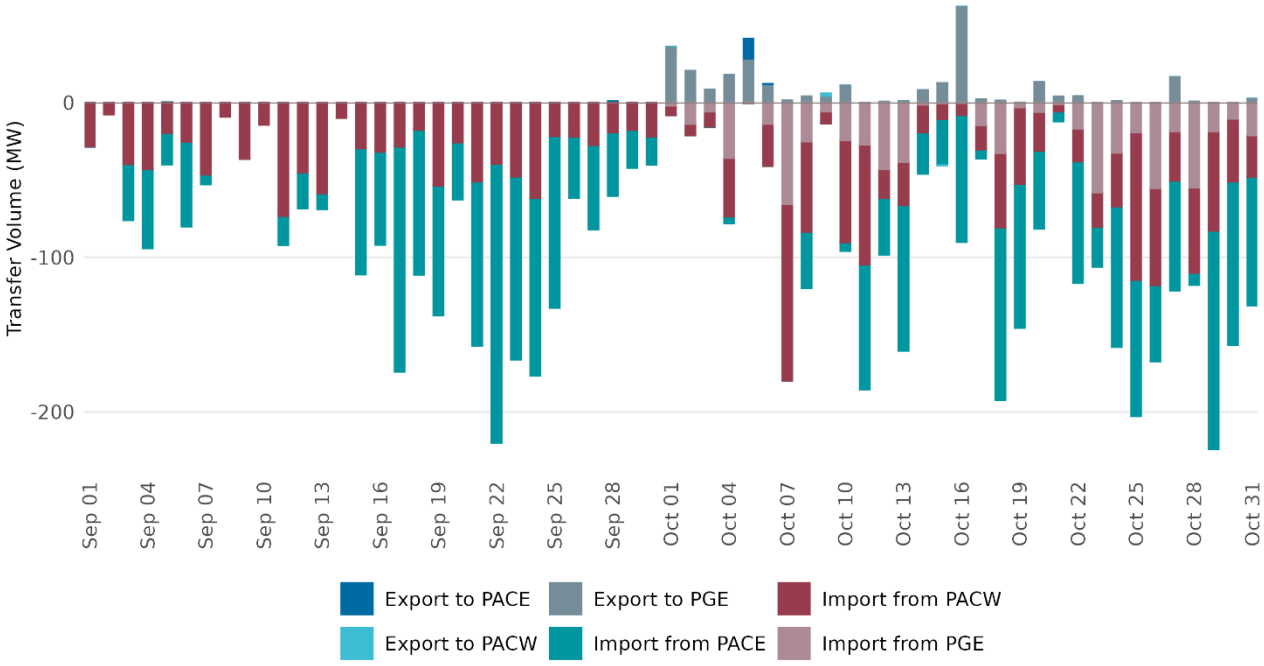
Reliability capacity transfers

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.

Reliability capacity up

Figure 155 and Figure 156 show CAISO's daily and hourly average RCU transfers on both export (+) and import (-) directions. Generally, RCU transfers for CAISO were predominantly imports from PACE and PACW throughout September and October, with minimal exports to PACE and PGE starting from October 1. Import volumes were generally higher and more volatile, occasionally exceeding 200 MW.

Figure 155: Daily average RCU transfers for CAISO



Similarly, Figure 156 shows CAISO was predominantly an RCU importer from August through October, with imports generally increasing during the daytime and reaching their highest levels during the afternoon hours. PACE accounted for much of the intraday increase in imports, while PACW provided a relatively consistent contribution. August recorded the largest import volumes, followed by lower levels in September and October. In October, PGE added a new RCU transfer path, contributing both imports and small but consistent exports, resulting in a more diversified RCU transfer profile.

Figure 156: Hourly average RCU transfers for CAISO

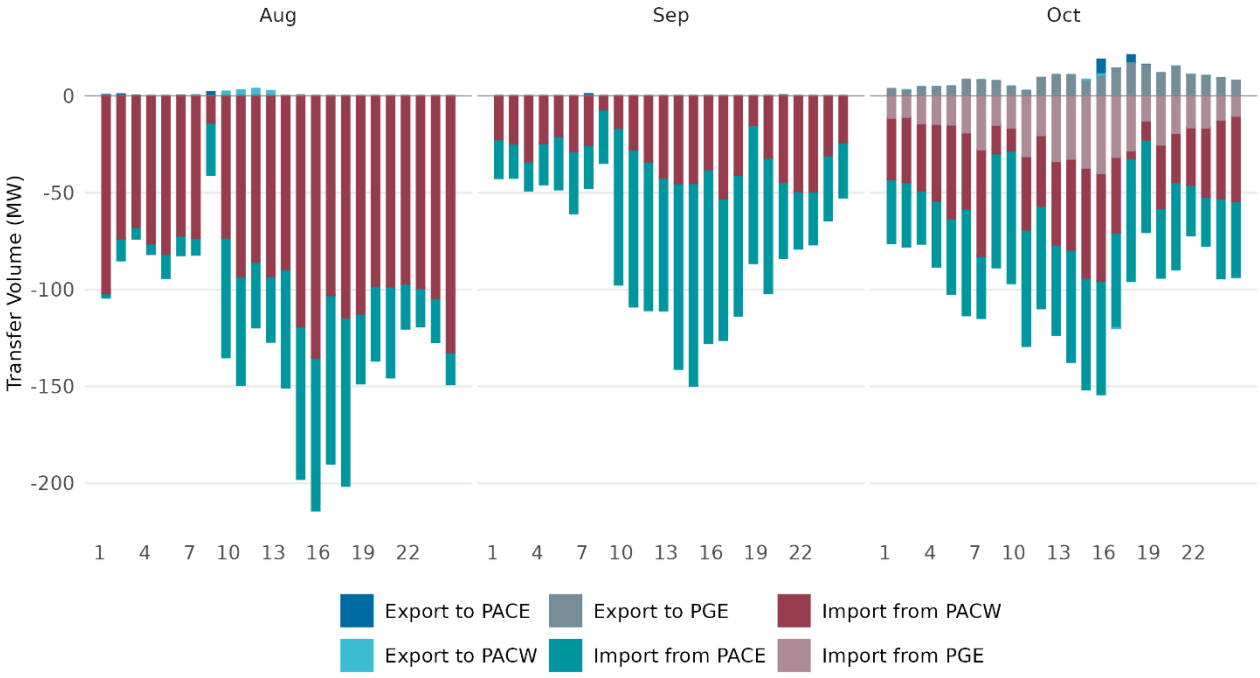
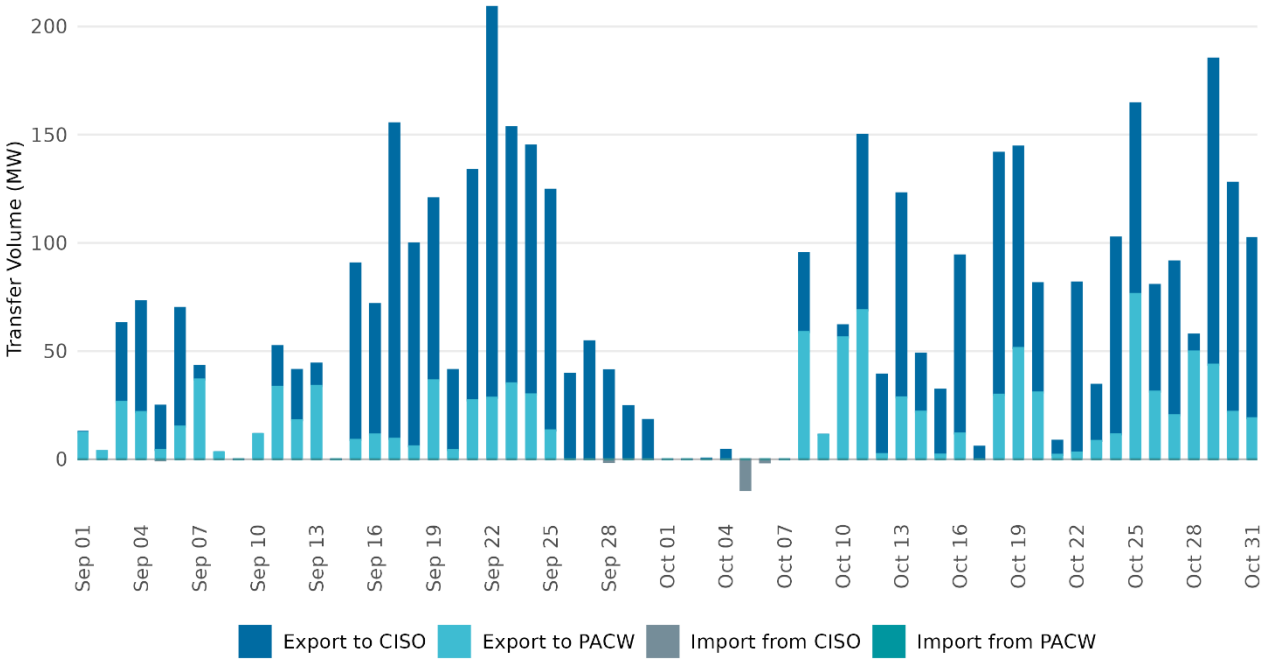


Figure 157 shows that daily average RCU transfers for PACE were predominantly exports to CISO and PACW throughout September and October, with minimal imports. Export volumes were generally higher and more volatile in September, peaking over 200 MW.

Figure 157: Daily average RCU transfers for PACE



As shown in Figure 158, export dominated the hourly average RCU transfer volumes for PACE in the past three months. Hourly average RCU transfer in August reached peaked at approximately 190 MW around HE16. The higher August volumes were primarily driven by increased exports to PACW and CISO, while imports remained limited throughout the three-month period. In September and October, there were more RCU exports to CAISO, although the total volume of RCU transfers was lower than August.

Figure 158: Hourly average RCU transfers for PACE

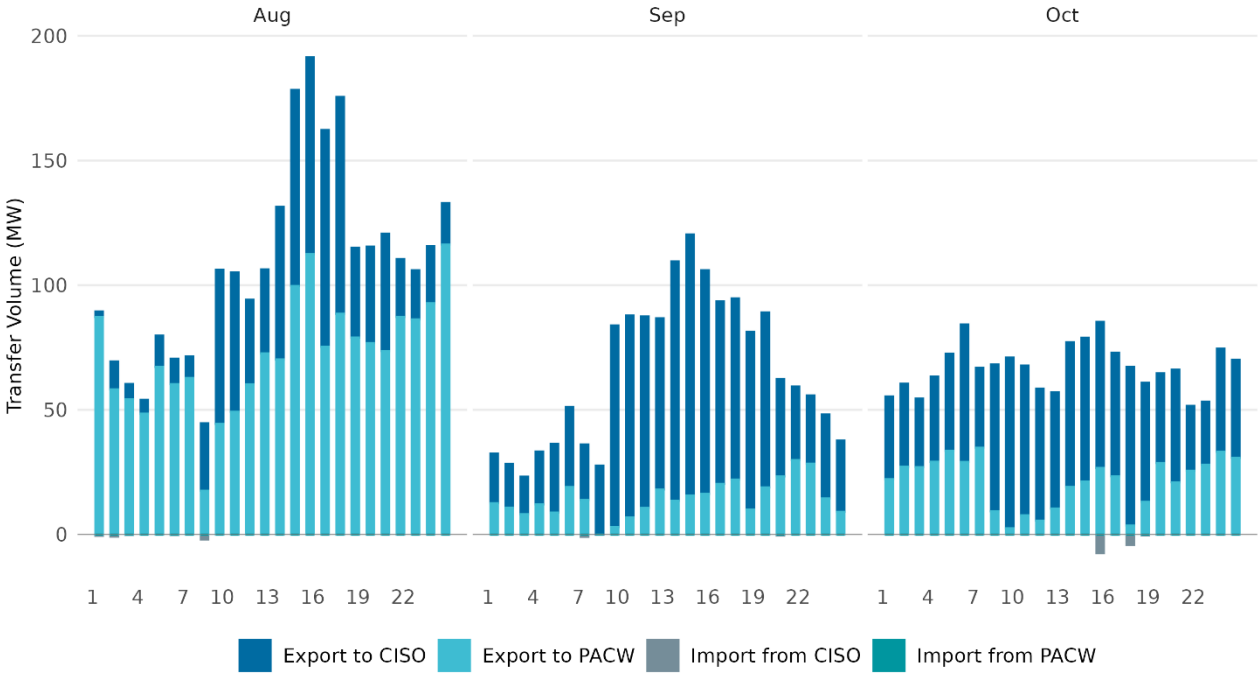


Figure 159 to Figure 160 show that RCU transfers for PACW were predominantly exports to CAISO and imports from PACE, exhibiting largely mirrored patterns in September. However, October also introduced PGE-related transfers, further diversifying PACW's RCU transfer activity.. Daily transfer volumes were generally higher and more volatile in October, with exports occasionally exceeding 100 MW. Hourly patterns indicate that both exports to CAISO and imports from PACE were highest during the afternoon and evening hours in August, while transfer volumes remained relatively low throughout September and October.

Figure 159: Daily average RCU transfers for PACW

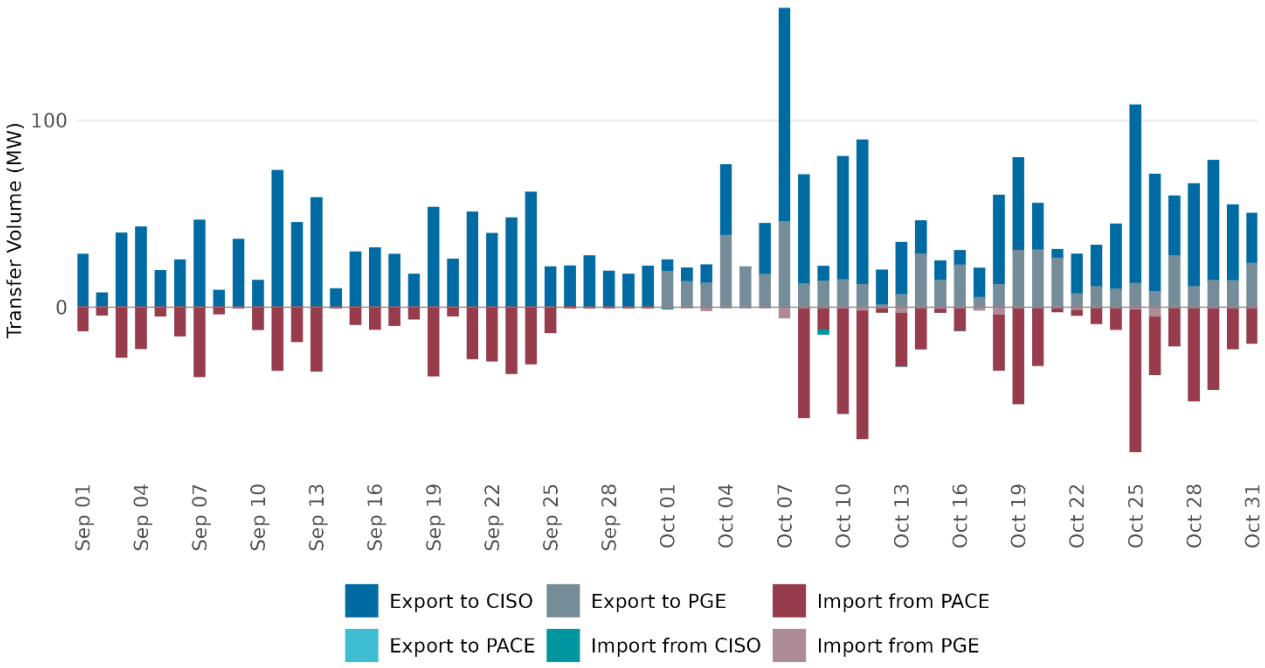


Figure 160: Hourly average RCU transfers for PACW

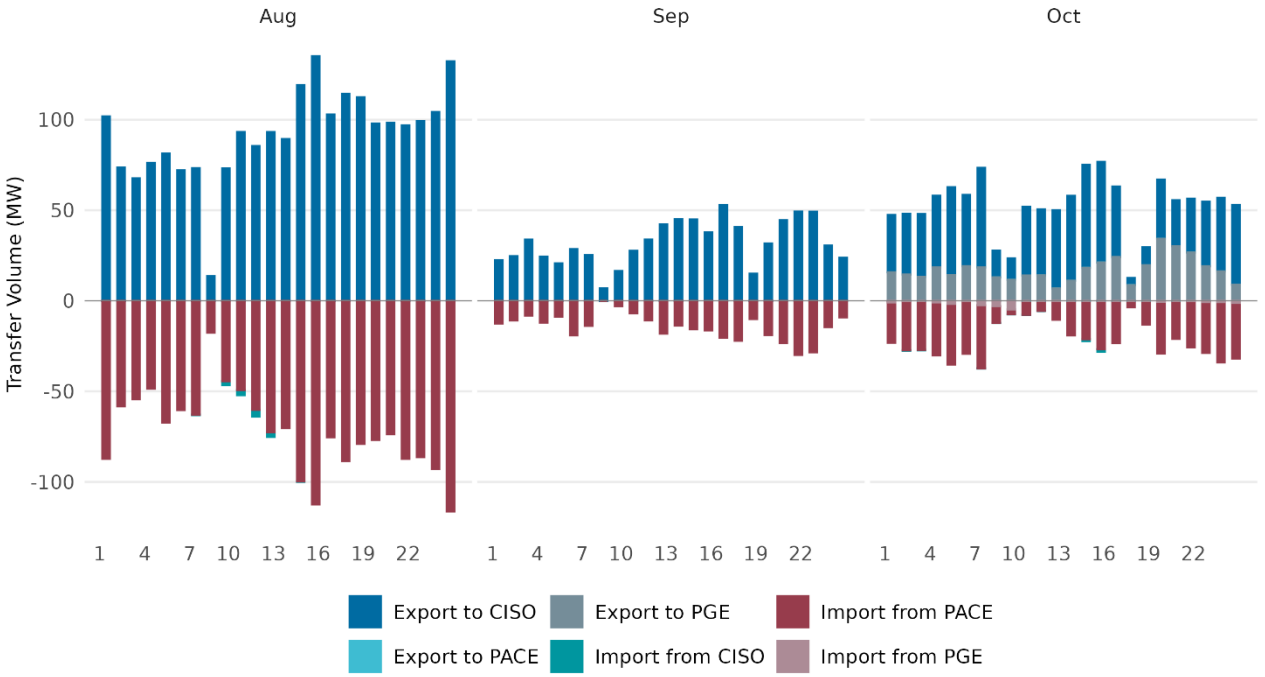


Figure 161: Daily average RCU transfers for PGE

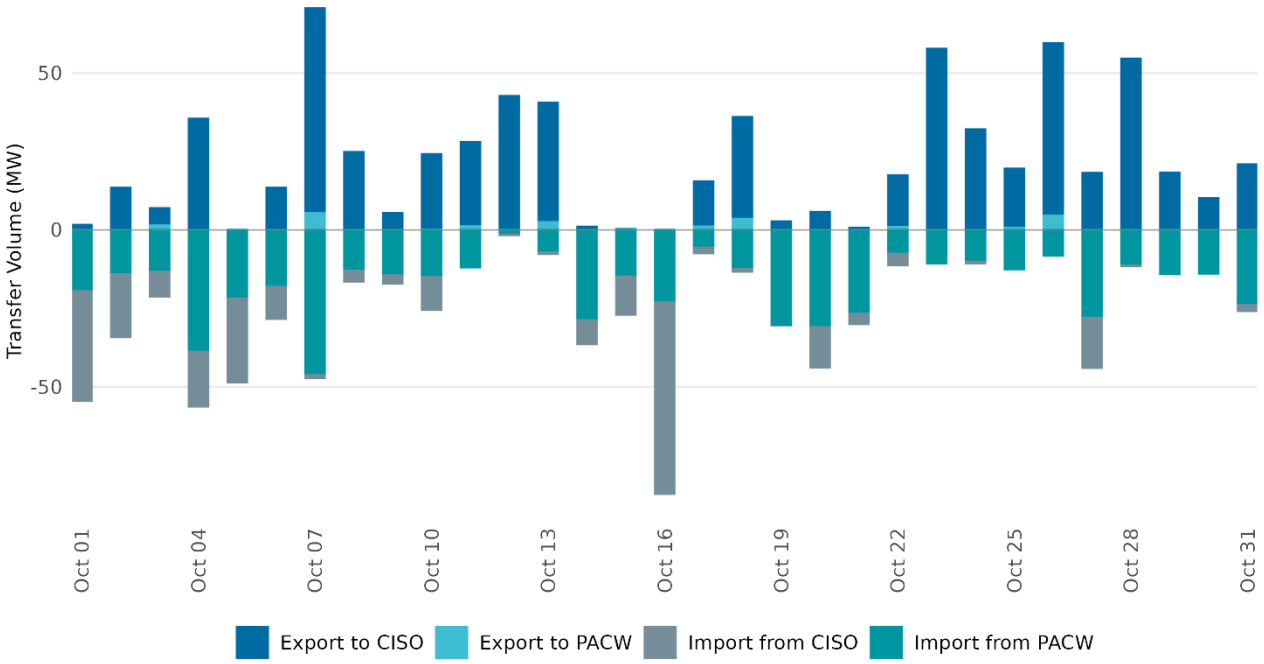
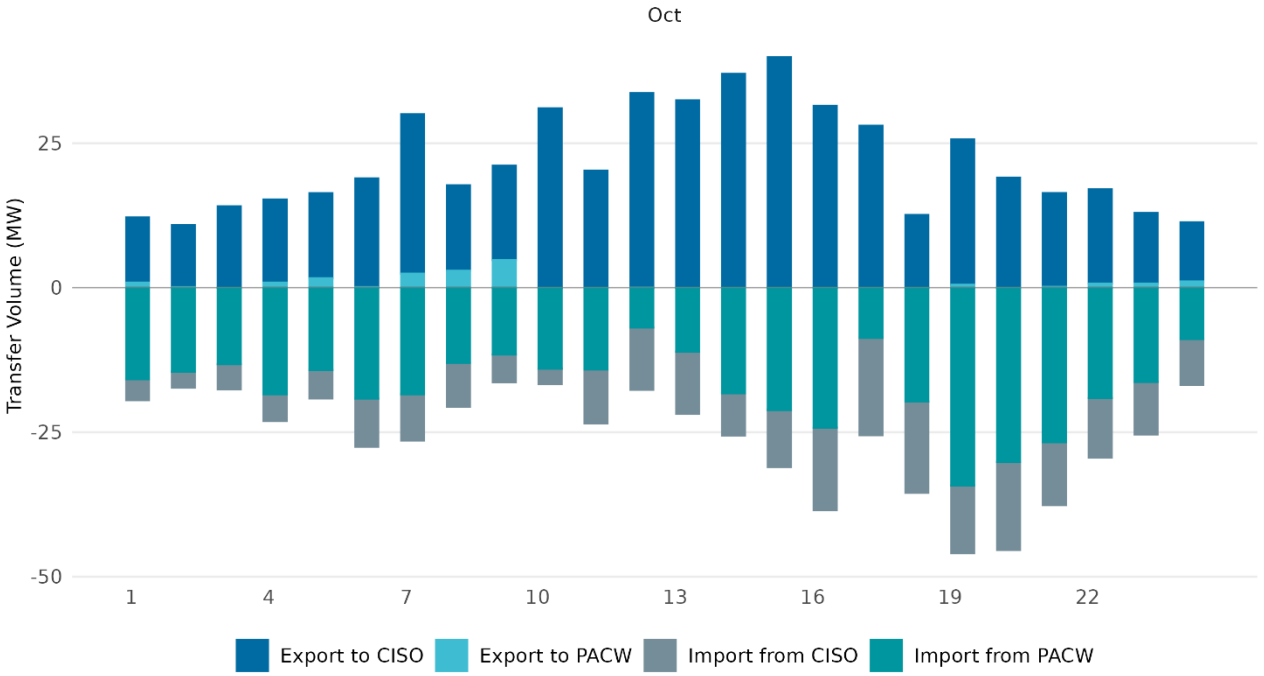


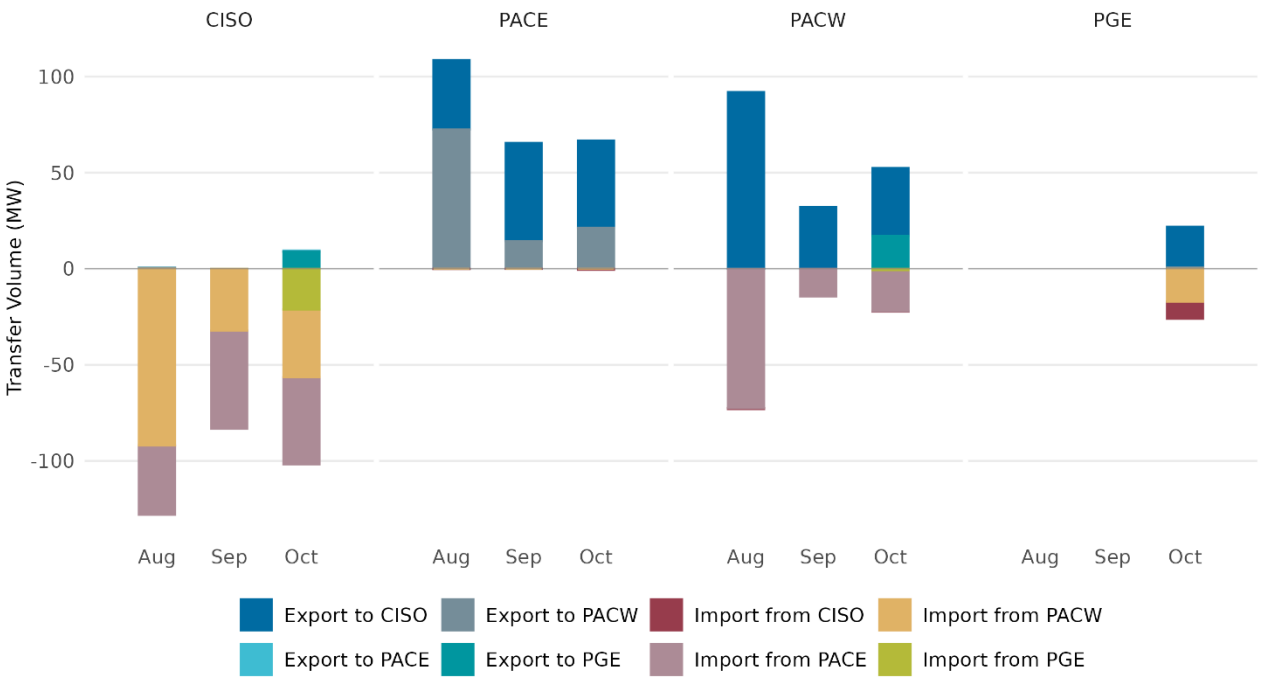
Figure 162: Hourly average RCU transfers for PGE



PGE exhibited substantial two-way RCU transfer activity during October. Exports were primarily directed to CAISO and remained relatively consistent throughout the day, increasing during the daytime before declining in the evening. Imports originated from both CAISO and PACW and showed greater hourly and daily variability, with the largest average hourly imports occurring around HE 19–20.

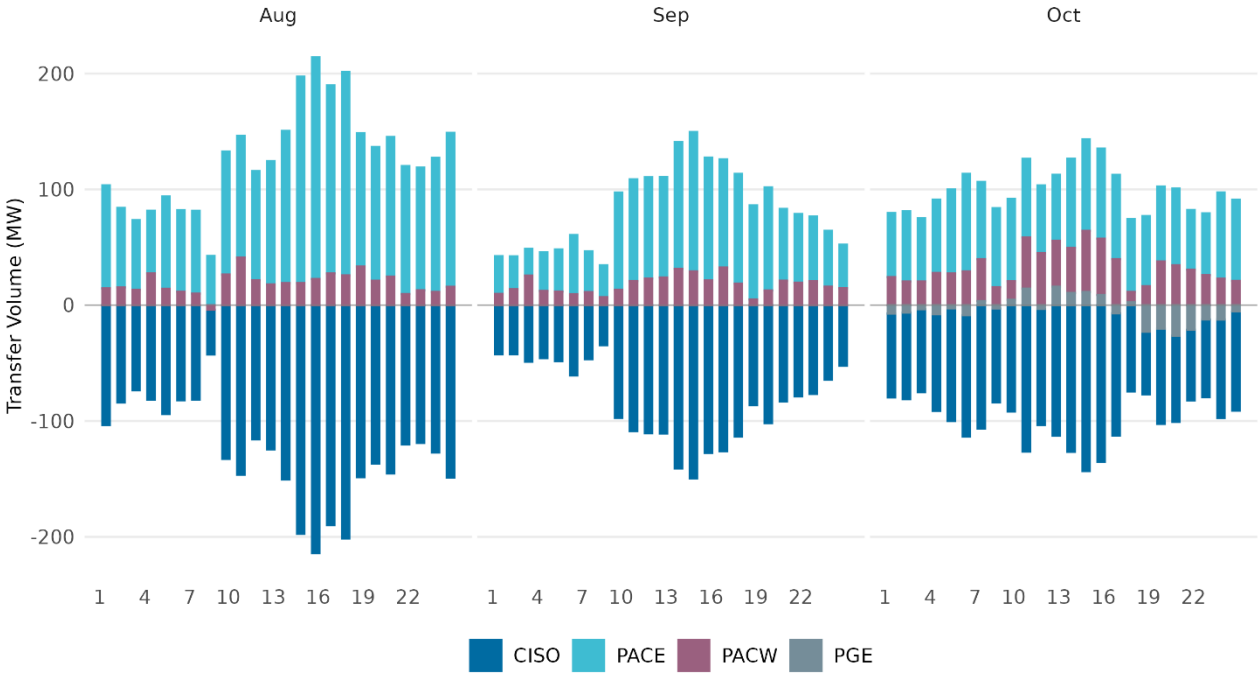
Figure 163 shows the summary of four BAAs' total RCU transfer volumes throughout August to October in both export (+) and import (-) directions. RCU transfers were characterized primarily by imports into CAISO and exports from PACE and PACW. Transfer volumes were highest in August and decreased substantially in September. In October, RCU activity became more diversified following PGE's entry, although CAISO remained the primary importing entity while PACE and PACW remained the major exporters. PGE exhibited relatively small two-way RCU transfers compared with the established EDAM entities.

Figure 163: Hourly average RCU transfers volumes in EDAM



In Figure 164, hourly net RCU transfers were dominated by exports from PACE and imports into CAISO across August through October. Transfer activity was highest in August, with PACE net exports exceeding 200 MW and CAISO net imports reaching approximately 200 MW during the afternoon hours. Transfer magnitudes declined in September and remained lower in October. With PGE joining EDAM in October, the RCU transfer pattern became more diversified, with PACW contributing additional net exports and PGE generally appearing as a net importer, while the dominant PACE-export/CAISO-import relationship remained unchanged.

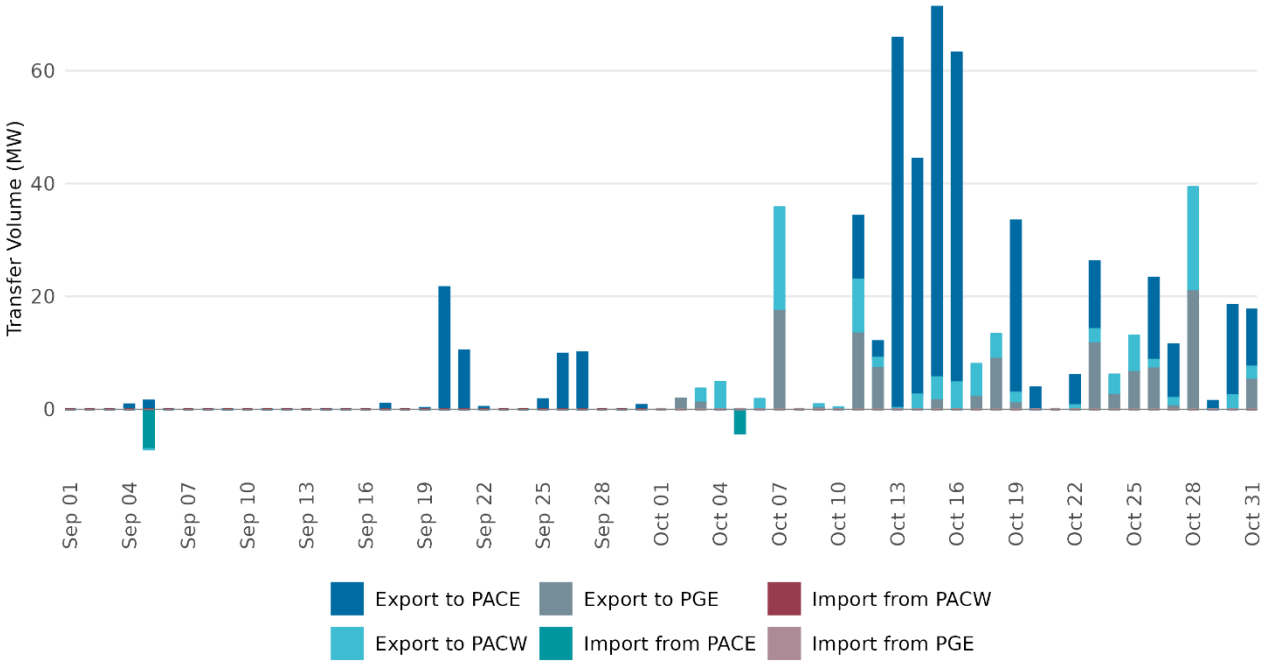
Figure 164: Hourly average net RCU transfers volumes in EDAM



Reliability capacity down

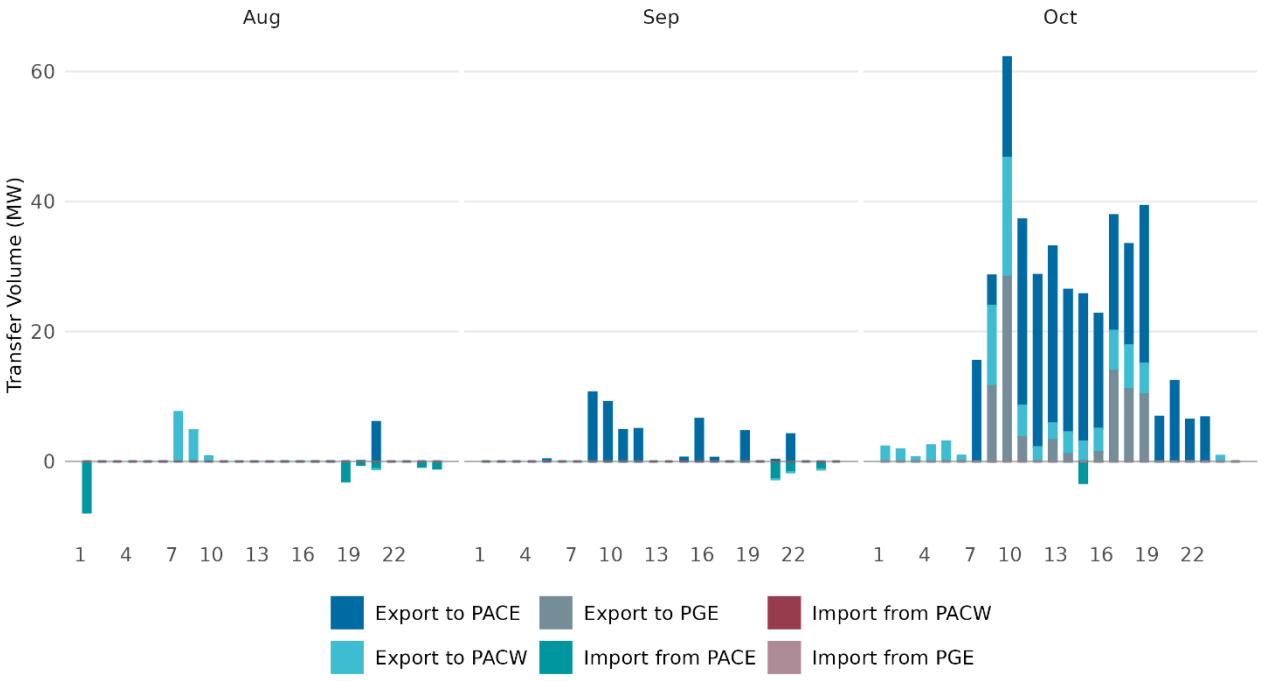
Figure 165 shows that daily average RCD transfers for CAISO were minimal throughout September and October, with most days experiencing little to no activity. Notable exports to PACE occurred in mid-October, peaking above 60 MW, while imports from PACE were limited to a few isolated days.

Figure 165: Daily average RCD transfers for CAISO



The hourly average RCD transfers for CAISO were generally low before October then increased significantly. October experienced the highest transfer volumes, with exports to other three BAAs above 60 MW during the morning hours.

Figure 166: Hourly average RCD transfers for CAISO



For PACE's RCD transfers, the daily and hourly average charts show variations between August and October. In August and September, PACE's exports were mainly to PACW, while there was limited import from CAISO. In October, there was much more import CAISO up to 28 MW in morning peak hours, but the overall export volume decreased.

Figure 167: Daily average RCD transfers for PACE

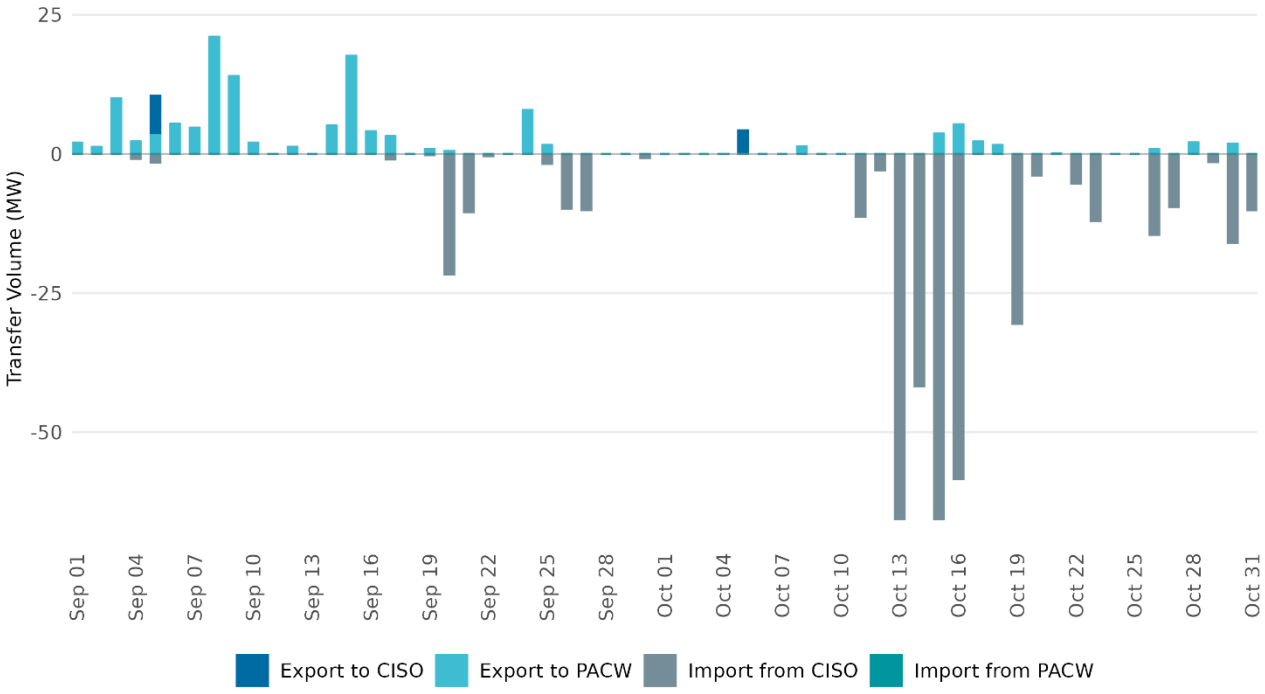
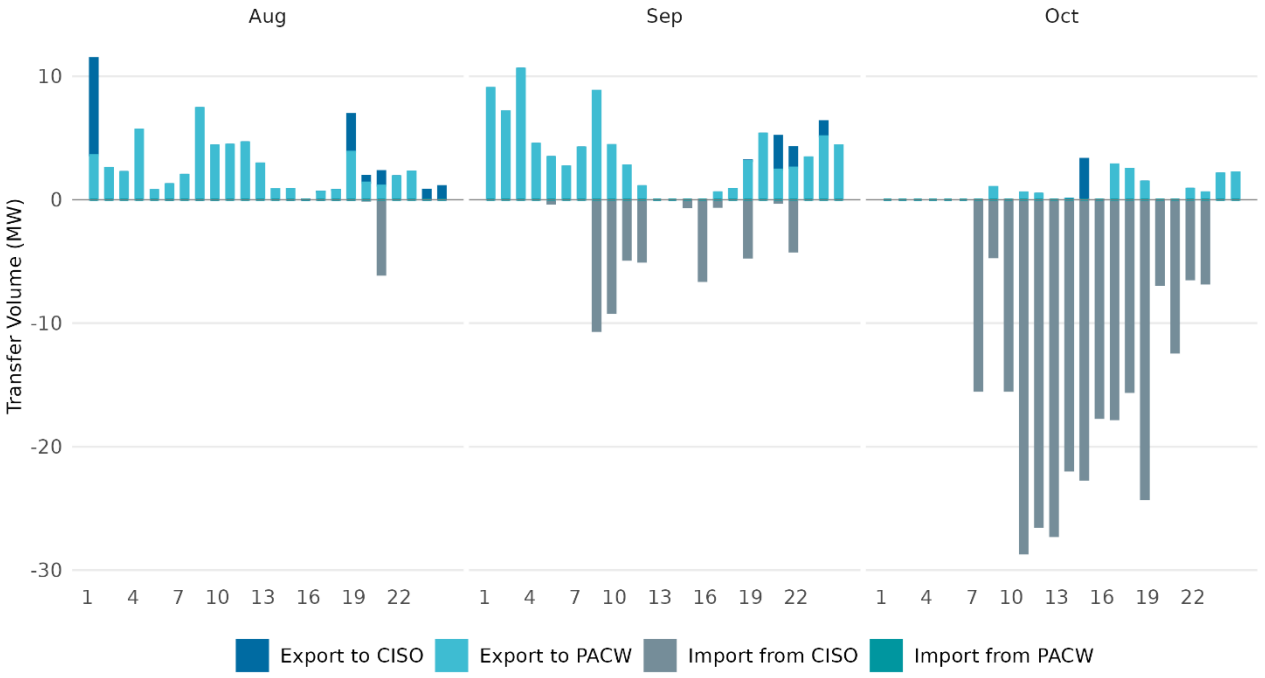


Figure 168: Hourly average RCD transfers for PACE



As for RCD transfer in PACW, the average imports were more dominantly from PACE in September and from CAISO in October, as a result PACW remained a net importer. The peak imports were over 20MW. From the hourly average, in October, the transfer pattern shifted as CAISO became a major source of RCD imports, resulting in substantially larger hourly import volumes, particularly around HE 10. PGE-related transfers also appeared in October but remained relatively small.

Figure 169: Daily average RCD transfers for PACW

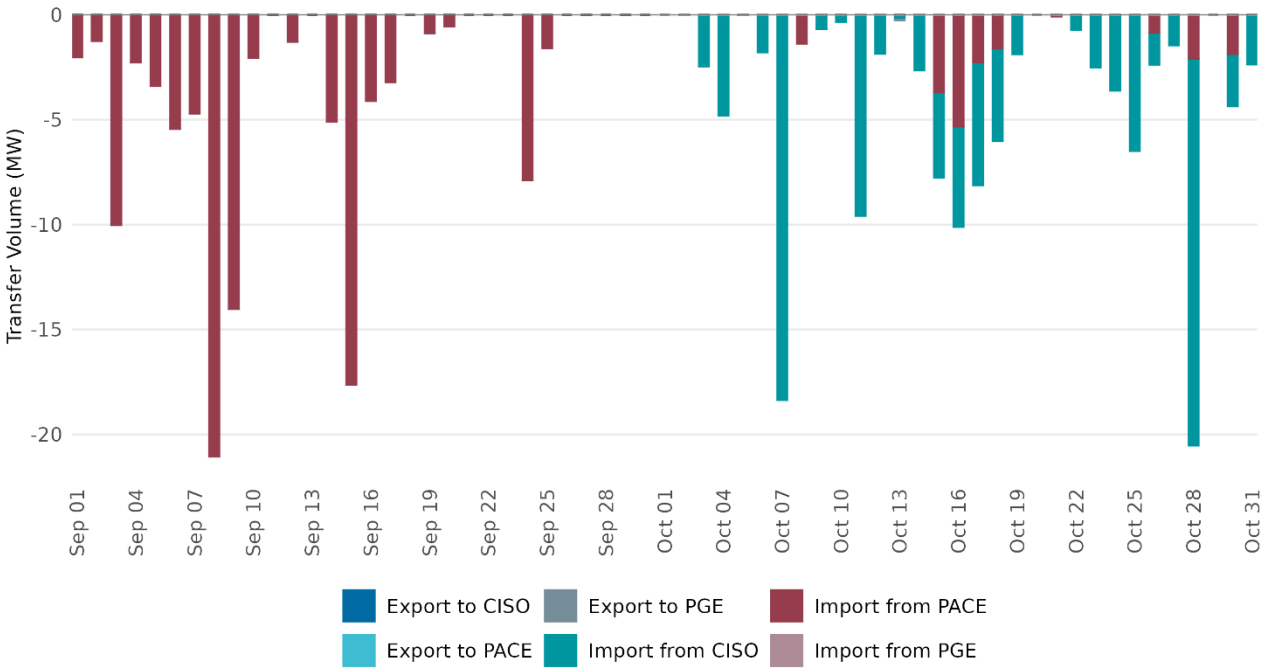
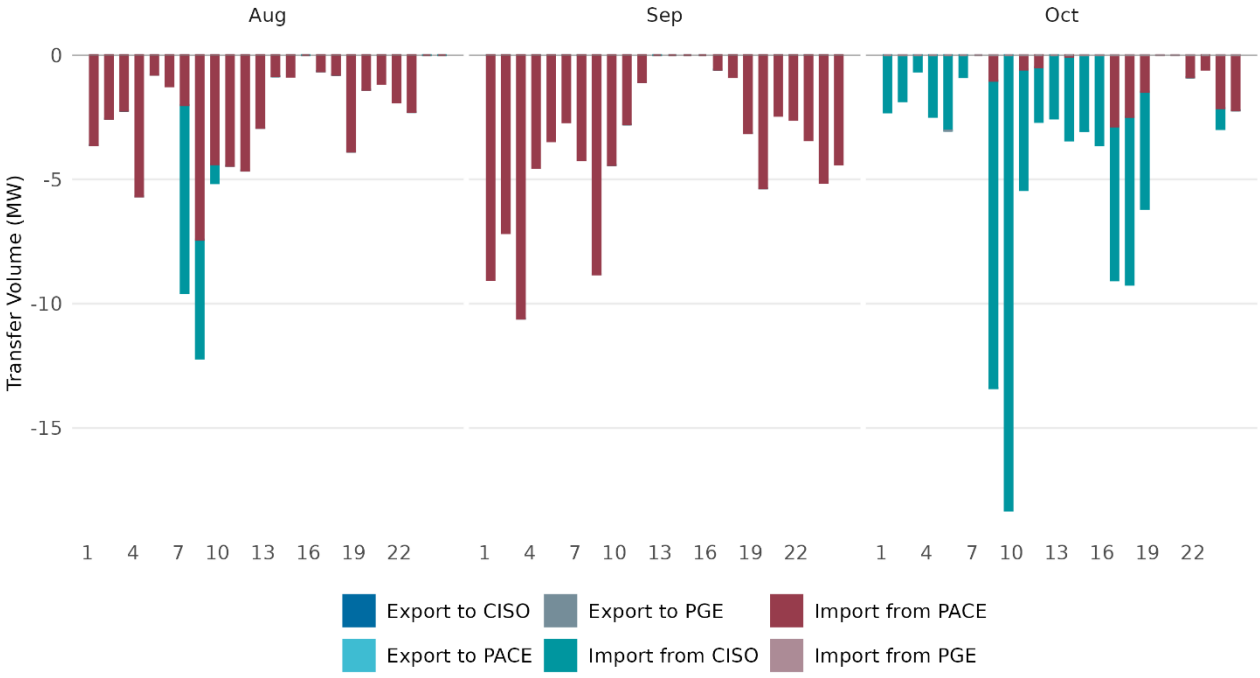


Figure 170: Hourly average RCD transfers for PACW



PGE's October RCD transfers were almost entirely imports from CAISO and were concentrated in a limited number of hours. The largest hourly import occurred around HE 9 at approximately 28 MW, followed by a smaller afternoon import period around HE 16–19. Daily imports were generally small, although several isolated days experienced considerably larger volumes, with the largest occurring around Oct. 28. Overall, RCD transfer activity between PGE and PACW and PGE's RCD exports were minimal.

Figure 171: Daily average RCD transfers for PGE

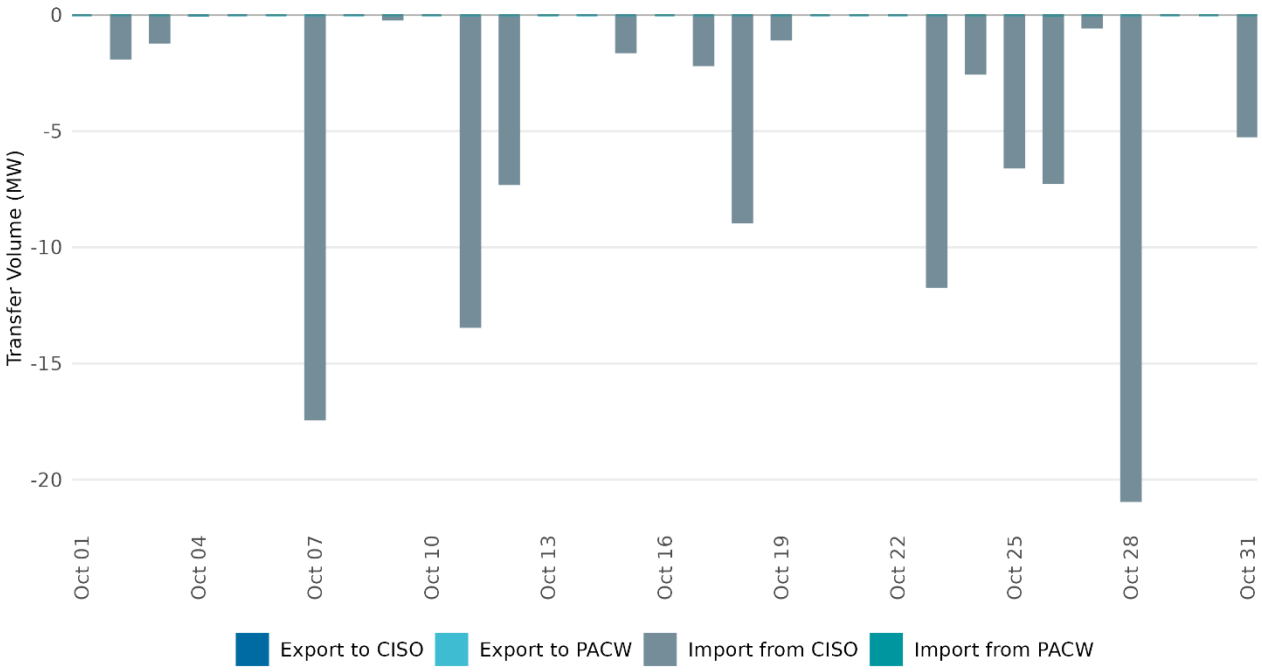
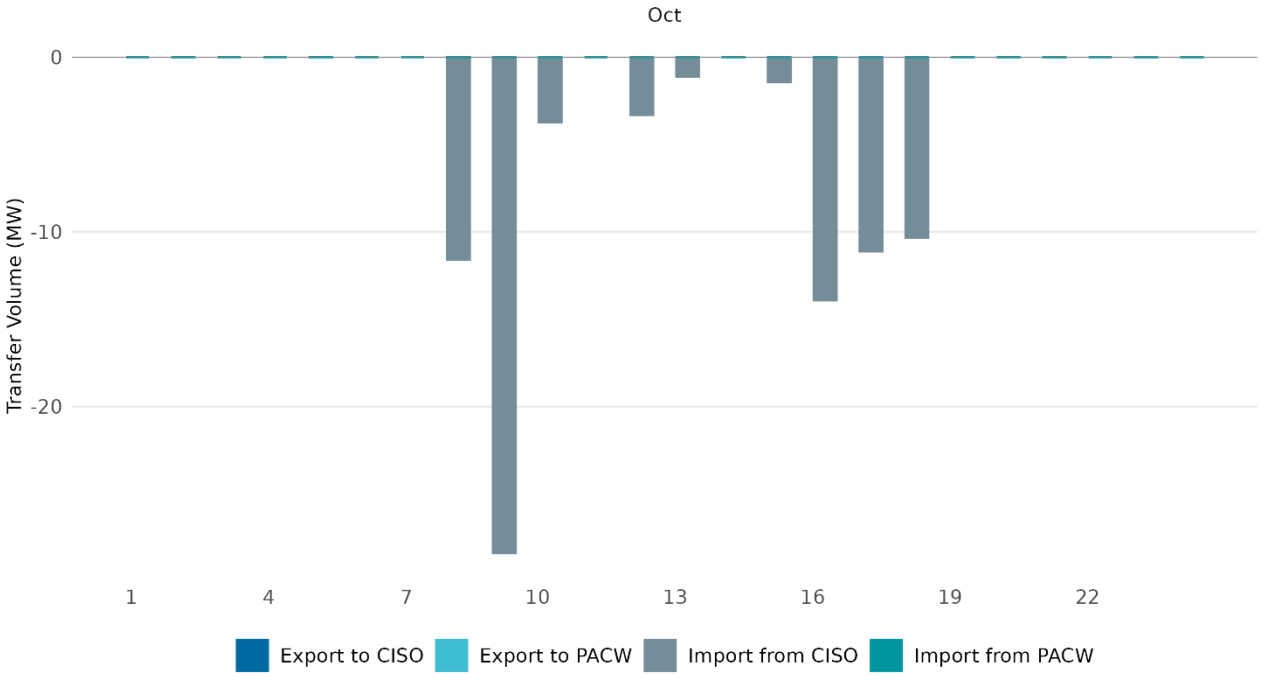


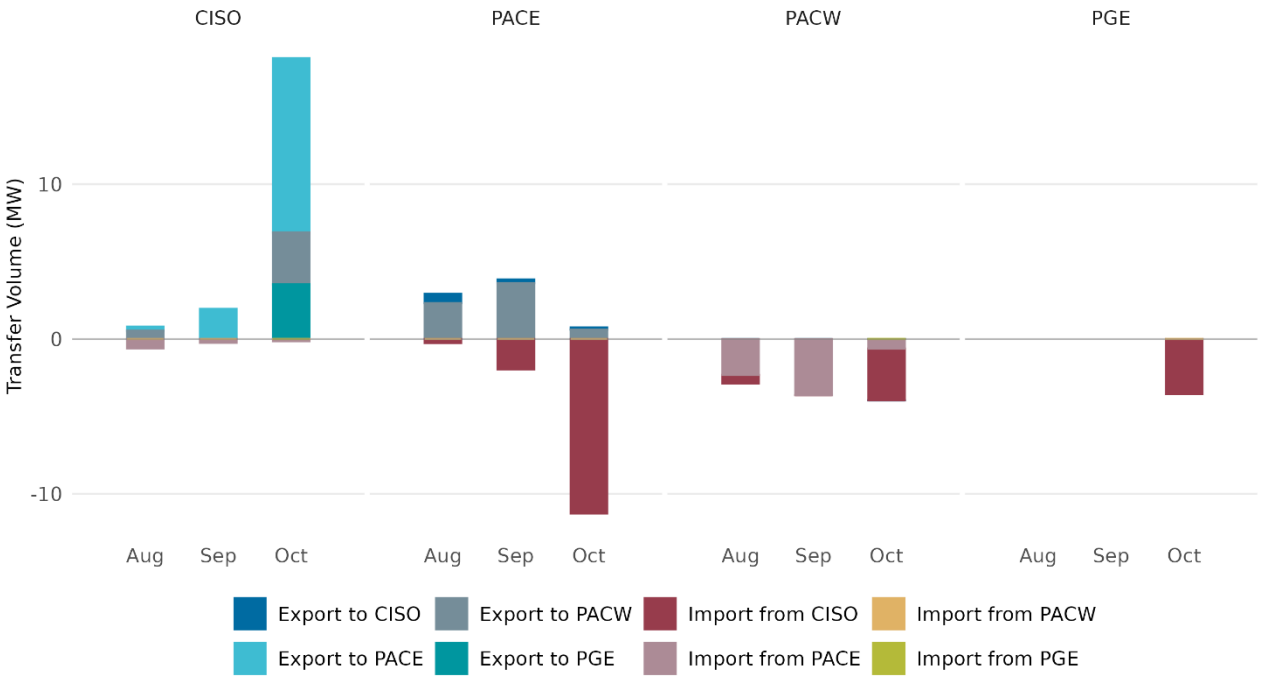
Figure 172: Hourly average RCD transfers for PGE



PGE's import is primarily from CAISO.

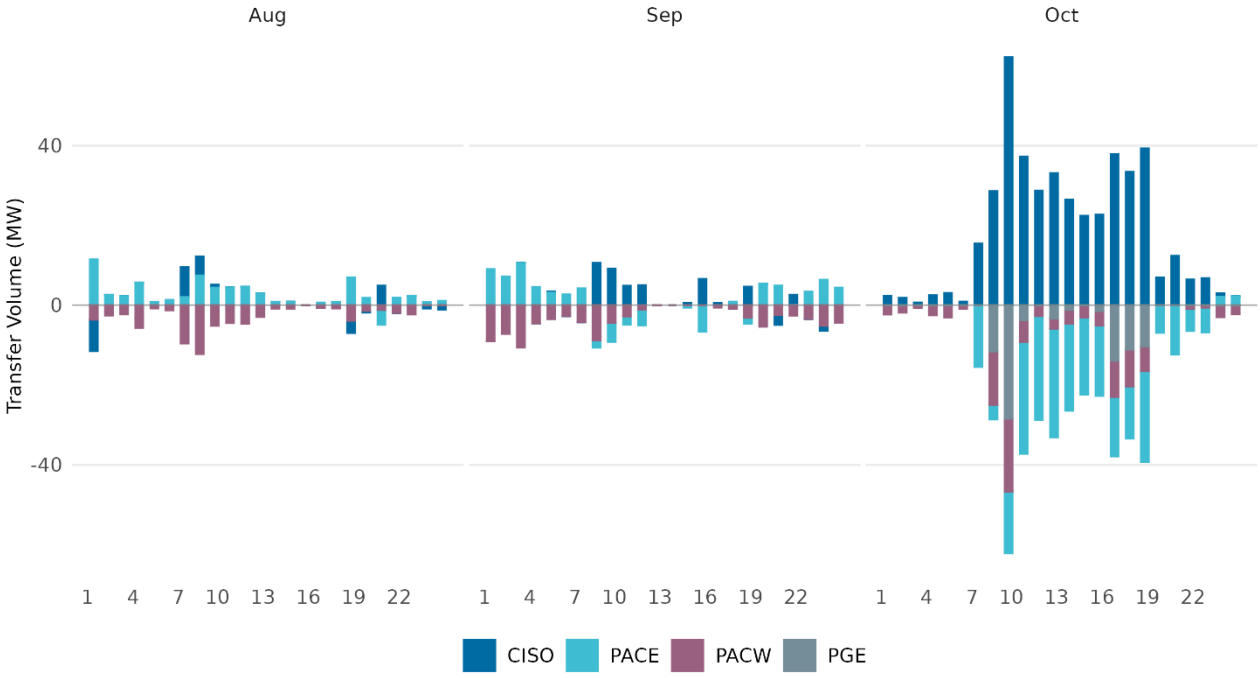
Figure 173 shows the summary of four BAAs' total RCD transfer volumes in both export (+) and import (-) directions. Generally, both BAAs have very different patterns across four months. CAISO recorded its largest net exports in October, primarily to PACE. PACW was predominantly a net importer, with the largest import volumes occurring in October and primarily associated with transfers from PACE. PGE's import is primarily from CAISO.

Figure 173: Hourly average RCD transfers volumes in EDAM



Net RCD transfer activity remained relatively limited in August and September but increased substantially in October. The October profile was characterized by strong CAISO net exports and corresponding net imports primarily into PACE, with PACW and PGE contributing additional import volumes. The largest transfer activity occurred around HE 9, when CAISO net exports reached approximately 60 MW and PACE recorded its largest net imports. Overall, October represents a clear increase in both the magnitude and diversity of RCD transfers across the EDAM footprint.

Figure 174: Hourly average net RCD transfers volumes in EDAM



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 8 shows the average MCC for the month of May to October for the EDAM DLAP/ELAP APnodes[5]. 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.

[5] These results are preliminary and subject to revision. A known data issue, as described in the market issues section, is currently under investigation, which may result in discrepancies in the analysis.

Table 8: Average congestion costs

	Average MCC ($/MWh)					
DLAP/ELAP	May	June	July	Aug	Sep	Oct
PGE						(0.30)
PACE	(0.80)	(0.75)	(0.19)	(0.22)	(0.65)	(2.33)
PACW	0.48	(0.87)	(0.93)	(1.96)	0.72	(0.28)
PGAE	4.04	2.29	(1.10)	(2.40)	1.65	0.56
SCE	(3.68)	(1.76)	0.56	1.35	(1.60)	(0.83)

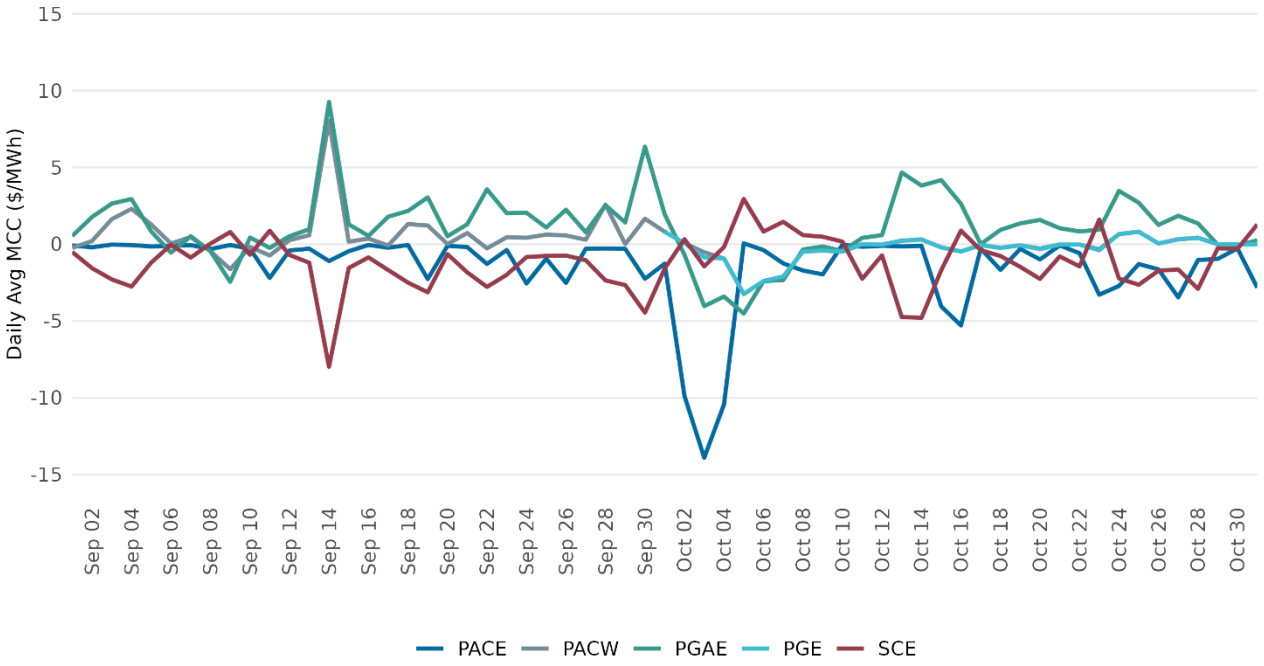
A positive number for MCC represents an increase in DLAP/ELAP LMP due to system congestion while a negative number represents a decrease in LMP from congestion. A positive MCC for a DLAP/ELAP indicates a more constrained area where cheaper energy may not be able to flow. In October, congestion impacts on PACE and PACW ELAP locational marginal prices were -$2.33 and -$0.28, respectively. PGE ELAP averaged -$0.30. CAISO DLAP SCE averaged -$0.83 for, while PGAE MCC averaged $0.56. Table 9 provides an hourly average of congestion costs across areas with the blue-green gradient indicating larger positive MCC prices and the gradient of violet indicates larger negative MCC prices. The South to North pattern is predominantly during high solar hours.

Table 9: Hourly average congestion costs

	Aug				Sep				Oct				
Trade Hour	PACE	PACW	PGAE	SCE	PACE	PACW	PGAE	SCE	PACE	PACW	PGAE	PGE	SCE
1	0.01	-1.98	-2.71	2.12	-0.19	-0.19	-0.31	0.06	-0.36	-0.73	-1.24	-0.72	-0.08
2	0.01	-1.89	-2.61	2.03	-0.17	-0.14	-0.20	-0.01	-0.39	-0.51	-0.95	-0.51	0.32
3	0.03	-1.48	-2.03	1.60	-0.13	-0.07	-0.14	-0.03	-0.42	-0.29	-0.57	-0.29	0.04
4	0.04	-1.47	-2.04	1.61	-0.10	-0.12	-0.19	0.04	-0.32	-0.25	-0.47	-0.25	0.01
5	0.02	-1.30	-1.79	1.40	-0.07	-0.09	-0.24	0.03	-0.23	-0.23	-0.44	-0.23	-0.03
6	0.05	-1.54	-2.12	1.73	-0.05	-0.08	-0.19	0.01	-0.44	-0.16	-0.38	-0.16	-0.32
7	0.05	-1.29	-1.72	1.42	-0.05	-0.03	-0.12	-0.07	-0.71	-0.08	-0.28	-0.08	-0.03
8	-0.04	-0.51	-0.54	0.28	-0.32	0.02	0.08	-0.43	-1.25	-0.04	0.02	-0.04	-0.02
9	-0.18	-0.82	-0.22	-0.65	-1.06	1.98	5.15	-5.02	-3.23	0.65	2.75	0.61	-2.60
10	-0.26	-1.06	0.06	-0.85	-1.10	1.84	6.23	-5.58	-3.03	0.37	4.40	0.36	-4.37
11	-0.22	-1.22	-1.63	0.10	-1.03	2.07	4.33	-4.11	-2.89	0.21	2.90	0.20	-3.12
12	-0.47	-1.67	-2.51	0.67	-1.00	1.93	4.08	-3.68	-2.90	-0.02	2.43	-0.03	-2.66
13	-0.52	-1.59	-2.42	0.51	-1.01	2.27	4.05	-3.66	-3.01	-0.13	2.04	-0.14	-2.31
14	-0.78	-1.73	-2.51	0.68	-1.09	2.13	3.86	-3.37	-3.31	-0.36	1.99	-0.36	-2.23
15	-0.87	-2.07	-2.95	0.98	-1.55	2.30	3.98	-3.26	-5.02	-0.36	2.24	-0.37	-1.91
16	-1.07	-3.03	-3.59	1.51	-2.04	2.30	3.88	-3.19	-6.48	0.00	3.15	-0.06	-2.33
17	-0.46	-2.64	-3.04	0.98	-2.20	2.63	4.10	-3.45	-6.68	-0.39	1.48	-0.40	-0.93
18	-0.47	-4.05	-3.84	2.12	-0.66	-0.39	0.66	-1.08	-3.47	-0.24	0.33	-0.24	-0.50
19	-0.13	-3.98	-4.39	3.03	-0.50	-0.16	0.78	-0.80	-2.99	-0.15	0.61	-0.15	-0.68
20	-0.04	-3.41	-4.11	2.92	-0.36	-0.09	0.39	-0.53	-2.67	-0.18	-0.28	-0.18	-0.31
21	-0.03	-2.00	-2.34	1.66	-0.27	-0.08	0.24	-0.40	-2.26	-0.74	-1.28	-0.74	0.68
22	-0.01	-2.66	-3.50	2.64	-0.28	-0.37	-0.36	0.09	-1.66	-1.52	-2.42	-1.77	1.67
23	-0.02	-1.86	-2.54	1.92	-0.19	-0.18	-0.23	-0.02	-1.34	-0.87	-1.46	-0.86	1.03
24	-0.01	-1.80	-2.53	1.95	-0.22	-0.26	-0.35	0.07	-0.75	-0.69	-1.18	-0.69	0.73

Figure 175 provides a daily trend of average congestion costs across the last two months. October saw the direction of congestion shift across EDAM areas due limited a limited heatwave at the start of the month.

Figure 175: 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.

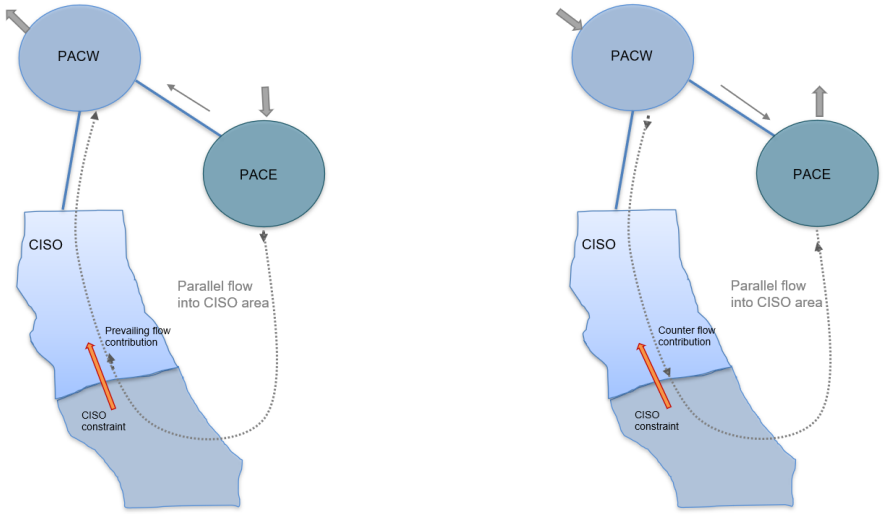
Figure 176: Parallel flow matrix example

	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 176 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 177 illustrates the concepts of prevailing and counter flows from a transaction between PAC areas creating a parallel flow in CAISO BAA.

Figure 177: Illustration of parallel flows



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

With the launch of EDAM/DAME, transactions from one EDAM BAA can directly impact transmission constraints in another BAA based on current system topology.

Table 10 goes a step further and breaks down the monthly average MCCs based on where the congestion is occurring. 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 of 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. The total in Table 10 ideally should align closely with the final MCC prices found on

Table 8, but due to possible data issues and/or price corrections, they may not align exactly.

Table 10: Estimated MCC breakdown by source of congestion[6]

LAP Congestion Price Impact ($/MWh)													
	Aug				Sep				Oct				
Origin of Congestion	PACE	PACW	PGAE	SCE	PACE	PACW	PGAE	SCE	PACE	PACW	PGE	PGAE	SCE
CISO	**-0.22**	**-1.96**	**-2.40**	**1.35**	**-0.65**	**0.72**	**1.65**	**-1.60**	**-2.33**	**-0.28**	**-0.30**	**0.56**	**-0.83**
Base	-0.21	-1.73	-2.11	1.16	-0.64	0.72	1.52	-1.52	-2.16	-0.27	-0.28	0.55	-0.85
IRD	0.000	0.000	0.01	0.00	-0.007	-0.004	0.08	-0.04	-0.004	-0.001	-0.001	0.01	0.02
IRU	-0.007	-0.23	-0.31	0.19	0.000	0.00	0.05	-0.04	-0.158	-0.010	-0.01	0.004	0.002

Based on this table, CAISO constraints across all deployment scenario constraint types, on average, had a -0.65 and 0.72 $/MWh MCC impact on PACE and PACW, respectively. New to EDAM, PGE also averaged a -$0.30 impact from CAISO constraints. There was no direct impact from PacifiCorp or Portland General Election congestion on any LAPs across the EDAM footprint.

[6] These results are preliminary. An identified data issue impacting the availability of shift factors may result in discrepancies between the total MCC reported.

Table 11: Congestion costs by constraint for October 2026

October 2026 Average Congestion Costs by Constraint		PACE			PACW			PGE			PGAE			SCE		
BAA	Constraint Name	Base	IRD	IRU	Base	IRD	IRU	Base	IRD	IRU	Base	IRD	IRU	Base	IRD	IRU
CISO	22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1													0.00		
CISO	22331_MIRASNTO_69.0_22644_PENSQTOS_69.0_BR_1 _1										(0.01)			(0.01)		
CISO	22342_HDWSH _500_22536_N.GILA _500_BR_1 _2	(0.00)	(0.00)		(0.00)	(0.00)		(0.00)	(0.00)		(0.00)	(0.00)		0.00	0.00	
CISO	22357_IV PFC1 _230_22358_IV PFC _230_PS_1	(0.03)									(0.01)	(0.00)	(0.00)	(0.00)		
CISO	22442_MELRSETP_69.0_22724_SANMRCOS_69.0_BR_1 _1													0.00		
CISO	22604_OTAY _69.0_22616_OTAYLKTP_69.0_BR_1 _1										(0.00)			(0.00)		
CISO	22716_SANLUSRY_230_24131_S.ONOFRE_230_BR_3 _1	(0.01)			(0.01)			(0.01)			(0.01)			(0.01)		
CISO	22771_BAY BLVD_230_22430_SILVERGT_230_BR_1 _1												(0.00)			0.00
CISO	22773_BAY BLVD_69.0_22352_IMPRLBCH_69.0_BR_1 _1													(0.00)		
CISO	22828_SYCAMORE_69.0_22756_SCRIPPS _69.0_BR_1 _1										(0.00)		(0.00)			
CISO	22831_SYCAMORE_138_22832_SYCAMORE_230_XF_1										(0.02)		(0.00)			
CISO	24016_BARRE _230_24154_VILLA PK_230_BR_1 _1	(0.06)			(0.03)			(0.03)			(0.02)			0.07		
CISO	24016_BARRE _230_25201_LEWIS _230_BR_1 _1	(0.04)			(0.01)			(0.02)			(0.01)			0.06		
CISO	24084_LITEHIPE_230_24091_MESA CAL_230_BR_1 _1				(0.00)		(0.01)	(0.00)		(0.01)	(0.00)		(0.01)	0.00		0.01
CISO	24091_MESA CAL_230_24076_LAGUBELL_230_BR_2_1	(0.03)		(0.00)	(0.05)		(0.00)	(0.05)		(0.00)	(0.05)		(0.00)	0.06		0.00
CISO	24114_PARDEE _230_24217_WARNETAP_230_BR_1 _1										0.00			(0.01)		
CISO	24701_KRAMER _230_24601_VICTOR _230_BR_2 _1										0.00			(0.03)		(0.00)
CISO	24716_COLWATER_115_24774_DUNNSIDE_115_BR_1 _1													0.11		
CISO	24723_CONTROL _115_24728_INYO-SCE_115_BR_1 _1															(0.00)
CISO	28727_IVANPAH _115_24778_MTN PASS_115_BR_1 _1													(0.02)		(0.00)
CISO	30050_LOSBANOS_500_30055_GATES1 _500_BR_1 _3	(0.00)			0.00			0.00			0.00			(0.01)		
CISO	30055_GATES1 _500_30060_MIDWAY _500_BR_1 _1	(0.01)			0.08			0.08			0.11			(0.11)		
CISO	30060_MIDWAY _500_24156_VINCENT _500_BR_2 _3	0.08			(0.25)			(0.25)			(0.35)			0.27		
CISO	30750_MOSSLD _230_30797_LASAGUIL_230_BR_1 _1										0.33			(0.28)		
CISO	30765_LOSBANOS_230_30790_PANOCHE _230_BR_2 _1				0.02			0.02			0.03			(0.05)		
CISO	30790_PANOCHE _230_30900_GATES _230_BR_1 _1				0.01			0.01			0.12			(0.11)		
CISO	30790_PANOCHE _230_30900_GATES _230_BR_2 _1				0.01			0.01			0.10			(0.10)		
CISO	30797_LASAGUIL_230_30790_PANOCHE _230_BR_2 _1										0.02			(0.02)		
CISO	30900_GATES _230_30889_CAFLTSSS_230_BR_1 _1										0.00			(0.00)		
CISO	30900_GATES _230_30935_ARCO _230_BR_1 _1										0.00			(0.00)		
CISO	30915_MORROBAY_230_30916_SOLARSS _230_BR_2 _1										0.00			(0.00)		
CISO	31227_HGHLNDJ2_115_31950_CORTINA _115_BR_1 _1										(0.02)					
CISO	31338_KONOCTI6_60.0_31344_EGLE RCK_60.0_BR_1 _1										0.00					
CISO	31640_TRES VIS_60.0_31718_TBLE MTN_60.0_BR_1 _1										0.00					
CISO	32056_CORTINA _60.0_30451_CRTNA M_1.0_XF_1										0.07			(0.02)		
CISO	32225_BRNSWKT1_115_32222_DTCH2TAP_115_BR_1 _1										0.00	0.00				
CISO	33020_MORAGA _115_32780_CLARMNT _115_BR_2 _1										0.00			(0.00)		
CISO	33500_MELNS JA_115_33509_AVENATP1_115_BR_1 _1										(0.01)					
CISO	33509_AVENATP1_115_33514_MANTECA _115_BR_1 _1										0.00					
CISO	33541_AEC_TP1 _115_33540_TESLA _115_BR_1 _1										(0.01)	(0.00)	(0.01)	(0.00)	0.00	0.00
CISO	33543_AEC_TP2 _115_33540_TESLA _115_BR_1 _1										(0.01)			0.00		
CISO	33932_MELONES _115_33500_MELNS JA_115_BR_1 _1										(0.00)					
CISO	33950_RVRBK TP_115_33934_TULLOCH _115_BR_1 _1										(0.00)		(0.00)			
CISO	34101_CERTANJ2_115_34116_LE GRAND_115_BR_1 _1										0.00	0.00	0.00			
CISO	34116_LE GRAND_115_34115_ADRA TAP_115_BR_1 _1										0.00		0.00	(0.00)		(0.00)
CISO	34214_LOS BANS_70.0_30765_LOSBANOS_230_XF_3										0.00			(0.00)		
CISO	34256_BORDEN _70.0_30805_BORDEN _230_XF_1										0.00	0.00				
CISO	34375_ULTPWRJ _115_34377_AIRPROD _115_BR_1 _1										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										0.11			(0.06)		
CISO	34430_HENRETTA_115_34519_LPNJCTSS_115_BR_1 _1										0.00			(0.00)		
CISO	34519_LPNJCTSS_115_34429_GWF_HEP _115_BR_1 _1										0.00			(0.00)		
CISO	34540_HENRITTA_70.0_30881_HENRIETA_230_XF_4										(0.00)		(0.00)			
CISO	34706_WESTPARK_115_34752_KERN PWR_115_BR_1 _1										0.00			(0.00)		
CISO	34778_FELLOWS _115_34800_MORGAN _115_BR_1 _1										(0.00)					
CISO	34873_Q484TP _70.0_34850_BLACKWLL_70.0_BR_1 _1											0.00				
CISO	35120_NEWARK D_115_36851_NORTHERN_115_BR_1 _1										(0.01)			(0.09)		
CISO	35122_NWARK EF_115_35602_ZNKER J2_115_BR_1 _1													(0.01)		
CISO	35122_NWARK EF_115_36851_NORTHERN_115_BR_2 _1										(0.00)			(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_35612_TRIMBLE _115_BR_1 _1										0.01			(0.01)		
CISO	35618_SN JSE A_115_35616_SNJOSEB _115_BR_1 _1										0.19		0.00	(0.18)		(0.00)
CISO	35618_SN JSE A_115_35620_EL PATIO_115_BR_1 _1										0.01			(0.01)		
CISO	35642_METCALF _115_30735_METCALF _230_XF_2										0.00			(0.00)		
CISO	35658_LS ESTRS_115_35659_NORTECH _115_BR_1 _1										0.00			(0.05)		
CISO	36711_DRLKSW _230_30900_GATES _230_BR_1 _1										0.03			(0.03)		
CISO	36850_KIFER _115_35615_FMC _115_BR_1 _1										(0.00)			(0.00)		
CISO	36851_NORTHERN_115_36852_SCOTT _115_BR_2 _1										(0.05)			(0.07)		
CISO	38615_DS AMIGO_230_30790_PANOCHE _230_BR_1 _1										(0.00)			(0.30)		
CISO	7320_CP6_NG										0.00	0.00	0.00			
CISO	7430_CP6_NG										0.17	0.00	0.02	(0.21)	(0.00)	(0.02)
CISO	7440_MetcalfImport_MossId-Metclf	(0.00)		(0.00)	(0.00)		(0.00)	(0.00)		(0.00)	0.00		0.00	(0.00)		(0.00)
CISO	7510-PAS-BAI-PAR-OOS_NG												0.00			(0.01)
CISO	7690-CONTRL-INYOKN_EXP_NG													(0.01)	(0.00)	(0.01)
CISO	7690-COOLWATER_KRAMER_IM_NG														0.00	0.00
CISO	7690-INYOKN_VOLTAGE_EX_NG													(0.00)		(0.00)
CISO	7720_JHINDS_CP2_NG													(0.00)		
CISO	7760_DEV_RDB_ALIS	(0.54)		(0.01)							0.02			0.29		0.00
CISO	7820_TL 230S_OVERLOAD_NG	(0.09)	(0.00)	(0.00)	(0.04)	(0.00)	(0.00)	(0.04)	(0.00)	(0.00)	(0.05)	(0.00)	(0.00)	(0.02)	(0.00)	(0.00)
CISO	7820_TL23040_IV_SPS_NG	(0.58)		(0.06)	(0.00)			(0.01)			(0.26)		(0.02)	(0.01)		(0.00)
CISO	8610_SylmarBNK_N-S_Import_NG	(0.44)		(0.08)							0.10		0.02	0.23		0.04
CISO	99254_J.HINDS2_230_24806_MIRAGE _230_BR_1 _1										0.00	0.00	0.00	0.01	0.03	0.00
CISO	HUMBOLDT_EXP_NG										(0.00)		(0.00)	0.00		0.00
CISO	HUMBOLDT_IMP_NG											0.01			(0.00)	
CISO	Line_Wilo-EOX_500KV	(0.09)									0.02			0.03		
CISO	OMS IV-ML OUTAGE_NG	(0.03)		(0.00)	(0.01)		(0.00)	(0.01)		(0.00)	(0.02)		(0.00)	0.00		0.00
CISO	OMS_20625036_TL13811_NG										0.00			0.00		
CISO	OMS_20864775_TL13811_NG										0.00			0.00		
CISO	OMS_21115171_SDGE PSPS OUTAGE_NG	(0.24)		(0.02)							(0.08)		(0.01)	(0.01)		(0.00)
CISO	OMS_21156170_SCE_PSPS_EXP													(0.05)		(0.00)
CISO	OMS_Devers230Bus_NG												0.00			(0.00)
CISO	OMS_TL23054_OUTAGE_NG	(0.01)									(0.01)			0.00		
CISO	TL50001+TL50003_OOS_SLINE_IMP	(0.04)	(0.00)	(0.00)							(0.01)	(0.00)	(0.00)	0.00	0.00	0.00

In summary, the preliminary assessment 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)[7] 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

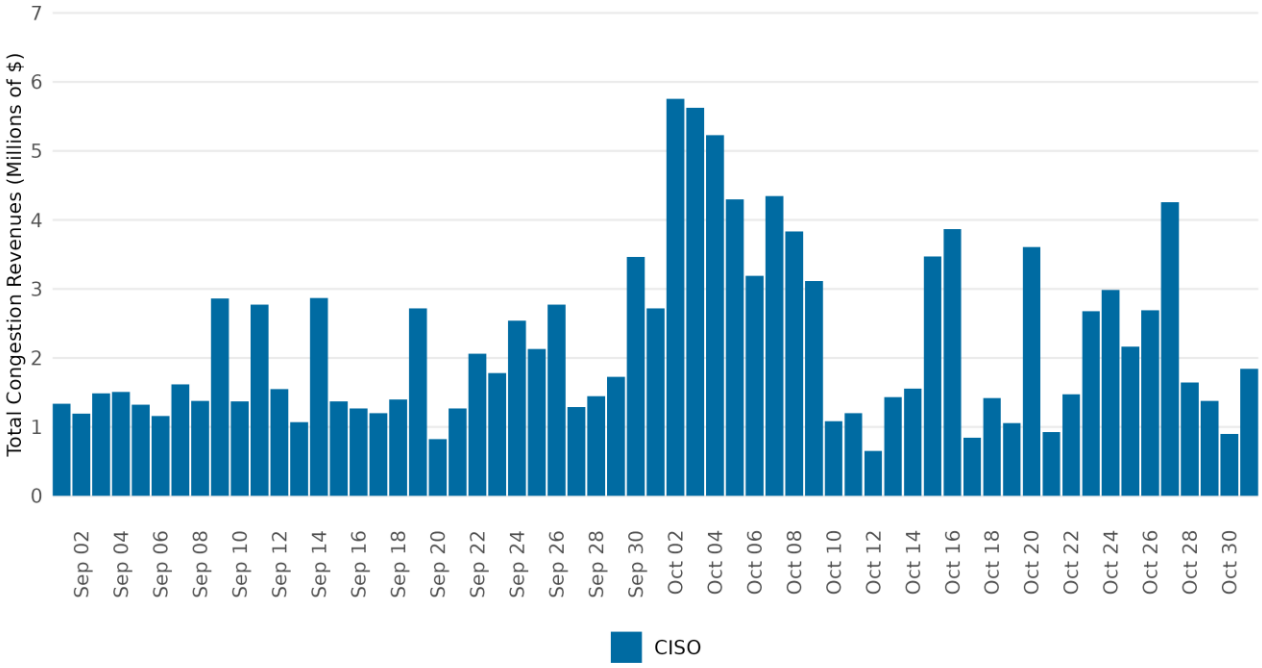
Congestion revenues

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. Please note that these results are preliminary and are subject to change. The following figures are representative of available data at the time of developing this report.

Figure 178 provides the daily BAA totals for congestion revenues based on the area where the congestion occurred.

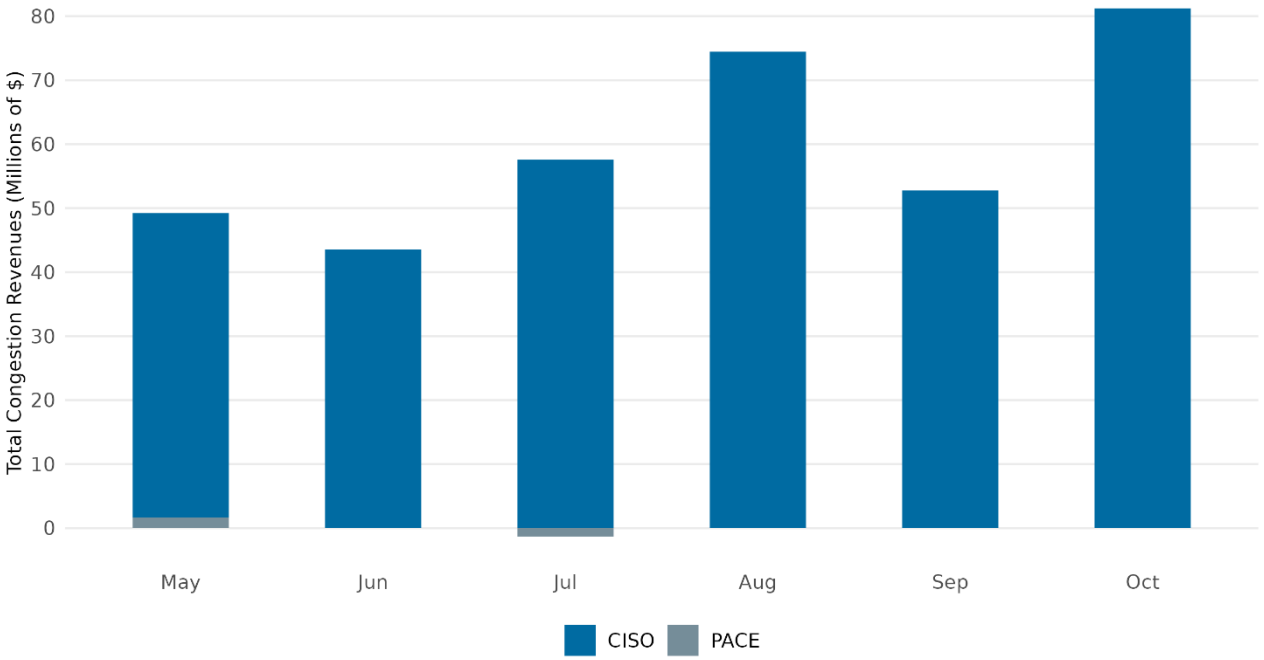
[7] https://stakeholdercenter.caiso.com/InitiativeDocuments/Stage-1-Analysis-Extended-Day-Ahead-Market-Congestion-Revenue-Allocation-Dec-11-2025.pdf

Figure 178: Daily congestion total by BAA



Total congestion revenues in October at the constraint level were $81.3M, attributed entirely to the CISO area. Much of the congestion occurring during the unusually high demand in early October. Figure 179 provides a monthly summary of the latest congestion totals since May 2026.

Figure 179: Monthly congestion total by BAA[8]



The current methodology 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 180 illustrates the daily total congestion revenues from CISO congestion that are returned to PAC areas given that they are associated with self-schedules supported by OATTs rights. These rights are either point-to-point rights or for Network service (NITS). Those rights are exercised and can be tracked through balanced CRN self-schedules. On the chart, a positive value indicates a payment, while negative values indicate a charge.

The allocation to all EDAM areas is about $549,000 in October. This is reflective of net credit back to due to their net schedules originally received congestion charges for providing prevailing flows on constraints the ISO areas. PAC received $511,000 while PGE received about $38,000. Figure 181 provides a monthly summary of this metric for previous months.

[8] This report uses more than one source of data to estimate congestion rents depending on the purpose of the metric, which in some cases may result in differences in values because certain inputs coming from settlements still reflecting data issues to be addressed. These estimates will be updated in subsequent reports.

Figure 180: Estimated total CRN congestion credit to EDAM BAAs from CISO congestion

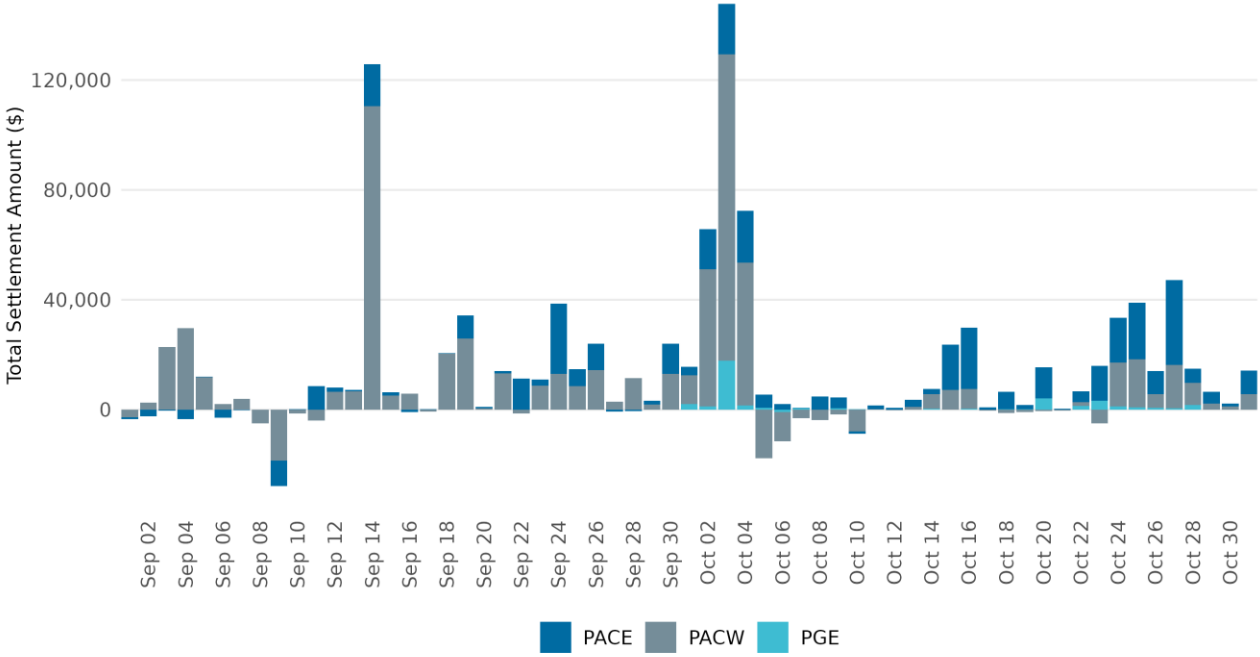


Figure 181: Total CRN congestion credit to EDAM BAAs from CISO congestion

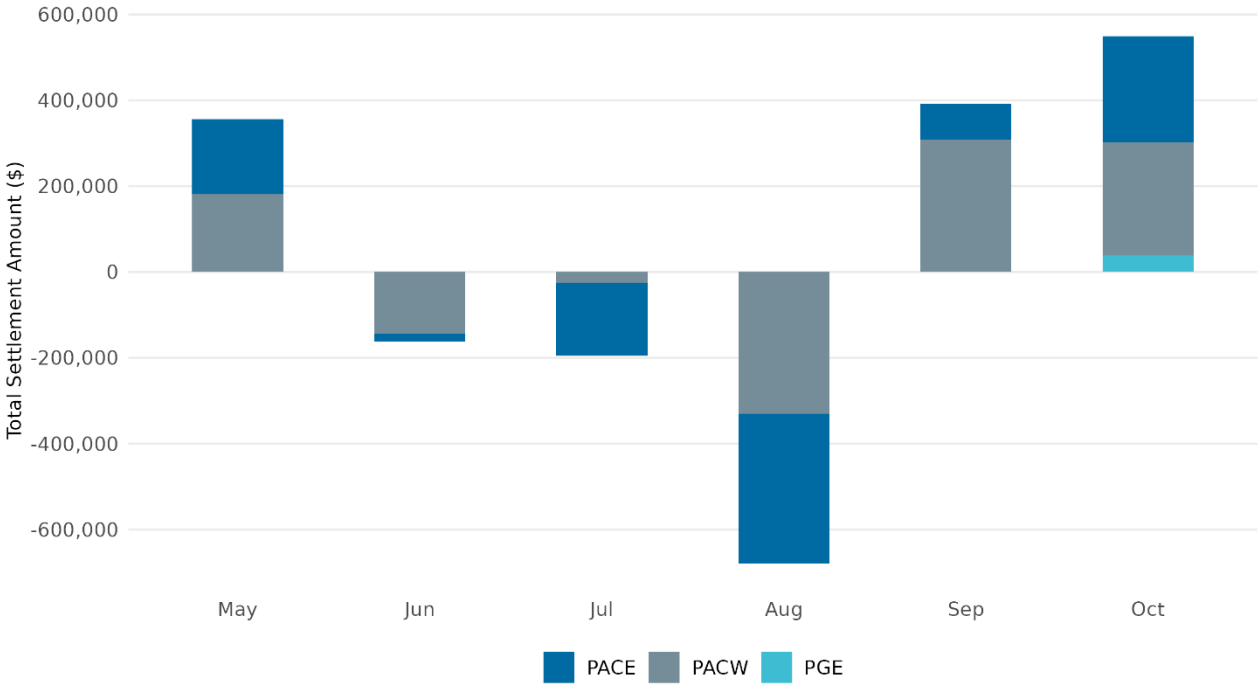


Table 12 provides a further breakdown of the CRA totals by resource type.

Table 13 provides the estimated CRA impact of the top five most impactful constraints. Impact is based on the absolute value of CRA settlement.

Table 12: Monthly CRA totals broken down by resource type

Month, Res Type	PACE	PACW	PGE	Grand Total
Sep	**83,326**	**308,362**		**391,688**
ETIE	(92,871)	232,670		139,799
GEN	487,162	(228,157)		259,004
ITIE	274,675	(324,108)		(49,434)
LOAD	(585,639)	627,958		42,319
Oct	**246,721**	**264,243**	**38,455**	**549,420**
ETIE	(335,362)	(235,279)	(91,511)	(662,152)
GEN	1,763,439	78,245	72,469	1,914,153
ITIE	497,874	693,207	216,444	1,407,524
LOAD	(1,679,229)	(271,929)	(158,947)	(2,110,106)

Table 13: Estimated CRA to for top five most impactful CAISO constraints

Month, Top Constraint	PACE	PACW	PGE
Sep	**46,381**	**241,312**	
30060_MIDWAY _500_24156_VINCENT _500_BR_2 _3	(14,687)	(47,237)	
30765_LOSBANOS_230_30790_PANOCHE _230_BR_2 _1	(980)	223,500	
30790_PANOCHE _230_30900_GATES _230_BR_2 _1	12,865	55,128	
7760_DEV_RDB_ALIS	30,750	21,916	
7820_TL 230S_OVERLOAD_NG	18,435	(11,996)	
Oct	**170,770**	**224,618**	**22,852**
30060_MIDWAY _500_24156_VINCENT _500_BR_2 _3	2,894	(54,225)	1,615
7760_DEV_RDB_ALIS	63,556	60,230	
7820_TL23040_IV_SPS_NG	34,901	136,406	18,878
8610_SylmarBNK_N-S_Import_NG	57,232	37,757	1,501
OMS_21115171_SDGE PSPS OUTAGE_NG	12,186	44,449	858

Figure 182 shows OATT-balanced self-schedule volumes as a share of total self-schedule volumes for each EDAM area. In October, OATT-balanced self-schedules accounted for 44% of total self-schedules in PACE, 79% in PACW, and 89% in PGE. Figure 183 shows the corresponding OATT-

balanced self-schedule volumes. During October, average volumes were 1,152 MW in PACE, 2,156 MW in PACW, and 1,186 MW in PGE.

Figure 182: Total self-schedules compared to OATT self-schedules by PAC area

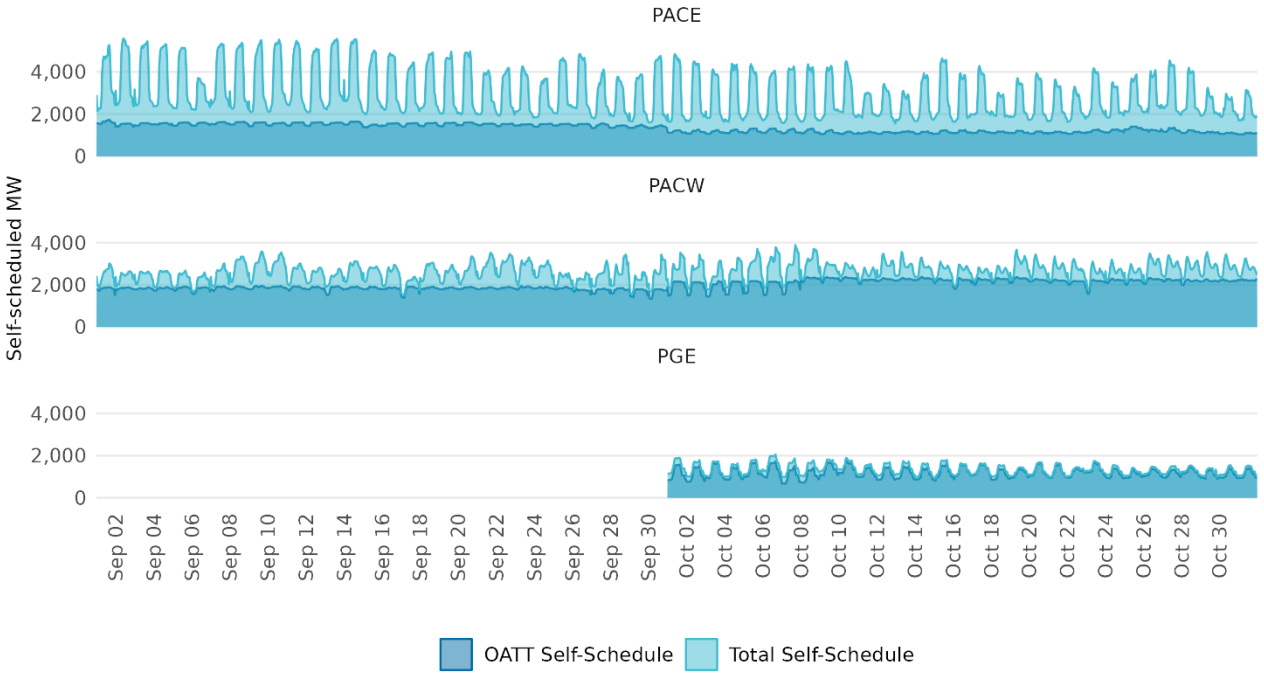


Figure 183: Total OATT self-schedule volumes by PAC area

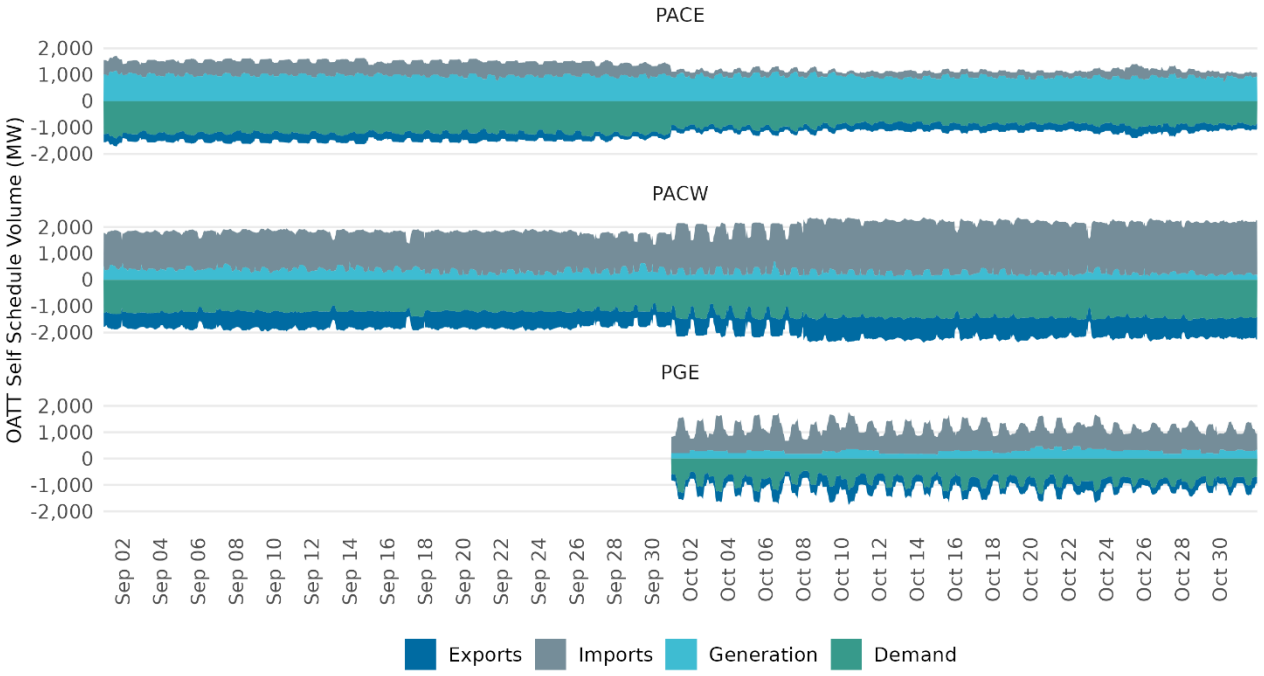
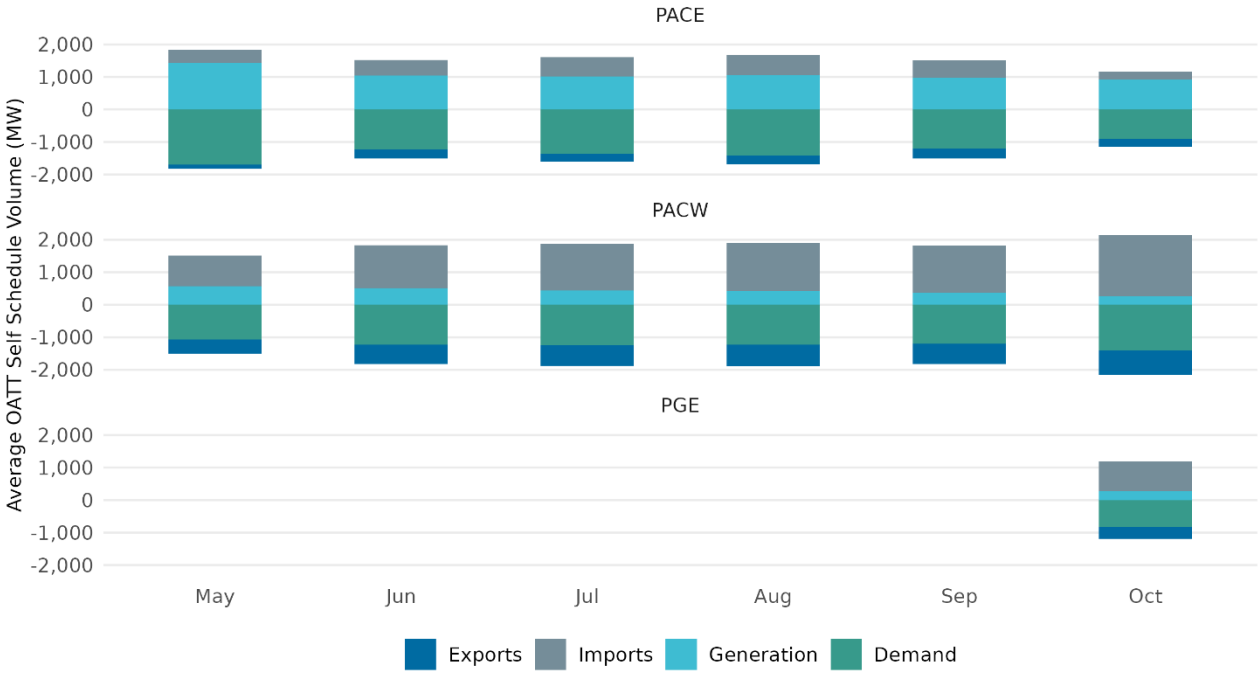


Figure 184: Monthly average OATT self-schedule volume



Congestion revenue rights

The Extended Day-Ahead Market (EDAM) continues to rely on locational marginal pricing. The existing design, under which day-ahead congestion rents are used to fund Congestion Revenue Rights (CRRs), remains fully in place for the CAISO balancing area. Congestion revenues collected on constraints within the CAISO balancing area are used to fund both allocated and auctioned CRRs. Currently, no CRRs exist for other balancing areas participating in EDAM.

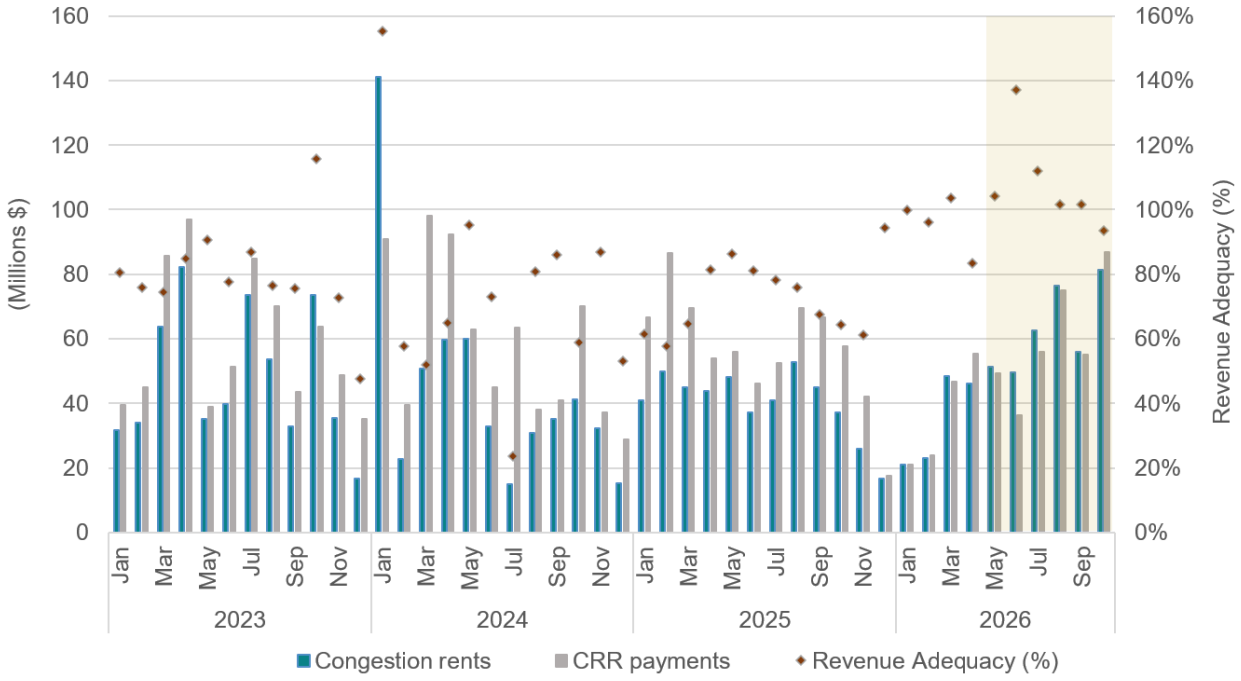
With EDAM implementation, schedules in the PacifiCorp (PAC) balancing area that impact flows on CAISO transmission constraints are assessed congestion charges based on their contribution to those constraints. However, the portion of congestion revenues collected on PAC schedules associated with self-schedules and the exercise of transmission rights is allocated back to PAC and is therefore excluded from the funds used to pay CRRs.

Revenue adequacy exists when congestion revenues collected in the day-ahead market are sufficient to cover the notional value of released CRRs. In principle, day-ahead congestion rents should fully fund CRR payments.

Under the partial funding policy adopted in January 2019, CAISO reduces CRR payments based on each CRR holder's contribution to deficits on a constraint-by-constraint basis. Because individual constraints may produce either surpluses or deficits, surpluses on one constraint are not used to offset deficits on another. While this pro-rata funding approach ensures CRR revenue neutrality, CAISO continues to monitor revenue adequacy because the primary objective is to release CRRs only up to the level that can be fully funded.

Figure 185 illustrates the monthly trend in CRR revenue adequacy. The bars show day-ahead congestion rents collected and the corresponding notional CRR payments. The purple markers indicate revenue adequacy as a percentage. Values below 100 percent reflect periods of CRR revenue inadequacy. Revenue adequacy for May through September has been over 100 percent, indicating that congestion rents collected in the day-ahead market have been greater than the CRR payments. October resulted in 93%, while not 100%, it is still relatively high in comparison to historical values. This outcome needs to be taken with caution since there are still revisions to settlement estimates as different issues are addressed. Further, given the low level of congestion rents related to non-CAISO EDAM schedules and the level of revenues allocated back to those entities, the level of revenue adequacy is not materially impacted by EDAM.

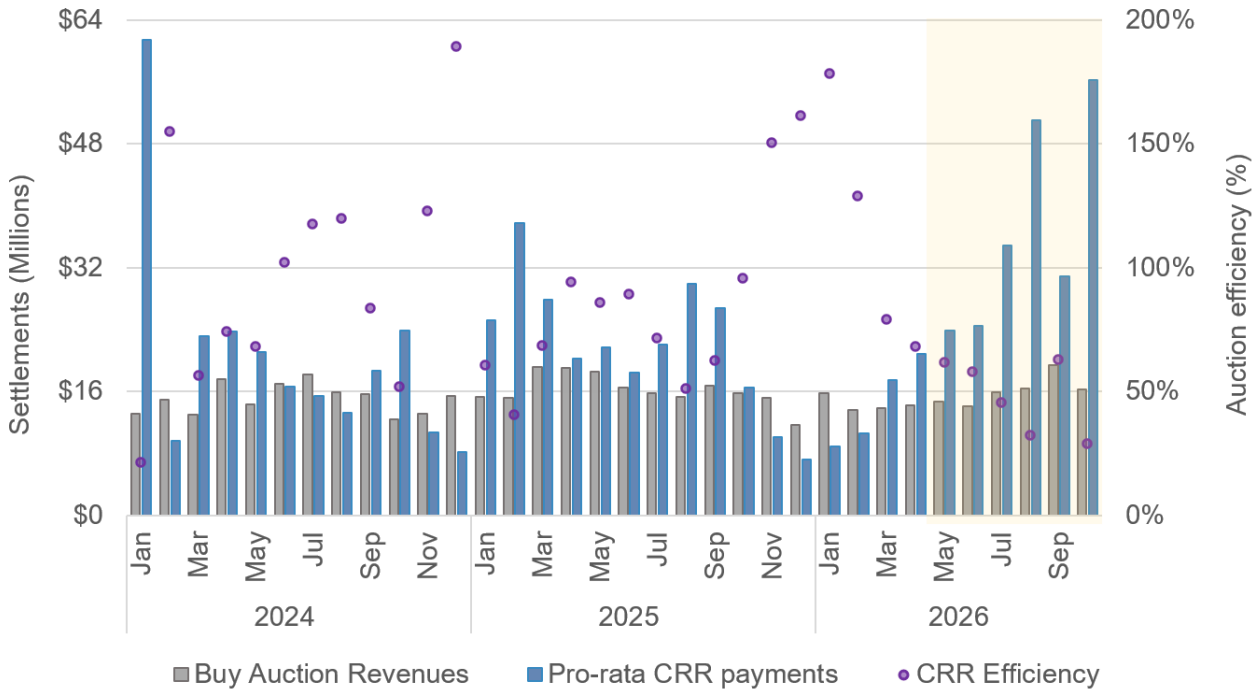
Figure 185: CRR revenue adequacy



Auction efficiency measures the difference between the price paid to acquire a CRR and the amount received through CRR settlements

Figure 186 illustrates these values in the bars, while the purple markers show auction efficiency as a percentage. Auction efficiency has been low from May through October, with October seeing the lowest ratio at just 26 percent when high congestion happened in the day-ahead market while moderate auction revenues were collected in the auction process. This trend is consistent with historical seasonal patterns, as higher summer loading conditions generally lead to increased congestion and reduced auction efficiency.

Figure 186: CRR auction efficiency



EDAM Net Export Constraints and RUC Adjustments

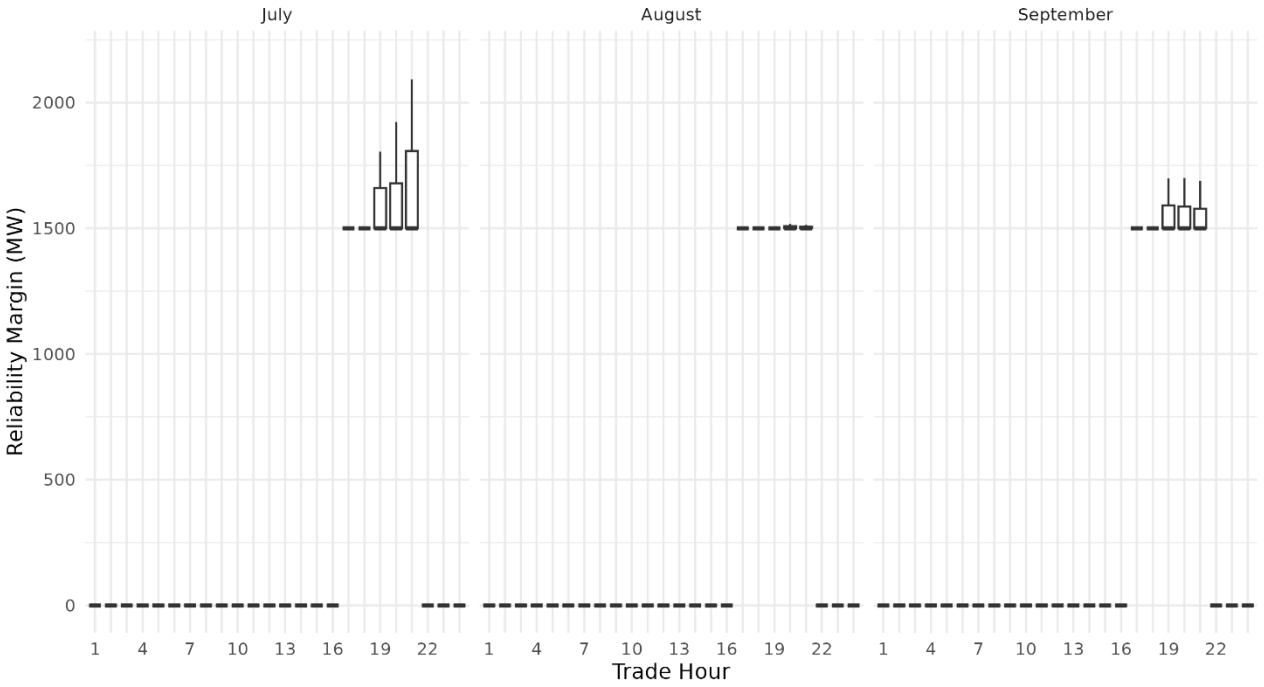
The EDAM export constraint and RUC adjustments are optional BA level constructs that help ensure sufficient procurement to support reliability going into the real-time market.

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 187: 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. This constraint has not been binding in the CAISO area in any hour since EDAM went live in May. Neither PACE nor PACW have opted to enforce this constraint so far.

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.

Figure 188 and Figure 189 show a comparison of RUC adjustments used in the periods of May-August for 2025 and 2026. In October 2026 there were 124 hours with a RUC adjustment, a minor increase from the 120 hours with RUC adjustments observed in October 2025. The maximum hourly average adjustment in October 2025 was 521 MW, while the hourly average adjustment in

October 2026 saw a steep increase to 1,394 MW. The reason for this pattern is the unusual high temperatures with high loads observed in early October 2026. Loads in early October were over 45,000 while in October 2025 they were significantly lower and not exceeding 35,000MW.

Figure 188: Day-ahead manual adjustments and demand in the ISO area

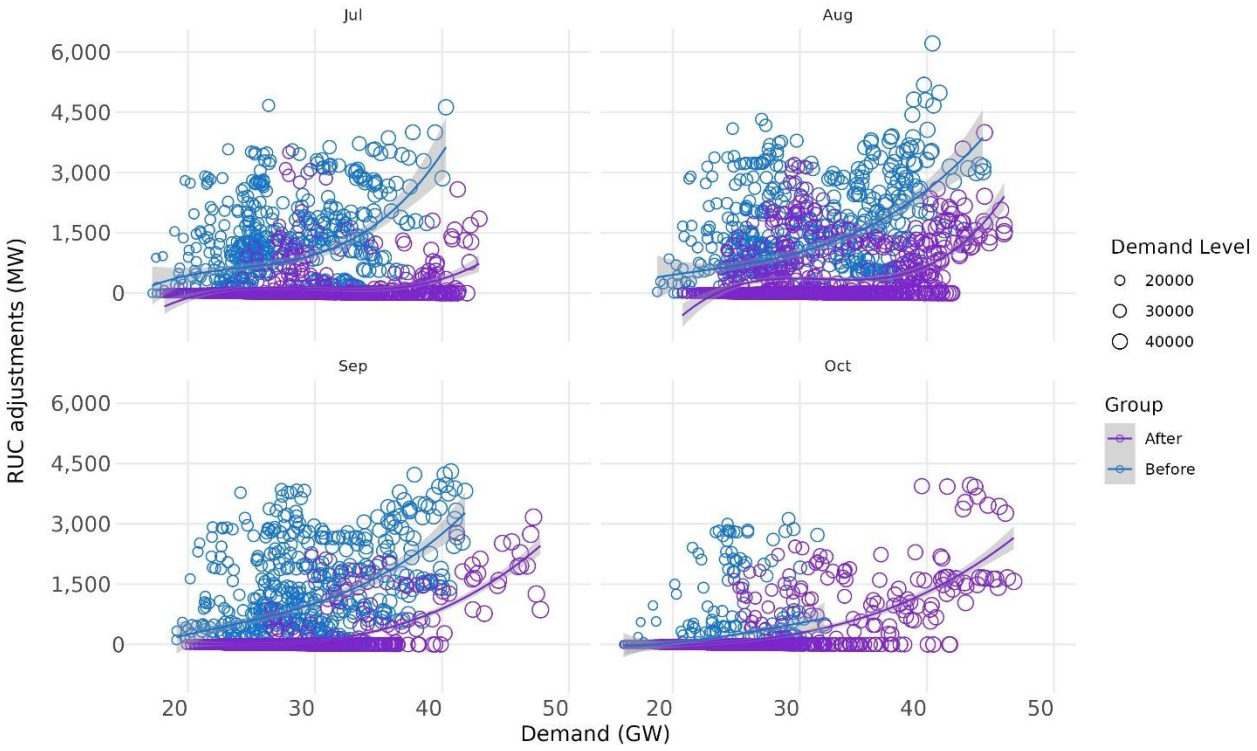


Figure 189 shows the trend over time on the use of RUC adjustment for ISO area, highlighting some key events relevant to the trends. Historically, more frequent and higher RUC adjustments are observed during conditions of high demand and tight supply conditions such as summer months. For summer 2026 and with the introduction of imbalance reserve, the daily trend of RUC adjustments has come down. October 2026 saw an increase relative to October 2025 due mainly the unusual higher loads exceeding 45,000 MW.

Figure 189: Hourly average of RUC adjustments

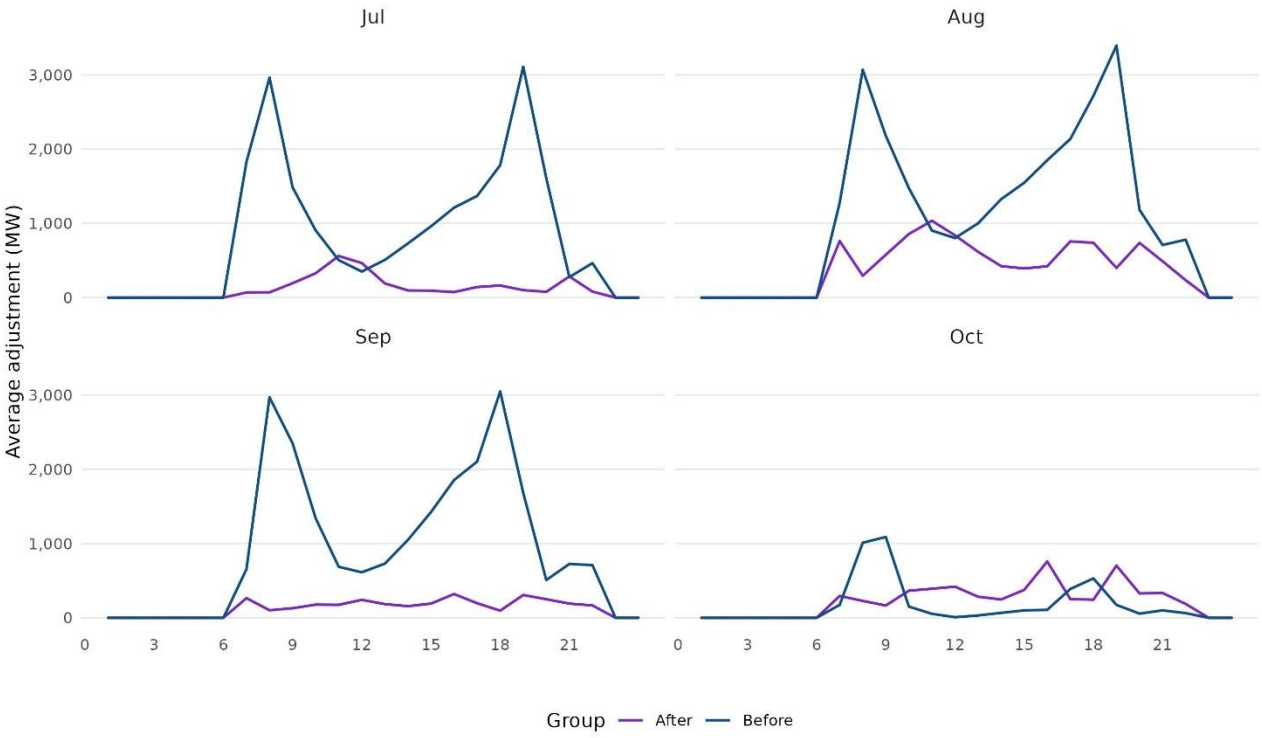


Figure 190: Historical RUC adjustments in the day-ahead market

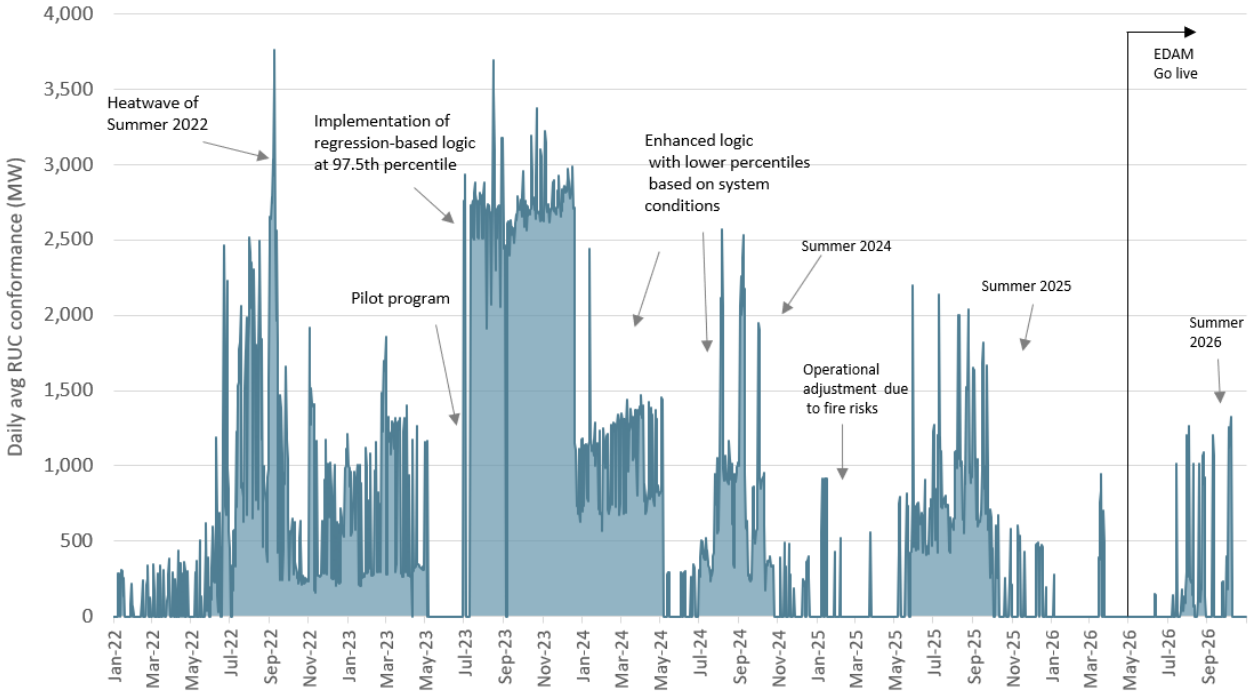
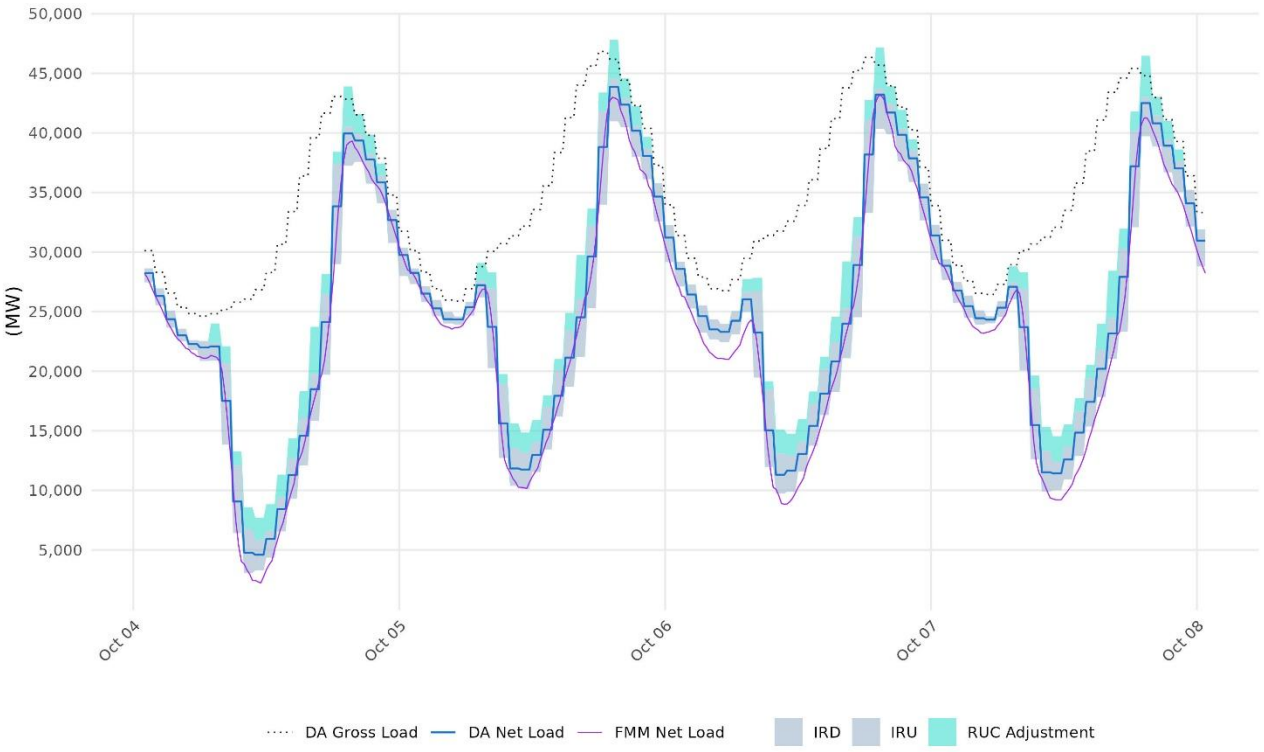


Figure 191 shows flexible capacity requirements for the day-ahead market for the days in which the ISO observed unusual high loads in early October. The dotted line is the gross load. The blue line represents day-ahead net load (gross load minus wind and solar schedules), while the purple line represents fifteen-minute net load. Upward and downward imbalance reserves define the capacity band around day-ahead net load. The light-blue area represents additional capacity required through RUC adjustments.

Figure 191: Procurement of flexibility needs during CAISO's peak time



On these days the net load in day-ahead was higher than the net load observed in real time. Given the uncertainty of how the high loads eventually would realized in real time, there was a RUC adjustment applied for the upward direction. Between imbalance reserves and RUC adjustments, there was flexibility in excess procured through the day-ahead process.

Figure 192 shows the trend over time on the use of RUC adjustment, IRU procurement, and IRU requirements for ISO area. This allows to see how IR and RUC adjustment complement to meet operational requirements for days when there is an expectation to secure capacity in the day-ahead market to meet uncertainty in real time. The IRU market requirement shows CAISO's adjusted flex ramp requirement to clear in IFM, and the operation requirement is a referenced value based on load forecast assed by an operation procedure.

Figure 192 shows a consistent diurnal pattern from July through October, characterized by two pronounced peaks around hours 8 and 19, with lower values during midday and overnight hours. In October, the IRU procurement during morning and evening peaks were lower than previous months, reaching approximately 3,000 MW and 3,200 MW, respectively, while the operation requirement declines substantially compared with August, remaining below approximately 1,000 MW for most hours.

The operational requirement is generally lower than the IR requirement because it applies primarily during high-load conditions, whereas the IR requirement is determined programmatically using statistically derived uncertainty. However, when peak load exceeds 42,000 MW, the operational requirement may exceed the IR requirement because it is set to the full uncertainty level based on the 97.5th percentile.

Figure 192: Hourly average of RUC adjustment, IRU procurement/requirements

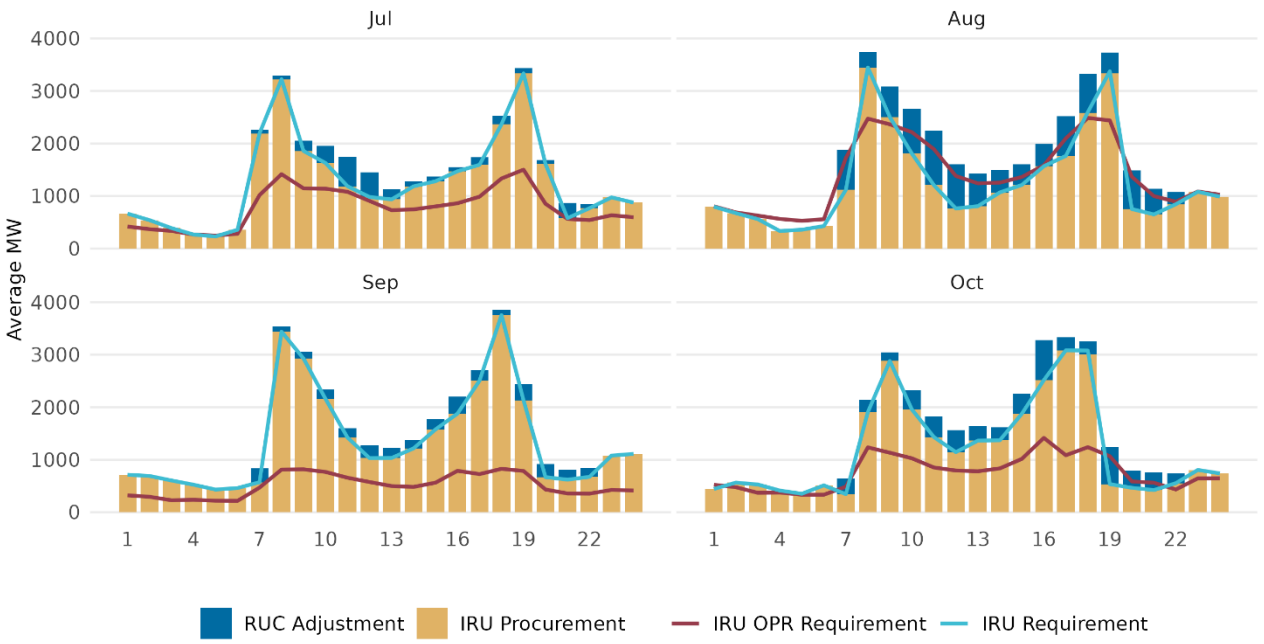
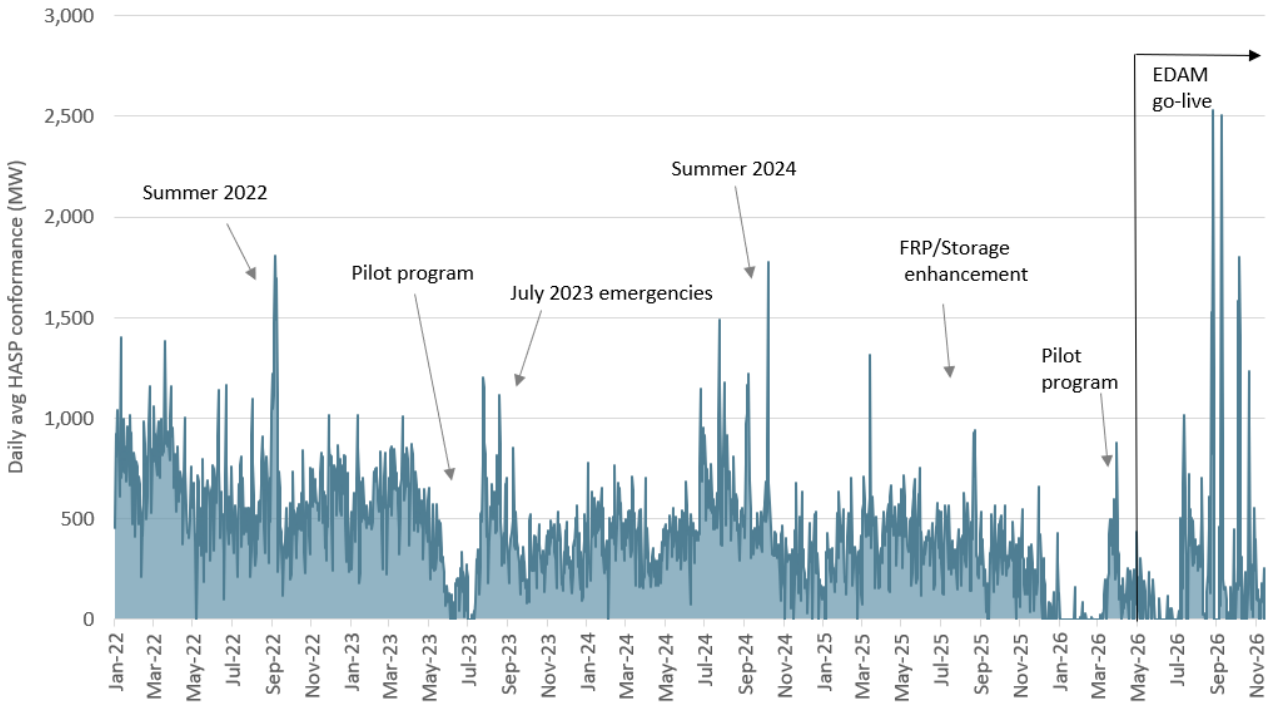


Figure 193 shows similar trend of load conformance for the hour ahead scheduling process (HASP). Historically, this market is utilized to gain additional ramping flexibility for peak hours since it is the last opportunity to schedule additional interties. Overall, the use of HASP load conformance has been consistent over time with higher use during summer conditions. In early 2026, its use was minimum during a pilot program used to understand the drivers for load conformance and its implications in subsequent real-time submarkets. This pilot ended in early March, and its use afterwards continue to be low until the first week of July, two months after the EDAM launched.

The load conformance reached up to 5,000 MW for peak hours during days when ISO area observed the peak of the year so far in September

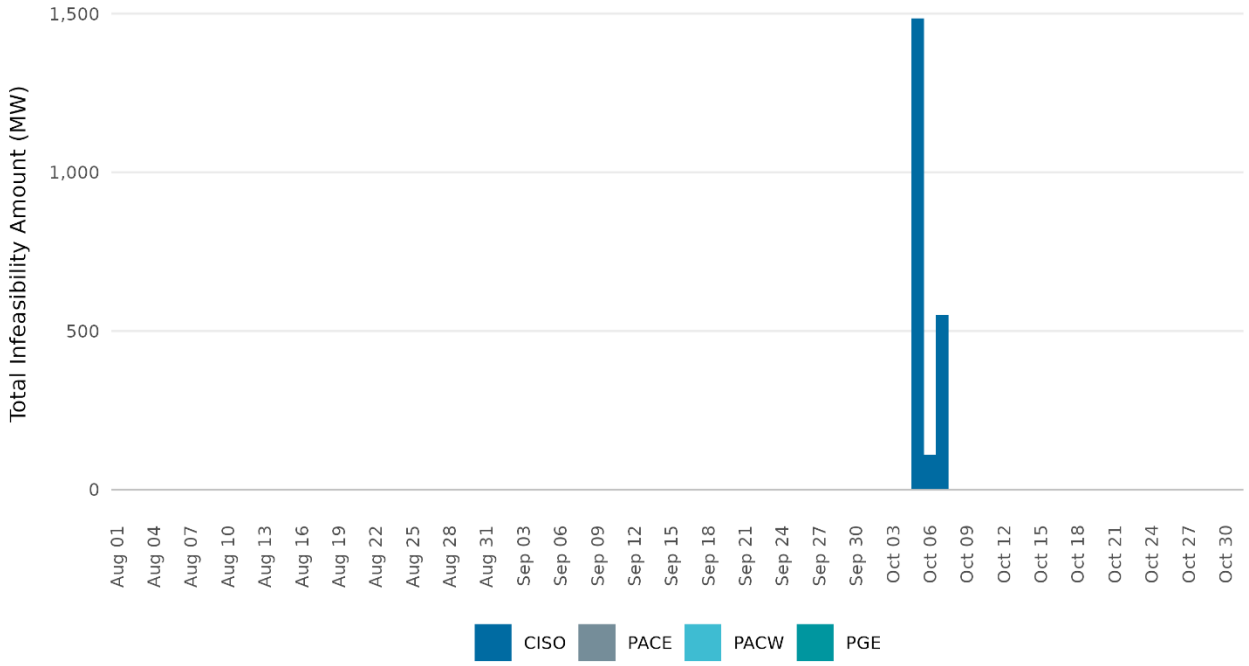
Figure 193: Historical load conformance in the hour ahead scheduling process



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. CISO observed under-supply infeasibilities of approximately 1,486 MW, 110.2 MW, and 551.5 MW on October 5, October 6, and October 7 respectively.

Figure 194: RUC Infeasibilities



Transitional Pricing

For the first six months following a new EDAM Entity's EDAM implementation, when power balance and/or transmission constraints within that entity's Balancing Authority Area are relaxed, CAISO will determine prices based on the last economic bid rather than administrative (penalty) prices. This transition-period pricing applies only to the new EDAM Entity's Balancing Authority Area. It does not apply to the CAISO Balancing Authority Area. This practice is also limited to the day-ahead market, and it does not apply in the real-time market[9]. The RUC infeasibilities reported in the prior section were all associated with the CAISO Balancing Authority Area.

There are no RUC infeasibilities in October for PACE, PACW and PGE Balancing Authority Areas. For infeasibilities observed in previous months, please refer to prior versions of the monthly report.

[9] A new WEIM Entity will receive transitional pricing in the real-time market for the first six months of its WEIM implementation.

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 195 and Figure 196 show the total number of resources subject to mitigation as determined by the IFM MPM and RUC MPM passes daily, 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. Gas and energy storage made up most resources subject to mitigation in IFM. In RUC, mitigation occurred much less frequently and was concentrated on a small number of days. In general, there were far fewer resources subject to mitigation in RUC.

Figure 195: Resources subject to mitigation in IFM MPM, by fuel type

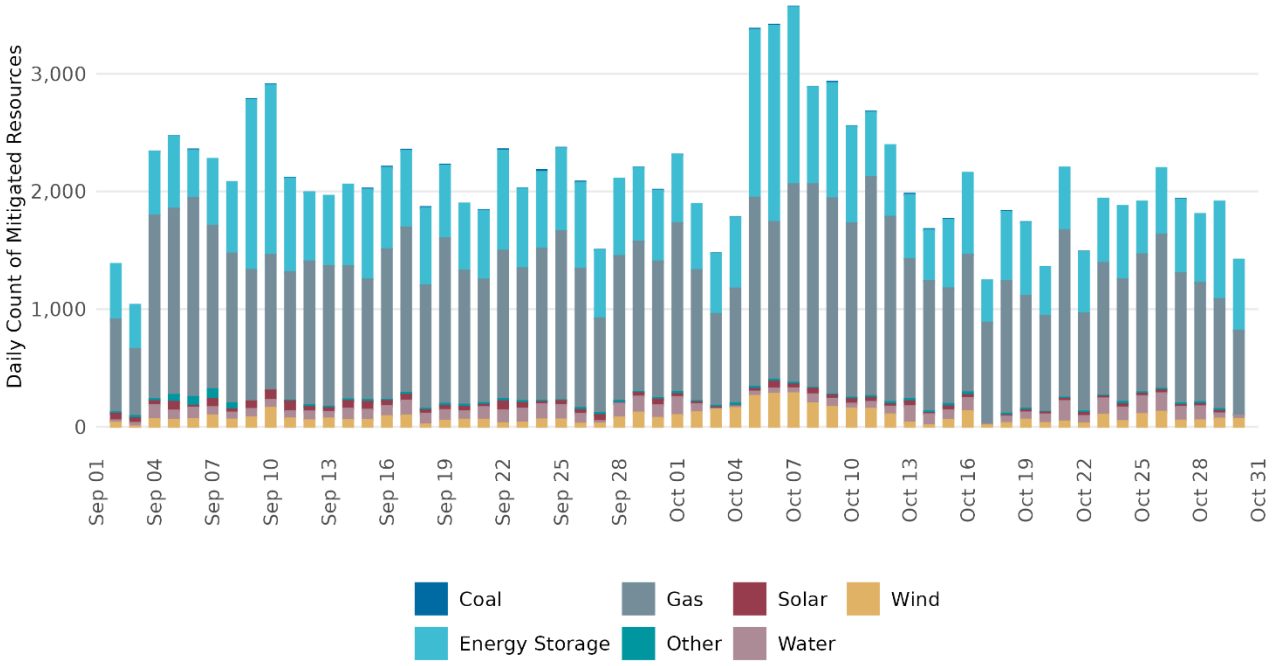


Figure 196: Resources subject to mitigation in RUC MPM, by fuel type

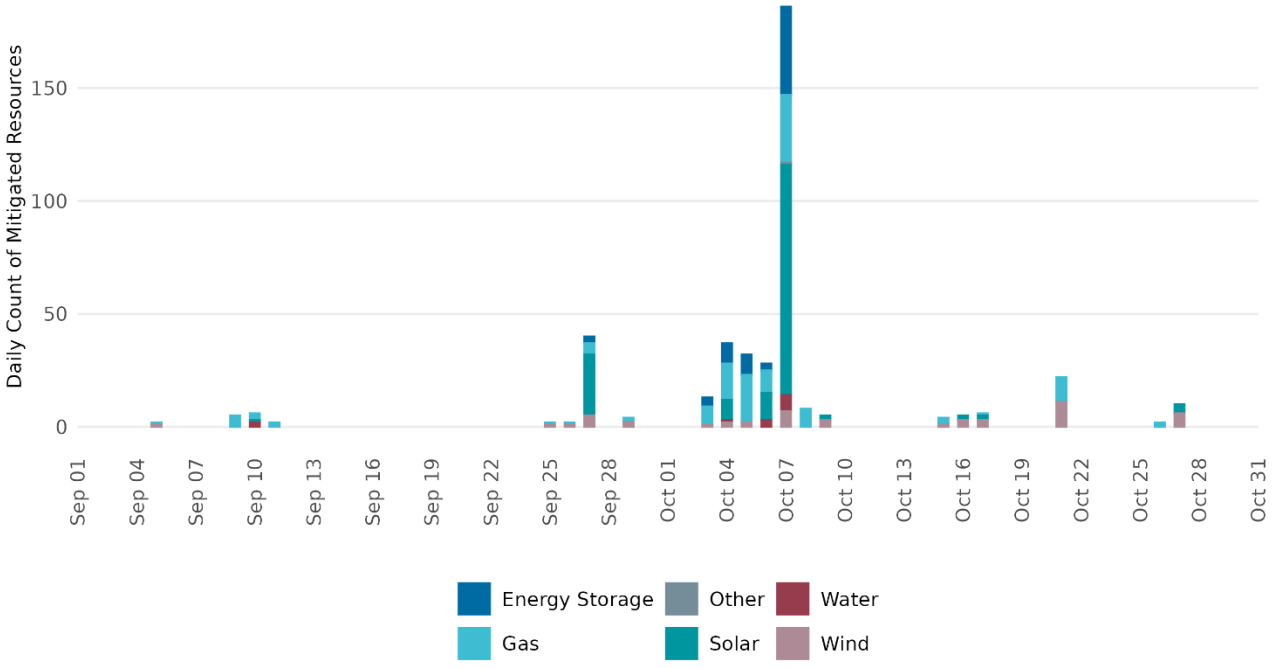


Figure 195 and Figure 196 show the same total counts as above but broken down by fuel type. Figure 197 shows that the number of PACE resources subject to mitigation in IFM has been relatively consistent. The number of resources subject to mitigation in RUC was significantly lower than in IFM. RUC mitigation remained relatively low through most of September and October, except for the first week of October for CISO.

Figure 197: Resources subject to mitigation in IFM MPM, by BAA

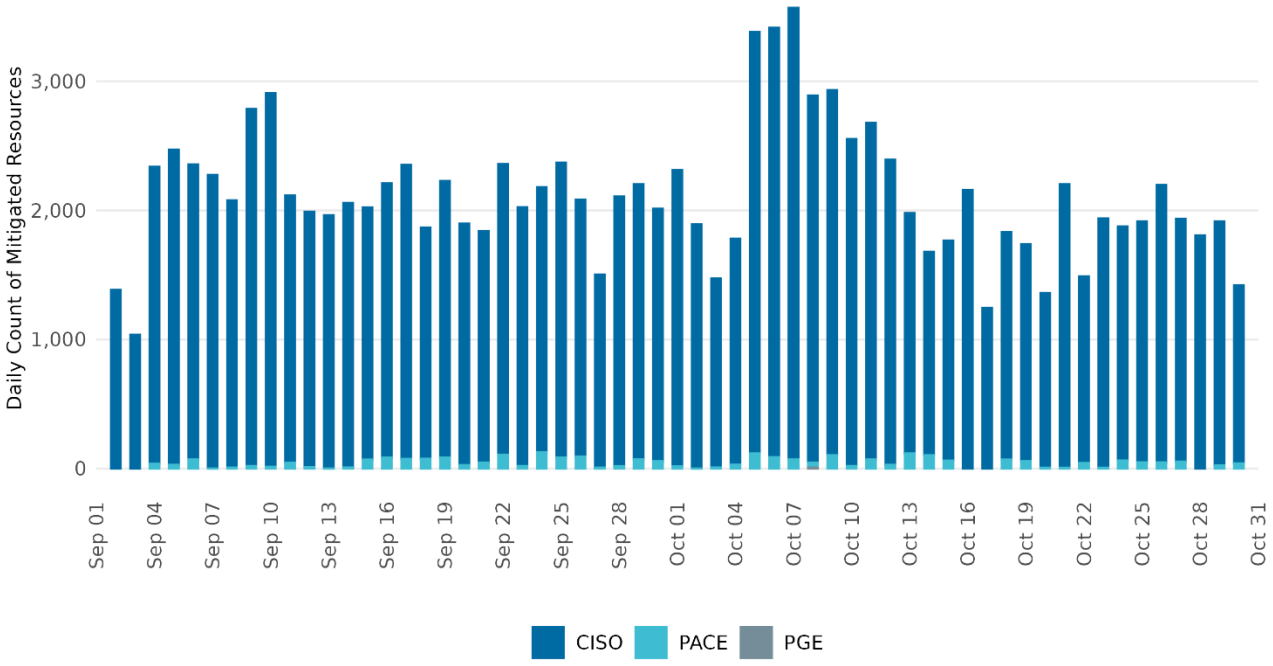


Figure 198: Resources subject to mitigation d in RUC MPM, by BAA

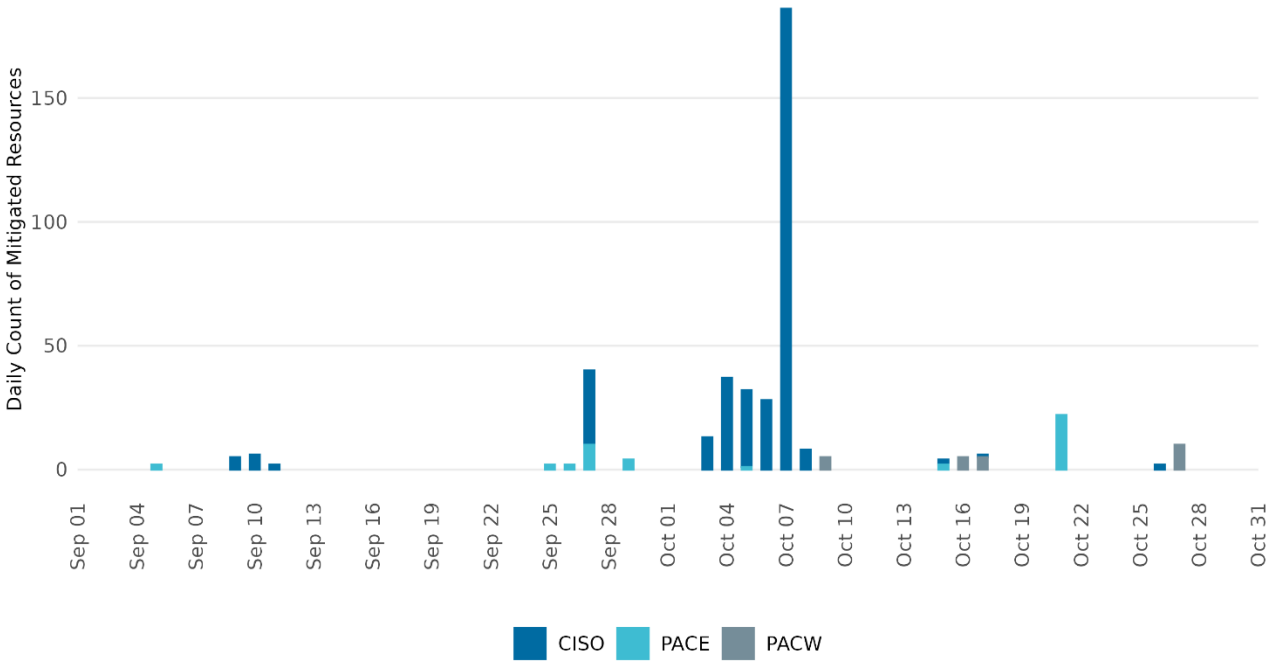


Figure 197 and Figure 198 show the average number of resources subject to mitigation in each hour of the day, by month for IFM and RUC, broken down by BAA. Figure 199 shows that mitigation

in IFM generally increased through the day and was highest during the late afternoon and evening hours in August, September, and October. There is a less consistent pattern in RUC, with relatively low levels of mitigation across most hours, particularly in September and October.

Figure 199: Resources subject to mitigation in IFM MPM, by fuel type hourly

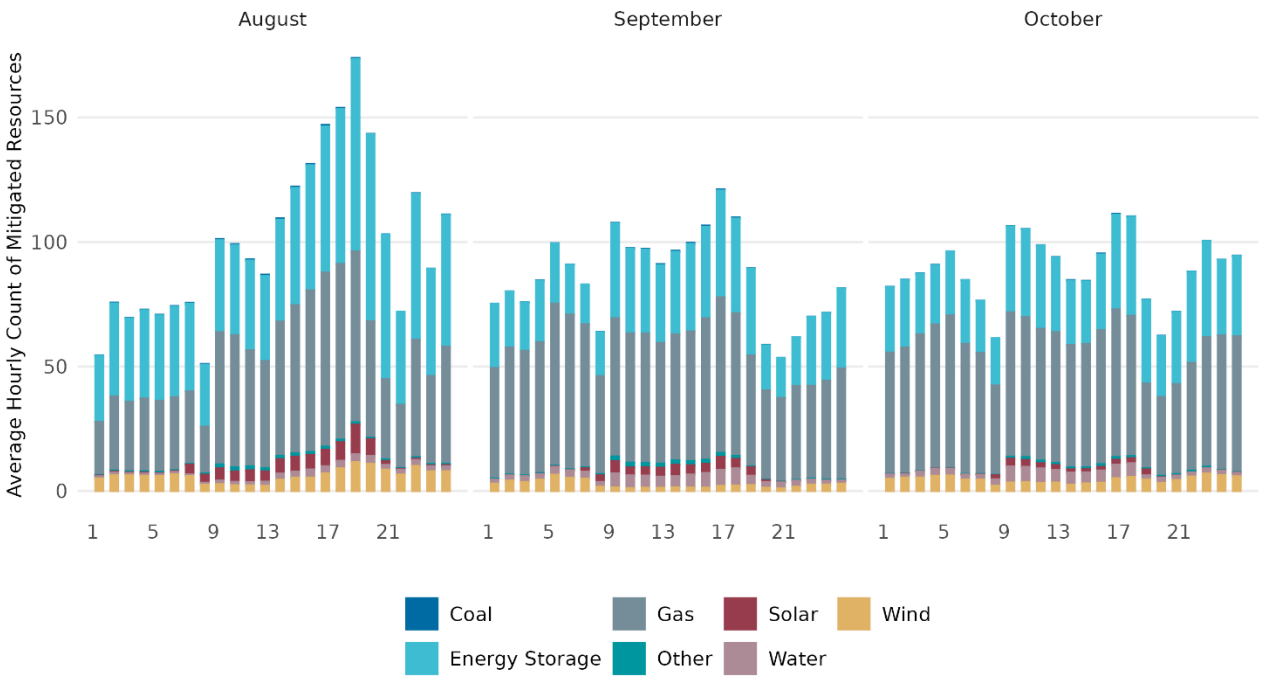
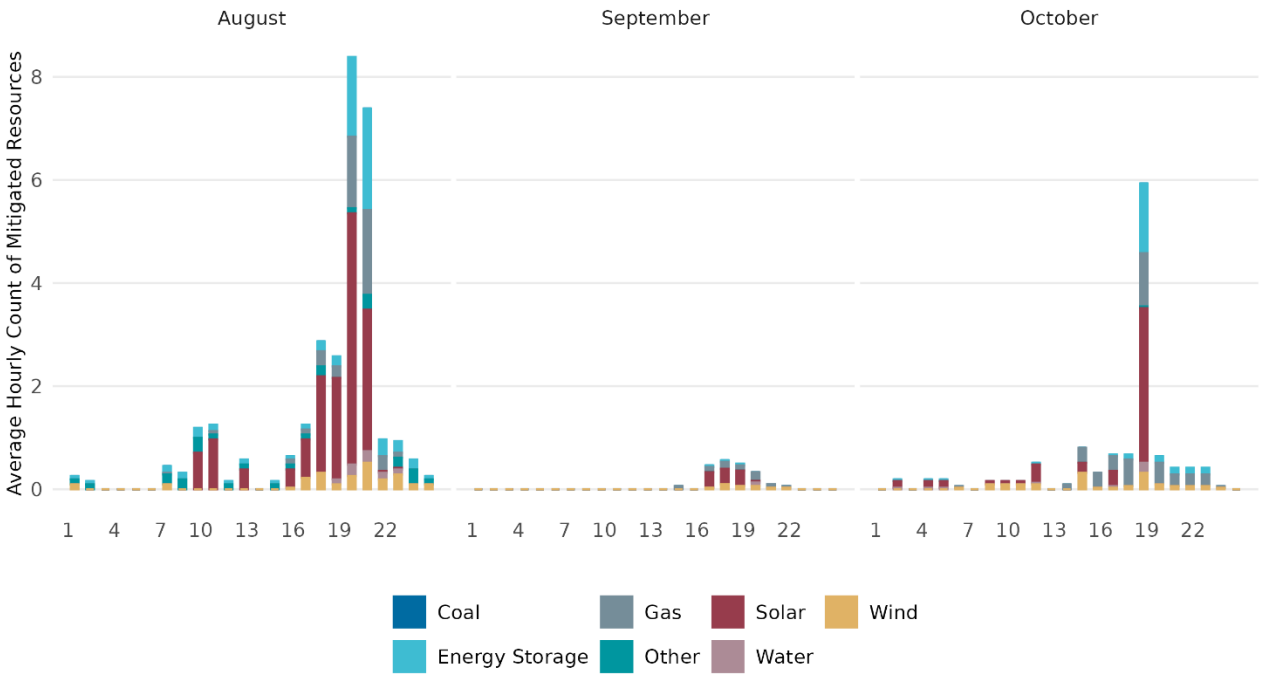


Figure 200: Resources subject to mitigation in RUC MPM, by fuel type hourly



Summer Conditions

Peak ISO Load

Although the ISO area recorded its highest load of the year so far on September 9 at 50,335 MW, October experience an atypical period of high loads in October 02-08, reaching a peak of 46,786 MW on October 5.

Figure 201 shows the historical load level distributions in the ISO area over the past six years. During summer months load levels have generally remained within a tight range with few outliers that would indicate extreme conditions. October saw a tail of high loads that were atypical for this time of the year; this is shown with the long right-hand side tail of October. The average daily peak load in October 2026 was 33,820 MW.

Figure 201: Historical distribution of load levels in the ISO area

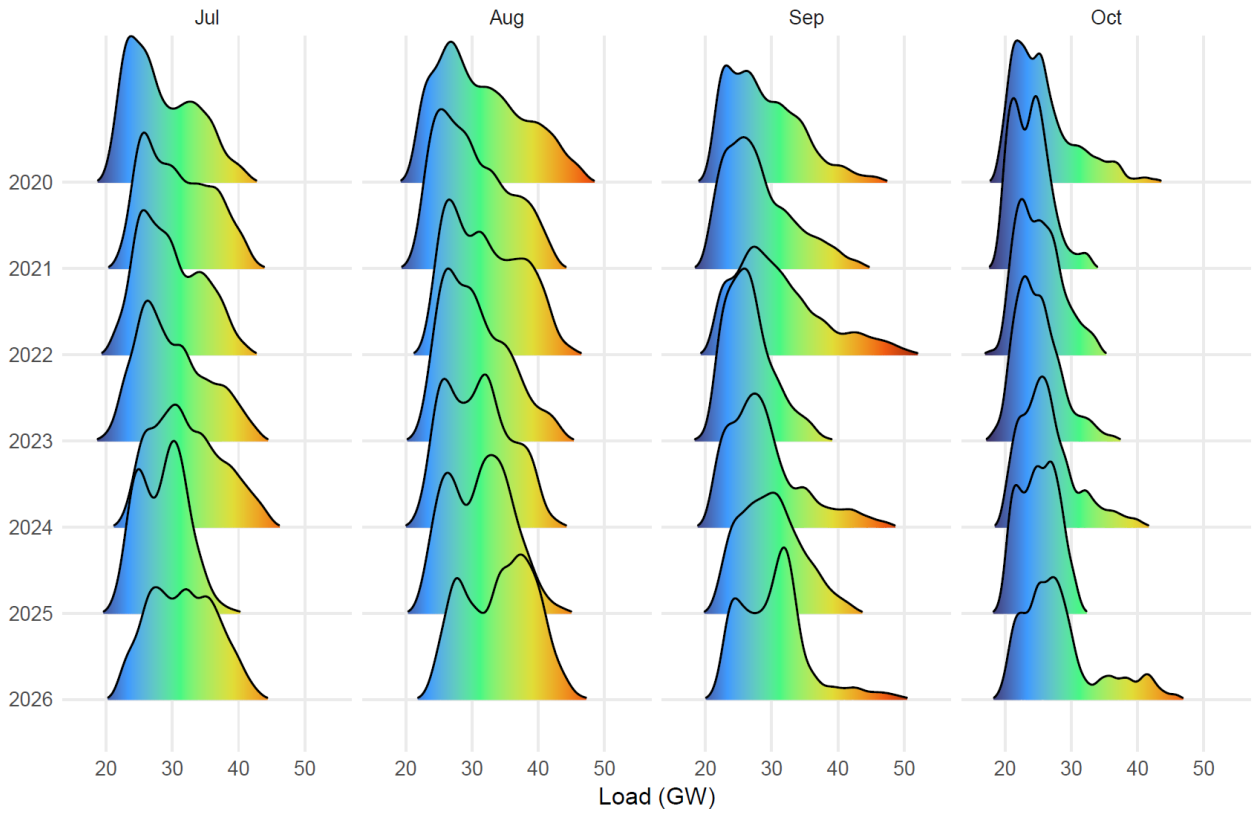
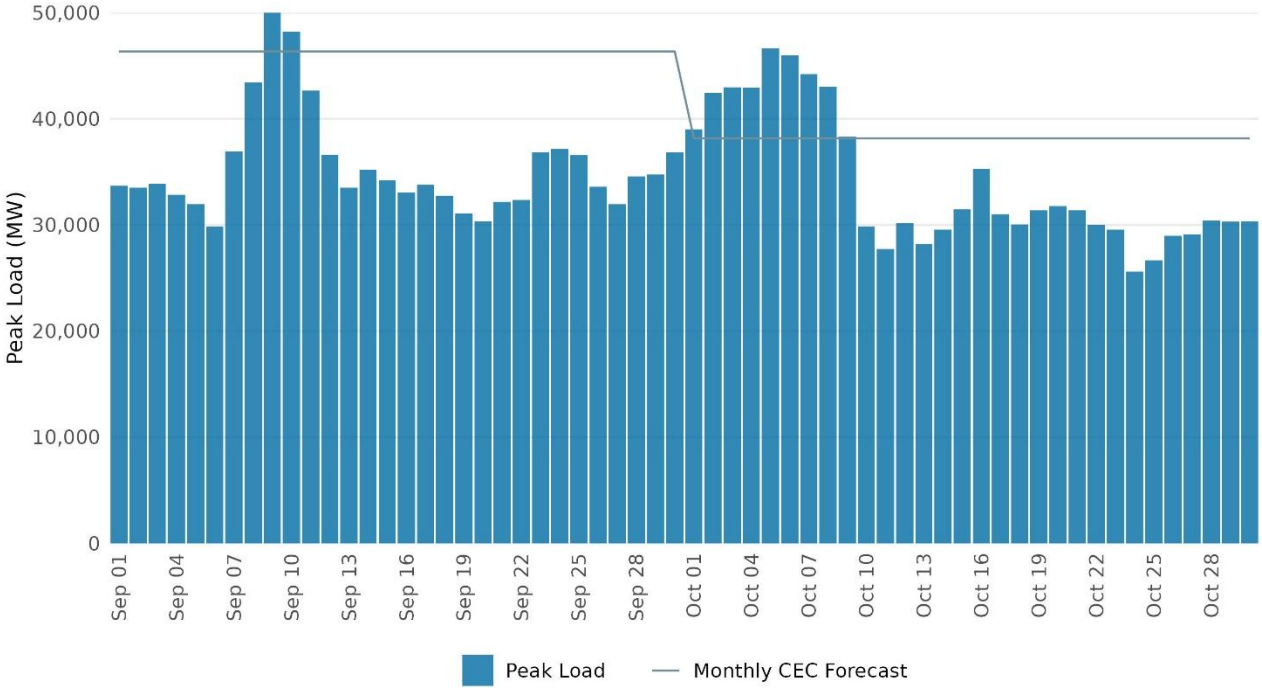


Figure 202 shows the 5-minute average daily load for August and September relative to the CEC month-ahead forecast used to assess the resource adequacy requirements. The instantaneous load peak in October 2026 was 46,786 MW on October 5. This peak exceeded the CEC month-ahead

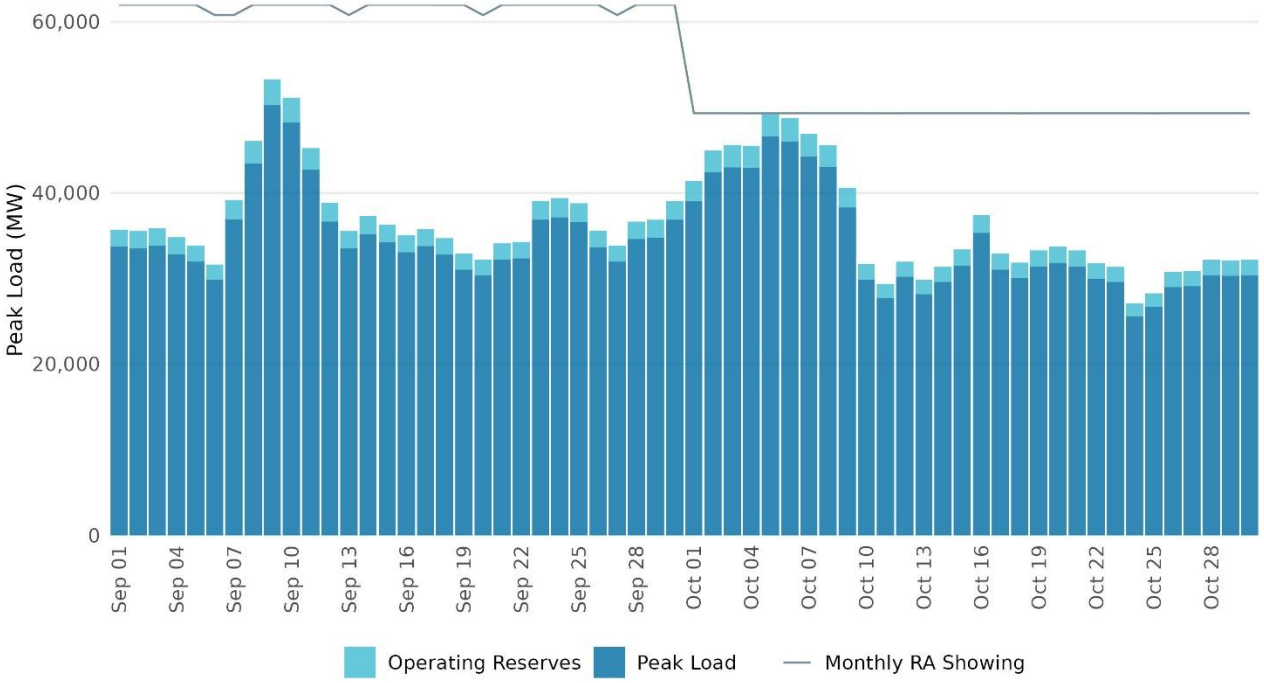
forecast of 38,173 MW. The figure below is based on the five-minute averages of the actual load. The highest five-minute average peak load for October was 46,786 MW.

Figure 202: Daily peak load and CEC month-ahead forecast



The actual load did not exceed the monthly RA showings in October 2026 as illustrated in Figure 203. There was plenty of headroom in the monthly RA supply in October to meet the observed levels of load except October 5 when the peak load + operating reserves were almost equal to RA showing. The gray line indicates nominal monthly RA showings. As discussed later in this report, the actual capacity made available into the ISO's market (accounting for outages and other factors) varies from day to day. In subsequent sections, the actual RA capacity made available in the market is shown more granularly for the month on an hourly basis.

Figure 203: Daily peak load, operating reserves and RA capacity

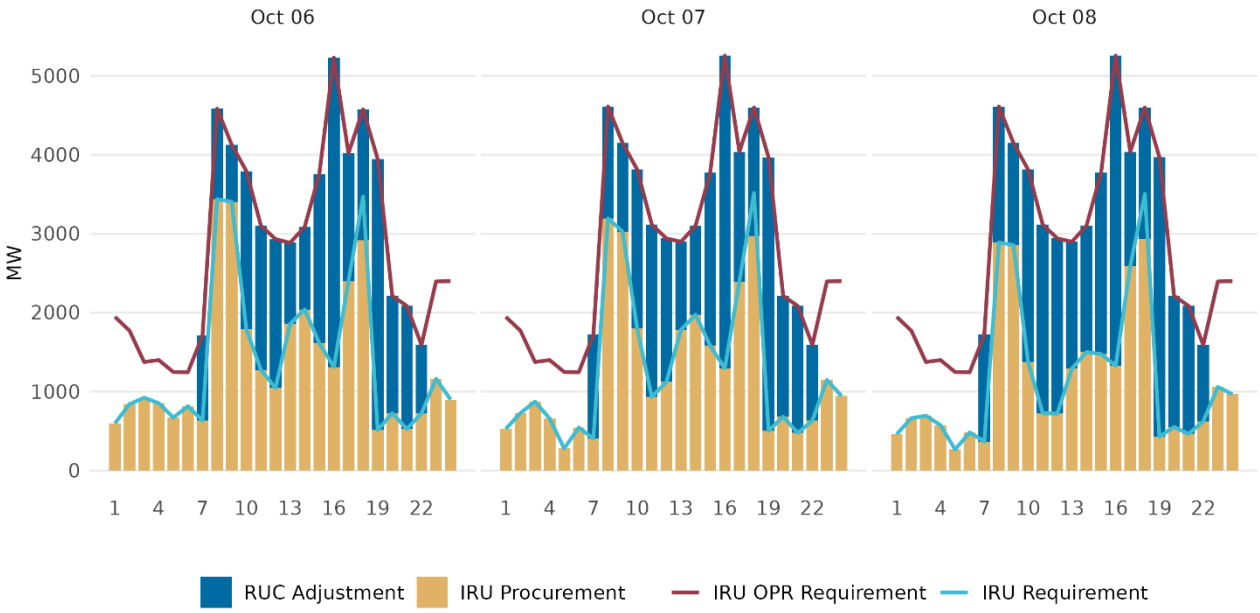


RUC Adjustment

The RUC load adjustment is an additional hourly MW value added to the forecasted load in RUC. Figure 204 shows hourly RUC adjustments, IRU procurement, IRU requirements, and IRU OPR requirements from October 6 through 8.

On those three days, RUC adjustments increased substantially during the morning and evening peaks, bringing the combined volume above 5,000 MW. IRU procurement remained relatively stable at approximately 2,000 MW during midday, while RUC adjustments supplied a significant share of the total. Because load forecasts exceeded 42,000 MW on both days, the IRU OPR requirement tracked the 97.5th percentile of the full IRU requirement. Combined IRU procurement and RUC adjustments were sufficient to meet the full IRU requirement during these peak-load days.

Figure 204: Daily RUC adjustment and IRU procurement/requirements



Market Prices

Market prices naturally reflect supply and demand conditions. As the market supply tightens, prices tend to rise.

Figure 205 compares the daily average prices across ISO's markets for the months of September and October.[10] The daily average fifteen-minute market prices reached $77/MWh ($119 in September), while the daily average day-ahead prices reached about $90/MWh ($101 in September), and the five-minute market prices reached a maximum of about $71/MWh ($93 in September). In October, the IFM maximum occurred on October 5, the FMM maximum occurred on October 6, and the RTD maximum occurred on October 21.

[10] Default Load Aggregation Point (DLAP) prices are a good indicator of overall prices. However, congestion may create price separation among DLAPs. The metrics presented here are based on a weighted average price of the DLAPs within the ISO area.

Figure 205: Average daily prices across markets, August and September 2026

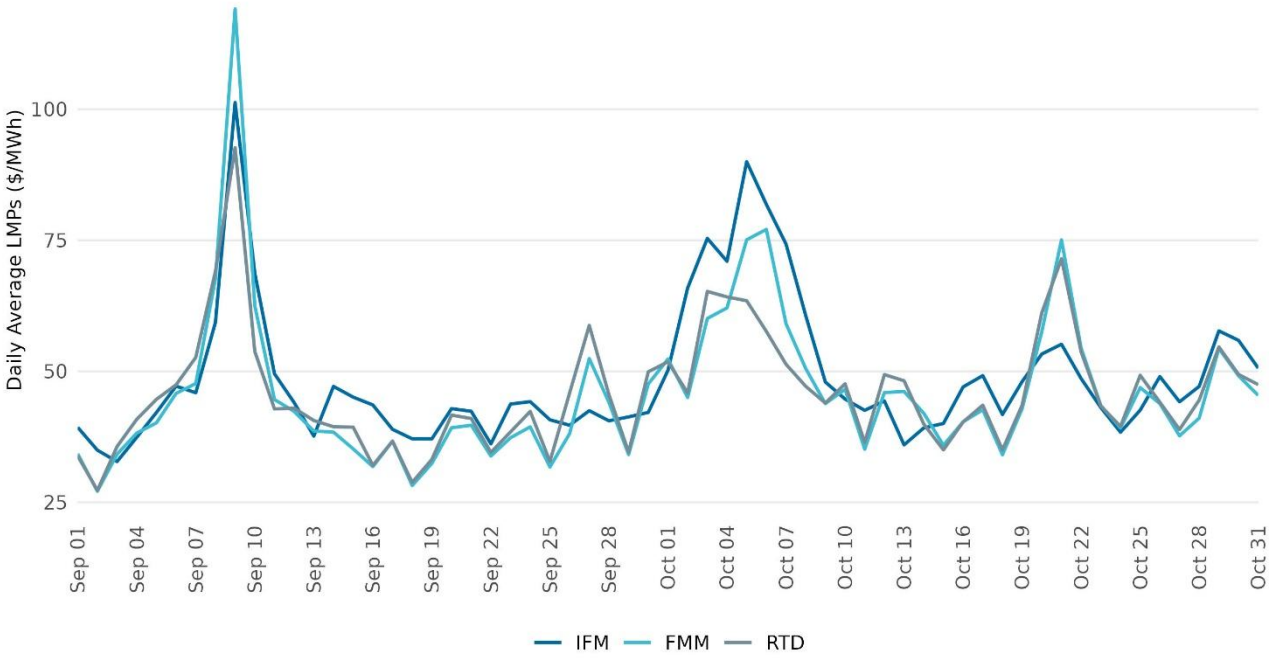


Figure 206 shows average hourly prices across ISO's markets for both September and October 2026. In October, the hourly average prices for the IFM, FMM, and RTD peaked in trade hours 19, 19, and 18 at $84/MWh, $73/MWh, and $66/MWh, respectively.

Figure 206: Average hourly prices across markets

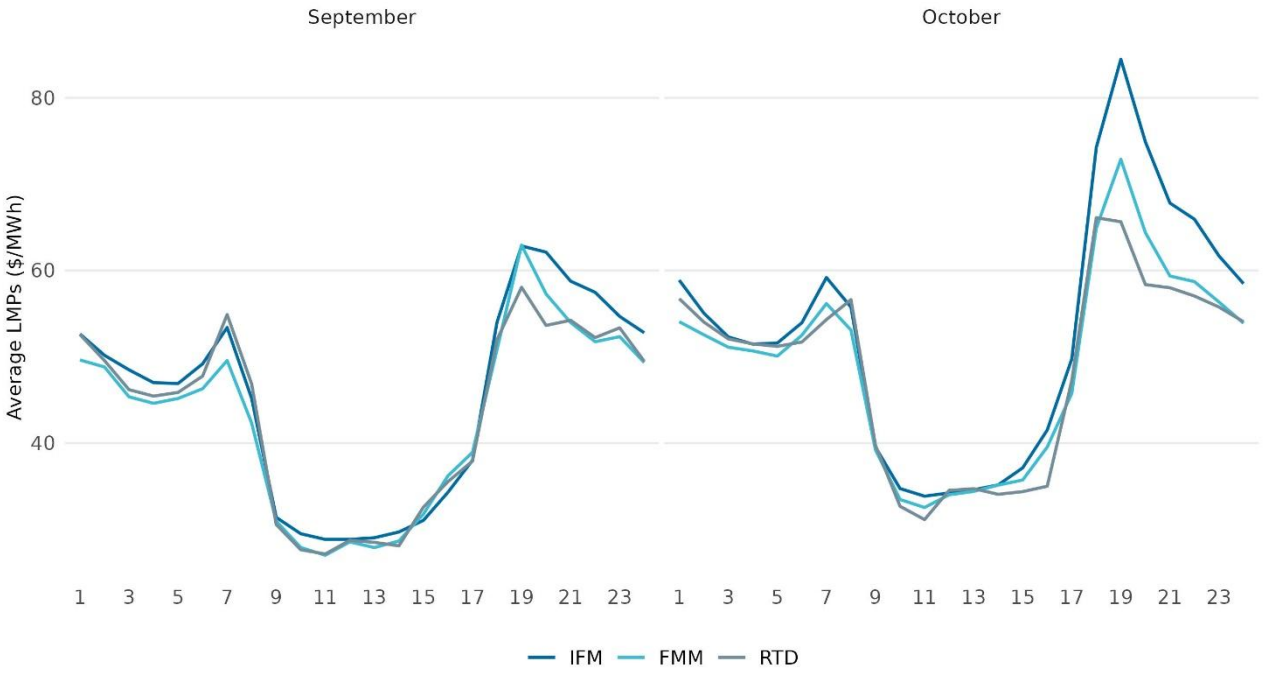
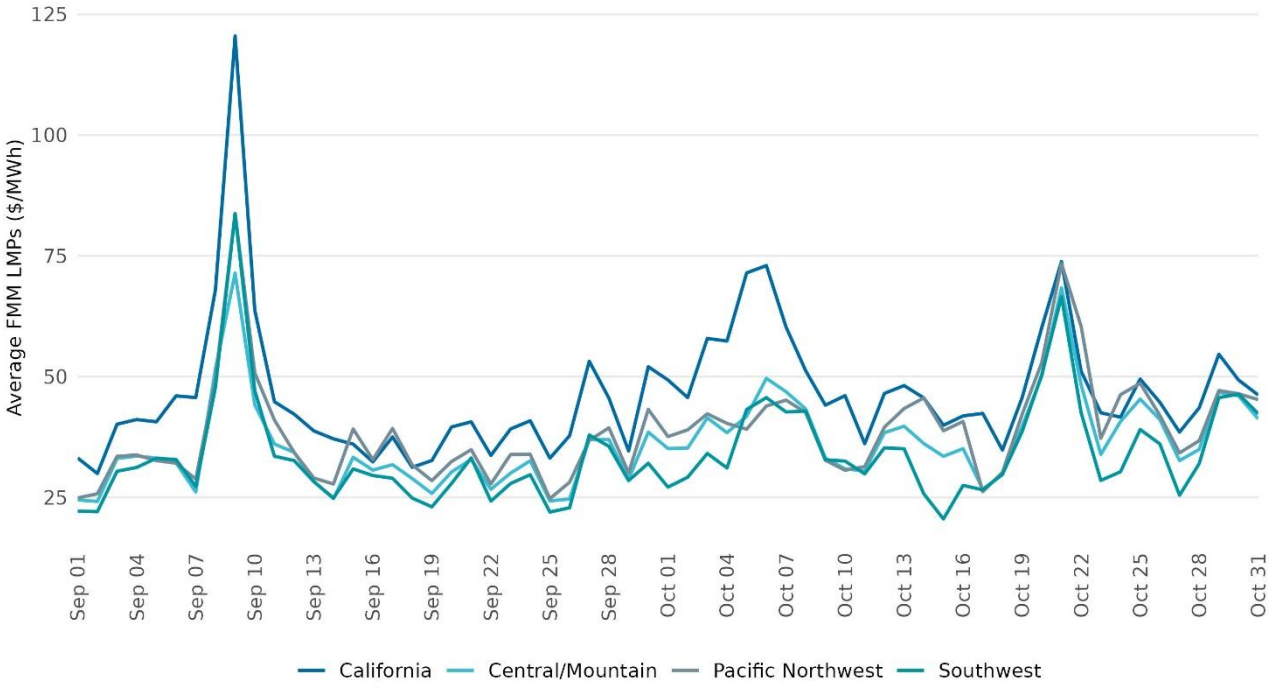


Figure 207 and Figure 208 show daily average LMPs for all four regions for the months of September and October. In September, the highest FMM regional daily average was observed in California on September 9 at about $121/MWh, while the highest RTD regional daily average occurred in California on September 9 at about $93/MWh. In October, the highest FMM regional daily average was observed in California on October 21 at about $74/MWh, while the highest RTD regional daily average occurred in Pacific Northwest on October 21 at about $72/MWh. On the September FMM peak date, prices across the four regions ranged from about $71/MWh to $121/MWh. On the October FMM peak date, average prices were about $74/MWh in California, $68/MWh in Central/Mountain, $73/MWh in Pacific Northwest, and $67/MWh in Southwest.

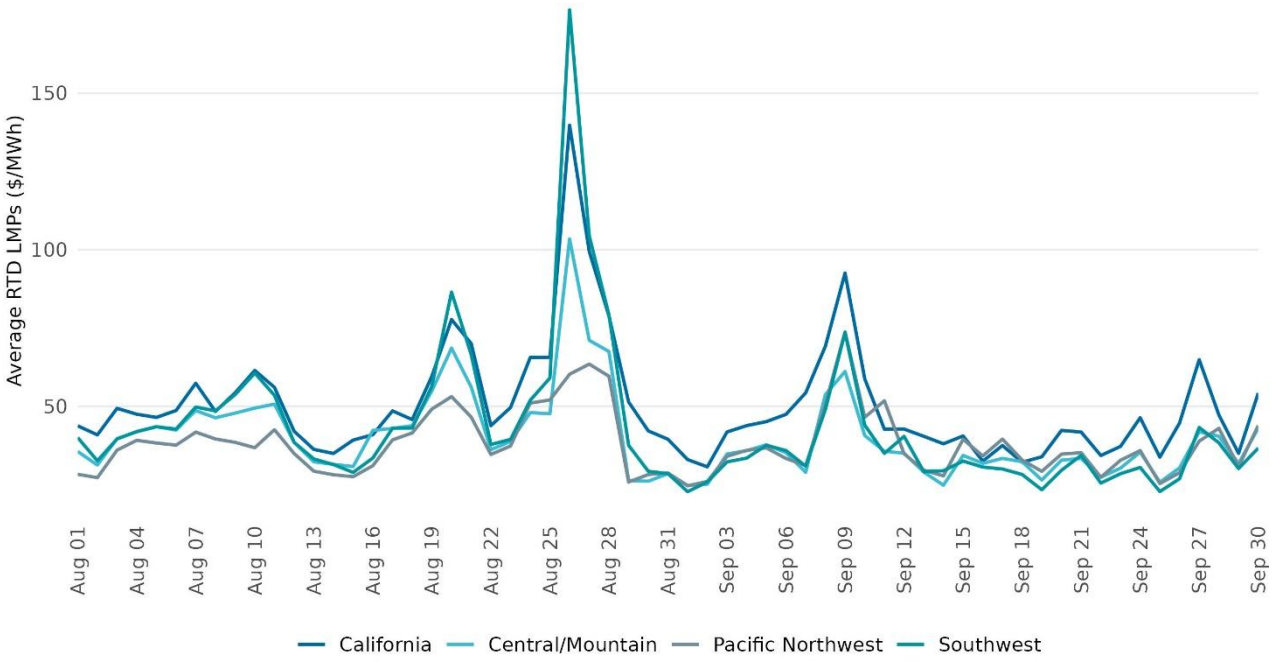
Figure 209 and Figure 210 further explore the peaks by depicting three-day periods of hourly averages for WEIM Load Aggregation Point (ELAP) prices aggregated by geographical region for RTD and FMM.[11]

Figure 207: Average daily prices across region for FMM market



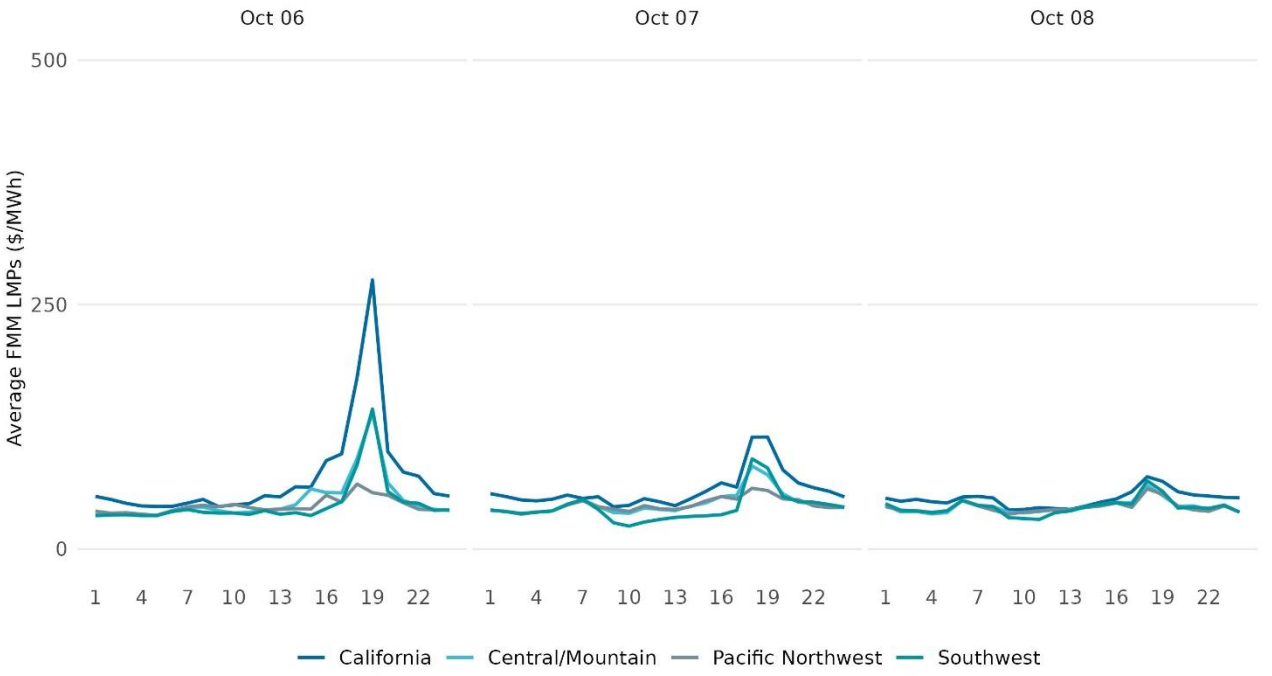
[11] The Pacific Northwest region includes balancing areas such as Bonneville Power Administration, Powerex, Avista Corporation, Avangrid Renewables, Tacoma Power, Seattle City Light, Puget Sound Energy, Portland General Electric Company, and PacifiCorp West. Southwest region includes Tuscon Electric Power, Public Service Company of New Mexico, Salt River Project, Western Area Power Administration, Arizona Public Service Company, El Paso Electric Company, and Nevada Power Company. Central/Mountain region includes Idaho Power Company, NorthWestern Energy, PacifiCorp East, Black Hills, and PowerWatch (formerly BHE Montana). California region includes ISO, Los Angeles Department of Water & Power, Balancing Authority of Northern California, and Turlock Irrigation District.

Figure 208: Average daily prices across region for RTD market



For FMM, on October 6, California is the highest at $275/MWh, followed by Southwest at $143/MWh. On October 7, California is the highest at $115/MWh, followed by Southwest at $92/MWh. On October 8, California is the highest at $74/MWh, followed by Southwest at $70/MWh.

Figure 209: Average hourly prices across region for FMM market



For RTD, on October 06, California is the highest at $98/MWh, followed by Central/Mountain at

$74/MWh. On October 07, California is the highest at $79/MWh, followed by Southwest at $69/MWh. On October 08, California is the highest at $63/MWh, followed by Southwest at $63/MWh.

Figure 210: Average hourly prices across region for RTD market

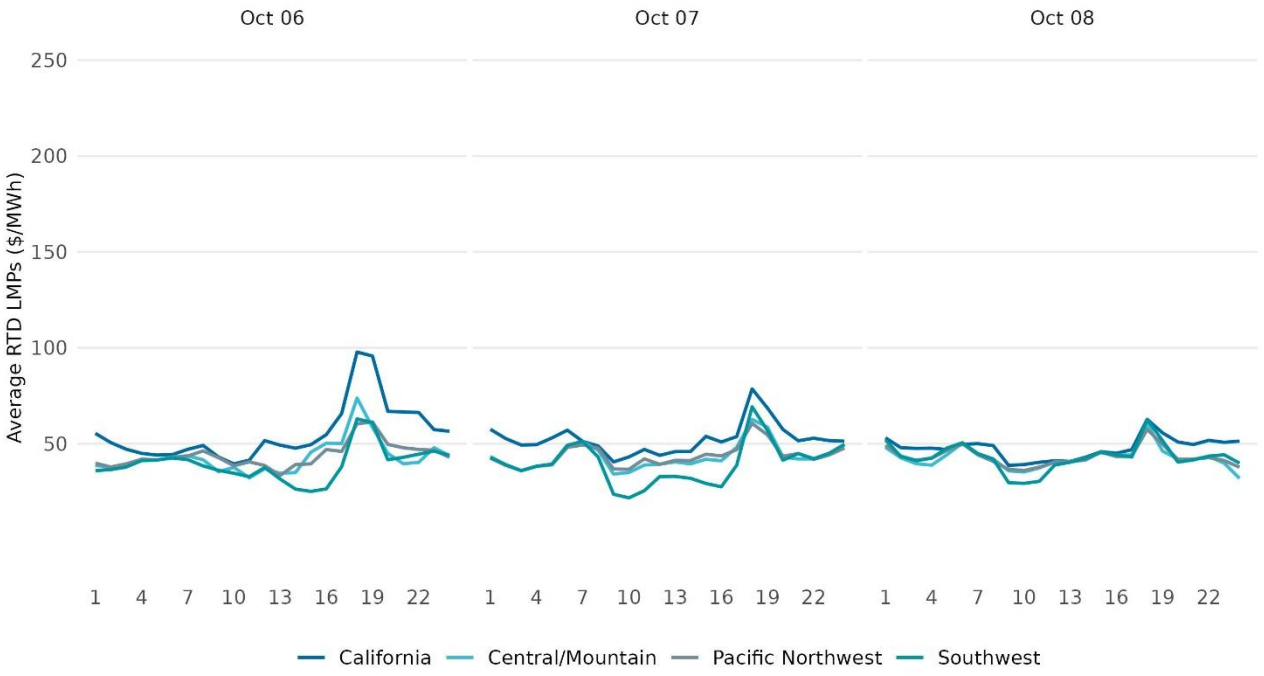


Table 14 shows the monthly average regional LMPs in the FMM and RTD markets from May through October 2026. California had the highest monthly average prices in October in both FMM and RTD, at $49.45/MWh and $49.11/MWh, respectively.

Table 14: Monthly Average Regional LMP ($/MWh) by Market and Region

Region	FMM						RTD					
	May	Jun	Jul	Aug	Sep	Oct	May	Jun	Jul	Aug	Sep	Oct
California	13.3	19.9	40.6	52.9	43.6	49.4	20.4	42.6	55.6	49.4	44.6	49.1
Southwest	9.8	24.5	36.4	46.9	31.7	35.9	25.3	40.9	52	35.9	33.7	37.6
Pacific Northwest	12.3	12.4	29.4	39	35.3	41.9	12.2	31.3	39.6	41.9	36.3	42.9
Central/Mountain	12.6	15.8	37.5	43.2	32.9	39.8	15.9	43.1	46.7	39.8	34.4	40.6

Renewable Production

CAISO's area utilizes hydro production throughout the year to meet demand needs.

Figure 211 shows the historical trend of total energy produced from hydro and other renewable resources. Hydro production for 2026 so far has been lower than previous years. Hydro production in October 2026 was about 2 percent lower than the production observed in October 2025. With the addition of more solar resources into the system, solar production in October 2026 was about 4 percent lower than the production in October 2025.

Figure 212 shows the daily renewable production for August, September, and October. Figure 213 shows the historical trend of solar production. Generation from hydro tends to be higher in the morning and evening hours while reaches lower values during midday hours when solar production is plentiful. Figure 214 below shows the hourly profile of the average energy produced from hydro resources as well as solar and wind resources for October 2026.

Figure 211: Historical trend of hydro and renewable production

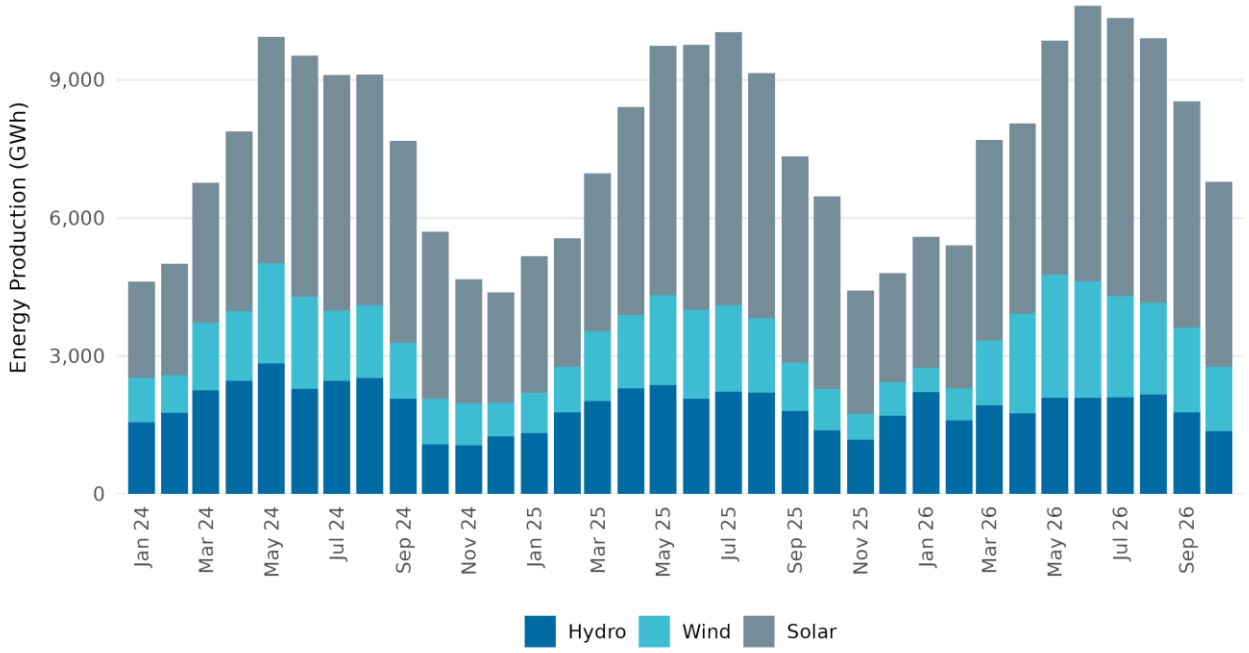


Figure 212: Daily trend of hydro and renewable production

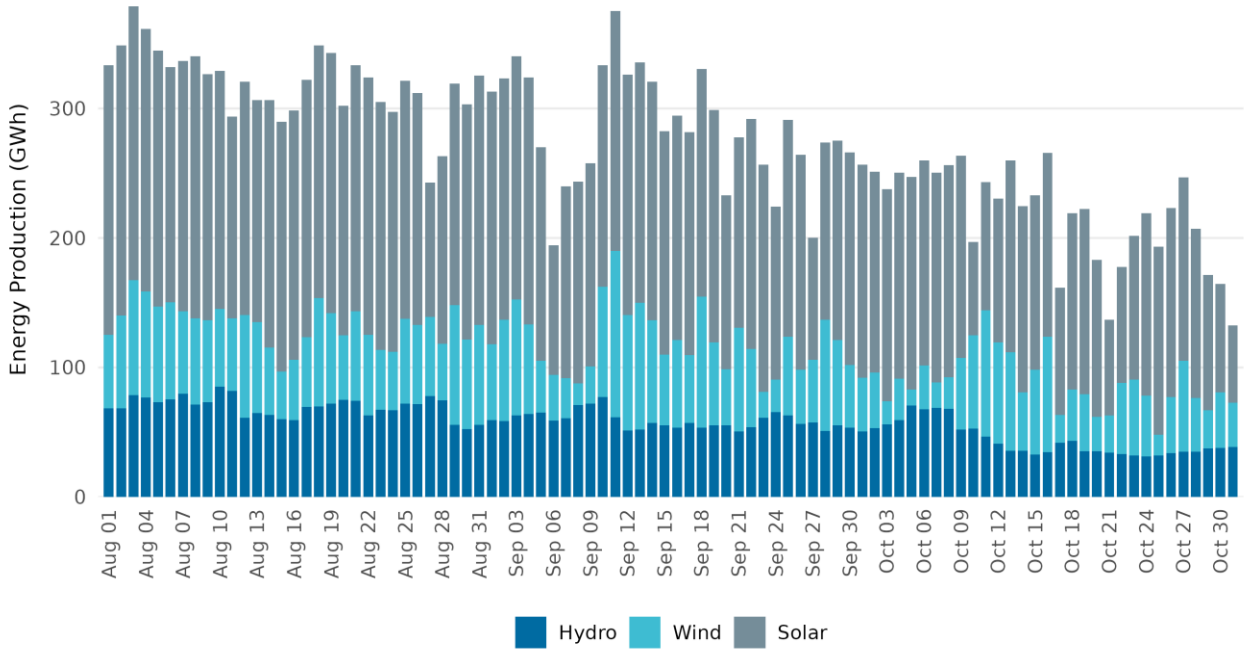


Figure 213: Historical trend of solar production

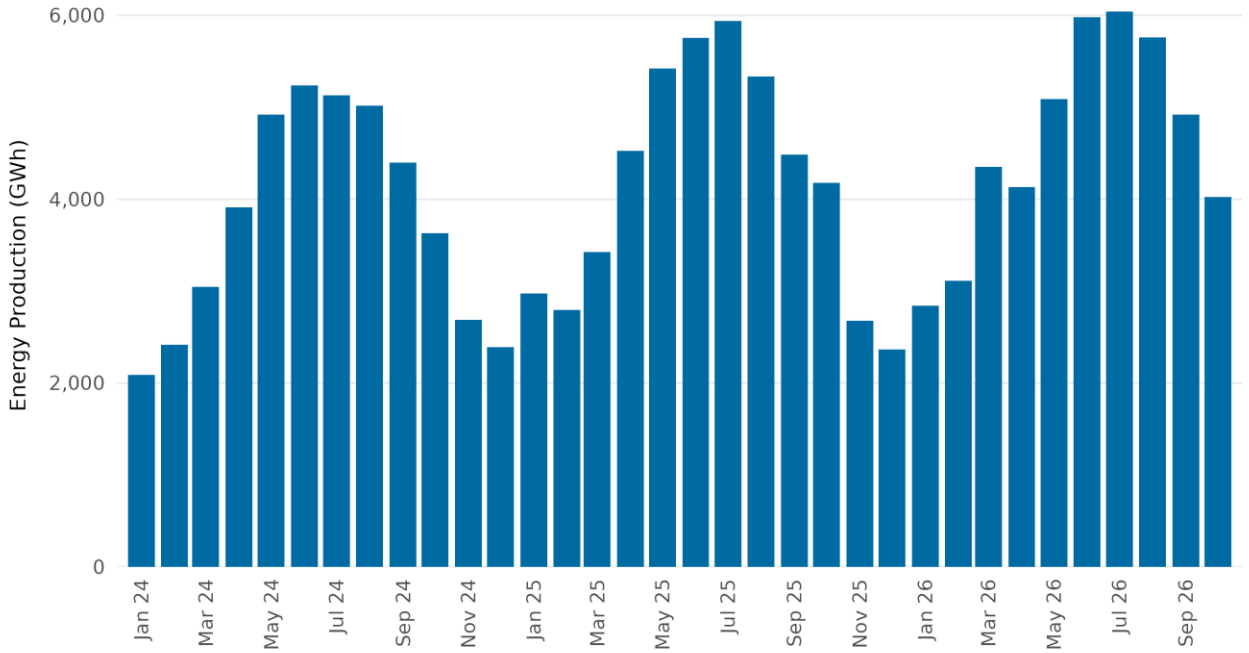
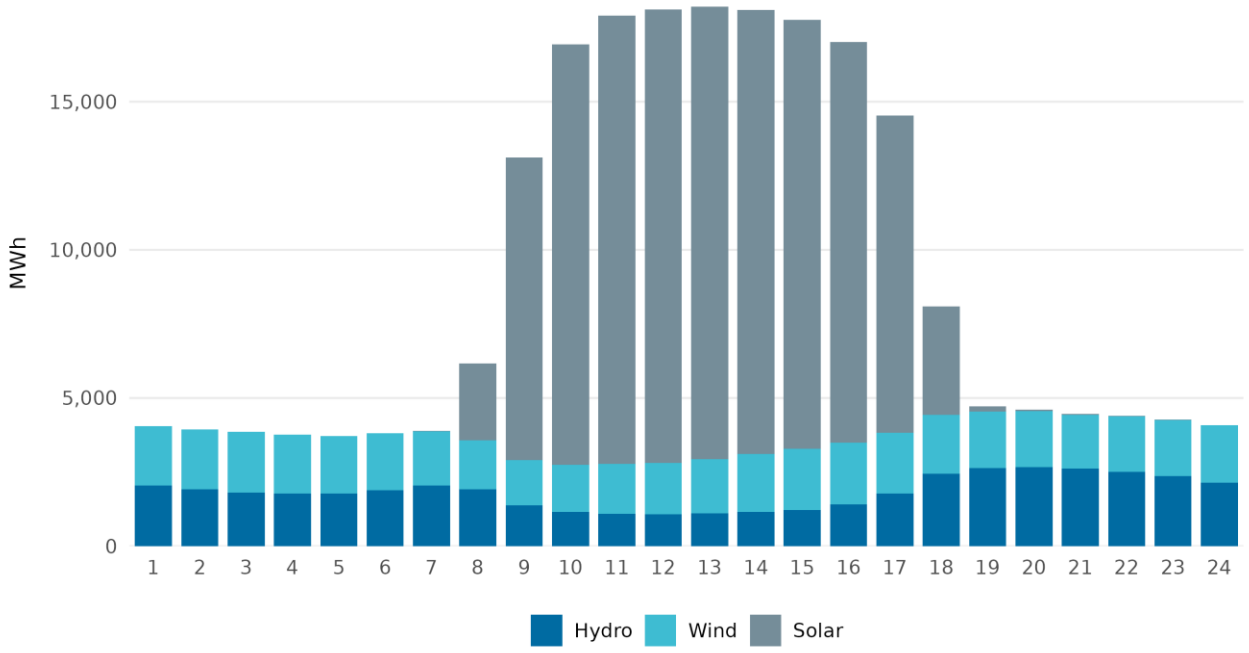


Figure 214: Hourly profile of wind, solar and hydro production for October

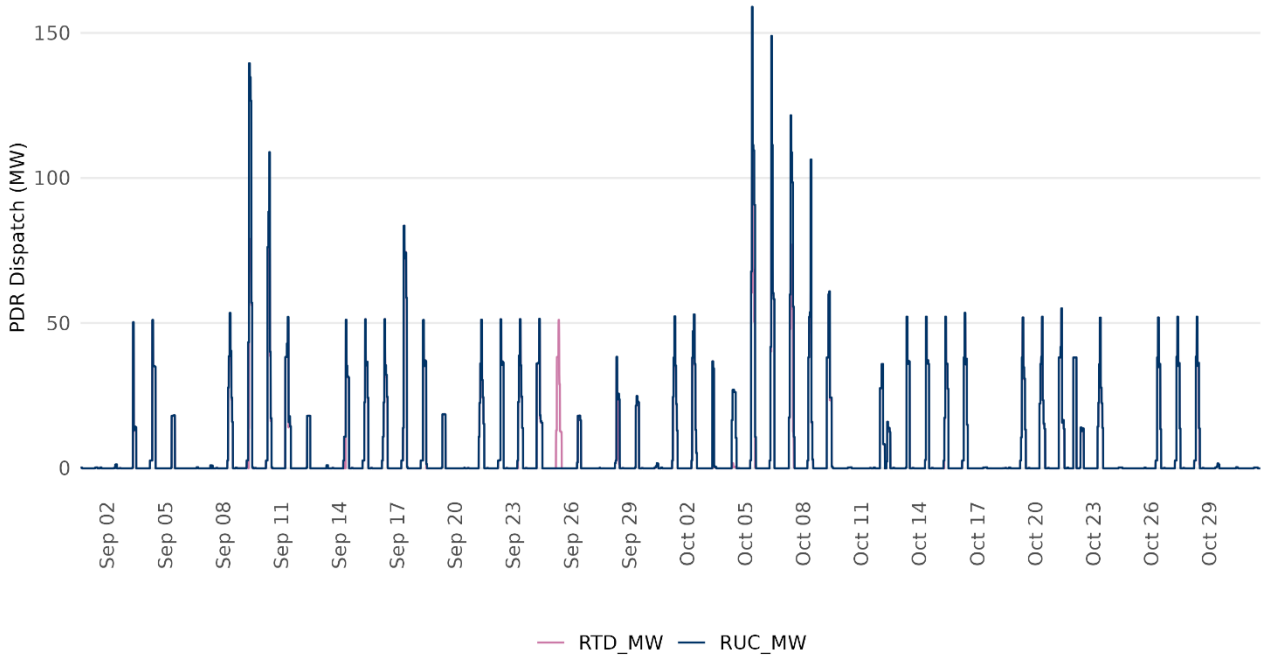


Demand Response

The ISO markets consider demand response programs designed to reduce demand based on system needs and trigger demand response programs through market dispatches. In the ISO's markets, there are two main market programs for demand response: economic (proxy) and reliability demand response. These programs use supply-type participation models that can be dispatched similar to conventional generating resources.

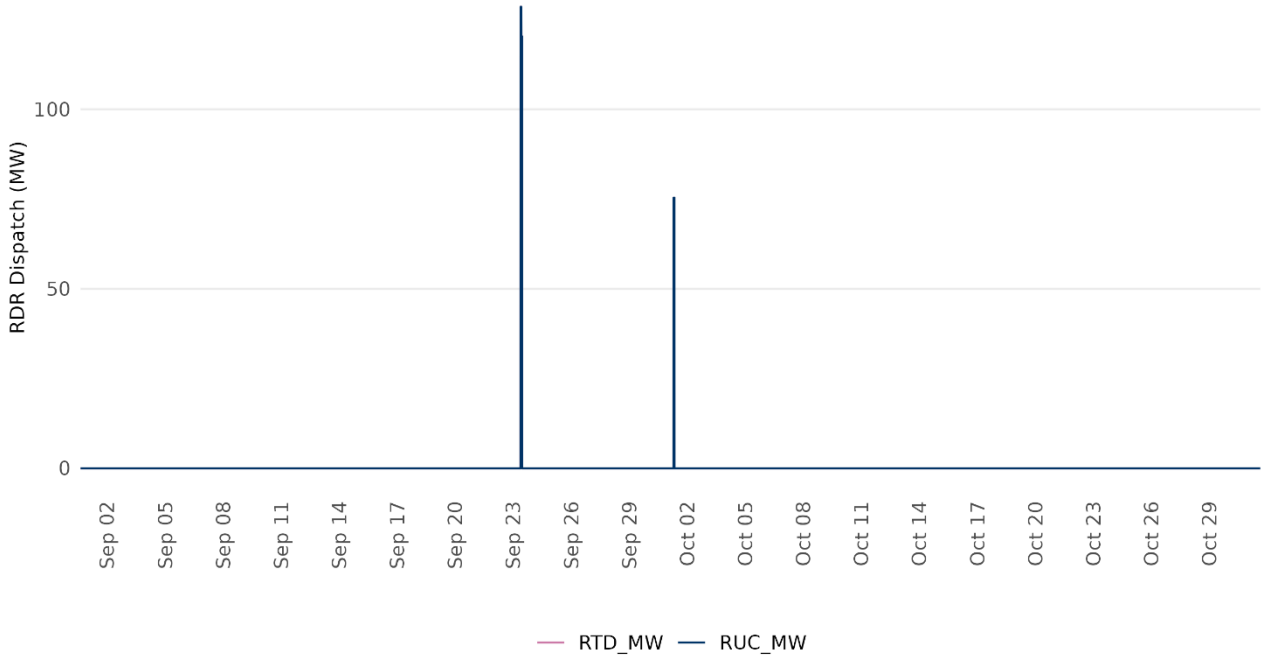
Figure 215 shows the dispatch of proxy demand resources (PDR) in both the day-ahead and real-time markets. PDRs are dispatched economically in all markets based on their bid-in prices. During the month of September and October, PDR resources were consistently dispatched in both the day-ahead and real-time markets and the times overlap but values are slightly different. The largest volume of PDR dispatches in the day-ahead timeframe occurred on October 5 at about 159 MW, whereas in the real-time market, it was a maximum of 111 MW on same day.

Figure 215: PDR Dispatches in day-ahead and real-time markets



Reliability demand response resources (RDRRs) were triggered on September 23 and October 1 . Figure 216 shows the dispatches of RDRRs in both the day-ahead and real-time markets. In the day-ahead market, these types of resources can be dispatched based on economics. The real-time market will consider these DAM dispatches as self-schedules. Therefore, these RDRRs will be dispatched in the real-time market even when there is no energy emergency alert declaration. The largest volume of RDRR dispatches in the real time market was on September 23 to about 129 MW for HE 19. RDRRs were dispatched in RUC and RTD market to the same amount of 129 MW at the same time, hence the lines for RUC MW and blue line for RTD MW are overlapping.

Figure 216: RDRR dispatches in day-ahead and real-time markets



Intertie Transactions

The ISO's system relies on imports that arrive into the balancing authority area through various interties, including Malin and NOB from the Northwest and Palo Verde and Mead from the Southwest. Interties are generally grouped into static imports and exports, or dynamic and pseudo tie resources, which are generally resource-specific. Similar to internal supply resources, interties can participate in both the day-ahead and real-time markets through bids and self-schedules. Additionally, the ISO's markets offer the flexibility to organize pair-wise imports and exports to define wheels. This transaction defines a static import and export at given intertie scheduling points, which are paired into the system to ensure both parts of the transactions will always clear at the same level. Because wheel transactions must be balanced, they do not add or subtract supply to the overall ISO system, regardless of the cleared level. However, they utilize scheduling capacity on interties and transmission capacity on ISO's internal transmission system. All intertie transactions will compete for scheduling and transmission capacity via scheduling priority and economic bids to utilize the scarce capacity on the transmission system.

Economic bids for imports are treated similarly to internal supply bids, while exports are treated similarly to demand bids, or fixed load through the load forecast feeds. These bids are bounded

between the bid floor (-$150/MWh) and bid cap ($1,000/MWh or $2,000/MWh). Each part of a wheel is also treated accordingly as supply or demand, but its net bid position is defined as the spread between its import and export legs.
Intertie transactions also have the flexibility to self-schedule. The ISO's market utilizes a series of self-schedules which define higher priorities than economic bids based on the attributes applicable to resources. Participants with such entitlements can submit intertie self-schedules using transmission ownership rights (TORs) or Existing Transmission Contracts (ETCs), as well as PTK and LPT.

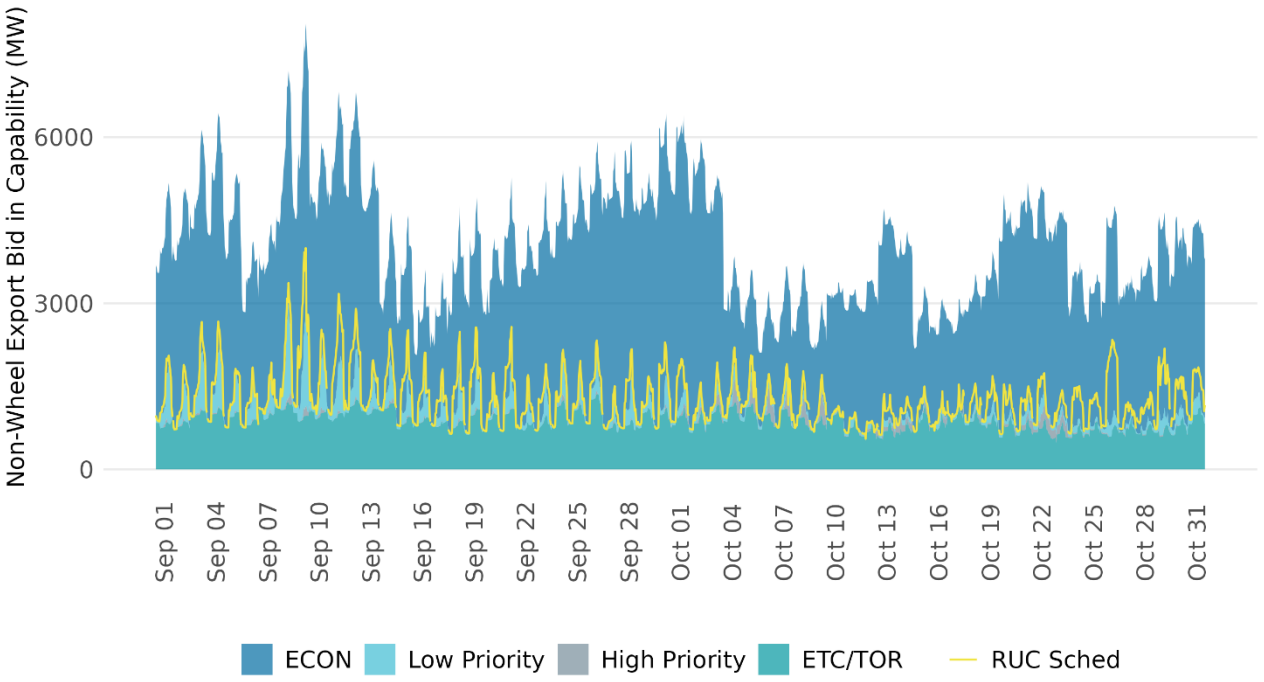
The ISO's markets will clear intertie transactions utilizing its least-cost optimization process in each of its market runs. Bids and self-schedules are considered in a merit order to determine the clearing schedules, and all resource bids and characteristics, and system conditions, are considered. In the upward direction, when supply capacity is limited, imports with self-schedules clear first, followed by economic bids from cheapest to most expensive up to the level of the market clearing price. Conversely, exports will clear first for ETC/TORs, then PTK exports, followed by LPT exports and lastly economic bids from most expensive to cheapest. Wheel transactions have a higher priority in the clearing process defined as the relative spread of penalty prices between the import and export sides.

Intertie supply

Figure 217 shows the capacity from static export transactions in the day-ahead market organized by types of exports. This capacity does not include export capacity associated with wheel transactions of any type because wheels are in balance on a net basis, and the export side of wheels does not reduce supply to the ISO supply stack.

This figure also illustrates the clearing schedules from the RUC process with the line in yellow. The RUC schedules are used as references instead of the IFM schedules because they are the relevant schedules for clearing interties in the day-ahead market. Export volumes in October decreased slightly compared to September.

Figure 217: Day-ahead Bid-in capacity and RUC cleared export



The RUC schedule plus RCD minus RCU represents the expected delivery and E-tags that market participants should submit in the pre-scheduling timeframe, and not the IFM schedule. While not required to submit their E-tags in the day-ahead timeframe, market participants are encouraged to do so and, in such cases, should base their E-tag on the RUC schedule. If not, E-tags greater than RUC schedules may be adjusted by the ISO. This applies to all dynamic and static intertie schedules.

Export bid capacity in the day-ahead market varies by hour and typically follows a daily profile. About 73 percent, 5 percent, 21 percent and 1 percent of the export capacity were for economic bids, LPT, ETC/TOR and PTK, respectively. The total of bid in export volume in October was lower compared to September. The highest RUC scheduled was in hour ending 15 on October 26th, at about 2341MW.

Figure 218 shows the same metric for imports. These volumes include both static imports and dynamic resources. Both ETC/TOR remained relatively stable through the months. There were lower volumes of economic bids in October compared to September, resulting in a lower total of bid in capacity. The "other" group includes regulatory must run priority capacity and the portion of Pmin for dynamic resources with a Pmin above 0 MW.

Figure 218: Day-ahead bid-in capacity and RUC-cleared imports

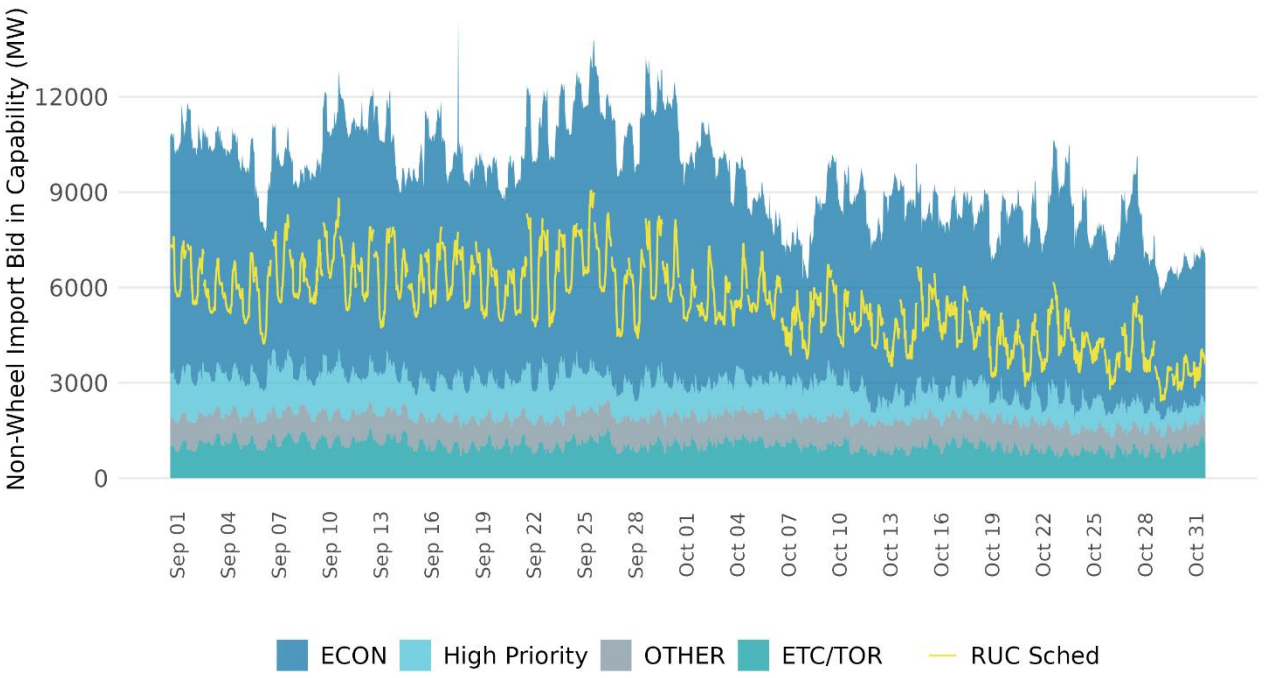
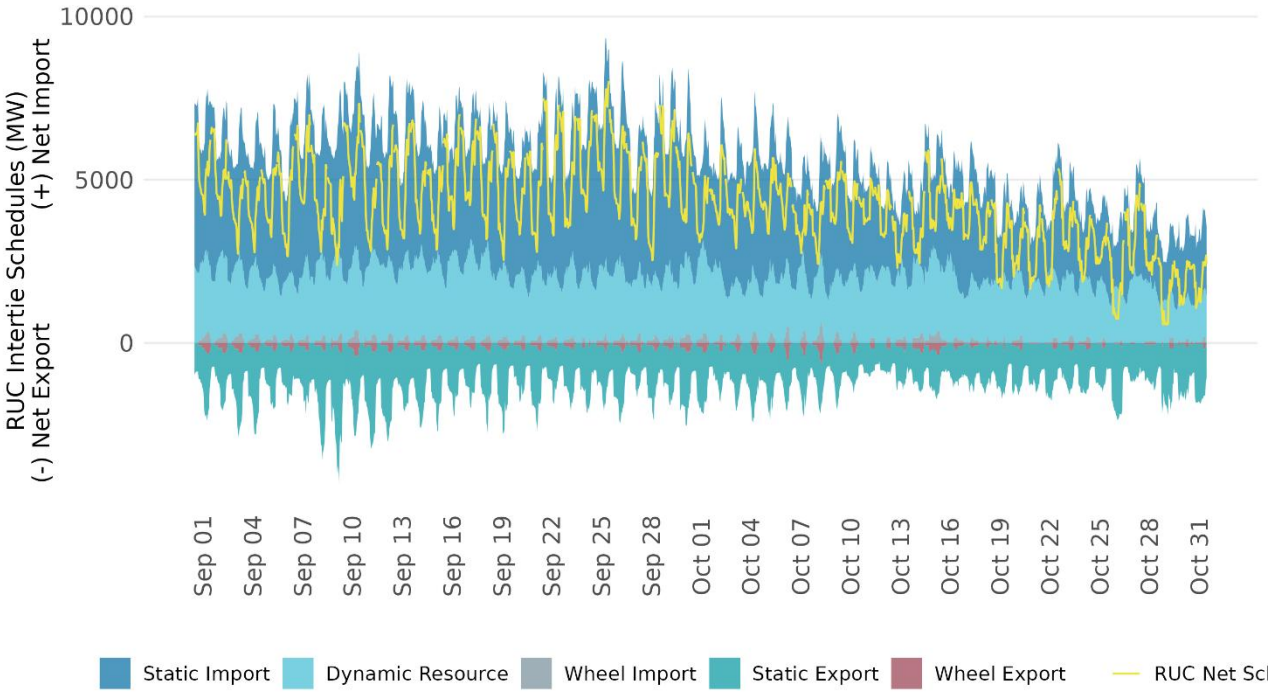


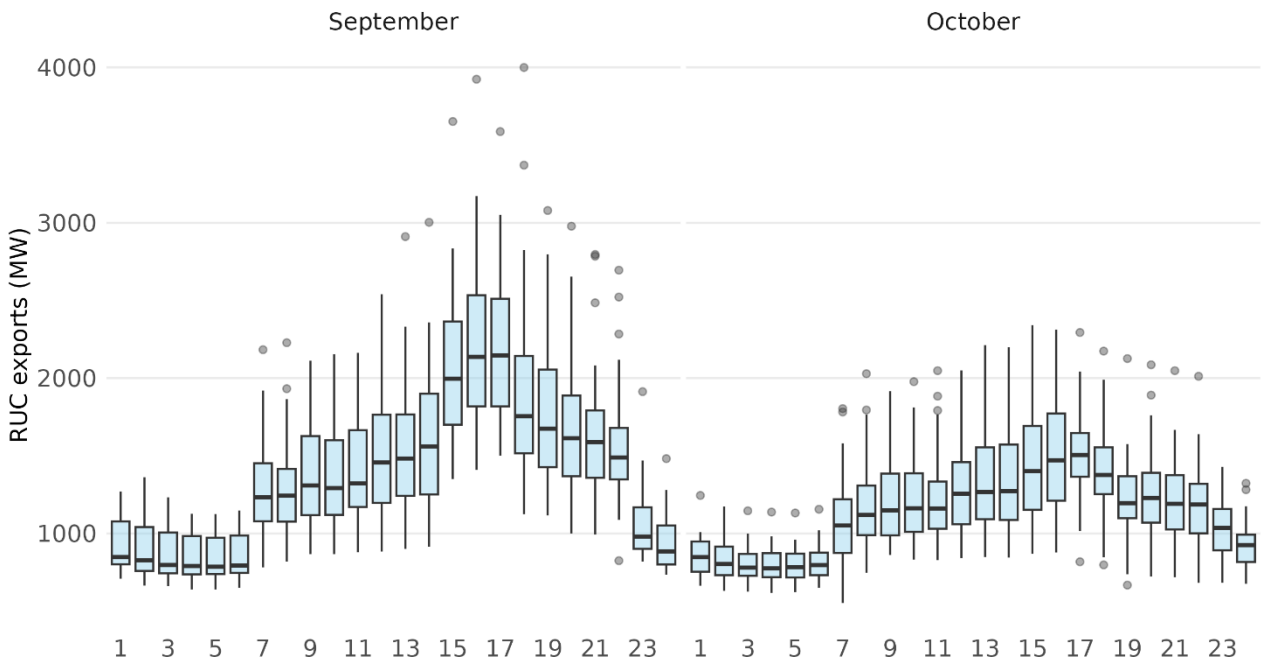
Figure 219 shows the overall intertie schedules organized by type of schedule, as well as the net interchange based on the RUC solution for two months. The net interchange projected in the RUC process reached its lowest level on October 29th in HE14 at about 558MW due to the higher level of exports cleared.

Figure 219: Breakdown of RUC cleared schedules



An area of interest since summer 2020 is the trend of exports in the ISO's system. Figure 220 illustrates the hourly distribution of RUC schedules for exports and that the highest volume occurred during afternoon hours. Compared to September, October had lower levels of RUC export in all hours. The highest volumes were cleared in hour ending 16.

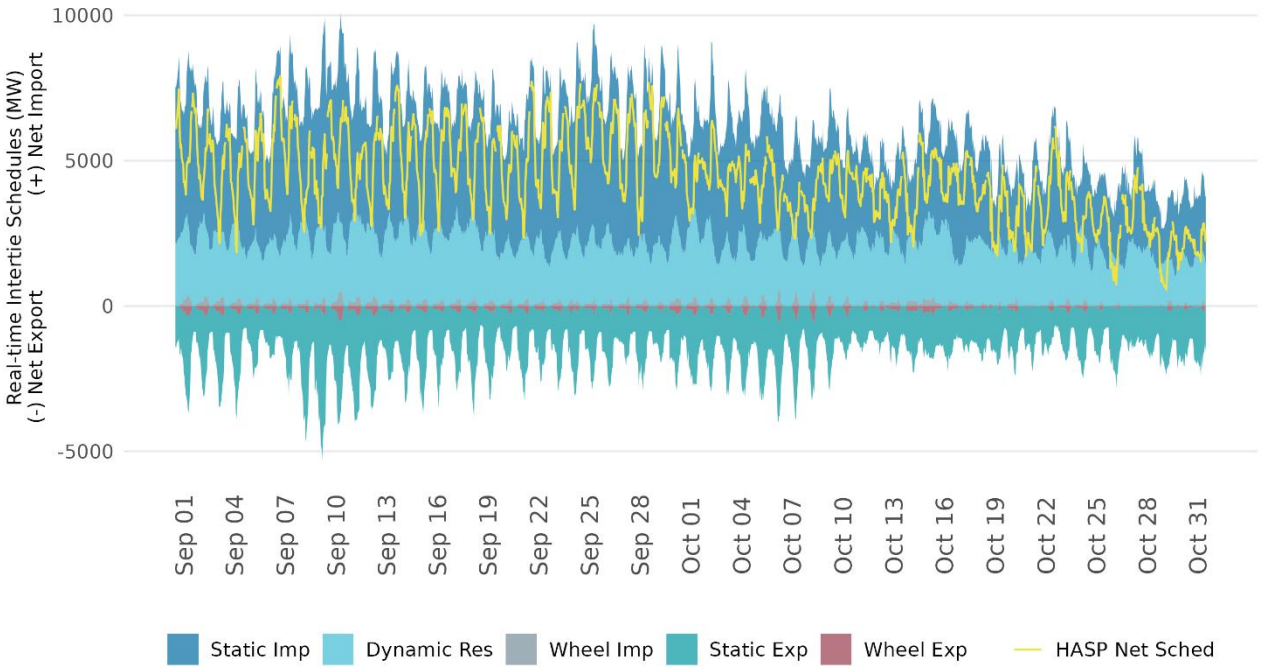
Figure 220: Hourly RUC exports



Intertie positions are largely set from the day-ahead market. Import or exports cleared in the day ahead may tend to self-schedule into the real-time to preserve their day-ahead priority. There may still be incremental participation in the real-time market through the HASP process, which allows resources to bid-in economically to buy back their day-ahead position or additional capacity in the real-time market.

Figure 221 shows both the cleared schedules in real time for interties of different groups, and the net intertie schedules cleared, referred to as net schedule interchange. The net schedule interchange was at its lowest value on October 29due to the high level of exports cleared on that day. The real-time market largely follows the trend observed in the day-ahead market. On average, for October, the net schedule in HASP was about 3,634MW across all the hours of the month and about 3,675MW for peak hours.

Figure 221: HASP cleared schedules for interties



The HASP market presents an opportunity for interties to clear through the market clearing process after the DAM is complete. Clearing the RUC process indicates that these exports were feasible to flow based on the projected system conditions in RUC and will be reassessed in real time.[12]

Each market, RUC or HASP, can assess reduction of exports based on prevailing system conditions and economics. Export reductions in RUC cannot self-schedule into real-time with day-ahead priority, but they are able to rebid into the real-time market and be fully assessed based on real-time conditions.

Figure 222 shows all the exports cleared in the HASP process and identifies the nature of such exports. Figure 178 shows the same breakdown for October 6 to 8. ETC/TOR is for export with scheduling priorities associated with transmission rights. The groups of DAM_PT or DAM_LPT stand for day-ahead exports coming into real-time market as self-schedules with high or low priorities. Similar classification is followed for those high and low priority exports coming into real-time directly (RT_PT and RT_LPT). ECON stands for economic exports. These exports are only for non-wheel transactions.

[12] Based on these rules implemented on August 4, 2021, through the summer enhancements described earlier and now in place, the ISO will no longer provide exports a higher priority than load in the real-time, and will only provide them equal in priority to load if the participant demonstrates that they continue to be supported by resources contracted to serve external load. Details are available at http://www.caiso.com/Documents/Jun25-2021-OrderAcceptingTariffRevisionsSubjecttoFurtherCompliance-SummerReadiness-ER21-1790.pdf

The volume of exports cleared in real time peaked at 3528MW on October 6. In October, volumes of exports cleared were lower than September, and low-priority bids constituted a significant portion of cleared exports.

Figure 222: Exports schedules in HASP

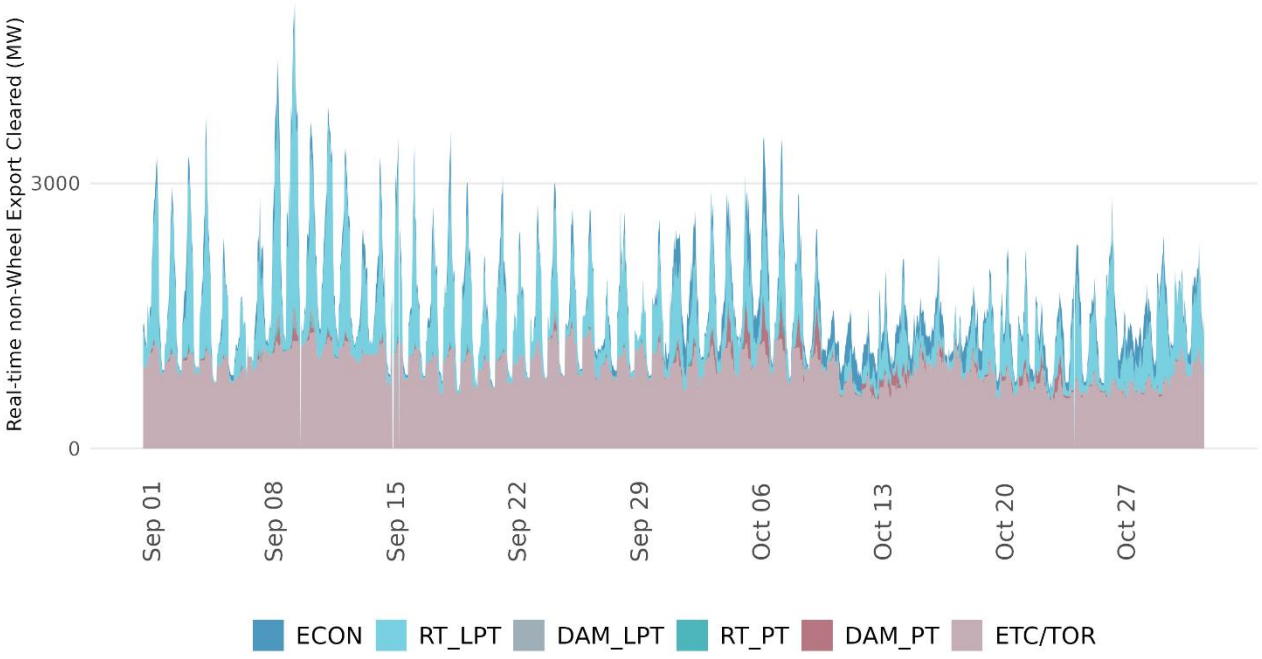
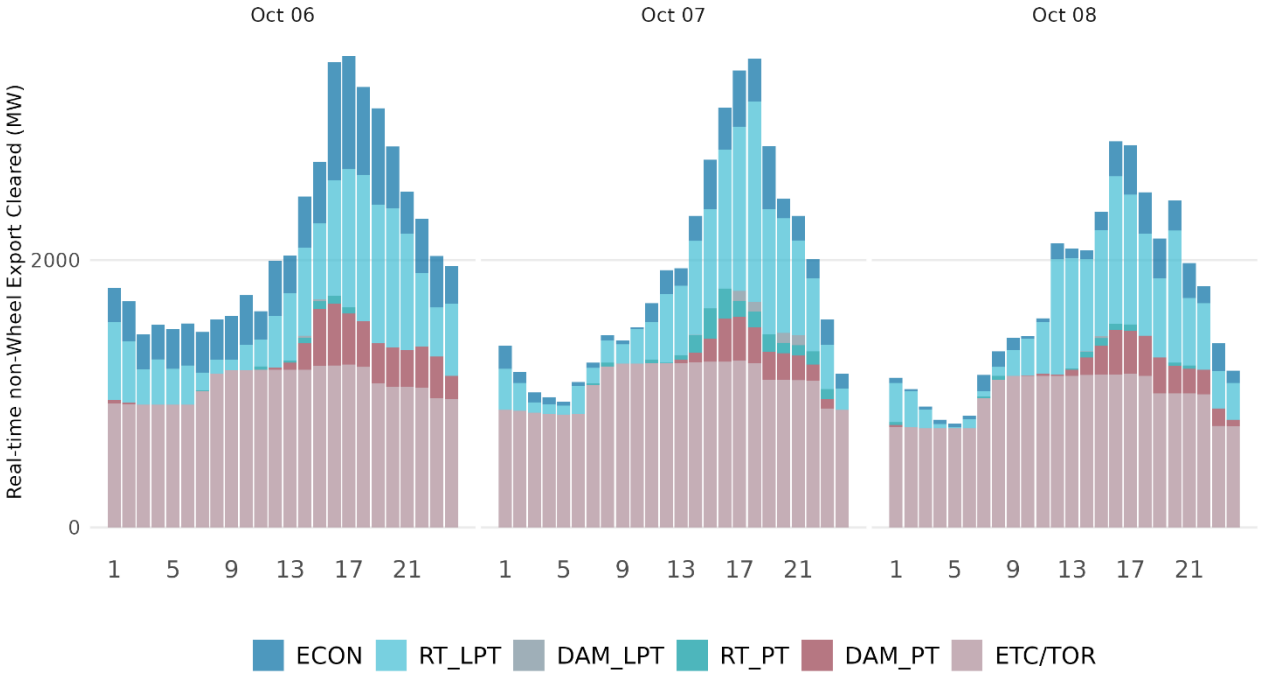


Figure 223: Exports schedules in HASP, October 6 to 8



Imports and exports were scheduled over multiple intertie scheduling points in October, with Malin, Palo Verde and NOB seeing the highest volume of transactions. Figure 224 through Figure 226 illustrate the trend of import and export schedules cleared in HASP for these top three intertie points. In October, the prevailing schedules were in the import direction on Malin and Palo Verde. NOB was on outage starting October 3rd through end of the month.

Figure 224: HASP schedules at Malin intertie

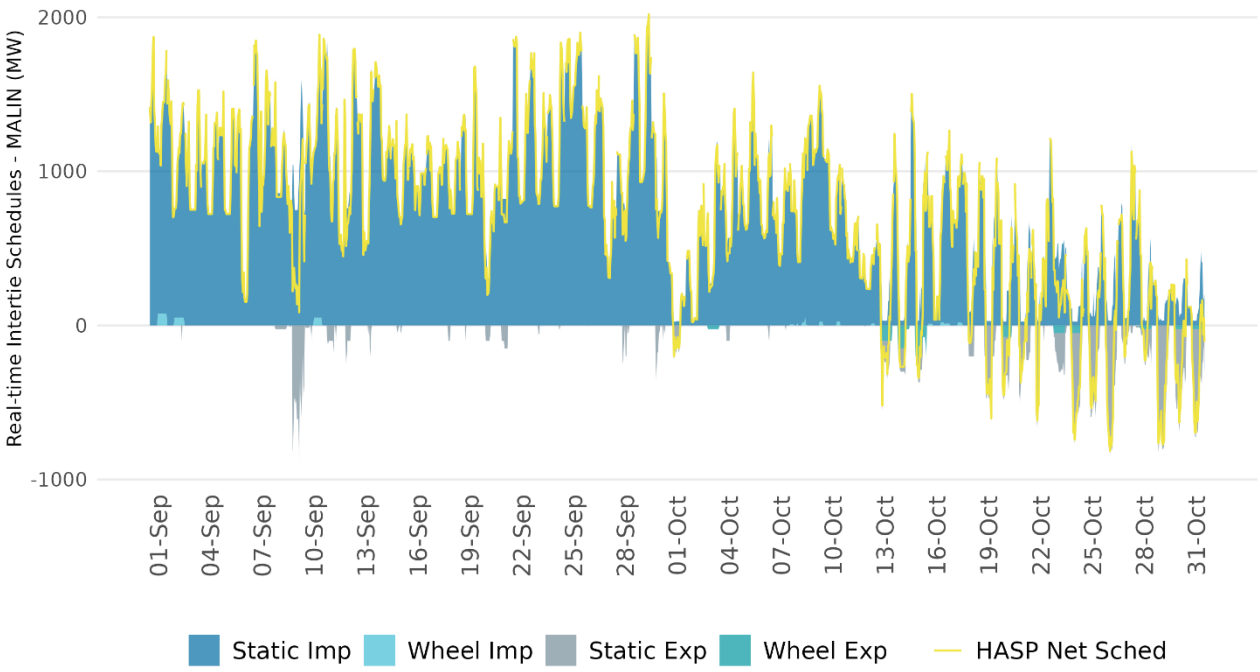


Figure 225: HASP schedules at Palo Verde intertie

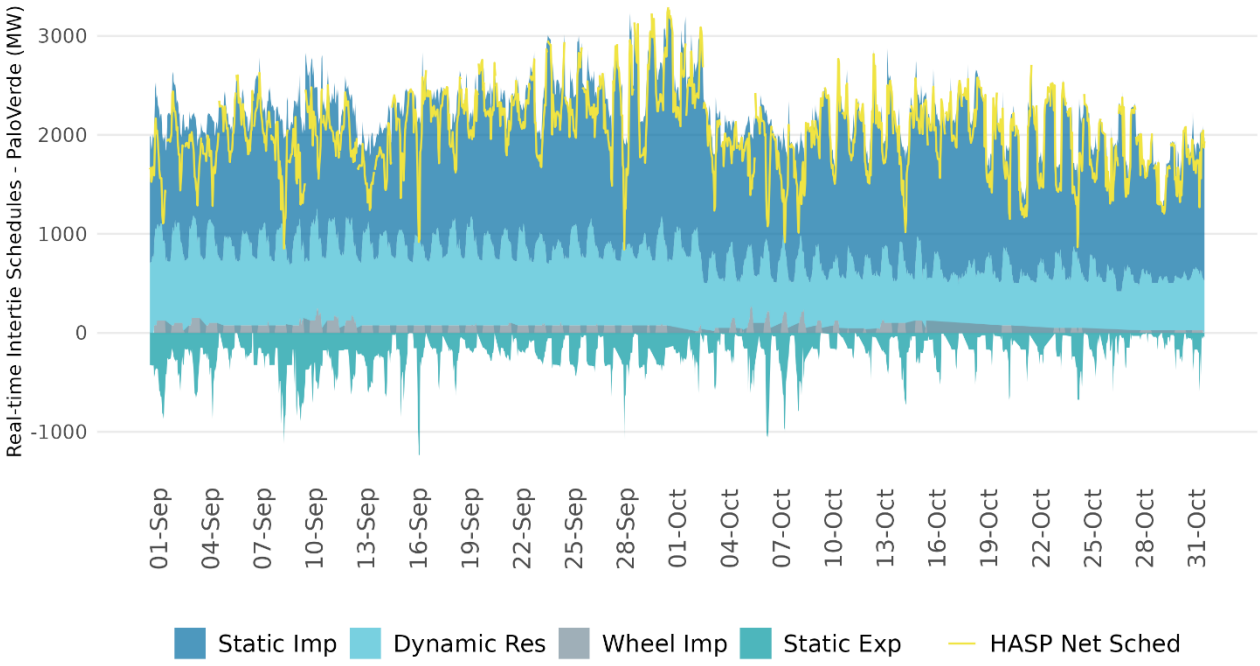


Figure 226: HASP schedules at NOB intertie

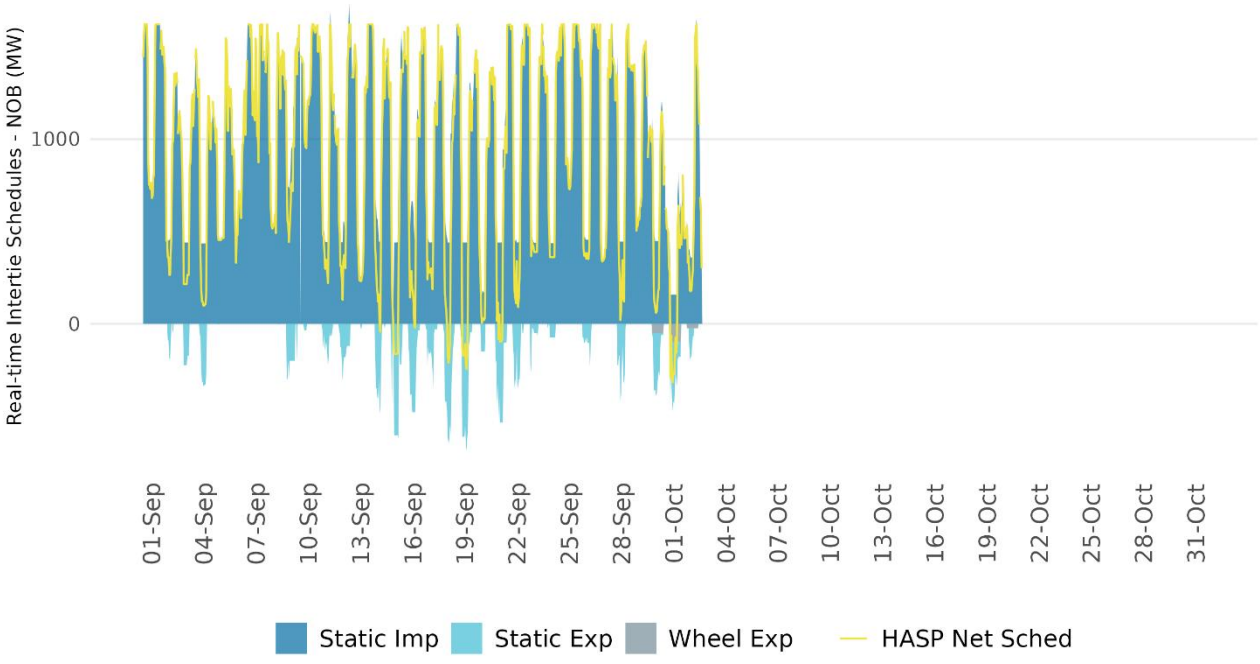
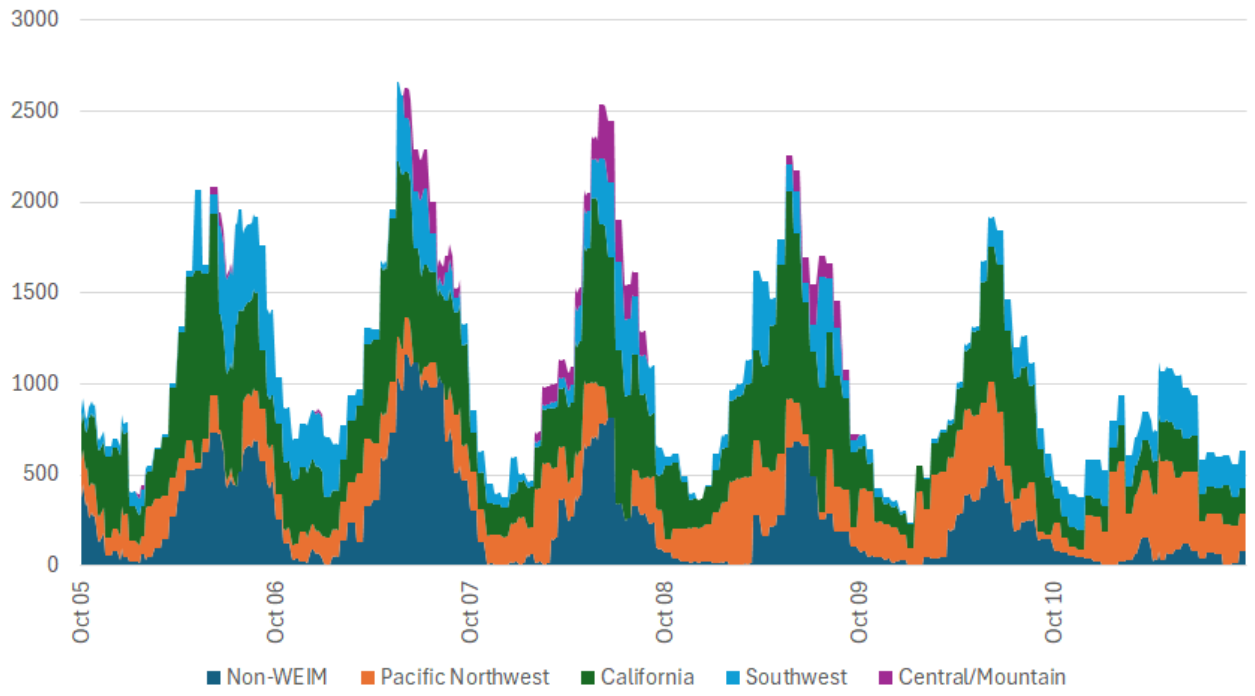


Figure 227 shows the total volume of intertie exports that are sourced from the ISO area and organized by the different areas in which the exports sink. For simplicity, these sink areas are grouped in regions of the western interconnection for all areas that are in the western energy imbalance market. There is one group also used to refer to the volume of export sinking into areas that are not part of the western energy imbalance market. During October heatwave, up to 2,656 MW of exports sourced from the ISO area supported multiple areas in the western interconnection.

Figure 227: Total volume of exports sourced from the ISO area



Storage and Hybrid Resources

In October 2026, there were about 250 storage resources registered in the ISO market. Storage resource here refers to the Limited Energy Storage Resource (LESR) type. Most storage resources participated in both the energy and ancillary service market. Batteries can arbitrage the energy price by consuming energy (charging) when prices are low, then subsequently delivering energy (discharging) during market intervals when prices are higher. Each storage resource has a maximum storage capability that reflects the physical ability of the resource to store energy.

The total state of charge from all the active resources participating in the market was about 71,000 MWh. In terms of the capacity made available to the markets, Figure 228 presents the daily average

of bid-in capacity for storage resources in the day-ahead market in August and September, and Figure 229 presents the hourly average from August to October, organized by price ranges. The bid-in capacity and prices remain stable throughout August and October.

Figure 228: Bid-in capacity for batteries in the day-ahead market, daily average

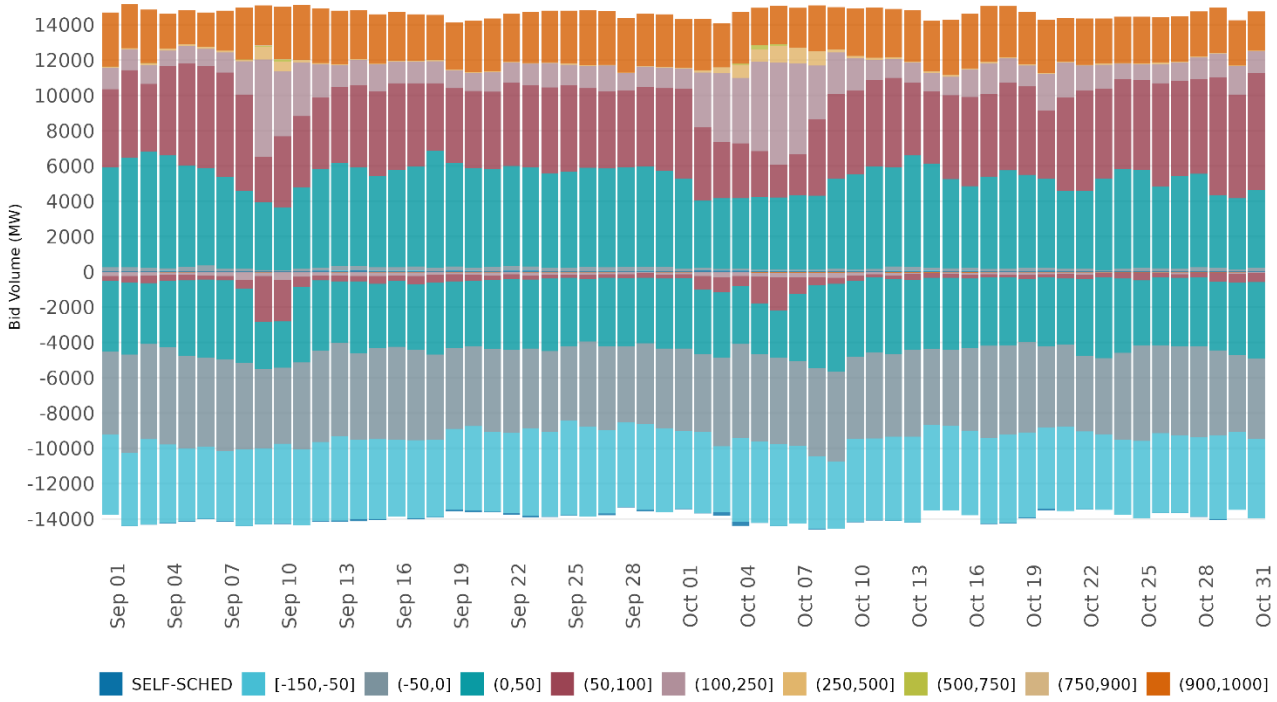
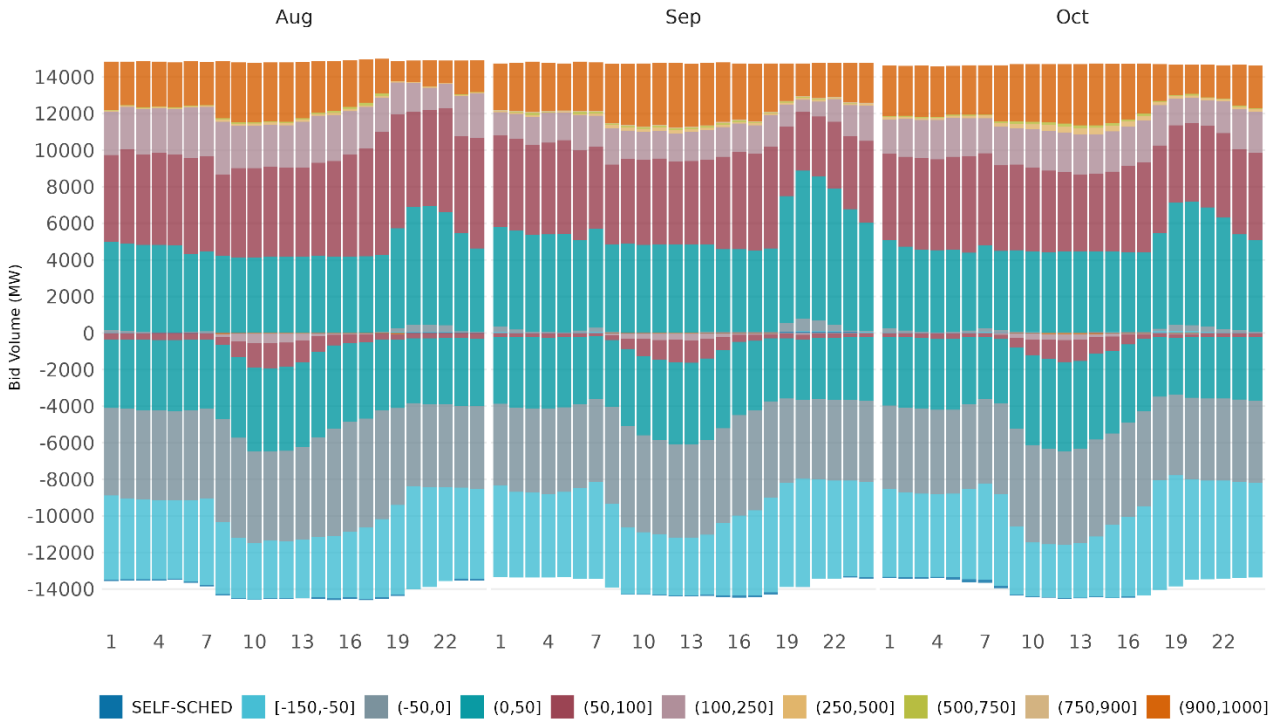


Figure 229: Bid-in capacity for batteries in the day-ahead market, hourly average



The negative area represents charging while the positive area represents discharging. The overall capacity in the market was roughly consistent throughout the months at about 14,000 MW. The bid-in capacity is organized by $/MWh price ranges. There were consistent patterns of batteries bidding to charge at negative prices and discharge at positive prices. Some resources bid reflected the willingness to charge when prices were up to $50. Conversely, they were almost always willing to discharge at higher prices. The green segments show bids close to or at the soft energy bid cap of $1,000/MWh and show that there was a certain volume of storage capacity expecting to discharge only at these high prices.

Figure 230 and Figure 231 present the bid-in capacity for the real-time market. The overall capacity follows a similar trend as the day-ahead market.

Figure 230: Bid-in capacity for batteries in the real-time market, daily average

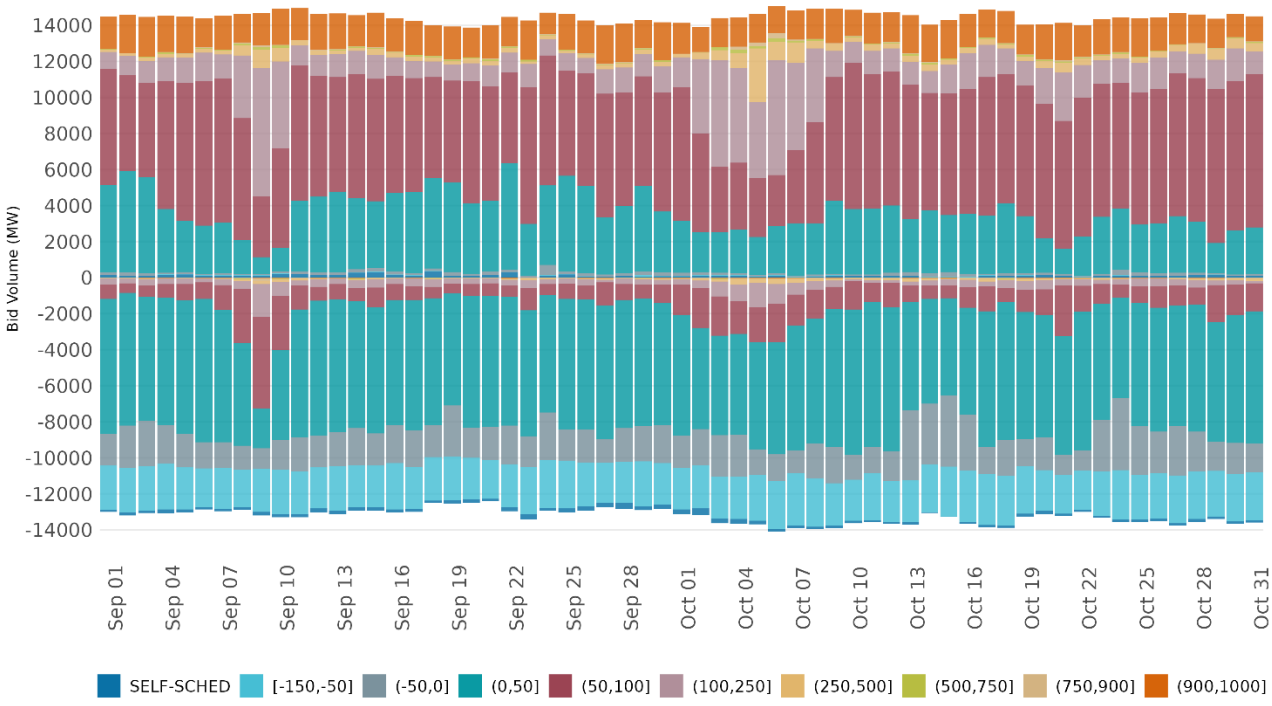


Figure 231: Bid-in capacity for batteries in the real-time market, hourly average

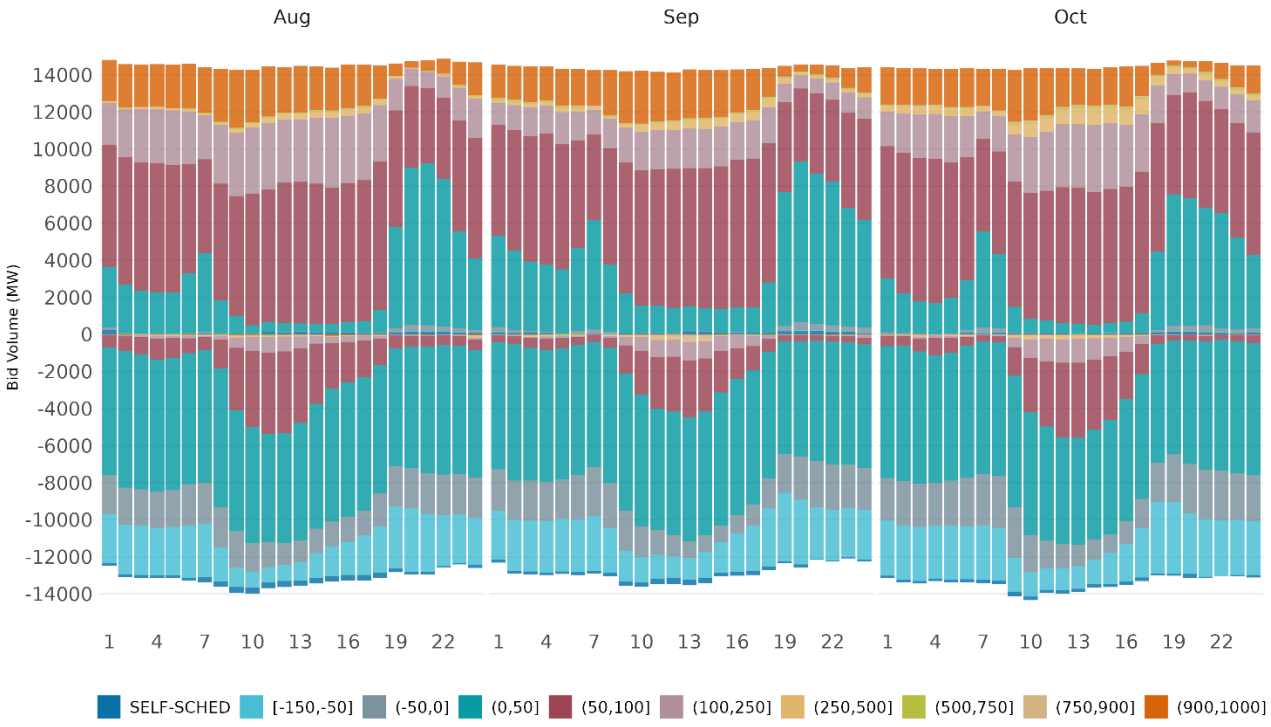


Figure 231 shows the hourly distribution of the storage capacity of resources participating in IFM and RTD throughout August to October. The day-ahead state-of-charge profile exhibited a consistent intraday pattern from August through October, with SOC remaining relatively low overnight, increasing rapidly during the daytime, reaching its highest levels during the afternoon, and declining sharply during the evening. August generally recorded the highest afternoon SOC levels, while September showed a modest reduction. October returned to relatively high afternoon SOC levels but exhibited noticeably greater day-to-day variability, particularly during the daytime charging and high-SOC hours.

Figure 232: Distributions of day-ahead state of charge

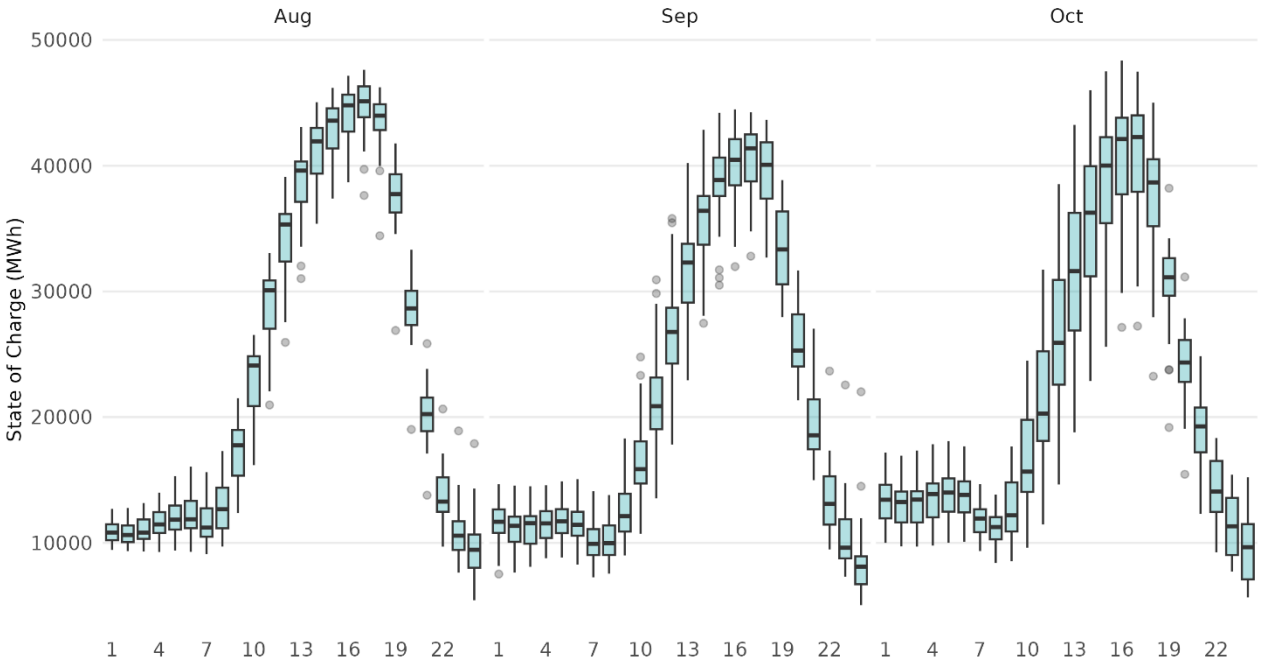
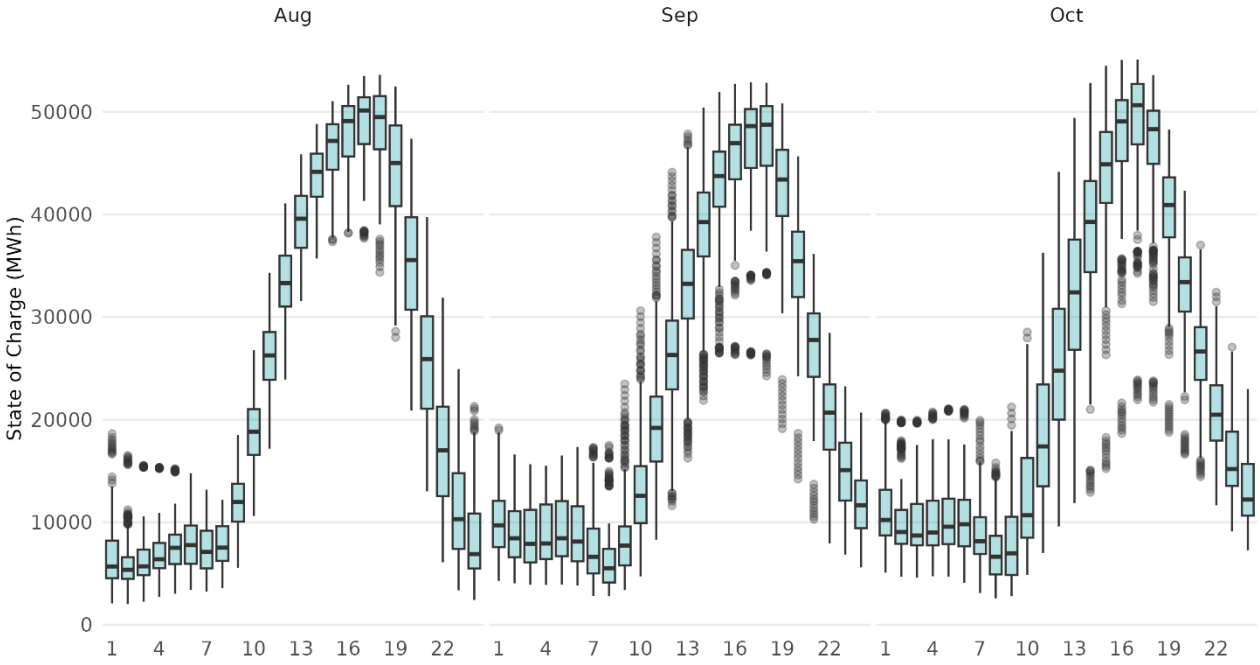


Figure 233: Distributions of real-time state of charge



Most of the storage resources in the ISO market are four-hour batteries, which implies that if a resource is fully charged, it will take four hours to discharge this resource completely. To arbitrage prices, it is expected that the resource would be charged as much as possible just prior to the hours with high energy prices. With the need for more supply as solar production diminishes, it is expected that storage resources would be discharging during net load peak hours. Figure 234 shows the distributions of energy awards in IFM, and Figure 235 shows the hourly distribution of real-time dispatch for batteries from August to October. These statistics are for batteries, either stand alone or the battery component of co-located resources; they do not include hybrid resources.

Figure 234: Hourly distribution of IFM energy awards for batteries

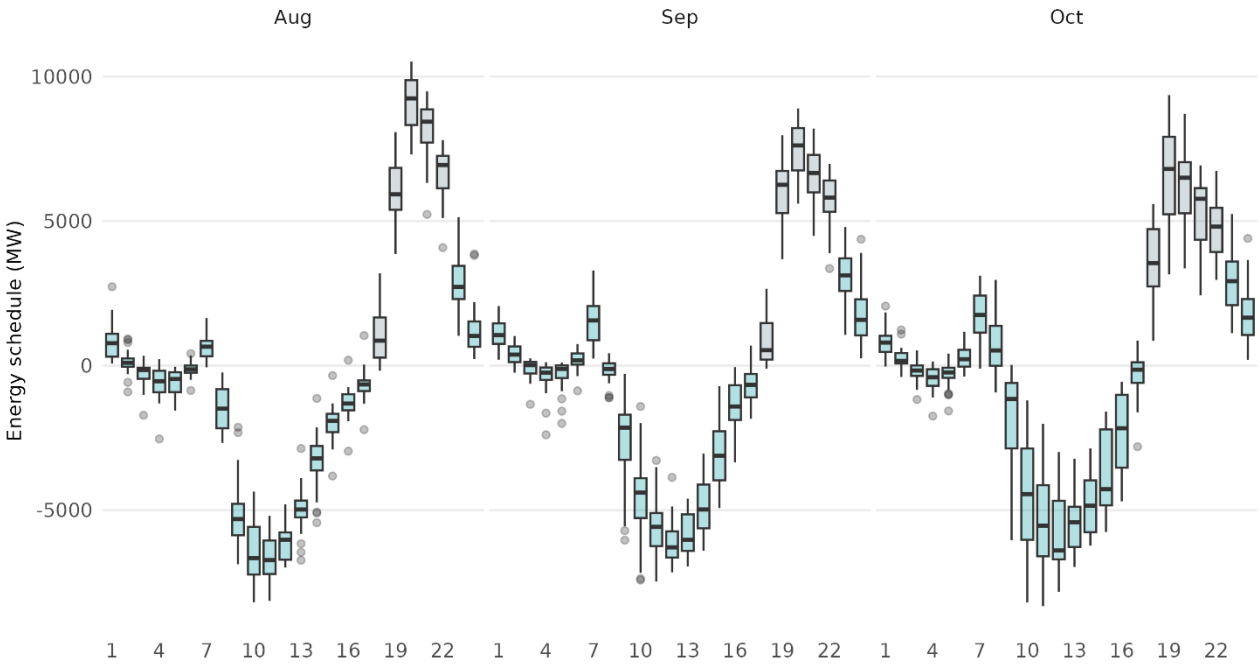
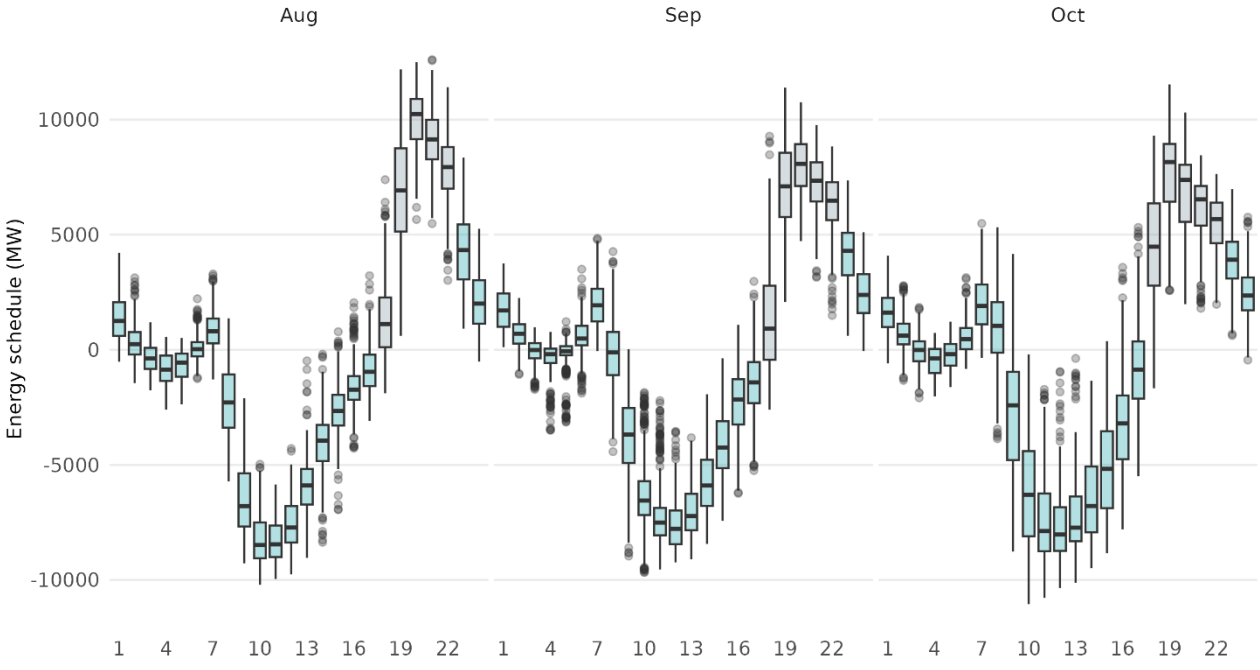
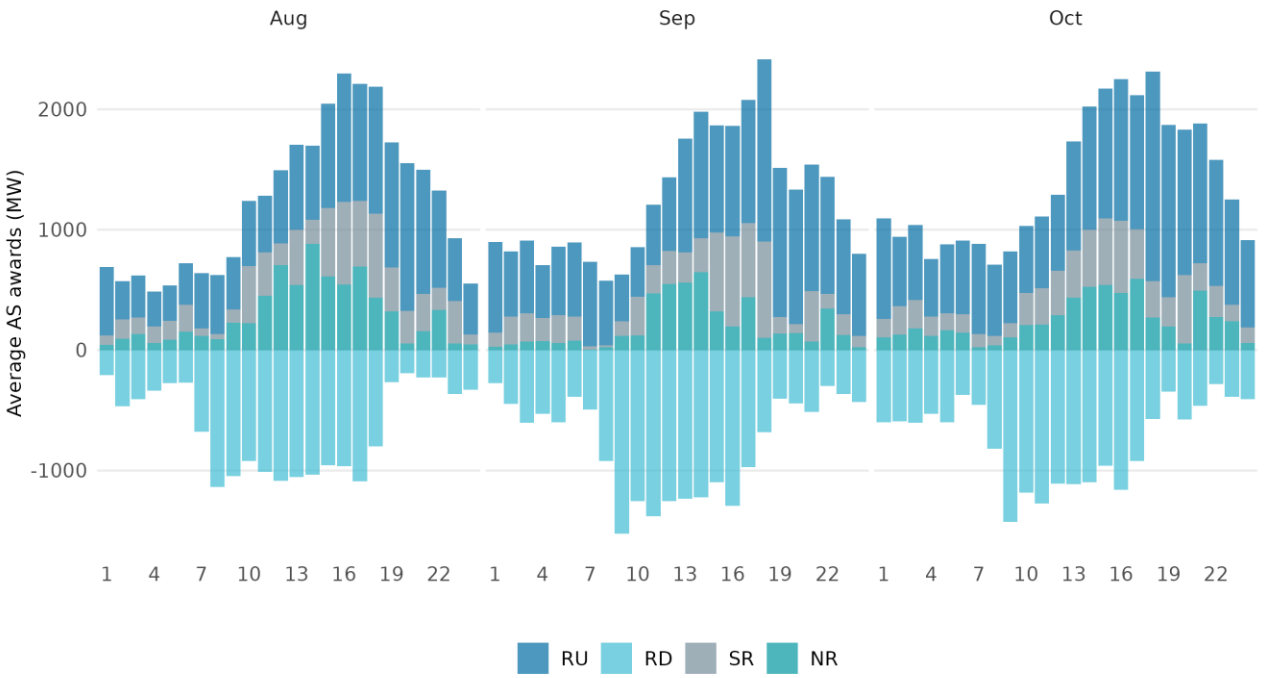


Figure 235: Hourly distribution of real-time dispatch for batteries



The storage resources continue to provide ancillary services to the market for the following products: regulation up, regulation down, spinning reserve, and non-spinning reserve. Figure 236 shows the average hourly AS awards in the real-time market.

Figure 236: Hourly average real-time storage AS awards



Beginning with the implementation of the Hybrid Resources Phase 2B project in February 2023, the ISO began tracking the market performance of hybrid resources. Hybrid resources are different resource types that sit behind a single resource ID – typically a solar resource paired with a storage resource.

Figure 237 and Figure 238 show the IFM and real-time energy awards for hybrid resources, respectively. August and September generally recorded higher and more concentrated daytime awards, while October showed lower median award levels and substantially greater day-to-day variability, particularly between HE 9 and HE 18. The pattern matches more closely the dispatch patterns of solar resources with some differences. The energy awards dip in the middle of the day when solar resources typically reach peak output. This is likely due to the energy storage component of the resource charging off of the solar component of the resource, resulting in a lower energy award. Another notable difference is that the evening ramp down as the sun sets is less steep compared to solar resources. This pattern is attributed to the storage component of the resource discharging in these evening hours, offsetting the decreased production of the solar component and resulting in a flatter decline in output.

Figure 237: Hourly distribution of IFM energy awards for hybrid resources

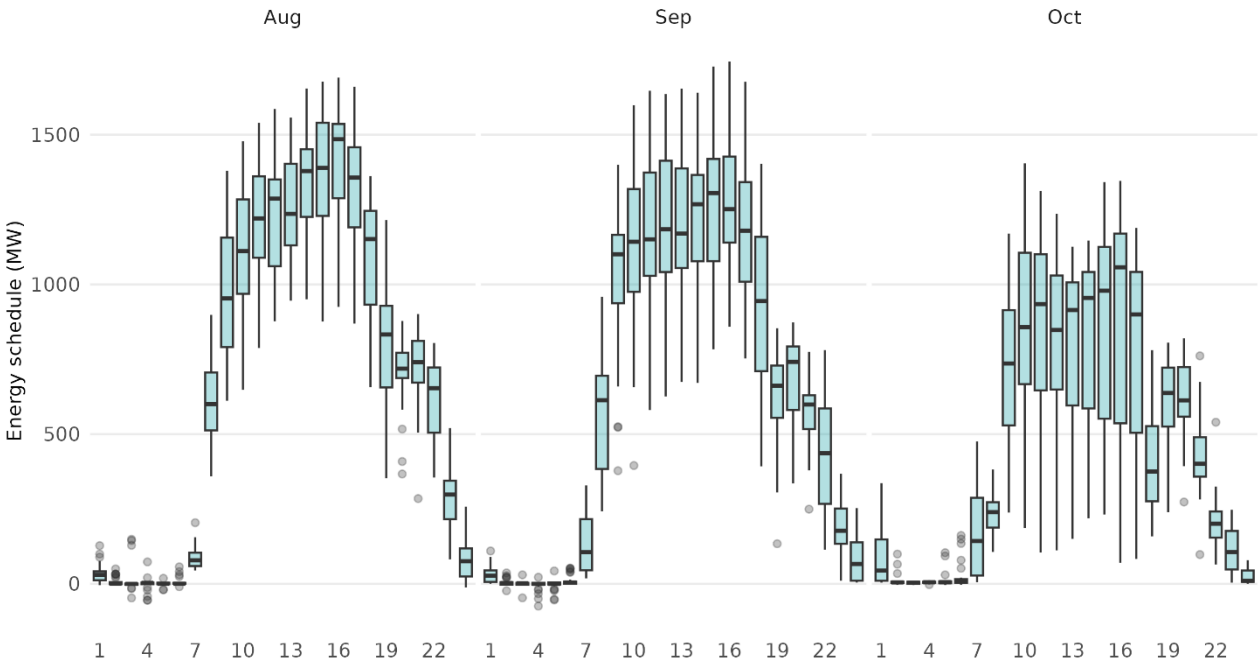
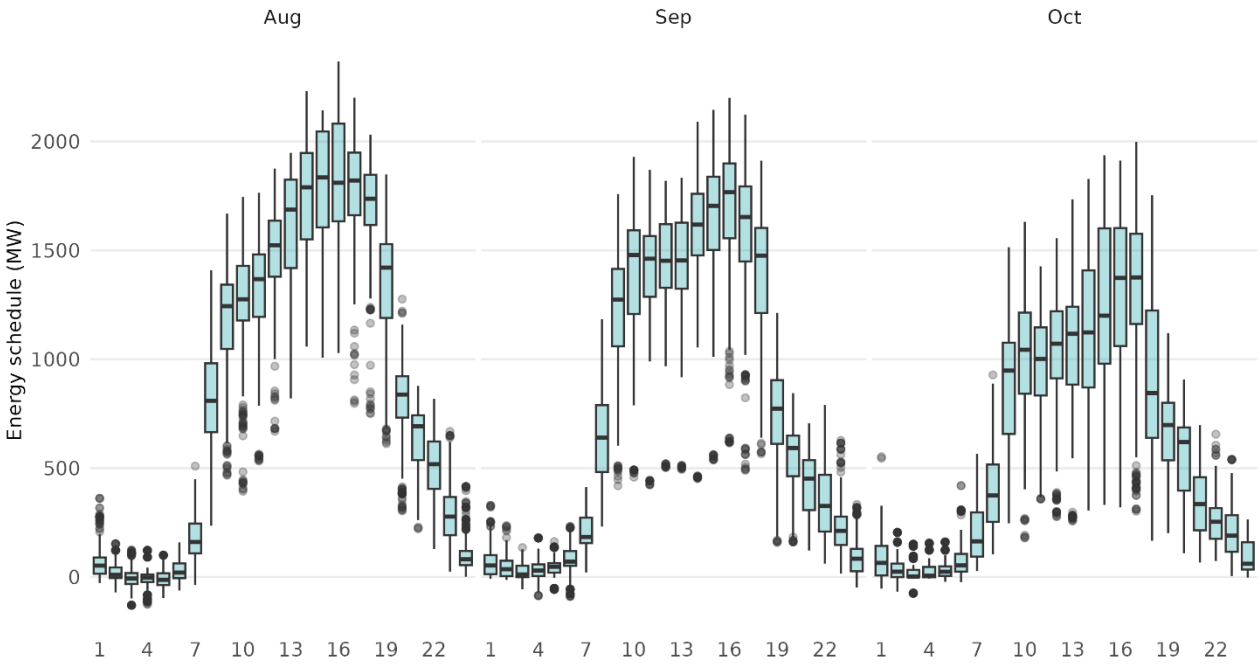
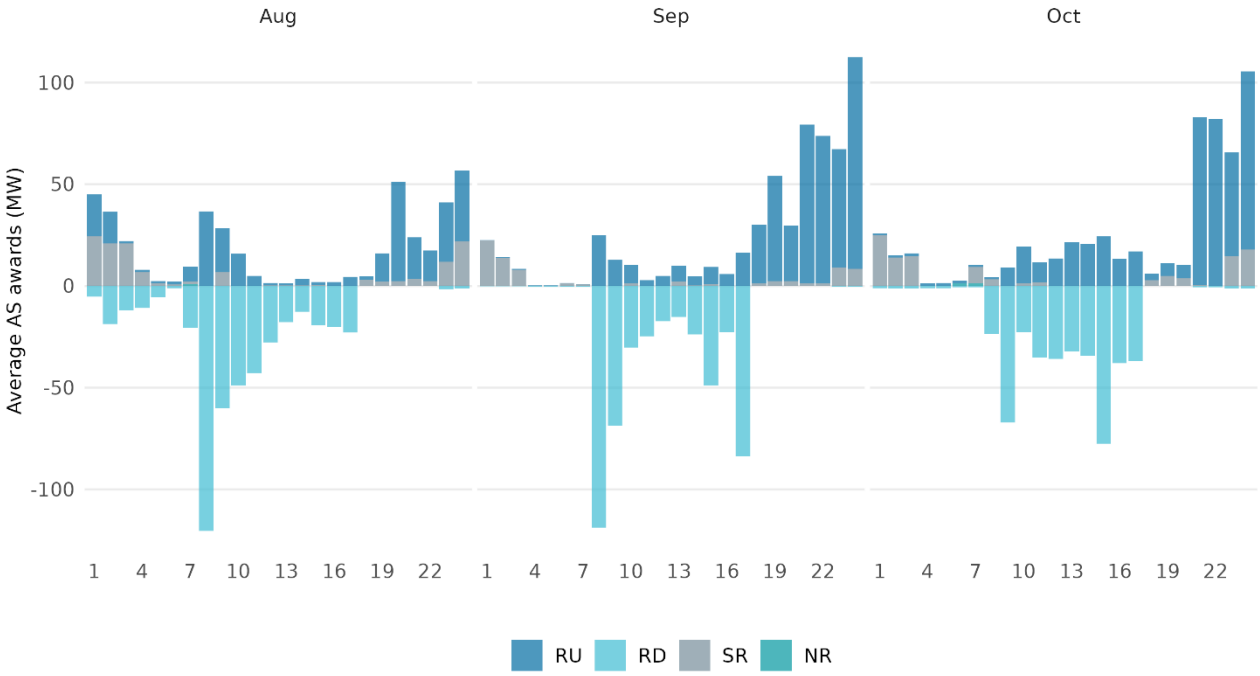


Figure 238: Hourly distribution of real-time dispatch for hybrid resources



Similar to storage resources, hybrid resources can also provide ancillary services to the market. Figure 239 shows the average hourly AS awards in real-time throughout August to October 2026.

Figure 239: Hourly average real-time hybrid AS awards



From October 6 to October 8, real-time energy schedules for storage resources exhibited a consistent daily charging and discharging pattern. Charging activity generally occurred during the late morning to early afternoon, with net schedules over 10,000 MW, while discharging peaked in the evening at approximately 9,000 MW. The corresponding real-time SOC increased during charging periods, reaching daily highs of approximately 51,000–53,000 MWh in the late afternoon, and declined during evening discharge periods. This pattern was consistent throughout all three days, with SOC reaching its highest level on October 6. Overall, the charts illustrate the critical role of storage resources during heatwave period.

Figure 240: Hourly real-time dispatch for storage resources, October 6 to October 8

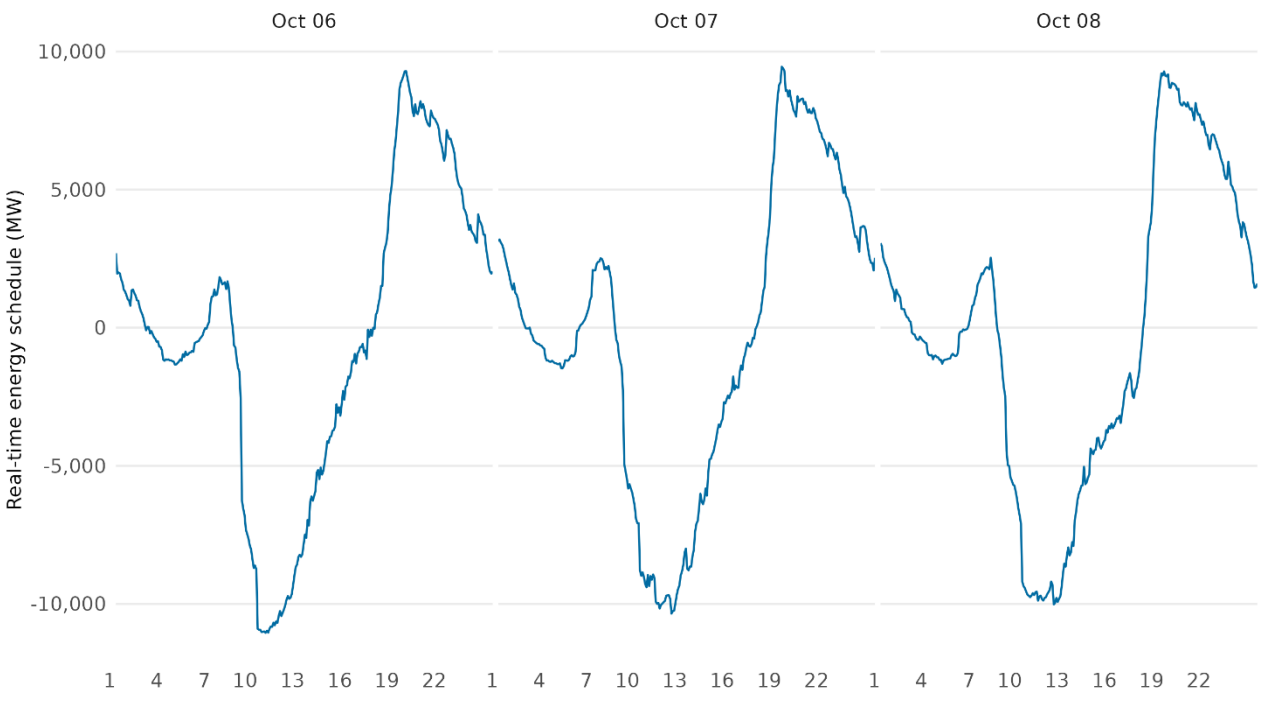
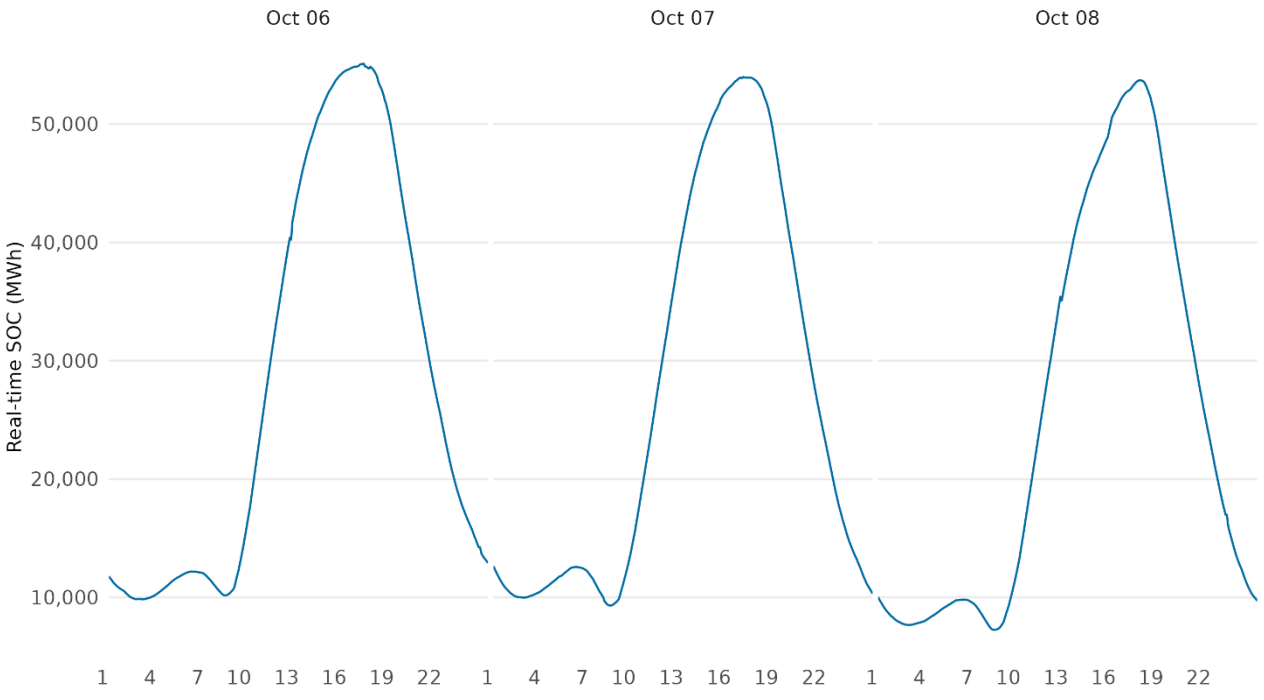


Figure 241: Hourly real-time SOC for storage resources, October 6 to October 8



Western Energy Imbalance Market

October experienced lower load conditions across the western interconnection than September. The highest load reached 134.6 GW on September 9. Figure 242 shows the daily peak load aggregated by WEIM regions for the month of September and October, with circle markers indicating each region's monthly peak[13]. Across the WEIM footprint, load peaks occurred on different days and times across the different regions of WEIM. The California region reached a maximum load of 60,361 MW on September 9. The Southwest region's maximum load occurred on September 10 at 33,395 MW. Pacific Northwest daily peak load was 29,166 MW on October 29. The Central/Mountain region hit its peak load on September 11 reaching 13,224 MW.

Figure 242: Daily peak load by WEIM region

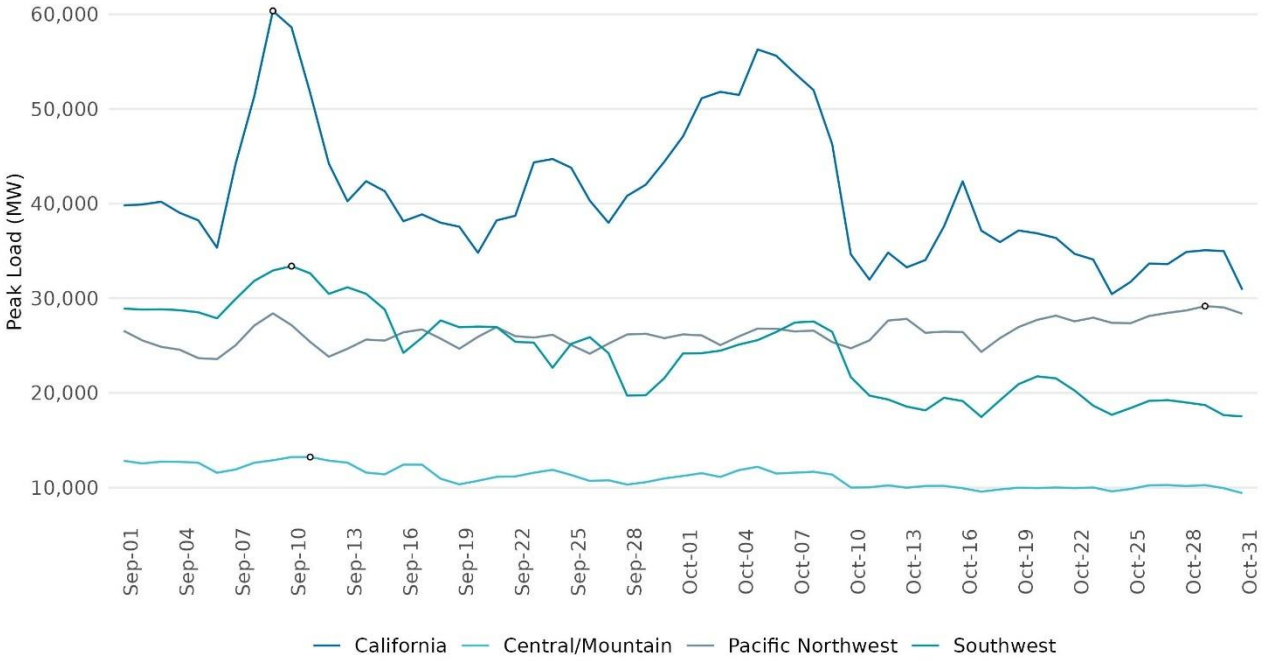


Figure 243 shows the average hourly peak load by WEIM region. Hourly peak loads occurred between hours ending 16 - 18 in September and October, on average, except for Pacific Northwest where September peak load occurred in hour ending 9.

[13] These regions are only for display purposes of the regional dynamics. The WEIM market clears supply and demand for each individual balancing area.

Figure 243: Average hourly peak load by WEIM region

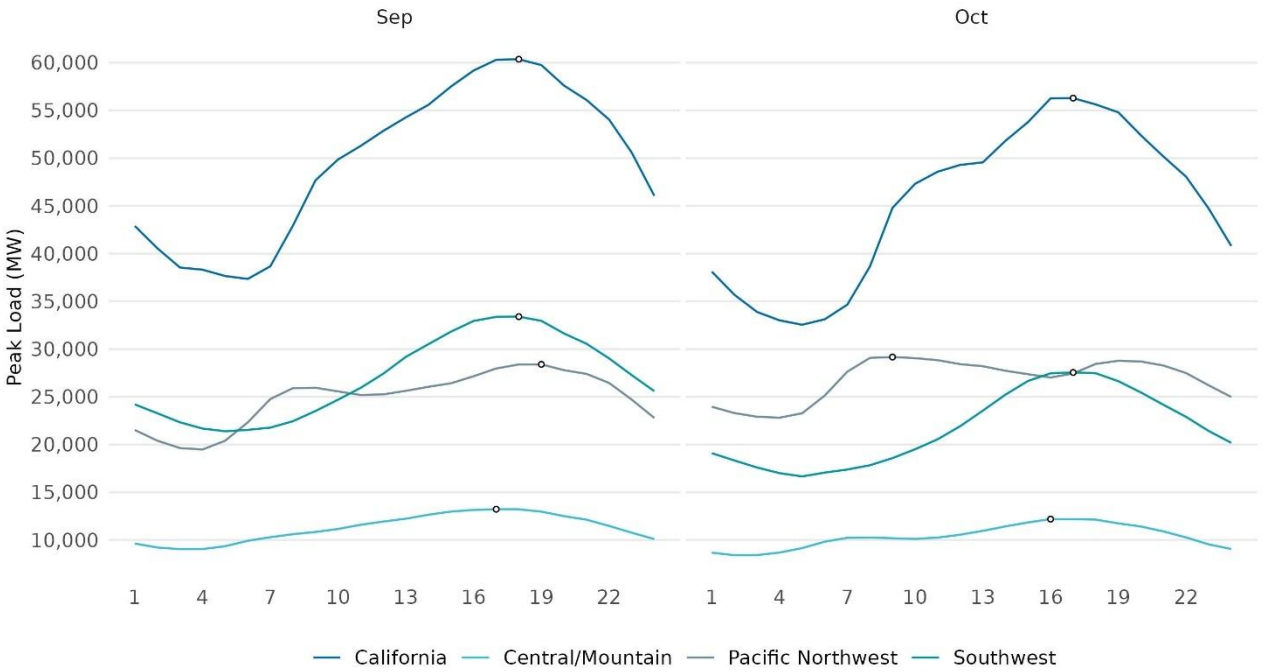
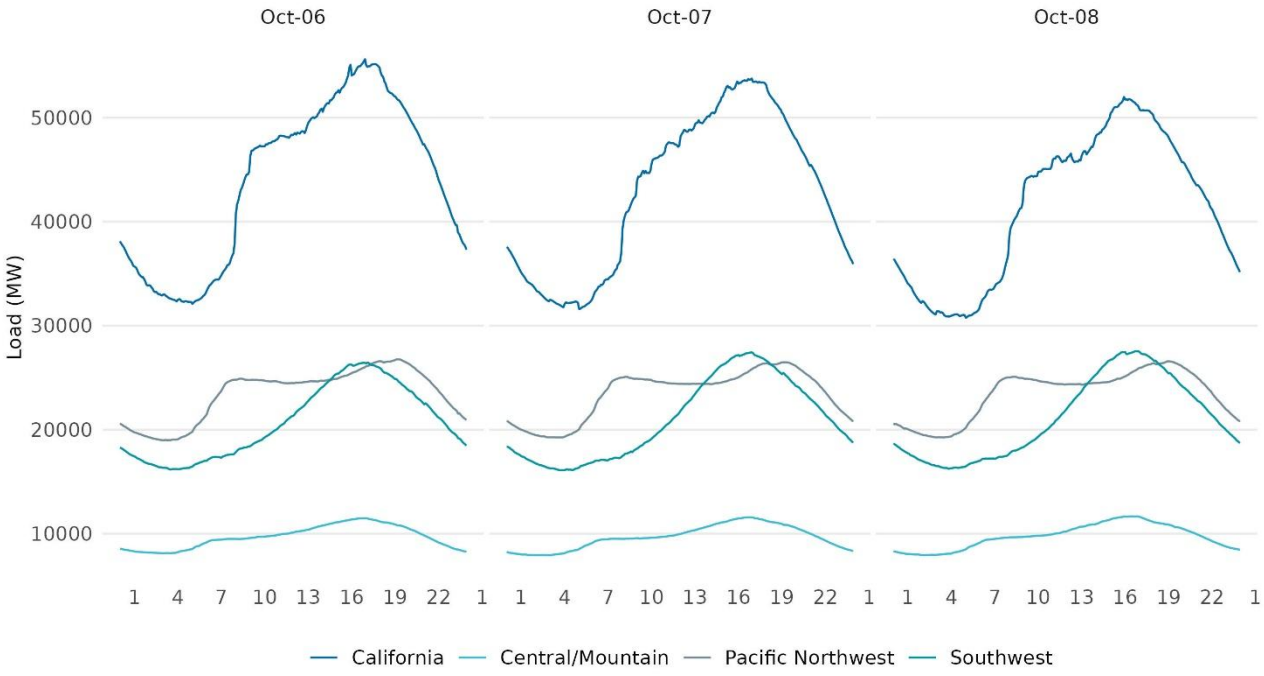


Figure 244 shows the hourly profile of actual load for the WEIM regions for October 6 to 8. California showed the strongest response to heat events, increasing the evening peak to about 55.6 GW on October 6. Both regions showed elevated overnight loads October 6. The Pacific Northwest and Central/Mountain regions showed a more muted response across the three days.

Figure 244: Hourly load profile for September –8-10, by WEIM region



WEIM transfers

The Western Energy Imbalance Market, or WEIM, provides an opportunity for participating balancing authority areas to serve their load while realizing the benefits of increased resource diversity. The ISO estimates WEIM's gross economic benefits on a quarterly basis.[14] One main benefit of the WEIM is the realized economic transfers among areas. These transfers are the realization of a least-cost dispatch by reducing more expensive generation in one area and replacing it with cheaper generation from other areas. In a given interval, import and export transfers can concurrently happen for one area.

Figure 245 shows the distribution of five-minute WEIM transfers for the CAISO area. A negative value represents an import into the CAISO from other WEIM entities. On average in October, CAISO transfers saw a milder shift towards importing from other areas in the WEIM. CAISO recorded its highest average net imports on September 26 of 4,098 MW and highest average net exports on September 13 of 5,504 MW.

Figure 245: Daily distribution of 5-minute RTD WEIM transfers for CAISO area

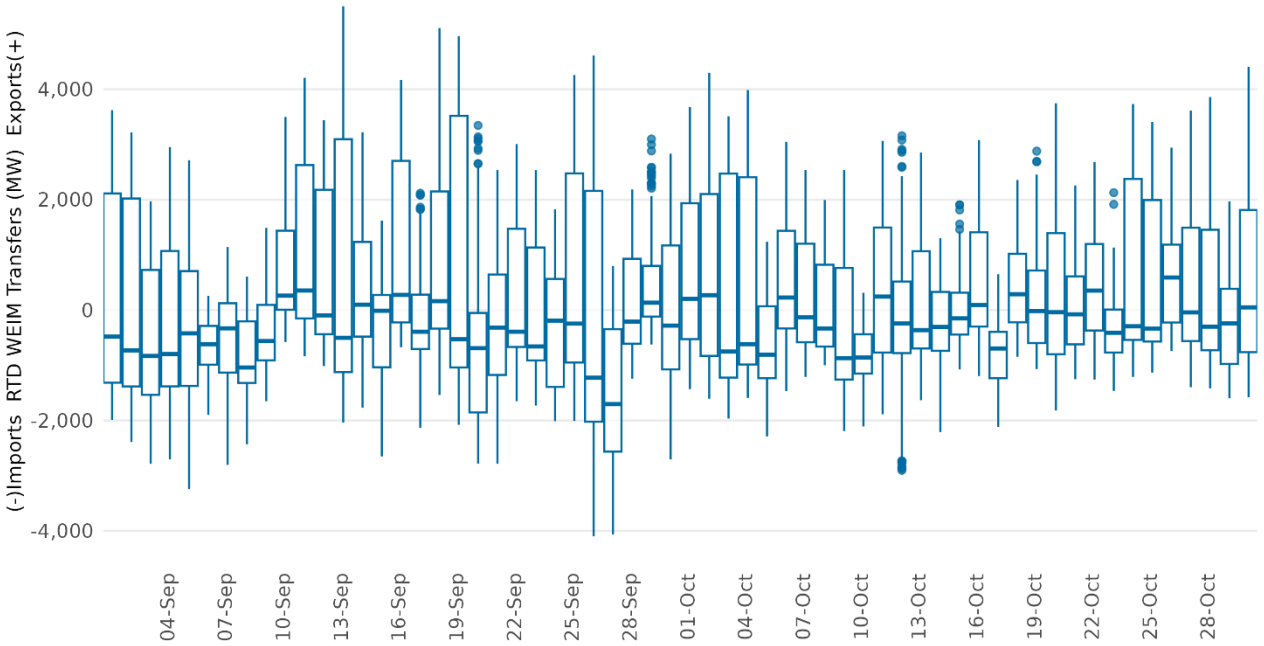


Figure 246 shows the CAISO's WEIM transfers in an hourly distribution. CAISO RTD WEIM transfers exhibit a consistent hourly pattern in both September and October, with net imports during overnight and evening hours and net exports during the daytime. September had generally higher and more variable daytime exports, with median exports reaching about 2,000

[14] The WEIM quarterly reports are available at https://www.westerneim.com/pages/default.aspx

MW and upper values exceeding 5,000 MW, while October daytime exports were somewhat lower and more concentrated.

Figure 246: Hourly distribution of 5-minute RTD WEIM transfers for CAISO area

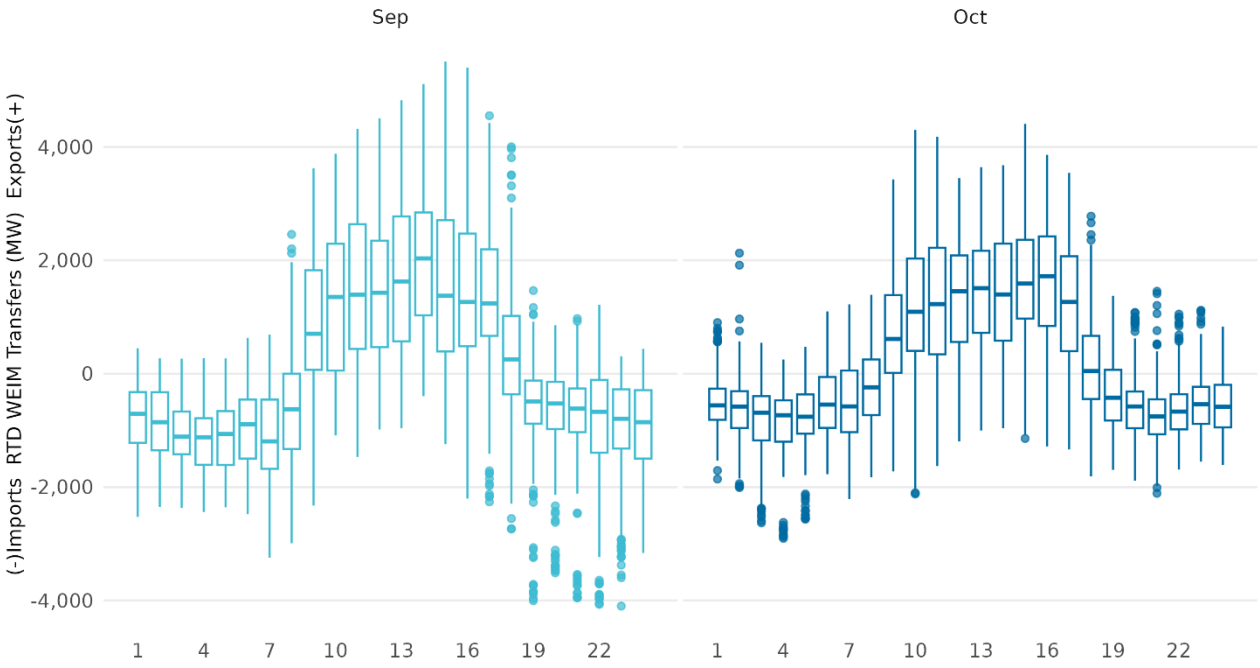


Figure 247 shows the distribution of RTD WEIM transfers for the CAISO area from October 4 to 6. The three days show a consistent intraday shift between imports and exports, but the magnitude varies considerably. Oct. 4 has the strongest exports, Oct. 5 has relatively limited exports, and Oct. 6 again shows substantial midday exports. The boxplots also indicate greater 5-minute variability during the hours when transfers are changing rapidly between imports and exports.

Figure 247: Daily distribution of 5-minute RTD WEIM transfers for CAISO area, October 4- 6

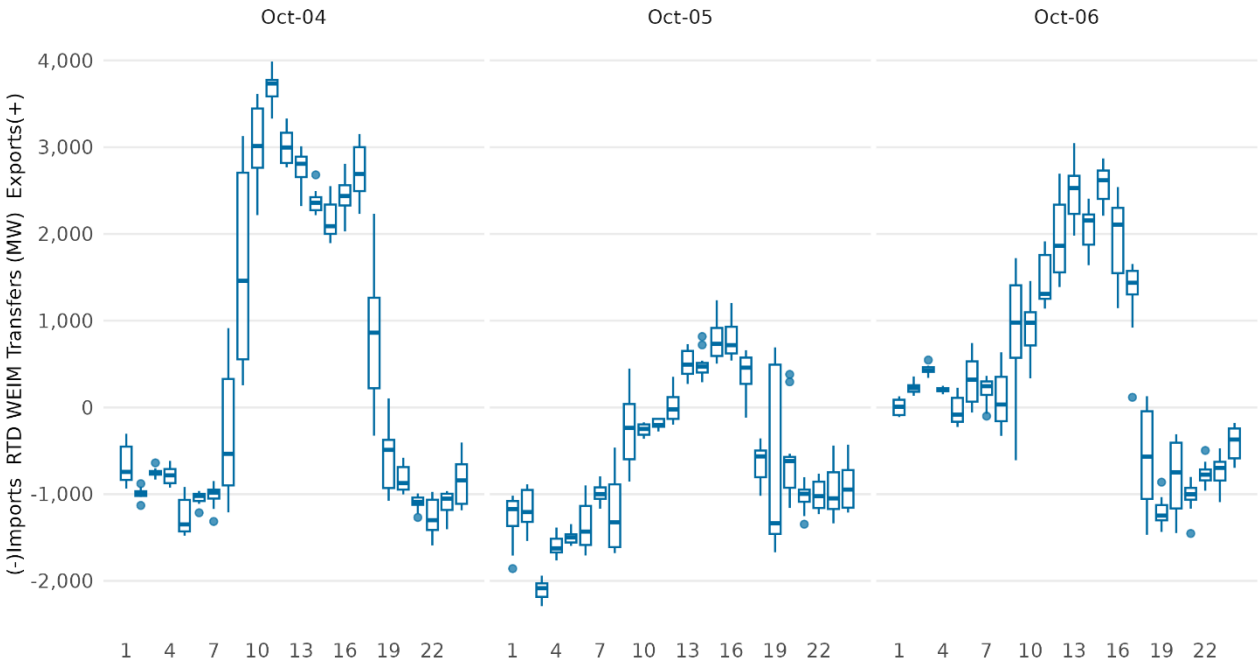


Figure 248 shows the distribution of WEIM transfers by region. Regional RTD WEIM transfer patterns vary substantially in both direction and magnitude in October. California exhibits the largest overall swings, ranging approximately from -4,000 MW of imports to +5,000 MW of exports, with frequent transitions between importing and exporting conditions. Central/Mountain is predominantly export-oriented, particularly in September, but export levels generally decline toward late October. Pacific Northwest remains the most consistently import-oriented region, with relatively smaller daily variation. Southwest is generally export-oriented based on daily medians but exhibits substantial intraday variability, with transfers ranging from roughly -4,000 MW to +3,500 MW. Overall, California and Southwest show the greatest variability, while Pacific Northwest displays the most persistent directional pattern.

Figure 248: Daily distribution of 5-minute RTD WEIM transfers by region

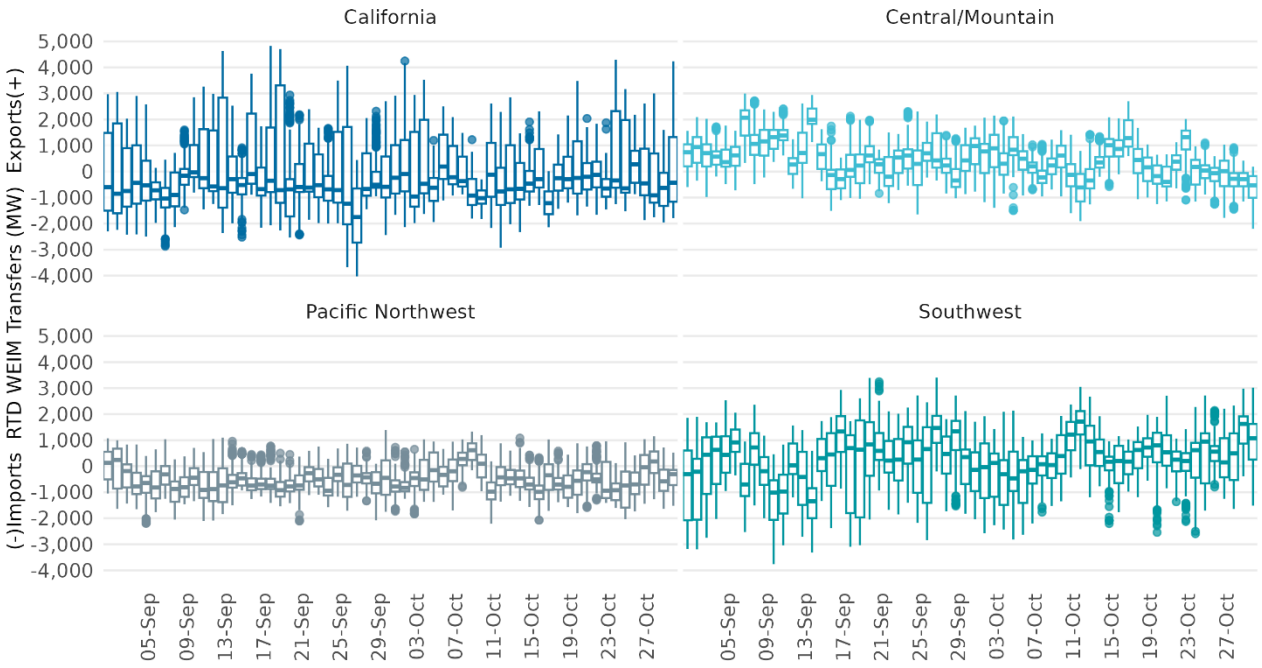
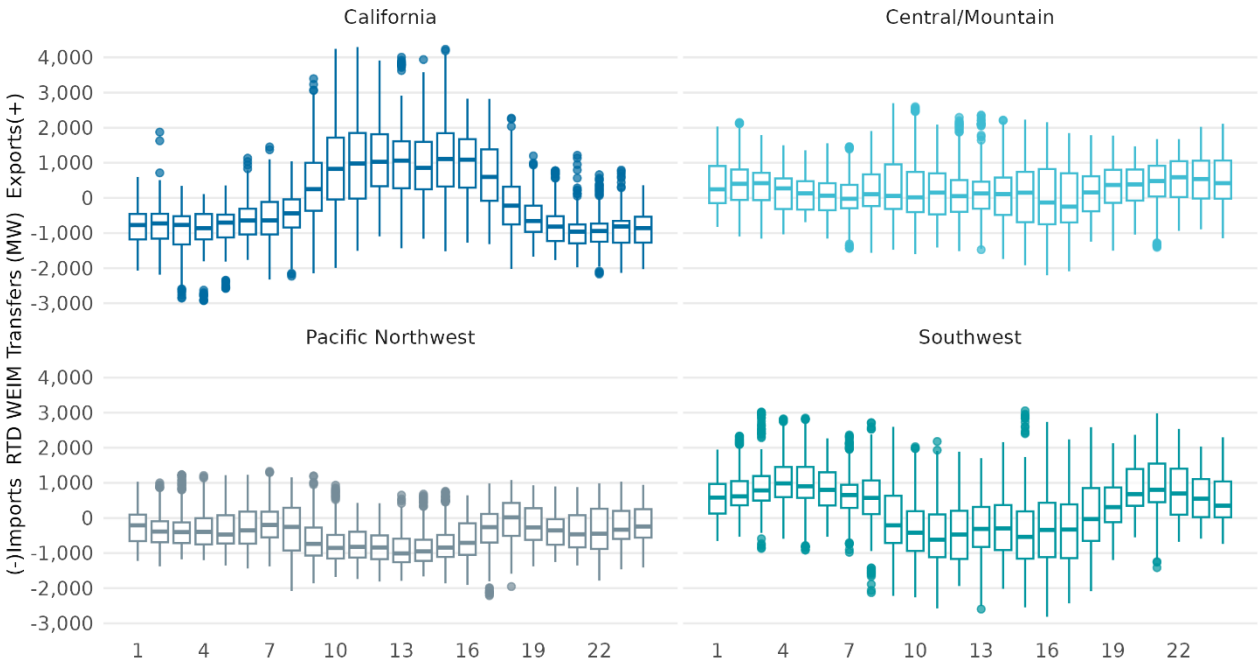


Figure 249 shows the hourly distribution of WEIM transfers by region in October. The California region was a net exporter in the midday hours and a net importer in the remaining hours particularly the evening peak and night-time hours. The Central/Mountain region was a relatively stable net exporter throughout the day generally providing up to 1000 MW of exports. The Pacific Northwest region's transfers were consistent in the hours spanning the late evening into the early morning, but net imports grew during the midday hours. The region's highest exports occurred in the ramping hours in the morning and evening. The Southwest region's transfers exhibit the clearest complementary pattern to California. The Southwest was a net importer during the midday hours and net exporter in the remaining hours.

Figure 249: Hourly distribution of 5-minute RTD WEIM transfers by region, October 2026



Assistance energy transfer

The Assistance Energy Transfer (AET) program was implemented with the Resource Sufficiency Evaluation Enhancements Phase 2, Track 1, effort which went live on July 1, 2023. The purpose of AET is to leverage the WEIM for energy assistance during under-supply conditions by optionally allowing incremental transfers at pre-set financial consequence following the failure of the WEIM Resource Sufficiency Evaluation (RSE). Assistance energy transfers are sourced from supply offers that are made voluntarily into the WEIM. Each WEIM BAA may voluntarily opt in to utilize assistance energy by notifying the ISO five business days in advance for a forward requested timeframe.

When a BAA that is not opted into AET fails the RSE, under current market rules, the market limits its WEIM energy transfers to the greater of the transfer amount from the last passed run's interval or the base scheduled transfer amount. If a BAA is opted into AET and fails the RSE in the upward direction, the BAA will still be allowed to receive WEIM energy transfers and pay an after-the-fact surcharge that is calculated based on the applicable energy bid cap of $1,000/MWh or $2,000/MWh. The surcharge is only applied to net-import WEIM BAAs and is limited to the lower of the quantity of the upward RSE insufficiency amount or the tagged dynamic transfers.

Figure 250 shows days when WEIM BAAs opted-in to AET and when they failed either the upward capacity test and/or the upward flexible ramping test. In October, nine WEIM BAAs opted into AET for some duration of the month. Of these, three BAAs did not have any instances of failed upwards RSE tests.

Figure 250: BAAs opted-in to Assistance Energy Transfers and RSE Upward Failures

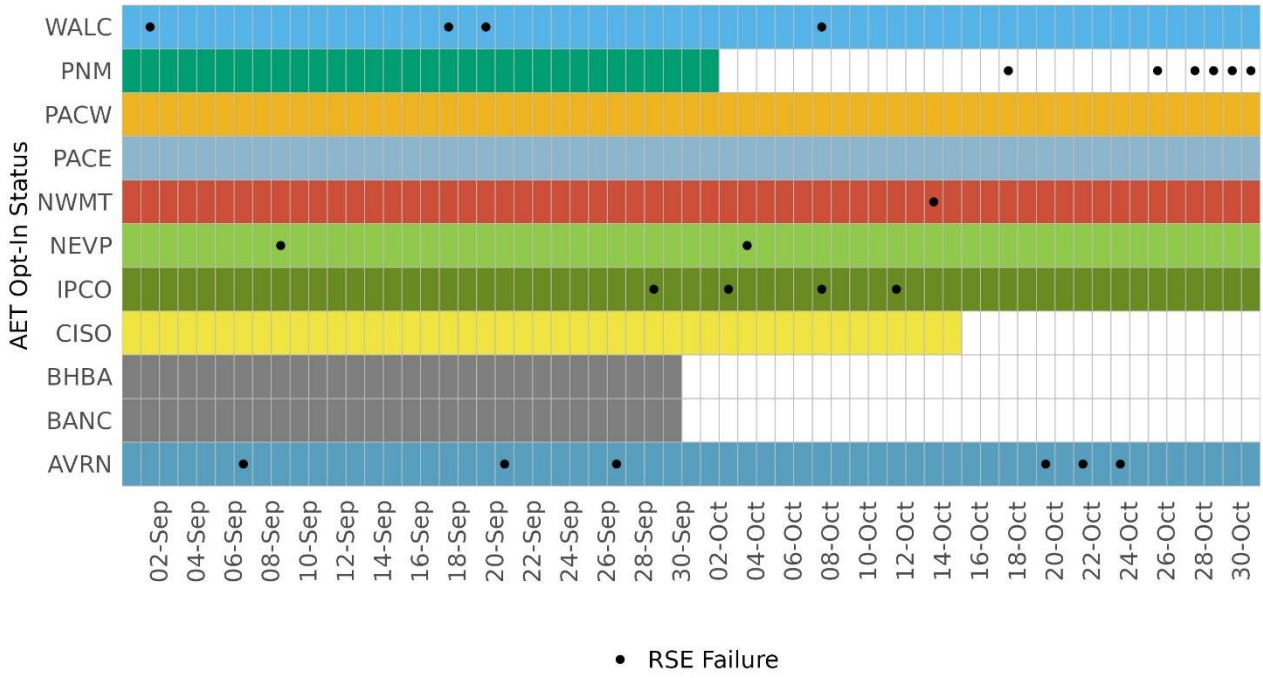
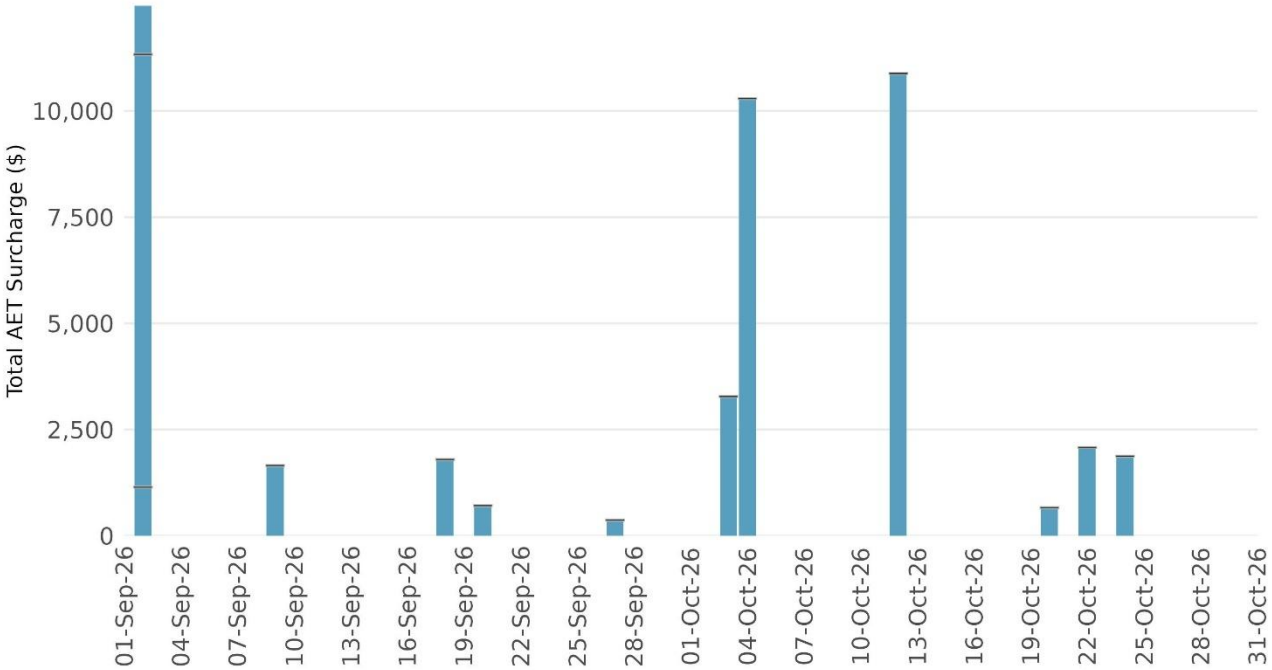


Figure 251 shows the breakdown of total AET surcharges assessed per day for October. By design, AET is only assessed for WEIM BAAs that fail the RSE and opt in ahead of time. The AET surcharge was only assessed for a total of six trading days in October. The total AET surcharges assessed in September were approximately $46,065 for all the BAAs that opted in.

Figure 251: Total daily AET surcharge assessed



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 252 to Figure 254 show the total wholesale costs for CAISO at a daily and monthly level. The average total cost per MWh is also shown in Figure 252 and Figure 253[15]. Looking at the monthly level, the total costs for October are up from September by about 14%. October surpassed the total cost of last year by about 64%.

[15] 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.

Figure 252: Total daily costs CAISO

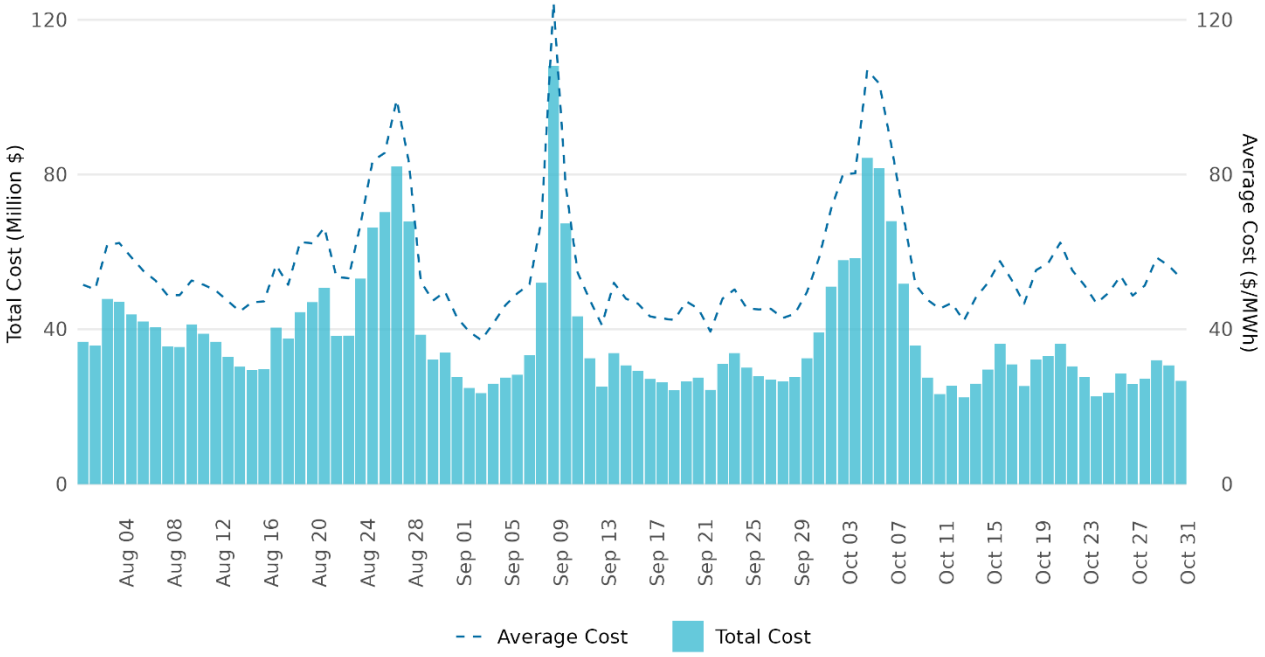


Table 15: Monthly Total Costs for CAISO

Month	Year 2025		Year 2026	
	Cost ($ Millions)	Avg cost ($/MW)	Cost ($ Millions)	Avg cost ($/MW)
May	518.65	31.4	319.64	19.8
Jun	622.08	35	432.35	24.2
July	803.08	41.1	952.82	45.4
Aug	996.04	45.9	1,347.06	59.3
Sep	961.43	48.6	1,005.61	51.4
Oct	704.32	40.5	1,151.37	61.8

Figure 253: Monthly total costs CAISO

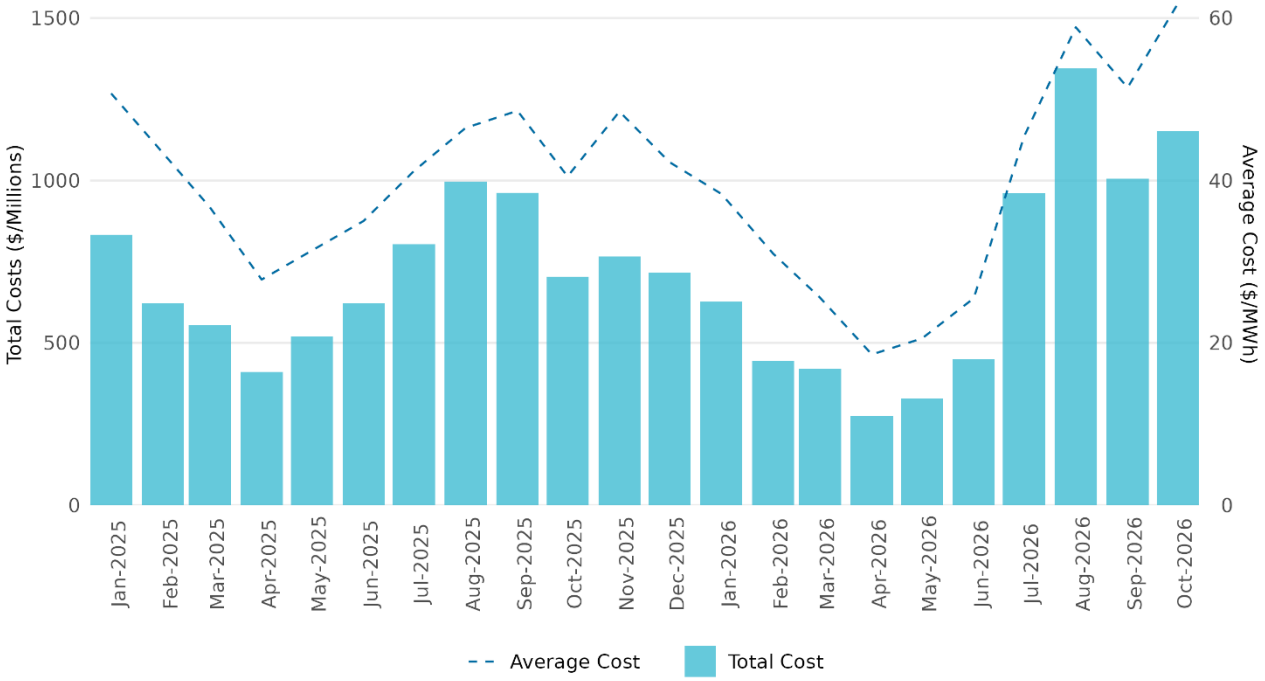
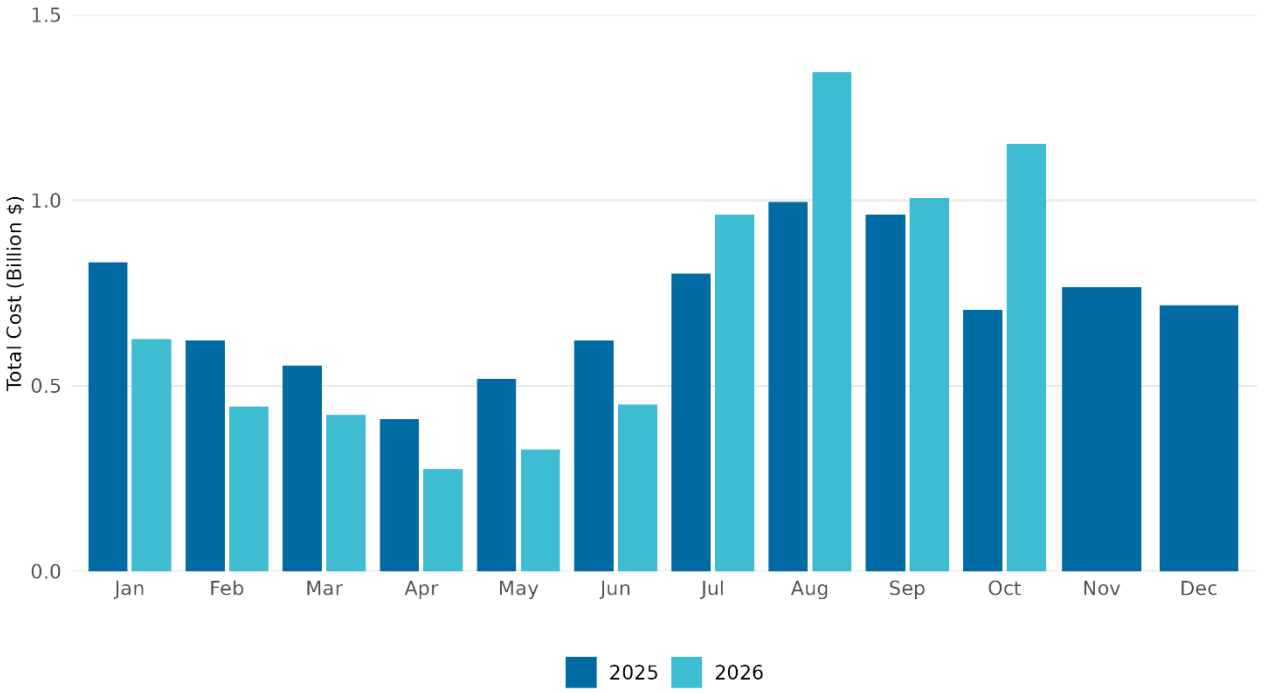


Figure 254: Monthly Total Costs CAISO, comparing 2025 to 2026



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, RTM BCR for CAISO on August 26th at approximately $1.9 million. Internal monitoring identified one bid cost calculation issue for each trade date that will be corrected and reflected in the T+70 settlement statement[16]. 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.

Figure 255 to Figure 260 illustrate the Bid Cost Recovery (BCR) trends for CAISO, PACW, and PACE across August, September, and October.

Figure 258: BCR of PGE by market

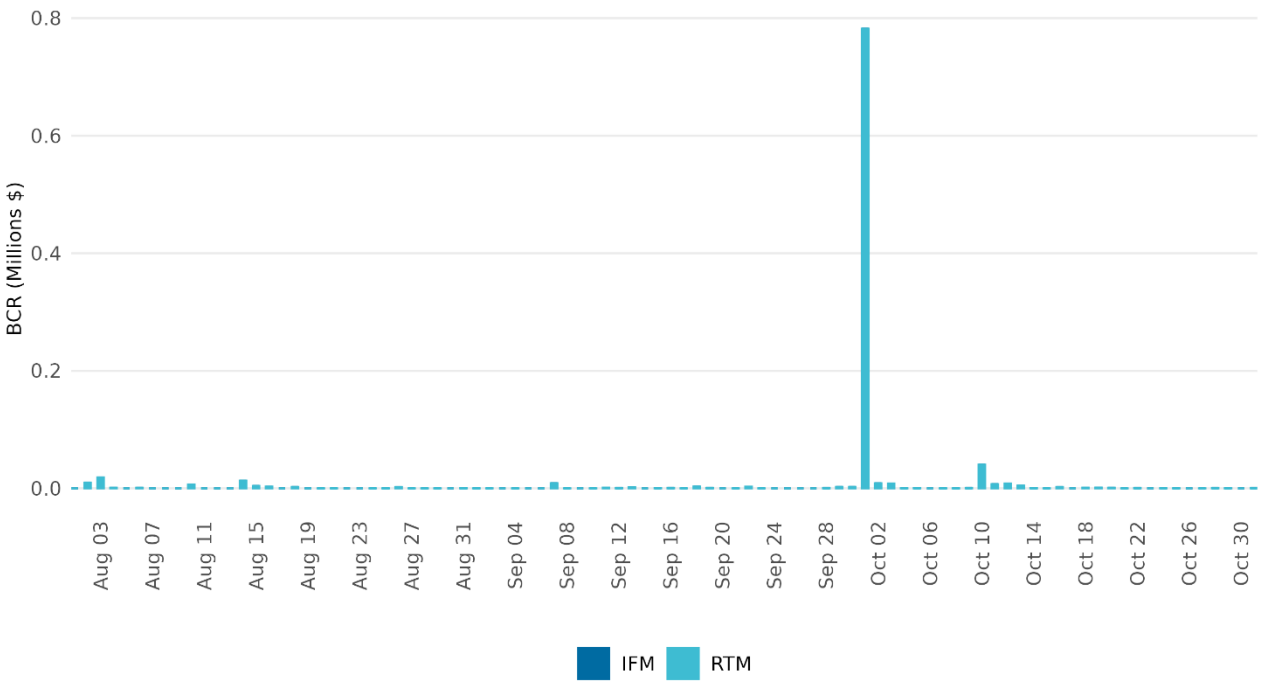


Figure 259 to Figure 260 compare BCR of three different BAAs across both the IFM and RTM. Note that PACE's IFM BCR starting the last three days of July through most of September are inaccurate

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

and will be corrected in the T+70 settlement statement. This issue was fixed late in September and will not persist going forward. Table 16 shows the BCR comparison between IFM and RTM for all EDAM BAAs from May to October. In October, IFM BCR across the EDAM footprint is down from September at just under $1M. However, RTM is up from September over 100% primarily due to CISO reaching $9.16M.

Table 16: BCR comparison between IFM and RTM for EDAM BAAs in $ millions

AREA	IFM						RTM					
	May	Jun	Jul	Aug	Sep	Oct	May	Jun	Jul	Aug	Sep	Oct
CISO	3.68	2.23	1.27	0.72	2.11	0.97	8.59	3.87	8.76	8.73	4.48	9.16
PACE	0.36	0.08	0.22	3.73	2.95	0.02	1.49	0.10	1.03	0.45	0.27	0.17
PACW	0.11	0.005	0	0.009	0.002	0.0001	0.25	0.025	0.06	0.028	0.027	0.026
PGE	0	0	0	0	0	0	0.10	0.06	0.05	0.06	0.02	0.87

Figure 255: BCR of CAISO by market

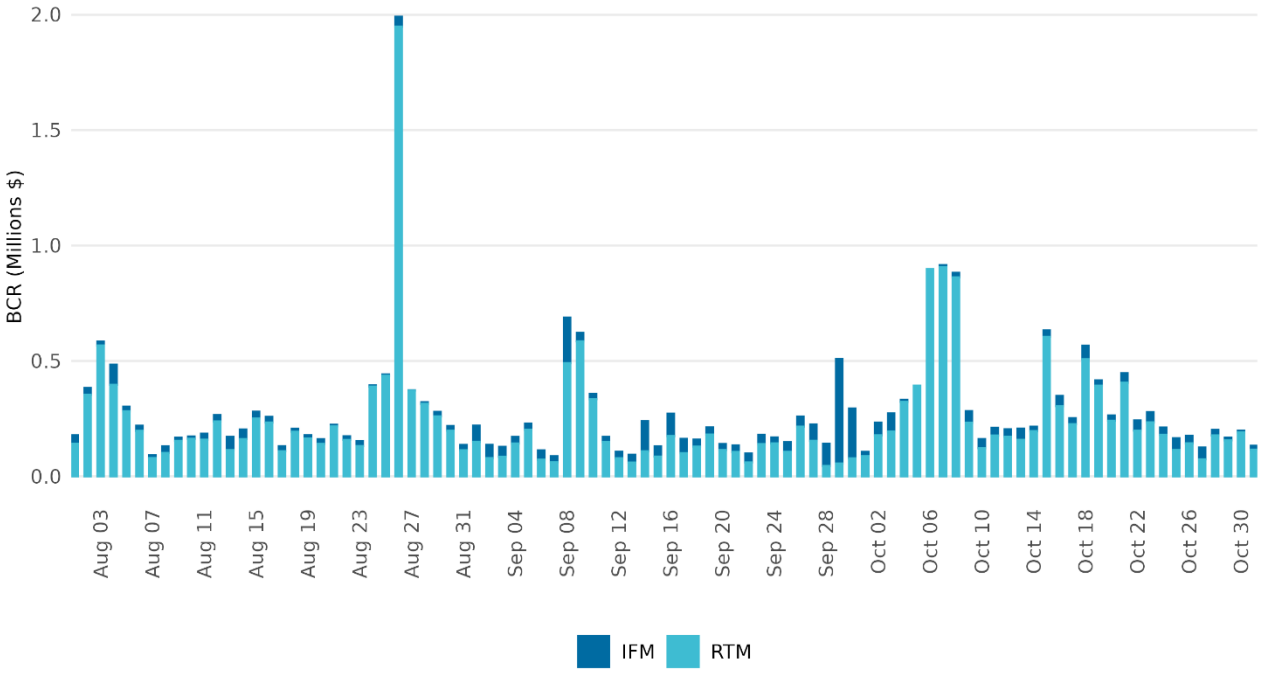


Figure 256: BCR of PACE by market

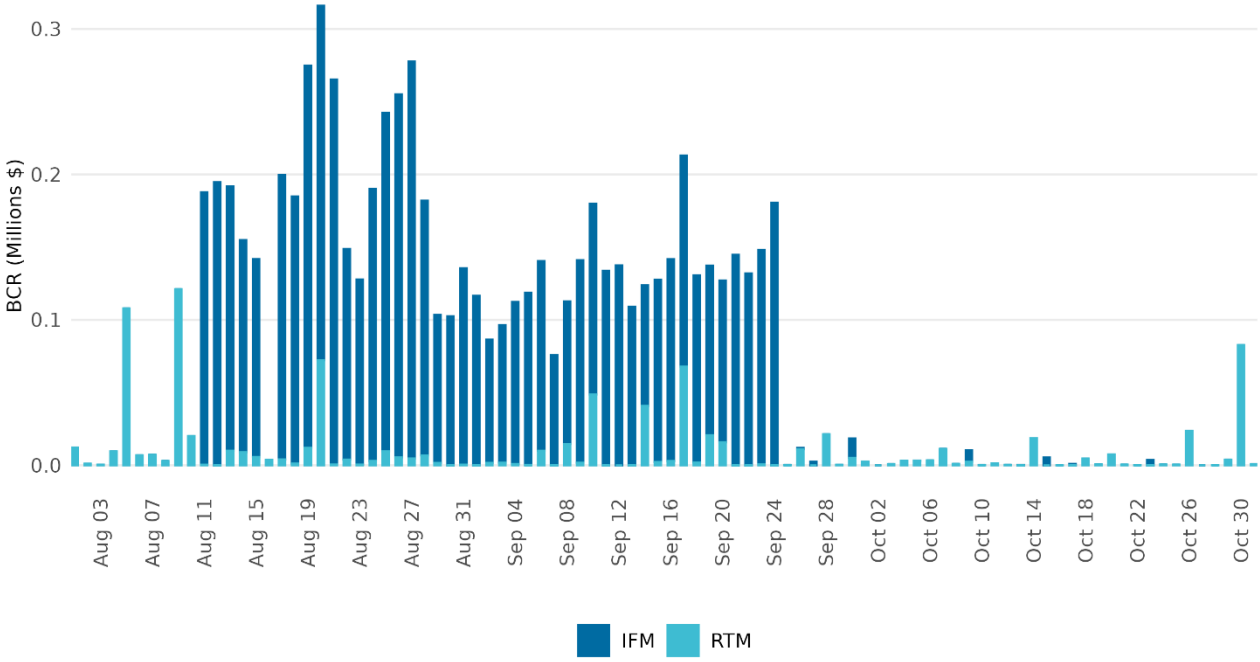


Figure 257: BCR of PACW by market

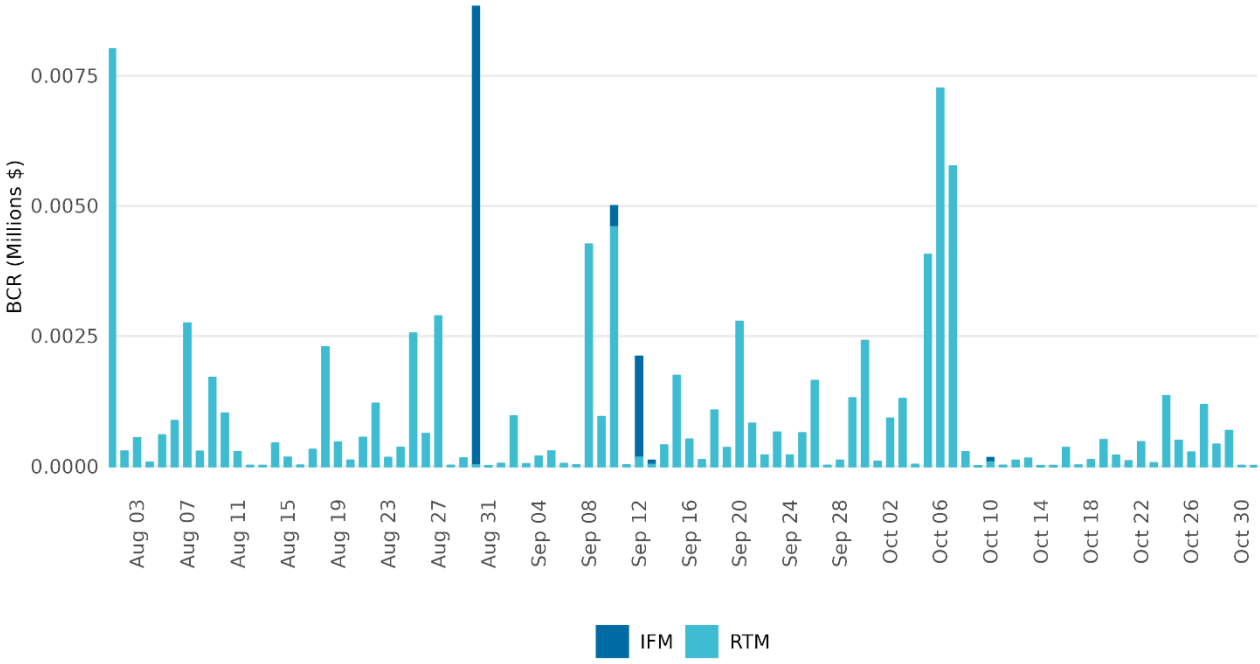


Figure 258: BCR of PGE by market

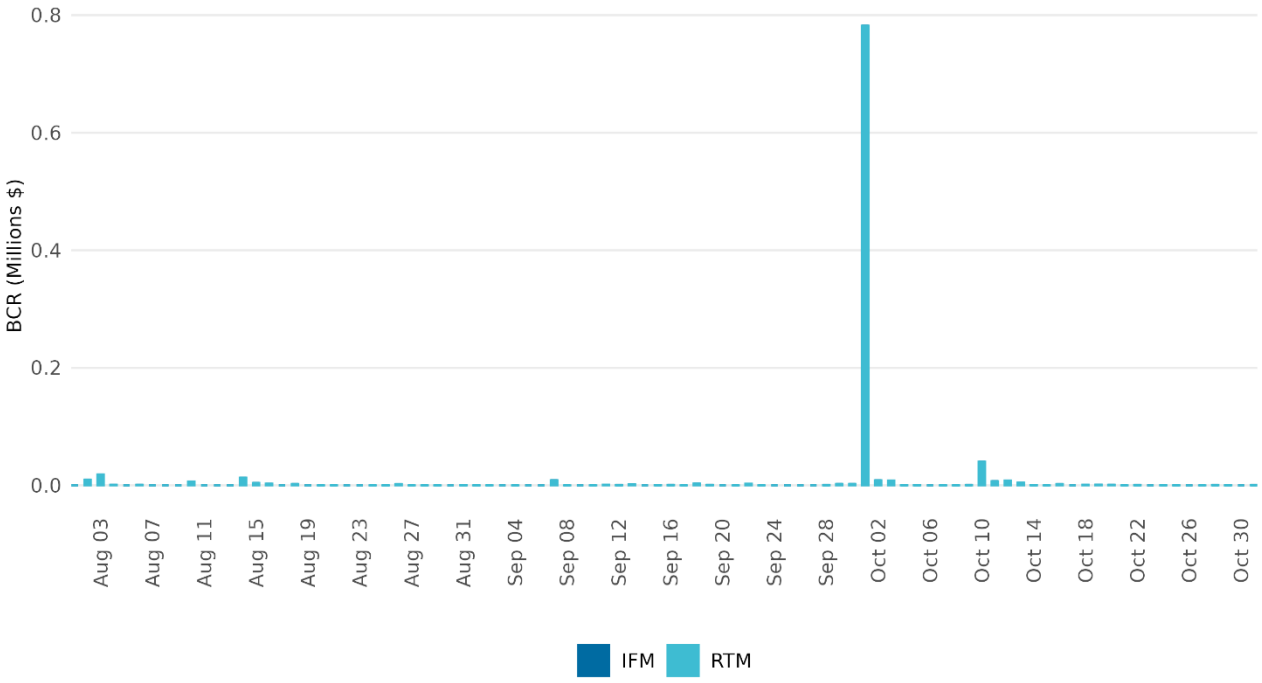


Figure 259: IFM BCR by BAA

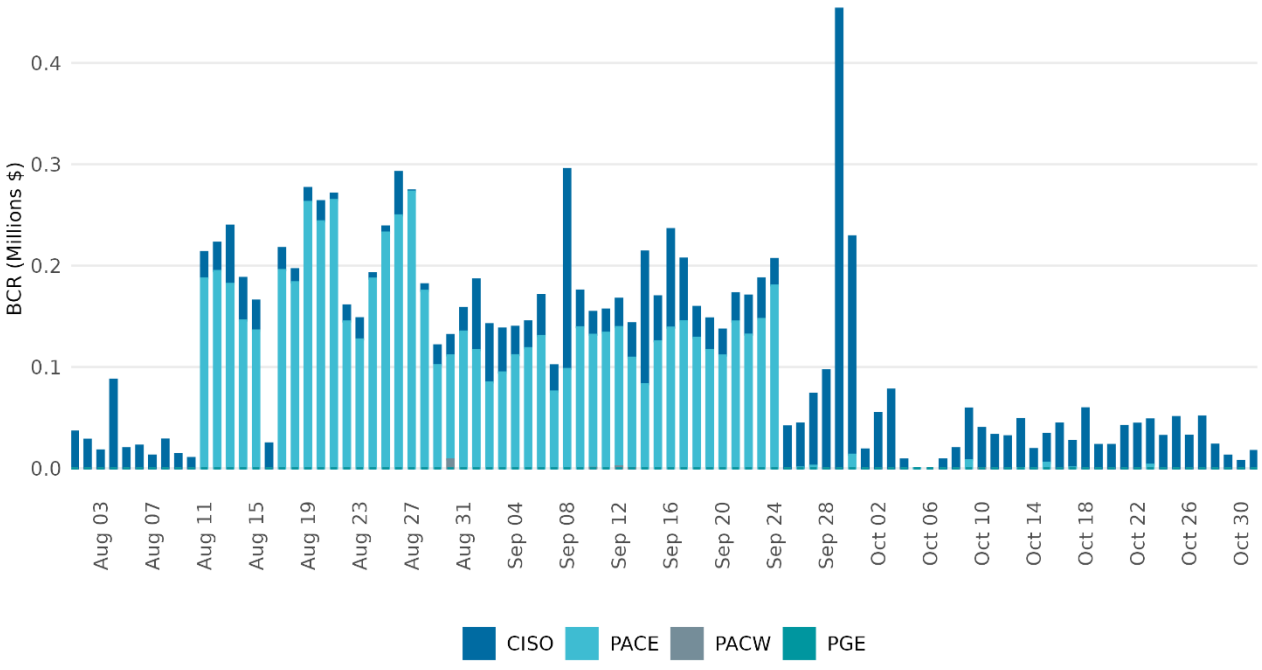
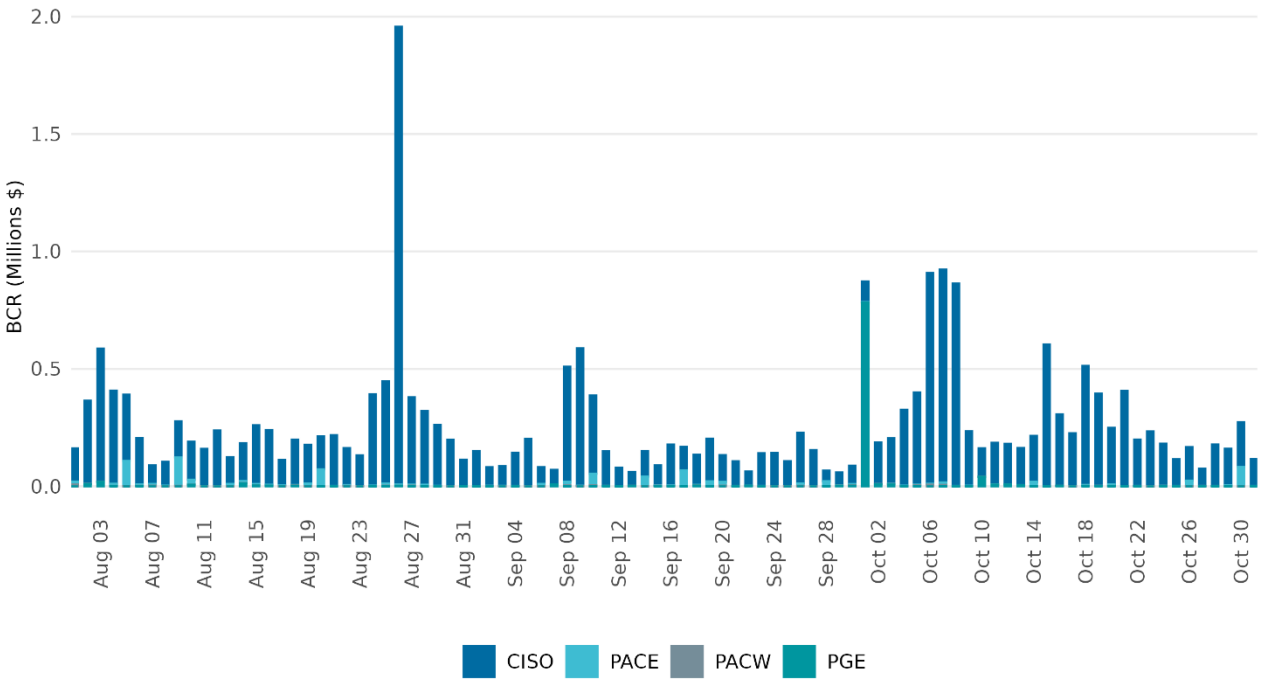


Figure 260: RTM BCR by BAA



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 261 shows the daily DA congestion offset for PAC areas. A negative amount reflects payment to the entity. A spike in DACO indicated that congestion has a significant impact on the market dispatch during corresponding intervals.

Table 17 shows the DA congestion offset comparison for PACE and PACW for the months of August to October.

Figure 261: DA Congestion Offset for PAC areas

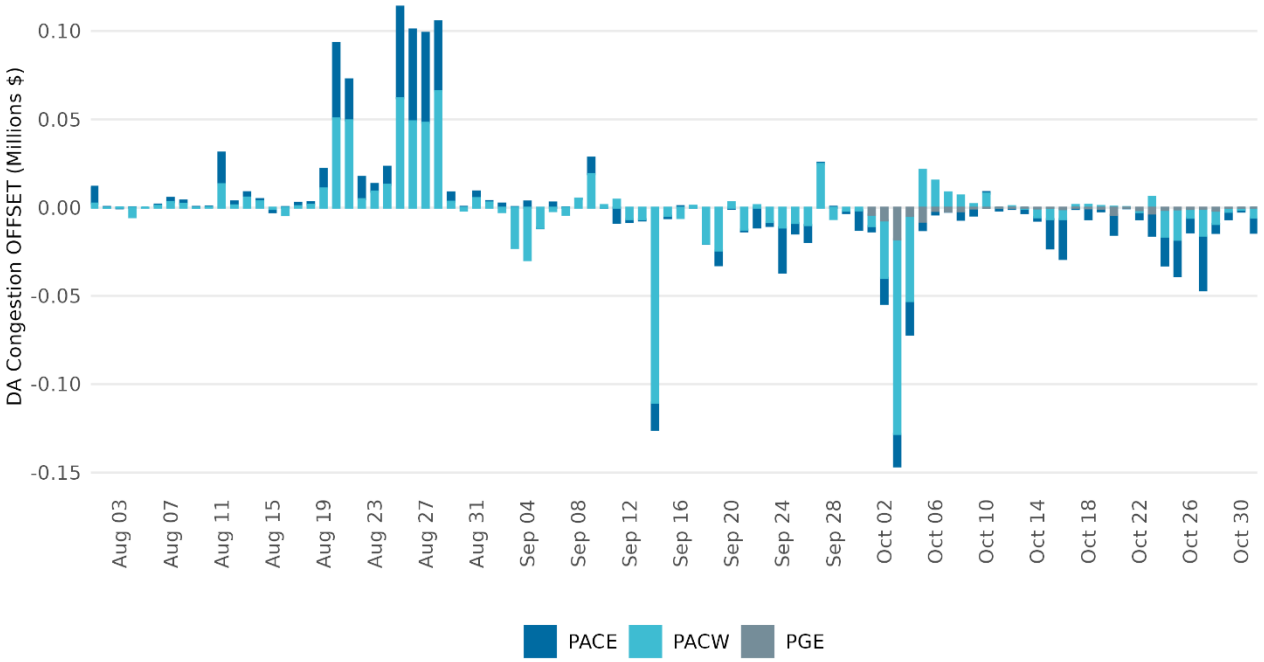


Table 17: DA Congestion Offset in $ millions

Area	May	Jun	Jul	Aug	Sep	Oct	Total
PACE	-1.98	-0.32	1.56	0.35	-0.08	-0.25	-0.72
PACW	-0.10	0.14	0.03	0.39	-0.25	-0.21	-0.004
PGE						-0.06	0.06
Total	-2.08	-0.19	1.59	0.74	-0.33	-0.52	-0.79

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 implement corrections in the T+70 and T+11M cycles if any discrepancies are identified. Any corrections will impact the numbers reported below and we will update these in the next monthly report.

Positive DA energy offset means charge to the entity, while negative means additional payments needed to be sent out. Table 18 shows the DA energy offset comparison between EDAM BAAs from August through October.

Figure 262: DA Energy Offset

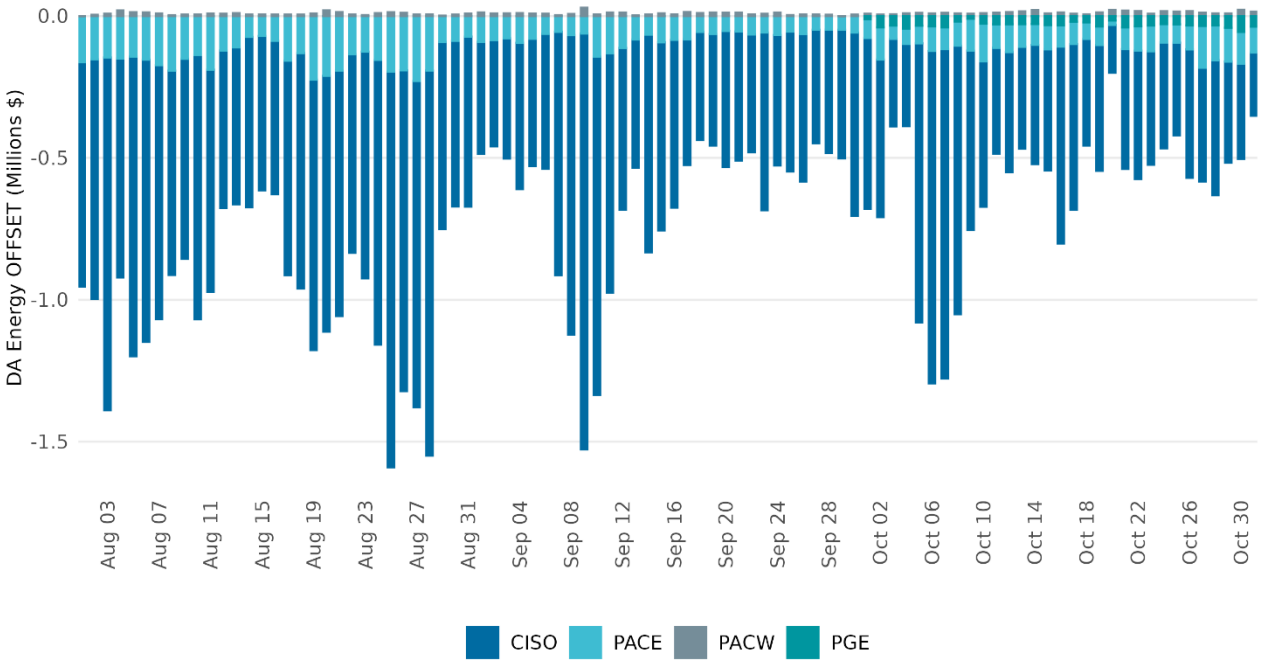


Table 18: DA Energy Offset for EDAM BAAs –in $ millions

Area	May	Jun	Jul	Aug	Sep	Oct	Total
CISO	-6.39	-8.22	-19.66	-26.21	-17.69	-15.65	-93.81
PACE	-0.23	-1.81	-4.07	-4.60	-2.21	-2.61	-15.54
PACW	0.08	0.07	0.17	0.26	0.27	0.39	1.25
PGE	0.00	0.00	0.00	0.00	0.00	-0.97	-0.97
Total	-6.53	-9.96	-23.55	-30.56	-19.63	-18.84	-109.07

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 263 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. The CISO area saw increased RTCO in early October due to brief but intense congestion in RTPD during the heatwave.

Figure 263: Real-Time Congestion Offset

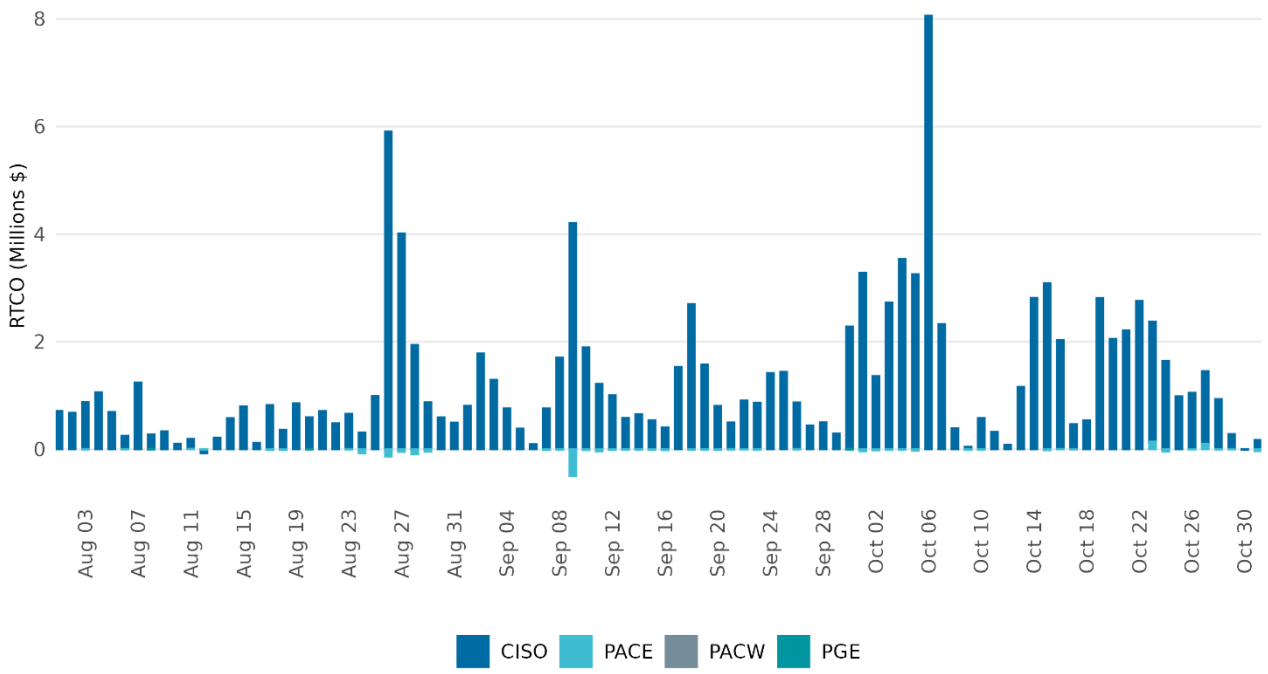


Table 19: Real-Time congestion offset for EDAM BAAs in $ millions

Area	May	Jun	Jul	Aug	Sep	Oct	Total
CISO	18.27	28.14	27.19	27.63	34.19	54.53	189.94
PACE	0.61	1.08	0.19	-0.41	-0.64	0.05	0.87
PACW	-0.04	0.00	0.00	0.00	0.00	0.00	-0.04
PGE	0.24	0.01	0.00	0.00	0.00	0.00	0.25
Total	19.08	29.23	27.38	27.22	33.55	54.57	191.02

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.

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 264 illustrates the Real-Time Imbalance Energy Offset (RTIEO) for the four 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.

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. Table 20 shows the real time energy offset comparison for EDAM BAAs.

Table 20: Real time energy offset for EDAM BAAs in $ millions

Area	May	Jun	Jul	Aug	Sep	Oct	Total
CISO	4.84	-3.42	-3.90	-5.15	0.83	1.11	-5.69
PACE	-0.75	-0.14	-0.63	0.32	0.06	-2.02	-3.17
PACW	0.28	-0.43	-0.50	-1.00	-0.42	0.12	-1.96
PGE	0.78	0.02	-0.14	0.06	0.35	0.48	1.56
Total	5.15	-3.97	-5.17	-5.77	0.82	-0.31	-9.25

Figure 264: Real-Time Imbalance Energy Offset

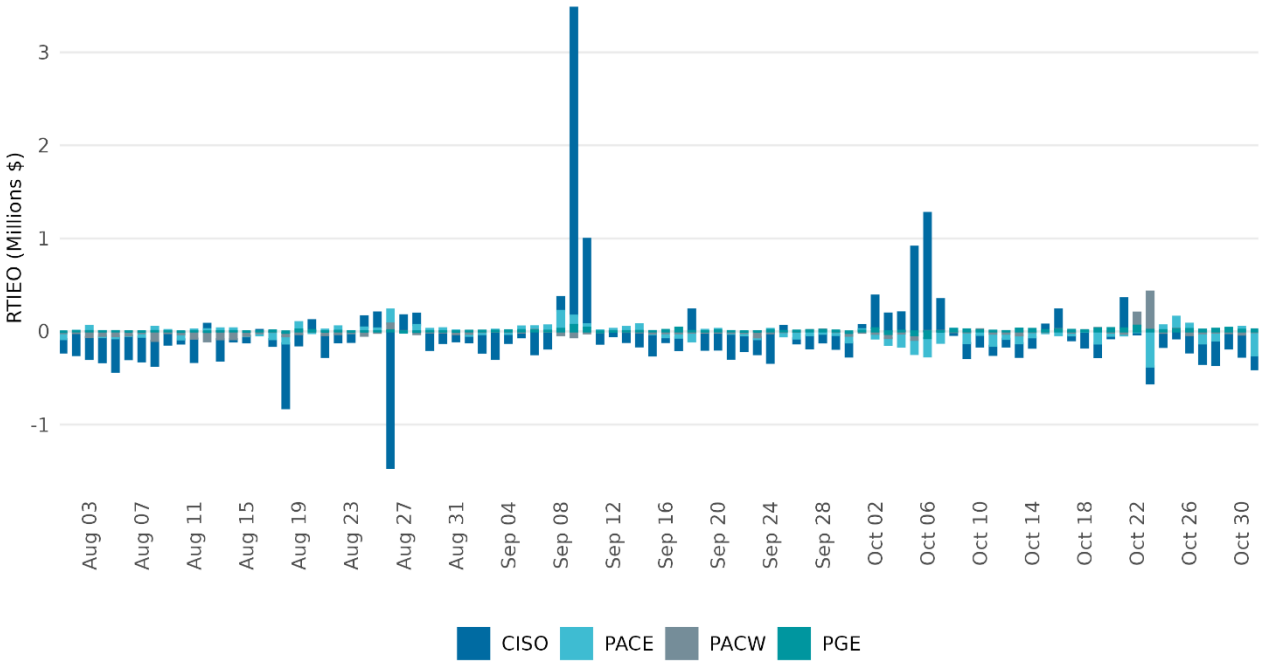
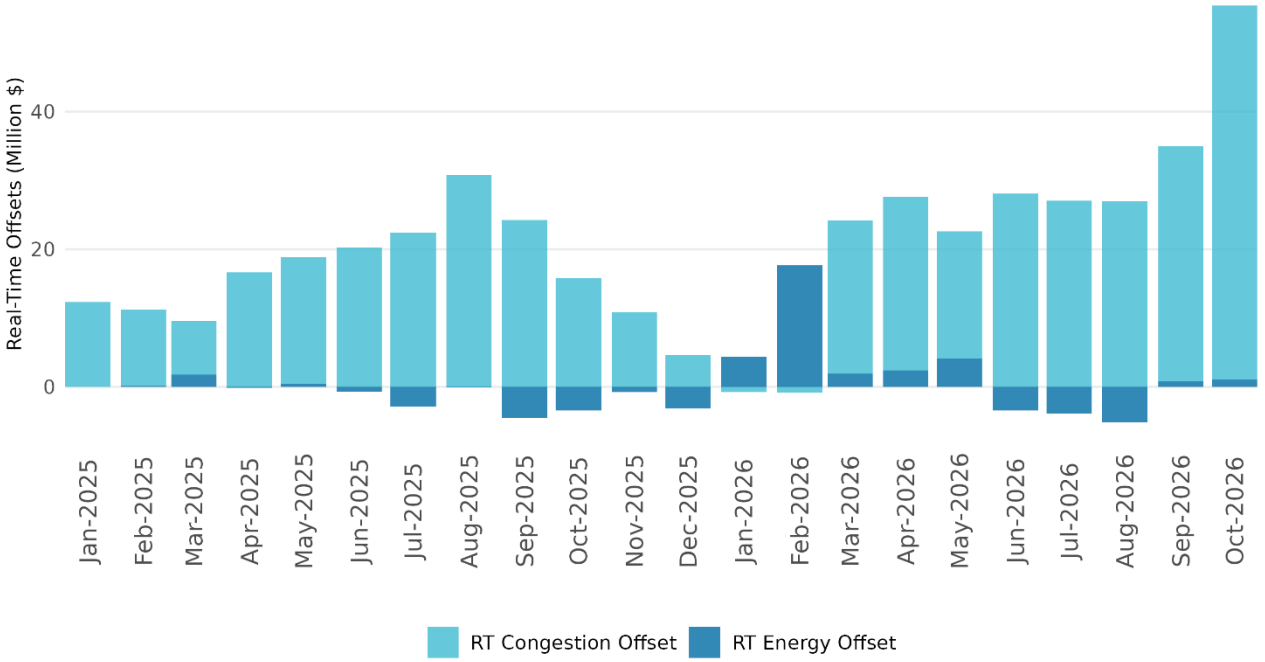


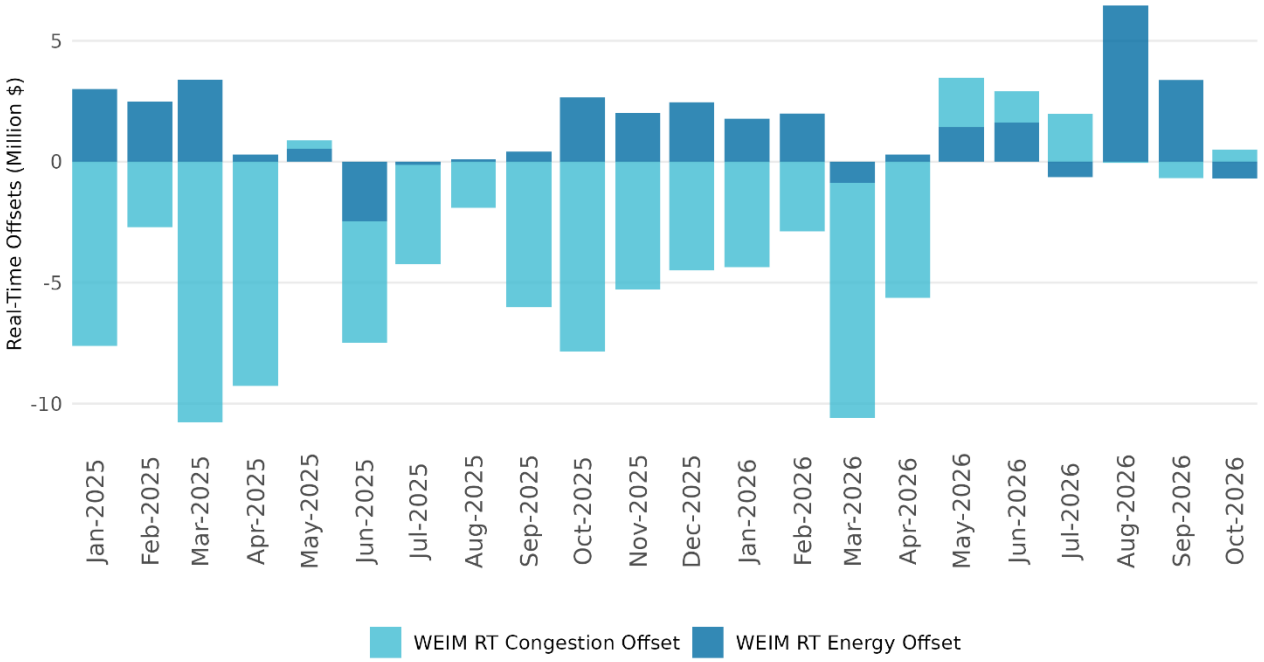
Figure 265 and Figure 266 show the monthly real-time congestion and energy offsets for CAISO area and the WEIM excluding CAISO area, respectively. The magnitude of the real-time energy offsets post EDAM launch are high compared to historical offsets. First, it is important to note that the real-time 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 265: 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 266: Monthly Total Real-Time Offsets for WEIM



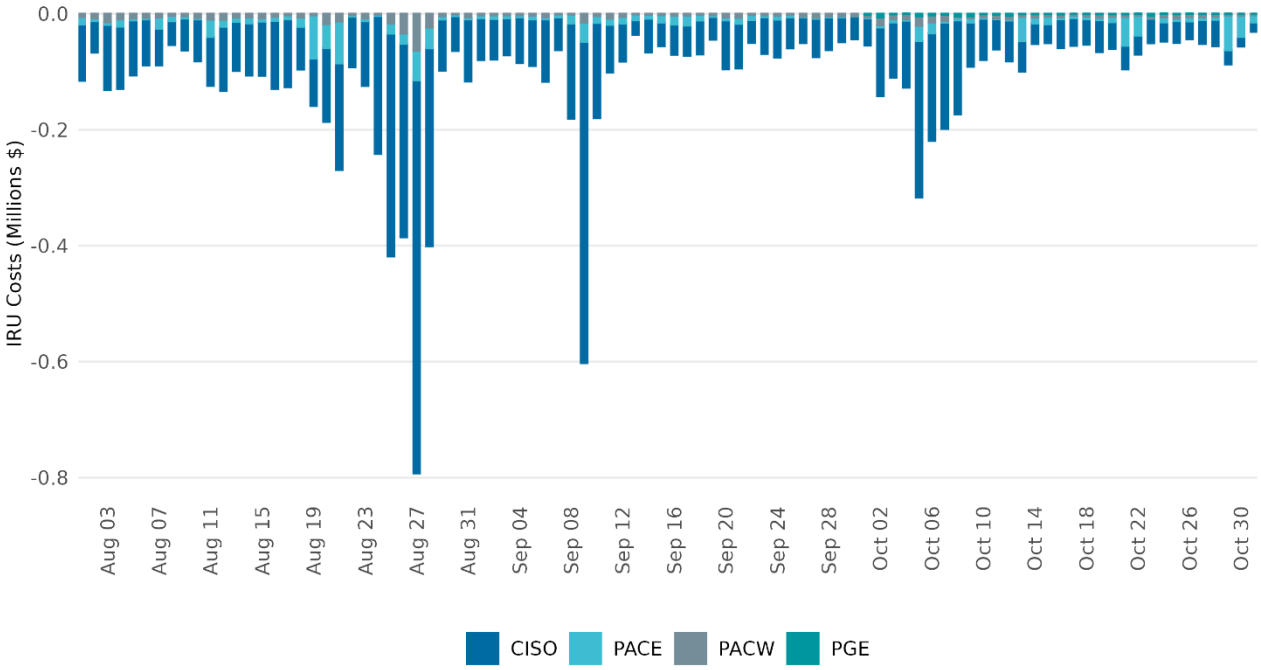
Imbalance reserves

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.

Figure 267 shows the daily trend of IRU costs for July through September. IRU costs increase significantly for the CAISO area around August 25th to August 27th. This is largely due to higher IRU prices across the same period. There are observed IRU elevated settlements across high demand periods in September and October for the same reasons.

Figure 267: 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 268 shows the daily costs for procuring IRD for July through September.

Figure 268: IRD settlement costs

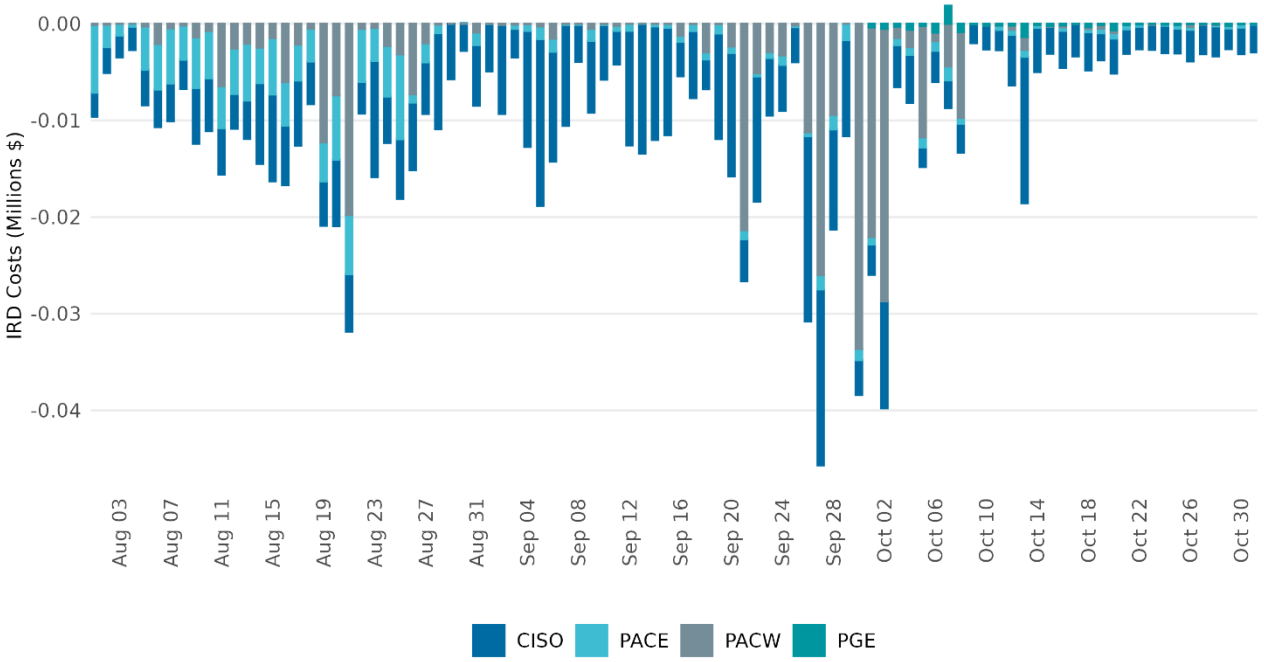


Table 21: Imbalance Reserves Total Monthly Settlement Costs

	IRU Total Costs ($million)						IRD Total Costs ($million					
BAA	May	June	July	Aug	Sep	Oct	May	June	July	Aug	Sep	Oct
CAISO	-2.07	-1.79	-2.30	-4.37	-2.52	-2.17	-1.23	-0.36	-0.28	-0.16	-0.27	-0.12
PACE	-0.22	-0.48	-0.34	-0.51	-0.24	-0.40	-0.16	-0.12	-0.20	-0.12	-0.02	-0.01
PACW	-0.36	-0.10	-0.16	-0.32	-0.12	-0.18	-0.21	-0.06	-0.03	-0.09	-0.12	-0.08
PGE	0.00	0.00	0.00	0.00	0.00	-0.04	0.00	0.00	0.00	0.00	0.00	-0.01

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 269 shows the daily RCU costs organized by BAA in July through September. 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 270 provides the daily trend of RCD cost by BAA in July through September. RCU costs spiked on the 27th due to higher RUC prices during peak hours on that day.

Figure 269: RCU settlement costs

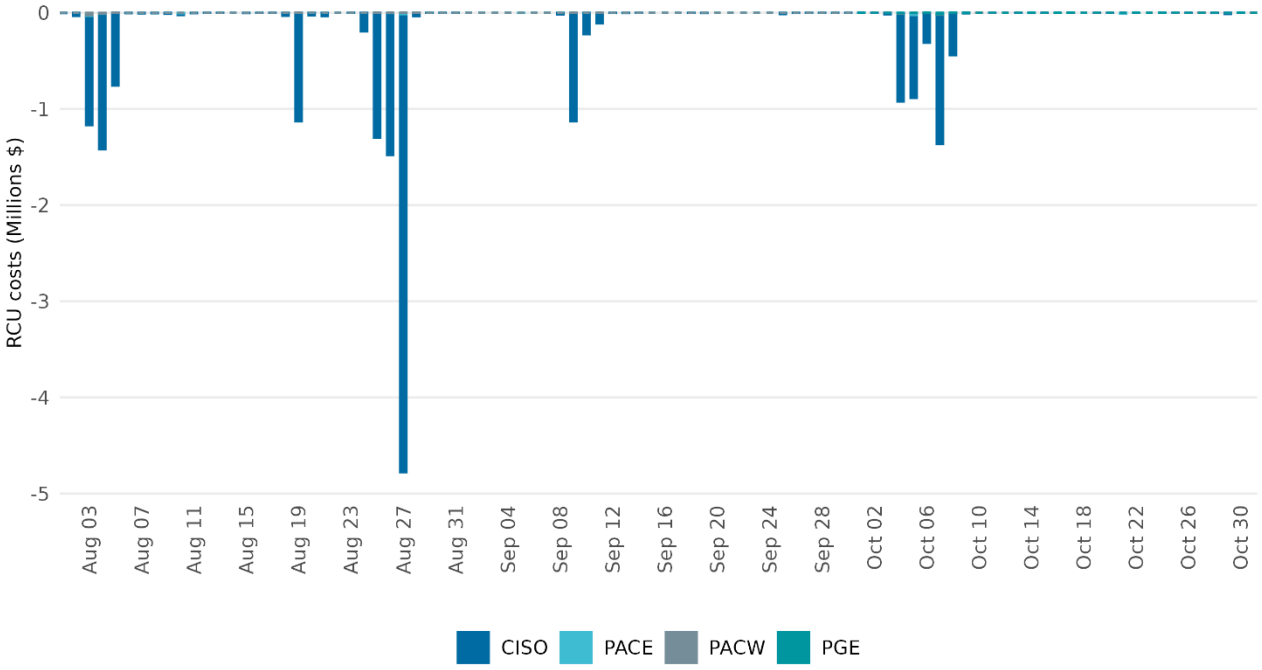


Figure 270: RCD settlement costs

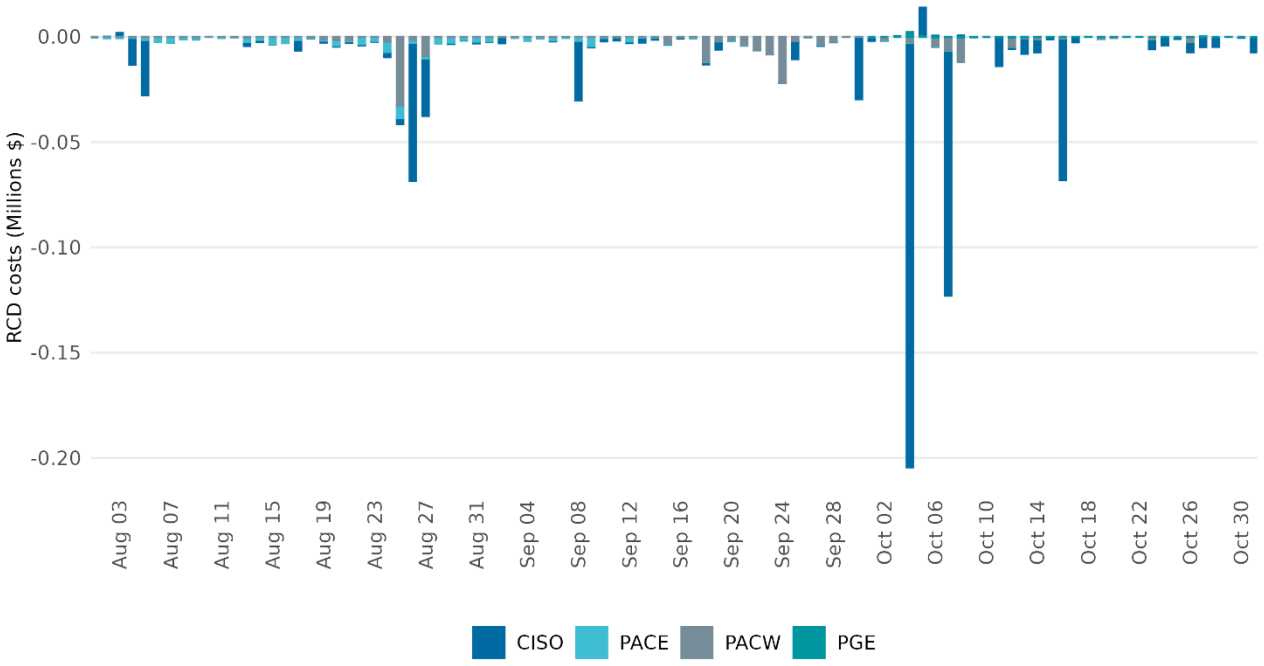
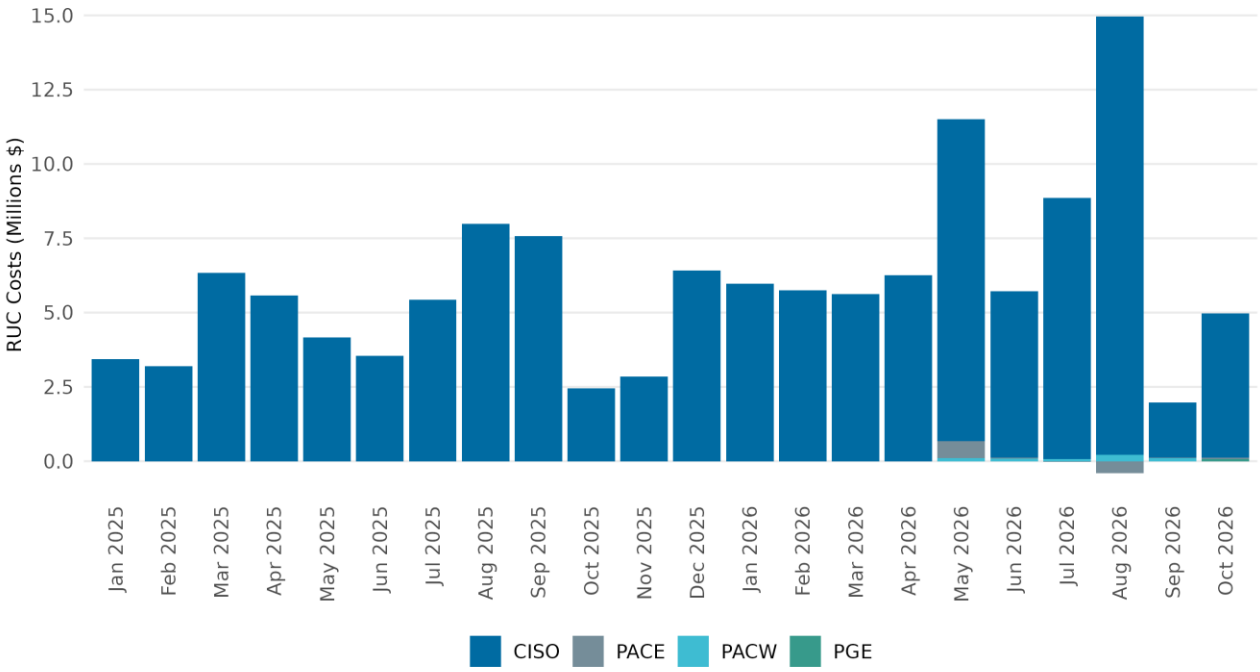


Table 22: Reliability Capacity Total Monthly Settlement Costs

	RCU Total Costs ($million)						RCD Total Costs ($million)					
BAA	May	June	July	Aug	Sep	Oct	May	June	July	Aug	Sep	Oct
CAISO	-9.06	-2.58	-6.79	-12.4	-1.51	-3.92	-0.84	-2.82	-0.06	-0.15	-0.09	-0.44
PACE	-0.32	-0.03	-0.03	-0.03	0.00	-0.03	0.00	-0.01	-0.05	-0.06	-0.02	0.00
PACW	-0.22	-0.01	-0.01	-0.04	0.00	-0.01	-0.02	-0.05	-0.07	-0.05	-0.07	-0.04
PGE	0.00	0.00	0.00	0.00	0.00	-0.03	0.00	0.00	0.00	0.00	0.00	0.00

Figure 271 tracks total RUC costs by month, providing a consistent view of costs before and after EDAM implementation. The monthly trend highlights how RUC-related costs have evolved under the changing market design and provides a basis for assessing cost patterns in the post-EDAM period. Since EDAM go-live, total RUC costs have reached $47.5M, with $46.6M attributed to the CISO BAA. Although comparable costs over the same five-month period in 2025 totaled $31.1M, resulting in a substantially higher cost level in 2026, the values are not directly comparable because EDAM introduced new reliability capacity products, settlement constructs, and cost allocation methodologies. Consequently, a portion of the increase reflects differences in market design rather than sole changes in procurement costs. Prior to EDAM implementation, RA resources were excluded from RUC payments and received no compensation in RUC. After EDAM implementation, RA capacity could be scheduled for RCU and RCD and received settlement allocation.

Figure 271: Monthly trend of RUC/Reliability Capacity costs by BAA



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 272 shows the GHG payments to EDAM entities that are supporting the energy imported into the GHG regulation area (California). Conversely, Figure 273 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 23 summarizes the monthly total GHG costs for PACE, PACW, and PGE.

Figure 272: Greenhouse Gas Settlement Costs in IFM

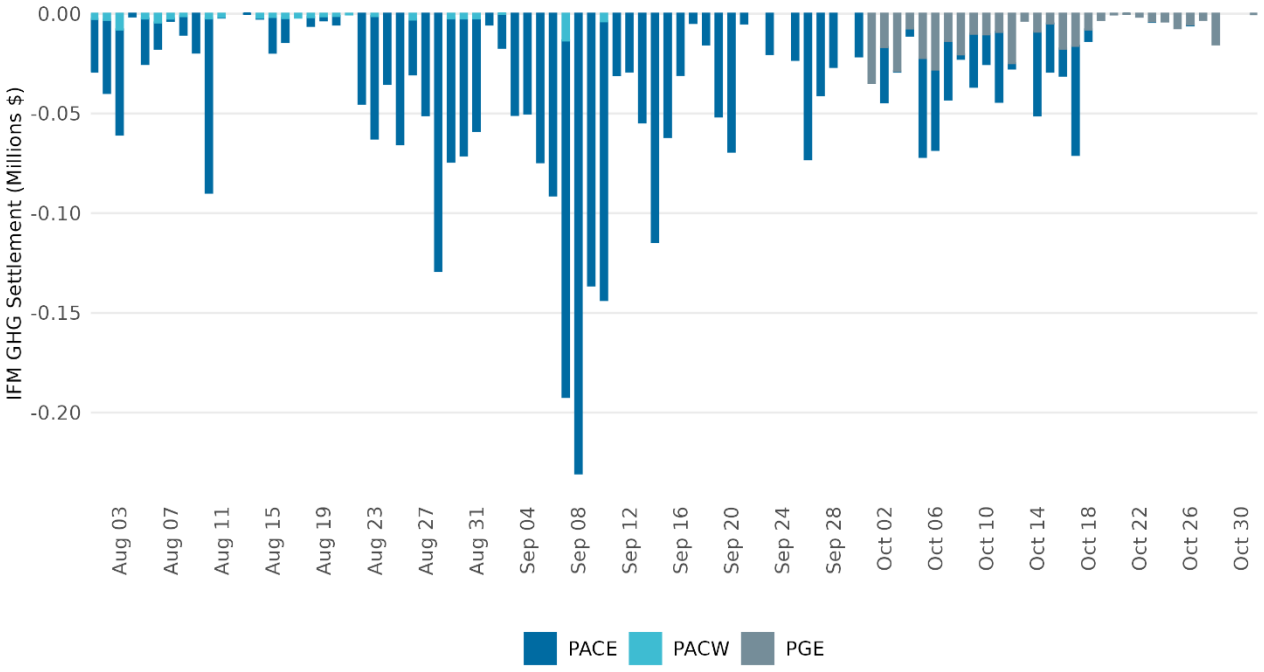


Figure 273: Greenhouse Gas Settlement Costs in RTM

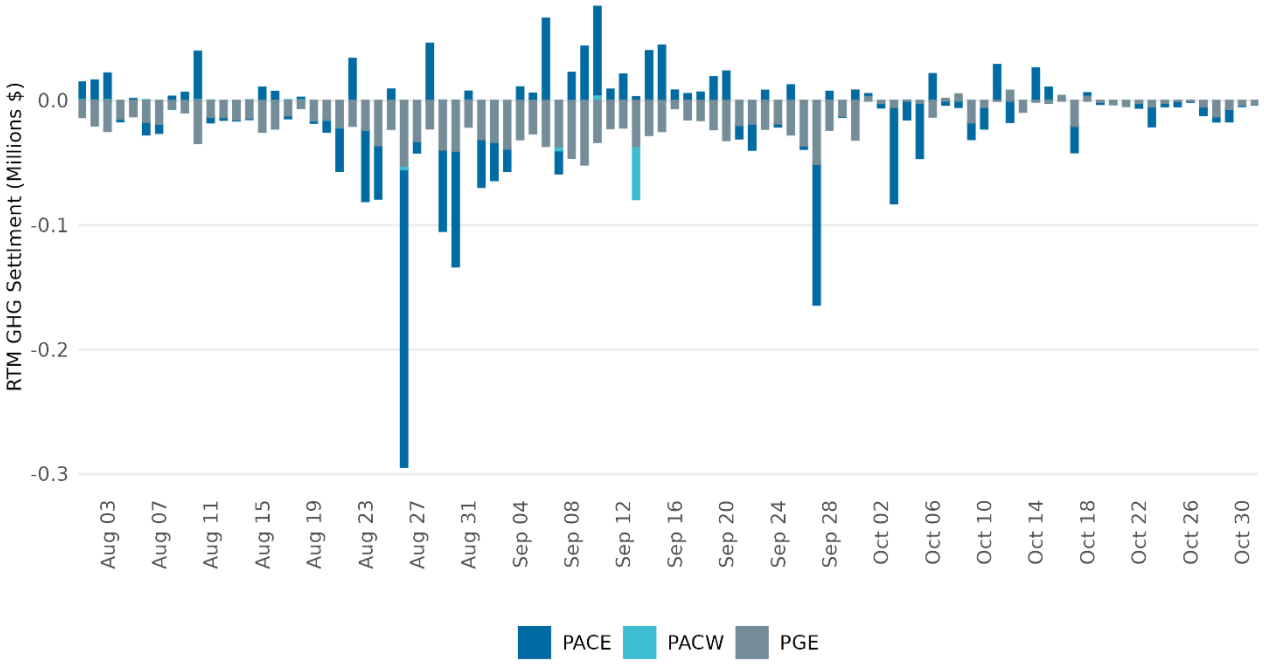


Table 23: IFM and RTM Monthly GHG Settlement Costs

	IFM GHG Costs ($ million)						RTM GHG Costs ($ million)					
BAA	May	June	July	Aug	Sep	Oct	May	June	July	Aug	Sep	Oct
PACE	-0.28	-0.20	-0.86	-0.92	-1.65	-0.37	-0.18	-0.18	0.12	-0.37	0.18	-0.18
PACW	-0.01	-0.03	-0.10	-0.05	-0.02	0.00	0.00	0.00	0.01	0.00	-0.04	0.00
PGE	0.00	0.00	0.00	0.00	0.00	-0.33	-0.10	-0.22	-0.39	-0.65	-0.85	-0.10

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 as early as 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.

The following issues have been previously reported:

- Reliability Capacity Awards at Negative Prices: Reliability Capacity has been awarded to resources at negative prices due to several issues, including software issues with MSG transitions, market-driven conditions related to optimality of solution and price formation. For price formation, negative marginal losses or congestion can drive prices below $0. CAISO has not corrected RC prices for these issues 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.
- 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.
- 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 is open. 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 is open. CAISO is working to correct this in the T+70 BD settlement statements.
- Non-Participating Resources in RUC: To prevent RUC solution failures and ensure timely day-ahead market publication, select generator and MSG configurations were excluded

from RUC participation[17]. CAISO determined that removing some MSG configuration bids in RUC resulted in a shutdown of affected MSG plants. CAISO continues to assess and monitor underlying causes of these RUC failures and continues to monitor and assess this issue.

- Daily Energy Limit not counted in EDAM Resource Sufficiency Evaluation (RSE): Due to a software issue, the daily energy limit for use-limited resources is not enforced in the EDAM RSE allowing these resources to be credited for more capacity than is available in the market. This issue was resolved on November 3, 2026.
- Bid Cost Recovery for Hybrid Resources: There is an issue processing the submitted bid costs for hybrid resources which is resulting in high bid cost recovery payments. This issue affects trade dates from May 1, 2026 and is open.
- Bid Cost Recovery for Dispatchable Demand Resources (DDR): There is an issue processing the submitted bid costs for DDR which is resulting in high bid cost recovery payments. This issue affects trade dates from May 1, 2026 and is open.
- High-Priority Exports in RUC: Under the current implementation, high-priority exports (PT exports) do not have a proxy Reliability Capacity Up bid in RUC. As a result, PT exports cannot be curtailed through RUC. CAISO intends to pursue a Tariff clarification and software update regarding the treatment and prioritization of high-priority exports.
- Greenhouse Gas (GHG) Reference Point for Multi-Stage Generators (MSGs): An MSG resource submits a single GHG bid in the EDAM and this bid should cover the MSG to the plant Pmax. There is a software issue that is not applying the GHG bid to all MSG configurations. This issue impacts trade date from May 1, 2026 and remains open.
- Capacity Counting in the Resupply Test: The resupply test that occurs in the SIBR application and occurs five hours before the relevant trade hour is not accounting for day-ahead awards correctly. EDAM BAAs that fail to e-tag day-ahead intertie awards may be included in the EDAM up pool in the real-time market when they should be excluded. This issue impacts trade date from May 1, 2026 and remains open

The following issue is new:

- Forecasted Movement during EDAM Switchover: With EDAM implementation, forecasted movement is charged or paid in the day-ahead market based on hourly changes in day-ahead schedules. When a new EDAM BAA joins the day-ahead market in HE 1, there is no day-ahead schedule in HE 24 to calculate forecasted movement so CAISO will eliminate forecasted movement settlement for this period.

[17] CAISO contacts the Scheduling Coordinators for resources that have bids removed in any market run.

Stakeholder Feedback and ISO's responses

There were two sets of stakeholder comment submitted in response to September's report. This section provides a summary of these comments and a summary of the responses as an easy reference. The detailed responses are available on the site where the stakeholder comments were originally posted.

CAISO appreciates the comments and recommendations provided by stakeholders regarding EDAM market performance, reporting transparency, congestion and transfer revenue allocation, imbalance reserve procurement, settlements, pricing mechanisms, self-scheduling, and market operations. The ISO values constructive feedback and stakeholder engagement during the initial months of EDAM operations. As the market continues to stabilize, CAISO is reviewing the requests for additional analyses, metrics, and reporting enhancements and will consider incorporating expanded information and clarifying existing metrics in future monthly EDAM performance reports and stakeholder discussions where appropriate. CAISO also recognizes the importance of continued transparency regarding operational challenges, market outcomes, and benefit allocation, and appreciates stakeholders' ongoing participation and feedback as the ISO works to further improve EDAM reporting and market understanding.

Pacific Gas & Electric (PG&E) requested additional information on three areas of EDAM performance. First, PG&E asked why a large portion of the IRU capacity procured in the day-ahead market was not utilized in real-time. Specifically, PG&E asked whether this was because the expected uncertainty did not occur or because other resources were able to meet the real-time need more economically, and requested additional information on the resources ultimately used. Second, PG&E asked for more detail on RCU procurement, particularly how much is driven by RUC adjustments compared with the underlying market forecast. Finally, PG&E requested clarification on the PACE BCR issue covering approximately July 29 through September 24, including how the correction will be reflected in settlements and whether previously settled amounts will be adjusted.

CAISO response:

The ISO previously provided analysis of imbalance reserve outcomes in the September report and during the September stakeholder call. Please refer to the call recording. The ISO will consider the suggested metric for splitting RUC procurement into RUC adjustments and load forecast differences relative to cleared demand. The BCR issue affecting the PACE area is described in the market issues section of the report. It was also discussed during the September stakeholder call, so please refer to that recording. Once the fix is in place, the ISO will provide an update on the timing, how it will be addressed.

WPTF supported CAISO's ongoing improvements to the EDAM and DAME market performance reports and requested two additional metrics in future monthly reports. First, WPTF requested information showing how often IRU and IRD prices fall within different price ranges for each BAA. Second, WPTF requested the amount of RCU and RCD procured at negative prices, separately by product and BAA. WPTF noted that including these metrics would help stakeholders better understand the frequency and magnitude of these market outcomes.

CAISO response:

Starting with the monthly report for September, CAISO has provided the IRU and IRD prices within different price ranges at the system level as shown in Figure 35 and 36. Figure 87 and 88 provides the frequency of RCU and RCD. CAISO will consider the suggestion to expand this metric at the BAA level for future reports. The ISO will also consider the suggested metric about the volume of reliability capacity cleared at negative prices for potential future reporting.