Q4 2023 Report on Market Issues and Performance

April 24, 2024

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California Independent System Operator

TABLE OF CONTENTS

LIST OF FIGURES iii
LIST OF TABLES v
Executive summary 7
Western energy imbalance market 10
1 Market Performance 12
1.1 Supply conditions 12
1.1.1 Natural gas prices 12
1.1.2 Renewable generation 13
1.1.3 Generation by fuel type 14
1.1.4 Generation outages 16
1.2 Energy market performance 19
1.2.1 Energy market prices 19
1.2.2 Bilateral price comparison 22
1.2.3 Imports and exports 24
1.3 Price variability 26
1.4 Convergence bidding 28
1.4.1 Convergence bidding revenues 28
1.5 Residual unit commitment 30
1.6 Ancillary services 34
1.6.1 Ancillary service requirements 34
1.6.2 Ancillary service scarcity 35
1.6.3 Ancillary service costs 36
1.7 Congestion 36
1.7.1 Congestion in the day-ahead market 37
1.7.2 Congestion in the real-time market 42
1.7.3 Congestion on interties 44
1.8 Congestion revenue rights 46
1.9 Real-time imbalance offset costs 48
1.10 Bid cost recovery 56
1.11 Imbalance conformance 57
1.12 Flexible ramping product 59
1.12.1 Flexible ramping product deliverability enhancements and market outcomes 59
1.12.2 Net load uncertainty for the flexible ramping product 64
1.13 Exceptional dispatch 70
2 Western energy imbalance market 74
2.1 Limitation of WEIM transfers to the ISO 74
2.1.1 Background 75
2.1.2 Impact on California ISO balancing area supply and demand 77
2.1.3 Impact on WEIM prices 79
2.1.4 Impact on WEIM transfer flows 83
2.1.5 Impact on WEIM transfer limits 85
2.1.6 Use of transfer limitation throughout the WEIM 89
2.2 Prices in the WEIM 90
2.3 Resource sufficiency evaluation 93
2.4 WEIM imbalance conformance 96

APPENDIX 99

Appendix A | Western energy imbalance market area specific metrics 99

A.1 Arizona Public Service 101
A.2 Avangrid 103
A.3 Avista Utilities 105
A.4 Balancing Authority of Northern California 107
A.5 Bonneville Power Administration...109
A.6 California ISO 111
A.6.1 Pacific Gas and Electric...112
A.6.2 Southern California Edison..113
A.6.3 San Diego Gas & Electric...114
A.7 El Paso Electric...115
A.8 Idaho Power...117
A.9 Los Angeles Department of Water and Power...119
A.10 NV Energy..121
A.11 NorthWestern Energy 123
A.12 PacifiCorp East 125
A.13 PacifiCorp West 127
A.14 Portland General Electric 129
A.15 Powerex...131
A.16 Public Service Company of New Mexico...133
A.17 Puget Sound Energy 135
A.18 Salt River Project...137
A.19 Seattle City Light...139
A.20 Tacoma Power 141
A.21 Tucson Electric Power 143
A.22 Turlock Irrigation District 145
A.23 Western Area Power Administration Desert Southwest...147

Appendix B | Internal constraint congestion impact on WEIM...149

LIST OF FIGURES

Figure 1.1 Monthly average natural gas prices ... 12
Figure 1.2 Average monthly renewable generation ... 14
Figure 1.3 Average hourly generation by fuel type (Q4 2023) ... 15
Figure 1.4 Change in average hourly generation by fuel type (Q4 2022 to Q4 2023) ... 16
Figure 1.5 Monthly average hydroelectric generation by year ... 16
Figure 1.6 Quarterly average of maximum daily generation outages by type – peak hours ... 17
Figure 1.7 Monthly average of maximum daily generation outages by type – peak hours ... 18
Figure 1.8 Quarterly average of maximum daily generation outages by fuel type – peak hours ... 19
Figure 1.9 Monthly load-weighted average energy prices for California ISO (all hours) ... 20
Figure 1.10 Monthly average SoCal City gas price and load-weighted average electricity prices for California ISO ... 21
Figure 1.11 Hourly load-weighted average energy prices (October-December) ... 22
Figure 1.12 Day-ahead California ISO and bilateral market prices (October-December) ... 23
Figure 1.13 Monthly average day-ahead and bilateral market prices ... 24
Figure 1.14 Average hourly net interchange by quarter ... 25
Figure 1.15 Average hourly resource adequacy imports by price bin ... 26
Figure 1.16 Frequency of high prices ($/MWh) by month ... 27
Figure 1.17 Frequency of negative prices ($/MWh) by month ... 28
Figure 1.18 Convergence bidding revenues and bid cost recovery charges ... 29
Figure 1.19 Average residual unit commitment adjustment by day (2022 versus 2023) ... 31
Figure 1.20 Determinants of residual unit commitment procurement ... 32
Figure 1.21 Hourly distribution of residual unit commitment operator adjustments (October–December 2023) ... 33
Figure 1.22 Residual unit commitment costs and volume ... 34
Figure 1.23 Average monthly day-ahead ancillary service requirements ... 35
Figure 1.24 Ancillary service cost by product ... 36
Figure 1.25 Day-ahead congestion rent and loss surplus by quarter (2022-2023) ... 38
Figure 1.26 Overall impact of congestion on price separation in the day-ahead market ... 39
Figure 1.27 Percent of hours with congestion impacting day-ahead prices by load area (>$0.05/MWh) ... 40
Figure 1.28 Day-ahead import congestion charges on major interties ... 45
Figure 1.29 Frequency of import congestion on major interties in the day-ahead market ... 46
Figure 1.30 Auction revenues and payments to non-load serving entities ... 47
Figure 1.31 Real-time imbalance offset costs ... 49
Figure 1.32 15-minute market aggregate load schedules (January 31, 2023 to February 2, 2023) ... 51
Figure 1.33 Impact of incorrect aggregate load schedules on hourly real-time price (February 1, 2023 to December 31, 2023) ... 52
Figure 1.34 Impact on incorrect aggregate load schedules on net charge to load (February 1, 2023 to December 31, 2023) ... 53
Figure 1.35 Estimated impact of incorrect aggregate load schedules by month ... 54
Figure 1.36 WEIM daily congestion offsets (January–December 2023) ... 55
Figure 1.37 WEIM daily 5-minute market component of congestion offset calculation (Issue period, June 26 to December 11, 2023) ... 56
Figure 1.38 Monthly bid cost recovery payments ... 57
Figure 1.39 Average hourly imbalance conformance adjustment (Q4 2022 and Q4 2023) ... 58
Figure 1.40 15-minute market hourly distribution of operator load adjustments (Q4 2023) ... 59
Figure 1.41 Frequency of non-zero system or pass-group flexible ramping product shadow price ... 61
Figure 1.42 Percent of upward system or pass-group flexible ramp procurement by fuel type ... 62
Figure 1.43 Percent of downward system or pass-group flexible ramp procurement by fuel type ... 63
Figure 1.44 Percent of upward system or pass-group flexible ramp procurement by region ... 63
Figure 1.45 Percent of downward system or pass-group flexible ramp procurement by region ... 64
Figure 1.46 Impact of pass-group inconsistency on uncertainty requirements (October–December 2023) ... 66
Figure 1.47 15-minute market pass-group uncertainty requirements (weekdays, October–December 2023) ... 68
Figure 1.48 5-minute market pass-group uncertainty requirements (weekdays, October–December 2023) ... 68
Figure 1.49 Average hourly energy from exceptional dispatch ... 71
Figure 1.50 Average minimum load energy from exceptional dispatch unit commitments ... 72
Figure 1.51 Out-of-sequence exceptional dispatch energy by reason ... 73
Figure 1.52 Excess exceptional dispatch cost by type ... 74
Figure 2.1 ISO area load conformance adjustments (July 24–27) ... 76
Figure 2.2 Dynamic WEIM imports into ISO area (evening hours, July 24–July 27) ... 77
Figure 2.3 Average hour-ahead CAISO balancing area supply and demand with and without WEIM import limitations (hours 16 to 20) ... 78
Figure 2.4 CAISO area hour-ahead supply and demand (Peak hours, November 15-16, 2023) ... 79
Figure 2.5 Average 15-minute market prices during WEIM import limitation (November 1 to November 15, hours 16 to 20) ... 81
Figure 2.6 Average 15-minute market prices without WEIM import limitation (November 16 to November 30, hours 16 to 20) ... 81
Figure 2.7 Average 5-minute market prices during WEIM import limitation (November 1 to November 15, hours 16 to 20) ... 82
Figure 2.8 Average hour-ahead WEIM exports during WEIM import limitation (November 1 to November 15, hours 16 to 20) ... 84
Figure 2.9 Average hour-ahead WEIM transfers without WEIM import limitation (November 16 to November 30, hours 16 to 20) ... 85
Figure 2.10 Frequency of upward capacity test failures by month and area (percent of intervals) ... 94
Figure 2.11 Frequency of upward flexibility test failures by month and area (percent of intervals) ... 95
Figure 2.12 Frequency of downward capacity test failures by month and area (percent of intervals) ... 95

Figure 2.13 Frequency of downward flexibility test failures by month and area (percent of intervals) 96

LIST OF TABLES

Table 1.1 Convergence bidding volumes and revenues by participant type 30
Table 1.2 Impact of congestion on overall day-ahead prices – top 25 primary congestion constraints 41
Table 1.3 Impact of internal transmission constraint congestion on 15-minute market prices – top 25 primary congestion constraints ... 43
Table 1.4 Impact of internal transmission constraint congestion on 5-minute market prices– top 25 primary congestion constraints 44
Table 1.5 Summary of import congestion in the day-ahead market (2022-2023) 46
Table 1.6 Estimated impact of incorrect aggregate load schedules on net charge to load (February 1, 2023 to December 31, 2023) 54
Table 1.7 Source of pass-group for calculating uncertainty and procuring flexible ramping capacity 65
Table 1.8 Average pass-group uncertainty requirements (October- December 2023) 69
Table 1.9 Actual net load error compared to mosaic regression pass-group uncertainty requirements (October-December 2023) 69
Table 1.10 Actual net load error compared to histogram regression pass-group uncertainty requirements (October–December 2023) 70
Table 2.1 Frequency and impact of transfer congestion in the WEIM (October–November) 83
Table 2.2 Average 15-minute market WEIM limits — excluding transfer lock periods (October–December, 2023) 86
Table 2.3 Average 15-minute market WEIM limits — during transfer lock periods (October–December, 2023) 87
Table 2.4 Average 5-minute market WEIM limits (October–December, 2023) 88
Table 2.5 Summary of dynamic WEIM transfer limitation to zero in at least one direction (2023) 90
Table 2.6 Summary of dynamic WEIM transfer limitation to zero in at least one direction (2023) 90
Table 2.7 Monthly 15-minute market prices 91
Table 2.8 Monthly 5-minute market prices 92
Table 2.9 Hourly 15-minute market prices (October–December) 92
Table 2.10 Hourly 5-minute market prices (October–December) 93
Table 2.11 Average frequency and size of imbalance conformance (October–December) 98
Table B.12 California — Impact of internal constraint congestion on 15-minute market prices (October–December 2023) 150
Table B.13 Desert Southwest — Impact of internal constraint congestion on 15-minute market prices (October–December 2023) 151
Table B.14 Intermountain West — Impact of internal constraint congestion on 15-minute market prices (October–December 2023) 152
Table B.15 Pacific Northwest — Impact of internal constraint congestion on 15-minute market prices (October–December 2023) 153

Executive summary

This report covers market performance during the fourth quarter of 2023 (October–December). Key highlights during this quarter include the following:

- **Prices decreased substantially compared to the same quarter of 2022** (Figure E.1). Day-ahead and real-time market prices decreased by about 60 percent, driven by lower natural gas prices and higher hydroelectric power.
- **Natural gas prices were significantly lower.** Average gas prices at Henry Hub, the national index, decreased over 50 percent from the same quarter of 2022, while prices at both California hubs decreased more than 60 percent (Figure E.2). This was the major driver of lower system marginal energy prices across the market.
- **Hydroelectric generation in the California ISO area increased 60 percent compared to Q4 2022.** Generation from batteries and solar increased by 47 percent and 15 percent, respectively. This increase in clean energy lowered reliance on net imports, which dropped 11 percent.
- **Average net imports decreased across all hours** compared to the fourth quarter of 2022. Average net interchange was in the export direction in hours-ending 10 through 16, driven by high solar output and large transfers out of the California area to the rest of the Western energy imbalance market (WEIM). Average net exports including WEIM transfers peaked at nearly 1,500 MW in hour-ending 14. This was almost 1,300 MW more than the largest average net export out of CAISO in Q4 2022.
- **The average total volume of capacity procured through the residual unit commitment (RUC) process was 135 percent higher than the same quarter of 2022.** The majority of this increase was driven by large manual operator adjustments to the RUC procurement target, which increased by about 340 percent compared to the fourth quarter of 2022.
- **The California ISO changed the process for determining manual adjustments to the RUC procurement target.** In summer 2023, the CAISO began using the *mosaic quantile regression* method to calculate the uncertainty component of the RUC load adjustment. Until December 21, the CAISO set this adjustment based on the 97.5th percentile of the regression model estimate of the upward uncertainty in the day-ahead net load forecast. This resulted in a large increase in RUC requirements and costs. On December 21, the CAISO began using the 50th percentile of the regression model estimate of uncertainty. The CAISO's current procedure calls for using the 50th, 75th, or 97.5th percentile of estimated upward uncertainty depending on CAISO's assessment of overall system conditions. Given the importance of RUC adjustments in terms of costs and reliability, DMM recommends that the CAISO balancing area continue working on a method for determining the appropriate level of RUC load adjustment.
- **Congestion rents on internal constraints in the day-ahead market decreased significantly – down to $226 million from $437 million in the fourth quarter of 2022.** The predominantly south-to-north congestion had a larger average impact on price differences between the load areas in the south and north in Q4 2023 despite the large decrease in congestion rent. This was due to the major constraints between the north and south changing direction much less frequently in the fourth quarter of 2023 compared to the fourth quarter of 2022.
- **Payouts to congestion revenue rights sold in the California ISO auction exceeded auction revenues received for these rights by $3 million in the fourth quarter, driving total losses from the auction in 2023 to $58 million.** These losses are borne by transmission ratepayers who pay for the full cost

of the transmission system through the transmission access charge. Changes to the auction implemented in 2019 have reduced, but not eliminated, losses to transmission ratepayers from the auction. DMM continues to recommend further changes to eliminate or further reduce these losses.

- **Real-time imbalance offset costs increased to $76 million,** up from $25 million in the fourth quarter of 2022. Real-time imbalance energy offset costs made up about 18 percent of these offset costs. Much of the energy portion of these costs is caused by load settling on an average real-time price that can differ significantly from the real-time market prices that generating resources are settled on. The main impact of this difference is to shift payments by load serving entities from the price they pay for real-time energy to charges for imbalance offset costs.
- **A systematic error in real-time prices used to settle California ISO load during much of 2023 was identified and the ISO is working to correct settlements.** The error occurred from February 1, 2023 through February 5, 2024. While the pricing errors were large in some intervals, DMM estimates that the issue only shifted about $7.1 million in net costs between load serving entities, including around $0.8 million in load costs to exporters.
- **Congestion rents and uplift from WEIM transfer constraints in the 5-minute market were misallocated between WEIM entities in some intervals** between July 26 and December 11, 2023. The ISO has corrected around $5 million of the incorrect allocation from trade date November 5. If this error had impacted all 5-minute market intervals, the maximum additional congestion rent that may have been impacted is $40 million. However, it is not clear to DMM how many intervals were impacted by the error.
- **Bid cost recovery payments decreased** for units in the California ISO and WEIM balancing areas compared to Q4 2022. In the California ISO, estimated payments totaled about $90 million compared to $92 million in Q4 of the prior year. However, estimated bid cost recovery payments associated with the residual unit commitment market increased by $29 million. In the WEIM balancing areas, estimated payments totaled about $7 million compared to $17 million in Q4 2022.
- **Ancillary service costs totaled $19 million – or $16 million less than Q4 2022.** These costs fell due to replacement of spinning reserves with lower cost non-spinning reserves, and a decrease in regulation down costs of almost $11 million from Q4 of the prior year.
- **Flexible ramping product system level prices were zero for over 99 percent of intervals** in the 15-minute market and in the 5-minute market. Nodal pricing and a new uncertainty calculation for the product were implemented in February 2023. Before implementation, prices were also zero in over 99 percent of intervals. The percentage of upward capacity supplied by resources in California and the Pacific Northwest in Q4 2023 was similar to the fourth quarter of 2022, the final full quarter prior to the implementation of the enhancements.
- **Upward load adjustments in the 15-minute market remained high but decreased compared to Q4 2022.** During the peak adjustment hour, hour-ending 18, the average adjustment fell to 1,650 MW from about 2,050 MW in 2022. The combination of high load adjustments up in the 15-minute market and much lower adjustments in the 5-minute market, contributed to the price difference between these markets.

Figure E.1 Monthly load-weighted average energy prices California ISO (all hours)

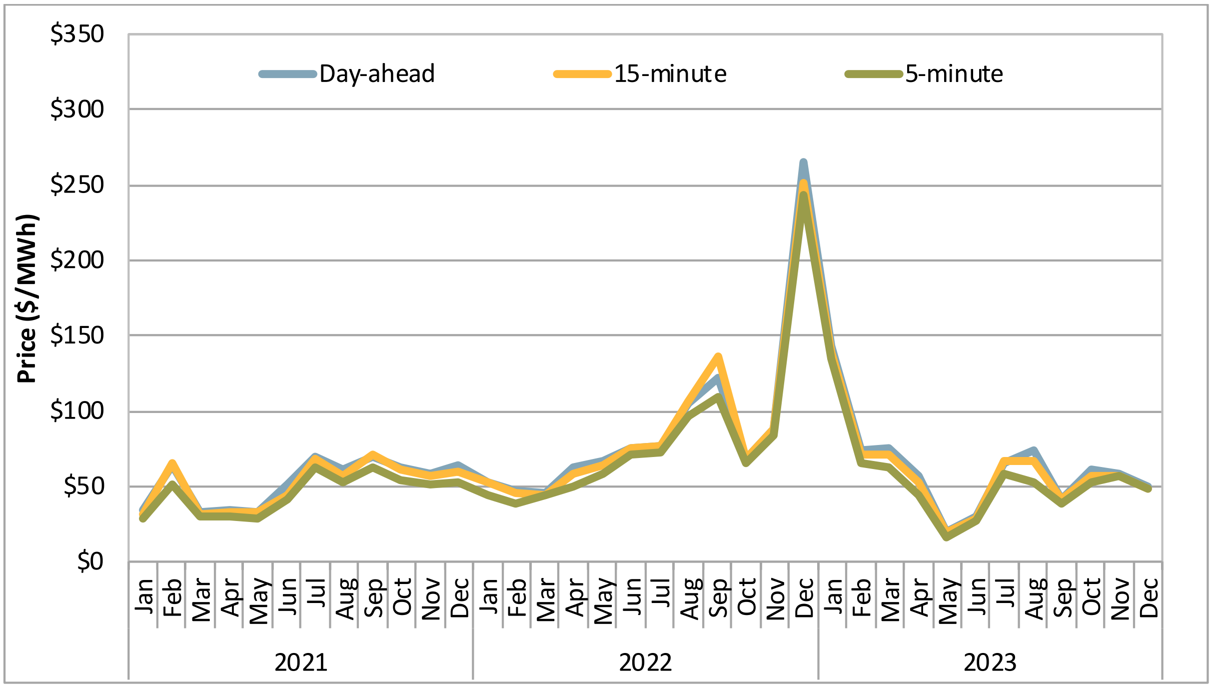
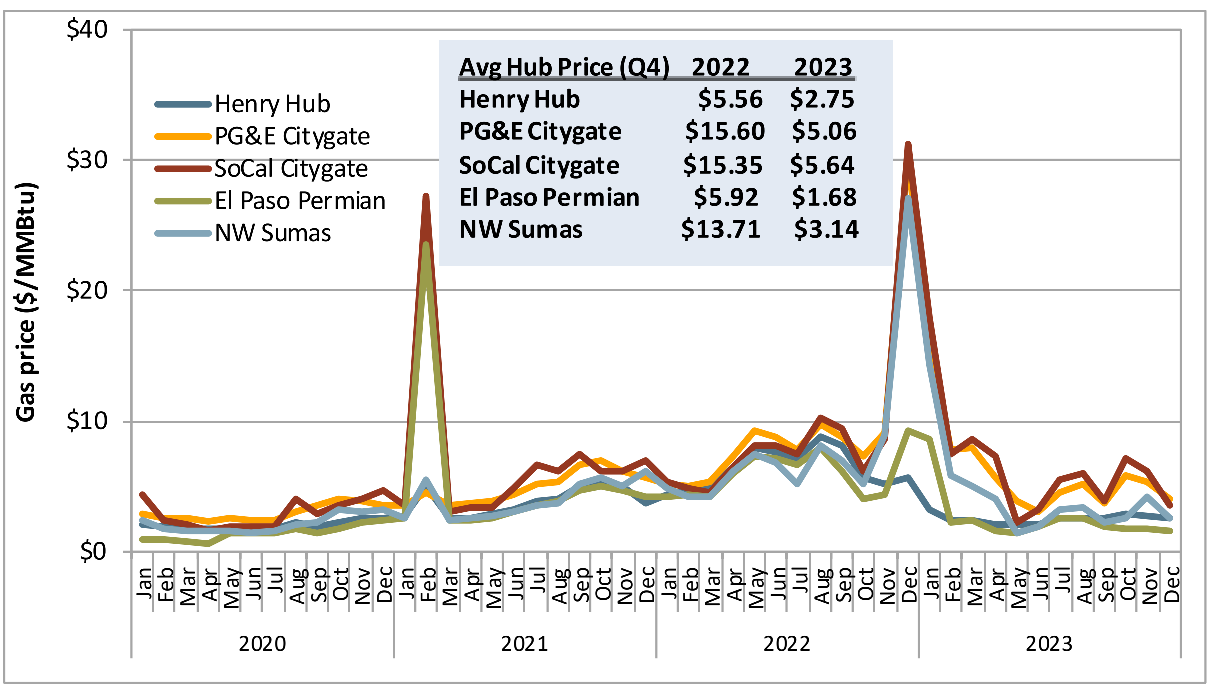


Figure E.2 Average monthly natural gas prices by hub



Western energy imbalance market

- **California ISO balancing area operators restricted most Western energy imbalance market (WEIM) transfers into the CAISO area in the hour-ahead and 15-minute markets during peak net load hours from July 26 through November 15.** CAISO area operators did not limit transfers in the 5-minute market. This created a significant, systematic modeling difference between the 15-minute and 5-minute markets. This modeling difference contributed to greater congestion between CAISO and other WEIM areas in the 15-minute market than in the 5-minute market. This difference in congestion was a major cause of lower prices in the 15-minute market than in the 5-minute market during peak hours in the Desert Southwest WEIM areas. This can cause inefficient resource commitment in the 15-minute market. Transfer capacity out of the Desert Southwest region was dramatically reduced in the 15-minute market due to these CAISO balancing area operator actions.
- **The California ISO explained the transfer limitations were needed in July and August for reliability reasons, but it is not clear why it continued these transfer limitations during the fourth quarter** through November 15.[1] The ISO has explained to DMM that it stopped the transfer limitations after implementing enhancements to system software to better address export self-schedules that declined hour-ahead market curtailments. However, system conditions that may have necessitated curtailing hourly block exports in the hour-ahead market did not arise during October and the first half of November. DMM recommends that CAISO provide greater transparency on when and why it may implement these limitations in the future. DMM also recommends that CAISO work with stakeholders to consider other methods of achieving the intended reliability outcomes without creating the large and systematic modeling differences between the 15-minute and 5-minute markets.
- **Powerex and WAPA Desert Southwest also limited dynamic WEIM transfers to zero in at least one direction during a substantial number of 15-minute market intervals during 2023.** However, Powerex's 549 intervals and WAPA Desert Southwest's 487 intervals were significantly less than the CAISO area's 1,914 intervals. CAISO's average decrease in transfer capacity during each event was over 41,000 MW, while Powerex's and WAPA's average decreases were around 50 MW and 5,200 MW, respectively.
- **Natural gas prices fell significantly across the WEIM** compared to the fourth quarter of 2022, resulting in large decreases in electricity prices across all balancing areas.
- **Prices in the Northwest region, plus Idaho Power and Northwestern, were higher than the rest of the WEIM during October** due to congestion on WEIM transfer constraints into these areas during most hours on average.[2] During the rest of the fourth quarter, prices in the Northwest were frequently higher during mid-day hours, when transfer congestion into the region prevented these areas from importing lower marginal cost system power.
- **Powerex continued to have significantly higher prices than other WEIM areas.** This was due to transfer congestion into the area during most intervals.

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1 For CAISO's explanation of why it used the transfer limitation in the third quarter of 2023, see *Summer Market Performance Report for July 2023,* California ISO, September 18, 2023, pp 132-134: https://www.caiso.com/Documents/Summer-Market-Performance-Report-for-July-2023.pdf

2 The Northwest region includes Portland General Electric, Puget Sound Energy, Seattle City Light, Tacoma Power, PacifiCorp West, Powerex, NorthWestern, Avista Utilities, and Bonneville Power Administration.

- **El Paso Electric had notably lower prices than other WEIM areas** due to transfer congestion out of the area in over a third of 5-minute market intervals.
- **Powerex and the California ISO were major net importers of WEIM transfers.** Powerex averaged over 575 MW across all hours. The California ISO was a significant net importer in the morning and evening hours, importing over 750 MW during hour-ending 22.
- **The major net exporters of WEIM transfers shifted significantly** between the mid-day period, when solar generation is typically at its highest, and the non-mid-day hours.
- **During the peak solar mid-day hours, the California ISO was the major net exporter of WEIM transfers,** exporting an average of over 1,700 MW between hours 10 and 16 to areas in the Northwest, California, and Southwest.
- **During non-mid-day hours, major exporters were Salt River Project, Arizona Public Service, Tucson Electric Power, and PacifiCorp West.**
- **NV Energy and PacifiCorp East were significant net exporters throughout much of the day.**
- **DMM is providing additional metrics, data, and analysis on the resource sufficiency tests in regular reports** as part of the *WEIM resource sufficiency evaluation* stakeholder initiative. These reports include many metrics and analyses not included in this report, such as the impact of several changes proposed or adopted through the stakeholder process.[3]
- **Appendix A includes hourly price and transfer figures for each WEIM area.**

[3] Department of Market Monitoring Reports and Presentations, *WEIM resource sufficiency evaluation reports*: http://www.caiso.com/market/Pages/MarketMonitoring/MarketMonitoringReportsPresentations/Default.aspx

1 Market Performance

This section covers performance of the California ISO balancing area wholesale energy markets and resource adequacy program during the fourth quarter of 2023.

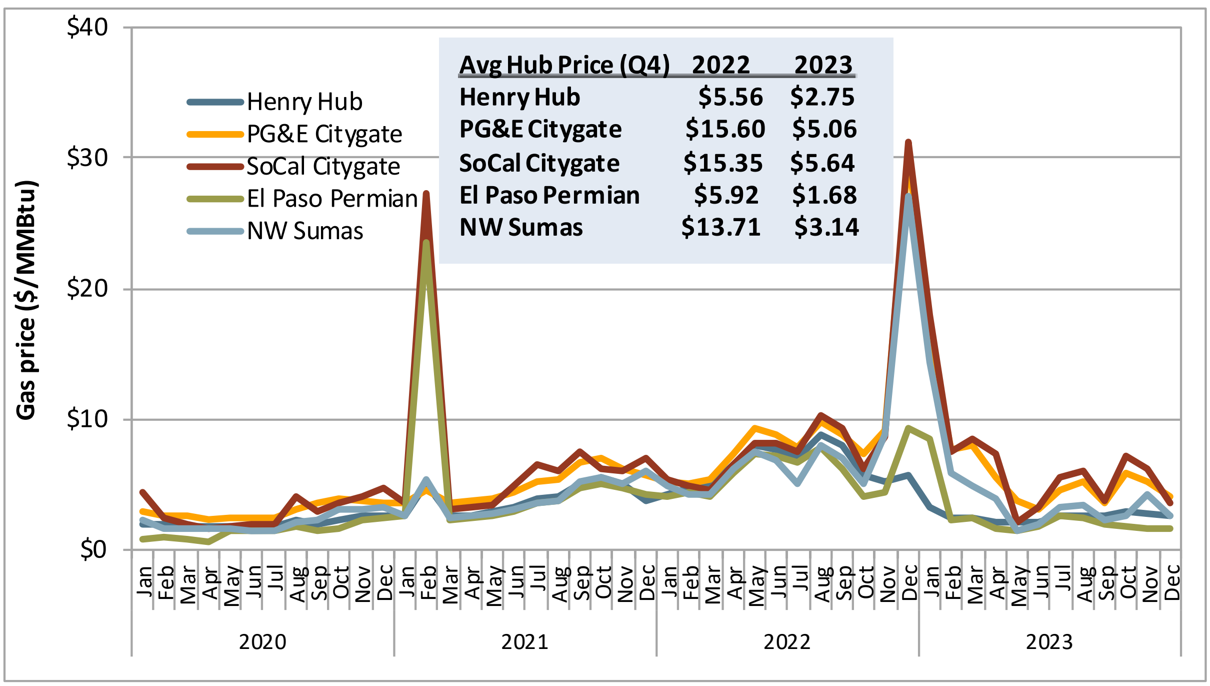
1.1 Supply conditions

1.1.1 Natural gas prices

Electricity prices in Western states typically follow natural gas price trends because gas-fired units are often the marginal source of generation in the California ISO (CAISO) balancing area and other regional markets. Average gas prices at major Western U.S. gas trading hubs rose above September 2023 prices in October and November before decreasing in December. However, gas prices in the fourth quarter were down significantly compared to the same quarter of 2022.

Figure 1.1 shows monthly average natural gas prices at key delivery points across the West, as well as the Henry Hub trading point, which acts as a point of reference for the national market for natural gas.

Figure 1.1 Monthly average natural gas prices



Average fourth quarter prices at the two main delivery points in California (PG&E Citygate and SoCal Citygate) increased by 13 percent and 10 percent compared to the previous quarter, respectively. The Northwest Sumas and the Henry Hub gas hub prices increased by six percent during the same time period. Prices at El Paso Permian decreased by 28 percent compared to the previous quarter. However, all delivery point prices decreased substantially when compared to the fourth quarter of 2022; Northwest Sumas (-77 percent), Permian (-72 percent), PG&E Citygate (-68 percent), SoCal Citygate (-63 percent), and Henry Hub (-51 percent).

On August 31, the CPUC issued an order increasing the inventory limit for the Aliso Canyon storage facility from 41.16 Bcf to 68.6 Bcf, which builds on the storage level set in 2021 of about 34 Bcf.[4] This action contributed to increasing SoCalGas total authorized storage inventory capacity to 119.5 Bcf.[5] SoCalGas fourth quarter 2023 storage inventory steadily increased from about 91 Bcf on October 1, 2023 to about 106 Bcf on December 31, 2023. This is in contrast to the fourth quarter 2022 storage levels, which fell from around 88 Bcf in October 2022 to about 62 Bcf by December 31, 2022.[6]

1.1.2 Renewable generation

In the fourth quarter, the average hourly generation from renewable resources increased by about 1,000 MW (13.5 percent) compared to the same quarter of 2022.[7] The availability of variable energy resources contributes to price patterns, both seasonally and hourly, due to their low marginal cost relative to other resources.

Figure 1.2 shows the average monthly renewable generation by fuel type.[8] Generation from hydroelectric and solar resources increased 60 percent and 15 percent, respectively, compared to the fourth quarter of 2022. Generation from wind, geothermal, and biogas-biomass resources decreased 10 percent, three percent, and six percent, respectively.

4 CPUC Proposed Decision to Protect Against Natural Gas Price Spikes in Southern California (I.17-02-002): https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/natural-gas/aliso-canyon/ac-storage-level-pd-0722823.pdf

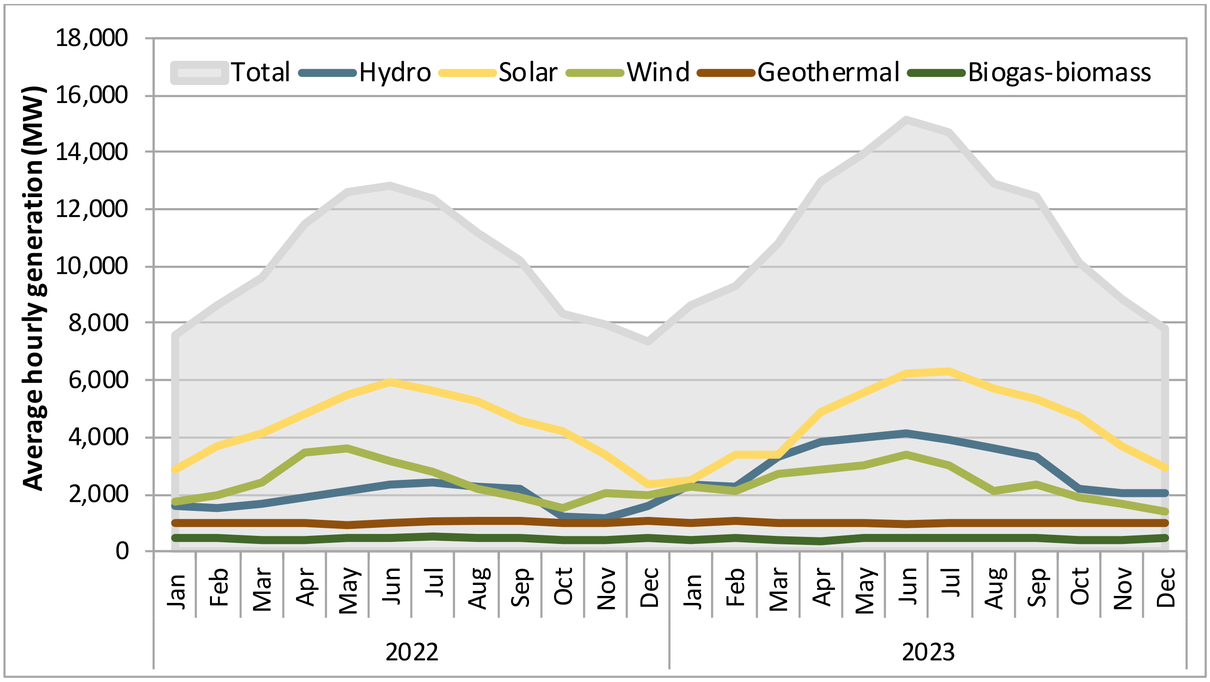
5 SoCalGas owns and operates four underground storage facilities: Aliso, Honor Rancho, La Goleta, and Playa Del Rey: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M328/K289/328289863.PDF

6 SoCalGas ENVOY Storage Inventory (Bcf): https://www.socalgasenvoy.com/index.jsp#nav=/Public/ViewExternal.showHome

7 Figures and data provided in this section are preliminary and may be subject to change.

8 Hydroelectric generation greater than 30 MW is included.

Figure 1.2 Average monthly renewable generation



1.1.3 Generation by fuel type

Hydroelectric and battery generation increased relative to the fourth quarter of 2022 by 60 percent and 47 percent, respectively. Average hourly generation by natural gas resources was unchanged, overall. Net imports into the CAISO balancing area decreased by 11 percent overall from the fourth quarter of 2022.[9]

Figure 1.3 shows the average hourly generation by fuel type during the fourth quarter of 2023, as measured by preliminary meter data. Total hourly average generation from California ISO resources peaked at about 27,500 MW during hour-ending 18. Battery generation also peaked during hour-ending 18 at about 2,800 MW. Non-hydroelectric renewable generation, including geothermal, biogas-biomass, wind, and solar resources, contributed to 16 percent of total generation during the peak net load hours,[10] up from 14 percent during the same time last year.

Figure 1.3 also shows the significant load from batteries charging, represented by points below the zero-axis, in midday hours.[11] On average, batteries charged the most during hour-ending 12 in the fourth quarter of 2023, at around 2,900 MW.

9 Figures and data provided in this section are preliminary and may be subject to change as final meter data is submitted.

10 Hours-ending 17 through 21.

11 Negative generation from hybrids and pumped-storage hydroelectric units were negligible, and were excluded from the figure.

Figure 1.3 Average hourly generation by fuel type (Q4 2023)

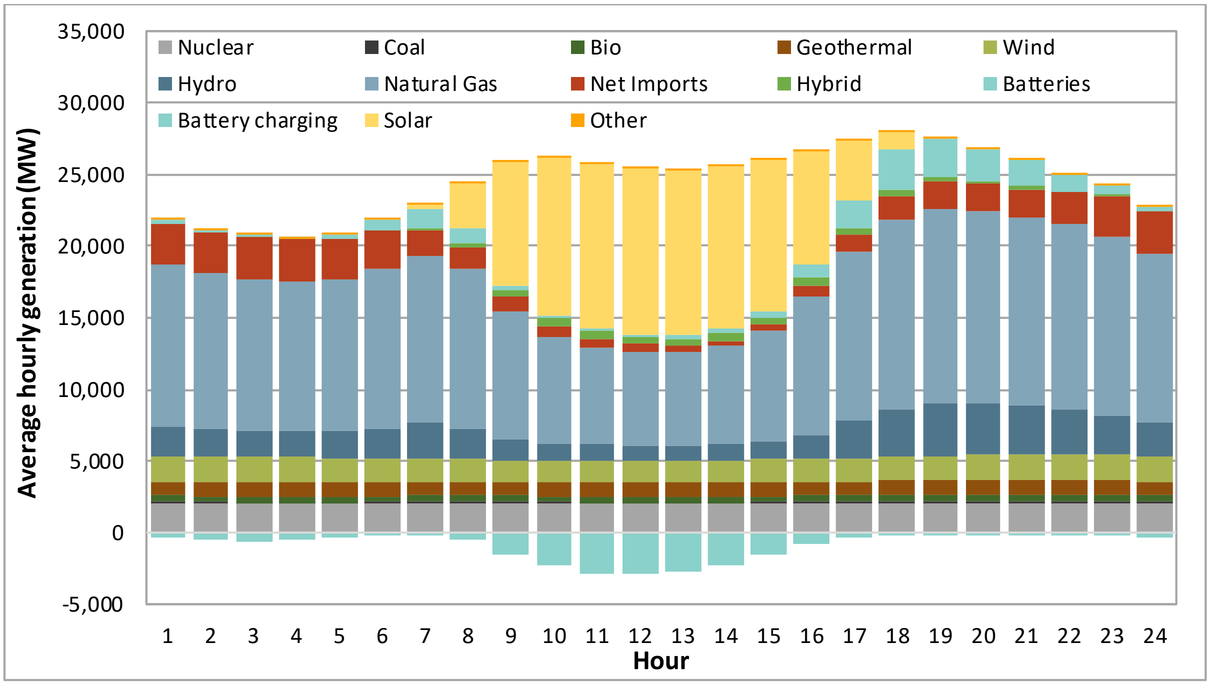


Figure 1.4 shows the change in hourly upward generation by fuel type between the fourth quarter of 2022 and fourth quarter of 2023.[12] In the chart, positive values represent increased generation relative to the same time last year and negative values represent a decrease in generation.

The net change shows that there was an increase in average hourly generation in most hours compared to the fourth quarter of 2022. Average battery generation increased in both the morning, from hours 6 to 8, and in the evening. Increasingly, batteries have been participating in energy arbitrage, and have been discharging during the high net load periods in both the morning and evening.

Figure 1.5 shows the monthly average hydroelectric generation from 2019 to 2023. Hydroelectric generation in the fourth quarter of 2023 was higher than the last three years and tracked most similarly to 2019.

12 Hybrid generation was included in the "Other" category in Q4 2022 but is identified as "Hybrid" in Q4 2023. Therefore, reductions in "Other" generation are offset by the additional "Hybrid" generation.

Figure 1.4 Change in average hourly generation by fuel type (Q4 2022 to Q4 2023)

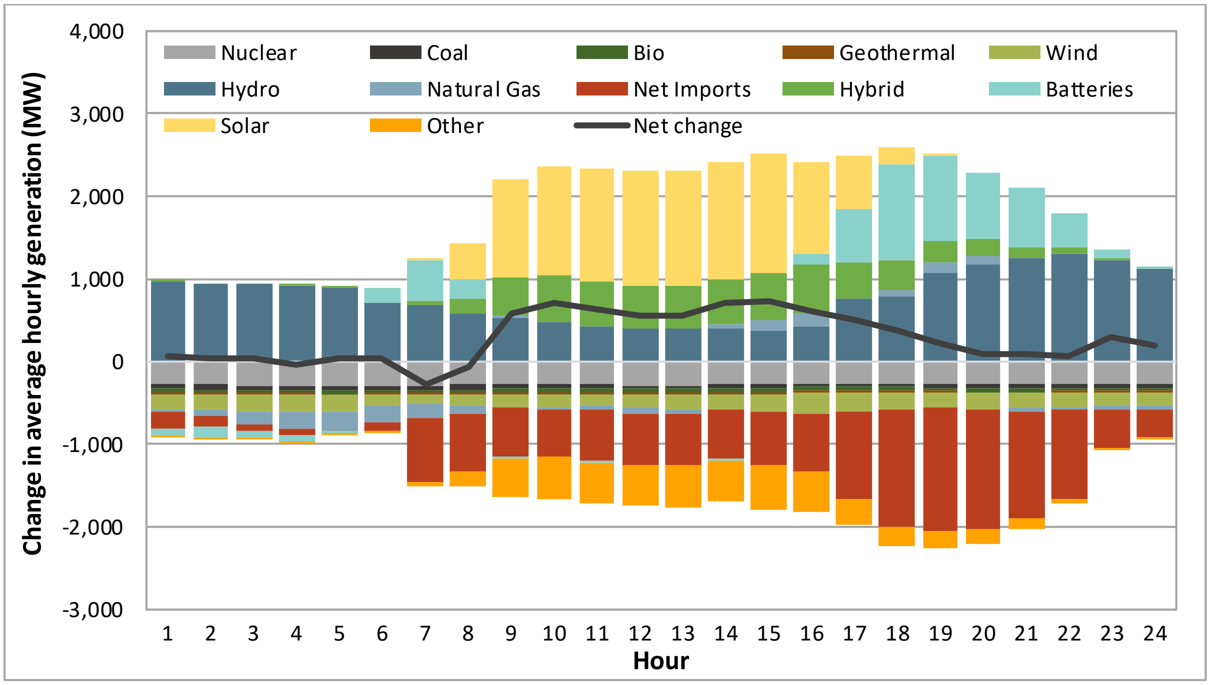
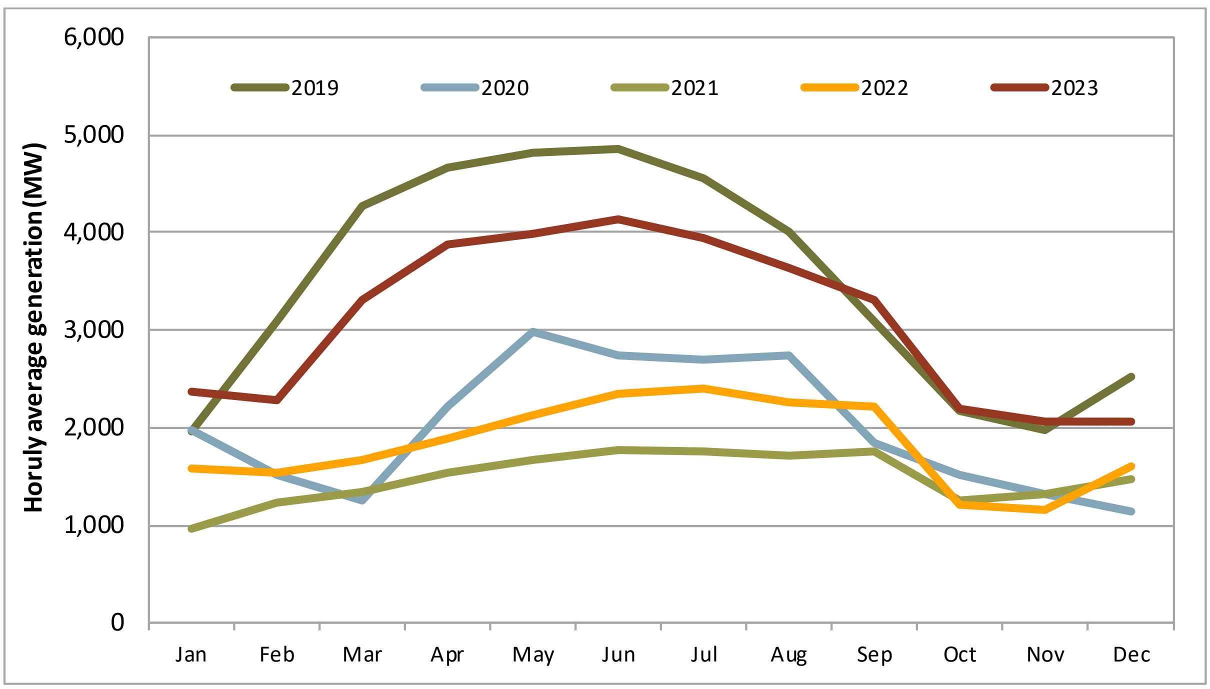


Figure 1.5 Monthly average hydroelectric generation by year



1.1.4 Generation outages

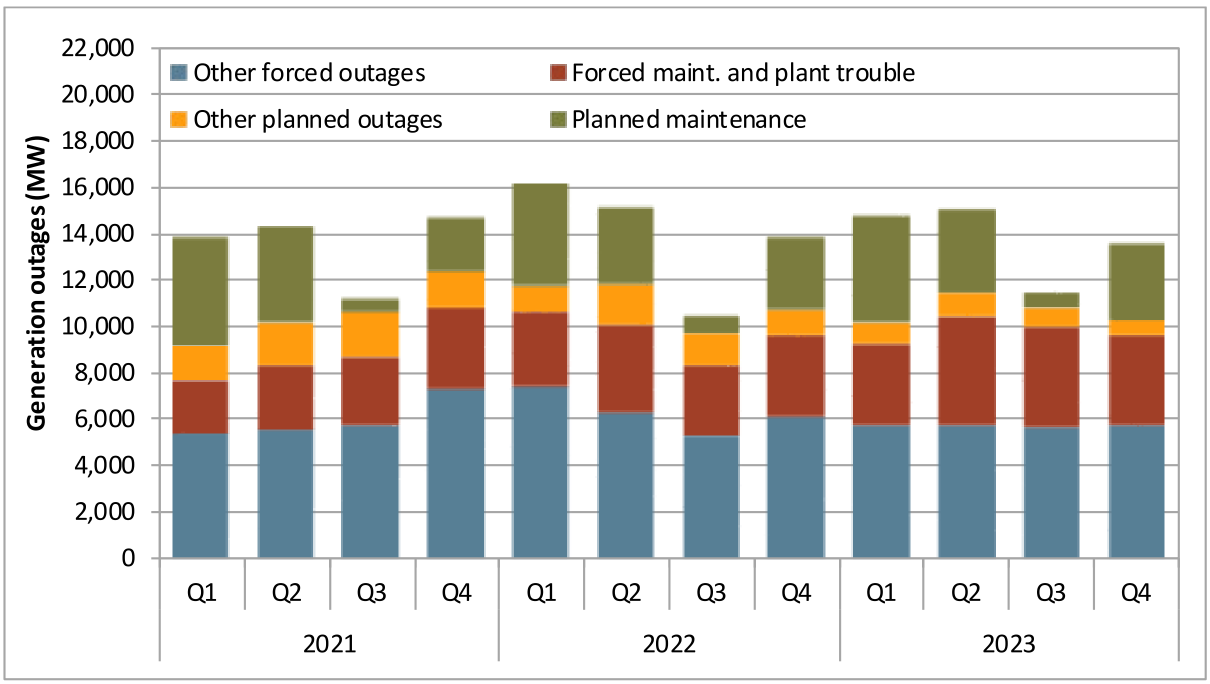
Total generation on outage in the California ISO balancing area averaged about 13,570 MW. This was a decrease of two percent from the fourth quarter of 2022. This decrease was driven by planned outages, which decreased by almost seven percent relative to the same time last year.

Under the current California ISO outage management system, known as WebOMS, all outages are categorized as either “planned” or “forced”. An outage is considered *planned* if a participant submitted it more than 7 days prior to the beginning of the outage. WebOMS has a menu of subcategories indicating the reason for the outage. Examples of such categories include plant maintenance, plant trouble, ambient due to temperature, ambient not due to temperature, unit testing, environmental restrictions, transmission induced, transitional limitations, and unit cycling.

Figure 1.6 and Figure 1.7 show the quarterly and monthly averages of maximum daily outages during peak hours by type from 2021 to 2023, respectively.[13] The typical seasonal outage pattern is primarily driven by planned outages for maintenance, which are generally performed outside of the high summer load period. Looking at the monthly outages, there are usually a higher number of outages in the fall and winter than the summer months. This trend continued in 2023 with planned maintenance outages increasing over the fourth quarter from the third quarter by over 450 percent.

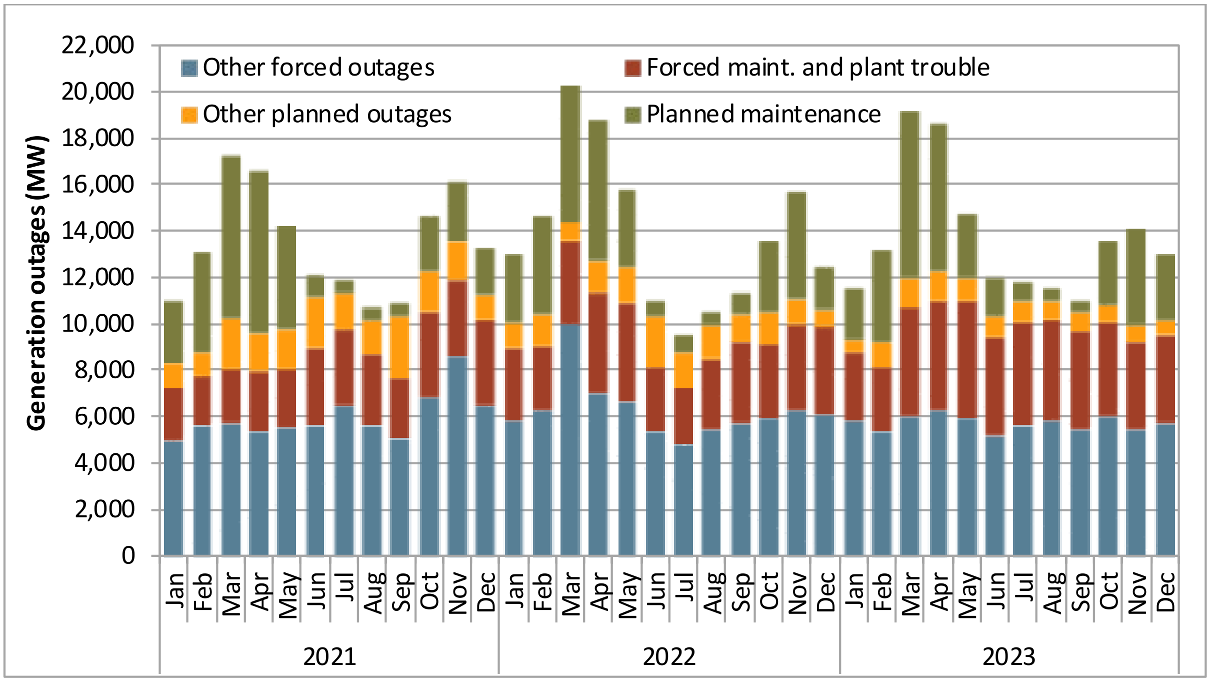
During the fourth quarter of 2023, the average total generation on outage in the California ISO balancing area was 13,570 MW, about 314 MW less than the fourth quarter of 2022, as shown in Figure 1.6. Forced outages were similar to the same quarter last year, while planned outages decreased by seven percent.

Figure 1.6 Quarterly average of maximum daily generation outages by type – peak hours



13 This is calculated as the average of the daily maximum level of outages, excluding off-peak hours. Values reported here only reflect generators in the California ISO balancing area and do not include outages in the Western energy imbalance market.

Figure 1.7 Monthly average of maximum daily generation outages by type – peak hours



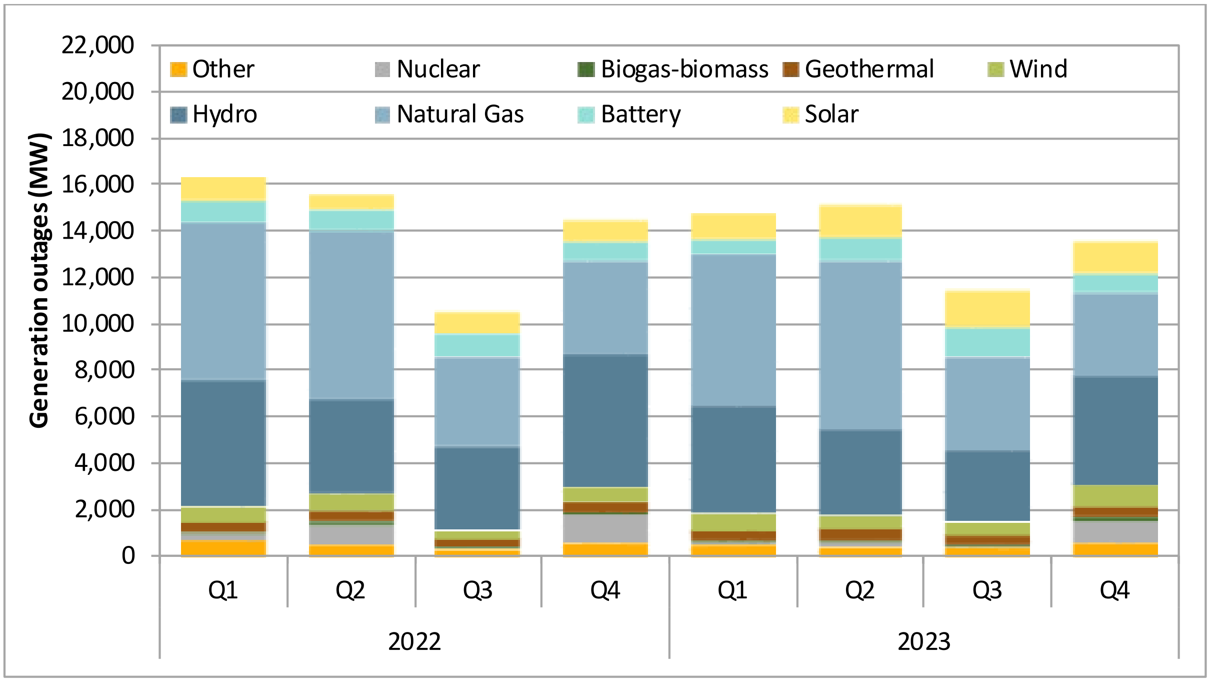
Generation outages by fuel type

Natural gas and hydroelectric generation on outage averaged about 3,589 MW and 4,656 MW during the fourth quarter, respectively. These two fuel types accounted for a combined 61 percent of the generation on outage for the quarter. The amount of hydroelectric generation on outage decreased 18 percent relative to the fourth quarter of 2022.

Figure 1.8 shows the quarterly average of maximum daily generation outages by fuel type during peak hours.[14] Hydro, natural gas, and nuclear outages decreased compared to the fourth quarter of 2022, while outages for all other resource types increased.

14 In this figure, the "Other" category contains demand response, coal, and additional resources of unique technologies.

Figure 1.8 Quarterly average of maximum daily generation outages by fuel type – peak hours



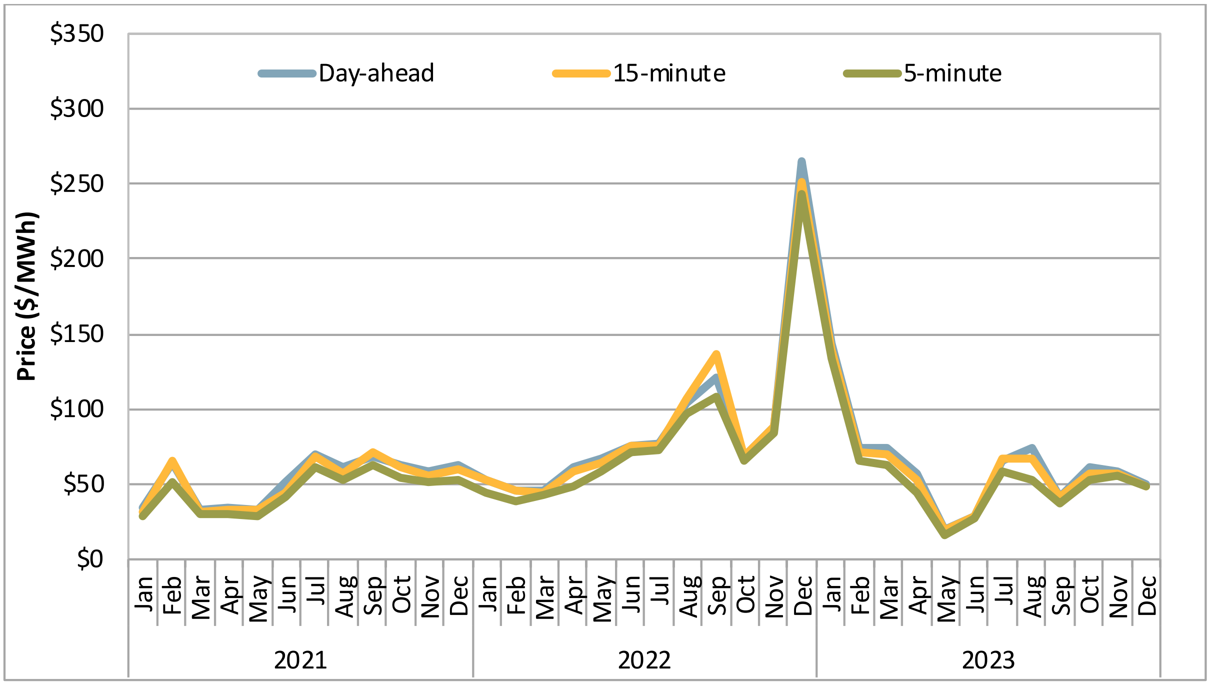
1.2 Energy market performance

1.2.1 Energy market prices

This section assesses energy market efficiency based on an analysis of day-ahead and real-time market prices. In 2023, the fourth quarter prices in the day-ahead, 15-minute, and 5-minute markets dropped by about 60 percent compared to the fourth quarter of the previous year. The average price of the three markets this quarter decreased to $55/MWh from $136/MWh in the same quarter of 2022.

Figure 1.9 shows load-weighted average monthly energy prices during all hours across the four largest aggregation points in the California ISO balancing area (Pacific Gas and Electric, Southern California Edison, San Diego Gas & Electric, and Valley Electric Association). Average prices are shown for the day-ahead (blue line), 15-minute (gold line), and 5-minute (green line) from January 2021 to December 2023.

Figure 1.9 Monthly load-weighted average energy prices for California ISO (all hours)



Over the quarter, day-ahead prices averaged $57/MWh, 15-minute prices averaged $55/MWh, and 5-minute prices averaged $53/MWh. Prices across all three markets were about 60 percent less than those in the fourth quarter of the prior year. December had the lowest prices, with an average over the three markets of about $50/MWh.

Low gas prices contributed to the low prices observed this quarter. Figure 1.10 shows monthly average gas prices at SoCal Citygate and load-weighted energy prices from January 2022 to December 2023. The chart shows that the monthly variation of the energy prices is highly correlated with gas prices. The black dashed line shows the monthly average gas price at SoCal Citygate. The colored lines illustrate energy prices. Over the past 24 months, both gas and energy prices exhibited similar fluctuations. The SoCal City gas price has remained down after declining from its peak in December 2022, averaging about $5.60/MMBtu during the fourth quarter of 2023.

This strong correlation between energy and gas prices can be attributed to gas-fired units often serving as the price-setting units within the market. A high gas price increases the marginal cost of generation for gas-fired units and non-gas-fired resources with opportunity costs indexed to gas prices. Market bids reflect these higher marginal costs.

Figure 1.10 Monthly average SoCal City gas price and load-weighted average electricity prices for California ISO

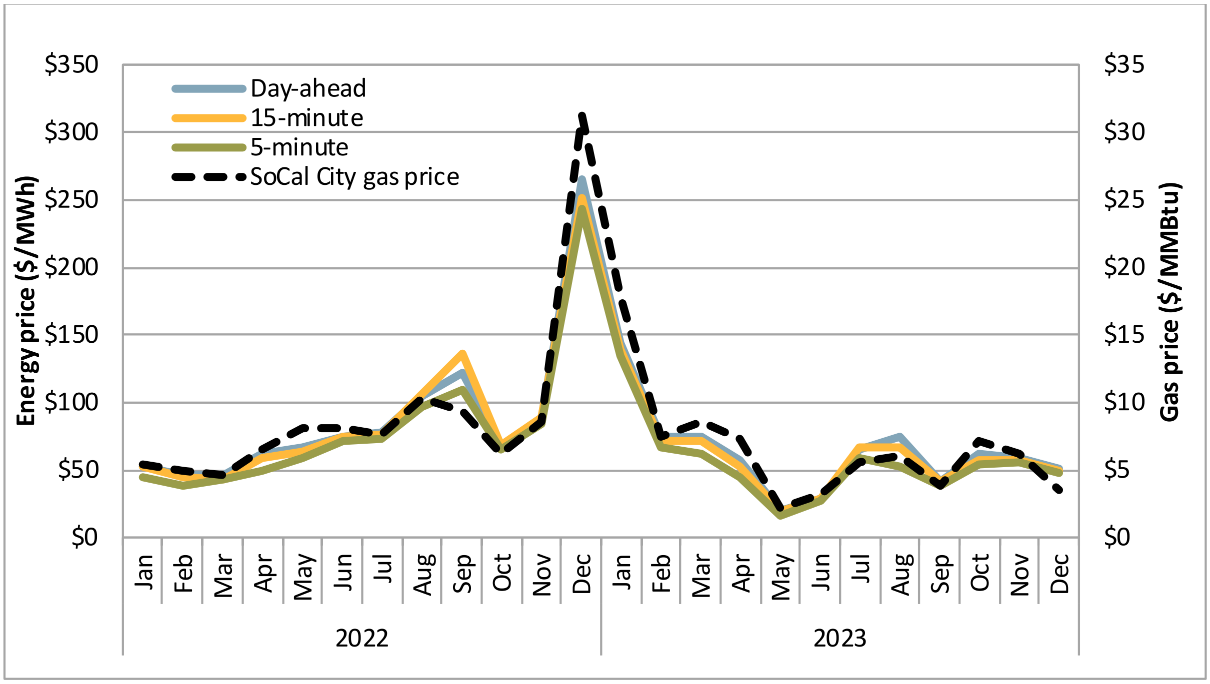


Figure 1.11 illustrates the hourly load-weighted average energy prices for the fourth quarter compared to the average hourly net load.[15] Average hourly prices shown for the day-ahead (blue line), 15-minute (gold line), and 5-minute (green line) are measured by the left axis, while the average hourly net load (red dashed line) is measured by the right axis.

Average hourly prices continue to follow the net load pattern, with the highest energy prices during the morning and evening peak net load hours. Energy prices and net load both increased sharply during the early evening, and peaked at hour-ending 19, when demand was still high but solar generation was substantially below its peak. The average net load in this quarter reached 24,921 MW at hour-ending 19.

During hour-ending 19, the day-ahead load-weighted average energy price was $117/MWh, the 15-minute price was $118/MWh, and the 5-minute price was $78/MWh. The 5-minute price consistently fell below the day-ahead and 15-minute market prices between hours-ending 16 and 21. This price gap was significant, with the average 5-minute price being $18/MWh lower than those of the other two markets. Day-ahead and 15-minute market prices typically tend to converge on average due to convergence (virtual) bidding.

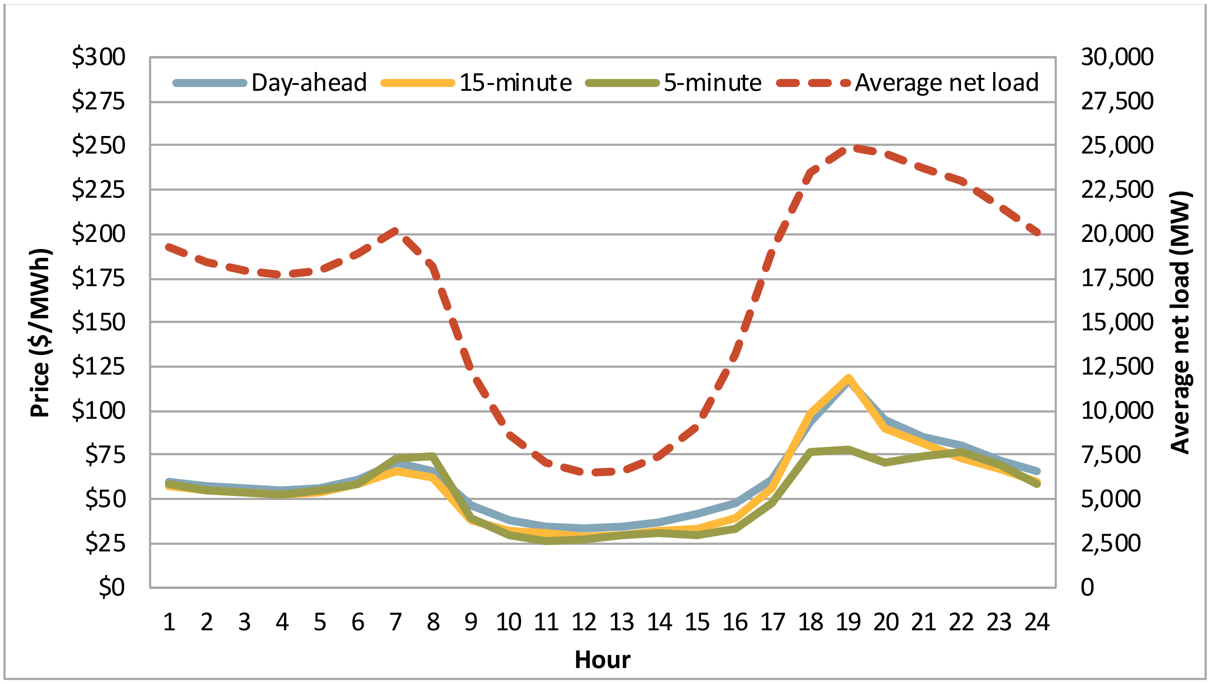
One major cause of the observed price separation between the 15-minute and 5-minute markets this quarter was load conformance. California ISO operators typically adjust the load forecast up significantly more in the 15-minute market than in the 5-minute market over the peak net load hours.[16] Another significant cause of the price separation this quarter was CAISO area operators limiting WEIM transfers

[15] Net load is calculated by subtracting the generation produced by wind and solar that is directly connected to the California ISO grid from actual load.

[16] Please see Section 1.11 for a detailed discussion on load conformance.

into the CAISO area in the 15-minute market but not in the 5-minute market during peak net load hours, starting on July 26 and lasting through November 15. This is described in detail in Section 2 of the Q3 2023 Report on Market Issues and Performance.[17]

Figure 1.11 Hourly load-weighted average energy prices (October-December)



1.2.2 Bilateral price comparison

Figure 1.12 shows the California ISO day-ahead load weighted average peak prices across the three largest load aggregation points (Pacific Gas and Electric, Southern California Edison, and San Diego Gas & Electric), as well as the average day-ahead peak energy prices from the Intercontinental Exchange (ICE) at the Mid-Columbia and Palo Verde hubs outside of the California ISO market. These prices were calculated during peak hours (hours-ending 7 through 22) for all days, excluding Sundays and holidays. The figure shows prices at the Mid-Columbia hub spiked significantly from October 24 through November 1.

The California ISO FERC Order 831 policy will increase the California ISO energy bid cap to $2,000/MWh if a 16-hour block peak bilateral price, scaled and shaped into hourly prices according to the shape of California ISO hourly prices, exceeds $1,000/MWh. Despite the high prices at Mid-Columbia in late October, there were no days in the fourth quarter of 2023 when the California ISO raised the energy bid cap above $1,000/MWh. Regional differences in prices reflect transmission constraints and greenhouse gas compliance costs.

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[17] Department of Market Monitoring, *Q3 2023 Report on Market Issues and Performance Report*, February 2024: https://www.caiso.com/Documents/2023-Third-Quarter-Report-on-Market-Issues-and-Performance-Feb-21-2024.pdf

Figure 1.12 Day-ahead California ISO and bilateral market prices (October-December)

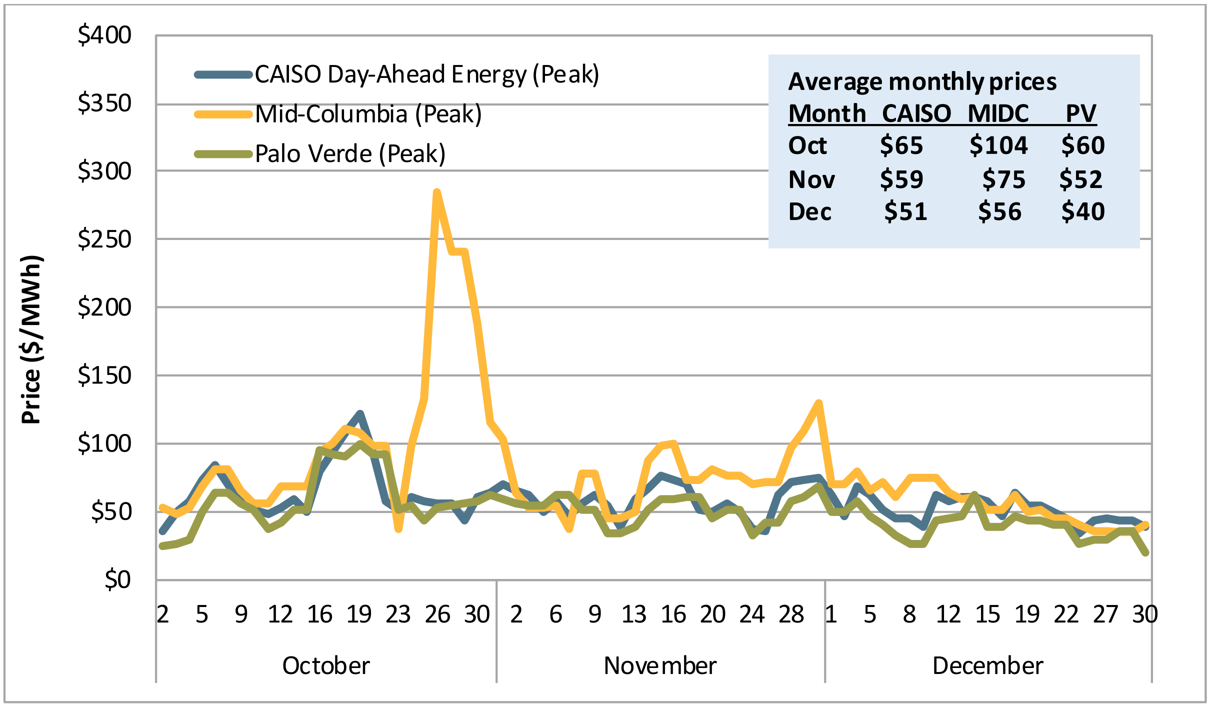
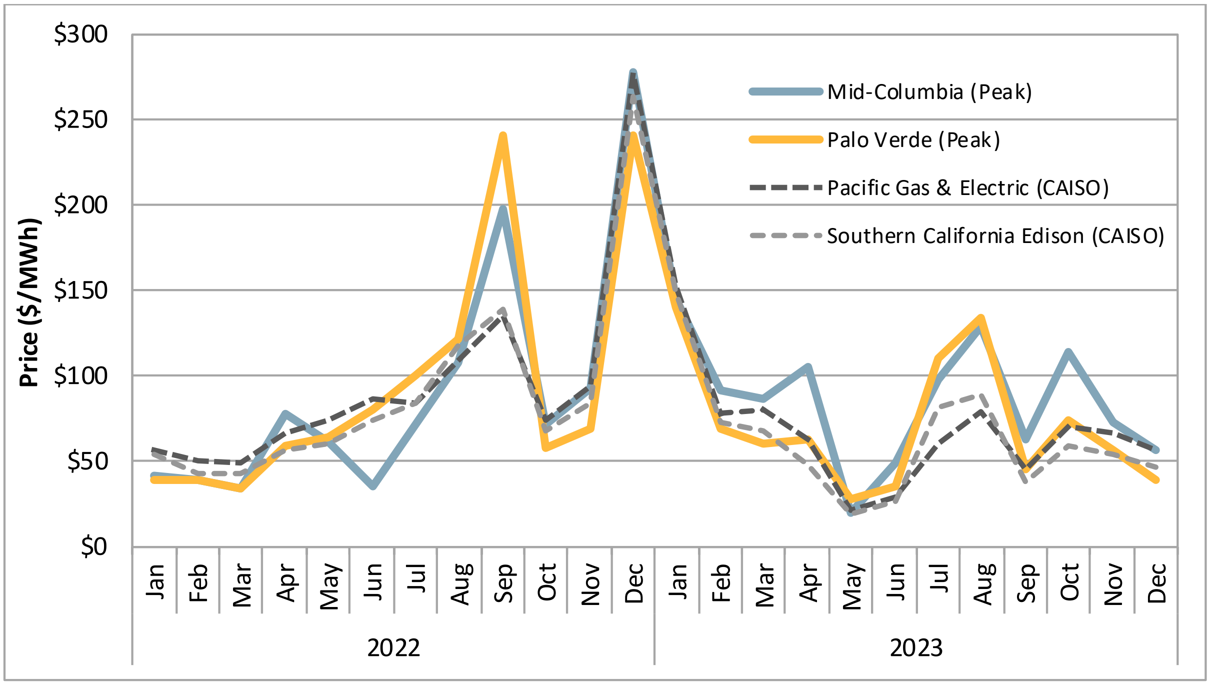


Figure 1.12 compares monthly average bilateral and California ISO day-ahead market prices for 2022 and 2023. Prices in the California ISO balancing area are represented at the Southern California Edison and Pacific Gas and Electric default load aggregation points (DLAPs). As shown in this figure, average bilateral prices for the quarter for Mid-Columbia (Peak) significantly exceeded prices at the California ISO DLAPs while Palo Verde (Peak) prices dipped below California ISO prices in November and December.

Figure 1.13 Monthly average day-ahead and bilateral market prices



1.2.3 Imports and exports

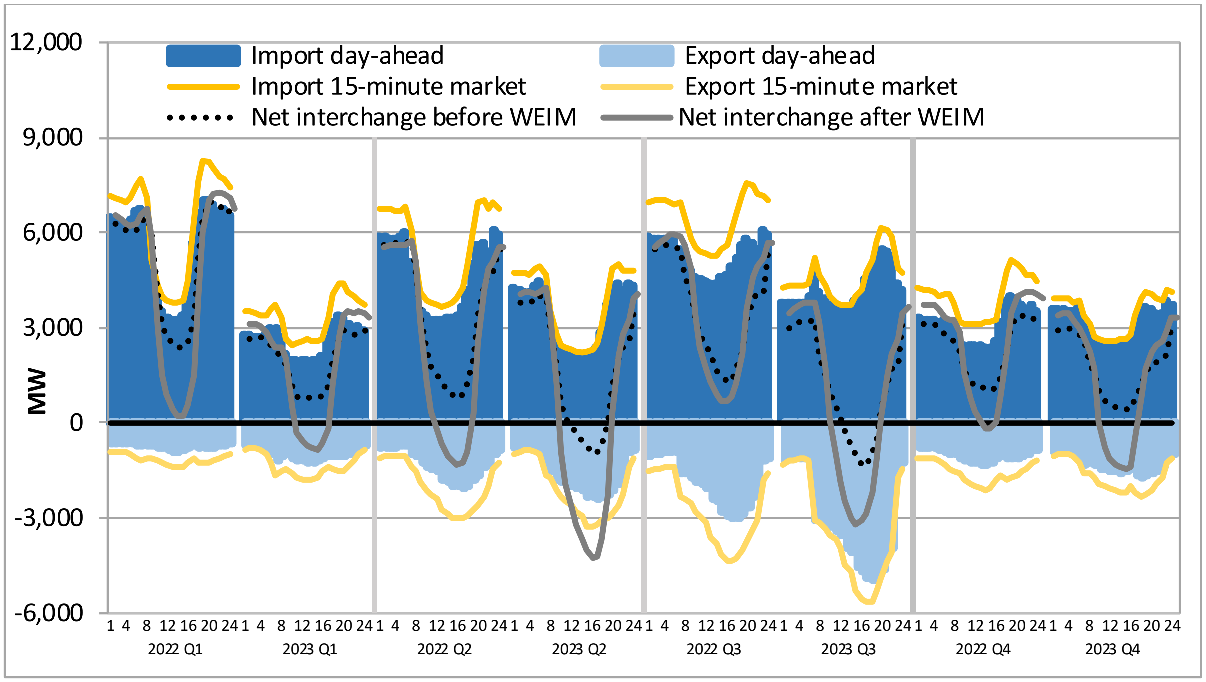
During the fourth quarter, average imports decreased slightly while exports increased slightly compared to the same quarter in 2022. As shown in Figure 1.14, average imports in the day-ahead market (dark blue columns) remained relatively consistent in all hours when compared to the same quarter of 2022, peaking at about 3,800 MW in hour-ending 23. Imports clearing the 15-minute market (dark yellow line) decreased in all hours of the day compared to the fourth quarter of 2022, peaking in hour-ending 22 at around 4,200 MW. Exports in both the day-ahead (light blue bars) and 15-minute (pale yellow line) increased by about 500 MW on average over the peak hours of 17-21 compared to the same quarter of 2022.

Figure 1.14 shows power flowing into the CAISO balancing area as positive and power flowing out of the CAISO area as negative. The dashed black line shows net interchange with the CAISO area before including WEIM transfers into or out of the CAISO area. The dashed black line is the sum of the 15-minute imports (dark yellow line) and the 15-minute exports (pale yellow line). Compared to the fourth quarter of 2022, the average net interchange decreased in each hour of the fourth quarter of 2023. Hour-ending 19 had the largest year-over-year decrease, roughly 1,500 MW.

The solid grey line adds WEIM transfers onto the net interchange calculation (dashed black line). When the grey line is below the dashed black line, this indicates WEIM transfers out of the CAISO balancing area. WEIM transfers were in the export direction on average between hours-ending 9 and 17.

Average net interchange including WEIM transfers (solid grey line) was in the export direction in hours-ending 10 through 16. Net exports including WEIM transfers peaked at nearly 1,500 MW in hour-ending 14. This was almost 1,300 MW more than the largest average net interchange in the export direction in Q4 2022.

Figure 1.14 Average hourly net interchange by quarter



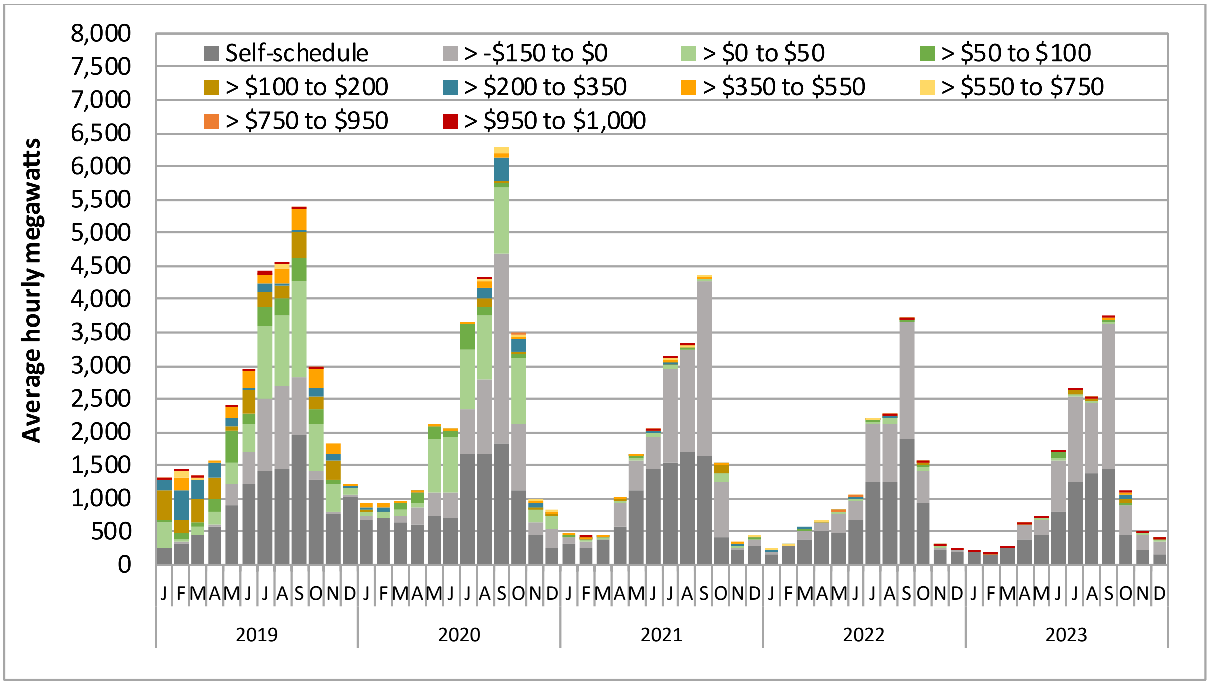
In June 2020, the CPUC issued a decision specifying that CPUC jurisdictional non-resource-specific import resource adequacy resources must bid into the California ISO markets at or below $0/MWh during the availability assessment hours.[18] These rules became effective at the beginning of 2021. They appear to have influenced the bid-in quantity and bid-in prices of imports. An overall decline in volumes began in late 2020 and continued throughout 2021, as well as into the first half of 2022. The $0/MWh or below bidding rule does not apply to non-CPUC jurisdictional imports.

Figure 1.15 shows the average hourly volume of self-scheduled and economic bids for resource adequacy import resources in the day-ahead market, during peak hours.[19] The dark grey bars reflect import capacity that was self-scheduled. The light grey bars show imports bid at or below $0/MWh. The remaining bars summarize the volume of price-sensitive resource adequacy import capacity in the day-ahead market bid above $0/MWh. Levels of resource adequacy imports appear to be reaching a new level of consistency after an initial decline following the June 2020 CPUC decision.

[18] In 2021, Phase 1 (March 20) and Phase 2 (June 13) of the FERC Order No. 831 compliance tariff amendment were implemented. Phase 1 allows resource adequacy imports to bid over the soft offer cap of $1,000/MWh when the maximum import bid price (MIBP) is over $1,000/MWh or when the California ISO has accepted a cost-verified bid over $1,000/MWh. Phase 2 imposed bidding rules capping resource adequacy import bids over $1,000/MWh at the greater of MIBP or the highest cost-verified bid up to the hard offer cap of $2,000/MWh.

[19] Peak hours in this analysis reflect non-weekend and non-holiday periods between hours-ending 17 and 21.

Figure 1.15 Average hourly resource adequacy imports by price bin



1.3 Price variability

In the fourth quarter of 2023, instances of prices exceeding $250/MWh significantly decreased to 0.17 percent from 16 percent in the same quarter of 2022. The proportion of intervals with zero or negative prices increased to 2.7 percent from 0.5 percent.

High prices

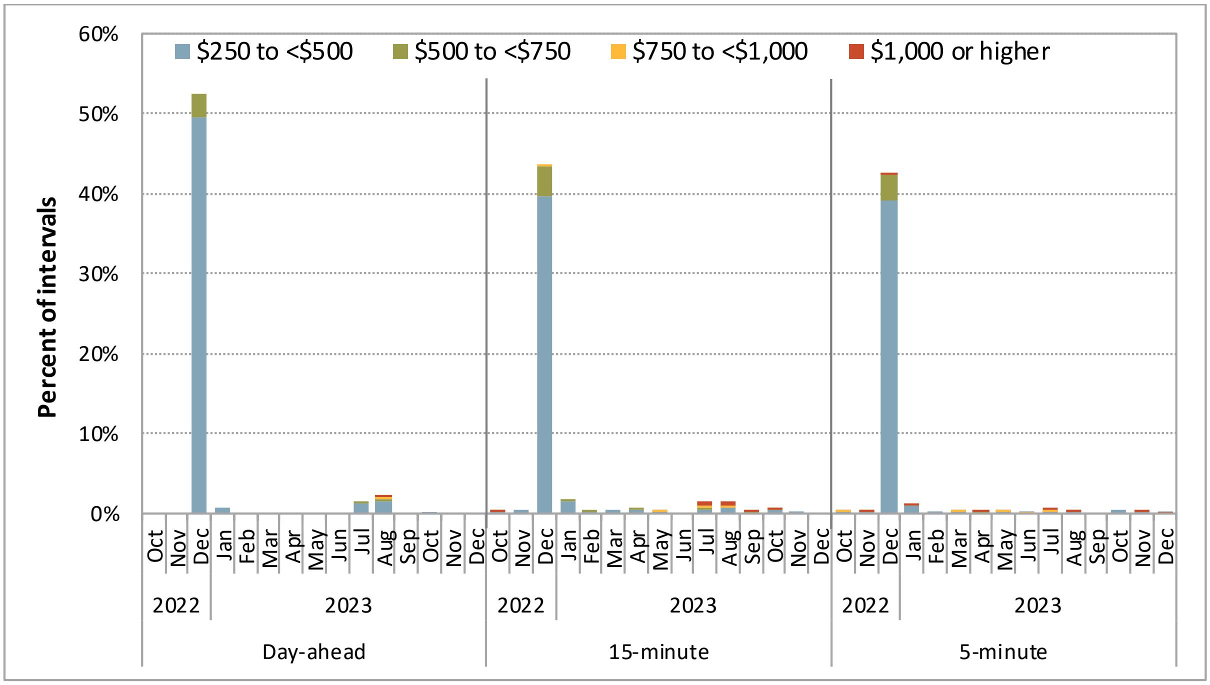
Figure 1.16 shows the frequency of high prices across all three markets for the three largest California ISO balancing area load aggregation points (LAP) by month, between October 2022 and December 2023.

In the day-ahead market, the frequency of high prices over $250/MWh significantly decreased compared to the same quarter of 2022. In the fourth quarter of 2023, the day-ahead market recorded 0.1 percent of intervals with an average price exceeding $250/MWh. In the same quarter of the previous year, 17 percent of intervals had prices above $250/MWh, particularly driven by over 50 percent of high price intervals in December 2022.

The 15-minute market also had a significantly lower frequency of price spikes in this quarter compared to the fourth quarter of 2022. The percentage of intervals with prices above $250/MWh was 0.2 percent, a significant decrease from 14.7 percent in the same quarter of 2022.

Similarly, the 5-minute market had a significantly reduced frequency of high prices this quarter. The percentage of intervals with prices above $250/MWh decreased to 0.2 percent in the fourth quarter of 2023 from 14.3 percent in the same quarter of the previous year.

Figure 1.16 Frequency of high prices ($/MWh) by month



This significant reduction in high price intervals was due to a return to more normal natural gas prices in the fourth quarter of 2023 compared to 2022. As illustrated in Figure 1.16, extreme natural gas prices in December 2022 caused over 40 percent of intervals to have prices in excess of $250/MWh that month.

Negative prices

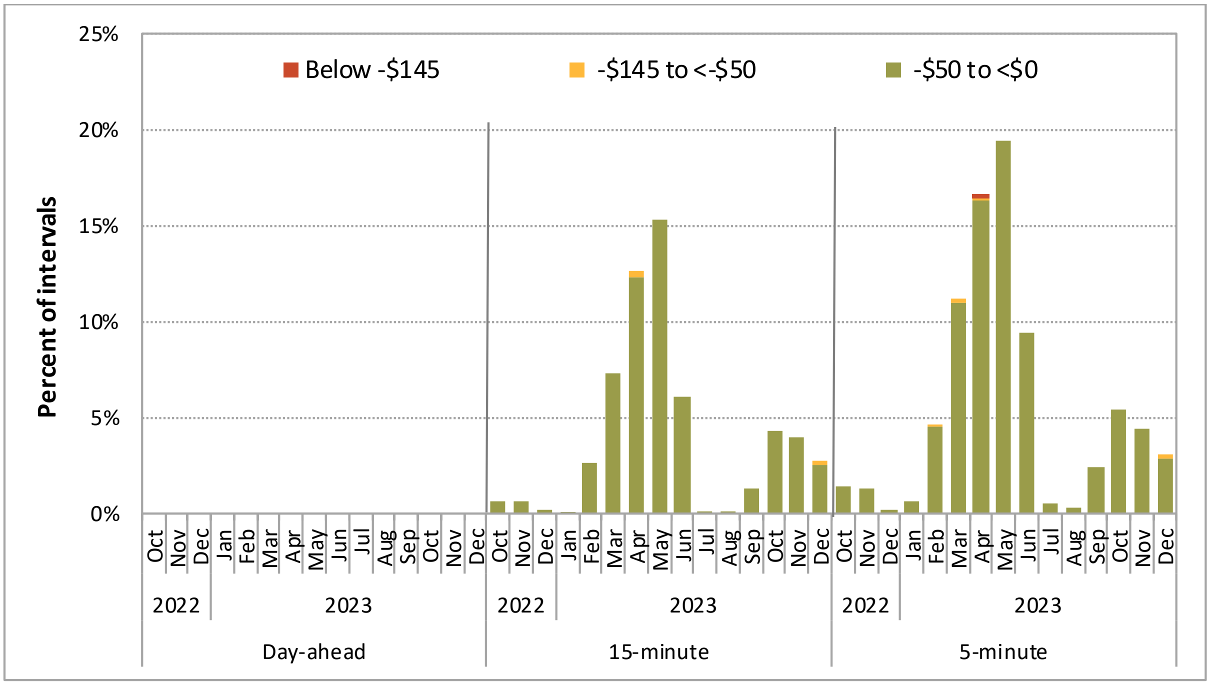
Figure 1.17 shows the frequency of negative prices across all three markets for the three largest load aggregation points (LAPs) by month between October 2022 and December 2023. In the real-time markets, the frequency of negative price intervals increased in Q4 2023 compared to the fourth quarter of 2022.

Negative prices tend to be most common when renewable production is high and demand is low. This is because in these scenarios, renewable resources are more likely to be the marginal energy source, and low-cost renewable resources often bid at or below zero dollars.

In the 15-minute market, the frequency of negative prices increased to 3.7 percent this quarter compared to 0.5 percent in the fourth quarter of 2022. In the 5-minute market, negative prices increased to 4.3 percent this quarter compared to one percent in the fourth quarter of 2022. There were no negative prices in the day-ahead market during the fourth quarters of 2022 or 2023.

The rise in negative pricing in the fourth quarter of 2023 compared to the same quarter of 2022 can largely be attributed to lower demand and higher renewable generation around midday in 2023.

Figure 1.17 Frequency of negative prices ($/MWh) by month



1.4 Convergence bidding

Convergence bidding is designed to align day-ahead and 15-minute market prices by allowing financial arbitrage between the two markets. In this quarter, the volume of cleared virtual supply exceeded cleared virtual demand, as it has in all quarters since 2014. Similar to the third quarter of 2023, in the fourth quarter, financial entities were the only convergence bidding participants who profited overall.

1.4.1 Convergence bidding revenues

Net revenues for convergence bidders were about $2.8 million for the fourth quarter, after inclusion of about $25 million of virtual bidding bid cost recovery charges, which are primarily associated with virtual supply.[20] Figure 1.18 shows total monthly revenues for virtual supply (green bars), total revenues for virtual demand (blue bars), the total amount paid for bid cost recovery charges (red bars), and the total payments for all convergence bidding inclusive of bid cost recovery charges (gold line). Before accounting for bid cost recovery charges:

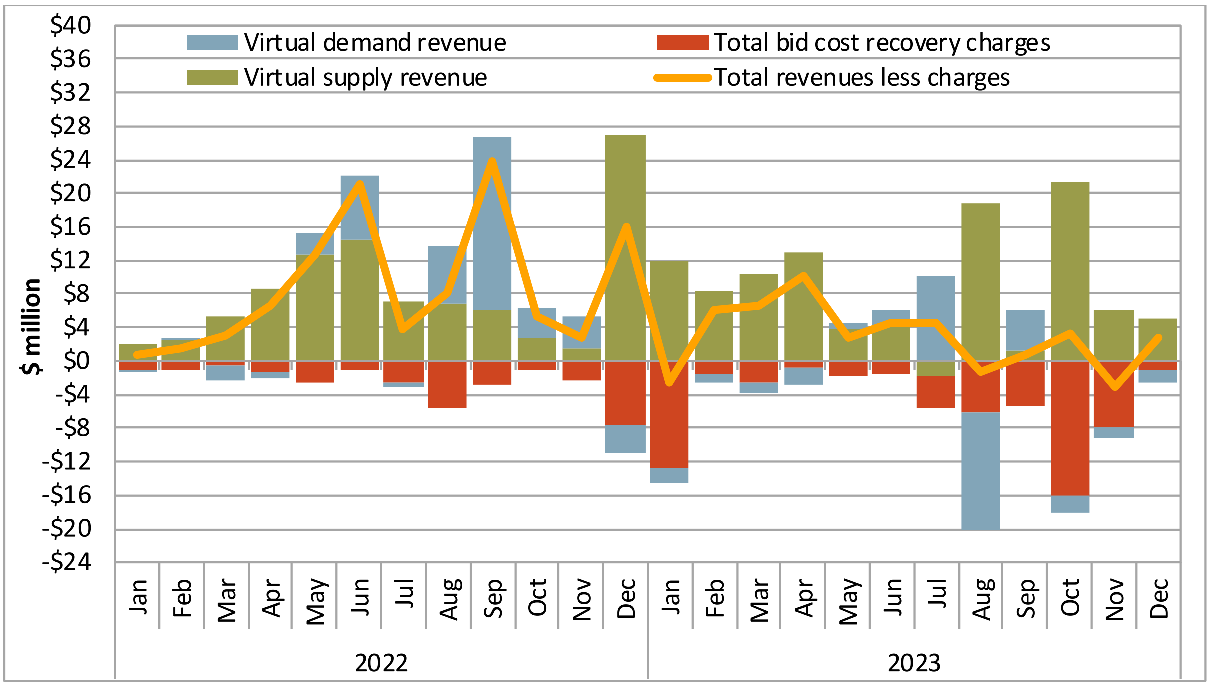
- Total market revenues were negative for November and positive for October and December. Bid cost recovery charges – especially those associated with sharing costs from residual unit commitment (RUC) procurement – contributed to low market revenues in October and November.
- Virtual demand revenues were negative in total for all months of the quarter, about -$2.1 million, -$1.3 million, and -$1.4 million for October, November, and December, respectively.

[20] Figures and data provided in this section are preliminary and may be subject to change.

- Before accounting for bid cost recovery, virtual supply revenues were about $21.4 million, $6 million, and $5.1 million for October, November, and December, respectively.

Bid cost recovery charges allocated to virtual bids were about $16 million, $7.9 million, and $1.1 million for October, November, and December, respectively. The majority of bid cost recovery allocated to virtual bidding participants in this quarter was charged to the residual unit commitment (RUC) tier 1 allocation, which helps offset costs related to periods with net virtual supply. Virtual supply leads to decreased unit commitment in the day-ahead market and increased unit commitment in RUC. When market revenues do not cover the commitment costs of resources committed in RUC, the resources receive bid cost recovery payments, and some of this bid cost recovery is allocated to virtual supply during periods with net virtual supply.

Figure 1.18 Convergence bidding revenues and bid cost recovery charges



Net revenues and volumes by participant type

Table 1.1 compares the distribution of convergence bidding cleared volumes and revenues, before and after taking into account bid cost recovery, in millions of dollars, among different groups of convergence bidding participants.[21]

After accounting for bid cost recovery, financial entities were the only participants who profited from convergence bidding overall. Before accounting for bid cost recovery, nearly all virtual bidding revenue was split between financial entities and marketers, at around 83.5 percent and 15.6 percent,

[21] This table summarizes data from the California ISO settlements database and is based on a snapshot of a given day after the end of the period. DMM strives to provide the most up-to-date data before publishing. Updates occur regularly within the settlements timeline, starting with T+9B (trade date plus nine business days) and T+70B, as well as others up to 36 months after the trade date. More detail on the settlement cycle can be found on the California ISO settlements page: http://www.caiso.com/market/Pages/Settlements/Default.aspx

respectively. Financial entities and marketers accounted for around 80 percent and 16.6 percent, respectively, of the cleared volume of virtual trades in the fourth quarter.

Table 1.1 Convergence bidding volumes and revenues by participant type

Trading entities	Average hourly megawatts			Revenues\Losses ($ million)				Total revenue after BCR
	Virtual demand	Virtual supply	Total	Virtual demand	Virtual supply before BCR	Virtual bid cost recovery	Virtual supply after BCR	
2023 Q4								
Financial	2,253	2,625	4,878	-$3.67	$26.53	-$16.50	$10.03	$6.37
Marketer	481	531	1,012	-$0.92	$5.18	-$4.93	$0.25	-$0.67
Physical load	0	15	15	$0.00	$0.25	-$0.64	-$0.40	-$0.40
Physical generation	27	148	175	-$0.15	$0.55	-$2.89	-$2.33	-$2.48
Total	**2,761**	**3,319**	**6,080**	**-$4.74**	**$32.51**	**-$24.96**	**$7.55**	**$2.82**

1.5 Residual unit commitment

The average total volume of capacity procured through the residual unit commitment (RUC) process in the fourth quarter of 2023 was 135 percent higher than the same quarter of 2022. Similar to the third quarter, the majority of this increase can be attributed to manual operator adjustments to the RUC procurement target, which increased by about 340 percent compared to the fourth quarter of 2022.

The purpose of the residual unit commitment market is to ensure that there is sufficient capacity on-line or reserved to meet actual load in real-time. The residual unit commitment market runs immediately after the day-ahead market and procures capacity sufficient to bridge the gap between the amount of physical supply cleared in the day-ahead market and the amount of physical supply that may be needed to meet actual real-time demand.

Operators will often increase the residual unit commitment market's target load requirement to a value above the day-ahead market load forecast. This allows the residual unit commitment market to procure extra capacity to account for uncertainty that may materialize in the load forecast and scheduled physical supply. During 2023, there were significant changes to how these amounts were determined, as summarized in Figure 1.19. This figure shows the average RUC adjustment on each day of 2022 (red) and 2023 (blue). The arrows in Figure 1.19 highlight three key changes that occurred in 2023:

1. During most of May and June, the ISO decreased residual unit commitment adjustments to zero each day as part of a pilot program for the ISO to assess the use of these adjustments, as well as imbalance conformance adjustments. Under the pilot program, no adjustments were used when demand was projected to be under 35,000 MW.[22]
2. Starting on June 30, the ISO began using the *mosaic quantile regression* method to calculate a portion of the RUC adjustments. This calculation is similar to that used to measure flexible ramping product uncertainty, except based on the historical difference between the *day-ahead* and real-time

[22] See CAISO's Summer Market Performance Report for June 2023, July 28, 2023, p 42: https://www.caiso.com/Documents/SummerMarketPerformanceReportforJune2023.pdf

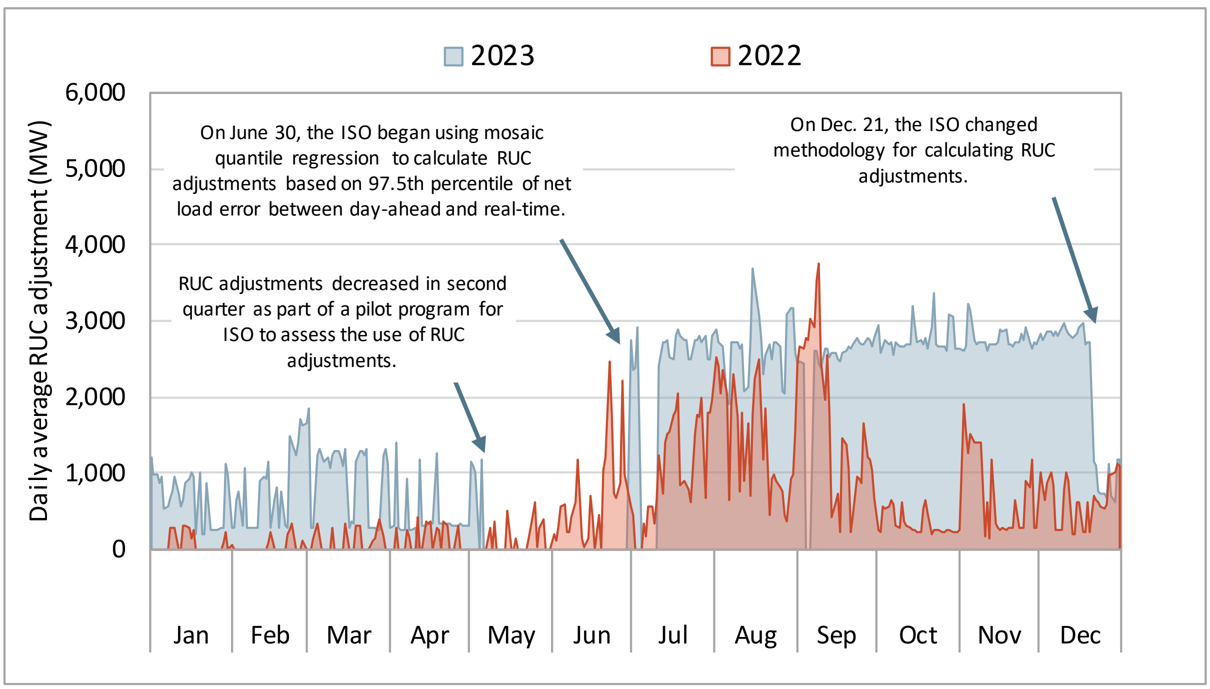
market forecasts for load, solar, and wind. This calculation was based on the 97.5th percentile of net load uncertainty that might materialize in real-time.[23]

3. Starting on December 21, the ISO implemented a new operating procedure that changed the methodology for calculating the RUC adjustments, effectively lowering the amount. Under *normal conditions*, the RUC adjustments are now calculated based on the 50th percentile of upward net load uncertainty. Operators can adjust the calculation any day based on the 75th or 97.5th percentile during periods of higher forecast uncertainty or extreme conditions.[24]

CAISO's new procedure for determining the uncertainty portion of the RUC load adjustment is to use an assessment of overall system conditions to decide if the RUC adjustment will be based on the 50th, 75th, or 97.5th percentile of upward uncertainty in the day-ahead net load forecast. On most days, this procedure calls for using a RUC adjustment that will only procure enough capacity to cover uncertainty 50 percent of the time (i.e., the 50th percentile of upward uncertainty). This indicates that there is still a substantial degree of judgment and discretion used in setting the RUC adjustment, even when using the mosaic quantile regression method to calculate the uncertainty component**.**

Given the importance of RUC adjustments in terms of costs and reliability, DMM recommends that the CAISO balancing area continue working on a method for determining the appropriate level of RUC load adjustment.

Figure 1.19 Average residual unit commitment adjustment by day (2022 versus 2023)



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23 The methodology is based on Imbalance Reserve product proposed as part of the California ISO day-ahead market enhancements initiative (DAME). More information on the results of this change can be found in the Market Performance and Planning Forum presentation, slides 210-227, September 27, 2023: https://www.caiso.com/Documents/Presentation-MarketPerformancePlanningForum-Sep27-2023.pdf

24 See CAISO Operating Procedure 1210, January 1, 2024, pp 12-13: https://www.caiso.com/Documents/1210.pdf

As shown in Figure 1.19, the use of the regression method significantly increased the size of the residual unit commitment adjustments in the fourth quarter of 2023 relative to the same quarter in 2022. This is also shown in Figure 1.20. Figure 1.20 shows the average residual unit commitment procurement by component. These adjustments increased significantly to about 2,560 MW per hour in the fourth quarter of 2023, compared to about 580 MW per hour in the same quarter of 2022.

Figure 1.20 shows that residual unit commitment procurement was also driven by the need to replace cleared net virtual supply bids, which can offset physical supply in the day-ahead market run. On average, cleared virtual supply (green bar) continued at a relatively high level for October and November, while in December it dropped to nearly zero.

The blue bar in Figure 1.20 depicts the day-ahead forecasted load versus cleared day-ahead capacity, which includes both physical supply and net virtual supply. This represents the difference between the CAISO day-ahead load forecast and the physical load that cleared the integrated forward market (IFM). On average, this factor contributed towards increasing residual unit commitment requirements by 530 MW per hour in the fourth quarter of 2023, up from about 280 MW in 2022.

Lastly, residual unit commitment also includes an automatic adjustment to account for differences between the day-ahead schedules of bid-in variable energy resources and the forecast output of these renewable resources. This intermittent resource adjustment reduces residual unit commitment procurement targets by the estimated under-scheduling of renewable resources in the day-ahead market, illustrated by the yellow bars in Figure 1.20.

Figure 1.21 shows the hourly distribution of these operator adjustments during the fourth quarter of 2023. The black line shows the average adjustment quantity in each hour and the red markers highlight outliers in each hour.

Figure 1.20 Determinants of residual unit commitment procurement

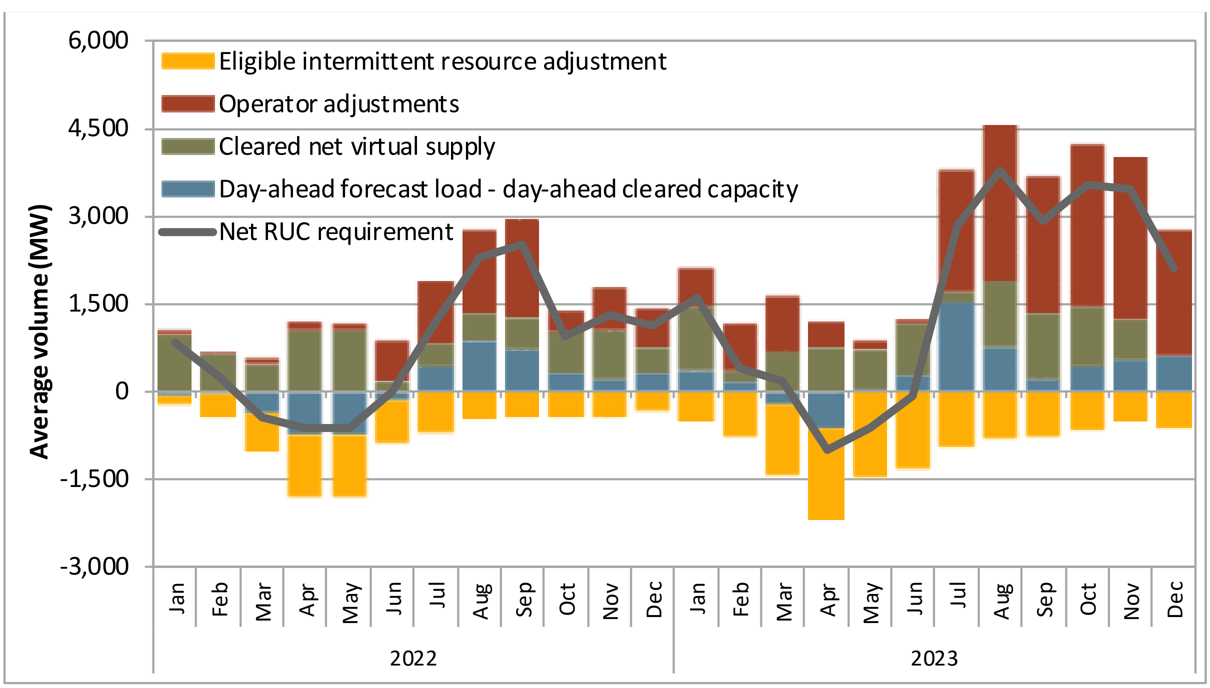


Figure 1.21 Hourly distribution of residual unit commitment operator adjustments (October–December 2023)

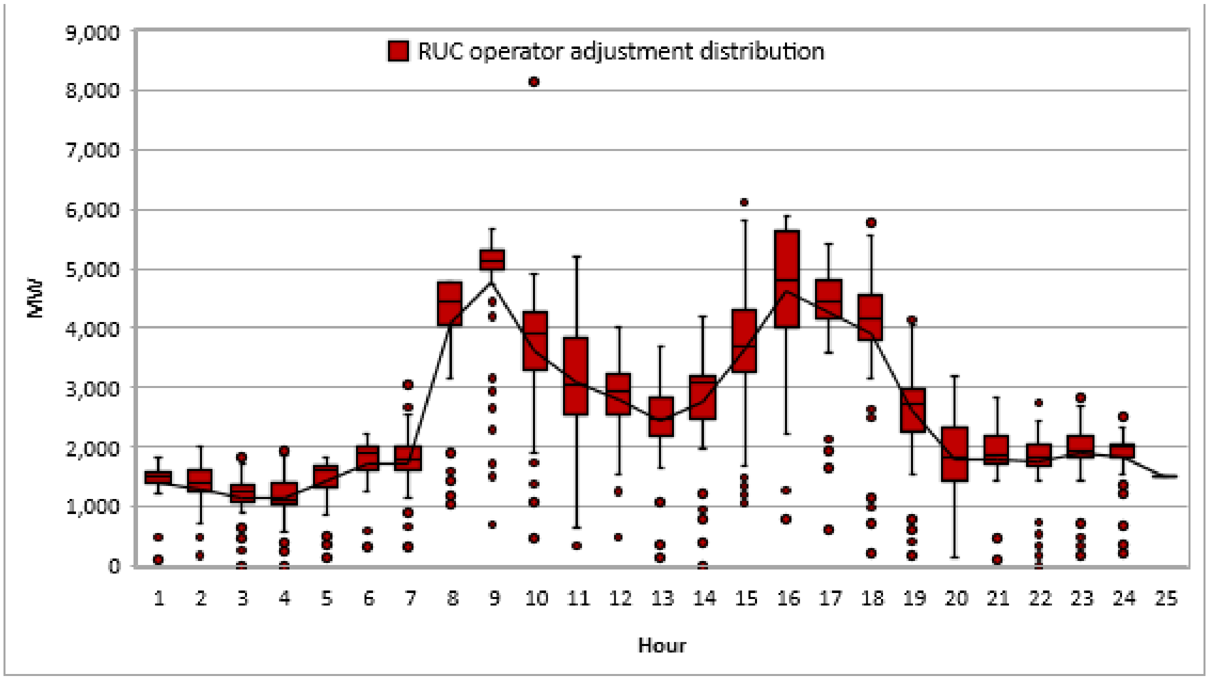
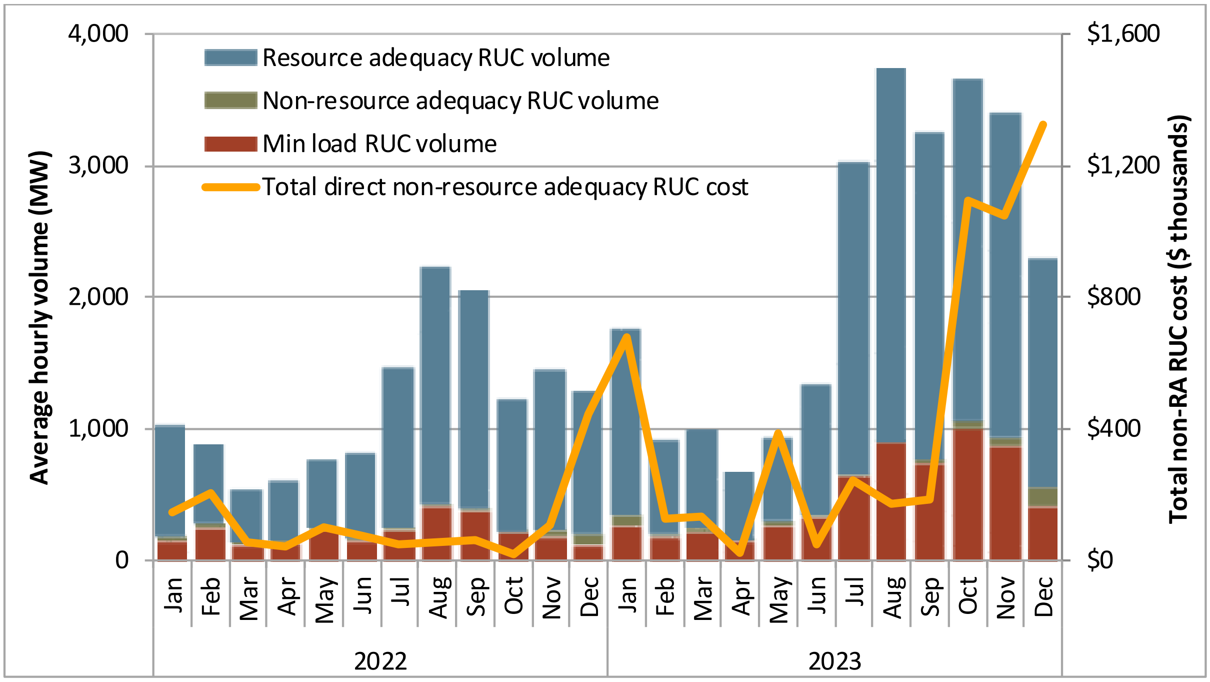


Figure 1.22 shows the monthly average hourly residual unit commitment procurement, categorized as non-resource adequacy, resource adequacy, or minimum load. The average residual unit commitment procurement for the quarter increased by 135 percent to about 3,111 MW in the fourth quarter of 2023 from an average of about 1,322 MW in the same quarter of 2022. Of the 3,111 MW capacity, the capacity committed to operate at minimum load averaged 760 MW.

Most of the capacity procured in the residual unit commitment market does not incur any direct costs from residual unit capacity payments because only non-resource adequacy units receiving awards in this process receive RUC capacity payments.[25] The total direct cost of non-resource adequacy residual unit commitment is represented by the gold line in Figure 1.22. In the fourth quarter of 2023, these costs were about $3.5 million, more than six times the costs in the same quarter of 2022.

[25] If committed, resource adequacy units may receive bid cost recovery payments in addition to resource adequacy payments.

Figure 1.22 Residual unit commitment costs and volume



1.6 Ancillary services

Ancillary service payments totaled $18.9 million, a 47 percent decrease from the same quarter last year. Average requirements were higher for operating reserves, while average requirements for regulation down decreased, and those for regulation up remained the same compared to the fourth quarter of 2022.

1.6.1 Ancillary service requirements

The California ISO procures four ancillary services in the day-ahead and real-time markets: spinning reserves, non-spinning reserves, regulation up, and regulation down. Procurement requirements are set for each ancillary service to meet or exceed Western Electricity Coordinating Council's (WECC) minimum operating reliability criteria, and North American Electric Reliability Corporation's (NERC) control performance standards.

The California ISO can procure ancillary services in the day-ahead and real-time markets from the internal system region, expanded system region, four internal sub-regions, and four corresponding expanded sub-regions.[26] Operating reserve requirements in the day-ahead market are typically set by the maximum of (1) 6.3 percent of the load forecast, (2) the most severe single contingency, or (3) 15 percent of forecasted solar production. Operating reserve requirements in real-time are

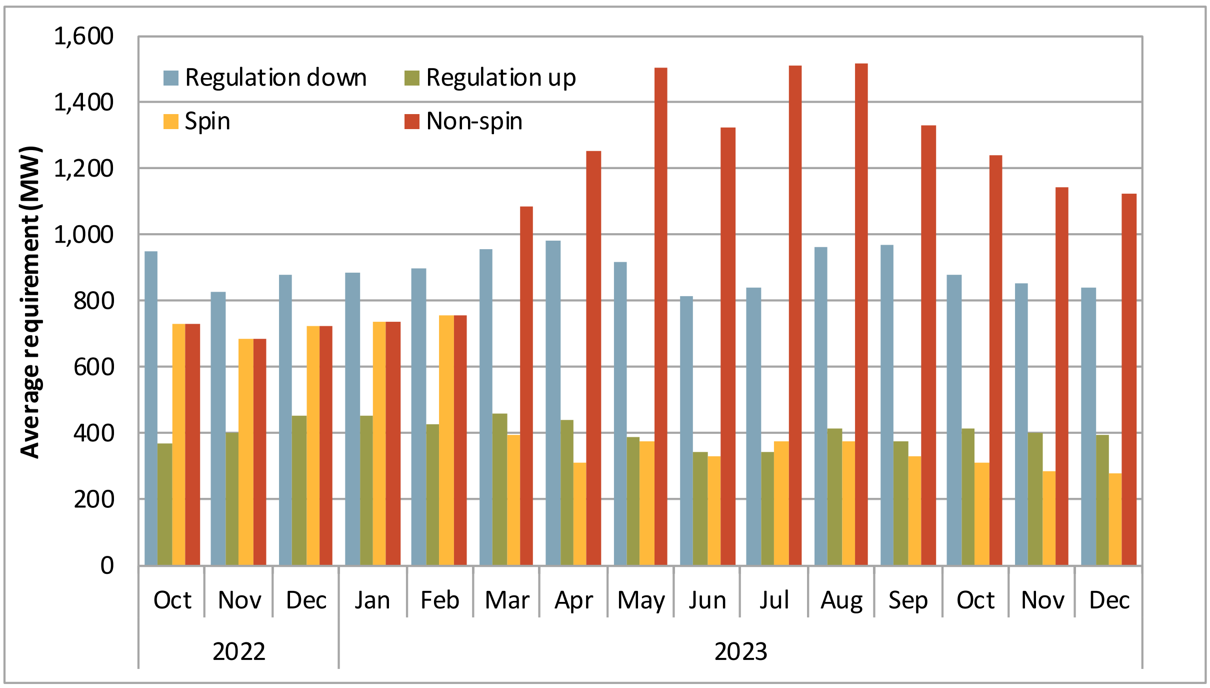
[26] More information on ancillary services requirements and procurement for internal and expanded regions is available in: Department of Market Monitoring, *2020 Annual Report on Market Issues & Performance*, August 2021, p 161: http://www.caiso.com/Documents/2020-Annual-Report-on-Market-Issues-and-Performance.pdf

calculated similarly, except using three percent of the load forecast and three percent of generation instead of 6.3 percent of the load forecast.

Starting on March 1, 2023, CAISO operators changed the procurement target for operating reserves following changes in WECC and NERC reliability standards, which now allow spinning reserves to account for less than 50 percent of requirements. In the fourth quarter of 2023, CAISO operators procured 20 percent of operating reserves as spinning reserves and the rest as non-spinning reserves.

Figure 1.23 shows monthly average ancillary service requirements for the expanded system region in the day-ahead market. Regulation down requirements decreased three percent compared to the fourth quarter of 2022. Average requirements for spinning and non-spinning reserves changed drastically, year-over-year, due to CAISO operators' new procurement targets. Average total operating reserve requirements increased by about 2.5 percent, compared to the fourth quarter of 2022.

Figure 1.23 Average monthly day-ahead ancillary service requirements



1.6.2 Ancillary service scarcity

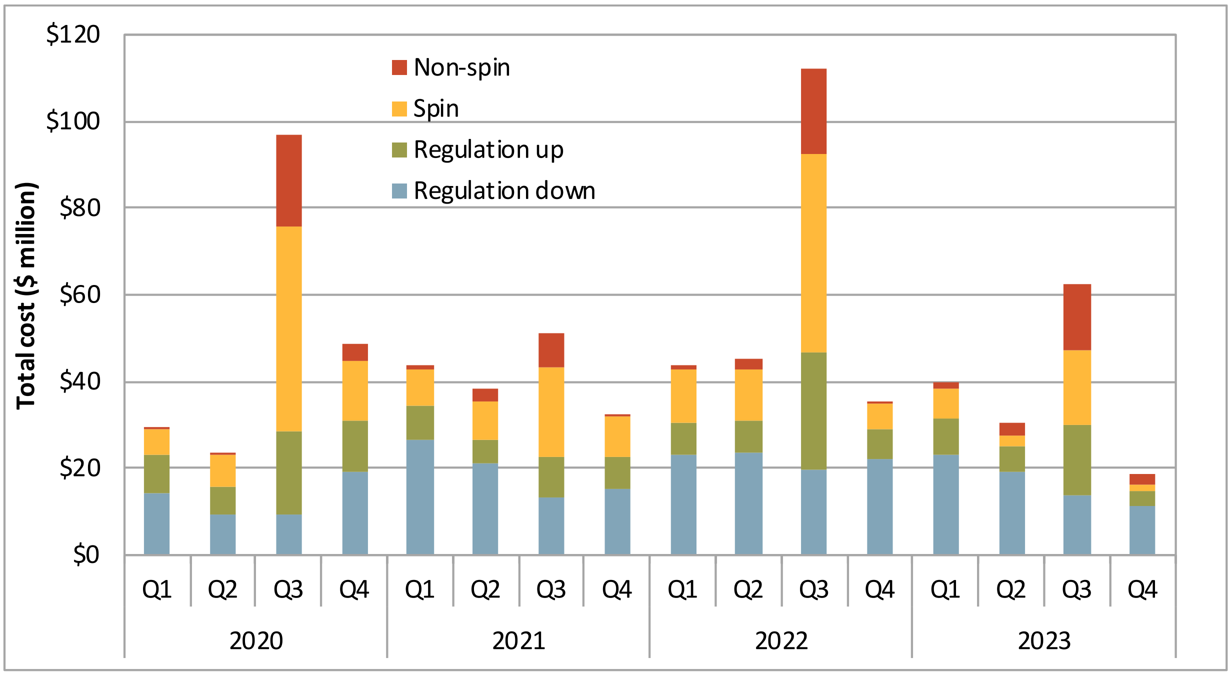
Scarcity pricing of ancillary services occurs when there is insufficient supply to meet reserve requirements. Under the ancillary service scarcity price mechanism, the California ISO balancing area pays a predetermined scarcity price for ancillary services procured during scarcity events. The scarcity prices are determined by a scarcity demand curve, such that the scarcity price is higher when the procurement shortfall is larger. No scarcity events occurred in the fourth quarter of 2023.

1.6.3 Ancillary service costs

Ancillary service payments totaled $18.9 million in the fourth quarter of 2023, around $43.3 million less than the previous quarter and $16.4 million less than the same quarter of the previous year.

Figure 1.24 shows the total cost of procuring ancillary service products by quarter.[27] Payments for regulation down, regulation up, and spinning reserve decreased 49 percent, 52 percent, and 74 percent, respectively, compared to the fourth quarter of 2022. Regulation down payments had the largest absolute decrease, at around $10.8 million. Non-spinning reserve payments had a nearly five-fold increase compared to the fourth quarter of 2022 because of higher requirements relative to total operating reserve requirements.

Figure 1.24 Ancillary service cost by product



1.7 Congestion

This section presents analysis of the effect of internal congestion on both day-ahead and real-time markets within the California ISO balancing area.[28] Additionally, it examines the impact of day-ahead

27 The costs reported in this figure account for rescinded ancillary service payments. Payments are rescinded when resources providing ancillary services do not fulfill the availability requirements associated with the awards. As noted elsewhere in the report, settlements values are based on statements available at the time of drafting and will be updated in future reports.

28 This report defines internal congestion as congestion on any constraint within a balancing authority area. Therefore, the effect of internal congestion on the CAISO balancing area may include effects of congestion from transmission elements within WEIM balancing areas. Analysis of internal congestion excludes transfer constraints and intertie constraint congestion.

congestion on interties. Detailed analysis of WEIM transfer congestion impact is addressed in Section 2.1.3. For metrics on WEIM internal congestion, refer to Appendix B.

Total congestion rent decreased to $226 million in the fourth quarter of 2023, down from $437 million in the same quarter of 2022. This decrease in congestion rent occurred despite congestion occurring more frequently in Q4 2023 compared to the same quarter of 2022.

The substantial decline in congestion rent can be attributed to considerably lower shadow prices on binding internal constraints. Moreover, the binding internal constraints in the fourth quarter of 2023 generally had smaller limits compared to those in the same period of 2022.

In the fourth quarter of 2023, congestion on internal constraints had a greater impact on load area price separation than in the same quarter of 2022. There was less congestion rent but greater congestion impact on load area price separation in Q4 2023 due to the major constraints changing direction less frequently in Q4 2023 compared to Q4 2022. The more consistent south-to-north internal congestion in Q4 2023 had a larger net effect on increasing prices in the PG&E load area relative to the SCE and SDG&E load areas in the south, despite generally lower shadow prices on the major constraints in Q4 2023 compared to Q4 2022.

The following sections provide an assessment of the frequency and impact of congestion on prices in the day-ahead, 15-minute, and 5-minute markets. It assesses the impact of congestion on local areas in the California ISO balancing area (Pacific Gas and Electric, Southern California Edison, and San Diego Gas & Electric).

Congestion in a nodal energy market occurs when the market model determines that flows have reached or exceeded the limit of a transmission constraint. Within areas where flows are constrained by limited transmission, higher cost generation is dispatched to meet demand. Outside of these transmission-constrained areas, demand is met by lower cost generation. This results in higher prices within congested regions and lower prices in unconstrained regions.

The impact of congestion on each pricing node in the California ISO system is calculated as the product of the shadow price of that constraint, and the shift factor for that node relative to the congested constraint. This calculation works for individual nodes as well as for groups of nodes that represent different load aggregation points or local capacity areas.[29]

1.7.1 Congestion in the day-ahead market

In the day-ahead market, the frequency of congestion is less than that observed in the 15-minute and 5-minute markets. Moreover, the impact on prices in the SCE and SDG&E region is lower compared to the real-time markets.

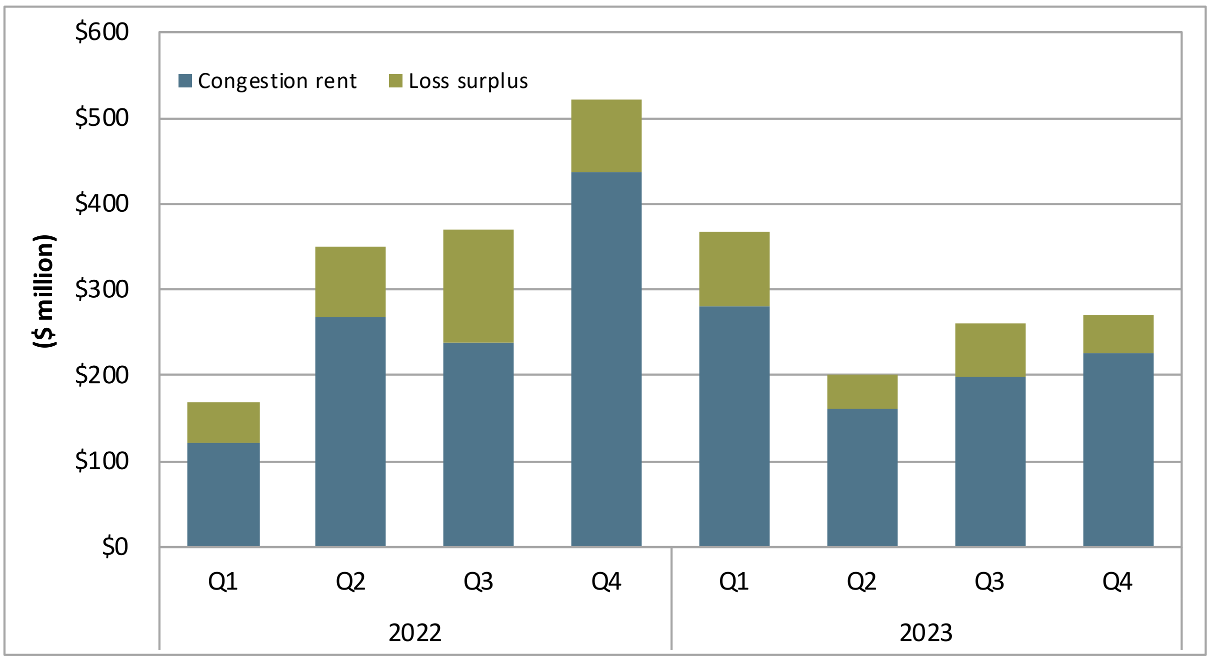
29 This approach does not include price differences that result from transmission losses.

Congestion rent and loss surplus

In the last quarter of 2023, congestion rent and loss surplus was $226 million and $25 million, respectively.[30] These respective amounts represent a decrease of 48 percent and 47 percent relative to the same quarter of 2022. This reduction of over $270 million was primarily due to internal congestion rent. This quarter saw a higher number of binding constraints, yet they generally had smaller capacities, and the average shadow price was lower compared to the last quarter of 2022.

In the day-ahead market, hourly congestion rent collected on a constraint is equal to the product of the shadow price and the megawatt flow on that constraint. The daily congestion rent is the sum of hourly congestion rents collected on all constraints for all trading hours of the day. The daily marginal loss surplus is computed as the difference between daily net energy charge and daily congestion rent. The loss surplus is allocated to measured demand.[31]

Figure 1.25 Day-ahead congestion rent and loss surplus by quarter (2022-2023)[32]



30 Information in this section is based on settlement values available at the time of drafting and will be updated in future reports. Updates can occur regularly within the settlements timeline, starting with T+9B (trade date plus nine business days) and T+70B, as well as others up to 36 months after the trade date. At the time of drafting, values for December have not passed the T+70B threshold.

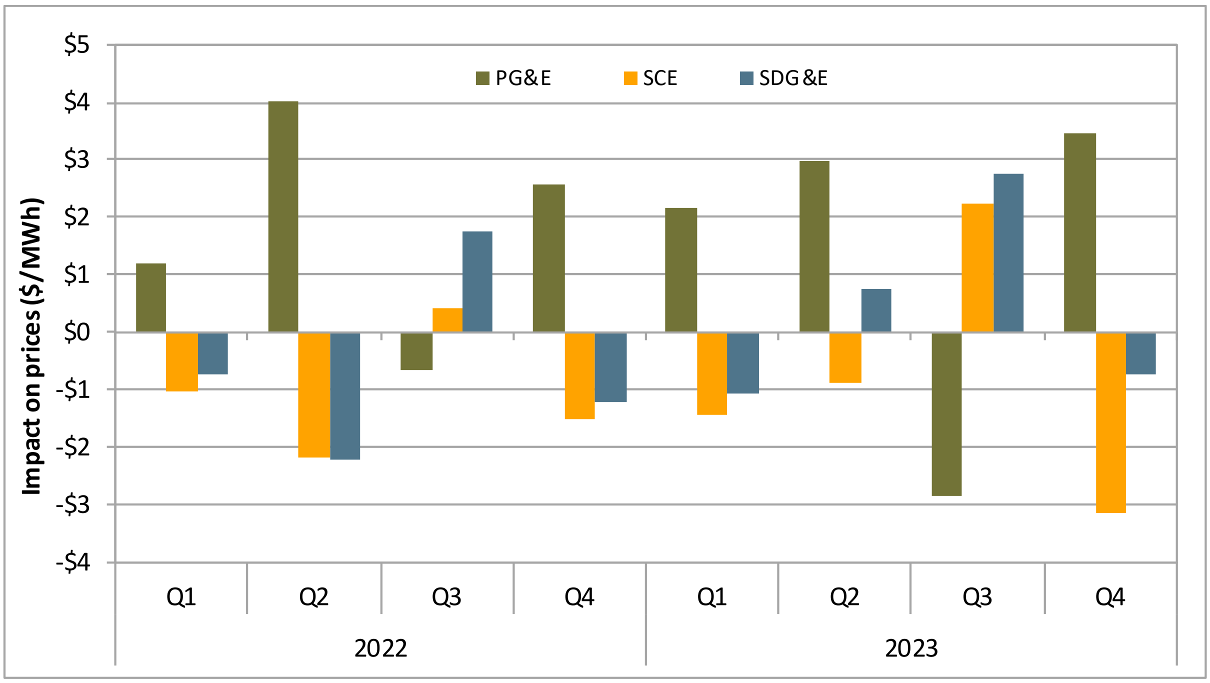
31 For more information on marginal loss surplus allocation, refer to: California ISO, *Business Practice Manual Change Management – Settlements and Billing,* CG CC6947 IFM Marginal Losses Surplus Credit Allocation: https://bpmcm.caiso.com/Pages/SnBBPMDetails.aspx?BPM=Settlements%20and%20Billing

32 Information in this chart is based on settlement values available at the time of drafting and will be updated in future reports. Updates can occur regularly within the settlements timeline, starting with T+9B (trade date plus nine business days) and T+70B, as well as others up to 36 months after the trade date. At the time of drafting, values for December have not passed the T+70B threshold.

Figure 1.26 shows the overall impact of congestion on day-ahead prices in each load area in 2022 and 2023. Figure 1.27 shows the frequency of congestion. Highlights for this quarter include:

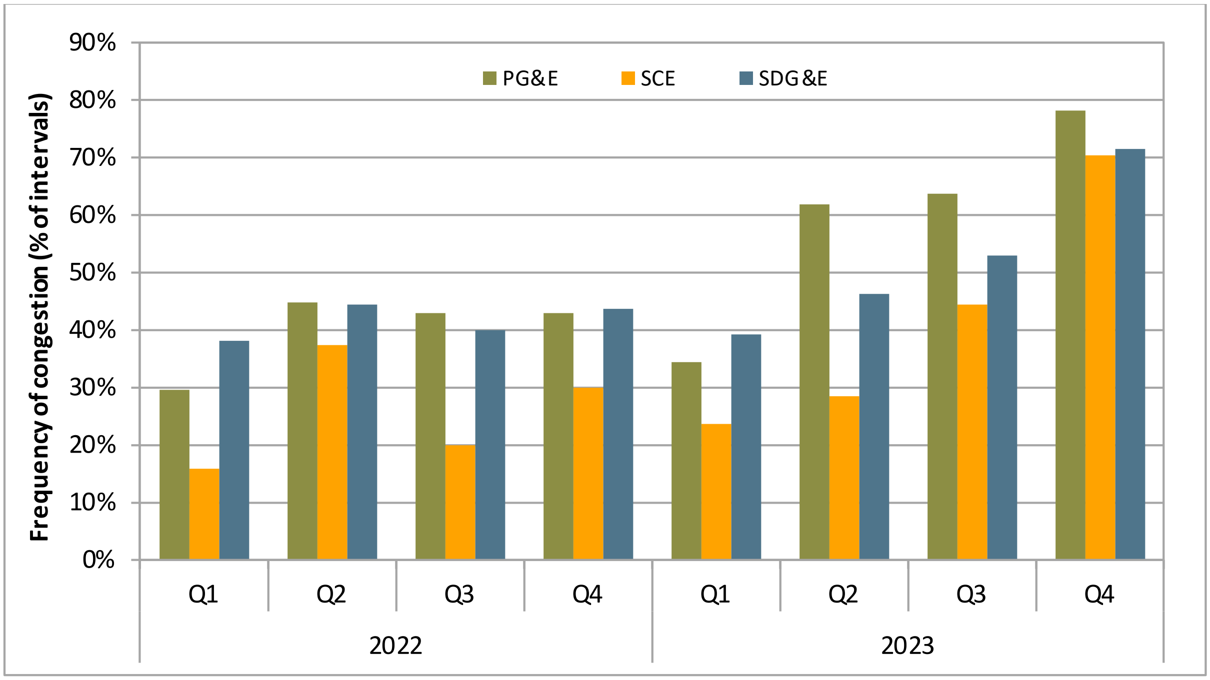
- The overall impact of day-ahead congestion on price separation in the fourth quarter was higher than during the same quarter of 2022.
- Day-ahead congestion increased quarterly average prices in PG&E by $3.45/MWh (six percent), while it decreased average SCE and SDG&E prices by $3.12/MWh (six percent) and $0.74/MWh (one percent), respectively.[33]
- The primary constraints affecting day-ahead market prices were the Tesla-Los Banos #1 500 kV line, Gates-Midway #1 500 kV line, and Moss Landing-Las Aguilas #1 230 kV line.

Figure 1.26 Overall impact of congestion on price separation in the day-ahead market



[33] Language in the report describing congestion as "increasing" or "decreasing" a price is describing the change relative to the particular reference bus used in that market. The ISO uses a particular reference bus – distributed amongst load nodes according to the load at each node's percentage of total load. However, in theory, any node could be used as the reference bus, and changing the reference bus would change the value of how much congestion "increased" or "decreased" prices at a node relative to the reference bus. While the specific value of an increase or decrease in congestion price is relative to the reference bus, the *difference* between the impact of congestion on one node and another node is not dependent on the reference bus. Therefore, in assessing the impacts of congestion on prices, DMM suggests the reader focus on the difference of the price impacts between nodes or areas, and not on the specific value of an increase or decrease to one node or area.

Figure 1.27 Percent of hours with congestion impacting day-ahead prices by load area (>$0.05/MWh)



Impact of congestion from individual constraints

Table 1.2 breaks down the congestion effect on price separation during the quarter by constraint.[34] The table presents the top 25 most congested lines, ranked by their impact, while the "Other" category shows the average impact of the remaining constraints. Color shading is used in the tables to help distinguish patterns in the impacts of constraints. Orange indicates a positive impact to prices, while blue represents a negative impact – the stronger the shading, the greater the impact in either the positive or negative direction.

The constraints with the greatest impact on day-ahead price separation for the quarter were Tesla-Los Banos #1 500 kV line, Gates-Midway #1 500 kV line, and Moss Landing-Las Aguilas #1 230 kV line.

Tesla-Los Banos #1 500 kV line

The Tesla-Los Banos #1 500 kV line (30040_TESLA_500_30050_LOSBANOS_500_BR_1_1) had the greatest impact on day-ahead prices during the fourth quarter. The line was congested during 15 percent of hours. For the quarter, congestion on the line increased average PG&E prices by $1.55/MWh, and decreased average SCE and SDG&E prices by $1.27/MWh and $1.18/MWh, respectively. This transmission line frequently reached its limits during solar production hours, from hour-ending 8 through hour-ending 16.

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[34] DMM calculates the congestion impact from constraints by replicating the nodal congestion component of the price from individual constraints, shadow prices, and shift factors. In some cases, DMM could not replicate the congestion component from individual constraints such that the remainder is flagged as "Other". In addition, constraints with price impact of less than $0.01/MWh for all LAPs in the region are grouped in "Other".

Gates-Midway #1 500 kV line

The Gates-Midway #1 500 kV line (30055_GATES1_500_30060_MIDWAY_500_BR_1_1) bound in 17 percent of hours over the quarter. For the quarter, congestion on the constraint increased average PG&E prices by $1.44/MWh and decreased average SCE and SDG&E prices by $1.21/MWh and $1.13/MWh, respectively. This transmission line was generally binding during solar production hours, from hour-ending 8 through hour-ending 16.

Moss Landing-Las Aguilas #1 230 kV line

The Moss Landing-Las Aguilas #1 230 kV line (30750_MOSSLD_230_30797_LASAGUIL_230_BR_1_1) bound in about 14 percent of hours. For the quarter, the constraint increased average PG&E prices by about $0.37/MWh, and decreased average SCE and SDG&E prices by $0.27/MWh and $0.26/MWh, respectively. This line was frequently binding during solar production hours, from hour-ending 10 through hour-ending 16.

Additionally, it is important to highlight that various constraints contributed to an increase in SDG&E prices. These lines are situated in or linked to the Imperial Valley, a region densely populated with solar power plants, and facilitates the flow of electricity from the Imperial Valley to the metropolitan area within the SDG&E region.

Table 1.2 Impact of congestion on overall day-ahead prices – top 25 primary congestion constraints

Constraint	Frequency	Average quarter impact ($/MWh)		
		PG&E	SCE	SDG&E
30040_TESLA_500_30050_LOSBANOS_500_BR_1_1	15.4%	1.55	-1.27	-1.18
30055_GATES1_500_30060_MIDWAY_500_BR_1_1	17.3%	1.44	-1.21	-1.13
30750_MOSSLD_230_30797_LASAGUIL_230_BR_1_1	13.8%	0.37	-0.27	-0.26
35621_IBM-HRJ_115_35642_METCALF_115_BR_1_1	7.7%	0.18	-0.14	-0.13
6410_CP1_NG	1.3%	-0.15	0.11	0.11
OMS_14369435_Miguel_BK80	2.5%	-0.04	-0.01	0.31
MIGUEL_BKs_MXFLW_NG	0.7%	-0.04	-0.01	0.31
22886_SUNCREST_230_22885_SUNCREST_500_XF_2_P	2.8%	-0.03	0.00	0.23
7820_TL23040_IV_SPS_NG	2.5%	-0.02	0.00	0.19
30790_PANOCHE_230_30900_GATES_230_BR_2_1	3.9%	0.08	-0.07	-0.06
35618_SNJSEA_115_35620_ELPATIO_115_BR_1_1	5.9%	0.07	-0.06	-0.06
OMS_14168328_IV-SXOUTAGE_NG	0.5%	-0.02	0.00	0.15
OMS14407105_50001_OOS_NG	0.5%	-0.02	0.00	0.15
OMS14407109_50001_OOS_NG	0.5%	-0.02	0.00	0.14
OMS14384679_50001_OOS_NG	1.0%	-0.02	0.00	0.12
7820_TL230S_OVERLOAD_NG	1.7%	-0.02	-0.01	0.12
22356_IMPRLVLY_230_21025_ELCENTRO_230_BR_1_1	1.7%	-0.01	-0.01	0.12
SYLMAR-AC_BG_NG	2.0%	-0.02	0.03	-0.07
OMS14204875ML_BK80_NG	0.4%	-0.01	0.00	0.08
30055_GATES1_500_30900_GATES_230_XF_11_P	1.6%	-0.03	0.02	0.02
OMS14407117_50001_OOS_NG	0.5%	-0.01	0.00	0.07
24801_DEVERS_500_24804_DEVERS_230_XF_2_P	2.7%	-0.01	0.01	-0.05
OMS14384680_50001_OOS_NG	0.4%	-0.01	0.00	0.06
22208_ELCAJON_69.0_22408_LOSCOCHS_69.0_BR_1_1	3.0%	0.00	0.00	0.06
7440_MetcalfImport_Tes-Metcalf	0.5%	0.03	-0.02	-0.02
Other	3.8%	0.22	-0.22	0.00
Total		3.45	-3.13	-0.74

1.7.2 Congestion in the real-time market

This section outlines the effects of internal congestion on both the 15-minute and 5-minute markets within the California ISO balancing area.[35]

In the fourth quarter, the constraints that had the greatest impact on price separation in the 15-minute and 5-minute markets were the Gates-Midway #1 500 kV line, Tesla-Los Banos #1 500 kV line, and the Imperial Valley-North Gila nomogram.[36]

Table 1.3 and Table 1.4 show the average effect of internal congestion on 15-minute market and 5-minute market prices in the California ISO balancing area. The tables show the top 25 most congested lines, ranked by their impact, while the "Other" category shows the average impact of the remaining constraints.

In the real-time market, there was more pronounced impact of constraints near renewable generation zones. The constraints associated with the Imperial Valley area increased the price in the SDG&E area, with minimal impact on other regions within the California ISO balancing area. These constraints are associated with solar generation pockets, areas of high solar generation, and reach into the metropolitan area within the SDG&E region.

Additionally, TOTAL_WYOMING_EXPORT and WINDSTAREXPORTTCOR are constraints within PacifiCorp East. Despite an average price impact of $0.11/MWh, their binding frequency exceeds 55 percent of the time. These constraints facilitate the delivery of energy from wind generation pockets to other balancing authority areas.

35 The metrics for WEIM internal congestion can be found in Appendix B.

36 These constraints are shown as 30055_GATES1_500_30060_MIDWAY_500_BR_1_1, 30040_TESLA_500_30050_LOSBANOS_500_BR_1_1, and 7820_TL50002_IV-NG-OUT_TDM in the tables, respectively.

Table 1.3 Impact of internal transmission constraint congestion on 15-minute market prices – top 25 primary congestion constraints

Constraint	Frequency	Average quarter impact ($/MWh)		
		PG&E	SCE	SDG&E
30055_GATES1_500_30060_MIDWAY_500_BR_1_1	13.6%	1.24	-1.79	-1.71
30040_TESLA_500_30050_LOSBANOS_500_BR_1_1	9.3%	0.52	-1.62	-1.55
7820_TL50002_IV-NG-OUT_TDM	2.8%	0.01	0.13	2.29
30050_LOSBANOS_500_30055_GATES1_500_BR_1_2	3.3%	0.38	-0.72	-0.69
30750_MOSSLD_230_30797_LASAGUIL_230_BR_1_1	9.4%	0.27	-0.47	-0.45
OMS_14369435_Miguel_BK80	2.1%	0.03	0.08	0.67
7820_TL230S_OVERLOAD_NG	4.2%	0.01	0.03	0.67
OMS_14330422_Miguel_BK81	0.5%	0.03	0.06	0.48
35618_SNJSEA_115_35620_ELPATIO_115_BR_1_1	2.0%	0.23	-0.15	-0.15
22886_SUNCREST_230_22885_SUNCREST_500_XF_2_P	1.7%	0.02	0.06	0.43
OMS14384679_50001_OOS_NG	0.9%	0.02	0.04	0.33
MIGUEL_BKs_MXFLW_NG	0.3%	0.02	0.04	0.31
22464_MIGUEL_230_22468_MIGUEL_500_XF_81	0.5%	0.01	0.03	0.28
TOTAL_WYOMING_EXPORT	55.4%	0.11	0.11	0.11
WINDSTAREXPORTTCOR	59.4%	0.11	0.11	0.11
22846_SANJCP_230-22260_ESCNDO_230-BR1	0.6%	0.02	0.03	-0.25
30790_PANOCHE_230_30900_GATES_230_BR_2_1	2.1%	0.05	-0.11	-0.10
35621_IBM-HRJ_115_35642_METCALF_115_BR_1_1	3.0%	0.14	-0.06	-0.06
7820_TL23040_IV_SPS_NG	1.2%	0.00	0.02	0.17
OMS14384680_50001_OOS_NG	0.4%	0.01	0.02	0.15
22260_ESCNDIDO_230_22844_TALEGA_230_BR_1_1	0.1%	0.01	0.02	-0.13
OMS_14291578_SUNCRESTBK80_NG	0.3%	0.01	0.02	0.13
OMS14407105_50001_OOS_NG	0.4%	0.01	0.02	0.13
OMS14204875ML_BK80_NG	0.2%	0.01	0.02	0.13
24801_DEVERS_500_24804_DEVERS_230_XF_1_P	2.9%	0.08	0.03	0.03
Other	1.5%	0.29	-0.15	-0.03
Total		3.59	-4.22	1.30

Table 1.4 Impact of internal transmission constraint congestion on 5-minute market prices– top 25 primary congestion constraints

Constraint	Frequency	Average quarter impact ($/MWh)		
		PG&E	SCE	SDG&E
30055_GATES1_500_30060_MIDWAY_500_BR_1_1	12.3%	1.22	-1.75	-1.68
30040_TESLA_500_30050_LOSBANOS_500_BR_1_1	9.0%	0.54	-1.71	-1.63
7820_TL50002_IV-NG-OUT_TDM	2.8%	0.01	0.13	2.25
30050_LOSBANOS_500_30055_GATES1_500_BR_1_2	3.0%	0.35	-0.67	-0.64
7820_TL230S_OVERLOAD_NG	4.3%	0.02	0.05	1.05
30750_MOSSLD_230_30797_LASAGUIL_230_BR_1_1	9.3%	0.23	-0.41	-0.39
OMS_14369435_Miguel_BK80	2.0%	0.03	0.09	0.77
OMS_14330422_Miguel_BK81	0.5%	0.03	0.06	0.51
22886_SUNCREST_230_22885_SUNCREST_500_XF_2_P	1.7%	0.02	0.06	0.41
35618_SNJSEA_115_35620_ELPATIO_115_BR_1_1	1.8%	0.19	-0.14	-0.13
TOTAL_WYOMING_EXPORT	49.7%	0.12	0.12	0.12
MIGUEL_BKs_MXFLW_NG	0.3%	0.01	0.04	0.31
WINDSTAREXPORTTCOR	55.5%	0.12	0.12	0.12
OMS14384679_50001_OOS_NG	0.8%	0.01	0.04	0.30
22464_MIGUEL_230_22468_MIGUEL_500_XF_81	0.4%	0.01	0.03	0.24
22846_SANJCP_230-22260_ESCNDO_230-BR1	0.5%	0.02	0.03	-0.22
30790_PANOCHE_230_30900_GATES_230_BR_2_1	2.3%	0.05	-0.11	-0.10
OMS14204875ML_BK80_NG	0.2%	0.01	0.02	0.18
35621_IBM-HRJ_115_35642_METCALF_115_BR_1_1	2.5%	0.11	-0.05	-0.05
22260_ESCNDIDO_230_22844_TALEGA_230_BR_1_1	0.1%	0.01	0.02	-0.15
30005_ROUNDMT_500_30015_TABLEMT_500_BR_2_2	0.5%	0.07	0.05	0.05
OMS14384680_50001_OOS_NG	0.3%	0.01	0.02	0.13
OMS_14291578_SUNCRESTBK80_NG	0.4%	0.01	0.02	0.13
6110_COI_N-S	0.4%	0.06	0.05	0.04
7820_TL23040_IV_SPS_NG	0.9%	0.00	0.01	0.13
Other	1.5%	0.23	-0.12	0.15
Total		3.47	-4.00	1.89

1.7.3 Congestion on interties

In the fourth quarter of 2023, the frequency of congestion on major interties increased relative to last year. Despite this, congestion rent decreased relative to the fourth quarter of 2022, primarily due to lower shadow prices and lower intertie limits.

The total import congestion charges reported by DMM represent the products of the shadow prices multiplied by the binding limits for the intertie constraints. For a supplier or load serving entity trying to import power over an intertie congested in the import direction, assuming a radial line, the congestion price represents the difference between the higher price of generation on the California ISO side of the intertie and the lower price of import bids outside of the California ISO area. This congestion charge also represents the amount paid to owners of congestion revenue rights that are sourced outside the California ISO area at points corresponding to these interties.

Figure 1.28 shows total import congestion charges in the day-ahead market for 2022 and 2023. Figure 1.29 shows the frequency of congestion on five major interties. Table 1.5 provides a detailed summary of this data over a broader set of interties. As highlighted in these charts and table:

- Total import congestion charges for the fourth quarter of 2023 were $8 million, compared to $13 million in the same quarter of 2022. Three major interties (Malin 500, NOB, and Palo Verde) accounted for over 90 percent of the total congestion charges. The Malin 500 intertie recorded the highest congestion rent, amounting to $4 million.
- The hours during which these major interties were binding increased in Q4 compared to the same quarter of 2022. The frequency of congestion on Malin rose from one percent to eight percent of hours in the day-ahead market, and congested hours on NOB rose from one percent to three percent. The frequency of congestion on Palo Verde dropped slightly from four percent to three percent of hours.

Figure 1.28 Day-ahead import congestion charges on major interties

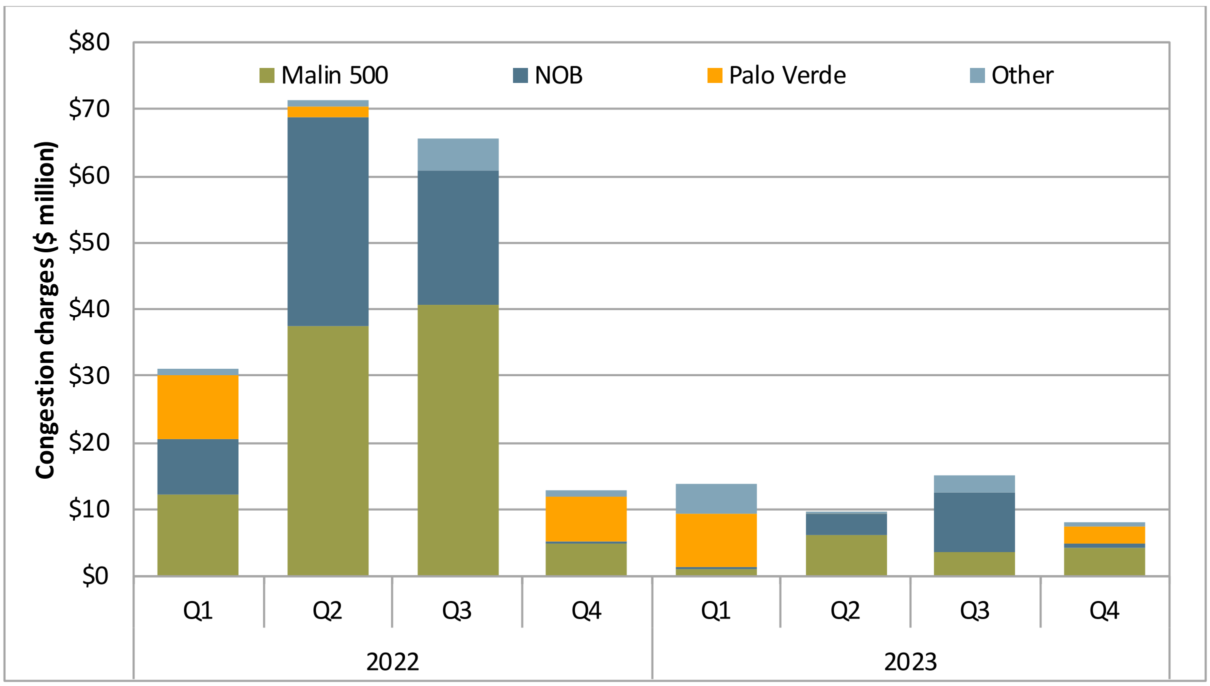


Figure 1.29 Frequency of import congestion on major interties in the day-ahead market

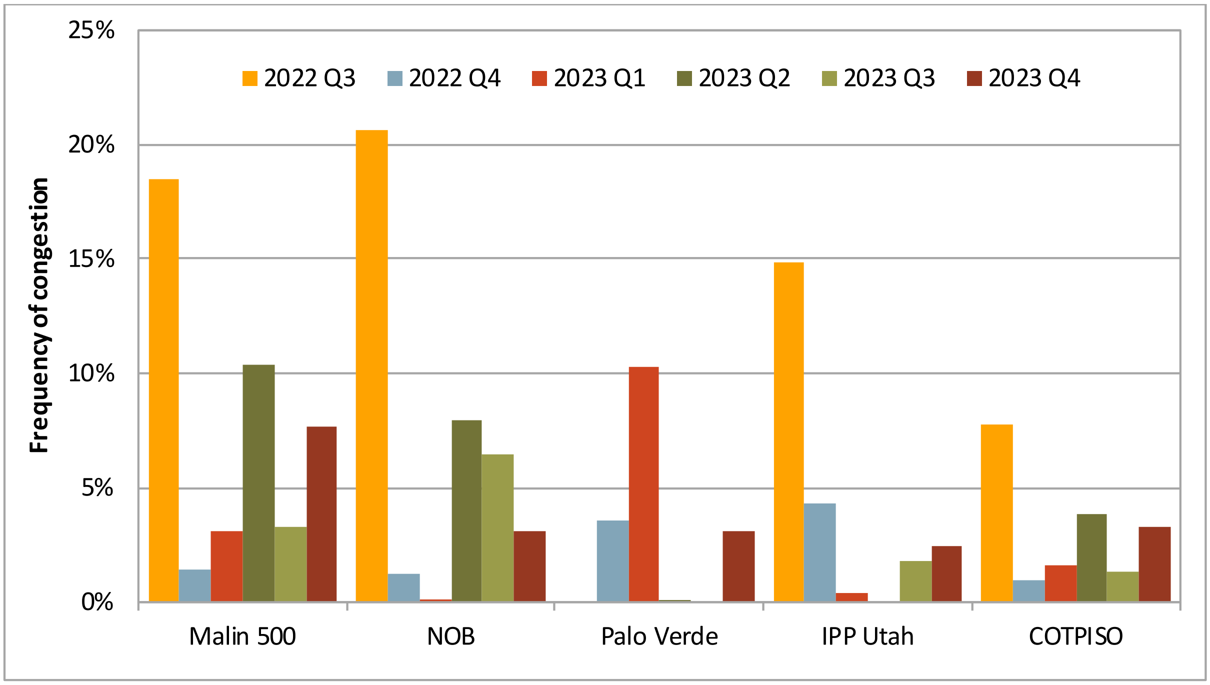


Table 1.5 Summary of import congestion in the day-ahead market (2022-2023)

Area	Intertie	Frequency of import congestion						Import congestion charges ($ thousand)					
		2022		2023				2022		2023			
		Q3	Q4	Q1	Q2	Q3	Q4	Q3	Q4	Q1	Q2	Q3	Q4
Northwest	Cascade	0%			0%			7			0		
	COTPISO	8%	1%	2%	4%	1%	3%	310	15	39	77	46	158
	Malin 500	18%	1%	3%	10%	3%	8%	40,646	4,786	1,183	6,266	3,467	4,110
	NOB	21%	1%	0%	8%	6%	3%	20,229	333	68	3,075	9,007	851
	Summit	0%	1%	0%		1%	0%	14	4	10		42	5
Southwest	Gonder IPP Utah					0%						21	
	IID-SCE			1%	1%					150	91		
	IPP Adelanto	0%	0%	7%				0	12	2,996			
	IPP Utah	15%	4%	0%		2%	2%	4,092	1,084	18		59	186
	Marketplace Adelanto						0%						81
	Mead	0%		0%		2%		308		75		2,370	
	Merchant	0%						101					
	Palo Verde		4%	10%	0%		3%		6,663	8,199	33		2,593
	Westwing Mead			2%						1,013			

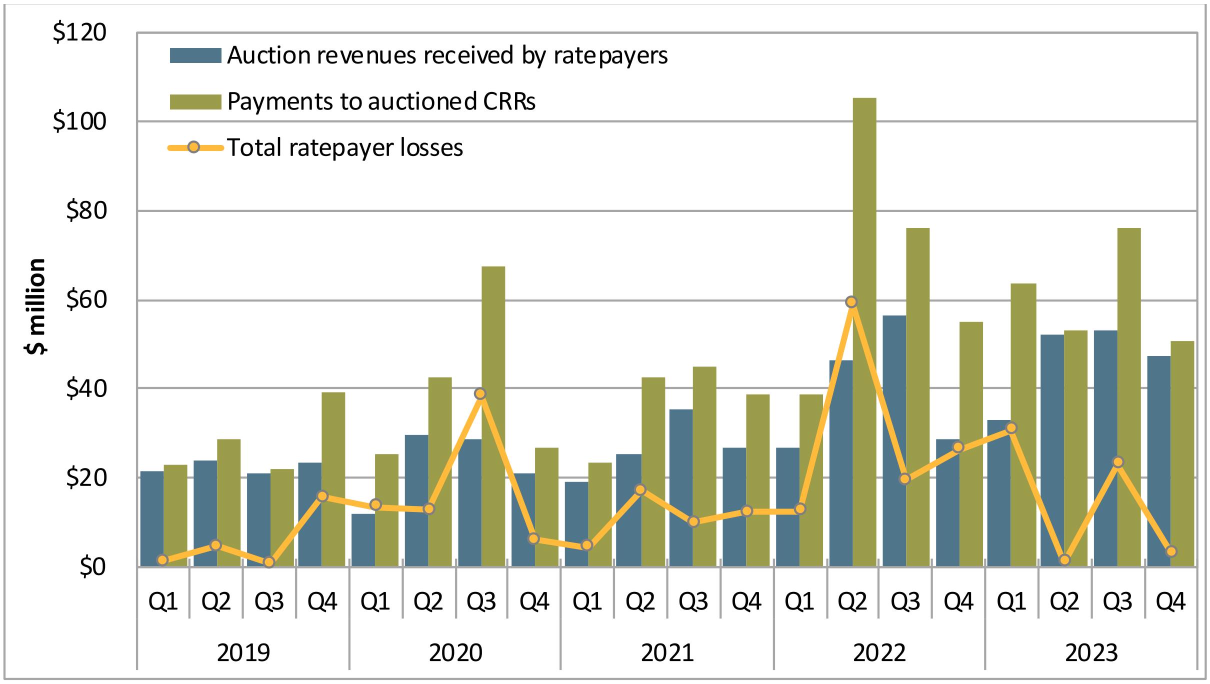
1.8 Congestion revenue rights

Congestion revenue right auction returns

Profits from the congestion revenue right (CRR) auction by non-load serving entities are calculated by summing revenue paid out to congestion revenue rights purchased by these entities, and then subtracting the auction price paid for these rights. While this represents a profit to entities purchasing rights in the auction, it represents a loss to transmission ratepayers.

As shown in Figure 1.30, transmission ratepayers lost about $3 million during the fourth quarter of 2023 as payments to auctioned congestion revenue rights holders were higher than auction revenues. This was a reduction from ratepayer losses of about $26 million in the fourth quarter of 2022.

Figure 1.30 Auction revenues and payments to non-load serving entities



During the fourth quarter of 2023:

- Financial entities received profits of about $1.2 million, down from about $18.6 million during the same quarter of 2022. Total revenue deficit offsets were about $12 million.[37]
- Marketers lost about $0.5 million from auctioned rights, down from $5.3 million in 2022. Total revenue deficit offsets were over $5 million.
- Physical generation entities gained about $2.7 million from auctioned rights, up from $1.9 million in 2022. Total revenue deficit offsets were nearly $2 million.

The $3 million in third quarter 2023 auction losses was only about 1.5 percent of day-ahead congestion rent. This is significantly down from 11.6 percent from the previous quarter and down from seven percent in the fourth quarter of 2022. The losses as a percent of day-ahead congestion rent were well below the average of 28 percent during the three years before the track 1A and 1B changes (2016 through 2018).[38]

37 The total congestion rent is calculated by constraint and compared to the total CRR payments across all scheduling coordinators (SCs) from the constraint. If the CRR payments are greater than the congestion rent collected for a constraint, the difference is charged as an offset to the SCs with net flows on the constraint.

38 California ISO, Congestion Revenue Rights Auction Efficiency Track 1A Draft Final Proposal Addendum, March 8, 2018: http://www.caiso.com/InitiativeDocuments/DraftFinalProposalAddendum-CongestionRevenueRightsAuctionEfficiency-Track1.pdf

The impact of track 1A changes, which limit the types of congestion revenue rights that can be sold in the auction, cannot be directly quantified. However, based on current settlement records, DMM estimates that changes in the settlement of congestion revenue rights made under track 1B reduced total payments to non-load serving entities by about $19 million in the fourth quarter. The track 1B effects on auction bidding behavior and reduced auction revenues are not known.

Rule changes made by the ISO reduced losses from sales of congestion revenue rights significantly in 2019, particularly in the first three quarters following their implementation. DMM continues to recommend that the ISO take steps to discontinue auctioning congestion revenue rights on behalf of ratepayers. The auction consistently continues to cause millions of dollars in losses to transmission ratepayers each year, while exposing transmission ratepayers to a risk of significantly higher losses in the event of unexpected increases in congestion or modeling errors. If the ISO believes it is highly beneficial to actively facilitate hedging of congestion costs by suppliers, DMM recommends the ISO convert the congestion revenue rights auction into a market for financial hedges based on clearing of bids from willing buyers and sellers.

1.9 Real-time imbalance offset costs

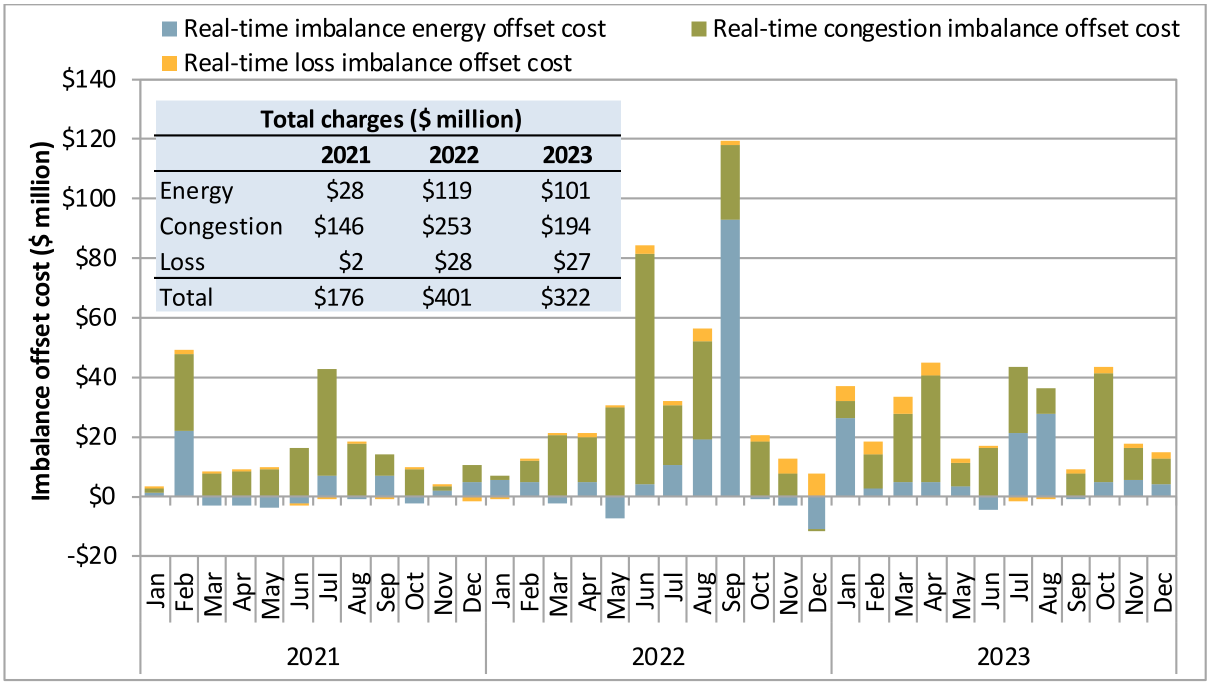
Real-time imbalance offset costs were $76 million in the fourth quarter of 2023.[39] This was a significant increase over the $25 million of real-time imbalance offset costs in the fourth quarter of 2022. In the fourth quarter of 2023, real-time *congestion* imbalance offset costs made up $56 million of these costs while real-time imbalance *energy* offset costs made up $14 million.

The real-time imbalance offset cost is the difference between the total money *paid out* by the California ISO balancing area and the total money *collected* by the California ISO area for energy settled in the real-time energy markets. Within the California ISO balancing area system, the charge is allocated as an uplift to measured demand (physical load plus exports).

The real-time imbalance offset charge consists of three components. Any revenue imbalance from the congestion components of real-time energy settlement prices is collected through the *real-time congestion imbalance offset charge* (RTCIO). Similarly, any revenue imbalance from the *loss* component of real-time energy settlement prices is collected through the *real-time loss imbalance offset charge,* while any remaining revenue imbalance is *recovered* through the *real-time imbalance energy offset charge* (RTIEO).

[39] Information in this section is based on settlement values available at the time of drafting and will be updated in future reports. Updates can occur regularly within the settlements timeline, starting with T+9B (trade date plus nine business days) and T+70B, as well as others up to 36 months after the trade date. At the time of drafting, values for December have not passed the T+70B threshold.

Figure 1.31 Real-time imbalance offset costs



Inconsistencies in settlement of real-time market demand and generation

Real-time revenue imbalances can be created by inconsistency between what generation is paid and what load pays. DMM has identified two significant sources of such inconsistency.

- Settling real-time load using an hourly price weighted by the absolute value of incremental load
- Settling real-time load using incorrect load schedules to weight prices

These two sources of real-time revenue load imbalances are described in more detail below.

Hourly price weighted by the absolute value of incremental load

Real-time *generation* is paid incrementally from one market to the next. The difference from the day-ahead to 15-minute market schedule is settled at the 15-minute market price, and the difference from the 15-minute to 5-minute market schedule (as well as from the 5-minute market to metered amount) is settled at the 5-minute market price. Real-time *load* is instead settled on the difference from the day-ahead schedules to metered load using a weighted average of the 15-minute and 5-minute market prices in each hour.

In some hours, the hourly real-time price is weighted by incremental load in the 15-minute and 5-minute markets. This price is calculated in a way that mathematically maintains revenue balance from day-ahead to 5-minute market schedules, but can be inappropriate in practice when applied to the difference between day-ahead scheduled load and *metered* load. Therefore, under some real-time conditions, real-time load is instead settled using an average hourly price that is weighted by the *absolute value* of incremental load in the 15-minute and 5-minute markets.[40] The *absolute value weighted average price* prevents extreme settlement outcomes under certain conditions, but also tends to cause the ISO to collect less money from real-time load than is paid to generators in the real-time market. This creates revenue shortfalls, which must be instead recovered through imbalance-offset charges.[41] The imbalance offset costs are allocated to total metered load plus exports. DMM recommends that the ISO settle real-time load incrementally in each market directly using market prices.

Incorrect load schedules to weight prices

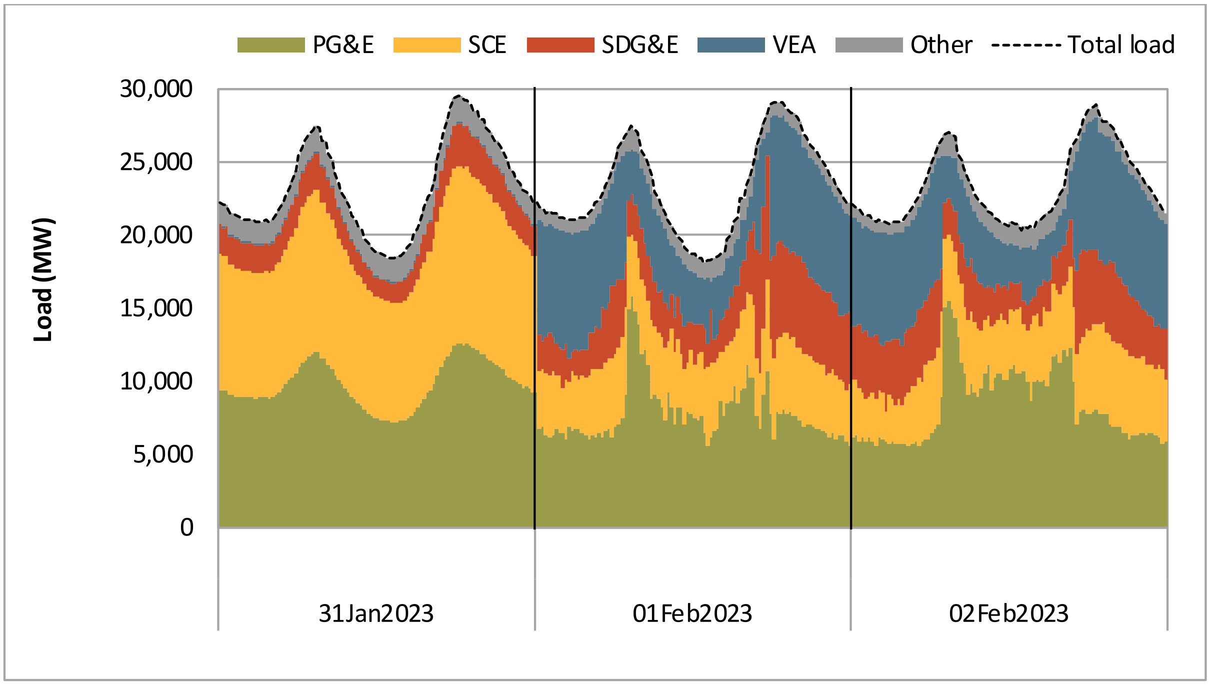
During most of 2023, incorrect load schedules for the CAISO balancing area load aggregation points (LAPs) were used to weight prices and settle real-time load imbalance. Figure 1.32 shows 15-minute market load schedules by LAP between January 31, 2023 and February 2, 2023.[42] Due to an error with the implementation of flexible ramping product refinements on February 1, 2023, the distribution of the total CAISO load to the load aggregation points were incorrect. For example, load schedules on the Valley Electric Association (VEA) aggregate node are typically less than 100 MW, but were over 10,000 MW in many hours during the year. 5-minute market schedules were also impacted, though to a lesser extent. This issue was corrected on February 5, 2024. The ISO is working on resettling the errors.

40 If the calculated weighted average price is outside the minimum or maximum of 15-minute and 5-minute market prices during the hour, then the ISO uses the absolute value weighted price. The absolute value weighted price is also used if these conditions exist for any individual price component (energy, congestion, losses, or GHG).

41 For more information, see DMM's special report: Department of Market Monitoring, *Real-time load settlement price calculation causing revenue imbalances*, August 30, 2023: http://www.caiso.com/Documents/Real-Time-Load-Settlements-and-Revenue-Imbalances-Aug-30-2023.pdf

42 Total load schedules on the metered subsystem load aggregation points (MLAP) and custom load aggregation points (CLAP) are grouped together in "Other".

Figure 1.32 15-minute market aggregate load schedules (January 31, 2023 to February 2, 2023)



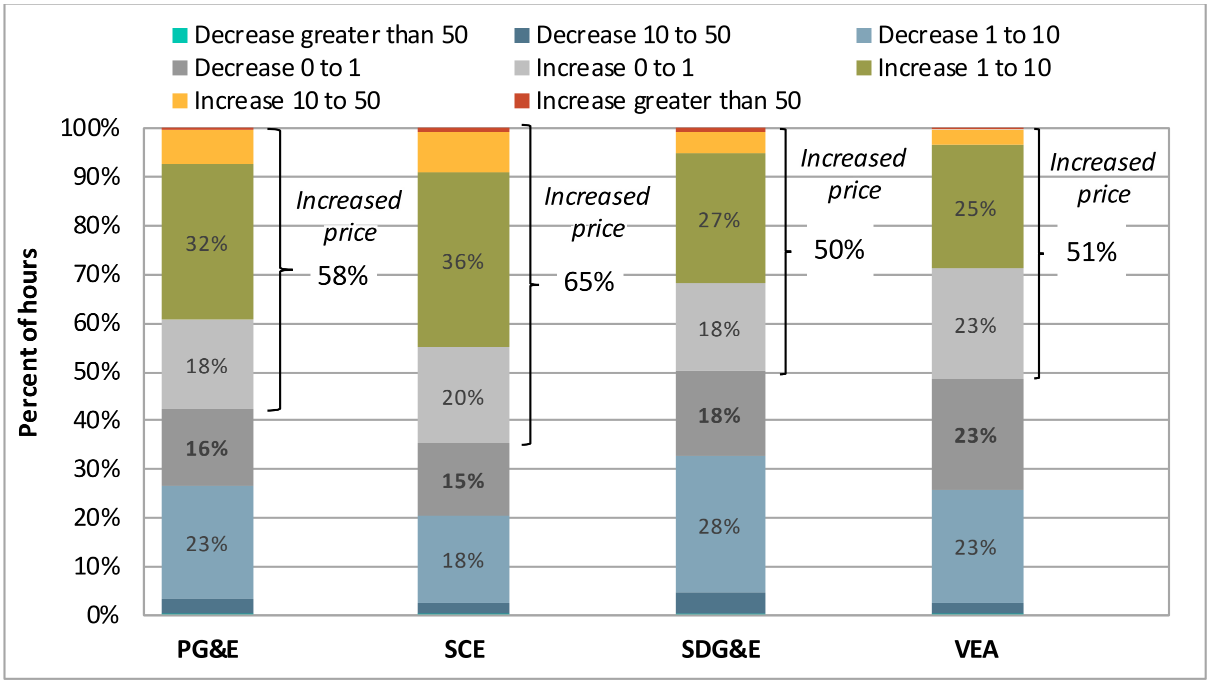
Non-participating real-time load is settled on the difference between the hourly day-ahead schedules and metered load, using an hourly weighted price calculated from the 15-minute and 5-minute market prices. Here, the incorrect aggregate load schedules do not impact the day-ahead or metered load, but do impact the weighting of prices in the calculation of the hourly real-time price.

Figure 1.33 summarizes the estimated impact of the error on the hourly real-time price used to settle load.[43] It shows the percent of hours in 2023 since February, in which the calculated price was higher or lower for each default load aggregation point because of the error. Overall, there was not an extreme directionality in the way the error impacted the prices, though it tended to increase the price.

The use of incorrect load schedules increased the price for SCE real-time load imbalance in 65 percent of hours. For PG&E, SDG&E, and VEA the error increased the price in 58, 50, and 51 percent of hours, respectively. In most hours, the impact on the hourly real-time price was less than $10 — though both these instances and the small percent of hours with more significant price differences can have a significant impact on total payments from load.

43 DMM estimates the impact of the error by comparing to a counterfactual calculation of the hourly real-time price using corrected aggregate load schedules. These aggregate load schedules were determined by using the normal load distribution and load aggregation factors to distribute the total market load to the aggregate load schedules. In some cases, this information was not available such that it had to be estimated.

Figure 1.33 Impact of incorrect aggregate load schedules on hourly real-time price (February 1, 2023 to December 31, 2023)



When metered load exceeds day-ahead schedules, load-serving entities will be charged for the incremental imbalance.[44] When metered load is less than day-ahead schedules, load-serving entities will instead be paid for the decremental imbalance. Figure 1.34 summarizes the percent of hours in 2023 since February 1 in which the error was estimated to contribute to either revenue surplus or revenue shortfall. Overall, the error is estimated to more frequently contribute to *revenue shortfalls*, either from the ISO collecting less from load-serving entities for incremental load imbalance or by paying load-serving entities more for decremental load imbalance. Across the default load aggregation points, this issue caused a revenue shortfall between 57 and 64 percent of hours between February 1 and December 31.

- ***Increased*** **price and** ***incremental*** **total metered load imbalance:** Load-serving entities were charged more overall for incremental load imbalance (increased net charge from load). The increased payment from load contributes to revenue surplus.
- ***Decreased*** **price and** ***decremental*** **total metered load imbalance:** Load-serving entities were paid less overall for decremental load imbalance in real-time (increased net charge to load). The decreased payments to load contributes to revenue surplus.
- ***Decreased*** **price and** ***incremental*** **total day-ahead to metered load imbalance:** Load-serving entities were charged less overall for incremental load imbalance (decreased net charge to load). The decreased payment from load contributes to revenue shortfall.

44 Assuming the hourly real-time price is positive.

- ***Increased* price and *decremental* total day-ahead to metered load imbalance:** Load-serving entities were paid more overall for decremental load imbalance (decreased net charge to load). The increased payments to load contributes to revenue shortfall.

Figure 1.34 Impact of incorrect aggregate load schedules on net charge to load (February 1, 2023 to December 31, 2023)

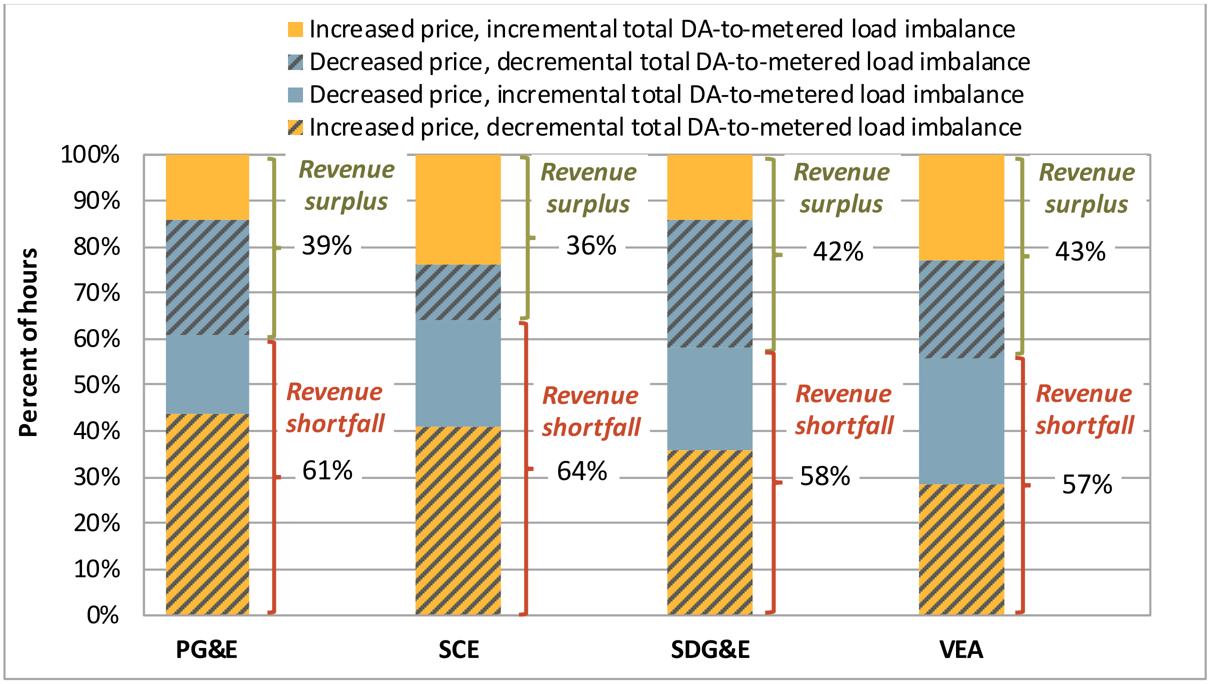


Figure 1.35 shows the monthly estimated impact of the error on settled non-dispatchable real-time load between February 1 and December 31, 2023. Table 1.6 shows the same information instead by load aggregation point over the entire period.[45] Any estimated revenue imbalance because of the error was assessed for each hour by load-serving entity and location, and shown summed as either contributing to shortfall or surplus. As shown in Figure 1.35, the effects contributing to either revenue surplus or revenue shortfall largely cancelled each other out in July and August, when prices were highest. Greater imbalance was instead accrued in the off-summer period. In net over this period, the error was estimated to decrease in-market payments from load (or increase the payments to load) by around $11.2 million. This effect would not have been balanced by generation and therefore would have contributed to revenue shortfall. The shortfall would have been recovered through the real-time imbalance offset charges, which shifts the allocation of these costs between load-serving entities and exporters based on measured demand. Between February and December, DMM estimates that this would have ultimately shifted around $7.1 million in net costs between market participants, including around $0.8 million in load costs to exporters.

45 "Other" category includes impact at Custom Load Aggregation Points (CLAP) and Metered Subsystem Load Aggregation Points (MLAP).

Figure 1.35 Estimated impact of incorrect aggregate load schedules by month

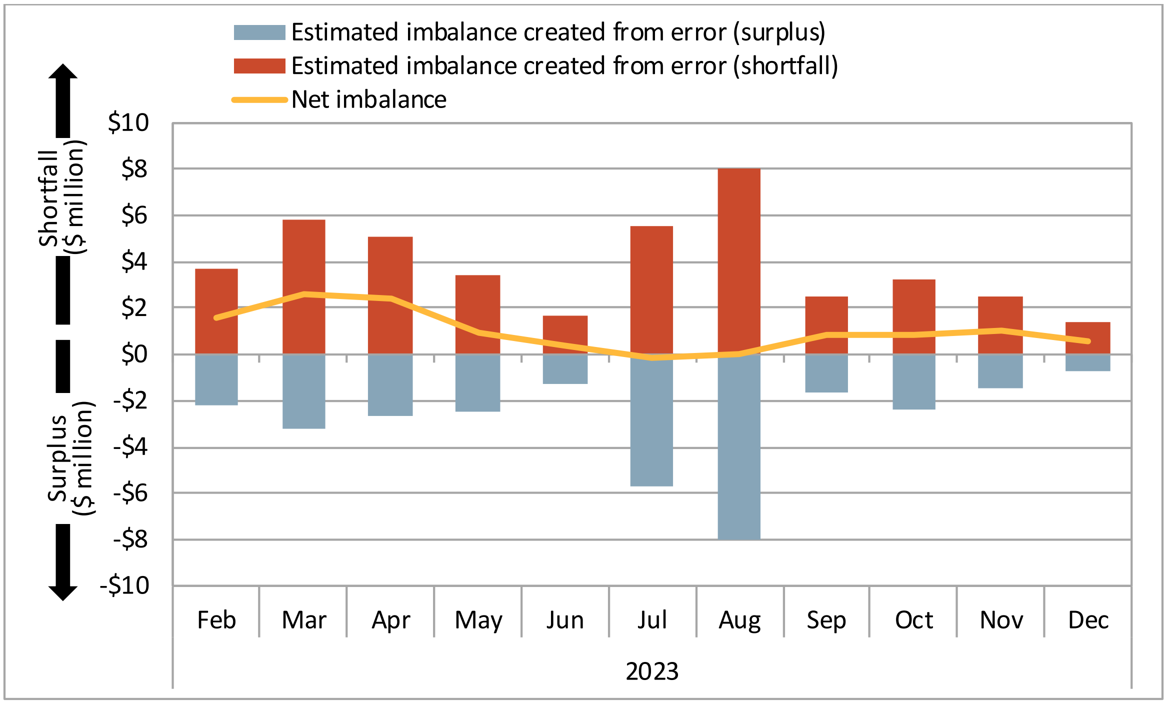


Table 1.6 Estimated impact of incorrect aggregate load schedules on net charge to load (February 1, 2023 to December 31, 2023)

LAP	Estimated impact of error (shortfall)	Estimated impact of error (surplus)	Estimated net shortfall
PG&E	$16,282,242	$12,474,293	$3,807,949
SCE	$18,793,455	$14,007,041	$4,786,415
SDG&E	$6,557,468	$4,661,010	$1,896,458
VEA	$180,919	$94,975	$85,944
Other	$1,099,241	$520,172	$579,069
Total	$42,913,325	$31,757,491	**$11,155,835**

Issue in allocation of real-time congestion imbalance offset costs

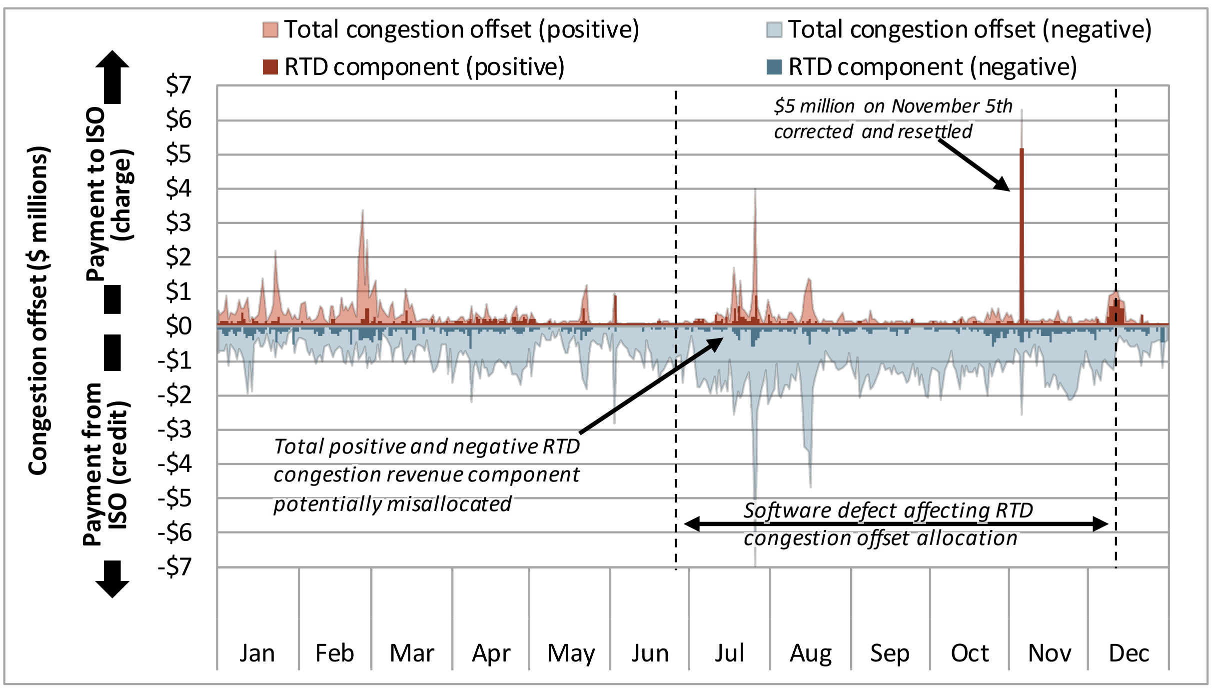
Real-time congestion imbalance offset costs occur when the congestion payments that the ISO pays out do not equal the congestion payments collected by the ISO (i.e., the payments and collections do not balance). This calculation considers the net congestion revenue from a number of components including 15-minute market instructed imbalance energy, 5-minute market instructed imbalance energy, uninstructed imbalance energy, and unaccounted for energy. Starting June 26, 2023, a software defect affected the allocation of the *5-minute market* component of the congestion offset calculation. The issue was fixed on December 12, 2023.

Figure 1.36 shows the daily 5-minute market congestion revenue during 2023 across all WEIM entities, where payments to the ISO (charge) are shown positive in red and payments from the ISO (credit) are shown negative in blue.[46] The *total* positive or negative congestion offset for each day is also shown for comparison in the lighter shades.

Figure 1.37 shows the same information, except with only the 5-minute market component during the period impacted by the issue. On November 5, an extreme event resulted in around $5 million in congestion imbalance in the Pacific Northwest region during 14 five-minute market intervals. This amount was then incorrectly allocated across a number of WEIM balancing areas in a way that was inconsistent with each area's expected share of the congestion component of the price. The ISO has manually corrected and resettled the congestion allocation for the 14 five-minute market intervals on November 5.

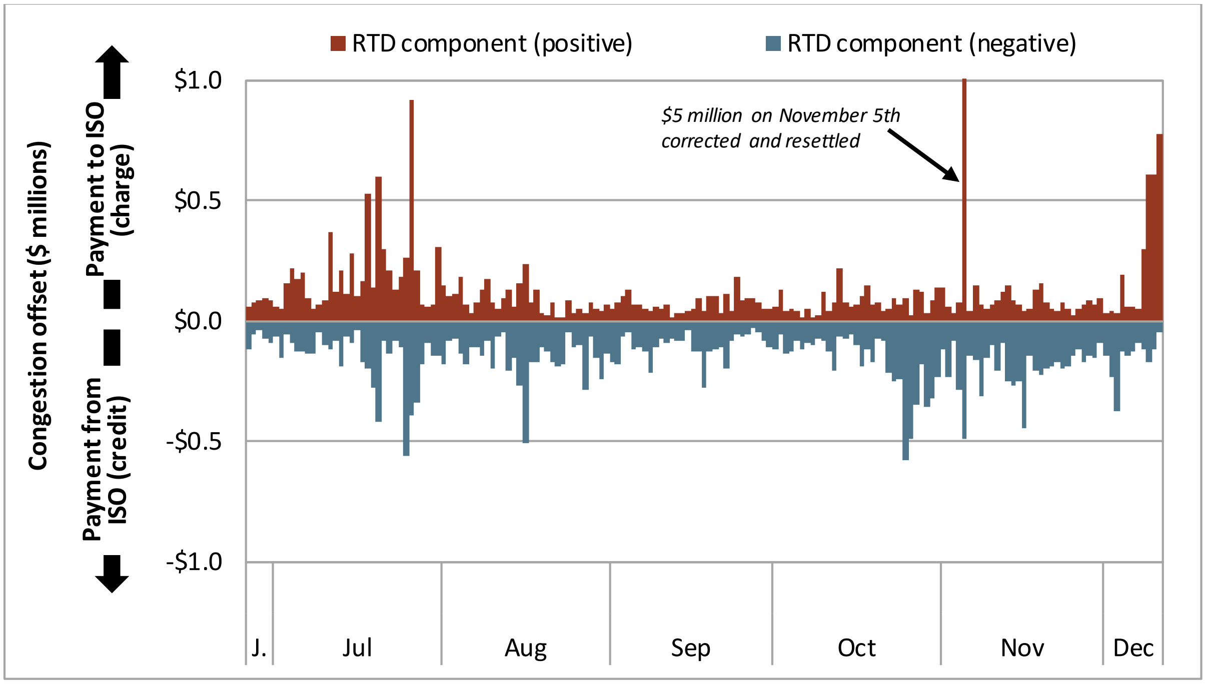
Due to the manual nature and complexity of this correction, the extreme outcome on November 5 was targeted, while additional hours and days during the period in which the issue had an impact were not adjusted. Over these 169 days, the total 5-minute component of congestion offsets paid to WEIM entities were around $26 million, while the amount charged to WEIM entities were around $19 million. DMM understands that some of this amount was misallocated to WEIM entities. However, any offsets associated with 5-minute market congestion on internal transmission constraints, for instance, would not have been impacted by the underlying issue.

Figure 1.36 WEIM daily congestion offsets (January–December 2023)



46 These amounts exclude congestion offset allocations to the CAISO balancing area. Most of the congestion offset allocation to the CAISO balancing area is expected to occur from internal transmission constraint congestion that was not impacted by the underlying issue.

Figure 1.37 WEIM daily 5-minute market component of congestion offset calculation (Issue period, June 26 to December 11, 2023)



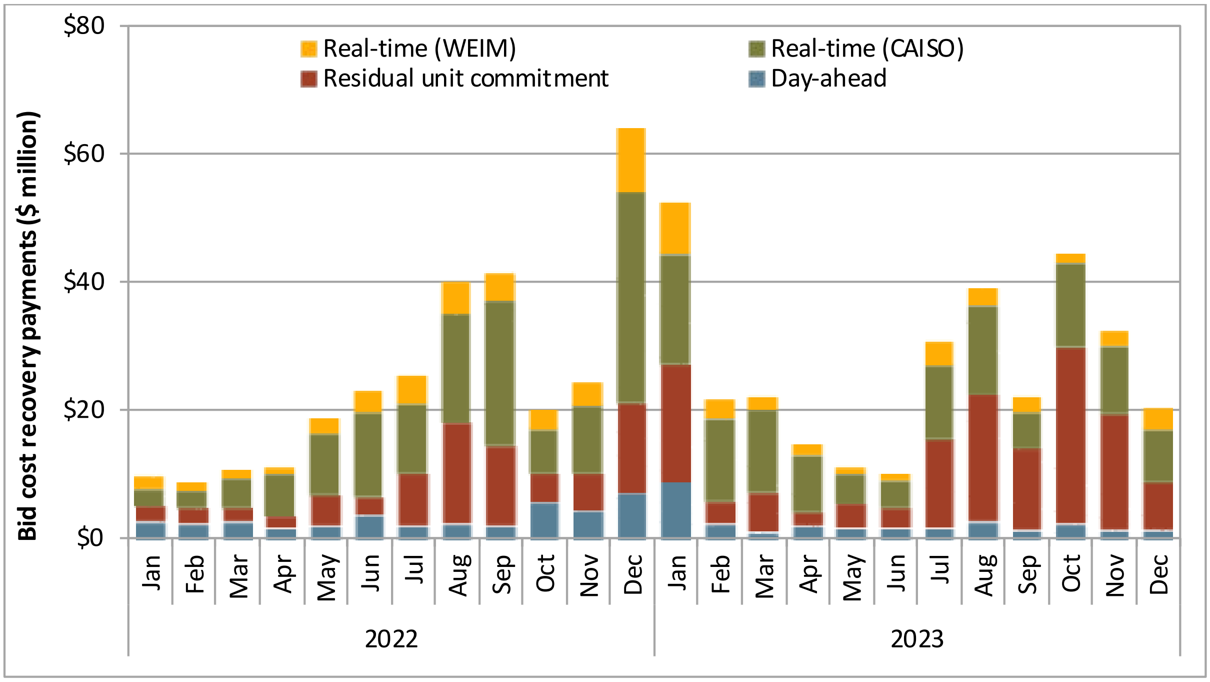
1.10 Bid cost recovery

During the fourth quarter of 2023, estimated bid cost recovery payments for units in the California ISO and Western energy imbalance market (WEIM) balancing areas totaled about $90 million and $7 million, respectively. These payments were lower than the same quarter of 2022, when payments totaled $92 million in the California ISO and $17 million in the WEIM areas.

Figure 1.38 shows monthly bid cost recovery payments in the fourth quarter of 2023. Bid cost recovery payments associated with the day-ahead integrated forward market totaled about $5 million, which was less than the $6 million in the fourth quarter of 2022. Bid cost recovery payments associated with residual unit commitment during the quarter totaled about $53 million, or about $29 million higher than the fourth quarter of 2022. Bid cost recovery attributed to the real-time market totaled about $39 million, $1 million lower than the payments in the previous quarter, and about $28 million lower than the same quarter of 2022. Out of the $32 million in real-time payments, about $7 million was allocated to non-California ISO resources participating in the WEIM.

Generating units are eligible to receive bid cost recovery payments if total market revenues earned over the course of a day do not cover the sum of all the unit's accepted bids. This calculation includes bids for start-up, minimum load, ancillary services, residual unit commitment availability, day-ahead energy, and real-time energy. Excessively high bid cost recovery payments can indicate inefficient unit commitment or dispatch. In the fourth quarter, about 82 percent of these payments, or about $80 million, were made to gas resources, followed by about $8 million to battery energy storage resources.

Figure 1.38 Monthly bid cost recovery payments



1.11 Imbalance conformance

Operators in the California ISO and the WEIM balancing areas can manually adjust the load forecasts used in the real-time markets in order to help maintain system reliability. The ISO refers to this as *imbalance conformance*. These adjustments are to account for potential modeling inconsistencies and inaccuracies, and to create additional unloaded ramping capacity in the real-time market.

Frequency and size of imbalance conformance adjustments

Beginning in 2017, there was a large increase in imbalance conformance adjustments during the steep morning and evening net load ramp periods in the California ISO balancing area hour-ahead and 15-minute markets. Figure 1.39 shows imbalance conformance adjustments in real-time markets for the fourth quarter of 2022 and 2023. Average hourly imbalance conformance adjustments in the hour-ahead and 15-minute markets decreased in the fourth quarter of 2023 relative to the same quarter of 2022, over both the morning and evening ramp periods. The evening peak highest hourly average of about 1,650 MW decreased about 400 MW compared to the prior year. During the morning ramp, the highest average hourly adjustments were around 120 MW. This was a decrease of about 600 MW compared to the fourth quarter of 2022.

The 5-minute market adjustments decreased in the morning ramp hours while increasing in the evening hours compared to the fourth quarter or 2022. Negative adjustments to the load forecast occurred prior to the morning ramp hours and during the mid-day period.

Figure 1.39 Average hourly imbalance conformance adjustment (Q4 2022 and Q4 2023)

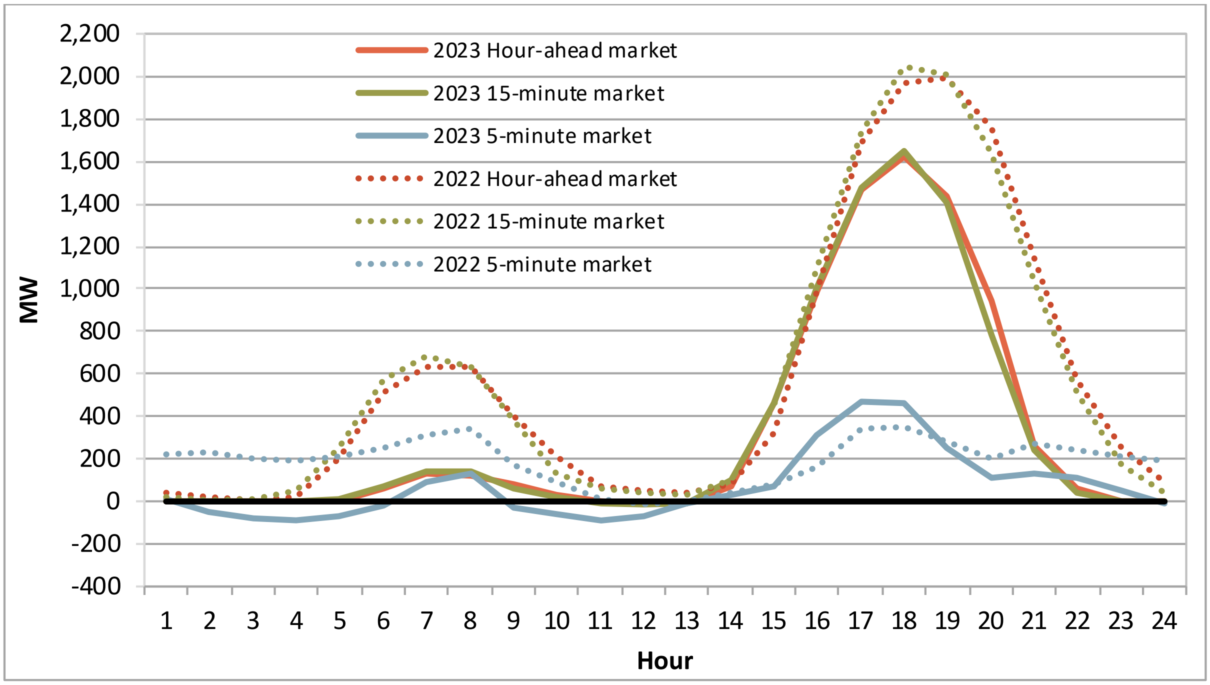
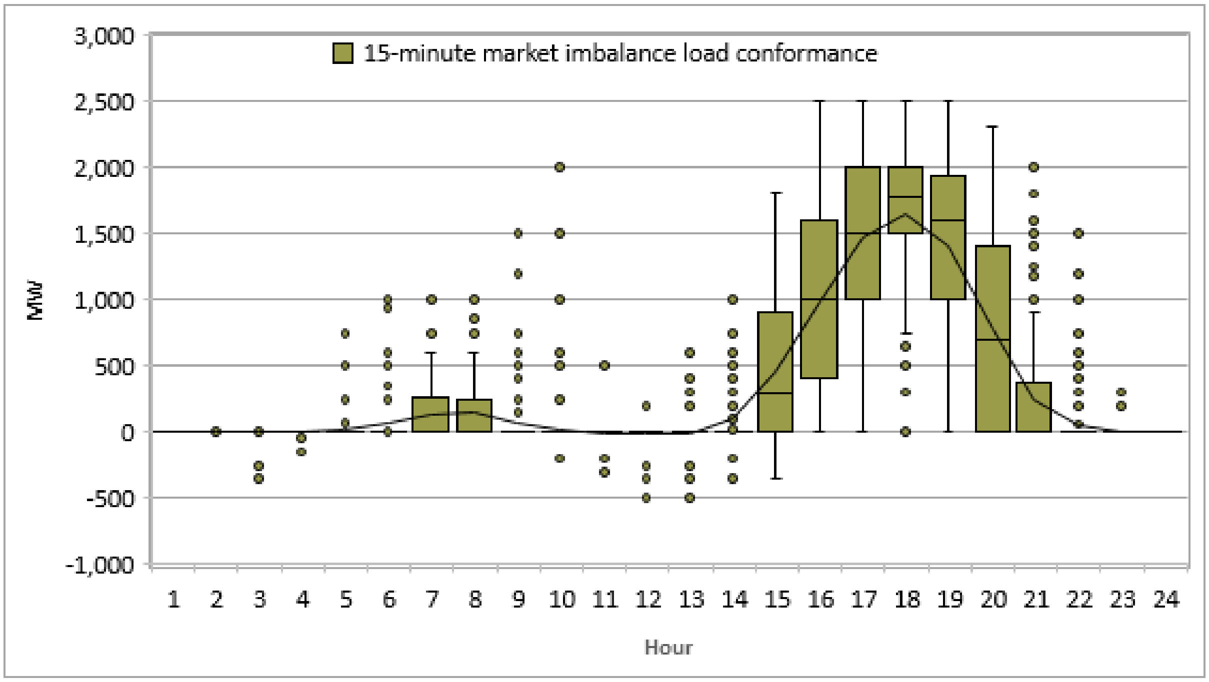


Figure 1.40 shows each hour's distribution of the 15-minute market load adjustments for the fourth quarter of 2023. This box and whisker graph highlights extreme outliers (positive and negative), minimum, lower quartile, median, upper quartile, and maximum, as well as the mean (line). The extreme outliers are represented by the filled "dots". The outside whiskers do not include these outliers. For the quarter, the maximums and major outliers in hours-ending 16 to 19, e.g., 2,500 MW, occurred during the late October and early November time periods associated with rapid solar ramp down.

Figure 1.40 15-minute market hourly distribution of operator load adjustments (Q4 2023)



1.12 Flexible ramping product

The flexible ramping product is designed to enhance reliability and market performance by procuring upward and downward flexible ramping capacity in the real-time market to help manage volatility and uncertainty surrounding net load forecasts.[47] The amount of flexible capacity the product procures is derived from a demand curve, which reflects a calculation of the optimal willingness-to-pay for that flexible capacity. The demand curves allow the market optimization to consider the trade-off between the cost of procuring additional flexible ramping capacity and the expected reduction in power balance violation costs.

1.12.1 Flexible ramping product deliverability enhancements and market outcomes

On February 1, 2023, the ISO implemented enhancements to the flexible ramping product. This introduced two significant changes. The first of these improves the deliverability by procuring and pricing flexible capacity at a nodal level to better ensure that sufficient transmission is available for this capacity to be utilized. The second significant change adjusted the calculation of the uncertainty requirement by incorporating current load, solar, and wind forecast information using a method called mosaic quantile regression.

47 The flexible ramping product procures both upward and downward flexible capacity, in both the 15-minute and 5-minute markets. Procurement in the 15-minute market is intended to ensure that enough ramping capacity is available to meet the needs of both the upcoming 15-minute market run and the three corresponding 5-minute market runs. Procurement in the 5-minute market is aimed at ensuring that enough ramping capacity is available to manage differences between consecutive 5-minute market intervals.

Flexible ramping product requirement and deliverability enhancements

The end of the demand curve is implemented in the ISO market optimization as a soft requirement that can be relaxed in order to balance the cost and benefit of procuring more or less flexible ramping capacity. This requirement for rampable capacity reflects the upper end of uncertainty in each direction that might materialize.[48] Therefore, it is sometimes referred to as the *flex ramp requirement* or *uncertainty requirement*.

The real-time market enforces an area-specific uncertainty requirement for balancing areas that fail the resource sufficiency evaluation. This requirement can only be met by flexible capacity within that area. Flexible capacity for the group of balancing areas that pass the resource sufficiency evaluation are pooled together to meet the uncertainty requirement for the rest of the system.

As part of flexible ramping product enhancements, deliverable flexible capacity awards are now produced through two deployment scenarios that adjust the expected net load forecast in the following interval by the lower and upper ends of uncertainty that might materialize. Here, the uncertainty requirement is distributed at a nodal level to load, solar, and wind resources based on allocation factors that reflect the estimated contribution of these resources to potential uncertainty. The result is more deliverable upward and downward flexible capacity awards that do not violate transmission or transfer constraints.

Flexible ramping product prices

As part of flexible ramping product enhancements, flexible ramping product prices are now determined locationally at each node. This price can be made up of two components. The first component is the shadow price associated with meeting the uncertainty requirement — either for the group of balancing areas that pass the resource sufficiency evaluation or the individual balancing areas that fail the tests.

The nodal price can also include a congestion component. This reflects the shadow price on transmission constraints and relative contribution to that congestion which is expected based on the dispatch of all flexible capacity in the deployment scenarios. At implementation of the enhancements on February 1, 2023, only base-case flow-based transmission constraints were modeled in the deployment scenarios. Nomogram constraints were later enforced for flexible ramping product procurement on September 13, 2023. Contingency flowgate constraints are being assessed for potential implementation in the future.

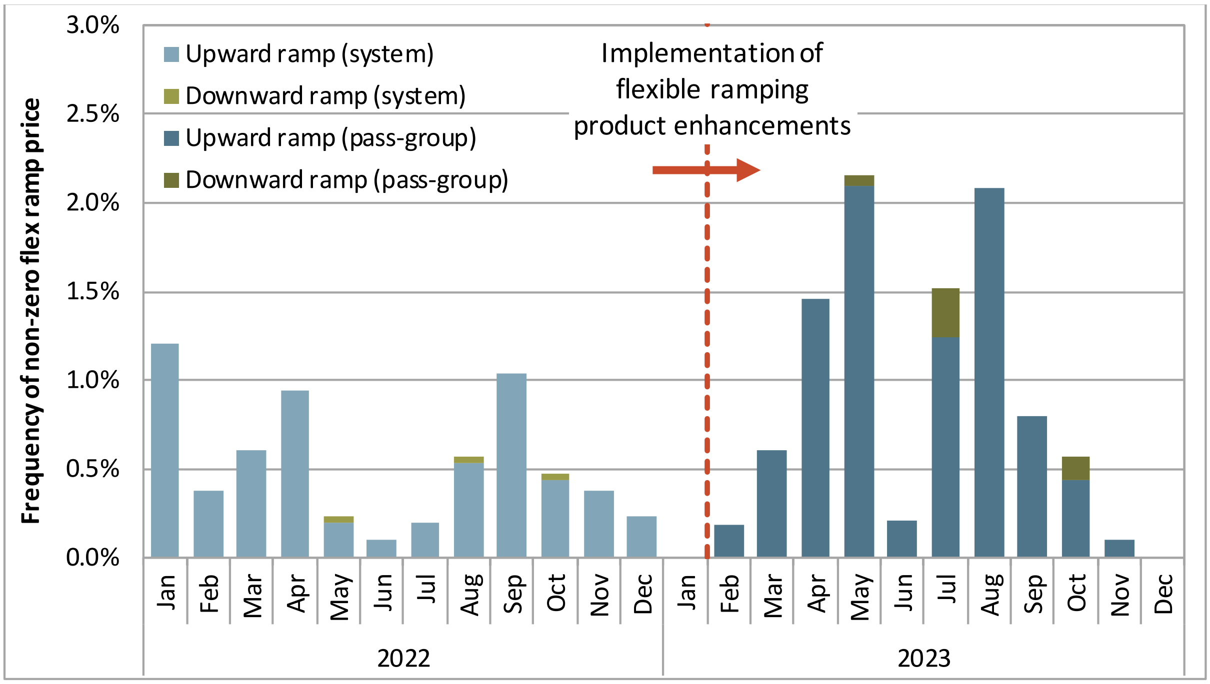
Flexible ramping product prices for the group of balancing areas that pass the resource sufficiency evaluation continue to be frequently zero since the enhancements were implemented on February 1, 2023. When the shadow price on this constraint is zero, this reflects that flexible capacity within this wider footprint of balancing areas that passed the resource sufficiency evaluation is readily available. Here, the upper end of the uncertainty requirement can be met by resources with zero opportunity cost for providing that flexibility

Figure 1.41 shows the percent of intervals since implementation of the enhancements in which the 15-minute market price for flexible capacity was non-zero for the *group of balancing areas that pass the*

48 Based on a 95 percent confidence interval.

tests.[49] This is the shadow price associated with meeting the pass-group uncertainty requirement and does not account for any congestion component that may affect the price of flexible capacity at a nodal level. This is compared against the frequency of non-zero prices on the constraint for *system*-wide flexible capacity that was in place prior to the enhancements. The frequency of non-zero prices were very low during the quarter. 15-minute market prices for upward flexible capacity within the pass-group were non-zero in less than 0.2 percent of intervals. In the month of December, 15-minute market prices for flexible capacity within the pass-group were always zero. In the 5-minute market, the frequency of non-zero prices were more infrequent — in less than 0.1 percent of intervals.

Figure 1.41 Frequency of non-zero system or pass-group flexible ramping product shadow price



Flexible ramping product procurement and impact of the enhancements

This section summarizes flexible capacity procured to meet the uncertainty needs of the greater WEIM system during the quarter. Figure 1.42 and Figure 1.43 show the percent of upward or downward flexible capacity that was procured from various fuel types, both before and after the enhancements that were implemented at the start of February 2023. Prior to the enhancements, these amounts reflect the percent of *system-wide* uncertainty. After the enhancements, these amounts instead reflect the percent of *pass-group* uncertainty for the group of balancing areas that passed the resource sufficiency evaluation.

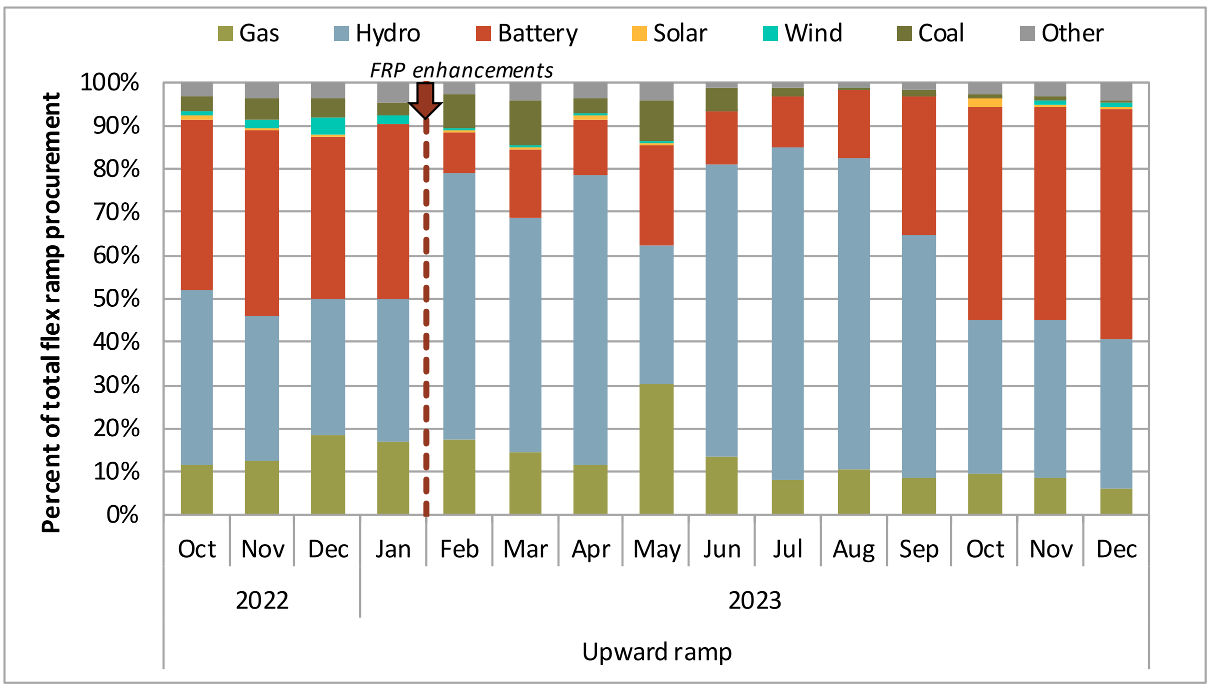
49 For the group of balancing areas that pass the resource sufficiency evaluation, the demand curves for flexible capacity are distributed out to *surplus zones.* These surplus zones are separate for each balancing area (or by LAP in the case of California ISO and BANC). The upper end of the demand curve for each surplus zone is equal to its share of the total pass-group uncertainty. In some cases, a balancing area may be transfer constrained from the rest of the system and unable to meet its share of pass-group uncertainty at a cost less than the value of the final segment of the demand curve. This figure will only capture shadow prices for the greater pass-group region and will not include prices associated with local "insufficiency".

During the quarter, battery resources contributed to much more upward and downward flexible capacity compared to the previous quarter. Battery resources made up almost 51 percent of upward flexible capacity and 26 percent of downward flexible capacity in Q4 2023. In Q3 2023, battery resources made up only 20 percent of upward flexible capacity and eight percent of downward flexible capacity. Hydro resources continued to supply a large portion of upward flexible capacity (35 percent), but they supplied a much lower portion compared to the previous quarter (68 percent).

Figure 1.44 and Figure 1.45 instead show the percent of upward or downward flexible capacity that was procured in various regions.[50] These regions reflect a combination of general geographic location as well as common price-separated groupings that can exist when a balancing area is collectively import or export constrained along with one or more other balancing areas relative to the greater WEIM system.

As shown in Figure 1.44, compared to the previous quarter, the percent of upward capacity procured within the CAISO increased significantly to around 60 percent of upward and downward flexible capacity. These levels are comparable to those prior to the implementation of flexible ramping product enhancements in February. Prior to the enhancements, a minimum requirement often required that a portion of system-wide flexible capacity be procured within CAISO to help mitigate issues with stranded flexible capacity elsewhere in the system.[51]

Figure 1.42 Percent of upward system or pass-group flexible ramp procurement by fuel type



50 For a list of the balancing areas in each region, see Appendix B.

51 The minimum requirement was a temporary measure prior to the implementation of flexible ramping product enhancements. This measure was removed with the implementation of the enhancements.

Figure 1.43 Percent of downward system or pass-group flexible ramp procurement by fuel type

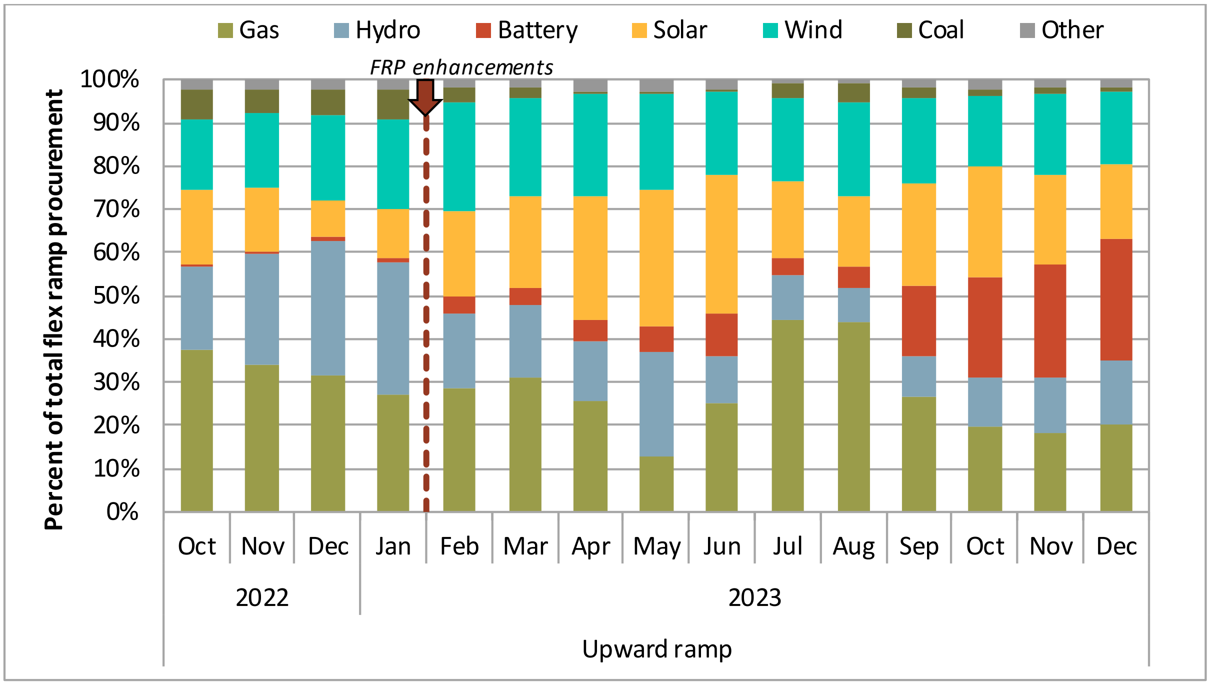


Figure 1.44 Percent of upward system or pass-group flexible ramp procurement by region

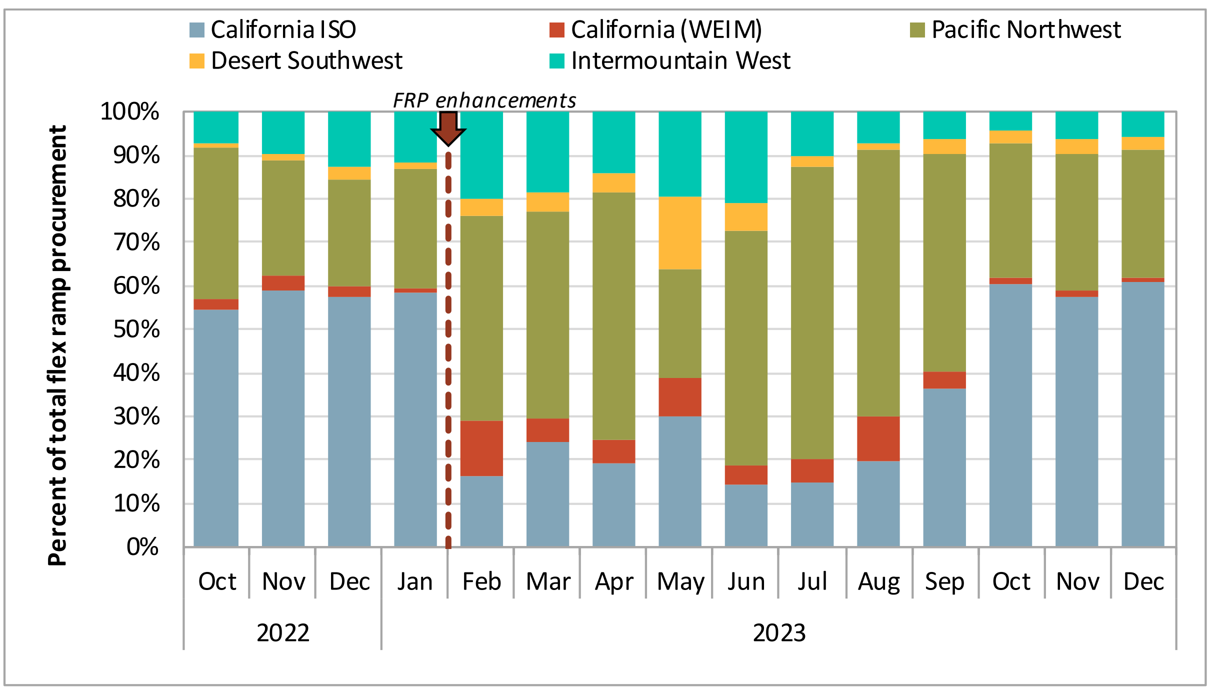
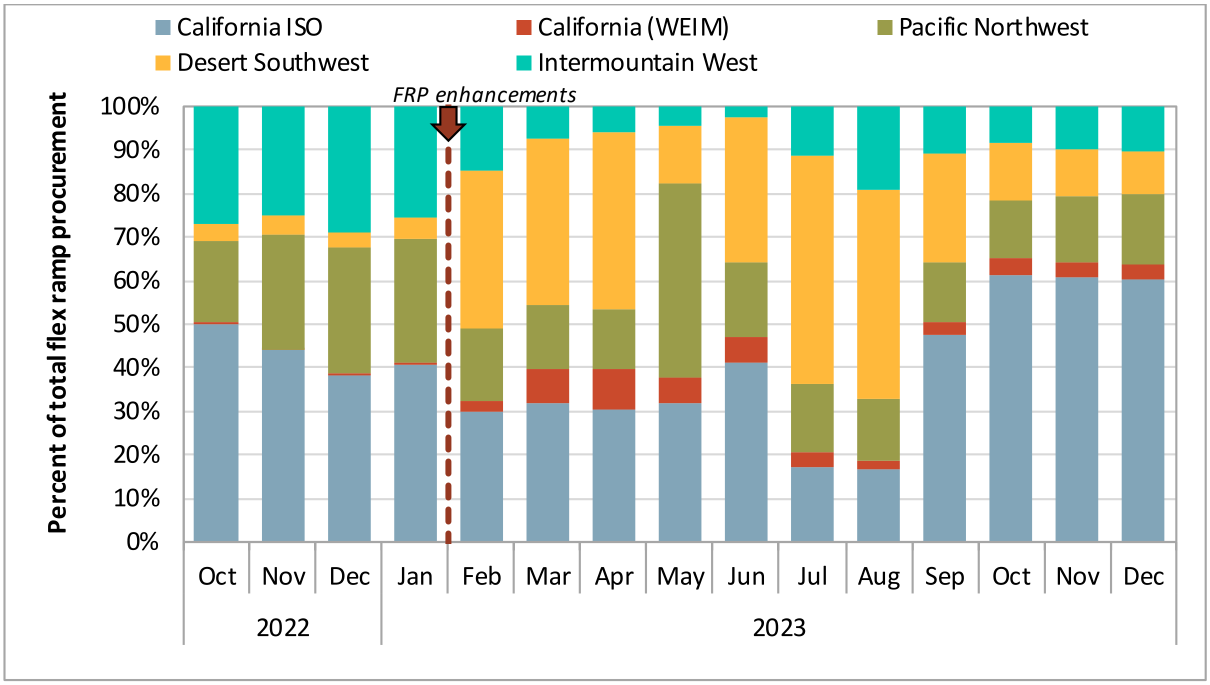


Figure 1.45 Percent of downward system or pass-group flexible ramp procurement by region



1.12.2 Net load uncertainty for the flexible ramping product

The uncertainty requirement is used as part of the flexible ramping product design to capture the extreme ends of net load uncertainty, such that it can be optimally relaxed based on the trade-off between the cost of procuring additional flexible ramping capacity and the expected cost of a power balance relaxation. Net load uncertainty is also included in the requirement of the flexible ramp sufficiency test (flexibility test) to capture additional flexibility needs that may be required in the evaluation hour due to variation in either load, solar, or wind forecasts.

The calculation of uncertainty was adjusted on February 1 using a method called mosaic quantile regression. This method applies regression techniques on historical data to produce a series of coefficients that define the relationship between forecast information (load, solar, or wind) and the extreme percentile of uncertainty that might materialize (95 percent confidence interval).[52]

Net load uncertainty for the group of balancing areas that passed the resource sufficiency evaluation

The flexible ramping product uses an area-specific uncertainty requirement for balancing areas that fail the resource sufficiency evaluation, which can only be met by flexible capacity within that area. Here, the regressions can be performed in advance and local uncertainty targets can be readily determined

[52] For a detailed explanation of the mosaic quantile regression calculation, see the Q1 2023 Report on Market Issues and Performance, Department of Market Monitoring, September 19, 2023, pp 66-70: http://www.caiso.com/Documents/2023-First-Quarter-Report-on-Market-Issues-and-Performance-Sep-19-2023.pdf

based on current forecast information when a balancing area fails the test. However, for the group of balancing areas that pass the resource sufficiency evaluation (known as the pass-group), the uncertainty calculation needs to first know which balancing areas make up this group so that it can perform the regression using historical data accordingly for that group.

To perform the regressions to estimate the pass-group uncertainty, the composition of balancing areas in this group is based on earlier test results for the first and second 15-minute market interval of each hour. In the first interval, the results from the earliest resource sufficiency evaluation (T-75) is used to define the pass-group. In the second interval, the results from the second resource sufficiency evaluation (T-55) is used to define the pass-group. This is based on the latest information available at the time of this process.

However, the current weather information that is ultimately combined with the regression results to calculate uncertainty are instead consistent with the group of balancing areas in the pass-group for flexible ramping capacity procurement. This is based on the second run of the resource sufficiency evaluation (T-55) for interval 1 and the final resource sufficiency evaluation (T-40) for intervals 2 through 4. Table 1.7 summarizes this inconsistency by showing which resource sufficiency evaluation run is used for each interval and process.

Table 1.7 Source of pass-group for calculating uncertainty and procuring flexible ramping capacity

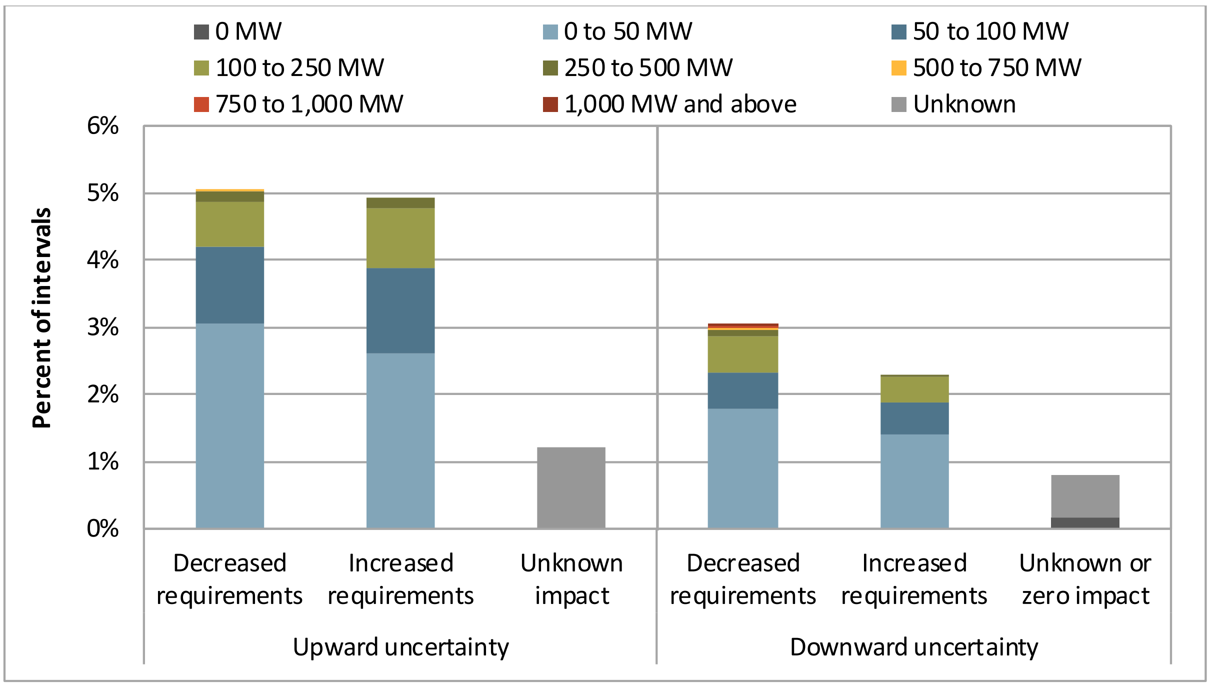
15-minute market interval	Current weather information for calculating uncertainty and flex ramp procurement	Regression inputs and outputs
1	Second run (T-55)	First run (T-75)
2	Final run (T-40)	Second run (T-55)
3	Final run (T-40)	Final run (T-40)
4	Final run (T-40)	Final run (T-40)

Using an inconsistent composition of balancing areas in the pass-group between the forecast and regression information can create significant swings in the calculated uncertainty for this group. For example, if you have a model to predict uncertainty based on forecast information of all but one balancing area passing the test (based on earlier test results), but then combine this with current forecast information of all balancing areas (based on later test results), then the calculated uncertainty can be disconnected from forecasted conditions in the system. DMM has requested that the ISO consider options to resolve inconsistencies in the composition of balancing areas in the pass-group.

During about 16 percent of intervals for the fourth quarter of 2023, the composition of balancing areas in the pass-group used for regression information was inconsistent with the composition of balancing areas in the pass-group used for current forecast information. Figure 1.46 summarizes the impact of this inconsistency on pass-group uncertainty requirements in cases when the composition of balancing areas differed between the two sets of data. The figure shows the percent of intervals in which the market uncertainty requirements (with inconsistent balancing areas in the pass-group) were higher or lower than counterfactual uncertainty requirements with a consistent composition of balancing areas in the pass-group.[53] These results are shown separately for the following categories to highlight the impact of this inconsistency on uncertainty requirements.

- **Decreased requirements** indicate that market uncertainty requirements for the pass-group were lower as a result of inconsistent balancing areas in the pass-group.
- **Increased requirements** indicate that market uncertainty requirements for the pass-group were higher as a result of inconsistent balancing areas in the pass-group.
- **No impact** indicates that uncertainty requirements were capped by thresholds in a way that resulted in the same uncertainty requirements.
- **Unknown impact** indicates that there was an inconsistent composition of balancing areas in the pass-group but data was not available to calculate the impact.

Figure 1.46 Impact of pass-group inconsistency on uncertainty requirements (October–December 2023)



Threshold for capping uncertainty

Uncertainty calculated from the quantile regressions is capped by the lesser of two thresholds. The thresholds are designed to help prevent extreme outlier results from impacting the final uncertainty. The *histogram* threshold is pulled for each hour from the 1st and 99th percentile of net load error observations from the previous 180 days.[54] The seasonal threshold is updated each quarter and is calculated based on the 1st and 99th percentile using observations over the previous 90 days. Here, each

[53] This analysis accounts for any thresholds that capped, or would have capped, calculated uncertainty requirements.

[54] The histogram threshold is updated every day. The distributions are separate for each hour and day type (weekday or weekend/holiday).

hour is calculated separately and the greatest upward and downward uncertainty across all hours sets the mosaic threshold for each hour of the same direction.

During the quarter, the thresholds capped upward and downward uncertainty for the group of balancing areas that passed the resource sufficiency evaluation in around 10 percent of intervals in the 15-minute market and seven percent of intervals in the 5-minute market. The histogram threshold capped calculated uncertainty much more frequently compared to the mosaic threshold.

A threshold is also in place that sets the floor for uncertainty at 0.1 MW in both directions. The upward and downward uncertainty is therefore set near zero when the uncertainty calculated from the quantile regression would be negative. During the quarter, the 15-minute market uncertainty calculated for the group of balancing areas that passed the resource sufficiency evaluation was set near zero by this threshold in 0.2 percent of intervals for upward uncertainty and 0.7 percent of intervals for downward uncertainty.

Results of quantile regression uncertainty calculation

Figure 1.47 compares 15-minute market uncertainty for the group of balancing areas that passed the resource sufficiency evaluation, both with the histogram method (pulled from the 2.5th and 97.5th percentile of observations in the hour from the previous 180 days) and with the mosaic quantile regression method. The green and blue lines show the average upward and downward uncertainty from each method, while the areas around the lines show the minimum and maximum amount over the month. The dashed red and yellow lines show the average histogram and mosaic thresholds, respectively, during the period.

Figure 1.48 shows the same information for 5-minute market uncertainty. 5-minute market uncertainty reflects the error between the binding and advisory net load forecasts in the 5-minute market.

Overall, pass-group uncertainty calculated from the quantile regression approach was typically lower or comparable to uncertainty calculated with the histogram approach. In particular, the regression-based uncertainty was much lower on average in the peak evening hours, in comparison to the histogram-based uncertainty. However, results of the regression-based approach vary more widely, including periods with much lower uncertainty.

Figure 1.47 15-minute market pass-group uncertainty requirements (weekdays, October–December 2023)

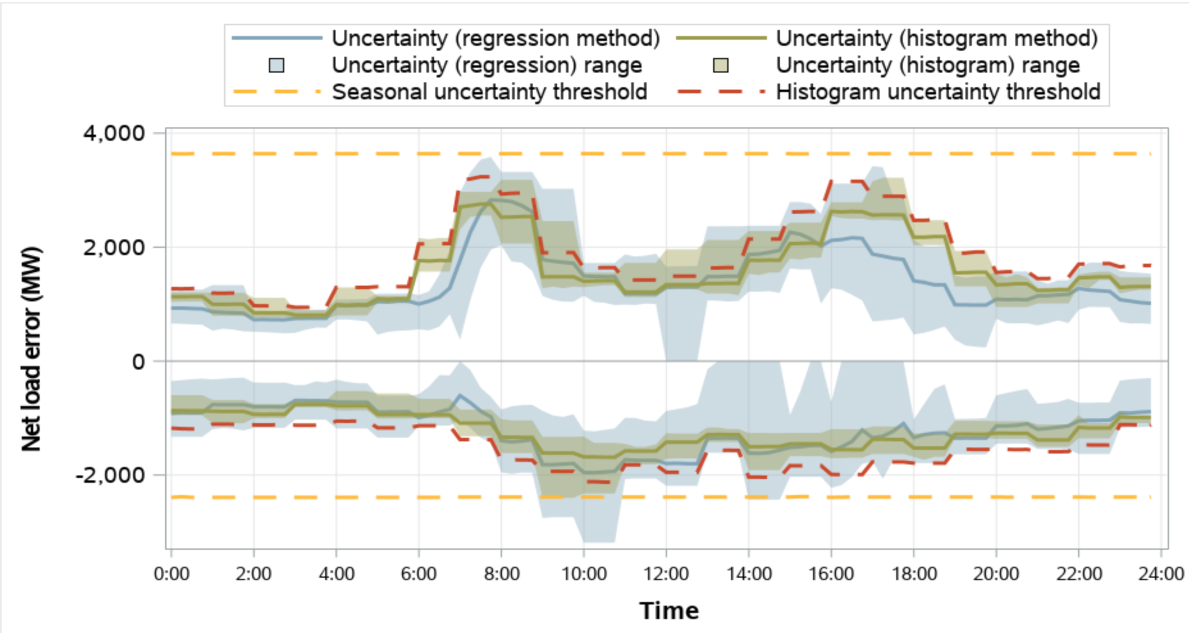


Figure 1.48 5-minute market pass-group uncertainty requirements (weekdays, October–December 2023)

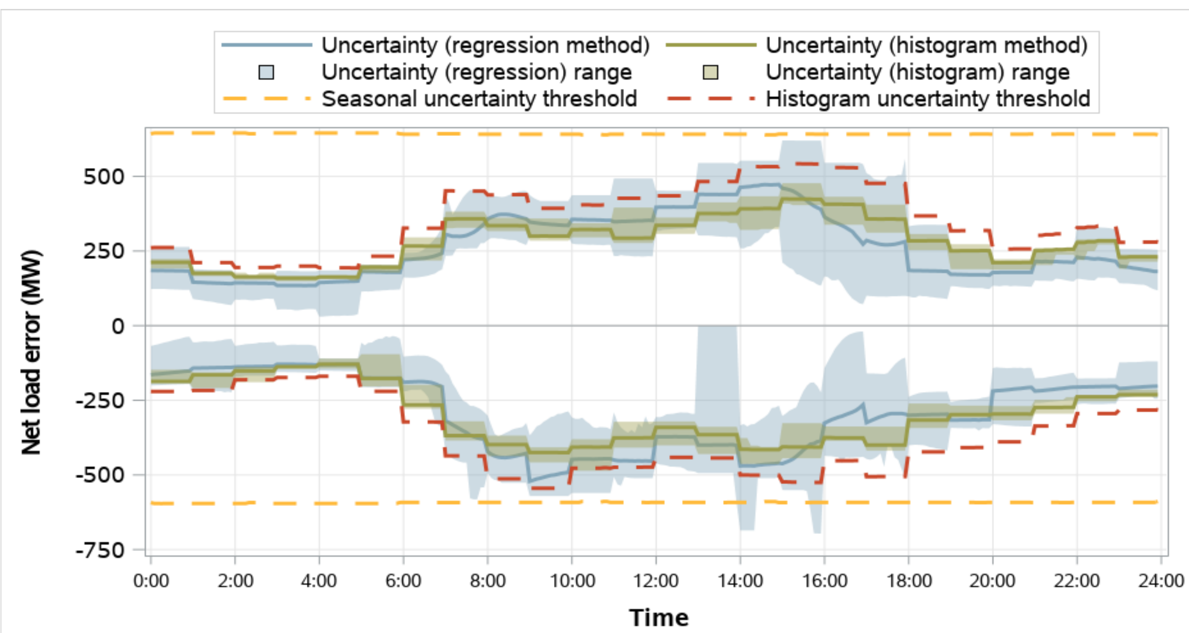


Table 1.8 summarizes the average uncertainty requirement for the group of balancing areas that passed the resource sufficiency evaluation, using both the histogram and mosaic quantile regression methods. On average across all hours, the 15-minute and 5-minute uncertainty calculated from the regression method was less than the histogram method for both directions.

Table 1.9 summarizes the actual net load error for the pass-group and how that compares to the mosaic regression uncertainty requirements for the same interval.[55] The left side of the table summarizes the closeness of the actual net load error to the pass-group uncertainty requirements when the actual net load error was within (or covered) by the upward or downward requirements. The mosaic regression requirements covered between 96 and 98 percent of actual net load errors across all markets and directions. The right side of the table summarizes when the actual net load error instead exceeded upward or downward uncertainty requirements.

Table 1.10 shows the same information except with requirements calculated from the histogram method. Coverage from the histogram method was more than the mosaic regression method, but by less than one percent across both directions and markets.

For more information on the calculated uncertainty used in the resource sufficiency evaluation for each balancing area since February, see DMM's monthly WEIM resource sufficiency evaluation reports.[56]

Table 1.8 Average pass-group uncertainty requirements (October-December 2023)

		Pass-group uncertainty		
Market	**Uncertainty type**	**Histogram**	**Mosaic**	***Difference***
15-minute market	Upward	1,627	1,417	-210
	Downward	1,216	1,190	-26
5-minute market	Upward	281	264	-16
	Downward	296	289	-7

Table 1.9 Actual net load error compared to mosaic regression pass-group uncertainty requirements (October-December 2023)

		Actual net load error falls within calculated uncertainty requirements		*Actual net load error exceeds requirement*	
Market	**Uncertainty type**	**Percent of intervals**	**Average distance to requirement (MW)**	**Percent of intervals**	**Average amount (MW)**
15-minute market	Upward	97%	1,322	3%	349
	Downward	96%	1,410	4%	383
5-minute market	Upward	98%	279	2%	83
	Downward	97%	292	3%	82

55 Actual 15-minute market net load error is measured as the difference between binding 5-minute market net load forecasts and the advisory 15-minute market net load forecast. Actual 5-minute market net load error is measured as the difference between the binding 5-minute market net load forecast and the advisory 5-minute market net load forecast. Both measurements are for the group of balancing areas that passed the resource sufficiency evaluation.

56 https://www.caiso.com/market/Pages/MarketMonitoring/MarketMonitoringReportsPresentations/Default.aspx

Table 1.10 Actual net load error compared to histogram regression pass-group uncertainty requirements (October–December 2023)

Market	Uncertainty type	*Actual net load error falls within calculated uncertainty requirements*		*Actual net load error exceeds requirement*	
		Percent of intervals	Average distance to requirement (MW)	Percent of intervals	Average amount (MW)
15-minute market	Upward	98%	1,522	2%	370
	Downward	97%	1,425	3%	418
5-minute market	Upward	98%	294	2%	111
	Downward	98%	298	2%	93

DMM has published a more detailed review of the mosaic quantile regression approach.[57] The coefficients estimated with the quantile regression method (as currently used) are not statistically different from zero in most instances in DMM's replication, and uncertainty is set at non-regression based caps in more than 10 percent of intervals. This lack of statistical significance and need to set uncertainty with non-regression based values suggests improved forecasting performance may be possible.

1.13 Exceptional dispatch

Exceptional dispatches are unit commitments or energy dispatches issued by operators when they determine that market optimization results may not sufficiently address a particular reliability issue or constraint. This type of dispatch is sometimes referred to as an out-of-market dispatch. While exceptional dispatches are necessary for reliability, they may create uplift costs not fully recovered through market prices, affect market prices, and create opportunities for the exercise of market power by suppliers.

Exceptional dispatches can be grouped into three distinct categories:

- **Unit commitment** — Exceptional dispatches can be used to instruct a generating unit to start up or continue operating at minimum operating levels. Exceptional dispatches can also be used to commit a multi-stage generating resource to a particular configuration. Almost all of these unit commitments are made after the day-ahead market to resolve reliability issues not met by unit commitments resulting from the day-ahead market model optimization.
- **In-sequence real-time energy** — Exceptional dispatches are also issued in the real-time market to ensure that a unit generates above its minimum operating level. This report refers to energy that would have likely cleared the market without an exceptional dispatch (i.e., that has an energy bid price below the market clearing price) as in-sequence real-time energy.
- **Out-of-sequence real-time energy** — Exceptional dispatches may also result in out-of-sequence real-time energy. This occurs when exceptional dispatch energy has an energy bid priced above the

57 Department of Market Monitoring, Review of mosaic quantile regression for estimating net load uncertainty, November 20, 2023: http://www.caiso.com/Documents/Review-of-the-Mosaic-Quantile-Regression-Nov-20-2023.pdf

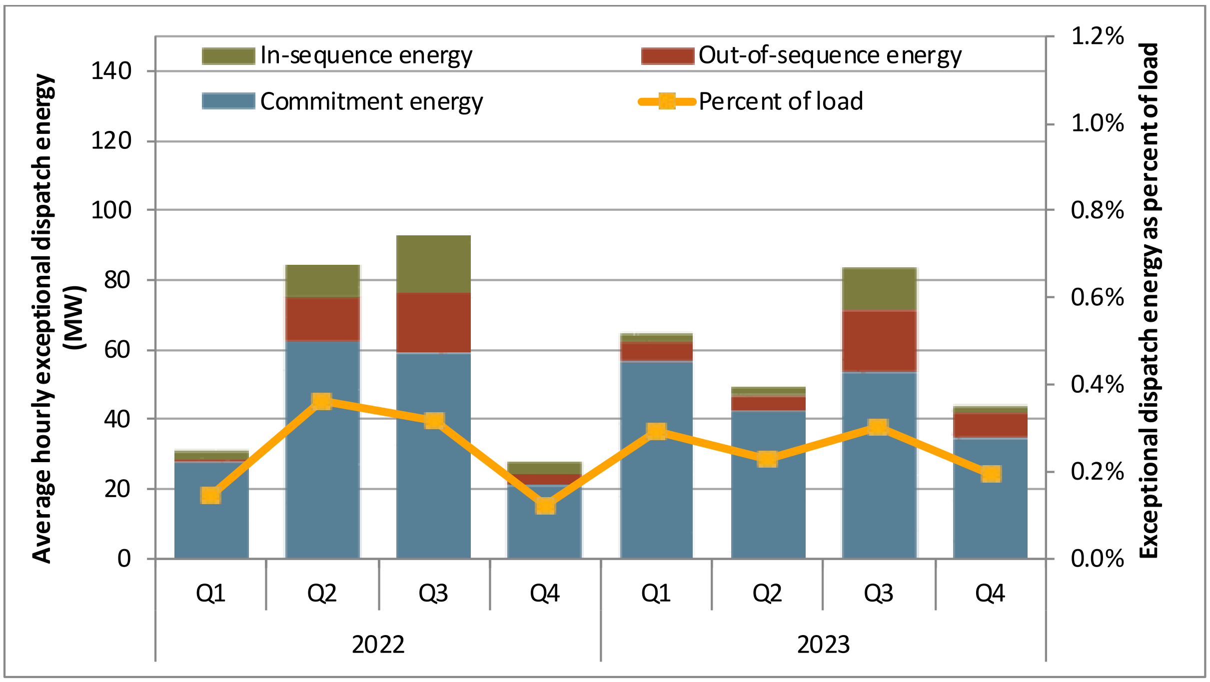
market-clearing price. In cases when the bid price of a unit being exceptionally dispatched is subject to the local market power mitigation provisions in the California ISO tariff, this energy is considered out-of-sequence if the unit's default energy bid used in mitigation is above the market clearing price.

Energy from exceptional dispatch

Energy from exceptional dispatch accounted for under one percent of total load in the California ISO balancing area. The average hourly total energy from exceptional dispatches, including minimum load energy from unit commitments, was 44 MWh in the fourth quarter of 2023, which is up from 28 MWh in the same quarter of 2022.

As shown in Figure 1.49, exceptional dispatches for unit commitments accounted for about 79 percent of all exceptional dispatch energy in this quarter,[58] about 16 percent was from out-of-sequence energy, and the remaining five percent was from in-sequence energy.

Figure 1.49 Average hourly energy from exceptional dispatch



Exceptional dispatches for unit commitment

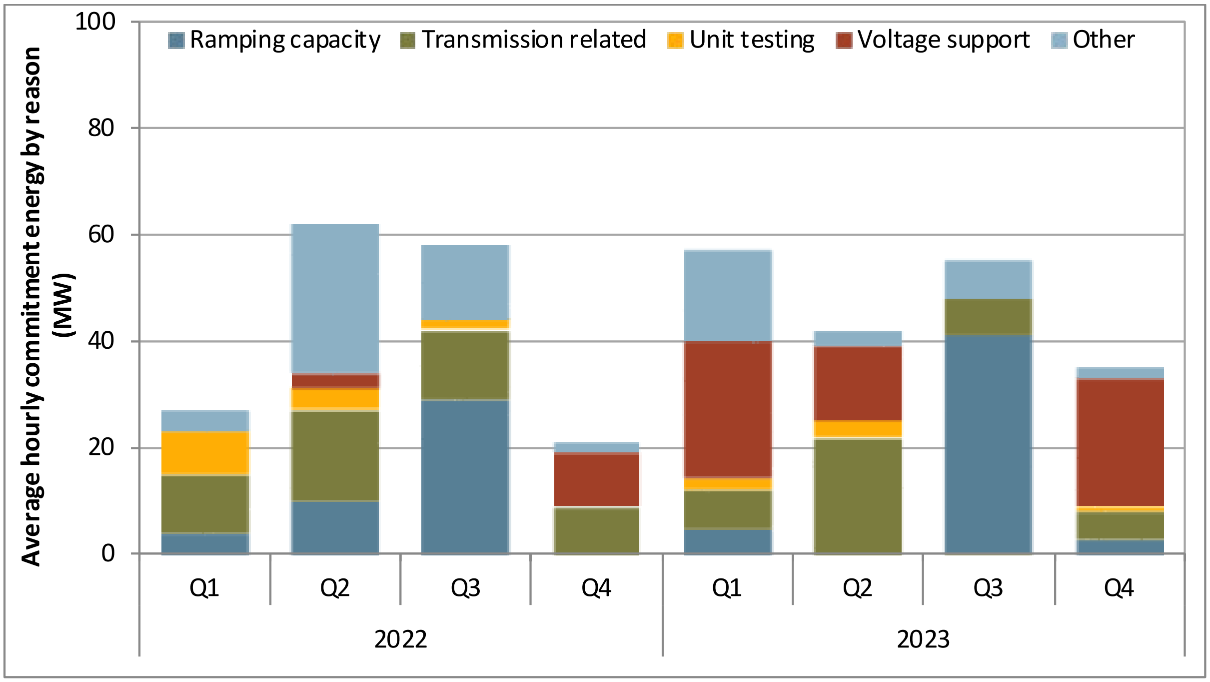
The California ISO balancing area operators occasionally find instances where the day-ahead market process did not commit sufficient capacity to meet certain reliability requirements not directly incorporated in the day-ahead market model. In these instances, the California ISO may commit additional capacity by issuing an exceptional dispatch for resources to come on-line and operate at

58 All exceptional dispatch data are estimates derived from Market Quality System (MQS) data, market prices, dispatch data, bid submissions, and default energy bid data. DMM's methodology for calculating exceptional dispatch energy and costs has been revised and refined since previous reports. Exceptional dispatch data reflected in this report may differ from previous annual and quarterly reports as a result of these enhancements.

minimum load. Multistage generating units may be committed to operate at the minimum output of a specific multistage generator configuration, e.g., one-by-one or duct firing.

As shown in Figure 1.50, the average minimum load energy from unit commitment exceptional dispatches increased from about 21 MW in the fourth quarter of 2022 to 35 MW in same quarter of 2023. Minimum load energy from unit commitment exceptional dispatches to provide voltage support (red bars) in the fourth quarter of 2023 increased by 140 percent from the same quarter in 2022.

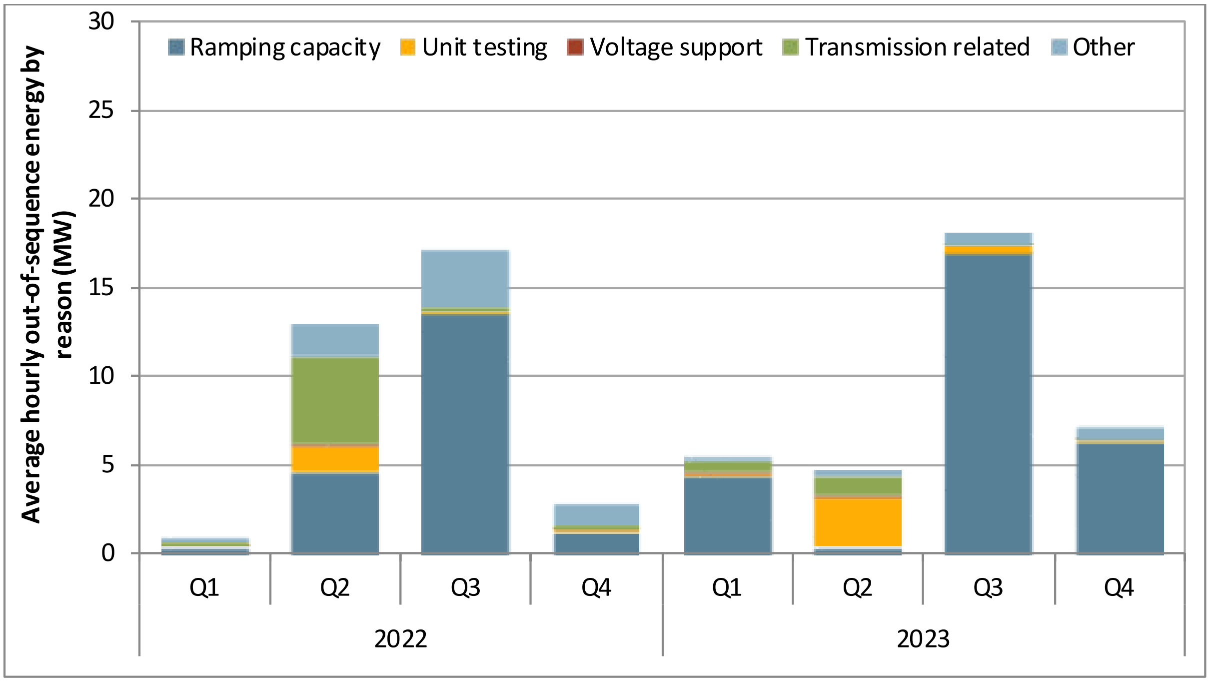
Figure 1.50 Average minimum load energy from exceptional dispatch unit commitments



Exceptional dispatches for energy

Figure 1.51 shows the average out-of-sequence exceptional dispatch energy by quarter for 2022 and 2023. The primary reason logged for out-of-sequence energy in the fourth quarter of 2023 was "exceptional dispatches for ramping capacity". Ramping capacity exceptional dispatches are predominantly used to ramp thermal resources to their minimum dispatchable level, which is a higher operating level, with a faster ramp rate, that allows these units to be more available to meet reliability requirements.

Figure 1.51 Out-of-sequence exceptional dispatch energy by reason

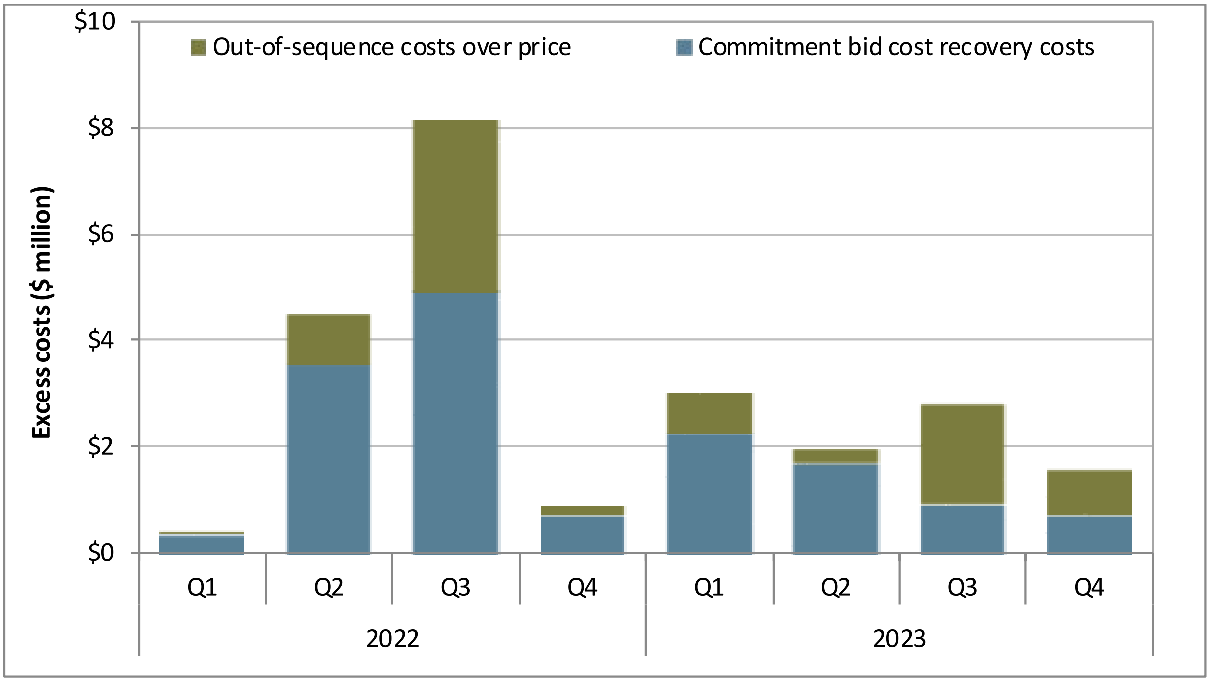


Exceptional dispatch costs

Exceptional dispatches can create two types of additional costs not recovered through the market clearing price of energy.

- Units committed through exceptional dispatch that do not recover their start-up and minimum load bid costs through market sales can receive bid cost recovery for these costs.
- Units exceptionally dispatched for real-time energy out-of-sequence may be eligible to receive an additional payment to cover the difference in their market bid price and their locational marginal energy price.
- Figure 1.52 shows the estimated costs for unit commitment and exceptional dispatch for energy above minimum load whose bid price exceeded the resource's locational marginal price. In the fourth quarter of 2023, out-of-sequence energy costs were $0.83 million, a 392 percent increase from the fourth quarter of 2022. The bid cost recovery payments awarded to resources that were committed via exceptional dispatch in the fourth quarter were $0.75 million, a five percent increase from the fourth quarter of 2022.

Figure 1.52 Excess exceptional dispatch cost by type



2 Western energy imbalance market

This section covers Western energy imbalance market (WEIM) performance during the fourth quarter.

2.1 Limitation of WEIM transfers to the ISO

On July 26, CAISO balancing area operators began limiting WEIM import transfers into the CAISO balancing area each day during the net peak hours. This limitation was put in place for the hour-ahead and 15-minute markets to mitigate risk during the critical hours that internal generation and hourly-block intertie schedules might be displaced by WEIM import transfers that may not materialize in real-time. This limitation typically lasted five hours each day and continued through much of the third quarter — with the final day on November 15, 2023.

This action created significant and systematic modeling differences between the 15-minute and 5-minute markets — including greater congestion between CAISO and other WEIM areas in the 15-minute market, compared to the 5-minute market. This difference in congestion was a major cause of lower prices in the 15-minute market than in the 5-minute market during peak hours in Desert Southwest WEIM areas.

DMM recommends that CAISO work with stakeholders to consider other methods of achieving intended reliability outcomes without creating the large and systematic modeling differences between the 15-minute and 5-minute markets. DMM also recommends that the ISO conduct analysis to better understand the root causes of the conditions that prompted the decision to limit the WEIM import schedules. This should include analysis of the factors that may cause WEIM import schedules that materialize in the 5-minute market to differ from advisory schedules in earlier market runs. DMM also recommends greater transparency if this approach would be used again in the future, including what criteria may lead the CAISO balancing area to resume the practice of limiting WEIM transfers and what criteria may lead operators to decide this is no longer needed.

It is not clear to DMM why the CAISO area continued these transfer limitations through November 15 in 2023. The ISO has explained to DMM that it stopped the transfer limitations after implementing a new tool that allowed operators to better address export self-schedules that declined hour-ahead market curtailments. However, system conditions that may have necessitated curtailing hourly block exports in the hour-ahead market did not arise during October and the first half of November, when the new operator tool was implemented.

Additional details on this action as well as its impact on the market are described in this section.

2.1.1 Background

One of the key benefits of the WEIM is the ability to transfer energy between balancing areas in the 15-minute and 5-minute markets. These transfers are the result of regional supply and demand conditions in the market, as lower cost generation is optimized to displace expensive generation and meet load across the footprint.[59] WEIM transfers are constrained by *transfer limits* that are made available by the WEIM entities to optimally transfer energy between areas.

WEIM transfers are defined as either *base*, *dynamic, or static*. Base WEIM transfers are fixed bilateral transactions between WEIM entities and are not optimized in the market. Dynamic WEIM transfers are optimized in all markets. Static WEIM transfers are a smaller subset of transfers (primarily between the Pacific Northwest areas and the CAISO area) that are only optimized in the hour-ahead and 15-minute markets.

The hour-ahead scheduling process (HASP) produces an optimized solution for four 15-minute intervals in the upcoming hour. It is included as part of a special run of the real-time unit commitment process that starts approximately 71.5 minutes prior to the hour. The majority of CAISO balancing area intertie schedules must be scheduled in hourly blocks and HASP is the final opportunity for these to be optimized in the market. These schedules are optimized against forecasted load, advisory generation dispatches, *and advisory WEIM transfers* across the footprint.

Operators can modify the load forecast used in the market through *load conformance* adjustments. In the CAISO balancing area, these adjustments are routinely used in the hour-ahead and 15-minute scheduling process to increase capacity to address uncertainty that can materialize around net load ramping periods. Load conformance in the 5-minute market is then typically much lower.

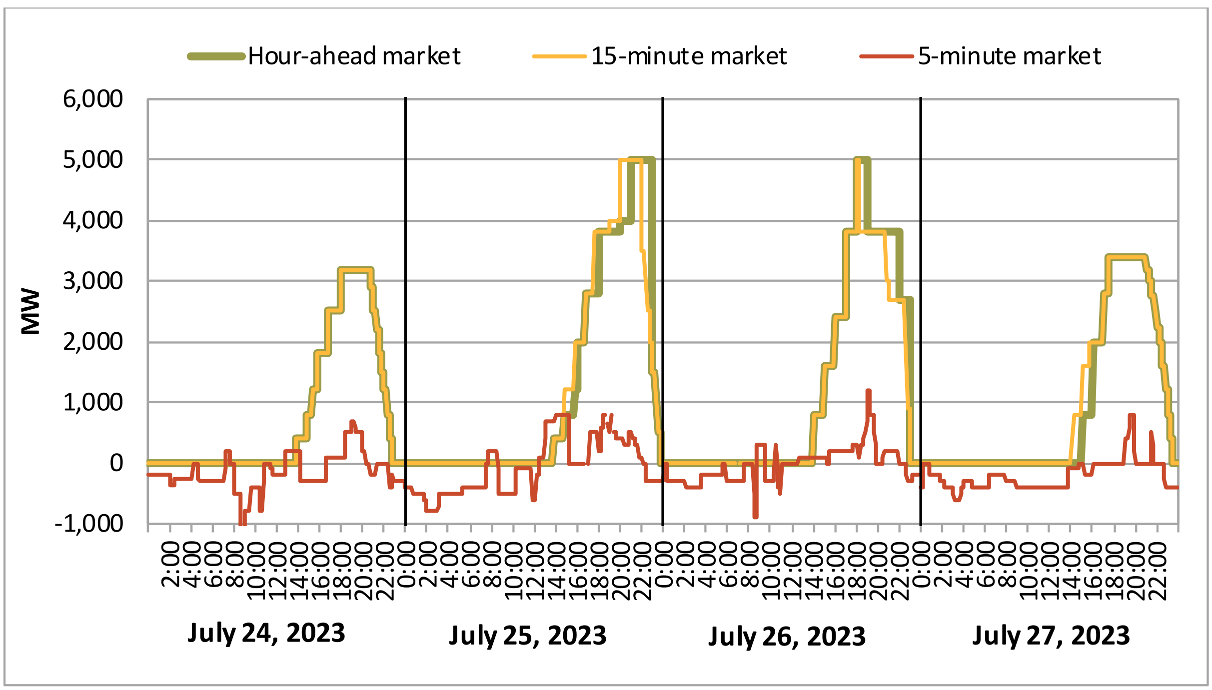
Figure 2.1 shows ISO load conformance adjustments between July 24 and July 27. When operators increase the load conformance in HASP, this can be met by a combination of factors, including increased commitment or dispatch of internal resources, increased hourly imports, decreased hourly exports, and changes to advisory WEIM transfers. To the extent that the increased load conformance is met by advisory WEIM imports, these transfers may not materialize in the 5-minute market due to either lower levels of load conformance or changes to projected supply conditions in the surrounding WEIM system.

[59] See Appendix A for figures on the average hourly transfers by quarter for each WEIM area.

Starting on July 26, during peak hours each day, CAISO balancing area operators limited dynamic WEIM import transfers into the CAISO balancing area in the hour-ahead and 15-minute markets to zero.[60] The intent of this action was to limit advisory WEIM imports that might offset a significant portion of the demand forecast or load conformance. This would instead allow increased load conformance to be served by internal generation and intertie schedules. As a result, the CAISO balancing area would have a reduced reliance on imports from the WEIM to meet internal demand, and its system would be better positioned to address uncertainty that may materialize. In the 5-minute market, the limit on WEIM transfers was lifted, allowing transfers to freely and optimally flow between the CAISO balancing area and neighboring balancing areas.[61]

Figure 2.2 shows dynamic WEIM imports into the CAISO balancing area in the evening hours between July 24 and July 27. The blue bars show advisory WEIM imports in the hour-ahead market. The red bars show WEIM imports in the 5-minute market. The green line shows the transfer lock periods in which imports were limited to zero in the hour-ahead market. Outside the lock periods, WEIM transfers into the CAISO balancing area in the hour-ahead market significantly exceeded what was realized in the 5-minute market in most intervals. During the lock periods, hour-ahead (and 15-minute market) transfers into the CAISO balancing area were limited to zero, but substantial 5-minute market imports were still able to flow in those peak evening hours.

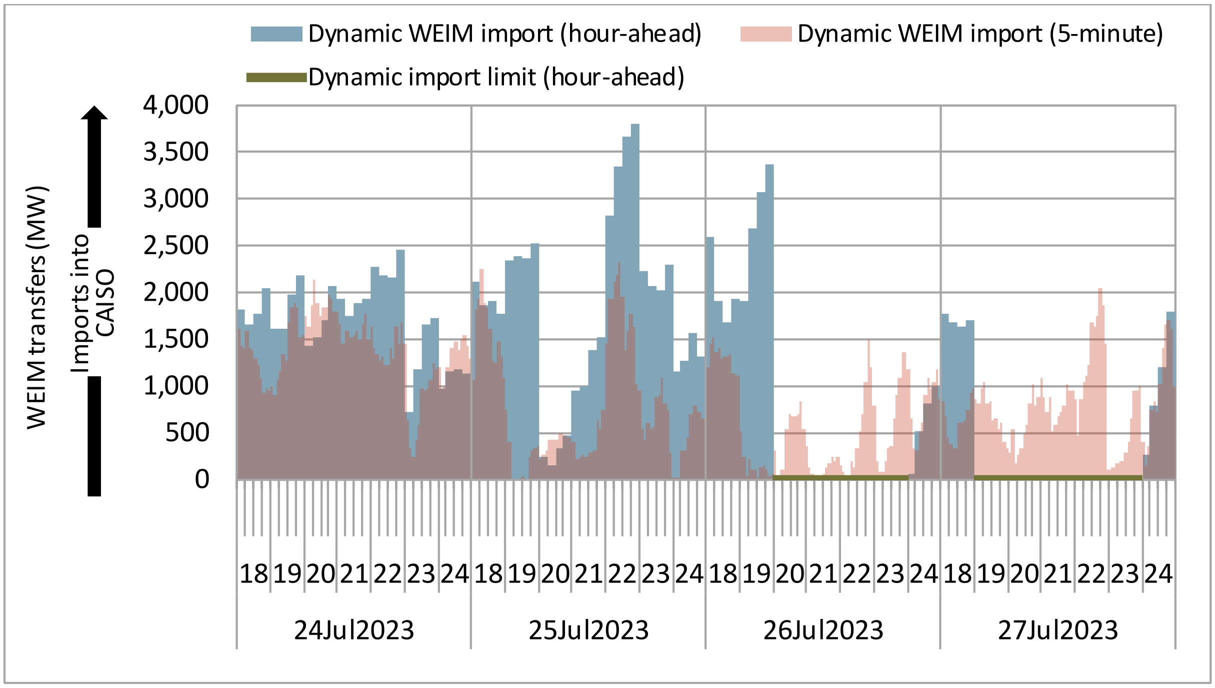
Figure 2.1 ISO area load conformance adjustments (July 24–27)



60 Static WEIM transfers were not impacted by the limit put in place in the peak hours starting July 26. Dynamic export transfers were also not impacted.

61 Subject to normal WEIM transmission limitations.

Figure 2.2 Dynamic WEIM imports into ISO area (evening hours, July 24–July 27)



2.1.2 Impact on California ISO balancing area supply and demand

When the WEIM imports into the California ISO balancing area are limited to zero in the hour-ahead market, the optimization generally balances the total load (including any load conformance) mostly from a combination of (1) increased internal generation, (2) increased hourly-block imports, (3) decreased hourly-block exports, and (4) decreased WEIM exports. This section summarizes supply and demand differences before and after the limitation on WEIM imports into the CAISO balancing area.

For the fourth quarter, the WEIM import limitation typically occurred between hours 18 and 22 during October, and between hours 16 and 20 during November (until its conclusion on November 15).[62] Figure 2.3 compares CAISO area supply and demand components during the WEIM import limitation intervals that occurred in the first half of November with the same hours in the second half of November (without the WEIM import limitation in place).[63] Both overall supply and overall demand in the absence of WEIM transfers were very similar in these two periods. Therefore, the primary impact of limiting transfers in the hour-ahead market was to reduce WEIM transfers flowing through the CAISO balancing area.

62 On the day of the solar eclipse — October 14, 2023 — the WEIM import limitation was also put in place between hours 9 and 13.

63 WEIM imports in Figure 2.3 and Figure 2.4 include both dynamic and static WEIM transfers. Static WEIM transfers were not impacted by the limit put in place in the peak hours. WEIM imports are therefore shown above zero during the WEIM transfer lock intervals.

Figure 2.3 Average hour-ahead CAISO balancing area supply and demand with and without WEIM import limitations (hours 16 to 20)

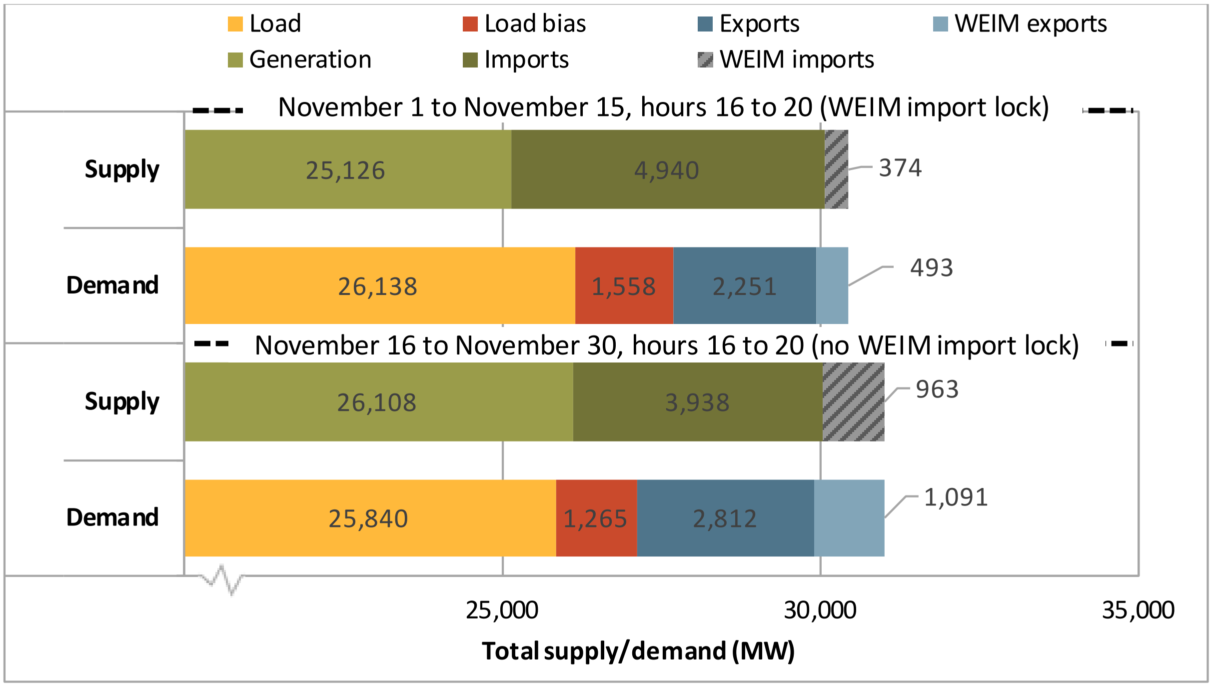
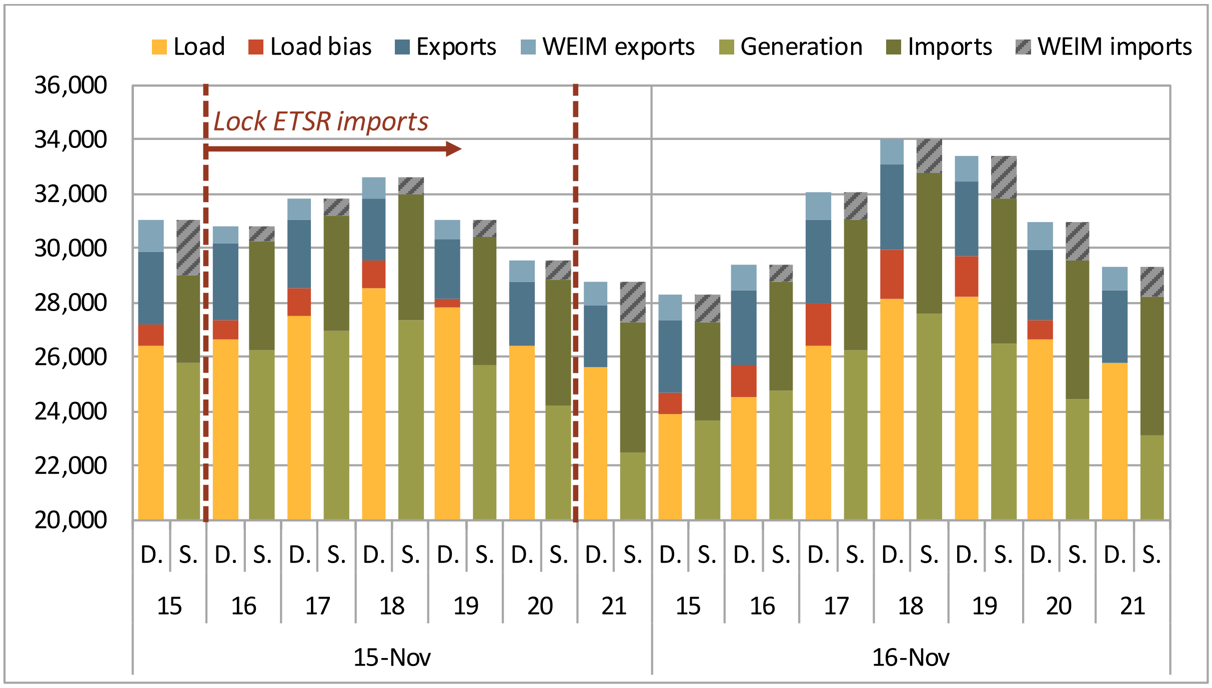


Figure 2.4 summarizes the hour-ahead supply and demand components on November 15 and November 16 — at the end of the practice of limiting WEIM imports into the ISO during the peak hours. On November 15, with the import limitation in place, the following outcomes occurred on average, relative to the same hours on November 16:

- WEIM imports were 550 MW less while combined load and load bias were 140 MW lower.
- Internal generation was around 180 MW higher.
- Hourly-block exports were around 400 MW lower while hourly-block imports were also around 440 MW *lower*.
- WEIM exports were 270 MW lower.

In comparing these days, the limitation on WEIM imports on November 15 does not appear to have resulted in a substantial increase in internal generation or net hourly block imports into the CAISO balancing area. It is not clear to DMM why the CAISO area continued these transfer limitations during the fourth quarter and through November 15. The ISO has explained to DMM that it stopped the transfer limitations after implementing a new tool that allowed operators to better address export self-schedules that declined hour-ahead market curtailments. However, system conditions that may have necessitated curtailing hourly block exports in the hour-ahead market did not arise during October and the first half of November.

Figure 2.4 CAISO area hour-ahead supply and demand (Peak hours, November 15-16, 2023)



2.1.3 Impact on WEIM prices

The WEIM allows the market to increase efficiency by optimizing energy transfers economically in real-time between WEIM areas, balancing supply and demand across the footprint with lower-cost generation. When the CAISO balancing area limited dynamic WEIM imports to zero in the peak hours of the hour-ahead and 15-minute markets, this reduced the ability for the market to displace higher cost energy in the California ISO with cheaper excess energy in the surrounding WEIM system. The result in these intervals was that most of the WEIM footprint was collectively export constrained at a lower price relative to the CAISO area during these periods.

Figure 2.5 shows average 15-minute market prices by component for each balancing area during the WEIM import limitation intervals that occurred in the first half of November. Figure 2.6 instead summarizes average 15-minute market prices in the same intervals for the second half of November (without the WEIM import limitation in place).

The system marginal energy price (SMEC) is the same for all WEIM entities, based on the marginal cost of energy at a reference location in the California ISO balancing area. The congestion on the WEIM transfer constraints (red bars) reflects the price impact because of intertie transmission constraint congestion that might separate the balancing area from the California ISO (or connected WEIM system).[64]

When transfer capacity limits the amount of energy that can flow from areas with lower cost supply to areas with higher cost supply, prices will be higher on the side of the constraint with higher cost supply. During the intervals when the CAISO balancing area limited dynamic WEIM imports to zero, the negative congestion component from WEIM transfer constraints reflects lower prices outside of the CAISO area, based on regional supply and demand conditions in this separated system.

During the peak hours of the first half of November (with the WEIM import limitation in place), 15-minute market prices for most balancing areas in the WEIM were around $16.41/MWh lower on average because of WEIM transfer congestion.[65] During the same hours in the second half of November (without the WEIM import limitation in place), WEIM transfer congestion in the 15-minute market was very low — increasing 15-minute market prices by around $0.23/MWh on average.

The limitation that was in place during the first half of November in the hour-ahead and 15-minute markets was not in place in the 5-minute market. For comparison, Figure 2.7 shows average *5-minute market* prices by component for each balancing area during the same intervals in the first half of November. With the limitation removed, WEIM transfer congestion was very low in the 5-minute market for most of the balancing areas.

64 This accounts for any constraint that can limit WEIM transfers between balancing areas. This includes congestion from (1) scheduling limits on individual WEIM transfers, (2) total scheduling limits following a resource sufficiency evaluation failure, or (3) intertie constraint (ITC) and intertie scheduling limit (ISL). Definitions for the other components in these figures as well as hourly price components for every balancing area are provided in Appendix A.

65 Excluding Powerex, BANC, Turlock Irrigation District, and El Paso Electric. During the CAISO transfer limitation, Powerex was typically *import constrained* at a higher price, while BANC and Turlock Irrigation District were often not congested relative to the CAISO balancing area. During the quarter, El Paso Electric was frequently export constrained because of limited dynamic export capacity rather than because of the CAISO import limitation.

Figure 2.5 Average 15-minute market prices during WEIM import limitation (November 1 to November 15, hours 16 to 20)

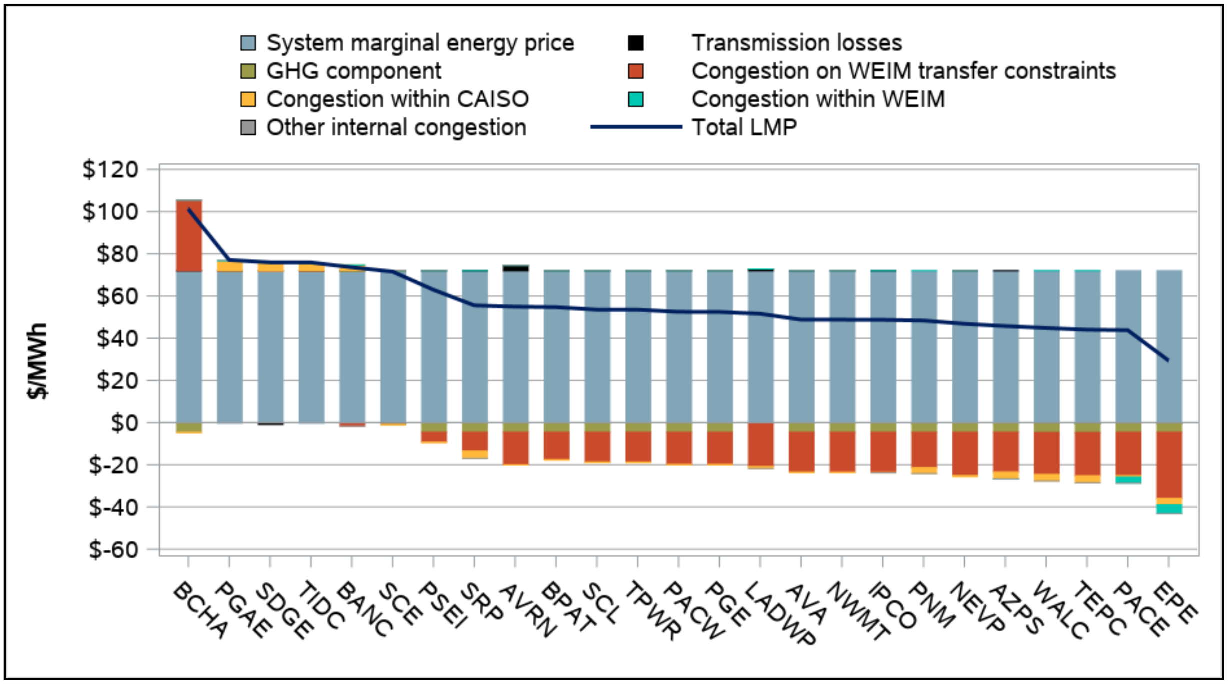


Figure 2.6 Average 15-minute market prices without WEIM import limitation (November 16 to November 30, hours 16 to 20)

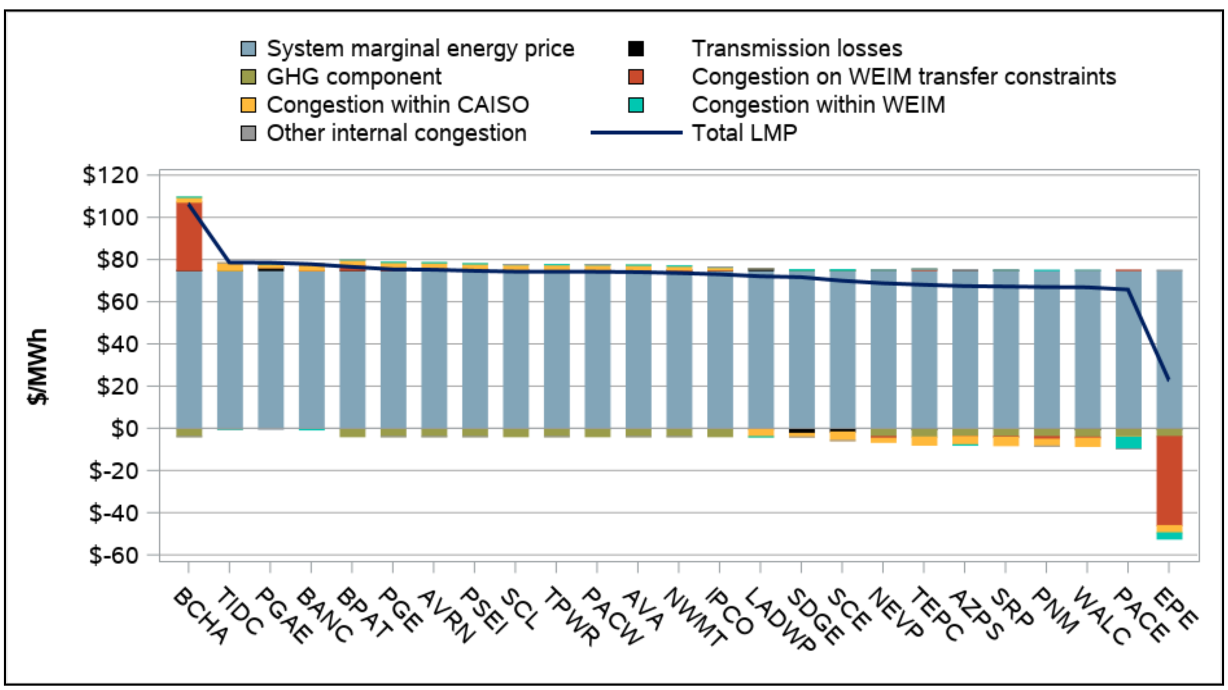


Figure 2.7 Average 5-minute market prices during WEIM import limitation (November 1 to November 15, hours 16 to 20)

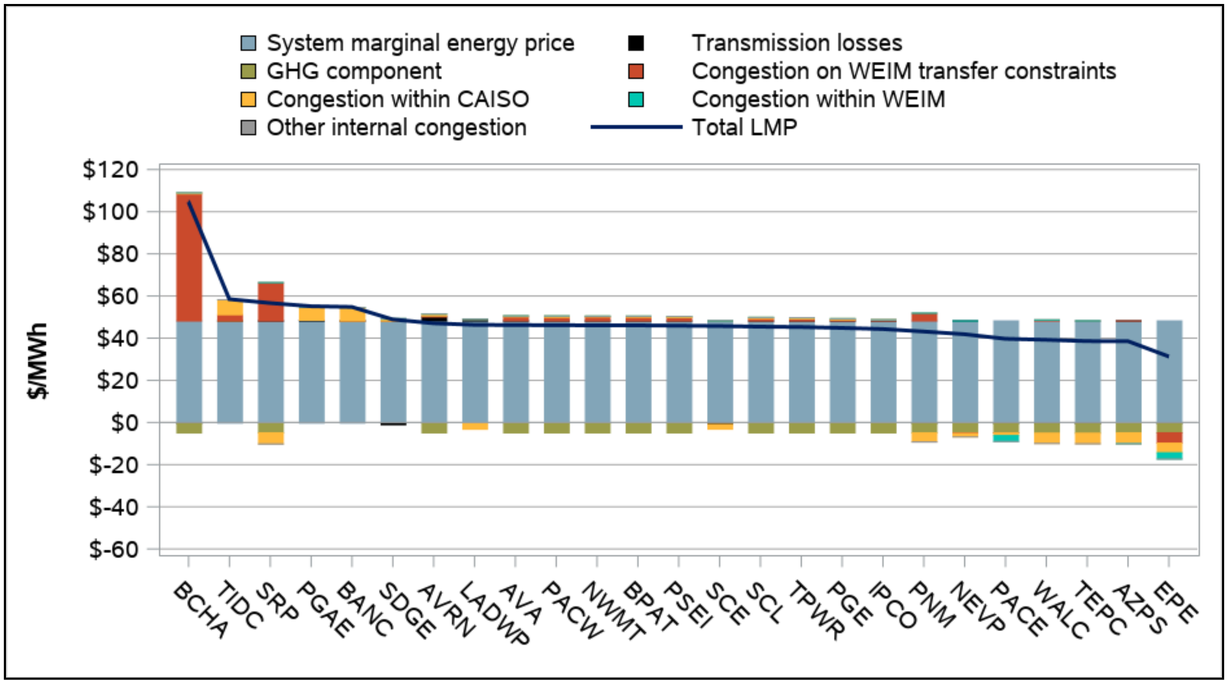


Table 2.1 shows the percent of intervals with WEIM transfer constraint congestion and the price impact of this congestion in each balancing area, over the entire quarter, for both the 15-minute and 5-minute markets. *Congested from area* reflects that prices are lower in the balancing area because of limited export capability out of the area or region, relative to the CAISO balancing area. *Congested into area* reflects that prices are higher within an area, because of limited import capability into the area or region. [66]

The WEIM import limitation during the peak hours for much of the fourth quarter was in place for the hour-ahead and 15-minute markets, but not in the 5-minute market. The result is that most WEIM balancing areas were consequently *export constrained* relative to the CAISO balancing area (congested from area) in at least six percent of intervals in the 15-minute market. In the 5-minute market, WEIM imports into the CAISO balancing area were not limited, and the congestion frequency and price impact were both much smaller.

Powerex was instead frequently *import constrained* relative to the CAISO balancing area because of WEIM transfer congestion in the fourth quarter. Powerex was congested into the area during around 88 percent of intervals in the 15-minute and 5-minute markets — with prices being around $36.50 and $38.50 higher in these markets, respectively. When a balancing area has net WEIM transfer import

66 When prices are higher within an area, this indicates that WEIM transfer congestion limited the ability for outside energy to serve that area's load.

congestion into an area, the market software triggers local market power mitigation procedures for resources in that area.[67]

El Paso Electric was frequently export constrained, during 42 percent of 15-minute market intervals and 34 percent of 5-minute market intervals. This was largely because of limited dynamic export capacity out of the balancing area.

Table 2.1 Frequency and impact of transfer congestion in the WEIM (October–November)

	15-minute market				5-minute market			
	Congested from area		Congested into area		Congested from area		Congested into area	
	Congestion Frequency	Price Impact ($/MWh)	Congestion Frequency	Price Impact ($/MWh)	Congestion Frequency	Price Impact ($/MWh)	Congestion Frequency	Price Impact ($/MWh)
BANC	2%	-$0.85	0.0%	$0.00	0.0%	$0.00	0.0%	$0.28
Turlock Irrigation District	2%	-$0.85	0.8%	$0.11	0.0%	$0.00	1%	$0.21
NV Energy	7%	-$3.46	0.0%	$0.03	0.1%	-$0.09	0.1%	$0.55
L.A. Dept. of Water and Power	7%	-$3.35	0.0%	$0.03	0.1%	-$0.05	0.1%	$0.40
Arizona Public Service	7%	-$3.65	0.0%	$0.07	0.3%	-$0.34	0.1%	$1.14
WAPA – Desert Southwest	7%	-$3.71	0.5%	$0.71	0.3%	-$0.28	0.4%	$0.69
Public Service Company of NM	7%	-$3.44	0.7%	$2.78	0.3%	-$0.18	0.5%	$3.75
PacifiCorp East	8%	-$3.38	3%	$0.31	1%	-$0.09	2%	$0.38
Tucson Electric Power	14%	-$4.28	1%	$0.29	6%	-$0.97	1%	$0.70
Idaho Power	6%	-$2.74	17%	$4.48	0.0%	$0.00	14%	$4.85
NorthWestern Energy	6%	-$2.65	19%	$6.27	0.2%	-$0.04	16%	$7.40
Avista Utilities	6%	-$2.62	19%	$6.41	0.1%	-$0.02	16%	$7.16
PacifiCorp West	7%	-$2.57	20%	$6.44	3%	-$0.56	15%	$7.16
Portland General Electric	7%	-$2.41	20%	$6.61	3%	-$0.53	15%	$7.08
Avangrid Renewables	8%	-$2.58	20%	$6.34	3%	-$0.65	15%	$6.95
Tacoma Power	8%	-$2.53	21%	$6.71	4%	-$0.73	16%	$7.37
Seattle City Light	8%	-$2.85	21%	$6.52	4%	-$0.84	17%	$7.47
Salt River Project	23%	-$6.46	8%	$2.51	15%	-$3.84	8%	$3.96
Puget Sound Energy	8%	-$2.50	22%	$9.44	4%	-$0.66	17%	$9.62
Bonneville Power Admin.	8%	-$2.48	23%	$7.52	3%	-$0.55	18%	$7.83
El Paso Electric Company	42%	-$13.98	3%	$0.92	34%	-$10.93	2%	$0.74
Powerex	1%	-$0.70	88%	$36.54	5%	-$0.96	88%	$38.51

2.1.4 Impact on WEIM transfer flows

The limitation on WEIM imports into the CAISO balancing area impacted transfer patterns throughout the WEIM footprint. Figure 2.8 shows average hour-ahead WEIM exports out of each area during the WEIM import limitation intervals that occurred in the first half of November.[68] Figure 2.9 instead shows average exports in the same hours for the second half of November (without the WEIM import

[67] If bid in supply after removing the three largest suppliers is less than the generation dispatched in the area in the market power mitigation run, bids in excess of the higher of default energy bids and the competitive LMP will be replaced by the higher of default energy bids and the competitive LMP. The California ISO balancing area is not subject to market power mitigation when WEIM transfer limits into the CAISO area are constrained.

[68] These figures exclude the fixed bilateral transfers between WEIM entities (base WEIM transfer schedules) and therefore reflect optimized flows in the market. Optimized dynamic and static WEIM transfers are both included. Static WEIM imports into the CAISO area (mostly from PacifiCorp West, Portland General Electric, and Puget Sound Energy) were not impacted by the WEIM import limitation. These figures also exclude transfer paths less than 25 MW (on average) for readability.

limitation in place). The curves show the path and size of exports where the color corresponds to the area the transfer is coming from. The inner ring, at the origin of each curve, measures average exports from each area. The outer ring instead shows *total* exports and imports for each area. Each small tick is 50 MW and each large tick is 250 MW.

As shown in the figures:

- **In the second half of November (without the WEIM import limitation), significant WEIM imports from the Desert Southwest region into the CAISO balancing area largely continued flowing onward to Powerex and BANC.** With the WEIM import limitation during the first half of November, CAISO balancing area imports through the WEIM were much lower (490 MW less), and exports out of the region were also much lower (510 MW less).
- **Average net exports out of the Desert Southwest region increased in the second half of November by over 310 MW**. Exports out of the region to PacifiCorp East, Idaho Power, and LADWP during the first half of the month largely shifted to the CAISO balancing area during the same hours in the second half of the month.
- **Average transfers in the Intermountain West region decreased significantly in the second half of November**. In the first half of November, excess energy from the Desert Southwest region generally flowed north to PacifiCorp East and Idaho Power.

Figure 2.8 Average hour-ahead WEIM exports during WEIM import limitation (November 1 to November 15, hours 16 to 20)

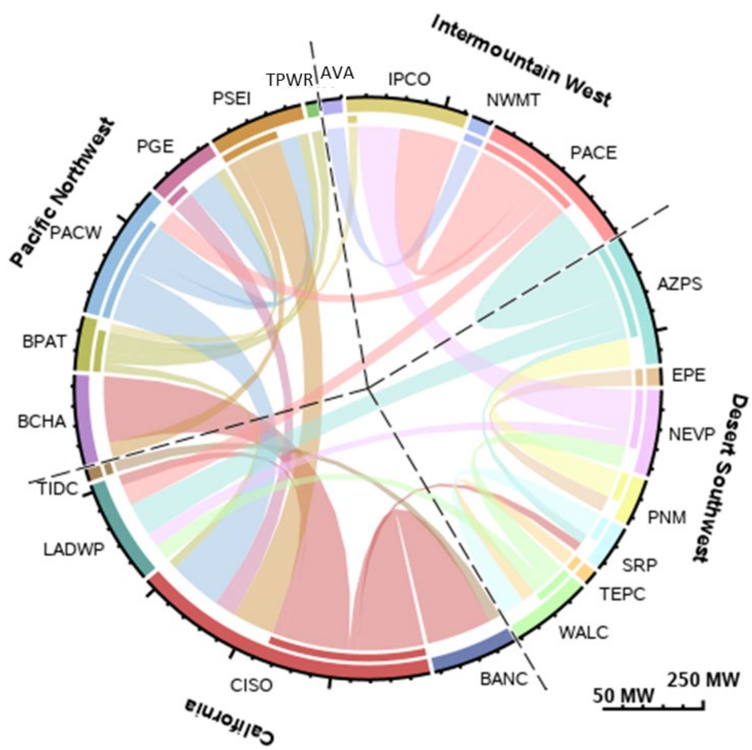
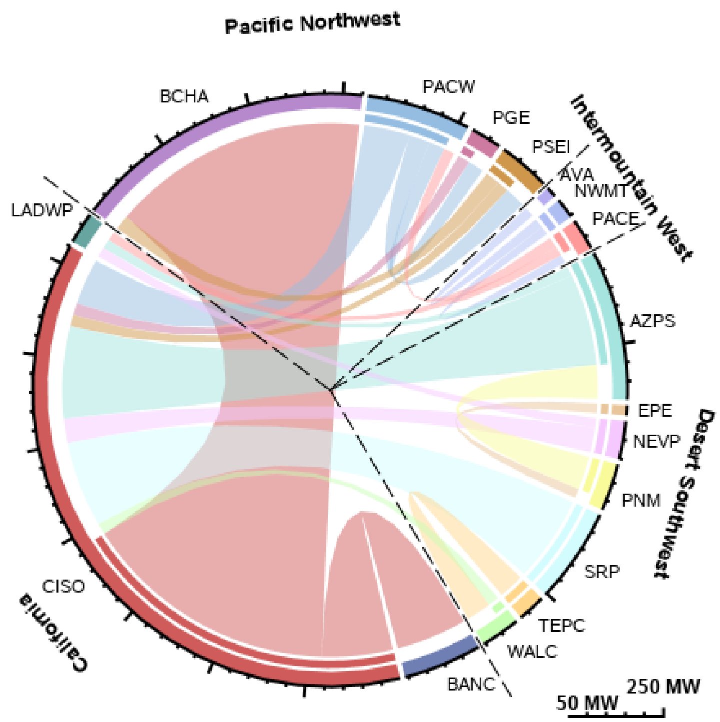


Figure 2.9 Average hour-ahead WEIM transfers without WEIM import limitation (November 16 to November 30, hours 16 to 20)



2.1.5 Impact on WEIM transfer limits

WEIM transfers between areas are constrained by transfer limits. These limits largely reflect transmission and interchange rights made available to the market by participating WEIM entities.

- Table 2.2 shows average 15-minute market import and export limits for each balancing area outside of the transfer lock periods during the fourth quarter.
- Table 2.3 shows average 15-minute market import and export limits during the peak-hour transfer lock periods. During these periods, the limit on *dynamic* WEIM imports into the CAISO balancing area are zero such that the positive CAISO area *total import limit* (around 500 MW) reflects only limits on *static* WEIM imports.
- Table 2.4 shows average 5-minute market import and export limits across all intervals during the fourth quarter.

The volumes shown in these tables exclude base WEIM transfer schedules and therefore reflect transfer capability that is made available by WEIM entities to optimally transfer energy between areas.

The balancing areas in these tables are grouped in one of four regions: California, Desert Southwest, Intermountain West, and Pacific Northwest. These regions reflect a combination of general geographic location as well as common price-separated groupings that can exist when a balancing area is collectively import or export constrained along with one or more other balancing areas relative to the greater WEIM system. The last two columns in these tables show WEIM transfer limits between these regions (out-of-region import and export limits).

The limitation on WEIM imports into the CAISO balancing area in the 15-minute market was not present in the 5-minute market. Import and export transfer capacity into or out of the Desert Southwest region were both over 30,000 MW in the 5-minute market. For the Pacific Northwest region, there was an average of around 1,680 MW of import and 800 MW of export transfer capacity into or out of the region. The lack of transfer capability out of the Pacific Northwest continued to contribute to price separation between the region and the rest of the WEIM.

Table 2.2 Average 15-minute market WEIM limits — excluding transfer lock periods (October–December, 2023)

Region/ balancing area	Total import limit	Total export limit	Out-of-region import limit	Out-of-region export limit
California			**29,733**	**32,135**
California ISO	39,105	35,912	26,377	27,678
BANC	4,319	4,116	0	0
LADWP	7,691	13,342	3,356	4,457
Turlock Irrig. District	880	1,027	0	0
Desert Southwest			**33,025**	**30,297**
Arizona Public Service	32,389	29,917	23,996	22,450
El Paso Electric	421	313	0	0
NV Energy	4,632	3,885	3,988	2,771
PSC New Mexico	975	1,083	0	0
Salt River Project	7,292	7,359	2,213	2,088
Tucson Electric	4,095	4,876	513	825
WAPA - Desert SW	6,154	5,797	2,314	2,163
Intermountain West			**1,873**	**2,816**
Avista Utilities	591	1,146	108	157
Idaho Power	1,912	2,837	529	915
NorthWestern Energy	664	917	34	25
PacifiCorp East	3,064	2,274	1,202	1,720
Pacific Northwest			**1,550**	**932**
Avangrid	711	650	16	17
Powerex	603	50	554	0
BPA	794	863	232	162
PacifiCorp West	1,453	1,662	437	416
Portland General Electric	695	742	132	168
Puget Sound Energy	1,259	1,024	153	139
Seattle City Light	445	455	27	30
Tacoma Power	361	257	0	0

Table 2.3 Average 15-minute market WEIM limits — during transfer lock periods (October–December, 2023)

Region/ balancing area	Total import limit	Total export limit	Out-of-region import limit	Out-of-region export limit
California			**4,273**	**31,394**
California ISO	491	35,786	491	27,310
BANC	4,149	530	0	0
LADWP	8,453	4,084	3,783	4,084
Turlock Irrig. District	957	770	0	0
Desert Southwest			**32,296**	**5,002**
Arizona Public Service	32,380	8,508	23,872	1,152
El Paso Electric	396	514	0	0
NV Energy	4,406	3,381	3,696	2,275
PSC New Mexico	981	1,154	0	0
Salt River Project	7,084	5,092	2,050	0
Tucson Electric	3,849	4,262	428	286
WAPA - Desert SW	6,121	5,010	2,250	1,288
Intermountain West			**1,964**	**2,553**
Avista Utilities	591	1,125	81	195
Idaho Power	1,953	2,777	587	804
NorthWestern Energy	692	879	28	20
PacifiCorp East	3,118	2,162	1,268	1,533
Pacific Northwest			**1,278**	**863**
Avangrid	707	624	14	16
Powerex	366	50	319	0
BPA	706	721	224	116
PacifiCorp West	1,424	1,566	380	358
Portland General Electric	687	701	141	176
Puget Sound Energy	1,209	1,131	174	169
Seattle City Light	441	441	25	28
Tacoma Power	357	248	0	0

Table 2.4 Average 5-minute market WEIM limits (October–December, 2023)

Region/ balancing area	Total import limit	Total export limit	Out-of-region import limit	Out-of-region export limit
California			**29,827**	**32,337**
California ISO	39,071	36,161	26,427	27,914
BANC	4,303	4,097	0	0
LADWP	7,756	13,227	3,400	4,422
Turlock Irrig. District	887	1,042	0	0
Desert Southwest			**33,067**	**30,535**
Arizona Public Service	32,512	30,082	24,112	22,623
El Paso Electric	419	331	0	0
NV Energy	4,595	3,907	3,943	2,794
PSC New Mexico	976	1,087	0	0
Salt River Project	7,271	7,352	2,198	2,101
Tucson Electric	4,072	4,865	506	823
WAPA - Desert SW	6,151	5,839	2,308	2,194
Intermountain West			**1,887**	**2,789**
Avista Utilities	593	1,143	105	160
Idaho Power	1,919	2,834	534	904
NorthWestern Energy	671	910	34	24
PacifiCorp East	3,072	2,271	1,213	1,700
Pacific Northwest			**1,683**	**802**
Avangrid	710	647	15	17
Powerex	591	50	542	0
BPA	834	891	279	199
PacifiCorp West	1,562	1,731	543	489
Portland General Electric	757	606	195	36
Puget Sound Energy	1,181	924	81	31
Seattle City Light	445	454	27	29
Tacoma Power	361	256	0	0

2.1.6 Use of transfer limitation throughout the WEIM

All WEIM entities have the ability to limit transfers to manage reliability in their system. This section summarizes events in which a balancing area has decreased participation in the WEIM by reducing total transfer limits *for either imports or exports* to zero. As discussed in the sections above, the CAISO balancing area limited WEIM imports to zero in the peak hours between July 26 and November 15. Here, the limit on all dynamic import WEIM transfers were simultaneously set to zero in only the hour-ahead and 15-minute markets. WEIM entities also have the ability to manage individual WEIM transfer limits. They can also manage a reliability situation internally by initiating a *Market Isolation.* This process will lock the WEIM transfers to zero (or to base schedules) while allowing the market to still produce optimized dispatch of internal resources.

Table 2.5 summarizes all 15-minute intervals in 2023 in which total dynamic WEIM transfers were limited to zero in at least one direction.[69] A single event is defined as one or more consecutive intervals with these conditions. The table shows the average length of each of these events as well as the average change in the WEIM transfer limits in each event (from the interval immediately before transfers were limited to zero, to the next interval).

Table 2.6 provides additional data for the same 15-minute intervals. First, the table shows the percent of these limitation intervals in which either only imports, only exports, or both directions were set to zero. Next, the table shows the percent of corresponding intervals in the 5-minute market that were also limited. Of note, there can be a timing delay between initiating and ending a transfer limitation, such that a transfer limitation intended for both markets will not always align in the corresponding intervals of both markets. In other cases, the underlying conditions that necessitated the transfer limitation were resolved prior to the 5-minute market.

The CAISO balancing area limited dynamic WEIM transfers to zero (in at least one direction) more frequently than other WEIM entities in 2023 — during over 1,900 intervals (or 475 hours) in 113 days. The magnitude of transfer capacity that was limited in the CAISO balancing area was also significantly greater than other WEIM entities, at around 41,700 MW on average in the import direction. The CAISO balancing area also only limited dynamic WEIM *imports* to zero, and only in the hour-ahead and 15-minute markets, whereas other WEIM entities generally tended to limit transfers in both directions and markets during a reliability event.

Powerex had almost 550 15-minute market intervals (or around 137 hours) in which dynamic WEIM import limits were set to zero. Powerex typically has very limited *dynamic* WEIM import capacity into the balancing area (typically 50 MW from Puget Sound Energy). In some intervals, the limit on this WEIM transfer is reduced to zero such that the interval is flagged accordingly for this summary. WAPA Desert Southwest had almost 490 15-minute intervals (or around 122 hours) in which WEIM transfers were limited to zero in both directions.

69 This summary captures intervals in which the sum of transfer limits on individual dynamic WEIM transfer resources for a balancing area is zero in at least one direction. This summary is not impacted by any resource sufficiency evaluation failure that may impact total transfer capacity.

Table 2.5 Summary of dynamic WEIM transfer limitation to zero in at least one direction (2023)

BAA	Total intervals (15 min. intervals)	Total events	Average length of event (15 min. intervals)	Event average decrease in ... import capacity	export capacity
California ISO	1,914	113	16.9	41,735	N/A
Powerex	549	44	12.0	50	48
WAPA DSW	487	9	54.1	5,227	5,368
BPA	96	18	5.3	552	809
NV Energy	47	2	23.5	5,479	5,028
Seattle City Light	27	3	6.3	70	80
Avista	27	7	3.9	436	647
Tacoma Power	21	5	3.8	256	149
PacifiCorp East	18	2	1.0	3,514	1,400
El Paso Electric	15	2	7.5	90	88
Portland Gen. Elec.	14	2	7.0	322	595
Puget Sound En.	4	1	4.0	707	767
PSC of New Mexico	4	1	4.0	826	942
PacifiCorp West	2	1	2.0	1,006	1,601
Arizona Publ. Serv.	1	1	1.0	6,729	7,603
Tucson Elec. Pow.	1	1	1.0	2,801	3,146
Avangrid	1	1	1.0	641	508

Table 2.6 Summary of dynamic WEIM transfer limitation to zero in at least one direction (2023)

BAA	Total intervals (15 min. intervals)	Percent of limitation intervals by direction: Both directions	Imports only	Exports only	Percent of corresponding intervals also limited in the 5-minute
California ISO	1,914	0%	100%	0%	0%
Powerex	549	1%	95%	4%	52%
WAPA DSW	487	100%	0%	0%	96%
BPA	96	100%	0%	0%	63%
NV Energy	47	100%	0%	0%	91%
Seattle City Light	27	41%	30%	30%	93%
Avista	27	85%	15%	0%	72%
Tacoma Power	21	90%	0%	10%	48%
PacifiCorp East	18	11%	0%	89%	81%
El Paso Electric	15	100%	0%	0%	64%
Portland Gen. Elec.	14	100%	0%	0%	71%
Puget Sound En.	4	100%	0%	0%	33%
PSC of New Mexico	4	100%	0%	0%	100%
PacifiCorp West	2	100%	0%	0%	50%
Arizona Publ. Serv.	1	100%	0%	0%	0%
Tucson Elec. Pow.	1	100%	0%	0%	0%
Avangrid	1	100%	0%	0%	0%

2.2 Prices in the WEIM

This section summarizes prices in the Western energy imbalance market (WEIM) during the fourth quarter. Table 2.7 and Table 2.8 show average 15-minute and 5-minute market prices by month. Table 2.9 and Table 2.10 instead show average hourly prices in the 15-minute and 5-minute markets during the fourth quarter. The color gradient highlights deviation from the average system marginal energy price (SMEC), shown in the top row. Here, blue indicates prices below that month's average system price and orange indicates prices above. The CAISO prices in the Pacific Gas and Electric (PG&E) and Southern California Edison (SCE) areas are included as points of comparison.

Congestion on WEIM transfer constraints often drives price separation between areas. When transfer constraints limit the amount of energy that can flow from areas with lower cost supply to areas with higher cost supply, prices will be higher on the side of the constraint with higher cost supply. In the peak hours of the 15-minute market, this was often the case due to the limitation on WEIM imports into the CAISO area, resulting in lower prices for most balancing areas, relative to the CAISO.[70] Greenhouse gas compliance costs can also contribute to higher prices in California relative to the rest of the system.

Table 2.7 Monthly 15-minute market prices

	2022												2023											
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
SMEC	$51	$44	$42	$59	$57	$55	$69	$97	$125	$69	$90	$246	$140	$73	$73	$55	$19	$28	$66	$67	$42	$57	$58	$50
PG&E (CAISO)	$54	$48	$47	$63	$68	$82	$74	$103	$136	$73	$95	$257	$140	$75	$76	$57	$18	$29	$58	$65	$44	$62	$62	$54
SCE (CAISO)	$52	$43	$40	$55	$59	$69	$78	$108	$136	$64	$83	$246	$140	$68	$65	$48	$20	$27	$73	$68	$39	$51	$53	$45
BANC	$53	$48	$48	$65	$68	$68	$72	$105	$131	$75	$95	$252	$142	$75	$76	$59	$19	$30	$56	$54	$42	$59	$62	$53
Turlock ID	$54	$49	$48	$69	$76	$68	$72	$100	$136	$76	$95	$266	$142	$76	$77	$61	$19	$30	$56	$54	$43	$60	$63	$54
LADWP	$50	$42	$41	$55	$57	$63	$77	$108	$135	$67	$87	$256	$142	$73	$68	$49	$20	$27	$67	$50	$36	$45	$52	$46
NV Energy	$40	$38	$35	$49	$53	$56	$69	$93	$117	$58	$79	$243	$131	$66	$66	$50	$17	$23	$59	$40	$33	$38	$48	$42
Arizona PS	$39	$34	$31	$45	$52	$64	$72	$97	$118	$56	$80	$250	$130	$66	$65	$50	$17	$24	$63	$41	$30	$34	$45	$38
Tucson Electric					$54	$64	$72	$96	$111	$57	$77	$222	$129	$63	$60	$47	$21	$26	$58	$38	$30	$33	$45	$39
Salt River Project	$39	$34	$33	$47	$55	$67	$67	$88	$93	$56	$76	$157	$119	$52	$60	$50	$22	$24	$62	$46	$28	$34	$45	$38
PSC New Mexico	$37	$34	$30	$43	$47	$49	$67	$84	$103	$58	$64	$114	$127	$64	$65	$67	$17	$24	$59	$40	$30	$40	$50	$40
WAPA - Desert SW																$57	$20	$24	$62	$41	$30	$34	$45	$40
El Paso Electric																$33	$18	$23	$48	$37	$29	$30	$20	$20
PacifiCorp East	$37	$35	$32	$45	$43	$39	$65	$81	$99	$59	$72	$193	$120	$63	$67	$52	$18	$26	$53	$38	$31	$40	$46	$40
Idaho Power	$43	$41	$35	$57	$47	$32	$69	$81	$92	$63	$84	$237	$132	$71	$73	$59	$16	$27	$52	$39	$33	$56	$53	$45
NorthWestern	$40	$37	$34	$57	$41	$15	$41	$69	$73	$64	$87	$243	$133	$72	$75	$61	$13	$27	$53	$39	$34	$62	$54	$46
Avista Utilities			$35	$57	$41	$12	$36	$67	$73	$65	$86	$246	$133	$72	$74	$64	$12	$27	$49	$39	$34	$63	$55	$46
Avangrid																$61	$7	$28	$49	$40	$37	$63	$56	$48
BPA					$46	$10	$46	$80	$92	$65	$86	$251	$133	$73	$73	$62	$5	$29	$55	$49	$38	$65	$57	$47
Tacoma Power			$30	$59	$44	$13	$39	$74	$80	$64	$85	$248	$134	$72	$73	$62	$6	$29	$50	$43	$37	$64	$55	$47
PacifiCorp West	$39	$35	$32	$59	$42	$13	$42	$76	$89	$64	$85	$244	$132	$71	$72	$61	$6	$28	$48	$39	$35	$64	$55	$47
Portland GE	$38	$35	$33	$59	$43	$15	$43	$77	$92	$65	$87	$244	$132	$71	$72	$62	$9	$29	$50	$43	$37	$65	$55	$47
Puget Sound Energy	$37	$34	$31	$59	$44	$13	$40	$74	$81	$64	$85	$249	$133	$73	$74	$62	$8	$29	$59	$44	$37	$69	$58	$48
Seattle City Light	$37	$34	$31	$60	$45	$12	$40	$74	$80	$64	$85	$249	$133	$75	$72	$61	$6	$28	$50	$45	$37	$64	$55	$47
Powerex	$36	$34	$32	$52	$46	$15	$37	$61	$69	$67	$82	$212	$129	$79	$84	$79	$14	$55	$94	$99	$83	$102	$98	$62

70 Dynamic WEIM imports were limited to zero in the peak hours of each day between July 26, 2023 and November 15, 2023. The limitation was only in place for the hour-ahead and 15-minute markets. The 5-minute market was not impacted.

Table 2.8 Monthly 5-minute market prices

	Jan 2022	Feb 2022	Mar 2022	Apr 2022	May 2022	Jun 2022	Jul 2022	Aug 2022	Sep 2022	Oct 2022	Nov 2022	Dec 2022	Jan 2023	Feb 2023	Mar 2023	Apr 2023	May 2023	Jun 2023	Jul 2023	Aug 2023	Sep 2023	Oct 2023	Nov 2023	Dec 2023
SMEC	$43	$38	$38	$50	$51	$45	$62	$88	$97	$66	$86	$241	$135	$68	$66	$47	$16	$27	$58	$53	$39	$53	$57	$49
PG&E (CAISO)	$45	$42	$48	$54	$63	$80	$73	$95	$110	$73	$92	$254	$136	$70	$68	$49	$16	$28	$52	$52	$42	$58	$62	$53
SCE (CAISO)	$43	$36	$39	$45	$54	$63	$72	$98	$107	$60	$77	$234	$133	$63	$58	$41	$16	$26	$62	$53	$35	$48	$52	$44
BANC	$45	$42	$49	$56	$65	$72	$70	$97	$107	$74	$92	$249	$138	$71	$68	$49	$16	$29	$54	$53	$42	$57	$62	$53
Turlock ID	$46	$43	$49	$60	$73	$72	$71	$94	$113	$77	$94	$263	$139	$72	$69	$52	$16	$30	$54	$53	$42	$58	$63	$54
LADWP	$42	$35	$38	$45	$51	$55	$70	$98	$106	$61	$81	$244	$134	$67	$59	$42	$16	$26	$62	$55	$37	$51	$53	$45
NV Energy	$35	$31	$33	$42	$49	$51	$67	$90	$90	$57	$76	$235	$126	$62	$60	$42	$14	$22	$56	$45	$34	$44	$50	$43
Arizona PS	$33	$29	$31	$37	$47	$59	$67	$89	$96	$54	$77	$240	$123	$66	$61	$42	$15	$24	$59	$45	$32	$40	$46	$40
Tucson Electric					$50	$58	$67	$89	$90	$54	$73	$215	$123	$60	$54	$40	$20	$26	$58	$44	$31	$38	$46	$40
Salt River Project	$35	$29	$33	$41	$54	$68	$68	$83	$75	$51	$72	$149	$109	$49	$54	$45	$23	$26	$61	$48	$27	$38	$49	$39
PSC New Mexico	$32	$31	$28	$35	$42	$45	$64	$78	$80	$57	$63	$123	$122	$60	$58	$53	$14	$24	$56	$44	$33	$46	$51	$42
WAPA - Desert SW																$40	$19	$26	$58	$44	$33	$38	$47	$40
El Paso Electric																$28	$16	$23	$47	$40	$30	$33	$23	$23
PacifiCorp East	$32	$30	$28	$39	$39	$29	$59	$74	$76	$57	$70	$192	$116	$59	$62	$45	$14	$25	$52	$43	$34	$44	$47	$40
Idaho Power	$38	$36	$30	$53	$43	$18	$60	$75	$76	$61	$80	$233	$127	$66	$68	$51	$13	$26	$52	$44	$35	$61	$54	$46
NorthWestern	$37	$34	$29	$53	$37	$4	$37	$64	$66	$64	$86	$241	$128	$67	$69	$56	$9	$27	$55	$46	$37	$67	$55	$48
Avista Utilities			$29	$54	$37	-$2	$31	$63	$65	$64	$83	$242	$129	$67	$69	$56	$10	$27	$51	$44	$37	$68	$55	$48
Avangrid																$56	$6	$27	$51	$44	$38	$68	$55	$48
BPA					$37	$2	$34	$68	$78	$63	$83	$247	$130	$68	$68	$57	$4	$28	$53	$48	$37	$69	$56	$47
Tacoma Power			$27	$57	$41	$7	$33	$67	$71	$62	$82	$246	$130	$67	$69	$56	$5	$28	$50	$45	$37	$69	$54	$47
PacifiCorp West	$35	$32	$28	$57	$39	-$2	$37	$68	$69	$63	$83	$239	$129	$66	$68	$56	$6	$26	$50	$42	$37	$68	$54	$47
Portland GE	$36	$32	$26	$57	$38	$0	$37	$68	$72	$63	$84	$239	$129	$66	$68	$56	$9	$27	$50	$45	$37	$69	$54	$47
Puget Sound Energy	$34	$32	$28	$57	$41	$7	$34	$66	$71	$62	$83	$247	$131	$68	$69	$56	$7	$28	$61	$47	$38	$74	$56	$47
Seattle City Light	$34	$32	$28	$58	$41	$5	$33	$67	$70	$62	$82	$247	$130	$69	$68	$56	$5	$27	$50	$46	$37	$68	$55	$47
Powerex	$34	$32	$31	$50	$44	$10	$32	$57	$67	$65	$80	$209	$127	$77	$83	$77	$14	$52	$87	$94	$77	$102	$101	$61

Table 2.9 Hourly 15-minute market prices (October–December)

Hour	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
SMEC	$55	$53	$52	$52	$54	$59	$64	$56	$41	$39	$37	$35	$35	$35	$38	$51	$67	$83	$86	$73	$69	$66	$62	$56
PG&E (CAISO)	$57	$55	$54	$53	$56	$61	$66	$61	$51	$49	$47	$45	$44	$44	$47	$57	$71	$86	$89	$74	$70	$67	$63	$57
SCE (CAISO)	$55	$52	$51	$51	$53	$58	$64	$51	$29	$23	$21	$20	$21	$22	$26	$43	$62	$81	$85	$73	$69	$66	$62	$56
BANC	$56	$53	$52	$52	$54	$60	$65	$59	$52	$51	$48	$46	$45	$46	$49	$57	$69	$77	$78	$71	$67	$66	$62	$56
Turlock ID	$56	$53	$52	$52	$54	$60	$65	$60	$53	$53	$51	$49	$47	$48	$52	$60	$71	$78	$78	$71	$68	$66	$62	$56
LADWP	$56	$53	$52	$51	$53	$59	$65	$53	$30	$24	$23	$22	$22	$23	$27	$44	$57	$63	$63	$59	$60	$66	$63	$56
NV Energy	$45	$42	$42	$43	$47	$53	$56	$45	$31	$28	$27	$27	$26	$26	$27	$42	$51	$56	$53	$50	$50	$50	$51	$46
Arizona PS	$43	$39	$39	$41	$46	$52	$56	$43	$25	$20	$19	$17	$18	$18	$21	$39	$51	$55	$53	$49	$48	$50	$51	$45
Tucson Electric	$43	$39	$39	$41	$44	$50	$53	$40	$25	$20	$19	$18	$18	$19	$22	$40	$51	$55	$52	$49	$48	$49	$51	$44
Salt River Project	$39	$38	$37	$38	$41	$54	$51	$38	$24	$22	$23	$23	$24	$23	$24	$37	$59	$55	$52	$46	$45	$48	$47	$40
PSC New Mexico	$45	$42	$42	$43	$47	$56	$59	$70	$39	$23	$21	$20	$20	$21	$22	$38	$58	$56	$59	$51	$50	$51	$52	$52
WAPA - Desert SW	$44	$42	$41	$42	$46	$52	$58	$42	$25	$17	$21	$15	$19	$18	$20	$37	$51	$57	$52	$49	$48	$49	$56	$45
El Paso Electric	$22	$20	$20	$21	$24	$30	$27	$23	$21	$15	$17	$21	$14	$15	$18	$26	$32	$33	$31	$28	$28	$25	$28	$23
PacifiCorp East	$42	$39	$39	$40	$44	$49	$53	$44	$34	$32	$31	$31	$30	$31	$33	$43	$51	$52	$50	$47	$47	$48	$49	$44
Idaho Power	$48	$46	$45	$48	$52	$56	$64	$54	$51	$48	$45	$45	$44	$45	$45	$53	$58	$60	$58	$56	$55	$54	$55	$50
NorthWestern	$49	$47	$47	$49	$54	$59	$63	$58	$56	$54	$51	$51	$50	$48	$48	$55	$61	$62	$61	$58	$57	$56	$56	$51
Avista Utilities	$49	$47	$47	$49	$54	$60	$64	$58	$57	$56	$53	$52	$51	$50	$50	$56	$62	$62	$61	$58	$57	$56	$56	$52
Avangrid	$50	$47	$47	$50	$54	$59	$62	$57	$58	$58	$56	$54	$54	$53	$52	$57	$63	$64	$62	$60	$59	$57	$57	$52
BPA	$53	$47	$47	$49	$53	$60	$61	$58	$59	$59	$57	$54	$54	$52	$53	$56	$64	$64	$62	$61	$61	$60	$57	$51
Tacoma Power	$50	$47	$47	$49	$53	$59	$60	$57	$57	$58	$56	$53	$53	$52	$52	$56	$62	$63	$61	$59	$59	$56	$62	$51
PacifiCorp West	$49	$47	$47	$49	$53	$59	$61	$57	$58	$58	$55	$54	$53	$52	$51	$56	$62	$65	$61	$59	$58	$56	$57	$51
Portland GE	$49	$47	$47	$49	$53	$59	$61	$58	$58	$57	$57	$53	$53	$53	$52	$57	$62	$64	$63	$60	$59	$56	$57	$51
Puget Sound Energy	$52	$47	$47	$49	$54	$59	$62	$57	$67	$61	$57	$54	$53	$53	$52	$57	$68	$74	$67	$71	$66	$62	$60	$51
Seattle City Light	$49	$47	$47	$49	$53	$58	$59	$56	$57	$57	$57	$53	$54	$51	$51	$56	$63	$63	$61	$59	$59	$55	$56	$50
Powerex	$81	$75	$75	$76	$78	$84	$89	$94	$91	$92	$91	$89	$89	$88	$85	$88	$95	$95	$96	$94	$94	$92	$84	$81

Table 2.10 Hourly 5-minute market prices (October–December)

Hour	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
SMEC	$55	$53	$52	$52	$54	$59	$70	$68	$41	$37	$36	$35	$36	$35	$35	$47	$58	$67	$66	$65	$67	$67	$63	$56
PG&E (CAISO)	$57	$55	$53	$53	$56	$61	$72	$74	$52	$48	$45	$45	$44	$44	$44	$52	$63	$71	$69	$66	$68	$68	$64	$57
SCE (CAISO)	$55	$53	$51	$51	$54	$58	$70	$63	$27	$20	$21	$21	$22	$21	$23	$40	$55	$67	$67	$65	$67	$67	$62	$55
BANC	$56	$53	$52	$52	$55	$59	$73	$76	$53	$50	$47	$47	$46	$45	$46	$52	$61	$68	$67	$65	$67	$67	$63	$56
Turlock ID	$56	$53	$52	$52	$55	$59	$70	$72	$54	$53	$50	$49	$48	$49	$49	$55	$63	$69	$67	$65	$67	$68	$63	$56
LADWP	$56	$53	$52	$51	$54	$59	$71	$65	$28	$21	$22	$22	$22	$21	$24	$42	$64	$73	$68	$66	$68	$68	$64	$56
NV Energy	$45	$43	$43	$45	$49	$55	$63	$61	$30	$26	$27	$27	$27	$27	$28	$43	$53	$64	$60	$58	$58	$54	$53	$47
Arizona PS	$44	$40	$40	$49	$51	$54	$62	$57	$21	$19	$25	$18	$19	$18	$20	$38	$52	$62	$59	$55	$56	$59	$53	$46
Tucson Electric	$44	$40	$41	$42	$46	$52	$59	$51	$21	$18	$20	$20	$23	$19	$23	$39	$53	$62	$63	$54	$54	$52	$52	$45
Salt River Project	$40	$38	$37	$39	$43	$58	$55	$41	$21	$22	$35	$30	$25	$26	$22	$46	$61	$59	$55	$53	$53	$48	$54	$41
PSC New Mexico	$46	$43	$43	$44	$50	$60	$66	$85	$33	$21	$21	$21	$22	$20	$21	$39	$67	$63	$73	$61	$55	$58	$54	$50
WAPA - Desert SW	$45	$43	$42	$47	$47	$54	$63	$54	$22	$16	$20	$17	$20	$18	$20	$37	$53	$65	$59	$55	$54	$53	$54	$46
El Paso Electric	$26	$22	$22	$23	$26	$35	$34	$30	$18	$15	$15	$19	$15	$15	$18	$27	$38	$41	$38	$36	$34	$31	$31	$25
PacifiCorp East	$43	$40	$40	$41	$45	$50	$58	$55	$33	$31	$30	$32	$31	$30	$31	$42	$52	$59	$56	$53	$53	$50	$51	$44
Idaho Power	$49	$46	$46	$48	$52	$57	$66	$66	$51	$48	$45	$47	$46	$45	$45	$53	$59	$66	$62	$59	$60	$57	$57	$51
NorthWestern	$60	$48	$47	$50	$54	$60	$68	$69	$57	$55	$53	$53	$51	$48	$48	$55	$62	$68	$64	$61	$61	$58	$59	$55
Avista Utilities	$54	$48	$47	$50	$54	$61	$68	$70	$59	$57	$55	$54	$53	$50	$50	$55	$62	$67	$64	$61	$61	$58	$59	$53
Avangrid	$50	$47	$47	$50	$54	$60	$66	$65	$60	$60	$57	$55	$53	$52	$51	$56	$63	$68	$64	$61	$62	$59	$59	$53
BPA	$51	$47	$47	$49	$53	$60	$65	$64	$60	$62	$58	$55	$54	$52	$51	$57	$63	$67	$64	$62	$63	$62	$59	$52
Tacoma Power	$50	$47	$47	$49	$53	$59	$65	$63	$59	$59	$56	$53	$54	$51	$51	$57	$63	$67	$63	$61	$61	$58	$63	$52
PacifiCorp West	$49	$47	$47	$49	$53	$59	$67	$64	$60	$59	$56	$55	$53	$52	$50	$56	$63	$69	$63	$60	$61	$58	$59	$52
Portland GE	$50	$47	$47	$49	$53	$59	$65	$64	$60	$59	$58	$55	$52	$52	$51	$57	$63	$67	$63	$61	$61	$58	$59	$52
Puget Sound Energy	$50	$47	$47	$49	$53	$59	$66	$64	$70	$61	$60	$55	$54	$52	$51	$57	$63	$77	$74	$68	$67	$61	$62	$52
Seattle City Light	$50	$47	$47	$49	$53	$59	$70	$64	$59	$58	$58	$55	$55	$52	$51	$57	$63	$67	$63	$61	$61	$57	$59	$51
Powerex	$82	$76	$75	$76	$88	$84	$88	$88	$90	$93	$91	$89	$91	$89	$87	$90	$93	$96	$95	$95	$95	$91	$84	$81

2.3 Resource sufficiency evaluation

As part of the WEIM design, each area, including the California ISO balancing area, is subject to a resource sufficiency evaluation. The resource sufficiency evaluation allows the market to optimize transfers between participating WEIM entities while deterring WEIM balancing areas from relying on other WEIM areas for capacity.

The evaluation is performed prior to each hour to ensure that generation in each area is sufficient without relying on transfers from other balancing areas. The evaluation is made up of four tests: the power flow feasibility test, the balancing test, the bid range capacity test, and the flexible ramping sufficiency test. Failures of two of the tests can constrain transfer capability:

- **The bid range capacity test (capacity test)** requires that each area provide incremental bid-in capacity to meet the imbalance between load, intertie, and generation base schedules.
- **The flexible ramping sufficiency test (flexibility test)** requires that each balancing area has enough ramping flexibility over an hour to meet the forecasted change in demand as well as uncertainty.

If an area that has not opted into Assistance Energy Transfers fails either the bid range capacity test or flexible ramping sufficiency test in the *upward* direction, WEIM transfers *into* that area cannot be increased.[71] If an area fails either test in the *downward* direction, transfers *out of* that area cannot be increased.

Figure 2.10 and Figure 2.11 show the percent of intervals in which each WEIM area failed the upward capacity and flexibility tests, while Figure 2.12 and Figure 2.13 provide the same information for the downward direction.[72] The dash indicates the area did not fail the test during the month.

In the fourth quarter of 2023:

- The Public Service Company of New Mexico (PNM) failed the upward flexibility test in around 1.4 percent of intervals.
- Puget Sound Energy failed the upward flexibility test in around 1.2 percent of intervals.
- All other balancing areas failed in less than one percent of intervals for each test type and direction.

Figure 2.10 Frequency of upward capacity test failures by month and area (percent of intervals)

	2022			2023											
	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Arizona Publ. Serv.	—	—	0.1	0.4	0.5	0.7	0.2	0.0	0.1	—	—	—	0.0	—	0.1
Avangrid							0.0	—	—	—	—	0.8	—	—	—
Avista	—	—	0.1	—	—	—	0.1	0.0	—	—	—	—	0.0	0.1	—
BANC	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
BPA	—	—	0.4	—	—	—	0.2	—	0.3	0.4	—	0.1	—	—	—
California ISO	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
El Paso Electric							0.0	0.1	0.3	0.8	0.0	0.1	0.1	—	—
Idaho Power	—	—	—	—	—	—	0.0	0.1	—	—	—	—	—	0.1	—
LADWP	—	—	—	0.1	—	—	—	—	—	0.1	0.0	—	—	—	0.0
NorthWestern En.	—	0.2	0.1	0.3	0.1	—	—	—	—	0.3	—	—	—	—	—
NV Energy	—	—	—	—	—	—	—	0.0	—	0.0	0.0	—	0.0	—	—
PacifiCorp East	—	—	0.3	—	—	—	—	—	—	0.0	—	—	—	—	—
PacifiCorp West	—	0.0	0.0	0.1	0.1	—	—	—	—	—	0.1	—	—	—	—
Portland Gen. Elec.	—	0.3	—	—	0.0	0.0	0.1	0.4	0.1	0.0	—	0.0	0.0	0.6	—
Powerex	—	0.0	—	—	—	—	—	0.1	—	—	—	0.1	0.0	0.0	—
PSC of New Mexico	—	—	—	—	—	0.7	0.3	0.2	0.0	—	0.0	0.1	0.1	—	0.1
Puget Sound En.	0.1	0.0	—	—	0.0	0.2	—	0.1	0.5	1.5	0.5	0.2	0.7	1.0	0.2
Salt River Proj.	0.2	0.0	0.0	1.0	0.4	1.1	0.9	0.2	0.0	2.8	1.2	0.0	0.8	0.2	0.1
Seattle City Light	0.0	0.0	0.2	0.0	0.1	—	—	—	—	0.1	0.9	—	0.1	0.6	—
Tacoma Power	—	—	—	0.0	0.1	0.1	—	0.1	—	—	0.1	—	0.1	0.0	—
Tucson Elec. Pow.	—	—	—	0.1	0.0	—	—	—	—	0.3	—	—	0.2	—	—
Turlock Irrig. Dist.	—	—	0.2	—	—	—	0.0	—	—	0.1	—	—	—	—	—
WAPA DSW							2.3	0.8	0.7	1.1	0.6	0.1	0.3	0.4	0.1

[71] Normally, if an area fails either test in the upward direction, net WEIM imports during the hour cannot exceed the greater of either the base transfer or the optimal transfer from the last 15-minute interval. Assistance Energy Transfers (AETs) give balancing areas access to excess WEIM supply that may not otherwise have been available following an upward resource sufficiency evaluation failure. Balancing areas can opt into AET to prevent their WEIM transfers from being limited during a test failure but will be subject to an ex-post surcharge.

[72] Results exclude known invalid test failures. These can occur because of a market disruption, software defect, or other error.

Figure 2.11 Frequency of upward flexibility test failures by month and area (percent of intervals)

	2022			2023											
	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Arizona Publ. Serv.	—	0.1	0.4	0.9	1.8	2.5	1.1	0.2	0.1	—	0.0	—	—	0.2	0.1
Avangrid							1.0	0.7	0.1	0.2	0.0	0.9	0.1	0.1	0.2
Avista	0.1	—	0.1	—	0.0	0.0	0.2	0.2	0.0	—	—	—	0.1	0.1	—
BANC	—	—	—	—	—	—	—	0.1	—	—	—	—	—	—	—
BPA	0.2	0.1	0.4	—	0.1	0.6	0.2	1.2	0.3	1.3	0.2	0.2	0.1	—	—
California ISO	0.0	—	—	—	—	—	—	—	—	—	—	—	—	—	—
El Paso Electric							0.8	0.7	0.3	2.1	0.5	0.6	0.4	0.2	0.1
Idaho Power	—	0.1	—	0.0	0.1	0.3	0.3	0.5	0.1	—	—	—	0.1	—	—
LADWP	0.1	—	—	—	0.3	—	0.1	0.0	0.1	0.0	0.2	0.0	—	—	0.1
NorthWestern En.	—	0.5	0.8	0.3	0.1	0.2	0.8	0.3	0.2	1.0	0.4	0.2	0.2	0.0	0.1
NV Energy	0.1	0.2	0.0	0.1	0.3	0.0	0.1	0.1	0.0	0.1	0.2	0.1	—	0.1	0.0
PacifiCorp East	0.1	—	0.0	0.1	—	0.0	0.1	—	0.0	0.2	—	—	—	—	—
PacifiCorp West	—	0.1	—	0.1	0.1	—	0.1	0.6	0.0	0.2	—	—	0.0	0.0	0.1
Portland Gen. Elec.	0.2	1.0	0.1	0.0	0.1	0.0	0.1	1.5	0.7	0.1	—	—	0.6	0.0	—
Powerex	—	—	—	—	0.2	—	—	—	—	—	—	—	—	—	—
PSC of New Mexico	0.2	0.1	0.8	0.2	—	1.2	5.1	0.9	0.6	0.7	0.5	0.3	1.9	1.9	0.3
Puget Sound En.	—	0.0	—	—	0.1	0.8	0.2	1.0	0.6	2.6	1.3	0.2	1.3	1.9	0.5
Salt River Proj.	0.6	0.5	0.8	3.5	1.2	1.7	2.0	0.6	0.2	3.7	1.1	0.3	0.6	0.4	0.2
Seattle City Light	—	0.1	0.0	—	0.1	—	—	—	—	—	0.5	0.0	0.0	—	—
Tacoma Power	—	0.2	—	0.2	0.1	0.2	—	0.1	—	—	—	—	0.2	0.0	—
Tucson Elec. Pow.	0.0	—	0.2	0.3	0.3	0.3	0.1	0.1	—	0.2	0.3	—	0.1	0.2	0.1
Turlock Irrig. Dist.	—	—	1.2	—	—	—	0.0	—	—	0.1	—	—	—	—	—
WAPA DSW							2.7	0.7	0.8	0.3	0.6	0.2	0.3	0.5	0.1

Figure 2.12 Frequency of downward capacity test failures by month and area (percent of intervals)

	2022			2023											
	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Arizona Publ. Serv.	—	—	0.1	—	—	0.6	—	—	—	—	—	—	—	—	0.8
Avangrid							—	—	—	—	—	—	—	0.3	—
Avista	0.0	—	—	—	—	—	0.0	—	—	—	—	—	—	—	—
BANC	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
BPA	—	—	—	—	0.1	—	0.2	0.1	—	—	—	—	—	—	—
California ISO	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
El Paso Electric							0.2	0.1	0.3	0.2	0.1	0.2	—	—	—
Idaho Power	—	—	—	—	—	—	—	—	0.0	—	—	—	—	—	—
LADWP	—	—	—	0.1	—	—	—	—	0.0	—	—	—	—	—	—
NorthWestern En.	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
NV Energy	—	—	—	—	—	—	0.1	0.1	0.6	0.1	—	—	—	—	—
PacifiCorp East	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
PacifiCorp West	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Portland Gen. Elec.	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Powerex	—	0.0	—	—	—	—	—	—	—	0.0	—	—	—	—	—
PSC of New Mexico	—	—	—	—	—	0.1	0.3	—	—	—	—	0.1	—	—	—
Puget Sound En.	—	—	—	—	—	—	—	0.1	—	—	—	—	—	—	—
Salt River Proj.	0.2	0.3	—	0.4	1.5	0.2	0.3	0.6	0.4	0.7	—	0.1	0.1	—	—
Seattle City Light	—	—	—	—	0.1	—	—	—	—	—	0.3	0.1	—	0.1	0.2
Tacoma Power	0.1	—	0.2	—	0.2	0.1	—	—	—	0.0	—	0.0	—	—	—
Tucson Elec. Pow.	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Turlock Irrig. Dist.	—	—	—	—	0.1	—	—	—	—	—	—	—	—	—	—
WAPA DSW							0.2	—	0.8	0.1	0.4	0.5	0.2	0.2	—

Figure 2.13 Frequency of downward flexibility test failures by month and area (percent of intervals)

	Oct 2022	Nov 2022	Dec 2022	Jan 2023	Feb 2023	Mar 2023	Apr 2023	May 2023	Jun 2023	Jul 2023	Aug 2023	Sep 2023	Oct 2023	Nov 2023	Dec 2023
Arizona Publ. Serv.	0.2	0.2	0.1	0.9	0.5	2.1	0.7	1.2	0.1	—	—	—	—	—	0.3
Avangrid							0.1	—	—	—	—	0.1	—	—	—
Avista	0.2	—	0.0	—	—	0.1	0.1	0.1	—	—	—	—	—	0.1	—
BANC	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
BPA	—	0.2	0.2	—	0.0	0.1	0.6	5.5	0.0	0.4	—	0.0	0.2	—	—
California ISO	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
El Paso Electric							0.2	0.9	1.9	0.5	—	0.3	—	0.2	0.3
Idaho Power	—	—	—	—	—	0.9	0.2	—	—	—	—	0.0	—	0.1	—
LADWP	—	—	—	0.1	—	—	—	—	—	—	—	—	—	—	—
NorthWestern En.	—	0.0	0.1	—	0.0	—	—	0.2	0.2	—	0.1	0.0	—	—	—
NV Energy	0.5	0.6	0.1	0.1	0.1	0.1	0.0	0.1	0.4	0.1	0.1	0.0	0.1	0.1	—
PacifiCorp East	—	—	—	—	—	—	—	—	—	—	—	0.0	0.1	—	—
PacifiCorp West	0.1	—	0.0	—	—	—	0.0	0.2	0.0	—	—	1.1	—	0.1	—
Portland Gen. Elec.	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Powerex	0.1	—	—	0.1	0.1	—	0.2	—	—	0.0	—	0.2	0.1	—	0.1
PSC of New Mexico	0.2	0.1	—	0.0	—	0.4	1.6	2.1	—	0.1	0.4	1.1	0.4	0.2	0.2
Puget Sound En.	0.1	—	—	—	—	—	—	0.8	—	—	—	—	—	—	—
Salt River Proj.	0.2	0.9	0.3	1.4	3.3	1.0	0.3	0.1	0.1	0.1	—	—	—	0.1	0.0
Seattle City Light	—	0.2	0.6	0.1	0.2	0.0	0.3	0.0	0.3	0.4	1.1	0.2	—	0.8	0.2
Tacoma Power	—	—	0.1	—	0.2	0.1	—	—	—	0.0	—	0.1	—	0.0	—
Tucson Elec. Pow.	—	0.0	—	—	—	—	—	—	—	—	—	—	—	—	—
Turlock Irrig. Dist.	—	0.1	—	0.1	0.1	0.1	0.1	0.4	—	—	—	—	—	0.1	—
WAPA DSW							2.7	0.5	0.7	0.1	0.2	0.6	0.8	0.2	0.1

Resource sufficiency evaluation reports

DMM is providing additional transparency surrounding test accuracy and performance in regular reports specific to this topic.[73] These reports include many metrics and analyses not included in this report, such as the impact of several changes proposed or adopted through the stakeholder process.

2.4 WEIM imbalance conformance

Frequency and size of imbalance conformance

Table 2.11 summarizes the average frequency and size of positive and negative imbalance conformance entered by operators in the WEIM and California ISO for the 15-minute and 5-minute markets during the quarter.

The Bonneville Power Administration, El Paso Electric, and Seattle City Light areas used negative imbalance conformance in the 15-minute market most frequently. Other areas had little to no negative conformance in the 15-minute market. Negative imbalance conformance in the 5-minute market was much more frequent by nearly all areas.

73 Department of Market Monitoring Reports and Presentations, *WEIM resource sufficiency evaluation reports*: http://www.caiso.com/market/Pages/MarketMonitoring/MarketMonitoringReportsPresentations/Default.aspx

The Bonneville Power Administration, NorthWestern Energy, and El Paso Electric areas had the greatest percent of positive imbalance conformance in the 15-minute market. Other areas had very little or no positive conformance in the 15-minute market. Nearly all areas used positive imbalance conformance in the 5-minute market; however, Seattle City Light, Avista Utilities, Turlock Irrigation District, BANC, and Tacoma Power used positive imbalance in three percent or less of intervals.

Table 2.11 Average frequency and size of imbalance conformance (October–December)

Balancing area	Market	Positive imbalance conformance			Negative imbalance conformance			Average hourly adjustment MW
		Percent of intervals	Average MW	Percent of total load	Percent of intervals	Average MW	Percent of total load	
California ISO	FMM	27.1%	1,168	0.0%	0.9%	-266	0.0%	315
	RTD	43.3%	317	0.0%	28.7%	-237	0.0%	69
Avangrid Renewables*	FMM	0.0%	N/A	N/A	0.0%	-80	N/A	0
	RTD	17.7%	31	N/A	6.8%	-33	N/A	3
BANC	FMM	0.0%	N/A	N/A	0.2%	-41	N/A	0
	RTD	0.1%	50	0.0%	0.3%	-43	0.0%	0
Turlock Irrigation District	FMM	0.0%	16	0.0%	0.0%	N/A	N/A	0
	RTD	0.1%	26	0.0%	0.0%	N/A	N/A	0
LADWP	FMM	0.7%	42	0.0%	2.0%	-43	0.0%	-1
	RTD	17.5%	38	0.0%	15.3%	-39	0.0%	1
NV Energy	FMM	0.0%	N/A	N/A	0.1%	-120	N/A	0
	RTD	37.5%	93	0.0%	5.7%	-103	0.0%	29
Arizona Public Service	FMM	0.0%	N/A	N/A	0.0%	N/A	N/A	0
	RTD	56.5%	61	0.0%	13.2%	-55	0.0%	27
Tucson Electric Power	FMM	0.0%	N/A	N/A	0.0%	N/A	N/A	0
	RTD	7.2%	58	0.0%	20.0%	-49	0.0%	-6
WAPA - Desert Southwest	FMM	0.0%	N/A	N/A	0.0%	N/A	N/A	0
	RTD	28.4%	20	0.0%	29.6%	-20	0.0%	0
El Paso Electric	FMM	10.9%	15	0.0%	12.5%	-15	0.0%	0
	RTD	13.4%	17	0.0%	16.9%	-17	0.0%	-1
Salt River Project	FMM	0.3%	60	0.0%	0.2%	-73	0.0%	0
	RTD	6.5%	65	0.0%	4.5%	-65	0.0%	1
Public Service Co. of New Mexico	FMM	0.4%	145	0.0%	0.0%	N/A	N/A	1
	RTD	30.9%	58	0.0%	17.0%	-64	0.0%	7
PacifiCorp East	FMM	0.0%	N/A	N/A	0.1%	-350	N/A	0
	RTD	4.7%	68	0.0%	24.9%	-87	0.0%	-19
Idaho Power	FMM	0.0%	N/A	N/A	0.0%	N/A	N/A	0
	RTD	24.9%	58	0.0%	10.3%	-54	0.0%	9
NorthWestern Energy	FMM	11.6%	13	0.0%	0.2%	-20	0.0%	1
	RTD	37.9%	14	0.0%	1.6%	-24	0.0%	5
Avista Utilities	FMM	0.1%	35	0.0%	2.4%	-36	0.0%	-1
	RTD	1.2%	22	0.0%	39.8%	-23	0.0%	-9
Bonneville Power Administration	FMM	35.2%	24	0.0%	64.2%	-32	0.0%	-12
	RTD	35.8%	24	0.0%	63.6%	-32	0.0%	-12
Tacoma Power	FMM	0.0%	N/A	N/A	0.0%	N/A	N/A	0
	RTD	1.2%	10	0.0%	4.8%	-7	0.0%	0
PacifiCorp West	FMM	0.0%	N/A	N/A	0.0%	N/A	N/A	0
	RTD	4.5%	73	0.0%	7.6%	-36	0.0%	1
Portland General Electric	FMM	0.0%	N/A	N/A	0.0%	N/A	N/A	0
	RTD	8.2%	28	0.0%	0.9%	-30	0.0%	2
Puget Sound Energy	FMM	0.0%	N/A	N/A	0.0%	N/A	N/A	0
	RTD	3.9%	29	0.0%	31.1%	-28	0.0%	-8
Seattle City Light	FMM	0.6%	24	0.0%	10.5%	-22	0.0%	-2
	RTD	1.8%	22	0.0%	77.6%	-23	0.0%	-18

*Avangrid Renewables is a generation-only entity and therefore load conformance cannot be measured as a percent of load

APPENDIX

Appendix A | Western energy imbalance market area specific metrics

Sections A.1 to A.23 include figures by WEIM area on the hourly locational marginal price (LMP) and dynamic transfers.[74] These figures are included for both the 15-minute and 5-minute markets. Key highlights of the quarter include:

- Compared to the fourth quarter of 2022, this quarter saw instances where WEIM transfer congestion led to lower prices during evening peak hours in the 15-minute market, especially for Desert Southwest entities. Powerex experienced a notable shift, with WEIM transfer congestion positively affecting the LMP, contrasting with the negative impact observed in the last quarter in 2022.
- WEIM transfer volumes increased for entities in the Desert Southwest and Pacific Northwest. Notably, Tacoma Power experienced a significant shift from the fourth quarter of 2022, transitioning from a net exporter to neighboring BAAs to a net importer this quarter.

The hourly locational marginal price decomposition figures break down the price into seven separate components. These components, listed below, can influence the prices in an area positively or negatively depending on the circumstances.

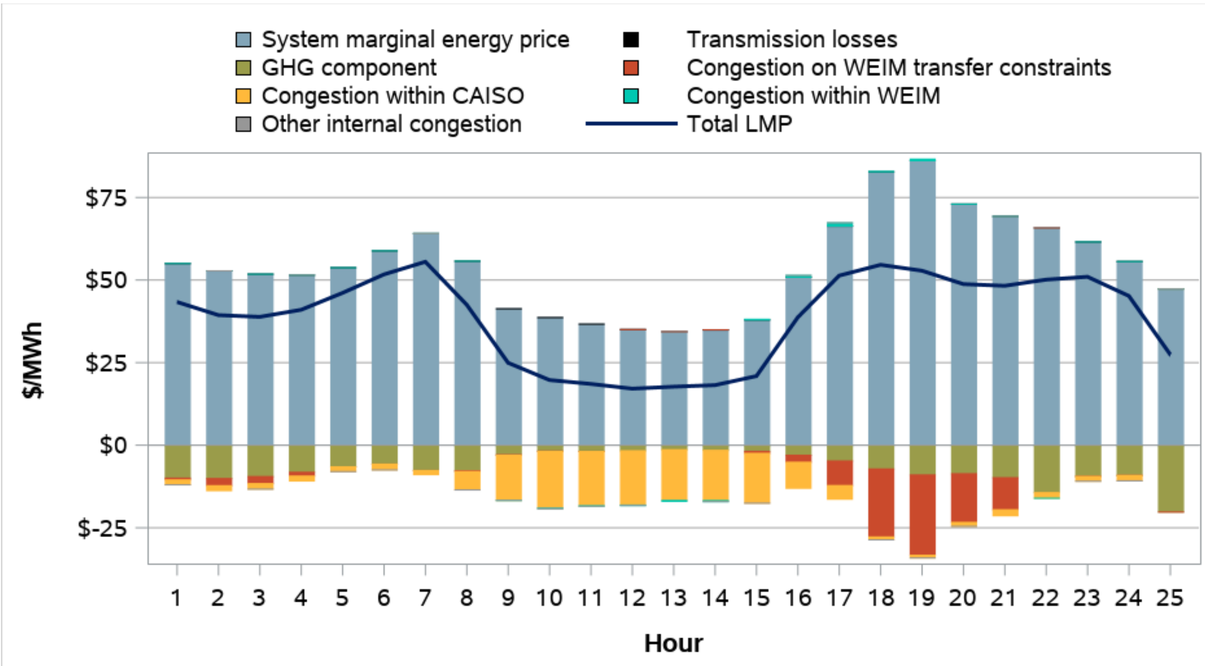
- **System marginal energy price**, often referred to as SMEC, is the marginal clearing price for energy at a reference location in the California ISO balancing area. The SMEC is the same for all WEIM areas.
- **Transmission losses** are the price impact of energy lost on the path from source to sink.
- **GHG component** is the greenhouse gas price in each 15-minute or 5-minute interval set at the greenhouse gas bid of the marginal megawatt deemed to serve California load. This price, determined within the optimization, is also included in the price difference between serving both California and non-California WEIM load, which contributes to higher prices for WEIM areas in California.
- **Congestion within California ISO** is the price impact from transmission constraints within the California ISO area that are restricting the flow of energy. While these constraints are located within the California ISO balancing area, they can create price impacts across the WEIM.
- **Congestion within WEIM** is the price impact from transmission constraints within a WEIM area that are restricting the flow of energy. While these constraints are located within a single balancing area, they can create price impacts across the WEIM.
- **Other internal congestion.** DMM calculates the congestion impact from constraints within the California ISO or within WEIM by replicating the nodal congestion component of the price from individual constraints, shadow prices, and shift factors. In some cases, DMM could not replicate the congestion component from individual constraints such that the remainder is flagged as *Other internal congestion.*

[74] These figures only include dynamic transfer capacity that has been made available to the WEIM for optimization. Therefore, transfers that have been base scheduled will not appear in the figures.

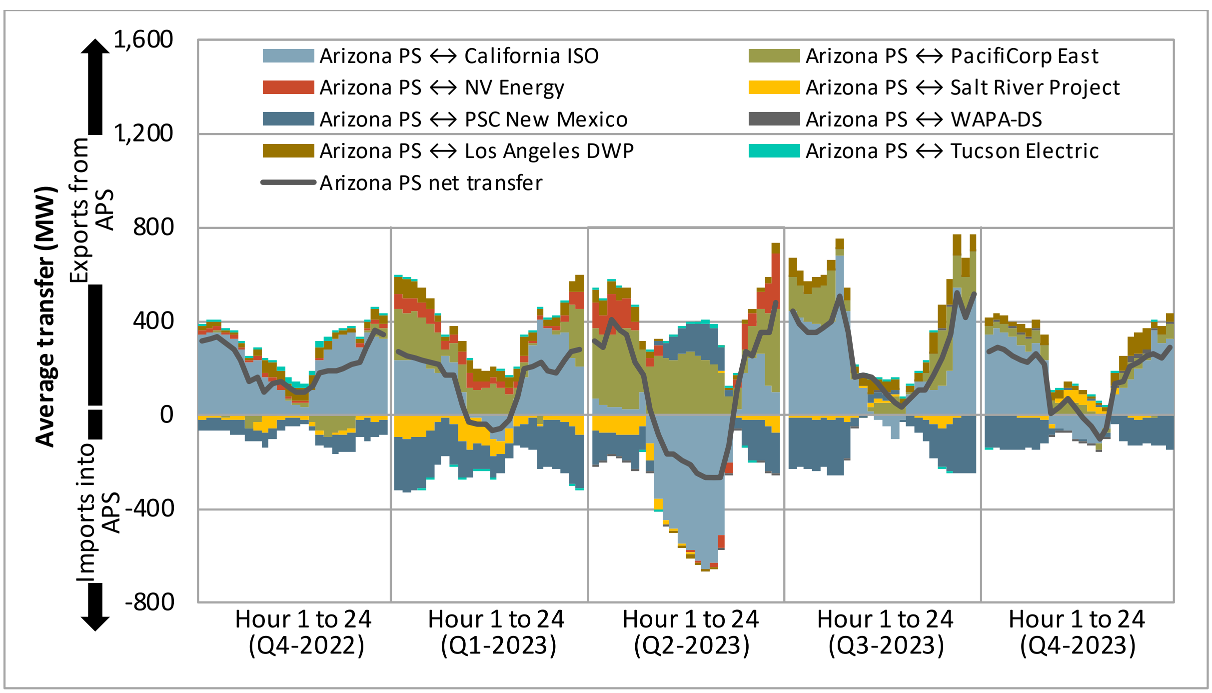
- **Congestion on WEIM transfer constraints** is the price impact from any constraint that limit WEIM transfers between balancing areas. This includes congestion from (1) scheduling limits on individual WEIM transfers, (2) total scheduling limits following a resource sufficiency evaluation failure, or (3) intertie constraint (ITC) and intertie scheduling limit (ISL).

A.1 Arizona Public Service

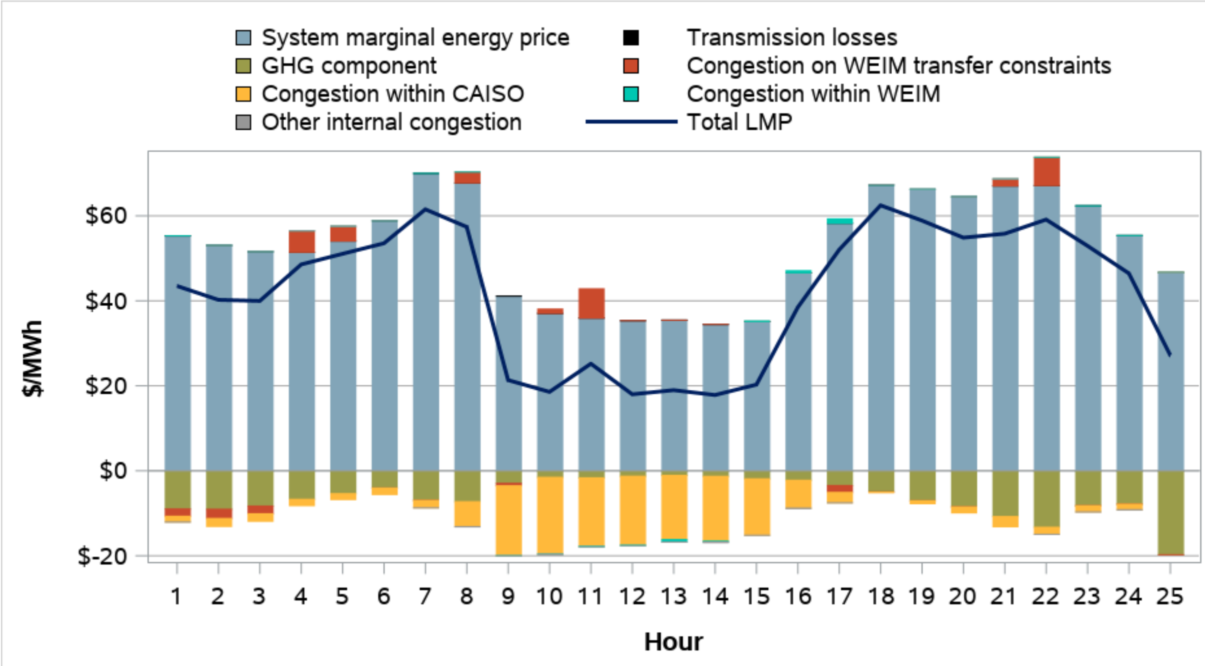
Appendix Figure A.1 Average hourly 15-minute price by component (Q4 2023)



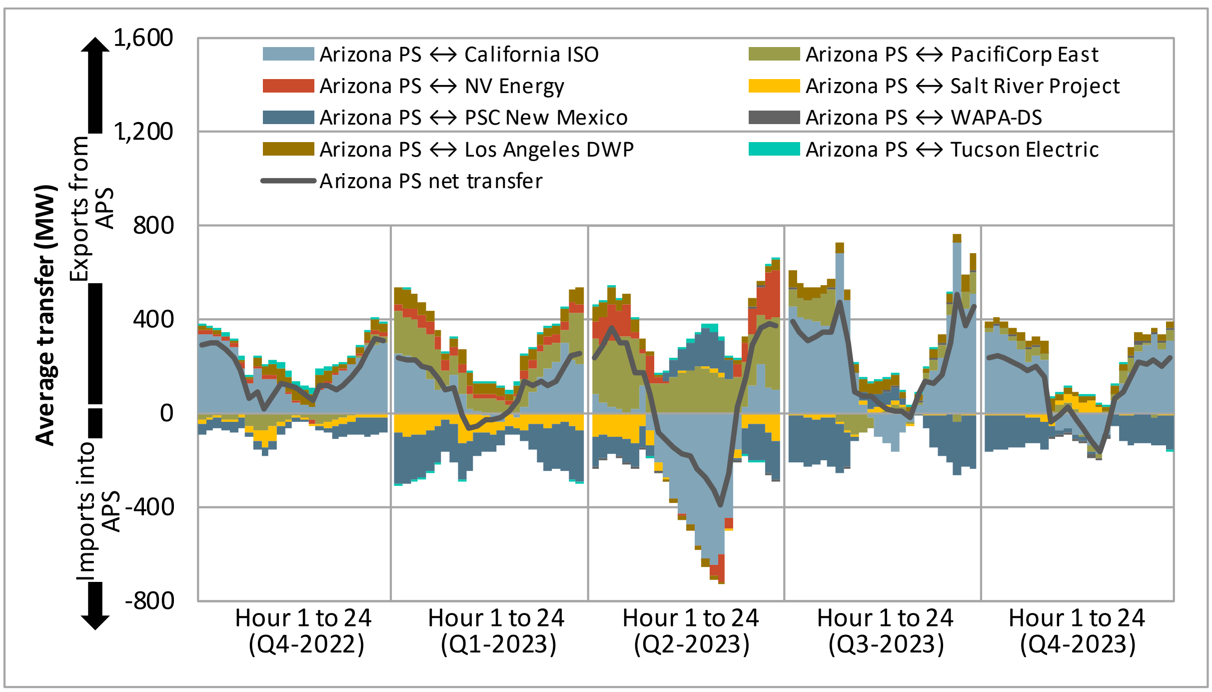
Appendix Figure A.2 Average hourly 15-minute market transfers



Appendix Figure A.3 Average hourly 5-minute price by component (Q4 2023)

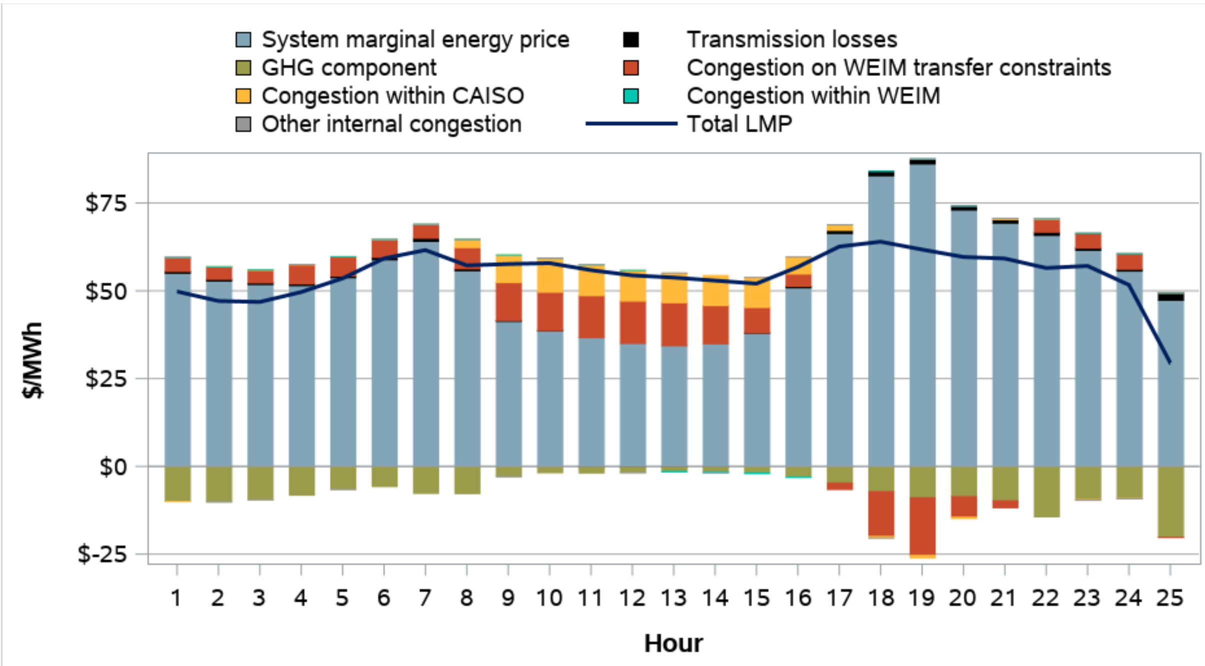


Appendix Figure A.4 Average hourly 5-minute market transfers

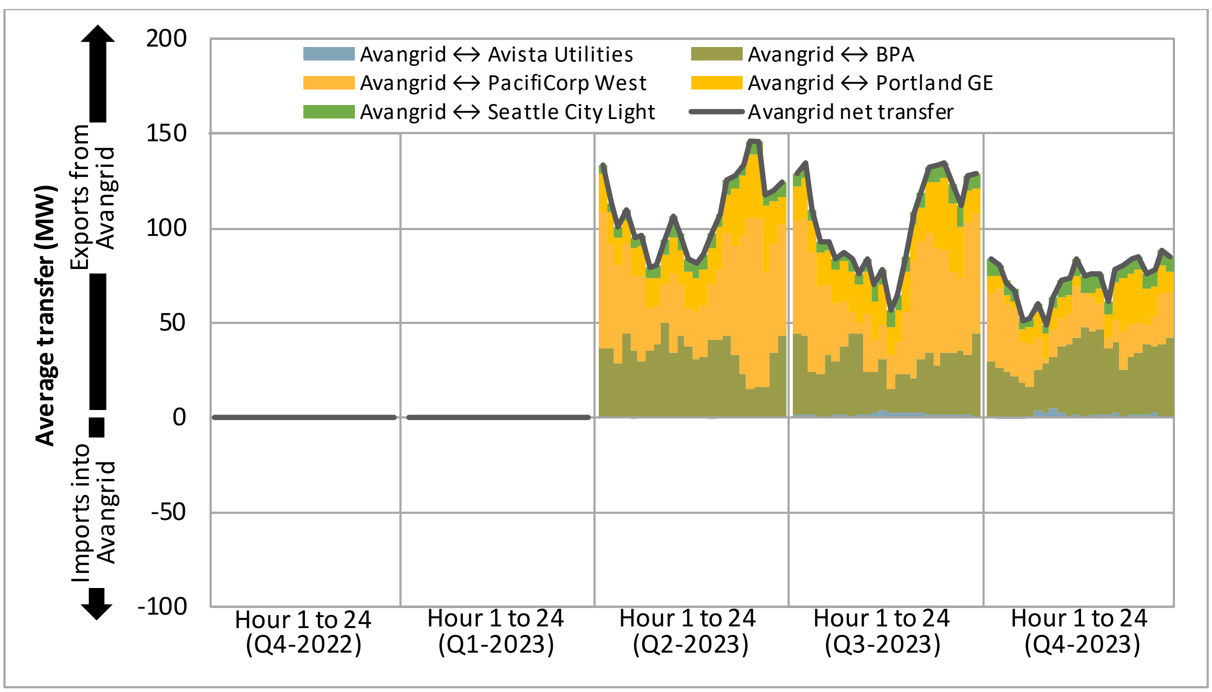


A.2 Avangrid

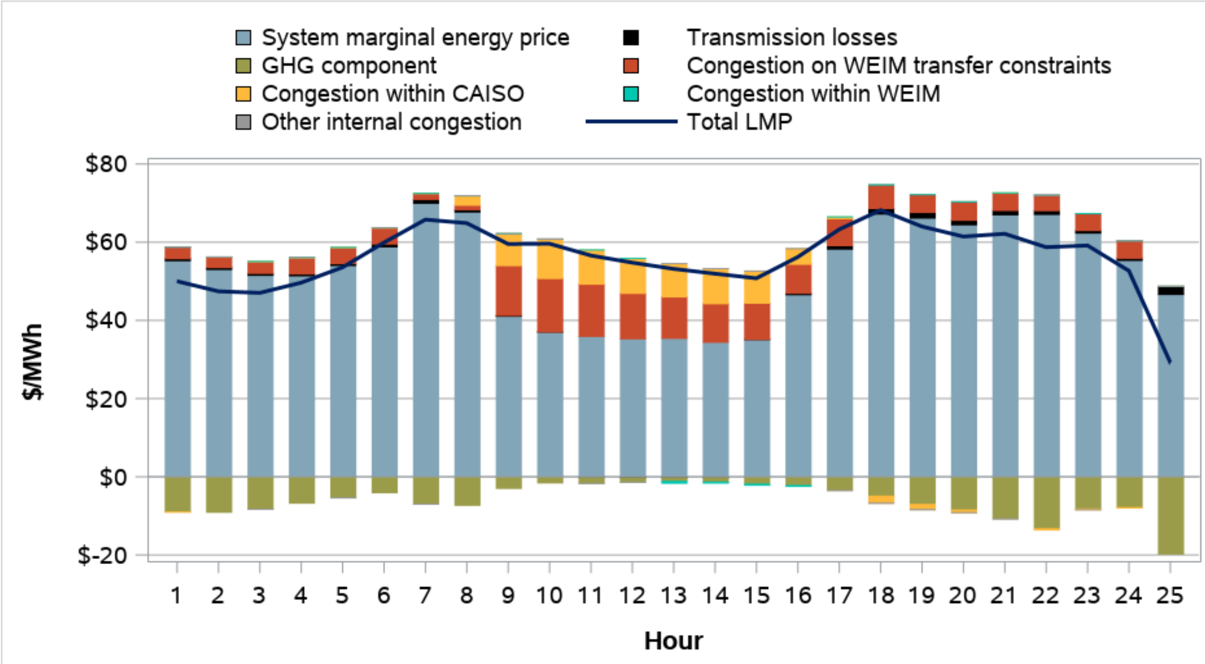
Appendix Figure A.5 Average hourly 15-minute price by component (Q4 2023)



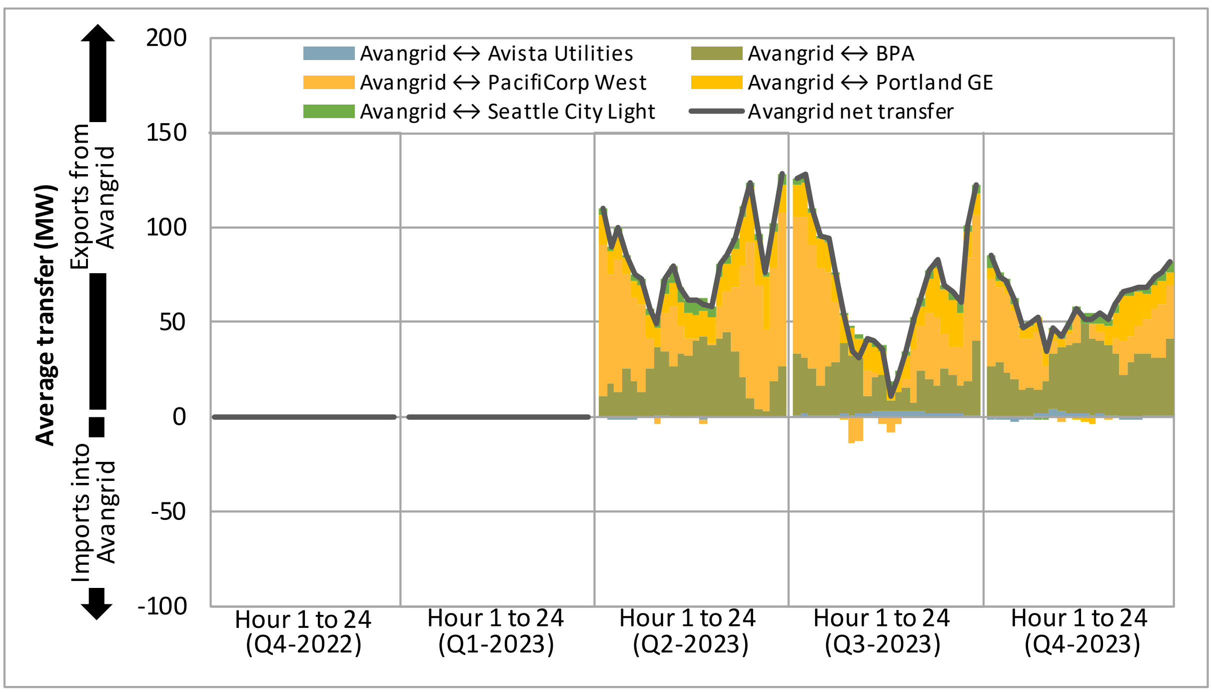
Appendix Figure A.6 Average hourly 15-minute market transfers



Appendix Figure A.7 Average hourly 5-minute price by component (Q4 2023)

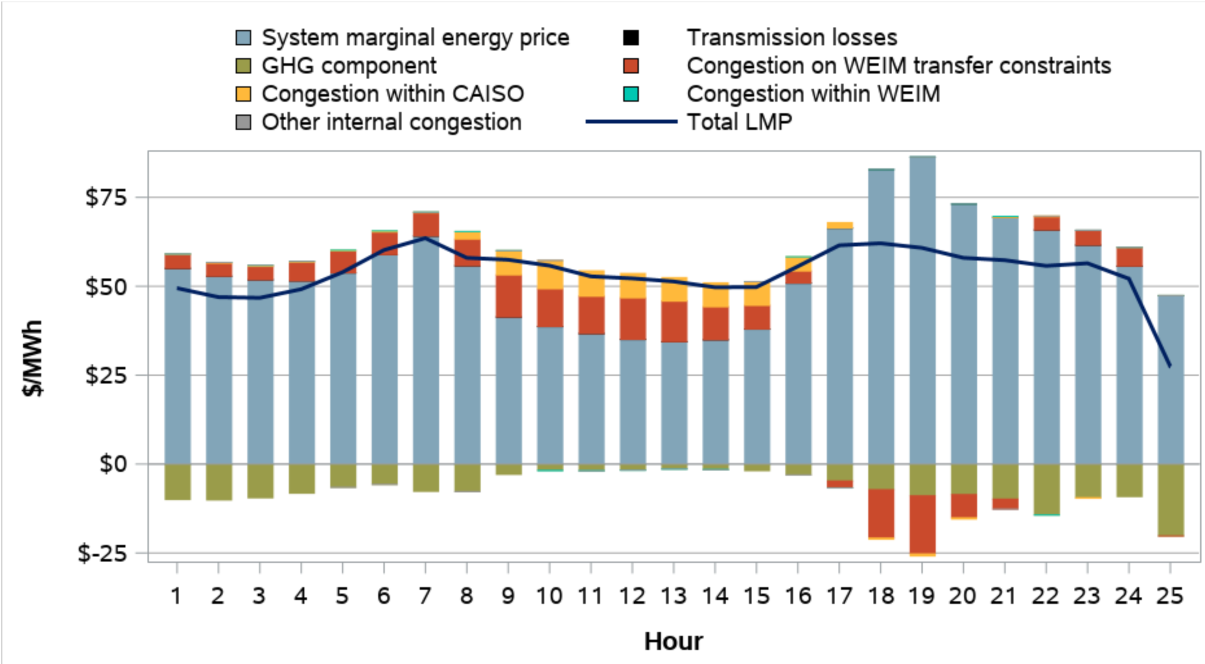


Appendix Figure A.8 Average hourly 5-minute market transfers

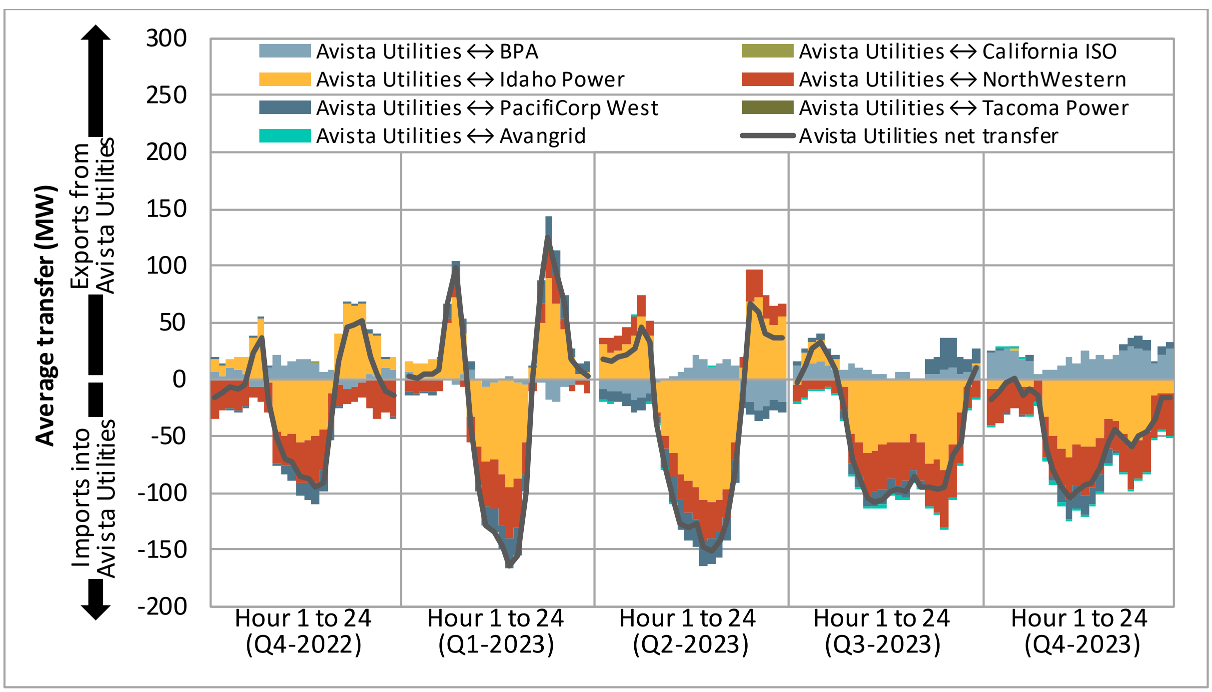


A.3 Avista Utilities

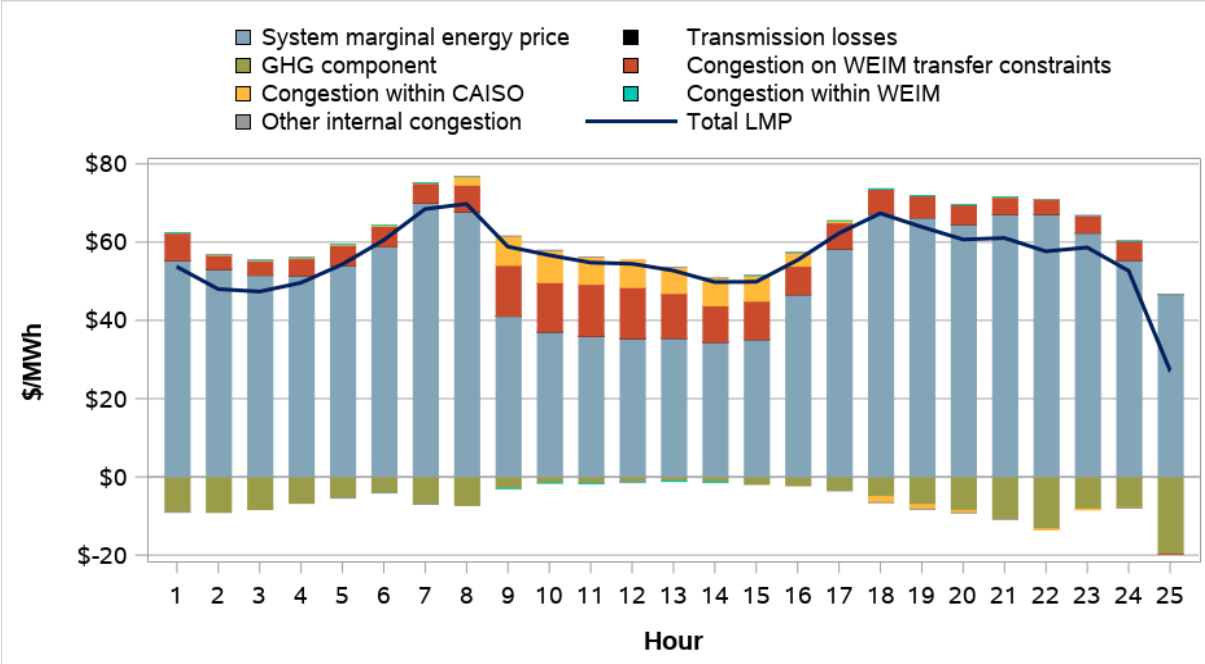
Appendix Figure A.9 Average hourly 15-minute price by component (Q4 2023)



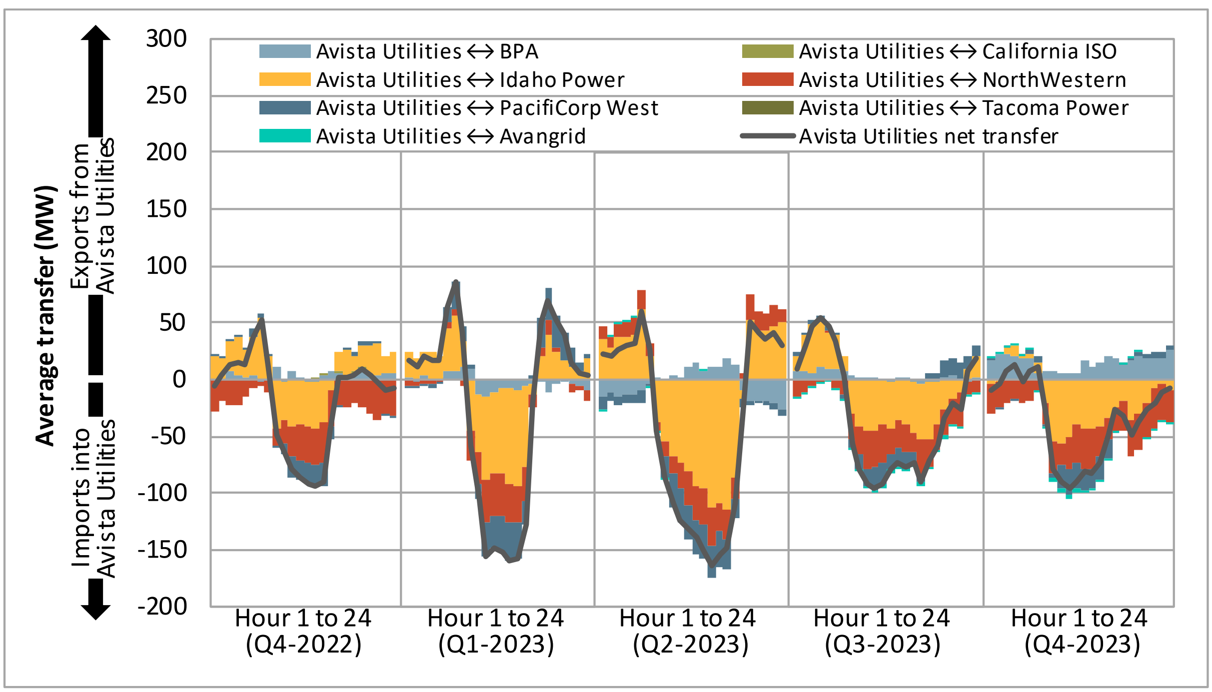
Appendix Figure A.10 Average hourly 15-minute market transfers



Appendix Figure A.11 Average hourly 5-minute price by component (Q4 2023)

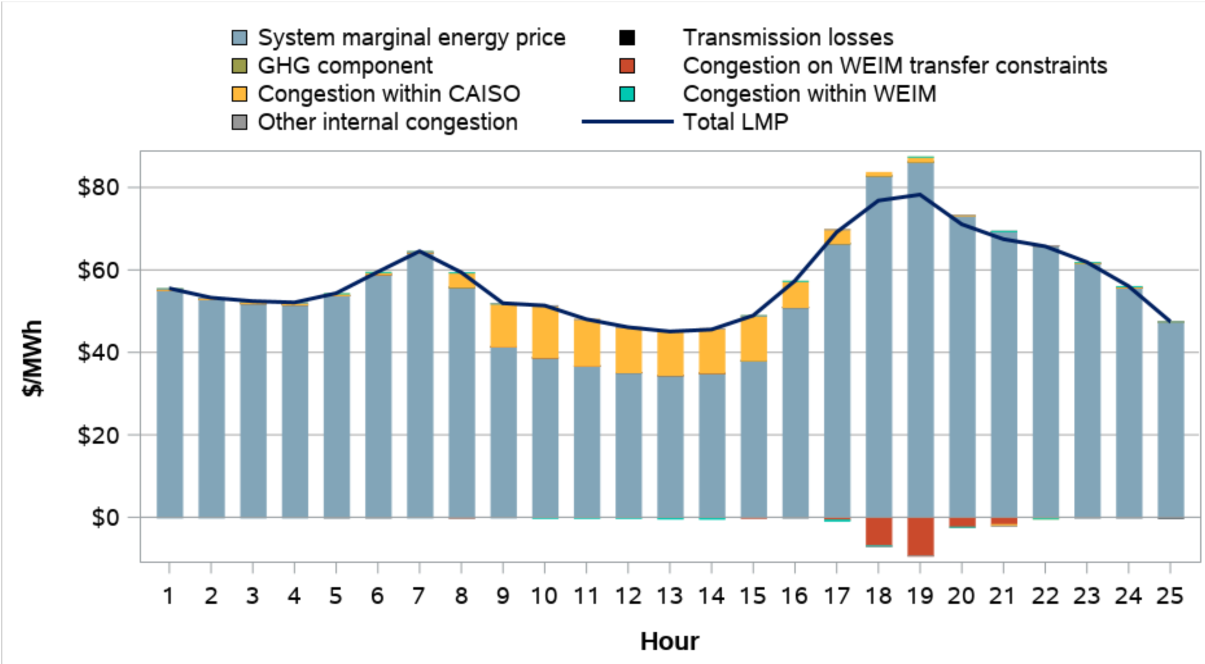


Appendix Figure A.12 Average hourly 5-minute market transfers

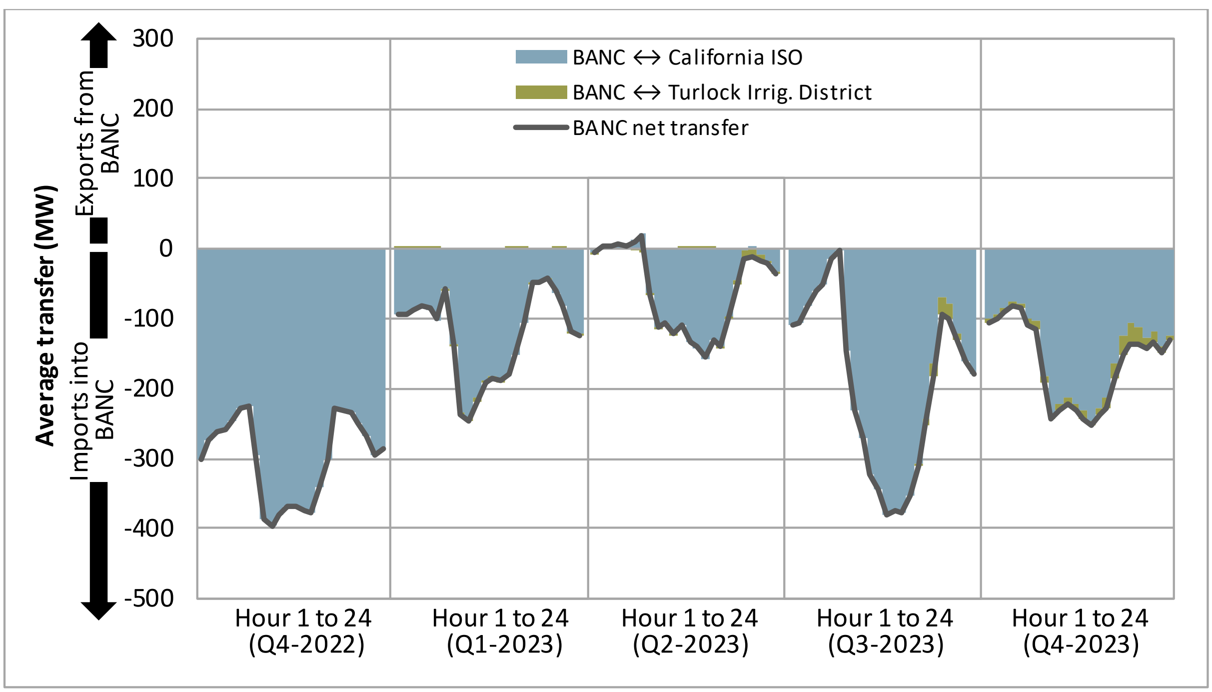


A.4 Balancing Authority of Northern California

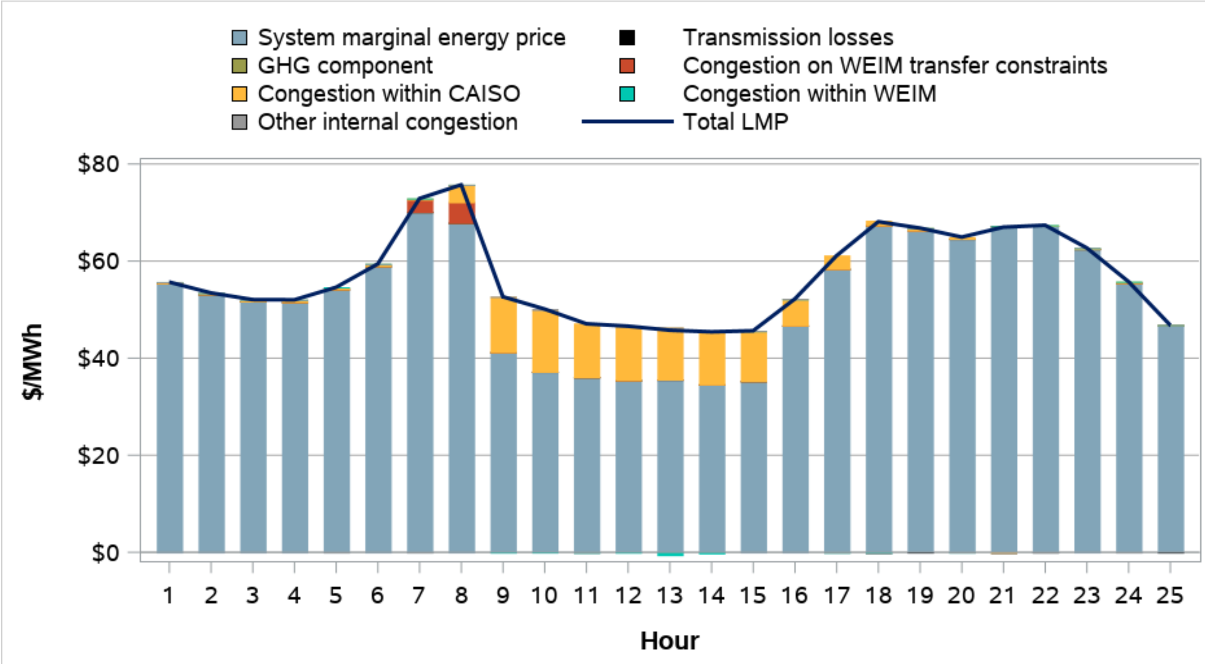
Appendix Figure A.13 Average hourly 15-minute price by component (Q4 2023)



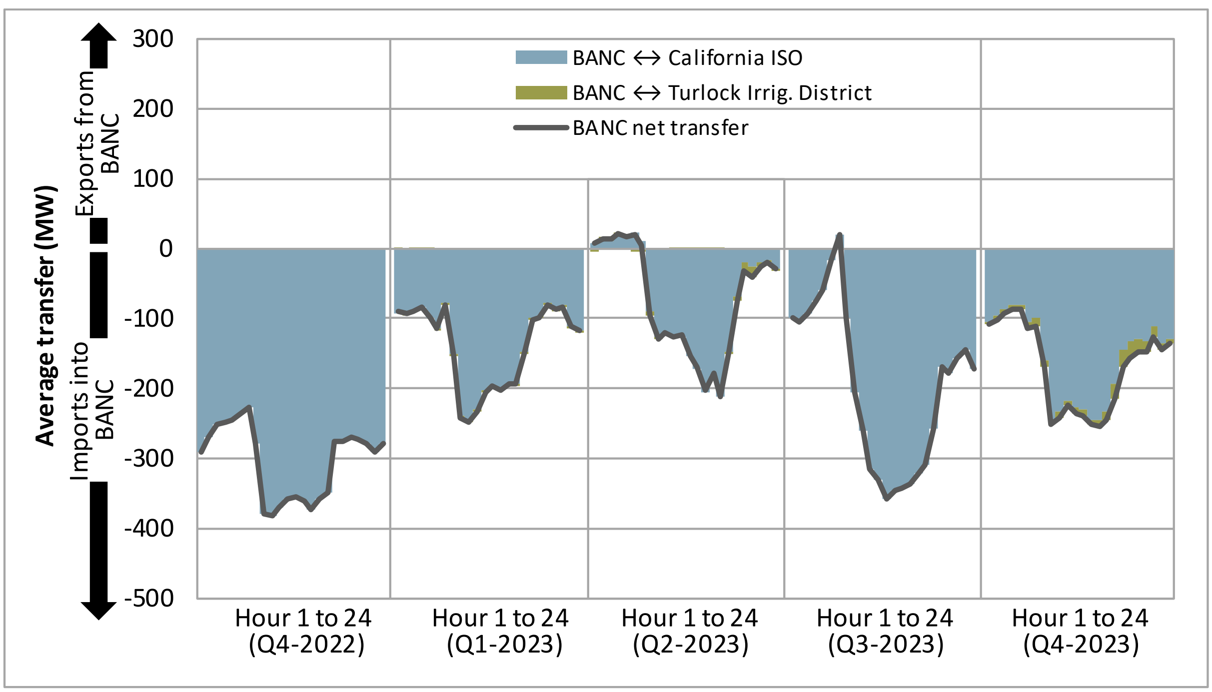
Appendix Figure A.14 Average hourly 15-minute market transfers



Appendix Figure A.15 Average hourly 5-minute price by component (Q4 2023)

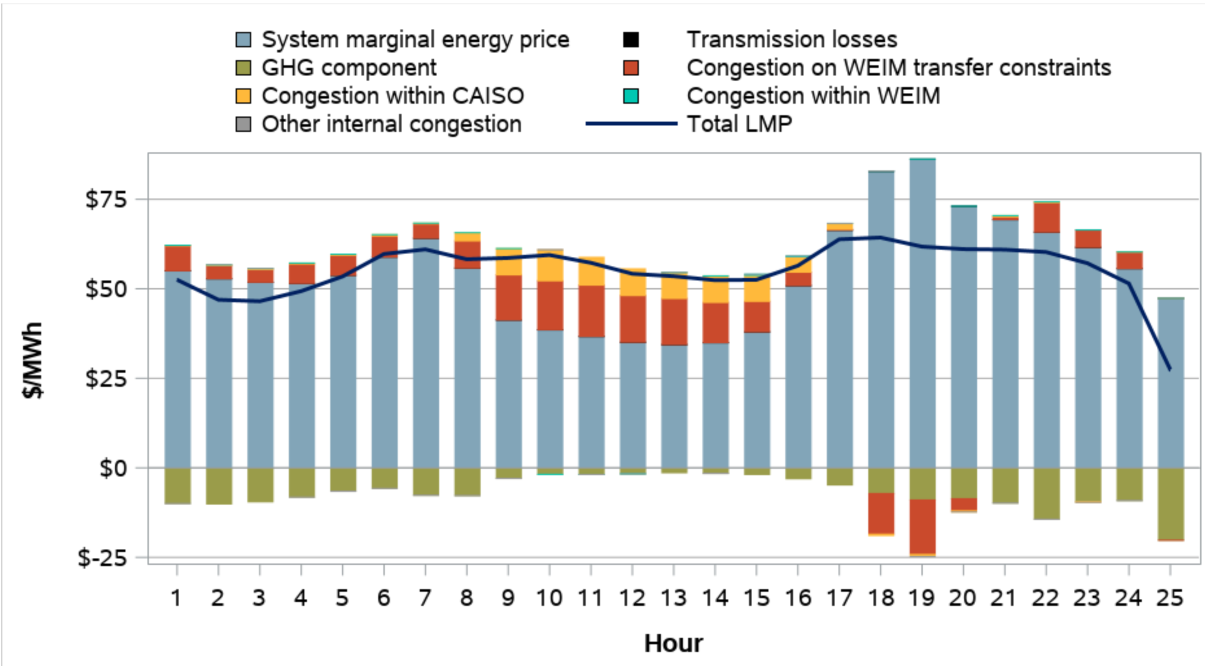


Appendix Figure A.16 Average hourly 5-minute market transfers

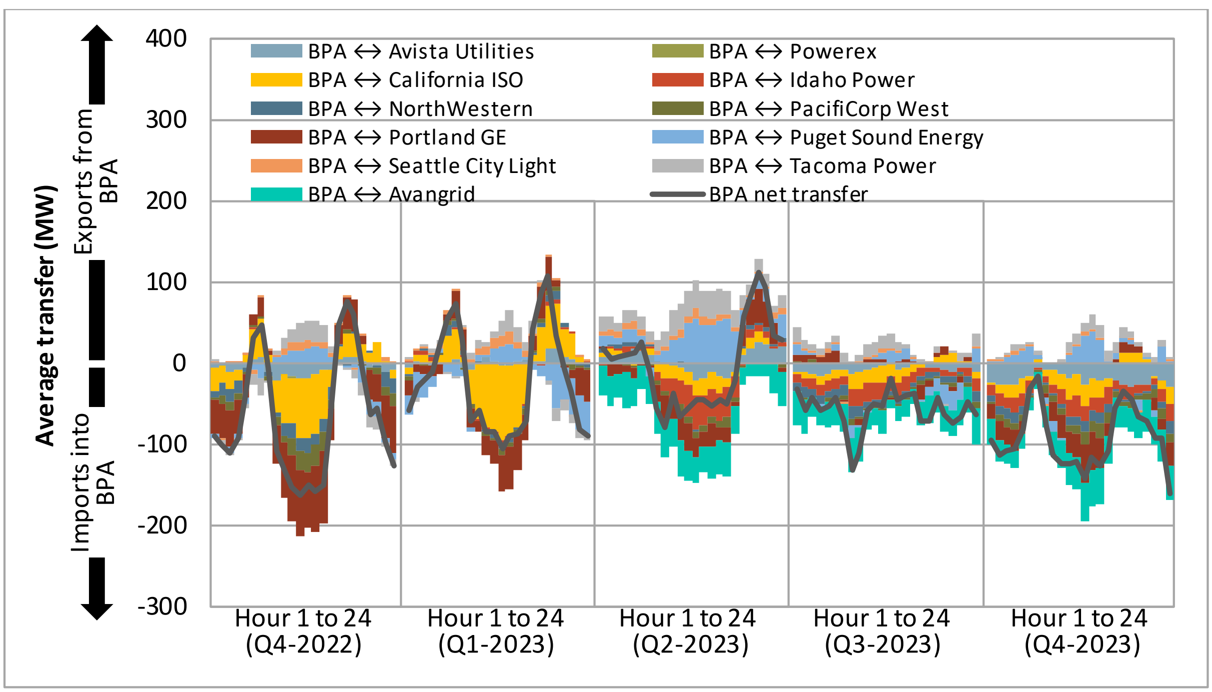


A.5 Bonneville Power Administration

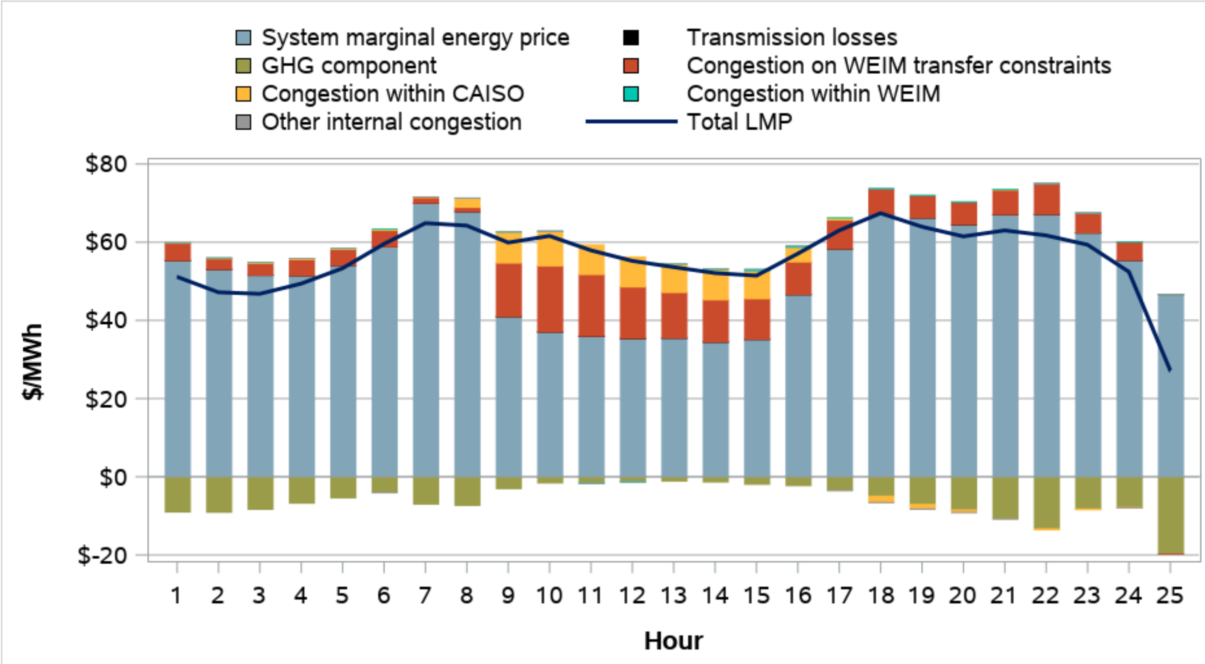
Appendix Figure A.17 Average hourly 15-minute price by component (Q4 2023)



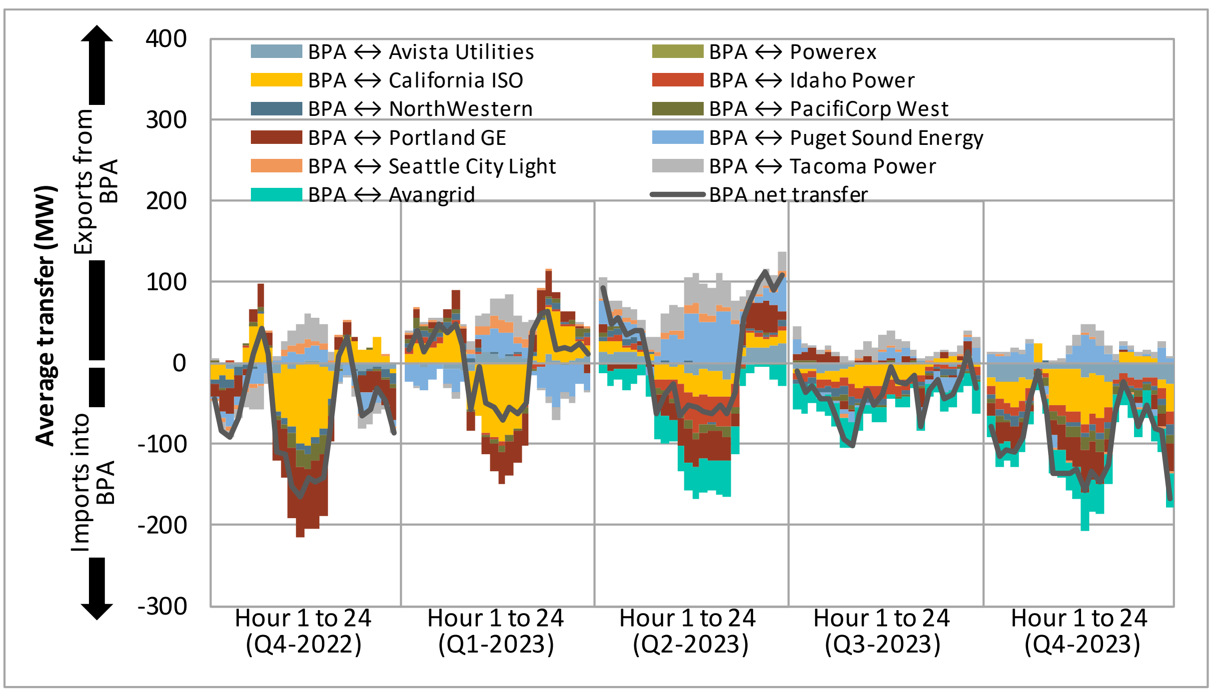
Appendix Figure A.18 Average hourly 15-minute market transfers



Appendix Figure A.19 Average hourly 5-minute price by component (Q4 2023)

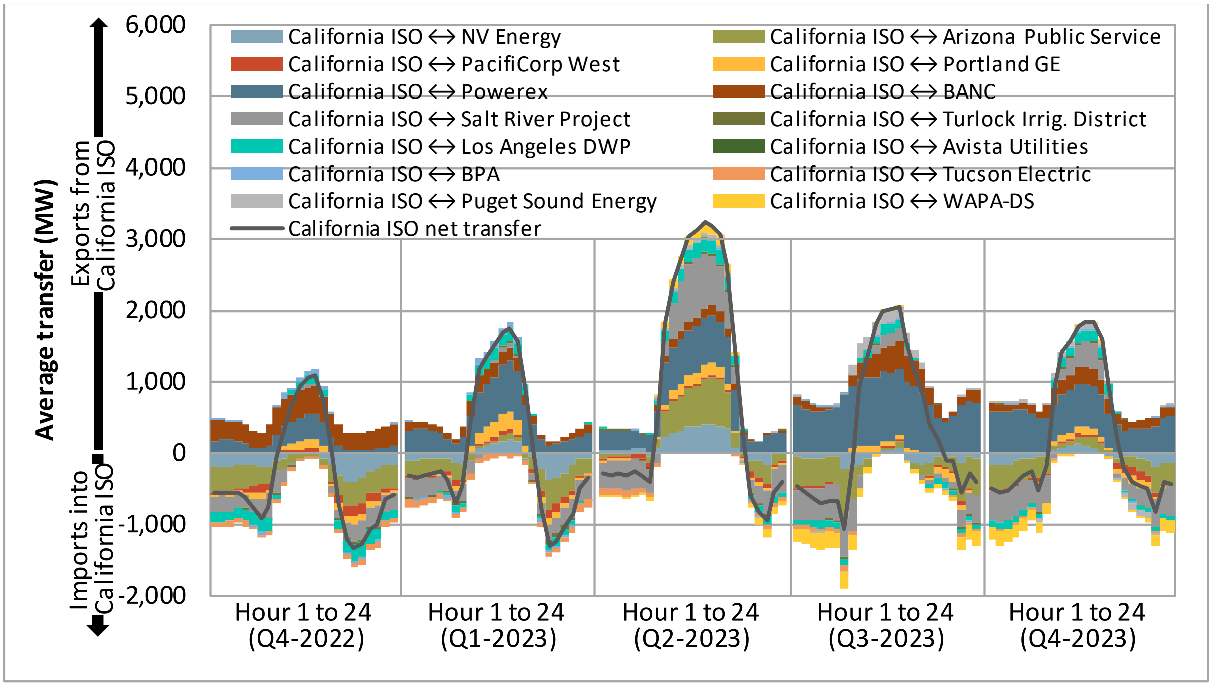


Appendix Figure A.20 Average hourly 5-minute market transfers

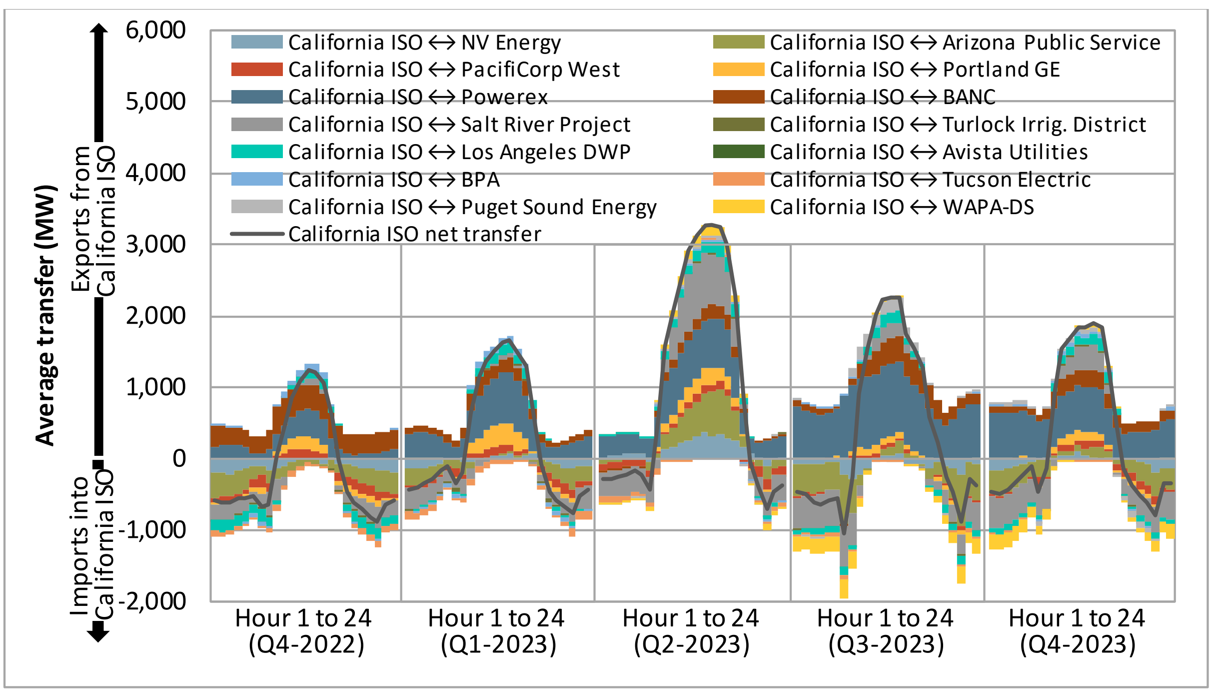


A.6 California ISO

Appendix Figure A.21 Average hourly 15-minute market transfers

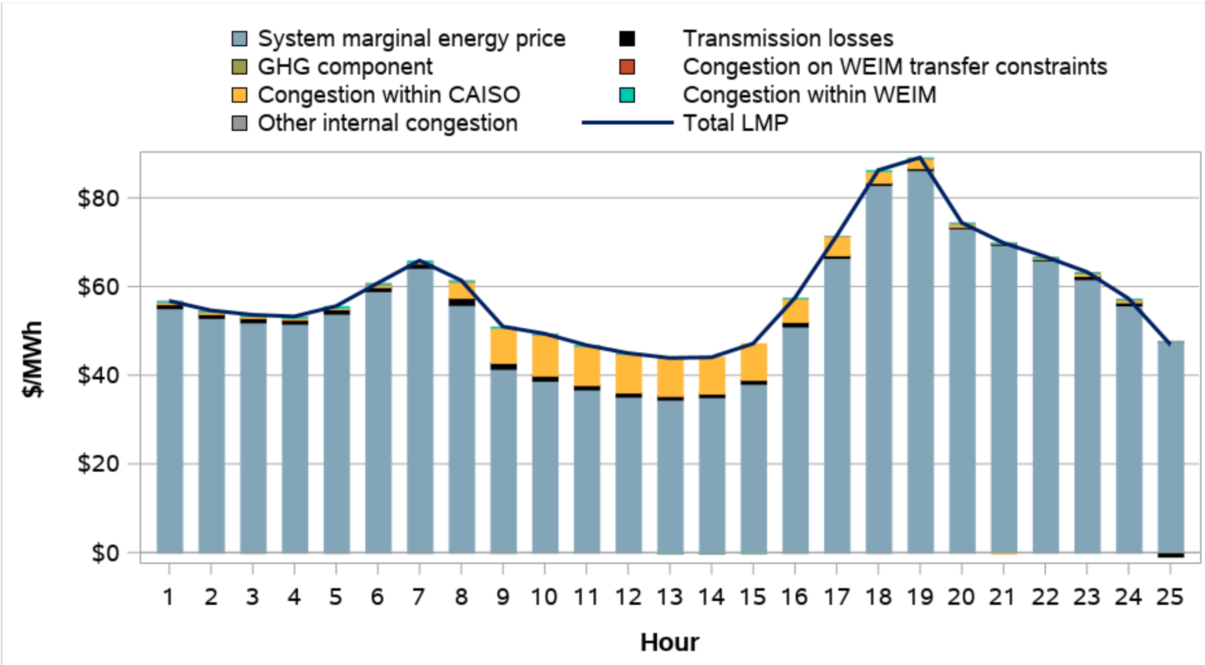


Appendix Figure A.22 Average hourly 5-minute market transfers

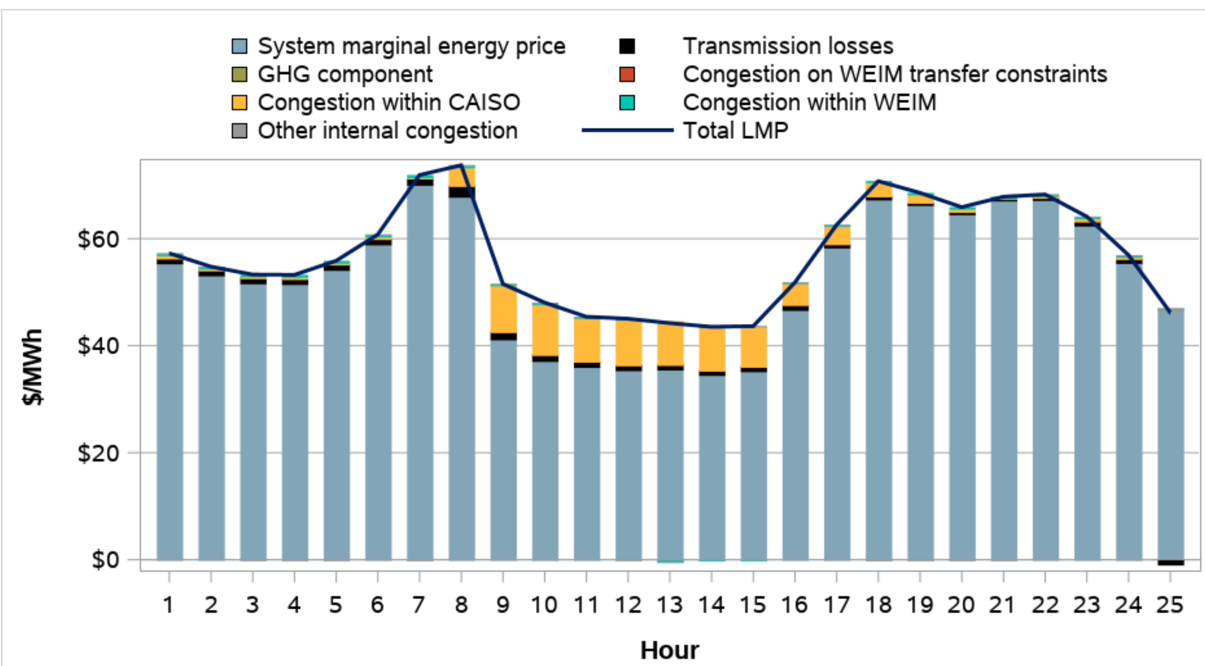


A.6.1 Pacific Gas and Electric

Appendix Figure A.23 Average hourly 15-minute price by component (Q4 2023)

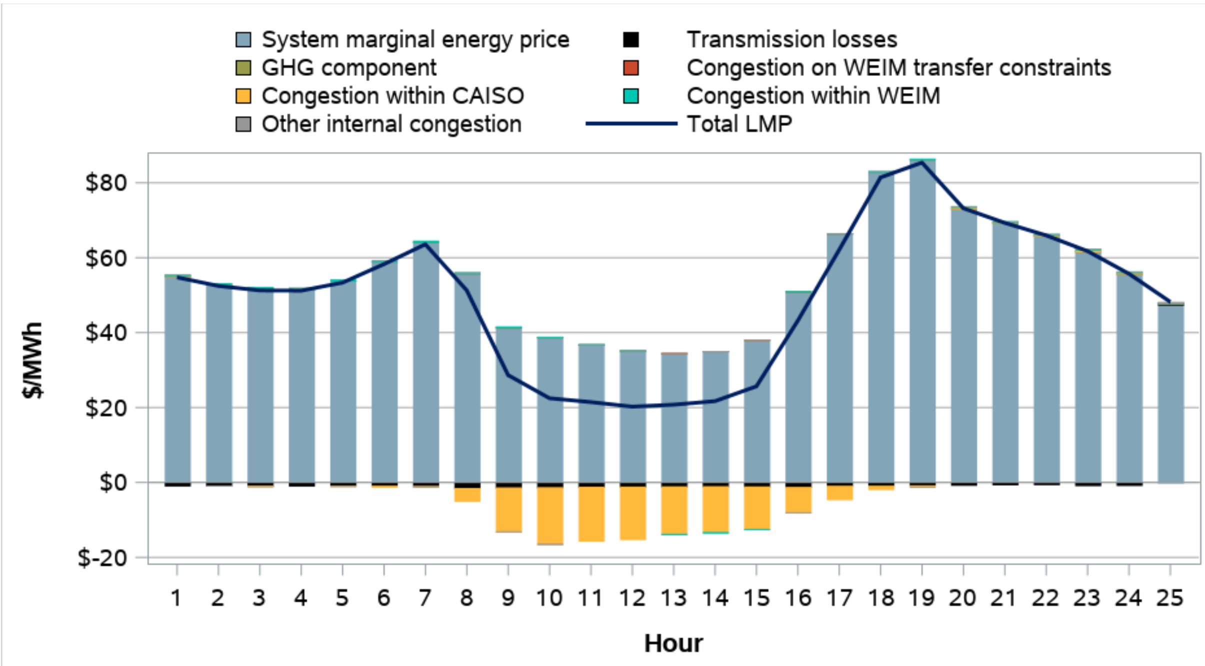


Appendix Figure A.24 Average hourly 5-minute price by component (Q4 2023)

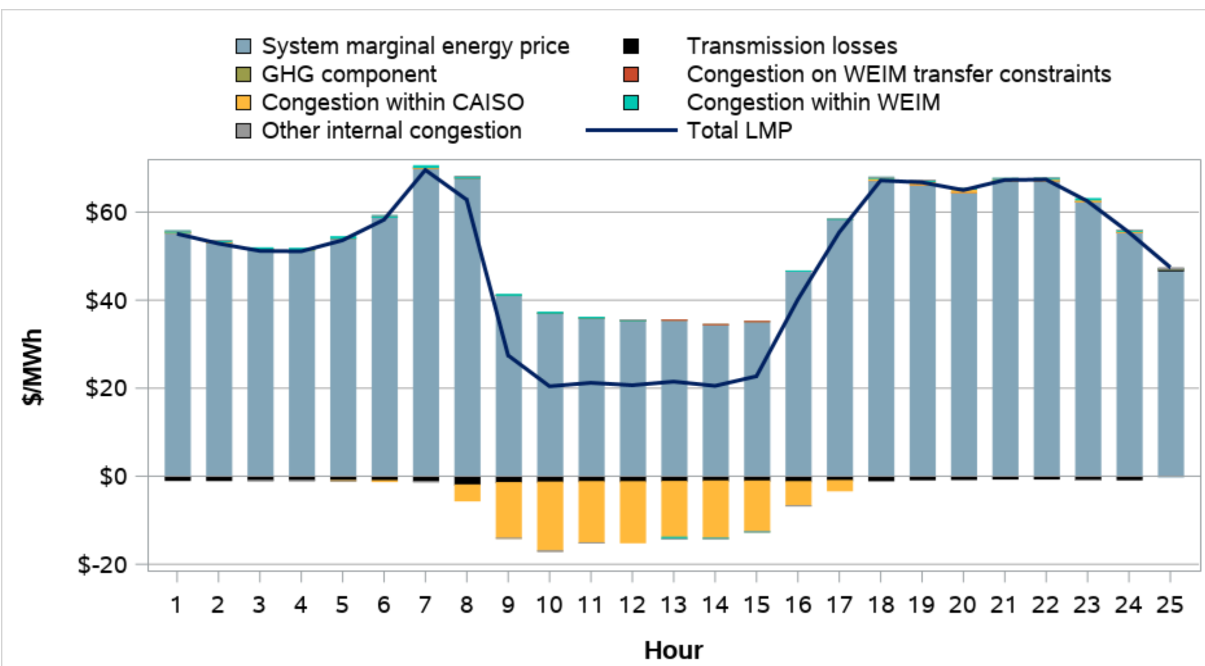


A.6.2 Southern California Edison

Appendix Figure A.25 Average hourly 15-minute price by component (Q4 2023)

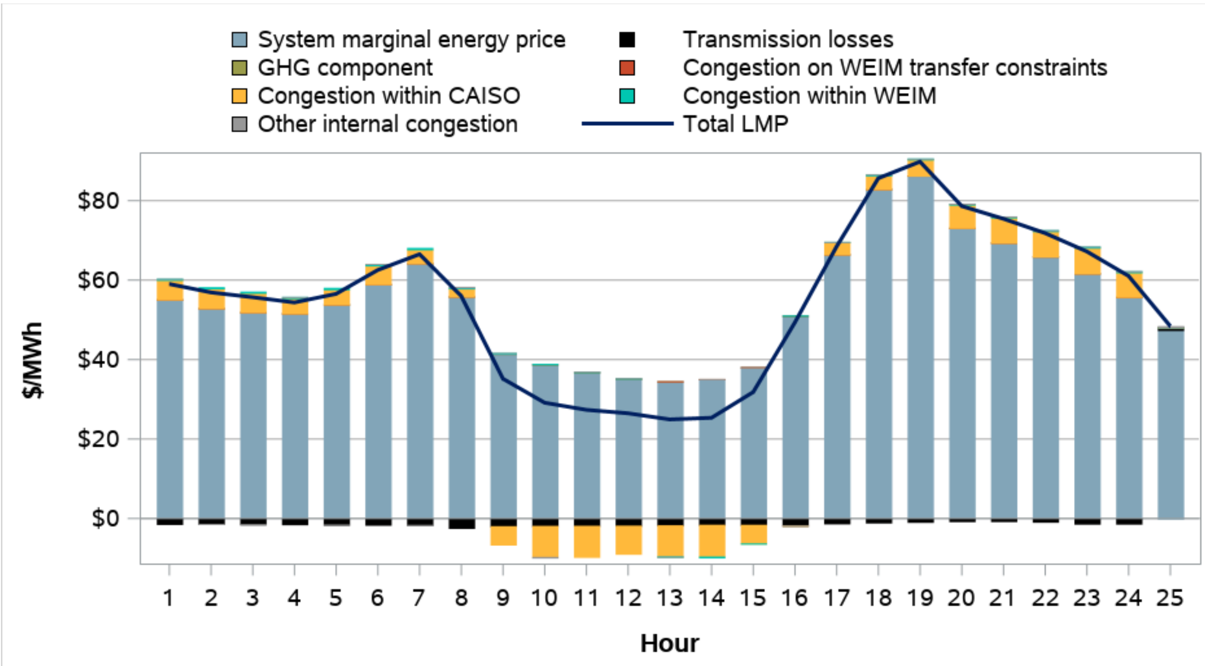


Appendix Figure A.26 Average hourly 5-minute price by component (Q4 2023)

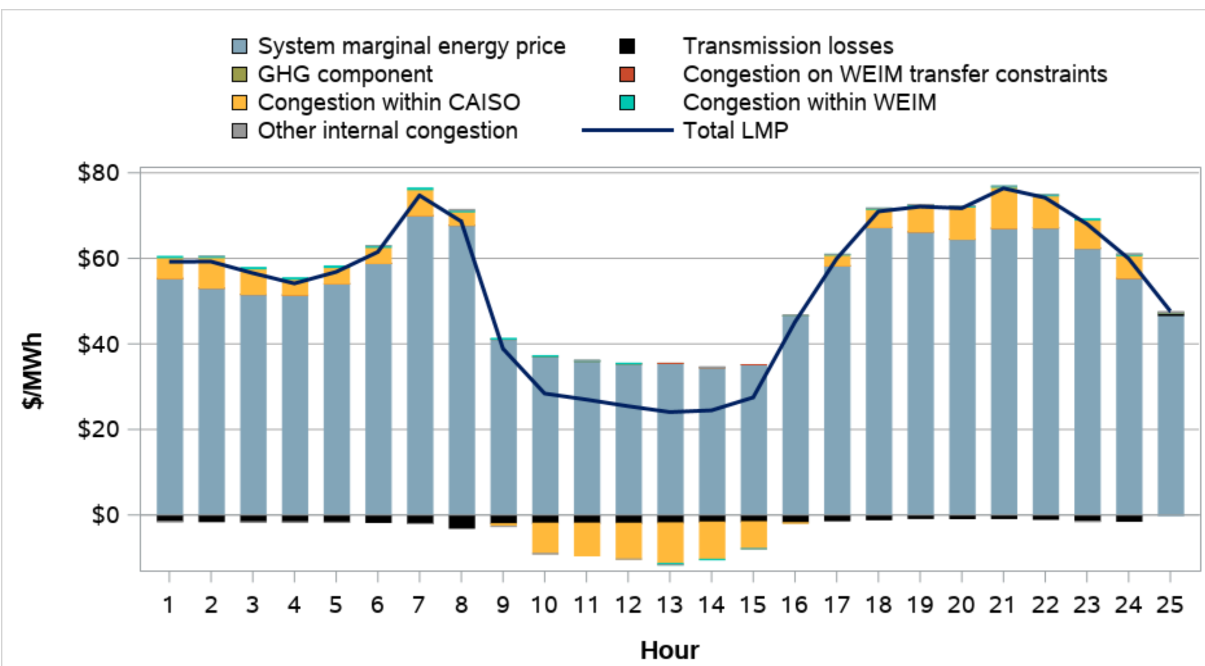


A.6.3 San Diego Gas & Electric

Appendix Figure A.27 Average hourly 15-minute price by component (Q4 2023)

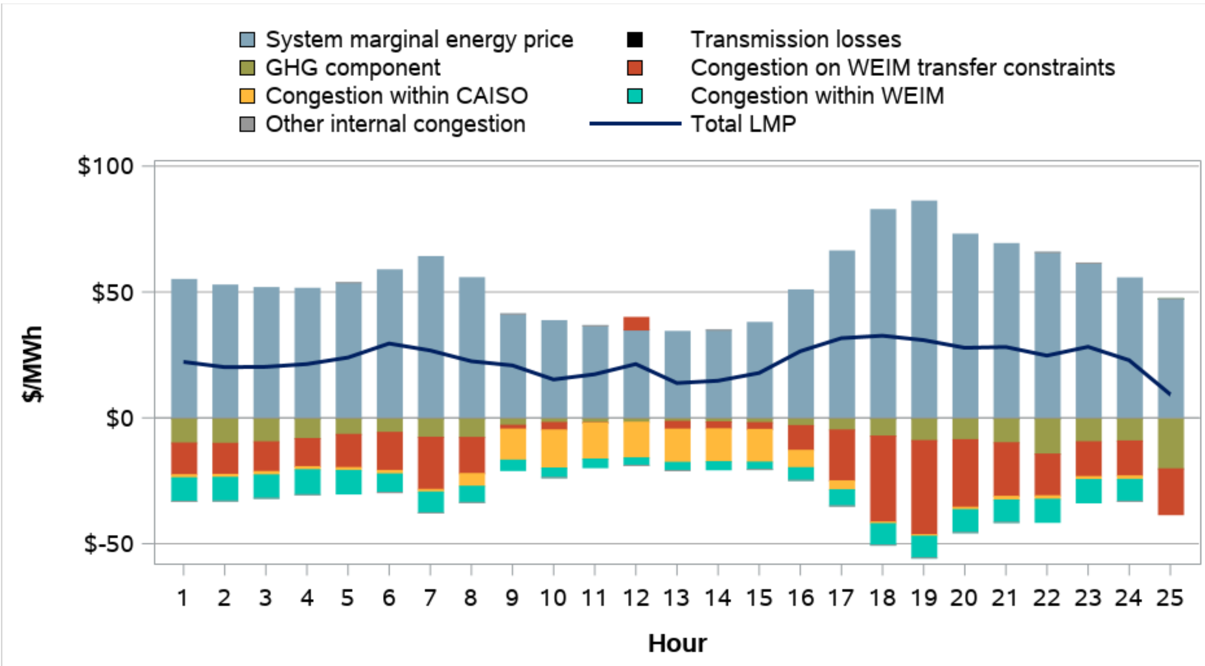


Appendix Figure A.28 Average hourly 5-minute price by component (Q4 2023)

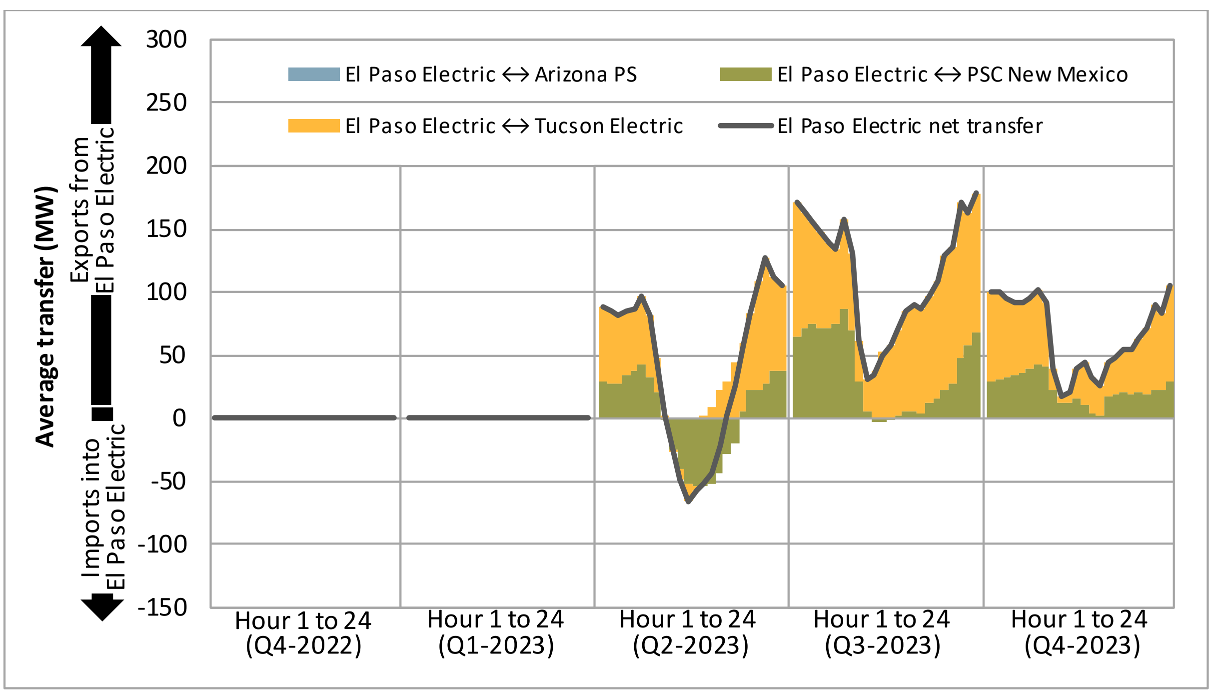


A.7 El Paso Electric

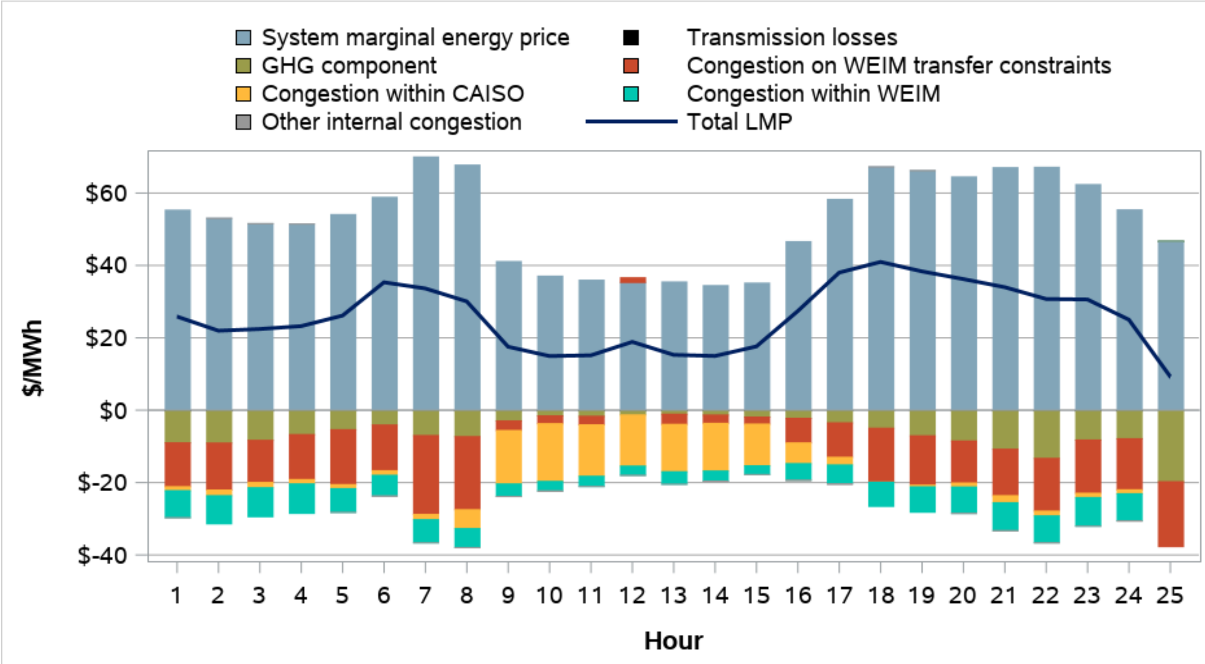
Appendix Figure A.29 Average hourly 15-minute price by component (Q4 2023)



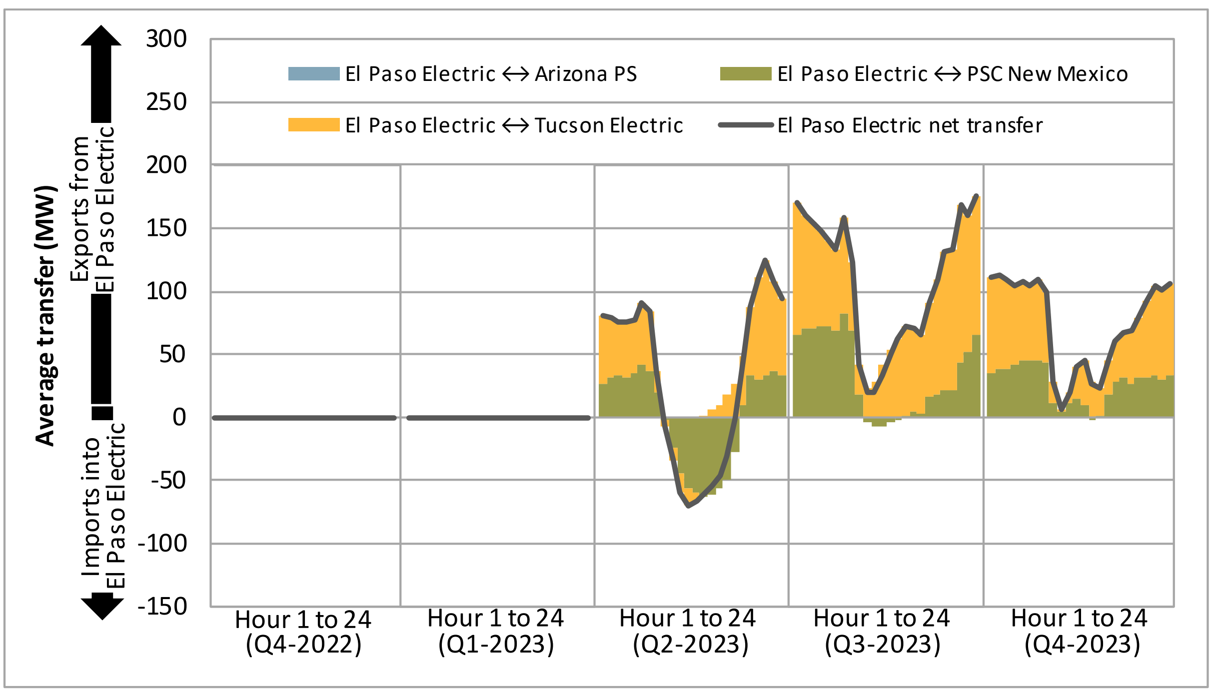
Appendix Figure A.30 Average hourly 15-minute market transfers



Appendix Figure A.31 Average hourly 5-minute price by component (Q4 2023)

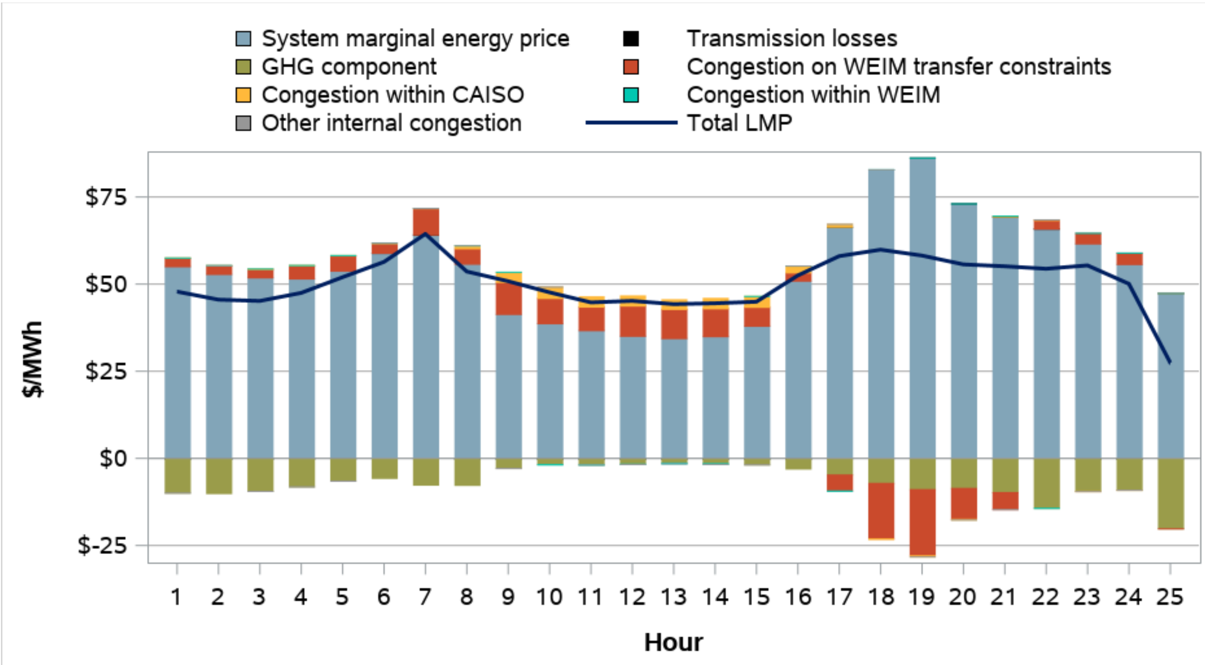


Appendix Figure A.32 Average hourly 5-minute market transfers

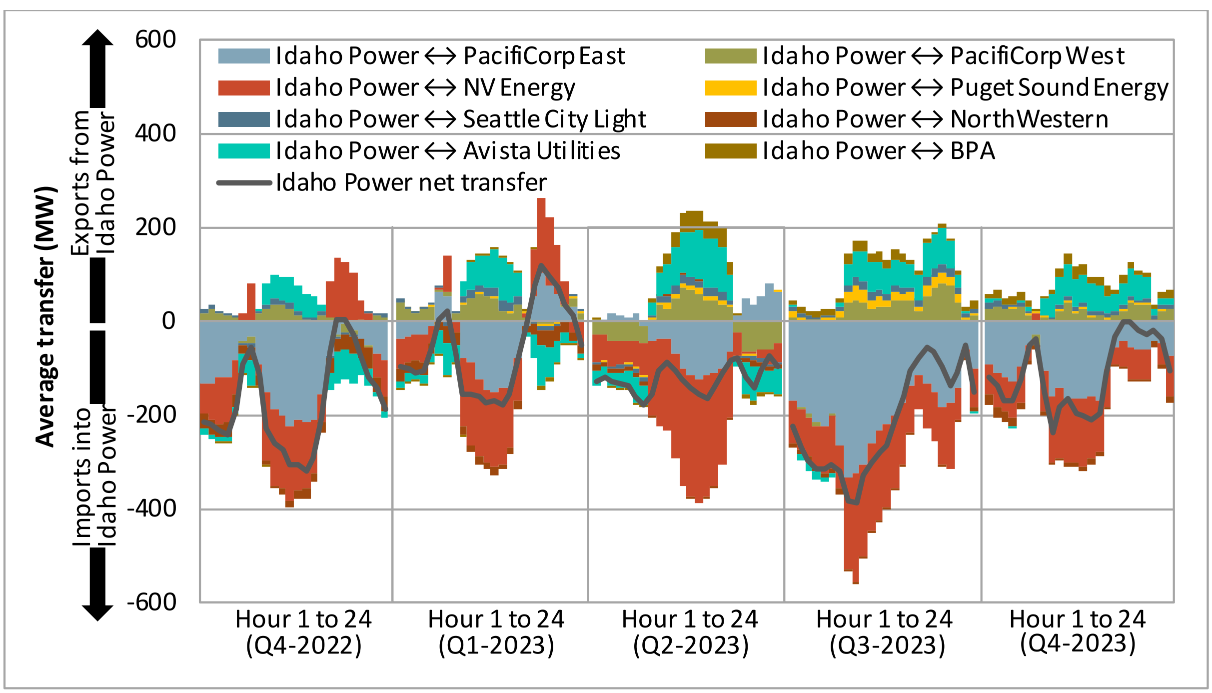


A.8 Idaho Power

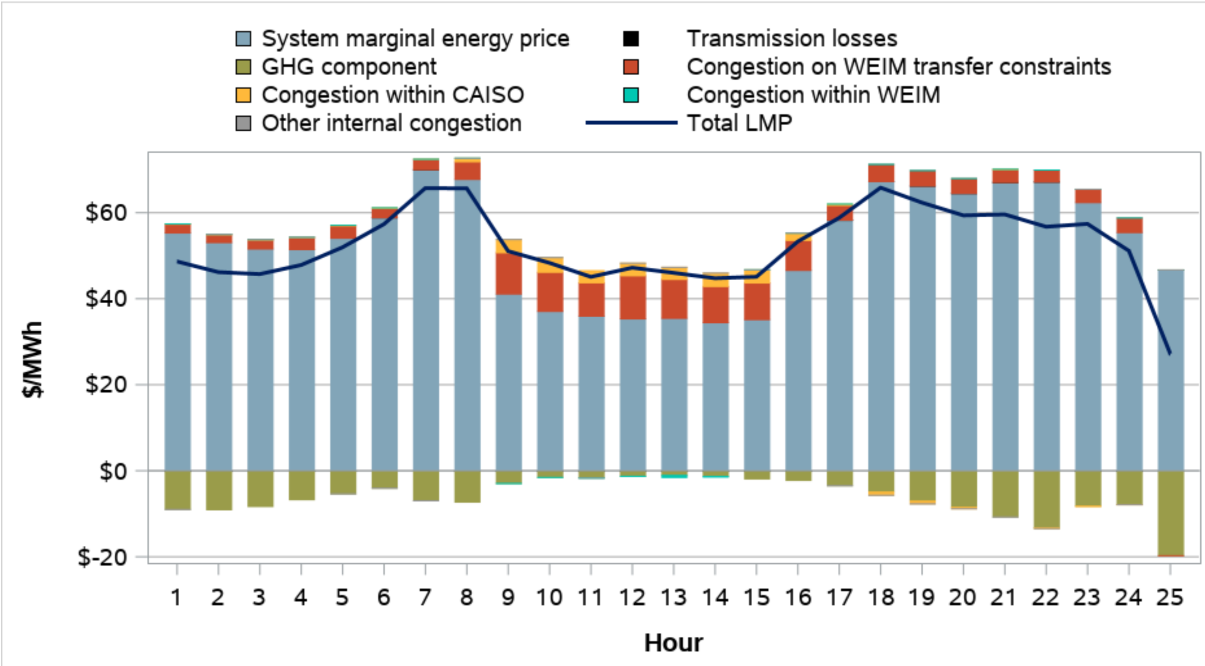
Appendix Figure A.33 Average hourly 15-minute price by component (Q4 2023)



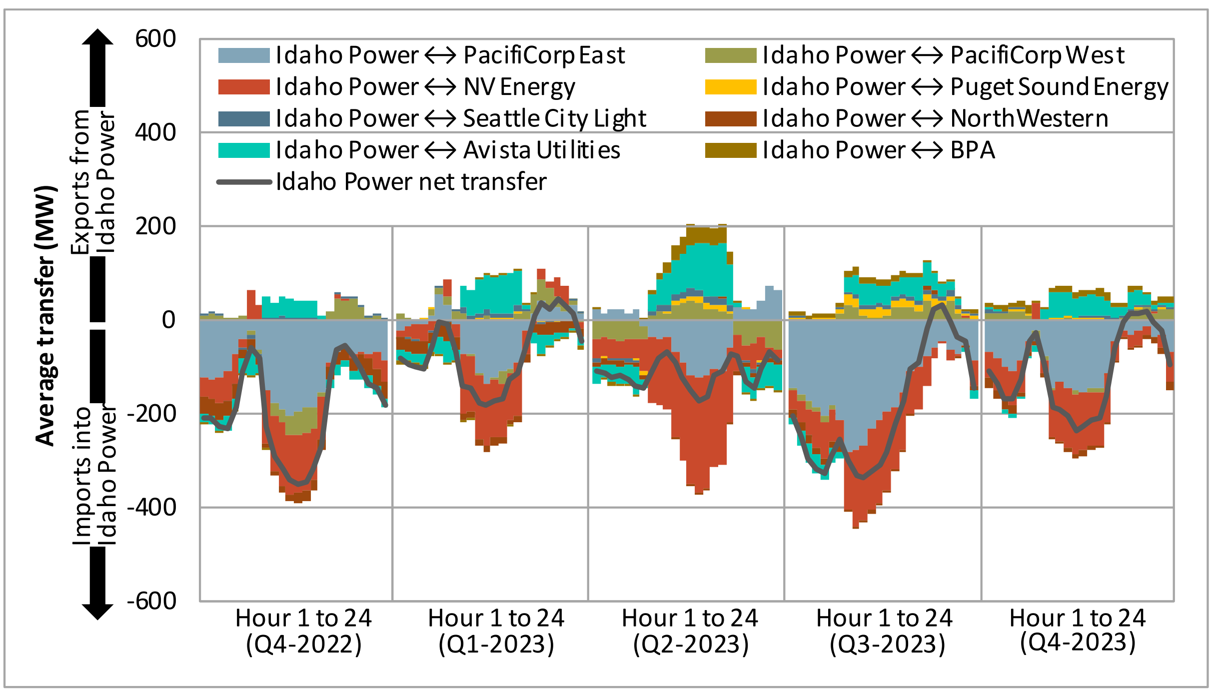
Appendix Figure A.34 Average hourly 15-minute market transfers



Appendix Figure A.35 Average hourly 5-minute price by component (Q4 2023)

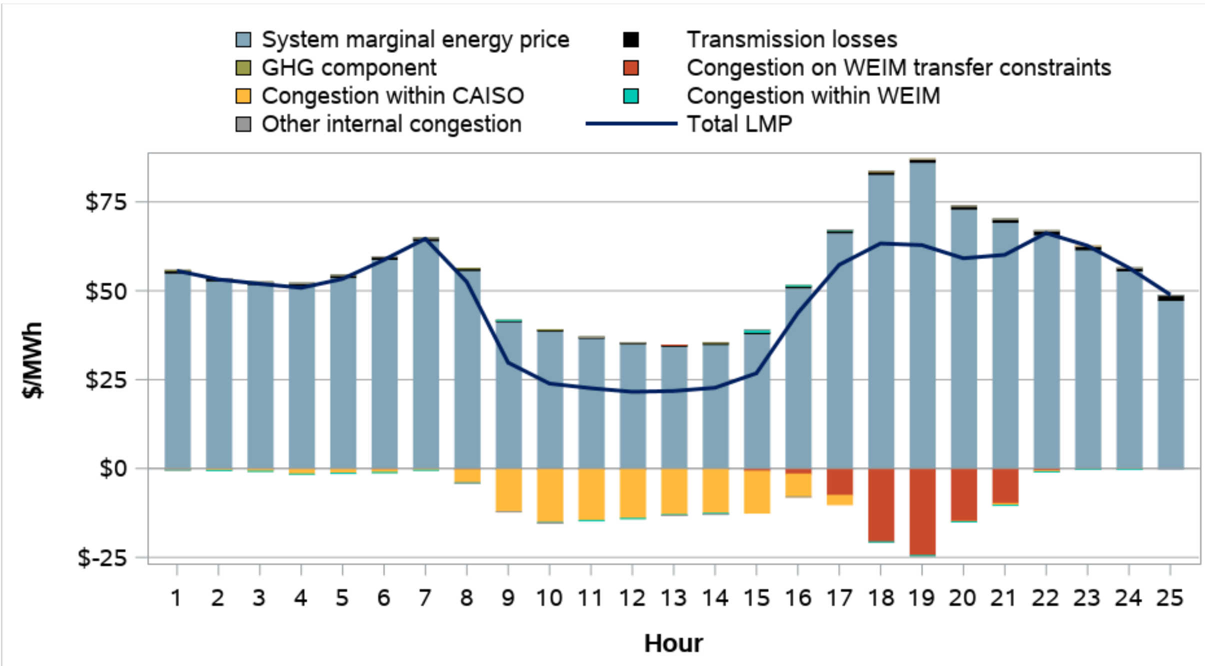


Appendix Figure A.36 Average hourly 5-minute market transfers

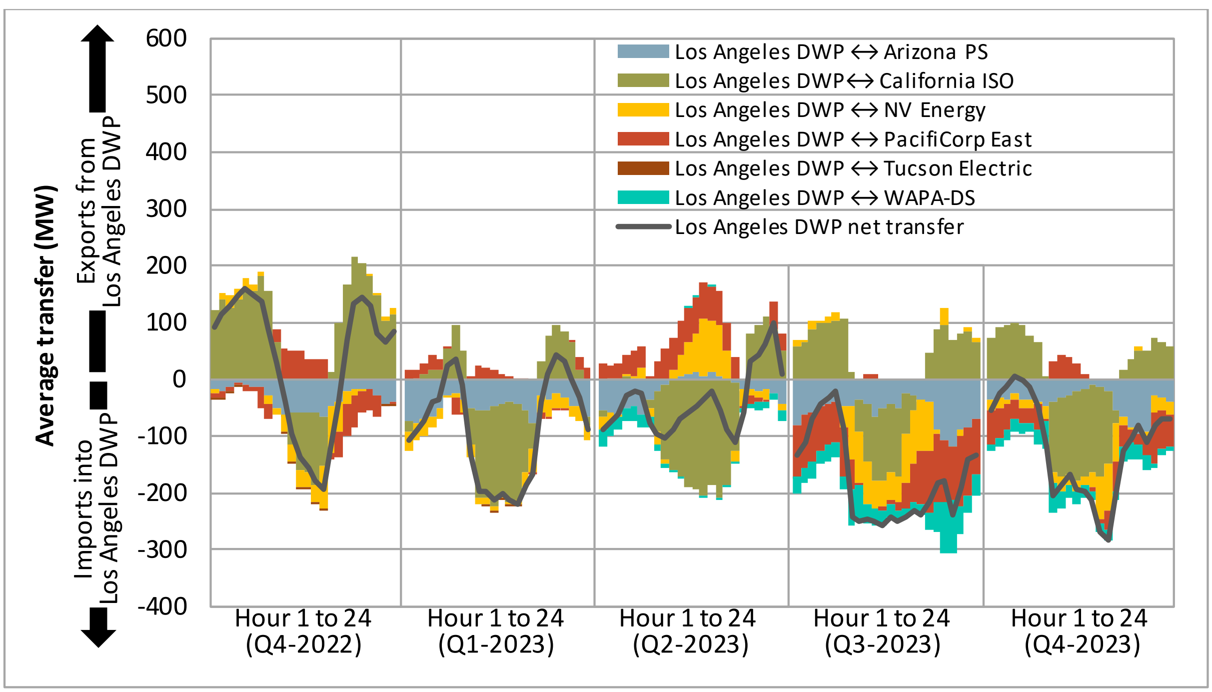


A.9 Los Angeles Department of Water and Power

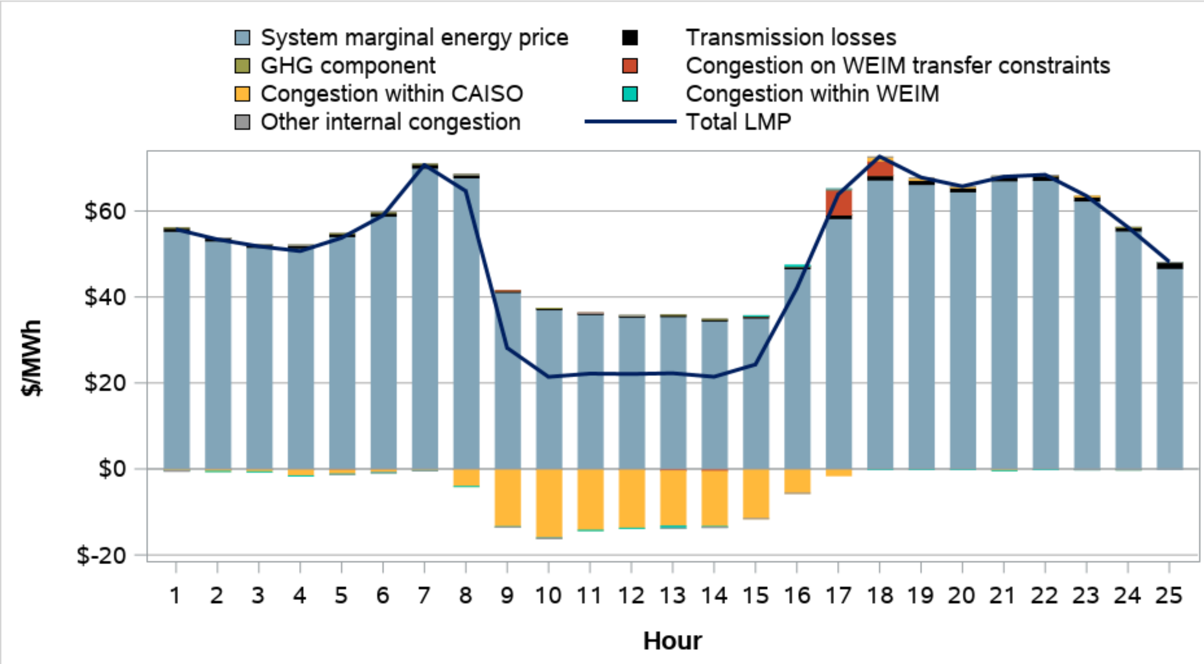
Appendix Figure A.37 Average hourly 15-minute price by component (Q4 2023)



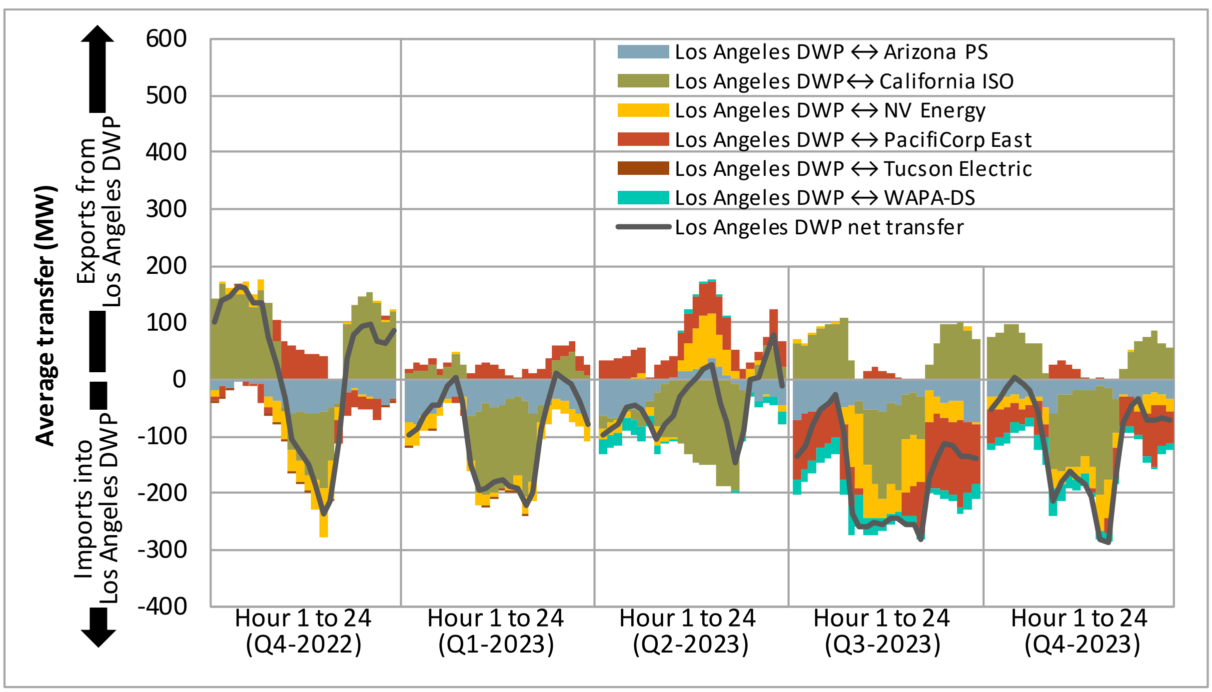
Appendix Figure A.38 Average hourly 15-minute market transfers



Appendix Figure A.39 Average hourly 5-minute price by component (Q4 2023)

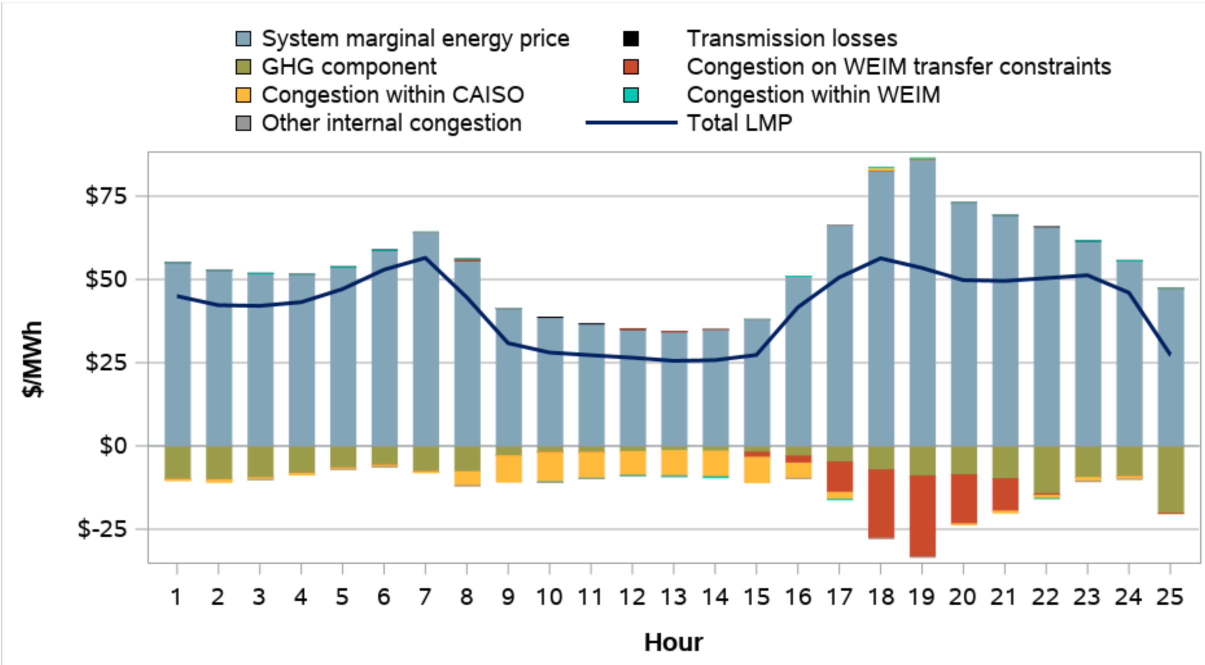


Appendix Figure A.40 Average hourly 5-minute market transfers

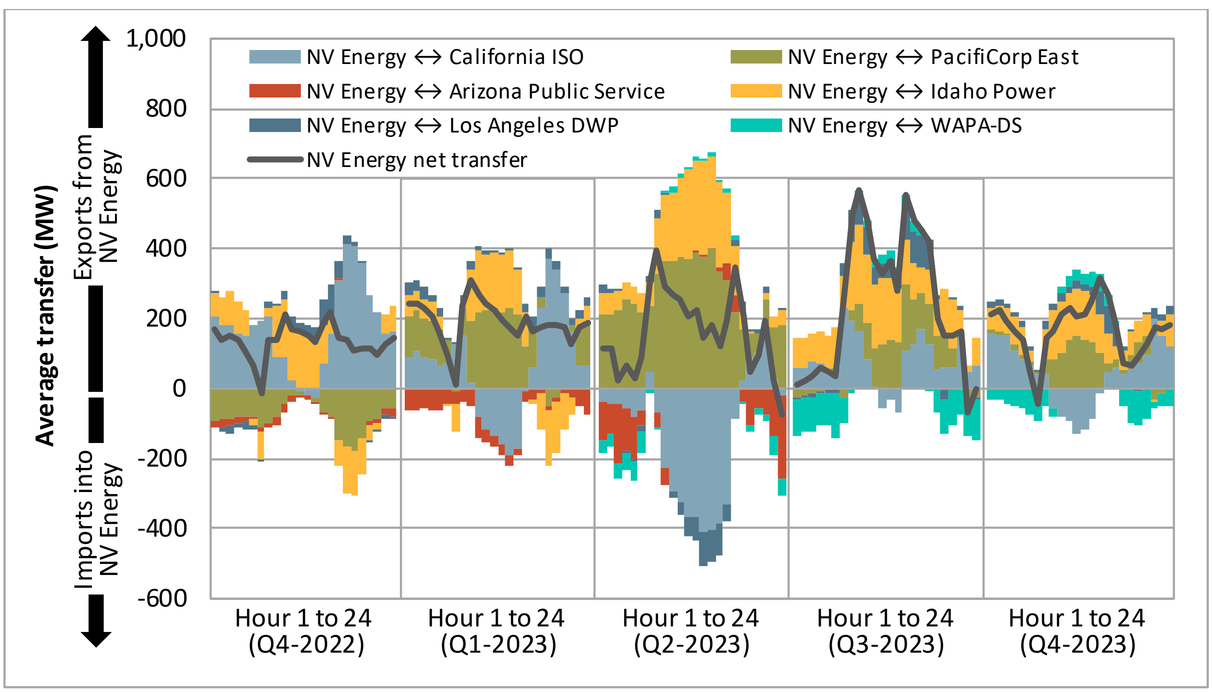


A.10 NV Energy

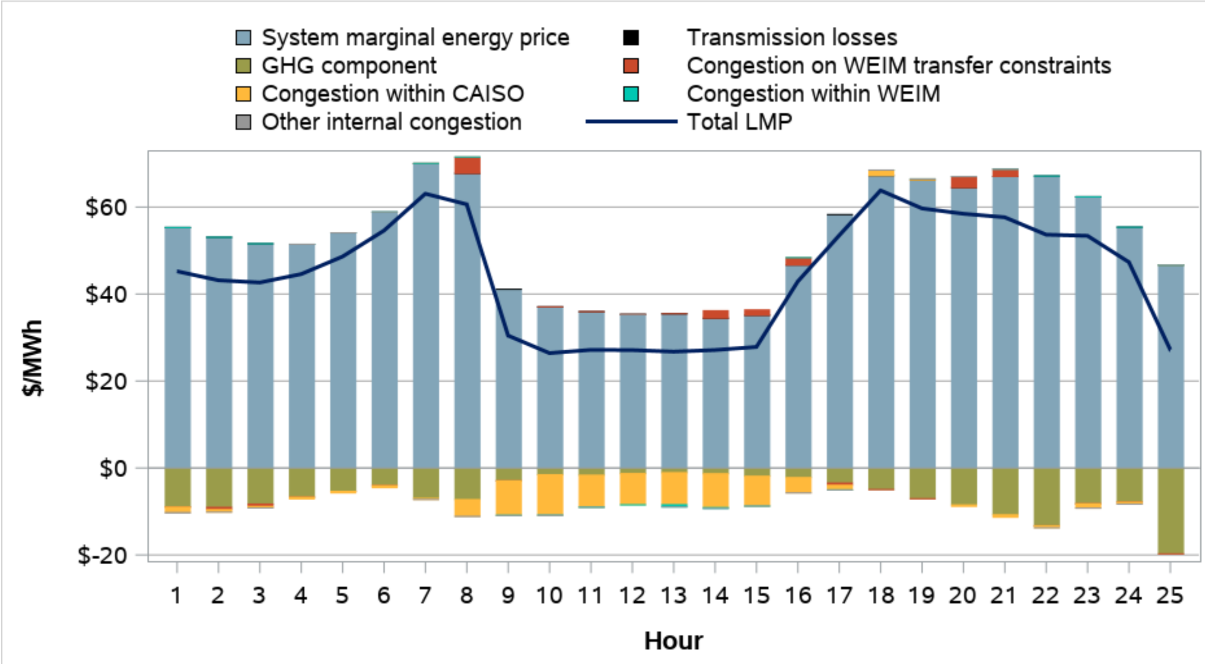
Appendix Figure A.41 Average hourly 15-minute price by component (Q4 2023)



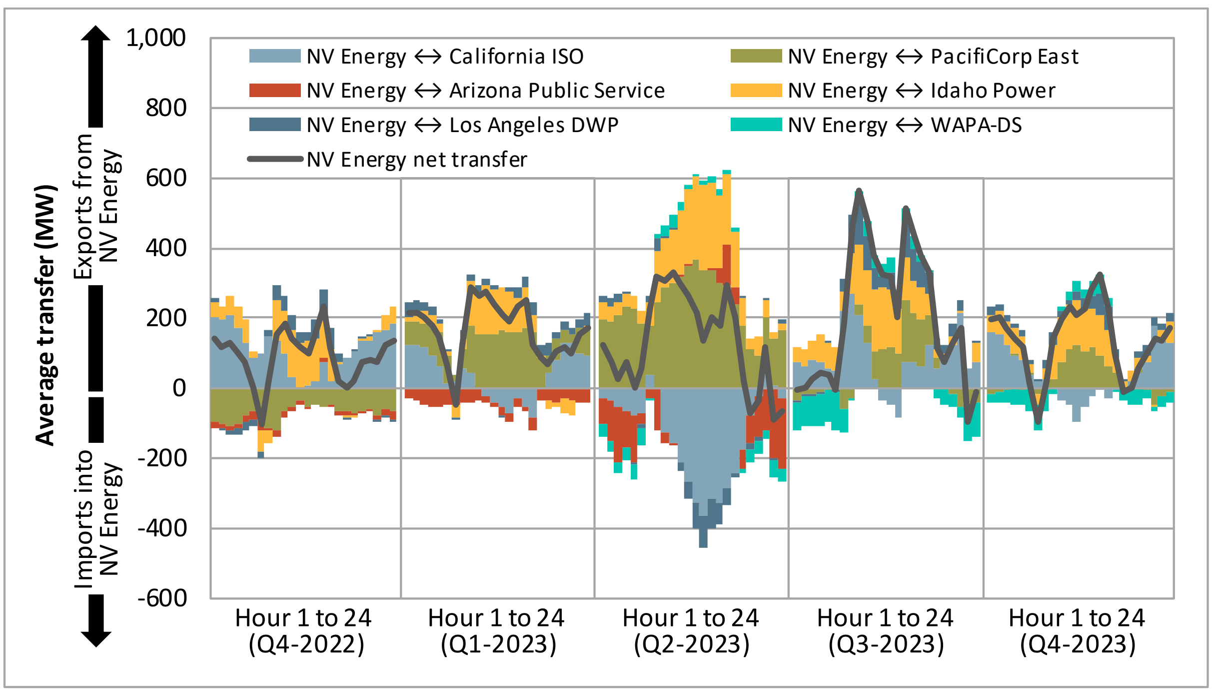
Appendix Figure A.42 Average hourly 15-minute market transfers



Appendix Figure A.43 Average hourly 5-minute price by component (Q4 2023)

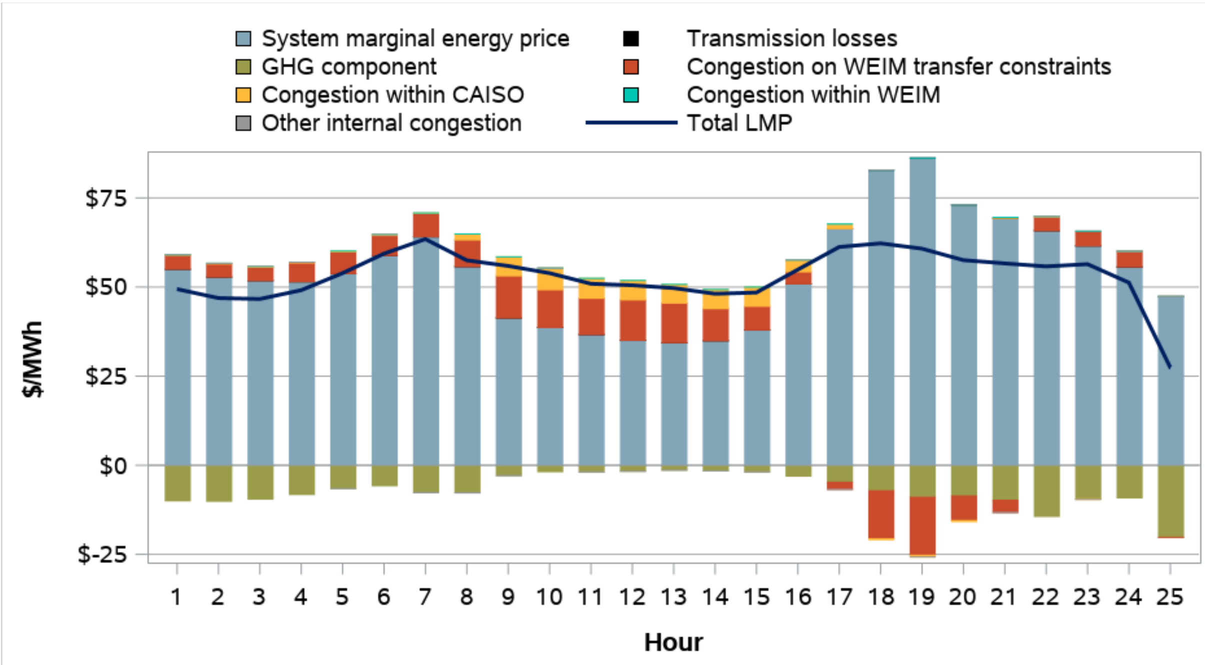


Appendix Figure A.44 Average hourly 5-minute market transfers

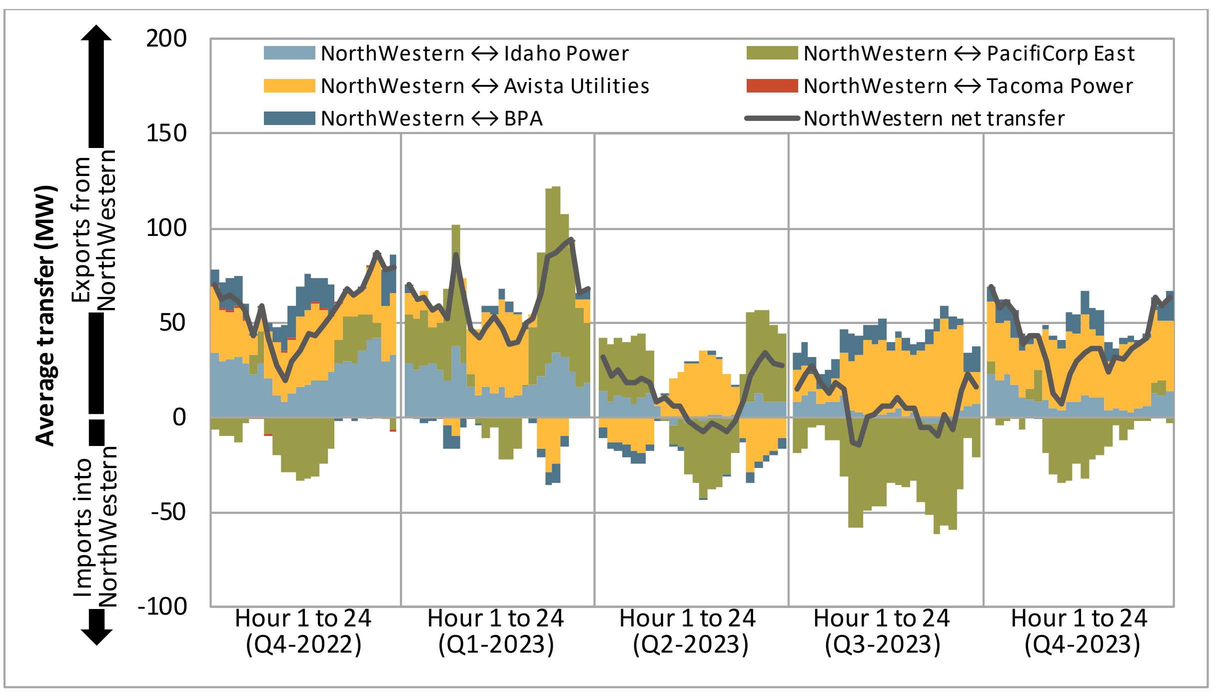


A.11 NorthWestern Energy

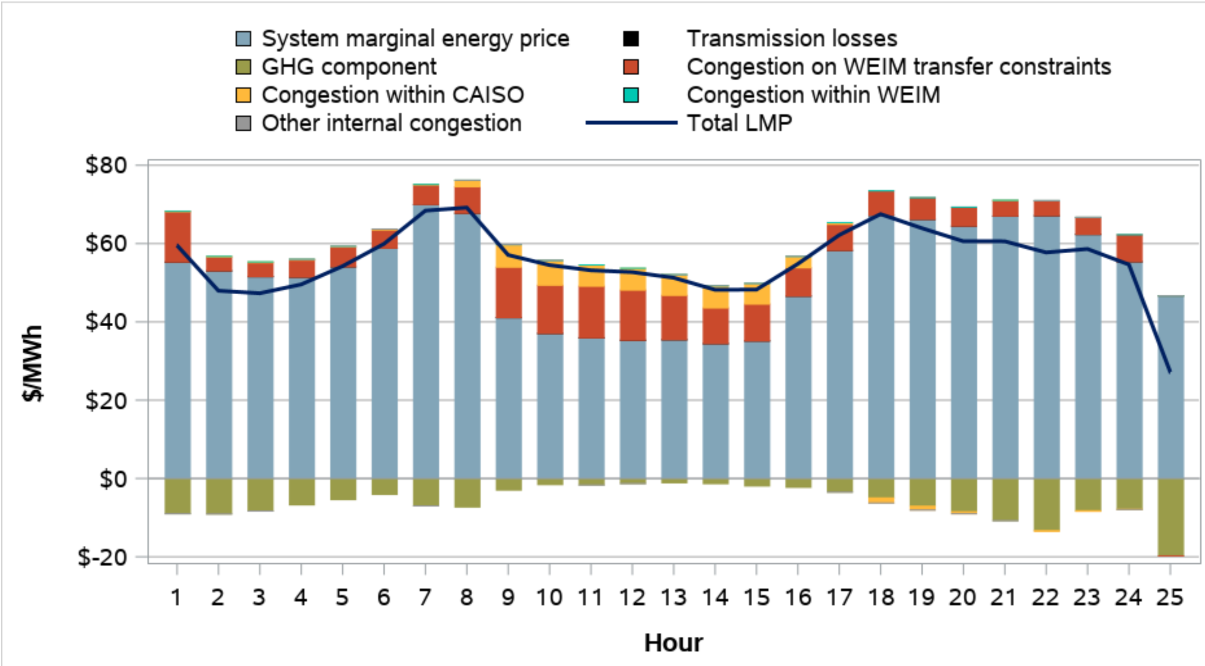
Appendix Figure A.45 Average hourly 15-minute price by component (Q4 2023)



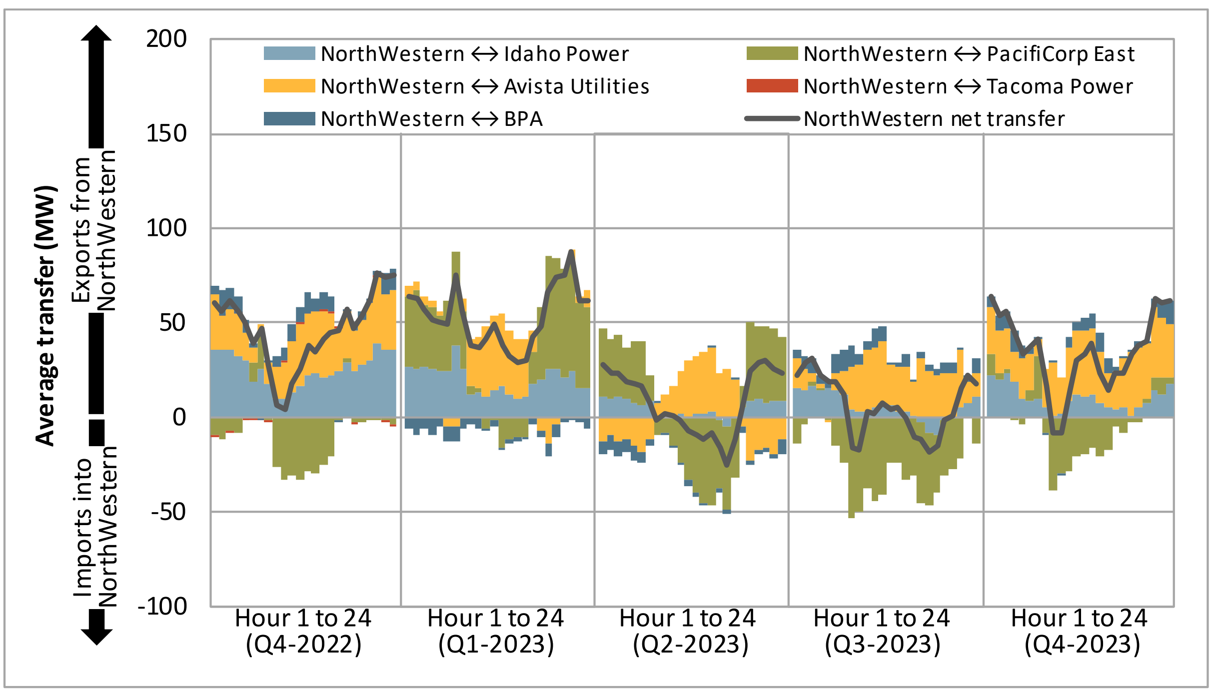
Appendix Figure A.46 Average hourly 15-minute market transfers



Appendix Figure A.47 Average hourly 5-minute price by component (Q4 2023)

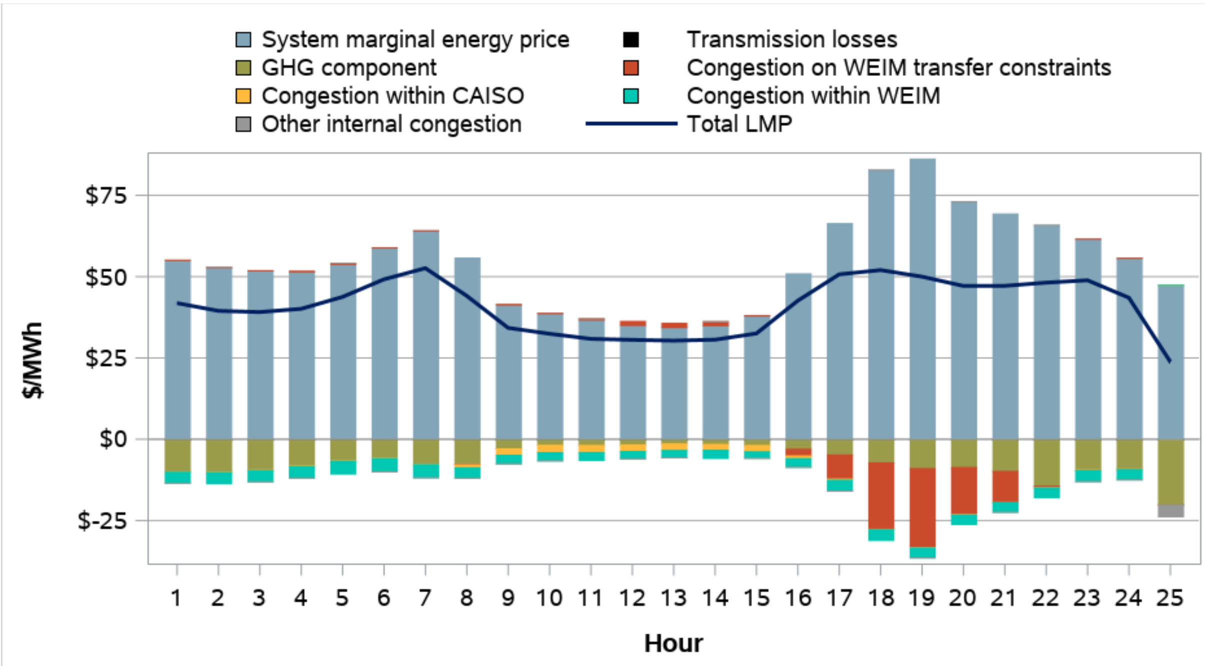


Appendix Figure A.48 Average hourly 5-minute market transfers

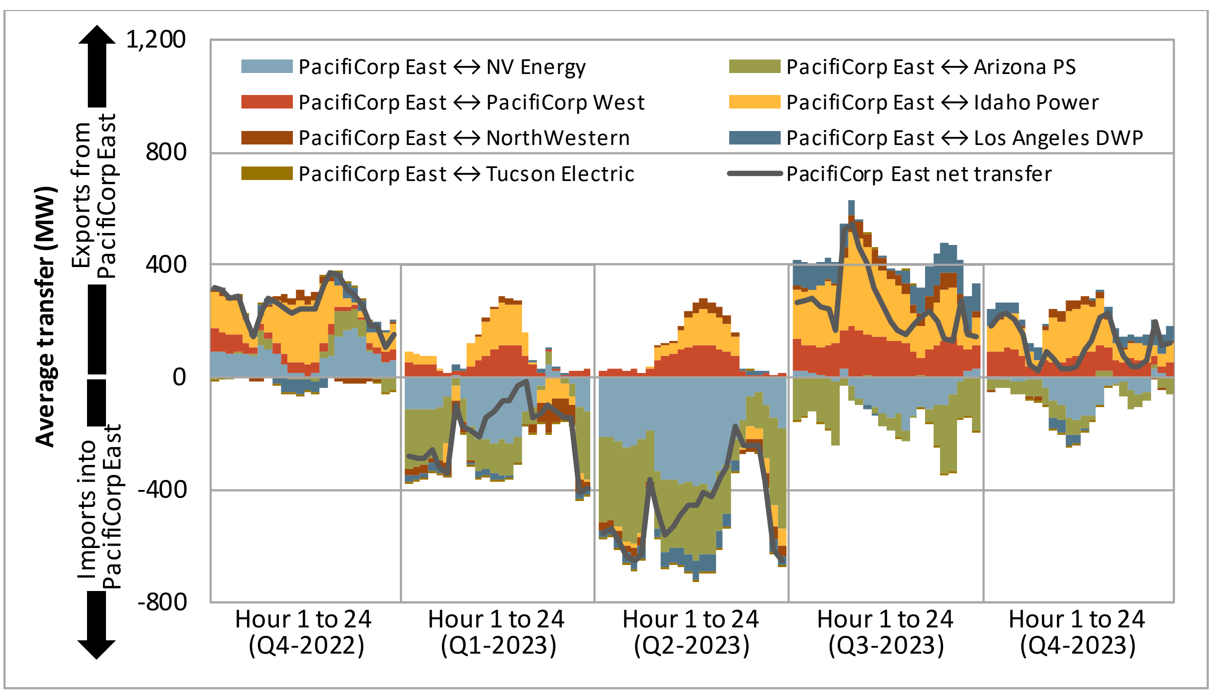


A.12 PacifiCorp East

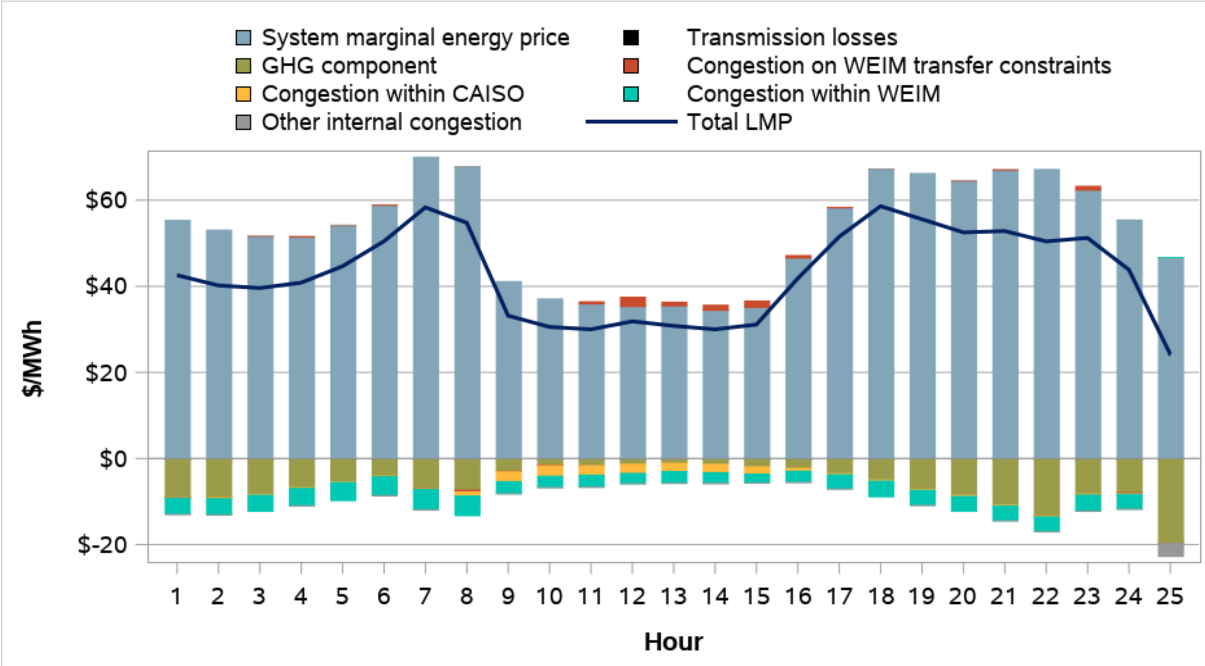
Appendix Figure A.49 Average hourly 15-minute price by component (Q4 2023)



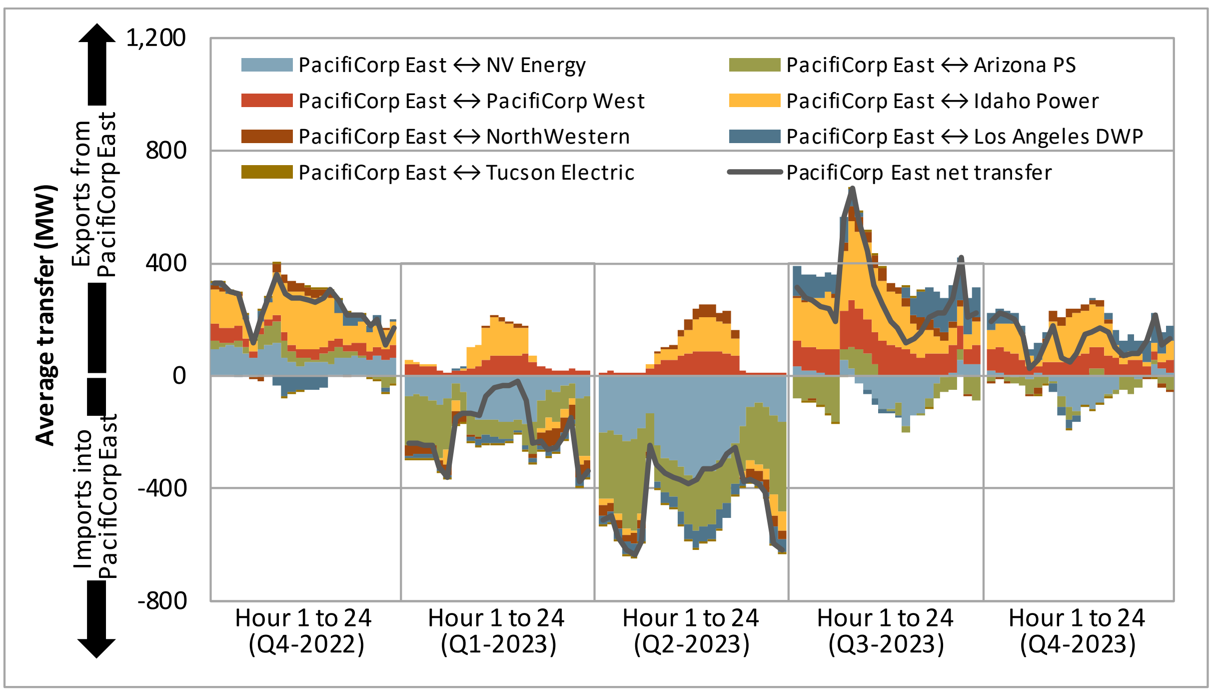
Appendix Figure A.50 Average hourly 15-minute market transfers



Appendix Figure A.51 Average hourly 5-minute price by component (Q4 2023)

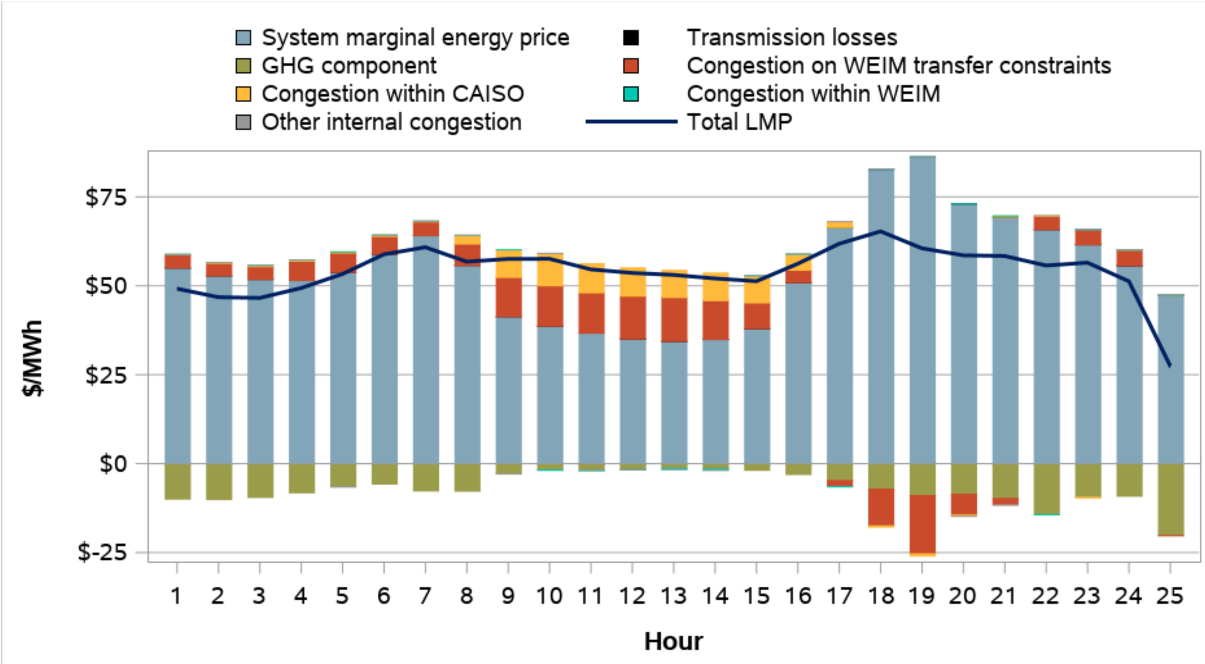


Appendix Figure A.52 Average hourly 5-minute market transfers

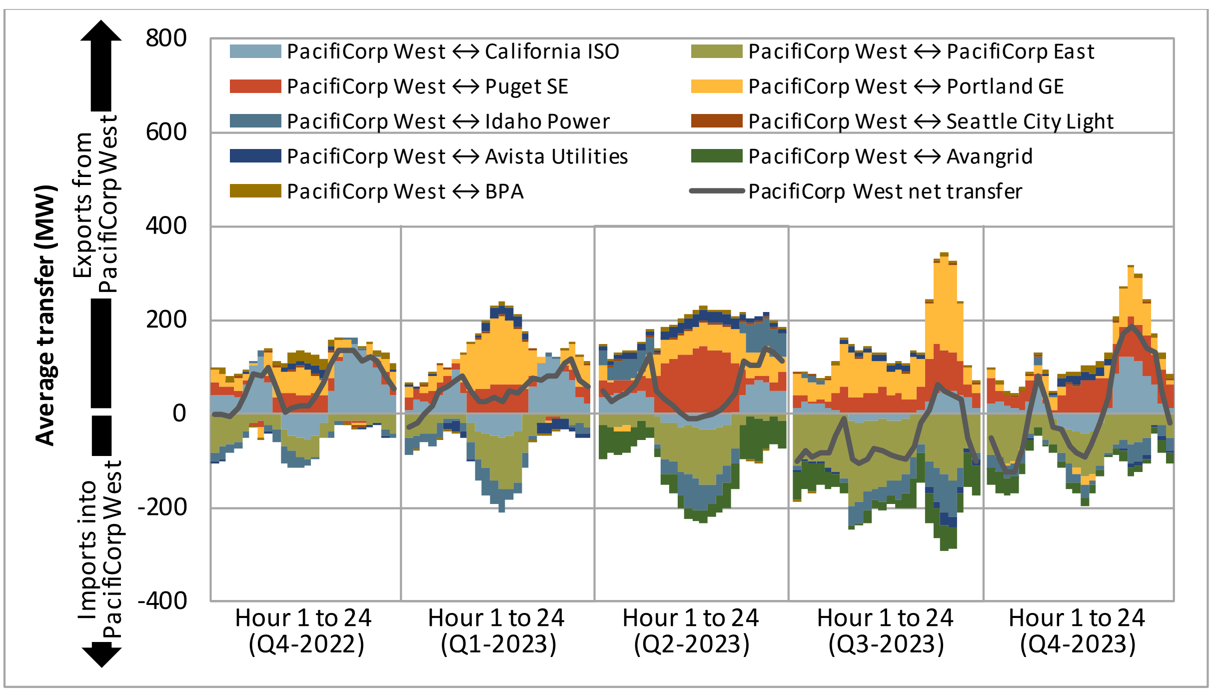


A.13 PacifiCorp West

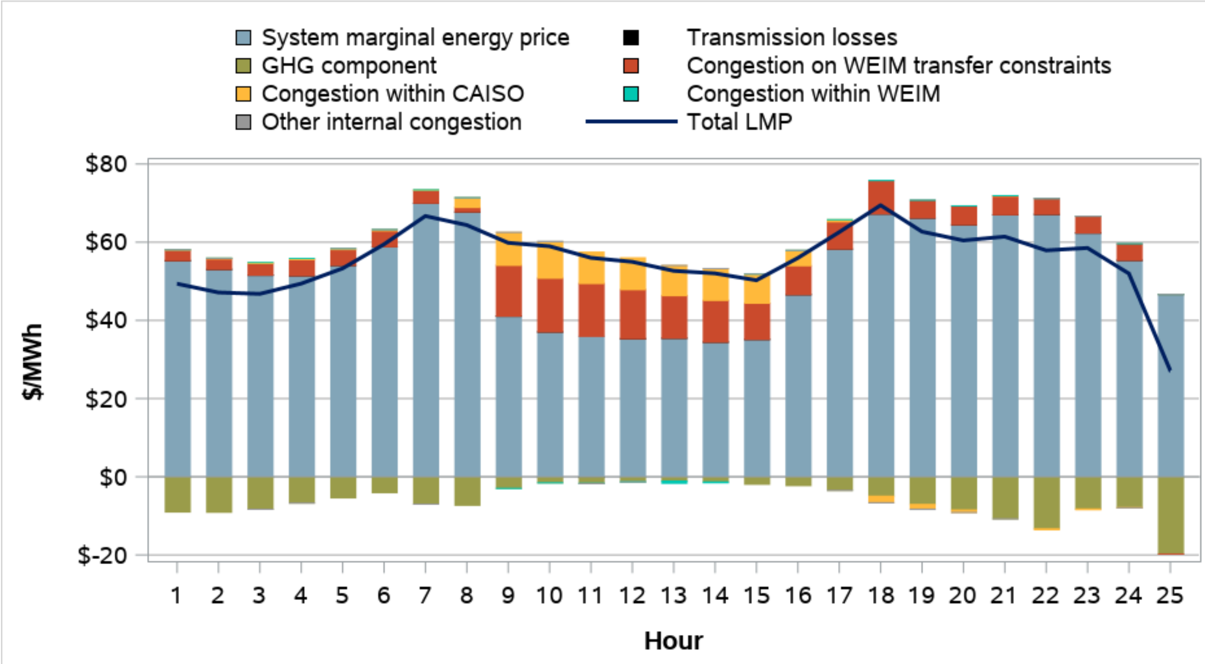
Appendix Figure A.53 Average hourly 15-minute price by component (Q4 2023)



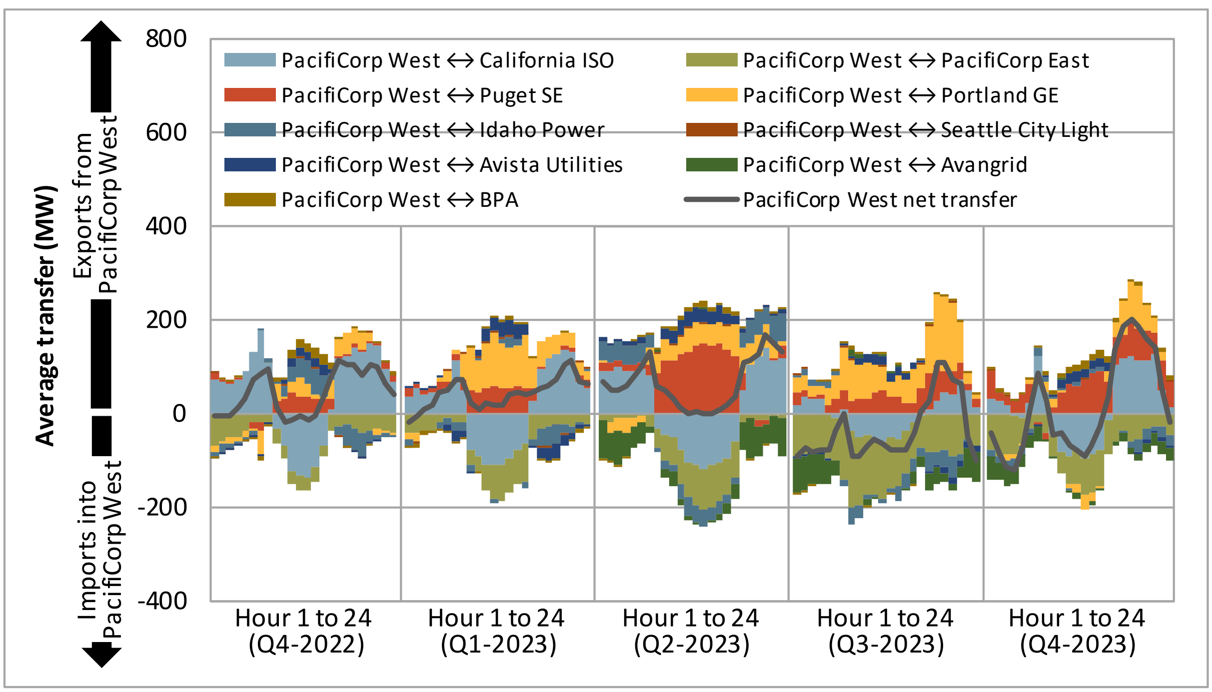
Appendix Figure A.54 Average hourly 15-minute market transfers



Appendix Figure A.55 Average hourly 5-minute price by component (Q4 2023)

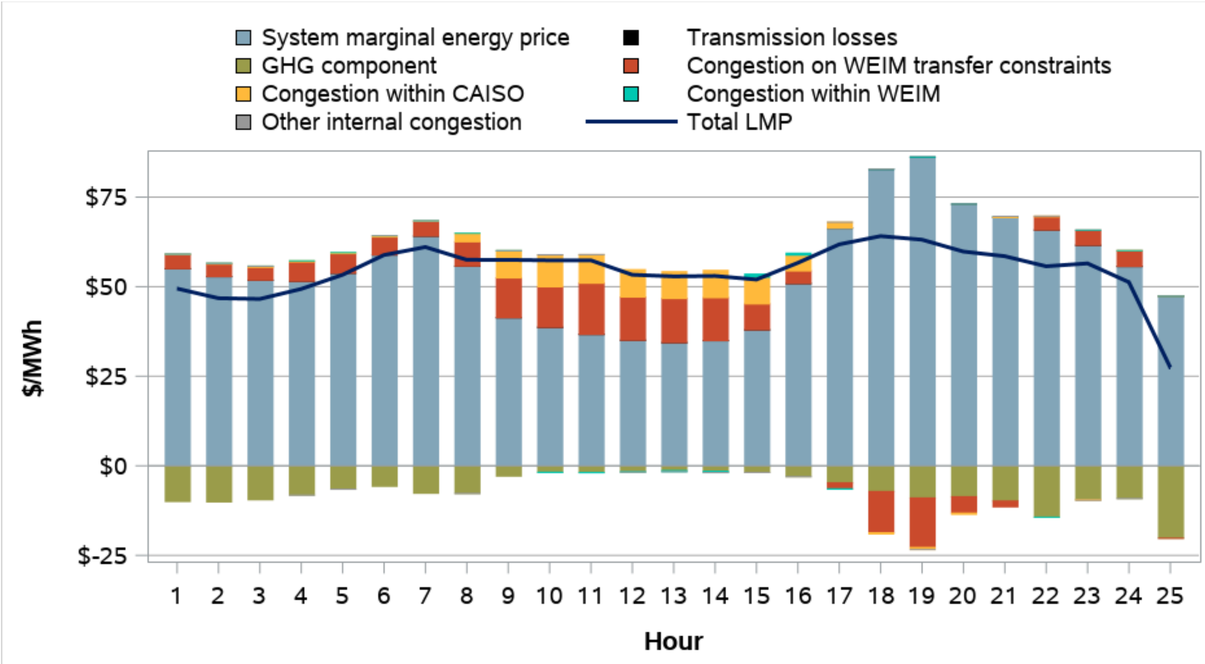


Appendix Figure A.56 Average hourly 5-minute market transfers

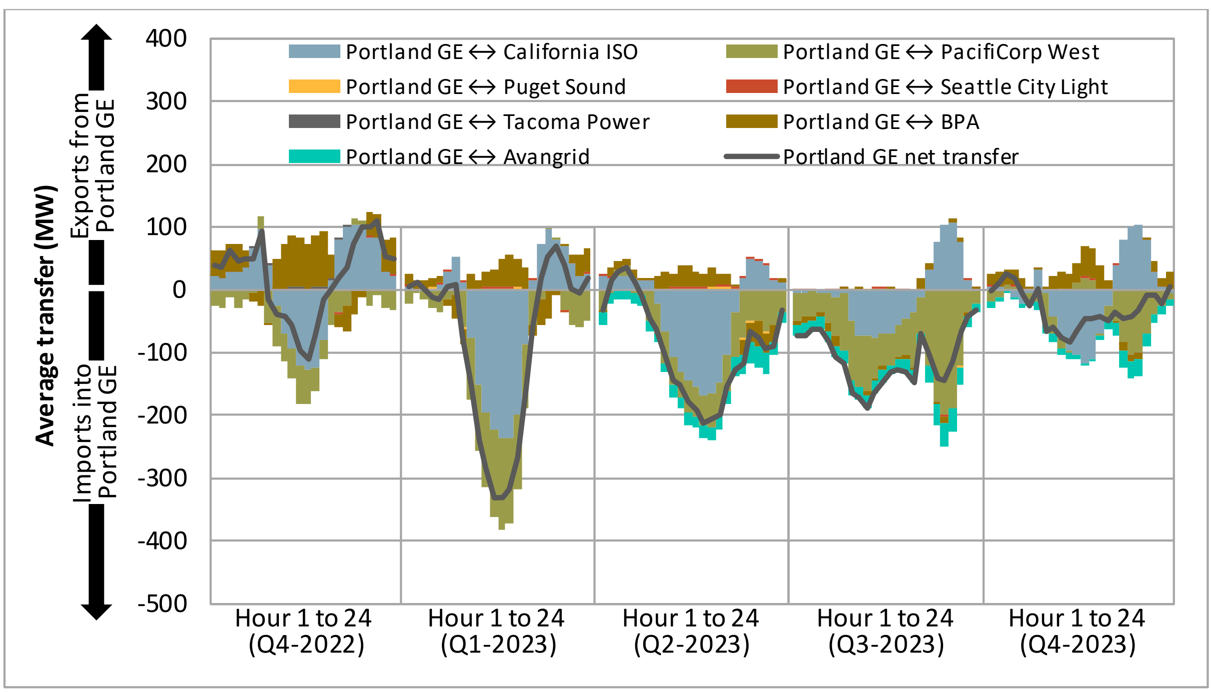


A.14 Portland General Electric

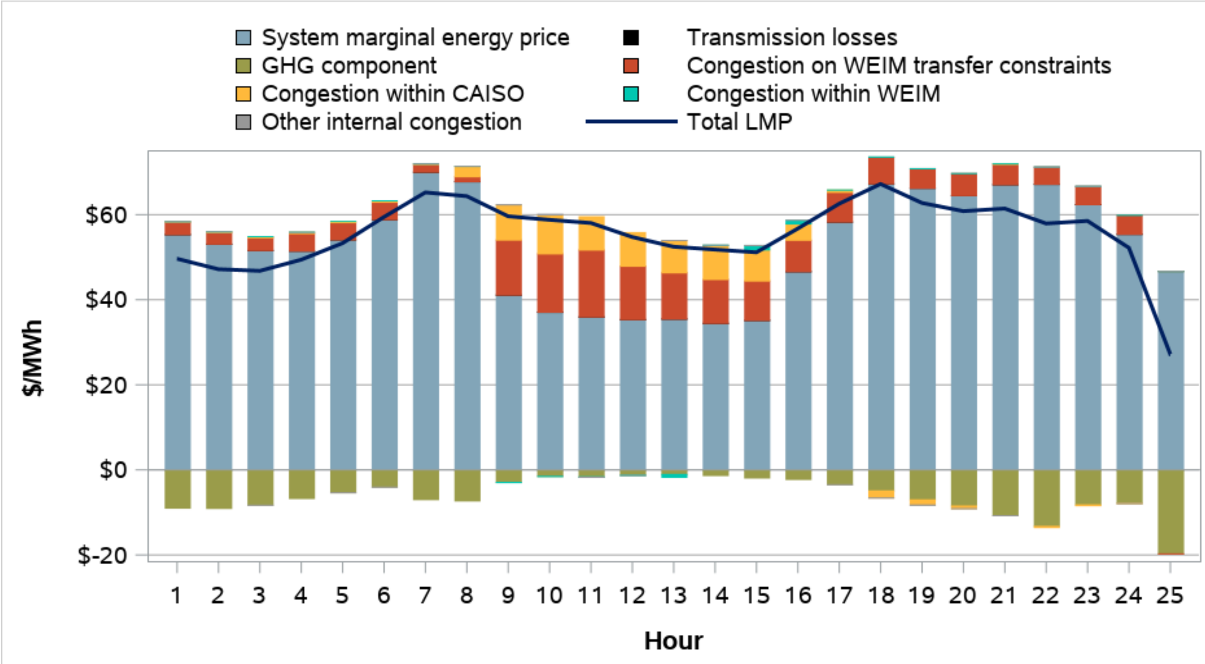
Appendix Figure A.57 Average hourly 15-minute price by component (Q4 2023)



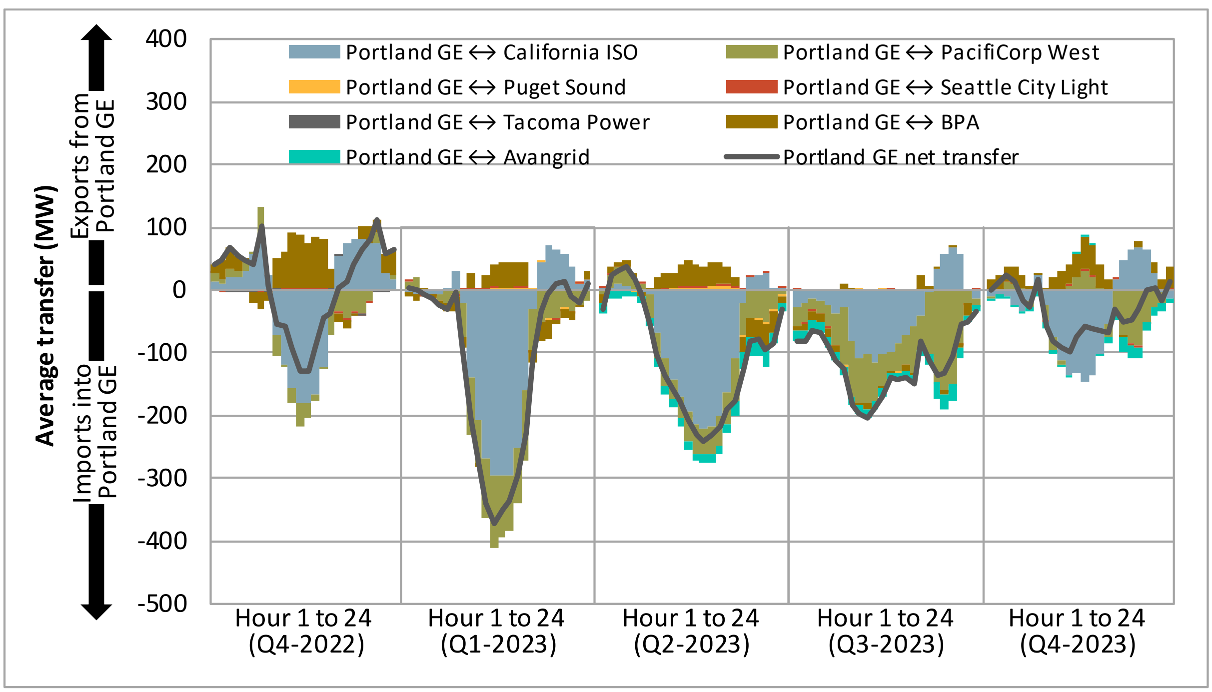
Appendix Figure A.58 Average hourly 15-minute market transfers



Appendix Figure A.59 Average hourly 5-minute price by component (Q4 2023)

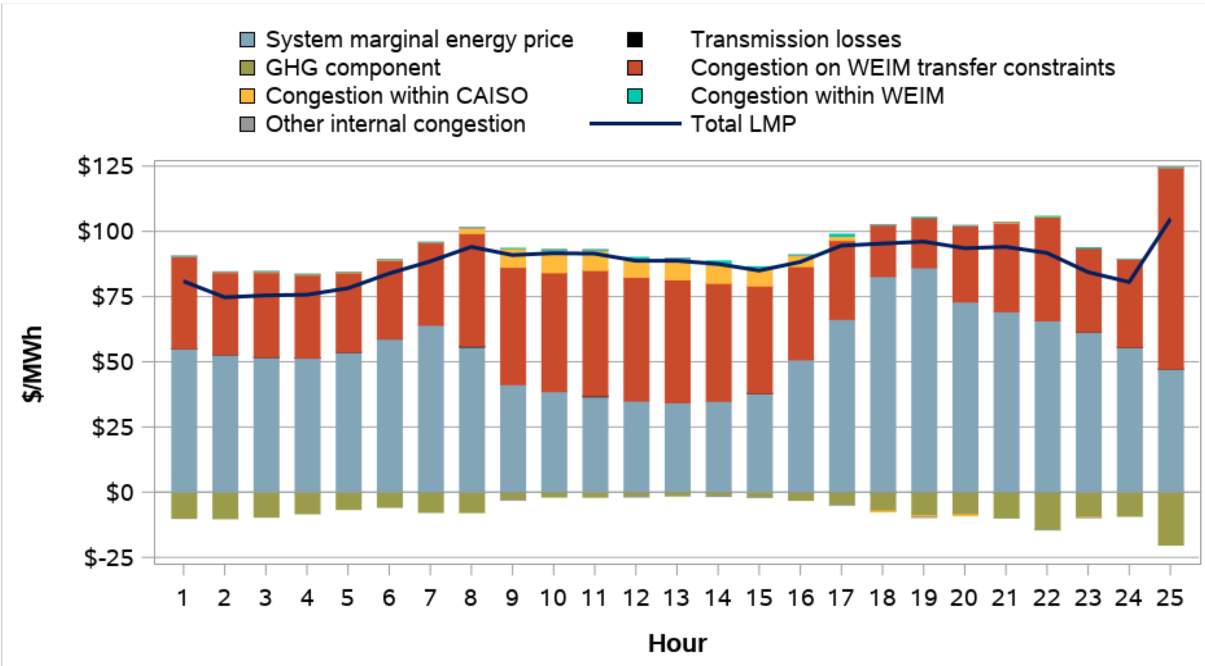


Appendix Figure A.60 Average hourly 5-minute market transfers

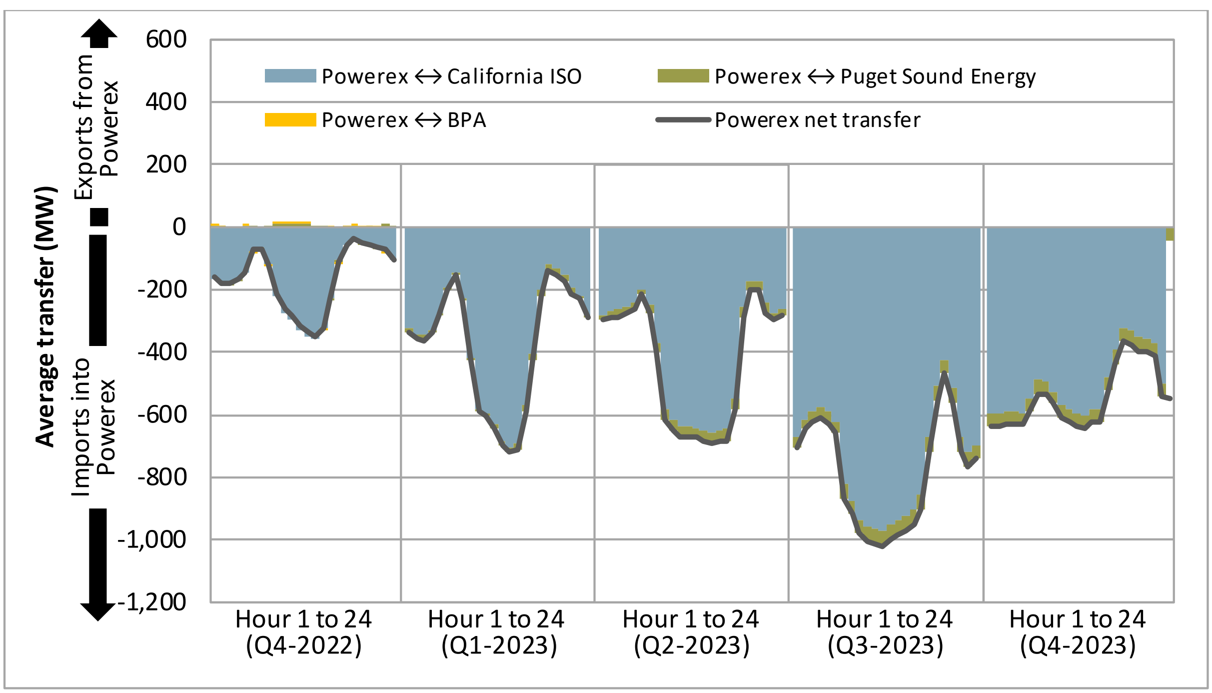


A.15 Powerex

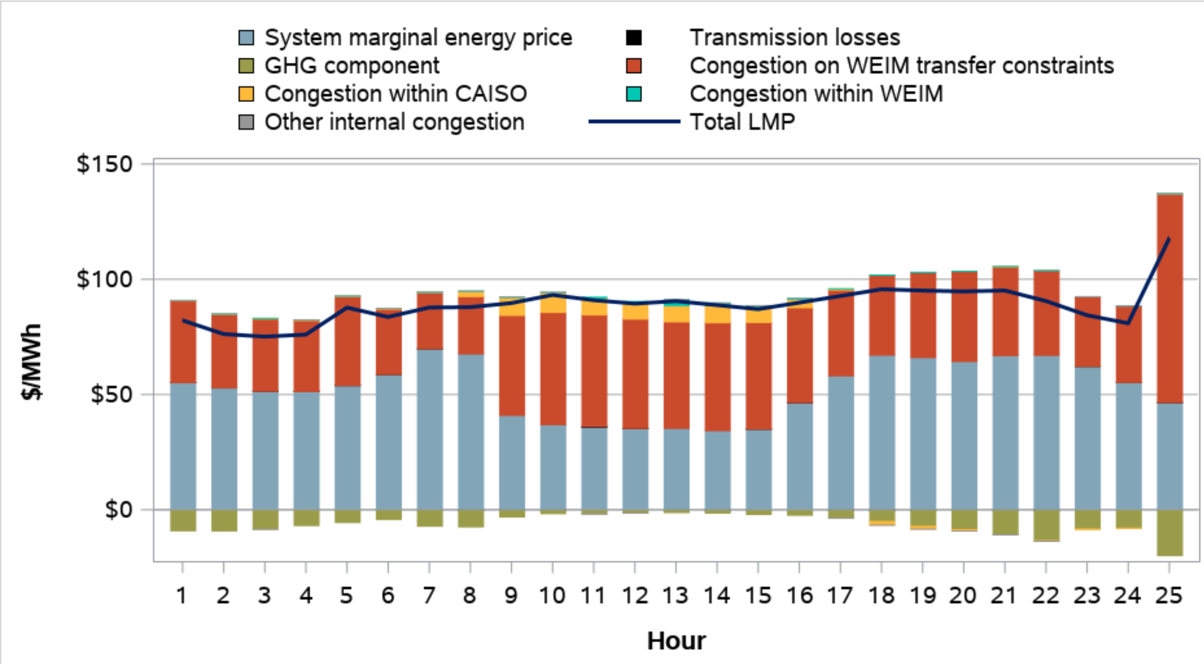
Appendix Figure A.61 Average hourly 15-minute price by component (Q4 2023)



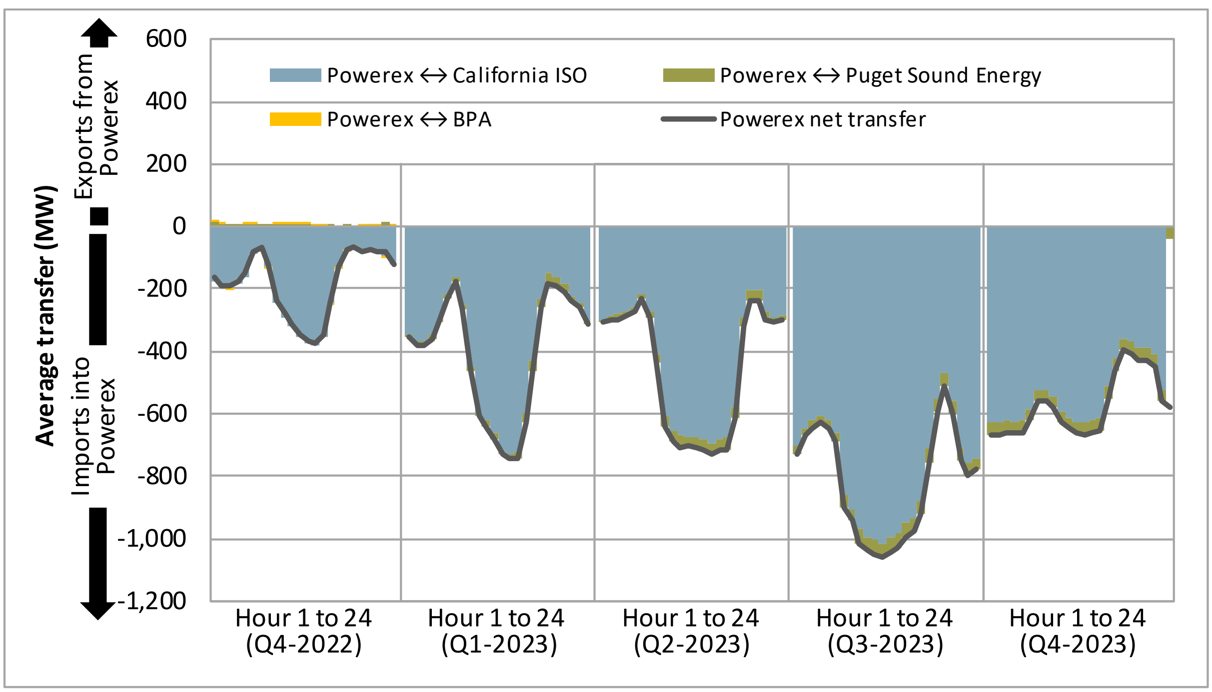
Appendix Figure A.62 Average hourly 15-minute market transfers



Appendix Figure A.63 Average hourly 5-minute price by component (Q4 2023)

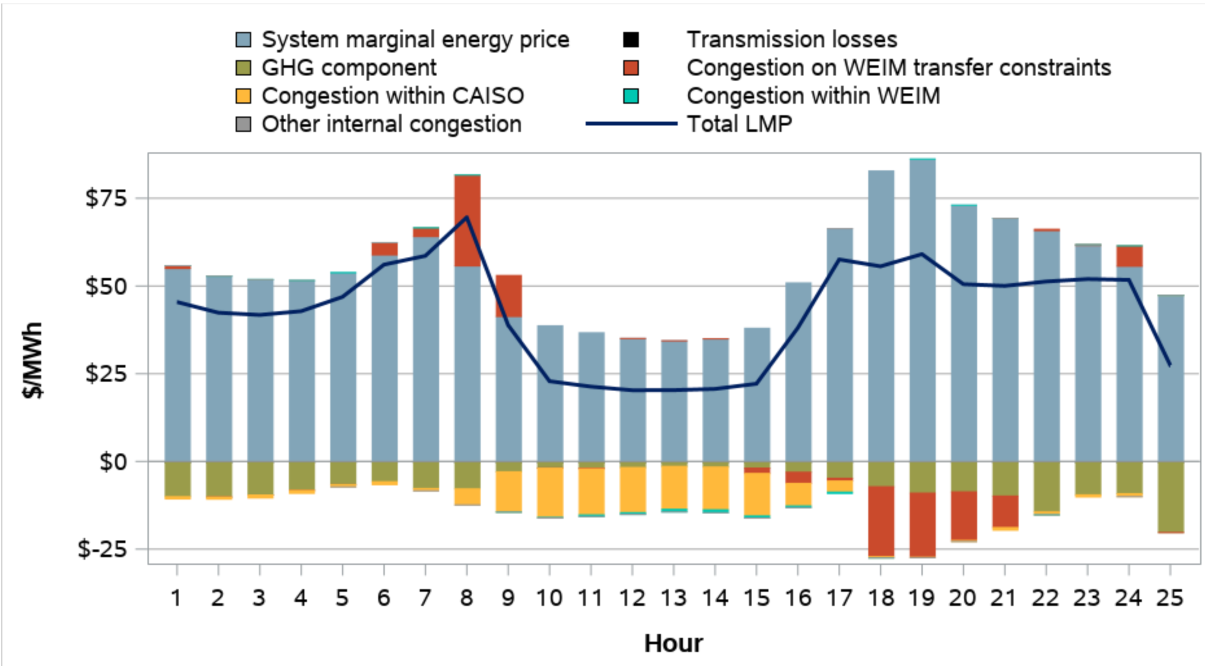


Appendix Figure A.64 Average hourly 5-minute market transfers

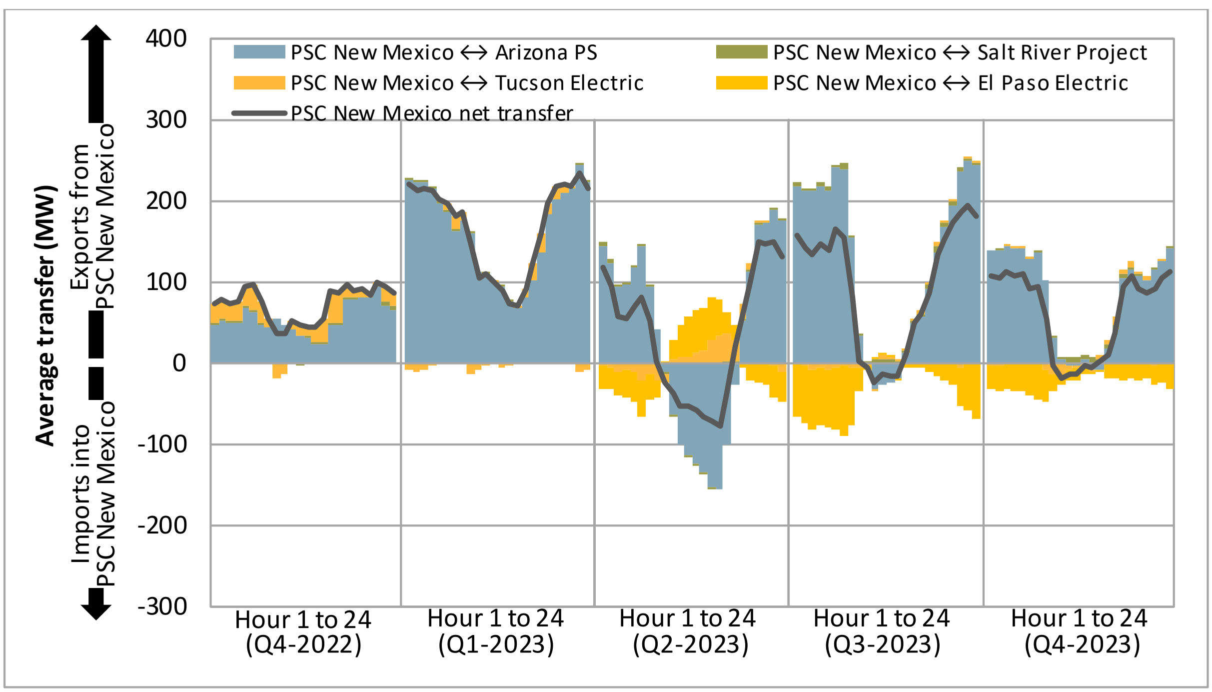


A.16 Public Service Company of New Mexico

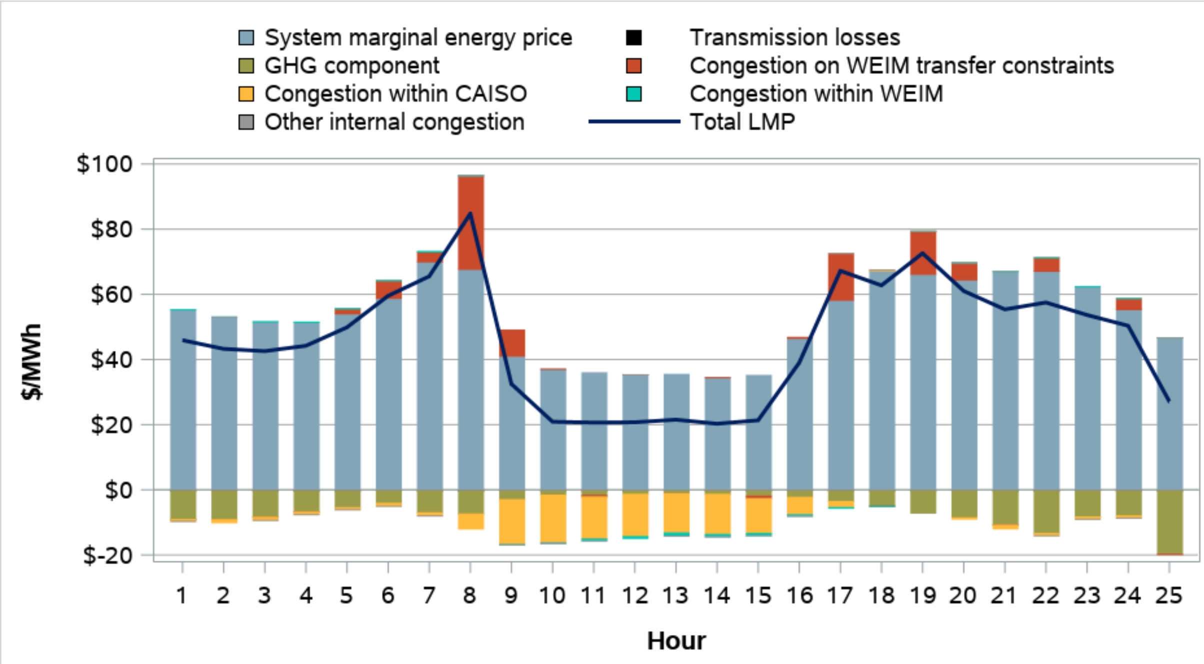
Appendix Figure A.65 Average hourly 15-minute price by component (Q4 2023)



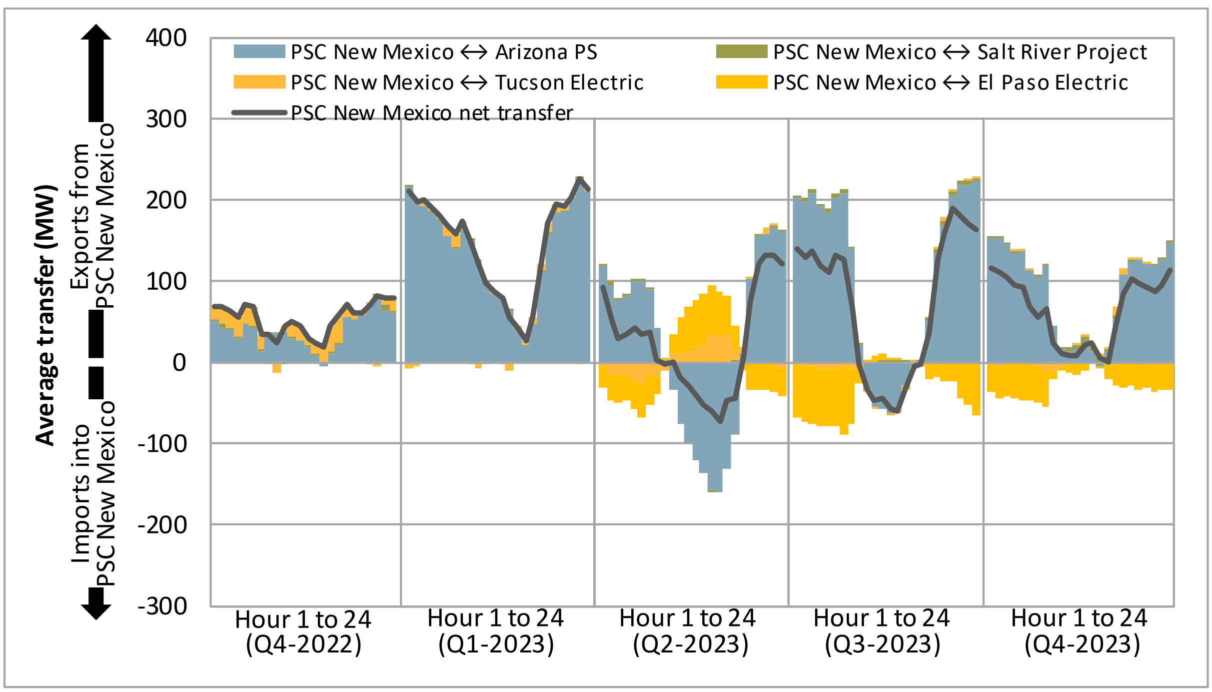
Appendix Figure A.66 Average hourly 15-minute market transfers



Appendix Figure A.67 Average hourly 5-minute price by component (Q4 2023)

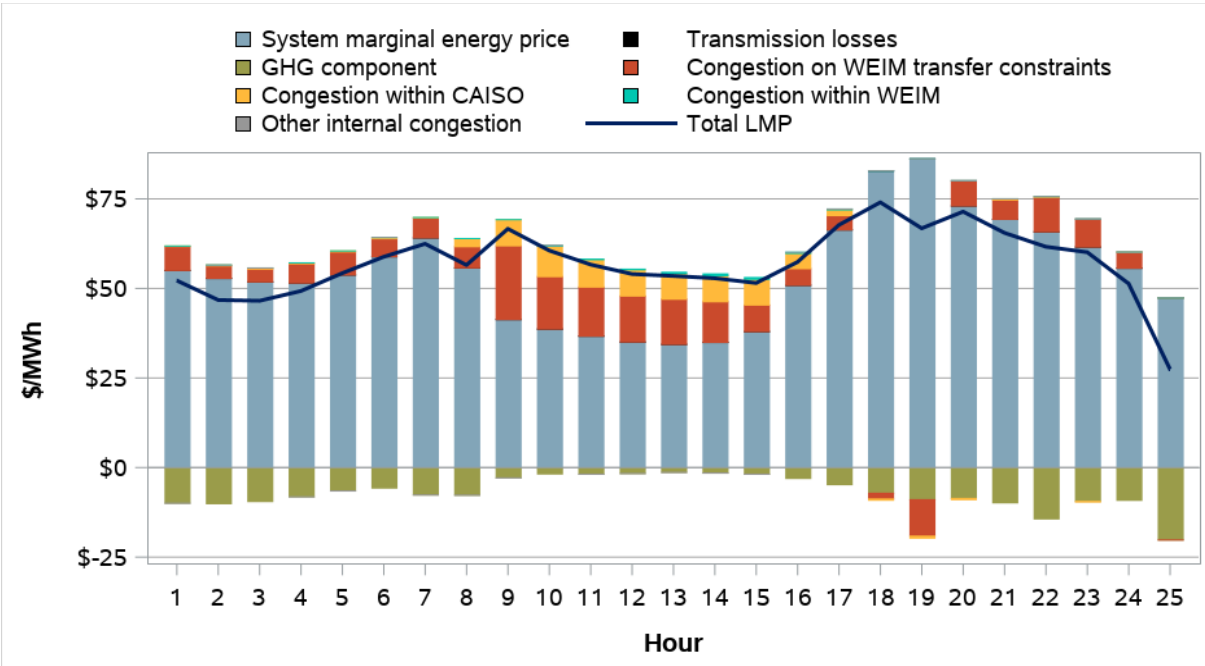


Appendix Figure A.68 Average hourly 5-minute market transfers

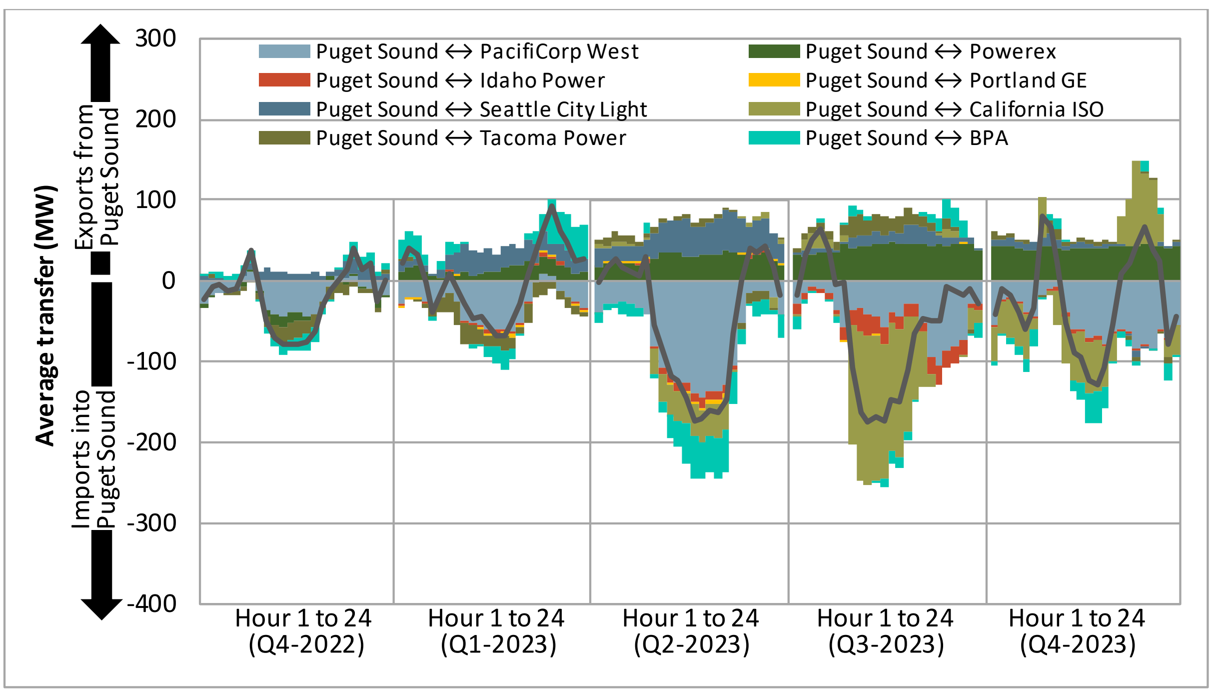


A.17 Puget Sound Energy

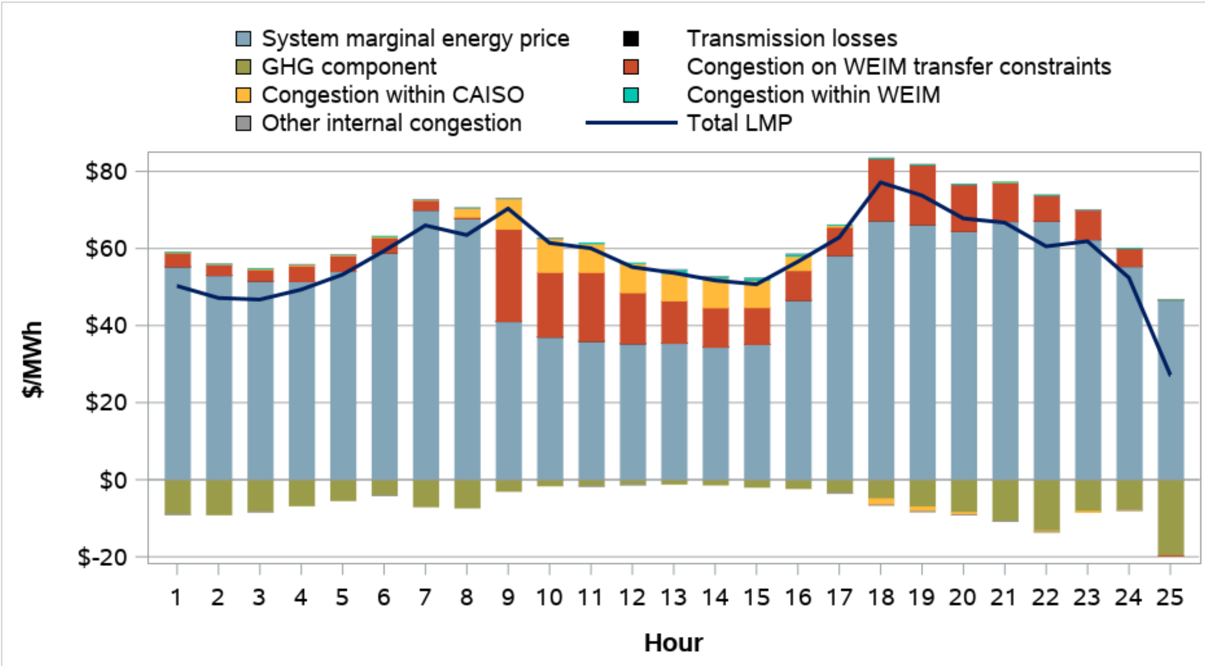
Appendix Figure A.69 Average hourly 15-minute price by component (Q4 2023)



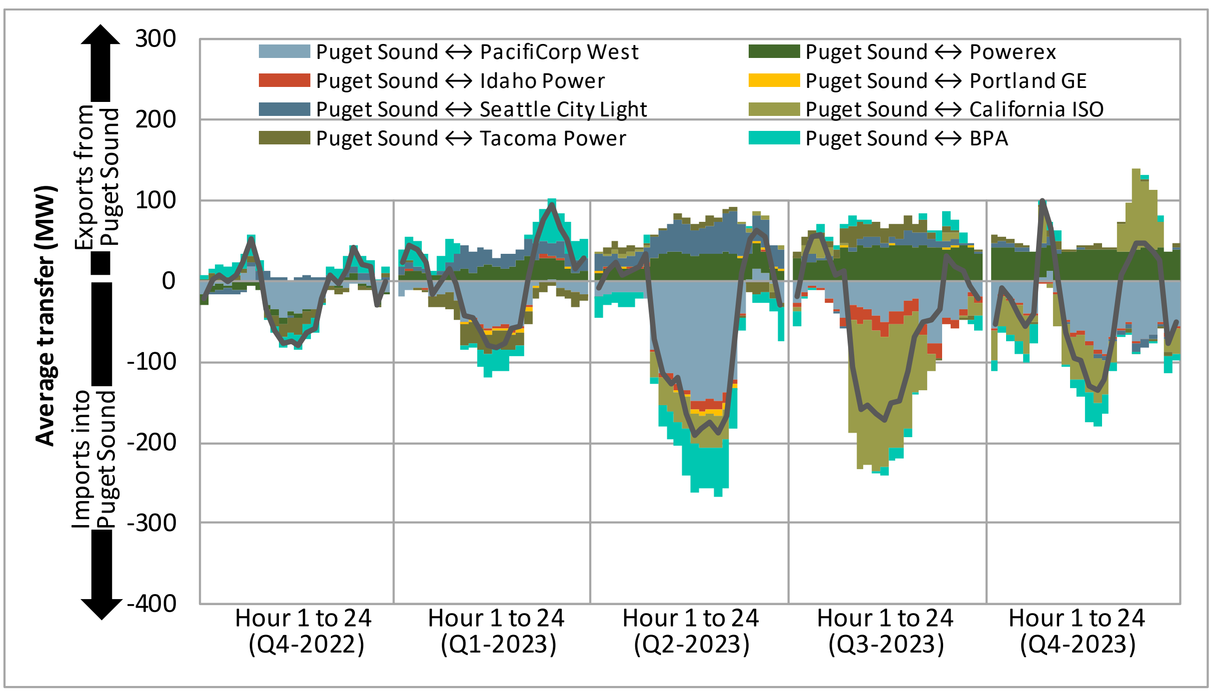
Appendix Figure A.70 Average hourly 15-minute market transfers



Appendix Figure A.71 Average hourly 5-minute price by component (Q4 2023)

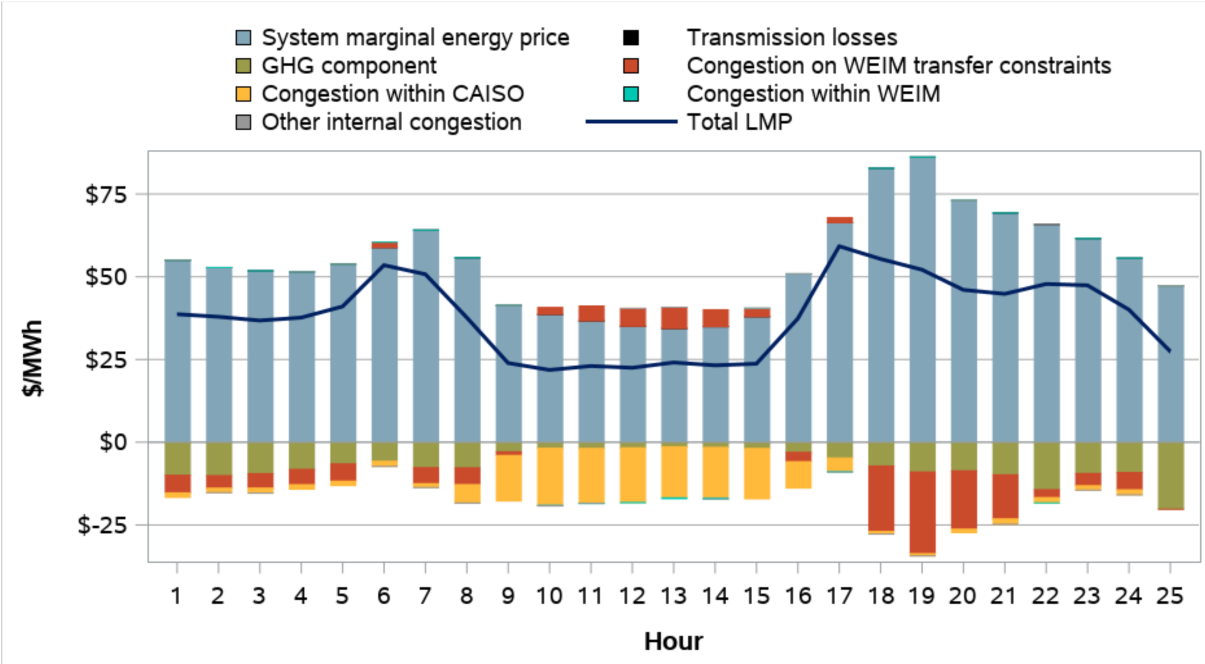


Appendix Figure A.72 Average hourly 5-minute market transfers

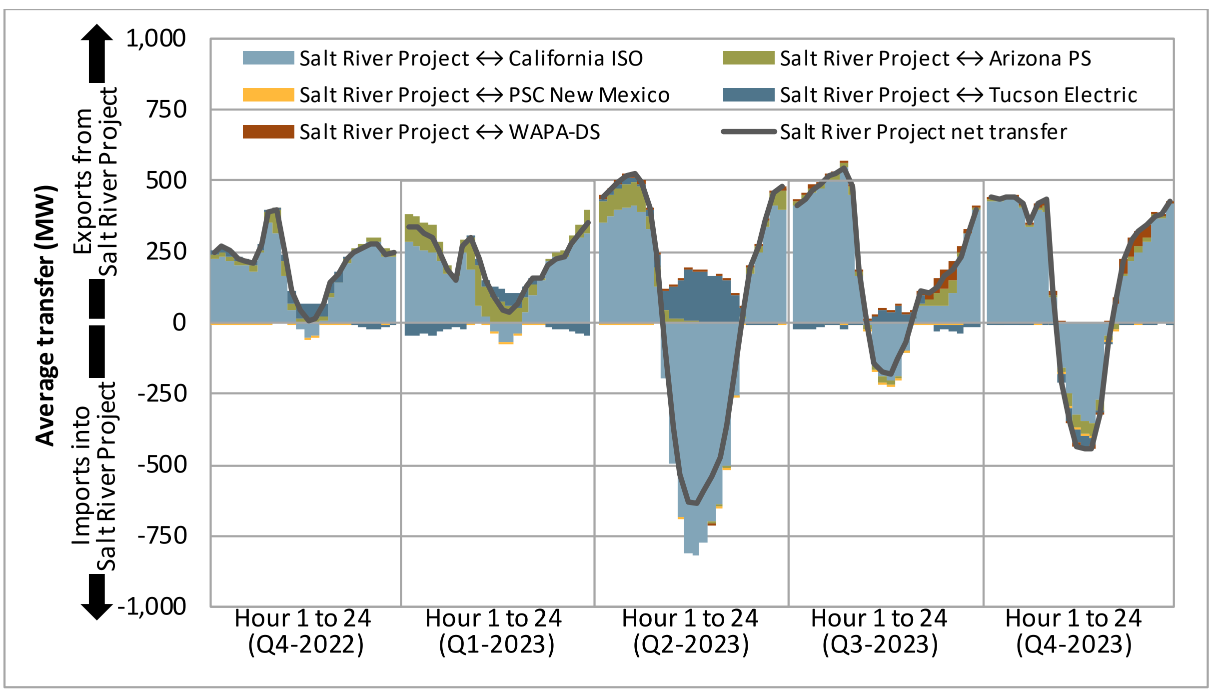


A.18 Salt River Project

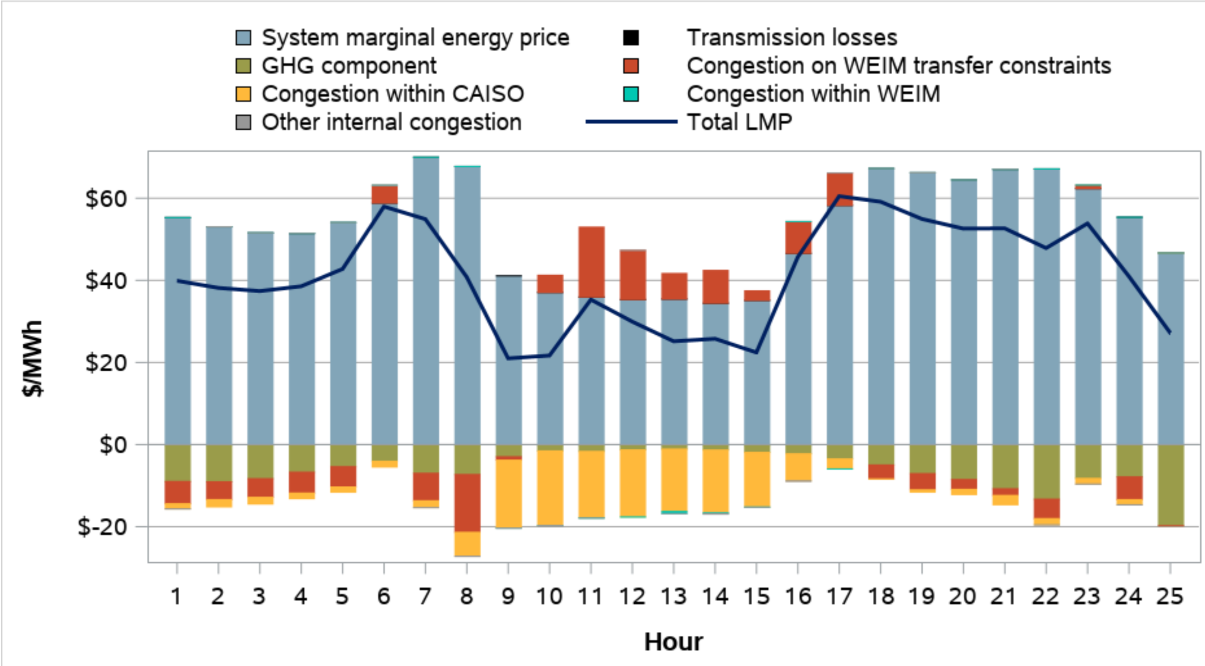
Appendix Figure A.73 Average hourly 15-minute price by component (Q4 2023)



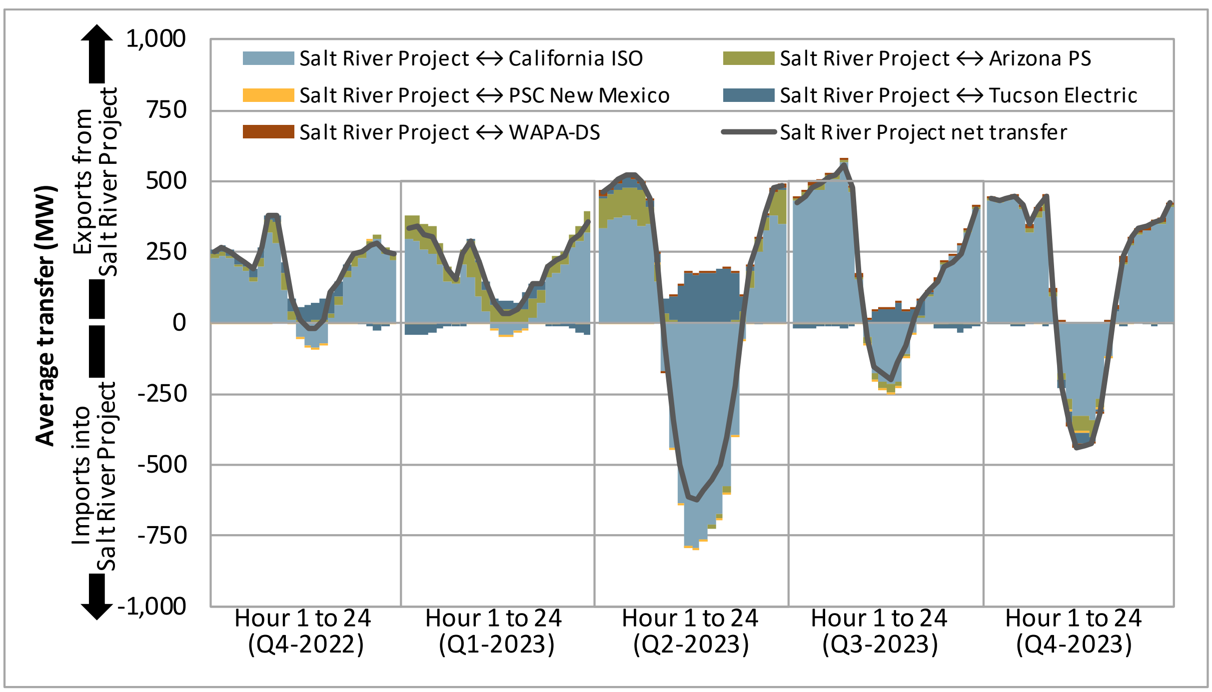
Appendix Figure A.74 Average hourly 15-minute market transfers



Appendix Figure A.75 Average hourly 5-minute price by component (Q4 2023)

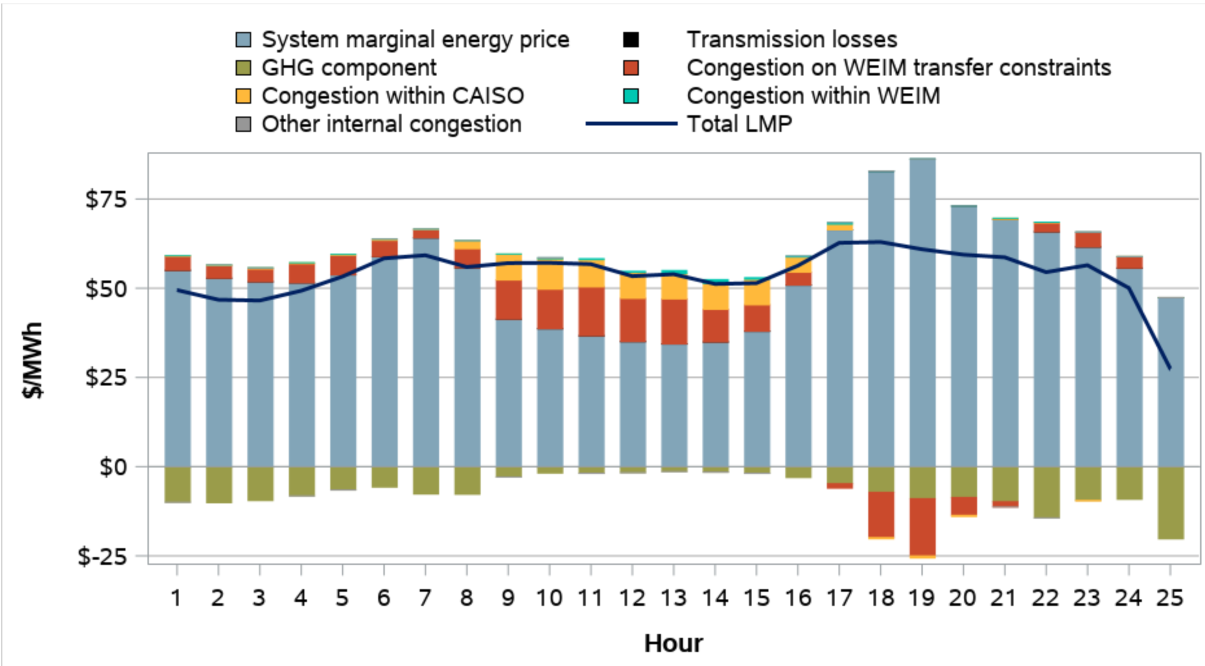


Appendix Figure A.76 Average hourly 5-minute market transfers

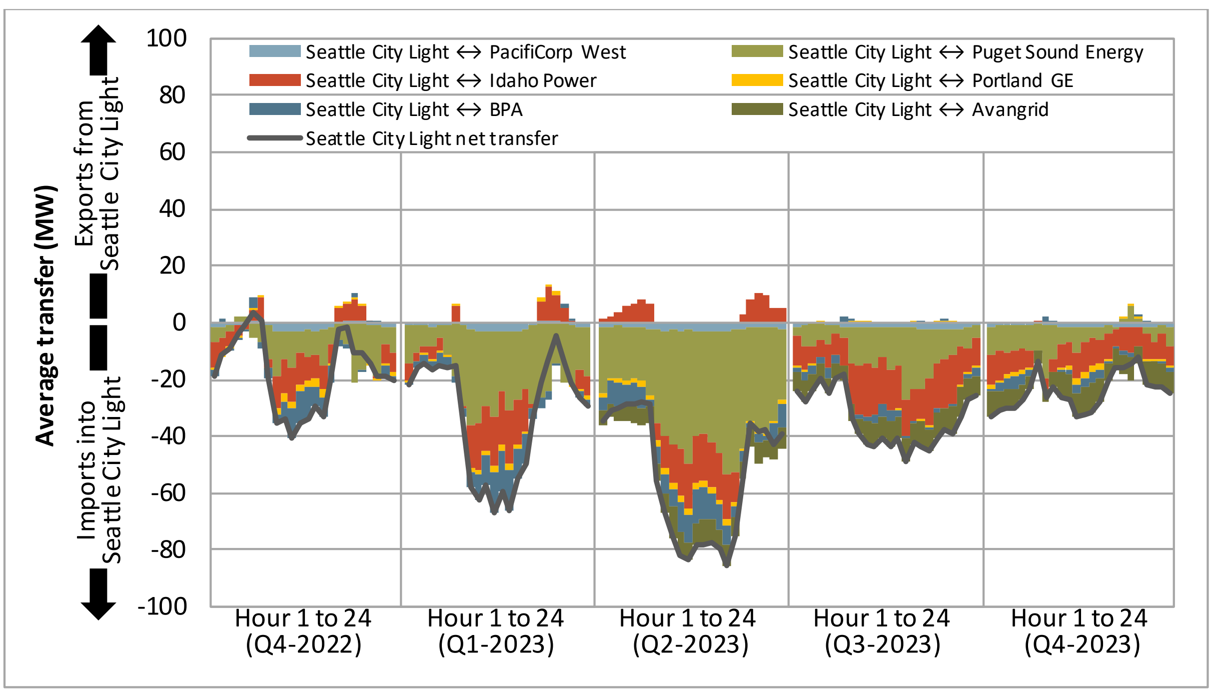


A.19 Seattle City Light

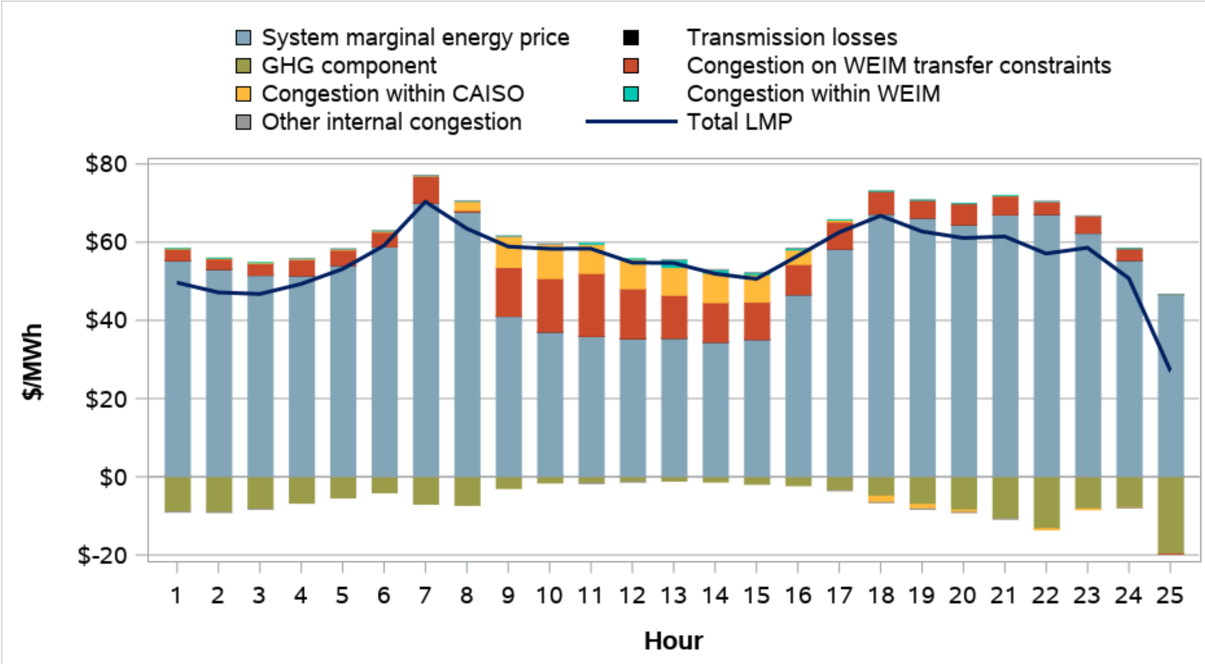
Appendix Figure A.77 Average hourly 15-minute price by component (Q4 2023)



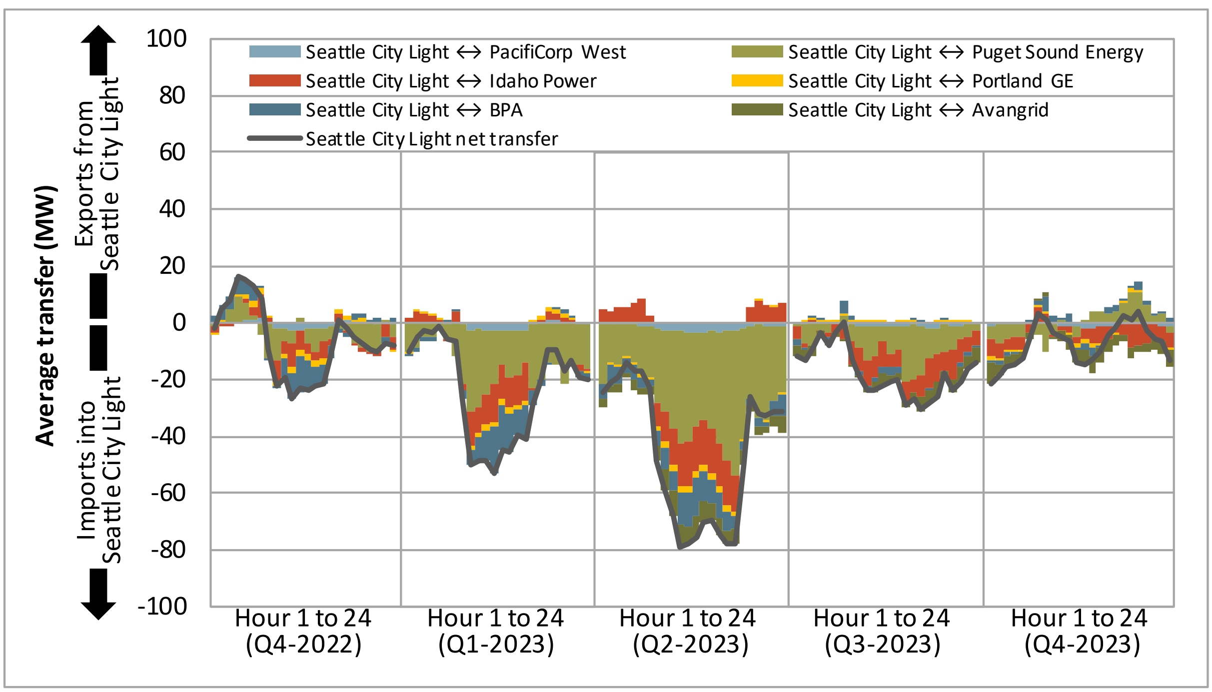
Appendix Figure A.78 Average hourly 15-minute market transfers



Appendix Figure A.79 Average hourly 5-minute price by component (Q4 2023)

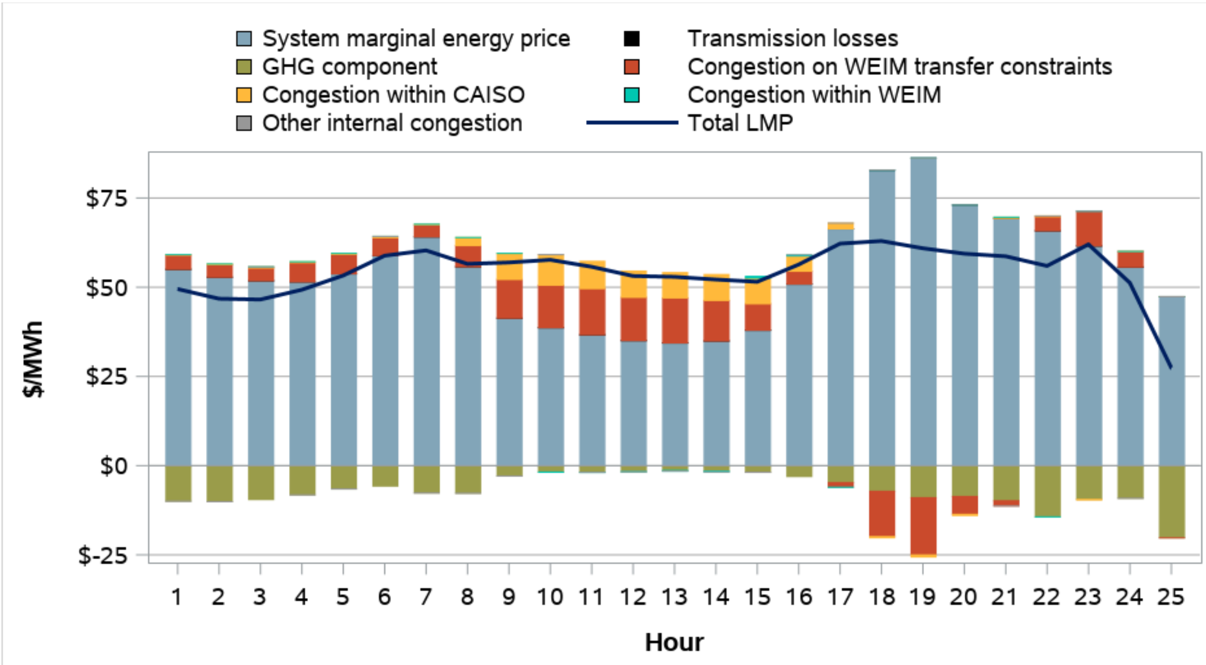


Appendix Figure A.80 Average hourly 5-minute market transfers

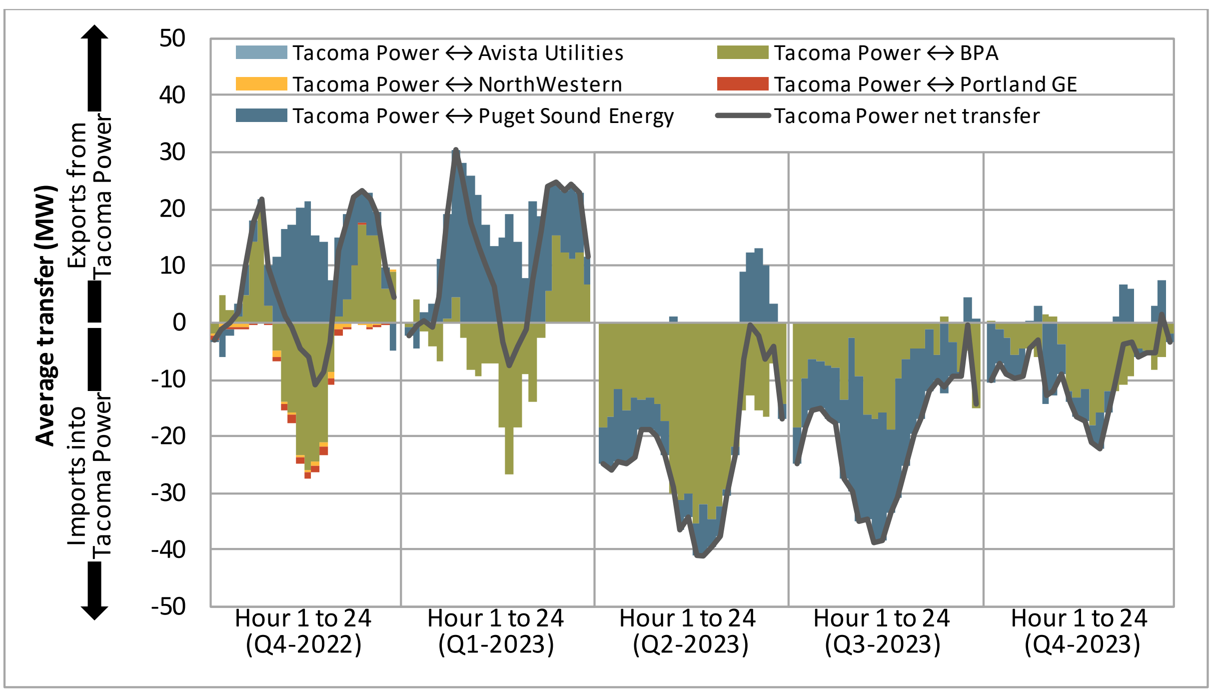


A.20 Tacoma Power

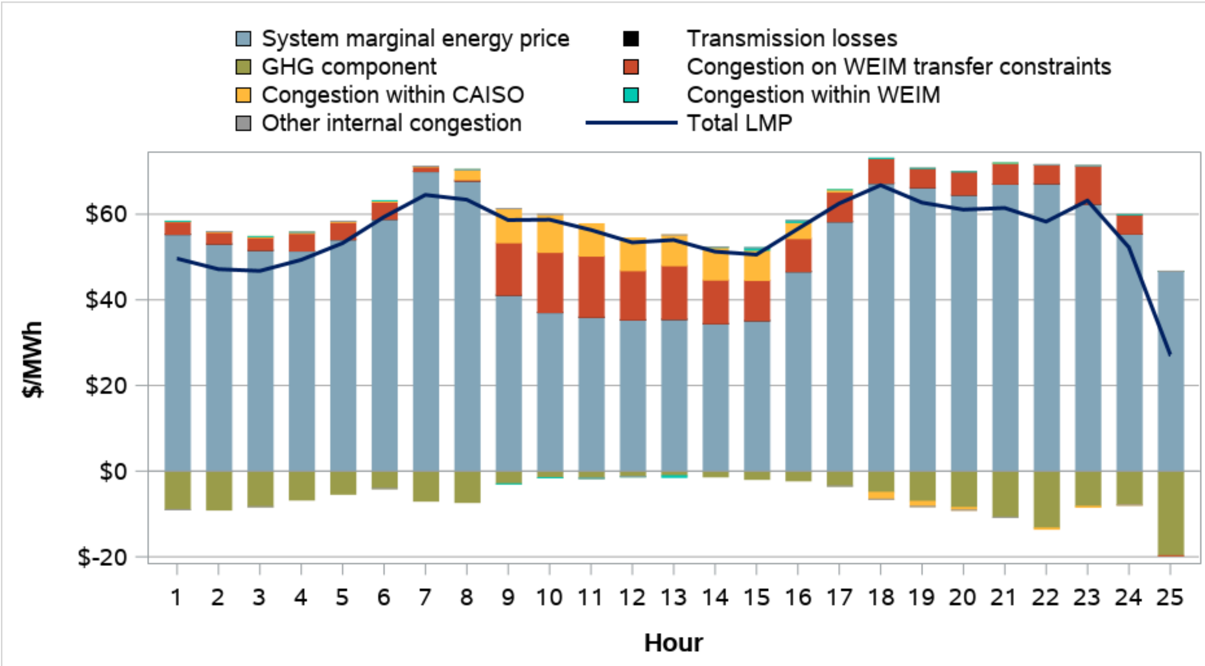
Appendix Figure A.81 Average hourly 15-minute price by component (Q4 2023)



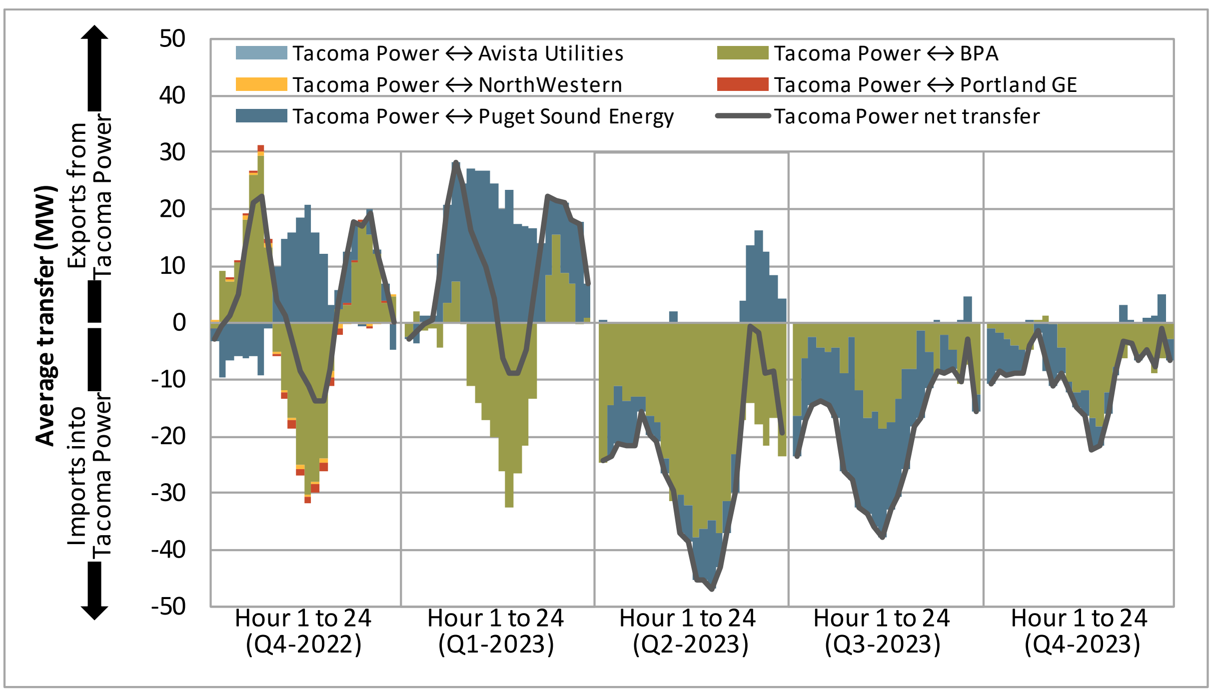
Appendix Figure A.82 Average hourly 15-minute market transfers



Appendix Figure A.83 Average hourly 5-minute price by component (Q4 2023)

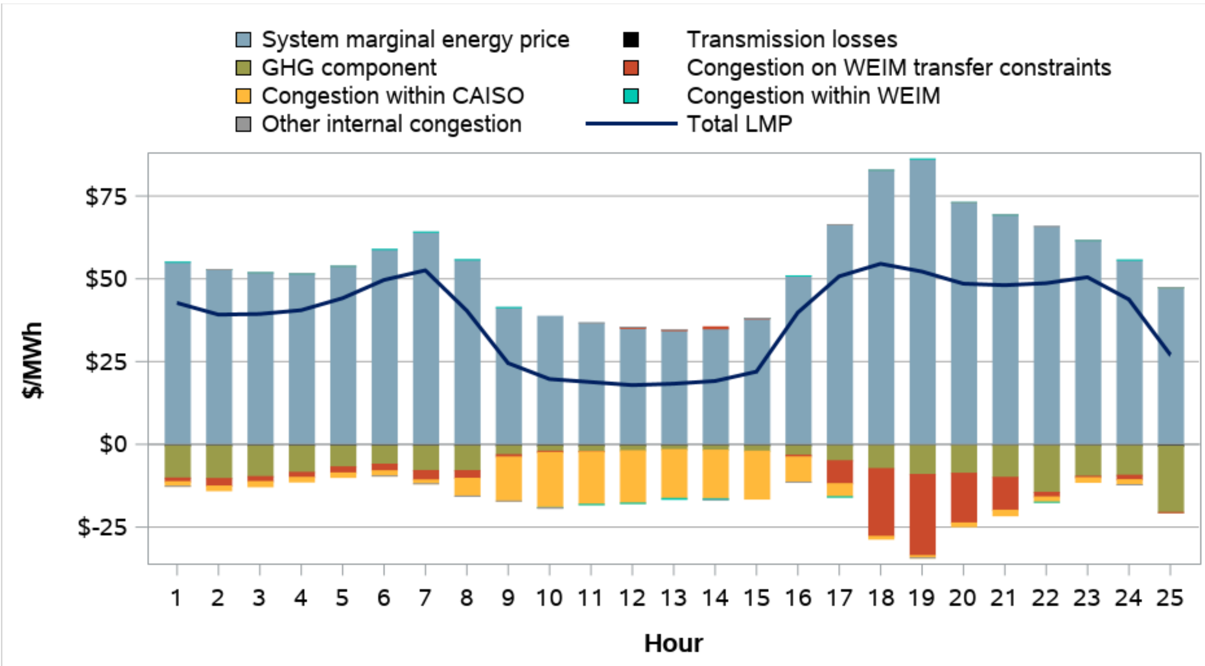


Appendix Figure A.84 Average hourly 5-minute market transfers

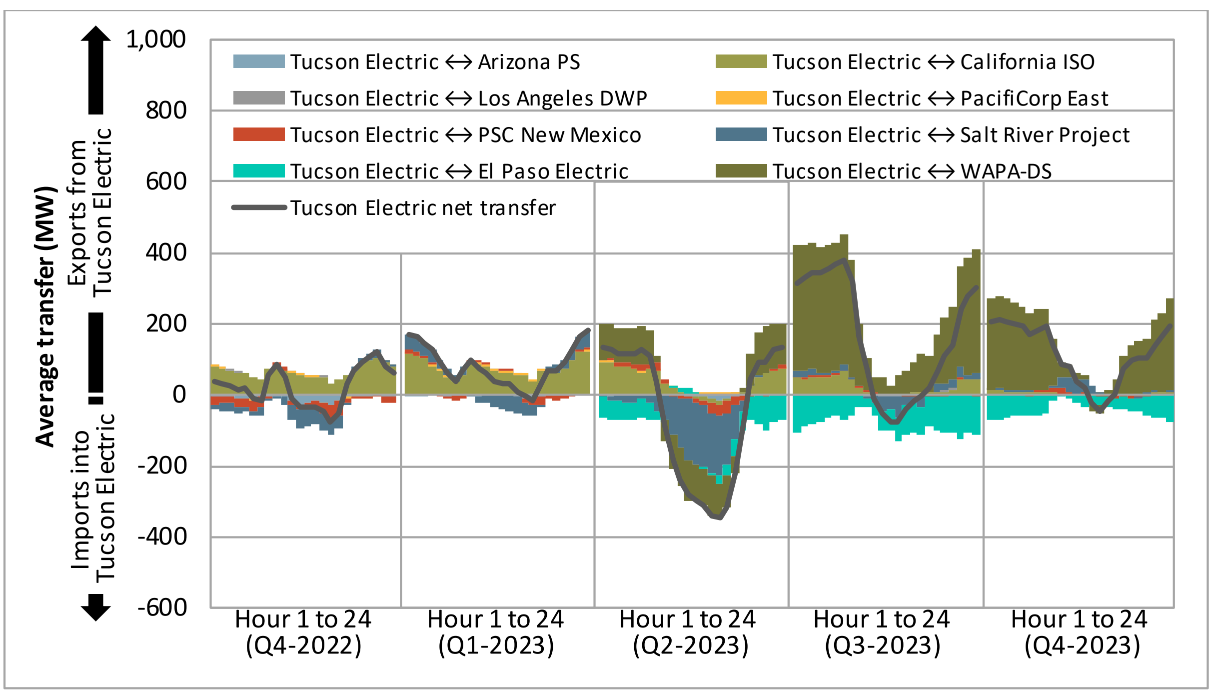


A.21 Tucson Electric Power

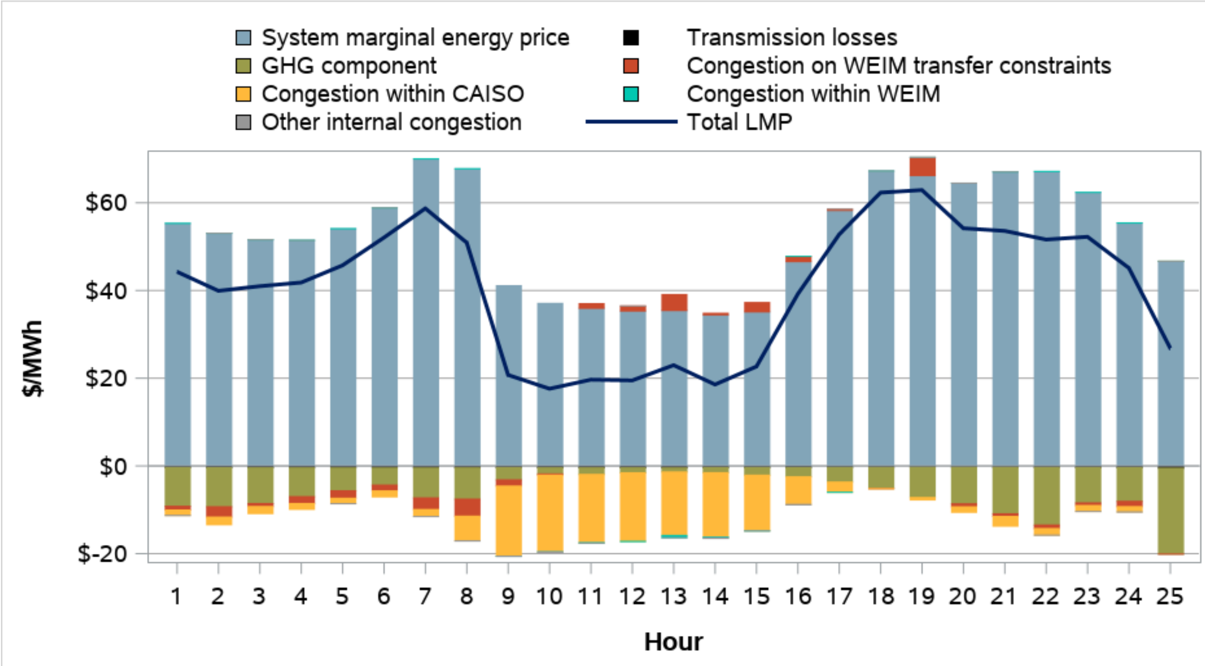
Appendix Figure A.85 Average hourly 15-minute price by component (Q4 2023)



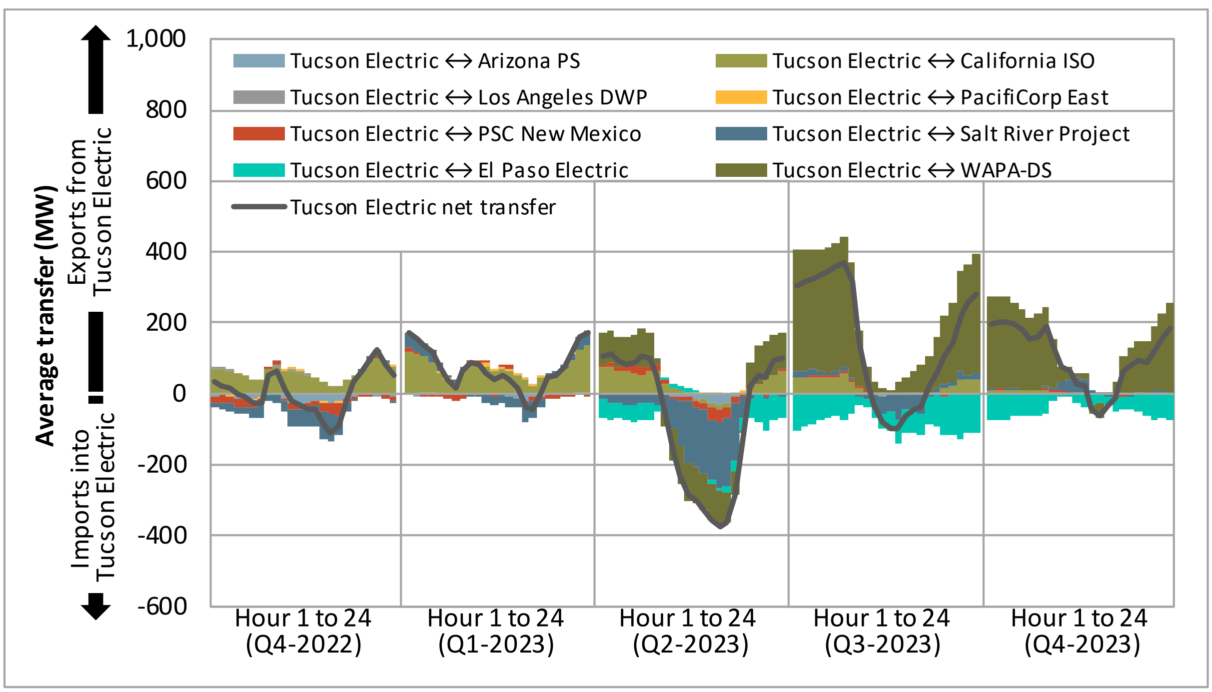
Appendix Figure A.86 Average hourly 15-minute market transfers



Appendix Figure A.87 Average hourly 5-minute price by component (Q4 2023)

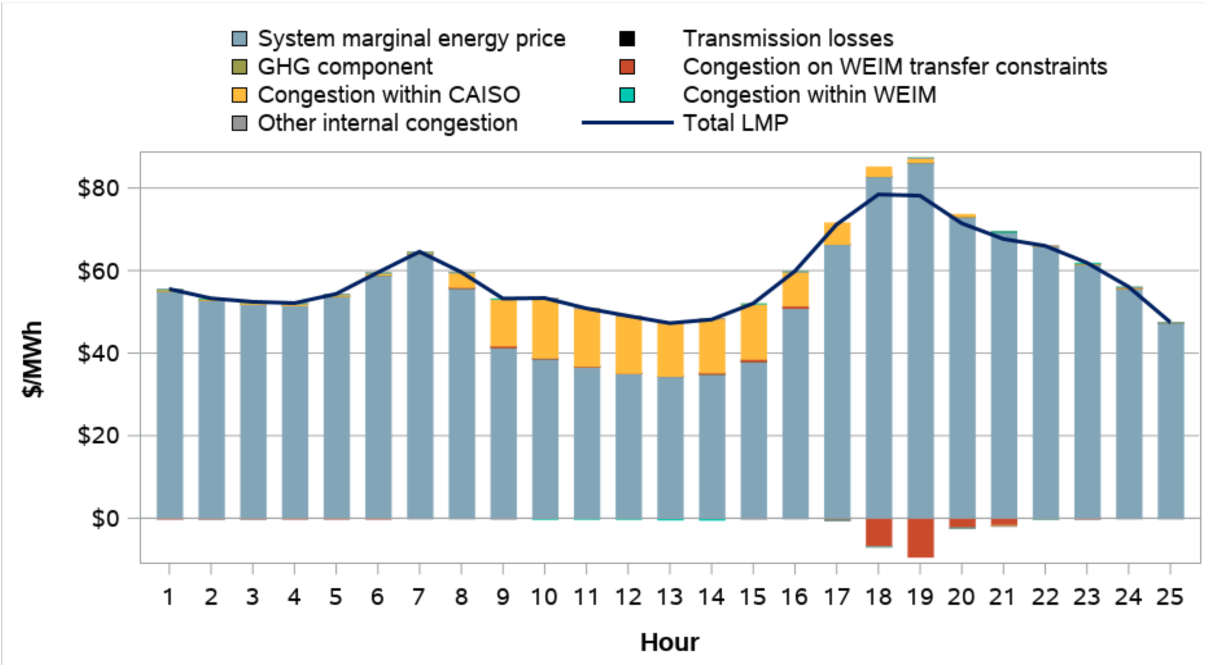


Appendix Figure A.88 Average hourly 5-minute market transfers

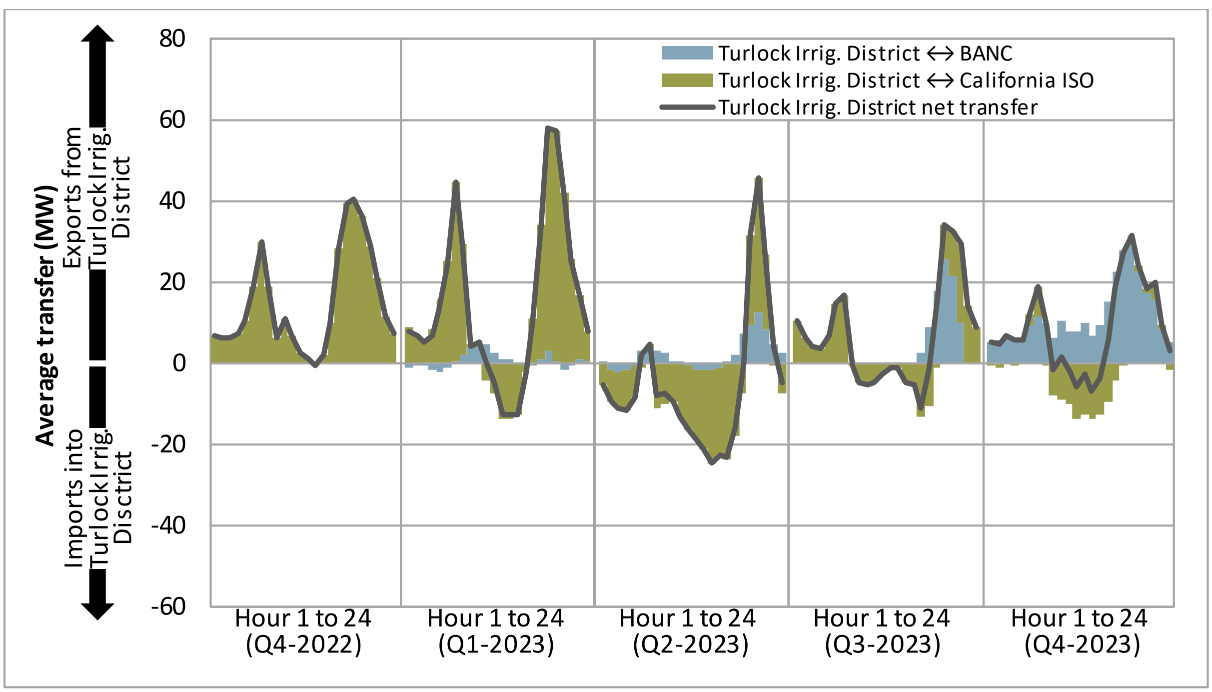


A.22 Turlock Irrigation District

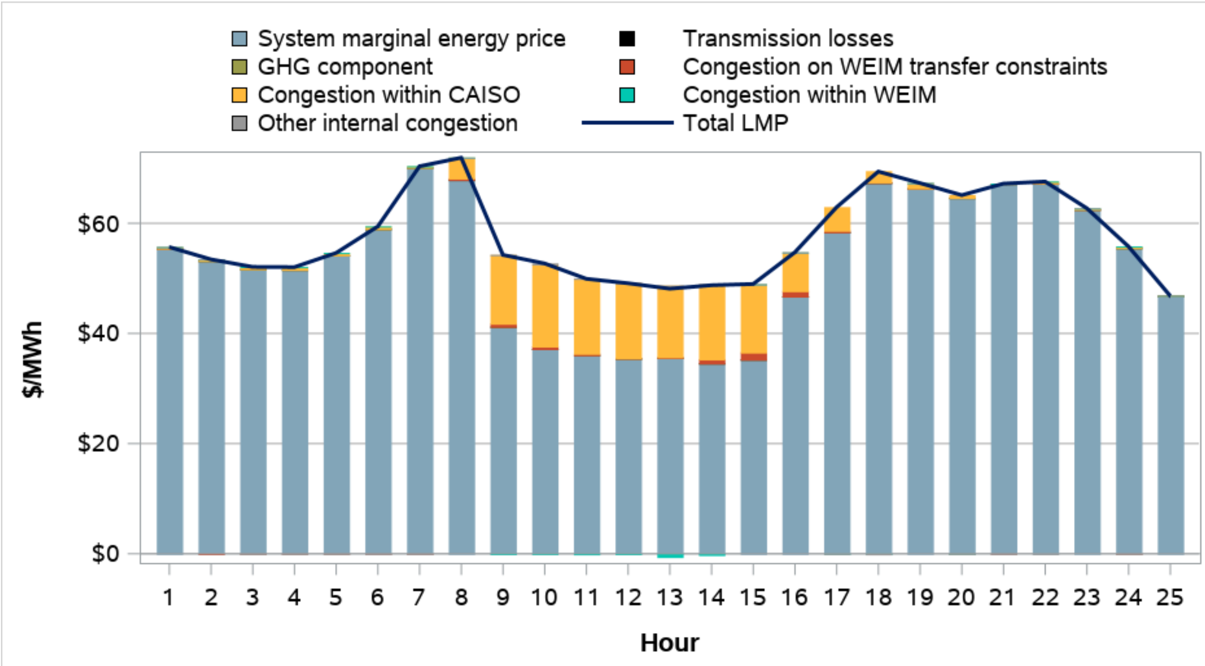
Appendix Figure A.89 Average hourly 15-minute price by component (Q4 2023)



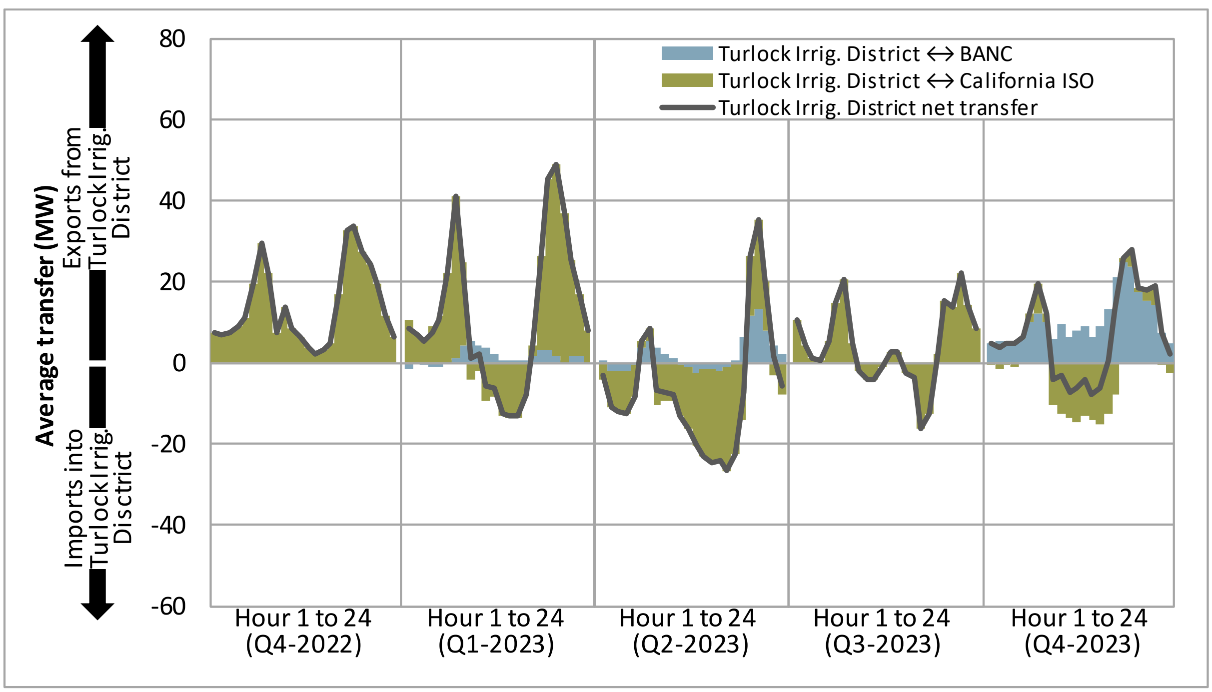
Appendix Figure A.90 Average hourly 15-minute market transfers



Appendix Figure A.91 Average hourly 5-minute price by component (Q4 2023)

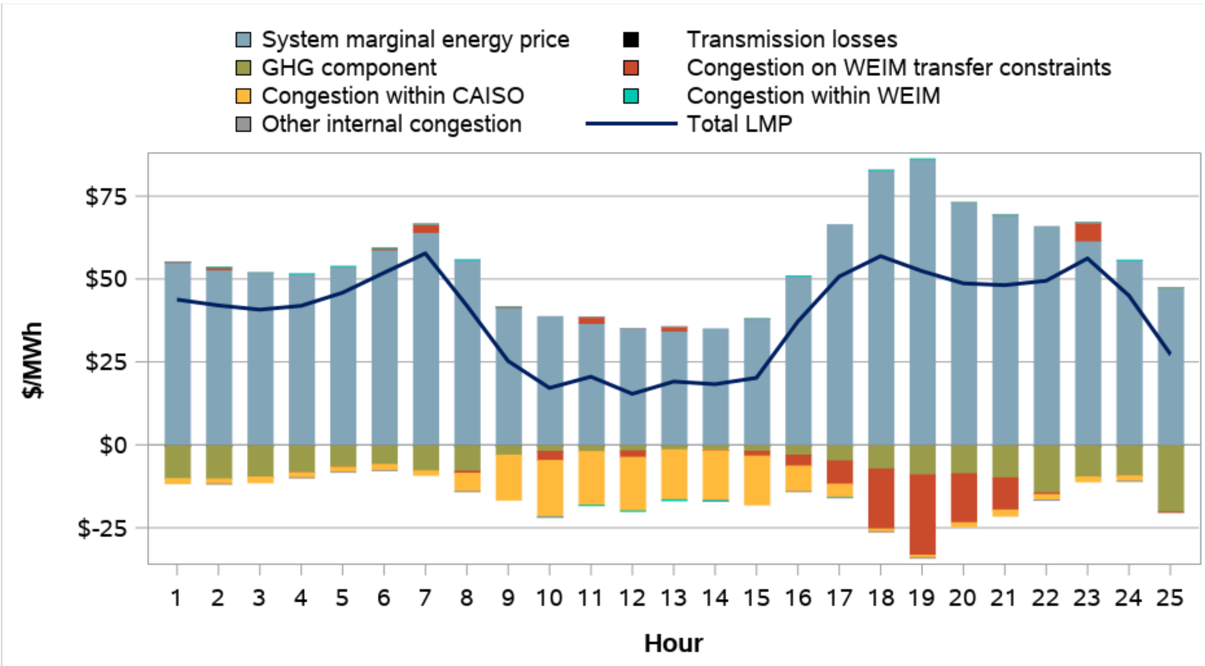


Appendix Figure A.92 Average hourly 5-minute market transfers

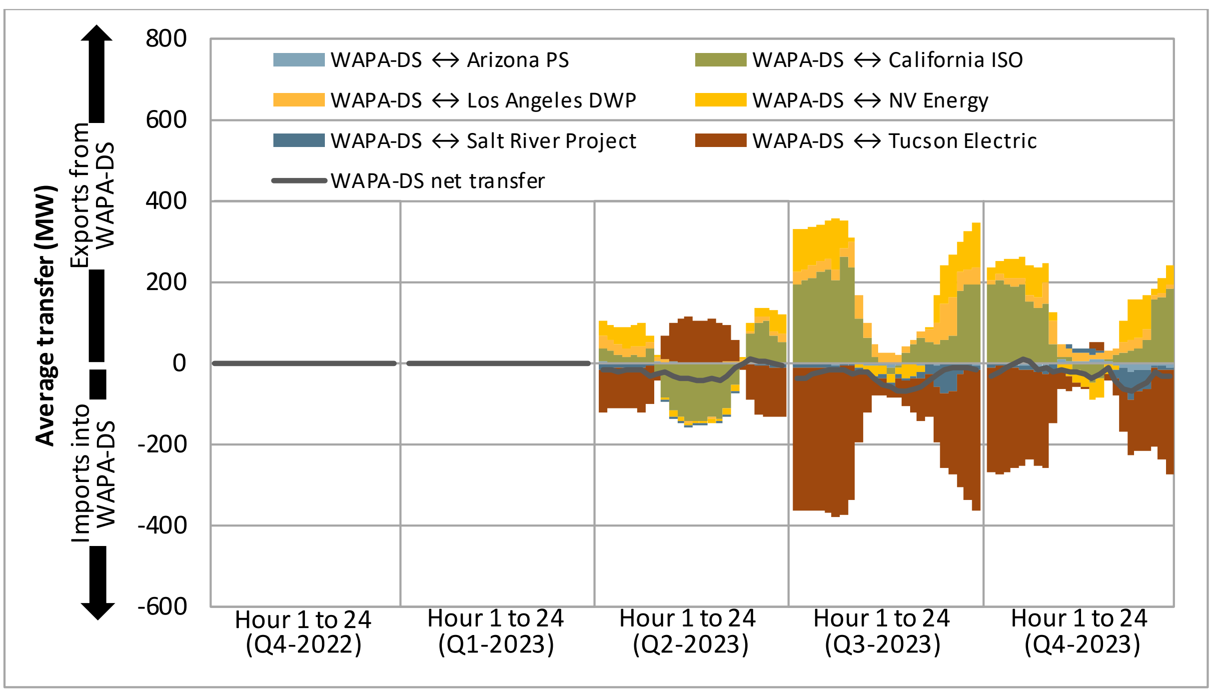


A.23 Western Area Power Administration Desert Southwest

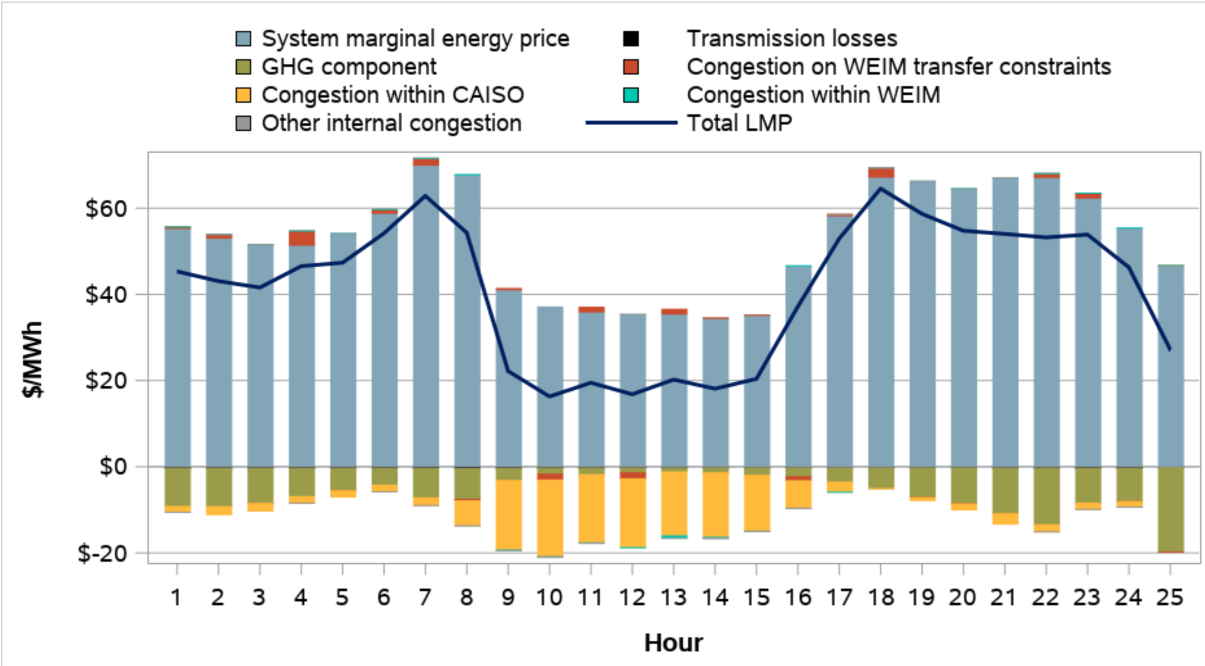
Appendix Figure A.93 Average hourly 15-minute price by component (Q4 2023)



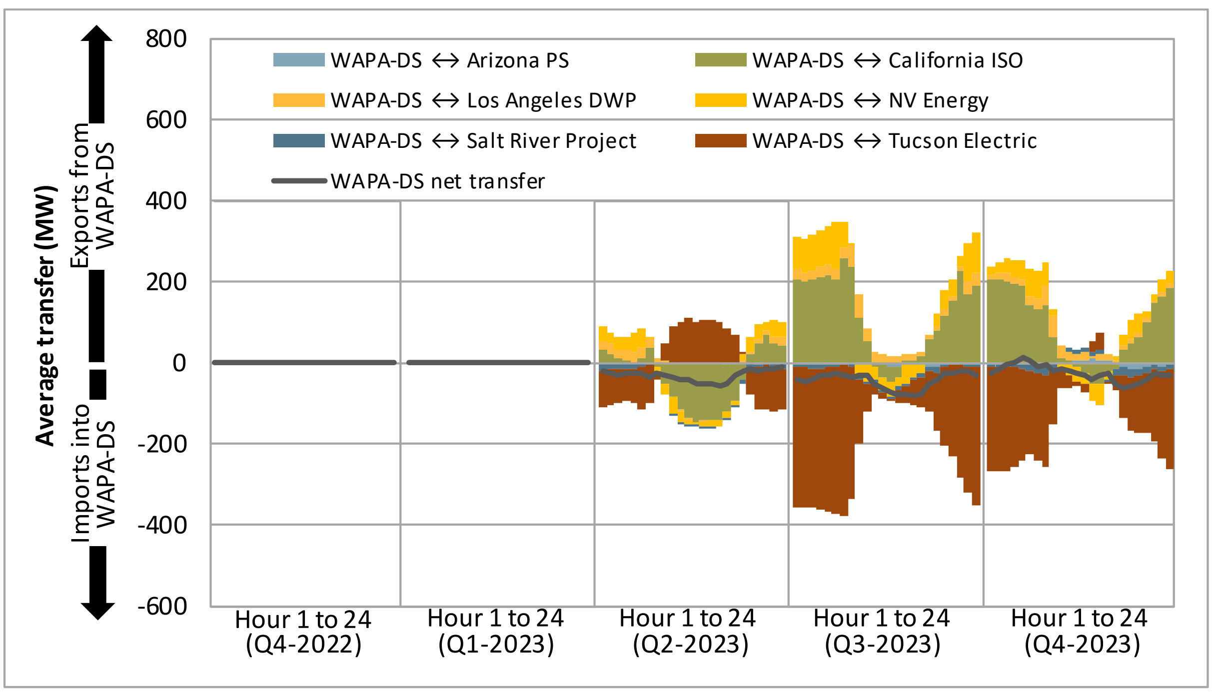
Appendix Figure A.94 Average hourly 15-minute market transfers



Appendix Figure A.95 Average hourly 5-minute price by component (Q4 2023)



Appendix Figure A.96 Average hourly 5-minute market transfers



Appendix B | Internal constraint congestion impact on WEIM

This section summarizes the price impact of internal congestion from individual constraints for each WEIM Load Aggregation Point (LAP). Table B.12 through Table B.15 show the overall impact of internal constraint congestion in the 15-minute market.[75] The WEIM entities are grouped into one of the four tables based on region: California, Desert Southwest, Intermountain West, and Pacific Northwest.[76] The constraints are sorted based on the location of the constraint and descending impact across LAPs in the region.

Color shading is used in the tables to help distinguish patterns in the impacts of constraints. Orange indicates a positive impact to prices, while blue represents a negative impact – the stronger the shading, the greater the impact in either the positive or negative direction.

Highlights for this quarter include:

- The net impact of internal constraint congestion had varied impacts across the WEIM. Overall, congestion lowered prices in the Desert Southwest and raised prices in the rest of the WEIM regions. Notably, internal constraints within the AZPS did not affect price in the Desert Southwest BAAs as significantly as in the fourth quarter of 2022.
- Internal congestion was most impactful in the EPE where it decreased price by $12.2/MWh, as well as in SRP, LADWP, and WALC, where it decreased prices by an average of $6.1/MWh.
- The primary constraints creating price separation in the 15-minute market were the Gates-Midway #1 500 kV line, Tesla-Los Banos #1 500 kV line, and Los Banos-Gates1 #1 500 kV line.

[75] Constraints with price impact of less than $0.01/MWh for all LAPs in the region are grouped in "Other".

[76] These regions reflect a combination of general geographic location, as well as common price-separated groupings that can exist when a balancing area is collectively import or export constrained, along with one or more other balancing areas, relative to the greater WEIM system.

Table B.12 California — Impact of internal constraint congestion on 15-minute market prices (October–December 2023)

Constraint location	Constraint	Average quarter impact ($/MWh)		
		BANC	TIDC	LADWP
BANC	XFMR1 500.OLN	-0.01	0.00	—
BPAT	INTNEL	-0.04	-0.04	-0.03
CISO	30055_GATES1 _500_30060_MIDWAY _500_BR_1 _1	1.46	1.51	-1.75
	30040_TESLA _500_30050_LOSBANOS_500_BR_1 _1	1.33	1.34	-1.58
	30050_LOSBANOS_500_30055_GATES1 _500_BR_1 _2	0.62	0.66	-0.71
	30750_MOSSLD _230_30797_LASAGUIL_230_BR_1 _1	0.12	0.47	-0.43
	24801_DEVERS _500_24804_DEVERS _230_XF_1 _P	0.04	0.05	0.05
	30790_PANOCHE _230_30900_GATES _230_BR_2 _1	0.08	0.11	-0.08
	7820_TL 230S_OVERLOAD_NG	0.00	0.00	0.00
	24801_DEVERS _500_24804_DEVERS _230_XF_2 _P	0.04	0.04	0.04
	30005_ROUND MT_500_30015_TABLE MT_500_BR_2 _2	0.03	0.04	0.02
	6110_COI_S-N	-0.03	-0.03	-0.02
	6110_COI_N-S	0.03	0.03	0.02
	SYLMAR-AC_BG_NG	0.01	0.02	-0.17
	35618_SN JSE A_115_35620_EL PATIO_115_BR_1 _1	—	0.41	—
	7440_MetcalfImport_Tes-Metcalf	0.02	0.04	-0.03
	6410_CP1_NG	-0.02	-0.02	0.02
	32214_RIO OSO _115_32225_BRNSWKT1_115_BR_1 _1	0.03	—	—
	30056_GATES2 _500_30060_MIDWAY _500_BR_2 _1	0.02	0.02	-0.02
	32218_DRUM _115_32222_DTCH2TAP_115_BR_1 _1	0.00	0.00	—
	22846_SANJCP_230-22260_ESCNDO_230-BR1	0.00	0.00	0.00
	99013_CAL CAPS_500_24801_DEVERS _500_BR_1 _1	0.01	0.01	0.01
	30765_LOSBANOS_230_38625_SN LS PP_230_BR_1 _1	0.05	0.13	—
	99002_MOE-ELD _500_24042_ELDORDO _500_BR_1 _2	0.00	0.00	0.00
	7430_CP6_NG	0.10	—	—
	22227_ENCINATP_230_22716_SANLUSRY_230_BR_2 _1	—	—	0.00
	24056_ETIWANDA_230_24901_VSTA _230_BR_1 _1	—	0.00	0.00
	32214_RIO OSO _115_32244_BRNSWKT2_115_BR_2 _1	0.00	—	—
	30765_LOSBANOS_230_30766_PADR FLT_230_BR_1A _1	0.00	0.02	0.00
LADWP	ATW_VEL 1	—	—	0.03
	FAR_AIR 2 o	—	—	-0.02
	TAR BK E	—	—	0.01
[redacted]	Other	0.02	0.03	-0.01
Total	Total	3.91	4.84	-4.65

Table B.13 Desert Southwest — Impact of internal constraint congestion on 15-minute market prices (October–December 2023)

Constraint location	Constraint	Average quarter impact ($/MWh)						
		AZPS	EPE	NEVP	PNM	SRP	TEPC	WALC
AZPS	Line_CC-GT_230KV	0.06	—	—	0.00	—	—	—
	LSS XFMR10 A 230KV	0.04	—	—	—	—	—	—
	Line_OC-LSS_230KV	-0.01	—	—	—	—	—	—
	OC XFMR1 A 69KV	0.01	—	—	—	—	—	—
BPAT	INTNEL	-0.03	-0.03	-0.03	-0.03	-0.03	-0.03	-0.03
CISO	30055_GATES1 _500_30060_MIDWAY _500_BR_1 _1	-1.54	-1.42	-0.93	-1.36	-1.54	-1.50	-1.54
	30040_TESLA _500_30050_LOSBANOS_500_BR_1 _1	-1.39	-1.27	-0.82	-1.21	-1.38	-1.35	-1.39
	30050_LOSBANOS_500_30055_GATES1 _500_BR_1 _2	-0.62	-0.57	-0.38	-0.54	-0.62	-0.60	-0.62
	7820_TL 50002_IV-NG-OUT_TDM	-0.52	-0.35	—	-0.02	-0.42	-0.43	-0.54
	30750_MOSSLD _230_30797_LASAGUIL_230_BR_1 _1	-0.27	-0.11	—	-0.06	-0.26	-0.22	-0.27
	24801_DEVERS _500_24804_DEVERS _230_XF_1 _P	-0.26	-0.23	-0.04	-0.21	-0.27	-0.24	-0.22
	OMS_14369435_Miguel_BK80	-0.21	-0.18	—	-0.17	-0.21	-0.20	-0.20
	30790_PANOCHE _230_30900_GATES _230_BR_2 _1	-0.07	-0.05	0.00	-0.03	-0.07	-0.07	-0.07
	7820_TL 230S_OVERLOAD_NG	-0.14	-0.13	-0.05	-0.12	-0.15	-0.15	-0.14
	24801_DEVERS _500_24804_DEVERS _230_XF_2 _P	-0.13	-0.11	-0.03	-0.10	-0.14	-0.12	-0.11
	22886_SUNCREST_230_22885_SUNCREST_500_XF_2 _P	-0.15	-0.13	-0.02	-0.12	-0.16	-0.14	-0.14
	OMS_14330422_Miguel_BK81	-0.13	-0.11	—	-0.10	-0.13	-0.13	-0.12
	30005_ROUND MT_500_30015_TABLE MT_500_BR_2 _2	0.02	0.02	0.01	0.02	0.02	0.02	0.02
	OMS 14384679_50001_OOS_NG	-0.11	-0.10	-0.03	-0.09	-0.11	-0.11	-0.10
	6110_COI_S-N	-0.02	-0.02	-0.01	-0.02	-0.02	-0.02	-0.02
	6110_COI_N-S	0.01	0.01	0.01	0.01	0.01	0.01	0.01
	MIGUEL_BKs_MXFLW_NG	-0.09	-0.08	—	-0.07	-0.09	-0.09	-0.09
	SYLMAR-AC_BG_NG	-0.02	-0.02	-0.02	-0.02	-0.02	-0.02	-0.02
	22464_MIGUEL _230_22468_MIGUEL _500_XF_81	-0.07	-0.06	—	-0.06	-0.07	-0.07	-0.07
	7440_MetcalfImport_Tes-Metcalf	-0.02	-0.02	-0.02	-0.02	-0.02	-0.02	-0.02
	6410_CP1_NG	0.02	0.02	0.01	0.01	0.02	0.02	0.02
	OMS 14384680_50001_OOS_NG	-0.05	-0.05	-0.01	-0.04	-0.05	-0.05	-0.05
	32214_RIO OSO _115_32225_BRNSWKT1_115_BR_1 _1	—	—	-0.27	—	—	—	—
	30056_GATES2 _500_30060_MIDWAY _500_BR_2 _1	-0.02	-0.01	-0.01	-0.01	-0.02	-0.02	-0.02
	OMS 14407105_50001_OOS_NG	-0.04	-0.04	-0.01	-0.04	-0.05	-0.04	-0.04
	32218_DRUM _115_32222_DTCH2TAP_115_BR_1 _1	—	—	-0.26	—	—	—	—
	22846_SANJCP_230-22260_ESCNDO_230-BR1	-0.05	-0.04	—	-0.03	-0.05	-0.04	-0.04
	99013_CAL CAPS_500_24801_DEVERS _500_BR_1 _1	-0.04	-0.03	-0.01	-0.03	-0.04	-0.04	-0.03
	OMS_14291578_SUNCREST BK80_NG	-0.04	-0.03	—	-0.03	-0.04	-0.04	-0.04
	OMS 14204875 ML_BK80_NG	-0.04	-0.03	—	-0.03	-0.04	-0.03	-0.04
	22260_ESCNDIDO_230_22844_TALEGA _230_BR_1 _1	-0.02	-0.02	—	-0.02	-0.02	-0.02	-0.02
	OMS 14407117_50001_OOS_NG	-0.02	-0.02	-0.01	-0.02	-0.02	-0.02	-0.02
	99002_MOE-ELD _500_24042_ELDORDO _500_BR_1 _2	-0.01	-0.02	0.00	-0.02	-0.01	-0.01	-0.01
	7820_TL23040_IV_SPS_NG	-0.02	-0.01	0.00	-0.01	-0.02	-0.02	-0.02
	22227_ENCINATP_230_22716_SANLUSRY_230_BR_2 _1	-0.01	-0.01	—	-0.01	-0.01	-0.01	-0.01
	7820_13810A_OVERLOAD_NG	-0.01	-0.01	—	-0.01	-0.01	-0.01	-0.01
	24056_ETIWANDA_230_24901_VSTA _230_BR_1 _1	-0.01	-0.01	—	-0.01	-0.01	-0.01	-0.01
	32214_RIO OSO _115_32244_BRNSWKT2_115_BR_2 _1	—	—	-0.03	—	—	—	—
PNM	115kv LK	—	-7.12	—	—	—	—	—
	115kv Pic Fro	—	0.09	—	-0.08	—	—	—
	115kv EB Fron	—	0.11	—	-0.06	—	—	—
	ABO S_COMP_WESP1	—	0.05	—	0.01	—	—	—
[redacted]	Other	-0.05	-0.06	-0.04	-0.04	-0.05	-0.05	-0.05
Total	Total	-6.07	-12.20	-3.00	-4.79	-6.10	-5.87	-6.07

Table B.14 Intermountain West — Impact of internal constraint congestion on 15-minute market prices (October–December 2023)

Constraint location	Constraint	Average quarter impact ($/MWh)			
		AVA	IPCO	NWMT	PACE
BANC	XFMR1 500.OLN	0.00	0.00	0.00	—
BPAT	INTNEL	-0.01	-0.03	—	-0.03
CISO	30055_GATES1 _500_30060_MIDWAY _500_BR_1 _1	0.95	0.36	0.74	-0.27
	30040_TESLA _500_30050_LOSBANOS_500_BR_1 _1	0.98	0.46	0.79	-0.18
	30050_LOSBANOS_500_30055_GATES1 _500_BR_1 _2	0.45	0.21	0.38	-0.07
	24801_DEVERS _500_24804_DEVERS _230_XF_1 _P	—	—	—	-0.04
	OMS_14369435_Miguel_BK80	—	—	—	0.00
	30790_PANOCHE _230_30900_GATES _230_BR_2 _1	0.03	—	0.00	—
	7820_TL 230S_OVERLOAD_NG	—	0.00	—	-0.04
	24801_DEVERS _500_24804_DEVERS _230_XF_2 _P	—	—	—	-0.04
	22886_SUNCREST_230_22885_SUNCREST_500_XF_2 _P	—	—	—	-0.03
	30005_ROUND MT_500_30015_TABLE MT_500_BR_2 _2	-0.04	-0.02	-0.03	-0.01
	OMS 14384679_50001_OOS_NG	—	—	—	-0.01
	6110_COI_S-N	0.03	0.02	0.03	0.01
	6110_COI_N-S	-0.03	-0.02	-0.03	-0.01
	SYLMAR-AC_BG_NG	0.00	0.00	—	-0.01
	7440_MetcalfImport_Tes-Metcalf	0.01	—	0.01	—
	6410_CP1_NG	-0.01	-0.01	-0.01	0.00
	OMS 14384680_50001_OOS_NG	—	—	—	0.00
	30056_GATES2 _500_30060_MIDWAY _500_BR_2 _1	0.01	0.01	0.01	0.00
	OMS 14407105_50001_OOS_NG	—	—	—	-0.01
	99013_CAL CAPS_500_24801_DEVERS _500_BR_1 _1	—	—	—	-0.01
	OMS_14291578_SUNCREST BK80_NG	—	—	—	0.00
	OMS 14407117_50001_OOS_NG	—	—	—	-0.01
	99002_MOE-ELD _500_24042_ELDORDO _500_BR_1 _2	—	—	—	0.00
PACE	TOTAL_WYOMING_EXPORT	—	—	—	-1.42
	WINDSTAR EXPORT TCOR	—	—	—	-1.37
	EAST_WYO_EXP	—	—	—	-0.21
[redacted]	Other	0.02	0.01	0.01	-0.03
Total	Total	2.39	0.99	1.90	-3.79

Table B.15 Pacific Northwest — Impact of internal constraint congestion on 15-minute market prices (October–December 2023)

Constraint location	Constraint	Average quarter impact ($/MWh)							
		AVRN	BCHA	BPAT	PACW	PGE	PSEI	SCL	TPWR
BANC	XFMR1 500.OLN	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
BPAT	INTNEL	-0.02	0.20	0.00	-0.04	-0.04	0.06	0.13	-0.02
CISO	30055_GATES1 _500_30060_MIDWAY _500_BR_1 _1	1.06	0.99	1.03	1.08	1.06	1.02	1.01	1.02
	30040_TESLA _500_30050_LOSBANOS_500_BR_1 _1	1.19	1.02	1.04	1.10	1.08	1.04	1.04	1.04
	30050_LOSBANOS_500_30055_GATES1 _500_BR_1 _2	0.50	0.46	0.47	0.49	0.48	0.47	0.47	0.47
	30750_MOSSLD _230_30797_LASAGUIL_230_BR_1 _1	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	30790_PANOCHE _230_30900_GATES _230_BR_2 _1	0.06	0.04	0.05	0.06	0.05	0.04	0.04	0.04
	24801_DEVERS _500_24804_DEVERS _230_XF_2 _P	0.02	—	—	0.00	0.00	—	—	—
	30005_ROUND MT_500_30015_TABLE MT_500_BR_2 _2	-0.05	-0.04	-0.04	-0.04	-0.04	-0.04	-0.04	-0.04
	6110_COI_S-N	0.04	0.03	0.03	0.03	0.03	0.03	0.03	0.03
	6110_COI_N-S	-0.04	-0.03	-0.04	-0.04	-0.04	-0.03	-0.03	-0.03
	SYLMAR-AC_BG_NG	0.01	0.00	0.01	0.01	0.01	0.00	0.00	0.00
	7440_MetcalfImport_Tes-Metcalf	0.02	0.01	0.01	0.01	0.01	0.01	0.01	0.01
	6410_CP1_NG	-0.02	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01
	30056_GATES2 _500_30060_MIDWAY _500_BR_2 _1	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
	99013_CAL CAPS_500_24801_DEVERS _500_BR_1 _1	0.00	—	—	—	—	—	—	—
	99002_MOE-ELD _500_24042_ELDORDO _500_BR_1 _2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	30765_LOSBANOS_230_30766_PADR FLT_230_BR_1A _1	0.00	—	—	—	—	—	—	—
PGE	MRHL_SHWD_V1607	-0.01	0.02	0.02	—	0.06	0.03	0.03	0.03
[redacted]	Other	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Total	Total	2.80	2.72	2.60	2.68	2.68	2.65	2.71	2.57