Extended Day-Ahead Market Performance August Report

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California Independent System Operator

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Executive Summary

On May 1, 2026, the California ISO, in partnership with PacifiCorp, successfully launched the Extended Day-Ahead Market (EDAM) alongside a suite of Day-Ahead Market Enhancements (DAME). This August report is the fourth 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.

August brought another month of high demand conditions this summer, with CAISO recording a peak load of 47,140 MW on August 26, exceeding the California Energy Commission's month-ahead forecast of 45,386 MW. Demand increased significantly relative to July, with CAISO peak load exceeding 40,000 MW on 23 days during the month. While these conditions represented the strongest demand environment since EDAM implementation, load levels remained broadly consistent with recent historical experience and below monthly Resource Adequacy showings, indicating sufficient capacity and comfortable reliability margins throughout the period. As a result, many of the changes observed in August market outcomes were driven by seasonal fundamentals rather than changes in EDAM market design or performance. At the same time, EDAM market outcomes continued to stabilize as participants gained experience with the new market framework matured and multiple settlements issues have been addressed.

Key Takeaways

Peak demand conditions increased prices and wholesale market costs

August's stronger summer conditions were reflected across energy market outcomes. Day-ahead energy prices increased across all participating BAAs, with average prices rising to approximately \$53/MWh in CAISO, \$46/MWh in PACE, and \$43/MWh in PACW, up from \$40/MWh, \$32/MWh, and \$31/MWh, respectively, in July. The highest daily average prices occurred during the August 26-27 heat event, when CAISO, PACE, and PACW day-ahead prices reached approximately \$83/MWh, \$72/MWh, and \$57/MWh, respectively. Real-time price volatility also increased late in the month as tighter system conditions reduced day-ahead and real-time price convergence.

These stronger market fundamentals contributed to significantly higher wholesale market costs. Total wholesale energy costs in CAISO increased from approximately \$0.95 billion in July to approximately \$1.3 billion in August, equivalent to an average energy cost of \$59.3/MWh. August 2026 wholesale energy costs were roughly 35 percent higher than

August 2025 levels and represented the highest monthly costs observed since EDAM implementation.

Transfers between areas provided operational and economic benefits

Market integration across the Western Interconnection continued to provide significant operational and economic value during summer conditions. CAISO relied increasingly on imports to meet peak demand while also supporting neighboring regions through substantial exports during periods of strong solar production. Intertie schedules remained robust, with major transfer paths such as Malin, Palo Verde, and NOB facilitating significant power flows across the region.

Within EDAM and the WEIM, transfer patterns reflected increasing regional diversity. California continued to export energy during midday solar hours and import energy during morning and evening ramp periods when regional support was most valuable. August saw increased net imports into CAISO relative to earlier months as regional demand strengthened and the economic value of imports increased. Overall, transfers, storage resources, and renewable generation worked together to maintain reliability while efficiently serving load during the summer's highest-demand period.

EDAM transfers reflected tightening summer conditions

August transfer patterns demonstrated increased utilization of EDAM products as reliability and flexibility needs intensified. Across the energy market, CAISO's decline in net exports continued while imports remained elevated. CAISO relied more heavily on imports, particularly from PACE, and exported less energy than in June. Meanwhile, PACE evolved from a net importer earlier in the summer to a significant net exporter in July and August, while PACW remained a net importer overall.

A similar shift occurred across reliability products. Imbalance Reserve Up (IRU) transfers became increasingly dynamic, with CAISO continuing to export upward reserves while also importing more support from PACW during key operating hours. PACE remained a major importer of IRU, while PACW increasingly supplied upward reserves to the broader EDAM footprint.

The most significant evolution occurred in Imbalance Reserve Down (IRD) transfers. CAISO's significant IRD exports observed earlier in the summer declined substantially, and the balancing authority shifted toward a more neutral position. PACE transitioned from a net importer to a net exporter of down reserves, while PACW continued importing down reserves but increasingly sourced them from PACE rather than CAISO.

Reliability Capacity Up (RCU) transfers reached their highest levels since EDAM implementation, driven by increased exports from both PACE and PACW and increased imports by CAISO. In contrast, Reliability Capacity Down (RCD) transfers declined substantially across all EDAM areas. Together, these patterns indicate growing regional sharing of upward flexibility and reliability services while system conditions reduced the need for downward reliability capacity.

Reliability products performed as intended during higher-load conditions

The summer peak period provided an important test of the new EDAM capacity products. Both Imbalance Reserves (IR) and Reliability Capacity (RC) continued to support system reliability while displaying signs of market maturation.

Imbalance reserve up prices increased and became more volatile in August compared to July, with the largest impact in PACE followed by CAISO. Daily average imbalance reserve up prices for all three BAAs spiked to 13 $/MWh on August 27, though the highest price was observed on August 20 in PACE at approximately 20 $/MWh. Meanwhile, imbalance reserve down prices remained low across EDAM BAAs, consistent with prior months. Price patterns continued to align with evening and morning ramping periods when operational flexibility was most valuable. The geographic diversity provided by the broader EDAM footprint continued to reduce aggregate reserve requirements by sharing renewable forecast uncertainty and load variability across participating areas.

The new reserve procurement framework also reduced reliance on manual uncertainty adjustments. During August, Residual Unit Commitment (RUC) adjustments occurred 40 percent of the time compared to 65 percent during August 2025, highlighting the operational benefits of reserve sharing across the expanded EDAM footprint. The optional EDAM net export constraint, which allows balancing authorities to limit exports when capacity may be needed for local reliability, did not bind in any hour for CAISO during May through August, indicating sufficient available capacity throughout the period. No RUC infeasibilities were observed during the month. These results suggest that EDAM resource sharing and the new reserve procurement framework reduced dependence on manual reliability actions relative to historical summer operations.

Reliability Capacity prices also increased substantially during the late-August heat event. The highest prices were observed on August 27, reaching approximately $57/MWh in CAISO, $48/MWh in PACW, and $42/MWh in PACE. Overall, the product continued to function as designed by securing both upward and downward capacity needed to manage forecast uncertainty and reliability risk.

Costs to procure Imbalance Reserve Up were higher across all three EDAM regions totaling $5.3 million in August compared to July's $2.89 million. The costs for Imbalance Reserve Down varied by region and were significantly lower at $0.37 million. Overall costs of procurement for reliability capacity reached $14.54 million for CAISO in the upward direction and $0.12 million for the CAISO in the downward direction, for the month of August. These were both substantially higher than the procurement costs in July, due mainly to the higher prices for those products. Costs for PacifiCorp East and West were generally consistent with July.

Congestion continued to be concentrated within the CAISO footprint

August congestion outcomes under EDAM were dominated by CAISO transmission constraints, particularly north-to-south limitations across Path 26. These constraints increased congestion costs in Southern California while producing offsetting benefits in Northern California and portions of the PacifiCorp footprint. Congestion impacts averaged approximately $1.35/MWh in the SCE area, compared to -$2.40/MWh in the PG&E area and -$1.96/MWh in PACW. Congestion patterns were most pronounced during peak-demand periods and generally reflected the same north-to-south flow limitations observed during the second half of July.

Congestion peaked between August 25 and August 27 following a temporary derate on a Path 26 transmission element, coinciding with the month's highest load and price conditions. Consistent with pre-implementation EDAM studies, PacifiCorp transactions contributed meaningfully to flows on CAISO constraints through parallel-flow effects, while CAISO transactions had negligible impacts on PacifiCorp constraints. Although nearly all congestion costs originated from CAISO transmission constraints, resulting congestion impacts were reflected across the broader EDAM footprint through locational price differences.

Total congestion revenues reached approximately $74.5 million in August, up from roughly $59 million in July, and were attributable almost entirely to CAISO constraints. However, the EDAM congestion revenue allocation framework, together with credits associated with transmission rights and qualifying self-schedules, largely offset cross-border congestion impacts. Self-schedules associated with PacifiCorp transmission rights averaged approximately 1,646 MW in PACE and 1,889 MW in PACW. Preliminary settlement results indicate a net congestion revenue allocation of approximately -$680,000 to PacifiCorp areas, reflecting charge-backs associated with counterflow transactions that had previously received congestion credits. Overall, August congestion outcomes remained broadly consistent with expectations established during EDAM design and stakeholder studies.

Offset costs continue to be an area of review

Market offset mechanisms generally functioned as intended during the first four months of EDAM operation, supporting revenue neutrality across day-ahead and real-time market settlements. Offsets are accounting mechanisms that reconcile differences between amounts collected and amounts paid through market settlements. While typically small relative to overall market activity, offsets can provide insight into the effects of congestion, price formation, and settlement design on market outcomes. They occur in both the Day-ahead and real-time market timeframe.

Congestion-related offsets were generally modest in the day-ahead market but increased during periods of elevated transmission congestion. Day-ahead congestion offsets were limited during most months, though both PacifiCorp East (PACE) and PacifiCorp West (PACW) experienced higher congestion offsets in July as summer operating conditions increased congestion costs. In real-time markets, congestion offsets were concentrated within the CAISO balancing area, reflecting the effects of transmission constraints and outage-related congestion. Real-time congestion offsets increased during periods when major transmission facilities were unavailable, highlighting the sensitivity of congestion costs to grid conditions and transmission availability.

Energy-related offsets were more significant and remain an area of continued review as the market adjusts to EDAM's new settlement framework. Day-ahead energy offsets generally increased over the summer as loads and energy prices rose, resulting in larger redistribution amounts required to maintain revenue neutrality. Real-time energy offsets changed materially following EDAM implementation because settlements now rely on area-specific marginal energy costs and updated greenhouse gas accounting provisions. As a result, post-EDAM energy offsets are not directly comparable to historical values observed prior to May 2026.

CAISO continues to evaluate several settlement outcomes and expects some reported values to change through future settlement recalculations and true-up processes. The ISO is actively reviewing the drivers of several energy offset results and investigating potential settlement adjustments. While some offset values have been larger than historical experience, market operators have emphasized that many of these outcomes reflect structural changes associated with EDAM implementation rather than indications of market performance concerns. Ongoing analysis will provide greater clarity as settlement data matures through subsequent recalculation cycles.

Other market performance indicators remained strong

Operational performance remained generally strong despite more challenging summer conditions.

- No Resource Sufficiency Evaluation failures occurred in any EDAM BAA.
- Convergence bidding activity increased compared to pre-EDAM levels.
- Average day-ahead GHG price was $8.25/MWh and followed expected intraday patterns.
- EDAM results were posted before 1:00 p.m. on 46 percent of August operating days, down from 53 percent in July, with most delays occurring during periods of higher market demand and increased complexity.
- Based on early EDAM operational experience, the ISO is implementing an enhancement effective October 1, 2026, to improve the treatment of storage resources in the Residual Unit Commitment process. The enhancement will enable greater use of storage resources in the day-ahead market.
- Market issues continued to be tracked through stakeholder forums and monthly reporting processes.

Conclusion

August provided the first meaningful assessment of EDAM performance under sustained summer operating conditions. Higher temperatures, stronger regional demand, and drove most of the notable differences between August, July and the May-June implementation period, including higher prices, changing transfer patterns, greater reliance on imports during peak periods, and increased market costs.

Despite these more challenging conditions, EDAM continued to operate reliably and largely as expected. Market outcomes generally became more stable over the first three months of operation, reliability products functioned effectively during periods of elevated demand, and interregional transfers helped balance supply and demand across the Western footprint. These results suggest that EDAM provides value under both moderate spring conditions and more demanding summer operating environments, while market participants continue to gain experience with the new framework.

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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 August report provides an overview of market performance during the first three months of EDAM/DAME operations, focusing on price formation, resource sufficiency outcomes, congestion costs and settlement cost trends across participating balancing authority areas for EDAM. As with CAISO's prior monthly performance reports, the objective is to offer timely and transparent insights into market performance, particularly during the initial period of a major market design transition.

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

The report evaluates costs associated with congestion revenue allocation, and settlement cost trends across the EDAM footprint. This includes an assessment of congestion revenues, breakdown of marginal component of congestion (MCC) at the transmission constraint level among participating BAAs. Also, as the system experienced high loads in August, this report includes various metrics on market performance during summer conditions.

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

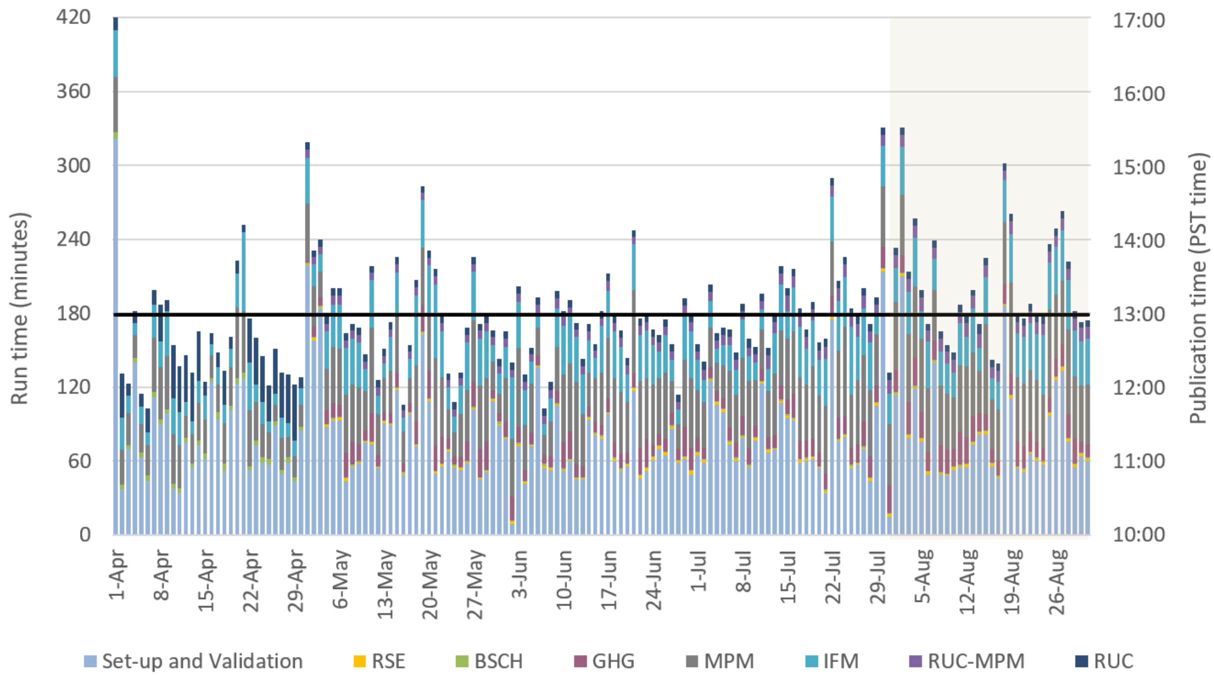
Day-Ahead Market Run

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

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

In addition to running three new processes within the standard window, EDAM is inherently more complex because it solves for a wider market footprint and so has a larger optimization problem to solve multiple times. This has increased the overall computational workload. Despite the complexity, CAISO maintains the goal of a 1:00 p.m. publication time. Figure 1 illustrates the additional time the CAISO took in the first days of EDAM operations to ensure all processes and runs were properly executed, and results could be closely assessed. This has taken longer to publish market results. After the first two weeks, CAISO gradually returned to more standard runs of the market and the market was able to publish DA results before 1:00 p.m. In August, EDAM results were posted before 1:00 p.m. in 14 out of 31 days, a reduction from the posting of 17 out of 31 days in July. 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 August.[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 and August, there were no RSE failures for any EDAM BAA.

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

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

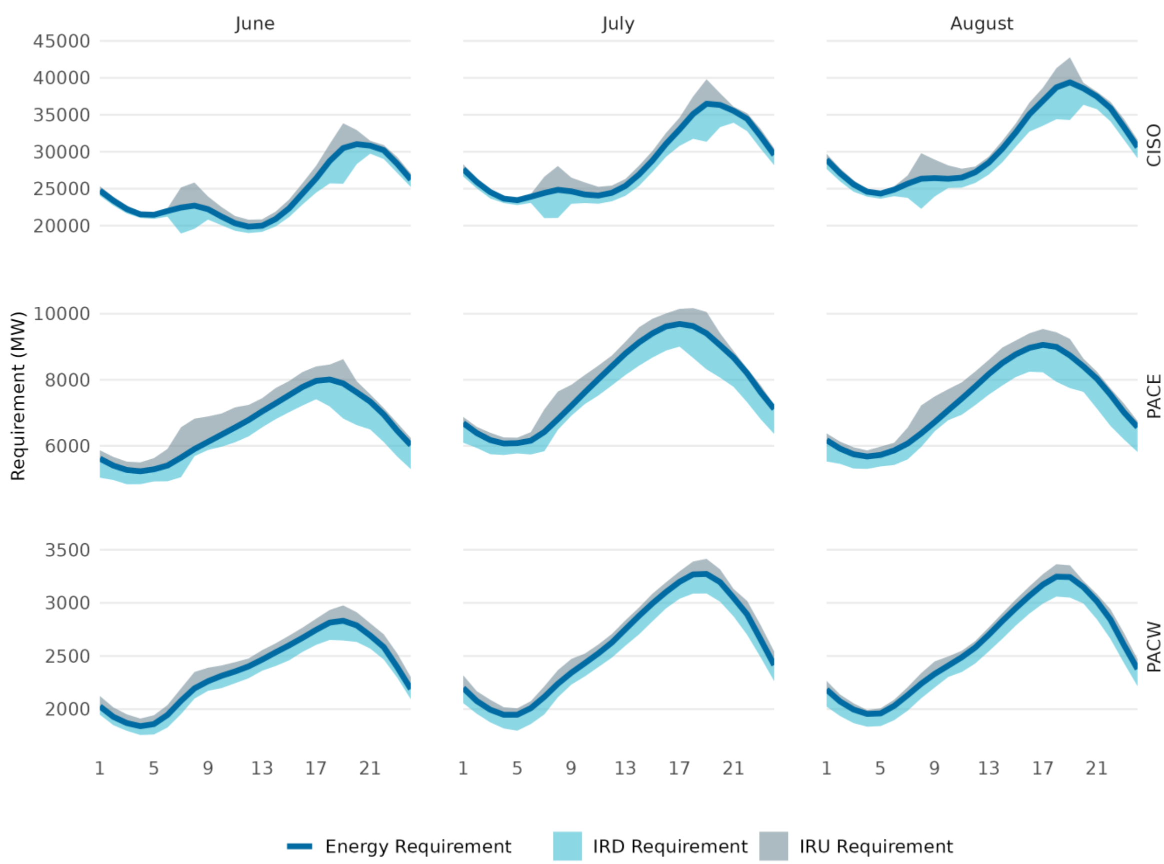


Table 2 gives the highest imbalance reserve upward and downward requirements for each BAA from May to August.

Table 2: Maximum imbalance reserve requirements by BAA

	Maximum IRU Requirement (MW)				***Maximum IRD Requirement (MW)***			
BAA	**May**	**June**	**July**	**August**	**May**	**June**	**July**	**August**
CAISO	3,629	3,486	3,536	3,867	5,320	5,487	5,985	5,310
PACE	1,028	1,028	964	1,045	1,100	1,125	1,125	1,133
PACW	225	229	214	207	241	259	259	252

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 June through August 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 June through August, 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 June through August seeing a slightly higher bid-in demand compared to the day-ahead forecast.

The shape of the day-ahead demand forecast hourly profile remained generally similar from June through August for all three BAAs. From June to July, all three BAAs saw higher evening peaks. In August, CAISO saw a further increase in the evening peak, while the peaks for PACE and PACW were slightly lower than in July. CAISO saw a smaller mid-day dip and higher evening peak, leading to a steeper afternoon ramp. Both PACE and PACW continued to show a significant evening peak with a steeper but also steadier increase in demand across daylight hours.

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

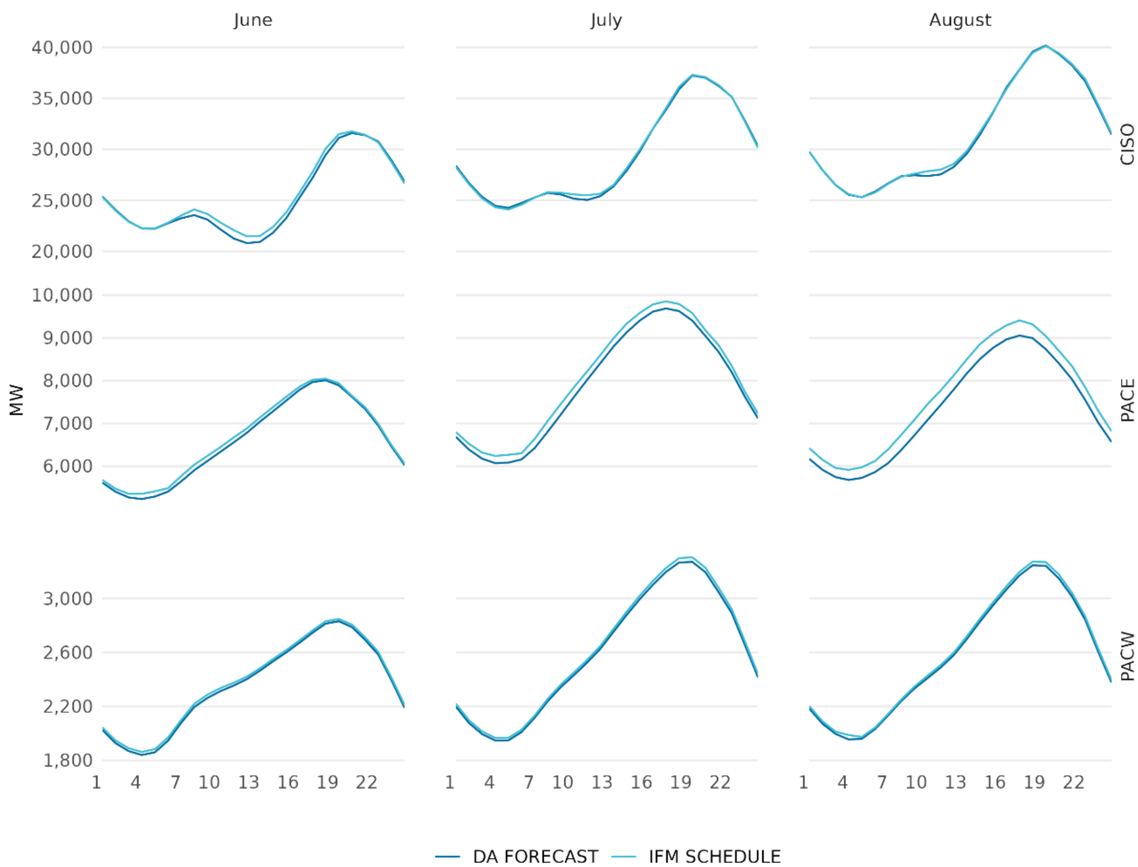


Table 3 shows the highest day-ahead demand forecast for a single hour for each EDAM BAA from May to August. From July to August, CAISO and PACW saw increases in forecasted peak demand, while PACE saw a decrease. The percentage changes were 7.4, -4.7, and 1.9 percent for CAISO, PACE, and PACW, respectively.

Table 3: Peak day-ahead demand forecasts

	Peak DA Demand Forecast (MW)			
BAA	**May**	**June**	**July**	**August**
CAISO	34,674	37,399	42,928	46,089
PACE	8,047	9,358	10,527	10,029
PACW	2,893	3,635	3,866	3,941

Day-Ahead Supply

Figure 4 presents the hourly average energy awards by fuel type for CAISO from May through August. 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 also increase from May to August, with higher peak levels observed over 40,000 MW in August. Gas generation plays an important role in meeting evening demand, especially in July and August, with awards increasing noticeably during the evening hours. These patterns illustrate the complementary roles of solar, storage, and gas resources in supplying CAISO system demand throughout the day in the first four months after EDAM launched.

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

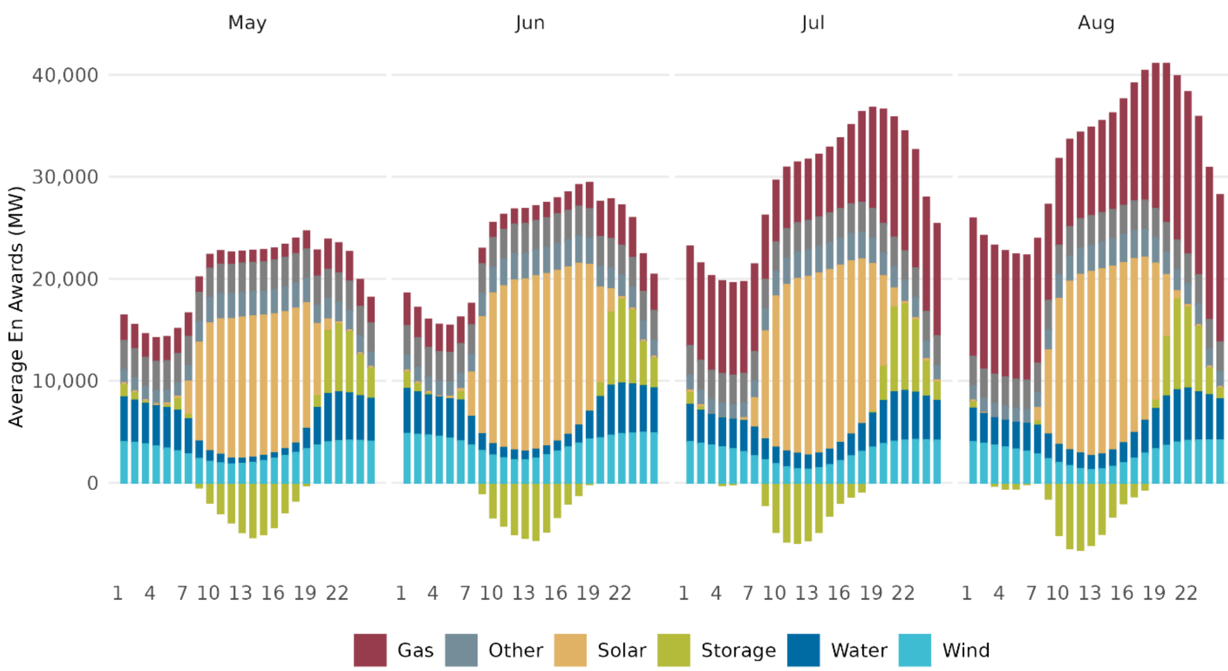


Figure 5 illustrates the hourly average energy awards by fuel type for PACE from May through August. The results show distinct monthly and hourly patterns across the resource mix. Coal provides a relatively stable level of energy and becomes a main contributor to the overall PACE's resource mix. Solar 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 (mainly hybrid) exhibit relatively small charging and discharging activity compared with CAISO. Overall energy awards increase from May into the summer months, with the highest hourly levels about 9,000 MW observed in July and August.

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

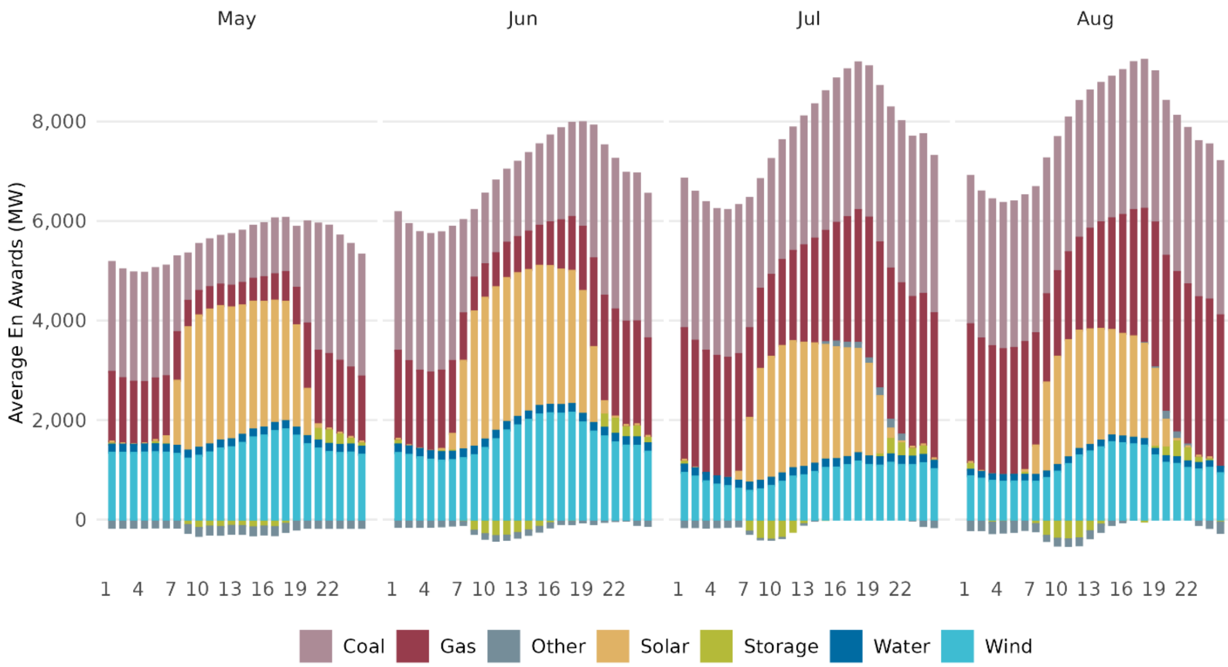
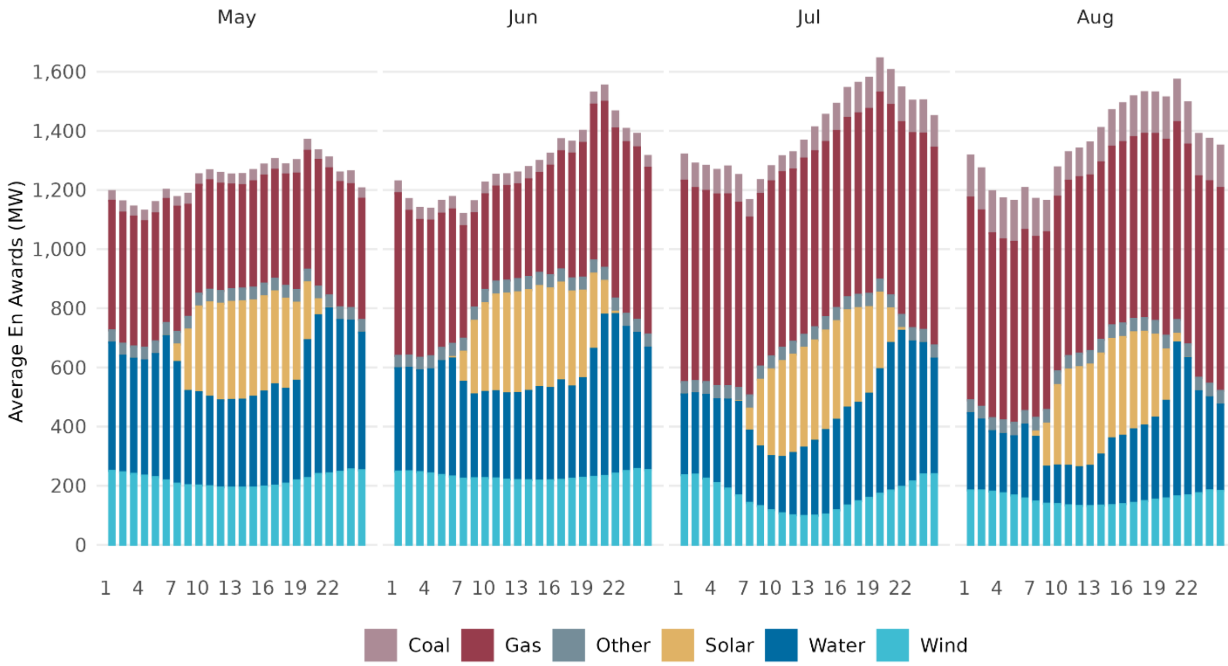


Figure 6 presents the hourly average energy awards by fuel type for PACW from May through August. Gas, wind, and water resources account for a substantial share of the energy awards throughout the period, while solar exhibits a clear daytime pattern. Wind awards are relatively stable in May and June but show greater hourly variation in July and August, with lower awards during daytime hours. 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 increase from May into the summer months, with the highest hourly levels over 1,600 MW occurring in July.

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



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.

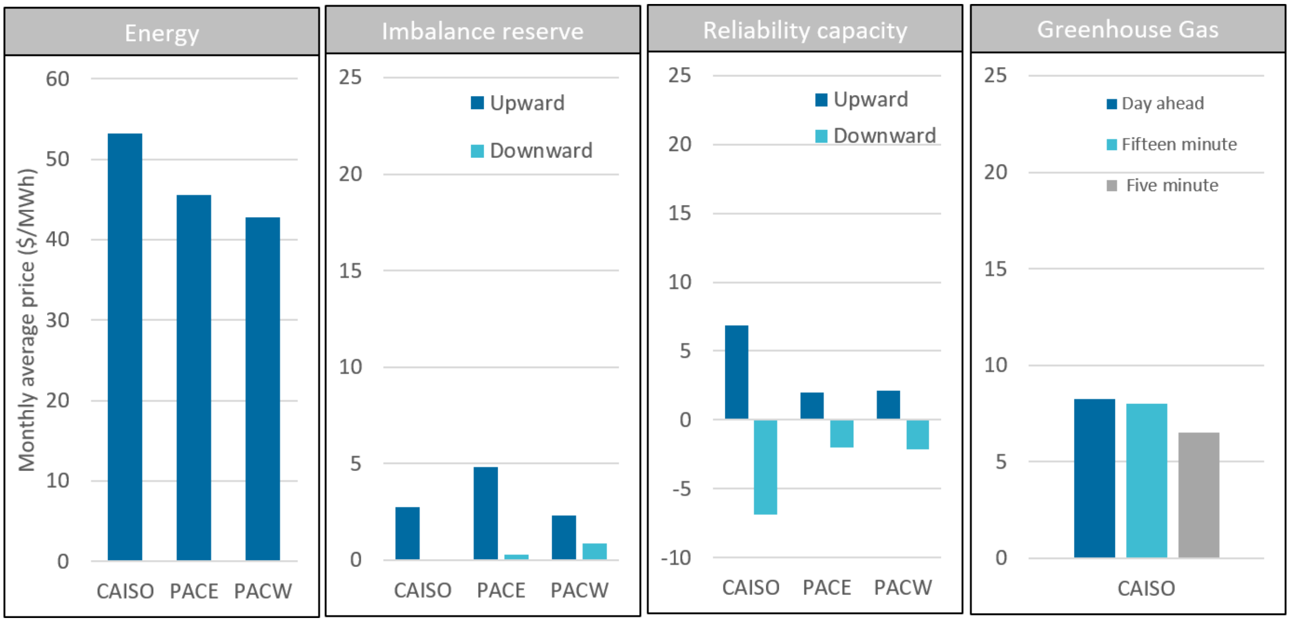
Procuring flexibility through the market promotes economic efficiency by identifying and securing the least-cost resources capable of providing these services. It also establishes transparent price signals that explicitly value flexibility, helping market participants better understand system needs and 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 June. With more than a month 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 seasonal conditions transition toward summer patterns, the results should be viewed as preliminary and may not yet fully reflect the extent of the changes introduced by EDAM/DAME. The CAISO will continue to monitor and evaluate market performance and will provide further analysis in upcoming monthly reports.

Figure 7 compares prices across all EDAM products for the month of August. 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 7: Pricing of EDAM products for August 2026



Seasonal conditions also play an important role in shaping price patterns as observed in the month of August. 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 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 are responsive to system conditions and daily changes in supply and demand. The figures in this section show the average IFM 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 8 shows the average hourly IFM LMPs. Compared to July, average prices in August increased across all three BAAs, primarily due to higher demand. Average day-ahead price separation among the three BAAs in August generally mirrored July during the first part of the day but diverged during the latter hours. From HE 1 through HE 15, CAISO day-ahead prices remained above those in PACE and PACW, while price separation between PACE and PACW remained minimal, consistent with July patterns. Beginning in HE 15, however, PACE prices increasingly diverged from PACW and rose to levels comparable to those observed in CAISO through HE 24.

Figure 9 shows that daily average IFM LMPs increased steadily across July and August. Daily average prices were particularly elevated in late August, with CAISO recording sustained high prices from August 25 through August 28 and PACE from August 19 through August 21. CAISO and PACE reached their highest daily average prices since May 1 on August 27, at $83.38/MWh and $71.76/MWh, respectively. PACW reached its highest daily average price on August 20 at $63.67/MWh.

Figure 8: Hourly IFM LMP averaged by month

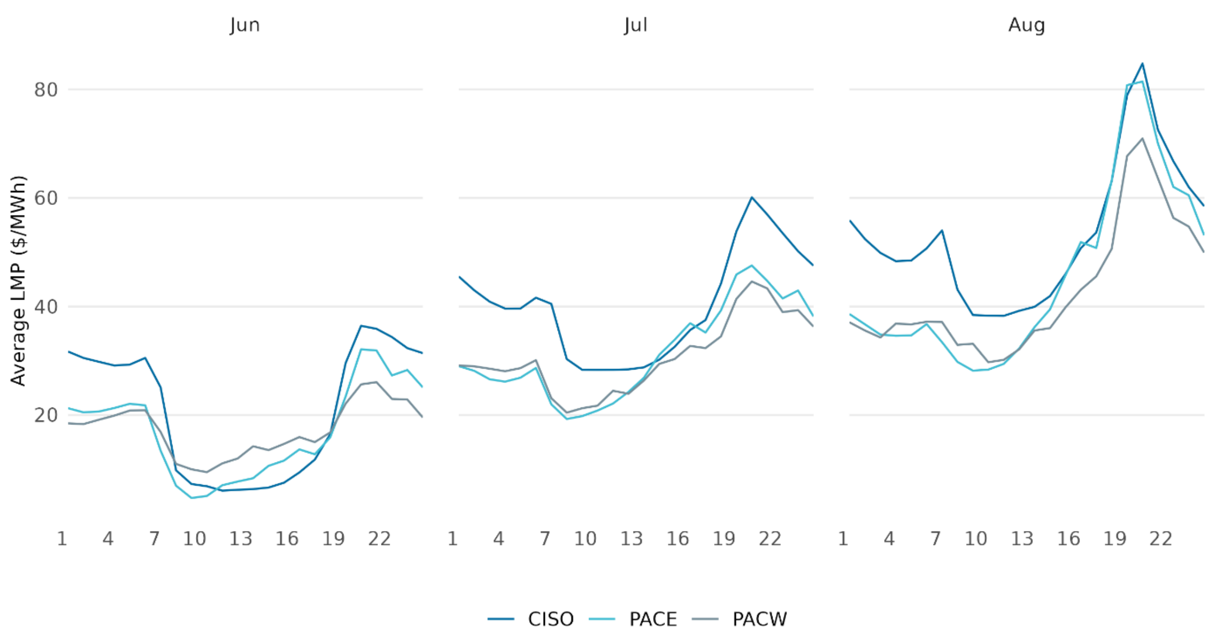
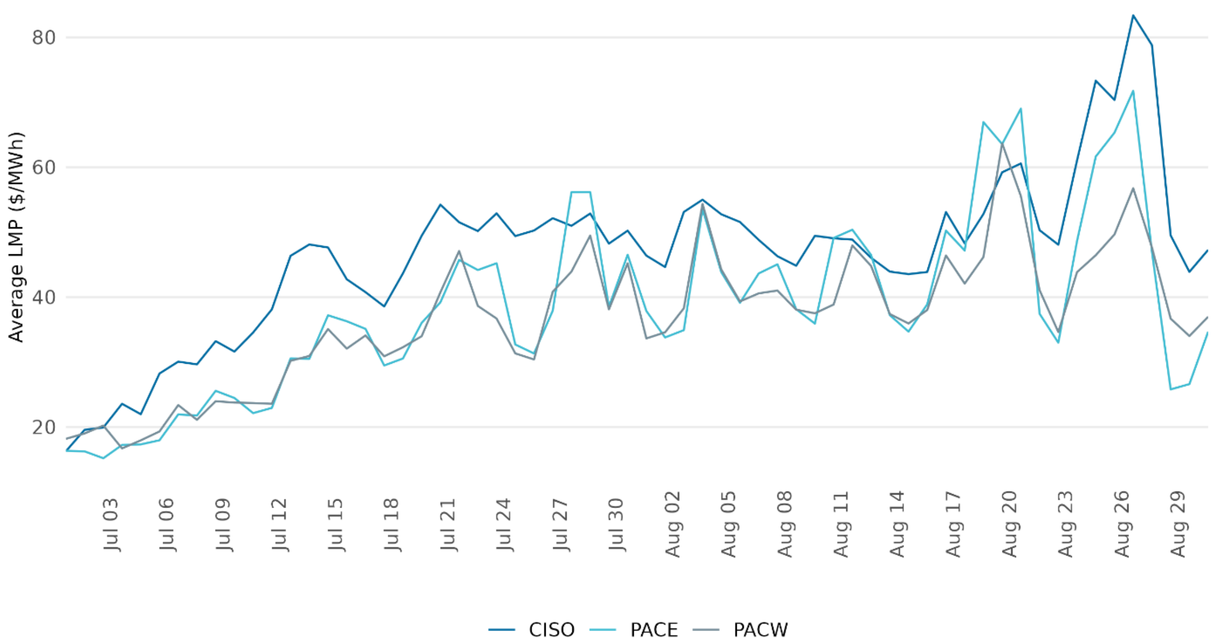
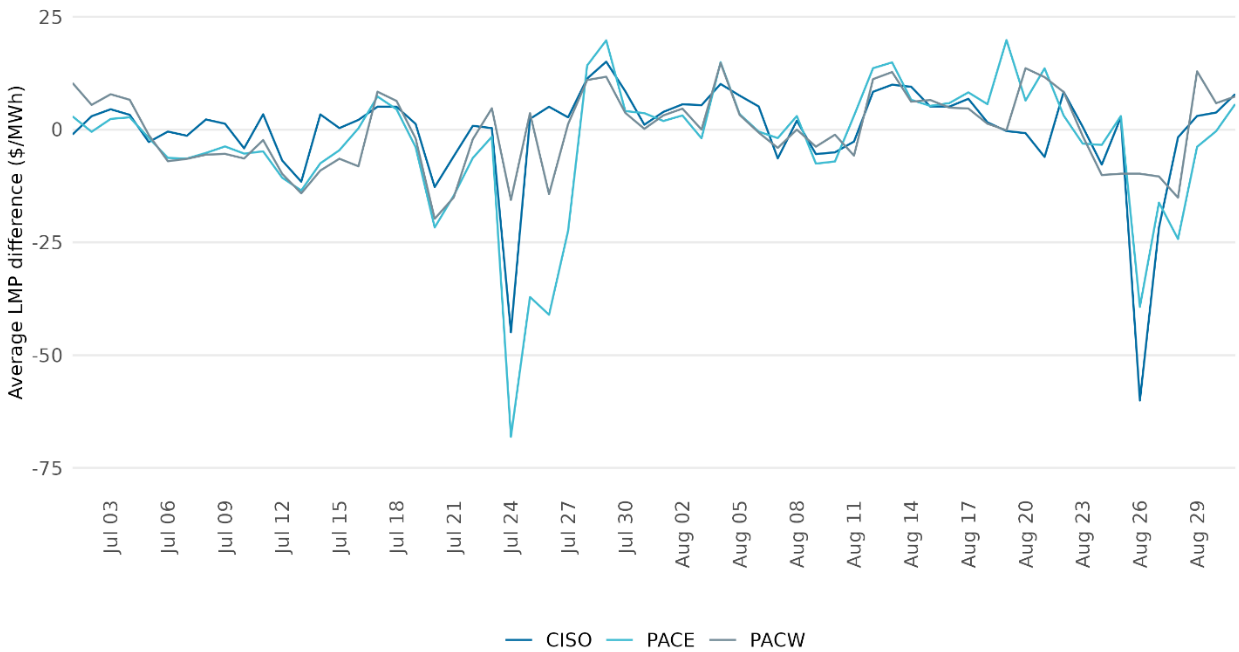


Figure 9: Daily average LMP by BAA



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 prices. Figure 10 illustrates the daily average spread between day-ahead market (IFM) and fifteen-minute market (FMM) prices for the EDAM BAAs in July and August, calculated as the daily average IFM LMP minus the daily average FMM LMP. A negative price reflects a higher real-time price compared to day-ahead price. A zero in the plot represents perfect convergence from day-ahead to real-time. In general, price convergence remained consistent from July to August except from August 26-28. Day-ahead LMPs were significantly lower than real-time prices during this time, particularly on August 26.

Figure 10: Average difference between IFM LMP and FMM LMP



Prices tend to vary from day to day as conditions vary. Trends in price convergence are better understood over longer time spans. Figure 11, Figure 12, and Figure 13 show the average monthly LMPs across the three markets for the EDAM BAAs, with only CAISO having IFM prices prior to May 2026. Figure 11 illustrates that price convergence between IFM and FMM observed in July and August for CAISO was like levels observed prior to EDAM implementation, however there was less price convergence between IFM and RTD. Figure 12 shows that PACW saw consistent price convergence in July and August. Figure 13 shows that price convergence in PACE improved in August compared to July. The decline in price convergence for CAISO and PACE was largely attributable to conditions on August 26-28.

Figure 11, Figure 12, and Figure 13 also illustrate the seasonal trends in prices. Average prices increased through the summer and reached their highest levels since 2025 in August. This pattern is consistent with the seasonal increase in electricity prices typically observed during summer months.

Figure 11: Monthly average price for CAISO area

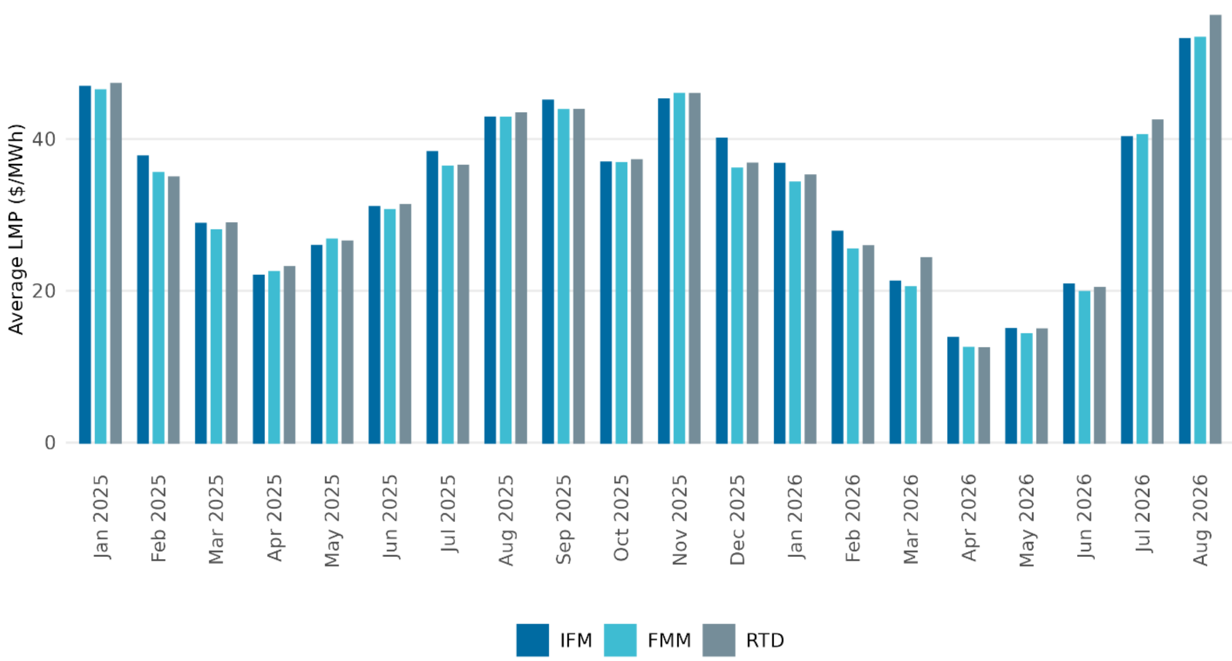


Figure 12: Monthly average price for PACW

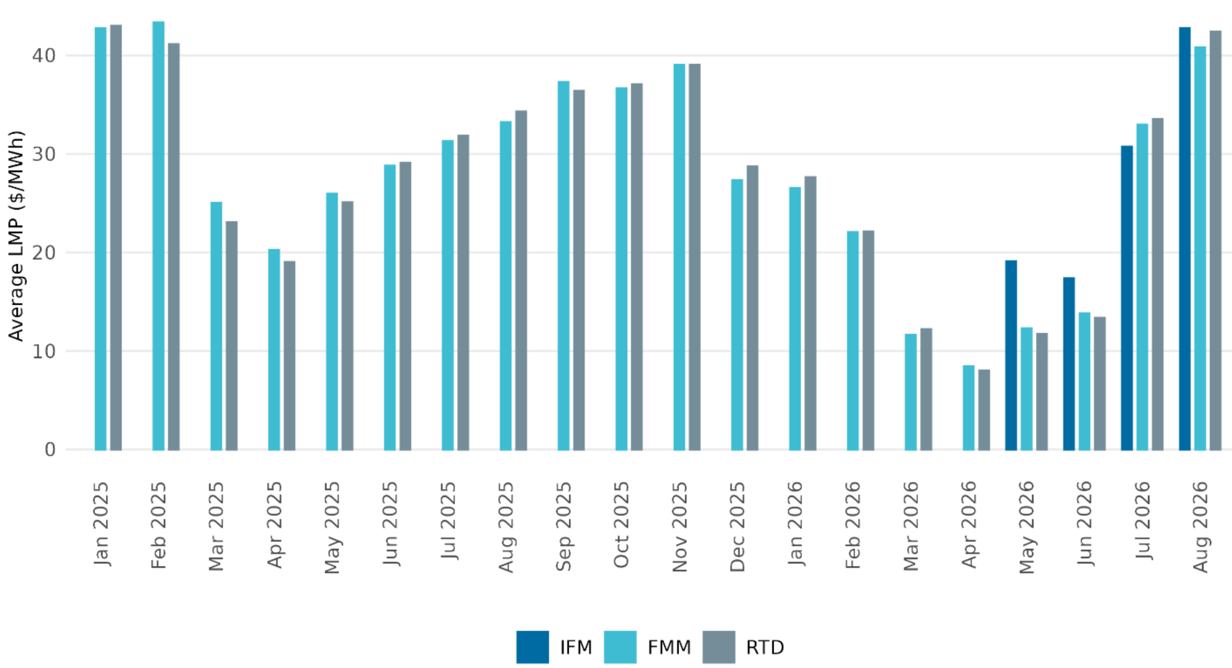


Figure 13: Monthly average price for PACE Average LMPs

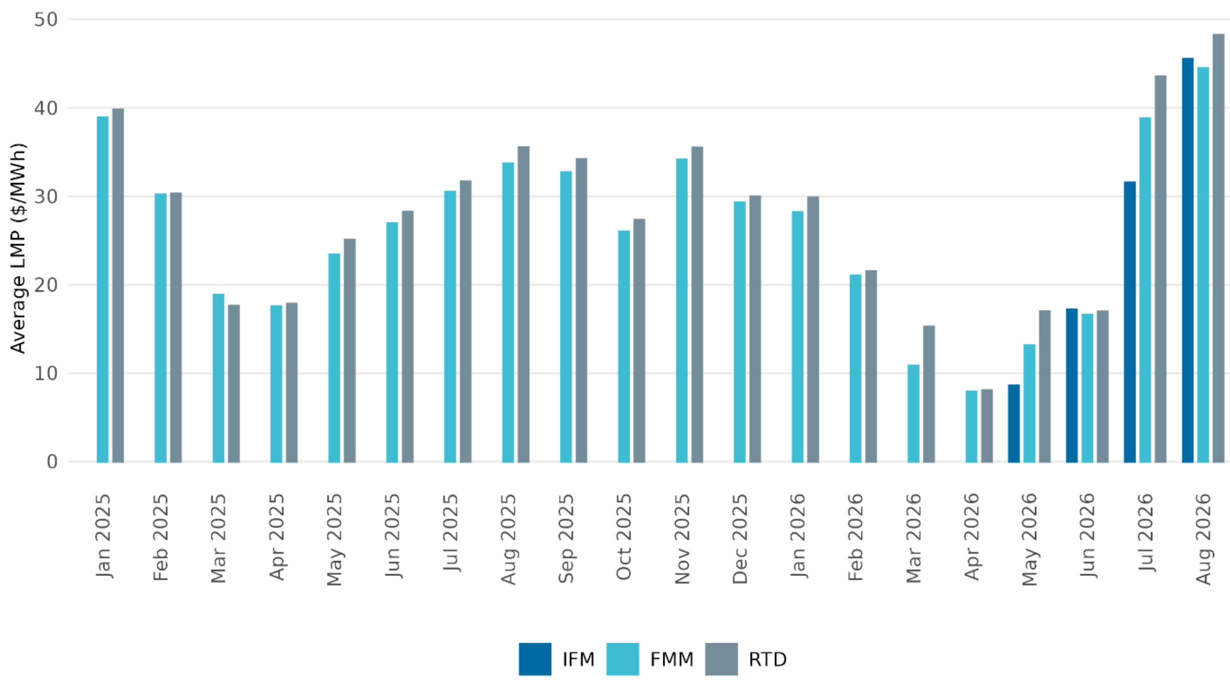
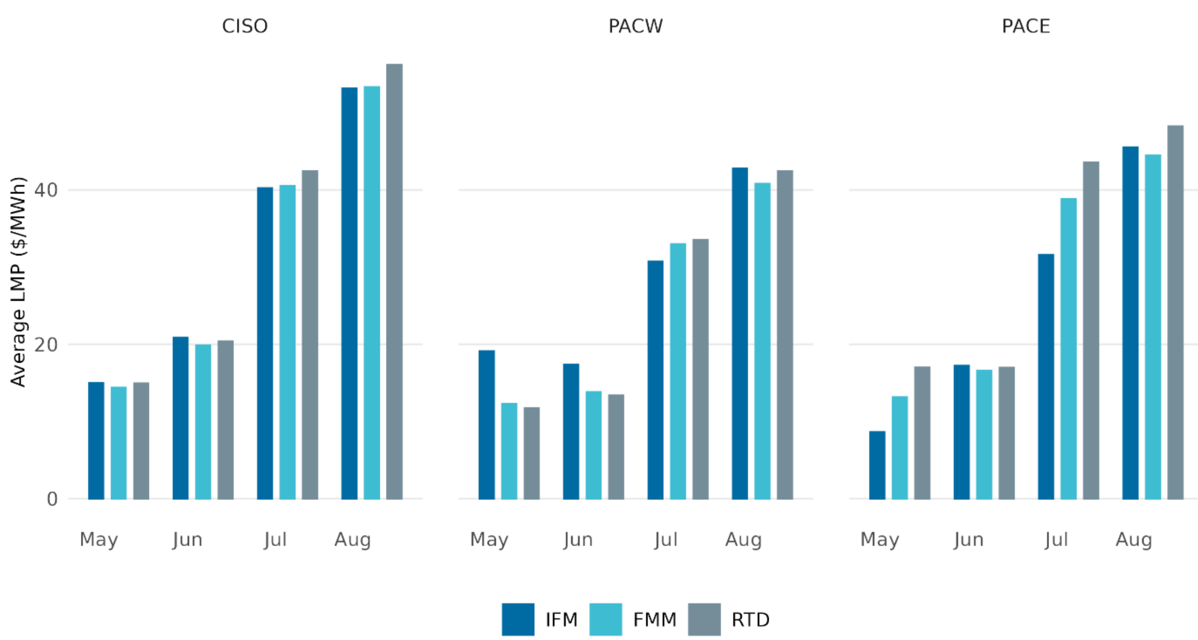


Figure 14 presents the same monthly average LMPs for May through August 2026 to ease the comparison among areas and months. Figure 14 summarizes the average LMP across each month for each market and BAA.

Figure 14: Monthly average LMPs



Price Volatility

Figure 15, Figure 16 and Figure 17 show the frequency of RTD LMPs falling in predefined $/MWh ranges in the given month for each BAA. Compared to July, all three BAAs saw a shift in prices to higher ranges. There were more LMPs in the range of 40 to 100 $/MWh, with the 40 to 100 $/MWh range the most frequent for CAISO. Compared to the summer months in 2025 this trend of the increasing frequency of higher LMPs is normal for this time of year, but July and August 2026 represented a steeper increase than 2025.

Figure 18 shows only the frequency of extreme LMPs in price ranges below -50 $/MWh and above 100 $/MWh. The frequency of LMPs in price ranges exceeding 100 $/MWh increased for CAISO in August compared to July, while for PACE this frequency reduced slightly. CAISO experienced its highest frequency of extreme LMPs since 2025 in August, while PACE experienced its highest frequency in both July and August. The frequency of negative LMPs was very low in August; CAISO did not see any negative prices, PACW saw 15 RTD intervals with prices in the -50 to 0 $/MWh range, and PACE saw 13 intervals with negative prices with 1 interval seeing a price in the -180 to -50 $/MWh range.

Figure 15: CAISO RTD LMP range frequency

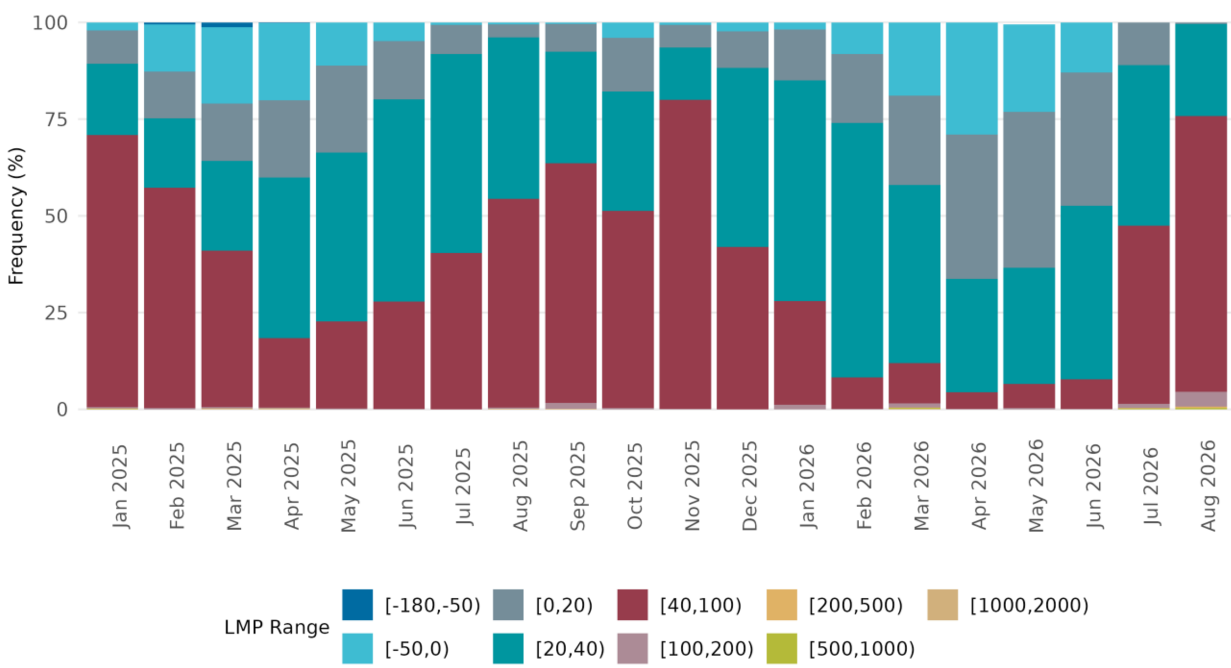


Figure 16: PACW RTD LMP range frequency

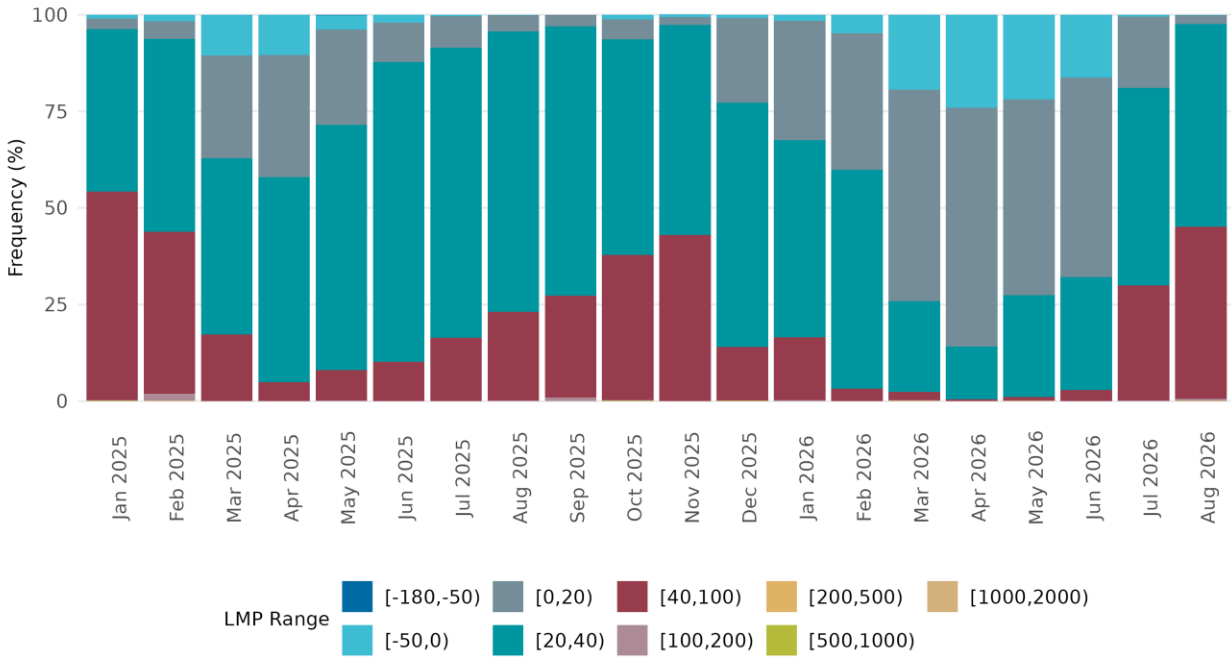


Figure 17: PACE RTD LMP Range Frequency

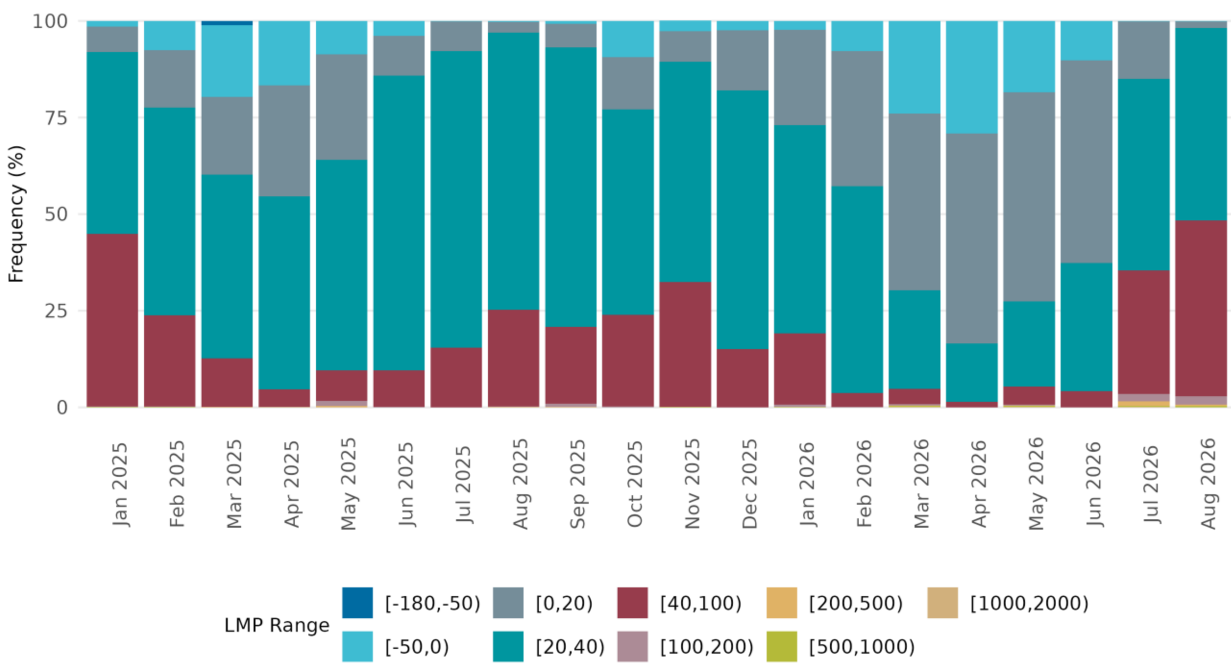
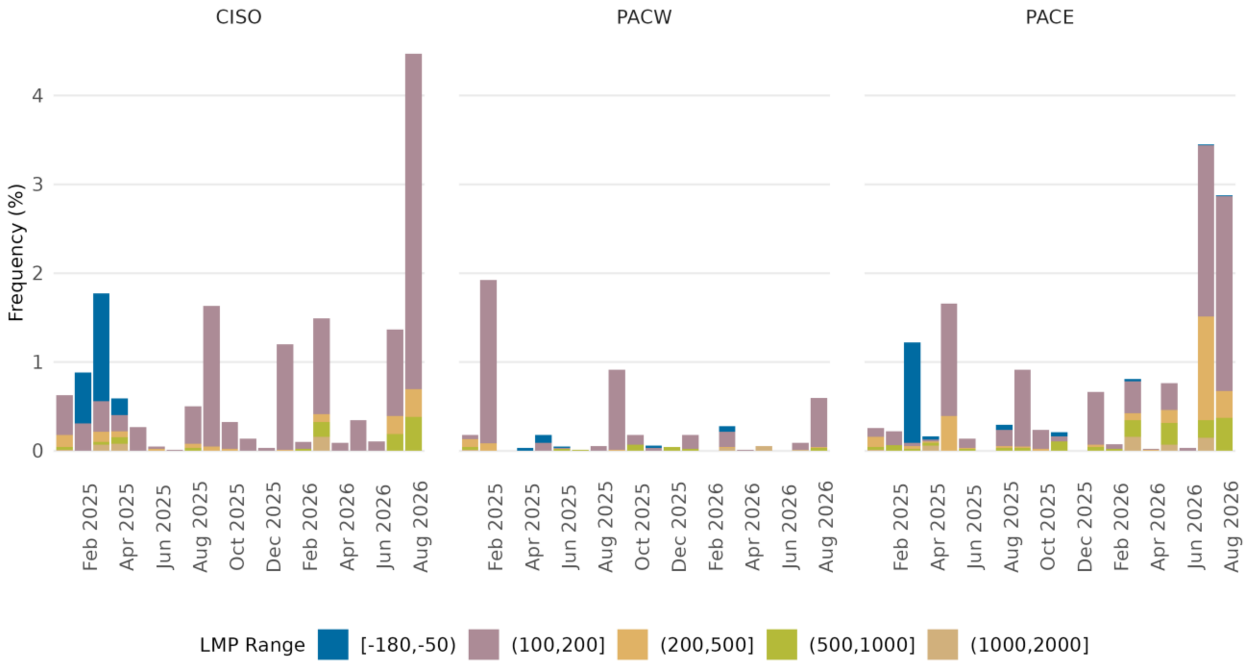


Figure 18: Frequency of low- and high-end LMPs



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

Figure 19: 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 (ν_j) or the lower EIM Transfer Scheduling Limit for BAA j (ξ_j):

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

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

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

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)

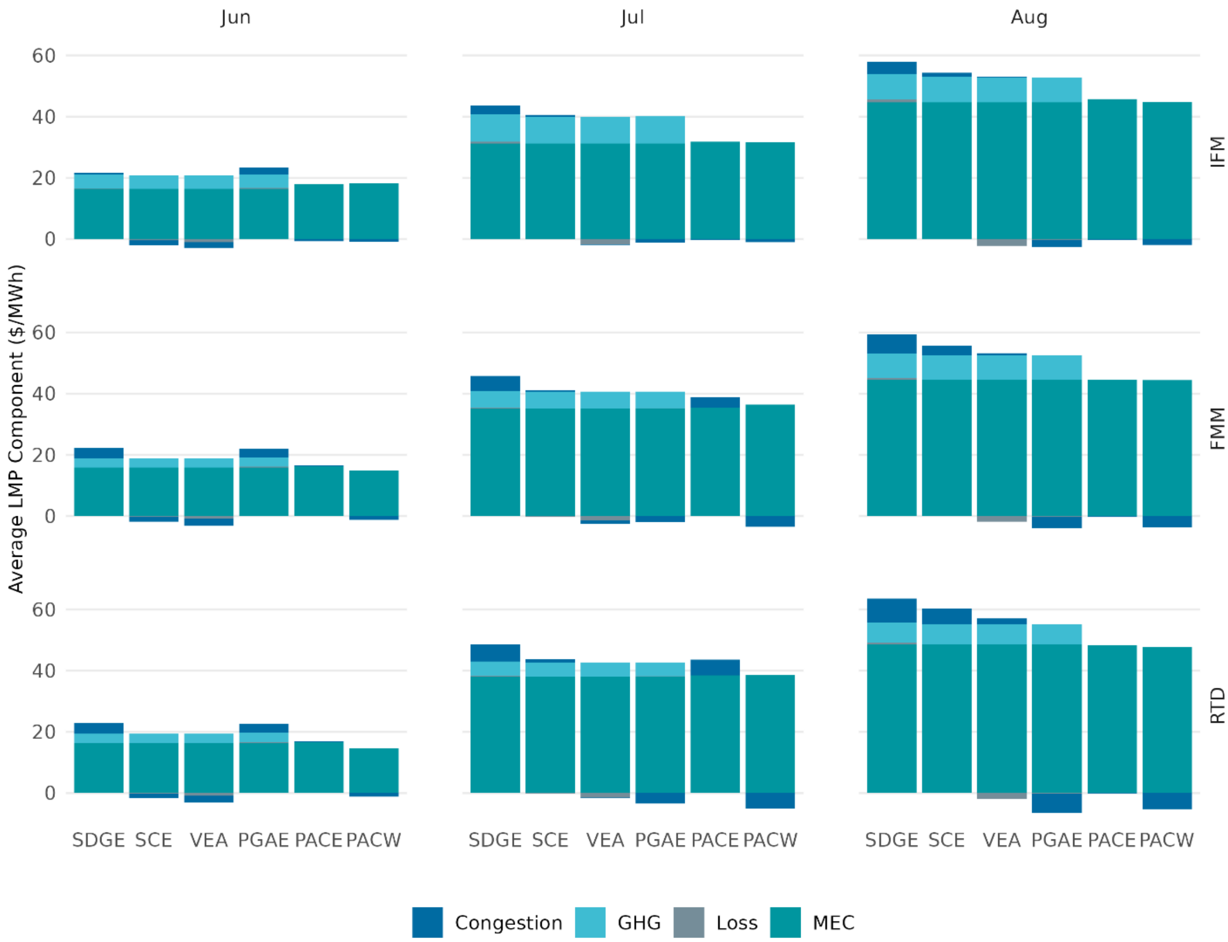
GHG prices

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 20 shows the monthly average LMP composition in IFM, FMM, and RTD for the PACE and PACW ELAPs as well as the four CAISO default load aggregation points (DLAPs) across June, July and August. 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 June to August for the three BAAs. In July and August, convergence of the monthly average MEC across all three BAAs in all three markets was more consistent than in June. Monthly average congestion in August was higher than in July for SDGE, SCE and VEA but lower for PGAE, PACE and PACW. The monthly average GHG component increased in August compared to July for CAISO in FMM and RTD but fell slightly in IFM.

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

Figure 20: Average monthly LMP components



Bilateral power price comparisons

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

Comparing bilateral power prices from ICE to CAISO market prices is useful as both CAISO and ICE markets reflect the willingness of buyers and sellers to trade next-day power and can provide some reference of how the marketplace valued power in the West. The comparison of power prices and energy quantity traded is also useful to assess what impact the new EDAM market may have on bilateral next-day power trading. However, these trends will need to be monitored over a longer period to provide a more robust assessment of any correlations because of EDAM operations.

Figure 21 and Figure 22 below show a comparison between EDAM BAA LMPs and next-day bilateral power prices at the Mid-Columbia (MidC) and Palo Verde (PV) hubs. These two hubs are highly liquid and geographically cover the north (MidC) and south (PV). While CAISO prices are hourly, next-day bilateral power trades in blocks for on-peak and off-peak periods[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.

Figure 21 shows that, on average in August, CAISO day-ahead LMPs were most strongly correlated with MidC and PV next-day bilateral power prices. CAISO day-ahead LMPs are a load weighted average of the four DLAPs and thus are correlated more with MidC or PV based on which DLAPs had higher loads and congestion. PACE day-ahead LMPs followed price trends of PV more than MidC, while PACW day-ahead LMPs trended more with MidC than PV. During high prices at MidC or PV, day-ahead LMPs for all three BAAs also saw high prices. MidC and PV prices rose during two periods in August, hitting peaks on August 4, 20 and 27. During these periods day-ahead LMPs for all three BAAs were elevated.

Figure 21: Daily average LMPs and bilateral power prices

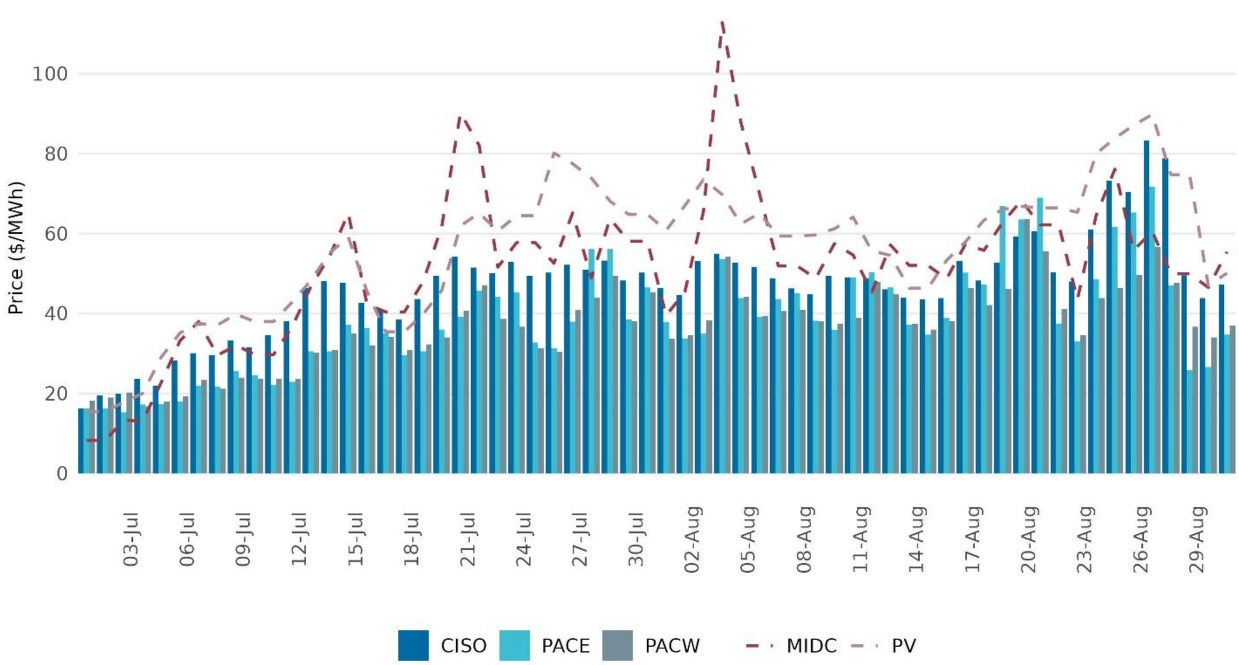


Figure 22 shows that CAISO day-ahead LMPs have historically shown some correlation with next-day bilateral power prices at MidC and PV. The high MidC price in February 2025 was due to a major Arctic cold snap. On the monthly average level, CAISO and PACE day-ahead LMPs have been more strongly correlated to PV than MidC, while PACW day-ahead LMPs show more correlation with MidC than PV.

[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 22: Monthly average LMPs and bilateral power prices

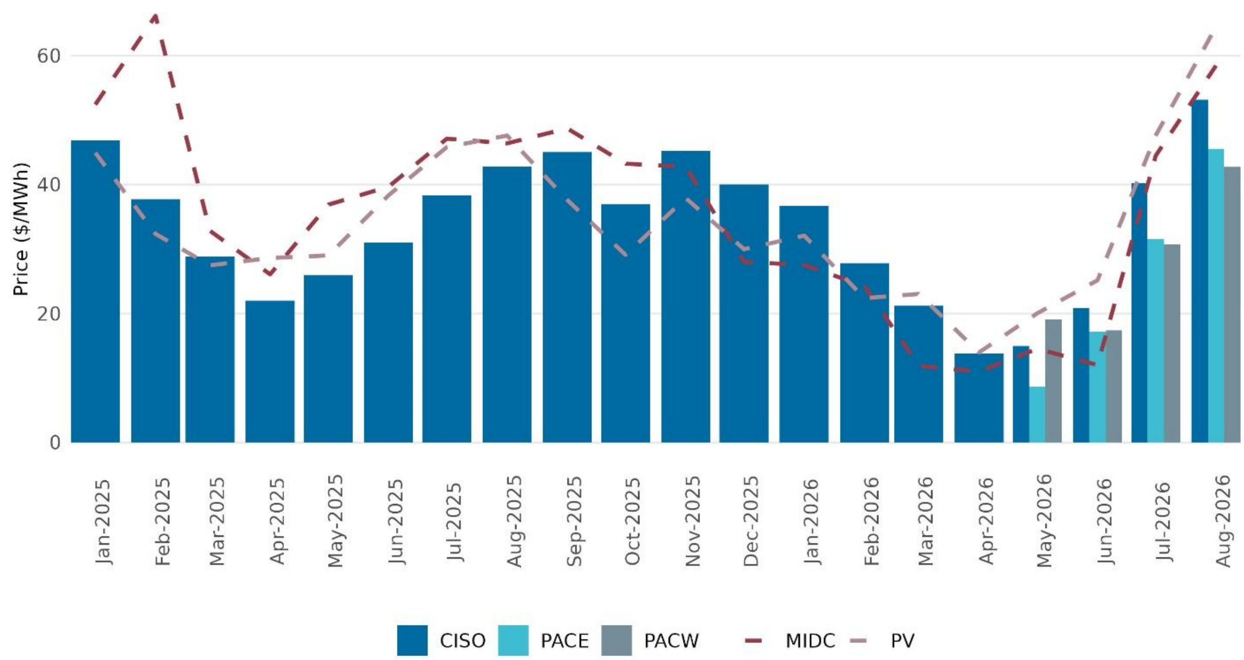


Figure 23 and Figure 24 show the daily energy volume traded for bilateral next-day power at MidC and PV hubs from April to August. For on peak, no power is traded on Sundays, which is an off-peak day. For off-peak, volumes are lowest during the weekdays. For both on- and off-peak, volumes are usually 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 August.

Figure 25 and Figure 26 show the monthly average energy volume traded since January 2025. On-peak volumes from May through August 2026 follow an increasing trend similar to 2025, while off-peak volumes show a decreasing trend over these months which is also similar to 2025.

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

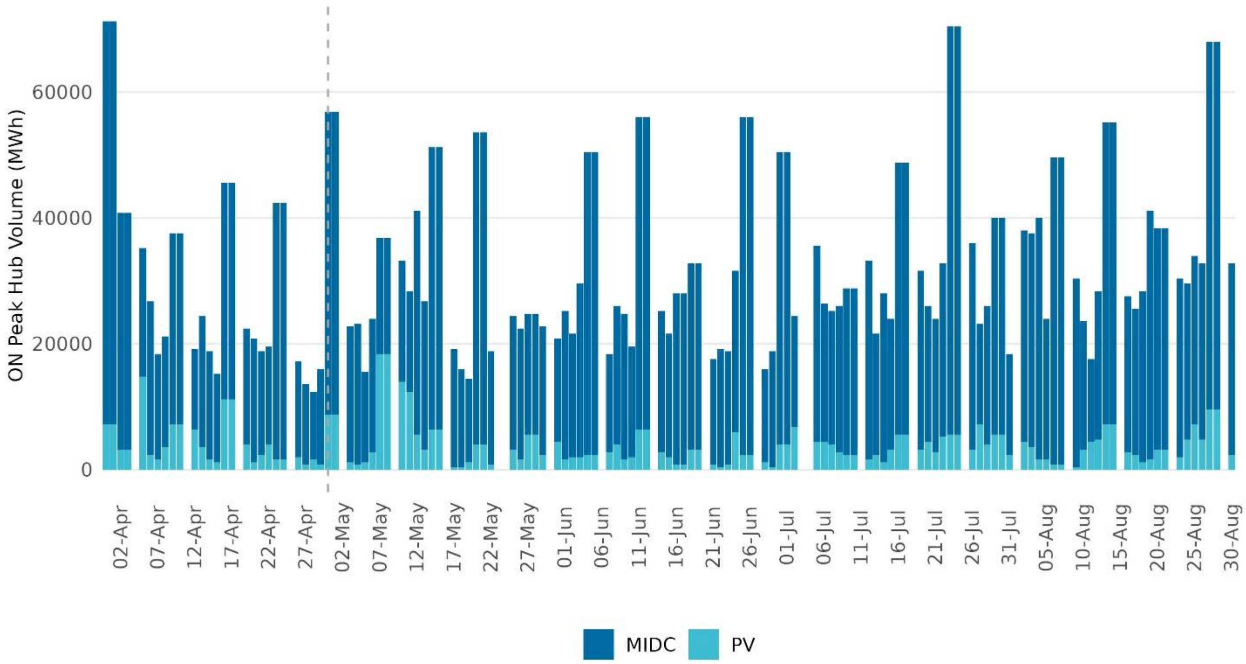


Figure 24: Total daily energy volume of bilateral trades (Off-peak)

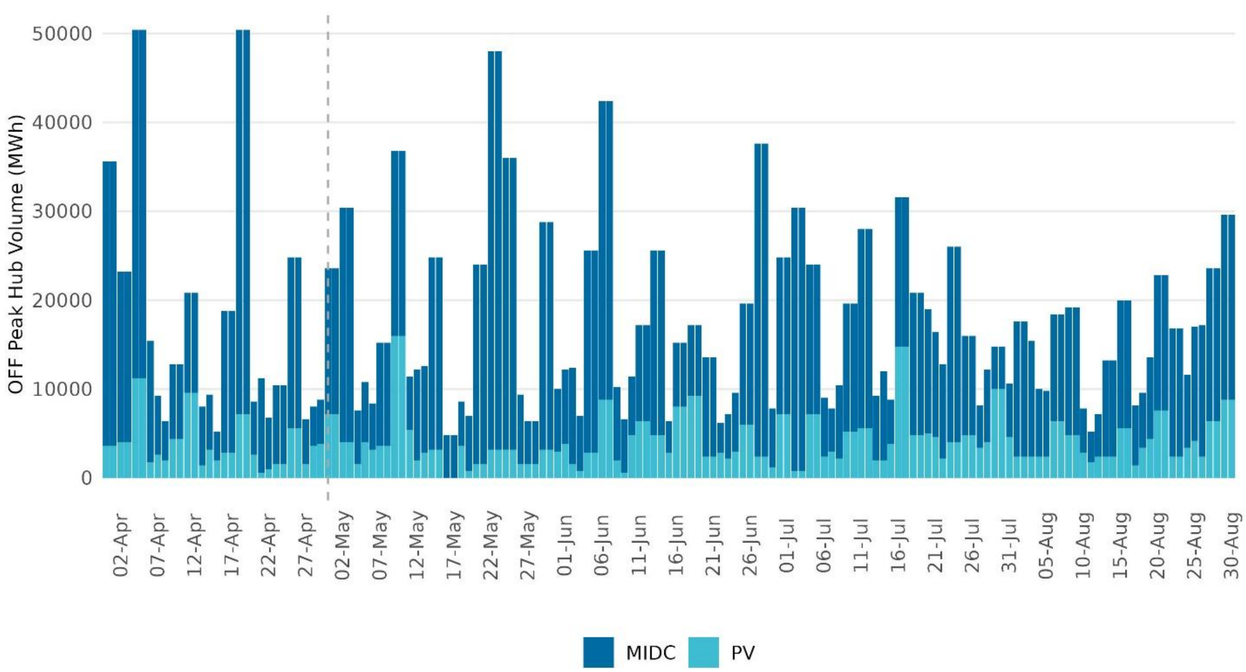


Figure 25: Total monthly energy volume of bilateral trades (On-peak)

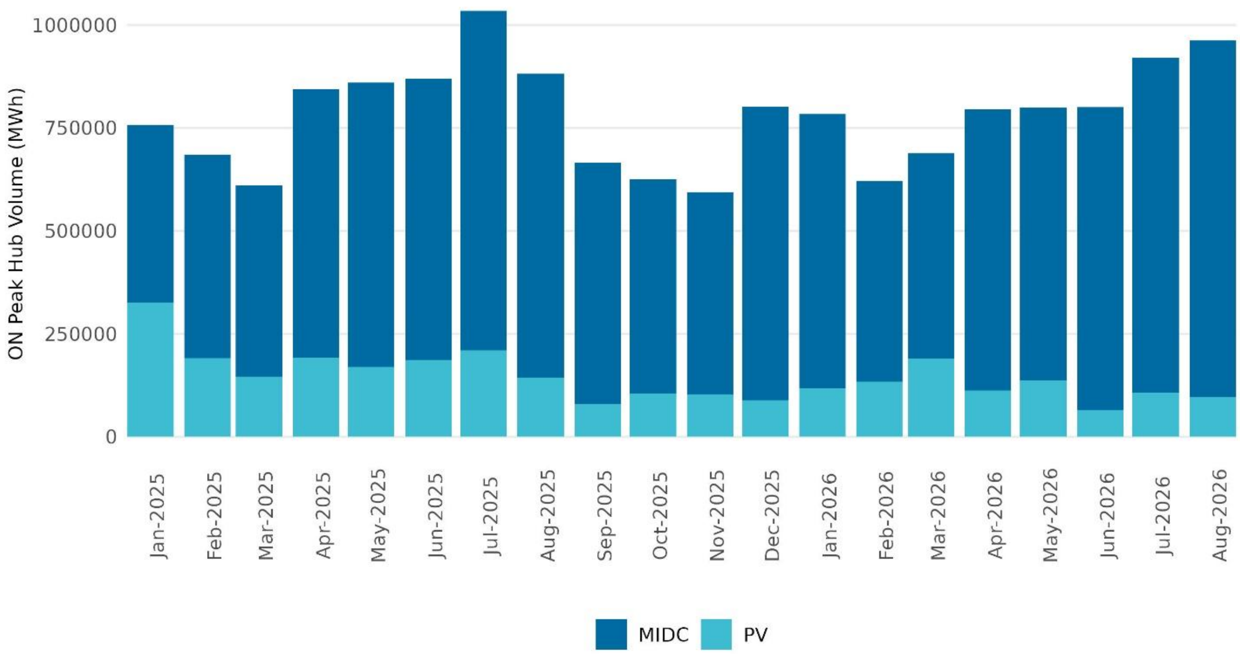
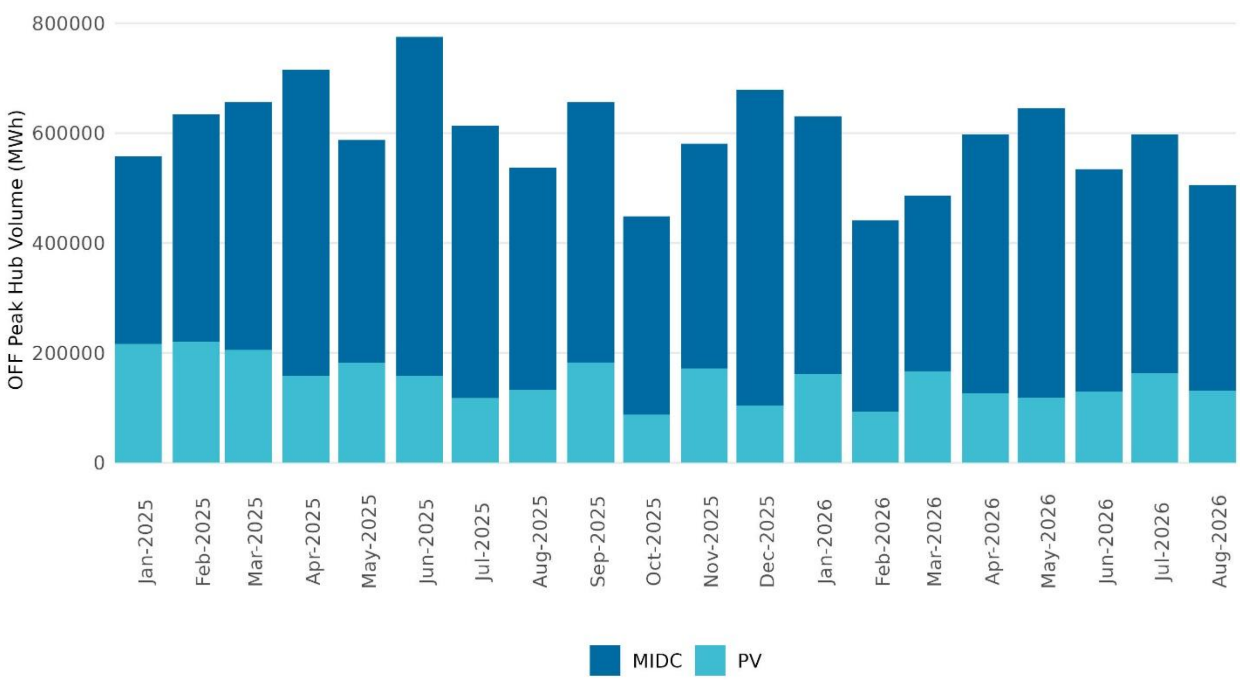


Figure 26: Monthly total energy volume of bilateral trades (Off-peak)



Ancillary services

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

Figure 27 shows CAISO ancillary services prices in IFM from June1st to August 31st. Overall, AS prices remained within typical ranges for all four commodities in August, with slightly elevated prices during the high heat days reflecting summer conditions.

Figure 27: Daily average of CAISO ancillary services prices in IFM

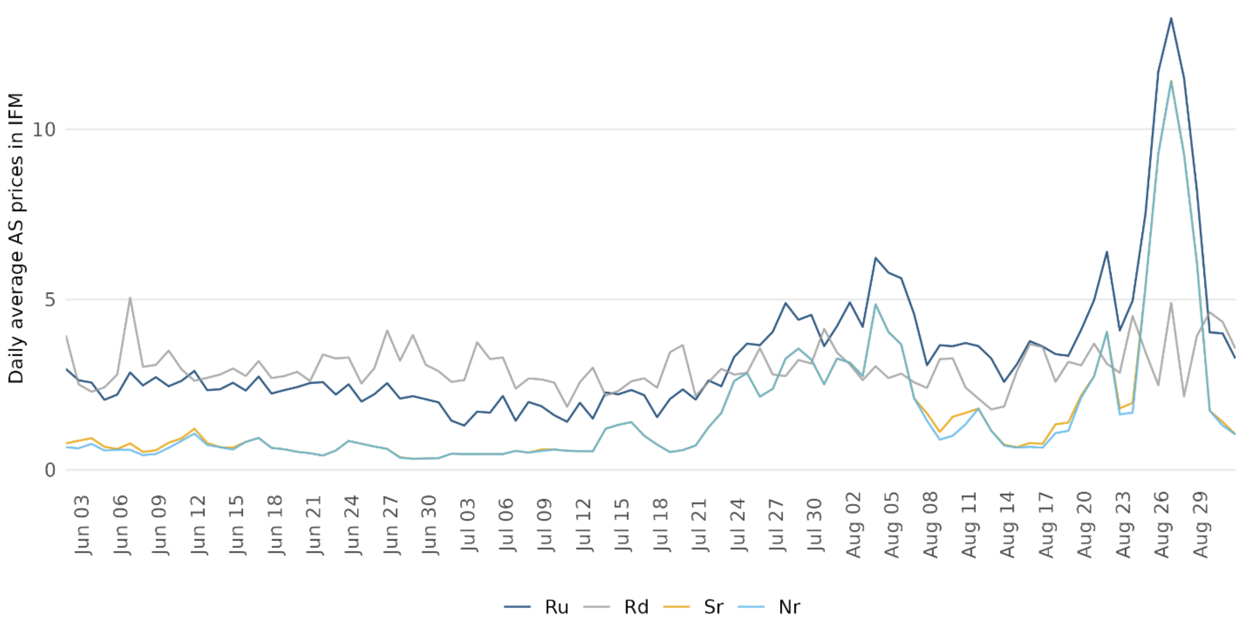
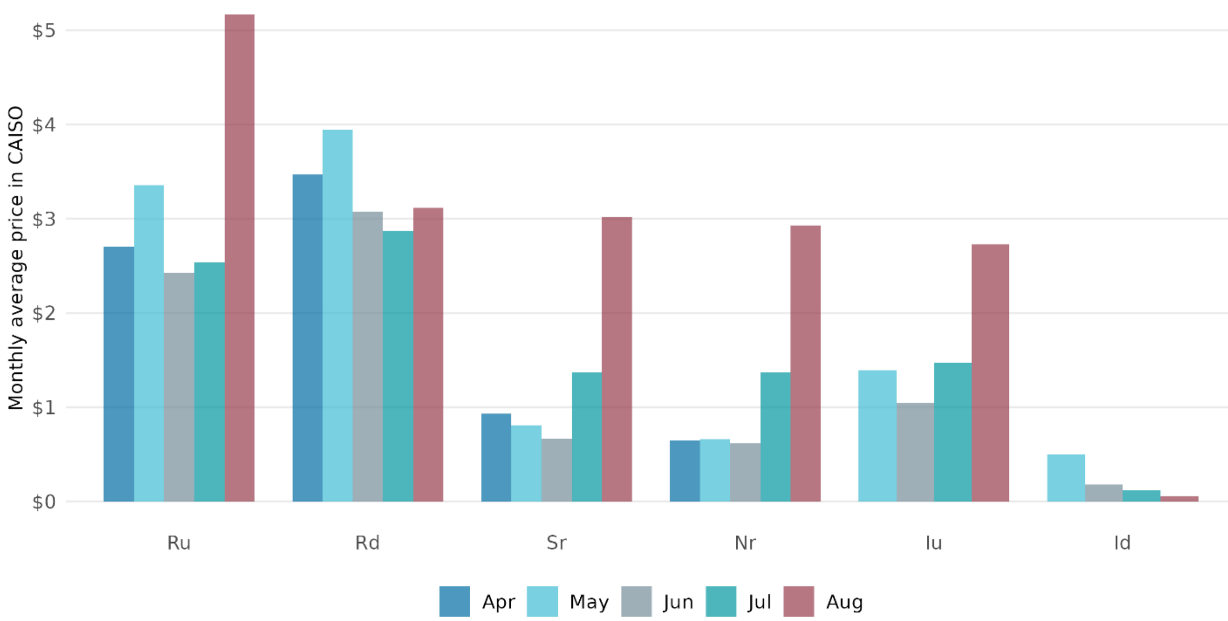


Figure 28 compares the monthly average AS prices in CAISO for April through August. Average regulation up, spin, and non-spin prices showed slight increases, while regulation down prices remained in similar ranges. New imbalance reserve prices in CAISO after May are added for reference. Average price of imbalance reserve up also saw slight increase in August, but was less than the average prices of regulation up and spin.

Figure 28: 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.

Figure 29 shows that PACE recorded the highest monthly average IRU price in August at $4.84/MWh, while PACW recorded the lowest at $2.32/MWh. Compared to previous months, August monthly average IRU prices were the highest observed for both CAISO and PACE. In PACW, the August monthly average IRU price exceeded July levels but remained below those observed in

May and June. Monthly average IRD prices remained low across all three BAAs in August, consistent with June and July.

Figure 30 and Figure 31 show the daily average IR prices in August. Daily average IRU prices were more volatile than in August, particularly in PACE, which experienced multiple price spikes. The highest daily average IRU price in PACE occurred on August 19 at $19.53/MWh. Daily average IRU prices for all three BAAs also spiked on August 27, converging at approximately $13/MWh. In contrast, daily average IRD prices were generally less volatile in August than in July, except in PACW. PACW experienced multiple IRD price spikes, with the highest daily average IRD price occurring on August 21 at $6.36/MWh.

Figure 32 and Figure 33 show the hourly average IR price profiles for all BAAs. In August, the highest hourly average IRU prices occurred in HE 20, consistent with July. This coincided with the hour of highest day-ahead demand, indicating that ramping needs are greatest when net load forecasts change during these periods. Hourly average IRD prices remained lower than IRU prices across all three BAAs. In CAISO and PACE, hourly average IRD prices were generally low and stable throughout the day, while PACW experienced a notable spike in HE 19, reaching $14.51/MWh.

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

Figure 29: Monthly average IR prices

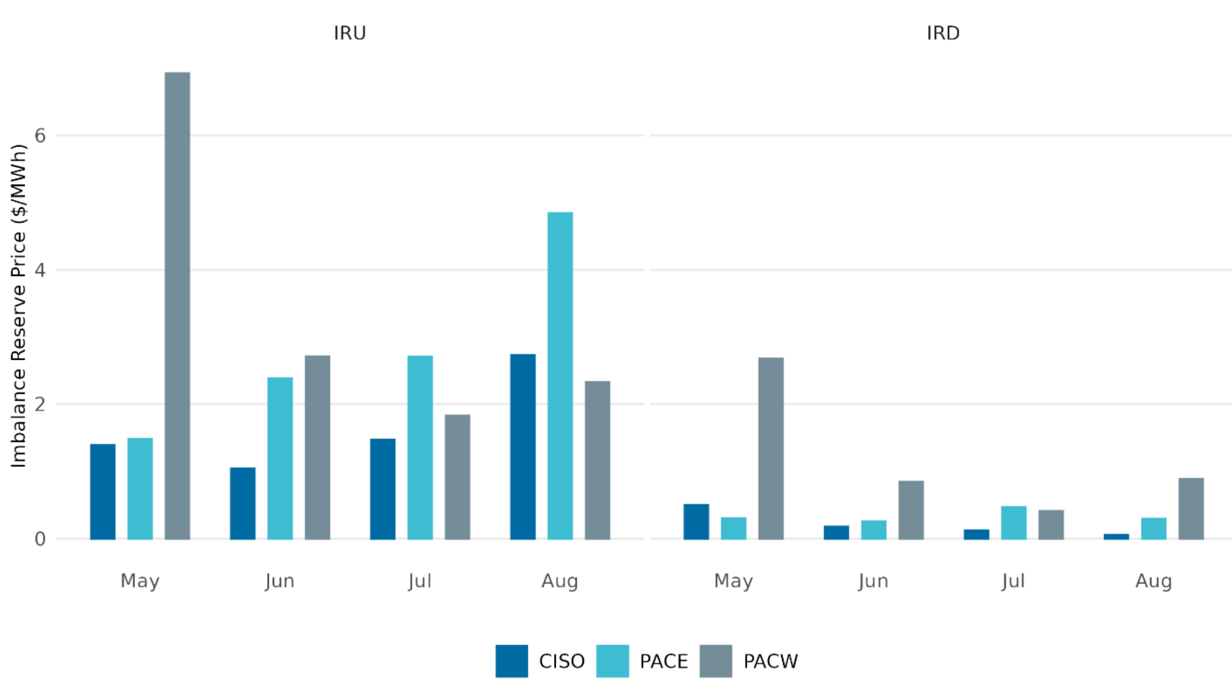


Figure 30: Daily average price of IRU

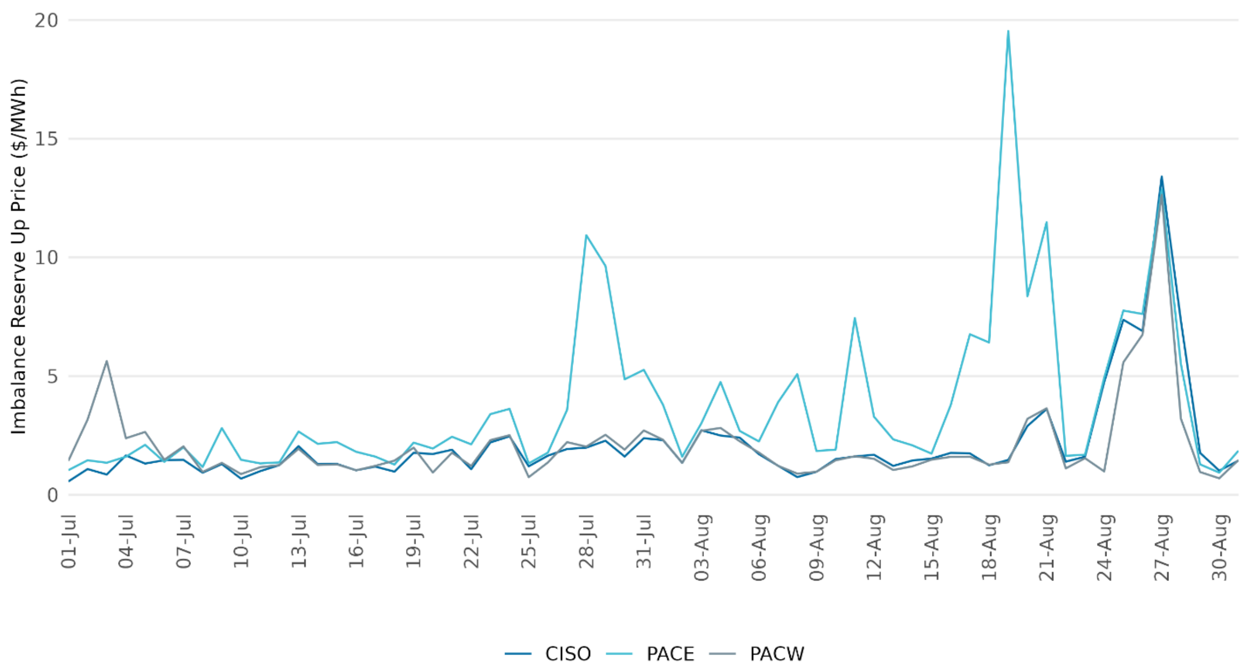


Figure 31: Daily average price of IRD

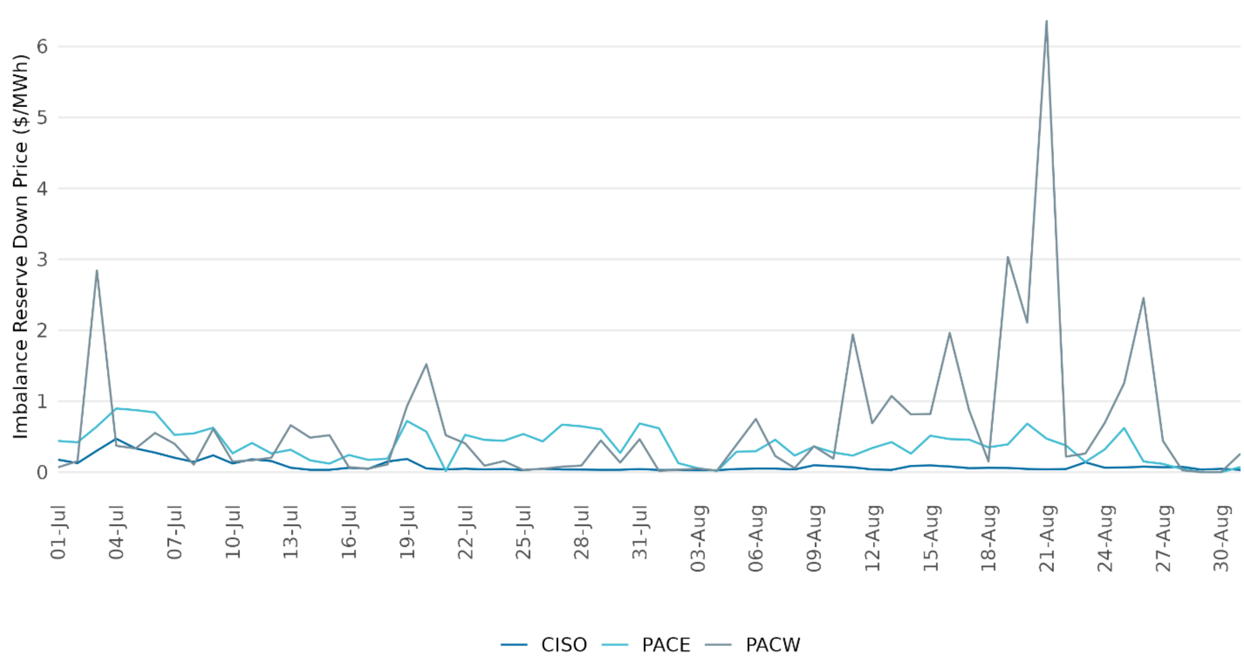


Figure 32: Hourly average price of IRU

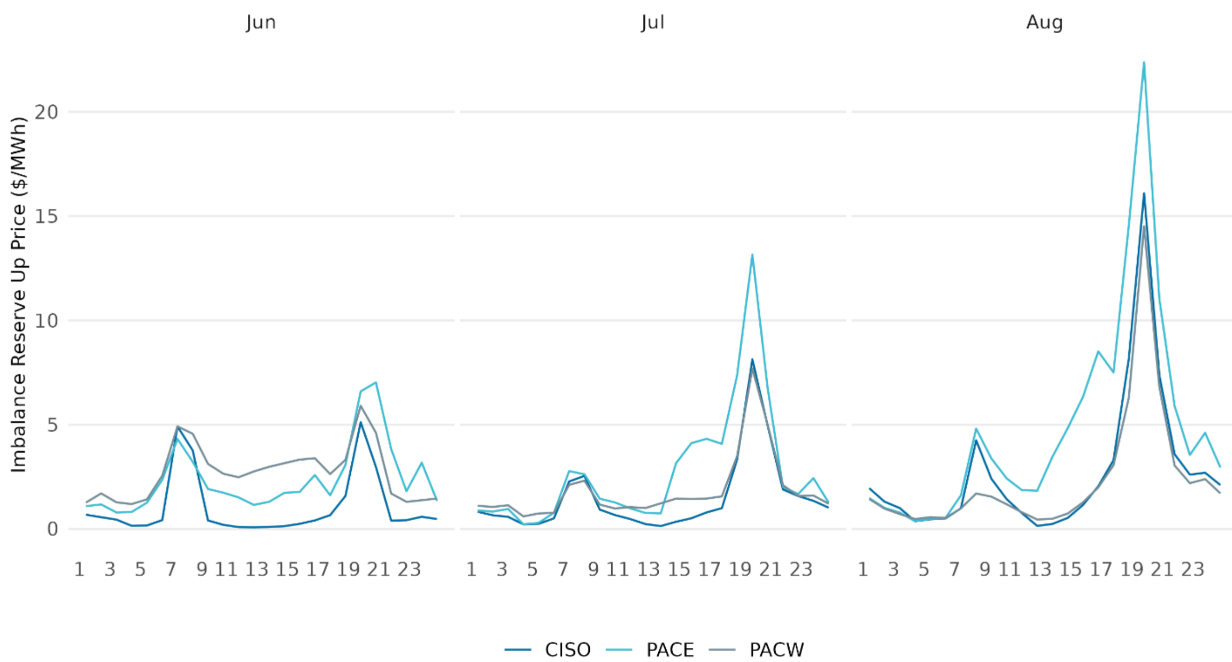
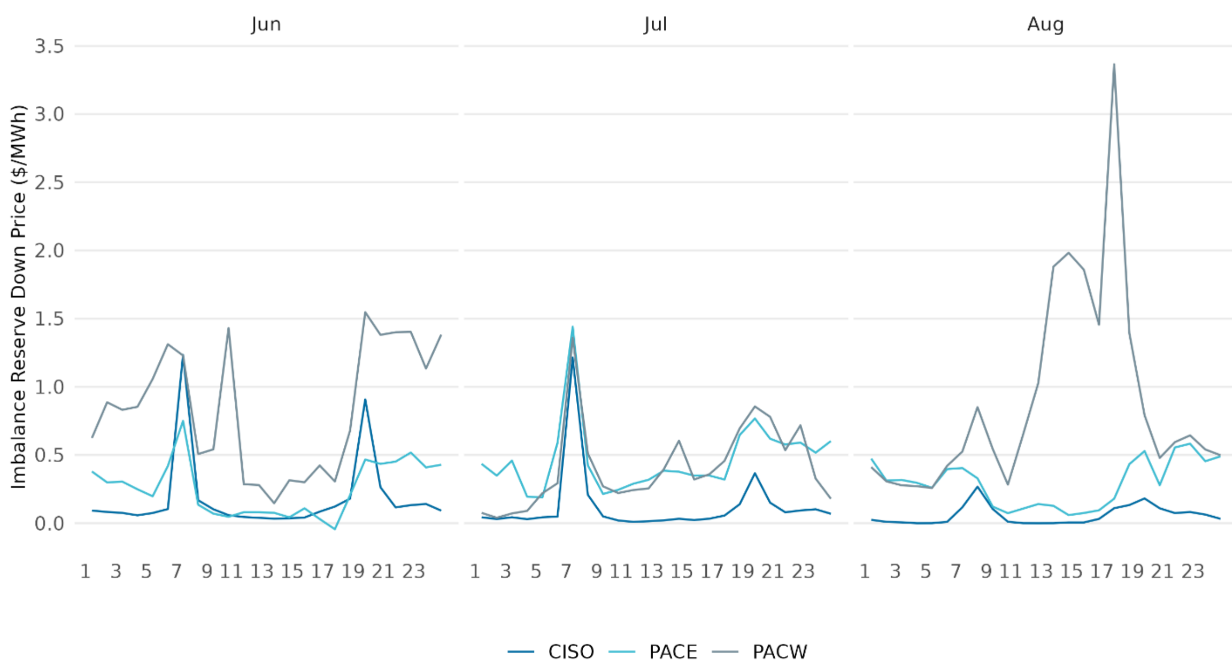


Figure 33: Hourly average price of IRD

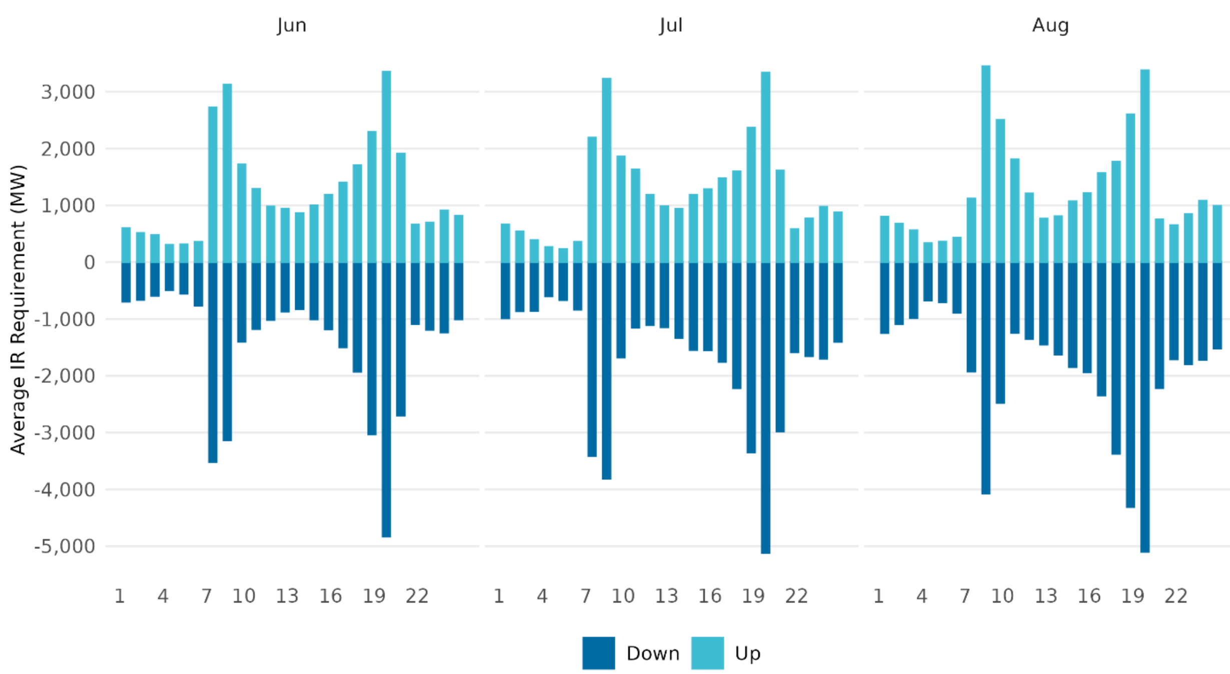


IR Requirements are calculated hourly for each BAA. Figure 34 to Figure 36 illustrate average IR requirements for each BAA by direction. The magnitude of IR procured is proportional to the magnitude of net load uncertainty associated with that BAA. CAISO is the largest footprint in the

EDAM with a large assortment of variable energy resources, so naturally it sees the highest amount of IR procurement.

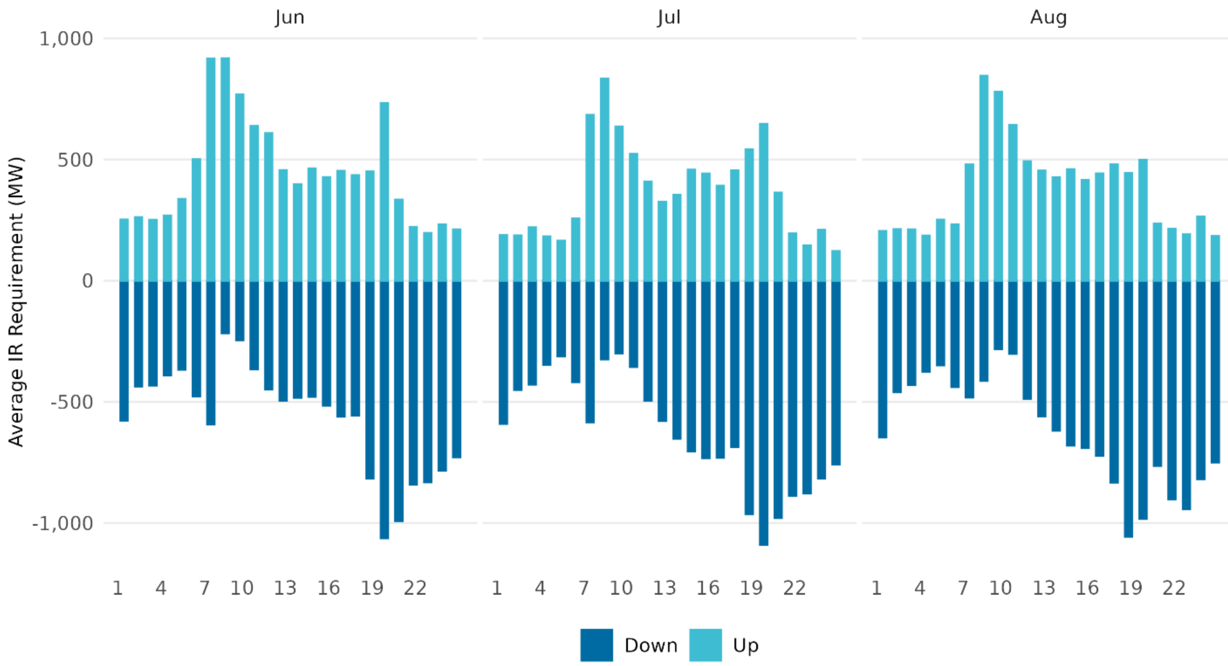
IR requirements for CAISO BAA are consistent in shape and magnitude since June. The highest requirements typically occur during the solar ramping hours where flexibility is required if the net load forecast changes.

Figure 34: Hourly average of IR requirements for CAISO



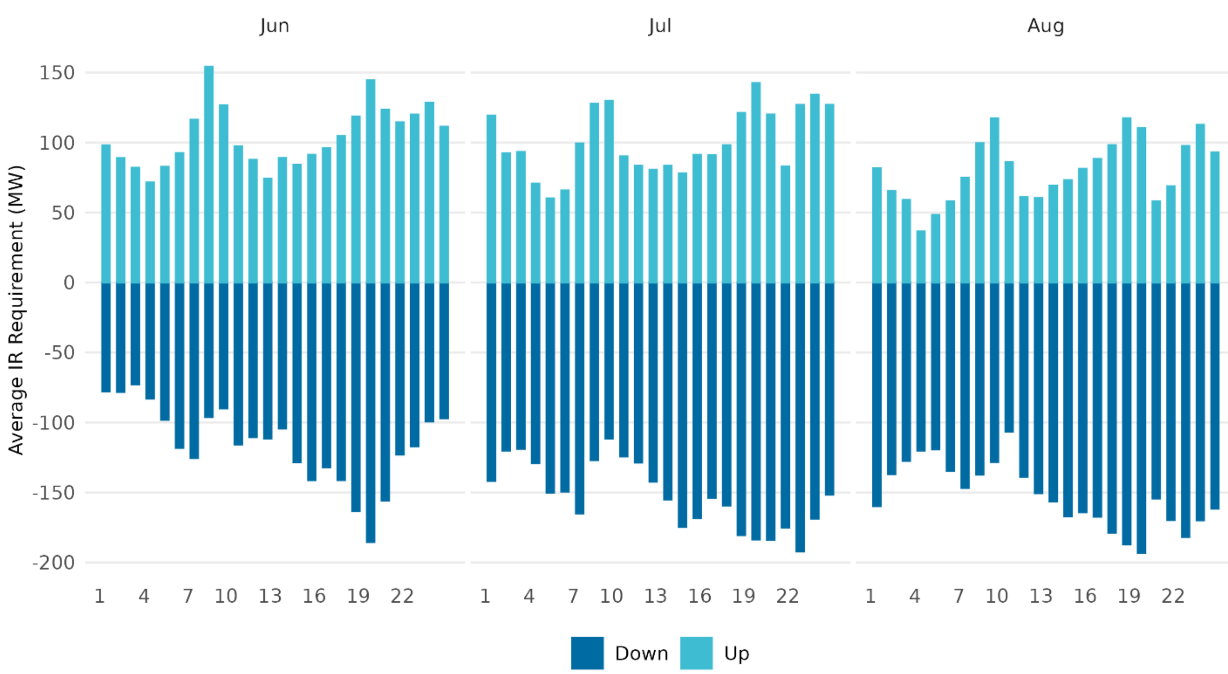
PACE IR requirements, on average, also saw the highest IRU requirements during the morning ramping hours and the highest IRD requirements during the evening peak. PACE IR requirements shape and magnitude also is stable since June.

Figure 35: Hourly average of IR requirements for PACE



PACW IRU requirements are relatively consistent throughout the day on average for both IRU and IRD.

Figure 36: Hourly average for IR requirements for PACW



EDAM expands the day-ahead market footprint. Uncertainty in each area, due to load and renewable variability, does not usually occur at the same time. Sharing supply and demand variability across a broader footprint brings diversity benefit to the EDAM BAAs, by reducing the total requirement needed compared with the total requirements when assessing area needs separately. Figure 37 and Figure 38 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 August 2026, the average diversity benefit allocation is shown in Table 5.

Table 5 Average Diversity benefit allocation

BAA	CISO		PACE		PACW	
IRU	384.8	70.0%	135.0	24.6%	29.9	5.4%
IRD	314.2	69.1%	111.8	24.6%	28.4	6.2%

Figure 37: Hourly average diversity benefit, IRU

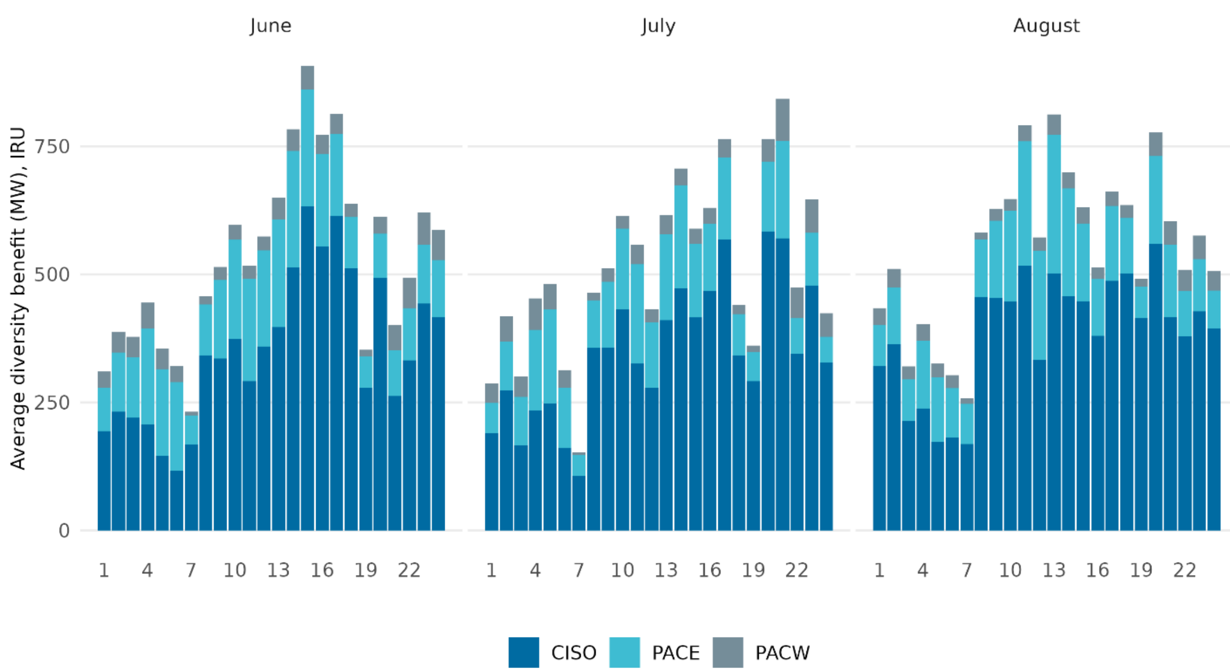


Figure 38 Hourly average diversity benefit, IRD

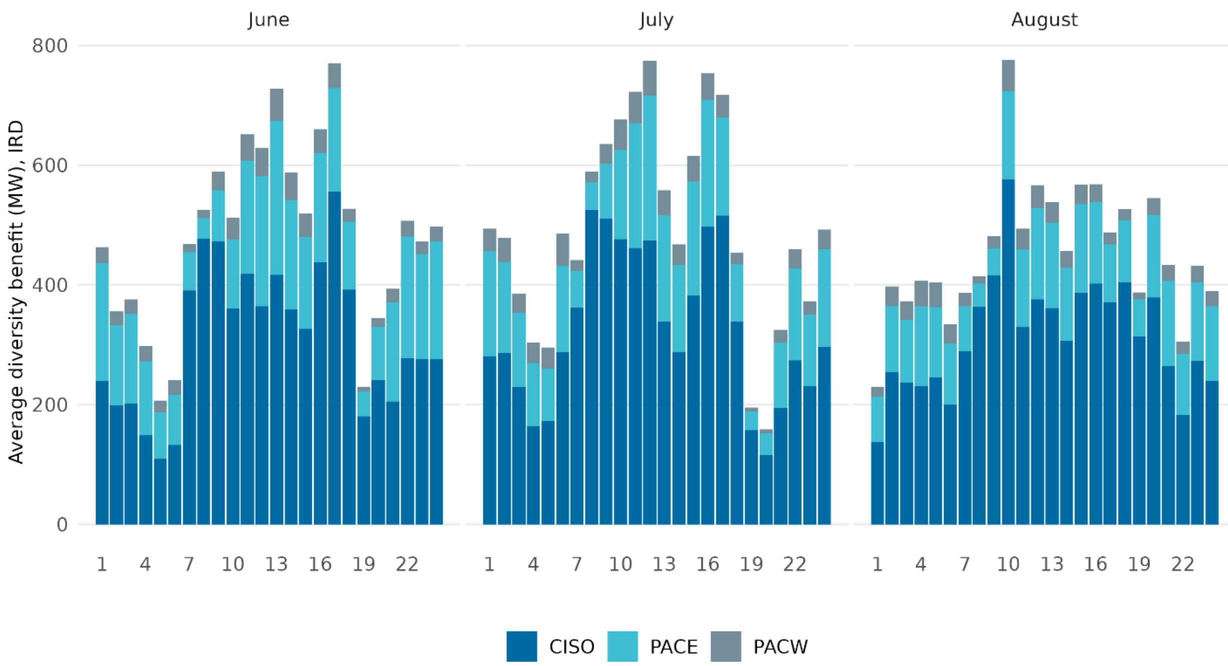


Figure 39 illustrates hourly average cleared IR by fuel type, positive direction indicates IRU and negative values indicate IRD, respectively. For the IRU direction, the resource mix exhibits a well-defined pattern, with gas resources providing the majority of IRU supply during overnight hours and remaining 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, with increases in IRD procurement from gas resources in July and August when demand was high.

Figure 39: Hourly average cleared IR by fuel type for CAISO

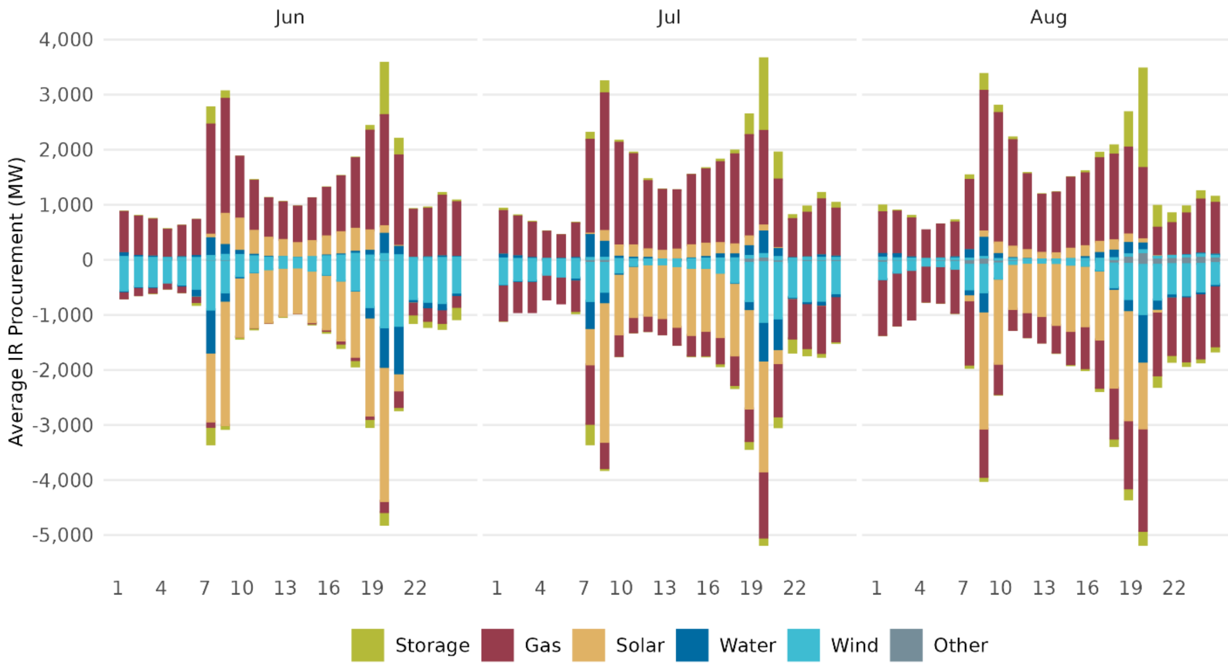


Figure 40 shows PACE's hourly average cleared IRU and IRD by fuel type, respectively. Unlike CAISO, the dominant resources in PACE are coal and wind, while gas and storage have minimal contribution. Coal resources provide the majority of the IRU supply in June but were gradually decreased in July, and then replaced by gas resources in August, with storage resources contributing to the remaining during daylight hours. In IRD supply, wind resources contribute the most, with the morning and evening ramp requirements provided by coal resources. The IRD procurement of PACE is stable across three months.

Figure 40: Hourly average cleared IR by fuel type for PACE

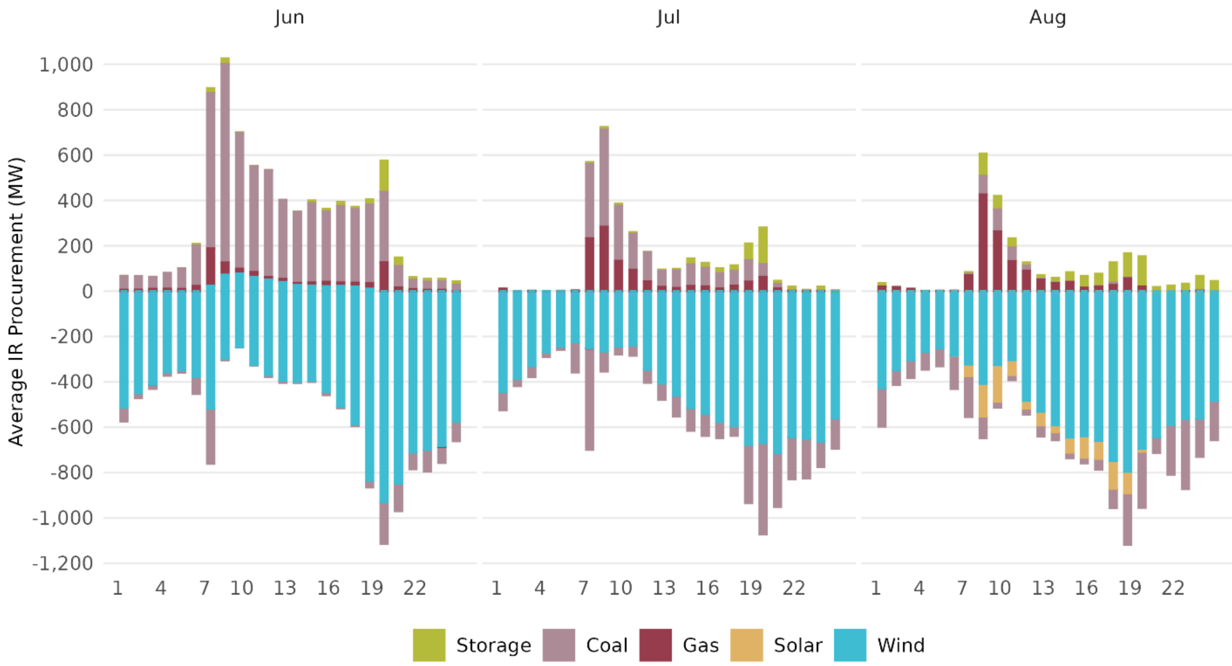
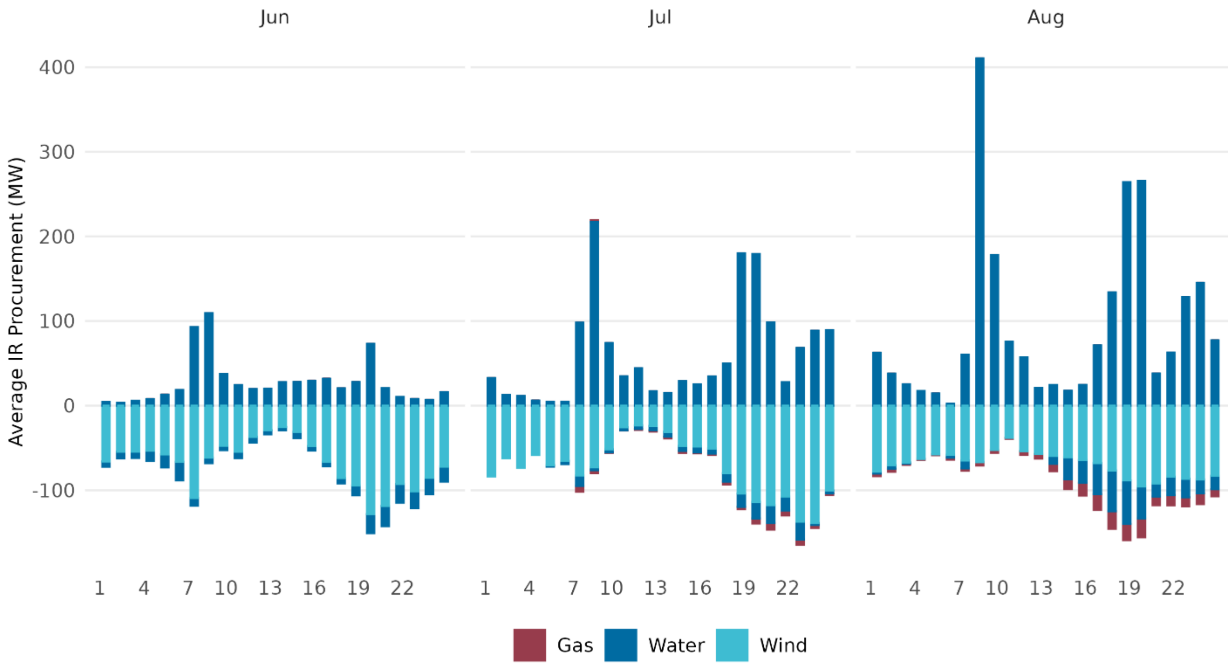


Figure 41 shows PACW's hourly average cleared IRU and IRD by fuel type, respectively. Unlike CAISO, the dominant resources in PACW are water and wind, while gas has minor contribution. Water resources provided nearly all the IRU supply and increased significantly in August. Wind resources contribute the most of IRD supply, and there were more gas resources providing IRD in August.

Figure 41: Hourly average cleared IR by fuel type for PACW



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.

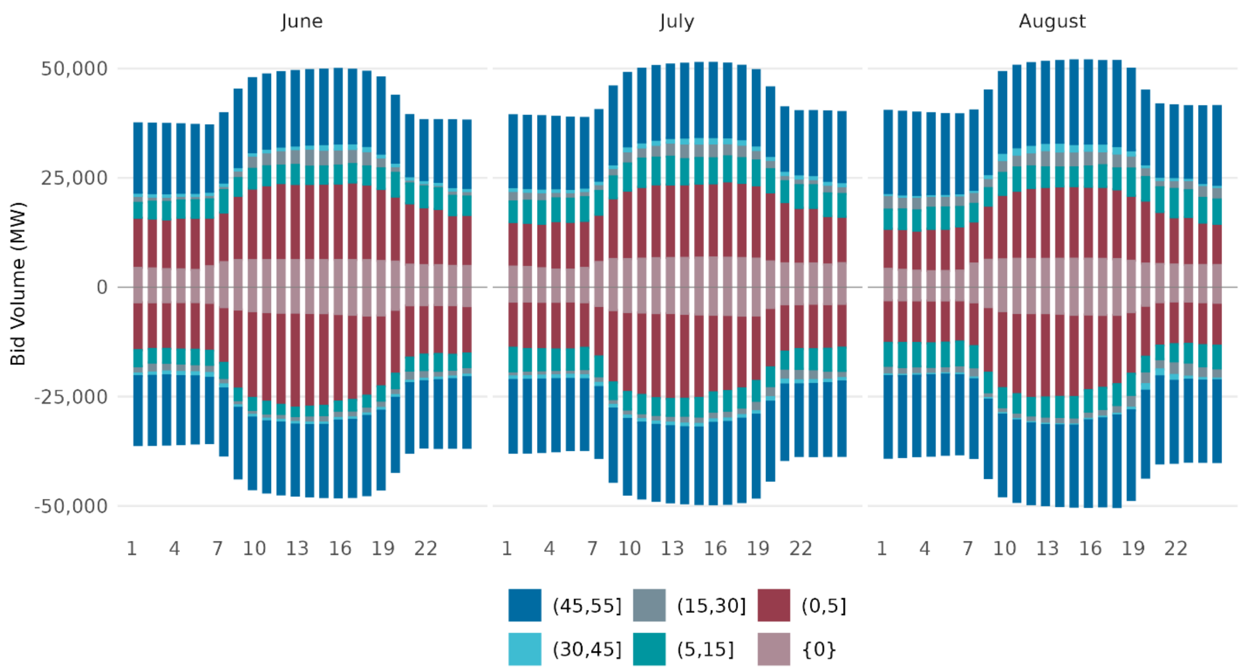
Imbalance reserves input bids

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 42 and Figure 43 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 June and August 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 July to August. The volume of bids in the upward direction is symmetrical to the volume for the downward direction.[4]

Figure 42: Hourly 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 43: Daily average volume of IR bids organized by price for CAISO

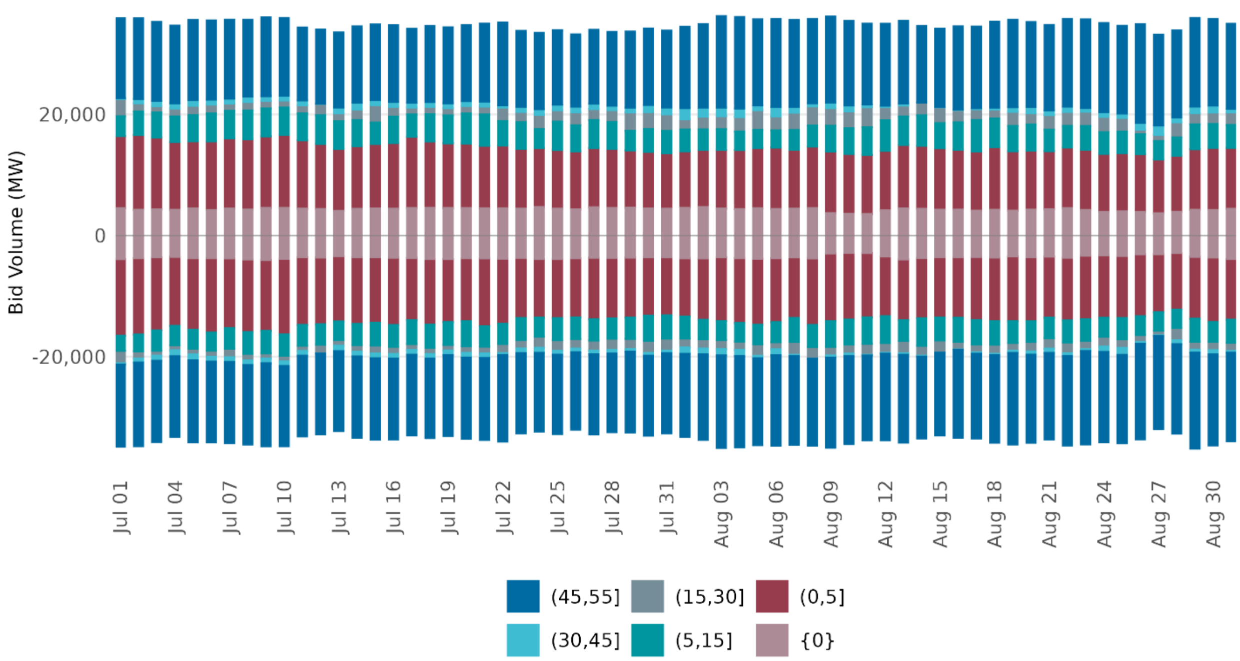


Figure 44 and Figure 45 illustrate CAISO's hourly and daily average IFM supply input bids for IR by fuel type. Energy storage, gas, and solar resources accounted for the largest share of submitted IR capacity throughout June and August, followed by water and wind resources.

Figure 44: Hourly average volume of IR bids organized by fuel type for CAISO

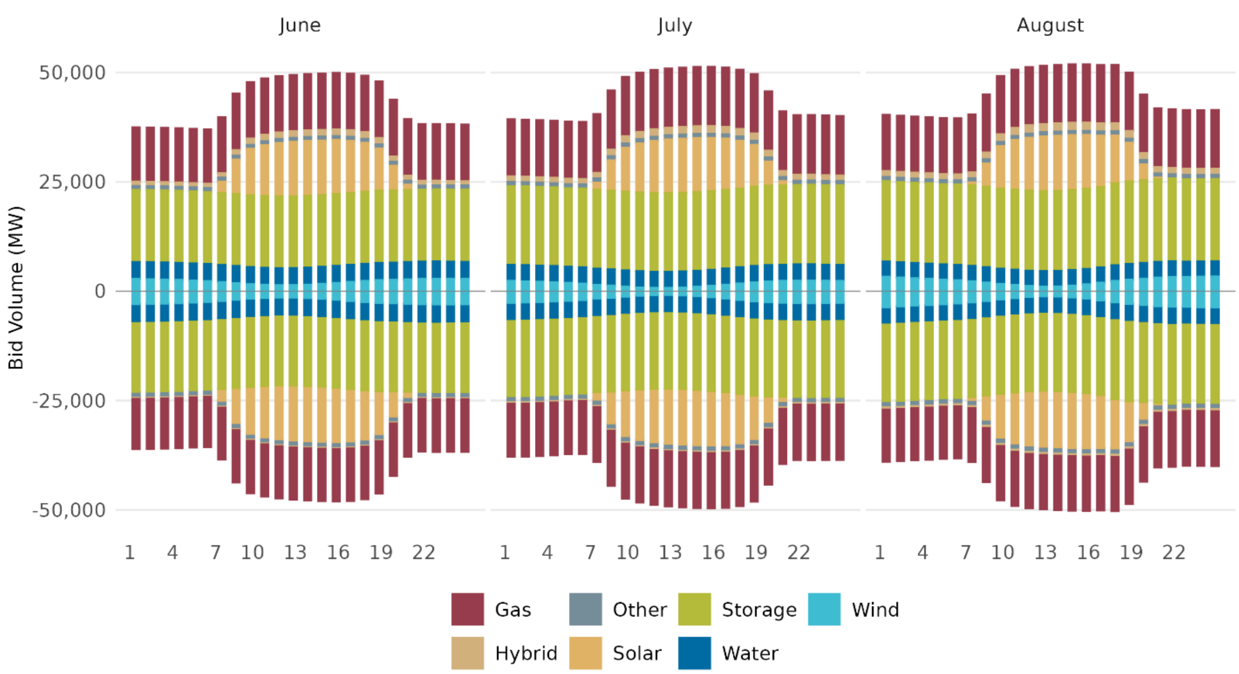


Figure 45: Daily average volume of IR bids organized by fuel type for CAISO

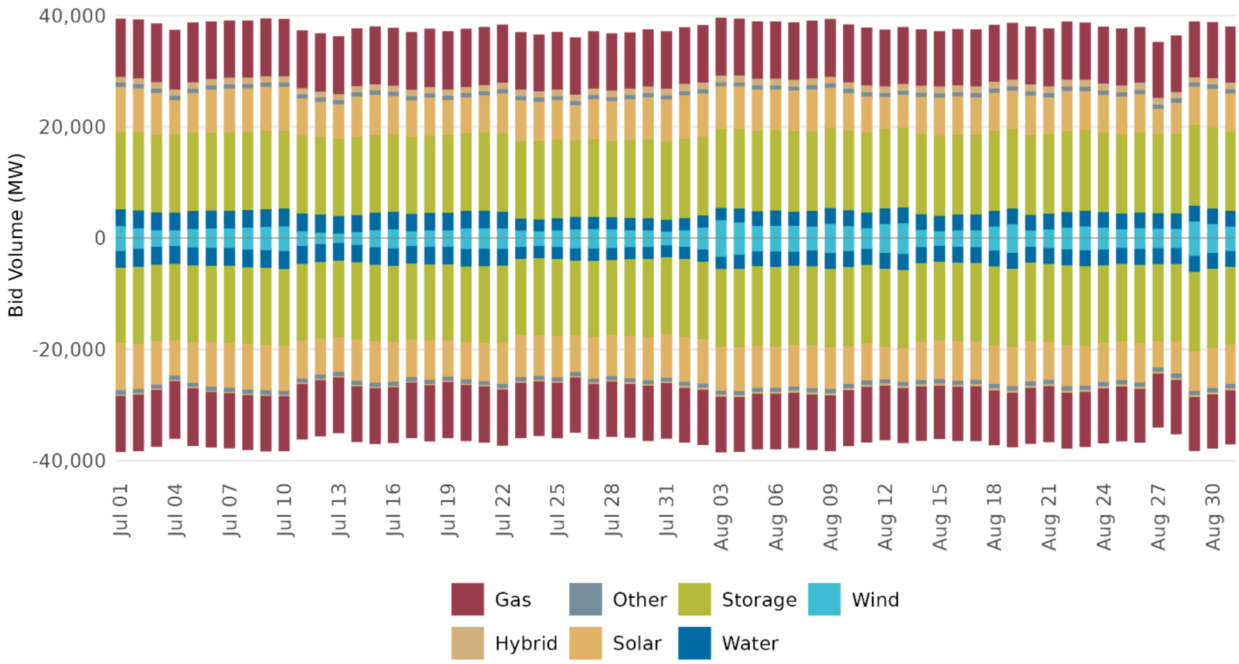


Figure 46 to Figure 48 illustrate the PACE's hourly and daily average IFM supply input bids for IR by bid price range. Low-priced bids ($0–5/MW) consistently accounted for the largest share of submitted IR capacity throughout the months with about 3,500 MW (or 80 percent), followed by bids in the 45–55 $/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. Generally, PACE's submitted IR capacity remained relatively stable during June and July, while in August, PACE started to shift a small portion of IRD bid from ($0–5/MW) to $0/MW.

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

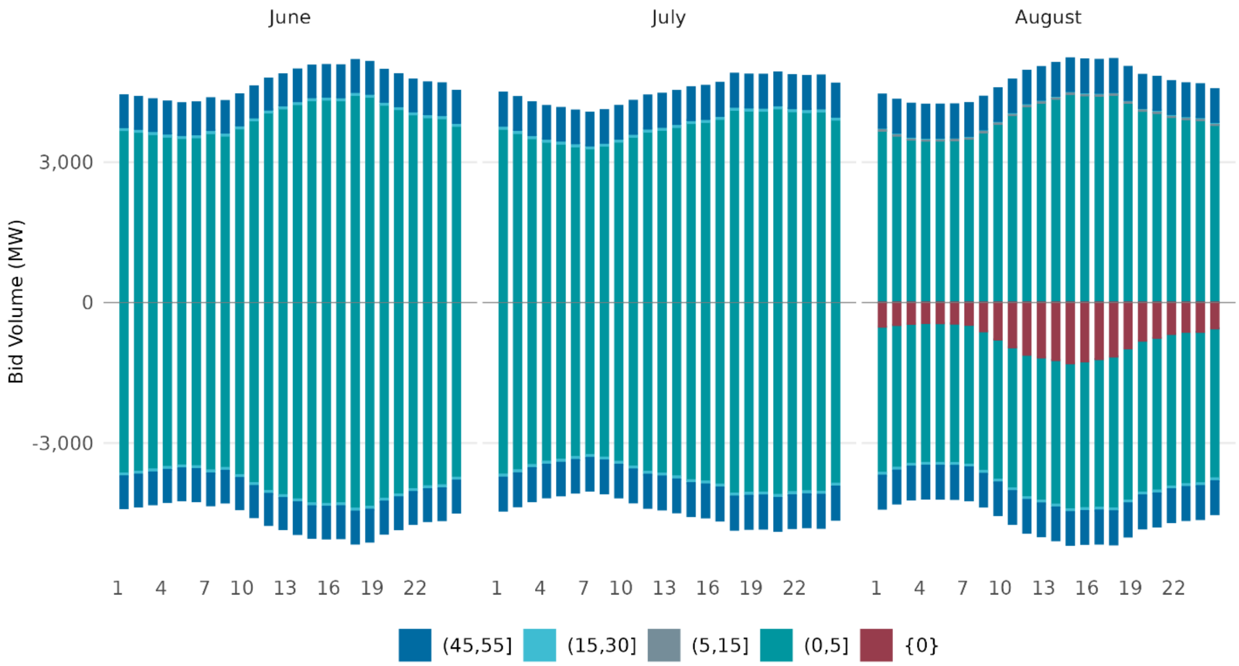


Figure 47: Daily average volume of IR bids by price for PACE

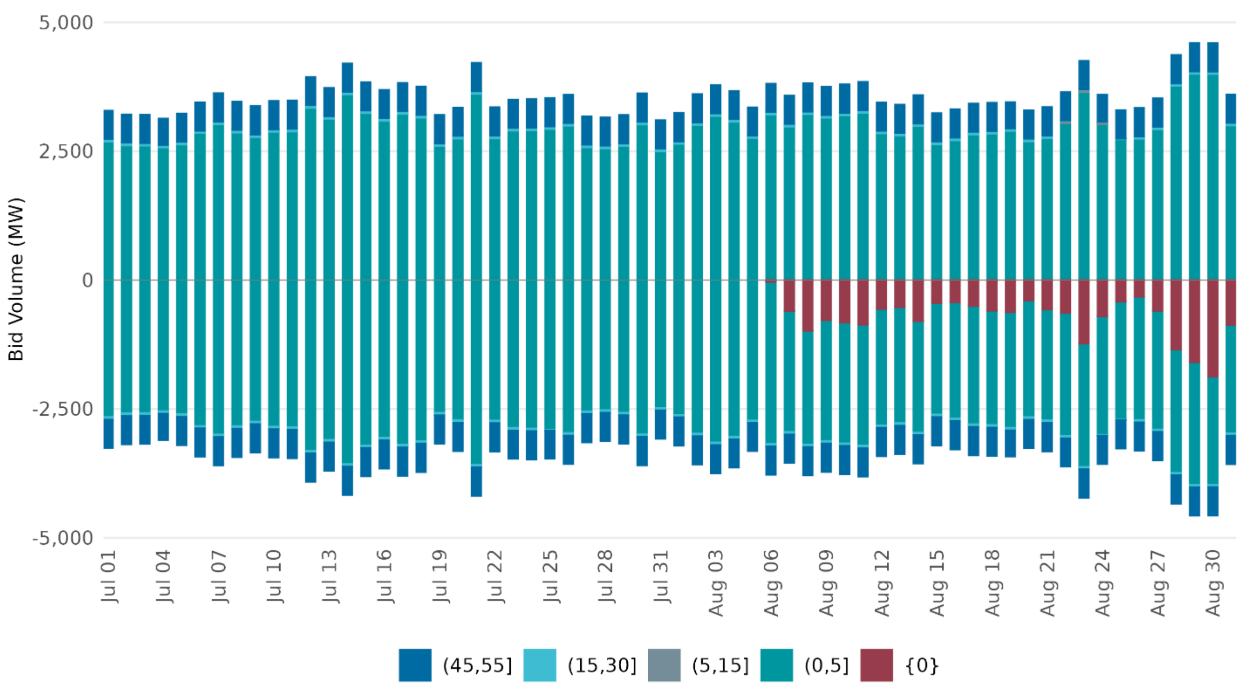


Figure 48 to Figure 49 illustrate PACE's hourly and daily average IFM supply input bids for IR by fuel type. Wind and coal accounted for the largest share of PACE's submitted IR capacity throughout June and August, followed by gas and storage resources. Wind resources' capacities were capped by renewable forecasts, causing variations in total bid volumes across the three months.

Figure 48: Hourly average volume of IR bids by fuel type for PACE

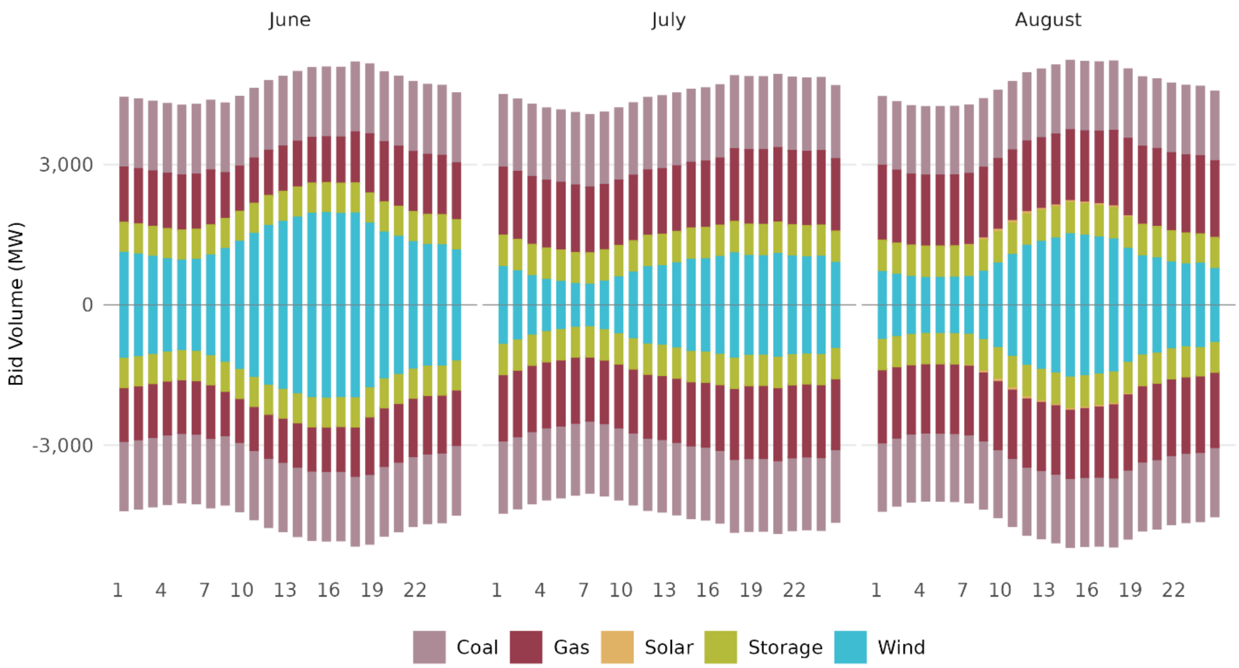


Figure 49: Daily average volume of IR bids by fuel type for PACE

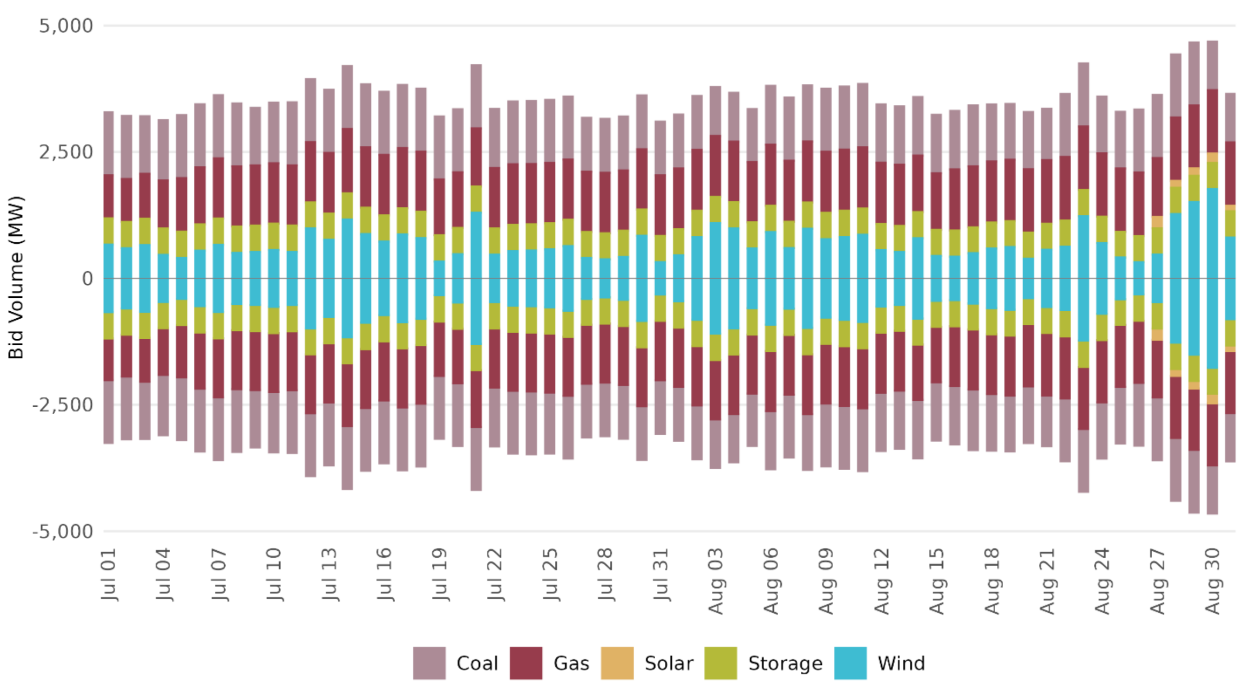


Figure 50 to Figure 53 illustrate the PACW's hourly and daily average IFM supply input bids for IR by bid price range and by fuel type. The price ranges are distributed across price ranges (0–5 $/MWh) and (5–15 $/MWh), and (45–55 $/MWh) with about 900 MW, and the remaining price range (15–30 $/MWh) represented a relatively small share of total submitted capacity. Water, gas, and wind accounted for the PACW's submitted IR capacity throughout June to August. 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 50 and Figure 51 show the hourly and daily variations by price buckets, respectively. The IR bid volumes increased while prices went down during the three months. At the beginning of June, PACW had some mid-priced bids in $15-30/MW. Then in August, PACW also adjusted more bid prices to $0/MW for IRD products.

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

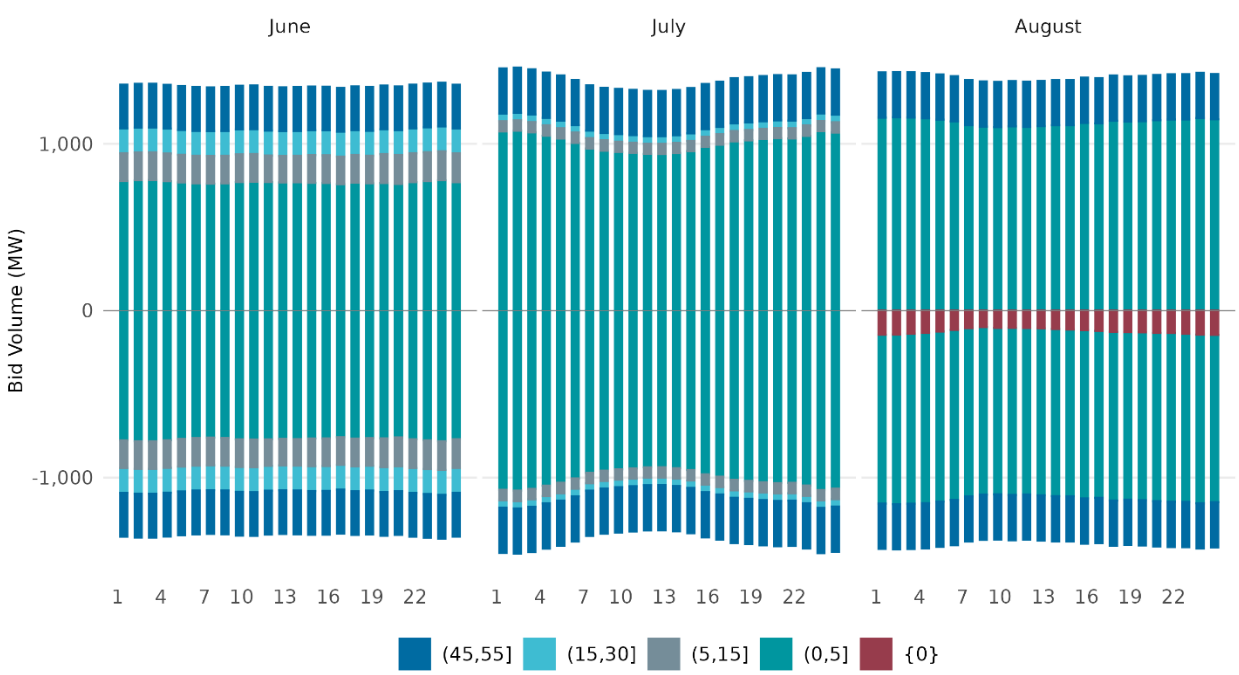


Figure 51: Daily average volume of IR bids organized by price by PACW

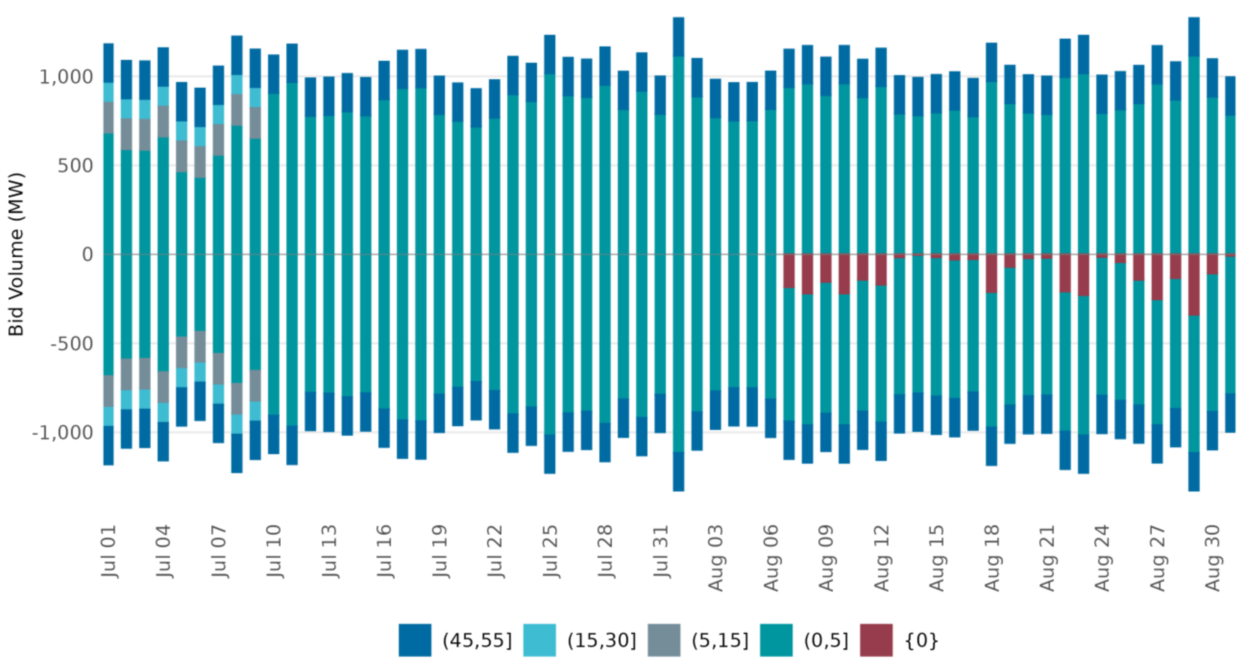


Figure 52 and Figure 53 show the hourly and daily variations by fuel type, respectively. PACW only has three fuel types bidding in IR products, i.e., gas, wind, and water. The bid volumes were highly dependent on wind forecasts, causing volume variations in both hourly and daily charts.

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

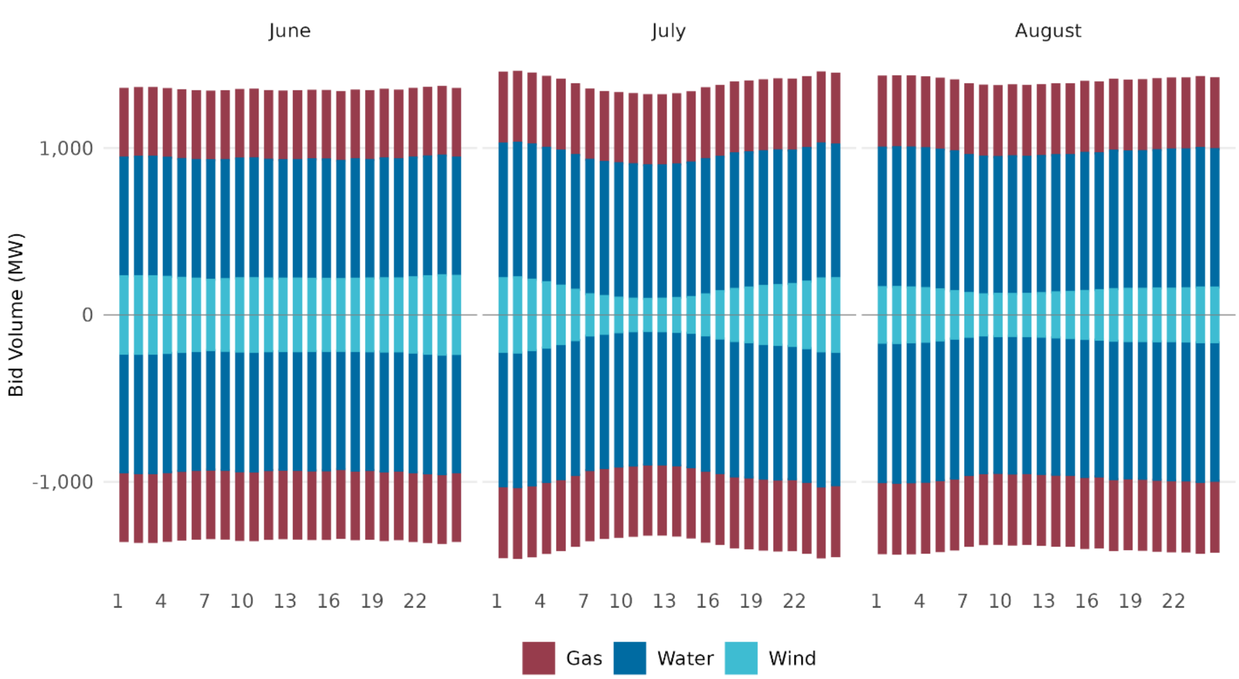
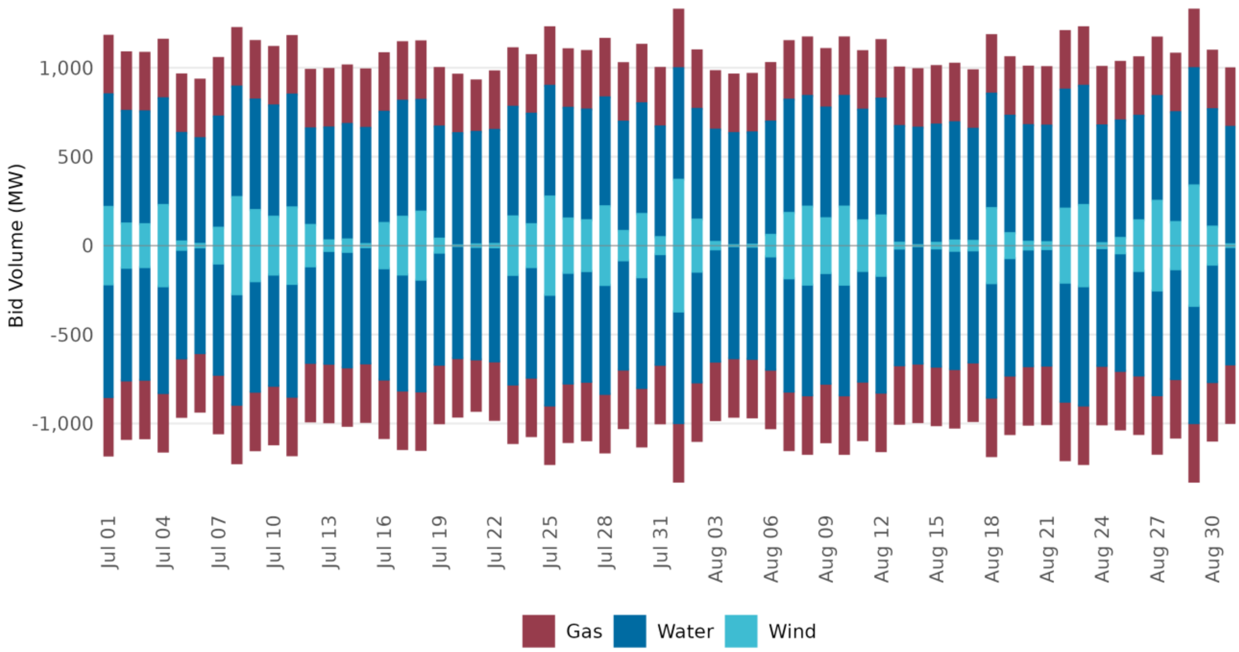


Figure 53: Daily average volume of IR bids organized by fuel type for PACW



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 August 2026, CAISO had demand curve procurement in the upward direction for 6 hours over four days. PACE had demand curve procurement in the upward direction for 39 hours over fifteen days. PACW had demand curve procurement in the upward direction for 4 hours over three days, and in downward direction for 5 hours over three days. Hourly averages of demand curve procurements are shown in Figure 54 and Figure 55. 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 54: Average imbalance reserve demand curve procurement, IRU

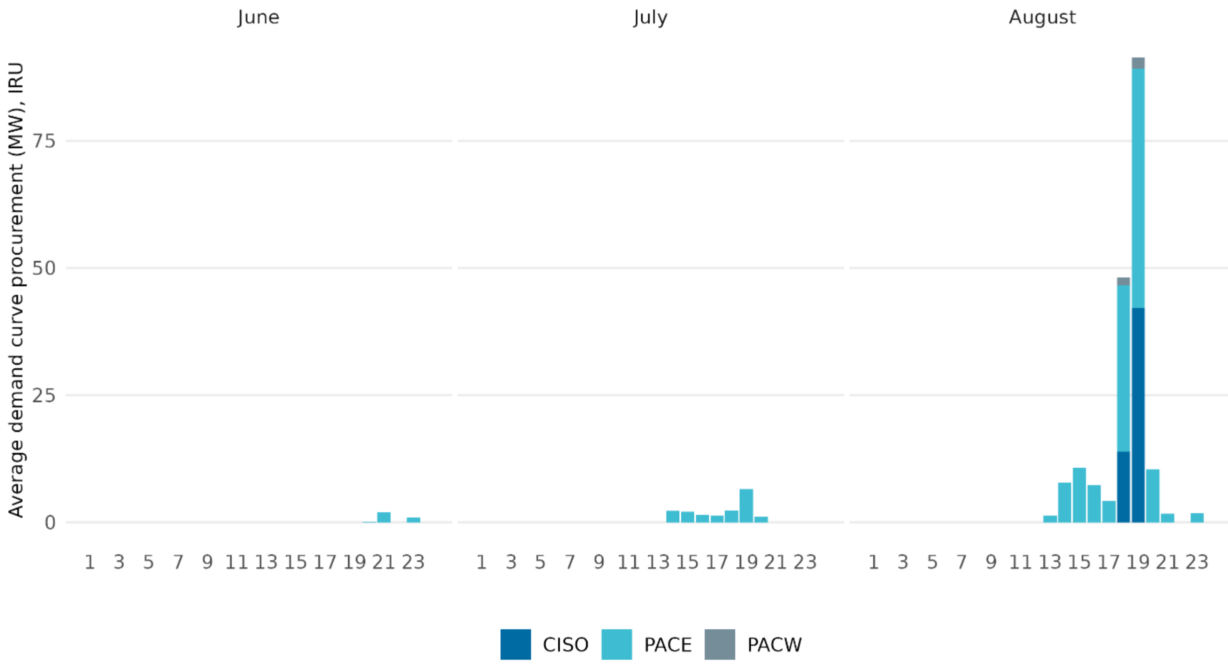


Figure 55: Average imbalance reserve demand curve procurement, IRD

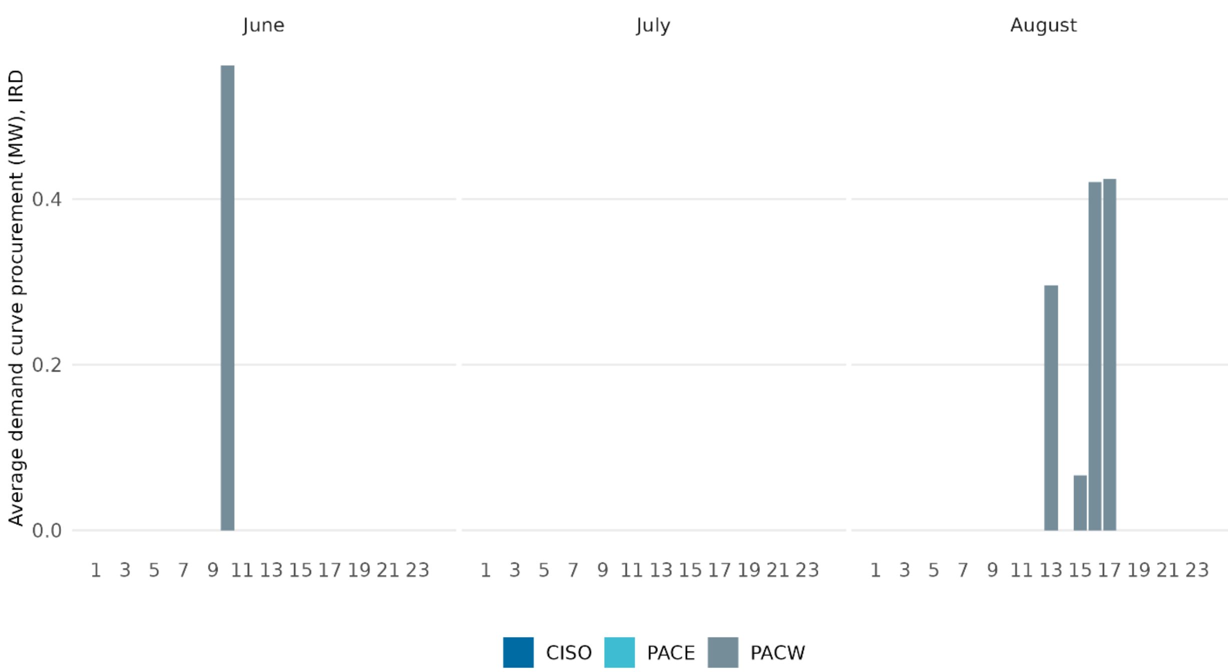


Figure 56 and Figure 58 show the hourly average net demand by EDAM BAA in June through August. Net demand is derived from demand forecast, net solar and wind forecast. The figures overlay hourly average IR procurement and requirement, for both up and down directions, and hourly average FMM net load uncertainty, 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 56: Average net demand with imbalance reserve procurement, CISO

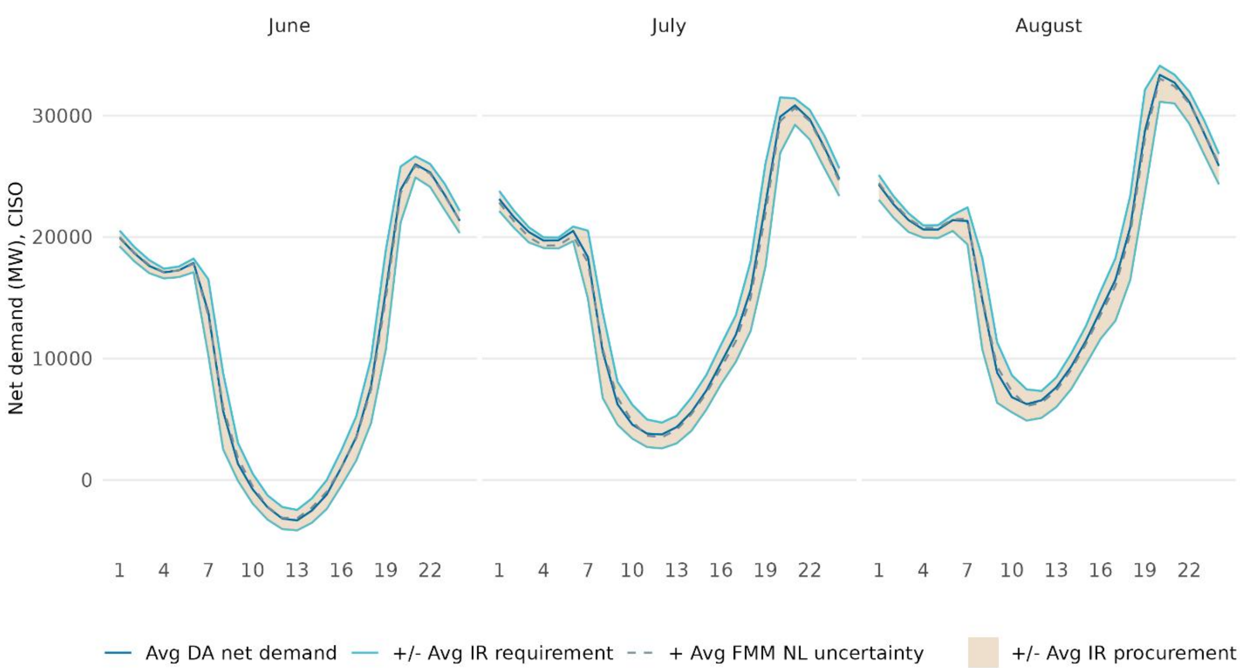


Figure 57: Average net demand with imbalance reserve procurement, PACE

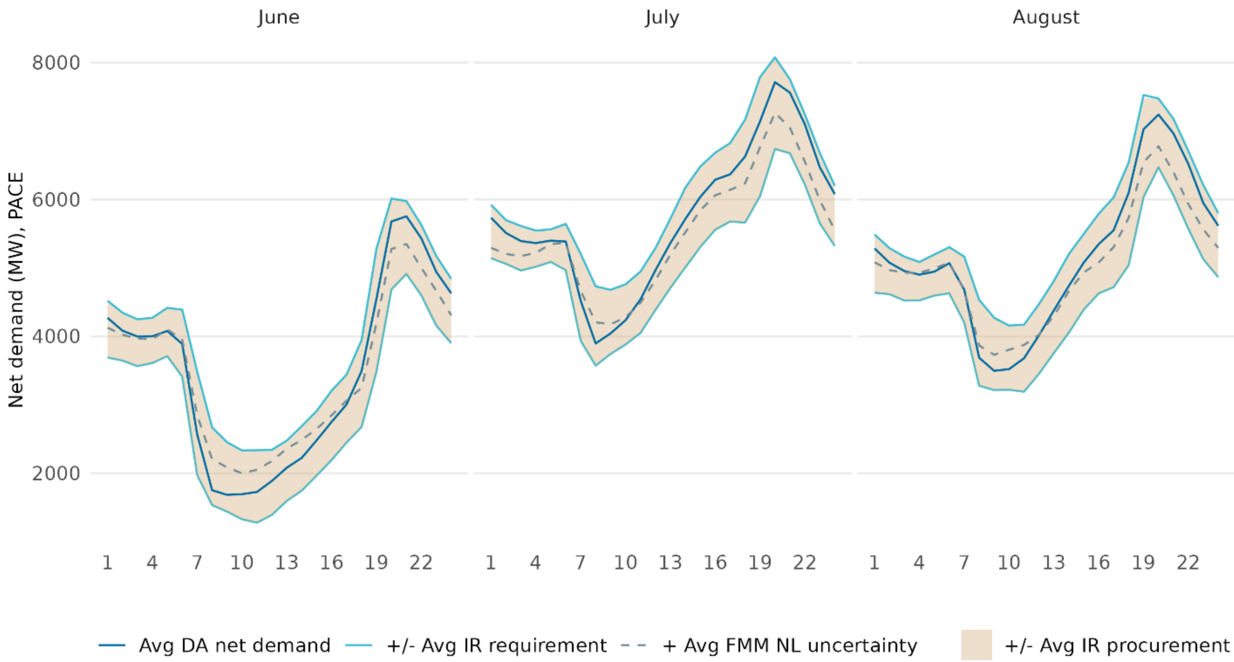


Figure 58: Average net demand with imbalance reserve procurement, PACW

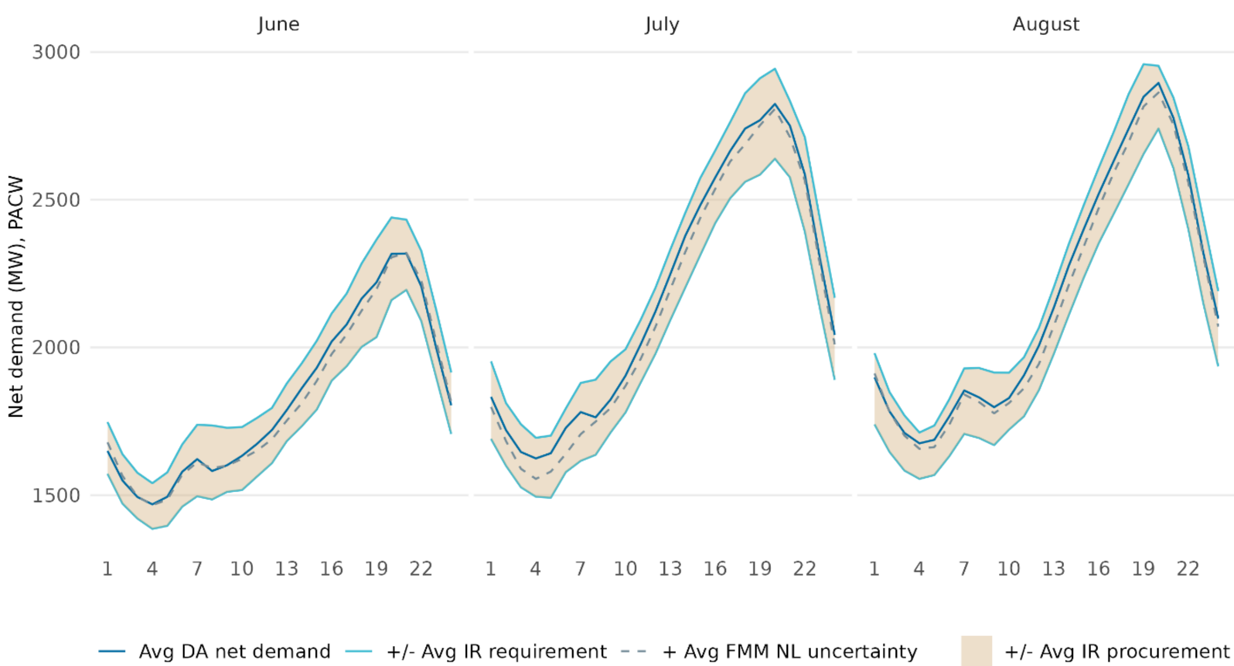


Figure 59 to Figure 61 illustrate for each EDAM BAA, average available capacity in the fifteen-minute market for the capacity awards of day-ahead imbalance reserves represented in stacked bar. These bars grouped the imbalance reserves into two groups, capacity that is utilized (deployed) in the FMM market, 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 and PACW 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

	June		July		August	
	IRU	IRD	IRU	IRD	IRU	IRD
CISO	13.5%	11.6%	15.5%	12.9%	18.4%	12.4%
PACE	27.6%	23.4%	43.0%	30.7%	43.2%	23.0%
PACW	30.4%	15.8%	15.9%	17.7%	21.7%	17.8%

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 59: Hourly average IR requirement, procurement and utilization. CISO

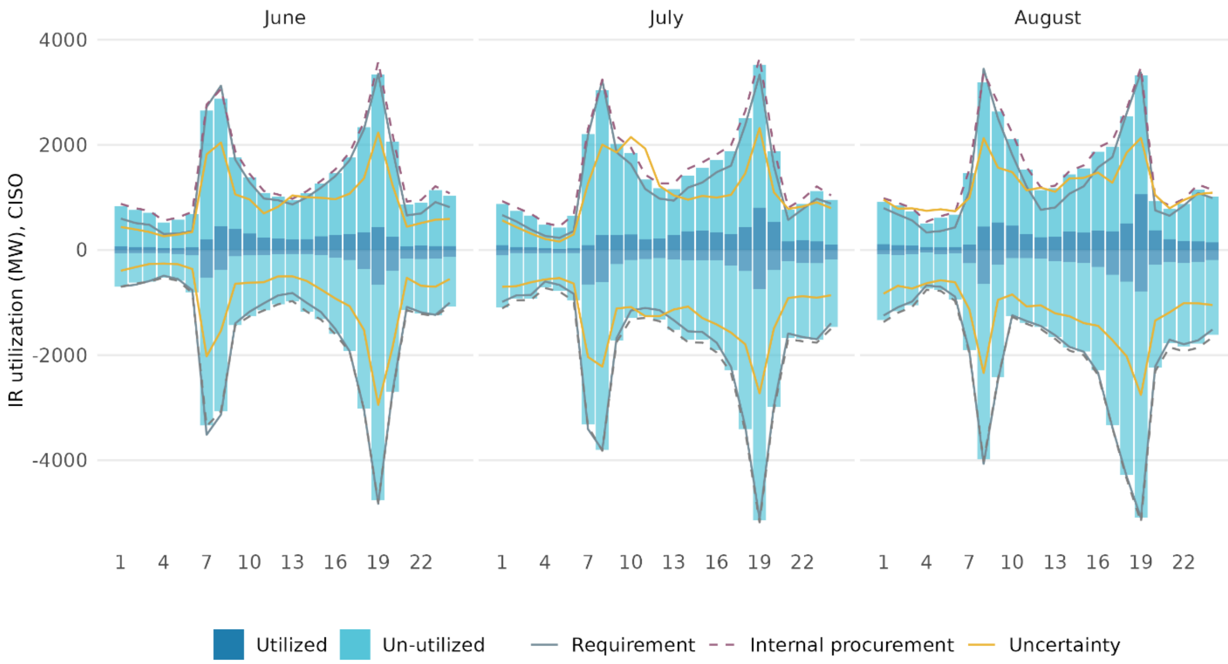


Figure 60: Hourly average IR requirement, procurement and utilization. PACE

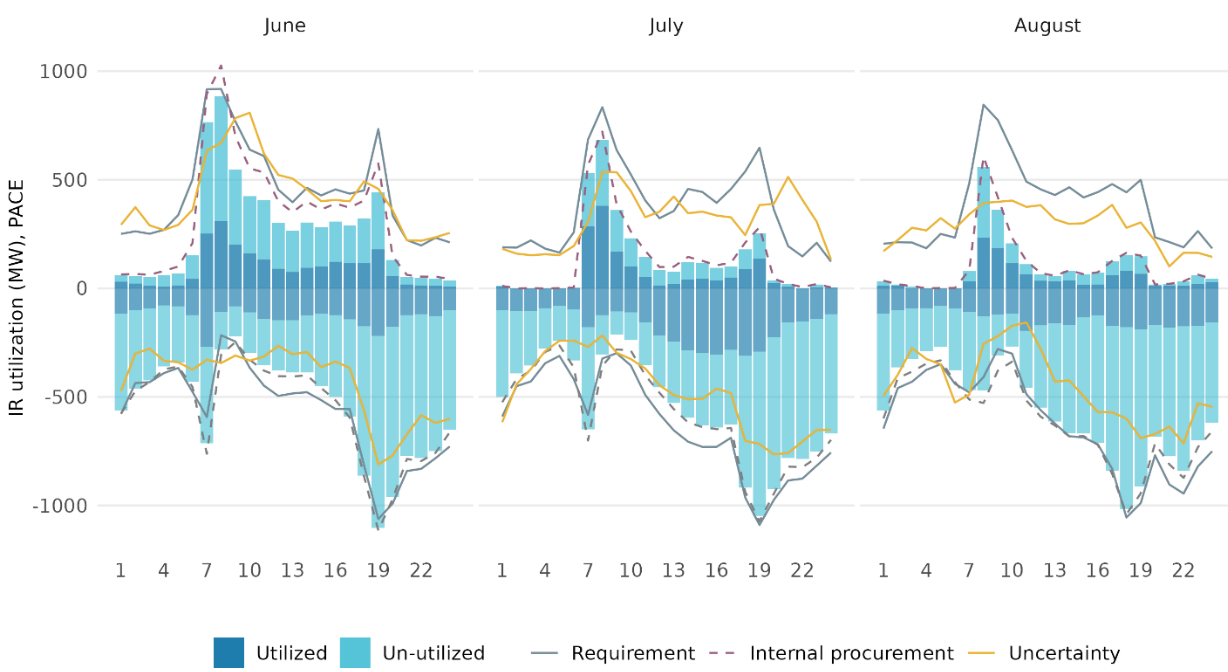
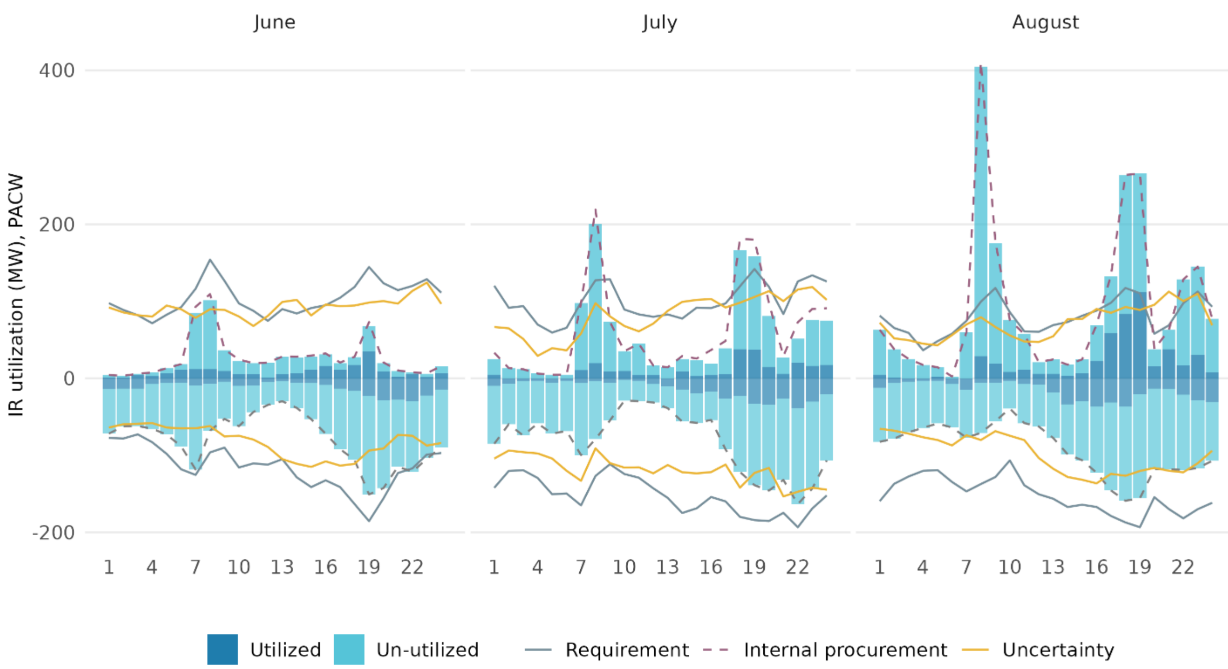


Figure 61: Hourly average IR requirement, procurement, and utilization, PACW



Imbalance reserves are procured in the IFM to manage net load forecast uncertainty, while reliability capacity is procured in the RUC process to bridge the gap between IFM bid-in demand and the demand forecast.

To evaluate the real-time performance of these day-ahead capacity products, 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 and reliability capacity awards. The portion of this schedule change that falls within the awarded capacity range is considered utilized.

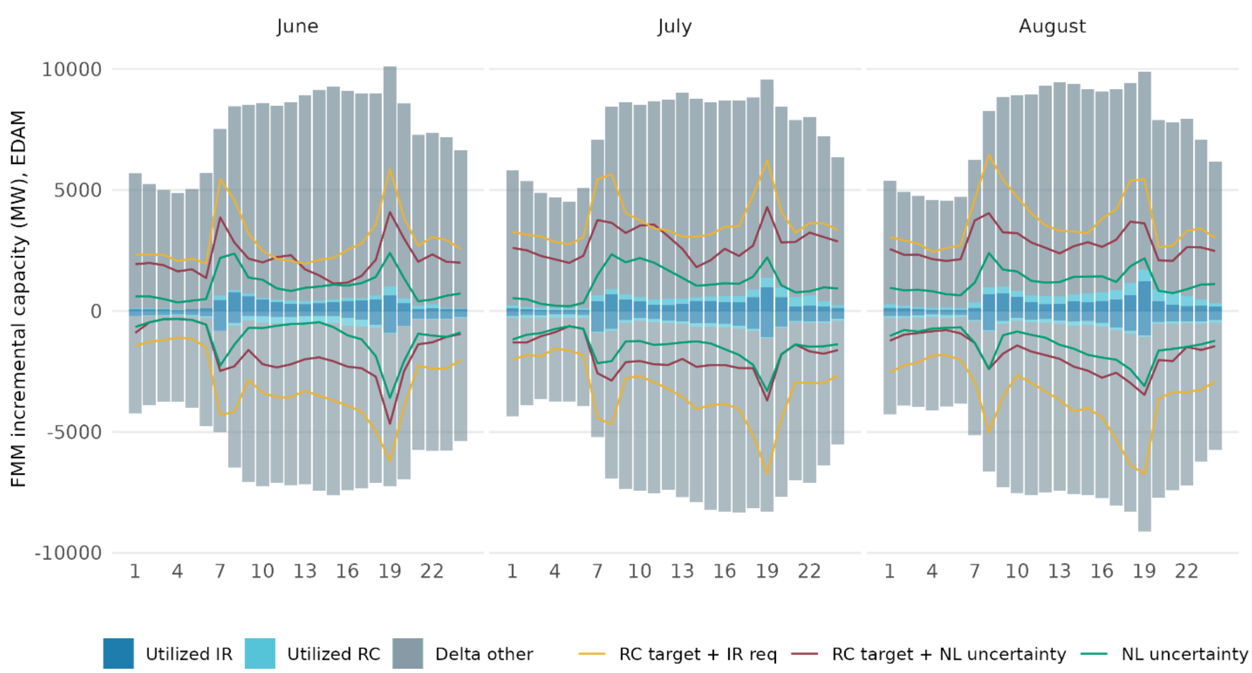
Imbalance reserve is procured in IFM for net load forecast uncertainty, while reliability capacity is procured to bridge the bid-in demand in IFM to demand forecast in RUC. To measure the day-ahead capacity products' performance in real time, the energy schedule difference from day-ahead to fifteen-minute market is taken at the resource level, and utilization is measured from mapping the corresponding ranges of the imbalance reserve and reliability capacity awards to the delta energy schedule. Figure 62 illustrates the average utilization of imbalance reserve (IR) and reliability capacity (RC) awards across the EDAM footprint in the fifteen-minute market. The stacked bars show the portion of day-ahead IR and RC awards that is utilized in real time, separately for upward and downward directions.

Additional real-time capacity scheduled beyond the day-ahead awards is represented by the "Delta Other" component. The total height of each stacked bar therefore represents the incremental real-time procurement within the EDAM footprint for the corresponding direction.

For any given interval, the net of the upward and downward incremental procurement reflects the real-time balancing needs within the EDAM footprint, as well as transfers to or from the broader WEIM footprint.

For comparisons, average realized net load uncertainty, the average realized net load uncertainty plus reliability capacity target, and the average imbalance reserve requirements plus reliability capacity target are included as lines. The realized net load uncertainties for the EDAM footprint are mostly less than the total of the BAA net load uncertainties due to the diversity benefit. Therefore, the percentage utilization for the EDAM footprint may be higher than each individual BAA percentage utilization for the same hours. In August, for EDAM footprint, the imbalance reserve up utilization relative to realized uncertainty is up to 56.9 percent in hour ending 19. The combined IRU and RCU utilization relative to realized uncertainty and reliability capacity target is up to 47.3 percent in hour ending 19.

Figure 62: Average utilized capacity for EDAM footprint



EDAM resources receiving imbalance reserve awards in the day-ahead market will have bidding obligations in the real time market. Figure 63 and Figure 64 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 63: Percentage IRU availability in FMM for EDAM footprint

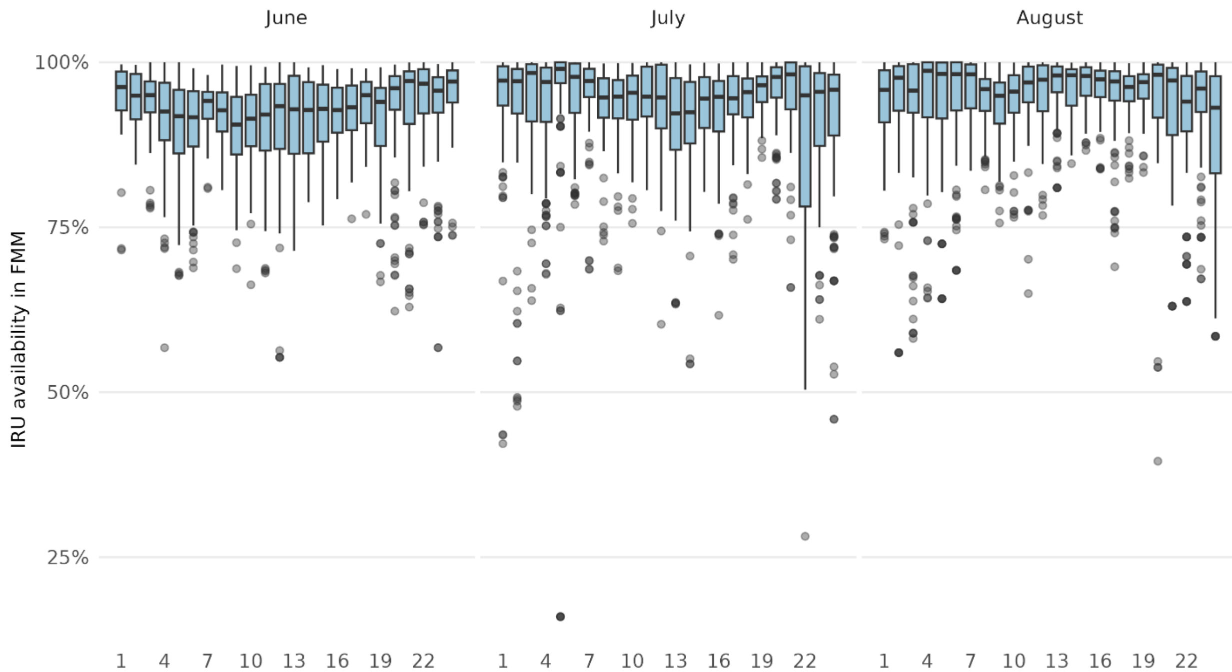


Figure 64: Percentage IRD availability in FMM for EDAM footprint

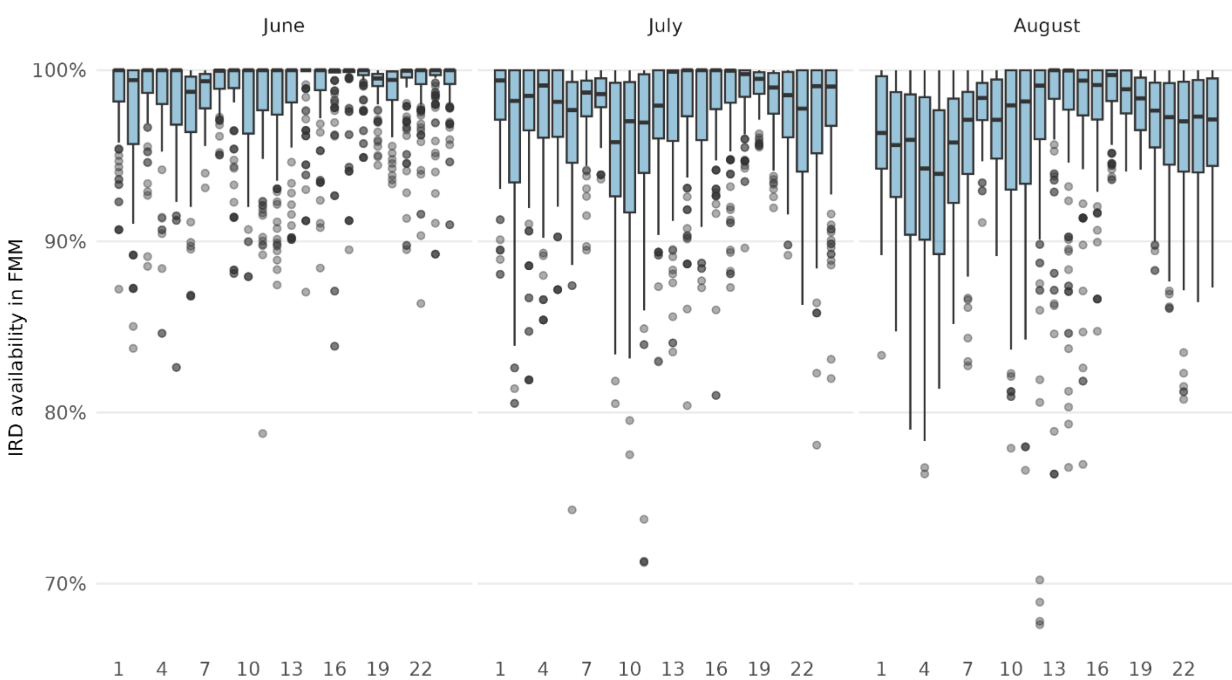


Figure 65 and Figure 66 show the hourly distributions of the utilized imbalance reserve up and down volumes, in the EDAM footprint in FMM. The utilization trends follow the shape of the imbalance reserve requirements, higher in the morning and evening peak hours for both up and down directions.

Figure 65: Hourly IR up utilization distribution in EDAM footprint

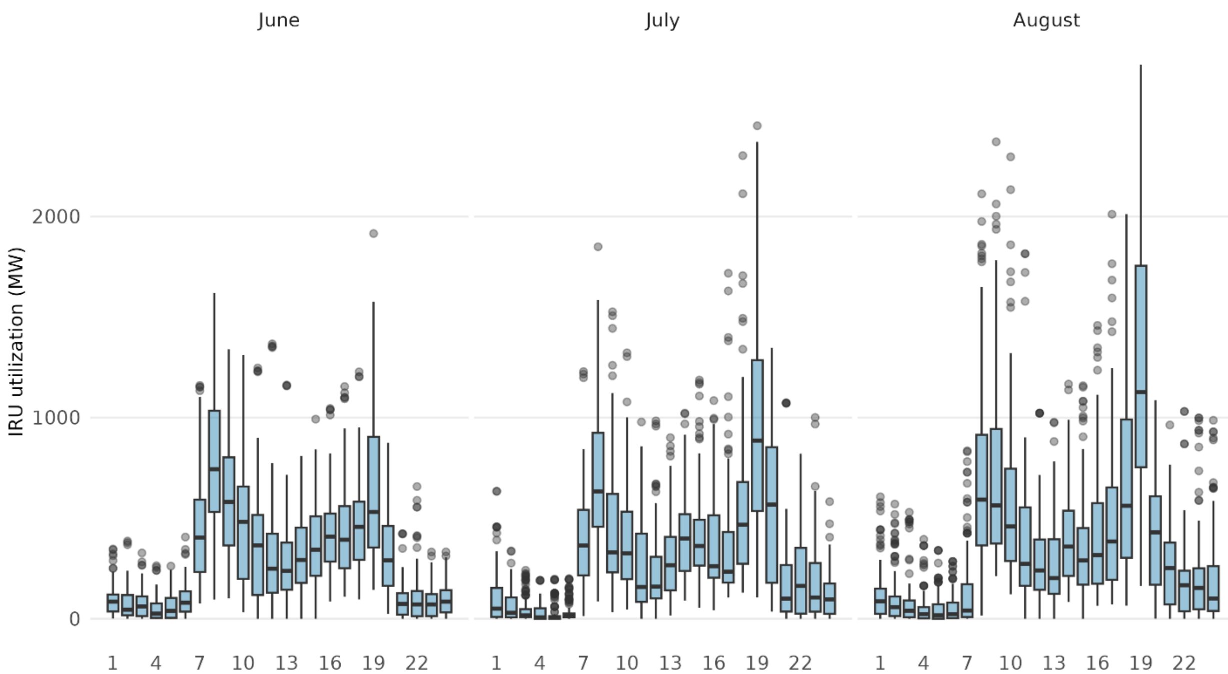
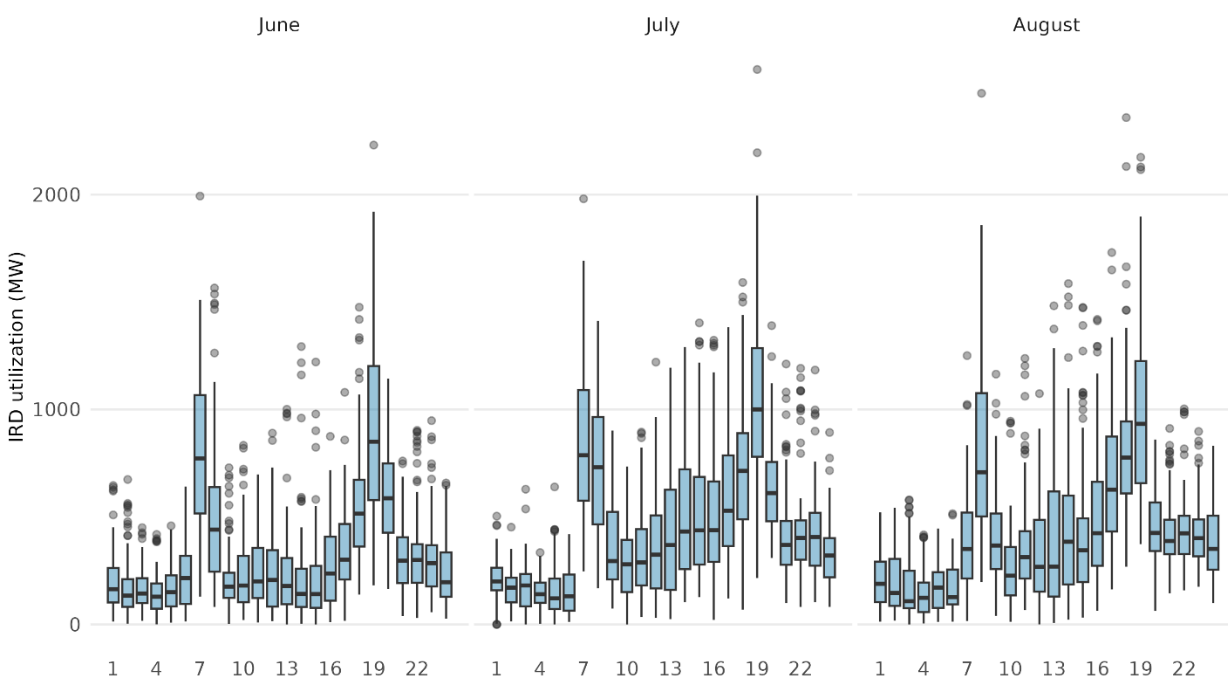


Figure 66: Hourly IR down utilization distribution in EDAM footprint



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 67 and Figure 68 show the nodal congestion components of the imbalance reserve marginal prices in upward and downward directions. For both the months of June through August, the imbalance reserve congestion is minimal and centered around $0/MWh. When analyzing the outliers for IRU in the month of August, there is positive congestion in the North (PGAE and PACW) and negative congestion in the South (SCE, SDGE and VEA). When analyzing the outliers for IRD in the month of August, there is negative congestion in SDGE. The MCC breakdown for monthly average IR congestion is provided in Table 11.

Figure 67: Nodal IRU congestion component of the IRU marginal price

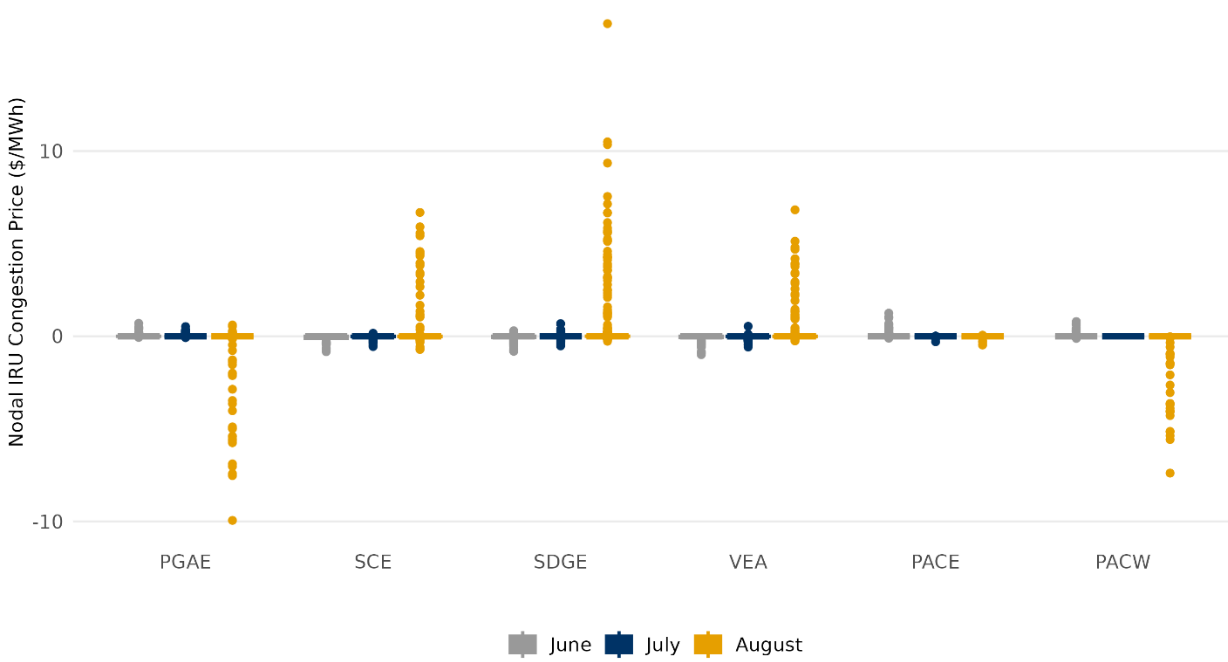
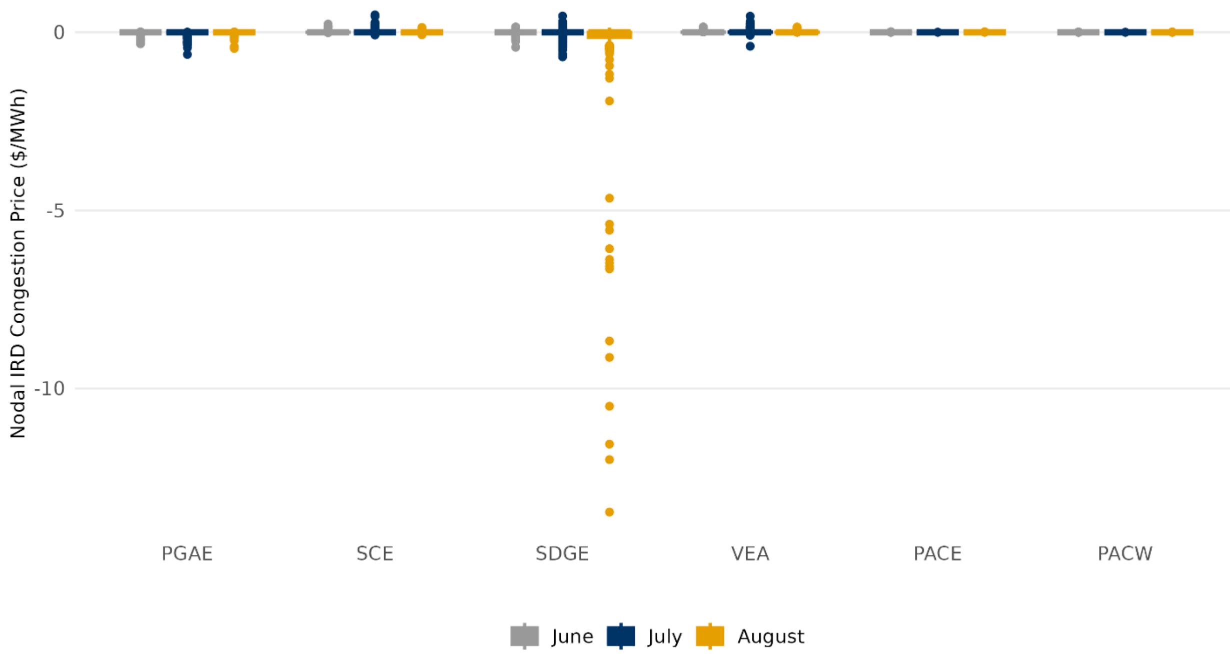


Figure 68: Nodal IRD congestion component of the IRD marginal price



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 first two MIDWAY-VINCENT constraints that were not enforced for IRU. Alternatively, as seen by the third MIDWAY-WIRLWIND constraint, the congestion pricing could be reduced in FMM resulting in better IRU deliverability in FMM.

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

August 2026 Average Congestion Costs by Constraint		Contingency	PACE			PACW			PGAE			SCE		
BAA	Constraint Name		Base	IRU	FMM	Base	IRU	FMM	Base	IRU	FMM	Base	IRU	FMM
CISO	30060_MIDWAY _500_24156_VINCENT _500_BR_2 _3	Y	(0.01)		(0.06)	(0.55)		(2.64)	(0.75)		(3.58)	0.54		2.69
CISO	30060_MIDWAY _500_24156_VINCENT _500_BR_1 _1	Y	0.01		0.00	(0.37)		(0.36)	(0.51)		(0.49)	0.41		0.40
CISO	30060_MIDWAY _500_29402_WIRLWIND_500_BR_1 _2	N	(0.01)	(0.01)		(0.40)	(0.23)	(0.05)	(0.54)	(0.31)	(0.06)	0.41	0.23	0.05
CISO	30750_MOSSLD _230_30797_LASAGUIL_230_BR_1 _1	Y							0.34		0.48	(0.23)		(0.28)
CISO	30060_MIDWAY _500_29402_WIRLWIND_500_BR_1 _2	Y	0.00			(0.07)		(0.23)	(0.10)		(0.32)	0.08		0.26
CISO	DOSMGO-PNOCHE_230_2_1	Y							(0.25)		(0.37)	(0.14)		(0.29)
CISO	24091_MESA CAL_230_24076_LAGUBELL_230_BR_2_1	Y	(0.06)			(0.07)		(0.13)	(0.08)		(0.15)	0.09		0.36
CISO	29400_ANTELOPE_500_29402_WIRLWIND_500_BR_1 _1	Y	(0.01)			(0.19)		(0.00)	(0.26)		(0.00)	0.19		0.00
CISO	6410_CP5_NG	N	0.00		(0.00)	(0.06)	(0.00)	(0.09)	(0.09)	(0.00)	(0.12)	0.07	0.00	0.09
CISO	6410_CP1_NG	N	0.00		0.00	(0.00)		(0.13)	(0.00)		(0.17)	0.00		0.13
CISO	30765_LOSBANOS_230_30790_PANOCHE _230_BR_2 _1	Y				0.15		0.01	0.05		0.02	(0.07)		(0.13)
CISO	34418_KINGSBRG_115_34428_CONTADNA_115_BR_1 _1	Y							0.06		0.17	(0.03)		(0.07)
CISO	35658_LS ESTRS_115_35659_NORTECH _115_BR_1 _1	Y							0.01		0.18	(0.02)		(0.10)
CISO	24701_KRAMER _230_24601_VICTOR _230_BR_2 _1	N							0.05	0.00		(0.09)	(0.00)	(0.09)
CISO	35122_NWARK EF_115_30630_NEWARK _230_XF_11	Y									0.19			(0.01)
CISO	7430_CP6_NG	N							0.01	0.01	0.07	(0.01)	(0.01)	(0.08)

For the month of August, the congestion component differences between upward imbalances reserves (IRU) in EDAM and energy component in the fifteen-minute market (FMM) are shown in Figure 69. The comparison is performed for all EDAM hours in which at least one internal generating resource receives a non-zero IRU award. The "Points" metric shown in each panel title represents the number of resource-hour combinations contained within that panel.

The top-right panel shows that 1,202.8 MW of IRU is procured when EDAM IRU congestion is zero and FMM energy congestion pricing is comparable to or lower than EDAM congestion pricing. The middle-right and bottom-left panels show an additional 77.8 MW of IRU procurement (7.3 MW + 70.5 MW) when IRU congestion is non-zero and FMM energy congestion pricing remains lower than EDAM congestion pricing. Together, these categories account for 1,280.6 MW of procured IRU (1,202.8 MW + 77.8 MW). This capacity is considered deliverable because FMM energy congestion is either similar to or lower than EDAM IRU congestion, indicating that congestion was appropriately reflected when the resources cleared the day-ahead market.

The remaining panels (top-left and middle-left) represent cases where FMM energy congestion exceeds EDAM IRU congestion by more than $1/MWh. These panels contain 456.0 MW of procured IRU (410.4 MW + 45.6 MW), representing the portion of total IRU procurement that could become stranded in FMM due to additional congestion not considered when the resources cleared in EDAM. As a share of total IRU procurement, this stranded volume represents 26.3% of the total (456.0 ÷ [456.0 + 1,280.6]).

Figure 70 shows the cumulative percentage of monthly IRU procurement in July and August as a function of the spread between FMM energy congestion and EDAM IRU congestion.

Figure 69: EDAM IRU and WEIM FMM energy congestion components

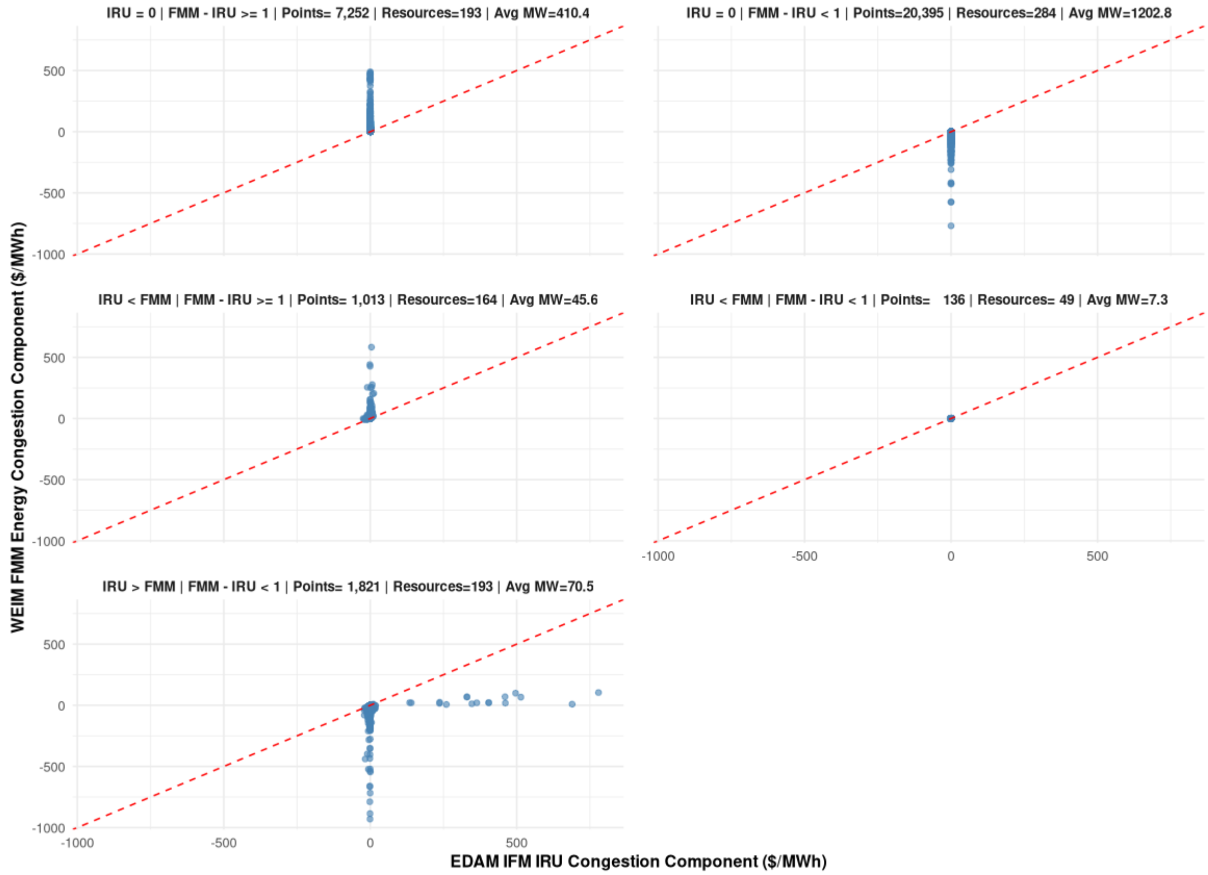
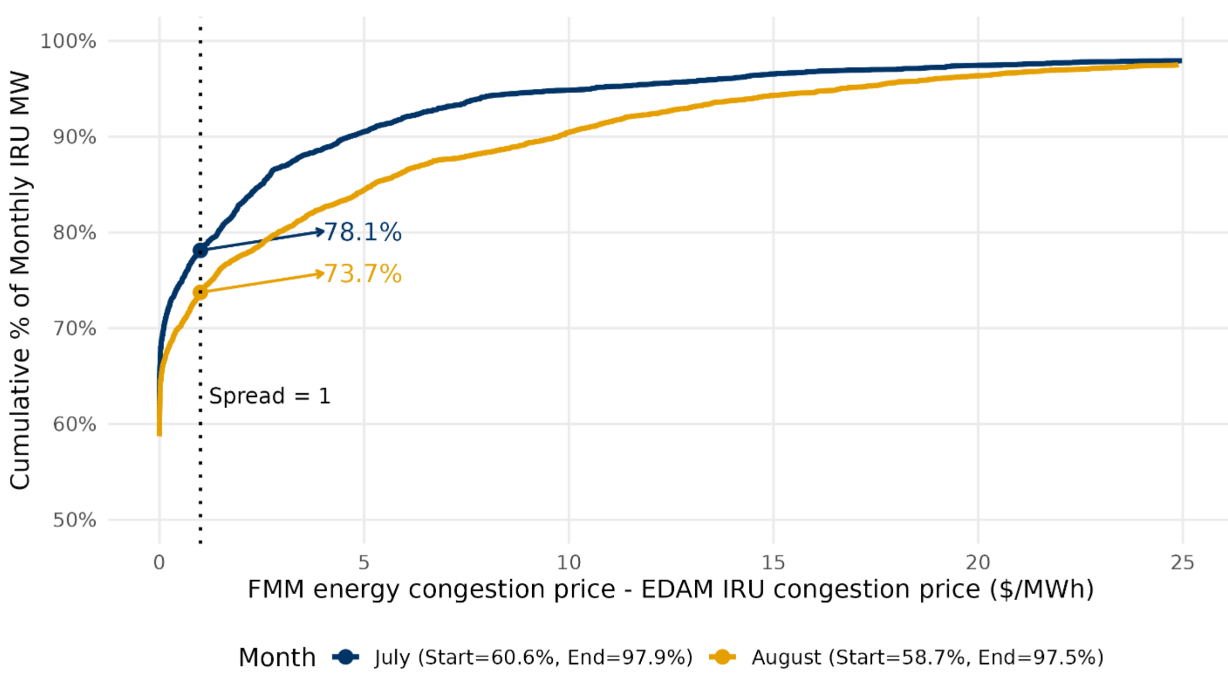


Figure 70: Cumulative percentage of total monthly IRU procurement



Reliability capacity

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

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.

Overall, prices for RC increased and were more volatile across all three BAAs in August compared to July as shown in Figure 71 and Figure 72, indicating that RCU needs were higher on average. CAISO RC prices increased the most from July, followed by PACW and PACE.

CAISO daily average RC prices reached their highest levels since EDAM on August 4 and August 27, at 79.48 $/MWh and 56.68 $/MWh, respectively, surpassing the previous all-time peak on July 24. PACW and PACE daily average RC prices also reached their highest levels since EDAM on August 27, at 47.77 $/MWh and 42.44 $/MWh, respectively. The lowest daily average RC price for CAISO was 0 $/MWh observed on 13 days. Daily average RC prices were lowest on August 21 in PACW dropping to -5.08 $/MWh, and on August 15 in PACE falling to -0.77 $/MWh.

As shown in Figure 74 and Figure 75, hourly average RC prices in CAISO were highest during the evening peak from HE 16 to 22, rising to 37.55 $/MWh in HE 20, and the morning peak in HE 7 at 11.72 $/MWh. For PACE, hourly average prices were highest during the evening peak from HE 16 to 20 peaking at 11.52 $/MWh in HE 16. PACW hourly average prices were highest during the evening peak and morning peak from HE 16 to 20 and in HE 7, reaching 10.28 $/MWh in HE 18, but also dropped to -5.74 $/MWh and -2.39 $/MWh in HE 8 and 23, respectively.

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.

Figure 71: Monthly average price of RCU and RCD

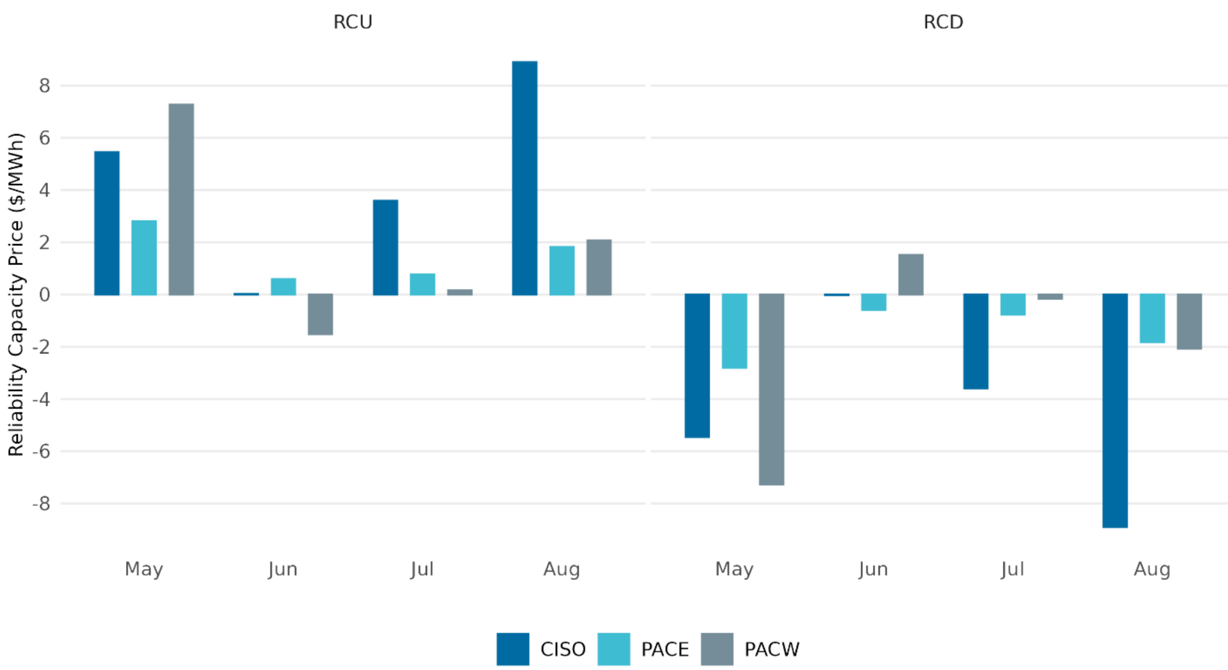


Figure 72: Daily average price of RCU

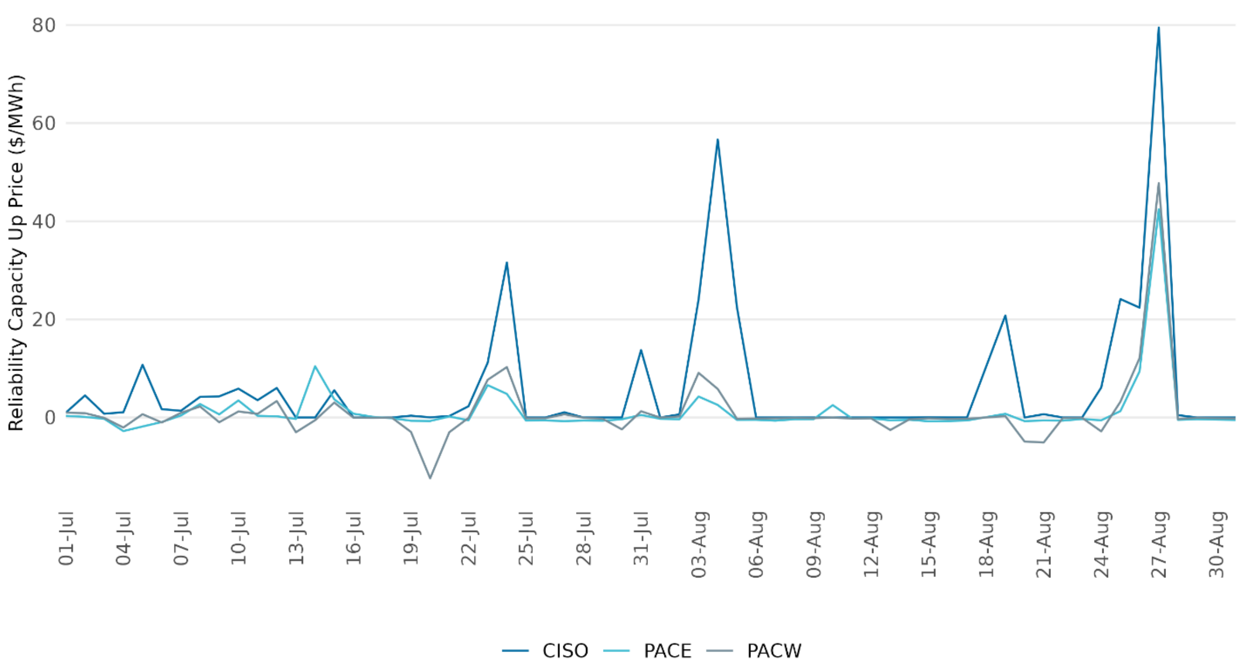


Figure 73: Daily average price of RCD

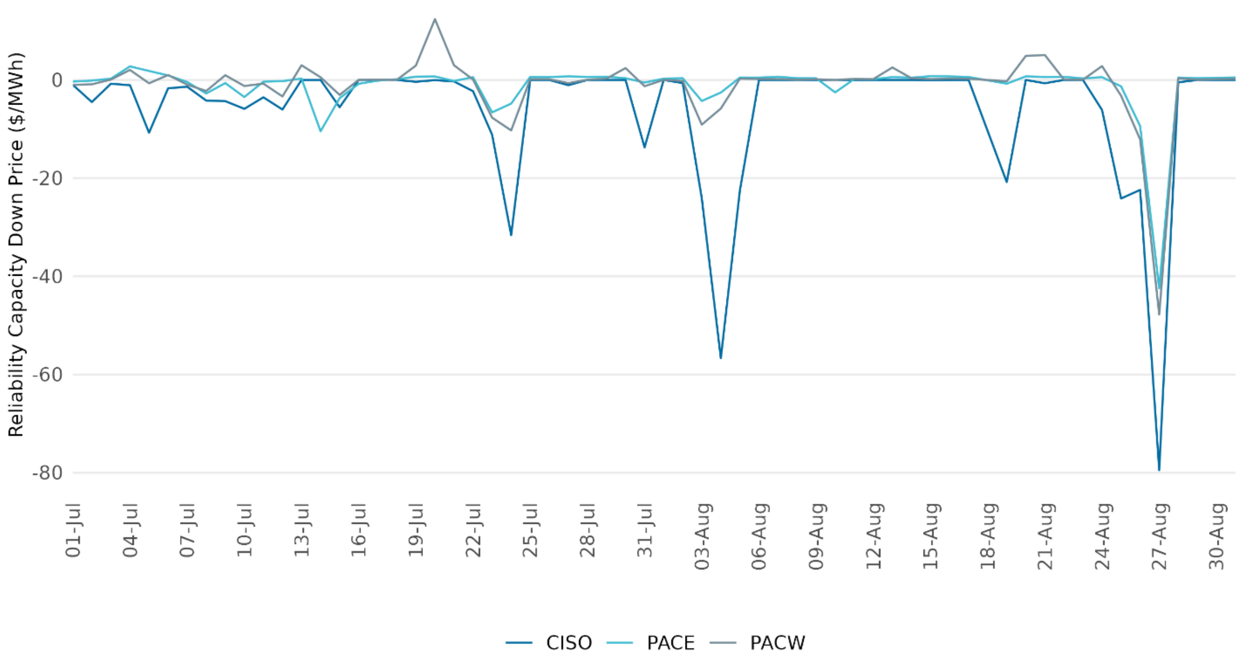


Figure 74: Hourly average price of RCU

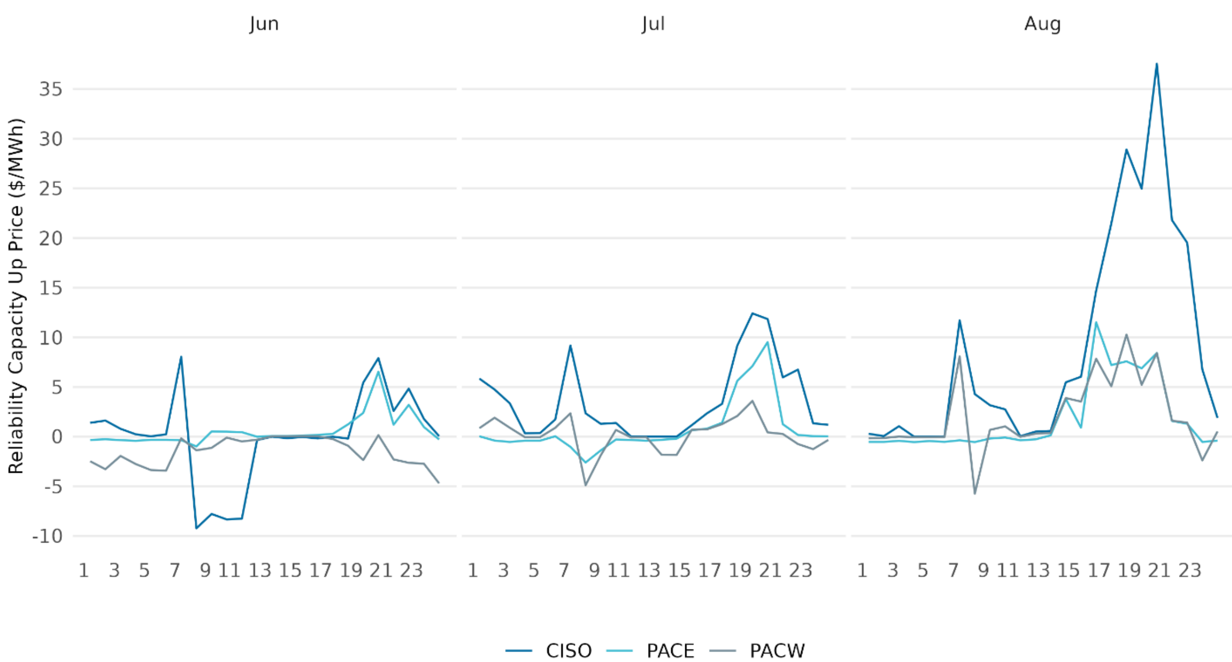


Figure 75: Hourly average price of RCD

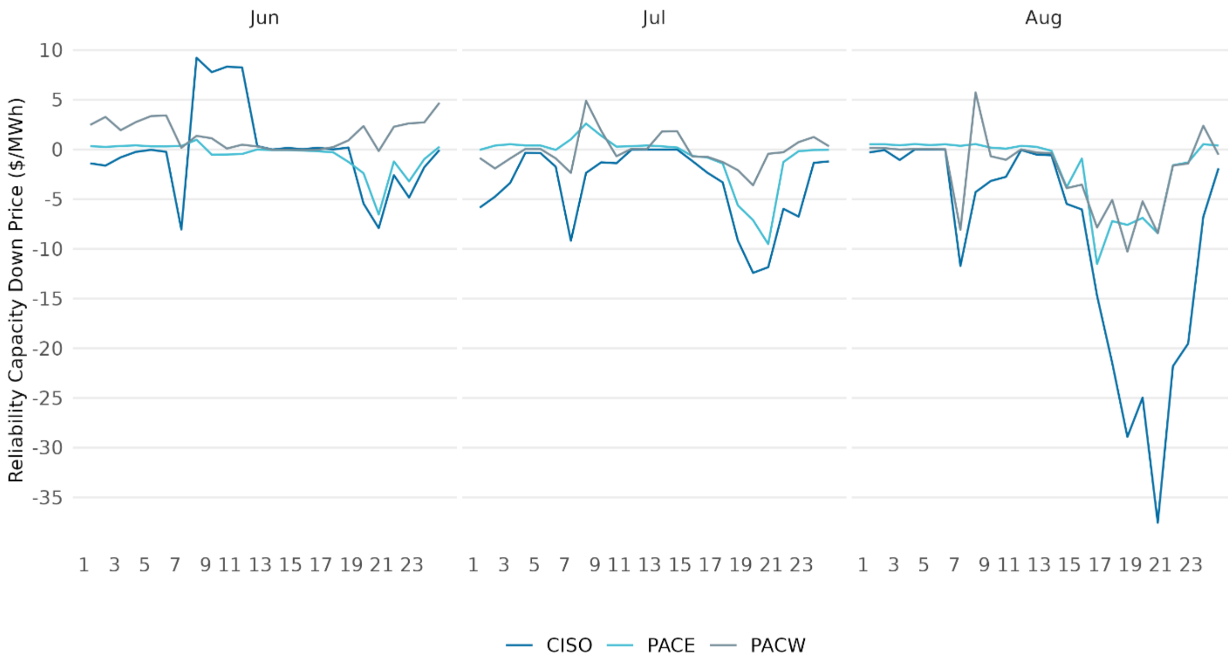
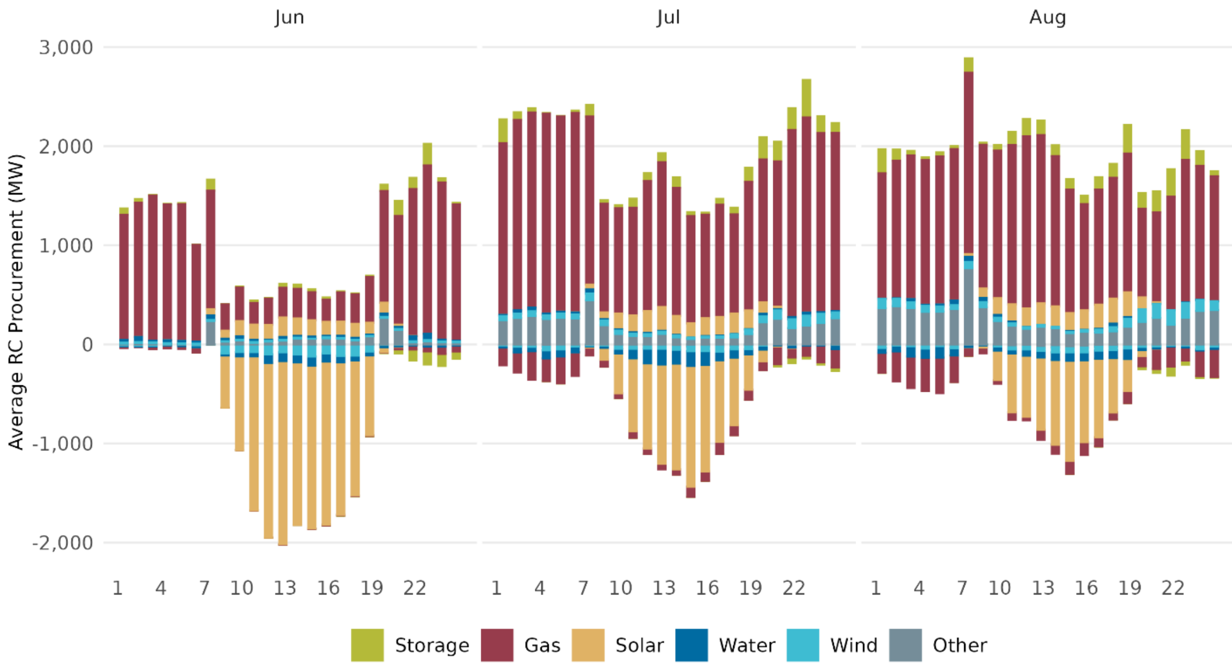


Figure 76 to Figure 78 illustrate the hourly average by technology supporting the procurement for each BAA.

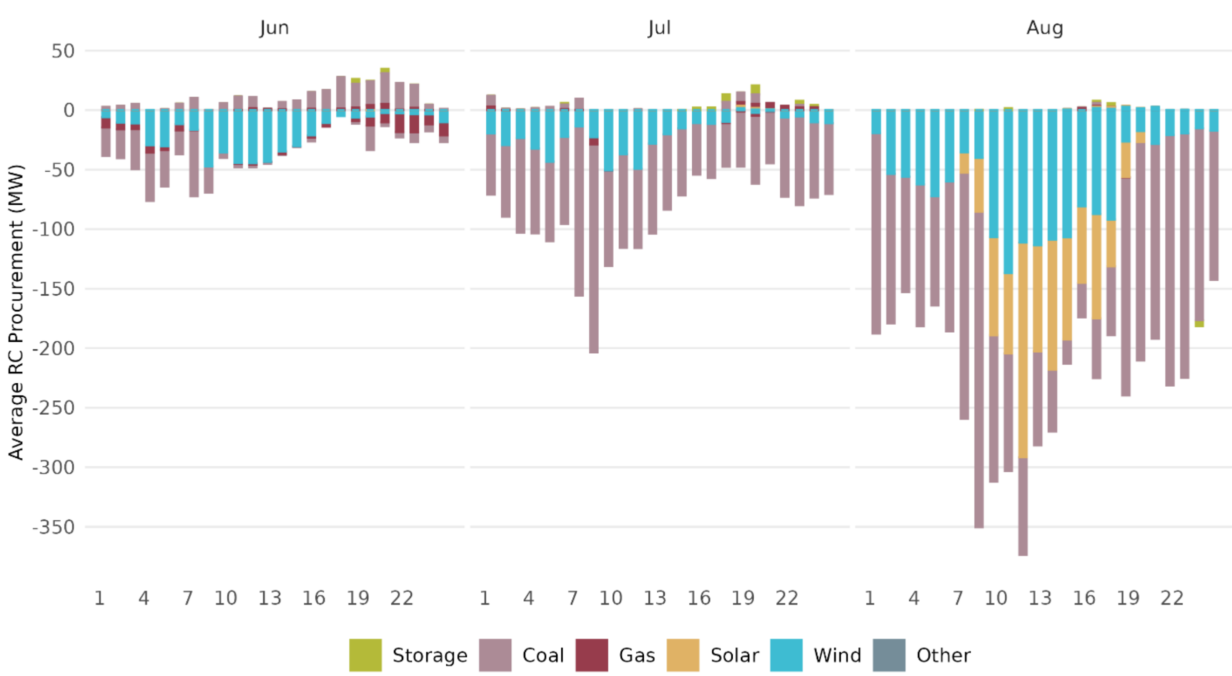
For CAISO in August, gas resources continue to make up the highest proportion of RCU, mostly during non-solar hours. The majority of RCD is procured during solar hours by solar resources. August procured the same level of RCU on average as July, with an obvious increase compared with June.

Figure 76: Hourly average of RC procurement for CAISO



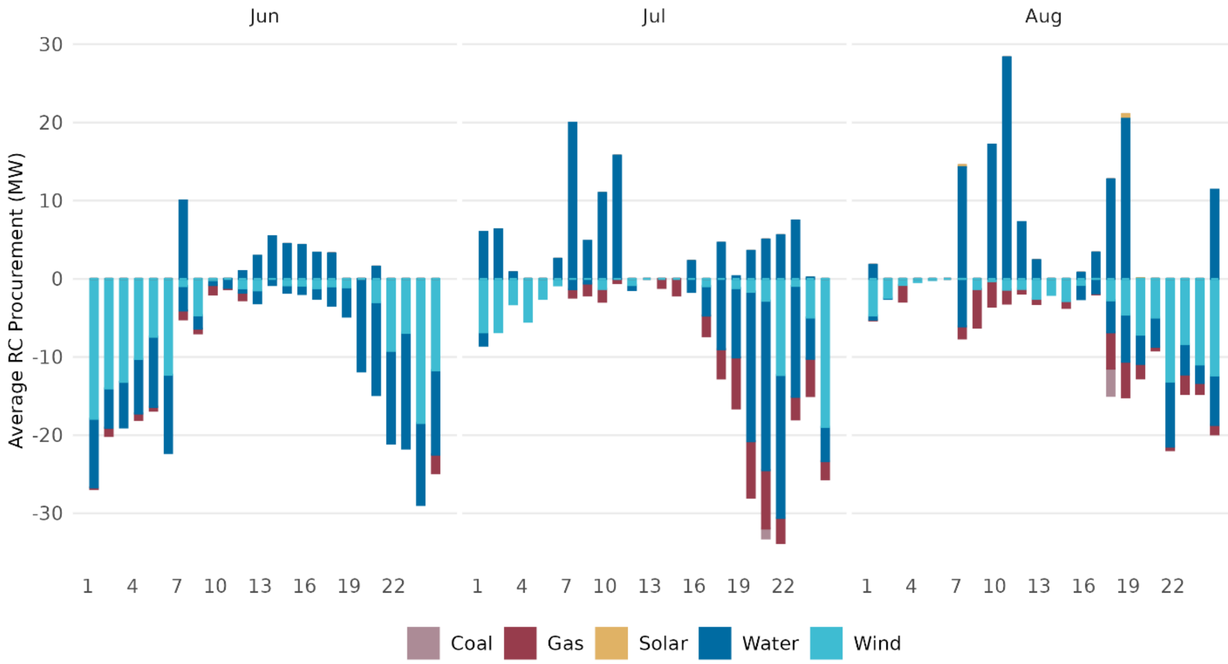
PACE reliability capacity is largely procured in the down direction and supplied primarily by coal and wind resources. RCD procurement has increased significantly, primarily from coal, wind, and solar in August.

Figure 77: Hourly average of RC procurement for PACE



PACW RC is primarily supplied by hydro and wind resources. In August, RCU procurement has been slightly more in early morning hours, with less RCD in the late evening.

Figure 78: Hourly average of RC procurement for PACW



Reliability capacity input bids

Figure 79 and Figure 80 illustrate CAISO's hourly average volume of RC bids by bid price range and fuel type throughout June to August 2026, respectively. Zero-priced bids consistently accounted for the largest share of submitted RC capacity throughout June and August with about above 30,000 MW (or about 50 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 June to August.

Figure 79: Hourly average volume of RC bids by price for CAISO

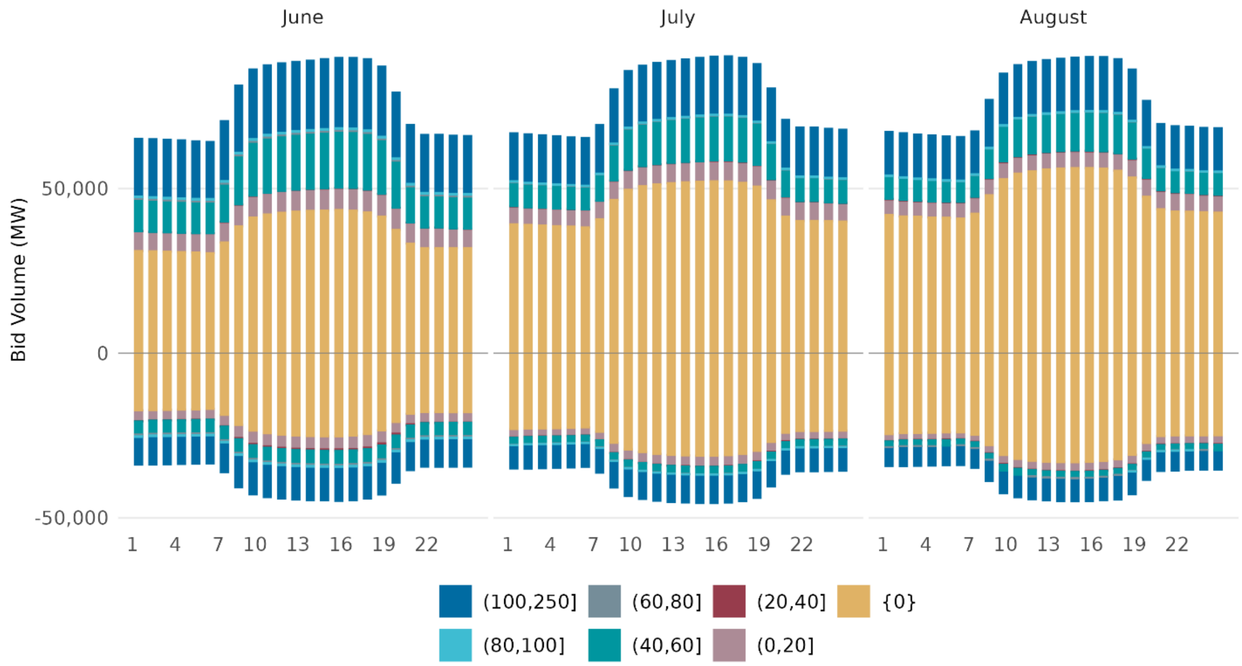


Figure 80: Hourly average volume of RC bids by fuel type by CAISO

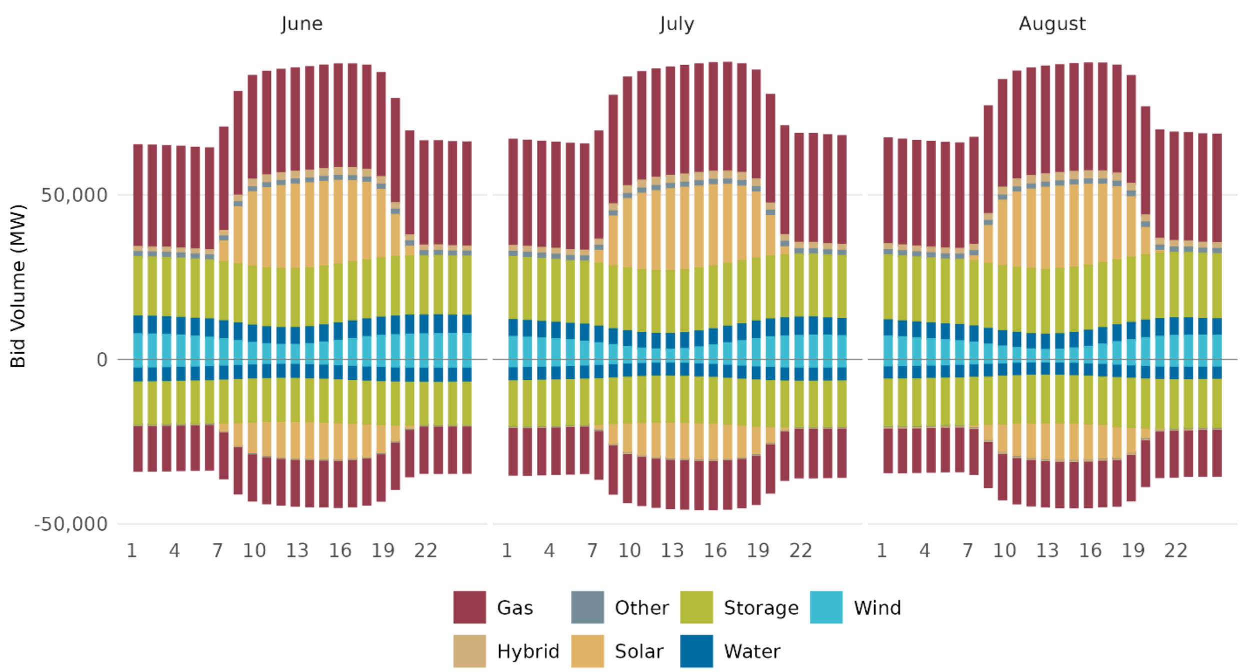


Figure 81 and Figure 82 illustrate the CAISO's daily average volume of RC bids by bid price range and fuel type, respectively. Generally, CAISO's submitted RC capacity remained relatively stable throughout July to August. Gas, solar, and energy storage accounted for the largest share of RC bid volumes.

Figure 81: Daily average volume RC bids by price for CAISO

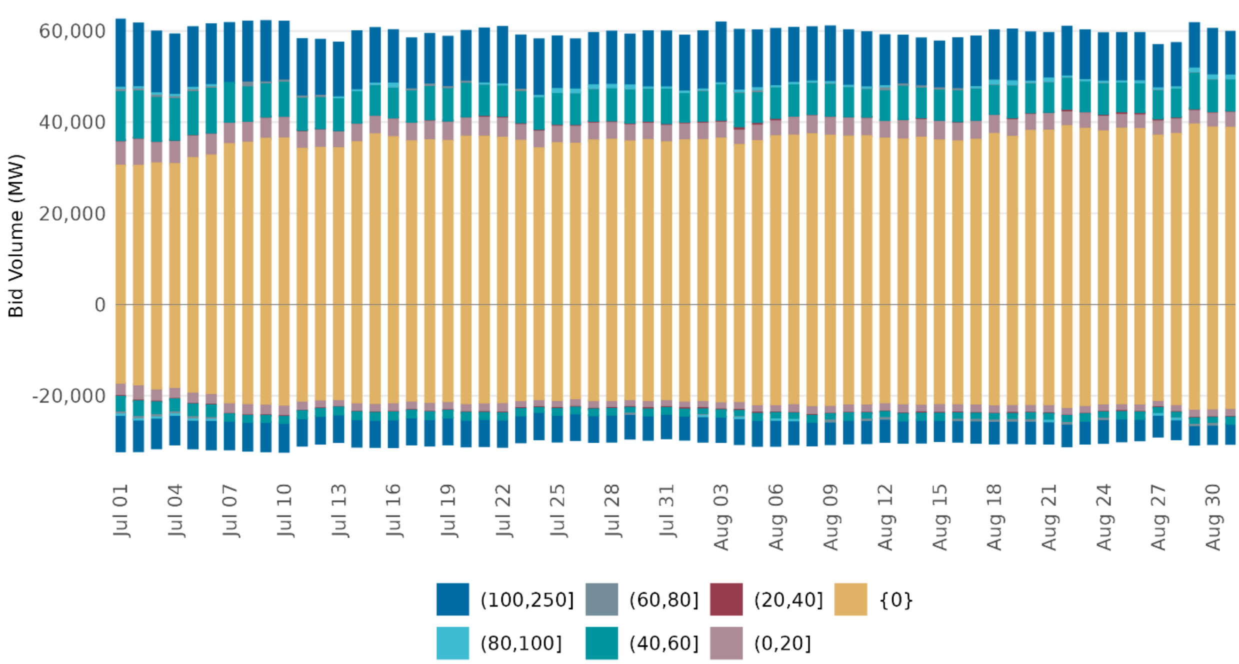


Figure 82: Daily average volume of RC bids by fuel type for CAISO

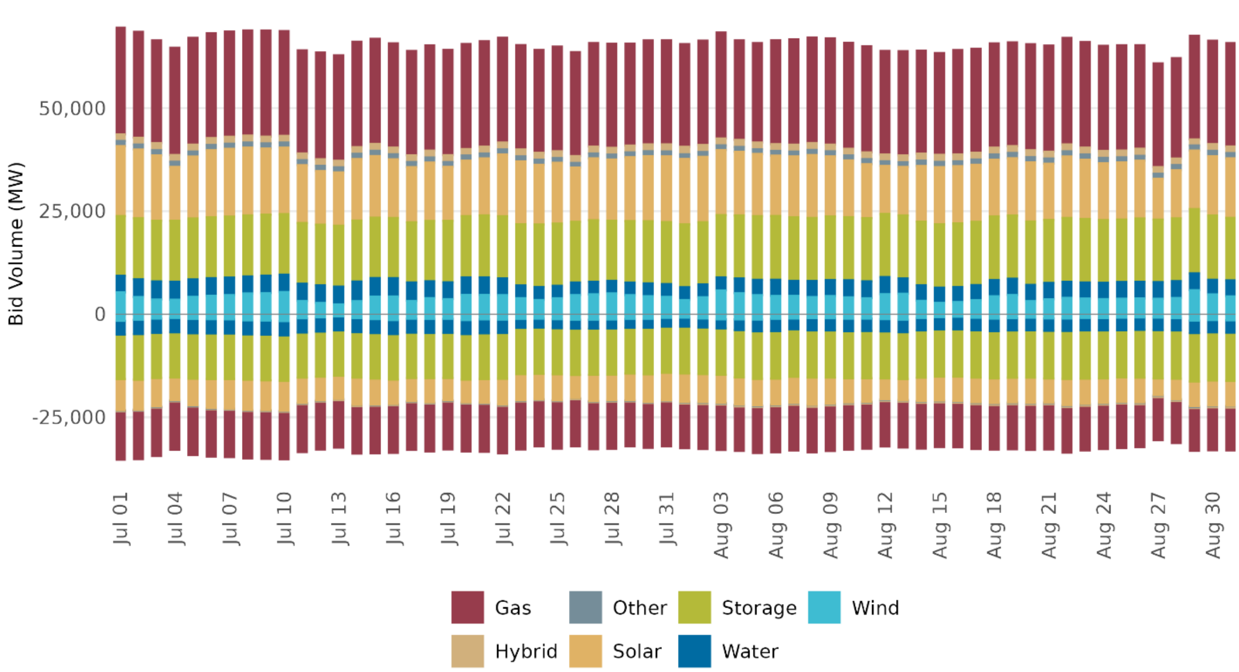


Figure 83 and Figure 84 illustrate the PACE's hourly average volume of RC bids by bid price range and fuel type, respectively. Low-priced bids ($0–20/MW) and moderate priced bids (40–60 $/MWh) consistently accounted for almost all the share of submitted RC capacity throughout the months. Coal, gas, and wind resources accounted for the largest share of submitted RC capacity, with some solar capacity bidding in RCU only.

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

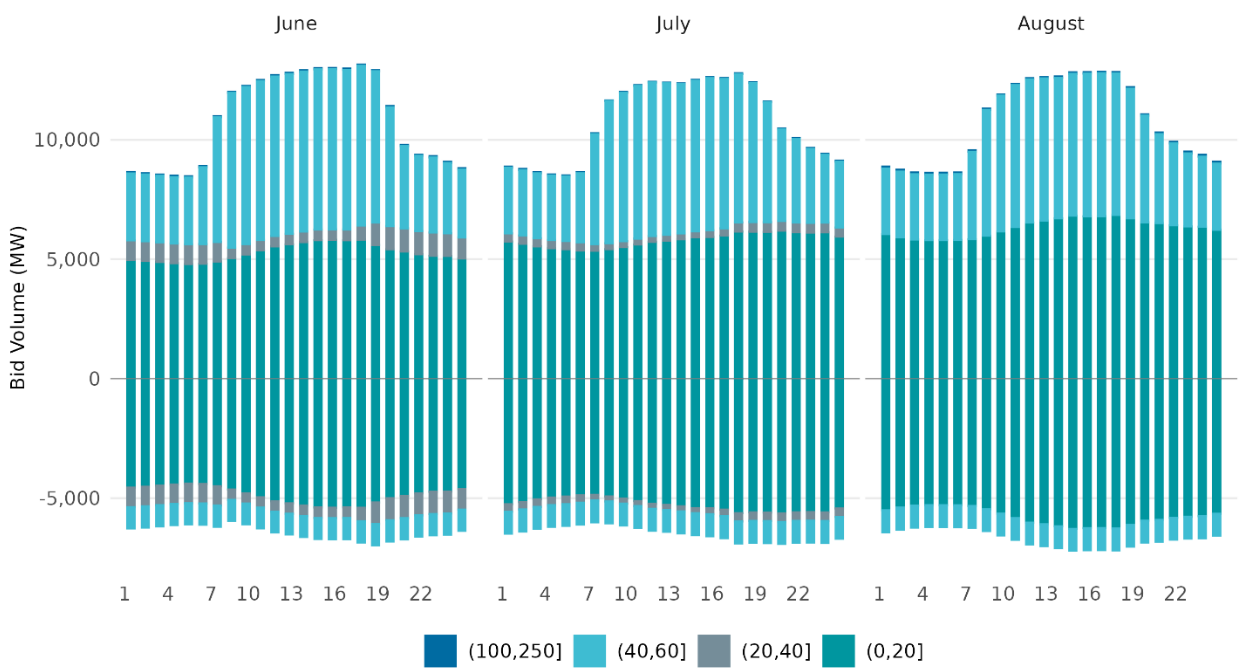


Figure 84: Hourly average volume of RC bids by fuel type for PACE

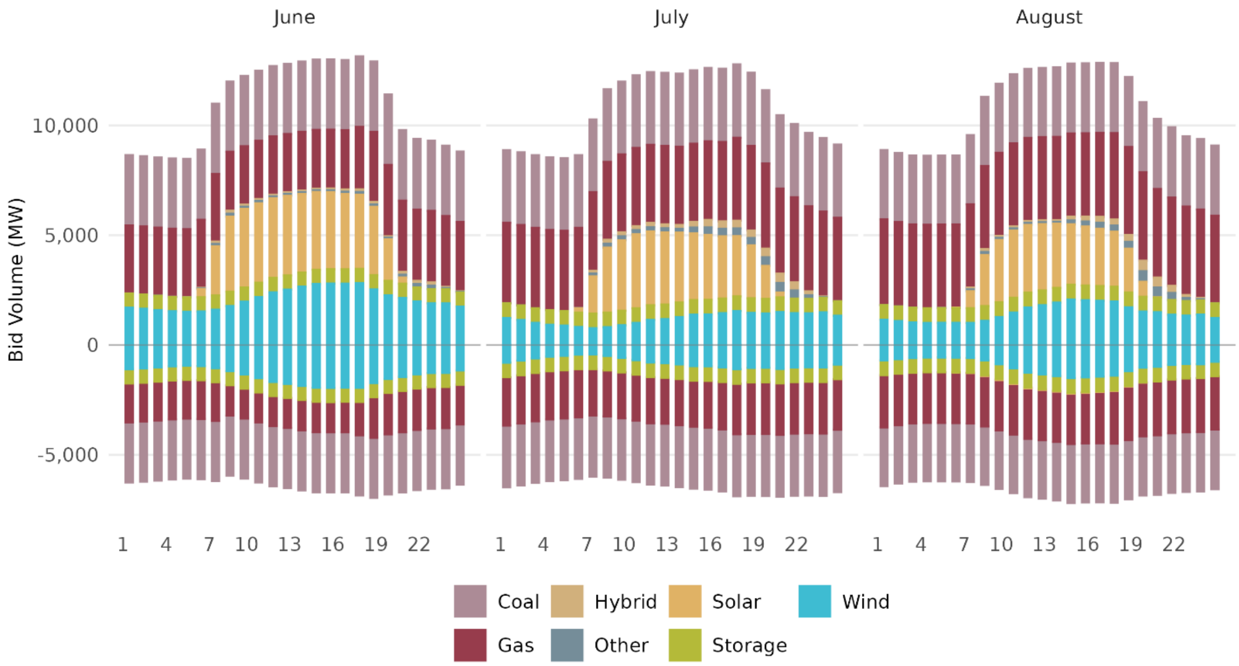


Figure 85 and Figure 86 plotted the daily average volume of PACE's RC products by price and fuel type, respectively. At the beginning of July, there were some ($20-40/MW) bids then adjusted to ($0-20/MW) range. As for the bid volume, it is dependent on renewable forecasts, and solar resources only submitted bids in RCU, leaving an asymmetrical bid volumes with RCU up to 10,000 MW and RCD only reaching 5,000 MW.

Figure 85: Daily average volume of RC bids by price by PACE

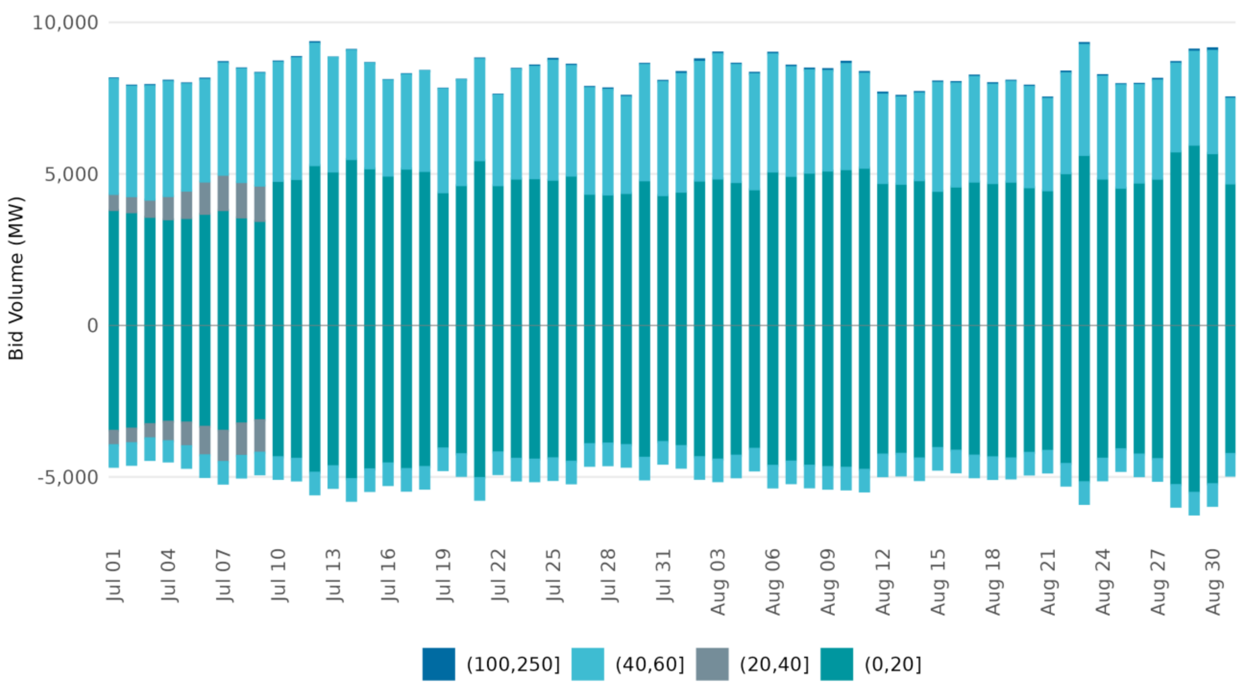


Figure 86: Daily average volume of RC bids by fuel type by PACE

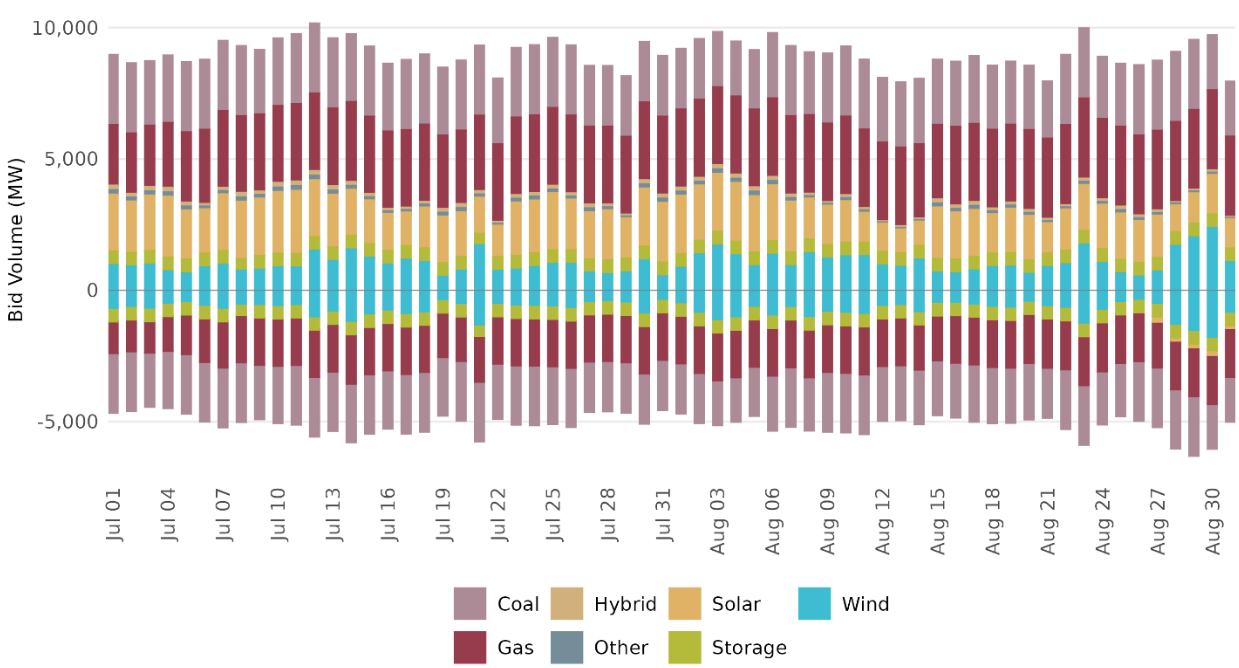


Figure 87 and Figure 88 illustrate PACW's hourly average volume of RC bids by price range and fuel type, respectively. Low-priced bids (0-20 $/MW) and moderate priced bids (40–60 $/MW) consistently accounted for the largest share of submitted RC capacity throughout the month with over 2,000 MW (or 90 percent of the total), followed by bids in the (100–250 $/MWh) range. It is noteworthy that in the down direction there are only low- 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. Similarly, PACW also has a asymmetric bid volumes, with RCU up to 2,700 MW while RCD only about 1,500 MW.

Figure 87: Hourly average volume of RC bids by price for PACW

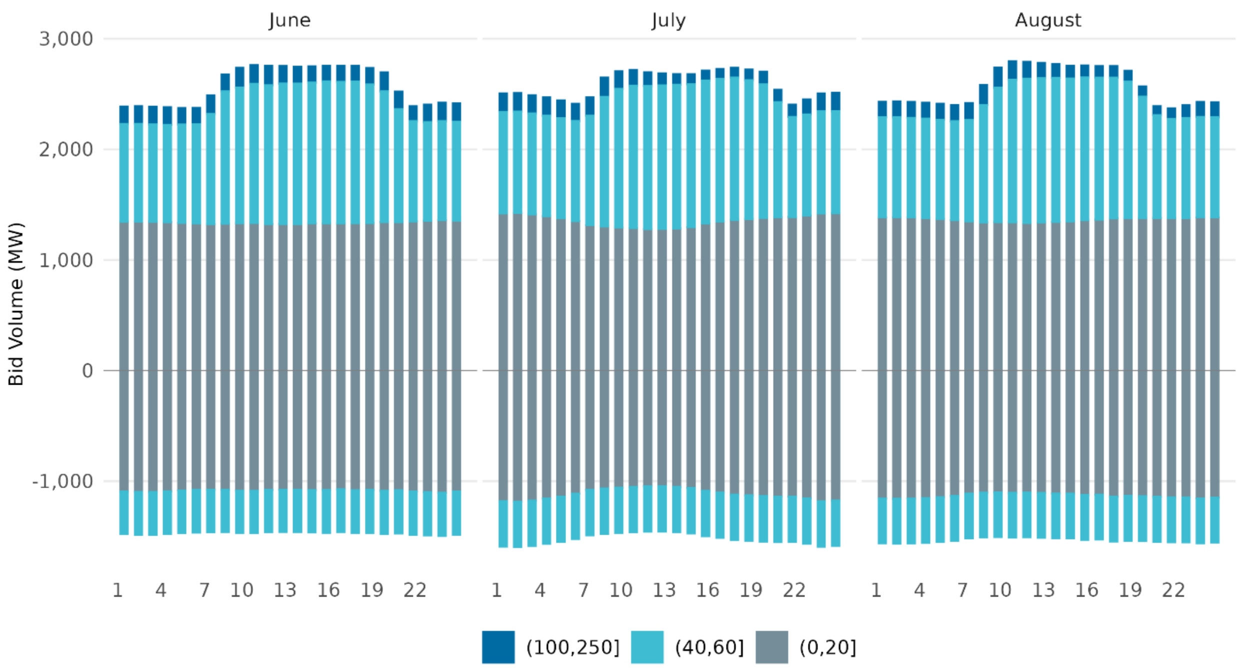


Figure 88: Hourly average volume of RC bids by fuel type for PACW

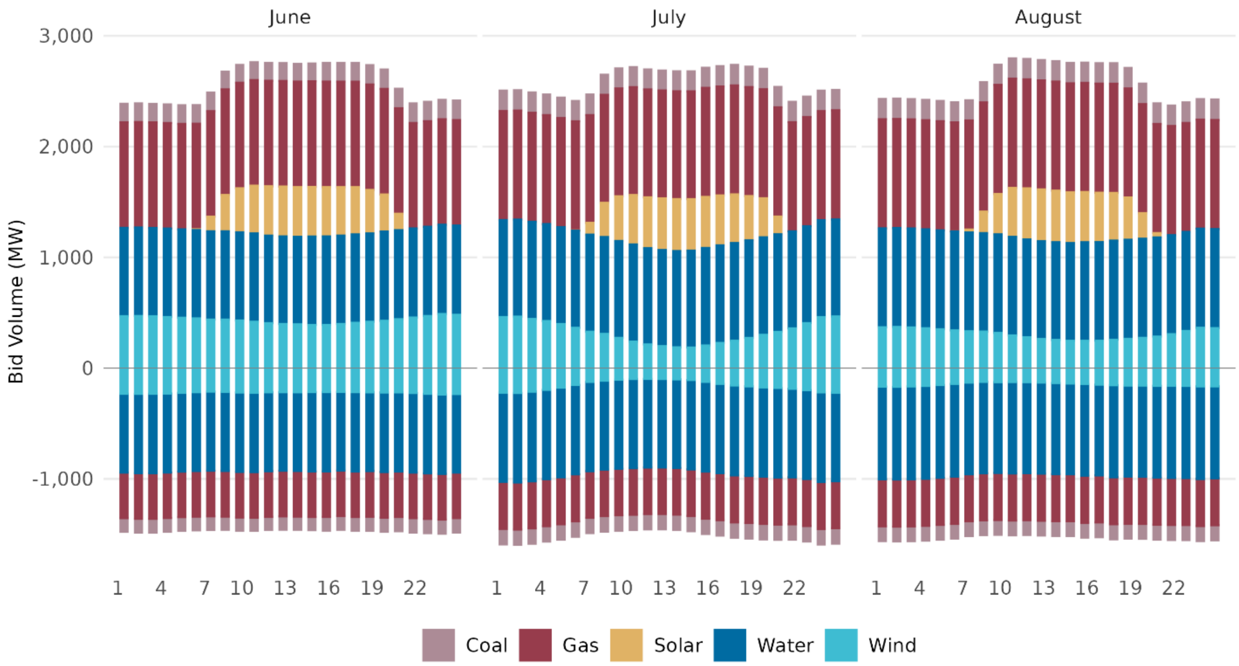


Figure 89 and Figure 90 illustrate PACW's daily average volume of RC bids. Generally, PACW's submitted RC capacity showed variations across both bid volumes and prices due to its dependency on its available renewable outputs.

Figure 89: Daily average volume of RC bids by price for PACW

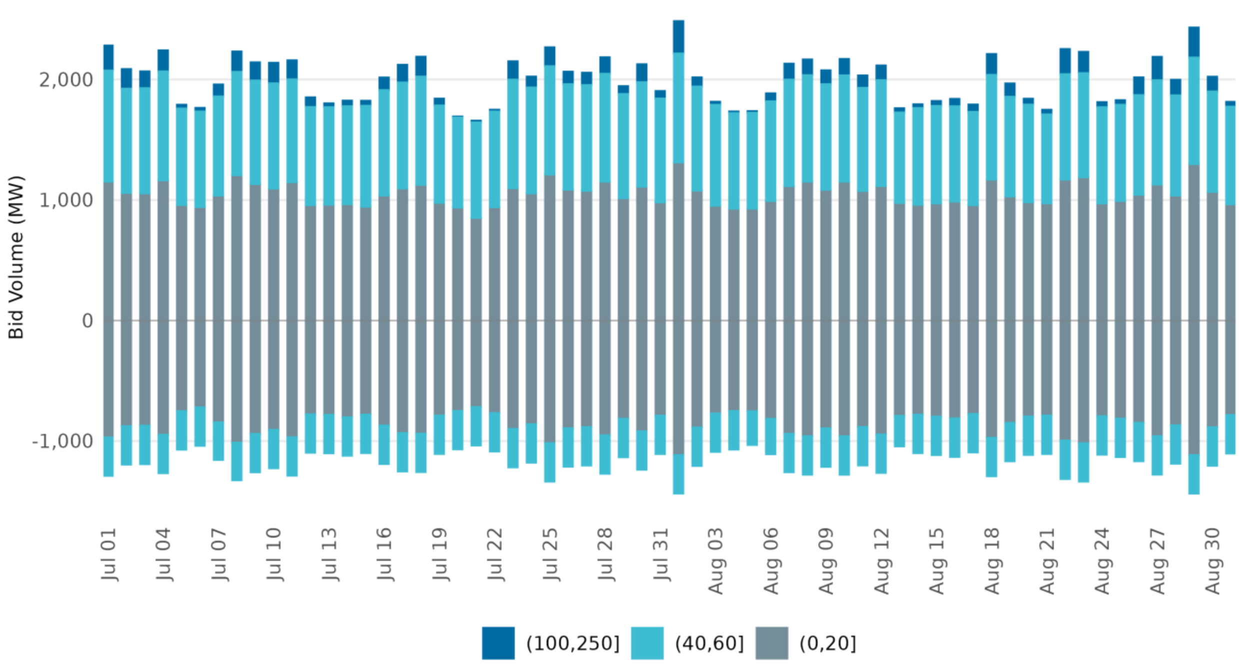
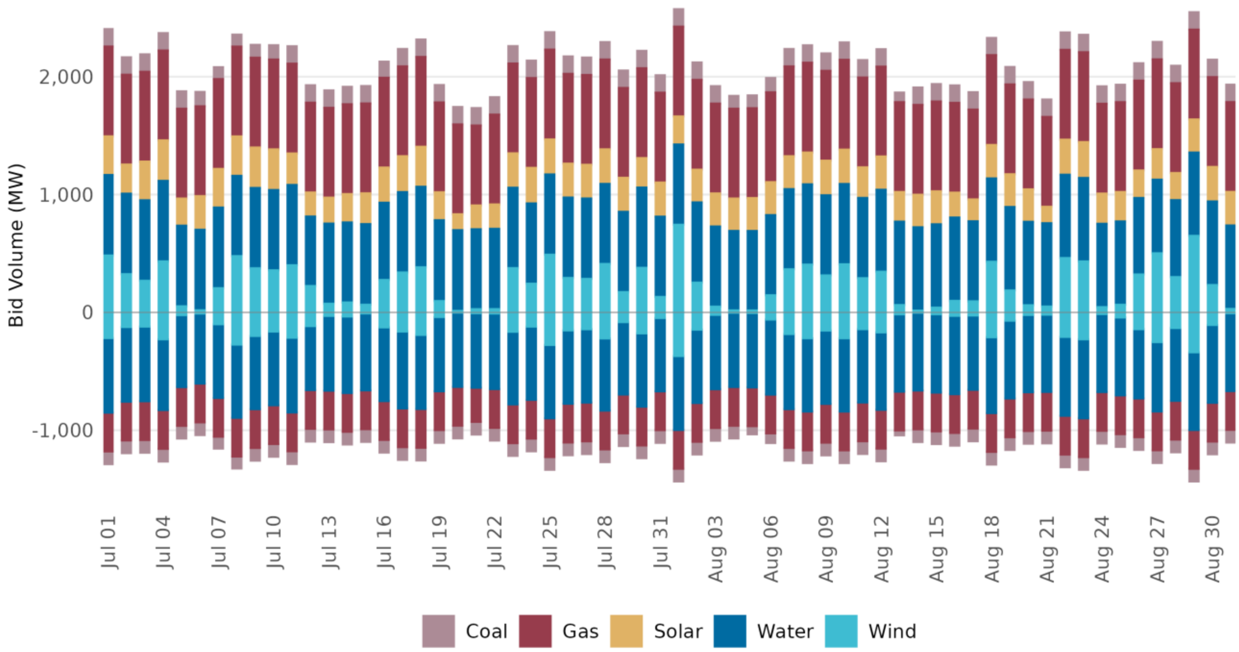


Figure 90: Daily average volume of RC bids by fuel type for PACW



Export reduction

In the month of August, there were instances of economic and low priority export reductions in the RUC process, shown in Figure 91. 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 92 shows the instances when the real-time market reduced exports in August, with the largest reduction happening on August 21 for low priority exports.

Figure 91: RUC export reduction

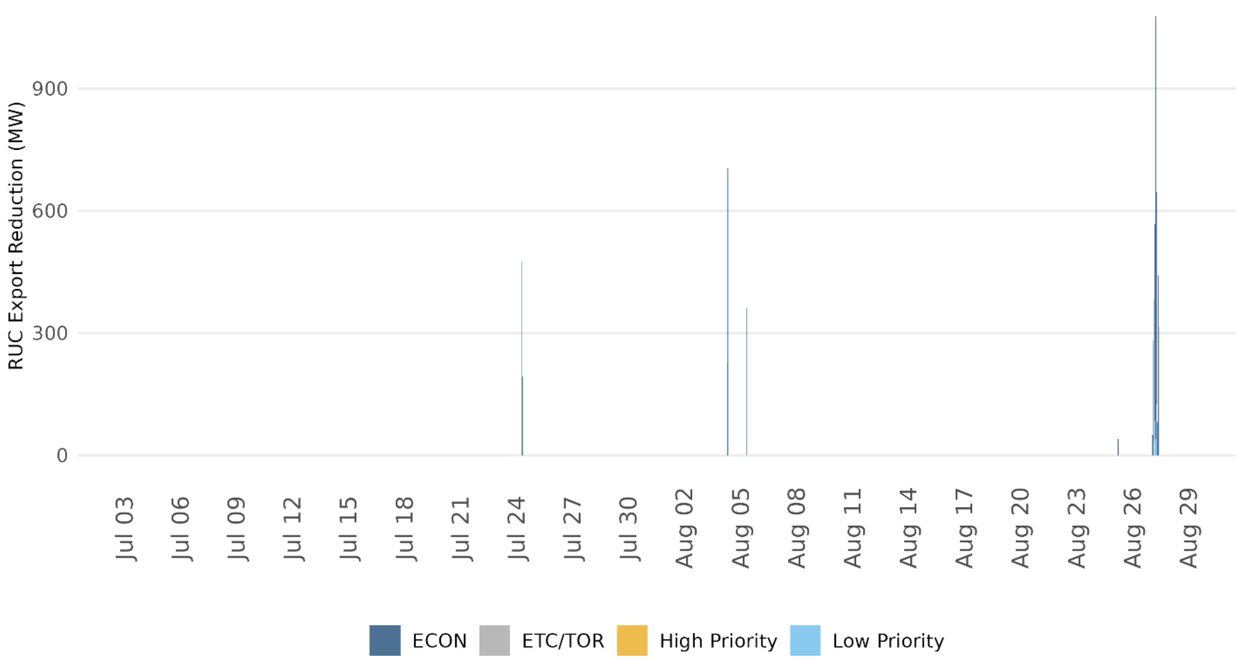
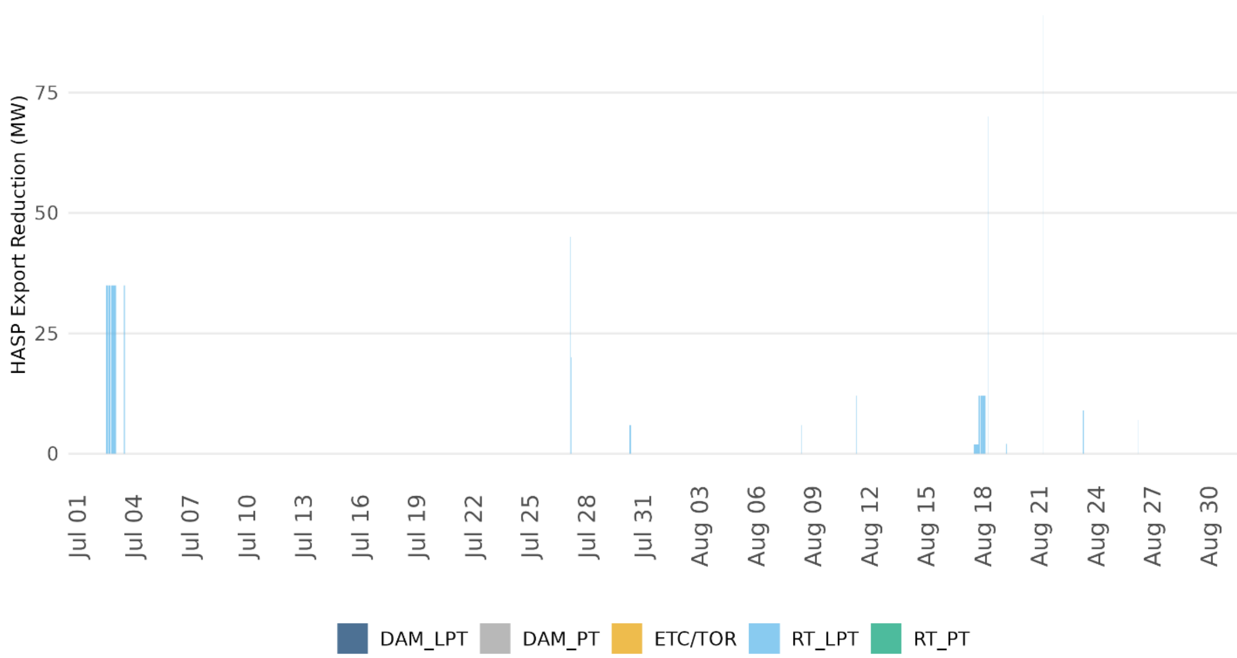


Figure 92: Exports reductions in HASP



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 93 shows the average hourly cleared virtual generation, virtual load, and the net virtual bids for each day in July and August in the day-ahead market. The net cleared virtual bid is defined as the total cleared virtual generation minus the total cleared virtual demand. Net cleared virtual bids in August were lower compared to July. Cleared virtual demand exceeded virtual generation on August 26 and 28. A software defect led to convergence bids, both virtual generation and virtual demand, to not be included in the day-ahead market for trade date 7/29. Virtual bids in 2025 in July and August were mostly net supply like in 2026.

Figure 93: Average hourly cleared virtual bids

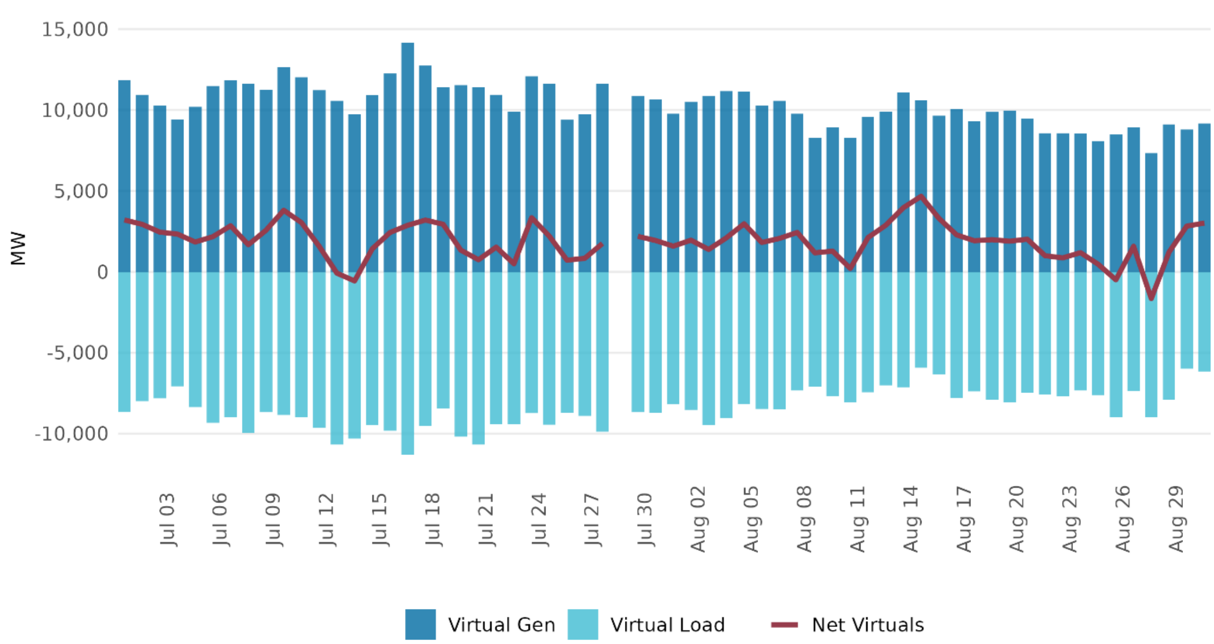


Figure 94 and Figure 95 show the hourly profile of average virtual supply and virtual demand, respectively, from June through August. Relative to July, both virtual supply and demand declined in August. Compared to June, average cleared virtual supply and demand in July and August was highest in the afternoon, reaching a peak in HE 16. Compared to 2025, the 2026 hourly profiles were generally similar but exhibited a more pronounced peak around HE 16 for July and August, along with higher overall virtual bid volumes.

Figure 96 shows the hourly profile of average net cleared virtual bids from June through August, calculated as cleared virtual supply minus cleared virtual demand. Positive values indicate net virtual supply, while negative values indicate net virtual demand. Net virtual bids generally shifted toward virtual demand during midday hours and toward virtual supply during the remaining hours. However, in July and August, net virtual supply persisted for several hours after the HE 7 morning peak. In August, net virtual demand occurred only in HE 15 and 16, compared to four midday hours in July. Net virtual bids were higher from HE 8 to 17 in August than in July, but lower during the remaining hours. Across all months, HE 7 and HE 22 exhibited the highest levels of net virtual supply. The 2025 profiles were broadly similar, with net virtual demand during midday hours and net virtual supply otherwise, and with peaks in HE 7 and HE 22. Unlike July and August 2026, however, 2025 did not exhibit net virtual supply during midday hours.

Overall, there does not appear to be a consistent difference from 2025 to 2026 across all months to indicate that these differences are driven by EDAM.

Figure 94: Average hourly cleared virtual supply

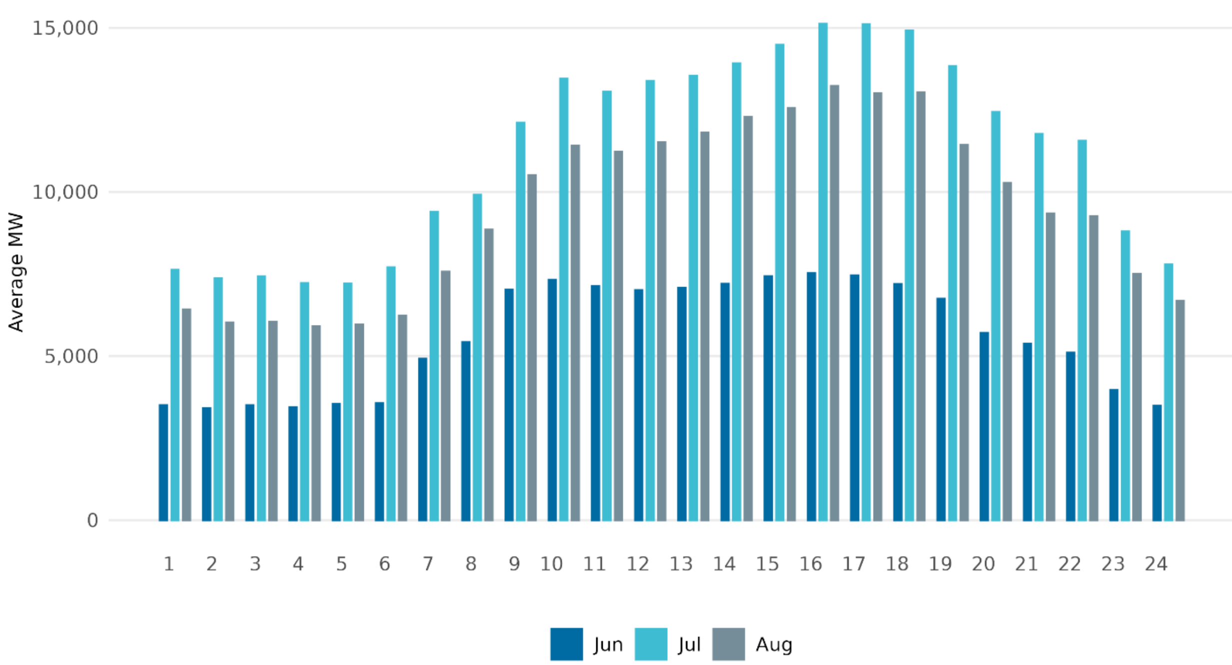


Figure 95: Average hourly cleared virtual demand

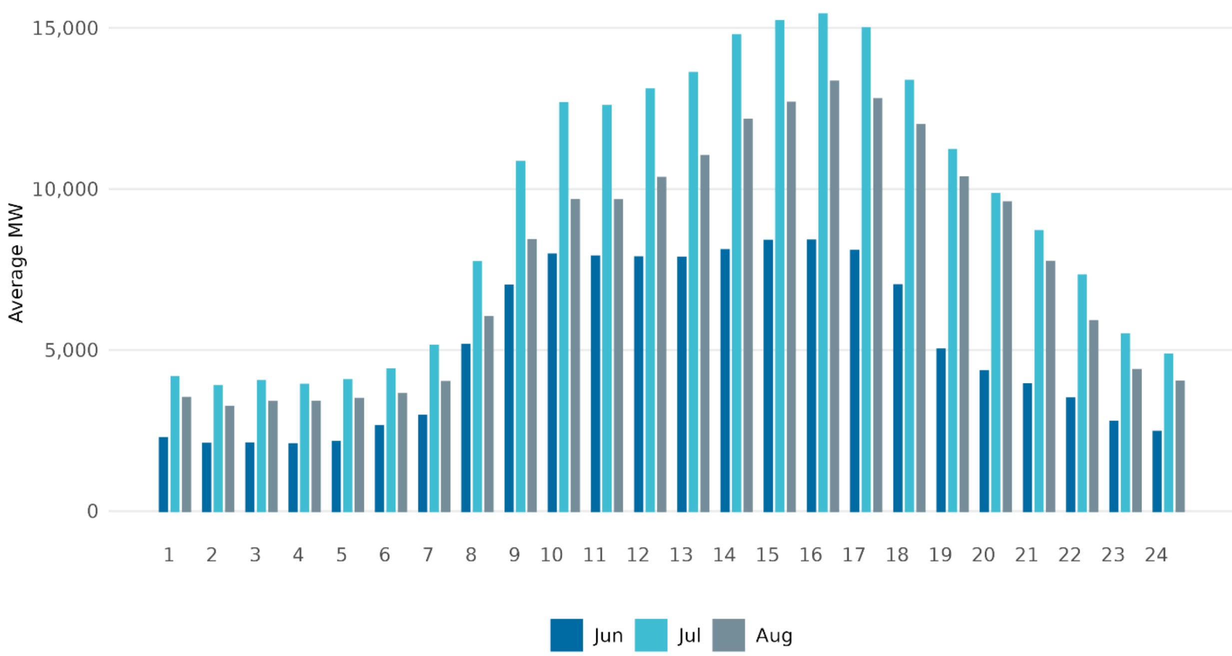
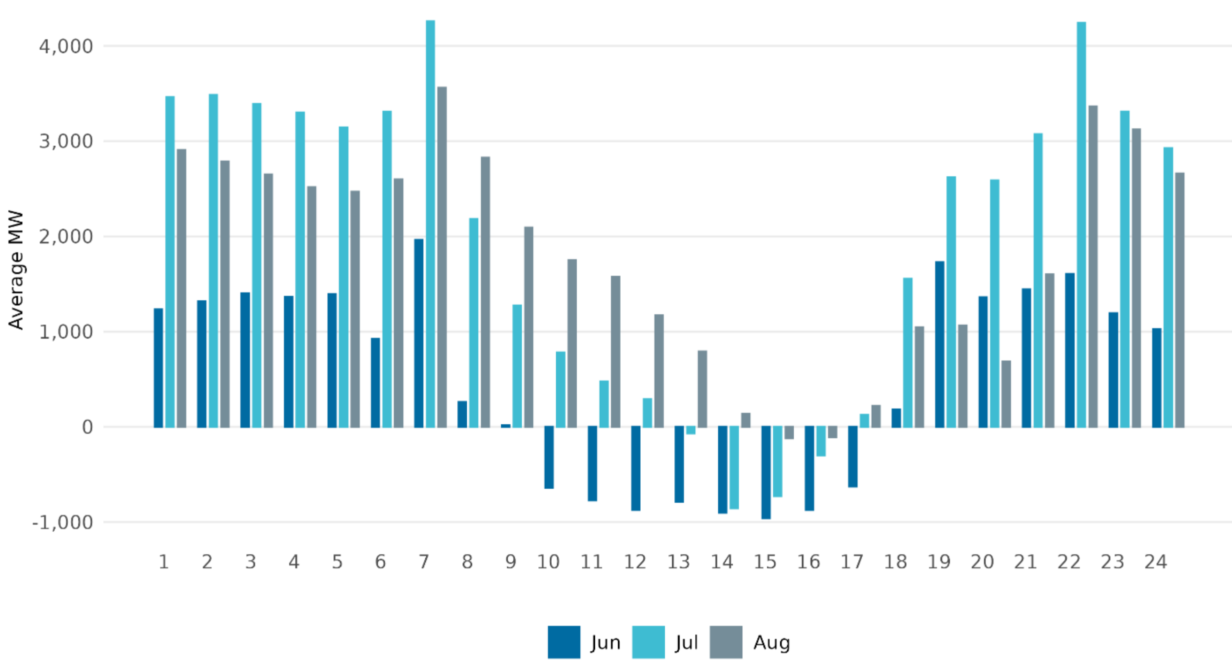


Figure 96: Average net hourly cleared virtual bids



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 August, the highest GHG price reached 35.0 $/MWh during Trade Hour 7 on August 27. The maximum hourly GHG allocation was 515 MW, occurring on multiple days in August.

Figure 97 shows the daily average GHG allocation for both July and August. In August, the daily average GHG allocation reached its highest level near the end of the month, peaking at 342 MW on August 28, followed by 292 MW on August 10. Overall, the level of GHG allocation in August was generally comparable to that in July.

Figure 97: Daily average GHG allocation

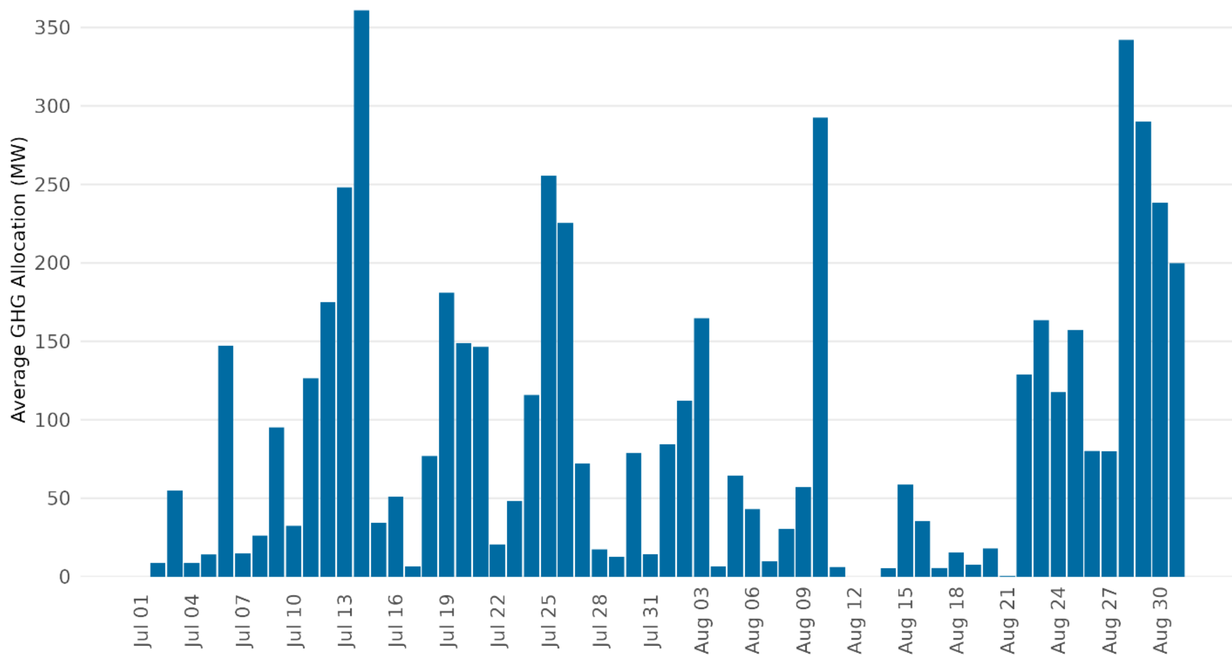


Figure 98 shows the daily average GHG prices in both July and August. In August, daily average GHG prices fluctuated throughout the month, with the highest daily average price reaching 15.1 $/MWh on August 28. Overall, the range of daily average GHG prices in August was similar to that observed in July.

Figure 98: Daily average GHG price

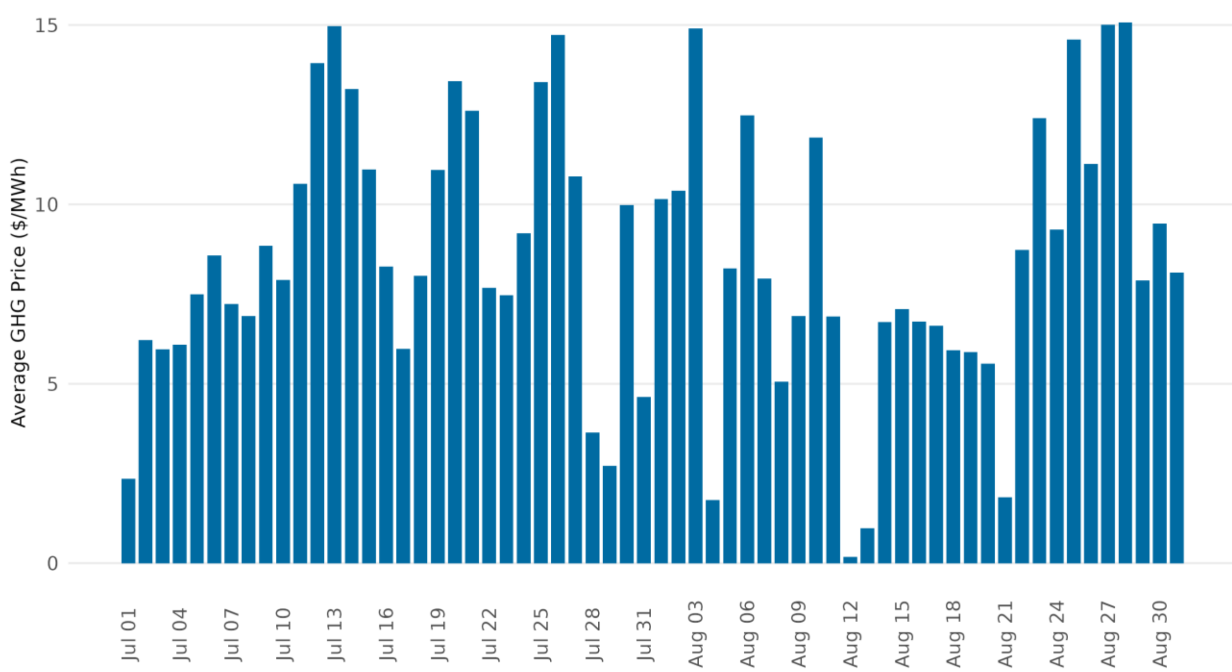


Figure 99 shows the hourly average GHG price by trade hour for June, July, and August. GHG prices were generally higher during the early morning hours (Hours 1–7), declined during the midday period (approximately Hours 10–17), and showed a modest increase again during the evening hours (Hours 19–24). 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 99: Hourly average GHG price

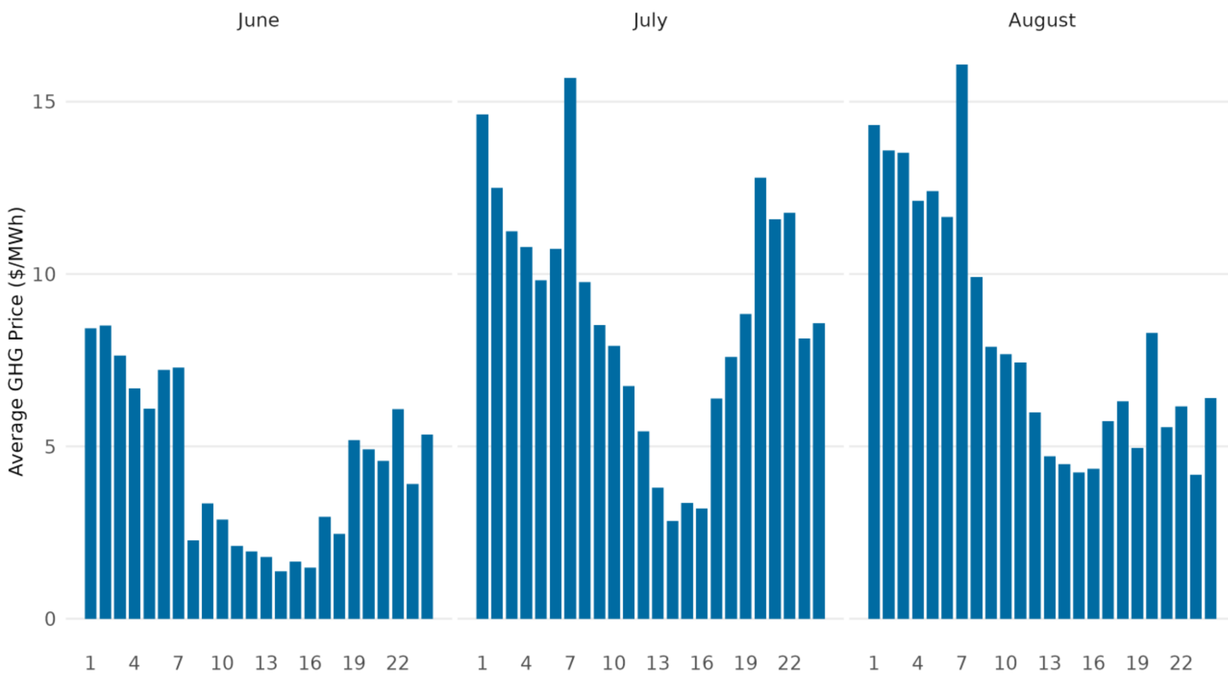
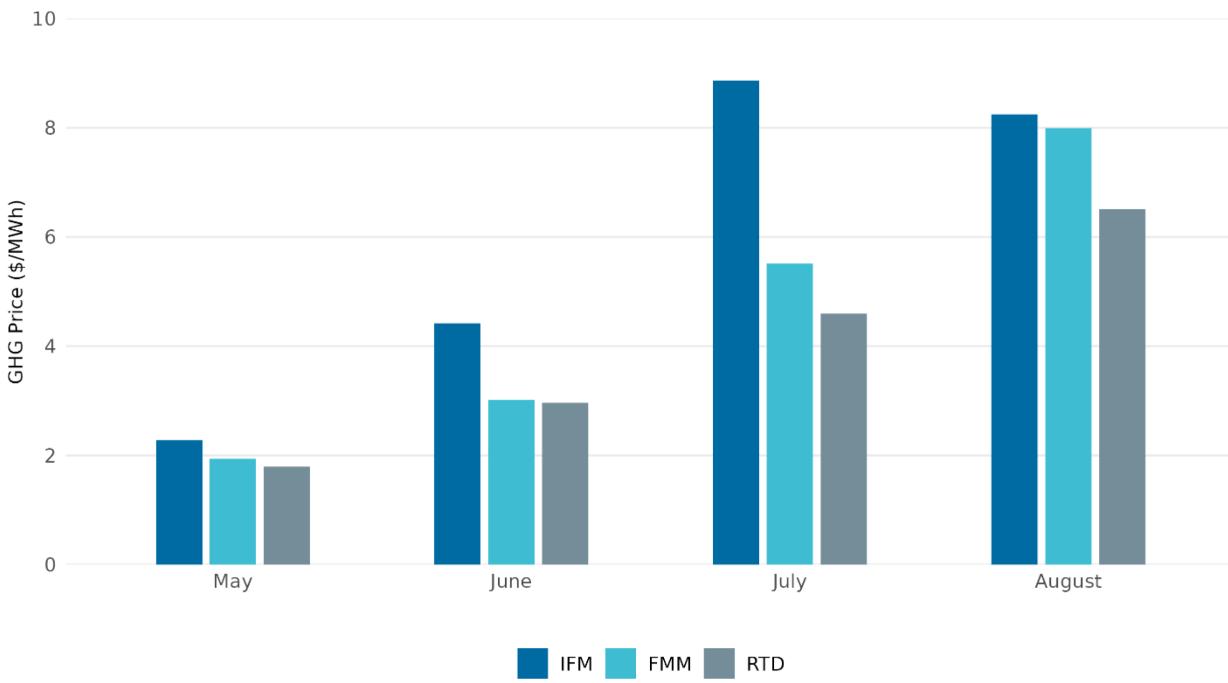


Figure 100 shows the monthly average GHG prices in the IFM, FMM, and RTD markets from May to August. GHG prices generally increased over this period, with only one exception in IFM, where GHG prices decreased slightly from July to August. Overall, IFM prices remained higher than real-time prices in all four months. 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 100: Monthly average GHG price by market



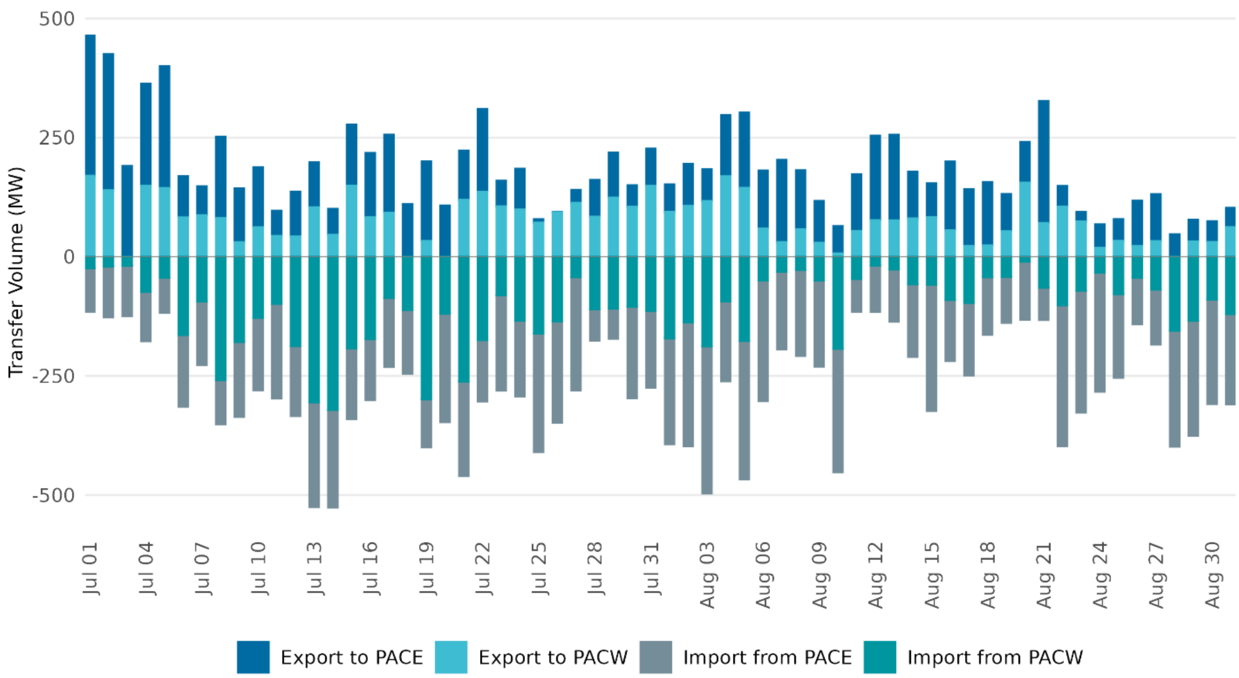
EDAM Transfers

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.

Energy transfers

Figure 101 illustrates CAISO daily average energy transfers in IFM in July and August 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 mid-July, CAISO had more imported energy from PACW. The average export volume generally decreased in July and August due to summer conditions.

Figure 101: Daily average energy transfers for CAISO



The hourly profile in Figure 102 exhibits variations in daily transfer volumes across June, July, and August. Overall, exports to PAC areas generally decreased and imports increased. June experienced the highest export levels, particularly in the daylight hours of the month. In July, export volumes were relatively moderate, while imports increased significantly, reaching some of the highest import levels observed during the three-month period with hourly average above 250 MW. August showed comparatively lower export volumes than June and July, but the imports were almost the same with July around 250 MW. Generally, in July and August there was noticeable increase in energy imports and reduction in exports due to summer weather.

Figure 102: Hourly average energy transfers for CAISO

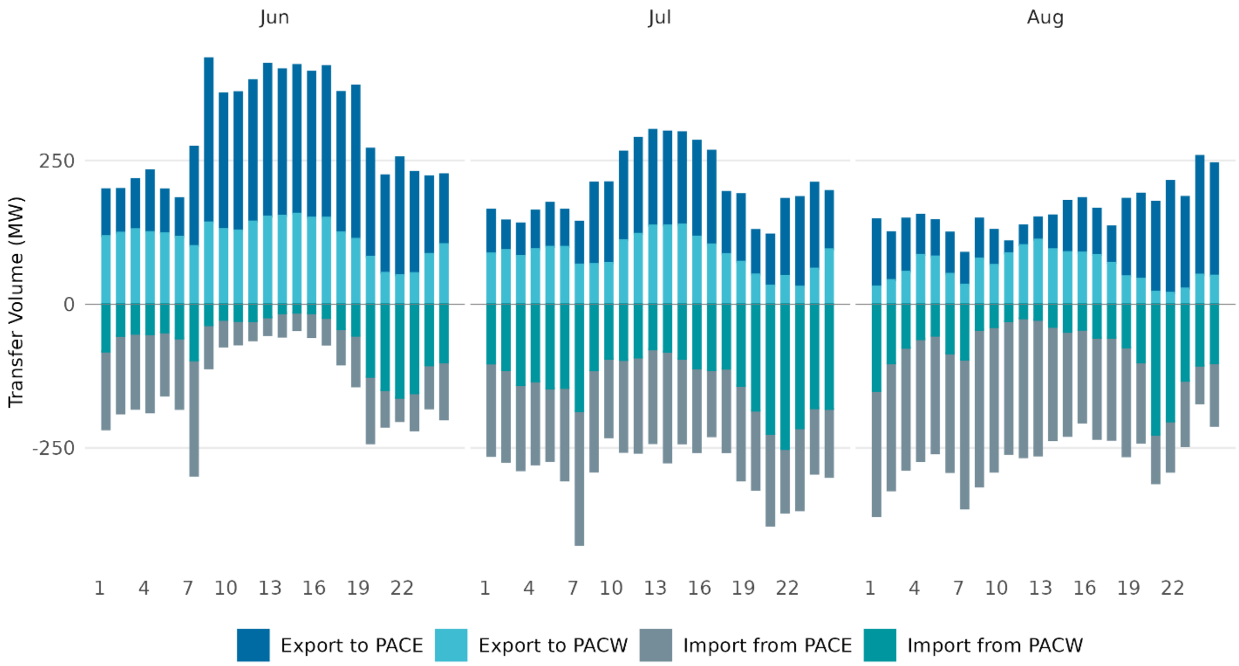


Figure 103 show PACE's daily and hourly average energy transfers throughout July to August 2026 in both export (+) and import (-) directions. Generally, PACE remained an importer to CISO in June but changed to a net exporter in July and August. In August the daily exports increased significantly and reached their highest of about 500 MW on several days. In the meantime, there was noticeable decrease in energy imports from CAISO.

The Figure 104 hourly profile also shows PACE's increasing exports as market evolves in August, with hourly average exports over 450 MW in morning peak hours. In contrast, imports from CAISO's decreased in July and August compared with May, from peak average import over 250 MW in May to about 200 MW in August, and the peak hours were shifted from solar peak hours to night hours.

Figure 103: Daily average energy transfers for PACE

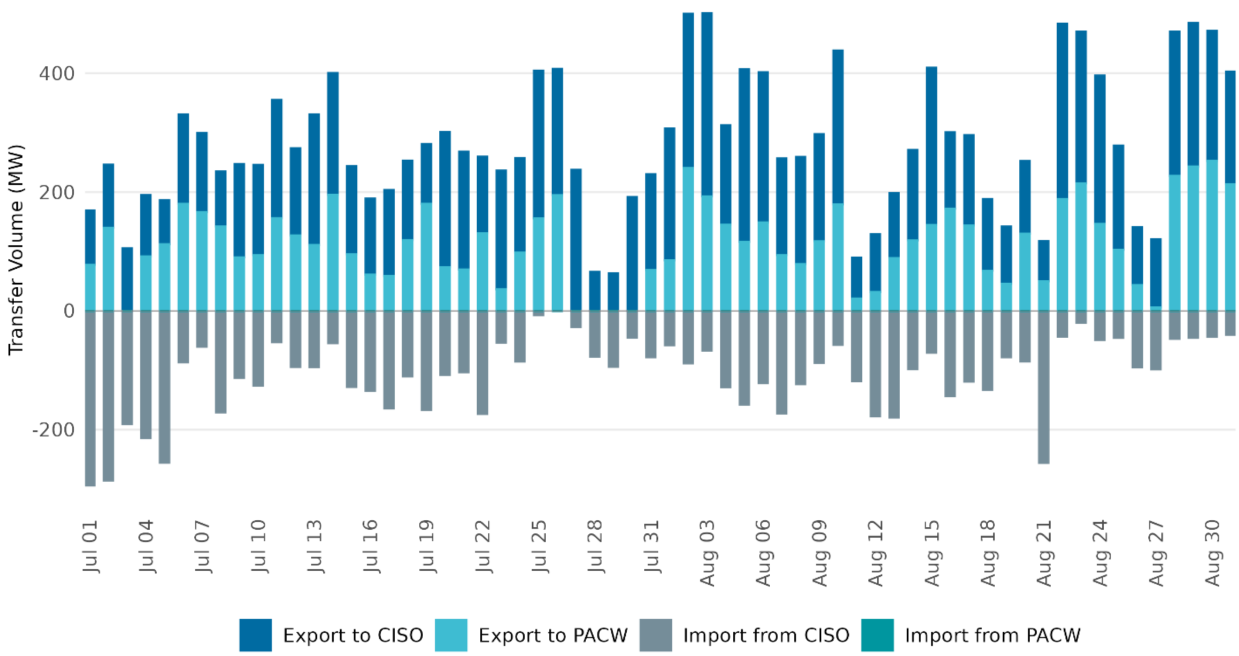


Figure 104: Hourly average energy transfers for PACE

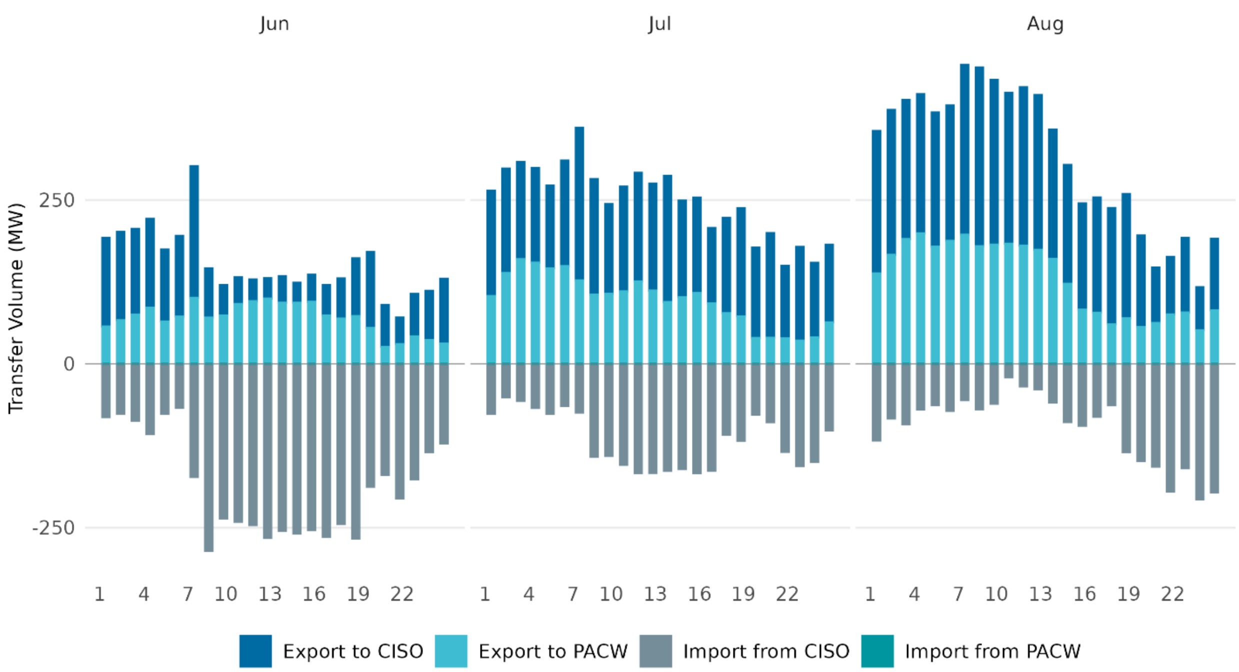


Figure 105 and Figure 106 show PACW's daily and hourly average energy transfers throughout July to August 2026 on both export (+) and import (-) directions. Generally, PACW was a net importer in both months, and more energy was imported from PACE, and August has more energy imports compared with July, with daily average maximum over 280 MW on August 2. The daily average profile shows a reduction in energy exports in August, and almost all energy exported was to CAISO. The hourly profile shows a slight increase in average imports in August compared with June and July, and export peak hours are about 290 MW at HE 4 and HE 13. In contrast, PACW's energy exports show a slight decrease in August compared with July.

Figure 105: Daily average energy transfers for PACW

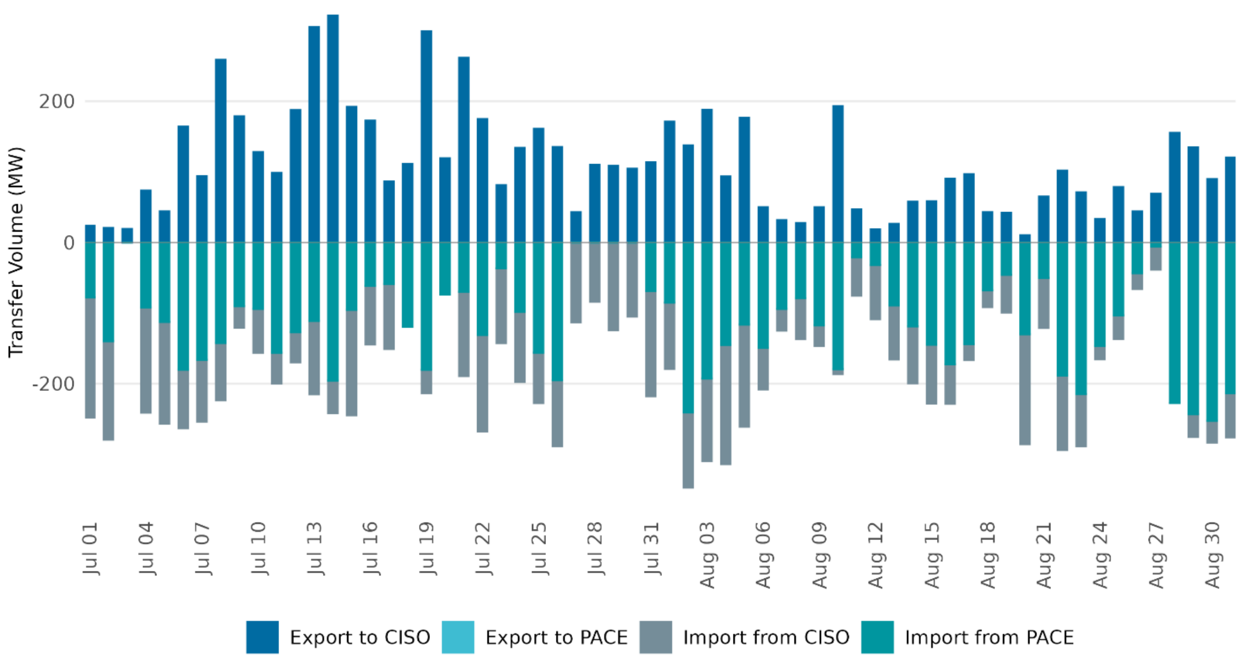


Figure 106: Hourly average energy transfers for PACW

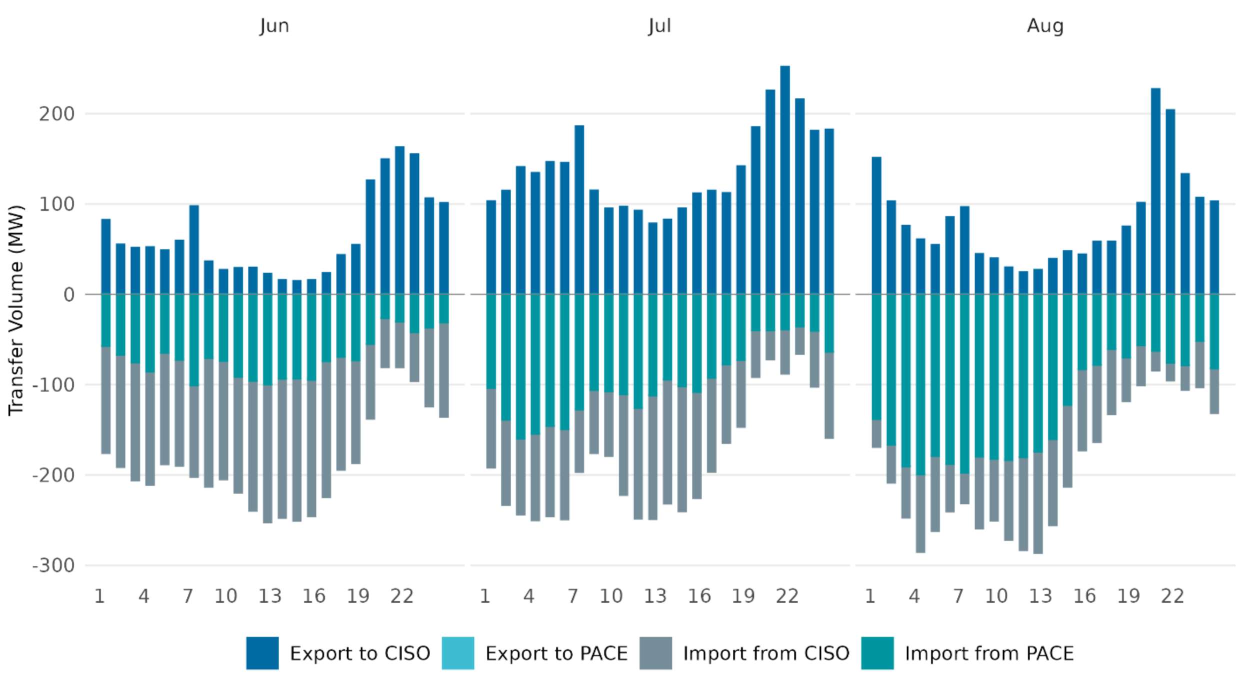
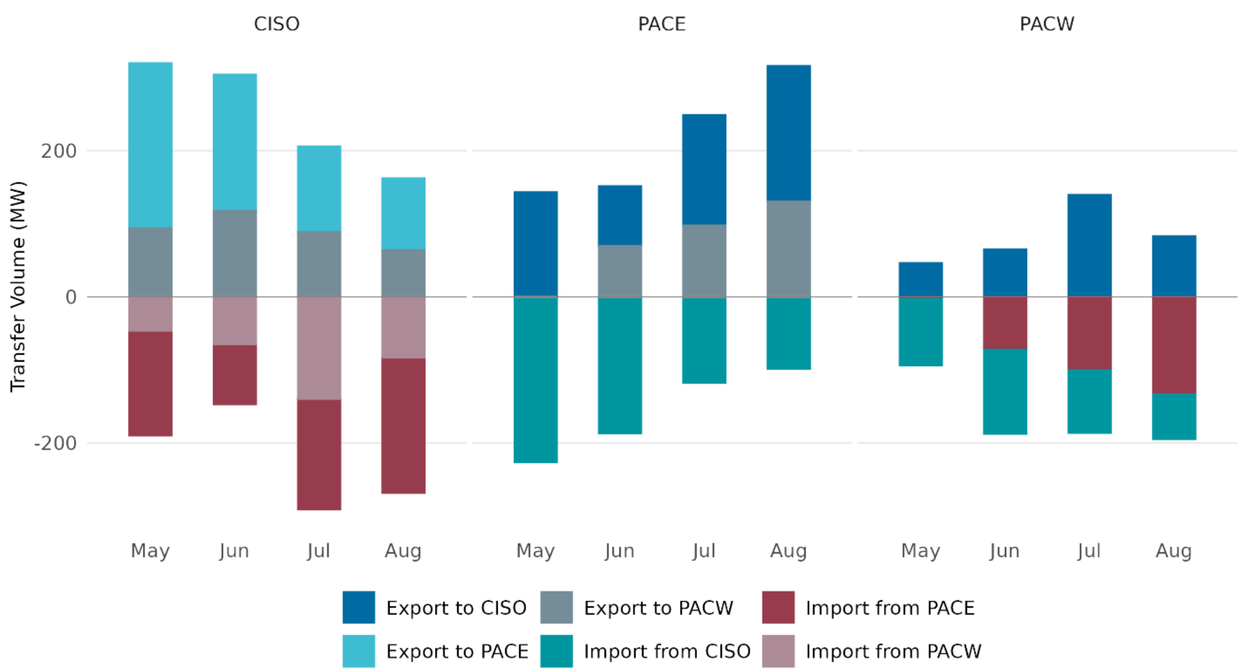


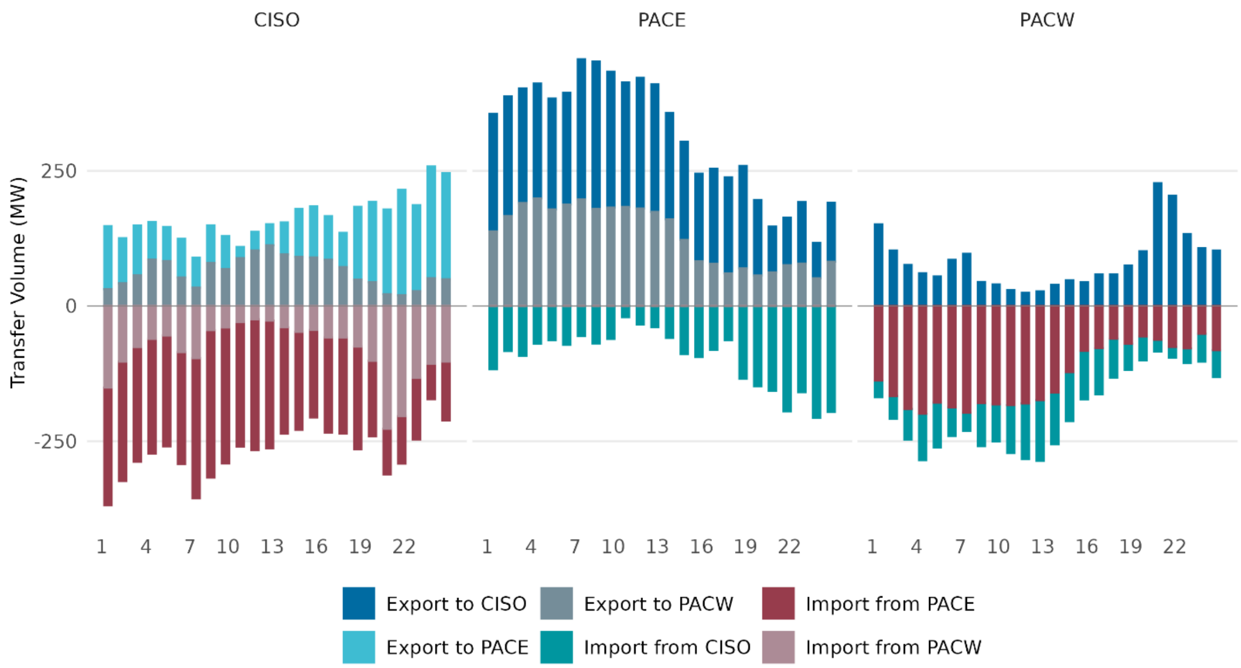
Figure 107 shows the summary of three BAAs' total energy transfer volumes throughout May to August in both export (+) and import (-) directions. For CAISO, the total export volumes show consistent downward trend over the past four months while imports increase a lot in July and August due to summer weather. In contrast, PACE's exports have been increasing, and imports have been declining over the past four months. PACW's exports reached the highest level in July and reduced in August while imports stayed stable throughout June to August. Besides, the transfer between PACW and PACE kept increasing since June, compared with almost no direct transfer between PACE and PACW in May.

Figure 107: Hourly average energy transfers volumes in EDAM



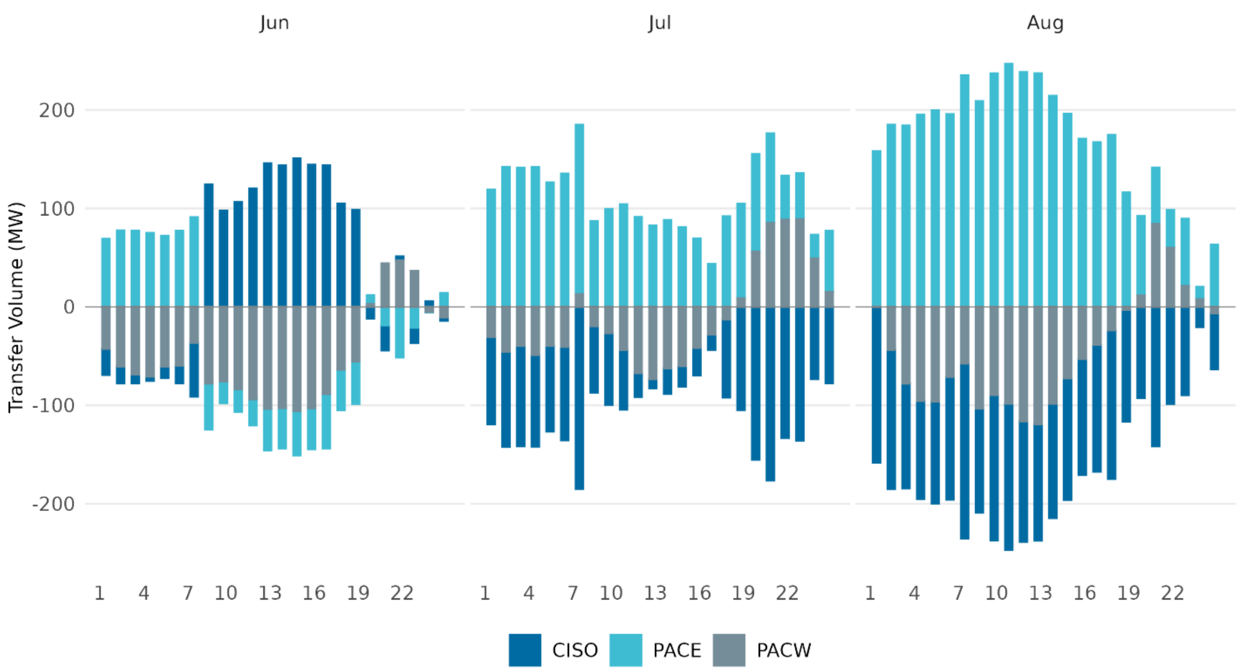
Hourly energy transfer patterns varied considerably across the three BAAs in August, as shown in Figure 108. In August, CAISO's imports were consistently larger and more variable across hours. PACE generally maintained a net exporter, with the largest export volumes occurring during the morning hours. PACW, by comparison, was a substantial net importer during most of the day, particularly during the morning and midday hours, before export volumes increased in the evening.

Figure 108: Hourly average energy transfers volumes in EDAM in August



Hourly energy net transfer patterns varied considerably across the three BAAs throughout June to August. CISO recorded net exports in June but switched to net importer in July and August, while PACE remained net exporter in three months, with both reaching their largest magnitudes during daytime hours. These patterns became more pronounced from June to August, with peak transfers approaching 250 MW in August. PACW exhibited a relatively stable negative transfer profile across most hours.

Figure 109: Hourly average net energy transfers volumes in EDAM



Imbalance reserves

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

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

Imbalance reserve up

As with energy, the market can transfer imbalance reserves among BAAs, which provide revenue to exporting areas and lower costs capacity reserves to importing areas.

Figure 110 and

Figure 111 show CAISO's daily and hourly average IRU transfers throughout July to August on both export (+) and import (-) directions. Generally, in both months CAISO exported IRU and most of the exports went to PACE, and the transfer volume stayed the same for two months, with the peak daily average IRU exports over 400 MW. Besides, there was a slight increase in IRU imports from PACW in August. The hourly profile shows noticeable IRU imports increase in August, with the peak imports over 300 MW at HE 8.

Figure 110: Daily average IRU transfers for CAISO

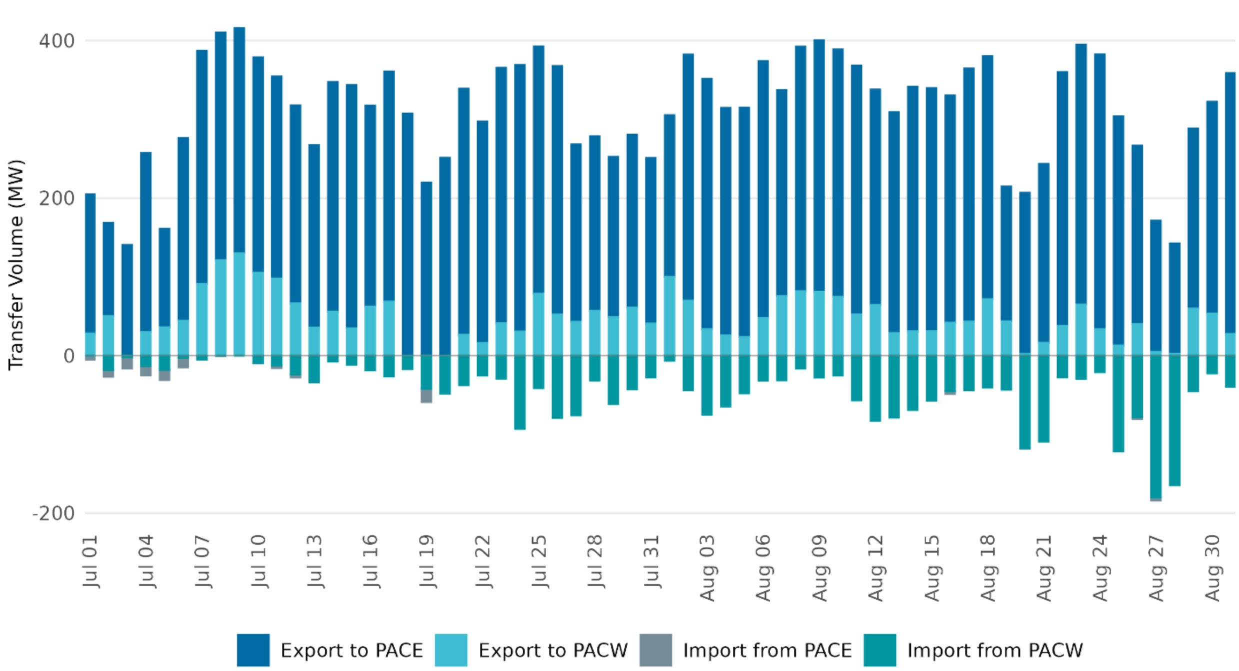


Figure 111: Hourly average IRU transfers for CAISO

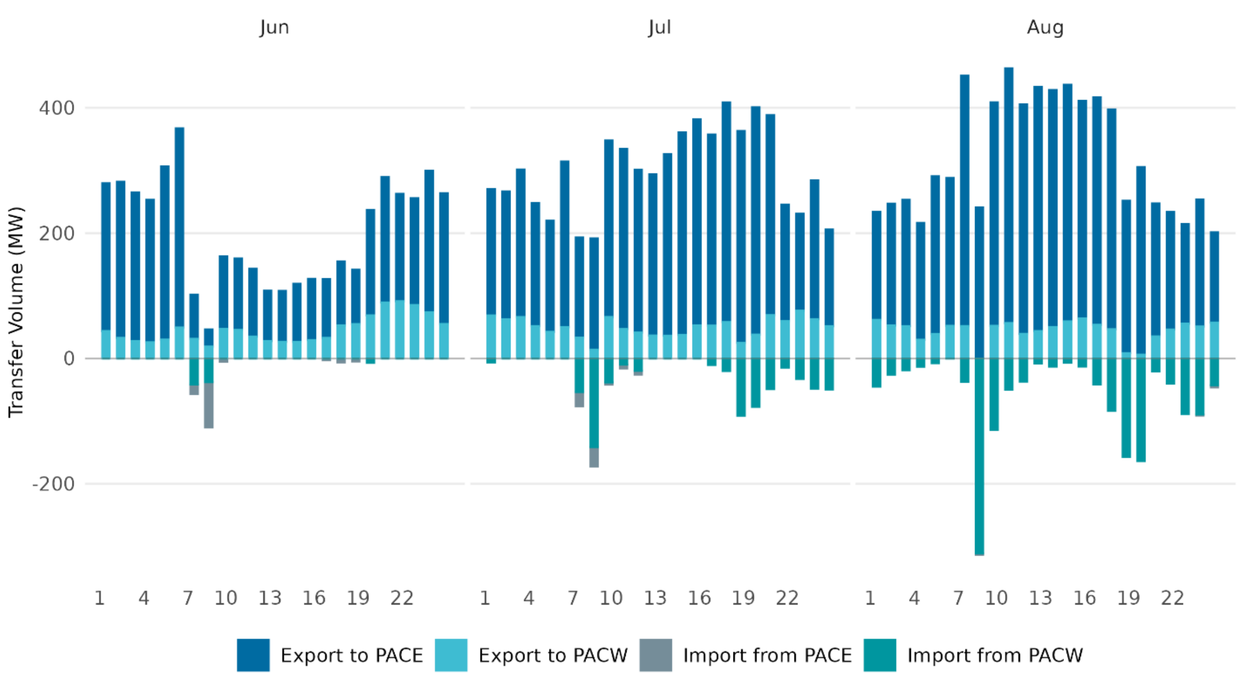


Figure 112 - Figure 113 show PACE's daily and hourly average IRU transfers throughout July to August 2026 on both export (+) and import (-) directions, respectively. Generally, PACE remained a net importer in both the months, and the import is almost all from CAISO. The daily IRU imports stayed at the same level as in July, with peak imports being over 300 MW, while exports dropped

further down to few MW. The hourly charts showed that PACE's IRU imports increased in August against July, with peak imports over 400 MW at HE 7 and HE 11.

Figure 112: Daily average IRU transfers for PACE

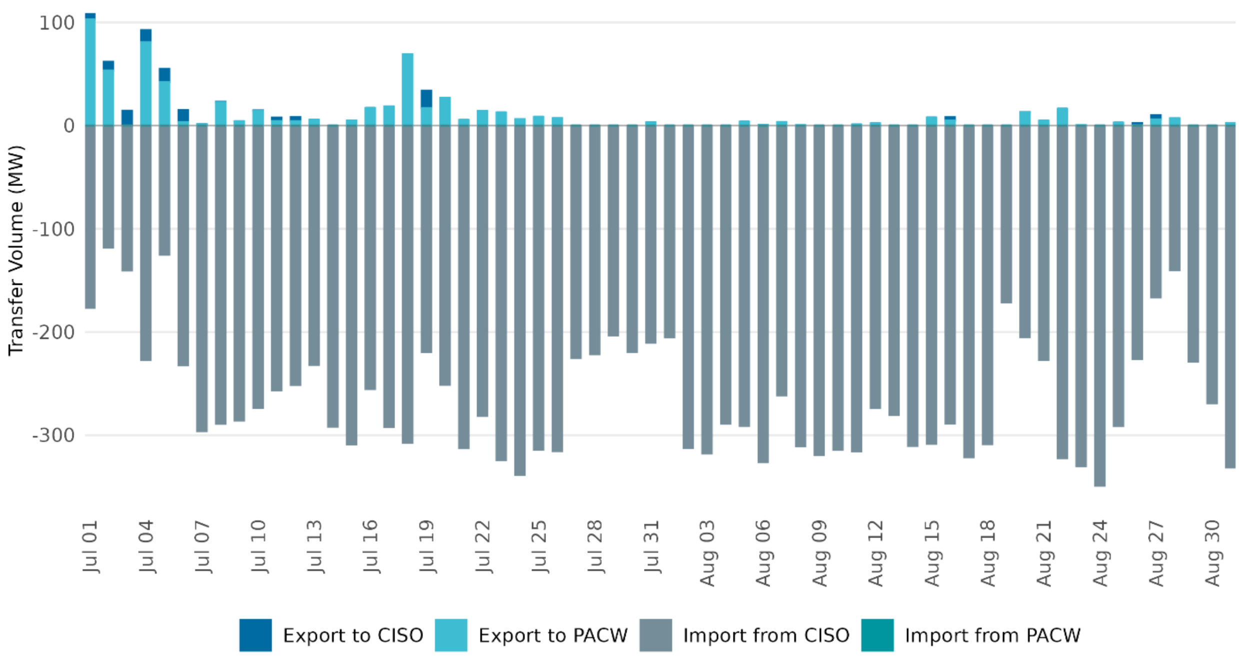


Figure 113: Hourly average IRU transfers for PACE

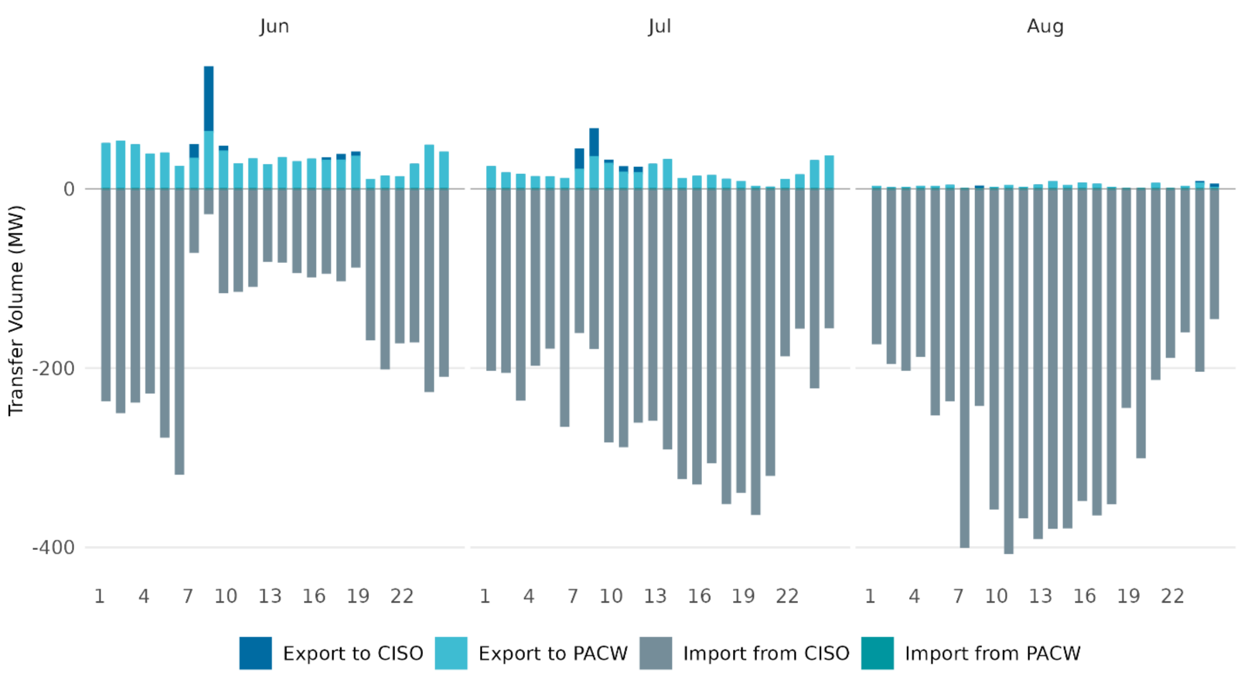


Figure 114 and Figure 115 show PACW's daily and hourly average IRU transfers throughout July to August 2026 on both export (+) and import (-) directions, respectively. Daily average IRU transfers showed an overall increase in PACW's exports to CISO from July through August. Export volumes were relatively low in early July but generally increased over the following weeks, with several pronounced peaks over 180 MW in late August. Meanwhile, imports from CISO remained persistent throughout the period but did not exhibit a clear trend. Transfers between PACW and PACE were comparatively limited.

The hourly profile shows a clear increase in PACW's exports to CISO from June to August. While exports were limited in June, they became more pronounced in July and August, particularly during the morning and evening peak hours. The largest export volume occurred around HE 8 in August, exceeding 300 MW. In contrast, imports from CISO remained relatively consistent throughout the three months, while transfers between PACW and PACE remained limited.

Figure 114: Daily average IRU transfers for PACW

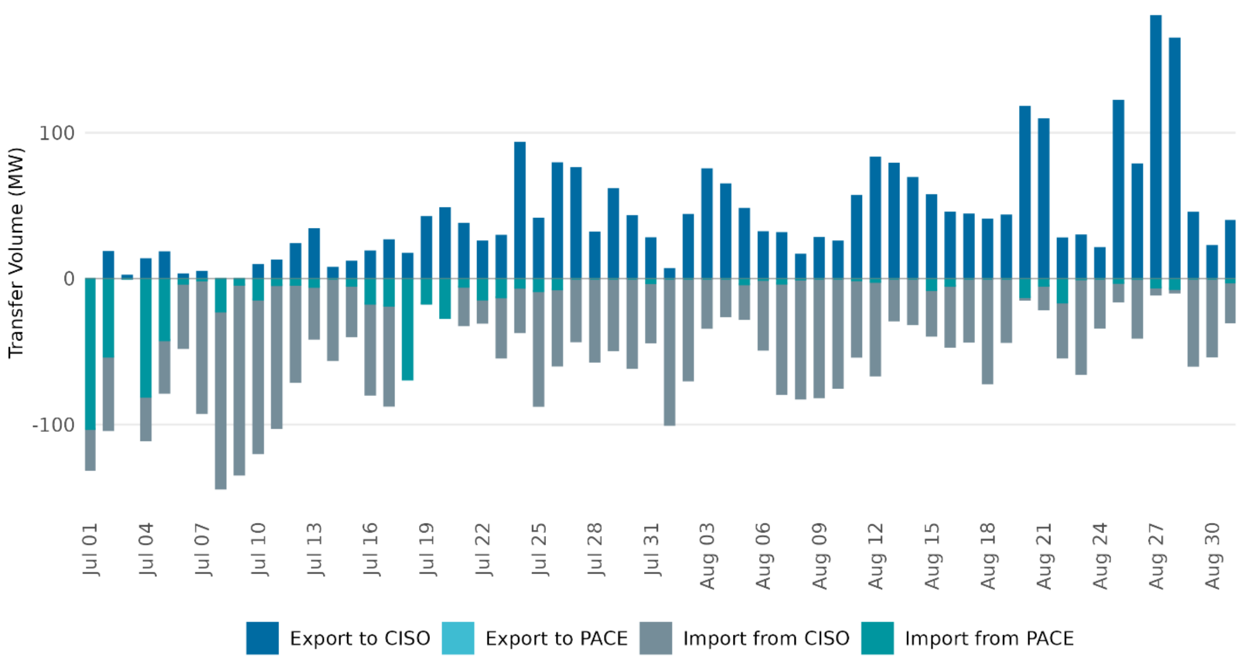


Figure 115: Hourly average IRU transfers for PACW

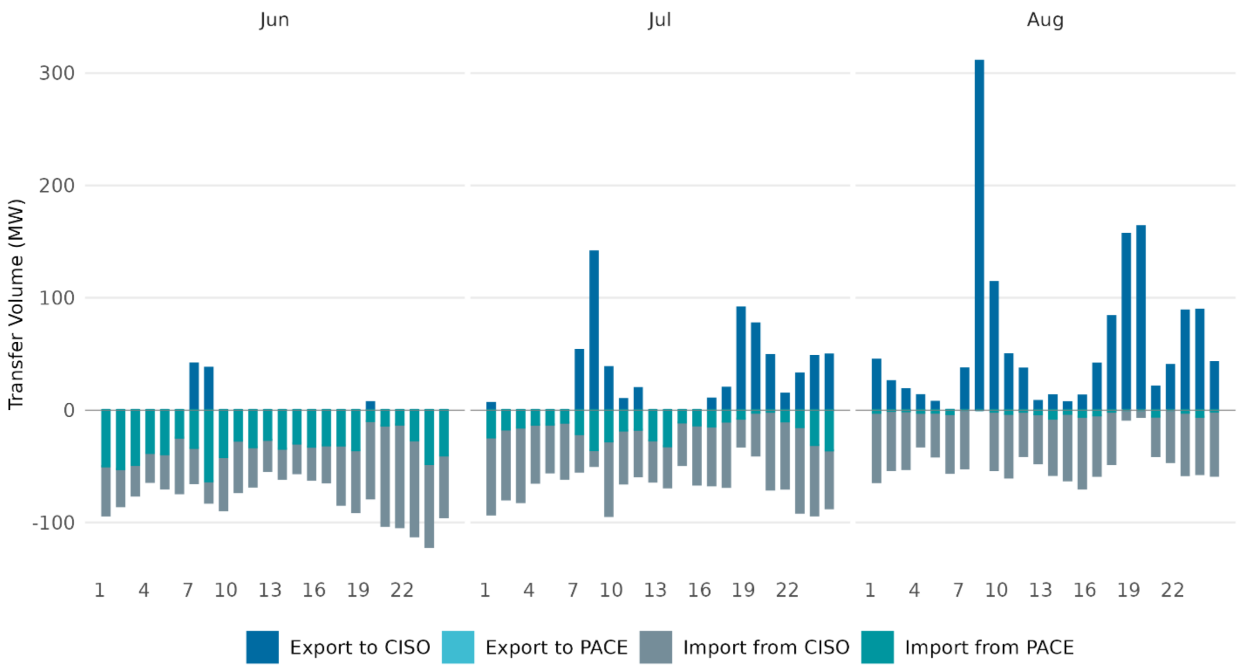
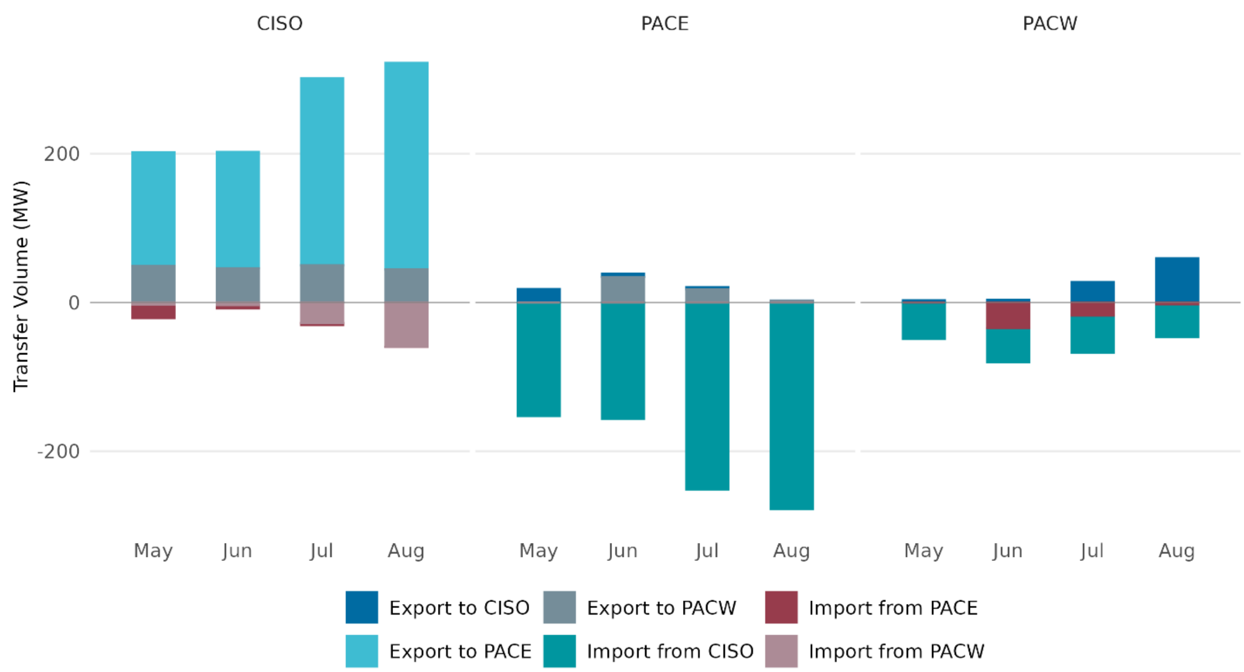


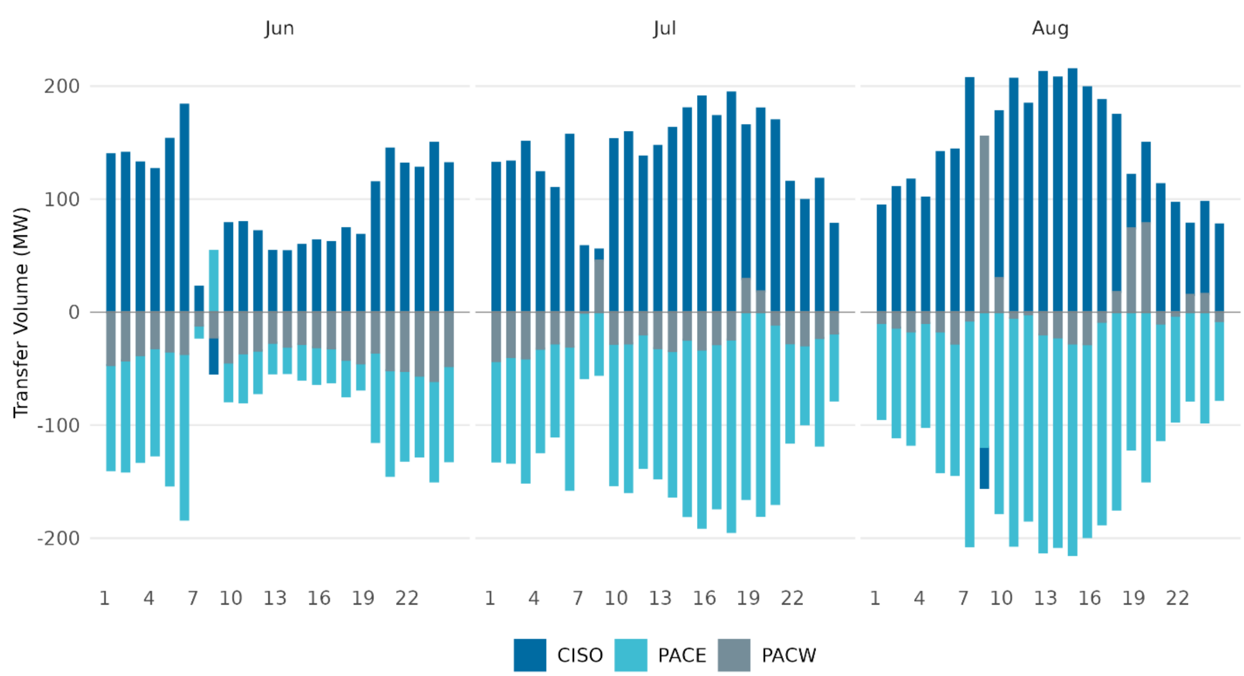
Figure 116 shows the summary of three BAAs' total IRU transfer volumes throughout May to August in both export (+) and import (-) directions. For CAISO, the total transfer volumes are almost the same in May and June, with only a noticeable increase in exports to PACE in July and August. In July and August, PACW also increased its IRU exports to CAISO.

Figure 116: Hourly average IRU transfers volumes in EDAM



For hourly IRU net transfer patterns, CISO recorded net exports in all months and PACE and PACE remained net importers. In July and August, IRU transfers reached largest magnitudes during daytime hours. These patterns became more pronounced from June to August, with peak transfers approaching 200 MW in August. The only exception is morning peak HE 8 when CAISO had IRU imports from PACE or PACW.

Figure 117: Hourly average net IRU transfers volumes in EDAM



Imbalance reserve down

For IRD products, as Figure 118 and Figure 119 show, CAISO's daily average IRD transfers fluctuated significantly throughout July to August, with exports generally outweighing imports. Export volumes were primarily driven by transfers to PACE, with notable peak reaching 300 MW in early August. Beginning on August 6, overall IRD exports volumes declined only with few exports to PACE. Toward the end of August, imports from PACE increased noticeably and exceeded exports on several days, resulting in a shift toward net imports.

The hourly chart exhibited a consistent diurnal pattern, with exports generally dominating during the daytime and peaking in the afternoon in June and July but not in August. July showed the highest export levels, while August experienced lower transfers during the morning and midday hours, followed by a notable increase in exports during the evening.

Figure 118: Daily average IRD transfers for CAISO

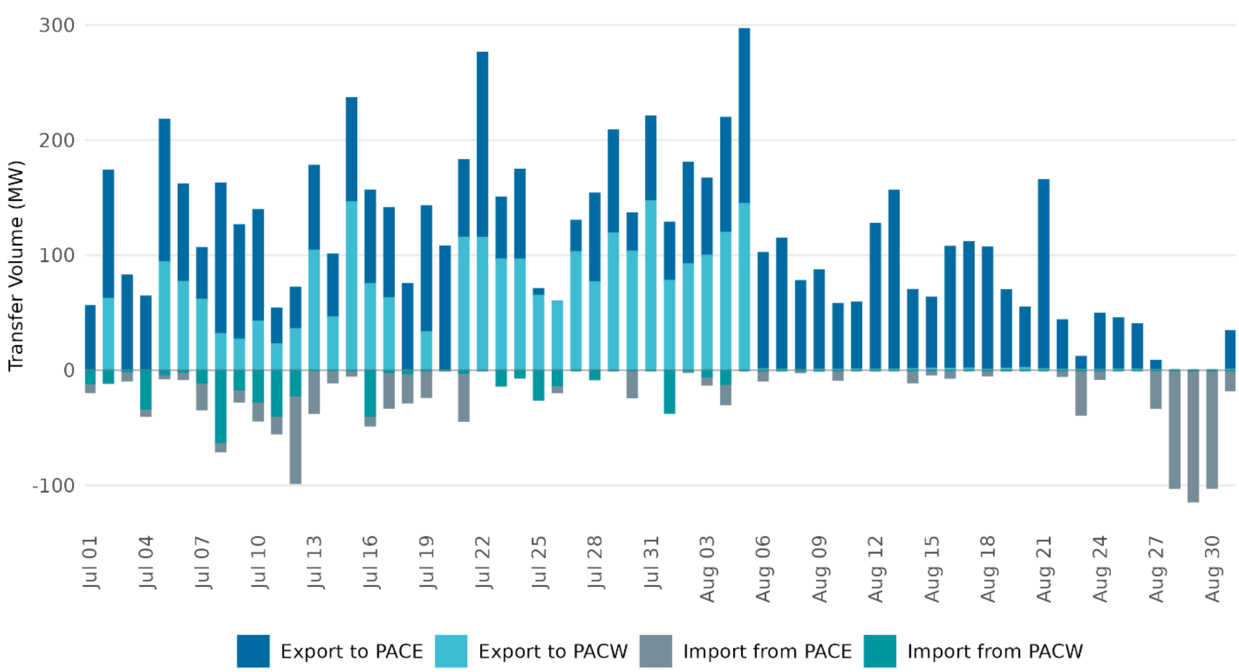
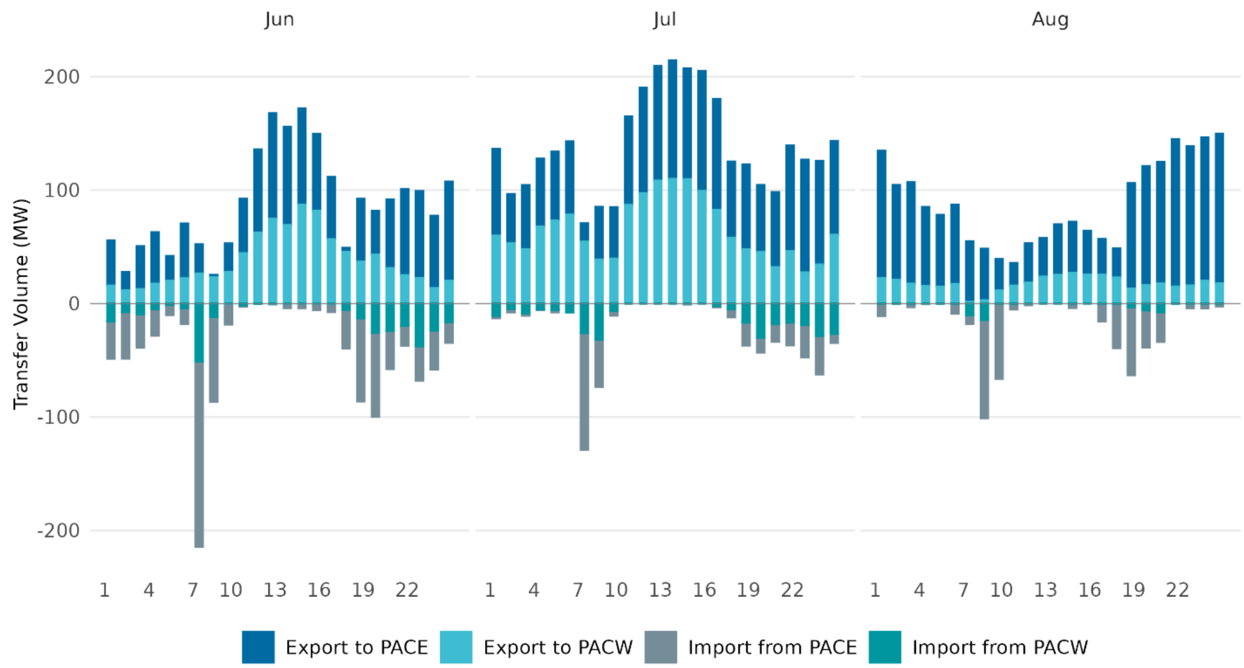


Figure 119: Hourly average IRD transfers for CAISO



PACE's IRD transfer showed a more dynamic pattern throughout July to August. As Figure 120 shows, during most of the days PACE remained a net exporter of IRD from CAISO but then switched to net exporter at the end of August. IRD export volumes were primarily driven by transfers to PACW, and there was a noticeable increase in IRD exports in August compared with July.

The hourly profile Figure 121 transfers showed a clear diurnal pattern, with imports from CISO generally higher during midday and late-evening hours and exports to CISO concentrated in the morning and early evening. Transfer volumes increased in August, driven by higher exports to PACW throughout the day and increased imports from CISO during the late-evening hours.

Figure 120: Daily average IRD transfers for PACE

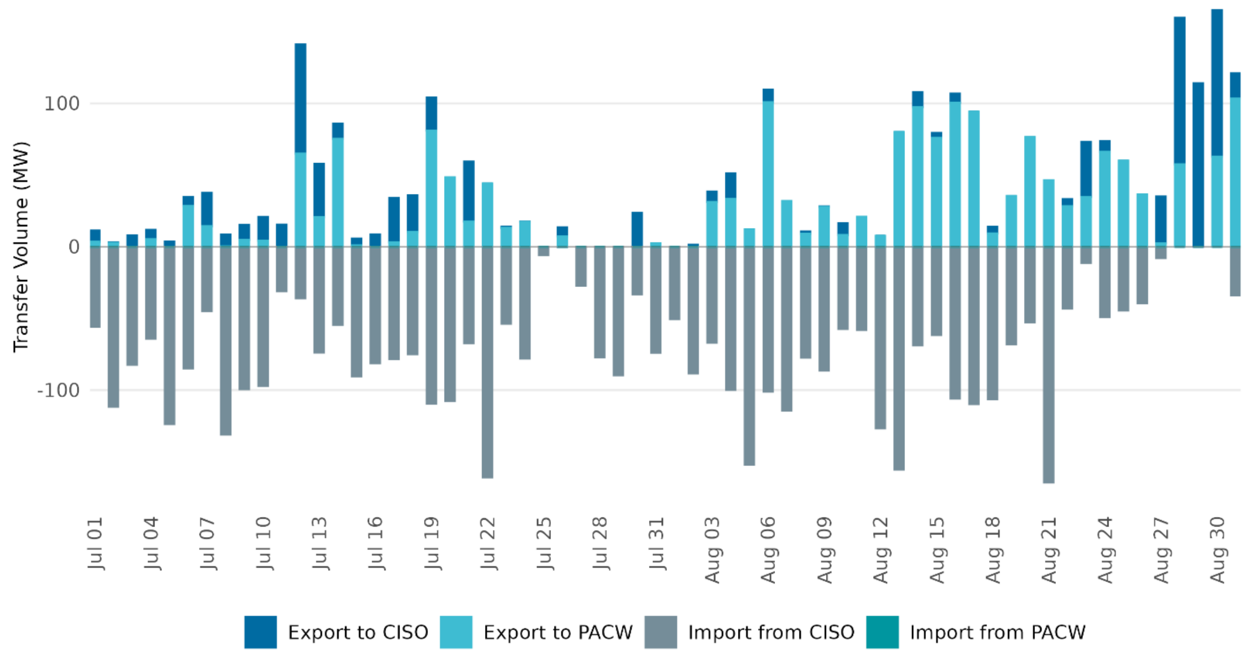
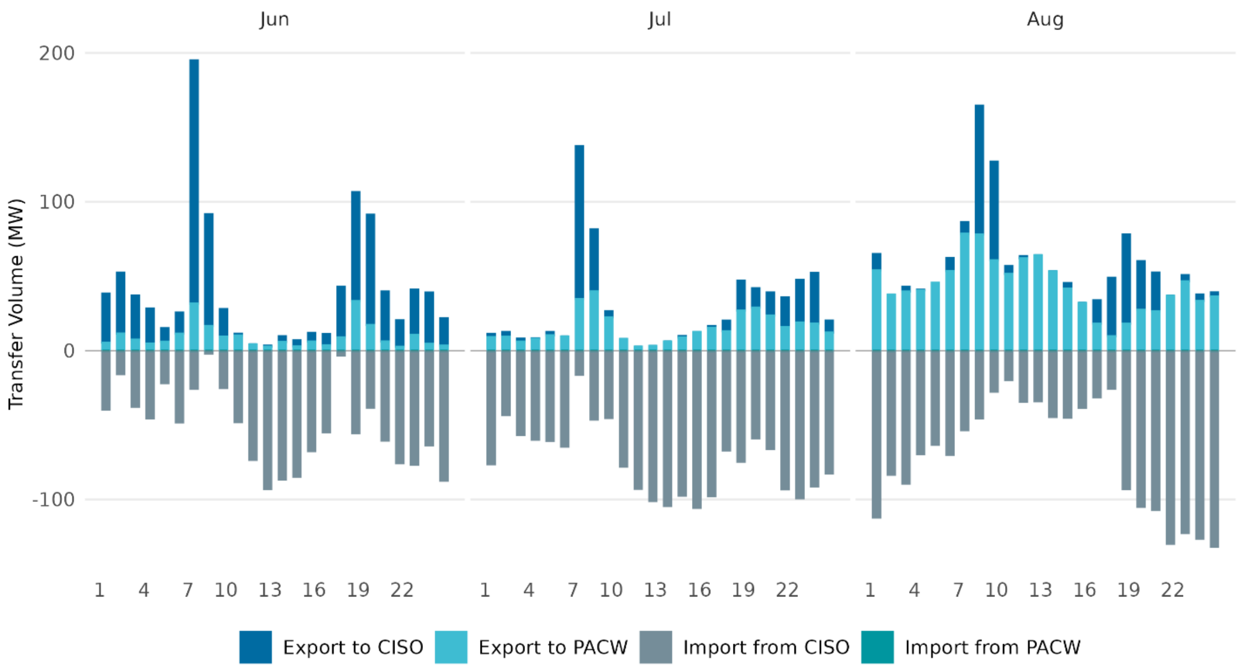


Figure 121: Hourly average IRD transfers for PACE



For IRD products, as Figure 122 and Figure 123 shows, PACW remained a net importer throughout July and August. While imports were primarily from CISO in July, they shifted toward PACE in August as imports from CISO declined substantially. Export activity remained relatively limited, particularly during August.

Figure 122: Daily average IRD transfers for PACW

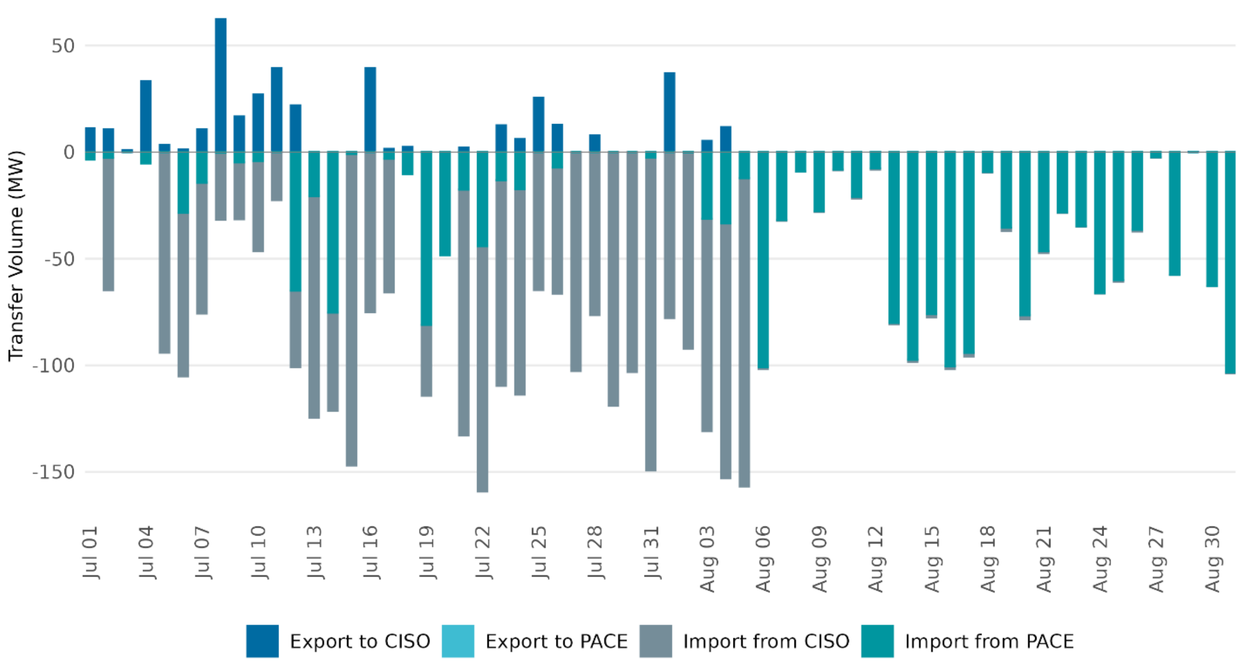


Figure 123: Hourly average IRD transfers for PACW

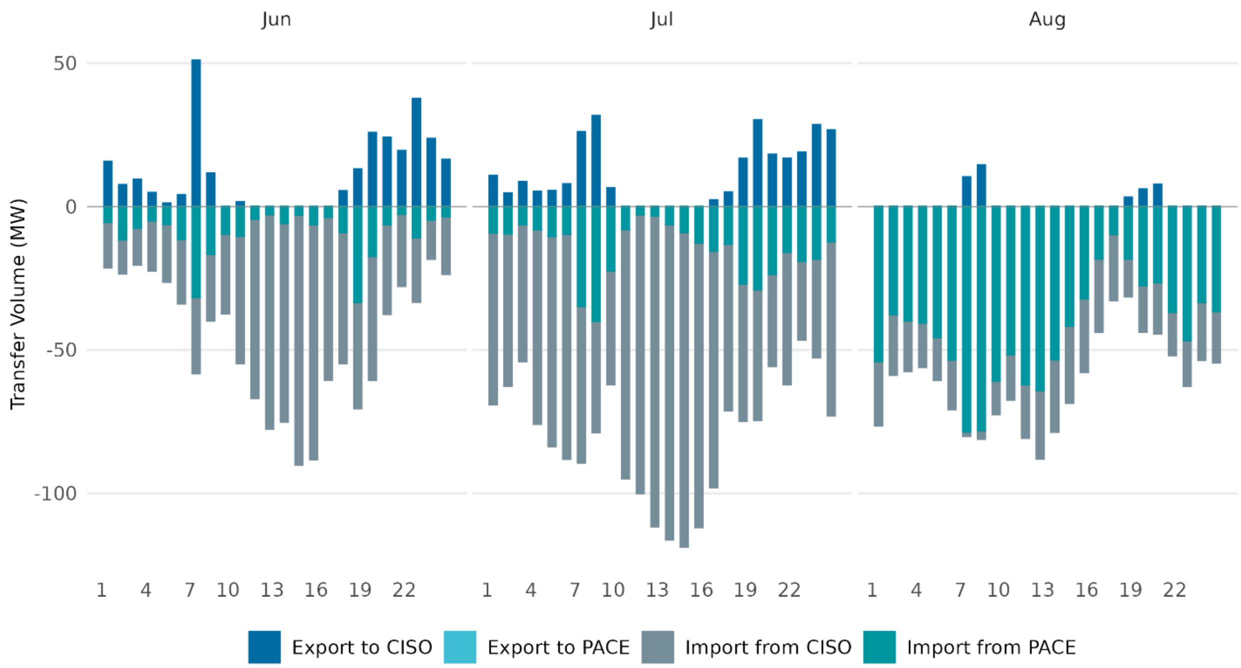
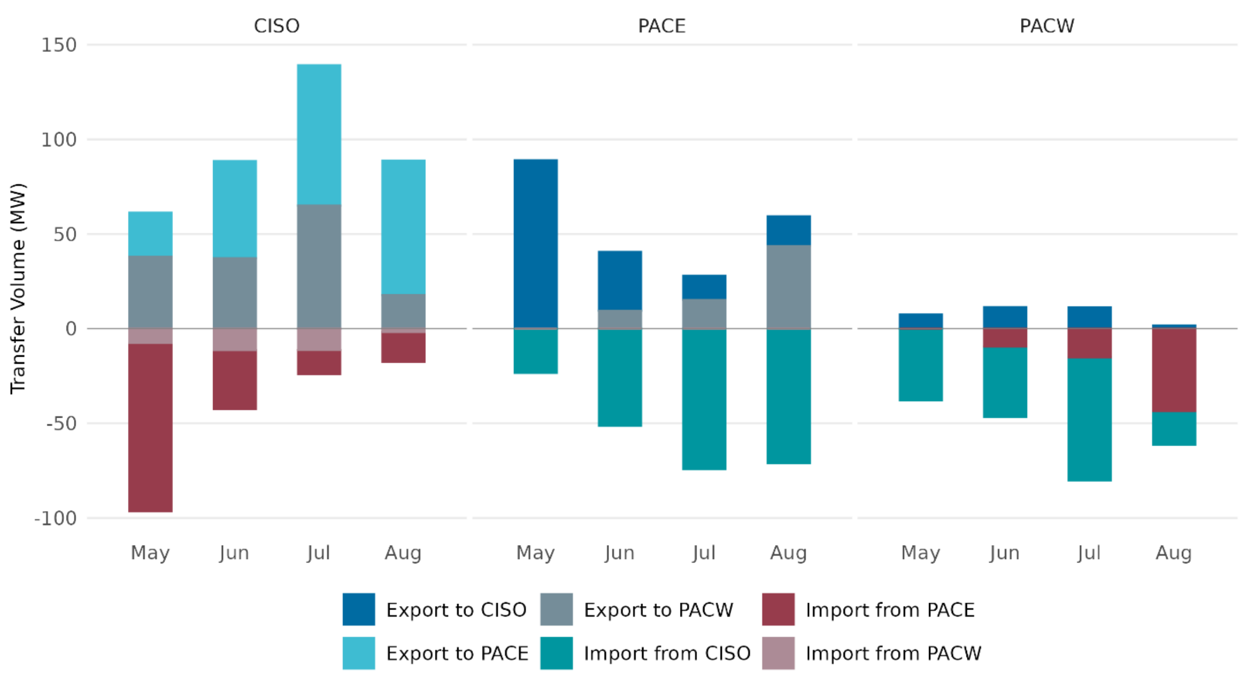


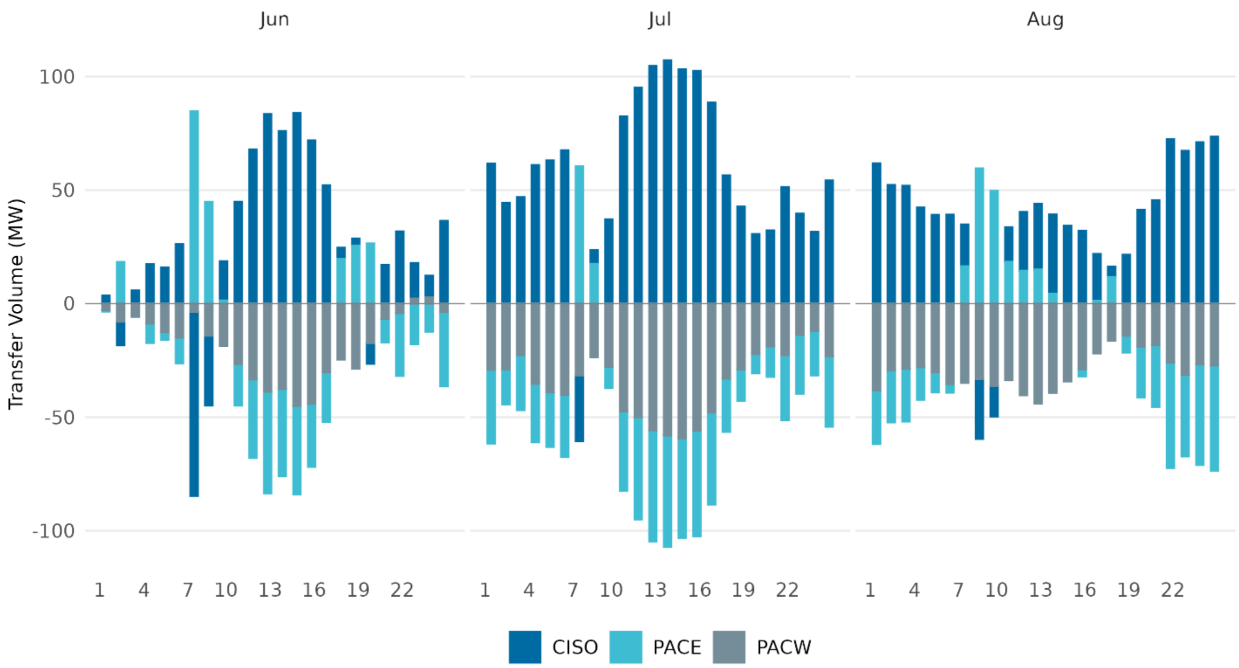
Figure 124 shows the total IRD transfer volumes varied considerably across the three BAAs from May through August. CAISO experienced increasing IRD exports transfer activity from May through July, reaching its highest level in July, followed by a decline in August, and its IRD imports kept decreasing throughout the three months. PACE IRD exports declined from May through July before rebounding in August, driven largely by increased exports to PACW. PACW remained predominantly a net importer, with imports shifting from CISO toward PACE in August.

Figure 124: Hourly average IRD transfers volumes in EDAM



For hourly IRD net transfer patterns, CISO remained net exporter in all months and PACE and PACE remained net importers. In July, IRD transfers reached peak over 100 MW during daytime hours. While in June and August, the peak net IRD transfers were about 150 MW. Similar with IRU, during morning peak HE 8 and 9, CAISO would import IRU from PACE or PACW.

Figure 125: 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 throughout May to August 2026.

Reliability capacity up

Figure 126 to

Figure 127 show CAISO's daily and hourly average RCU transfers on both export (+) and import (-) directions. Generally, CAISO remained a net importer for RCU in three months. In June and July there were only limited RCU exports, and the main RCU importing pairing entity is PACW.

The hourly profile shows there were some RCU exports in May but almost reduced to zero in most hours in June and July. The RCU products were mainly imported from PACW, and peak RCU imports were over 130 MW in morning and afternoon peak hours.

Figure 126: Daily average RCU transfers for CAISO

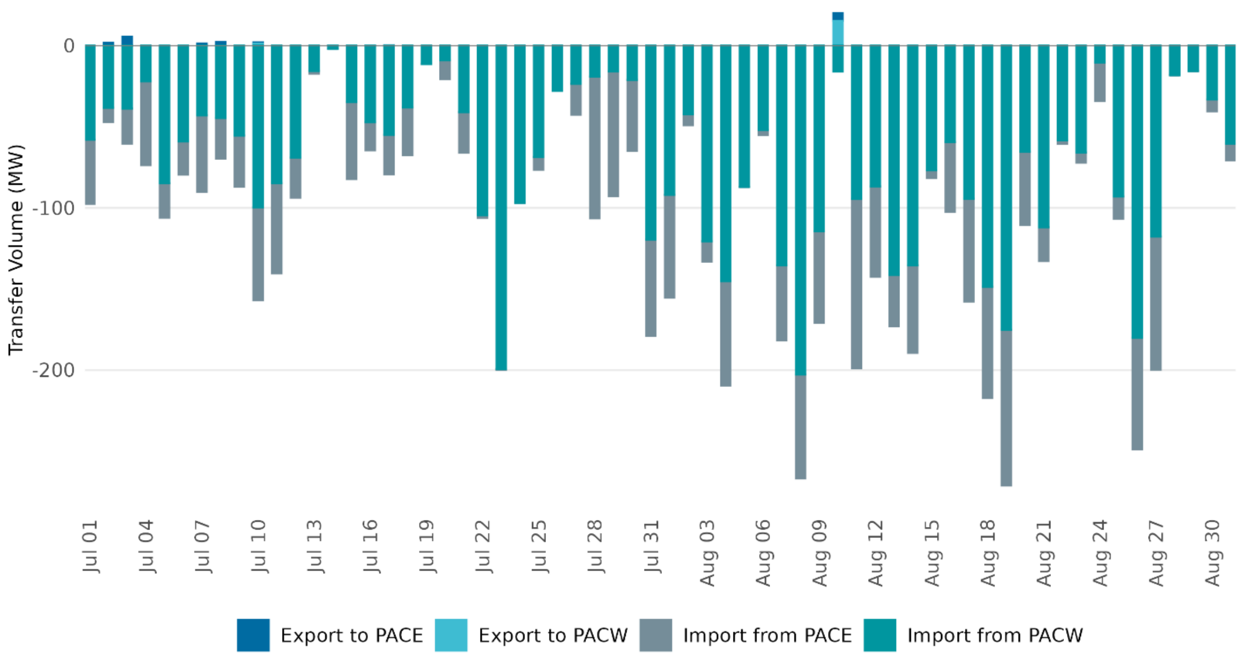


Figure 127: Hourly average RCU transfers for CAISO

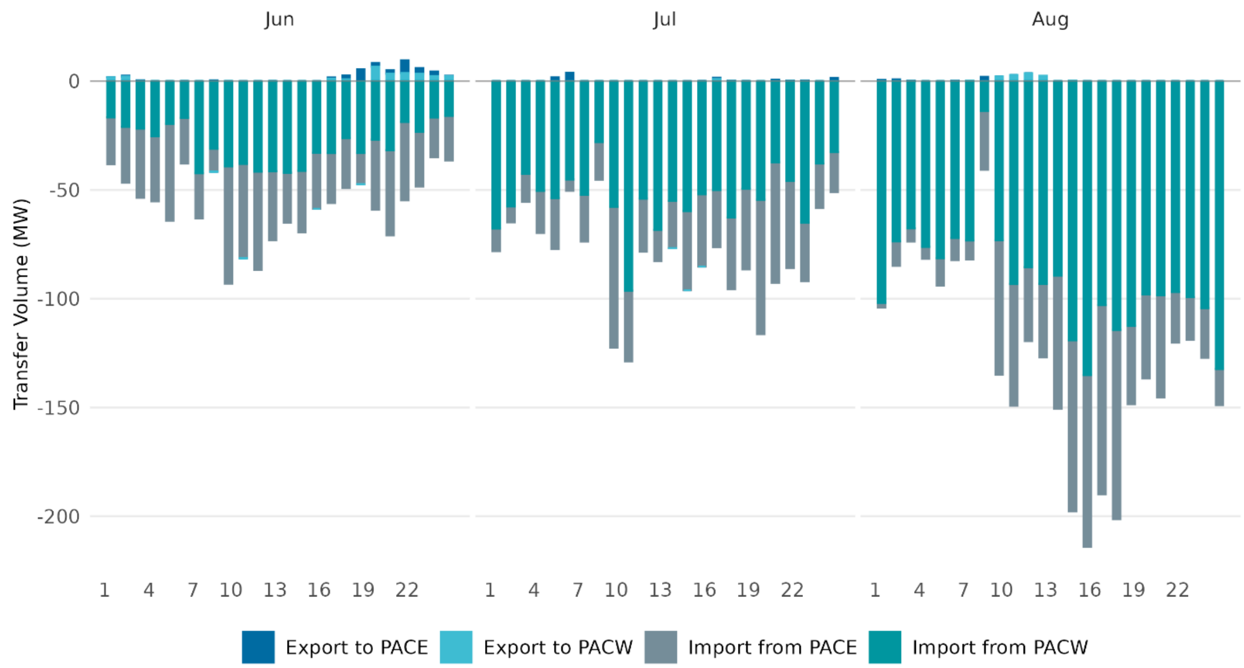


Figure 126 to Figure 131show PACE's daily and hourly average RCU transfers in July and August 2026 on both export (+) and import (-) directions. PACE RCU transfer activity increased notably in August compared with July. In August, transfer volumes were more elevated and variable, with multiple days exceeding 250 MW. The increase was predominantly driven by exports to PACW and CISO, while import activity remained limited throughout the period.

As shown in Figure 129, hourly average RCU transfer volumes for PACE increased from June through August. Hourly average RCU transfer in August increased substantially during the afternoon hours and 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.

Figure 128: Daily average RCU transfers for PACE

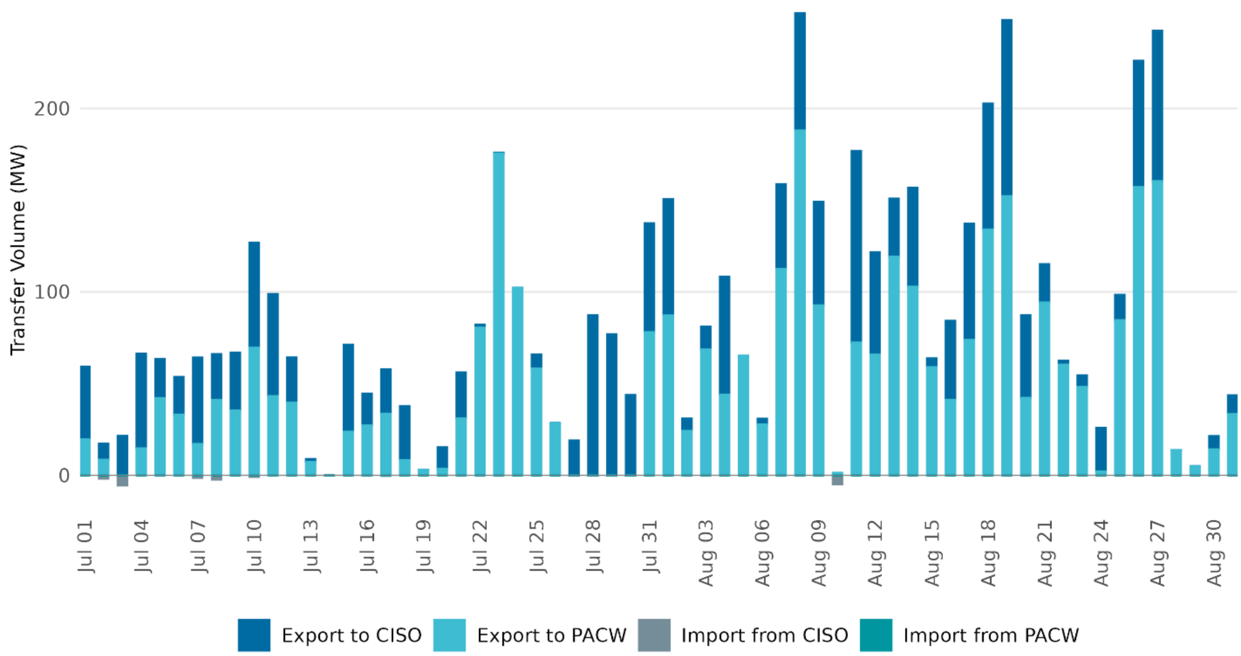


Figure 129: Hourly average RCU transfers for PACE

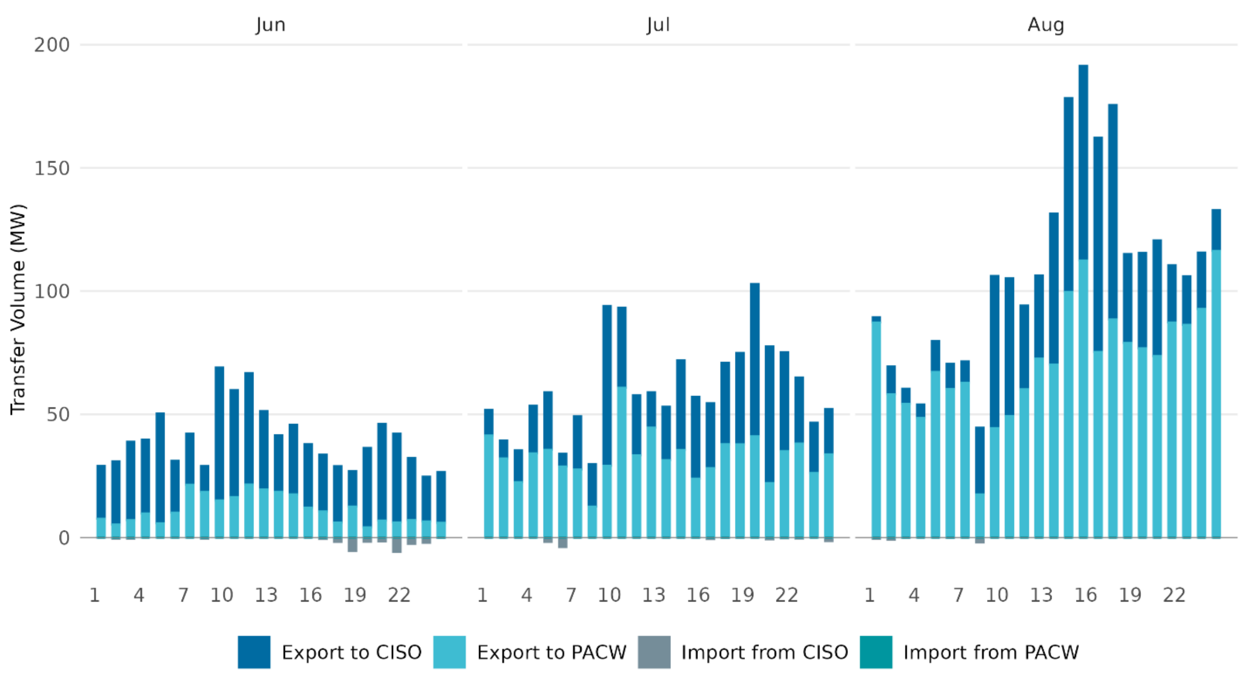


Figure 130 to Figure 131 show PACW's daily and hourly average RCU transfers throughout July to August 2026 on both export (+) and import (-) directions. Generally, daily average RCU transfers for PACW became more pronounced in late July and August, with larger and more variable transfers in both directions. Exports were primarily to CAISO, while imports were predominantly from PACE. Several days in late July and August experienced transfer volumes exceeding 180 MW, indicating substantially higher RCU transfer activity compared with early July.

As shown in Figure 131, hourly average RCU transfer activity for PACW increased from June through August, with the most increase occurring in August. Both exports to CISO and imports from PACE increased substantially, particularly during the afternoon hours, indicating greater bidirectional transfer activity compared with June and July.

Figure 130: Daily average RCU transfers for PACW

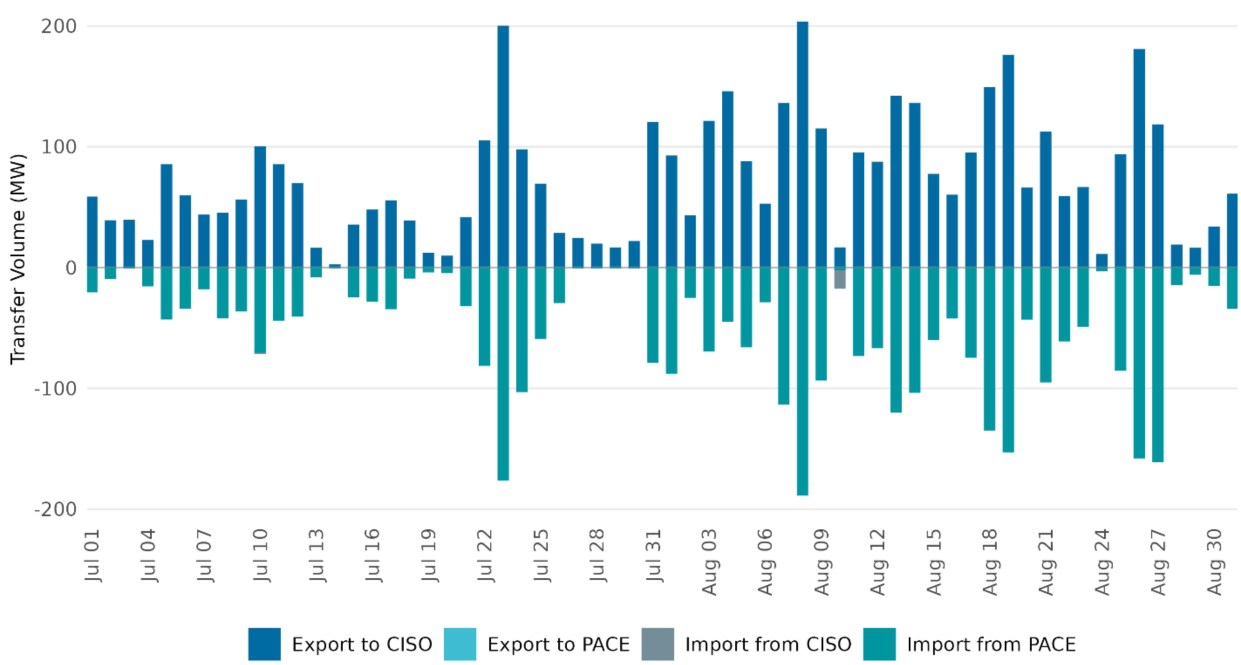


Figure 131: Hourly average RCU transfers for PACW

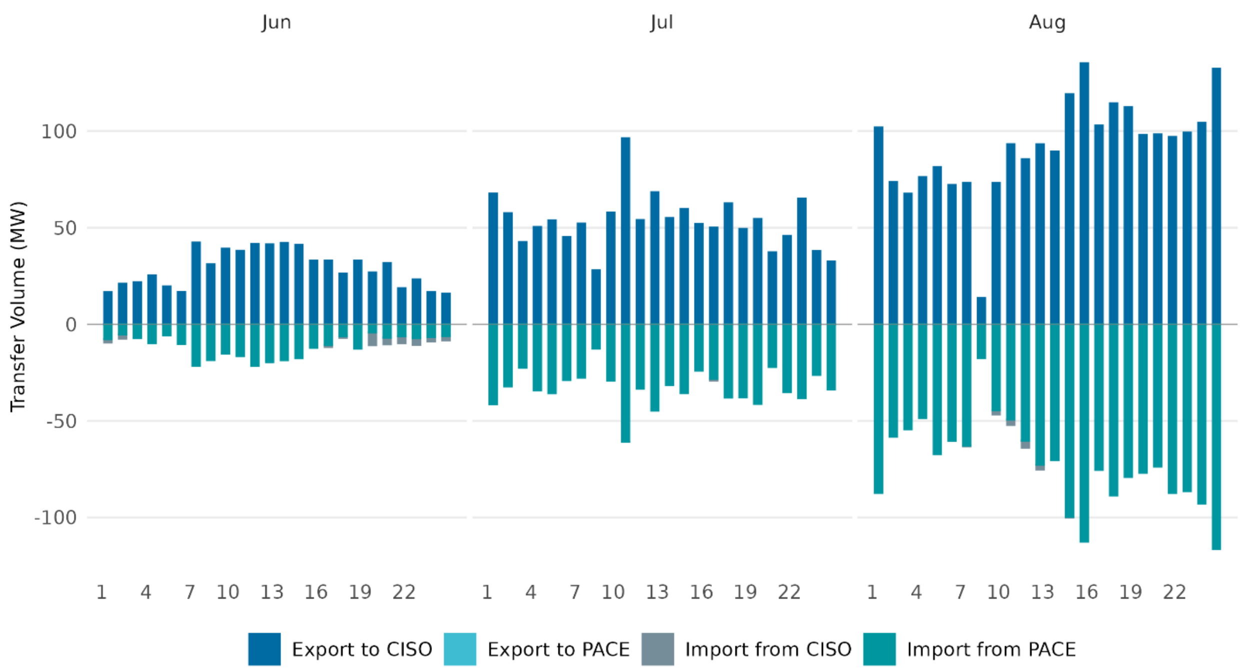
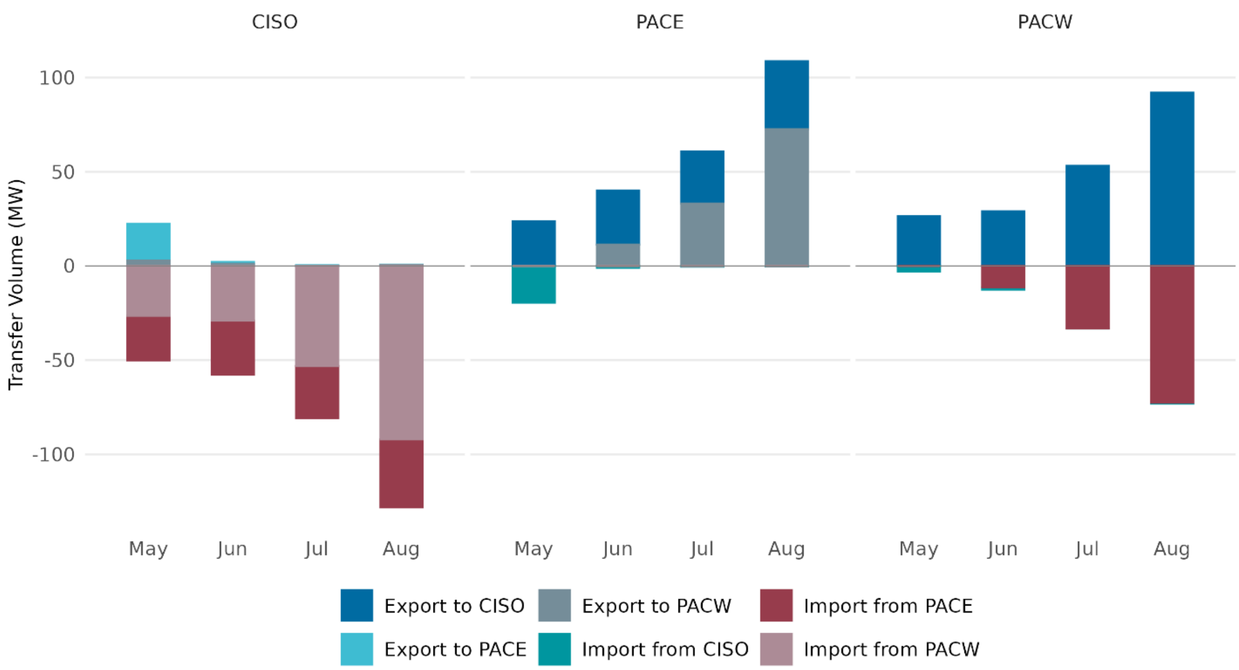


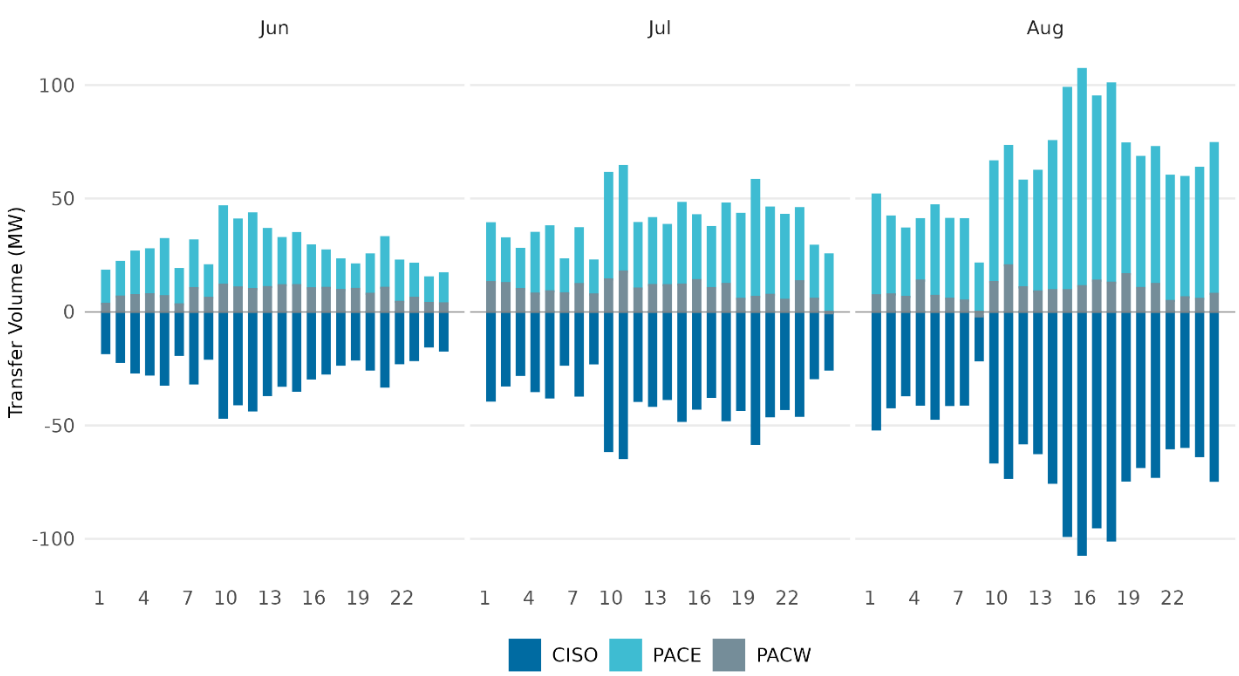
Figure 132 shows the summary of three BAAs' total RCU transfer volumes throughout May to August in both export (+) and import (-) directions. Total RCU transfer volumes increased substantially from May through August across the three BAAs, reaching their highest levels in August. The increase was primarily associated with higher transfers from PACE and PACW to CISO, accompanied by increased transfers between PACE and PACW. The results show a noticeable increase in overall RCU transfer activity due to summer conditions.

Figure 132: Hourly average RCU transfers volumes in EDAM



Hourly RCU net transfer shows increasingly pronounced patterns from June to August. CISO generally recorded imports, while PACE and PACW showed net exports, with both reaching their largest magnitudes during afternoon hours in August. PACW transfers remained relatively small and stable throughout the three months.

Figure 133: Hourly average net RCU transfers volumes in EDAM



Reliability capacity down

CAISO's RCD transfers were more concentrated on the exports side in July, with several days' imports dominating the transfers. Generally, CAISO remained a net exporter in July and there was only limited RCD transfer in August. The hourly profile shows the average import peak is in evening hours. In June and July, CAISO's RCD imports during night hours decreased, while exports increased during morning peak hours, while in August, there were limited RCD transfers.

Figure 134: Daily average RCD transfers for CAISO

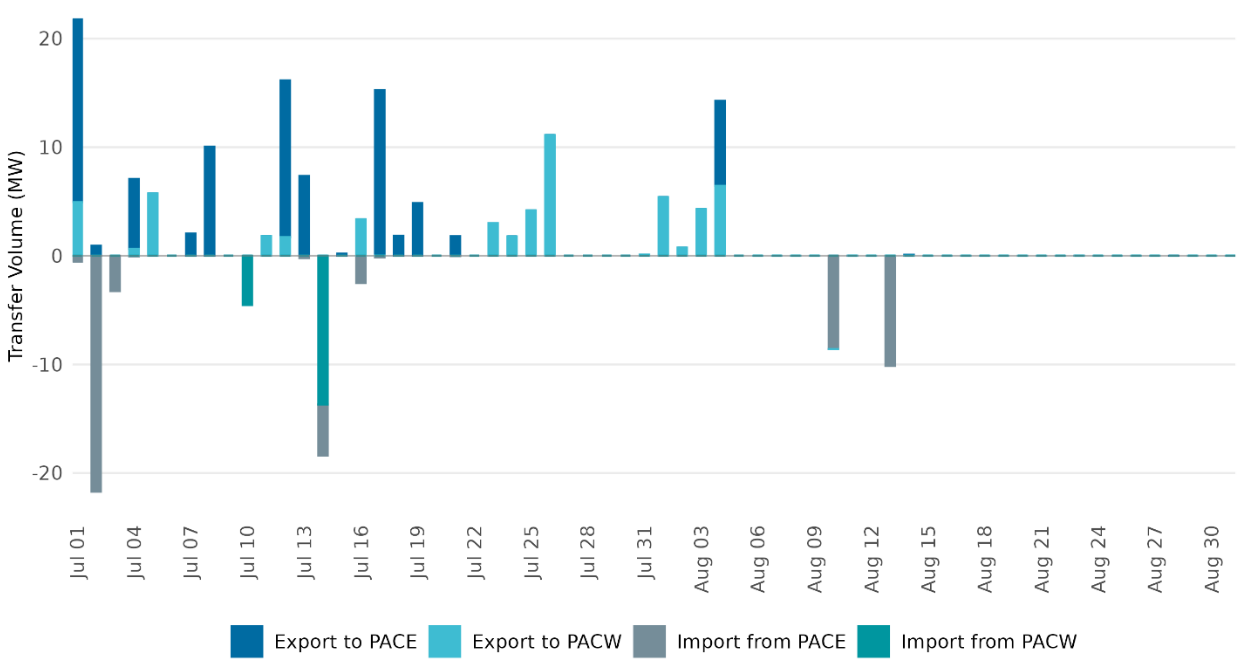
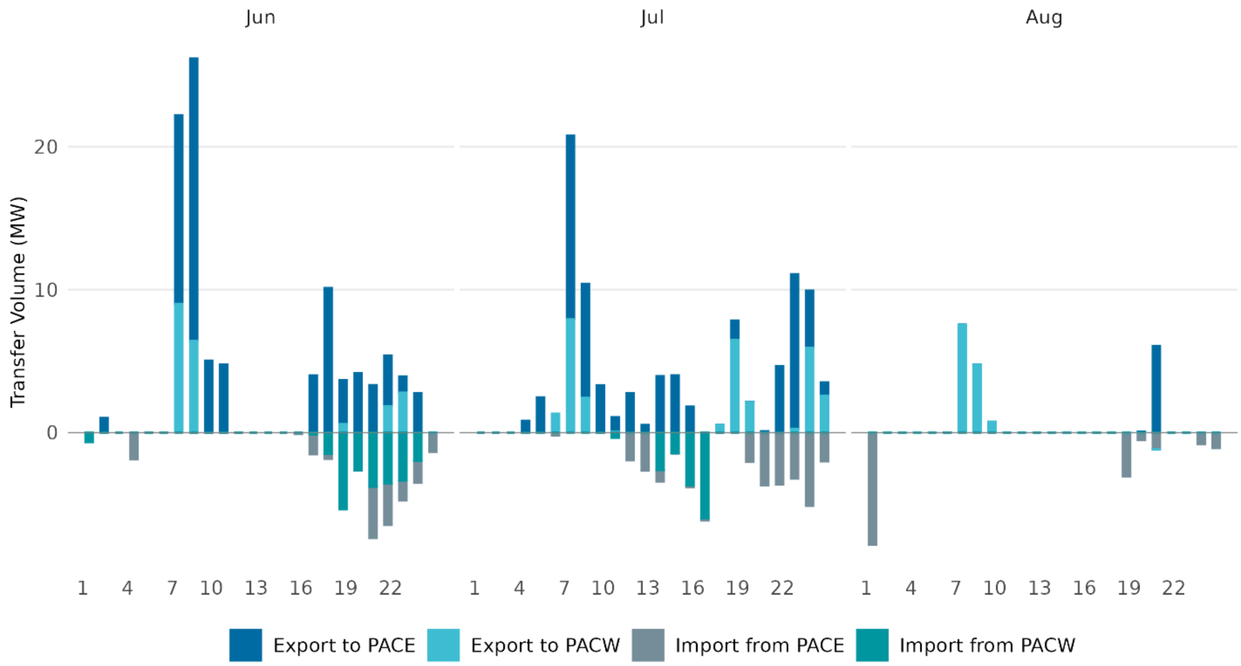


Figure 135: Hourly average RCD transfers for CAISO



For RCD products, PACE's average transfer showed different patterns in August In June and July, PACE's RCD exports were mainly to PACW, and most imports were from CAISO. However, in August there was only limited import from CAISO and only in HE 19.

Figure 136: Daily average RCD transfers for PACE

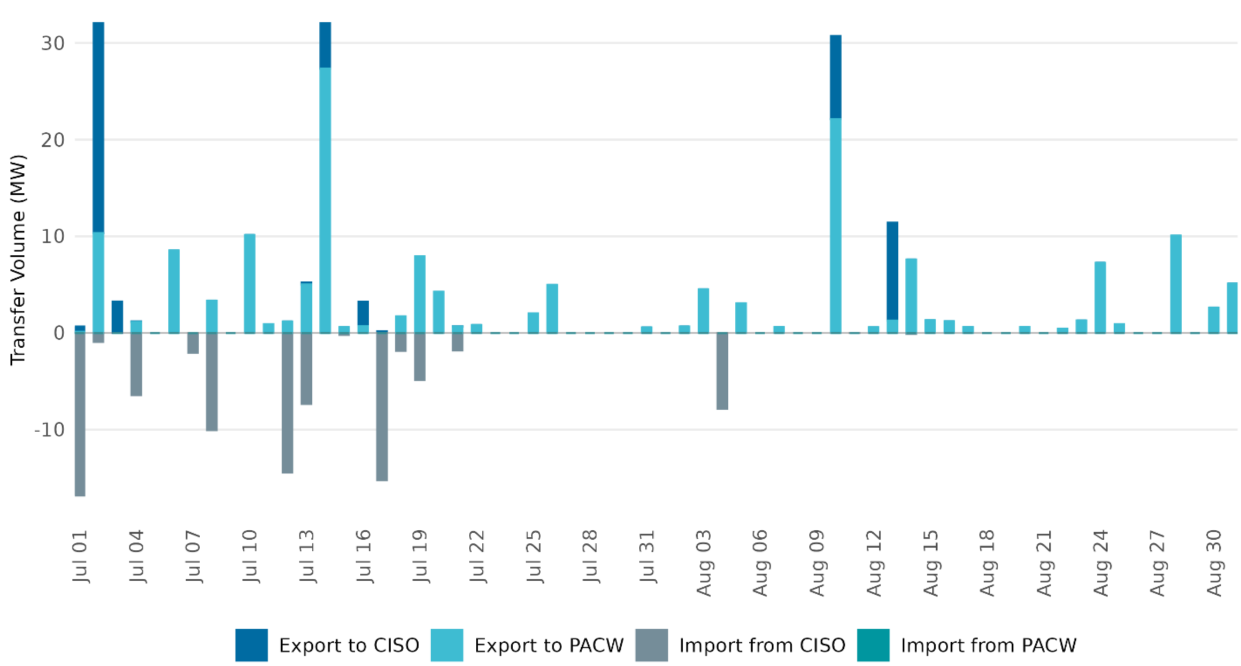
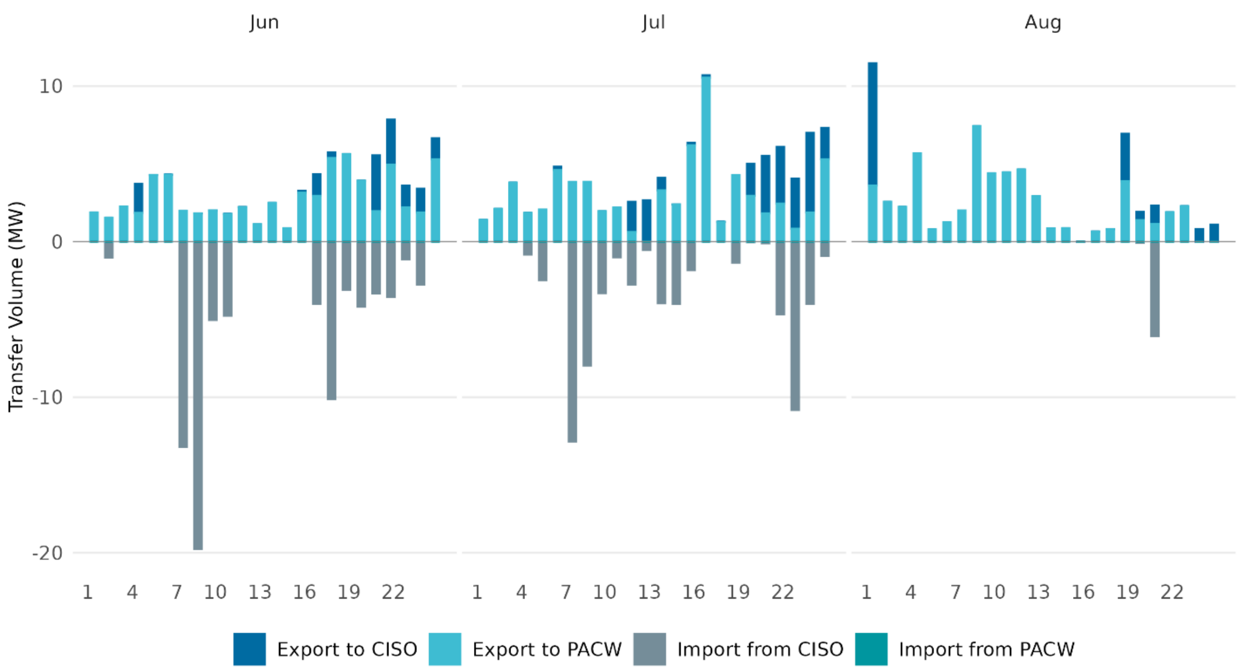


Figure 137: Hourly average RCD transfers for PACE



As for RCD transfer in PACW, the average imports were more mainly from PACE, as a result PACW remained a net importer. In June and July, PACW exported some RCD to CAISO during afternoon peak hours. However, the RCD exports to CAISO discontinued in August.

Figure 138: Daily average RCD transfers for PACW

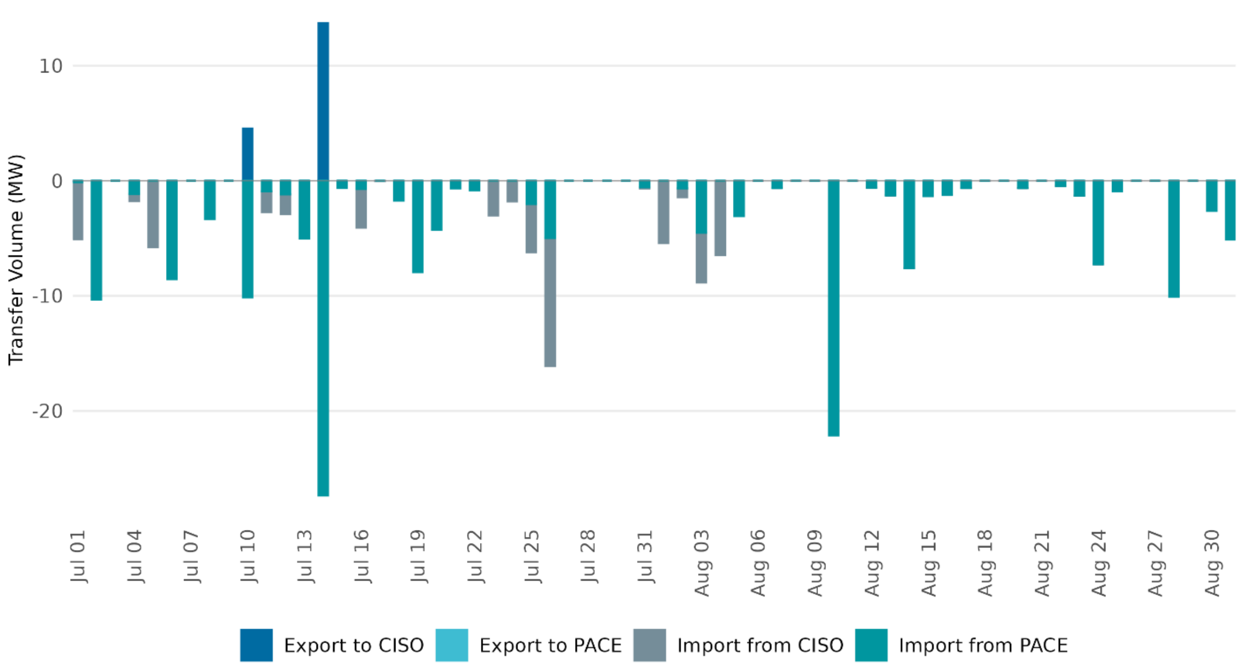


Figure 139: Hourly average RCD transfers for PACW

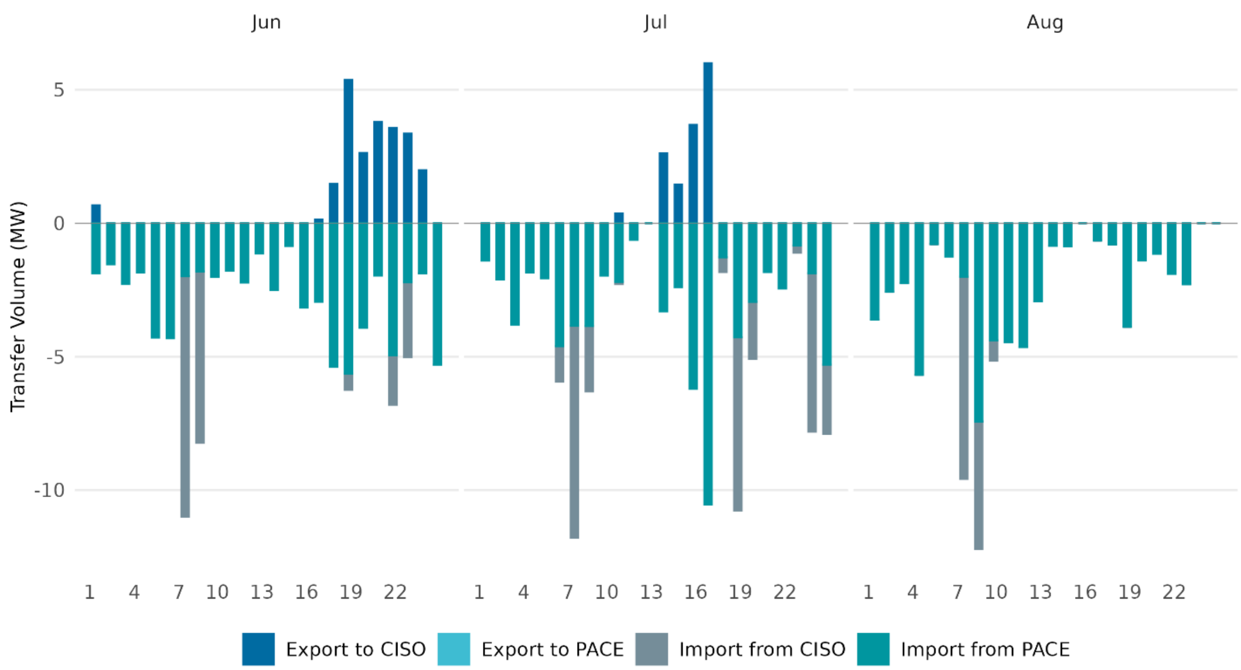
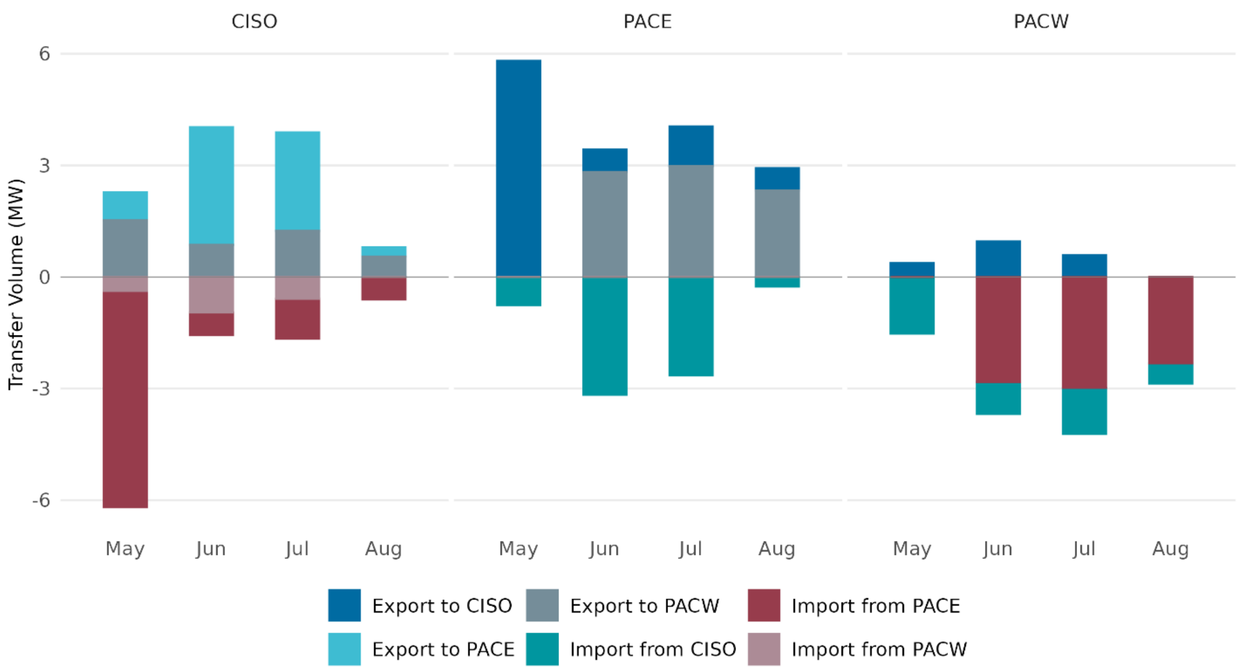


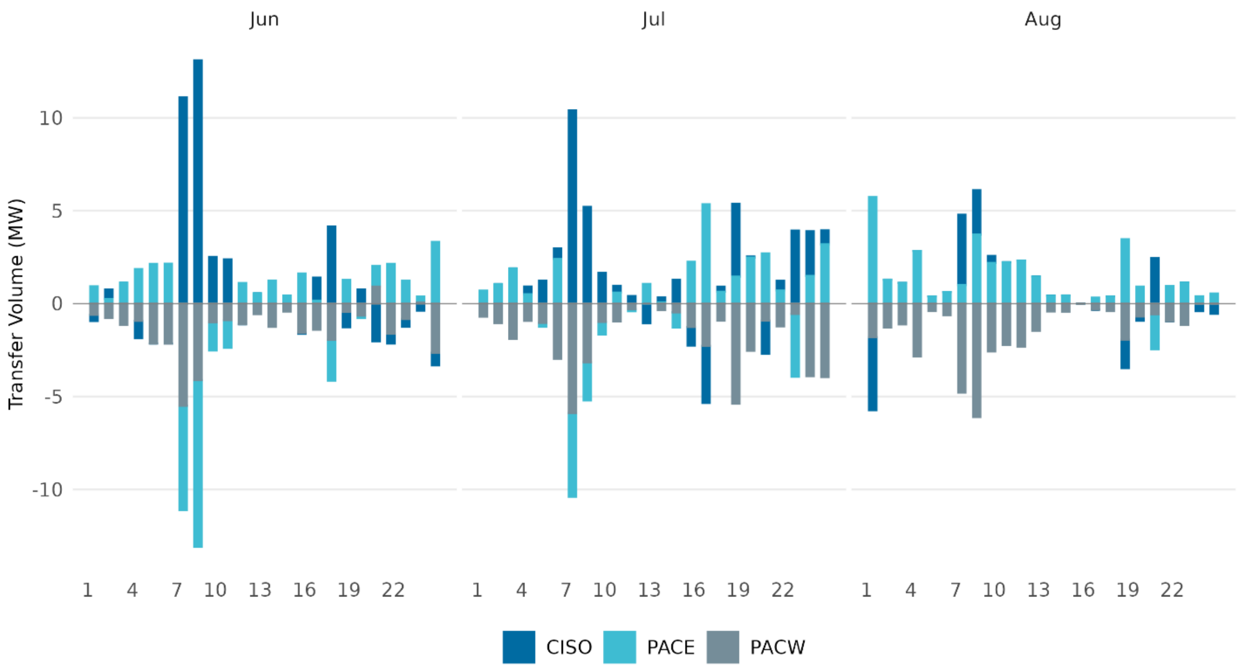
Figure 140 shows the summary of three BAAs' total RCD transfer volumes throughout May to August in both export (+) and import (-) directions. Generally, both BAAs have very different patterns across four months. CISO recorded its largest net imports in May, primarily from PACE, while PACE showed relatively high transfer activity in both directions during May through July. PACW was predominantly a net importer, with the largest import volumes occurring in June and July and primarily associated with transfers from PACE. By August, transfer volumes were substantially lower across all three BAAs.

Figure 140: Hourly average RCD transfers volumes in EDAM



Hourly RCD net transfer showed relatively small volumes across the three BAAs. Transfers were generally within ±5 MW, except for several notable spikes, particularly during morning hours in June and July. Overall, RCD transfers became less volatile in August.

Figure 141: 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 August 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.

Table 8: Average congestion costs

	Average MCC ($/MWh)			
DLAP/ELAP	**May**	**June**	**July**	**Aug**
PACE	(0.80)	(0.75)	(0.19)	(0.22)
PACW	0.48	(0.87)	(0.93)	(1.96)
PGAE	4.04	2.29	(1.10)	(2.40)
SCE	(3.68)	(1.76)	0.56	1.35

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

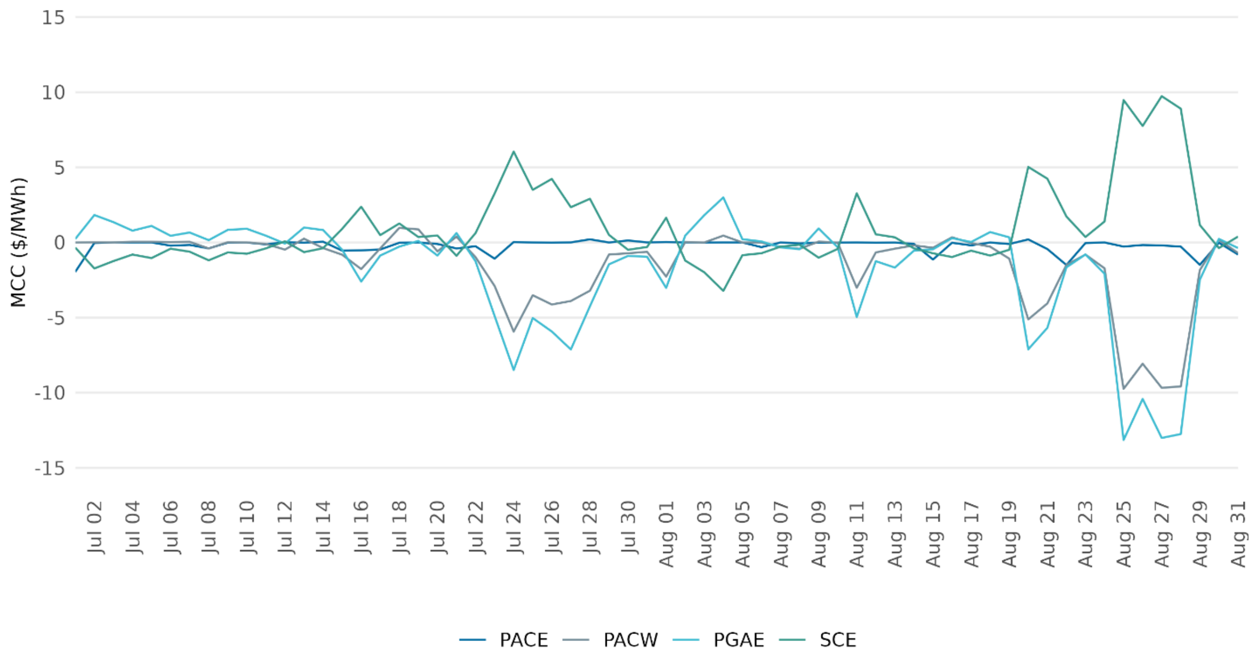
A positive number for MCC represents an increase in DLAP/ELAP LMP due to system congestion while a negative number represents a decrease in LMP from congestion. A positive MCC for a DLAP/ELAP indicates a more constrained area where cheaper energy may not be able to flow. In August, congestion impacts on PACE and PACW ELAP locational marginal prices, at -$0.22 and -$1.96, respectively. In contrast, within CAISO DLAPs, SCE MCC averaged $1.35, while PGAE MCC averaged -$2.40. CISO congestion patterns in August average out to predominately a North to South pattern due to congestion along Path 26 constraints binding due to high demand in Southern California Table 9 provides an hourly average of congestion costs across areas with the green gradient indicating larger positive MCC prices and the gradient of violet indicates larger negative MCC prices. The North to South pattern is predominant throughout the day with some relief during high solar hours.

Table 9: Hourly average congestion costs

	Jun				Jul				Aug			
Trade Hou	PACE	PACW	PGAE	SCE	PACE	PACW	PGAE	SCE	PACE	PACW	PGAE	SCE
1	-0.99	-1.46	0.32	0.16	0.00	-0.94	-1.16	0.85	0.01	-1.98	-2.71	2.12
2	-0.89	-1.61	0.35	0.10	0.04	-0.93	-1.13	0.90	0.01	-1.89	-2.61	2.03
3	-0.65	-1.00	0.23	0.10	-0.05	-0.53	-0.59	0.47	0.03	-1.48	-2.03	1.60
4	-0.70	-1.33	0.32	0.11	-0.11	-0.49	-0.62	0.53	0.04	-1.47	-2.04	1.61
5	-0.68	-1.00	0.28	-0.06	-0.20	-0.43	-0.54	0.49	0.02	-1.30	-1.79	1.40
6	-0.87	-1.41	0.39	-0.01	-0.01	-0.44	-0.60	0.42	0.05	-1.54	-2.12	1.73
7	-0.33	-0.52	0.17	-0.08	-0.03	-0.33	-0.47	0.30	0.05	-1.29	-1.72	1.42
8	-0.55	0.03	3.18	-3.04	-0.33	-0.11	0.11	-0.30	-0.04	-0.51	-0.54	0.28
9	-0.45	0.45	5.14	-4.69	-0.30	-0.09	0.44	-0.96	-0.18	-0.82	-0.22	-0.65
10	-0.44	0.35	5.39	-4.73	-0.33	-0.17	0.52	-0.96	-0.26	-1.06	0.06	-0.85
11	-0.27	0.54	3.31	-3.85	-0.30	-0.44	-0.20	-0.40	-0.22	-1.22	-1.63	0.10
12	-0.30	0.34	3.75	-3.41	-0.19	-0.57	-0.54	-0.19	-0.47	-1.67	-2.51	0.67
13	-0.17	0.66	3.70	-3.39	-0.15	-0.66	-0.68	-0.13	-0.52	-1.59	-2.42	0.51
14	-0.28	0.69	4.11	-3.56	-0.26	-0.65	-0.78	0.07	-0.78	-1.73	-2.51	0.68
15	-0.22	1.07	4.25	-3.91	-0.46	-0.68	-1.22	0.44	-0.87	-2.07	-2.95	0.98
16	-0.19	0.44	4.47	-4.04	-0.60	-1.42	-2.06	1.09	-1.07	-3.03	-3.59	1.51
17	-0.37	0.50	4.31	-3.91	-0.56	-1.54	-2.97	0.00	-0.46	-2.64	-3.04	0.98
18	-0.65	-0.90	3.45	-2.80	-0.50	-2.66	-2.76	1.89	-0.47	-4.05	-3.84	2.12
19	-1.23	-2.19	1.89	-0.87	-0.09	-2.86	-3.13	2.50	-0.13	-3.98	-4.39	3.03
20	-2.16	-4.30	2.25	-0.58	-0.07	-1.58	-1.75	1.38	-0.04	-3.41	-4.11	2.92
21	-1.56	-3.03	1.40	-0.27	-0.03	-1.06	-1.16	0.98	-0.03	-2.00	-2.34	1.66
22	-1.58	-3.04	1.15	-0.05	-0.01	-1.49	-1.91	1.50	-0.01	-2.66	-3.50	2.64
23	-1.19	-2.16	0.68	0.16	-0.01	-1.14	-1.50	1.26	-0.02	-1.86	-2.54	1.92
24	-1.16	-2.06	0.54	0.27	0.00	-1.21	-1.73	1.40	-0.01	-1.80	-2.53	1.95

Figure 142 provides a daily trend of average congestion costs across the last two months. Southern California prices continue to average higher than Northern California and PACW across higher congestion days. The largest daily average prices occurred between August 25th through August 27th due to a brief derate on one of the Path 26 transmission elements.

Figure 142: Daily average congestion cost by area



Parallel flows

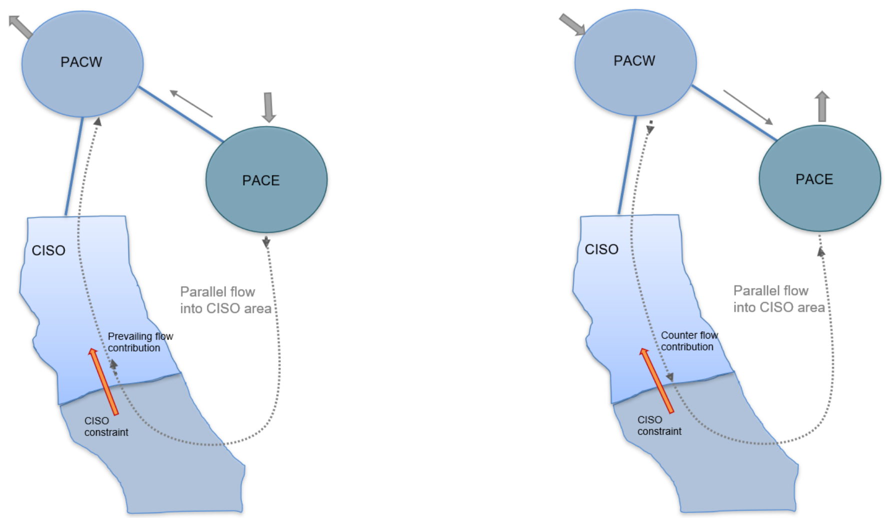
A more fundamental assessment of EDAM transaction effects is to examine their flow contributions on transmission constraints. Transactions in one BAA can contribute to flows on transmission constraints in another BAA; these are known as *parallel flow.* The data is presented in a matrix of transactions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

Figure 143: 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 143 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 144 illustrates the concepts of prevailing and counter flows from a transaction between PAC areas creating a parallel flow in CAISO BAA.

Figure 144: Illustration of parallel flows



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

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

Table 10 goes a step further and breaks down the MCCs based on where the congestion is sourced. This is calculated by taking the shift factors of each DLAP/ELAP and applying them to across all binding transmission constraints and their shadow prices for each hour. Then, the hourly MCCs are aggregated and normalized to $/MWh to reconstruct the monthly average MCC in the previous figure, but with a breakdown 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]

Congestion Price Impact ($/MWh)												
	June				July				Aug			
Cause of Congestion	**PACE**	**PACW**	**PGAE**	**SCE**	**PACE**	**PACW**	**PGAE**	**SCE**	**PACE**	**PACW**	**PGAE**	**SCE**
CISO	**-0.82**	**-0.90**	**-1.04**	**0.58**	**-0.19**	**-0.92**	**-1.04**	**0.58**	**-0.22**	**-1.96**	**-2.40**	**1.35**
Base	-0.71	-0.74	-1.09	0.64	-0.19	-0.92	-1.09	0.64	-0.21	-1.73	-2.11	1.16
IRD	-0.02	-0.05	0.02	-0.01	0.000	0.000	0.02	-0.01	0.000	0.000	0.01	0.00
IRU	-0.002	-0.11	0.03	-0.05	-0.002		0.03	-0.05	-0.007	-0.23	-0.31	0.19
PACE	**0.08**	**0.03**	**-0.05**	**-0.05**			**-0.05**	**-0.05**				
Base	0.02	0.01	-0.05	-0.05			-0.05	-0.05				
IRD	0.01											
IRU	0.04	0.03	-0.001	-0.001			-0.001	-0.001				

Based on this table, CAISO constraints across all deployment scenario constraint types, on average, had a -0.22 and -1.87 $/MWh MCC impact on PACE and PACW, respectively. There was no direct impact from PacifiCorp congestion on CISO DLAPs which is represented by the grayed-out sections of the table. PACW congestion was limited to ITC constraints; therefore, there was not any direct parallel flow impact to the MCC of other LAPs. There was no PACE congestion in August.

6 These results are preliminary. An identified data issue impacting the availability of shift factors will result in discrepancies between the total MCC reported in 6 and the breakdown by transmission constraint.

Table 11: Congestion costs by constraint for August 2026

August 2026 Average Congestion Costs by Constraint		PACE			PACW			PGAE			SCE		
BAA	Constraint Name	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	22464_MIGUEL _230_22468_MIGUEL _500_XF_81	(0.01)						(0.00)					
CISO	22524_MORHILTP_69.0_22440_MELROSE _69.0_BR_1 _1							(0.00)			(0.00)		
CISO	22532_MURRAY _69.0_22306_GARFIELD_69.0_BR_1 _1										(0.00)		
CISO	22604_OTAY _69.0_22616_OTAYLKTP_69.0_BR_1 _1							(0.00)			(0.00)		
CISO	22773_BAY BLVD_69.0_22352_IMPRLBCH_69.0_BR_1 _1							(0.00)			(0.00)		
CISO	22773_BAY BLVD_69.0_22604_OTAY _69.0_BR_2 _1							(0.00)			(0.00)		
CISO	22831_SYCAMORE_138_22124_CHCARITA_138_BR_1 _1										0.00		
CISO	22886_SUNCREST_230_22885_SUNCREST_500_XF_2 _P	(0.02)			(0.00)			(0.01)			0.00		
CISO	24016_BARRE _230_24154_VILLA PK_230_BR_1 _1	(0.00)						(0.00)			0.00		
CISO	24091_MESA CAL_230_24076_LAGUBELL_230_BR_2 _1	(0.06)			(0.08)			(0.08)			0.10		
CISO	24386_MESA CAL_500_24392_MESA2I _13.8_XF_2H	(0.03)			(0.04)			(0.04)			0.05		
CISO	24701_KRAMER _230_24601_VICTOR _230_BR_2 _1							0.05		0.00	(0.09)		(0.00)
CISO	24801_DEVERS _500_24804_DEVERS _230_XF_1 _P	(0.01)						0.00			0.00		
CISO	29400_ANTELOPE_500_29402_WIRLWIND_500_BR_1 _1	(0.01)			(0.19)			(0.26)			0.19		
CISO	30060_MIDWAY _500_24156_VINCENT _500_BR_1 _1	0.01			(0.37)			(0.51)			0.41		
CISO	30060_MIDWAY _500_24156_VINCENT _500_BR_2 _3	(0.01)			(0.55)			(0.74)			0.54		
CISO	30060_MIDWAY _500_29402_WIRLWIND_500_BR_1 _2	(0.01)		(0.01)	(0.47)		(0.23)	(0.64)		(0.31)	0.49		0.23
CISO	30635_NWK DIST_230_30731_LS ESTRS_230_BR_1 _1	(0.00)			(0.00)			0.00			(0.00)		
CISO	30655_ADCC _230_30630_NEWARK _230_BR_2 _1	(0.00)			(0.00)			0.01			(0.00)		
CISO	30750_MOSSLD _230_30797_LASAGUIL_230_BR_1 _1							0.35		0.00	(0.24)		(0.00)
CISO	30765_LOSBANOS_230_30766_PADR FLT_230_BR_1 _1							(0.02)		(0.00)	(0.00)		(0.00)
CISO	30765_LOSBANOS_230_30790_PANOCHE _230_BR_2 _1				0.15			0.05			(0.07)		
CISO	30790_PANOCHE _230_30900_GATES _230_BR_1 _1				0.00			0.00			(0.00)		
CISO	30805_BORDEN _230_30810_GREGG _230_BR_2 _1							0.01			(0.01)		
CISO	30875_MC CALL _230_34370_MC CALL _115_XF_1 _P							0.00			(0.00)		
CISO	30879_HENTAP1 _230_30885_MUSTANGS_230_BR_1 _1							0.00			(0.00)		
CISO	30885_MUSTANGS_230_30900_GATES _230_BR_2 _1							0.00			(0.00)		
CISO	31227_HGHLNDJ2_115_31950_CORTINA _115_BR_1 _1							(0.00)					
CISO	32056_CORTINA _60.0_30451_CRTNA M_ 1.0_XF_1							0.00			(0.00)		
CISO	32214_RIO OSO _115_32225_BRNSWKT1_115_BR_1 _1							(0.00)			0.00		
CISO	32218_DRUM _115_32244_BRNSWKT2_115_BR_2 _1							0.00					
CISO	32225_BRNSWKT1_115_32222_DTCH2TAP_115_BR_1 _1							0.00					
CISO	33020_MORAGA _115_32790_STATIN X_115_BR_2 _1							0.00			(0.00)		
CISO	33020_MORAGA _115_32790_STATIN X_115_BR_3 _1							0.00			(0.00)		
CISO	33315_RAVENSWD_115_38028_PLO ALTO_115_BR_1 _1										(0.00)		
CISO	33541_AEC_TP1 _115_33540_TESLA _115_BR_1 _1							(0.00)	0.00	(0.01)	0.00	(0.00)	0.00
CISO	34100_CHWCHLLA_115_34101_CERTANJ2_115_BR_1 _1							0.00		0.00			
CISO	34101_CERTANJ2_115_34116_LE GRAND_115_BR_1 _1							0.01	0.00	0.00			
CISO	34116_LE GRAND_115_34115_ADRA TAP_115_BR_1 _1							(0.00)		0.01	(0.01)		(0.00)
CISO	34134_WILSONAB_115_30800_WILSON _230_XF_1							0.00			(0.00)		
CISO	34134_WILSONAB_115_34144_MERCED _115_BR_1 _1							0.00					
CISO	34158_PANOCHE _115_34350_KAMM _115_BR_1 _1							(0.00)					
CISO	34214_LOS BANS_70.0_34272_WRGHT PP_70.0_BR_1 _1								0.00				
CISO	34256_BORDEN _70.0_30805_BORDEN _230_XF_1							0.00	0.00				
CISO	34256_BORDEN _70.0_34262_CASSIDY _70.0_BR_1 _1							0.00	0.00				
CISO	34366_SANGER _115_34370_MC CALL _115_BR_3 _1							0.02			(0.01)		
CISO	34418_KINGSBRG_115_34405_FRWT TAP_115_BR_1 _1							(0.00)					
CISO	34418_KINGSBRG_115_34428_CONTADNA_115_BR_1 _1							0.06			(0.03)		
CISO	34540_HENRITTA_70.0_30881_HENRIETA_230_XF_4							(0.02)	0.00	(0.00)			
CISO	34700_SMYRNA 2_115_34742_SEMITRPJ_115_BR_1 _1							(0.00)					
CISO	34706_WESTPARK_115_34752_KERN PWR_115_BR_1 _1							0.01			(0.00)		
CISO	34716_LRDO JCT_115_34718_KERN OIL_115_BR_1 _1							0.00			(0.00)		
CISO	34774_MIDWAY _115_34225_BELRDG J_115_BR_1 _1								0.00	0.00			
CISO	35061_PSEMCKIT_115_34225_BELRDG J_115_BR_1 _1							0.00					
CISO	35120_NEWARK D_115_36851_NORTHERN_115_BR_1 _1							0.00			(0.00)		
CISO	35122_NWARK EF_115_35602_ZNKER J2_115_BR_1 _1										(0.00)		
CISO	35603_ZNKER J1_115_35612_TRIMBLE _115_BR_1 _1							0.00			(0.00)		
CISO	35618_SN JSE A_115_35616_SNJOSEB _115_BR_1 _1							0.02			(0.01)		
CISO	35618_SN JSE A_115_35620_EL PATIO_115_BR_1 _1							0.00			(0.00)		
CISO	35658_LS ESTRS_115_35659_NORTECH _115_BR_1 _1							0.01			(0.02)		
CISO	35659_NORTECH _115_36851_NORTHERN_115_BR_1 _1										(0.00)		
CISO	36851_NORTHERN_115_36852_SCOTT _115_BR_2 _1							0.02			(0.05)		
CISO	38615_DS AMIGO_230_30790_PANOCHE _230_BR_1 _1							(0.03)			(0.00)		
CISO	39021_SC21ATP _70.0_34888_ARVIN _70.0_BR_1 _1							0.04					
CISO	6410_CP1_NG	0.00			(0.00)			(0.00)			0.00		
CISO	6410_CP5_NG	0.00			(0.06)		(0.00)	(0.09)		(0.00)	0.07		0.00
CISO	7320_CP6_NG							0.00	0.00	0.00			
CISO	7430_CP6_NG							0.01	0.00	0.01	(0.01)	(0.00)	(0.01)
CISO	7510-PAR-PAS-OOS_NG							0.00		0.00	(0.00)		(0.00)
CISO	7510-Pastoria-Pardee_NG							0.00		0.00	(0.00)		(0.00)
CISO	7690-CONTRL-INYOKN_EXP_NG										(0.03)	(0.00)	(0.03)
CISO	7690-COOLWATER_KRAMER_IM_NG										0.00	0.00	0.00
CISO	7720_JHINDS_CP2_NG										(0.00)		(0.01)
CISO	7760_DEV_RDB_ALIS	(0.00)									0.00		
CISO	7820_TL 230S_OVERLOAD_NG	(0.00)	(0.00)		(0.00)	(0.00)		(0.00)	(0.00)		(0.00)	(0.00)	
CISO	7820_TL23040_IV_SPS_NG	(0.01)			(0.00)			(0.01)			(0.00)		
CISO	99254_J.HINDS2_230_24806_MIRAGE _230_BR_1 _1							(0.01)			0.01	0.00	
CISO	DOSMGO-PNOCHE_230_2_1							(0.25)		(0.00)	(0.14)		(0.00)
CISO	HUMBOLDT_EXP_NG							(0.01)		(0.01)	0.00		0.00
CISO	HUMBOLDT_IMP_NG							0.00	0.00		(0.00)	(0.00)	
CISO	HUMBOLDT_IMP_NG_30								0.00			(0.00)	
CISO	OMS IV-ML OUTAGE_NG	(0.01)			(0.01)			(0.01)			0.00		
CISO	OMS_19695948_DEV_RDB_ALIS	0.00		(0.00)				0.00		0.00	(0.01)		(0.00)
CISO	OMS_20616030_SERRANO-VALLEY_NG	0.00		0.00				0.00		0.00	(0.00)		(0.00)
CISO	OMS_TL23054_OUTAGE_NG	(0.05)			(0.01)			(0.02)			(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

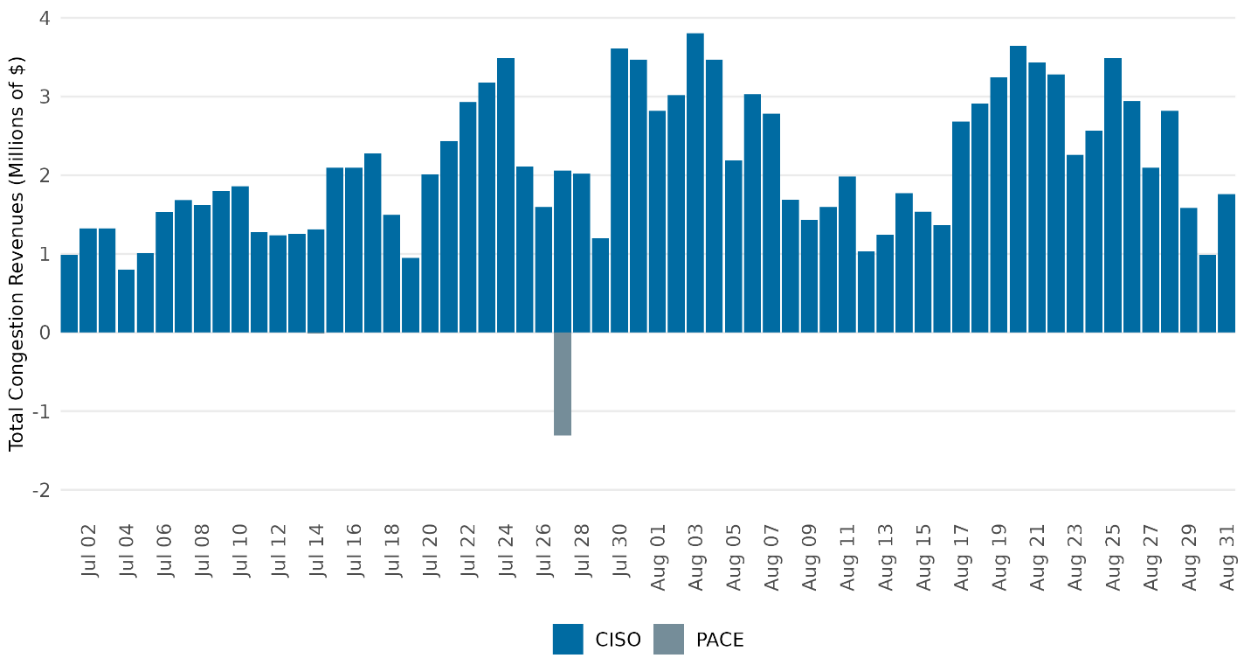
Congestion revenues

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 145 provides the daily BAA totals for congestion revenues based on the area the congestion occurred.

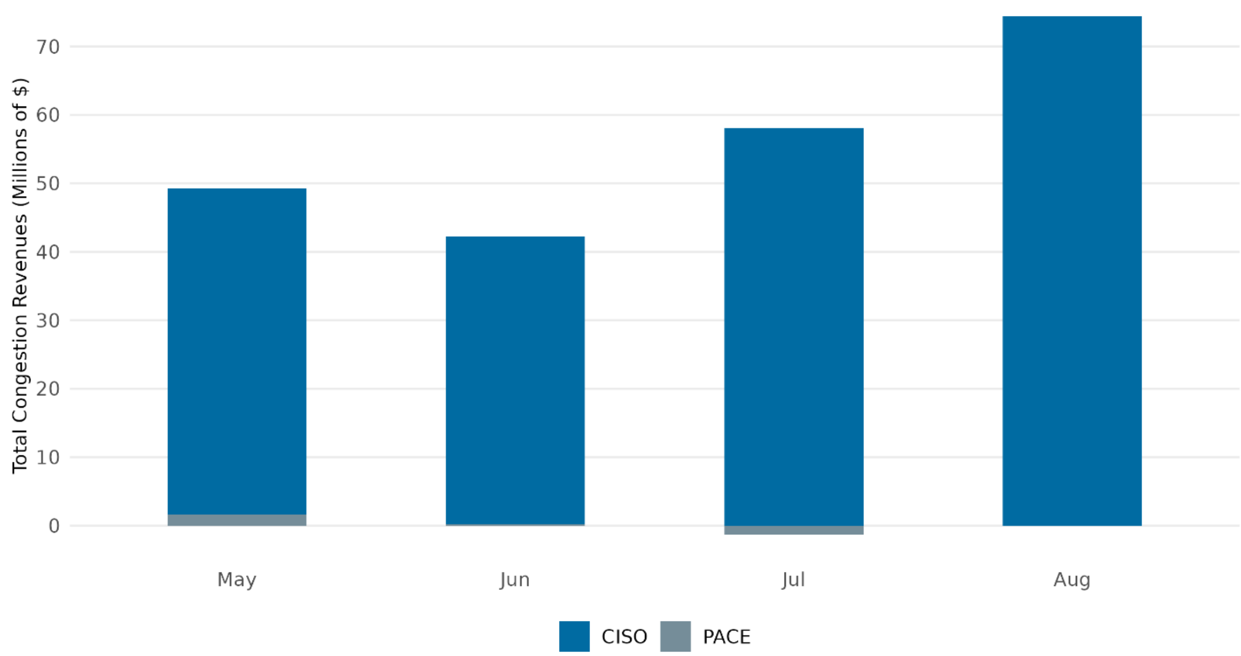
[7] https://stakeholdercenter.caiso.com/InitiativeDocuments/Stage-1-Analysis-Extended-Day-Ahead-Market-Congestion-Revenue-Allocation-Dec-11-2025.pdf

Figure 145: Daily congestion total by BAA



Total EDAM congestion revenues in August were $74.5M attributed entirely to constraints in the CISO area. This metric is after any adjustments for CRN flow, so PACW ITC congestion is neutralized by PACW OATT credits. Figure 146 provides a monthly summary of the latest congestion totals since May 2026.

Figure 146: 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 147 provides the breakdown of total congestion rents collected in the CISO area generated by parallel flows from PAC areas transactions, including adjustments for credits associated with firm transmission rights. The estimates in vivid blue are the congestion revenues that are returned to PAC for being associated with self-schedules supported with OATT rights; the bars in grey stand for the congestion revenues collected on CAISO constraints from PAC transactions that stay in the CISO area. The dark blue line represents the total amount of congestion revenue from constraints int the CAISO area. In August, PAC transactions resulted in a total of -$694k of congestion revenues on CISO constraints. Of the -$694k, 680k was charged to PAC to bring flows from self-schedules associated with OATT credits back to neutrality, resulting in a net total of -$14k remaining with CISO. Figure 148 provides a monthly summary of this metric.

[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 147: Congestion revenues on CAISO constraints from PAC schedules

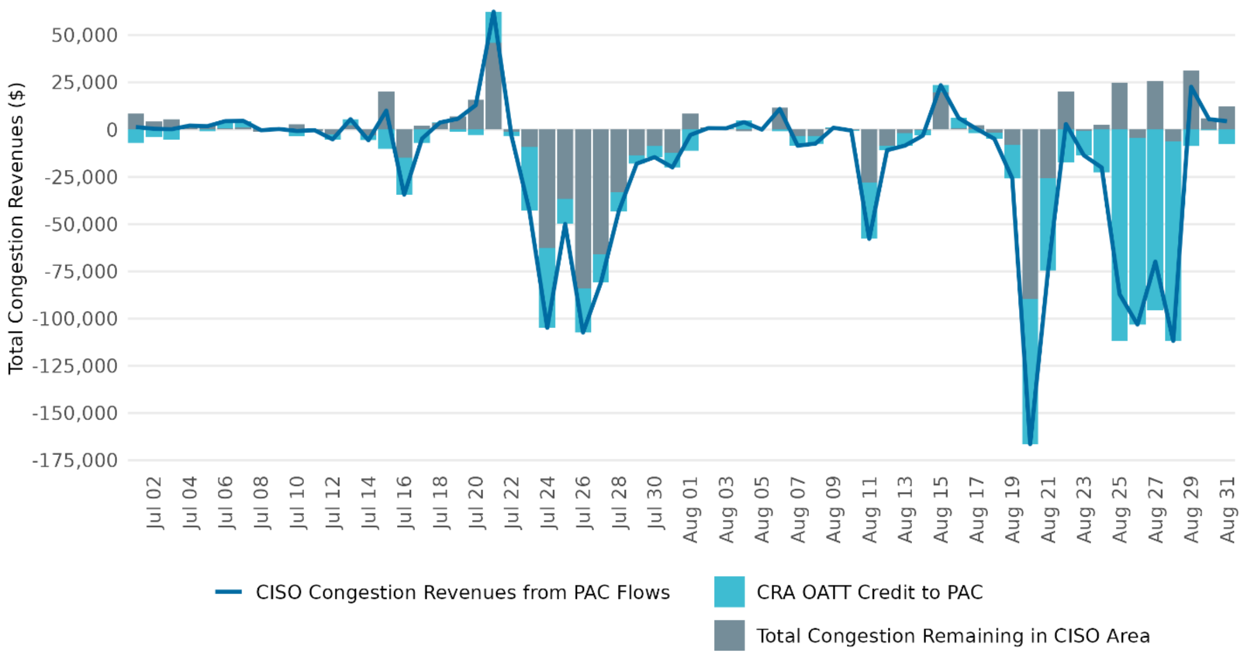


Figure 148: Net congestion revenues on CAISO constraints from PAC schedules

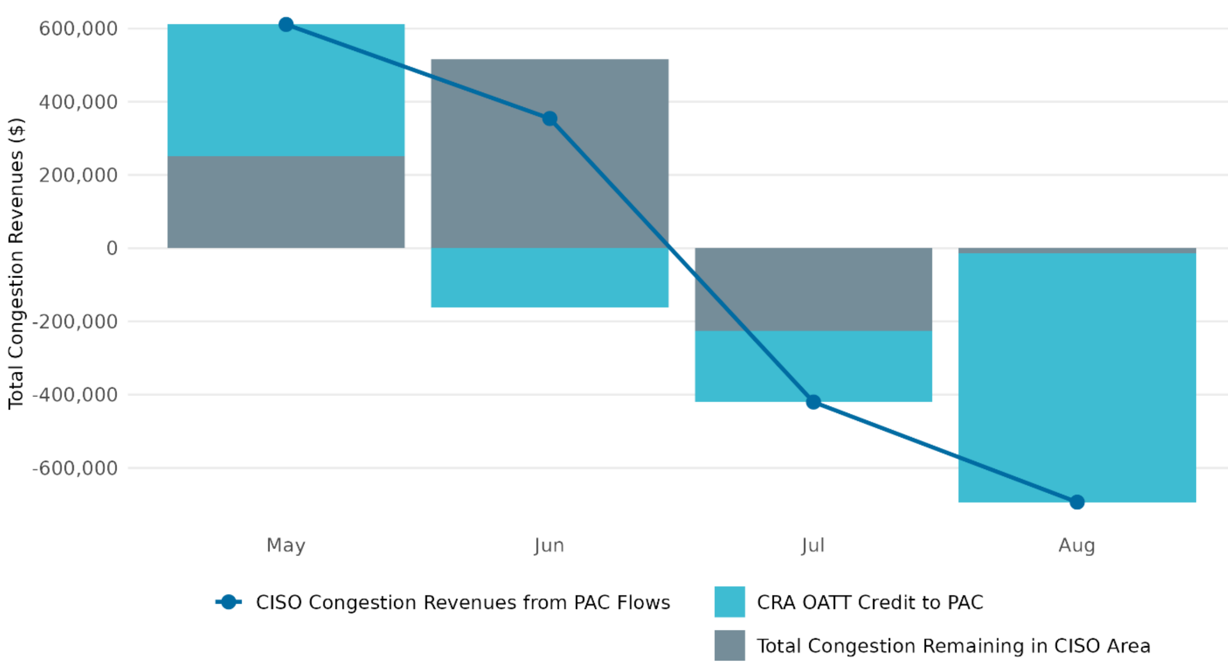


Figure 149 illustrates the daily total congestion revenues from CISO congestion that are returned to PAC areas given that they are associated with self-schedules supported by OATTs rights. These rights are either point-to-point rights or for Network service (NITS). Those rights are exercised and can be tracked through balanced CRN self-schedules. On the chart, a negative value indicates a payment, while positive values indicate a charge.

The allocation to PAC areas is about -$680,000 in August. This is reflective of net charge back to PAC due to their schedules originally received congestion payments for providing counterflows to congestion in the ISO areas. Figure 150 provides a monthly summary of this metric for previous months.

Figure 149: Estimated total CRN congestion credit to PAC from CISO congestion

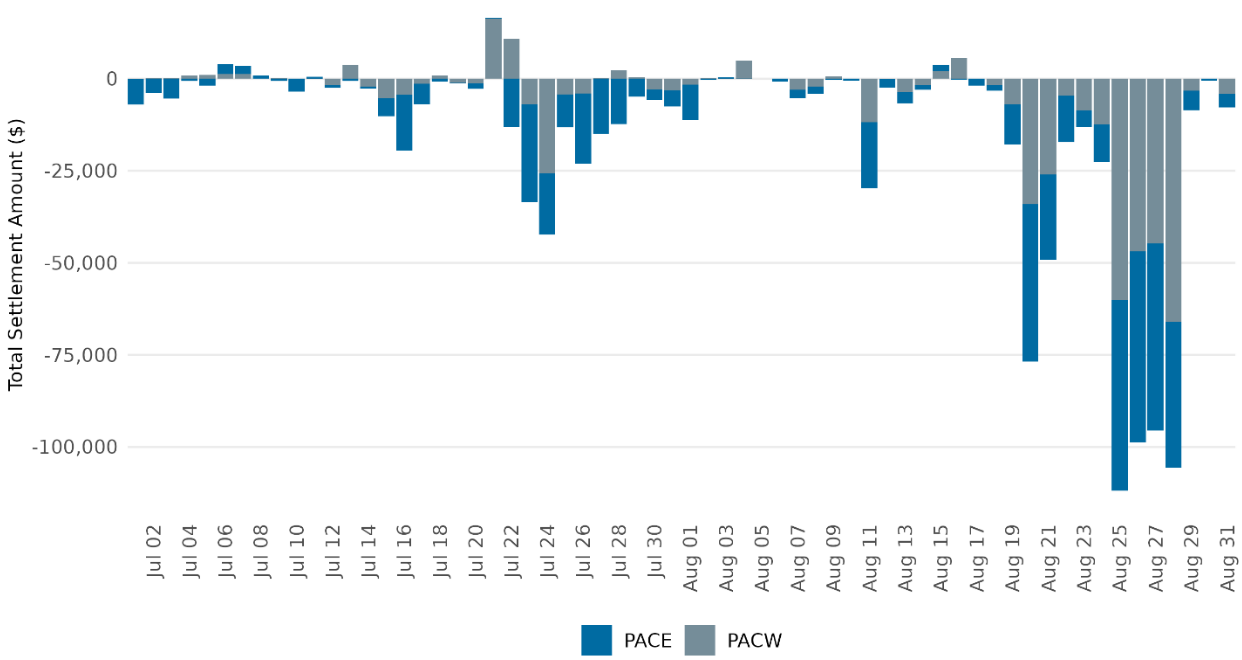


Figure 150: Total CRN congestion credit to PAC from CISO congestion

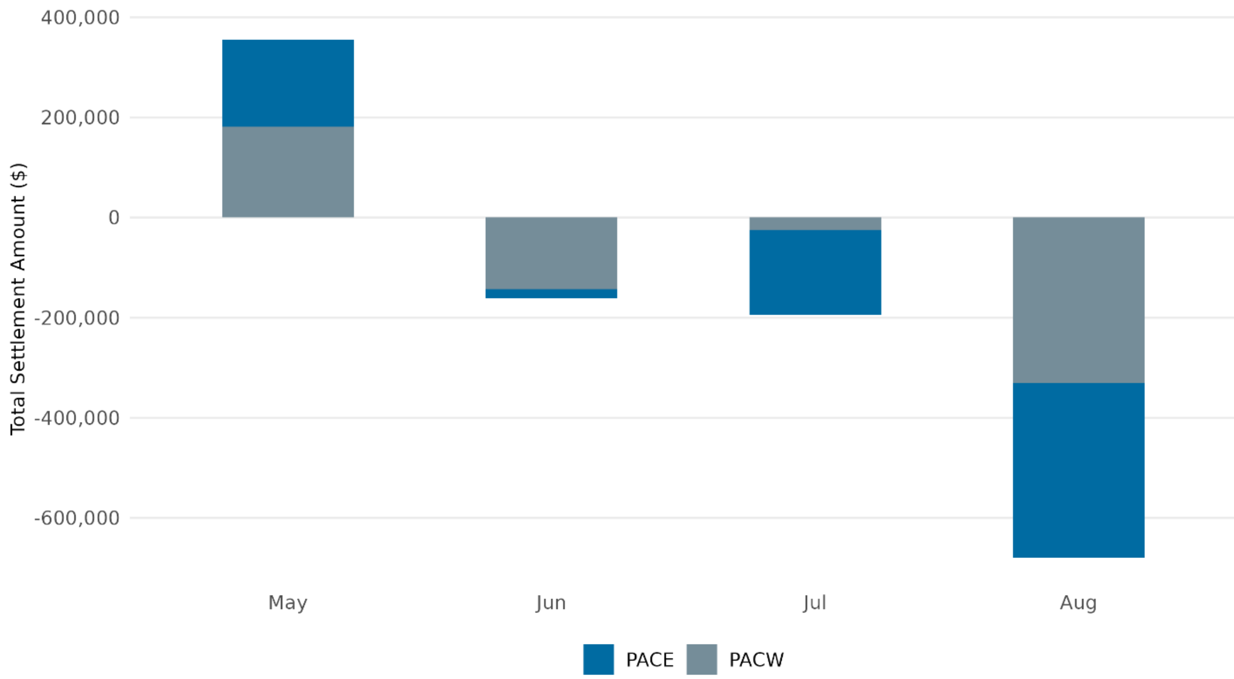


Figure 151 shows the volumes of OATT balanced self-schedules with respect to the total volume of all types of self-schedules for each PAC area. The proportions of OATT balanced self-schedules for PACE and PACW were 41% and 63% in August, respectively. Figure 152 provides the volumes of OATT balanced self-schedules for each PAC area. In August, PACE averaged 1,646 MW while PACW averaged 1,889 MW as seen in Figure 153.

Figure 151: Total self-schedules compared to OATT self-schedules by PAC area

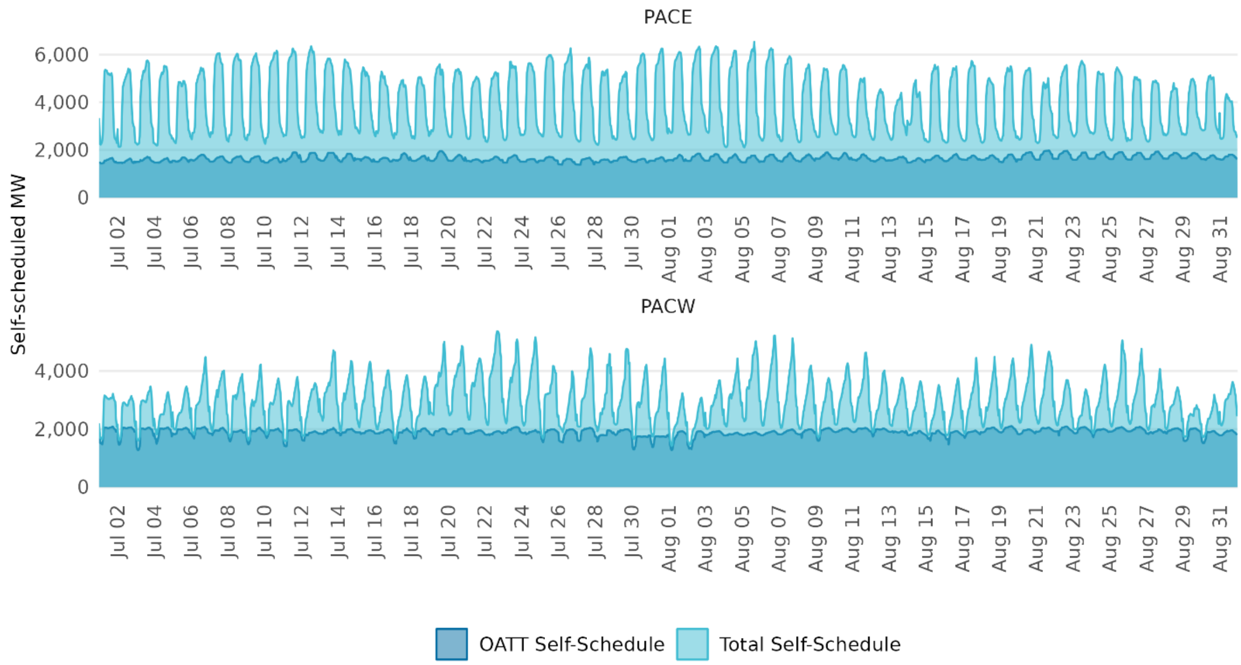


Figure 152: Total OATT self-schedule volumes by PAC area

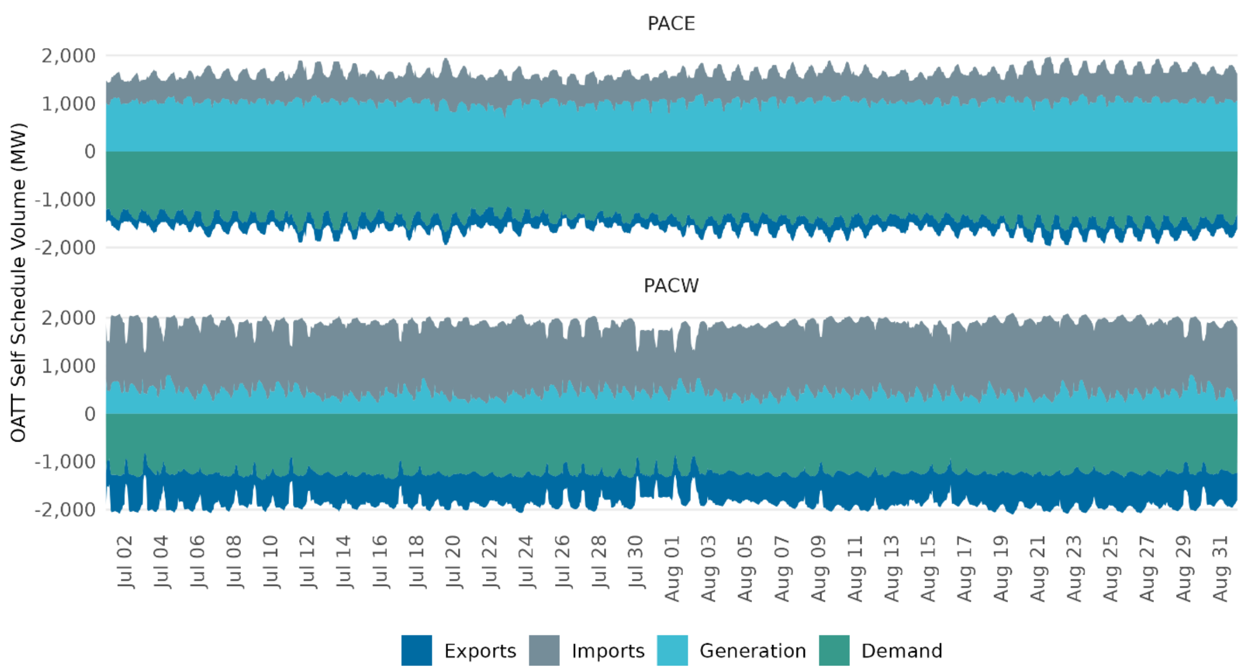
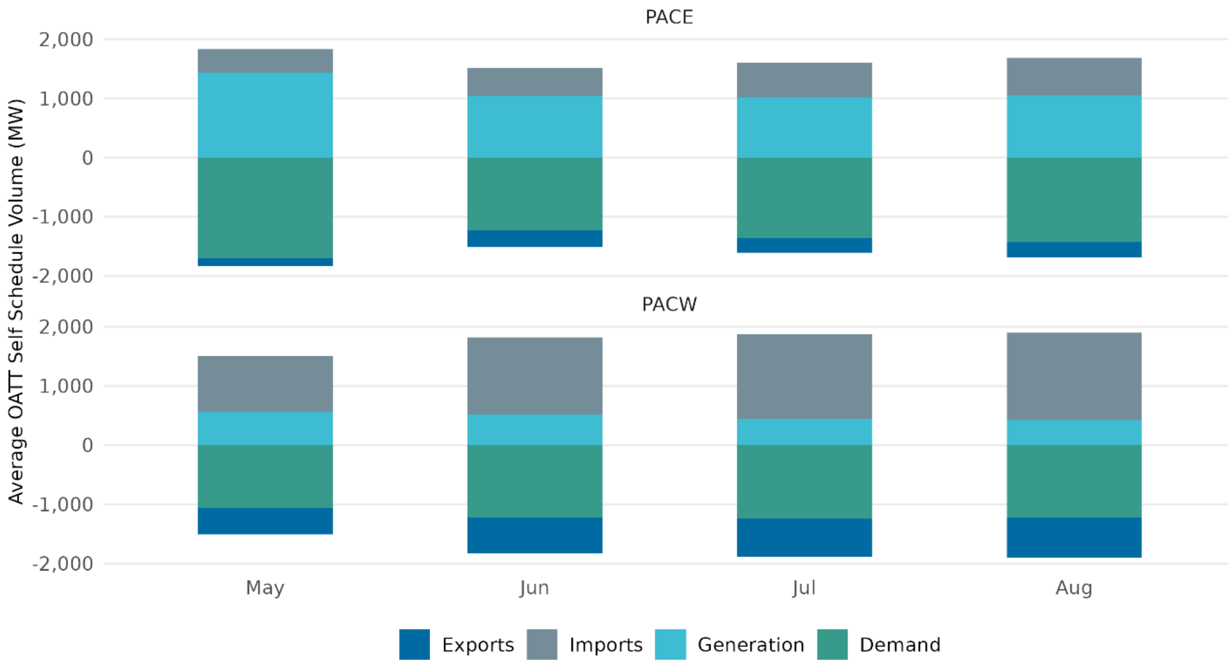


Figure 153: Monthly average OATT self-schedule Volume



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.

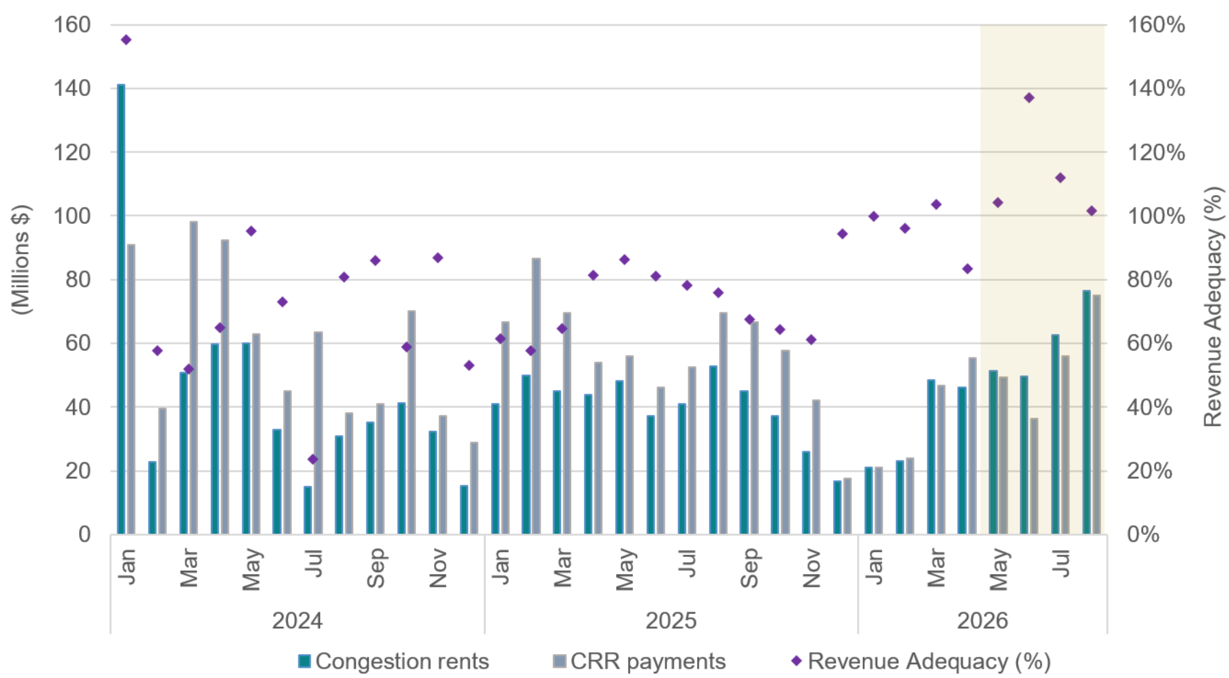
With EDAM implementation, schedules in the PacifiCorp (PAC) balancing area that impact flows on CAISO transmission constraints are assessed congestion charges based on their contribution to those constraints. However, the portion of congestion revenues collected on PAC schedules associated with self-schedules 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 154 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 August has been over 100 percent, indicating that congestion rents collected in the day-ahead market have been greater than the CRR payments. This outcome need to be taken with caution since there are still revisions to settlement estimates as different issue are addressed. Further, give the low level of congestion rents related to PAC schedules and the level of revenues allocated back to PAC, the level of revenue adequacy is not materially impacted by EDAM.

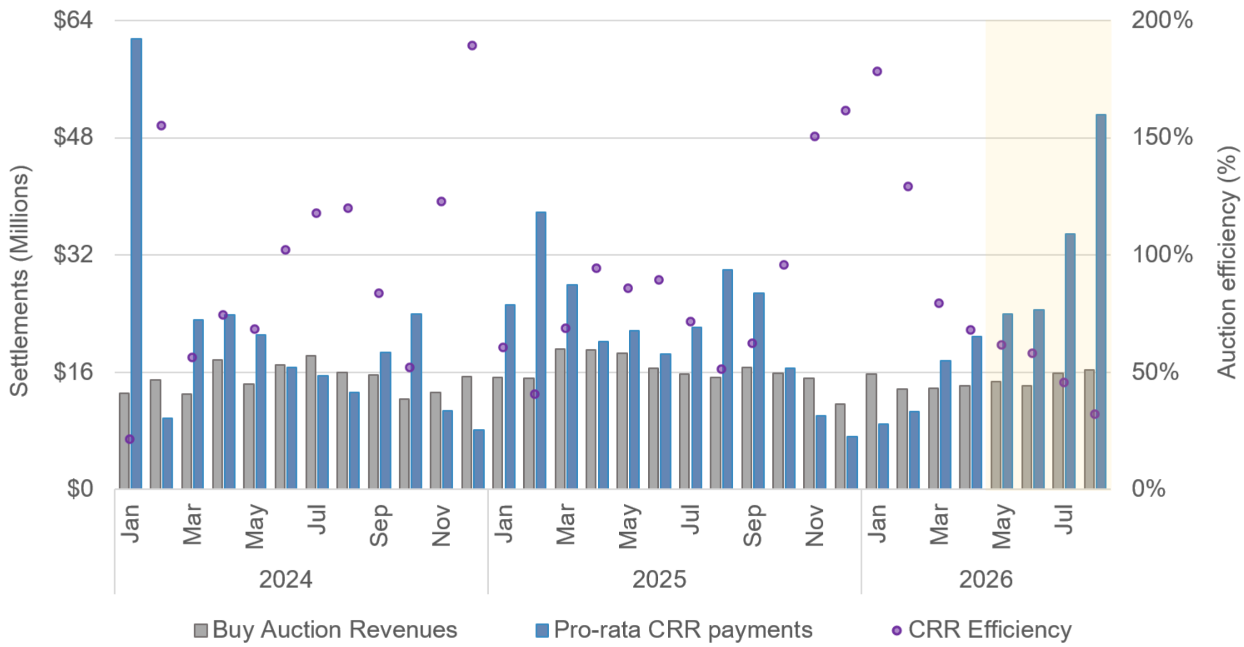
Figure 154: CRR revenue adequacy



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

Figure 155 illustrates these values in the bars, while the purple markers show auction efficiency as a percentage. Auction efficiency was relatively low from May through August, following EDAM implementation. However, this trend is consistent with historical seasonal patterns, as higher summer loading conditions generally lead to increased congestion and reduced auction efficiency.

Figure 155: CRR auction efficiency



EDAM Net Export Constraints and RUC Adjustments

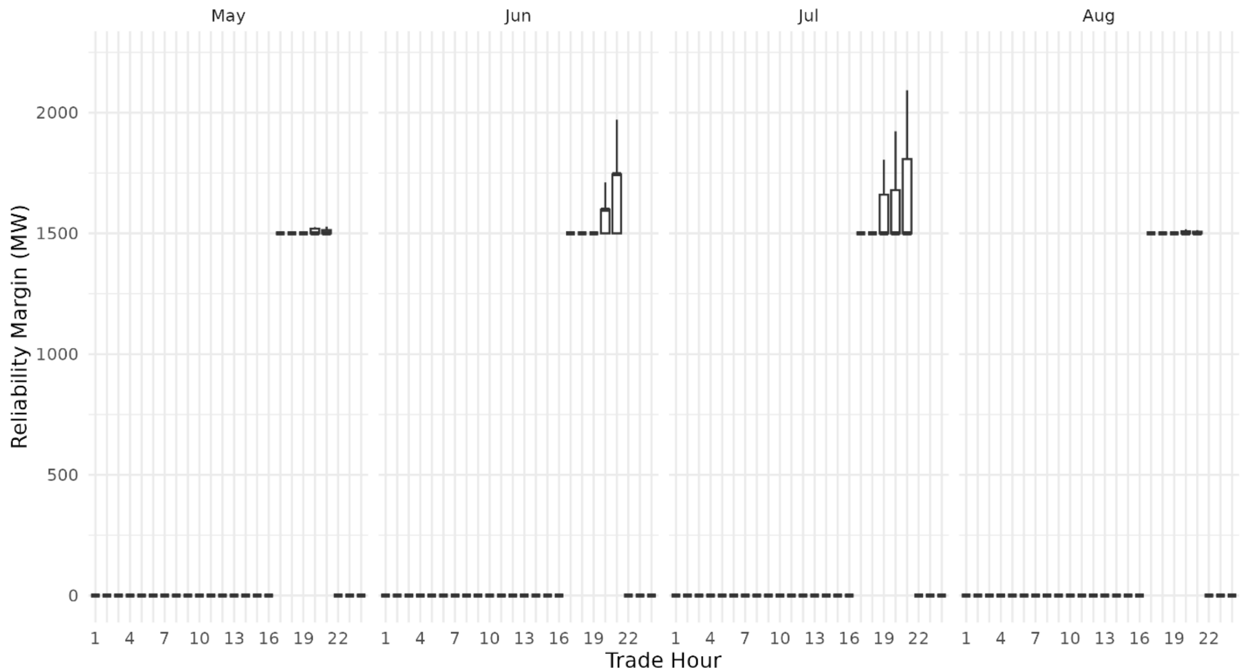
The EDAM export constraint and RUC adjustments are optional BA level constructs that help ensure sufficient procurement to support reliability going into the real-time market.

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 156: 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 157 and Figure 158 show a comparison of RUC adjustments used in the periods of May-August for 2025 and 2026. In August 2026 there were 298 hours with a RUC adjustment, a reduction from the 486 hours with RUC adjustments observed in August 2025. The maximum hourly average adjustment in August 2025 was 3390 MW in hour ending 19, while the hourly average adjustment in August 2026 saw a steep reduction to 400 MW.

Figure 157: Day-ahead manual adjustments and demand in the ISO area

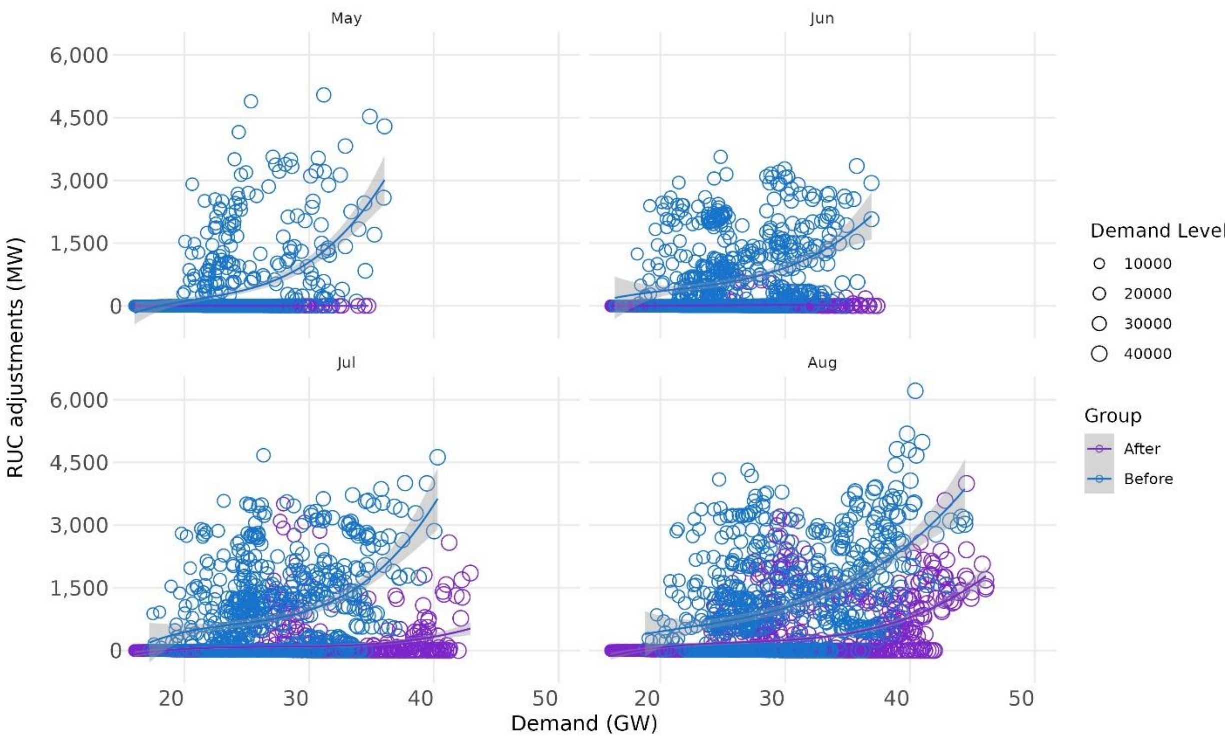


Figure 158 shows the trend over time on the use of RUC adjustment for ISO area, highlighting some key events relevant to the trends. Historically, more frequent and higher RUC adjustments are observed during conditions of high demand and tight supply conditions such as summer months. For summer 2026 and with the introduction of imbalance reserve, the daily trend of RUC adjustments has come down.

Figure 158: Hourly average of RUC adjustments

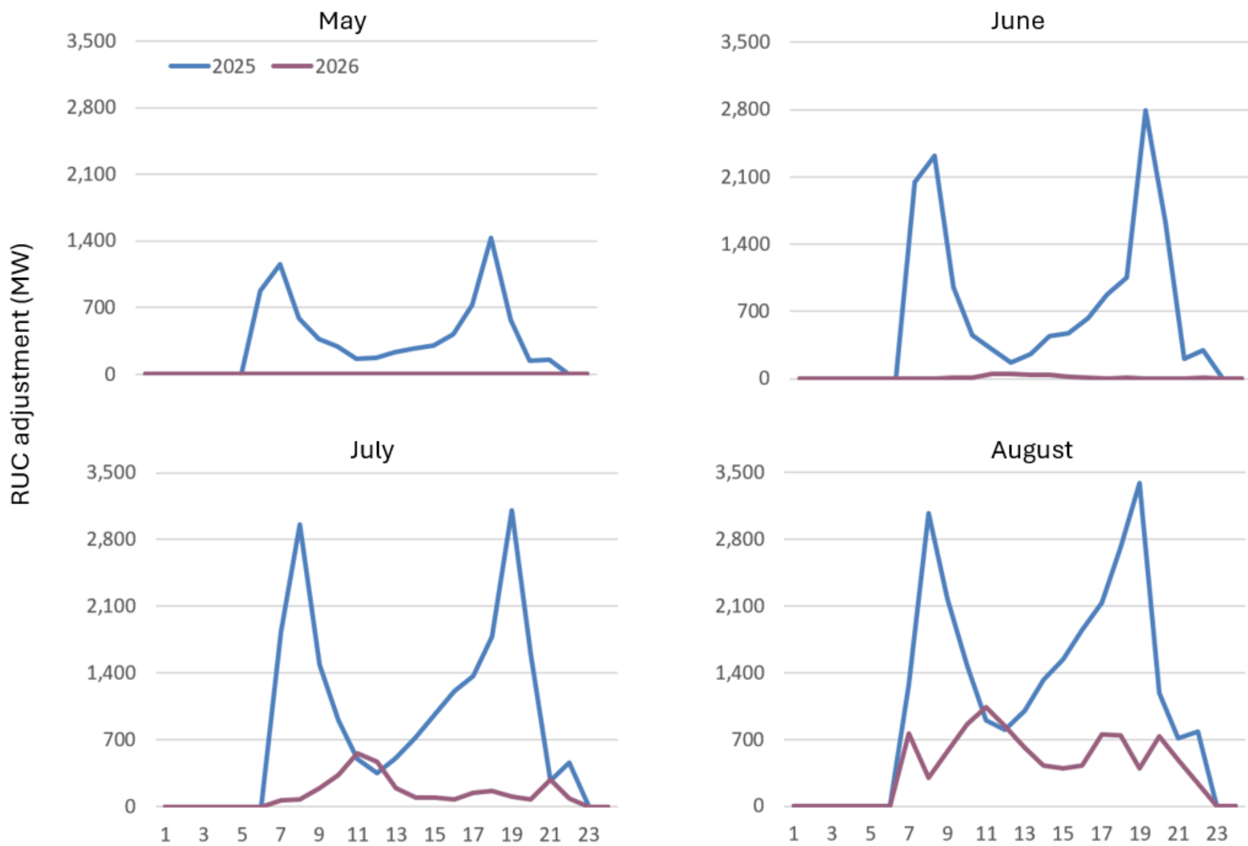


Figure 159: Historical RUC adjustments in the day-ahead market

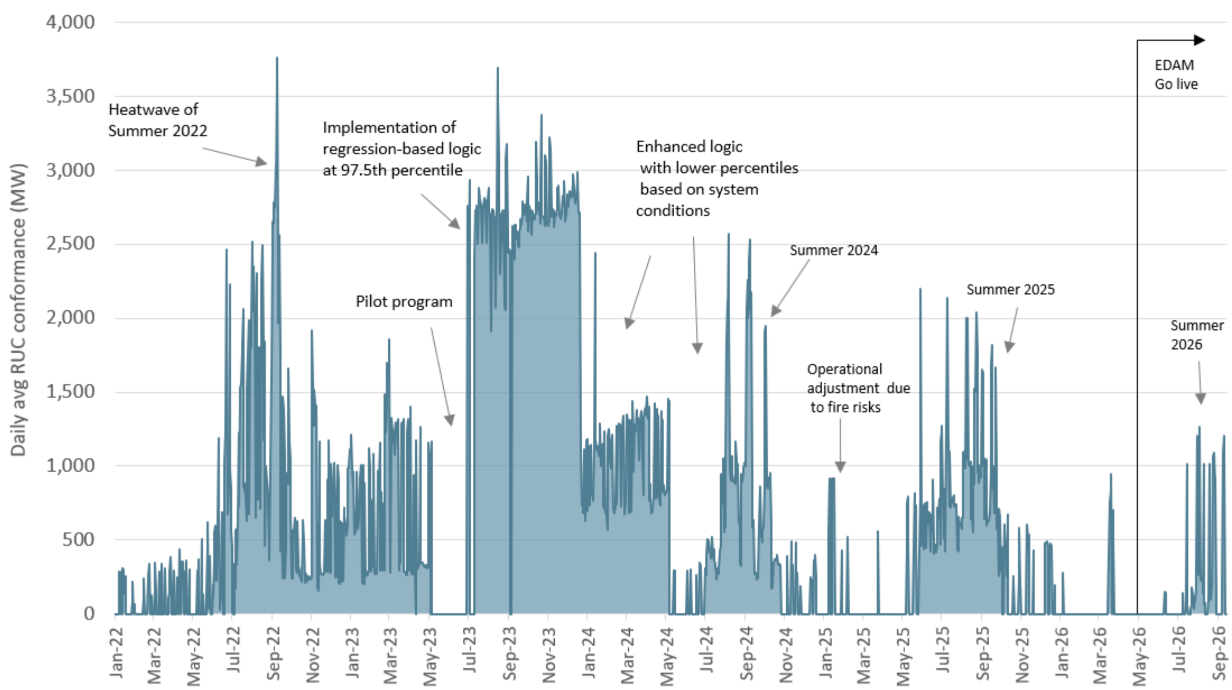
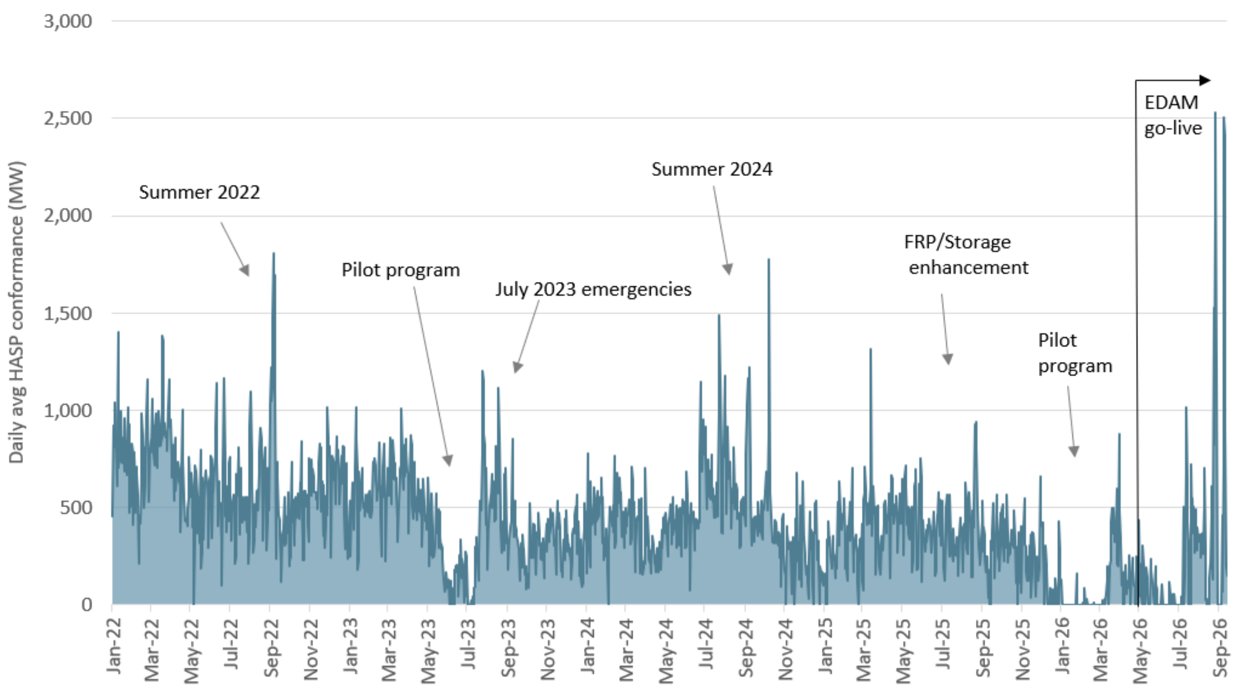


Figure 160 shows similar trend of load conformance for the hour ahead scheduling process (HASP). Historically, this market is utilized to gain additional ramping flexibility for peak hours since it is the last opportunity to schedule additional interties. Overall, the use of HASP load conformance has 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

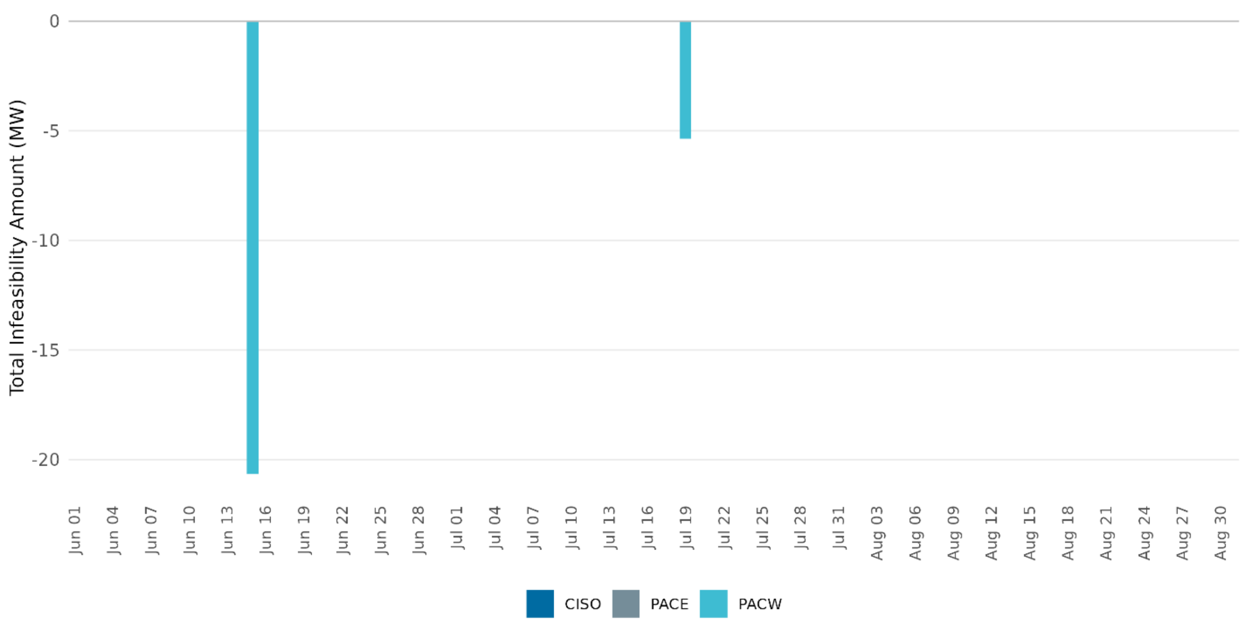
Figure 160: Historical load conformance in the hour ahead scheduling process



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. PACW observed over-generation infeasibilities of approximately 21 MW on June 15 and 5 MW on July 19. No RUC infeasibilities were observed in August.

Figure 161: 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 priced using the last economic bid instead of the RUC infeasibility penalty price.

There are no RUC infeasibilities for the month of August. For infeasibilities observed in previous months, please refer to the July's monthly performance report. The infeasibilities in the prior months were analyzed in the previous version 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 162 and Figure 163 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. There was a market issue resulting from a patch that impacted market power mitigation on day-ahead trade dates July 8-18. During the impacted trade dates, no PACE or PACW resources were subjected to mitigation. There were also significantly fewer CAISO resources subjected to IFM mitigation, particularly gas resources. No resources were subject to mitigation in RUC from July 8-18. Outside of the impacted dates, gas and energy storage make up most resources subject to mitigation in IFM. In RUC, gas resources made up a relatively small share of resources subject to mitigation. In general, there were far fewer resources subject to mitigation in RUC.

Figure 162: Resources subject to mitigation in IFM MPM, by fuel type

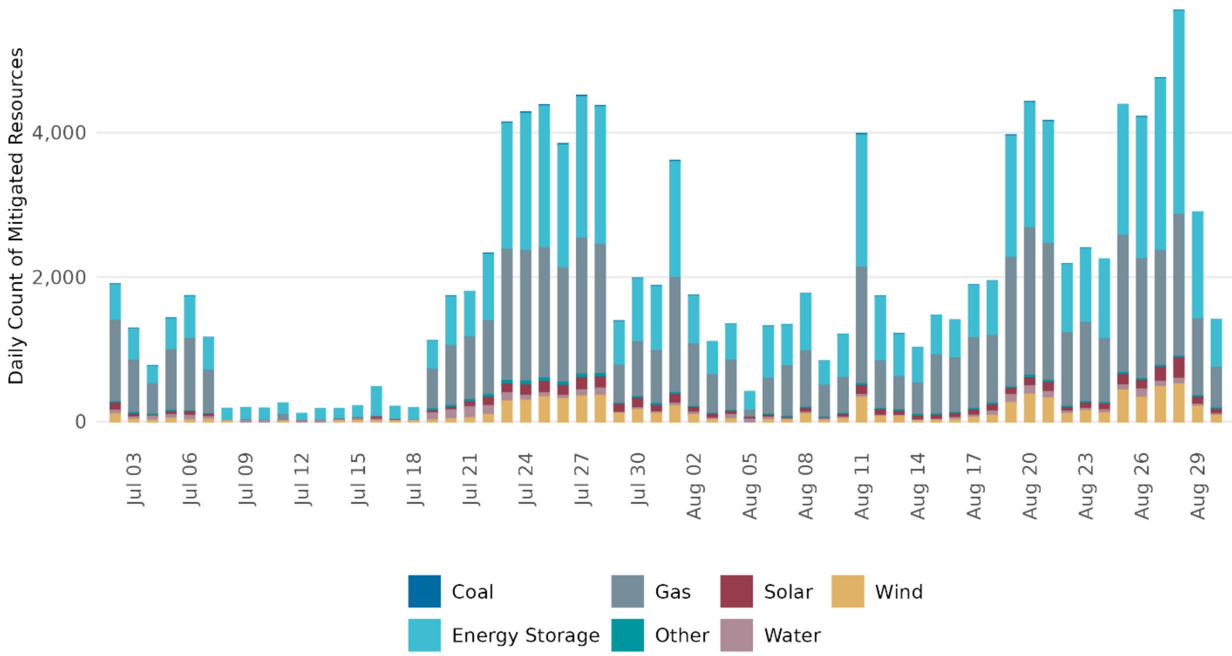


Figure 163: Resources subject to mitigation in RUC MPM, by fuel type

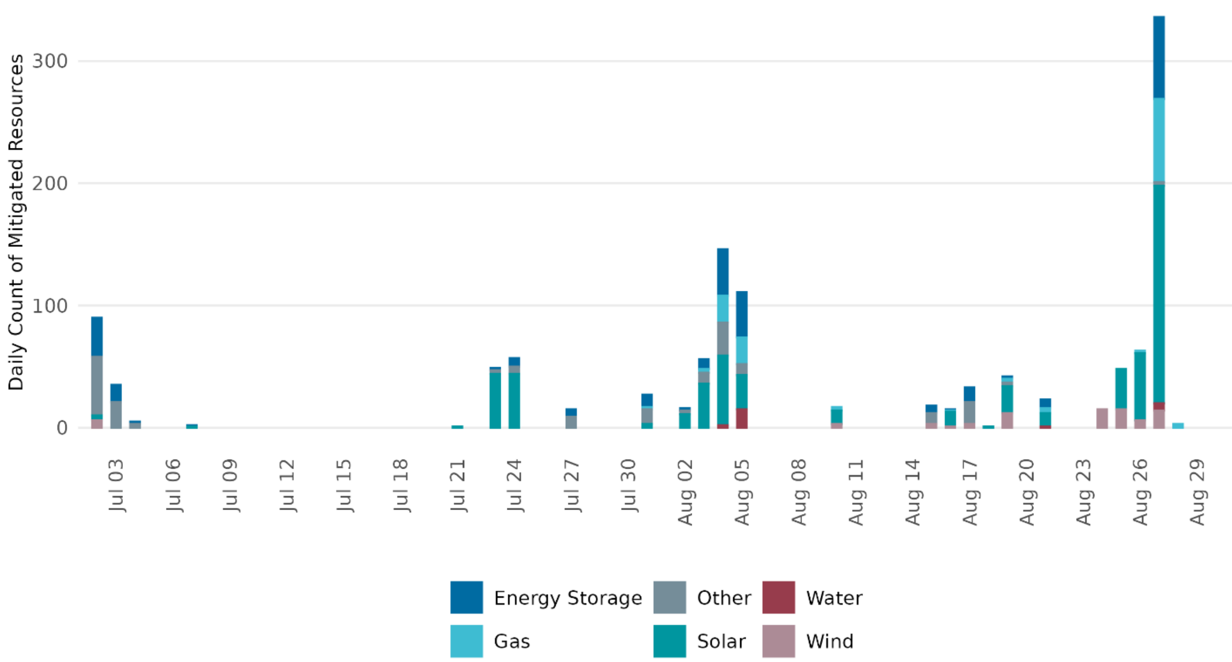


Figure 164 and Figure 165 show the same total counts as above but broken down by BAA. Figure 164 shows that the number of PACE resources subject to mitigation in IFM has been relatively consistent, excluding July 8-18. Even when excluding July 8-18, the number of resources subject to mitigation in RUC was significantly lower than in IFM, especially for PACE and PACW. RUC mitigation remained relatively low through most of July and August.

Figure 164: Resources subject to mitigation in IFM MPM, by BAA

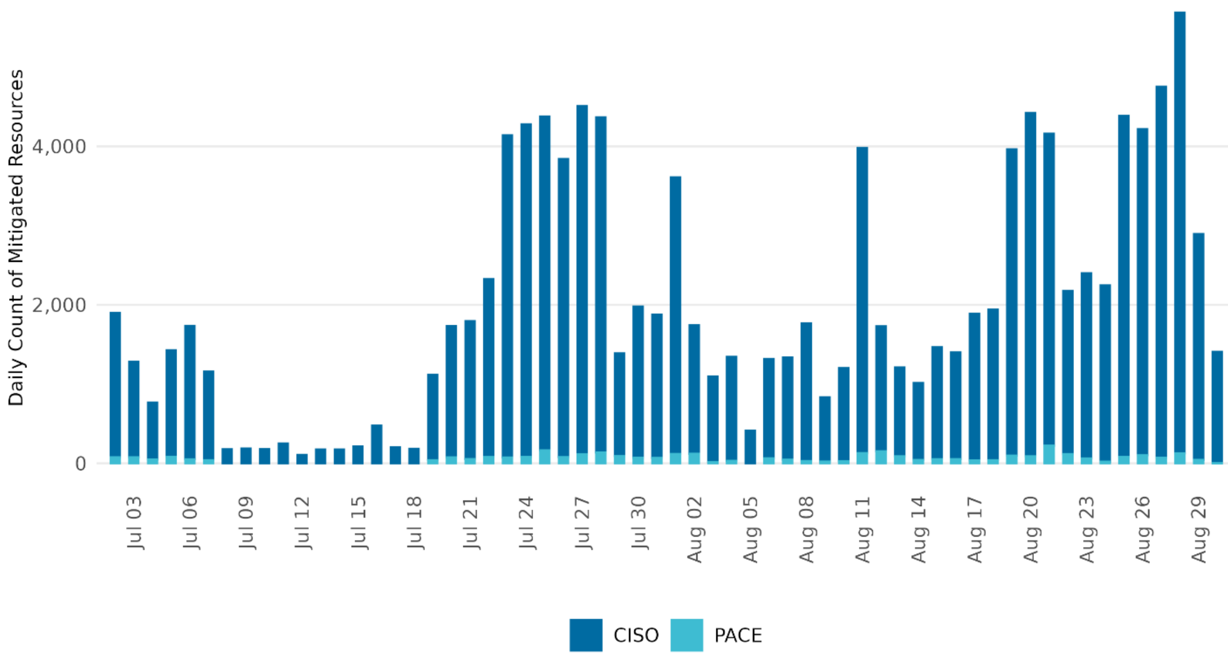


Figure 165: Resources subject to mitigation d in RUC MPM, by BAA

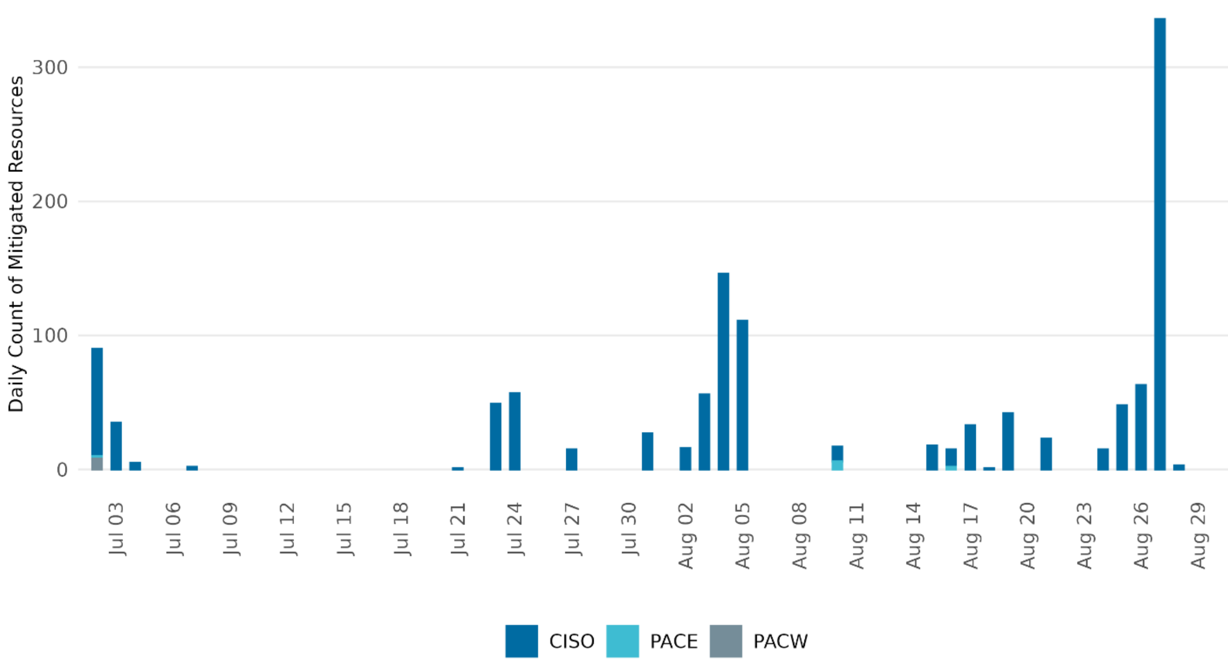


Figure 166 and Figure 167 show the average number of resources subject to mitigation in each hour of the day, by month for IFM and RUC, broken down by fuel type. Figure 166 shows that mitigation in IFM is typically highest during the middle of the day when there is a lot of solar production, while in July and August it was highest during the evening peak. There is a less consistent pattern in RUC.

Figure 166: Resources subject to mitigation in IFM MPM, by fuel type hourly

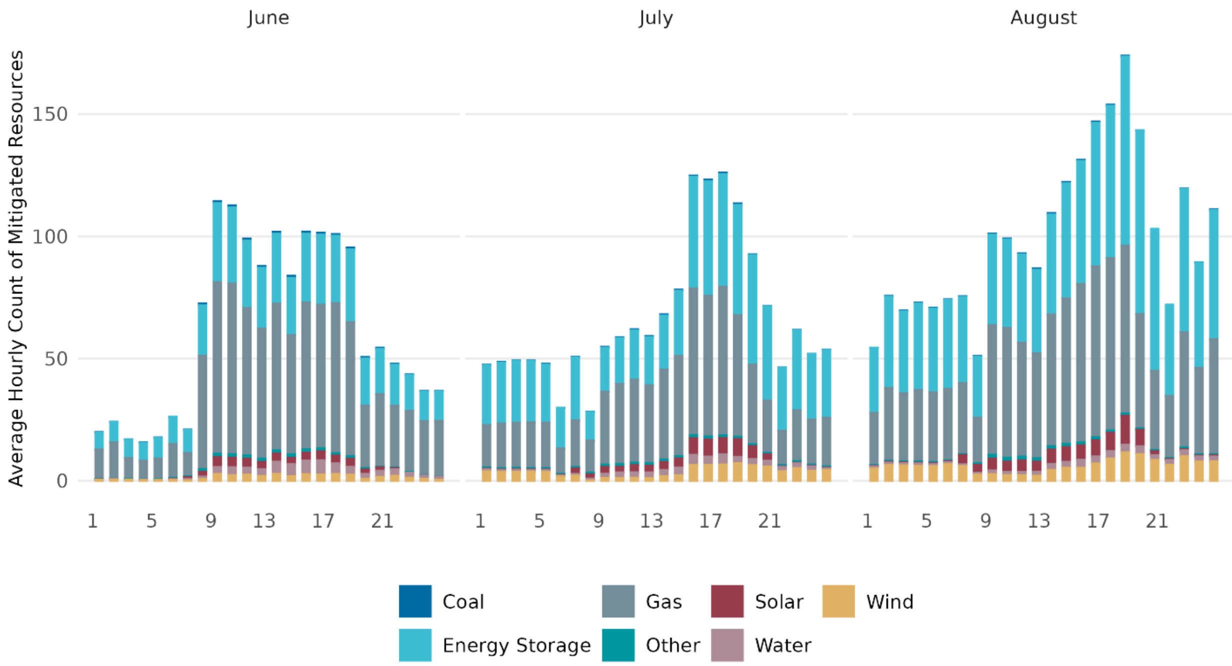
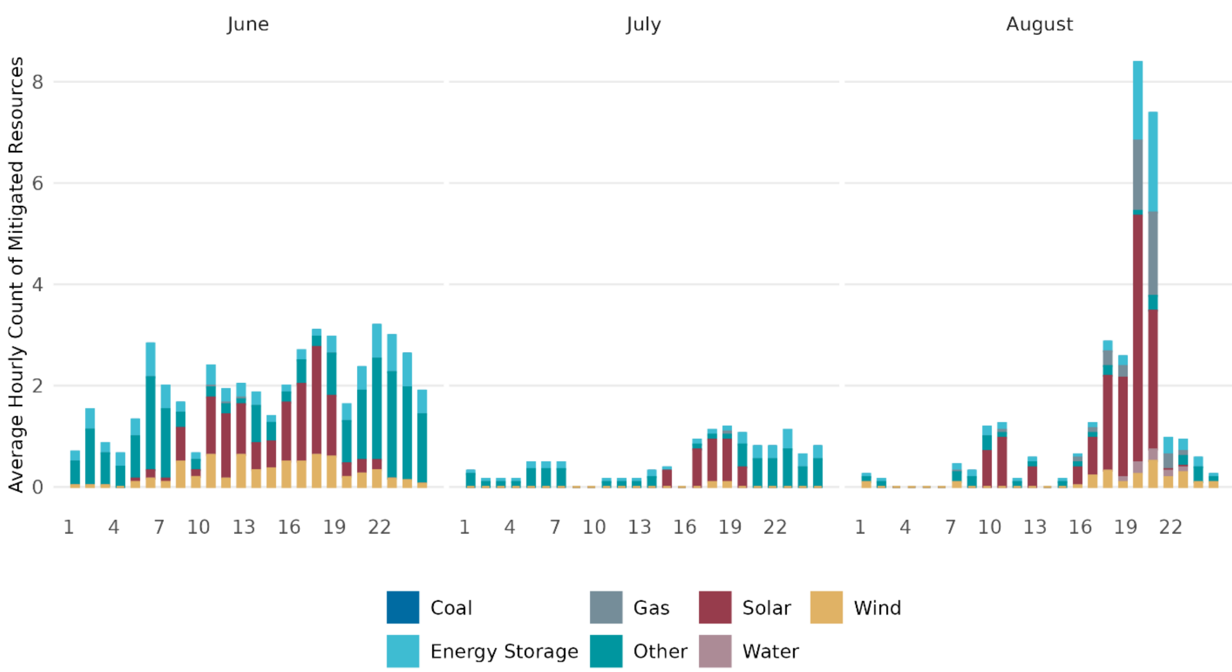


Figure 167: Resources subject to mitigation in RUC MPM, by fuel type hourly



Summer Conditions

Peak ISO Load

The ISO area recorded its highest load of the year so far on August 26 at 47,140 MW. This level was within the range observed in previous years and was largely consistent with historical load levels. Load peaks in August increased from the previous month, exceeding 40,000 MW on 23 days and exceeding 45,000 MW at the monthly peak. The average daily peak load in August 2026 was 40,803 MW.

Figure 168 shows the historical load level distributions in the ISO area over the past six years. Load levels have generally remained within a tight range with few outliers that would indicate extreme conditions. The short distribution tails suggest that load variability has been limited. Load peaks in August increased from the previous month, exceeding 40,000 MW on 23 days and exceeding 45,000 MW at the monthly peak. The average daily peak load in August 2026 was 40,803 MW.

Figure 168: Historical distribution of load levels in the ISO area

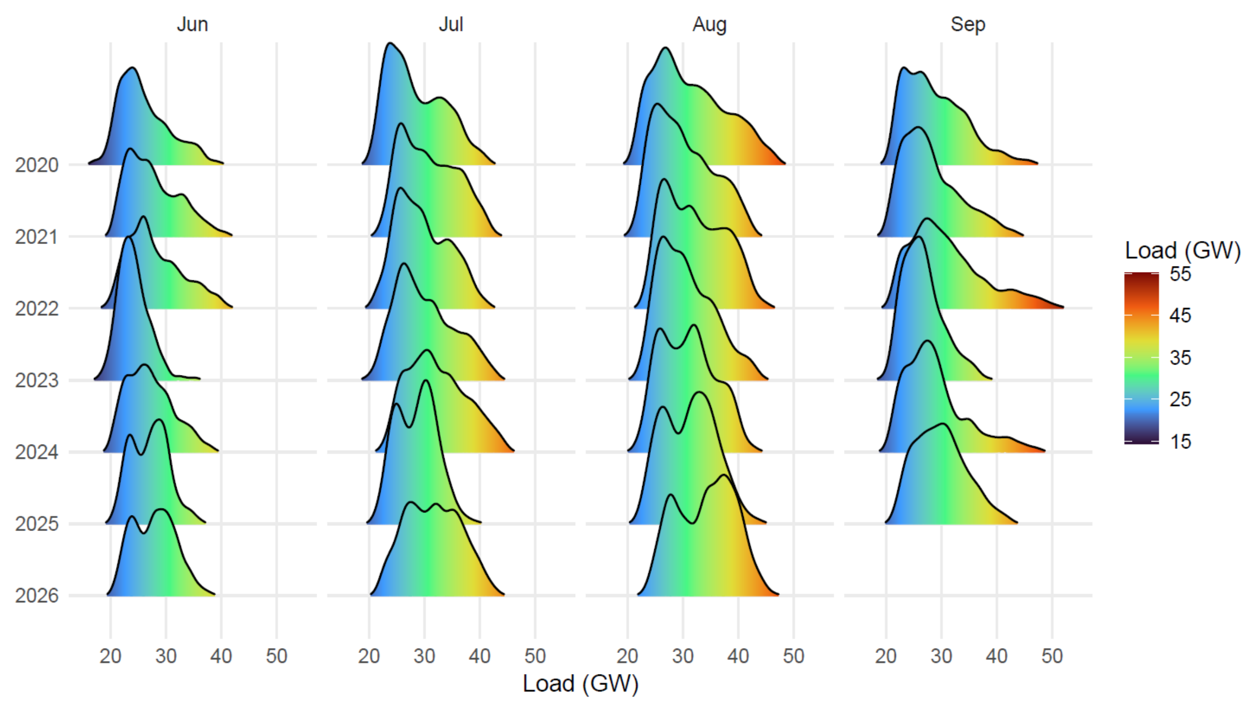
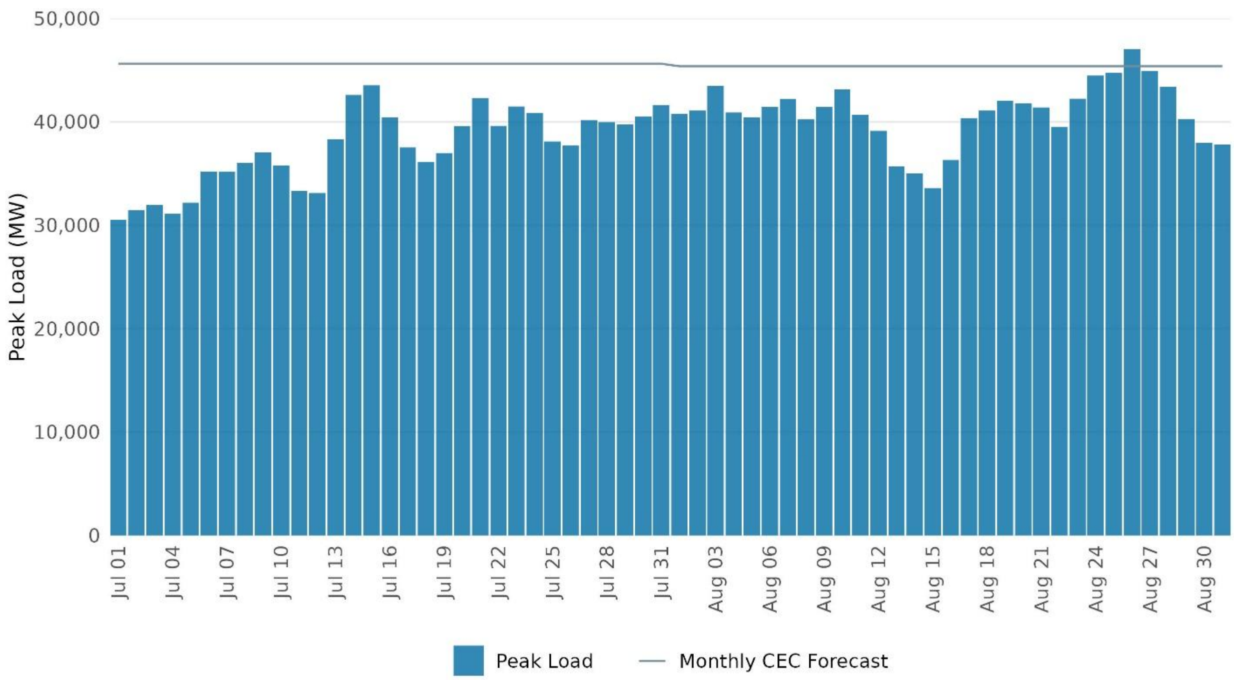


Figure 169 shows the 5-minute average daily load for July and August relative to the CEC month-ahead forecast used to assess the resource adequacy requirements. The instantaneous load peak in August 2026 was 47,140 MW on August 26. This peak exceeded the CEC month-ahead forecast of 45,386 MW. The figure below is based on the five-minute averages of the actual load. The highest five-minute average peak load for the month of August was 47,069 MW.

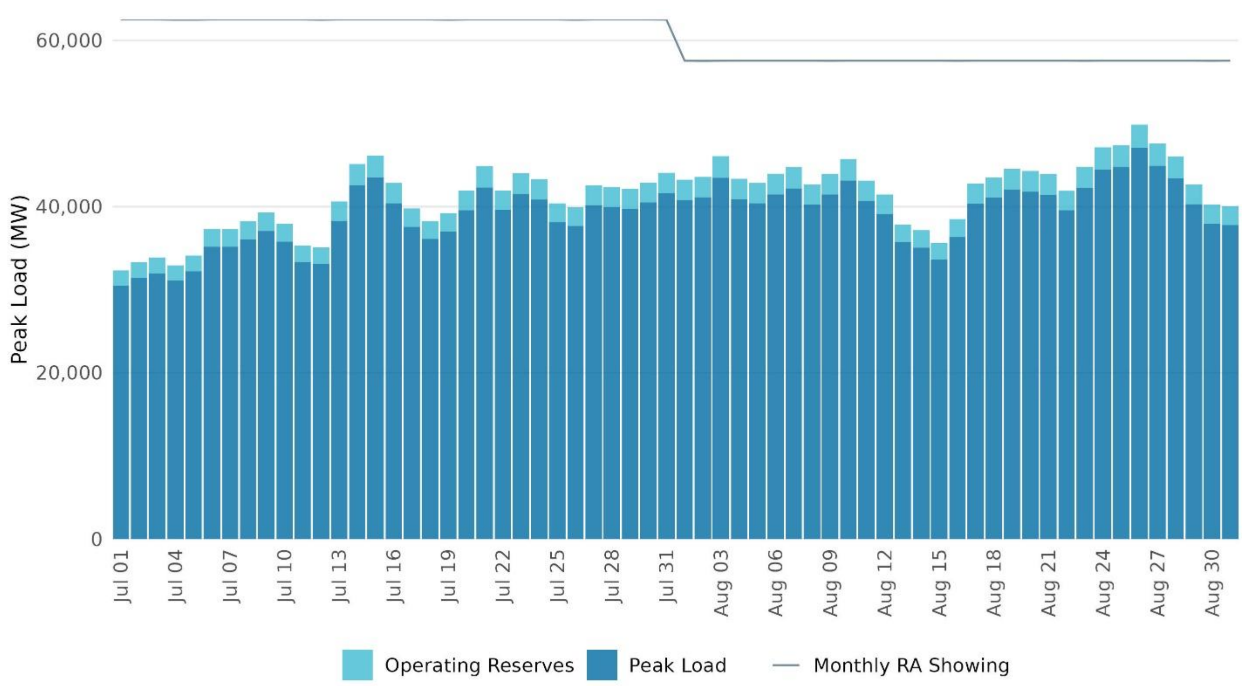
Figure 169: Daily peak load and CEC month-ahead forecast



The actual load did not exceed the monthly RA showings in August 2026 as illustrated in

Figure 170. There was plenty of headroom in the monthly RA supply in August to meet the observed levels of load. 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 170: Daily peak load, operating reserves and RA capacity



Market Prices

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

Figure 171 compares the daily average prices across ISO's markets for the months of July and August.[10] The daily average fifteen-minute market prices reached $143/MWh ($109 in July), while the daily average day-ahead prices reached about $86/MWh ($55 in July), and the five-minute market prices reached a maximum of about $164/MWh ($117 in July). In August, the IFM maximum occurred on August 27, the FMM maximum occurred on August 26, and the RTD maximum occurred on August 26.

Figure 171: Average daily prices across markets, July and August 2026

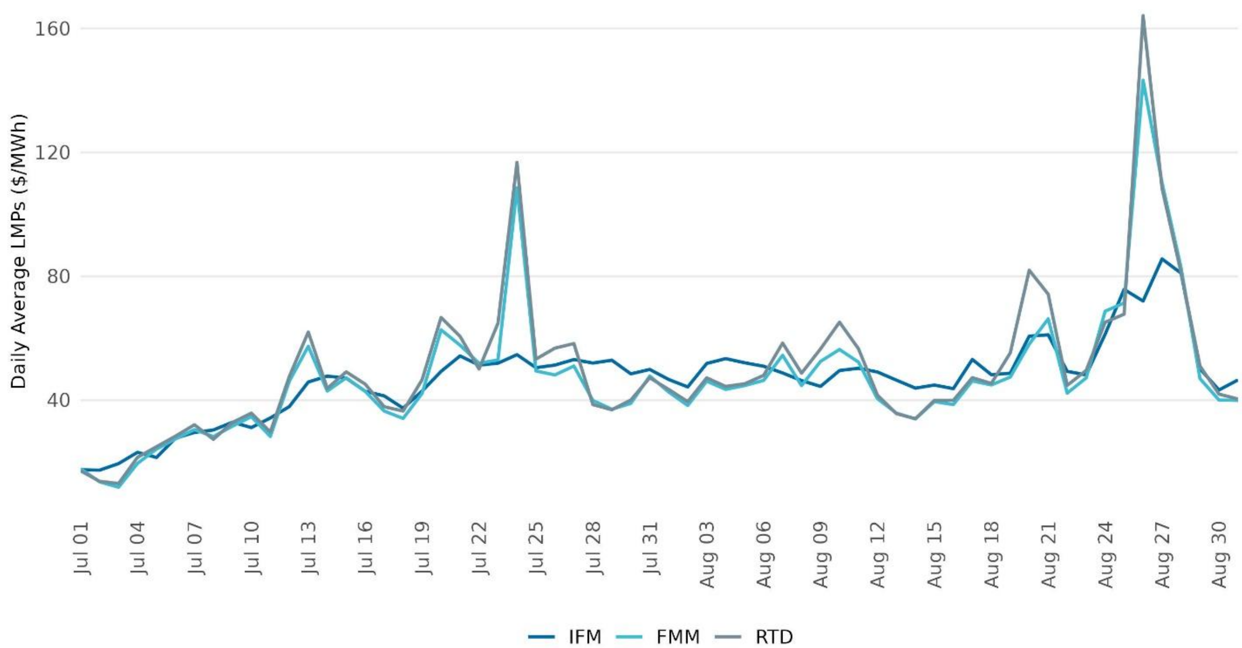


Figure 172 shows average hourly prices across ISO's markets for both July and August 2026. In August, the hourly average prices for the integrated forward market, the fifteen-minute market, and the real-time dispatch market peaked in trade hours 20, 22, and 23 at $86/MWh, $89/MWh, and $90/MWh, respectively.

[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 172: Average hourly prices across markets

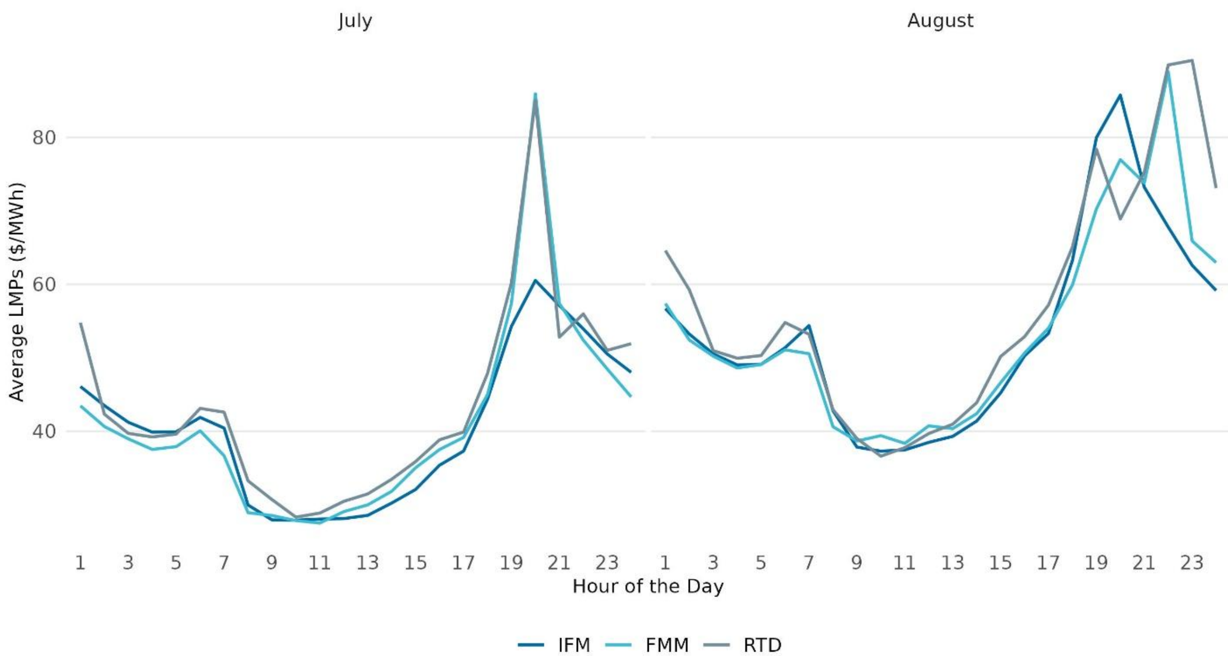


Figure 173 and Figure 174 show daily average LMPs for all four regions for the months of July and August. In July, the highest FMM regional daily average was observed in Southwest on July 24 at about $118/MWh, while the highest RTD regional daily average occurred in Southwest on July 24 at about $135/MWh. In August, the highest FMM regional daily average was observed in Southwest on August 26 at about $140/MWh, while the highest RTD regional daily average occurred in Southwest on August 26 at about $177/MWh. On the July FMM peak date, prices across the four regions ranged from about $49/MWh to $118/MWh. On the August FMM peak date, average prices were about $125/MWh in California, $87/MWh in Central/Mountain, $59/MWh in Pacific Northwest, and $140/MWh in Southwest.

Figure 175 and Figure 176 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]

[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 173: Average daily prices across region for FMM market

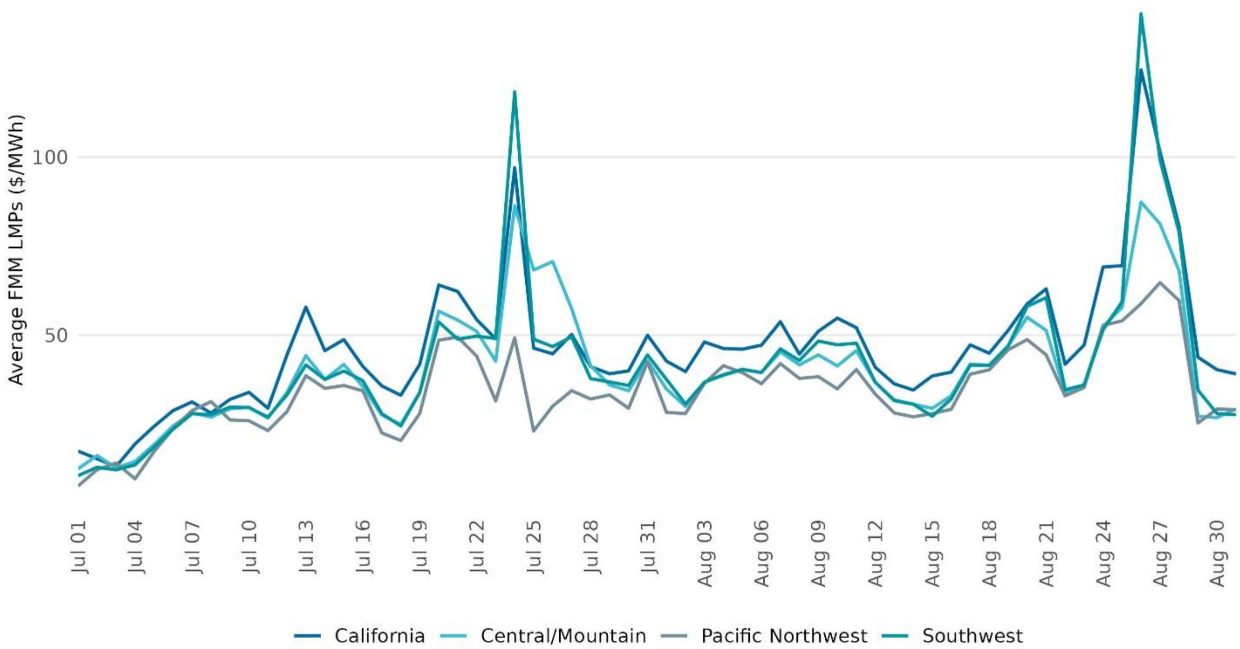
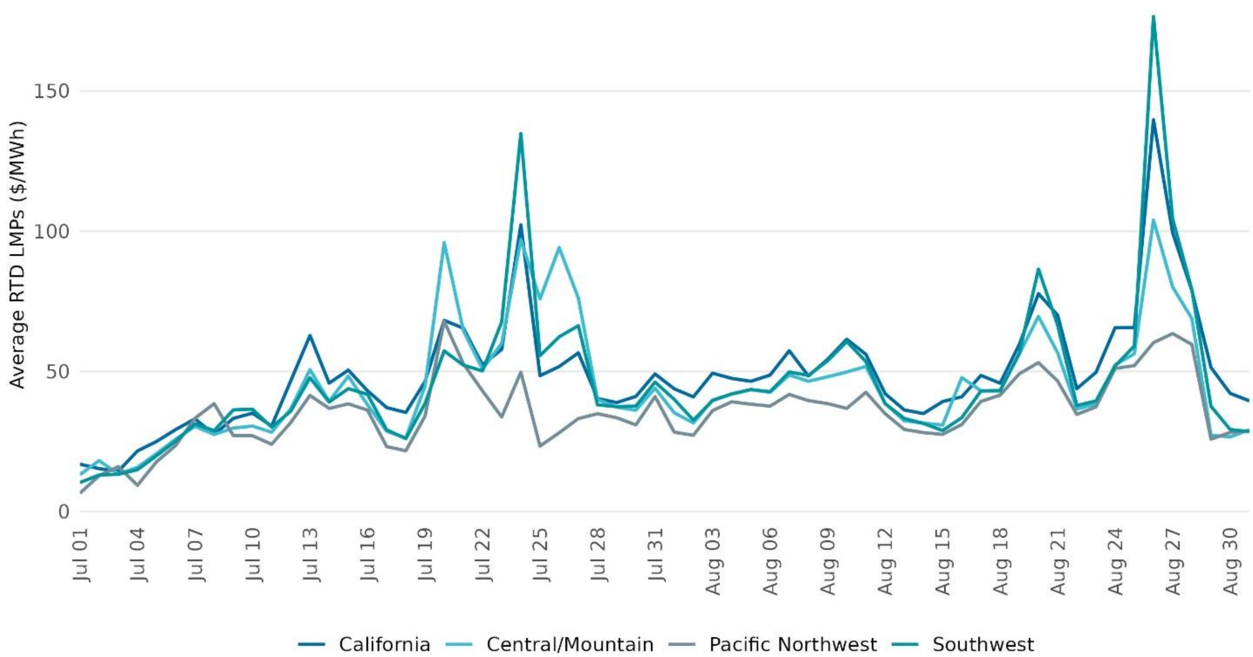
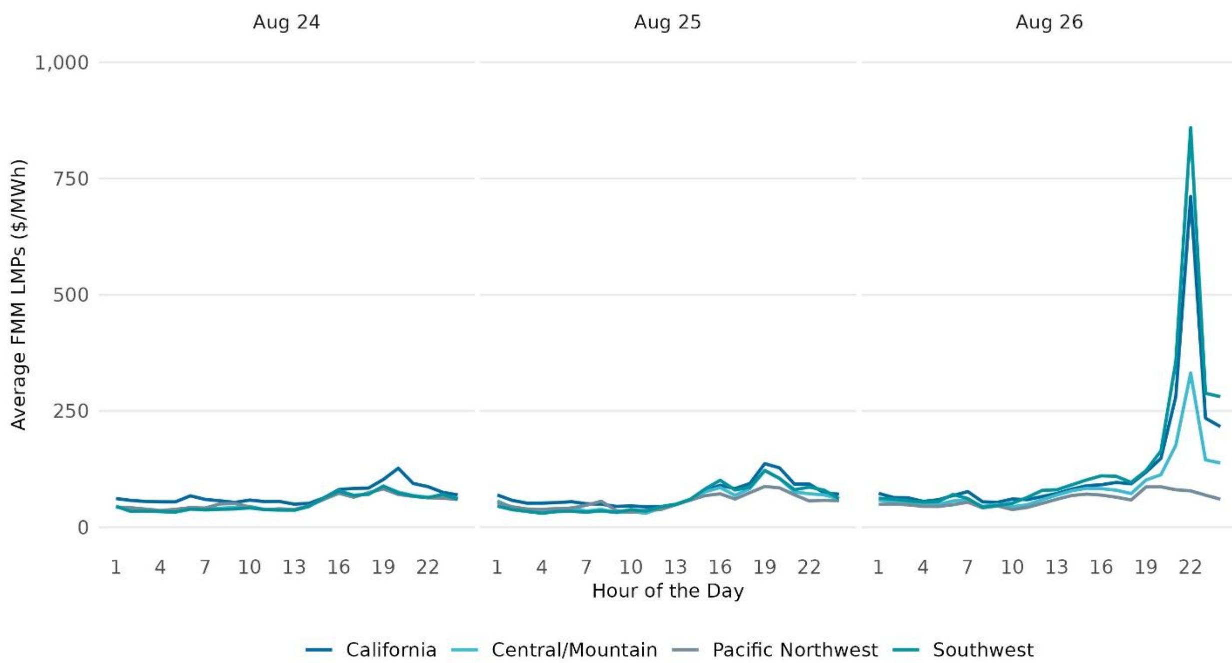


Figure 174: Average daily prices across region for RTD market



For FMM, On August 24, California is the highest at $127/MWh, followed by Central/Mountain at $88/MWh. On August 25, California is the highest at $137/MWh, followed by Southwest at $122/MWh. On August 26, Southwest is the highest at $859/MWh, followed by California at $711/MWh.

Figure 175: Average hourly prices across region for FMM market



For RTD, On August 24, California is the highest at $109/MWh, followed by Southwest at $91/MWh. On August 25, Southwest is the highest at $100/MWh, followed by California at $95/MWh. On August 26, Southwest is the highest at $1035/MWh, followed by California at $707/MWh.

Figure 176: Average hourly prices across region for RTD market

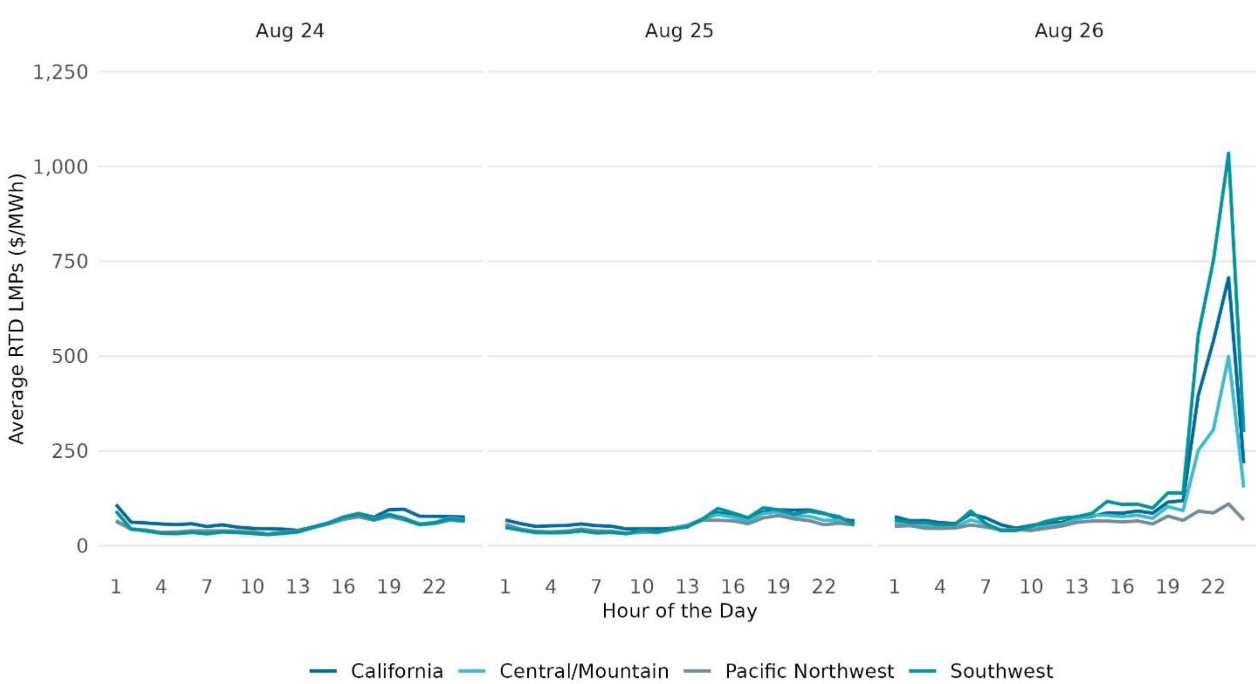


Table 12 shows the monthly average regional LMPs in the FMM and RTD markets from May through August 2026. Average prices generally increased across all four regions over this period. California had the highest monthly average prices in August in both FMM and RTD, at $52.9/MWh and $55.6/MWh, respectively.

Table 12: Monthly Average Regional LMP ($/MWh) by Market and Region

Region	FMM				RTD			
	May	June	July	August	May	June	July	August
California	13.3	19.9	40.6	52.9	14.0	20.4	42.6	55.6
Southwest	9.8	24.5	36.4	46.9	11.0	25.3	40.9	52.0
Pacific Northwest	12.3	12.4	29.4	39.0	10.8	12.2	31.3	39.6
Central/Mountain	12.6	15.8	37.5	43.2	14.8	15.9	43.1	46.7

Renewable Production

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

Figure 177 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 August 2026 was about 2 percent lower than the production observed in August 2025. With the addition of more solar resources into the system, solar production in August 2026 was about 8 percent higher than the production in August 2025.

Figure 178 shows the daily renewable production for June, July, and August. Figure 179 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 180 below shows the hourly profile of the average energy produced from hydro resources as well as solar and wind resources for August 2026.

Figure 177: Historical trend of hydro and renewable production

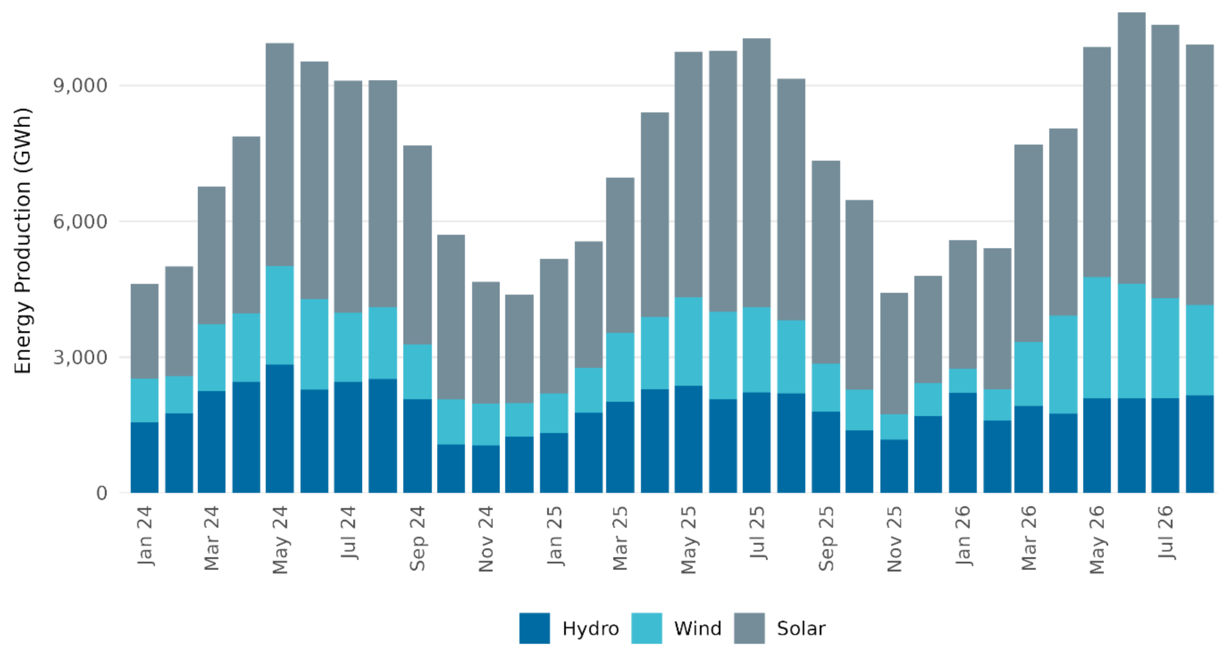


Figure 178: Daily trend of hydro and renewable production

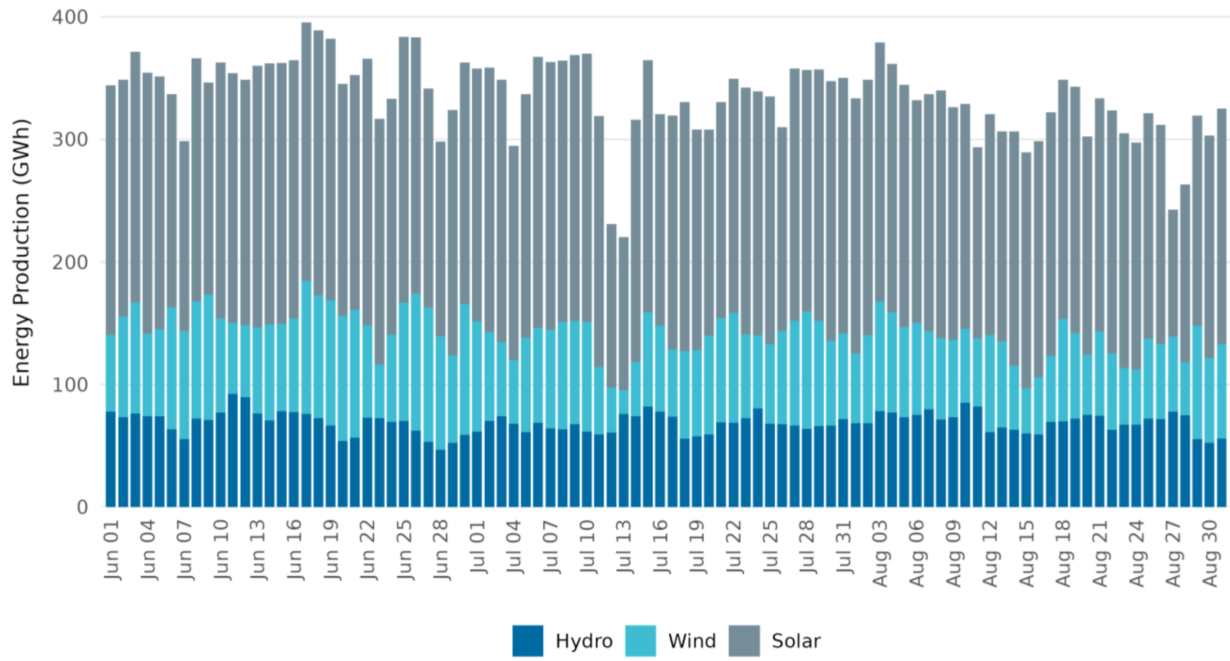


Figure 179: Historical trend of solar production

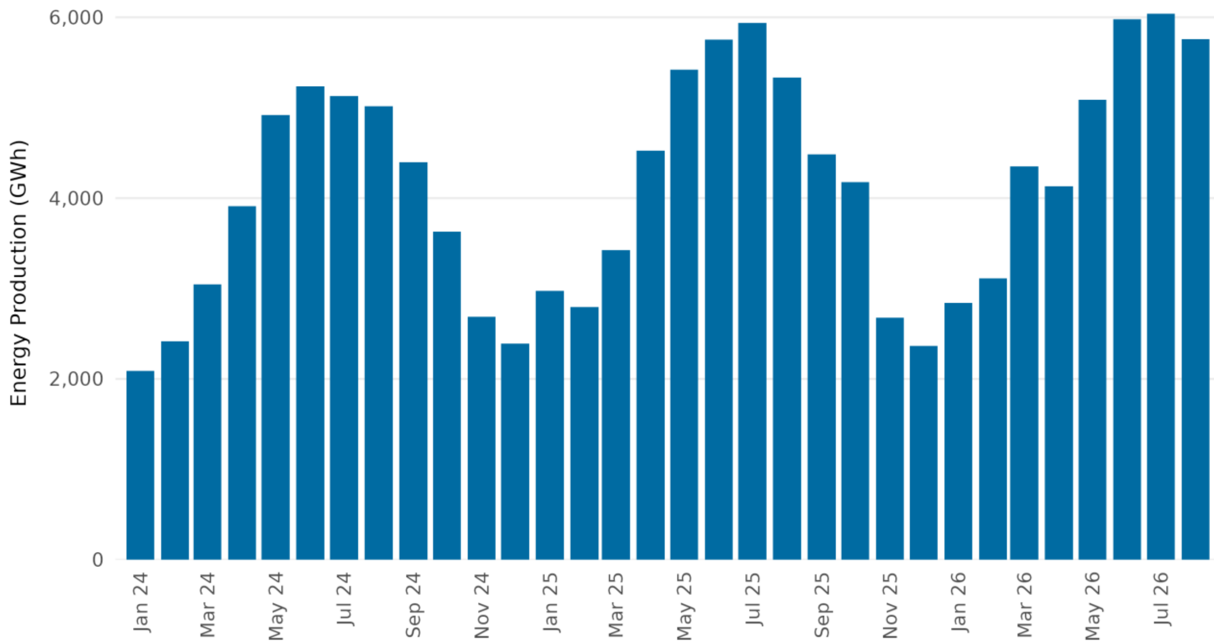
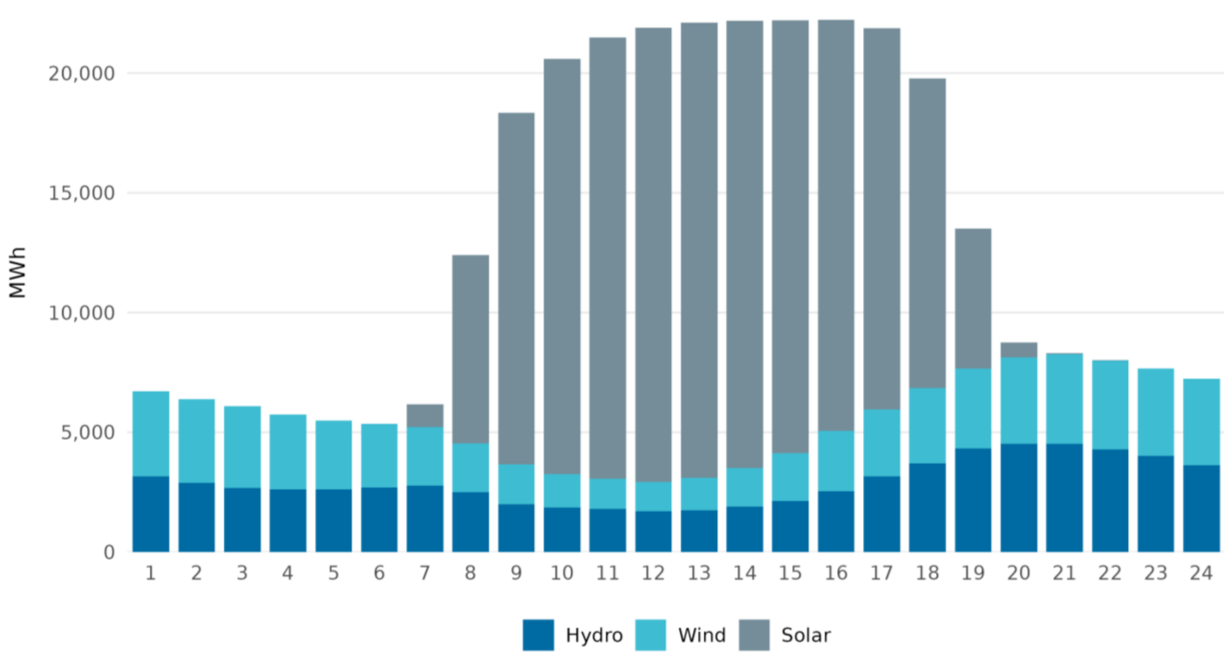


Figure 180: Hourly profile of wind, solar and hydro production for August

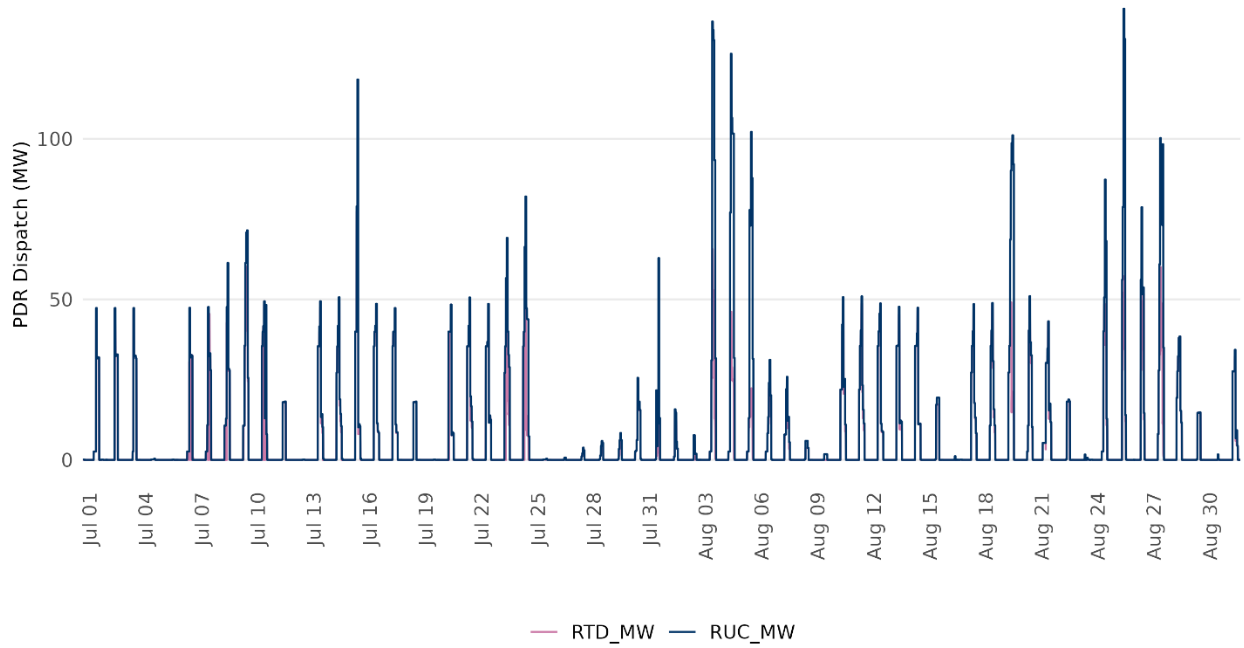


Demand Response

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.

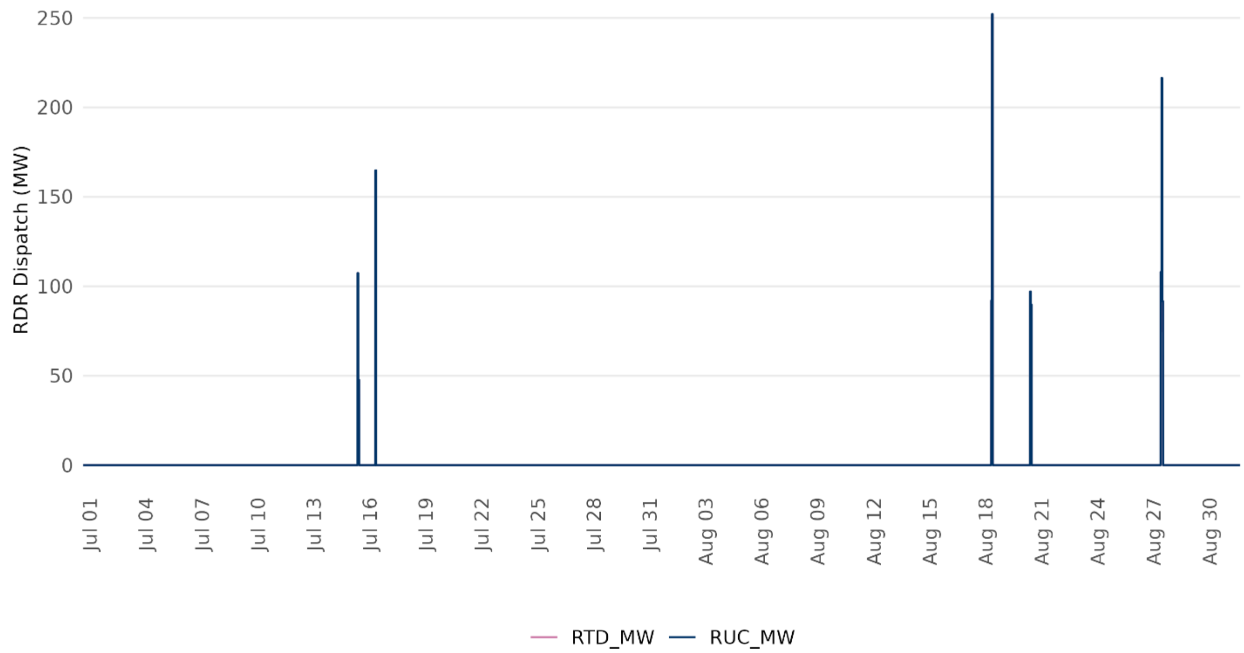
Figure 181 shows the dispatch of proxy demand resources (PDR) in both the day-ahead and real-time markets. PDRs are dispatched economically in all markets based on their bid-in prices. During the month of July and August, PDR resources were consistently dispatched in both the day-ahead and real-time markets and the times overlap but values are slightly different. The largest volume of PDR dispatches in the day-ahead timeframe occurred on August 25 at about 140 MW, whereas in the real-time market, it was a maximum of 83 MW on July 15.

Figure 181: PDR Dispatches in day-ahead and real-time markets



Reliability demand response resources (RDRRs) were not triggered in the real-time market during July. Figure 182 shows the dispatches of RDRRs in both the day-ahead and real-time markets for July and August. 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 August 18 to about 252 MW for HE 18. RDRRs were dispatched in RUC and RTD market to the same amount of 252 MW at the same time, hence the lines for RUC MW and blue line for RTD MW are overlapping.

Figure 182: 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.

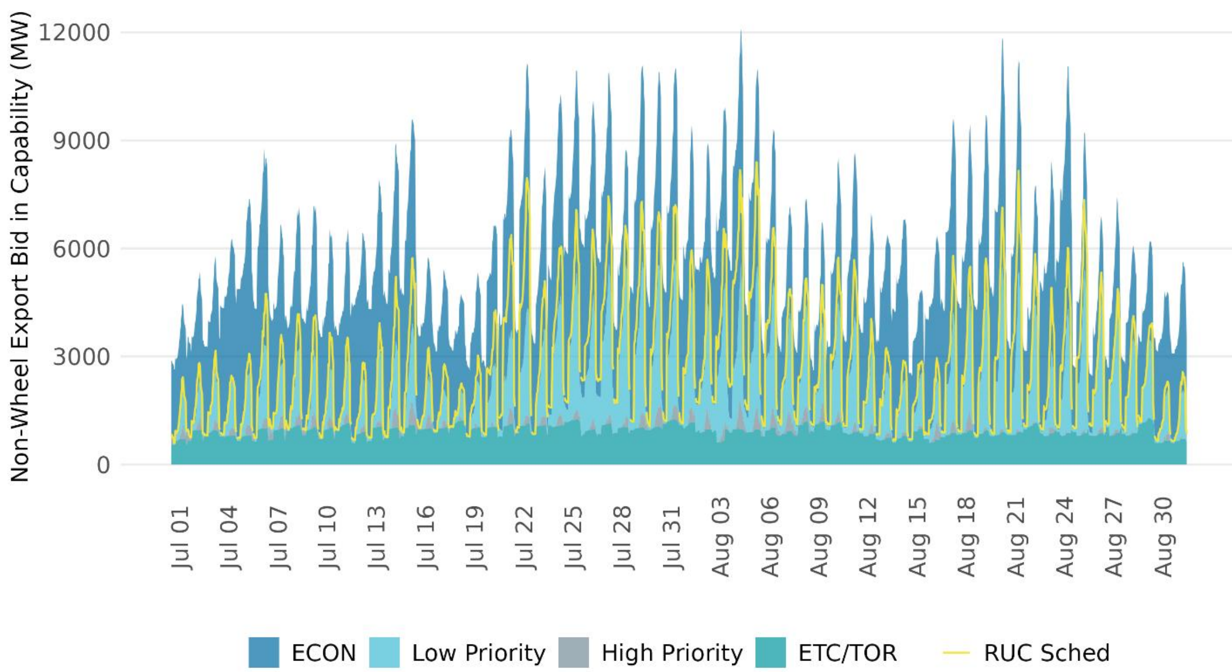
The ISO's markets will clear intertie transactions utilizing its least-cost optimization process in each of its market runs. Bids and self-schedules are considered in a merit order to determine the clearing schedules, and all resource bids and characteristics, and system conditions, are considered. In 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 183 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. Given the high loads in August in the west, export volumes remained high similar to July.

Figure 183: 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 61 percent, 21 percent, 16 percent and 2 percent of the export capacity were for economic bids, LPT, ETC/TOR and PTK, respectively. The total of bid in export volume in August was at similar levels comparing to July. The highest RUC scheduled was in hour ending 18 on August 5, at about 8398 MW.

Figure 184 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 smaller volumes of economic bids in August comparing to July, resulting in a slightly 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 184: Day-ahead bid-in capacity and RUC-cleared imports

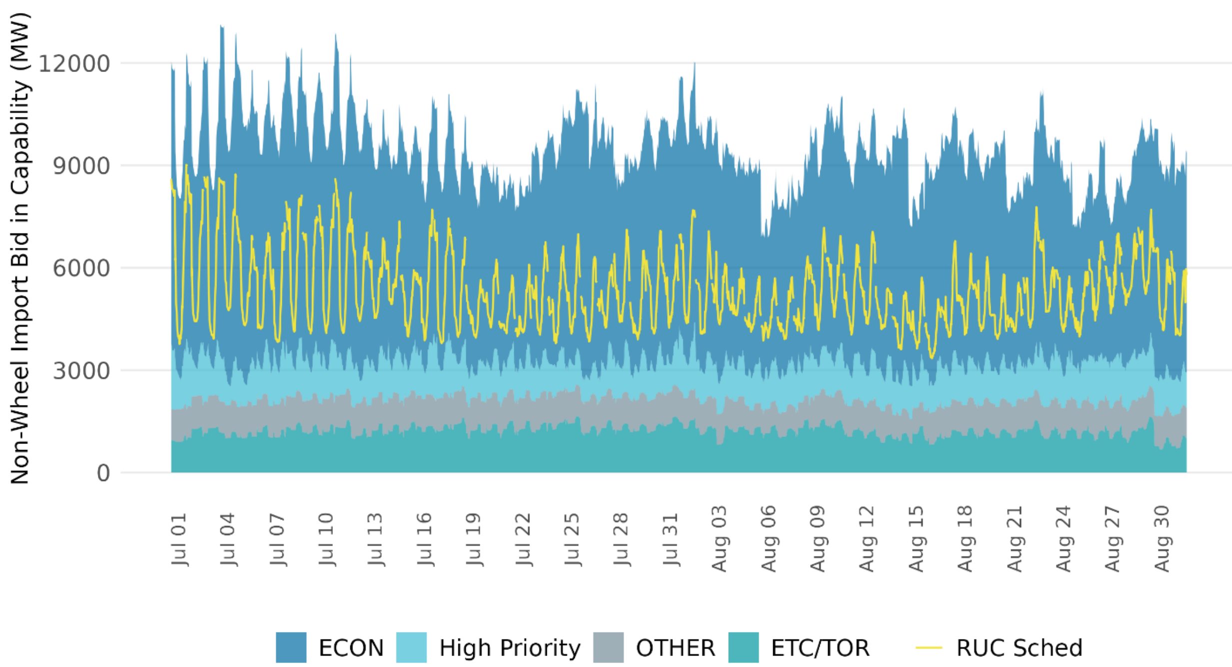
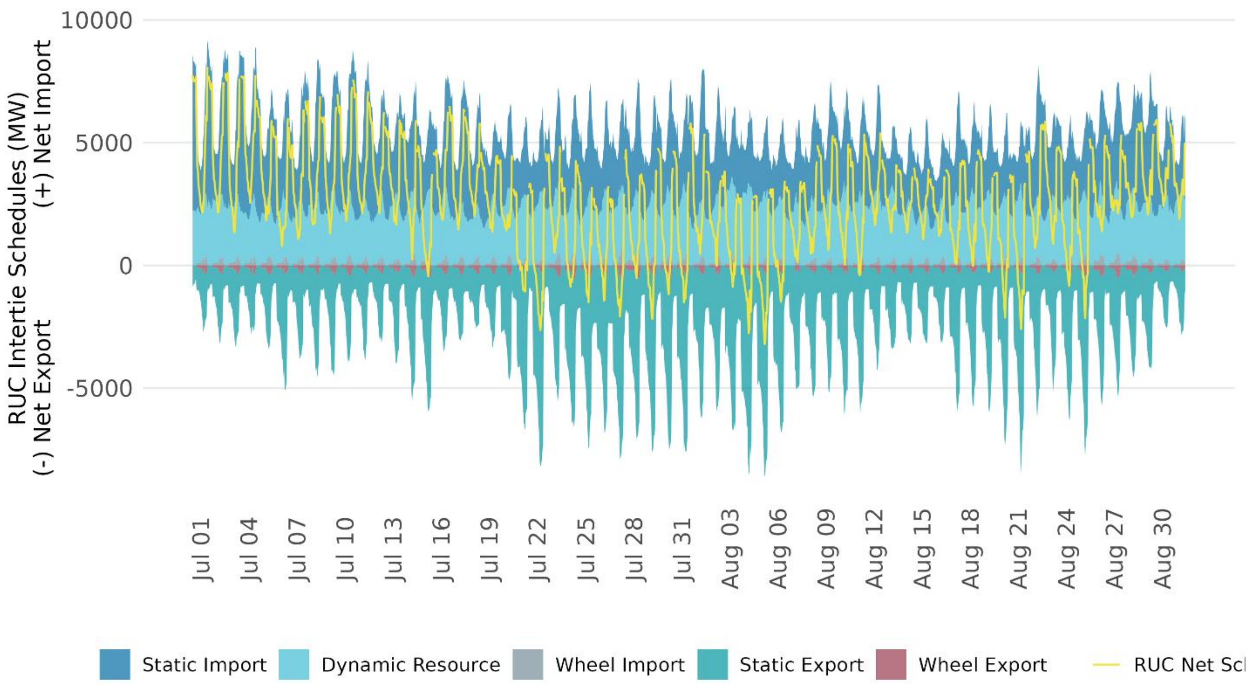


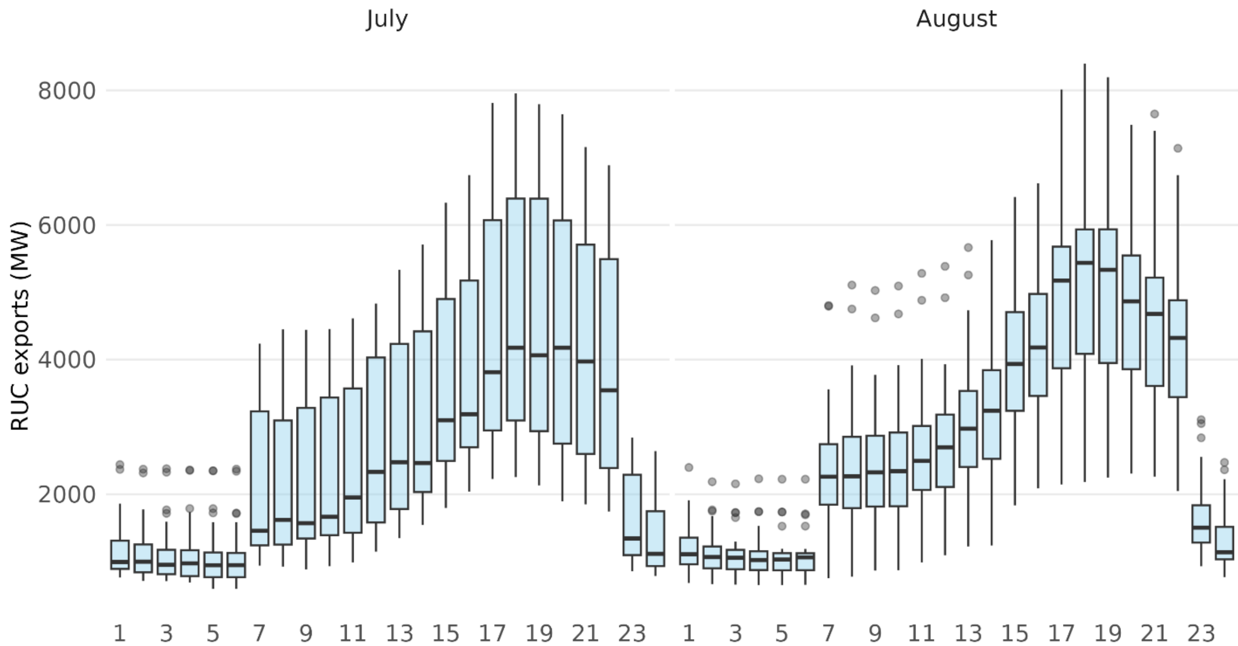
Figure 185 shows the overall intertie schedules organized by type of schedule, as well as the net interchange based on the RUC solution for two months. The net interchange projected in the RUC process reached its lowest level on August 5 in HE18 at about -3202 MW due to the higher level of exports cleared.

Figure 185: Breakdown of RUC cleared schedules



An area of interest since summer 2020 is the trend of exports in the ISO's system. Figure 186 illustrates the hourly distribution of RUC schedules for exports and that the highest volume occurred during afternoon hours. Compared to July, August had higher medians with more compact spreads in RUC export hourly distributions for hours ending 7 to 22. The highest volumes were cleared in hour ending 18 and 19.

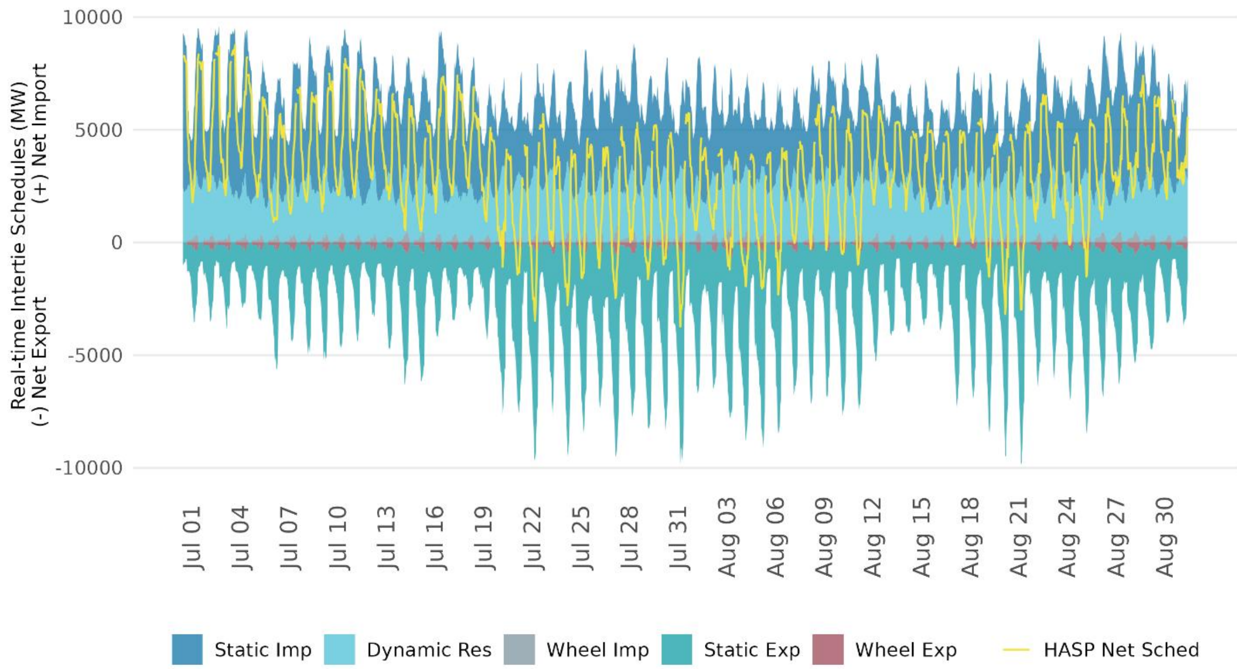
Figure 186: Hourly RUC exports



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 187 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 August 20 due to the high level of exports cleared on that day. The real-time market largely follows the trend observed in the day-ahead market. The net schedule remained low in August. On average, for August, the net schedule in HASP was about 2806MW across all the hours of the month and about 1088MW for peak hours.

Figure 187: 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 188 shows all the exports cleared in the HASP process and identifies the nature of such exports. Figure 178 shows the same breakdown for August 24 to 26. 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 9,543MW on August 21. In August, volumes of exports cleared were comparable to July, and low-priority bids constituted a significant portion of cleared exports.

Figure 188: Exports schedules in HASP

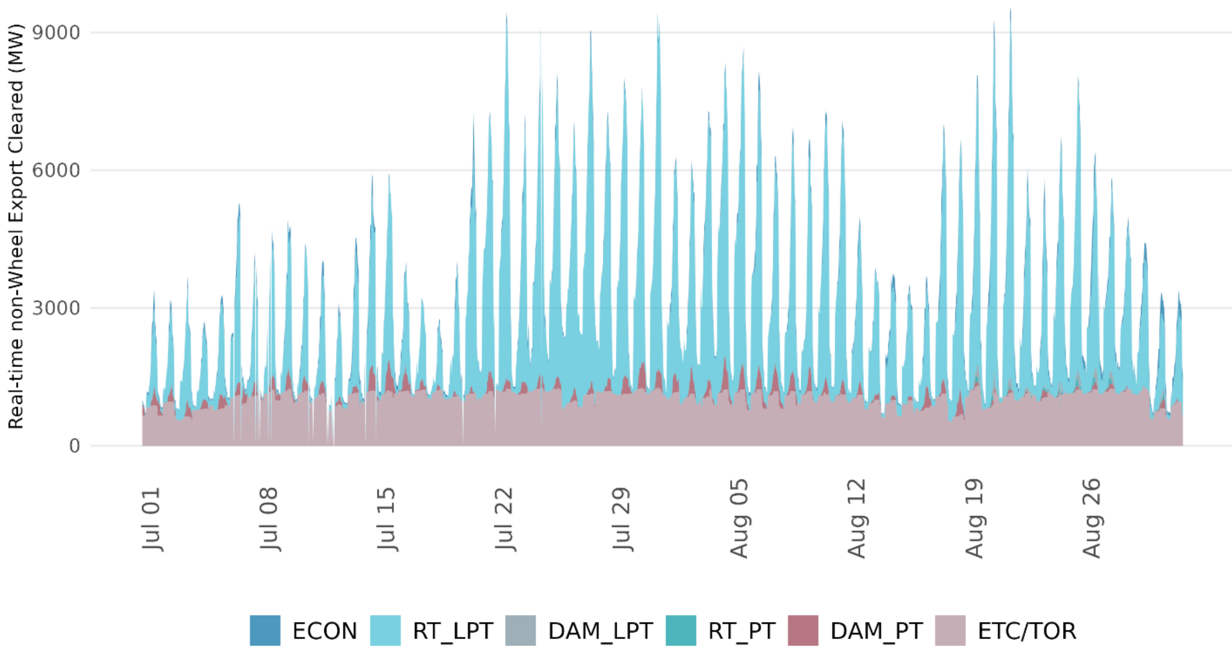
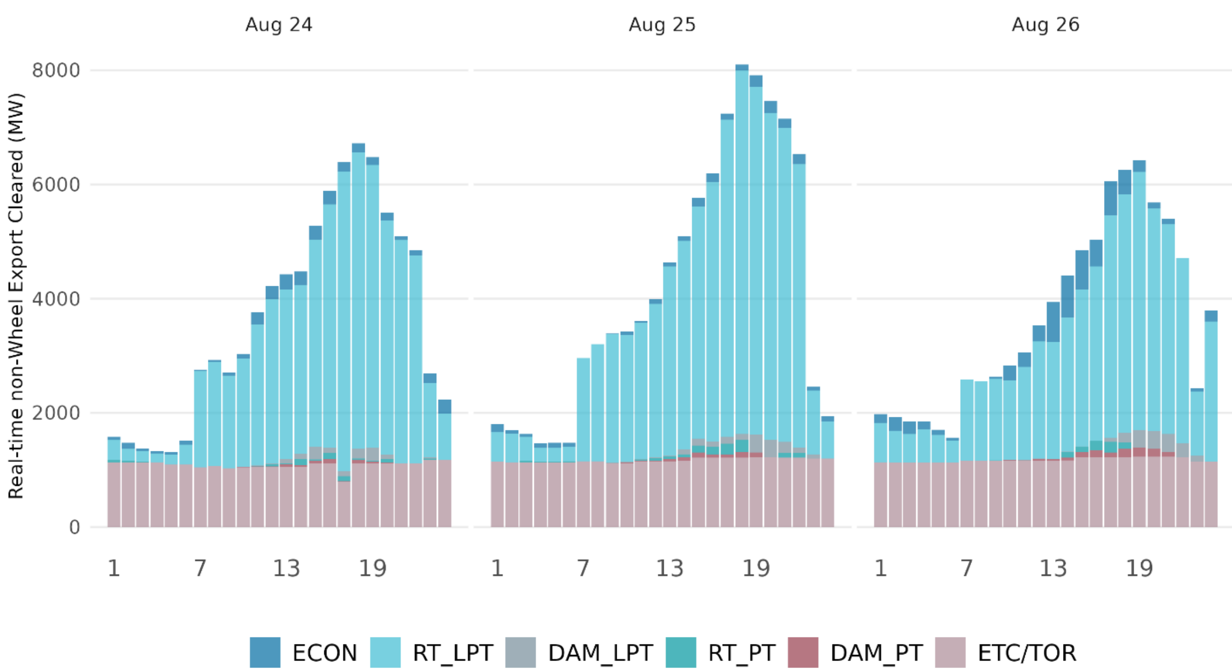


Figure 189: Exports schedules in HASP, August 24 - 26



Imports and exports were scheduled over multiple intertie scheduling points in August, with Malin, Palo Verde and NOB seeing the highest volume of transactions. Figure 190 through Figure 192 illustrate the trend of import and export schedules cleared in HASP for these top three intertie points. In August, the prevailing schedules were in the import direction.

Figure 190: HASP schedules at Malin intertie

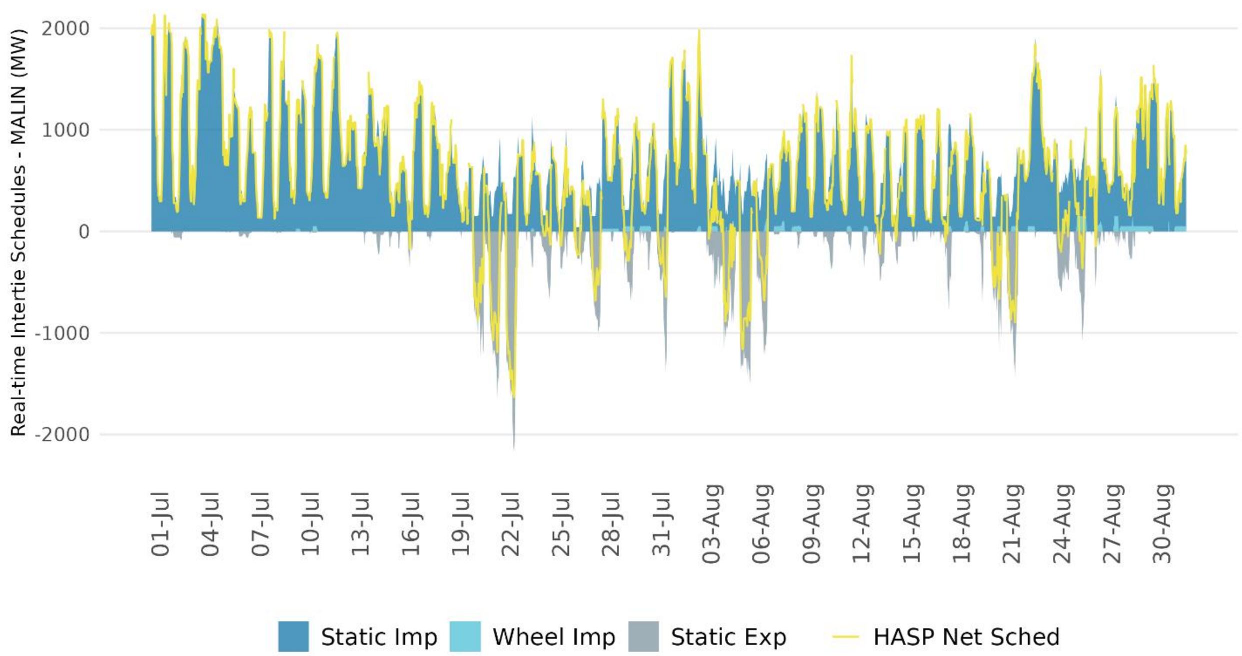


Figure 191: HASP schedules at Palo Verde intertie

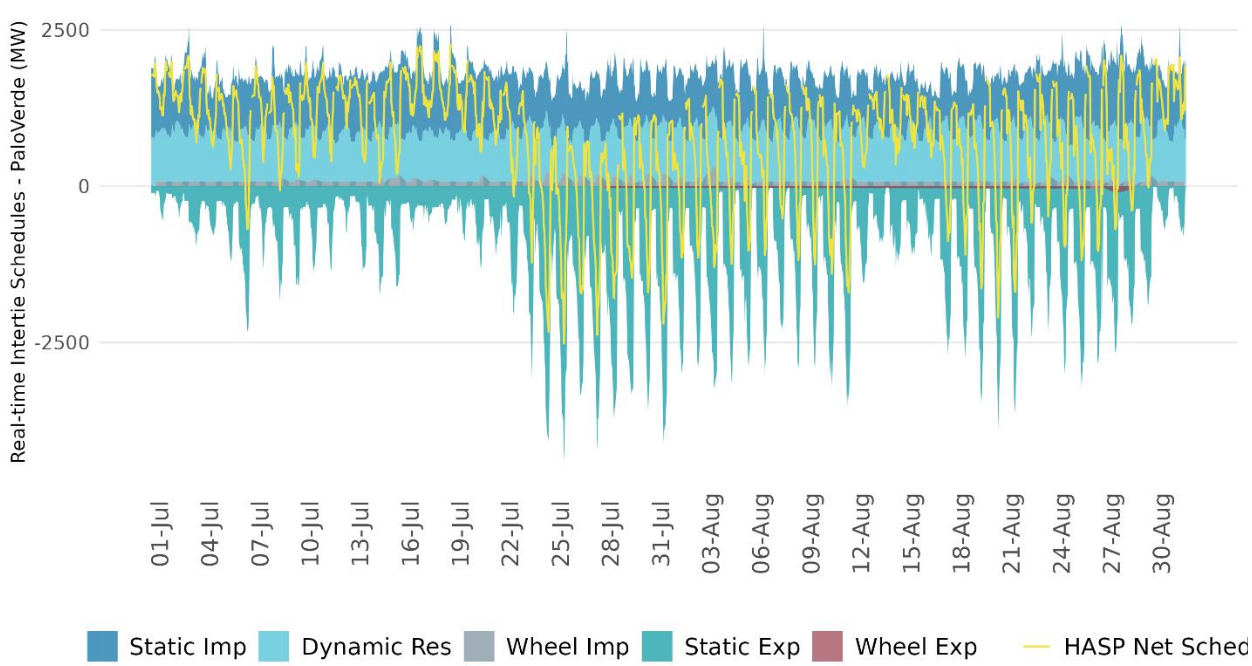


Figure 192: HASP schedules at NOB intertie

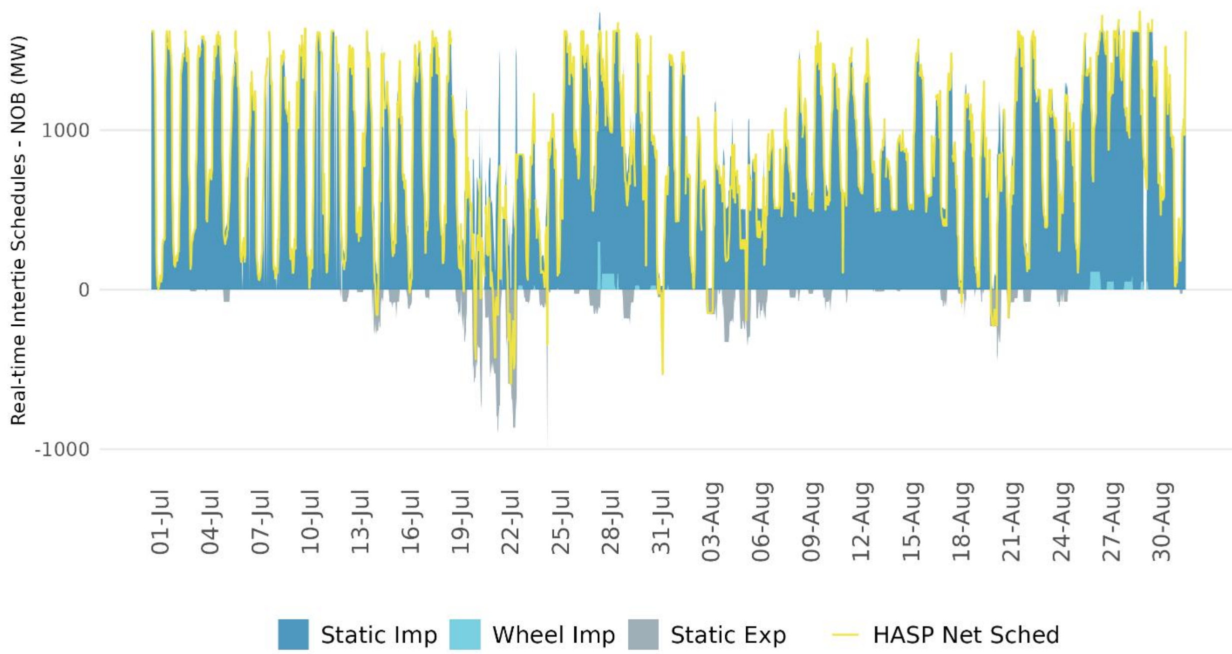
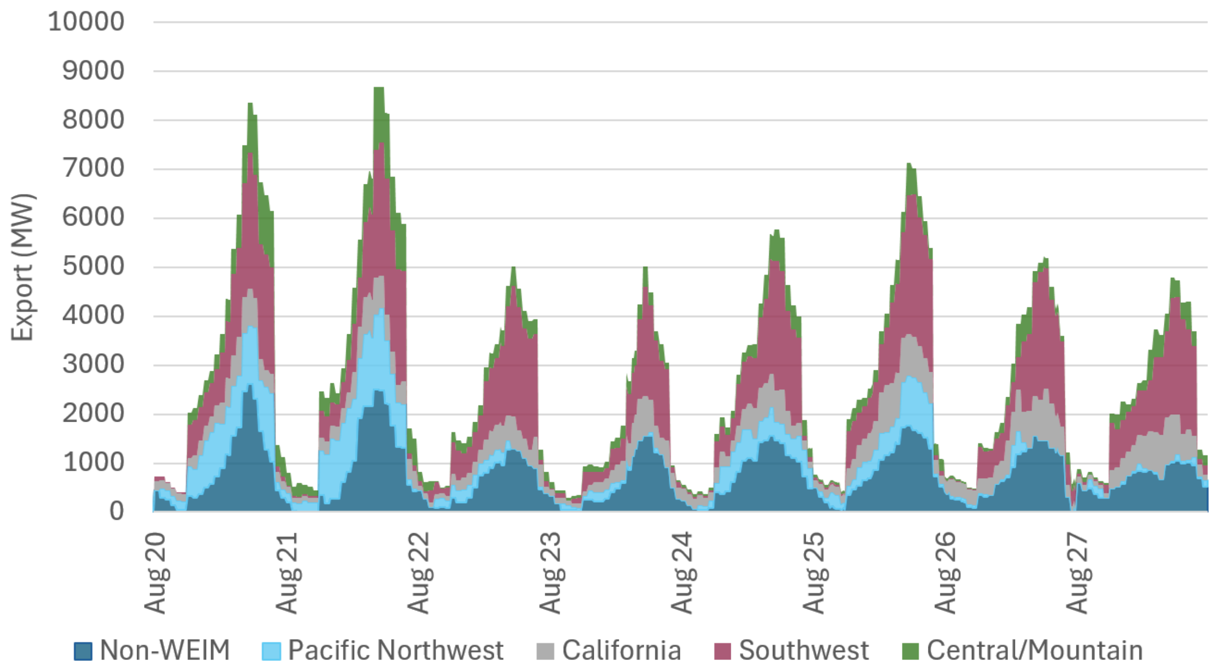


Figure 193 shows the total volume of intertie exports that sourced from the ISO area and organized by the different areas in which the exports sink. For simplicity, these sink areas are grouped in regions of the western interconnection for all areas that are in the western energy imbalance market. There 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 August heatwave, up to 8,681 MW of exports sourced from the ISO area supported multiple areas in the western interconnection.

Figure 193: Total volume of exports sourced from the ISO area



Storage and Hybrid Resources

In August 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 194 presents the daily average of bid-in capacity for storage resources in the day-ahead market in July and August, and Figure 195 presents the hourly average from June to August, organized by price ranges. In August, more bid-in capacity was shifted from low-priced bucket ($0-50/MWh) to mid-priced ($50-100/MWh) in both daily and hourly average charts.

Figure 194: Bid-in capacity for batteries in the day-ahead market, daily average

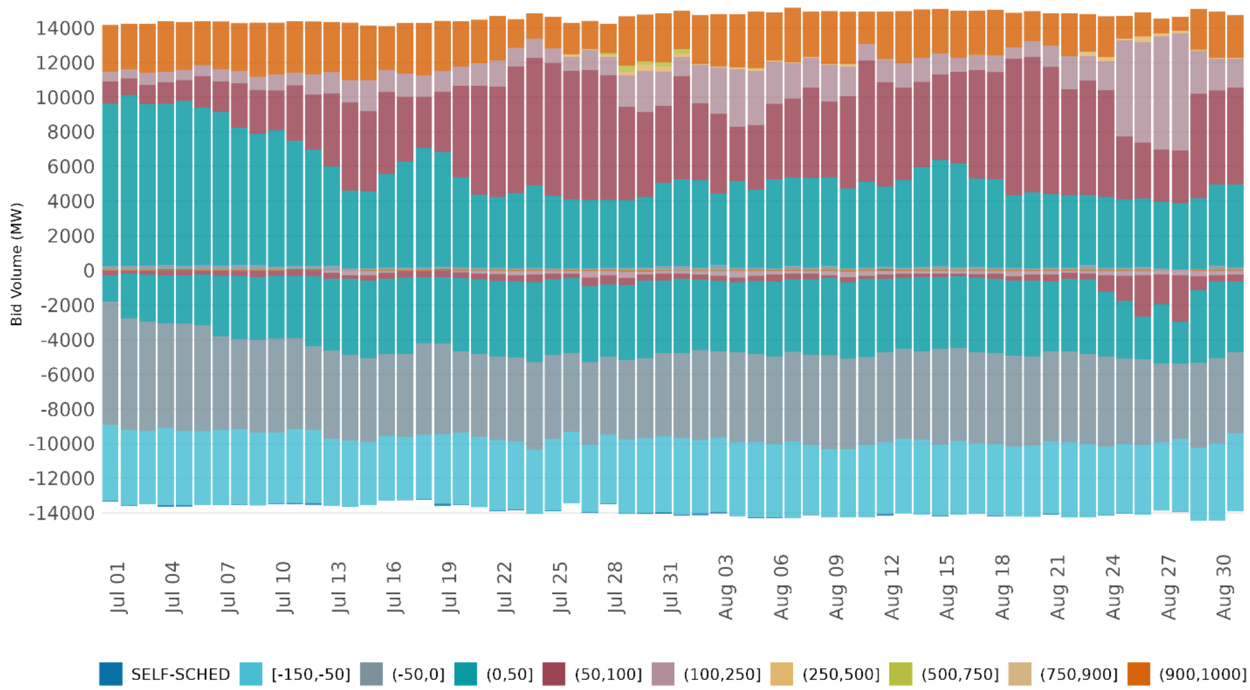
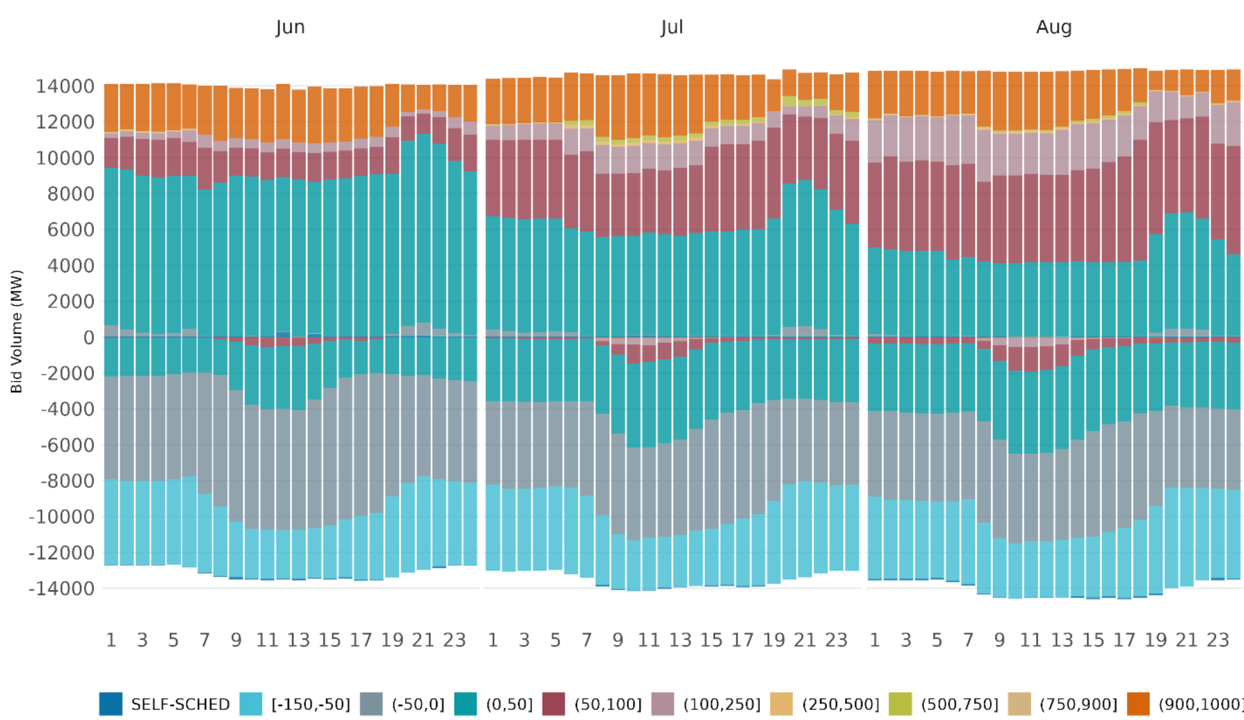


Figure 195: Bid-in capacity for batteries in the day-ahead market, hourly average



The negative area represents charging while the positive area represents discharging. The overall capacity in the market was roughly consistent through 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 196 and Figure 197 present the bid-in capacity for the real-time market. The overall capacity follows the similar trend as the day-ahead market. One thing to note is that more low-price buckets ($0-50/MWh) were shifted to moderate-price buckets ($50-100/MWh) under summer conditions.

Figure 196: Bid-in capacity for batteries in the real-time market, daily average

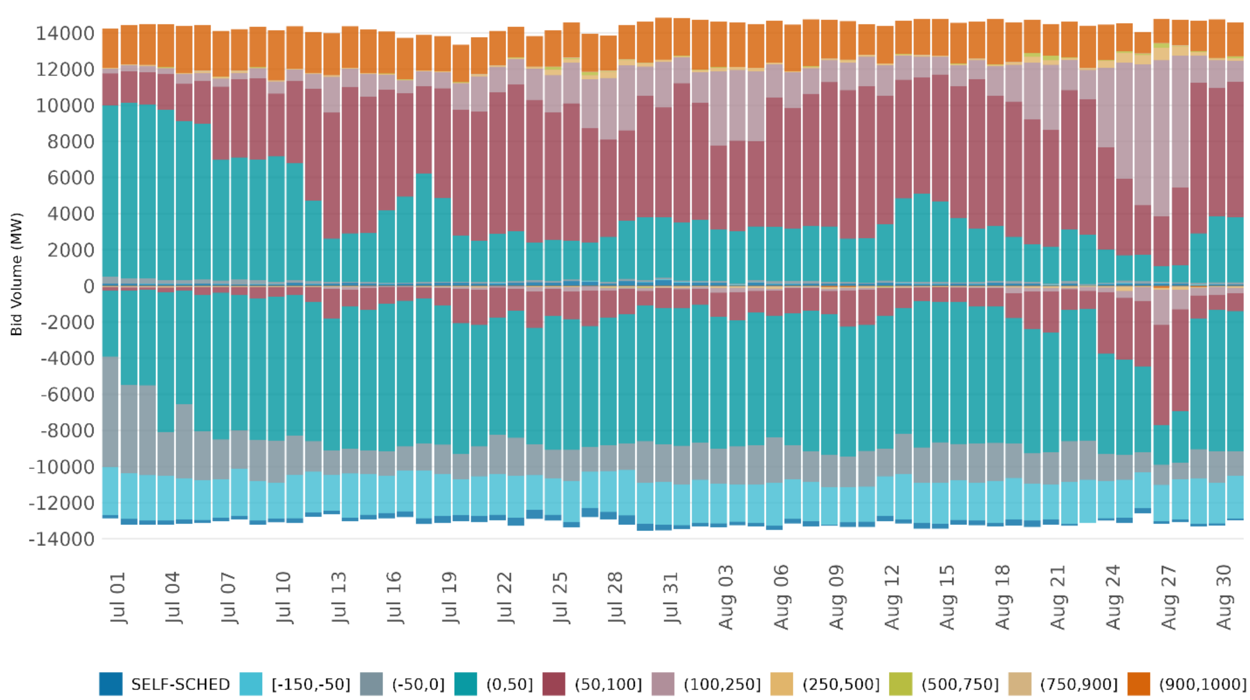


Figure 197: Bid-in capacity for batteries in the real-time market, hourly average

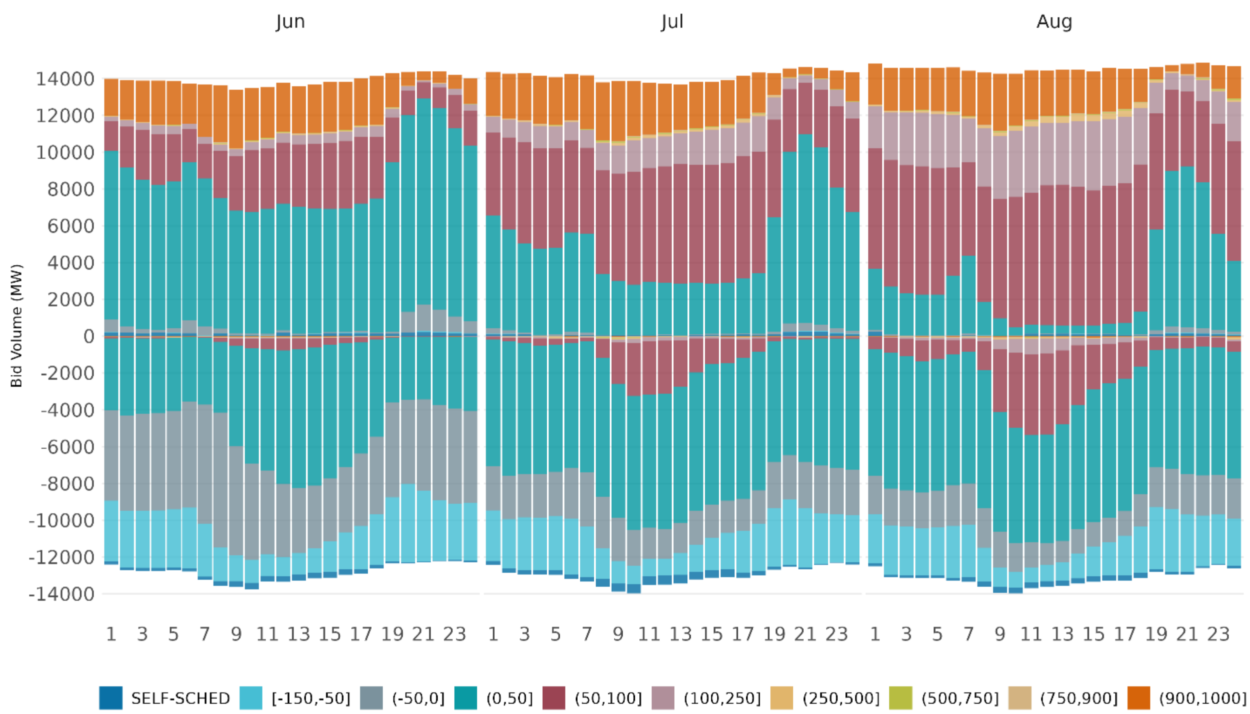


Figure 198 shows the hourly distribution of the storage capacity of resources participating in IFM and RTD throughout June to August. The box plot shows the median, 25th percentile, 75th percentile, and outliers for the total state of charge. Storage resources charge in hours when there is abundantly cheap energy from solar resources in the daytime. The system reached maximum stored energy by hour ending 16, followed by a period of steady discharge from hours ending 18 through 24. In August, the highest system state of charge in IFM was around 47,625 MWh, roughly 67 percent of the total capacity, which occurred in the hour ending 17 on August 20. The peak hourly state of charge in the real-time market was 54,686 MWh in hour ending 18 on July 29, at

roughly 77 percent of the total capacity, higher than the day-ahead peak state of change. Also, the state of charge in the real-time market had a wider spread compared to the day-ahead market.

Figure 198: Distributions of day-ahead state of charge

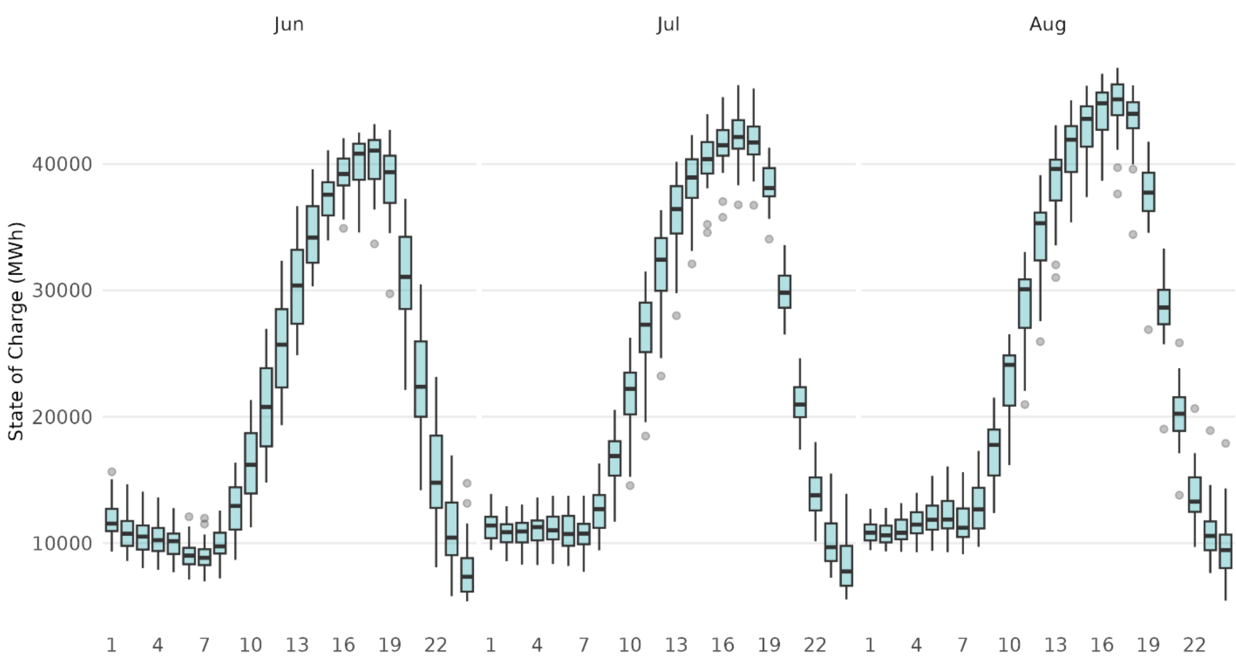
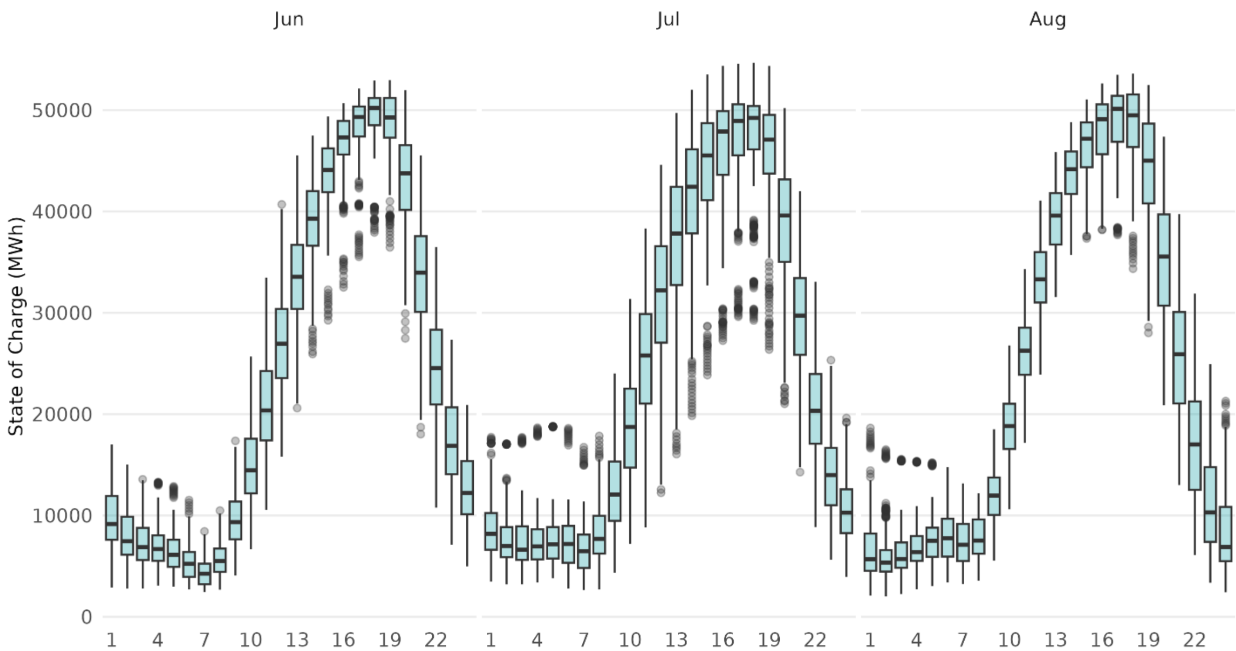


Figure 199: Distributions of real-time state of charge



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 200 shows the distributions of energy awards in IFM, and Figure 201 shows the hourly distribution of real-time dispatch for batteries from June to August. These statistics are for batteries, either stand alone or the battery component of co-located resources; they do not include hybrid resources.

Figure 200: Hourly distribution of IFM energy awards for batteries

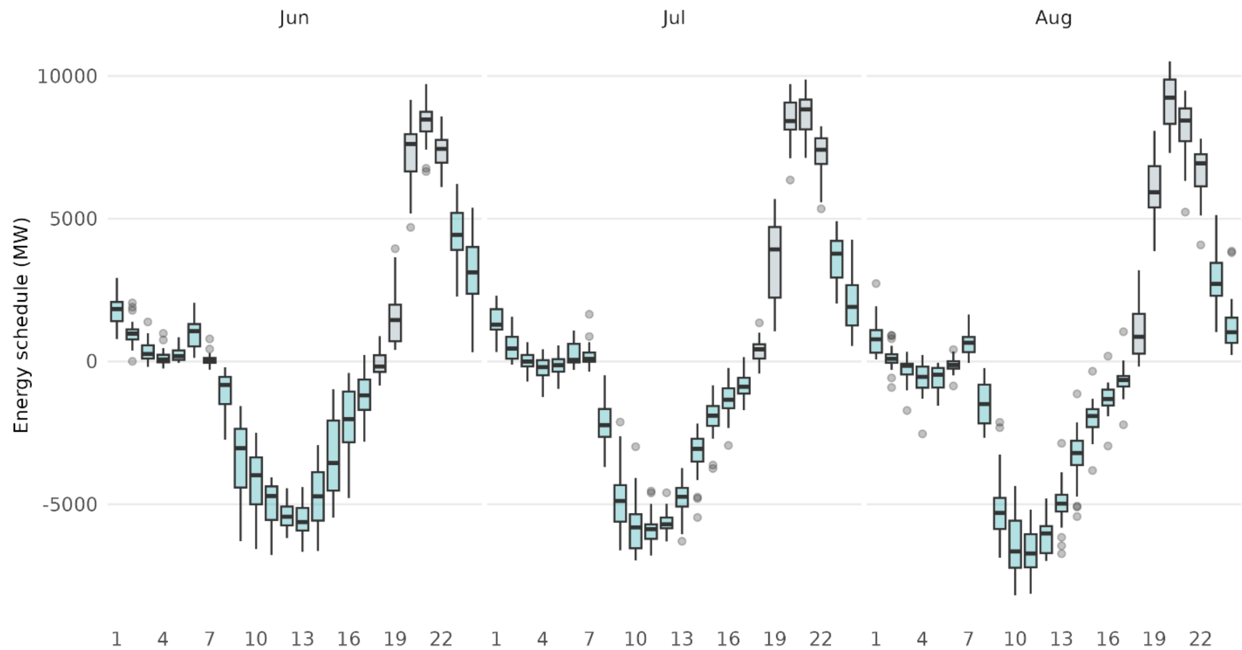
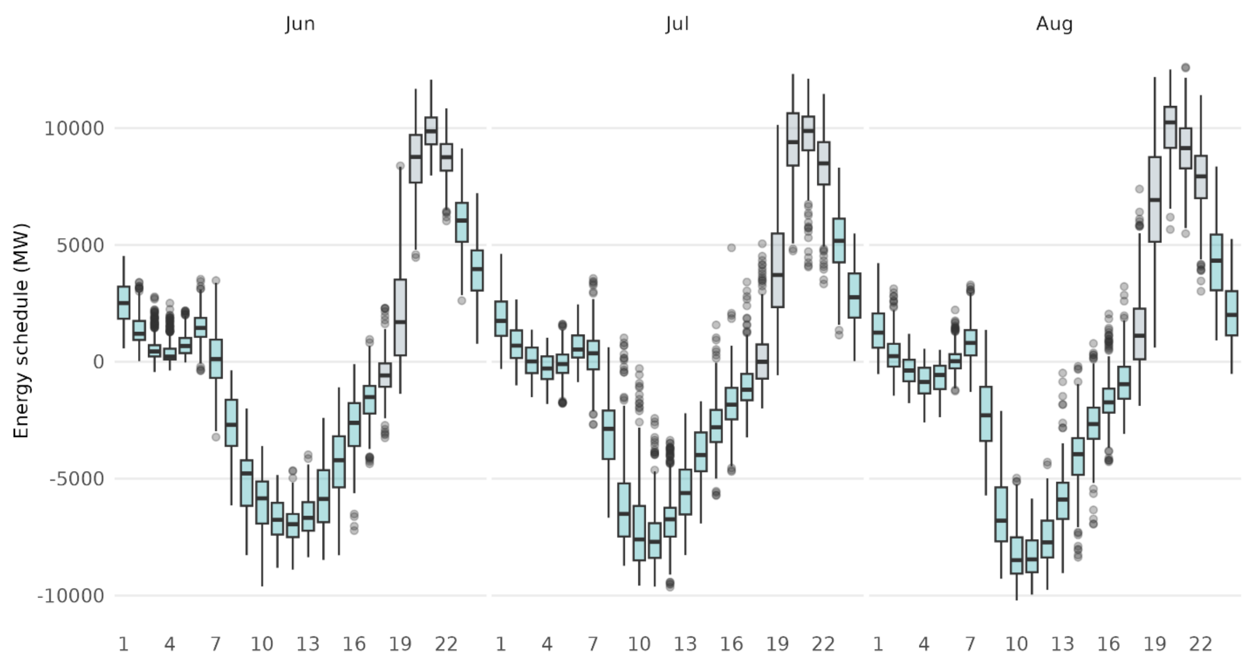
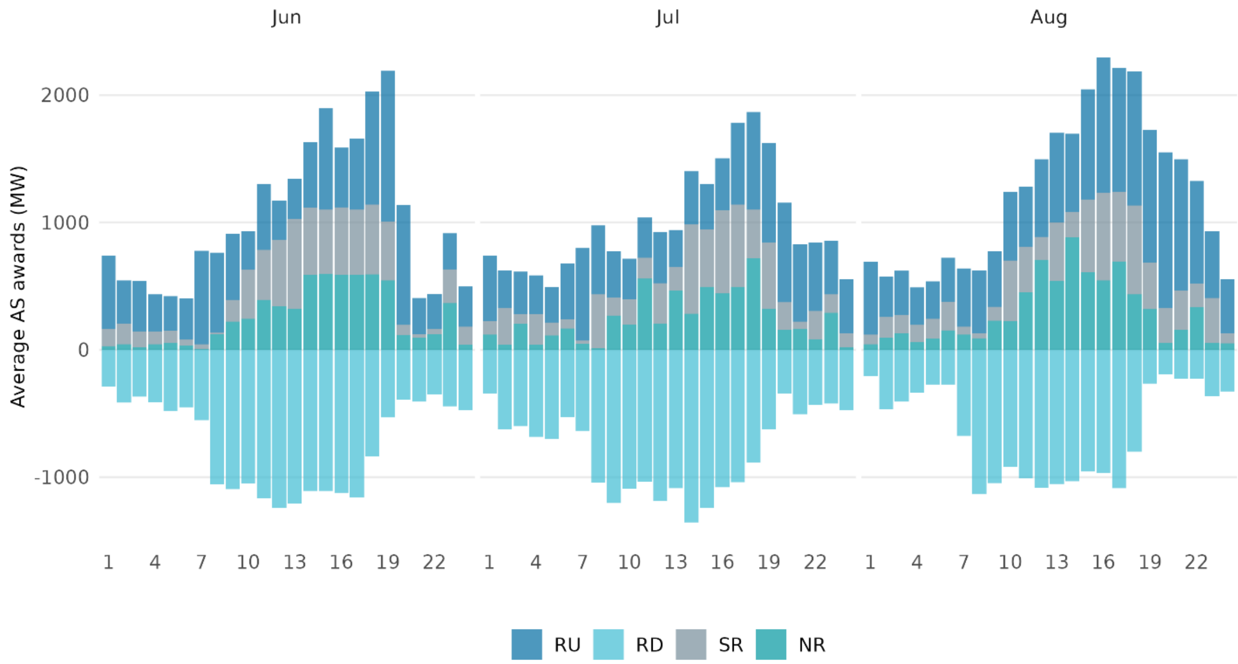


Figure 201: Hourly distribution of real-time dispatch for batteries



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 202 shows the average hourly AS awards in the real-time market.

Figure 202: 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 203 and Figure 204 show the IFM and real-time energy awards for hybrid resources, respectively. 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. Both the energy schedules in IFM and RTD in August had an obvious increase in the midday hours compared to schedules in June and July, indicating hybrid resources charged more during mid-day hours under summer conditions.

Figure 203: Hourly distribution of IFM energy awards for hybrid resources

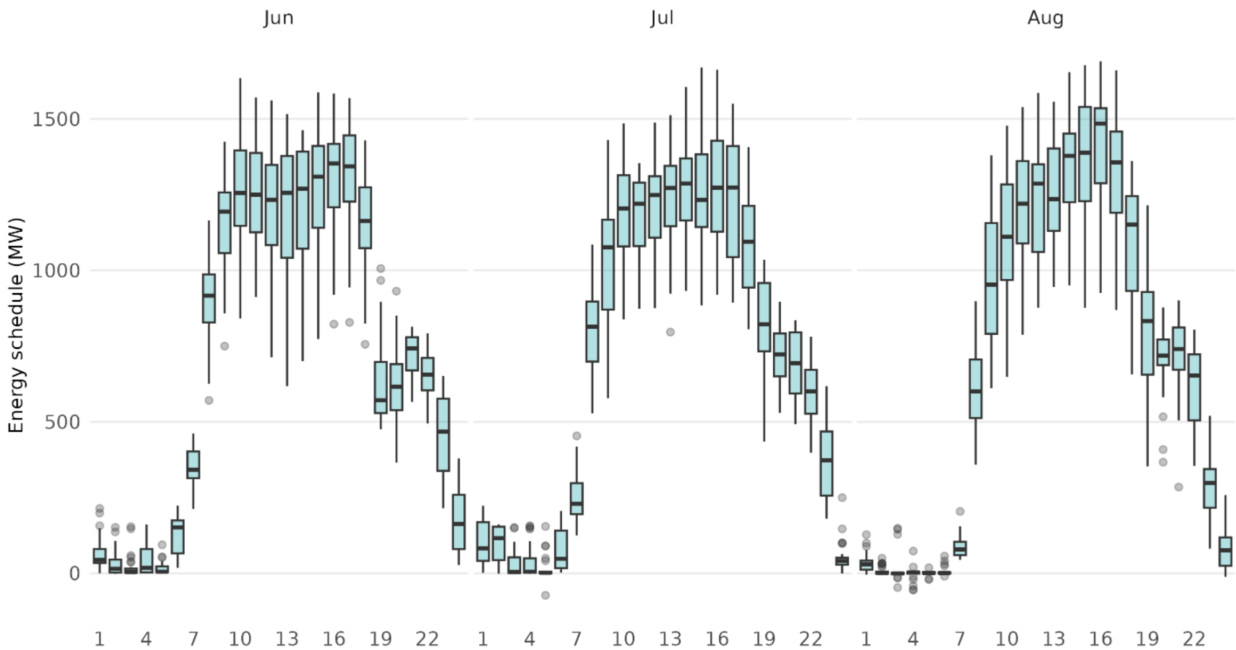
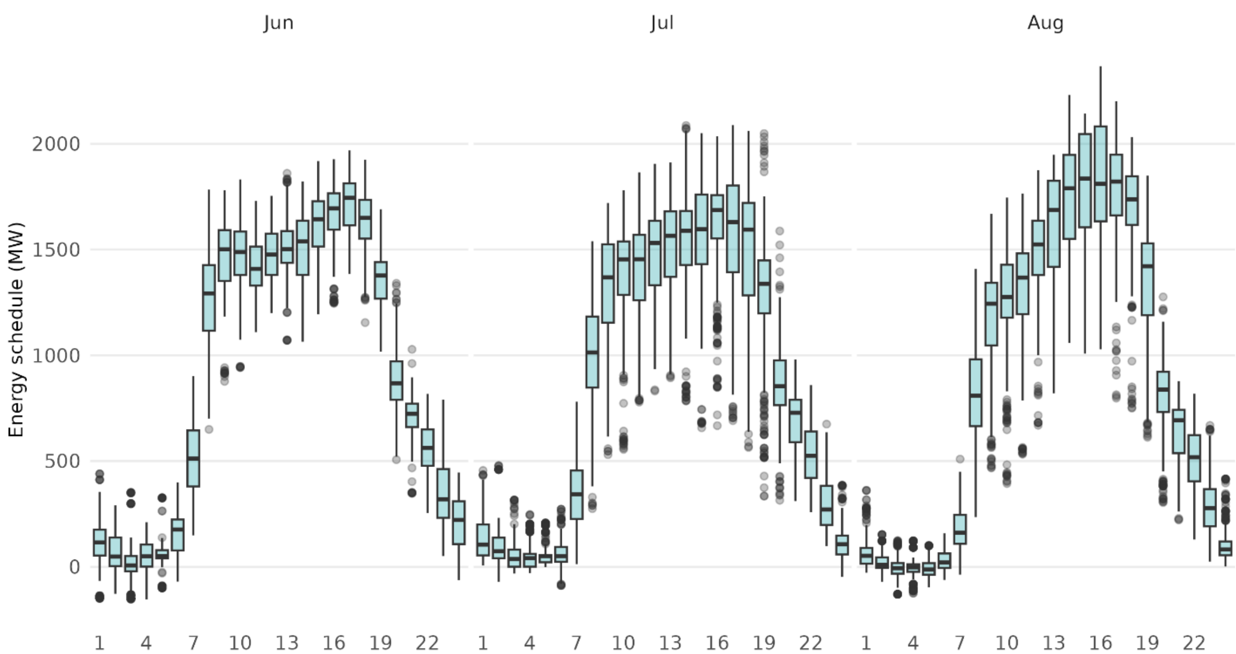
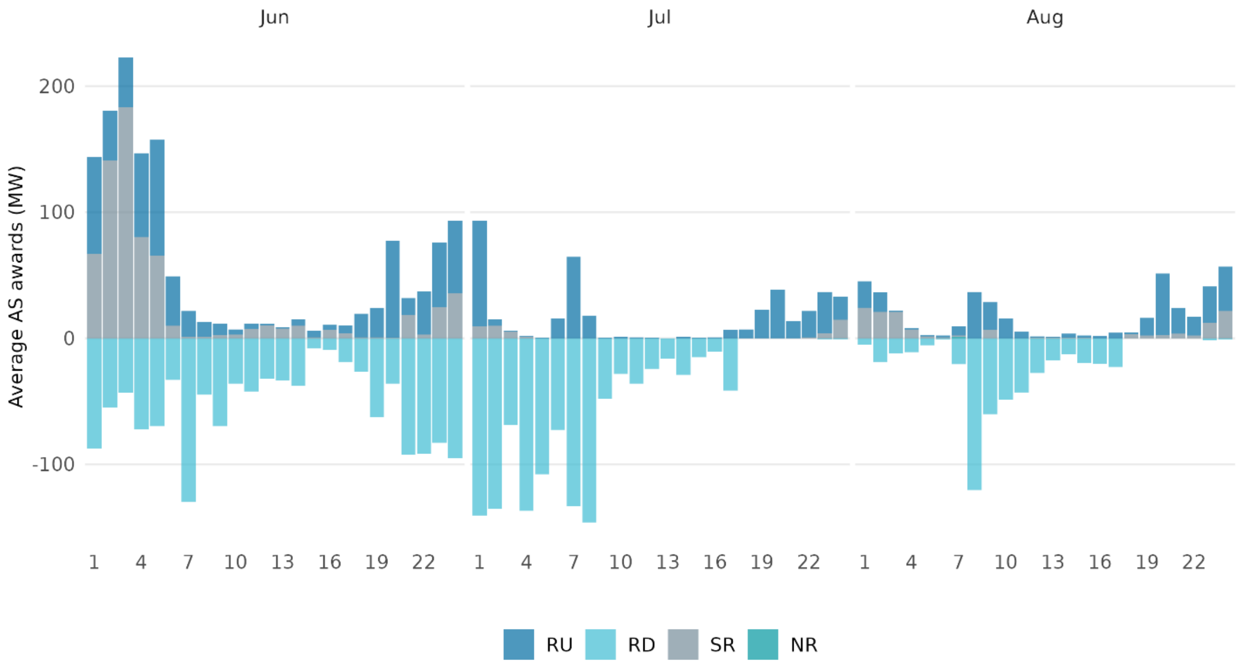


Figure 204: Hourly distribution of real-time dispatch for hybrid resources



Similar to storage resources, hybrid resources can also provide ancillary services to the market. Figure 205 shows the average hourly AS awards in real-time throughout June to August 2026.

Figure 205: Hourly average real-time hybrid AS awards



Western Energy Imbalance Market

August experienced lower load conditions across the western interconnection than July with the highest load of 139.6 GW on August 26. Regarding the WEIM footprint, load peaks occurred on different days and times across the different regions of WEIM.

Figure 206 shows the daily peak load aggregated by WEIM regions for the month of August, with circle markers indicating each region's monthly peak[13]. The California region reached a maximum load of 57,023 MW on August 26, surpassing its July peak of 52,931 MW on July 15. The Central/Mountain region reached an August peak of 16,729 MW on August 1, compared to a higher July peak of 17,373 MW on July 20. The Pacific Northwest region reached a maximum load of 33,559 MW on August 6, below its July peak of 35,288 MW on July 21. Similarly, the Southwest region reached an August peak of 37,430 MW on August 3, slightly below its July peak of 37,636 MW on July 24.

[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 207 shows the hourly peak load by WEIM region. Across all four regions, hourly peak load occurred between HE 17 and HE 18 in both July and August. California's hourly peak load increased in August relative to July, while the Pacific Northwest's hourly peak load decreased. Hourly peak loads in the Central/Mountain and Southwest regions were similar across the two months.

Figure 206: Daily peak load by WEIM region

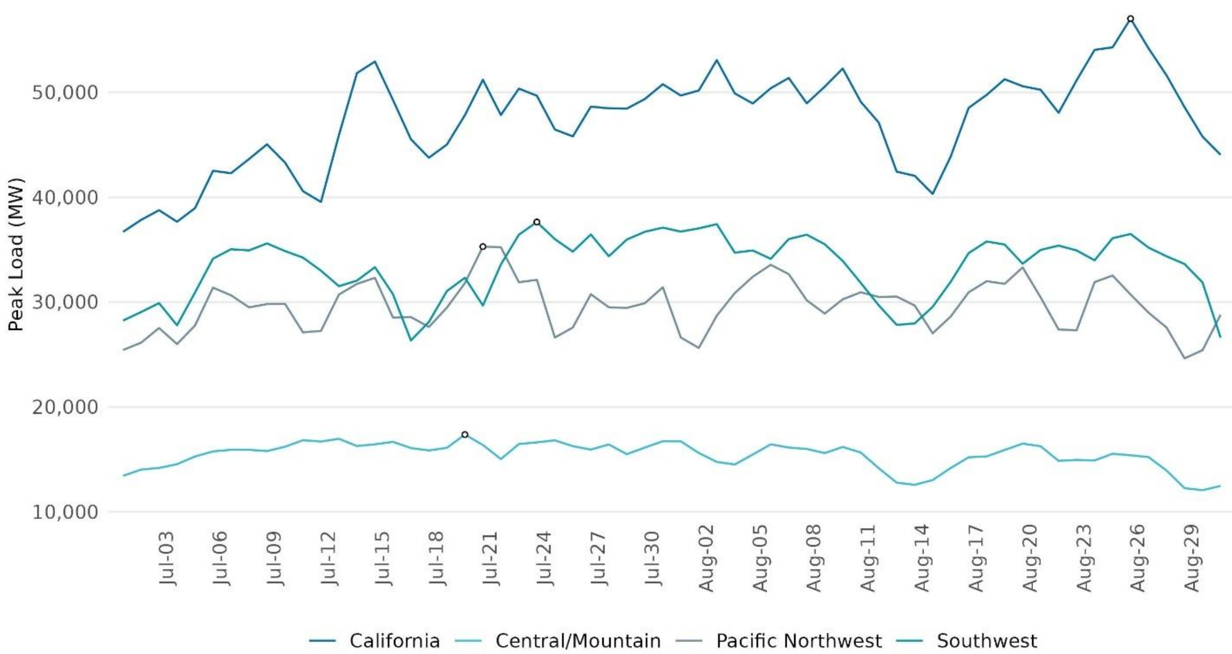


Figure 207: Hourly peak load by WEIM region

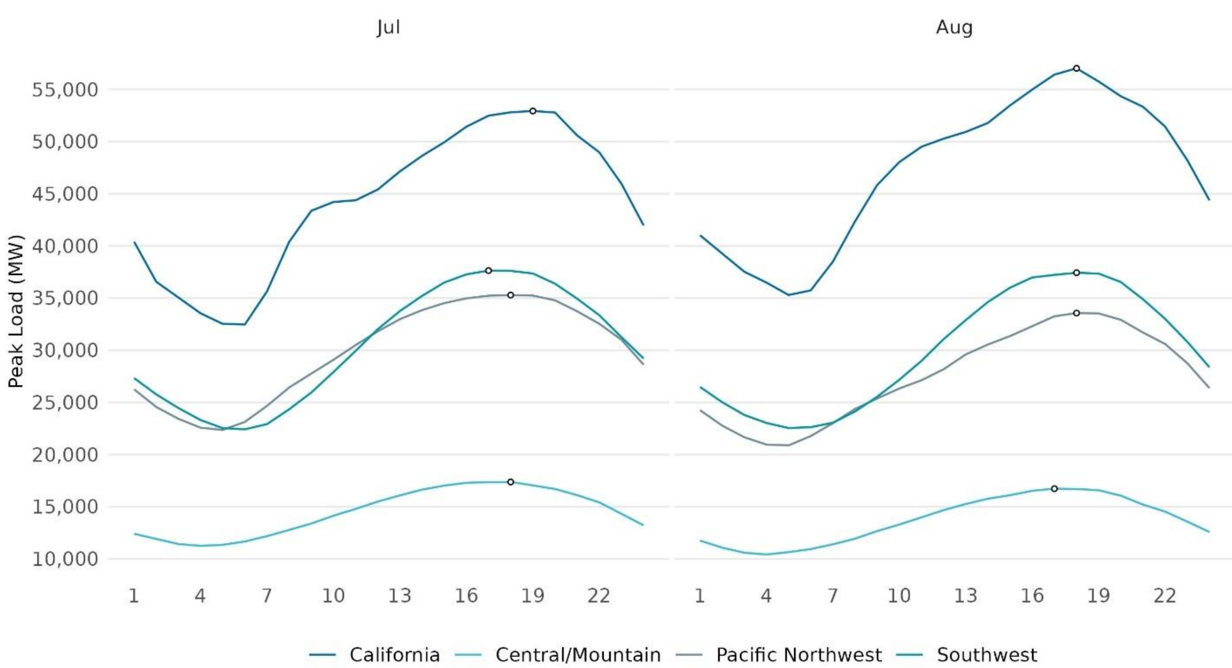
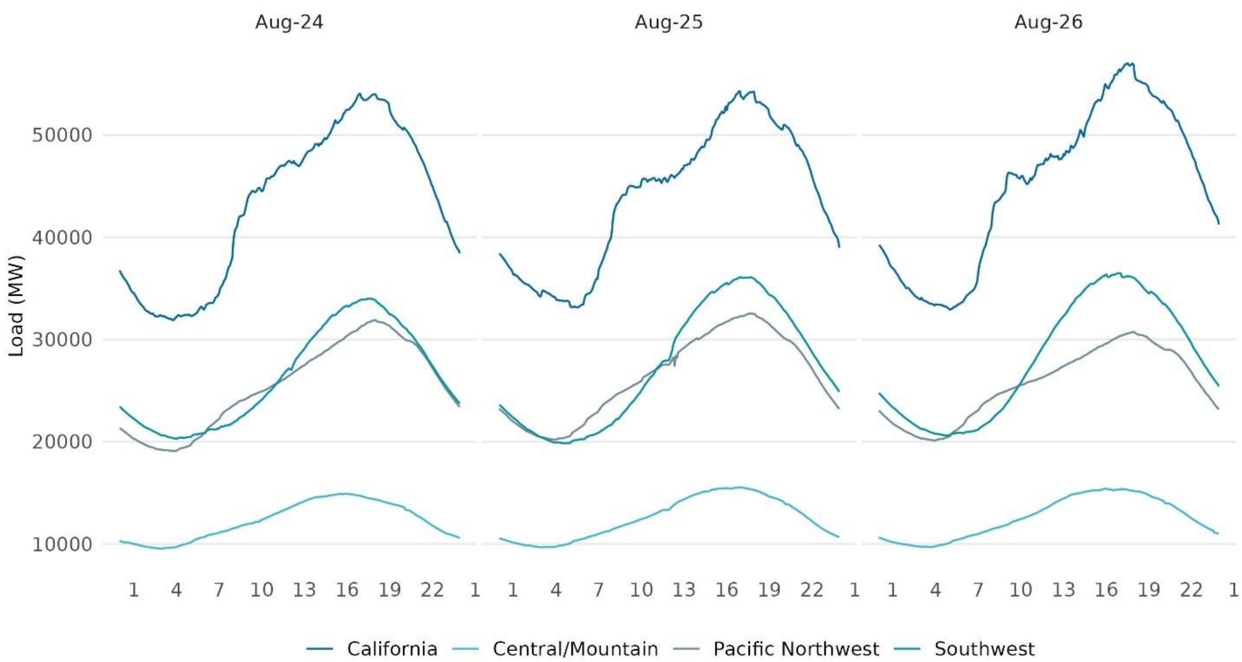


Figure 208 shows the hourly profile of actual load for the WEIM regions for August 24 – 26. Loads increased each day in the California and Southwest regions. Central/Mountain loads increased from August 24 to 25, while Pacific Northwest loads increased from August 24 to 25 before declining on August 26.

Figure 208: Hourly load profile for August 24 - 26, 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 209 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 August, CAISO transfers were imports from other areas in the WEIM, compared to net exports in July. CAISO recorded its highest average net imports on August 30 and highest average net exports on August 9.

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

Figure 209: Daily distribution of 5-minute RTD WEIM transfers for CAISO area

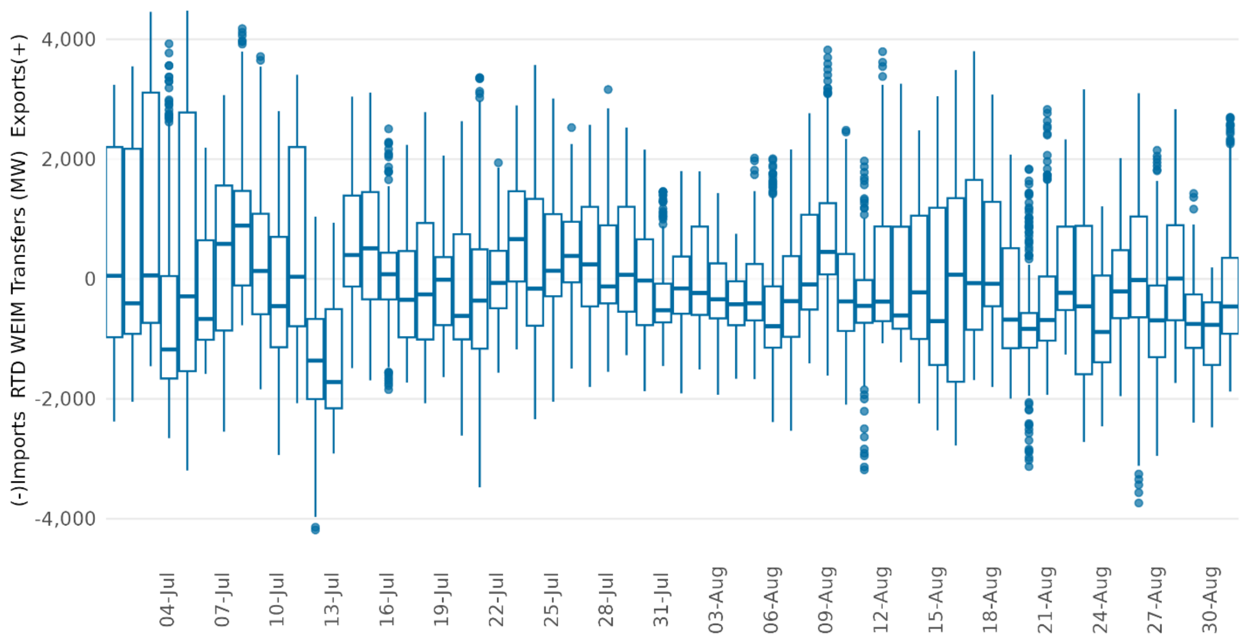


Figure 210 shows the CAISO's WEIM transfers in an hourly distribution, which highlights the typical profile of the CAISO transfers which are generally export transfers during periods of solar production. During the evening ramp the transfers become a net import to the CAISO area. This trend is typical across summer months. Net export transfers in August were lower than in July, and transfers overall were lower in August than in July.

Figure 210: Hourly distribution of 5-minute RTD WEIM transfers for CAISO area

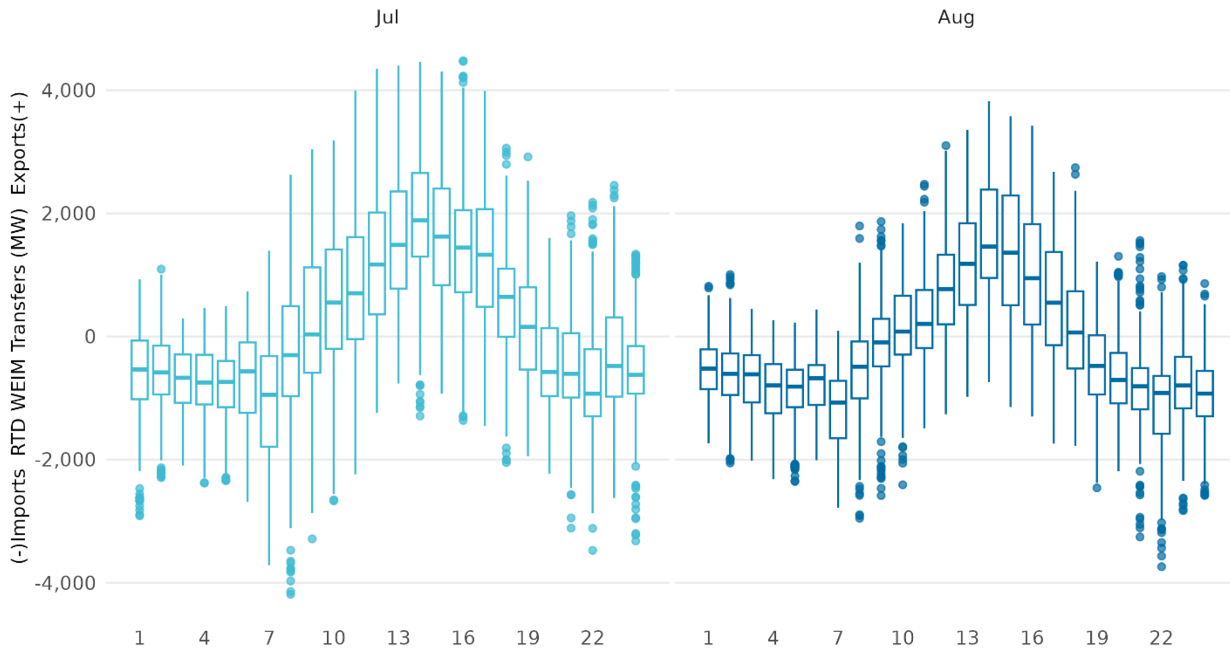


Figure 211 shows the distribution of WEIM transfers by region. California shifted from net exports in July to net imports in August, while net exports from the Central/Mountain region increased and peaked on August 29. Net imports into the Pacific Northwest region also increased relative to July. The Southwest region remained a net exporter in August, with export levels exceeding those observed in July. California and the Central/Mountain region experienced the largest month-over-month changes in WEIM transfers.

Figure 211: Daily distribution of 5-minute RTD WEIM transfers by region

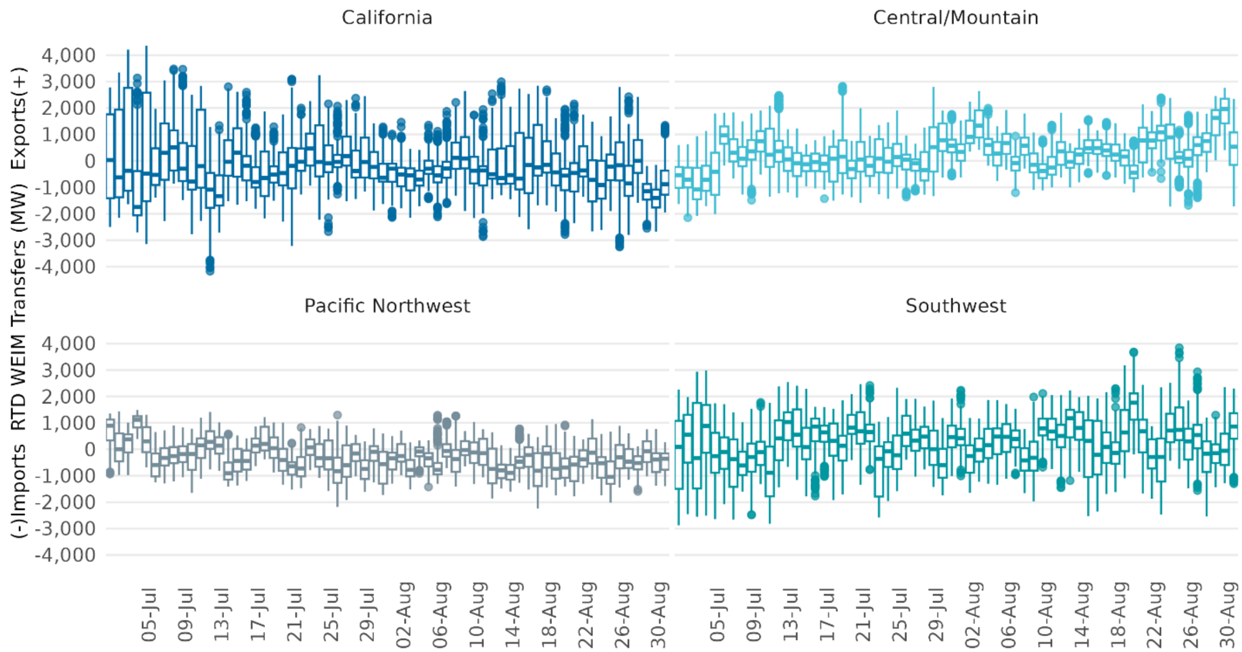
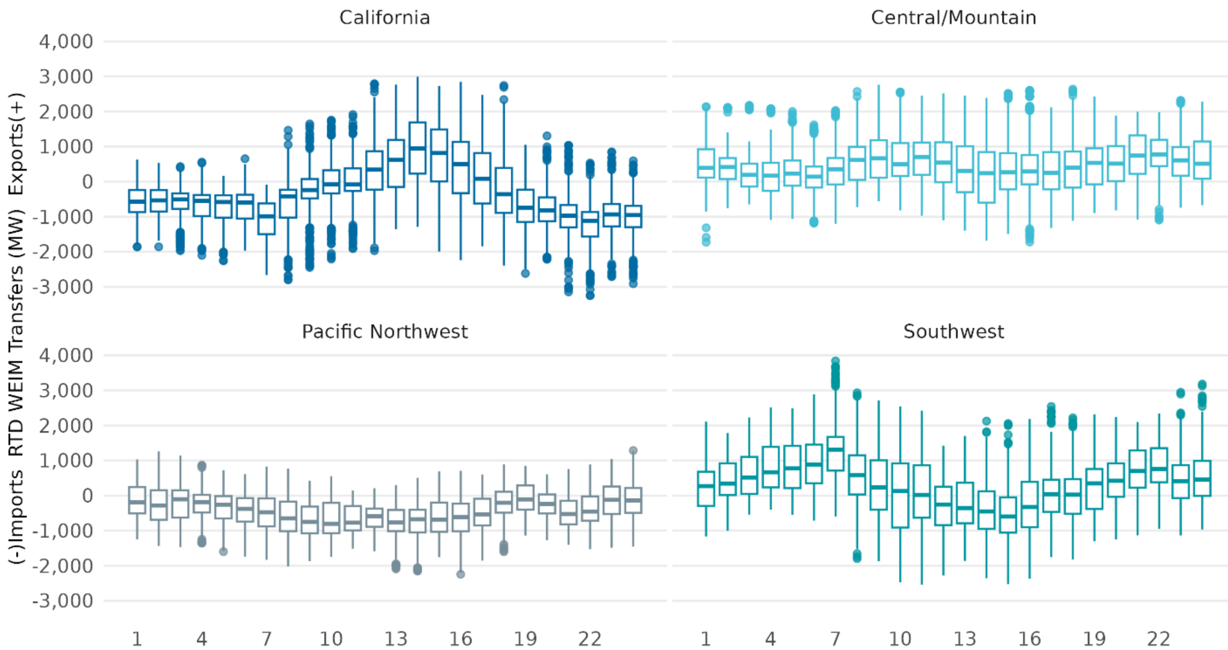


Figure 210 show the hourly distribution of WEIM transfers by region in August. Transfer patterns were distinct across regions but generally consistent between the two months. The California region was a net exporter in the midday hours and a net importer in the remaining hours. In the Central/Mountain region, net export transfers were highest during the morning and evening peak hours, while net import transfers were highest in the hours leading up to the morning and evening peaks. Pacific Northwest transfers were consistently net imports with the highest levels reached in the middle of the day. For the Southwest region, net export transfers were highest during the morning and evening peaks, while net import transfers were highest during the midday hours. Across regions, the Southwest and Central/Mountain had the most similar transfer patterns.

Figure 212: Hourly distribution of 5-minute RTD WEIM transfers by region, August 2026



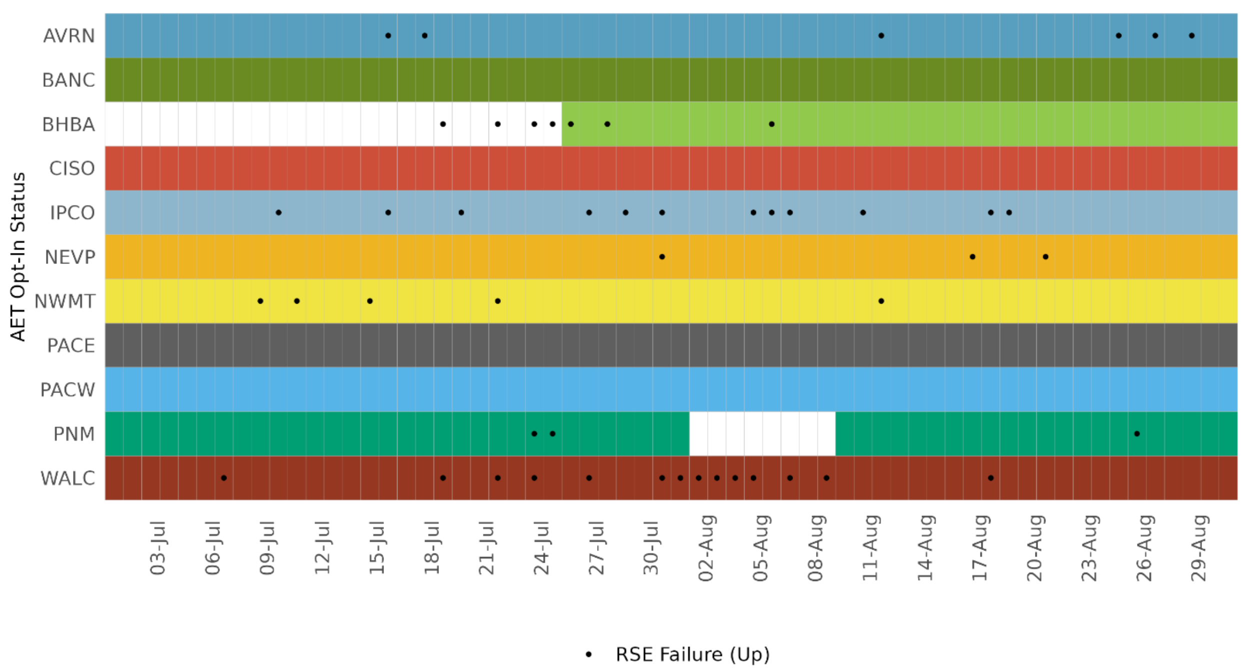
Assistance energy transfer

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 213 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 August 2026, eleven WEIM BAAs opted into AET for some duration of the month. The CISO, PACW and PACE BAAs opted-in to AET in August and did not fail the upwards RSE tests. WEIM BAAs experienced fewer upwards RSE failures in August than in July.

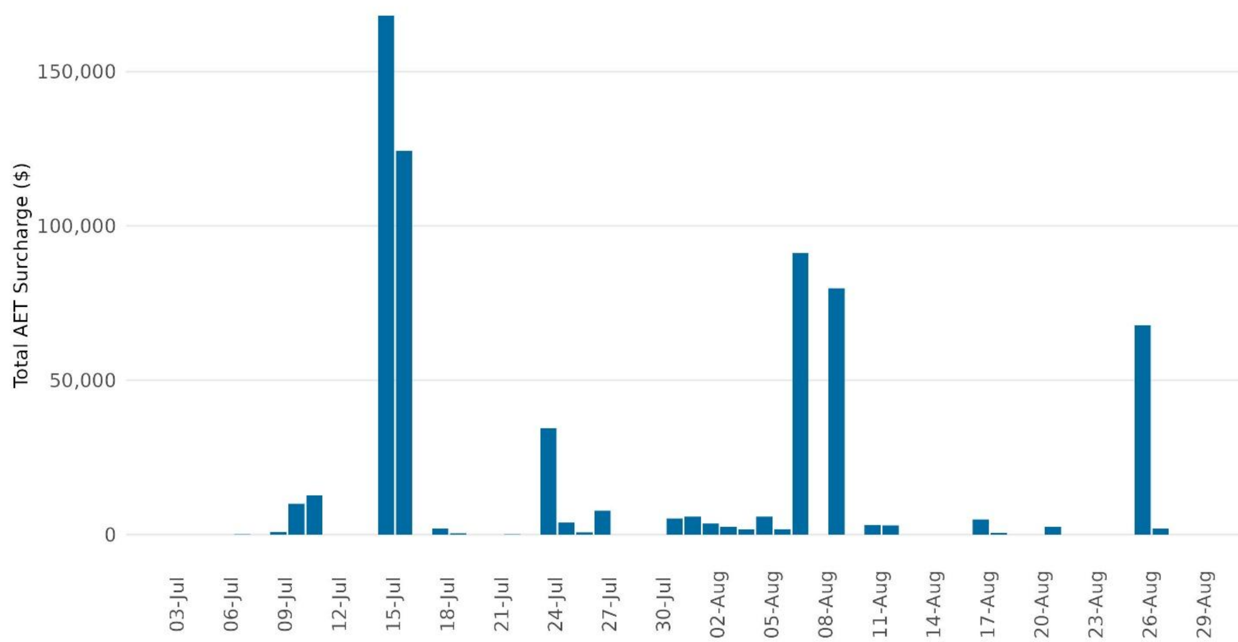
Figure 213: BAAs opted into Assistance Energy Transfers and RSE Upward Failures



The total AET surcharges assessed in August were approximately $275,550 for all the BAAs that opted in.

Figure 214 shows the breakdown of total AET surcharges assessed per day for August 2026. By design, AET is only assessed for WEIM BAAs that fail the RSE and opt in ahead of time. Thus, the AET surcharge was only assessed for a total of fifteen trading days in August.

Figure 214: 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 215 to
Figure 217 show the total wholesale costs for CAISO at a daily and monthly level. The average total cost per MWh is also shown in Figure 215 and Figure 216[15]. Looking at the monthly level, the total

[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.

costs for August were highest since EDAM go-live. Like July, August surpassed the total cost of last year by 35%. Higher costs in August are primarily attributable to day-ahead energy costs.

Figure 215: Total daily costs CAISO

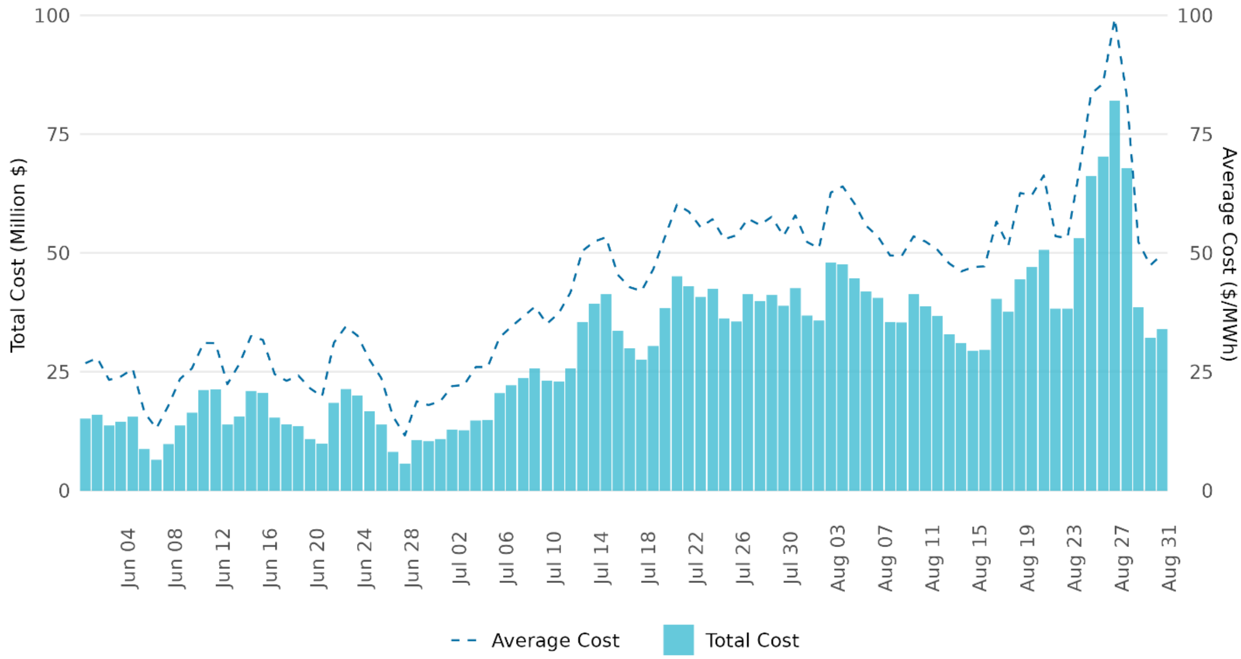


Table 13: Monthly Total Costs for CAISO

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

Figure 216: Monthly total costs CAISO

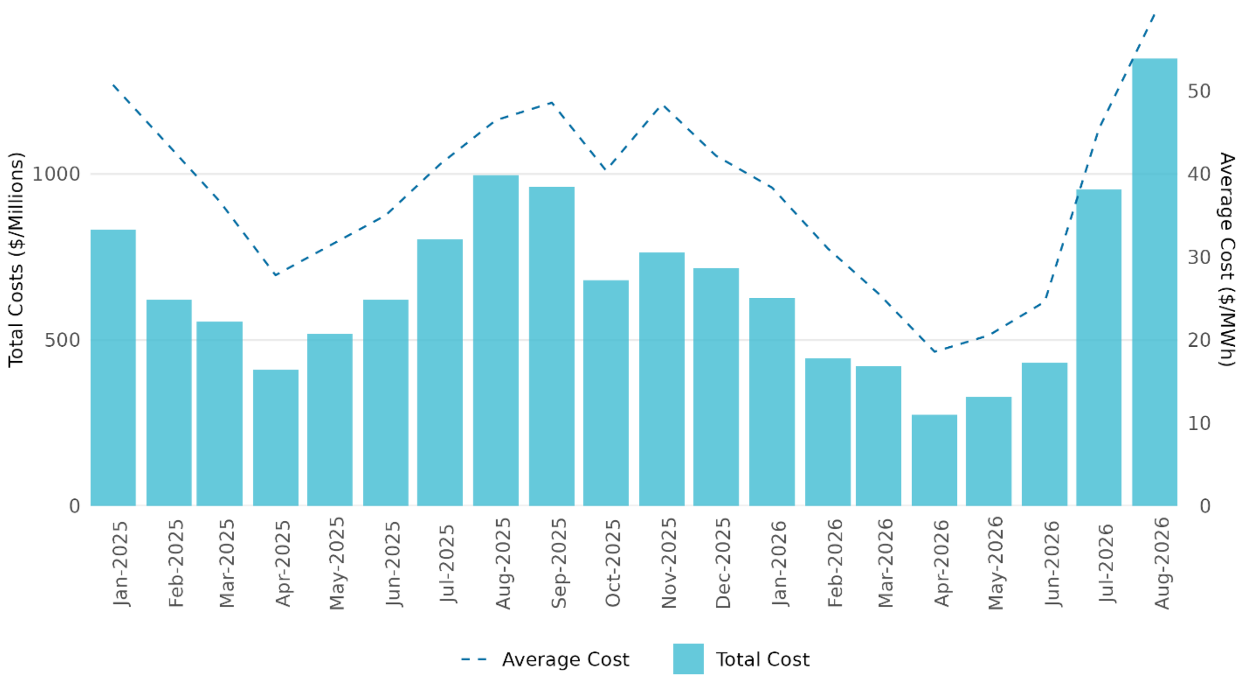
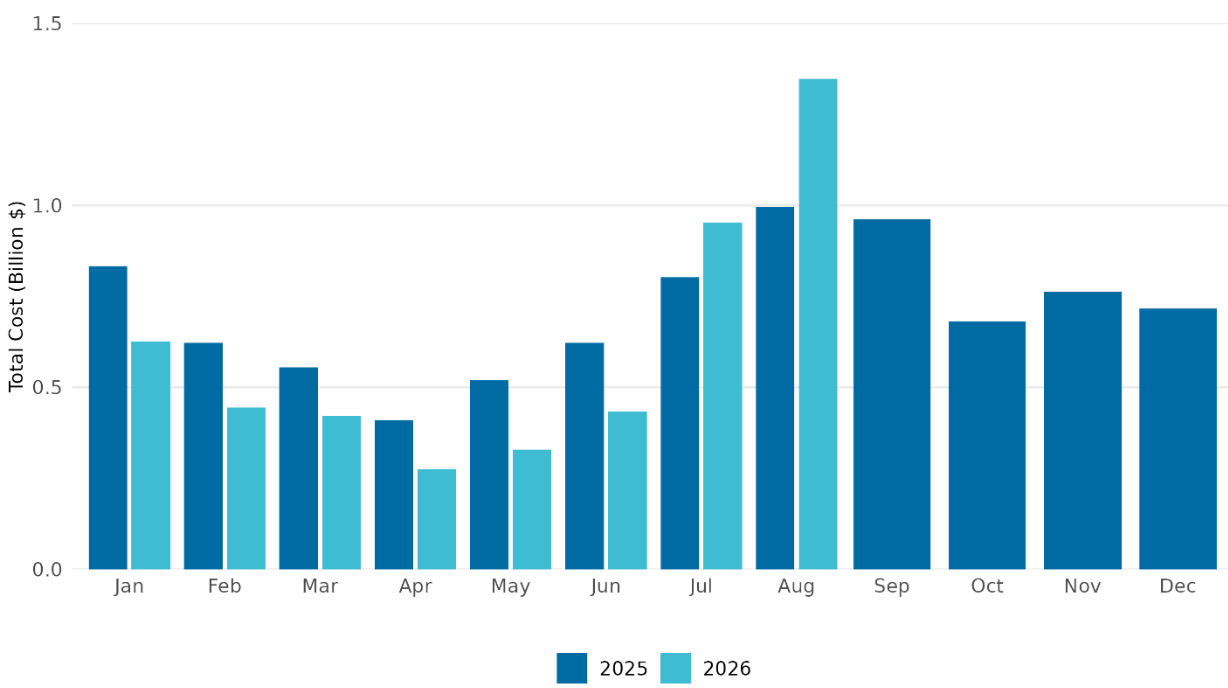


Figure 217: Monthly Total Costs CAISO, comparing 2025 to 2026



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+72 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 218 to Figure 222 illustrate the Bid Cost Recovery (BCR) trends for CAISO, PACW, and PACE across June, July and August. Figure 221 to Figure 222 compare BCR of three different BAAs in IFM and RTM. Note that PACE's IFM BCR starting the last three days of July through August are inaccurate and will be corrected in the T+70 settlement statement. Table 14 shows the BCR comparison between IFM and RTM for all EDAM BAAs from May to August. BCR costs in the IFM have continued to decrease since EDAM go-live after accounting for the inaccurate BCR numbers for PACE. Overall, BCR has been higher in real-time than in day-ahead across all areas. Real-time BCR costs have decreased in August over July, after discounting August 26th for the CAISO area.

Table 14: BCR comparison between IFM and RTM for EDAM BAAs in $ millions

Area	**IFM**				**RTM**			
	May	June	July	August	May	June	July	August
CISO	3.17	2.22	1.23	0.72	8.06	3.57	7.03	7.8
PACE	0.36	0.08	0.545	5.45	1.41	0.115	0.99	0.432
PACW	0.097	0.005	0	0.009	0.26	0.0265	0.06	0.03

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

Figure 218: BCR of CAISO by market

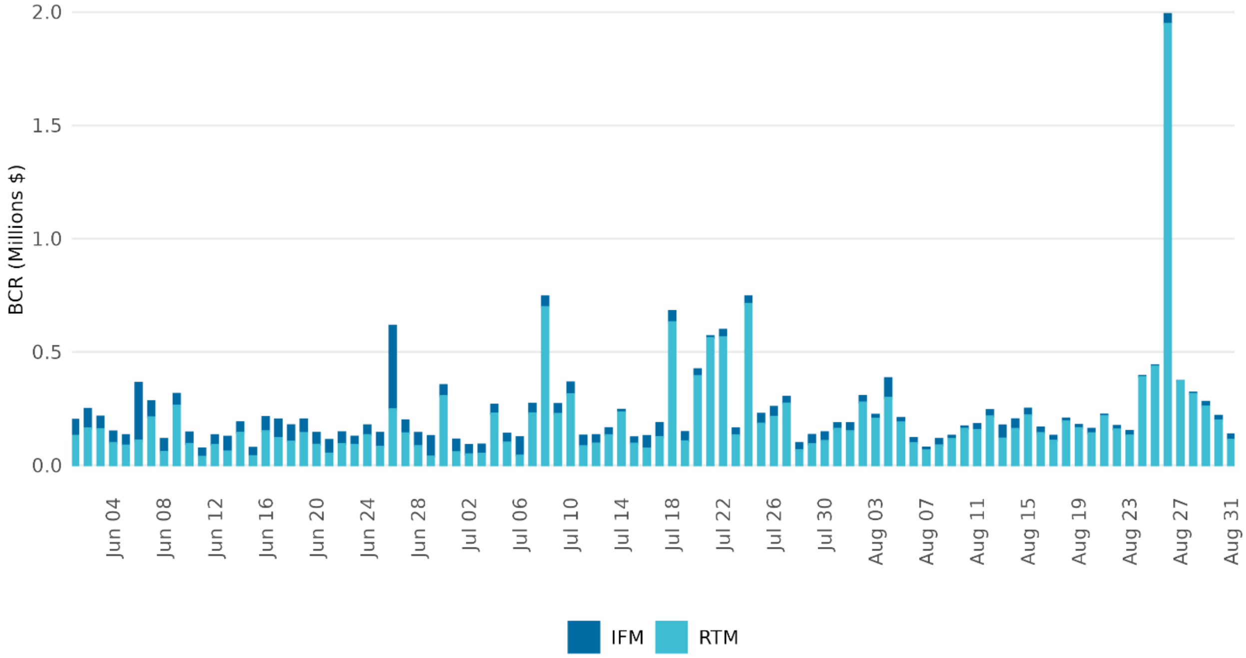


Figure 219: BCR of PACE by market

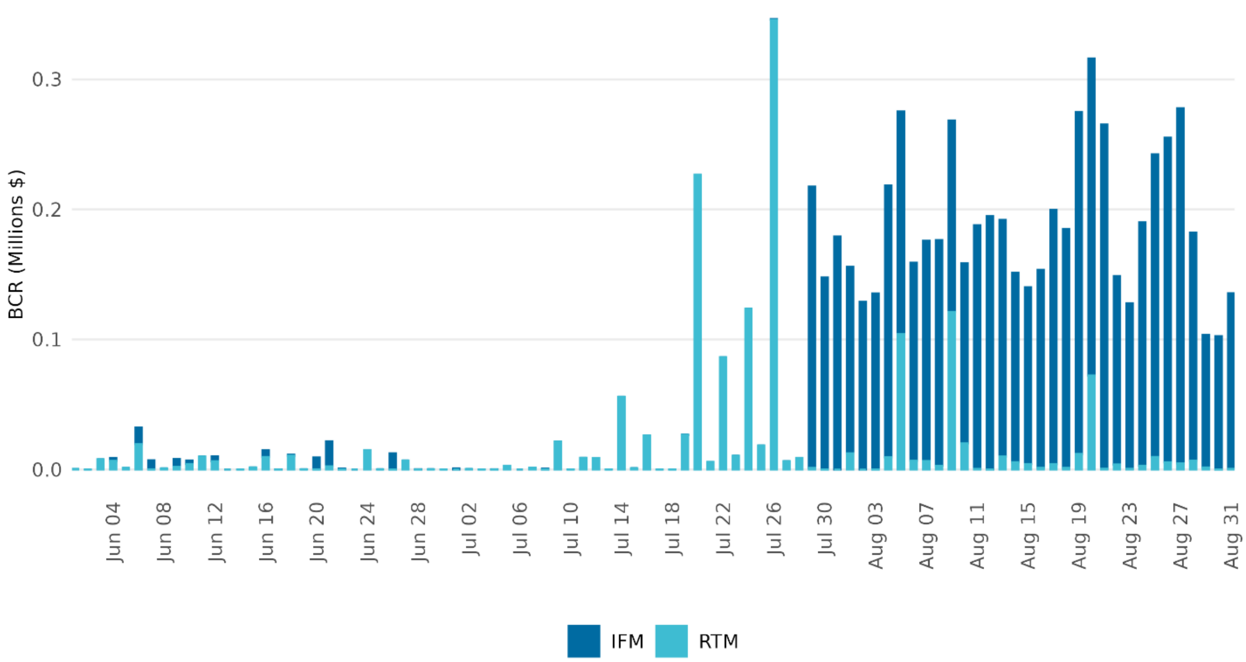


Figure 220: BCR of PACW by market

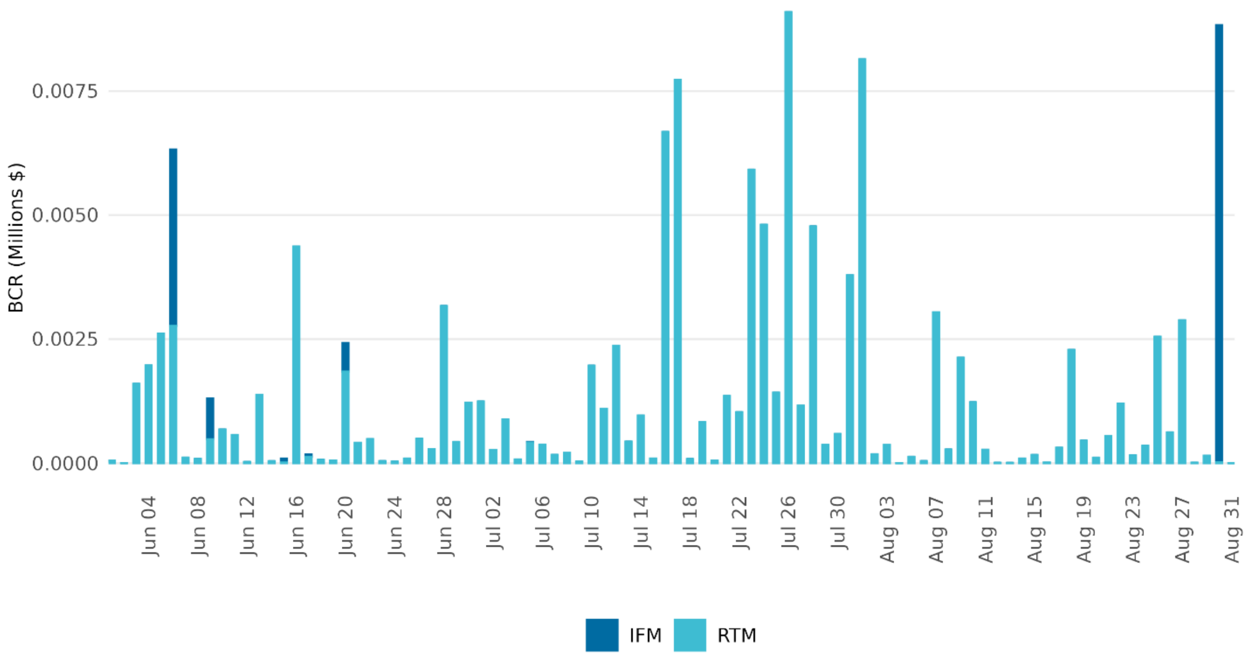


Figure 221: IFM BCR by BAA

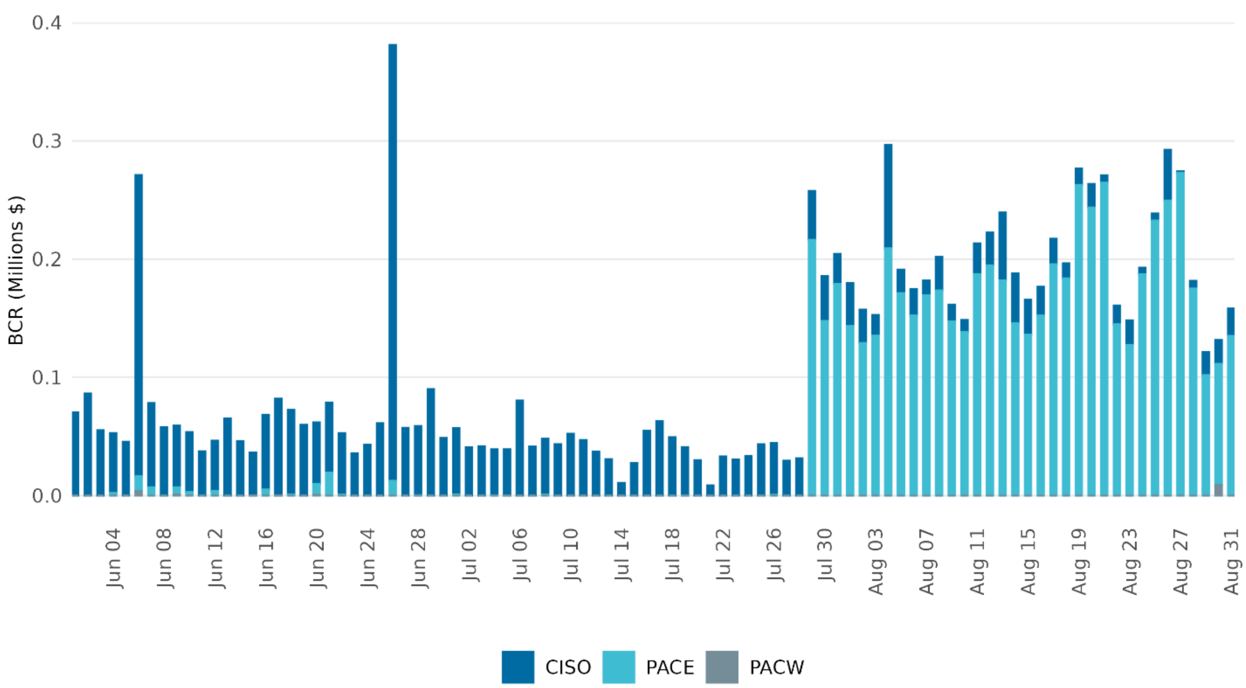
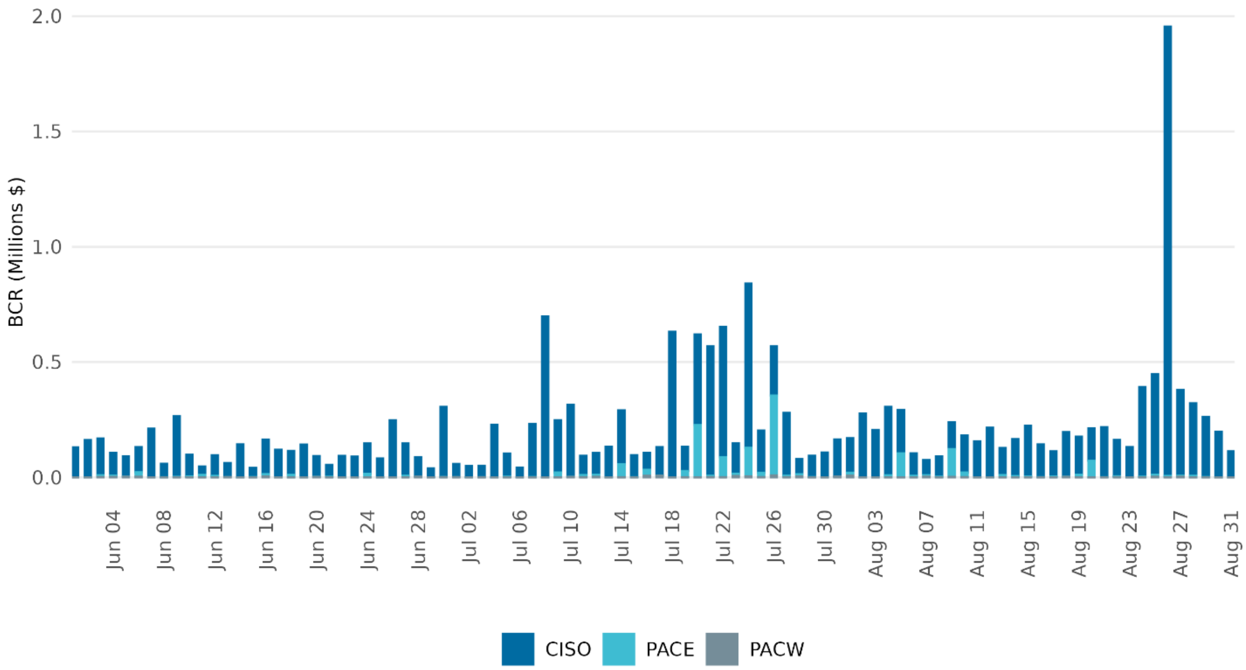


Figure 222: RTM BCR by BAA



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 223 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 15 shows the DA congestion offset comparison for PACE and PACW for the months of July to August.

Figure 223: DA Congestion Offset for PAC areas

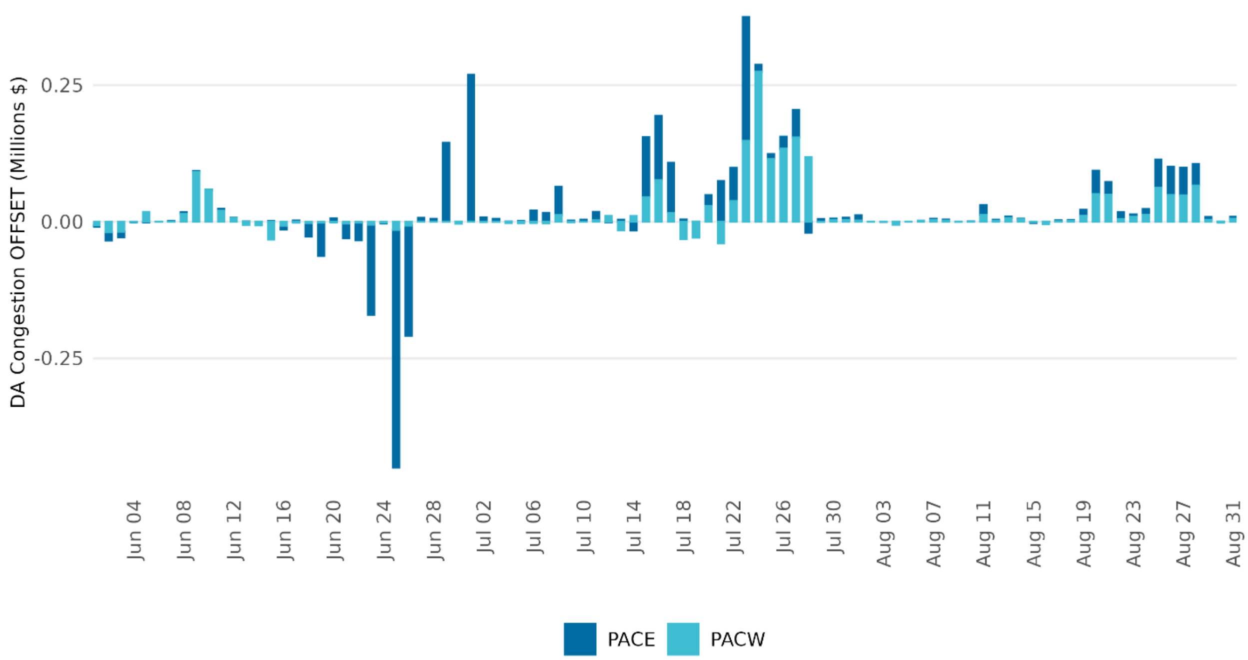


Table 15: DA Congestion Offset in $ millions

Area	May	Jun	Jul	Aug	Total
PACE	0.39	-0.81	1.17	0.35	1.1
PACW	-0.22	0.07	1.06	0.4	1.31
Total	0.17	-0.74	2.23	0.75	2.41

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. The spike of May 19 for CAISO was related to slightly higher loads at higher marginal energy cost. It was accrued in the morning and evening hours. Table 16 shows the DA energy offset comparison between EDAM BAAs from June to August.

Figure 224: DA Energy Offset

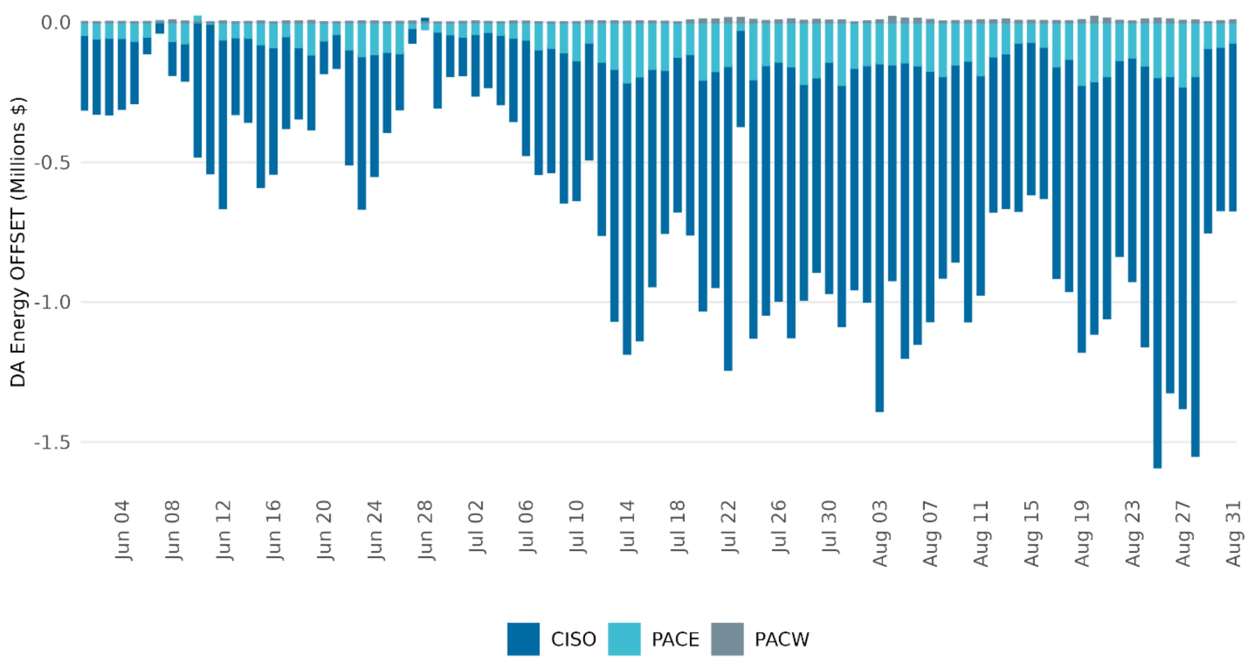


Table 16: DA Energy Offset for EDAM BAAs –in $ millions

Area	May	Jun	Jul	Aug	Total
CISO	-6.39	-8.21	-19.67	-26.21	-60.48
PACE	-0.23	-1.81	-4.07	-4.60	-10.71
PACW	0.08	0.07	-0.17	0.26	0.24
Total	-6.54	-9.95	-23.91	-30.55	-70.95

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 225 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 late August. Congestion was higher during this period due to a planned outage on a highly impacted transmission constraint.

Figure 225: Real-Time Congestion Offset

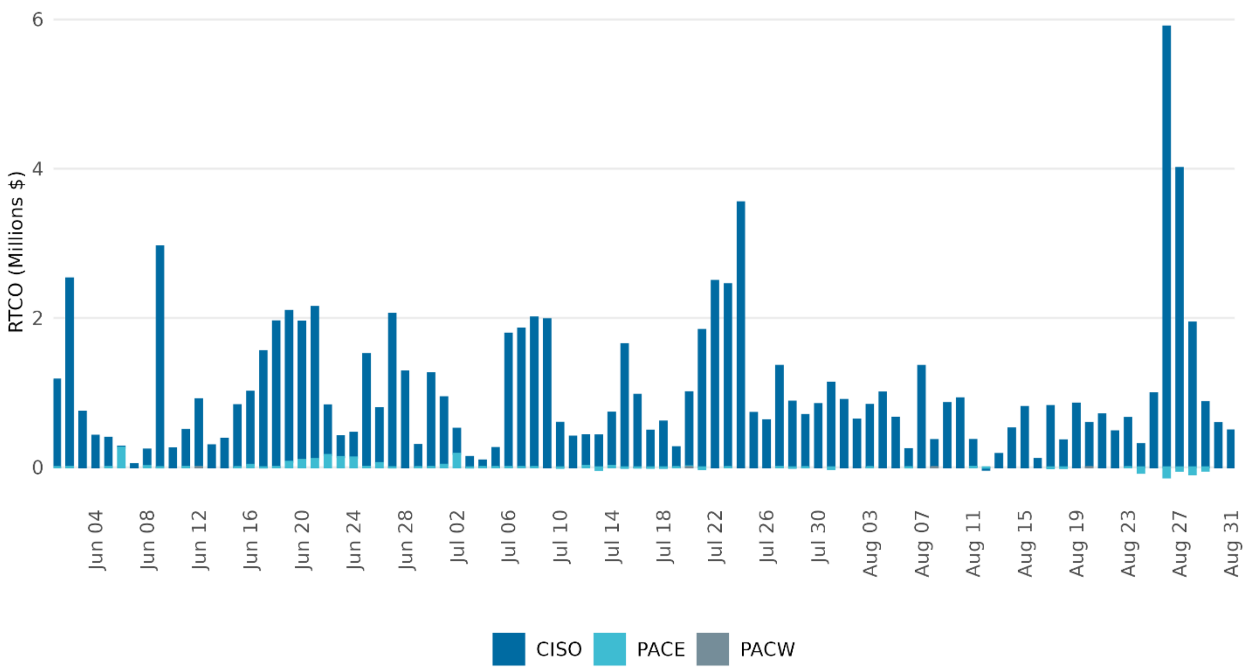


Table 17: Real-Time congestion offset for EDAM BAAs in $ millions

Area	May	Jun	Jul	Aug	Total
CISO	21.92	30.47	33.52	29.34	115.25
PACE	0.68	1.05	0.14	-0.41	1.46
PACW	-0.04	-0.00	-0.00	-0.00	-0.04
Total	22.56	31.52	33.66	28.93	116.67

Real-Time imbalance energy offset

Real time imbalance energy offset (RTIEO) is very similar to DAEO. In settlements, RTIEO is a market neutrality charge code that ensures CAISO remains revenue neutral in the real time market. RTIEO is a residual amount due to an imbalance between real time energy payments and charges. RTIEO allocates this residual amount back to measured demand. Figure 226 illustrates a notable shift in RTIEO following the implementation of EDAM. While external BAAs, such as PACW and PACE, experienced an increase in RTIEO, there was a simultaneous reduction in CAISO's own offset.

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

Figure 226 illustrates the Real-Time Imbalance Energy Offset (RTIEO) for the three balancing areas, where a positive value indicates an additional charge collected from the BAA and a negative value indicates an additional payment sent out to them.

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 18 shows the real time energy offset comparison for EDAM BAAs.

Table 18: Real time energy offset for EDAM BAAs in $ millions

Area	May	Jun	Jul	Aug	Total
CISO	0.43	-23.47	-4.20	-5.16	-32.4
PACE	0.27	3.42	1.35	-0.06	4.98
PACW	0.80	2.17	-0.18	-0.49	2.3
Total	1.5	-17.88	-3.03	-5.71	-25.12

Figure 226: Real-Time Imbalance Energy Offset

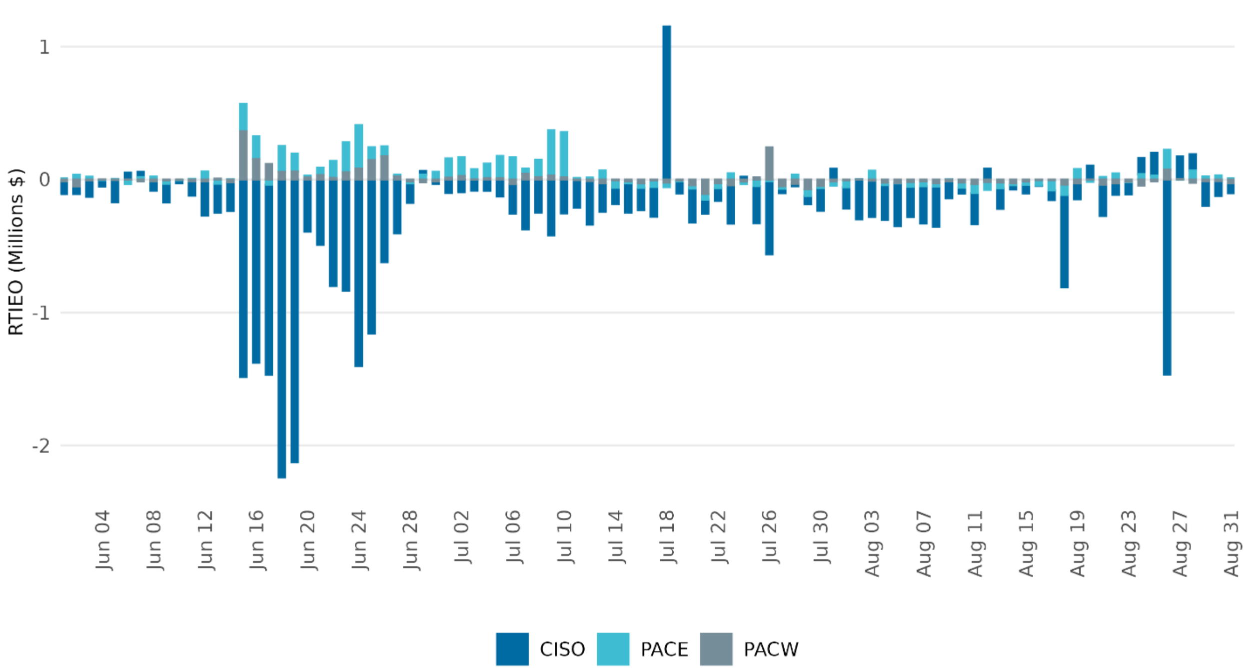
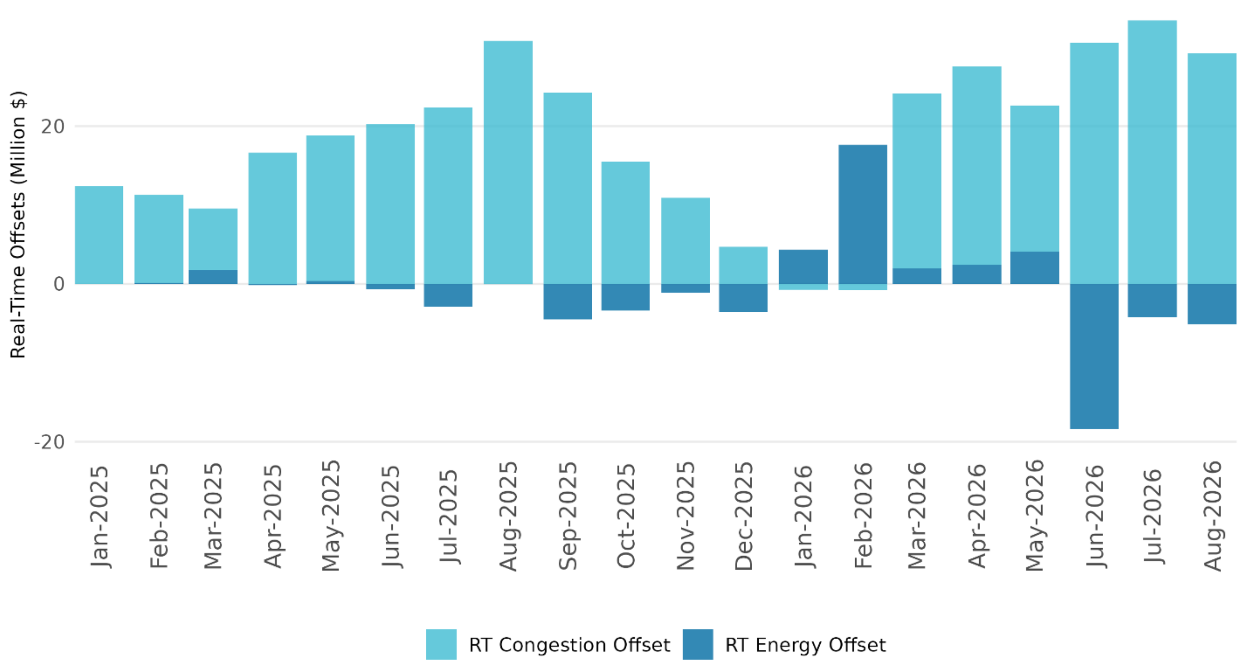


Figure 227 and Figure 228 show the monthly real-time congestion and energy offsets for CAISO area and the WEIM excluding CAISO area, respectively. CAISO offsets remained within normal ranges, with an energy offset slightly more negative than seen in other months since the start of 2025. In June, the energy offset remained negative but got significantly larger. Figure 228 shows that in May through July, the WEIM not including CAISO saw a positive congestion offset and a large, positive energy offset. August is has a relatively low RTCO amount of about $-44k.

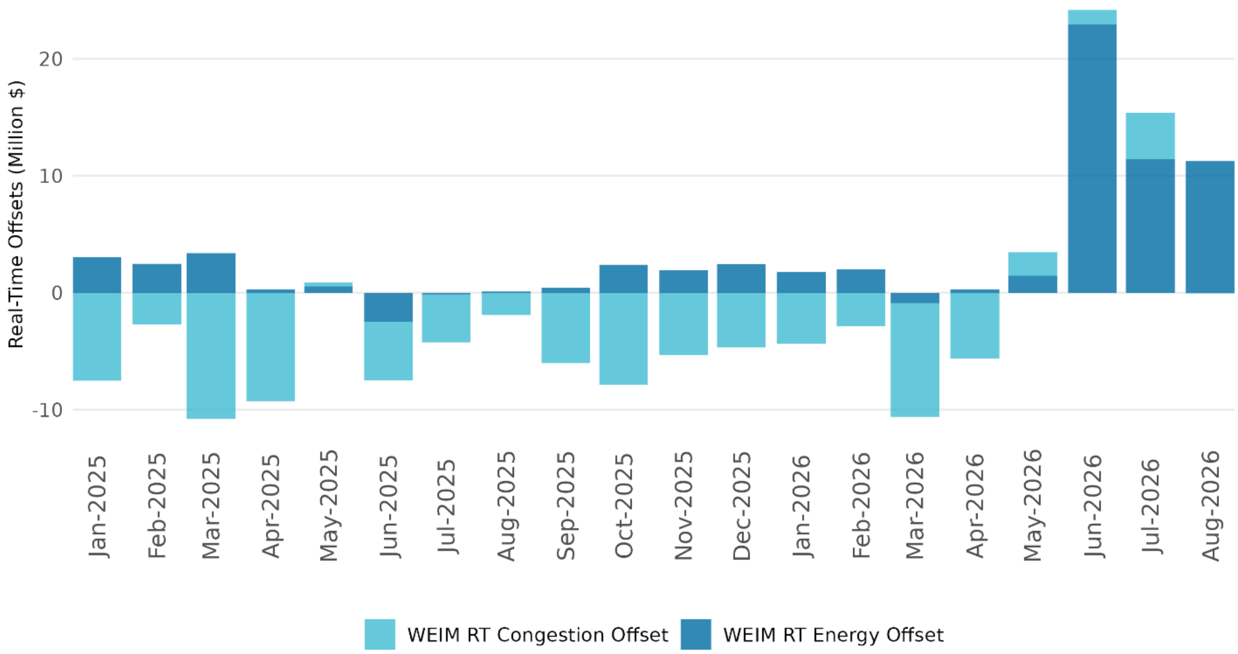
The magnitude of the real-time energy offsets for May and June are very high compared to historical offsets. First, it is important to note that the real-time imbalance energy offset (RTIEO) results observed after the May 1 EDAM go-live are not directly comparable to pre-EDAM outcomes. This is primarily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

Figure 227: 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 228: Monthly Total Real-Time Offsets for WEIM



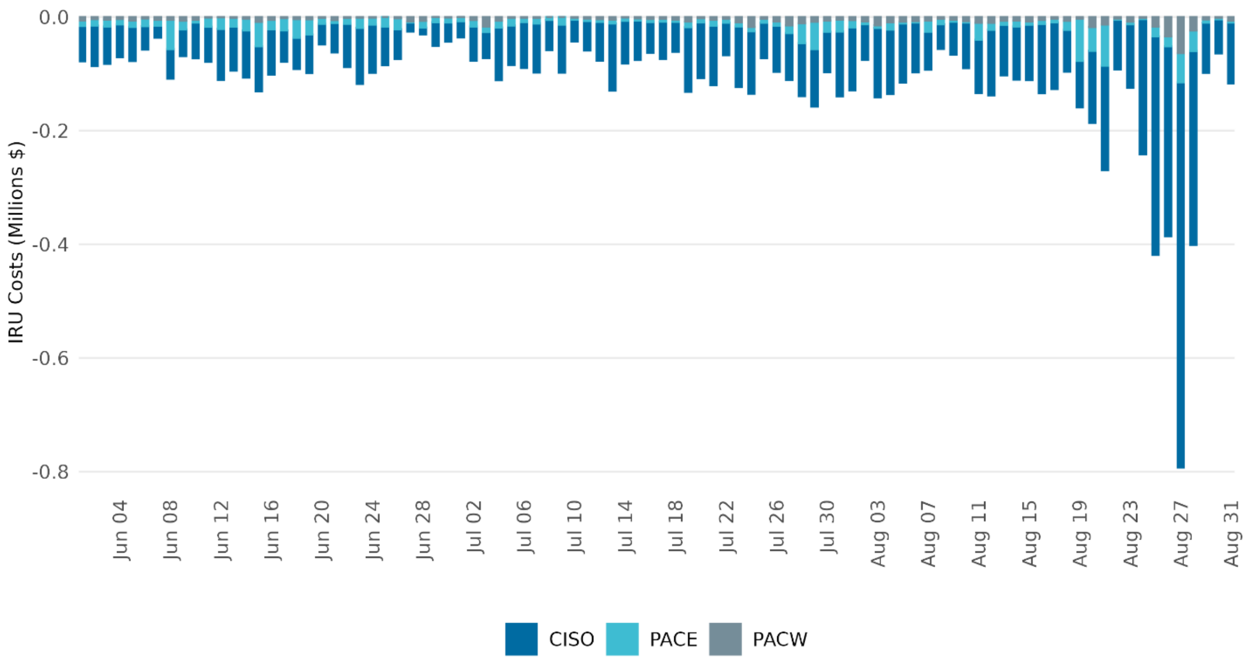
Imbalance reserves

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 229 shows the daily trend of IRU costs for June through August. 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.

Figure 229: 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 230 shows the daily costs for procuring IRD for June through August.

Figure 230: IRD settlement costs

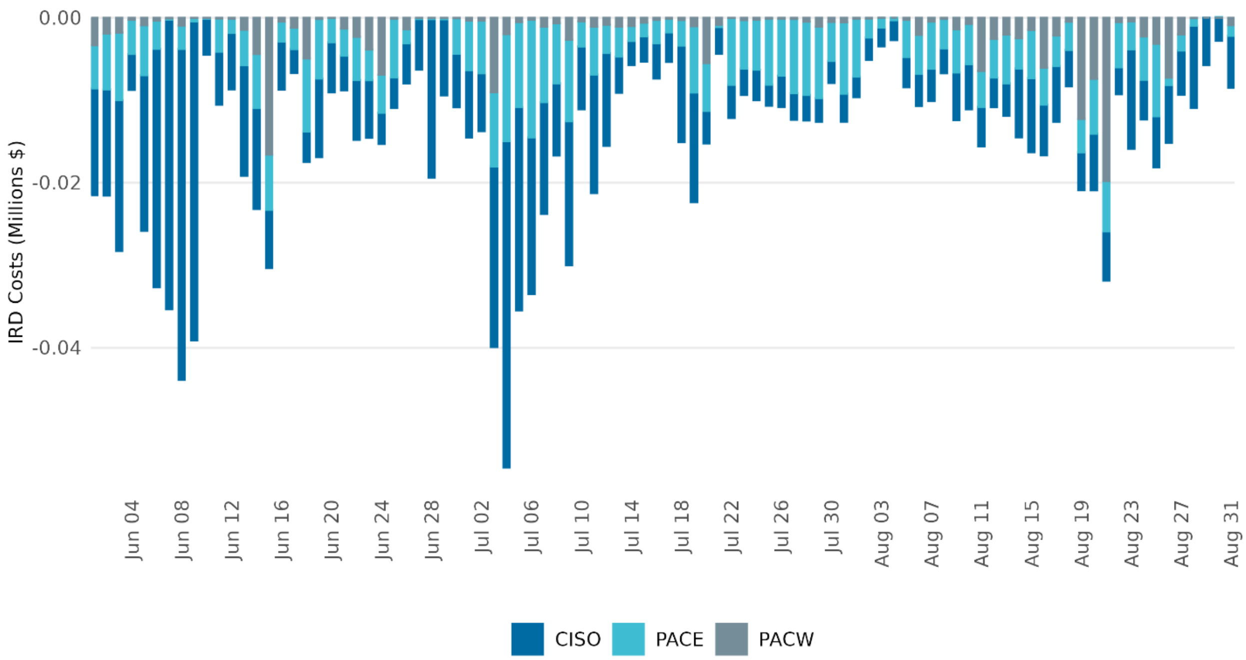


Table 19: Imbalance Reserves Total Monthly Settlement Costs

	IRU Total Costs ($million)				IRD Total Costs ($million)			
BAA	May	June	July	Aug	May	June	July	Aug
CAISO	-2.11	-1.73	-2.39	-4.47	-1.28	-0.36	-0.28	-0.16
PACW	-0.37	-0.10	-0.16	-0.32	-0.215	-0.06	-0.03	-0.09
PACE	-0.17	-0.49	-0.34	-0.51	-0.164	-0.12	-0.20	-0.12

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 231 shows the daily RCU costs organized by BAA in June through August . 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 232 provides the daily trend of RCD cost by BAA in June through August. RCU costs spiked on the 27th due to higher RUC prices during peak hours on that day.

Figure 231: RCU settlement costs

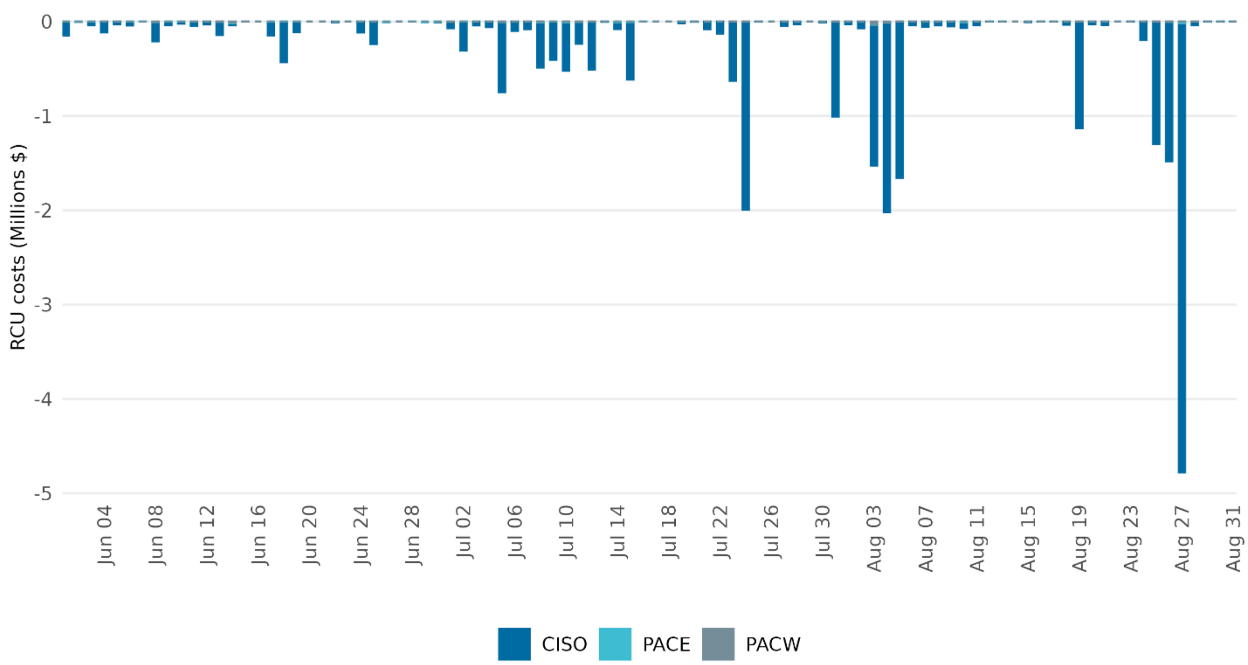
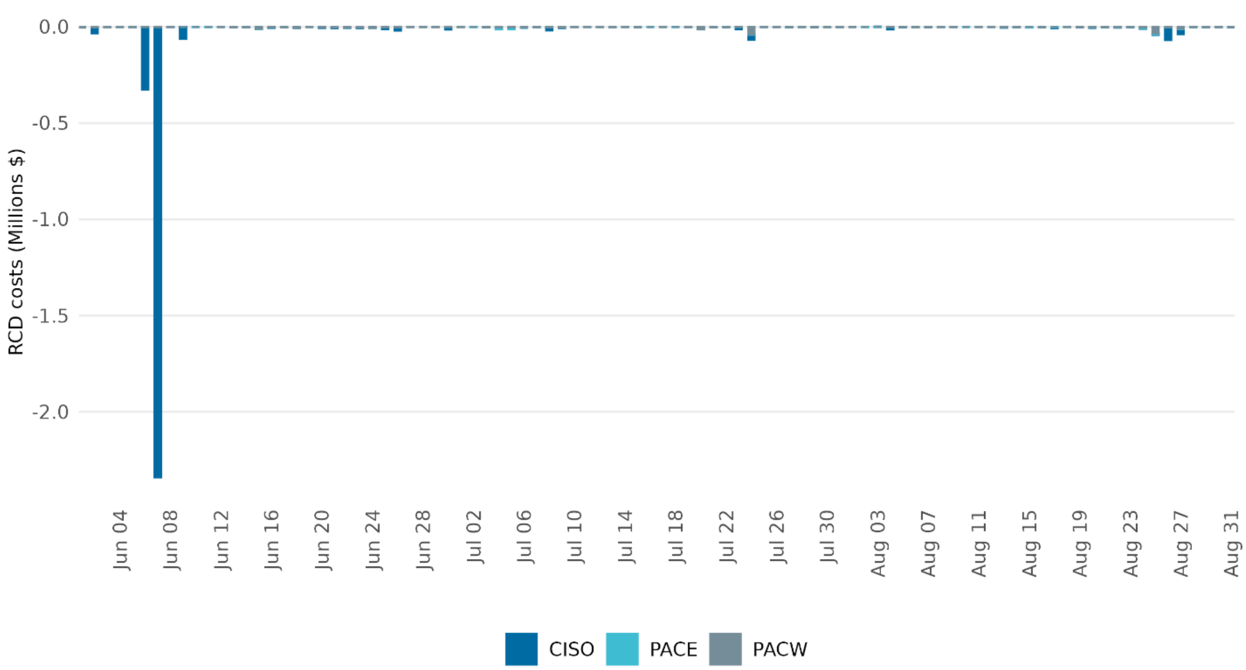


Figure 232: RCD settlement costs



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

Table 20: Reliability Capacity Total Monthly Settlement Costs

	RCU Total Costs ($million)				RCD Total Costs ($million)			
BAA	May	June	July	Aug	May	June	July	Aug
CAISO	-8.09	-1.53	-8.16	-14.54	-0.87	-2.82	-0.06	-0.12
PACW	-0.22	-0.01	-0.01	-0.04	-0.02	-0.05	-0.07	-0.05
PACE	-0.32	-0.03	-0.03	-0.03	-0.003	-0.01	-0.05	-0.06

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 233 shows the GHG payments to EDAM entities that are supporting the energy imported into the GHG regulation area (California). Conversely, Figure 234 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 21 summarizes the monthly total GHG costs for PACE and PACW.

Figure 233: Greenhouse Gas Settlement Costs in IFM

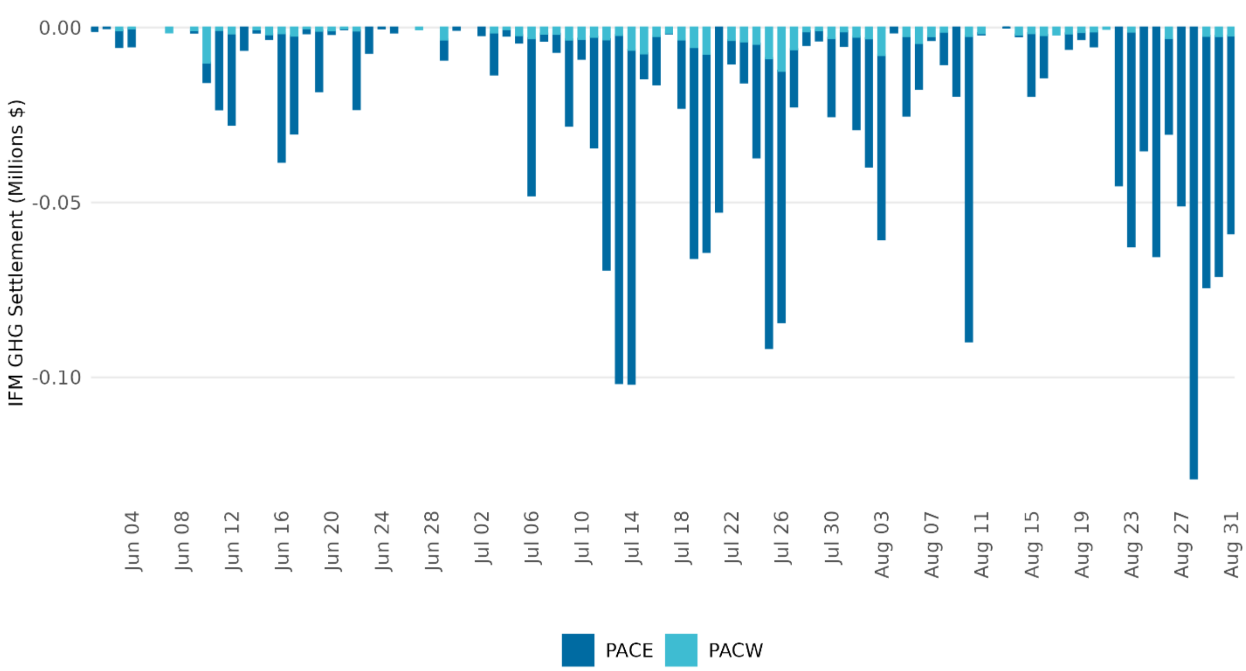


Figure 234: Greenhouse Gas Settlement Costs in RTM

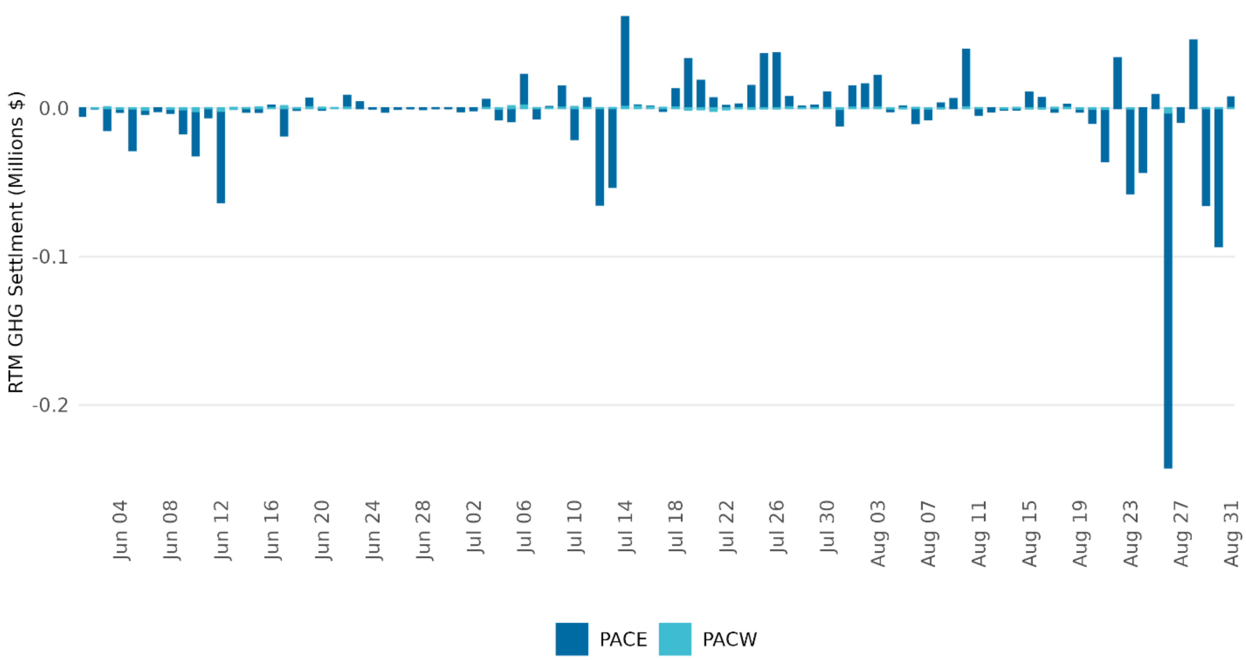


Table 21: IFM and RTM Monthly GHG Settlement Costs

	IFM GHG Costs ($ million)				RTM GHG Costs ($ million)			
BAA	May	June	July	Aug	May	June	July	Aug
PACW	-0.01	-0.03	-0.11	-0.05	0.0005	-0.002	0.005	-0.001
PACE	-0.28	-0.20	-0.86	-0.92	-0.18	-0.18	0.12	-0.37

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.

- 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. Additionally, CAISO has identified a software issue impacting the congestion component for tie-generators where the congestion component for nomograms and transmission constraints is not included in the RC price. The software issue for tie-generator RC congestion was resolved on July 24, 2026. 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.
- Storage Resources and RCD: Storage resources are unable to provide RCD despite being economic and having sufficient state-of-charge headroom. When operating in a neutral state or charging state, the minimum energy bid limit is incorrectly constrained to 0 MWh or the IFM charging value. This issue was resolved on September 14, 2026.
- 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.
- High Reliability Capacity Down prices due to solution limited by IFM commitment: Reliability Capacity Down can only be awarded to resources that are on-line and committed by the IFM. Additionally, down capacity range is limited by energy self-schedules, Ancillary Services and Imbalance Reserves awarded in IFM. This is not a software issue but it is a dynamic due to the requirement to run RUC only after IFM is complete. CAISO will continue monitoring to ensure the new market functionality is working as intended.
- Commitment Costs in the day-ahead Resource Sufficiency Evaluation (RSE): The RSE test is considering non-zero minimum load costs and transition costs which economically prevents some resources from providing energy and Imbalance Reserve. This issue was resolved on

September 14, 2026. The RSE failure on June for PAC area that was driven by this issue has been deemed invalid.

- 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 affects trade dates from May 1, 2026 and is open.
- 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.
- Low-Priority Exports in RUC: Low-priority exports receive a $250 proxy Reliability Capacity Up bid in RUC and will be curtailed when RUC prices are $250 or higher. There are two software issues impacting the bid set-up and curtailment for low-priority export and CAISO will resolve this in an upcoming software update.
- 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.

Enhanced Battery Participation in RUC

An enhancement to the existing market logic that enables battery charging in the Residual Unit Commitment (RUC) process will become effective for trade date October 1, 2026. The changes were discussed with market participants and incorporated into the Market Operations BPM through PRR 1678.

This enhancement increases battery participation by allowing the state of charge (SOC) resulting from Residual Capacity Down (RCD) awards to be used to provide Residual Capacity Up (RCU) in

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

other intervals. The same concept applies in reverse, where an RCU award can create charging headroom that enables a battery to provide RCD.

To support this functionality, the RUC envelope constraints will be modified as shown below, with the changes highlighted in red:

$$\left.\begin{array}{l} SOC_{i,t}^{(u)} = \begin{pmatrix} SOC_{i,t-1}^{(u)} - EN_{i,t}^{(+)} - \eta_i\, EN_{i,t}^{(-)} - ARU_t\, RU_{i,t} - ASR_t\, SR_{i,t} - \\ ANR_t\, NR_{i,t} - AIRU_t\, IRU_{i,t} - ARCU_t\, RCU_{i,t} + \eta_i\, ARCD_t\, RCD_{i,t} \end{pmatrix} \geq \underline{SOC}_{i,t} \\ SOC_{i,t}^{(d)} = \begin{pmatrix} SOC_{i,t-1}^{(d)} - EN_{i,t}^{(+)} - \eta_i\, EN_{i,t}^{(-)} + \eta_i\, ARD_t\, RD_{i,t} + \\ \eta_i\, AIRD_t\, IRD_{i,t} + \eta_i\, ARCD_t\, RCD_{i,t} - ARCU_t\, RCU_{i,t} \end{pmatrix} \leq \overline{SOC}_{i,t} \end{array}\right\}$$

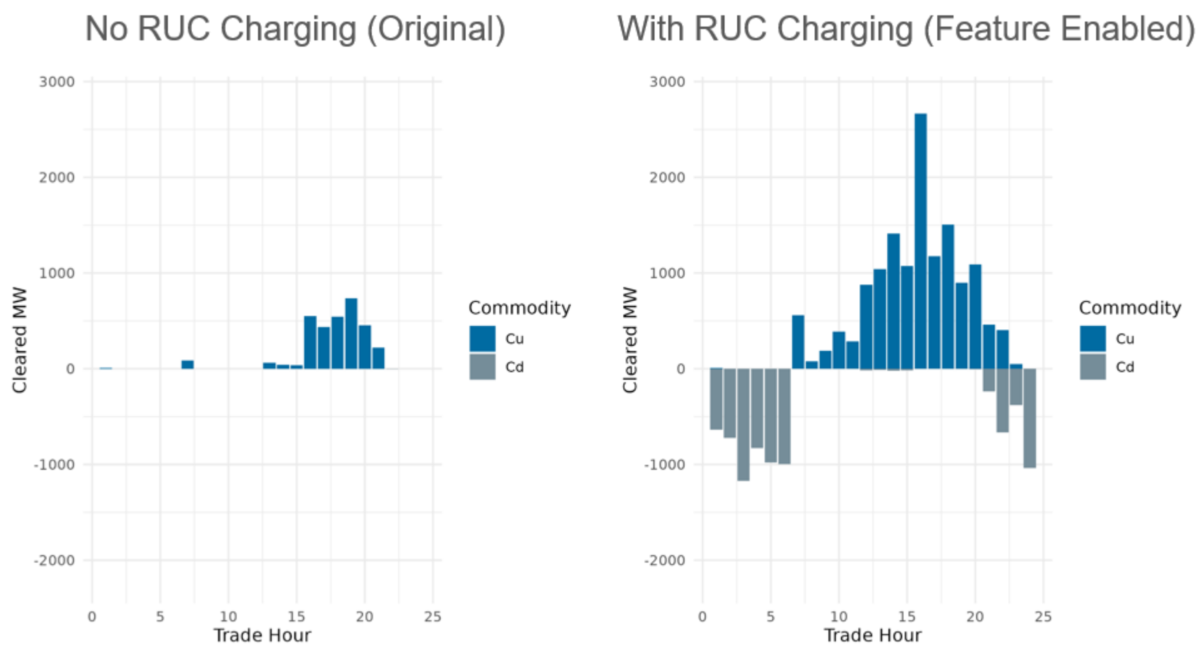
By incorporating the RCD term into the upper state-of-charge (SOC) envelope constraint, RCD awards can support RCU awards in subsequent intervals. The impact of an RCD award on SOC is adjusted by the charging efficiency (η) and the RCD envelope multiplier (ARCDt). This configurable parameter determines the portion of an RCD award that contributes to SOC available in future intervals. Similarly, the RCU envelope multiplier (ARCU) specifies the portion of an RCU award that is treated as energy consumed when calculating future SOC. These parameters were established through the configurable parameters stakeholder process prior to EDAM go-live and are currently set to 1.0 for both ARCU and ARCD.

This enhancement is expected to increase battery participation in the RUC process. Under the current implementation, batteries can provide residual capacity (RC) awards only from SOC that remains available after the integrated forward market (IFM) optimization. Analysis of the September 9 trade date indicates that enabling this feature would increase battery participation throughout the day.

The figure below compares actual battery awards with a counterfactual scenario in which the enhancement is enabled. In the actual case, RUC battery awards are minimal despite strong RUC prices during HE 15 through HE 21. This outcome reflects IFM optimization, which does not account for subsequent RUC needs. As a result, batteries have little incentive to reserve SOC for RUC, leaving limited flexibility for the commitment process.

With the enhancement enabled, RUC can award additional charging capacity through RCD awards, increasing operational flexibility while maintaining the same resource-level constraints applied in IFM. This allows RUC to charge and discharge batteries in the most cost-effective intervals. By utilizing RCD awards during early morning and late evening hours, RUC can increase SOC and maximize the amount of RCU available during the evening peak period in HE 15 through HE 21.

Figure 235: CISO Battery Participation in RUC Comparison



Stakeholder Feedback and ISO's responses

There were two sets of stakeholder comments submitted in response to July'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 Company identified additional items to improve the usability of the report and provide more information on EDAM performance. The additional items include: robust statistical assessment of causal EDAM effects on market performance, EDAM trends and metric presented month-to-month, Imbalance Reserve utilization and value assessment and performance metric harmonization and interpretation related to real-time offsets and congestion analysis. It also requests additional analysis on market power mitigation and storage resources.

> <u>CAISO response</u>: The ISO appreciates PG&E's feedback and its constructive suggestions for improving the usefulness of this report. While the ISO will continue to evaluate additional metrics and areas for analysis, there are practical limitations to the scope of such assessments.
>
> One area of interest is quantifying the incremental impact of DAME and EDAM relative to the day-ahead market design that existed prior to their implementation. However, the ISO does not believe that statistical analyses alone can reliably produce such conclusions. Any attempt to estimate a counterfactual outcome by extrapolating historical market conditions would rely on a series of assumptions and may not accurately capture the new market dynamics introduced by DAME and EDAM.
>
> These market enhancements introduced new products and changed how energy is procured and priced in the day-ahead market. Participants have also adapted their bidding strategies to account for products that did not exist prior to May 1. As a result, historical market outcomes do not provide a directly comparable baseline for measuring the effects of the new design.
>
> More importantly, the expanded market introduces a wider generation mix that can change the pricing dynamics that statistical analysis using a different footprint cannot reliably captured. Also, changes in the day-ahead market solution can have cascading effects on real-time market outcomes. Because the markets are sequential, each day's solution influences the starting conditions for the following day and may affect market outcomes over multiple subsequent days. These intertemporal and market-coupled dynamics cannot be fully captured through straightforward statistical assessments.
>
> For these reasons, the ISO believes that statistical analyses attempting to isolate the impact of DAME and EDAM may not provide a reliable measure of the actual effects of the new market design.
>
> Regarding the request for additional analysis of market power mitigation and storage resources, the ISO may consider expanding the scope of future assessments once the core evaluation of EDAM and DAME performance, which remains the primary focus of this effort, is complete

TransAlta Energy requests a deeper review of the price differences between IRU and IRD prices and the relationship between IRU/IRD and RCU/RCD products. TransAlta Energy would also like to see a breakdown of congestion revenue flows by BA and a decomposition to identify congestion revenue impacted by loop flow, more information on transfer capacity and intertie pricing.

> CAISO response: The ISO appreciates Transalta's feedback and suggestions. In response to stakeholder interest, ISO has already expanded the congestion-related metrics in the August report to include balancing area-level congestion impacts and the allocation of congestion revenues back to each balancing area.
>
> The ISO will consider additional analysis of the differences between upward and downward flexibility prices in future reports. However, it is important to recognize that upward and downward flexibility are distinct market products and therefore clear at separate prices. Each product has its own set of bids, requirements, and supply conditions, all of which are evaluated concurrently with energy in market optimization.
>
> The resources available to provide upward and downward flexibility often differ due to system conditions and resource economics. For example, during midday periods with significant solar generation, downward flexibility can typically be procured at relatively low cost because solar resources can readily reduce output. The same resources generally have limited ability to provide upward flexibility during those hours. As a result, downward flexibility prices are often lower than upward flexibility prices.
>
> Similarly, during peak hours when additional upward ramping capability is needed, upward flexibility becomes more valuable and is typically priced higher. In contrast, downward flexibility can often be procured from resources that are already dispatched higher and have available downward operating range. Consequently, upward flexibility prices will generally exceed downward flexibility prices, reflecting the differing supply characteristics and operational needs associated with each product.