PERFORMANCE OF ISO'S SYSTEM DURING OCTOBER 14, 2023 ECLIPSE

December 13, 2023

California ISO

The following members of the CAISO contributed to the analysis of this report:

Timothy Beach

Kevin Head

Zhu Liang

Clyde Loutan

Michael Martin

Lysha Matsunobu

Amber Motley

Brian Murray

Aung Oo

John Rudolph

Zachary Ricciardulli

Hudson Sangree

Miheer Shah

Jessica Stewart

Tobiah Steckel

Katie Wikler

Kun Zhao

Hong Zhou

Abhishek Hundiwale

Contents

List of Figures 5
Acronyms 7
Executive Summary 9
Introduction 11
Solar Eclipse 11
Impacts to ISO Load and Renewables 13
Grid-Scale Solar Reduction 13
Temperature and Wind Impacts 16
CAISO Load Forecast 19
CAISO Forecast Zone Case Study 22
Net Load 23
Impacts to WEIM Load and Renewables 25
WEIM Load Forecast 29
WEIM Entity Case Study 32
Uncertainty Requirements 33
RUC Adjustments 33
Regulation Requirements 34
Flex Ramp Product Requirements 35
Market Performance 39
Market prices 39
Regulation 42
Curtailments 48
Resource performance 49
Generation Mix 51
Storage Performance 52
Flexible Ramping Product 58
Net Schedule Interchange 63
WEIM Transfers 65

Exceptional Dispatches ... 68
Operational Performance ... 70
Control Performance Standard (CPS1) ... 74

List of Figures

Figure 1 A map of the October 14, 2023 annular eclipse path and percent obscuration across the US 12
Figure 2: Cloud cover on October 14, 2023 14
Figure 3: October 14, 2023 eclipse solar production 15
Figure 4: Comparing the DA, HASP, FMM and RTD forecasts for the eclipse. 16
Figure 5: Sacramento hourly observed temperatures for October 13-15, 2023 18
Figure 6: Average wind speed and direction for selected 10 sites 18
Figure 7 CAISO DA+7 through T-120 load forecasts and actuals during eclipse timeframe 20
Figure 8 CAISO HASP through RTD load forecasts and actuals during eclipse timeframe 20
Figure 9 CAISO BTM solar forecasts and actuals throughout eclipse day 21
Figure 10 CAISO forecast zone Day Ahead model suite performance and published forecast 23
Figure 11 CAISO net load impact from eclipse during ramping period 24
Figure 12 Eclipse net load ramp rates compared to 2023 actual ramp rates 25
Figure 13 The WEIM grid-connected solar impacts on the eclipse day compared to a recent clear sky day. 26
Figure 14 WEIM regional BTM solar forecasts and BTM solar actuals 27
Figure 14 WEIM regional Day Ahead forecast, T-120 forecast, and load actuals 30
Figure 15 WEIM regional T-60 through RTD forecasts and load actuals 31
Figure 16 WEIM entity T-60 forecast performance across model suite 33
Figure 17 RUC adjustments and realized uncertainty 34
Figure 18 Comparison of regulation procured to regulation needed 35
Figure 19 FRP for CISO FMM market 37
Figure 20 FRP for CISO RTD market 37
Figure 21 FRP for EIM BAA area in FMM market 38
Figure 22 FRP for EIM BAA area in RTD market 38
Figure 23 Hourly average DLAP prices by market 40
Figure 24. Hourly average WEIM ELAP prices by geographical region, FMM 41
Figure 25. Hourly average WEIM ELAP prices by geographical region, RTD 41
Figure 26 Regulation up (Ru) requirement and prices in day-ahead (IFM) 42
Figure 27 Regulation down (Rd) requirement and prices in the day-ahead (IFM) 43
Figure 28 Regulation up (Ru) requirement and prices in real-time market (FMM) 44
Figure 29 Regulation down (Rd) requirement and prices in real-time market (FMM) 44
Figure 30. Day-ahead regulation up and down costs 45
Figure 31. Real-time regulation up and down costs 46
Figure 32. Day-ahead regulation costs, September 1 through October 31 46
Figure 33. Real-time regulation costs, September 1 through October 31 47
Figure 34. Daily regulation costs, September 1 through October 31 47
Figure 35 Hourly average VERs curtailment comparing over three days 48

Figure 36 DOT vs actual production for solar production 50
Figure 37 Solar production with curtailments vs load for October 14 50
Figure 38 Comparison of Load, Net Load, Solar and Wind production for October 14 51
Figure 39 Generation Mix of the energy produced 52
Figure 40 State of charge, RUC vs. RTD 53
Figure 41 Energy Schedules, RUC vs. RTD 54
Figure 42 RTD energy awards for storage resources and RTD SMEC 55
Figure 43 Day-ahead (IFM) AS awards 56
Figure 44 Real Time (FMM) AS awards 57
Figure 45: Hybrid and co-located resource performance 58
Figure 46 FRU passing group requirement vs. procurement 59
Figure 47 FRU procurement by region 60
Figure 48 FRU procurement by resource type 60
Figure 49 FRD requirement vs. procurement 61
Figure 50 FRD procurement by region 62
Figure 51 FRD procurement by resource type 62
Figure 52: Net schedule interchange in RTD for October 13 through 15 63
Figure 53: Net schedule interchange by market for October 14 64
Figure 54: Net schedule interchange in RTD by major intertie for October 14 65
Figure 55: Dynamic WEIM Transfer Volume for CAISO, FMM, October 13 to October 15 66
Figure 56: Dynamic WEIM Transfer Volume for CAISO, RTD, October 13 to October 15 66
Figure 57: Dynamic WEIM Transfer Volume for WEIM Participants by Region, FMM, October 13 to October 15 67
Figure 58: Dynamic WEIM Transfer Volume for WEIM Participants by Region, RTD, October 13 to October 15 68
Figure 59: Exceptional Dispatch volumes by hour on October 14 69
Figure 60: Exceptional Dispatch volumes by day from October 7 to 21 70
Figure 61: Solar Production vs. Frequency 71
Figure 62: Solar Production vs. ACE 72
Figure 63: Solar Production During the Eclipse 73
Figure 64: CAISO’s Demand vs. Solar Production 74
Figure 65: CAISO’s Solar Production vs. Control Performance Standard 1 (CPS1) 75
Figure 66: ACE vs Frequency 76

Acronyms

ACE	Area Control Error
AGC	Automatic Generation Control
AVA	Avista
AVRN	Avangrid
AZPS	Arizona Public Service
BAA	Balancing Authority Area
BANC	Balancing Authority of Northern California
BPA	Bonneville Power Authority
BTM	Behind the Meter rooftop solar
CPS1	Control Performance Standard
DLAP	Default Load Aggregated Point
DOT	Dispatch Operating Point
ELAP	EIM Load Aggregation Point
EPE	El Paso Electric
F	Fahrenheit
FMM	Fifteen Minute Market
FRD	Flexible Ramp down
FRP	Flexible Ramp Product
FRU	Flexible Ramp up
FSP	Forecast Service Provider
GNRC	Generic non-generating resource
HASP	Hour Ahead Scheduling Process
HE	Hour Ending
IFM	Integrated Forward Market
IPCO	Idaho Power Company
ISO	California Independent System Operator
LADWP	Los Angeles Department of Water and Power
LESR	Limited Energy Storage Resource
LMP	Locational Marginal Price
LSE	Load Serving Entity
MW	Megawatt
MWh	Megawatt-hour
NEVP	NV Energy
NGR	Non-Generating resource
NOB	Nevada-Oregon Border
NR	Non-Spinning Reserve
NSI	Net Scheduled Interchange
NWMT	Northwestern Energy
OASIS	Open Access Same-Time Information System
OR	Operating Reserves

PACE	PacifiCorp East
PACW	PacifiCorp West
PDT	Pacific Daylight Time
PGE	Portland General Electric
PNM	Public Service Company of New Mexico
PSE	Puget Sound Energy
PV	Photovoltaic
RCWEST	Reliability Coordinator West
RD	Regulation down
RTD	Real Time Dispatch (5-min) market
RTM	Real-Time Market
RU	Regulation up
RUC	Residual Unit Commitment
SCL	Seattle City Light
SMEC	System Marginal Energy Component
SOC	State of Charge
SR	Spinning Reserve
SRP	Salt River Project
TEPC	Tucson Electric Power
TIDC	Turlock Irrigation District
TPWR	Tacoma Power
VER	Variable Energy Resource
WALC	WAPA Desert Southwest Region
WEIM	Western Energy Imbalance Market
WECC	Western Electricity Coordinating Council

Executive Summary

On the morning of October 14, 2023, an annular solar eclipse passed over the Western United States, darkening large swaths of Oregon, California, Nevada, Utah, Arizona and New Mexico.

The last solar eclipse in 2017 was a total eclipse, also in the morning. In contrast, an annular eclipse leaves a ring of light visible around the dark circle of the moon. This year's annular eclipse had a bigger impact than the 2017 eclipse because of large increases in solar power in the California Independent System Operator (ISO) and the Western Energy Imbalance Market (WEIM) in the past six years.

This report details the system and market performance of the ISO and the impacts to the WEIM, Reliability Coordinator West (RC West) and other balancing authority areas (BAAs) because of the loss of solar generation during the eclipse. Notable findings include the following.

The eclipse affected the WEIM from 8 a.m. to 11 a.m. Pacific Daylight Time (PDT). Across the WEIM's footprint, which covers much of the West, the moon obscured 65% to 90% of the sun's light depending on location.

The ISO BAA experienced the eclipse in the same timeframe, with maximum impact at 9:30 a.m. The sun was obscured by 68% along the Southern California coast and by 89% in Northern California. The reduction in solar radiation directly affected the output of photovoltaic (PV) generating facilities, behind-the-meter (BTM) rooftop solar, and load and net load within the ISO and WEIM areas.

The growth in solar generation since 2017 exacerbated the eclipse's effects. Grid-scale solar grew from 10,000 MW in 2017 to 16,500 MW in 2023, and behind-the-meter solar surged from 5,700 MW to 14,350 MW in the same timeframe. Among WEIM entities, grid-scale solar increased from 866 MW in 2017 to 10,280 MW in 2023, and behind-the-meter solar rose from 738 MW to 6,458 MW.

In partnership and coordination with entities in the West, the ISO prepared for months for the eclipse and closely monitored its effects across the region. In particular, the ISO took proactive measures to manage the eclipse conditions effectively. These included additional procurement for regulation, charging storage resources ahead of time, additional procurement of day-ahead commitment capacity, and tighter control bands to balance the system in real time.

The solar eclipse impacted load, solar production and behind-the-meter supply. The partial obscuration of the sun increased load by 2,064 MW. When the obscuration subsided and output of rooftop solar returned to normal levels, load decreased by 5,738 MW.

The change in the ISO's grid-scale solar generation during the eclipse was about 1,000 MW greater than in 2017. In 2017, solar production dropped from 6,392 MW at the start of the eclipse to 2,845 MW during maximum obscuration – a difference of 3,547 MW. On October 14, solar generation fell from 7,731 MW to 3,231 MW – a difference of 4,500 MW. Solar generation then returned to full production of 9,721 MW at the end of the eclipse.

As solar production and load experienced steep changes, other supply technologies — including gas-fired plants, hydropower, imports and storage resources — offset these changes. Battery storage resources, which have increased dramatically in the ISO in the past three years, played a role in offsetting the eclipse's effects. Storage resources provided about 1,500 MW of capacity in real time. Storage resources also supplied a significant portion of regulation capacity.

The ISO's market performed effectively to consider the eclipse effects and efficiently dispatch resources. It managed solar production effectively, requiring instances of solar curtailments to manage the expected ramps. It awarded imports accordingly to compensate for supply changes. Prices changed according to conditions, increasing when supply was limited because of the loss of solar production.

During the eclipse, the WEIM proved to be an effective mechanism to manage conditions throughout its Western footprint by determining optimal transfers in its areas when those transfers were needed most. Overall, WEIM transfers reflected the economic and operational benefits that the interstate market offers to participating entities by maximizing supply diversity and transferring supply from where it was available to where it was required in real-time. The WEIM transfers out of the ISO area dipped to 1,165 MW at maximum obscuration, then bounced back to 3,185 MW at the end of the eclipse.

WEIM regions had varying eclipse impacts on renewables generation and load depending on levels of installed grid-scale solar and BTM rooftop solar. The Desert Southwest and Central regions saw the largest impacts to load, with respective differences of 1,273 MW and 853 MW between eclipse maximum and post-eclipse minimum.

Introduction

The ISO navigated the impacts of the annular solar eclipse through coordinated efforts among teams within the ISO and close coordination with market participants and balancing authorities in the WEIM footprint. This report details the impacts observed on October 14 and how the measures described by the ISO in its August 31 Solar Eclipse Technical Bulletin assisted with navigating the eclipse. It provides an analysis of market performance and operational performance during the solar eclipse event.

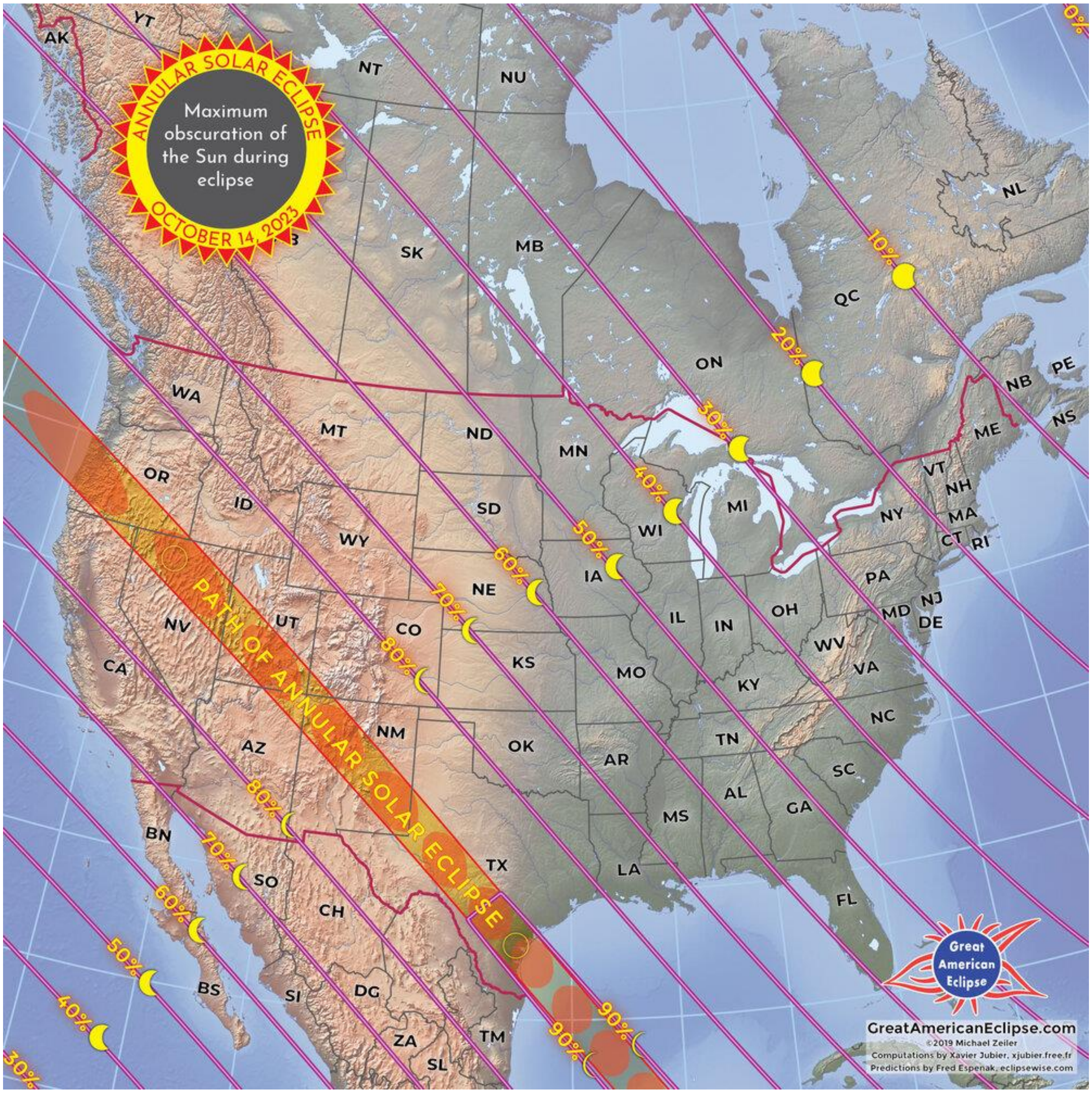
Solar Eclipse

On October 14, 2023 an annular solar eclipse passed over the Western United States

Large areas of Oregon, Nevada, Utah and New Mexico experienced the maximum effects of the eclipse. Smaller areas of California and Arizona saw the full annular eclipse; other parts of the states experienced a partial eclipse. Across the WEIM, the maximum solar obscuration varied from 65-90% depending on the distance from the path of annularity. Major solar production areas of California were affected by a partial eclipse between 8:05 a.m. and 11:00 a.m.

Figure 1 shows the path of the annular eclipse across the United States. The northern and southern path limits of areas experiencing annularity are shown between the red lines with yellow shading. Areas outside of the annular line, such as most of California, experienced varying amounts of partial eclipse based on distance from the central path, which is denoted by the percentages throughout the map.

Figure 1 A map of the October 14, 2023 annular eclipse path and percent obscuration across the US



Impacts to ISO Load and Renewables

Grid-Scale Solar Reduction

Solar obscuration defines the solar irradiance reduction striking the earth at a given location such as a PV solar site. As these locations get farther from the central path of the eclipse, the percentage of solar obscuration lessens. PV solar site production was reduced during the eclipse by the amount of solar obscuration. The solar eclipse began when the PV solar sites were ramping up to the maximum amount of daily production and ended when the sites were entering their midday peak of daily production. Production was reduced from the time the eclipse started around the solar sites in Northern California. As the eclipse waned, the solar production returned at a much greater ramp rate than normal from 9:30 a.m. to 10:20 a.m. because the sun angle continued to increase during the time the sun was obscured. For the period of 10:20 a.m. to 11:00 a.m., supplemental dispatch and follow Dispatch Operating Target (DOT) instructions sent to many of the solar resources impacted the output across the fleet. This helped to moderate the rate of solar ramping that came back on after the eclipse maximum period.

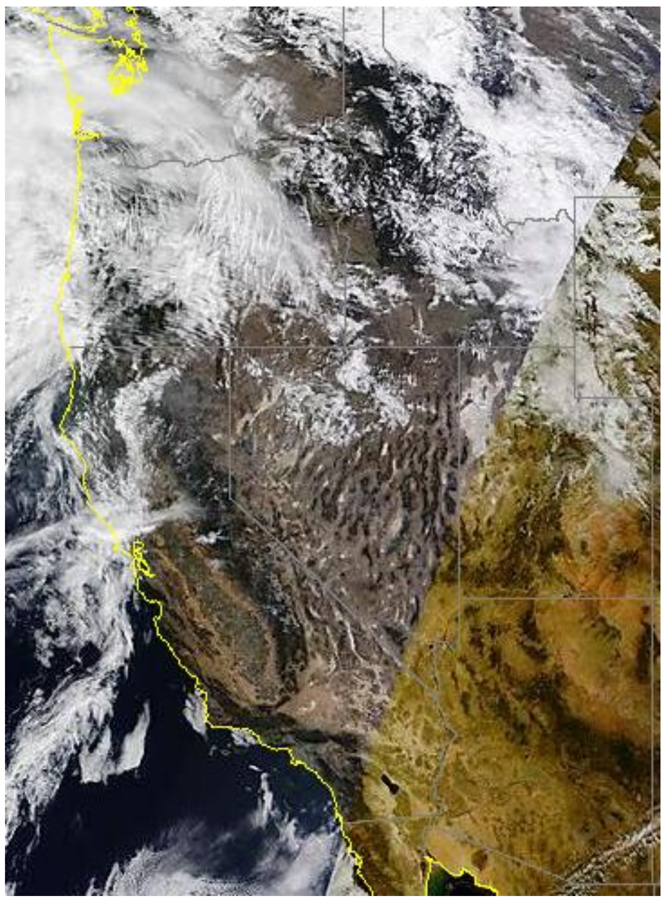
Table 1: The start, maximum, and end times of the eclipse for the different grid-scale PV solar within the CAISO BAA and the approximate reductions in output at those times

Forecast Area	Eclipse Start Time (a.m.)	Eclipse Max Time (a.m.)	Eclipse End Time (a.m.)	Eclipse Max Obscuration	Oct. 2023 Regional Capacity	Forecast Area Production at Eclipse Max[1]		Observed Area Production at Eclipse Max	
					MW	% of CAP	MW	% of Cap	MW
N. San Joaquin	8:05	9:20	10:43	80%	305	12%	38	6%	18
S. San Joaquin	8:06	9:22	10:46	75%	4,355	16%	693	16%	689
Mojave	8:07	9:24	10:50	73%	4,141	20%	812	19%	767
LA Basin	8:08	9:25	10:51	72%	266	13%	34	13%	35
Coachella/Imperial Valley	8:09	9:27	10:55	72%	2,635	23%	608	17%	445
S. Nevada	8:08	9:27	10:54	81%	1,407	15%	218	11%	158
Colorado River Valley	8:09	9:27	10:55	75%	2,241	19%	420	26%	573
Yuma	8:09	9:29	10:57	78%	1,115	18%	202	15%	172
							3,023		**2,857**

[1] The MW sum for the "area production at the eclipse maximum" (minimum area production) and "area production at eclipse end" are less than the minimum area production and production at the eclipse end time represented on the graph due to the eclipse maximum and times varying by each region.

Using the data from Table 1, the ISO calculated[2] the approximate amount of solar energy expected to be produced on October 14, assuming a full sun day with no clouds. The table compares the forecasted eclipse impact with the observed impact. There were some regions, such as the southern San Joaquin Valley, the Los Angeles Basin and Yuma where the forecasts at the eclipse time were very close to the observation. Other areas such as the northern San Joaquin and the Coachella/Imperial Valley came in lower than the preliminary eclipse forecast. The observed cloud cover on the eclipse day is shown below in Figure 2. For the northern San Joaquin region, cloud cover on the morning of the eclipse likely played a role in the actuals coming in lower than the preliminary forecast. Other regions that were full sun and saw the observations come in lower than forecast were likely due to the preliminary forecasts not incorporating detailed weather forecasts.

Figure 2: Cloud cover on October 14, 2023[3]



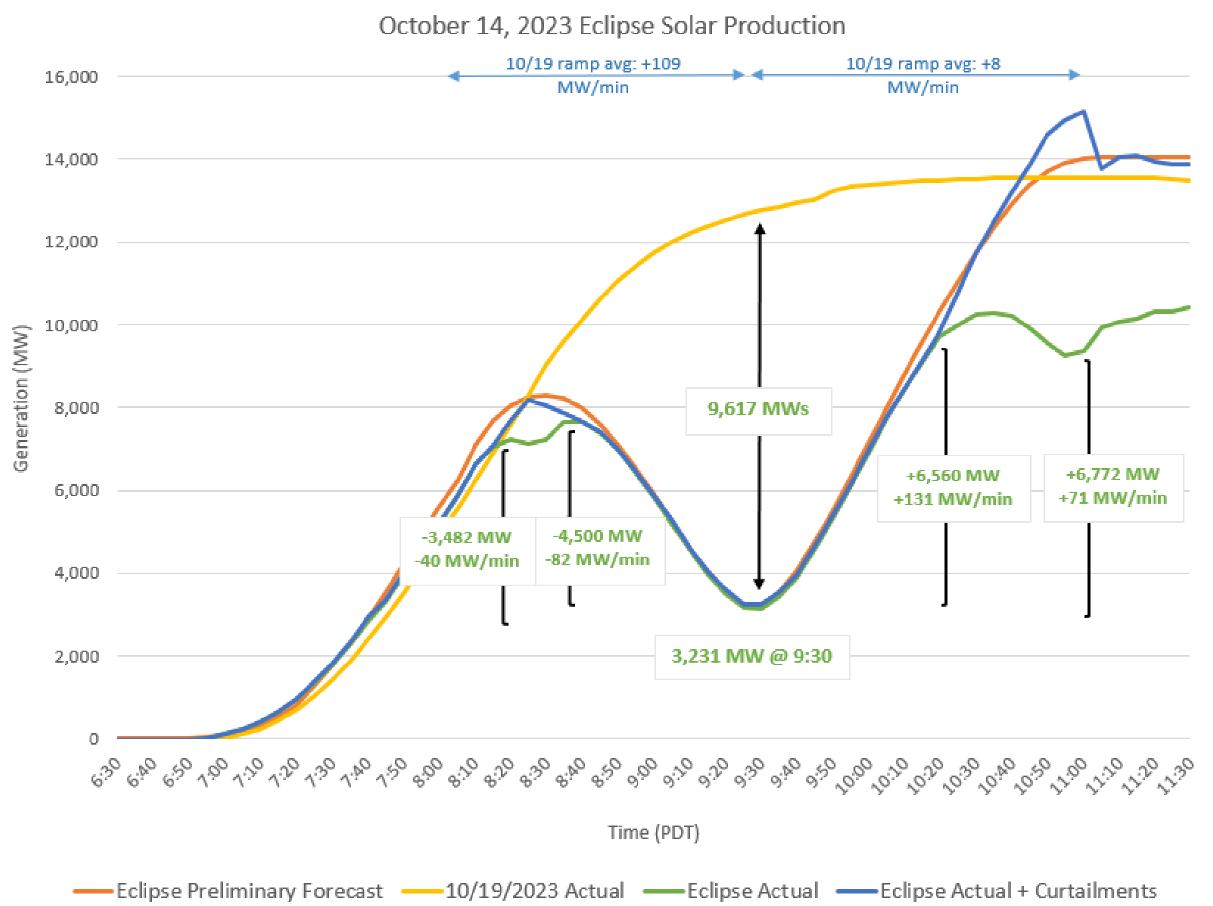
As illustrated in Figure 3, a reduction of 3,482 MW was observed for the period of 8:10 a.m. through the eclipse maximum at 9:30 a.m., with a ramp rate of -40 MW per minute. In comparison, on October 19, a

[2] Based on approximate gen at eclipse maximum time from October 14, 2022, adjusted for capacity updates between 2022-2023 then adjusted for the eclipse max percent obscuration.

[3] https://ge.ssec.wisc.edu/modis-today/index.php?satellite=t1&product=true_color&date=2023_10_14_287

recent sunny day, the average ramp rate during this period was +109 MW per minute. For the period of 8:05 a.m. through 8:30 a.m., although the eclipse had begun, solar generation continued to increase because the amount of solar irradiance reaching the surface was still increasing due to the angle of the sun rising in the sky. Because this was a partial solar eclipse, solar production didn't stop completely but was reduced by 9,617 MW compared to a clear sky day, reaching a minimum of 3,231 MW at 9:30 a.m.

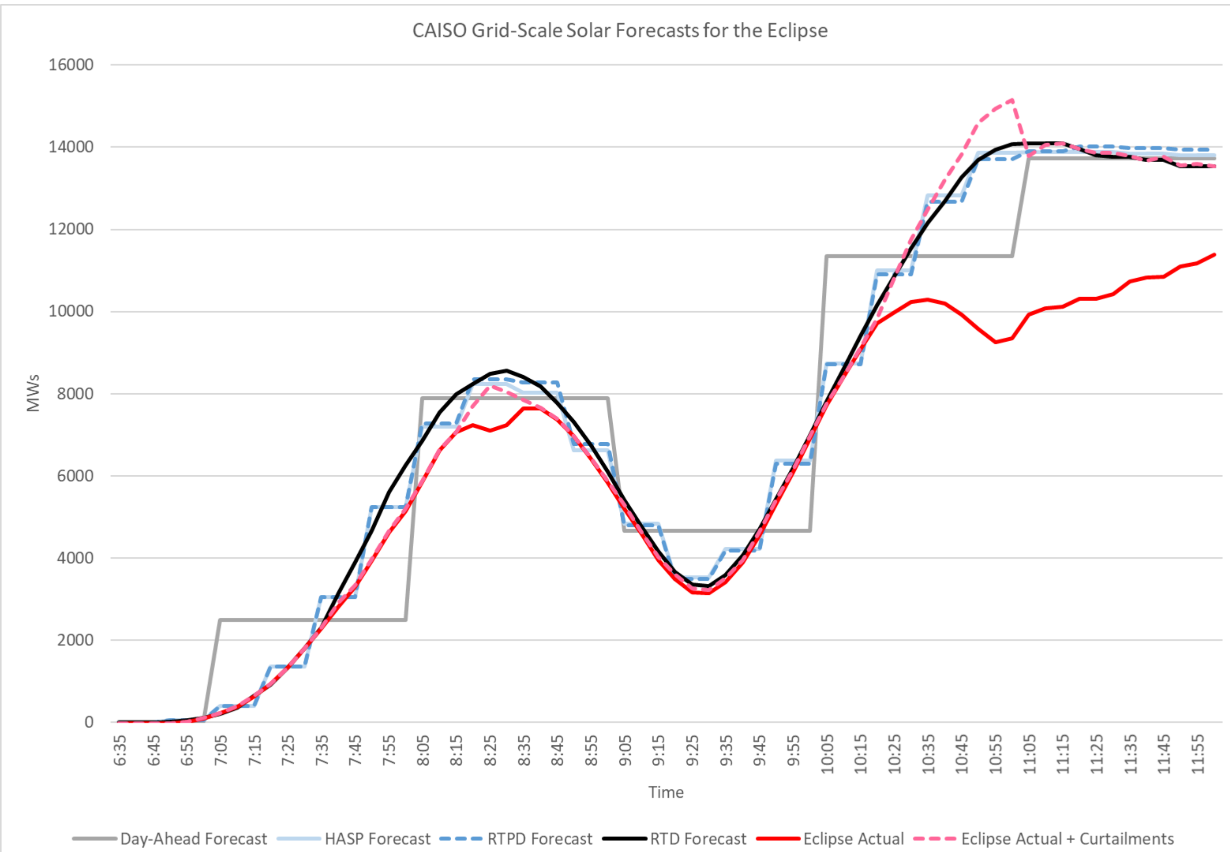
Figure 3: October 14, 2023 eclipse solar production



As the eclipse waned, the return to normal production caused an average ramp-up of +131 MW per minute for the period of 9:30 a.m. to 10:20 a.m. All ramp rates are an average MW per minute over a given period. On a sunny day, the typical ramp-up during this 50-minute period is 15 MW per minute. After 10:20 a.m., solar curtailments were present across the system, limiting the ramping of the solar output through the end of the eclipse at 11 a.m. For the full eclipse ramp-up period of 9:30 a.m. to 11 a.m., the average ramp-up was +71 MW per minute. On a recent full sun day, the average ramp rate during the same period was +8 MW per minute.

Looking the solar observations compared to various forecast horizons in Figure 4, there was some slight over-forecasting for the solar maximum before going into the ramp-down due to the eclipse. However, the HASP, FMM and RTD forecasts more accurately predicted the minimum solar generation at the eclipse obscuration maximum around 9:30 a.m. The day-ahead forecast over-forecasted the output, probably because the day-ahead forecasts use an hourly average, which smoothed out the overall impact of the eclipse compared to the higher-resolution forecasts. The return of solar generation after the eclipse was also well forecast.

Figure 4: Comparing the DA, HASP, FMM and RTD forecasts for the eclipse.



Temperature and Wind Impacts

Other weather-related effects of the eclipse are temperature and grid-scale wind generation. Table 2 shows the average observed temperature reductions based on obscuration percentages during the eclipse compared to the same hours on October 13 and 15, 2023.

Table 2: Approximate potential temperature impacts during the eclipse based on maximum obscuration

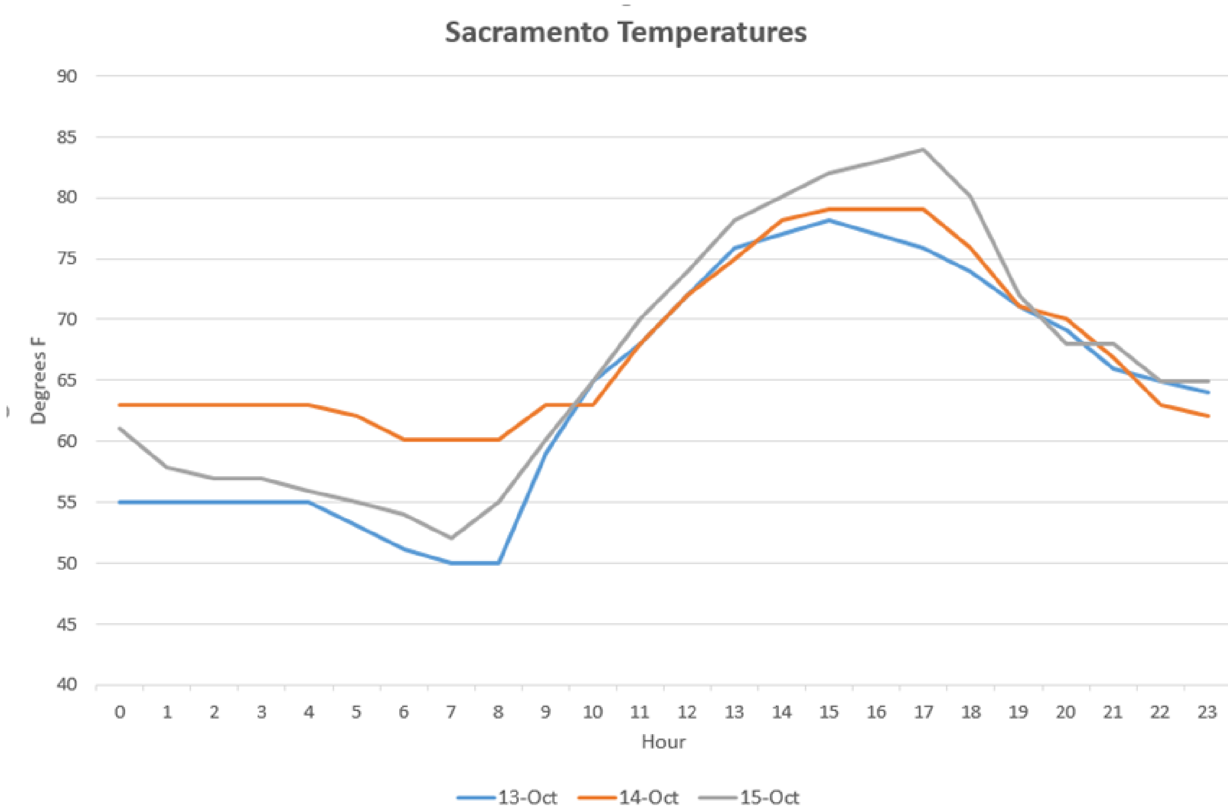
Obscuration level	Observed temperature reduction (˚F)
< 70%	3˚
71-80%	5˚
>80%	6˚

A study[4] of the 2017 eclipse said that for eclipses that occur in the morning, such as the one on October 14, the rate of temperature decrease between the start of the eclipse and maximum obscuration was greater than the rate of temperature increase between maximum obscuration and the end of the eclipse. As a result, the temperature for the rest of the day on October 14 was expected to warm more slowly compared to a non-eclipse day, even after the eclipse was over, leading to a reduced maximum daily temperature.

This impact was not conclusively seen across California, however. While the temperature during the rest of the day on Oct. 14 was lower than days before and after the eclipse, the rate of cooling and warming before and after the maximum obscuration made it more difficult to draw a conclusion. The temperature data analyzed for this eclipse was hourly, while other studies used temperature data on a shorter timescale, such as one-minute data, allowing a more detailed analysis. In addition, because this eclipse occurred in October when the sun shone less directly, temperature impacts were not as drastic as they would be during the summer months. Data for Sacramento, which had a solar obscuration of around 80%, is shown below in Figure 5.

[4] Effect of 21 August 2017 solar eclipse on surface-level irradiance and ambient temperature | International Journal of Energy and Environmental Engineering (springer.com)

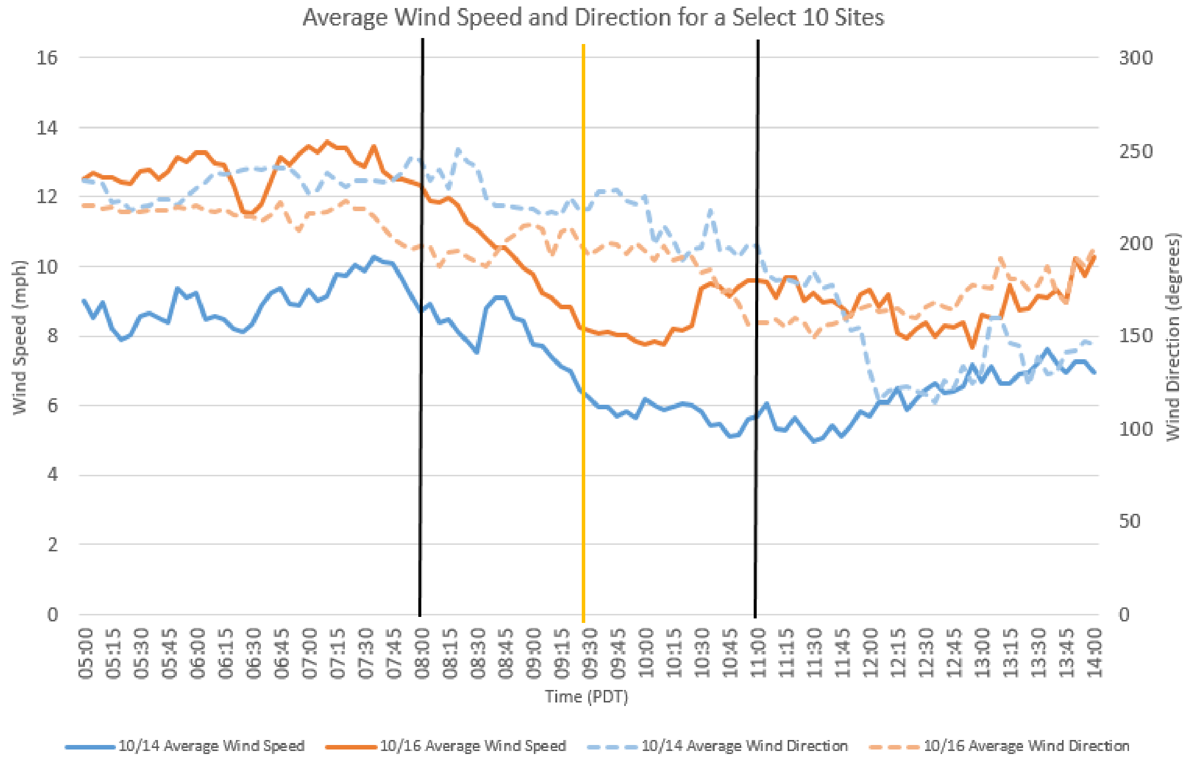
Figure 5: Sacramento hourly observed temperatures for October 13-15, 2023



Eclipses also affect wind speed and direction, with the largest impacts closest to the path of totality. Wind speeds have decreased by approximately 2-6 mph near the path of totality during prior eclipses. Wind directions tend to rotate counter-clockwise during an eclipse from its start through maximum obscuration, and clockwise from maximum obscuration to the end of the eclipse.[5] Figure 6 shows the wind speed and direction changes across California during the October 14 eclipse compared to a similar day.

Figure 6: Average wind speed and direction for selected 10 sites

[5] Effect of 21 August 2017 solar eclipse on surface-level irradiance and ambient temperature | International Journal of Energy and Environmental Engineering (springer.com)



The average wind speed (solid lines) and direction (dashed lines) for ten sites across California during the eclipse (blue) and a similar non-eclipse October day (orange). The black lines denote the start and end of the eclipse and the yellow line denotes the maximum obscuration time. Throughout California, wind speeds decreased by about 2-3 mph from the eclipse's start to maximum obscuration, but similar decreases were observed on a non-eclipse day in mid-October. Wind speed remained fairly constant from the eclipse's peak to its end. Wind direction remained steady throughout most of the eclipse at around 200 degrees, which is out of the south-southwest, and did not experience any counter-clockwise rotation during the eclipse different from a non-eclipse day.

CAISO Load Forecast

There is more than 14,350 MW of BTM rooftop solar capacity in the ISO footprint. On the eclipse day, partial obscuration of the sun reduced output of rooftop solar and increased load by 2,064 MW from 8:25 a.m. to 9:20 a.m., as shown in Figure 7. As obscuration of the sun subsided and output of rooftop solar returned to normal levels, load decreased 5,738 MW from 9:20 a.m. to 11:00 a.m.

Figure 7 CAISO DA+7 through T-120 load forecasts and actuals during eclipse timeframe

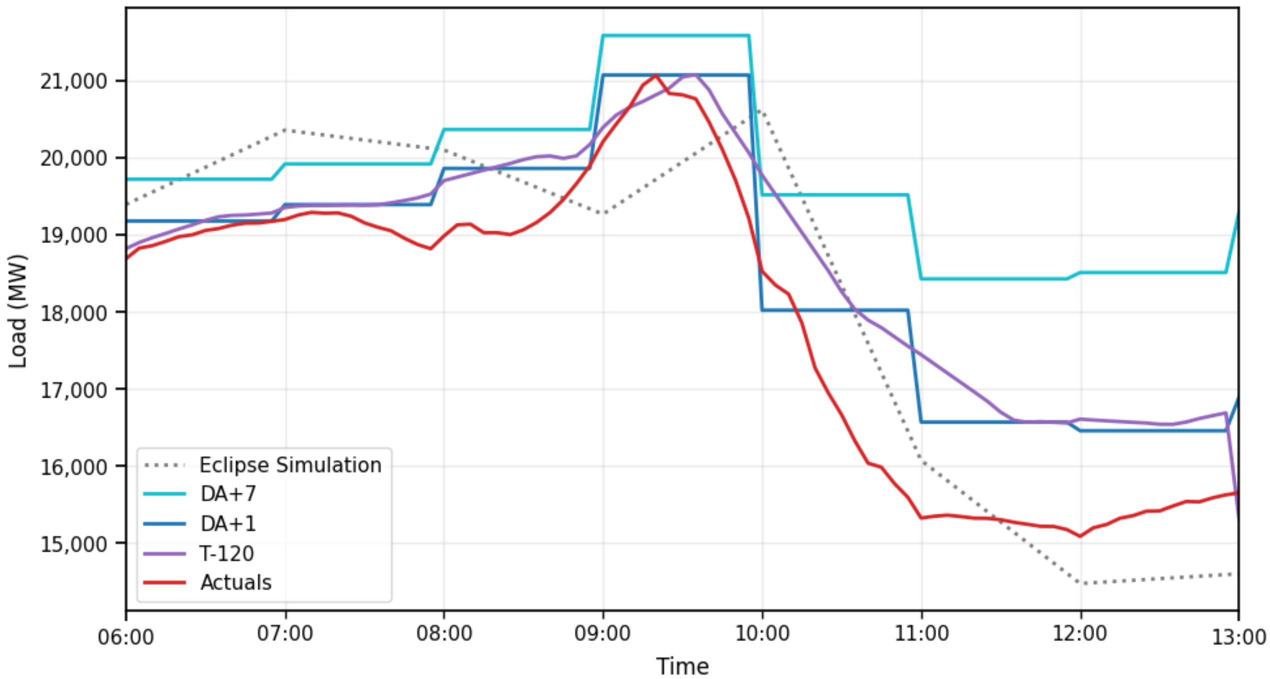
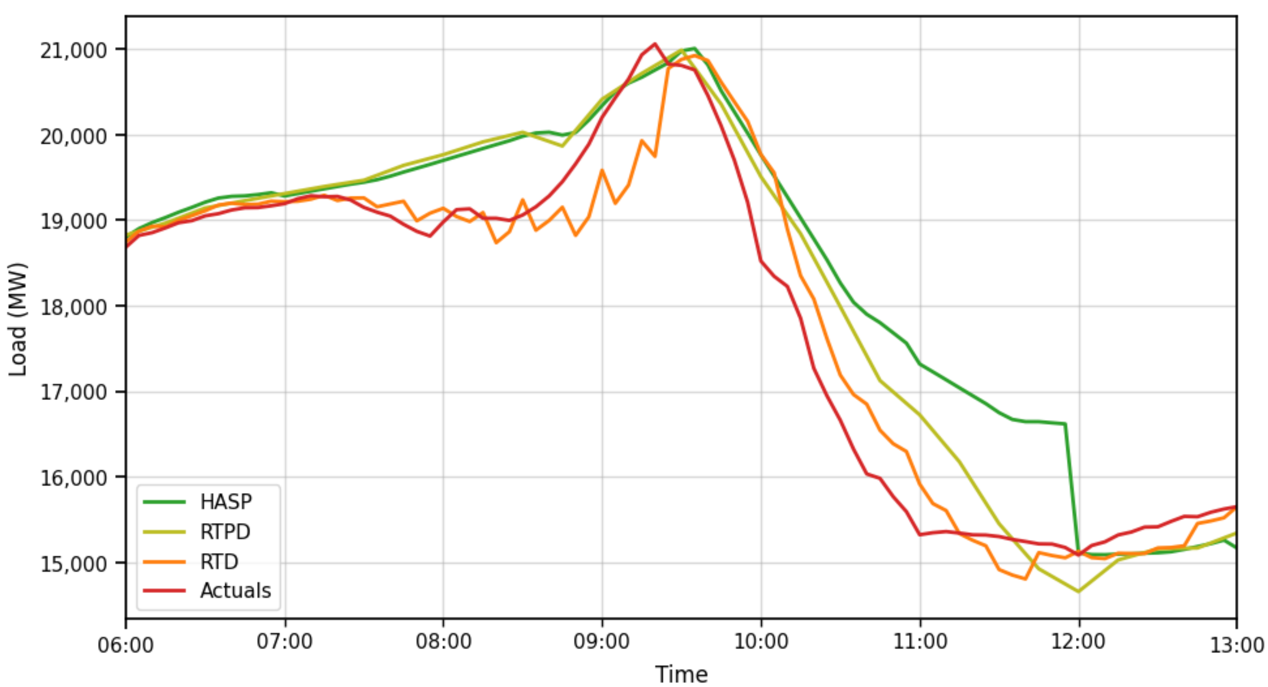


Figure 8 CAISO HASP through RTD load forecasts and actuals during eclipse timeframe



Model forecasts for the ISO generally performed better on the ramp-up period for both the longer term forecast and the real-time forecasts. DA+7 and DA+1 forecasts both predicted higher load than the eventual post-eclipse minimum. Real-time models similarly over-forecasted during the post-eclipse hour due to the sharp load ramping rate.

Figure 9 below shows ISO-wide BTM solar forecasts and actuals throughout the eclipse day.

Figure 9 CAISO BTM solar forecasts and actuals throughout eclipse day

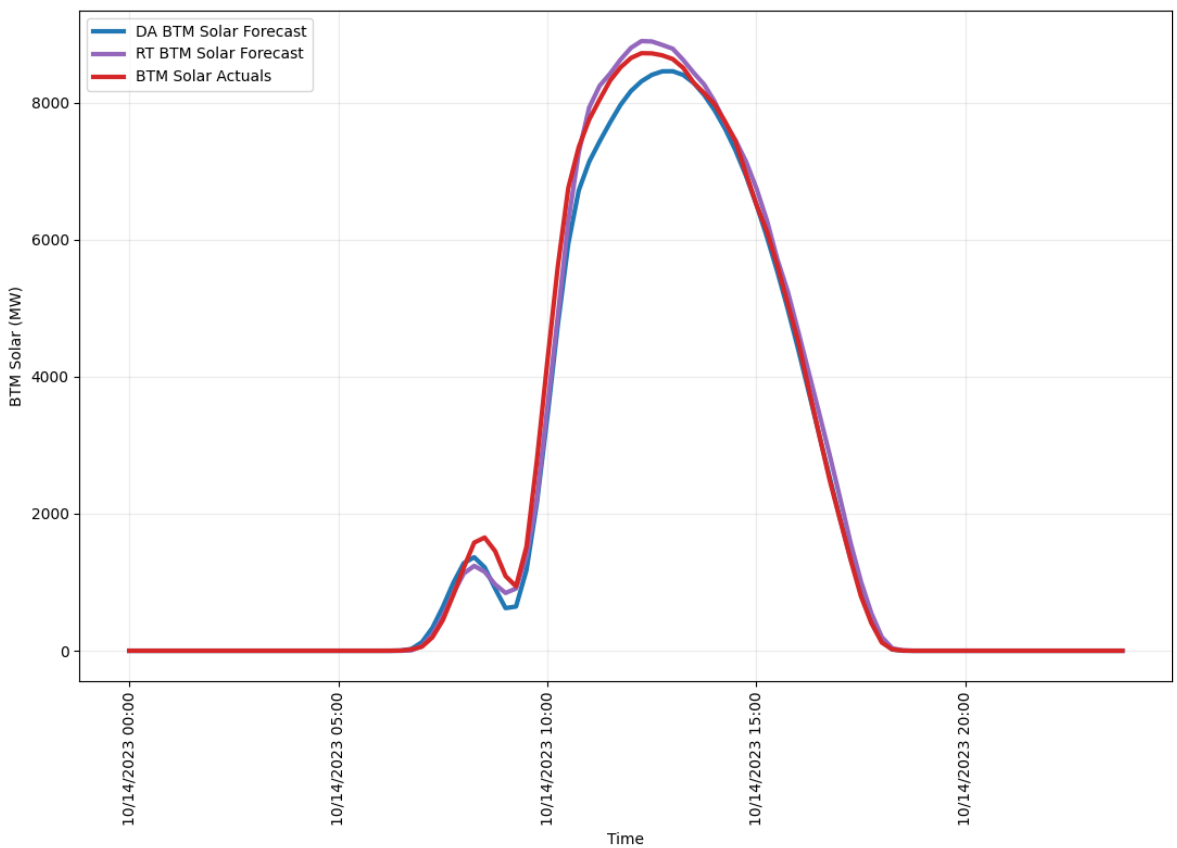


Table 3: CAISO eclipse gross load ramping data

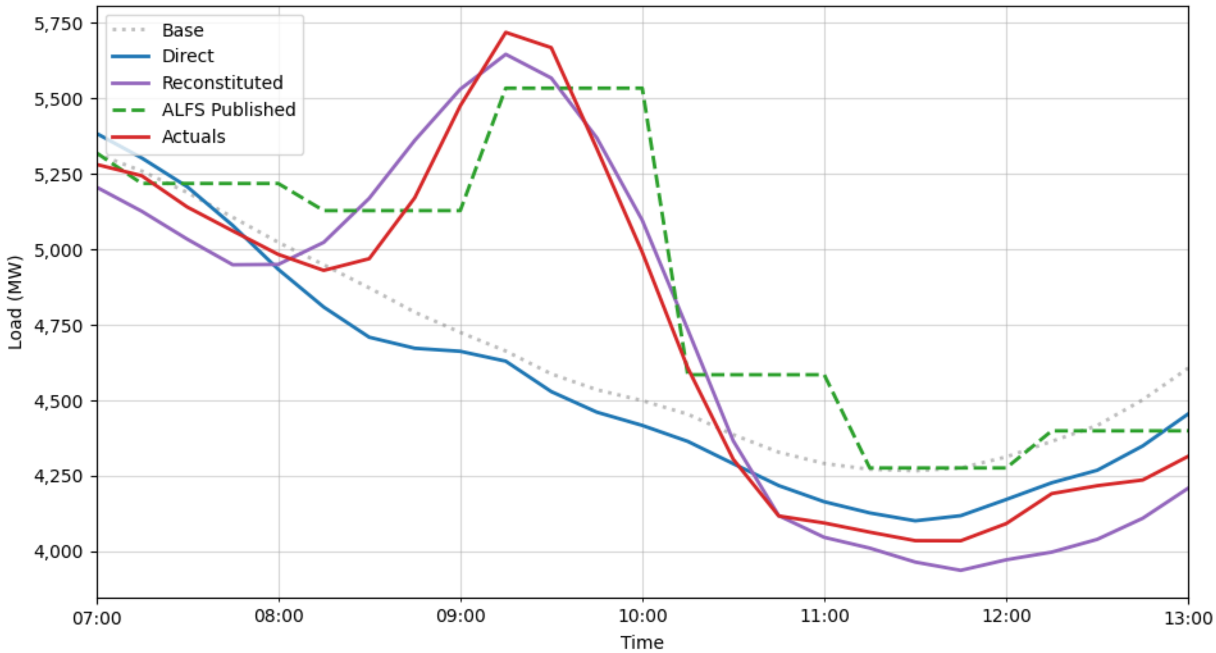
	Start	End	Load Start	Load End	Total Ramp (MW)	Average Ramp (MW/min)	Max Ramp (MW/min)	Typical Ramp (MW/min)
Ramp Up	8:15	9:15	19,023	21,061	2,038	34	63	-34
Ramp Down	9:15	11:00	21,061	15,323	-5,738	-55	-137	-20

	Start	End	Load Start	Load End	Total Ramp (%)	Average 15 Min Ramp (%)	Max 15 Min Ramp (%)	Typical 15 Min Ramp (%)
Ramp Up	8:15	9:15	18,969	21,343	9.5%	2.4%	4.4%	-2.5%
Ramp Down	9:15	11:00	21,343	14,701	-26.9%	-3.8%	-9.5%	-1.7%

CAISO Forecast Zone Case Study

An ISO forecast zone was selected for a case study to highlight model performance across different demand modeling methodologies. Figure 10 shows the day-ahead forecast for the forecast zone's model suite. CAISO base models utilize a suite of weather data to predict gross load. Direct models utilize weather data in conjunction with BTM solar data to predict gross load. Reconstituted models utilize weather data to predict the sum of gross load and BTM Solar. The forecasted BTM solar is then subtracted from the predicted value, leaving a residual predicted gross load value. Although the direct model failed to identify a strong relationship between BTM solar changes and actual loads for this forecast zone, other regions exhibited better performance from direct models. This zone's reconstituted model more accurately accounted for changes in load due to forecasted BTM solar accuracy remaining relatively high during the eclipse period. Reconstituted models generally performed well across forecast zones during the eclipse. The published day-head forecast ultimately utilized the reconstituted model profile as a guide for manual adjustments during the eclipse period.

Figure 10 CAISO forecast zone Day Ahead model suite performance and published forecast



Net Load

Figure 11 highlights net load fluctuation on October 14 during the eclipse period, and Table 4 reports the key net-load ramping data. From 8:15 a.m. to 9:15 a.m., net load increased by 5,975 MW. During the ramp-up period, net load increased by approximately 100 MW per minute on average, with a max ramp rate of +190 MW per minute. As the eclipse began to wane, net load dropped by 12,355 MW from 9:15 a.m. to 11:00 a.m. During the ramp-down period, net load decreased by approximately 118 MW per minute on average with a maximum down-ramp of -267 MW per minute.

Figure 11 CAISO net load impact from eclipse during ramping period

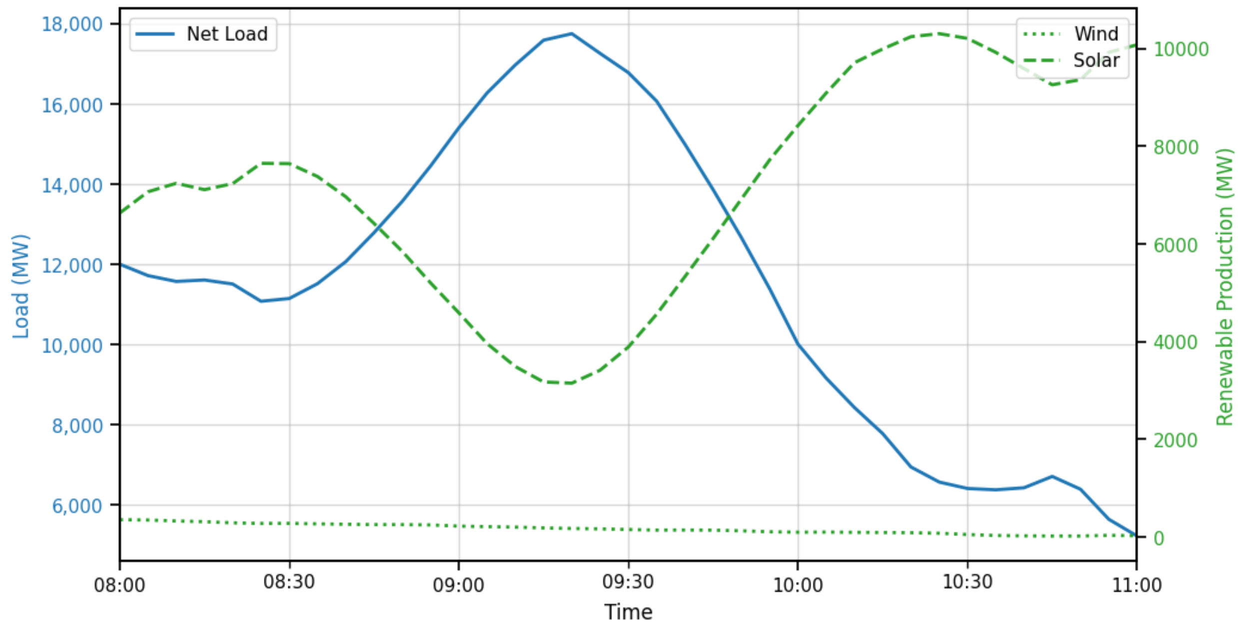


Table 4 CAISO eclipse net load ramping data

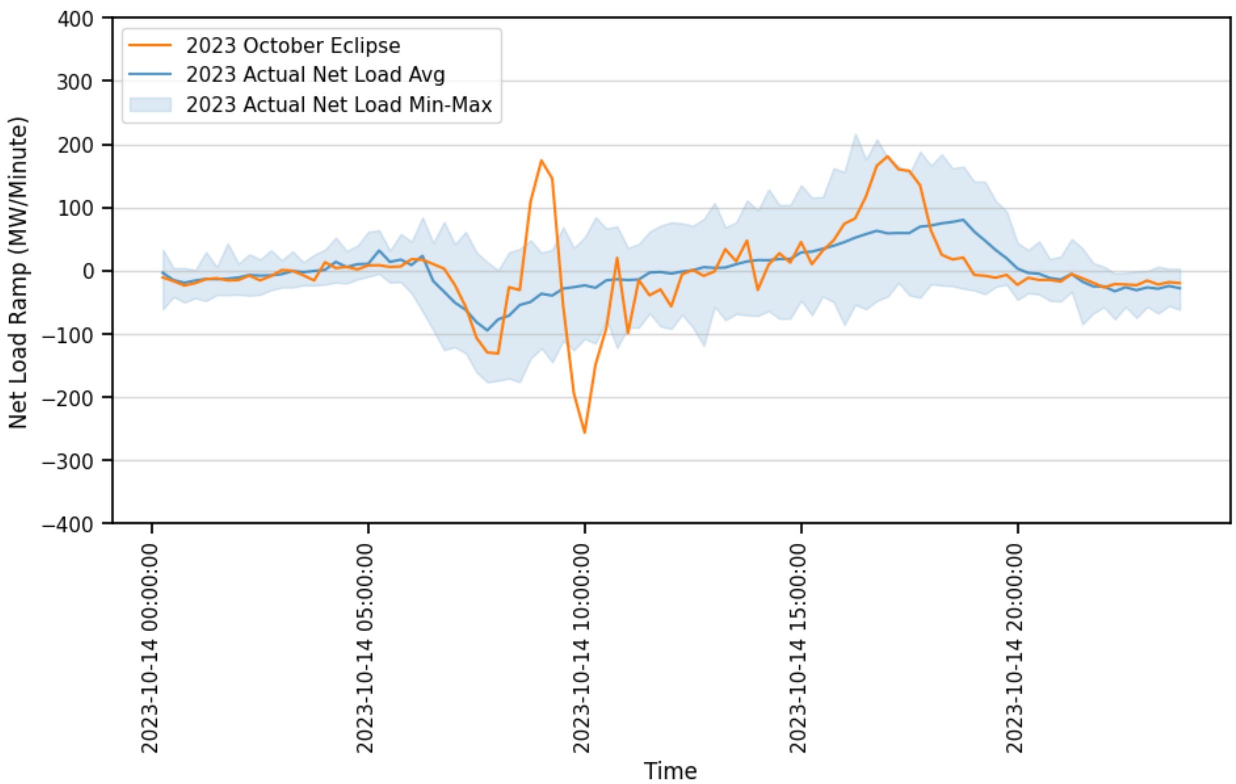
	Start	End	Load Start	Load End	Total Ramp (MW)	Average Ramp (MW/min)	Max Ramp (MW/min)	Typical Ramp (MW/min)
Ramp Up	8:15	9:15	11,607	17,582	5,975	100	190	-96
Ramp Down	9:15	11:00	17,582	5,227	-12,355	-118	-267	-33

	Start	End	Load Start	Load End	Total Ramp (%)	Average 15 Min Ramp (%)	Max 15 Min Ramp (%)	Typical 15 Min Ramp (%)
Ramp Up	8:15	9:15	11,607	17,582	51.5%	12.9%	24.5%	-11.0%
Ramp Down	9:15	11:00	17,582	5,227	-70.3%	-10.0%	-22.6%	-6.0%

Figure 12 illustrates the eclipse ramping requirements relative to actual ramping data for 2023[6]. Ramp rates for the eclipse ramp-up period are higher than those typically experienced in the morning but are in line with the steeper ramps experienced during 2023 evening peaks. Ramp rates in the ramp-down period are steeper than those experienced to date in 2023. The minimum ramp rate during the ramp-down period of -267 MW per minute exceeds the minimum in 2023 by approximately 100 MW per minute.

[6] Includes 15-min net load data from Jan 1st 2023 – Aug 17th 2023

Figure 12 Eclipse net load ramp rates compared to 2023 actual ramp rates



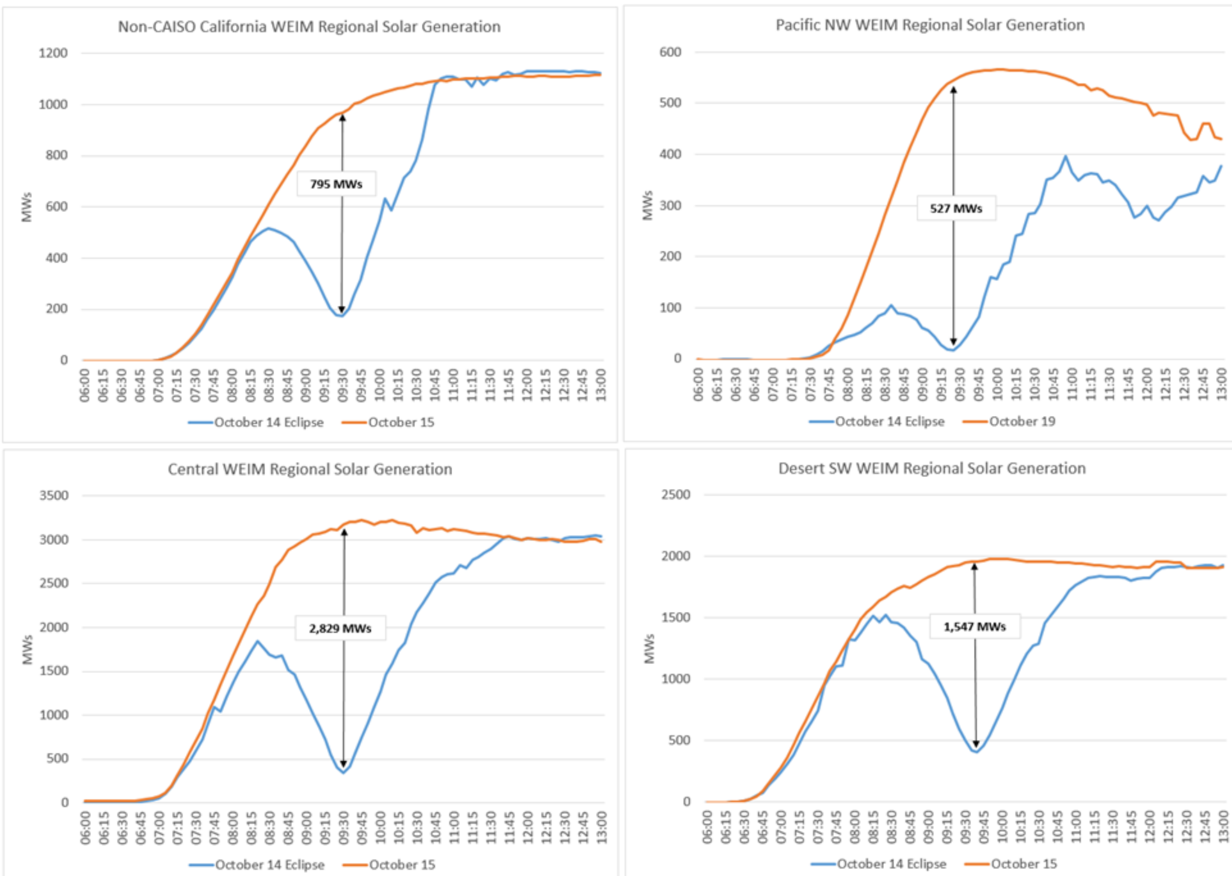
Impacts to WEIM Load and Renewables

WEIM Grid Connected and Rooftop Solar

The WEIM footprint includes 22 participants and 21 balancing authority areas. Most WEIM participants submit forecasts for their renewables generation through their own forecast service providers (FSPs). The CAISO serves as the real-time load forecast service provider for most WEIM entities . The CAISO receives estimates of installed rooftop BTM solar for load-serving WEIM entities. WEIM BTM capacity estimates are provided to a third-party vendor, which generates a BTM solar forecast that the CAISO can incorporate into its load forecasting process.

Table 5 shows the approximate estimates of grid-connected and rooftop BTM solar for each WEIM entity. Also included is a mapping of each WEIM entity to a broader geographic WEIM region. The WEIM regions were impacted at various times as the eclipse passed through the West. Figure 13 shows the impact of each WEIM regional aggregate grid-connected solar for the eclipse day compared to a recent clear-sky day. Cloudy skies across much of the Pacific Northwest and parts of the central region contributed to lower output during the eclipse maximum and after the eclipse end for the Pacific Northwest.

Figure 13 The WEIM grid-connected solar impacts on the eclipse day compared to a recent clear sky day.



The WEIM rooftop solar impacts, as well as the day-ahead and real-time forecasts, are shown in Figure 14.

Figure 14 WEIM regional BTM solar forecasts and BTM solar actuals

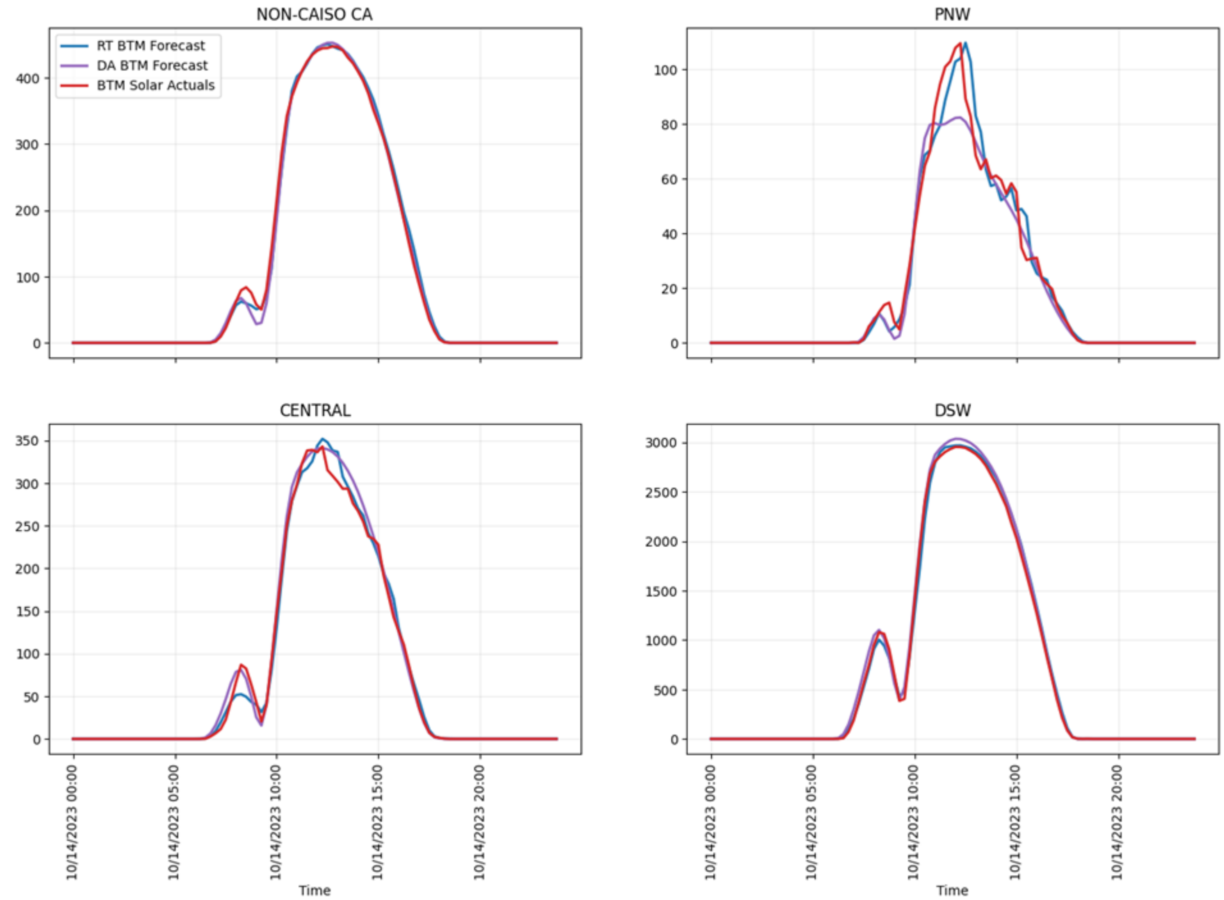


Table 5: WEIM grid connected and rooftop BTM solar capacity

Region	Approx. Grid Connected Solar (MW)	Approx. Rooftop BTM Solar (MW)
California	**1,561**	**953**
Balancing Area of Northern CA (BANC)	407	335
Los Angeles Department of Water and Power (LADWP)	1,154	564
Turlock Irrigation District (TID)		55
Central	**4,807**	**1,453**
Idaho Power Company (IPCO)	473	116
Northwestern Energy (NWMT)	178	38
NV Energy (NEVP)	2,471	835
PacifiCorp East (PACE)	1,685	464
Desert Southwest	**2,851**	**3,402**
Arizona Public Service (AZPS)	794	1,761
El Paso Electric Company (EPE)	285	170
Public Service Company of New Mexico (PNM)	841	340
Salt River Project (SRP)	436	497
Tucson Electric Power (TEPC)	428	503
WAPA Desert Southwest Region (WALC)	67	130
Pacific Northwest	**1,061**	**650**
Avangrid (AVRN)	522	
Avista (AVA)	20	21
Bonneville Power Authority (BPA)	138	88
PacifiCorp West (PACW)	381	173
Portland General Electric (PGE)		161
Puget Sound Energy (PSE)		149
Seattle City Light (SCL)		44
Tacoma Power (TPWR)		15
WEIM Totals	**10,280**	**6,458**

WEIM Load Forecast

Eclipse impacts on WEIM loads varied with proximity to the eclipse path and levels of installed BTM rooftop solar. Generally, eclipse impacts were more pronounced in regions with higher levels of BTM capacity relative to native load.

Eclipse impacts by region are shown in Figure 15[7]. The Desert Southwest region showed the greatest eclipse impacts with morning load increasing 1,172 MW (+12.9% relative to eclipse start load). The Central WEIM region showed a load increase of 592 MW (+5.2%), and the non-CAISO California WEIM region showed a load increase of 357 MW (+9.0%).

The Desert Southwest similarly showed the largest impact from eclipse maximum to post-eclipse minimum with load decreasing 1,273 MW (-12.4% relative to eclipse maximum load). The Central WEIM region showed load decreasing 853 MW (-7.1%), and non-CAISO California WEIM region showed load decreasing 189 MW (-4.4%).

[7] CAISO loads are not included in this graphic

Figure 15 WEIM regional Day Ahead forecast, T-120 forecast, and load actuals

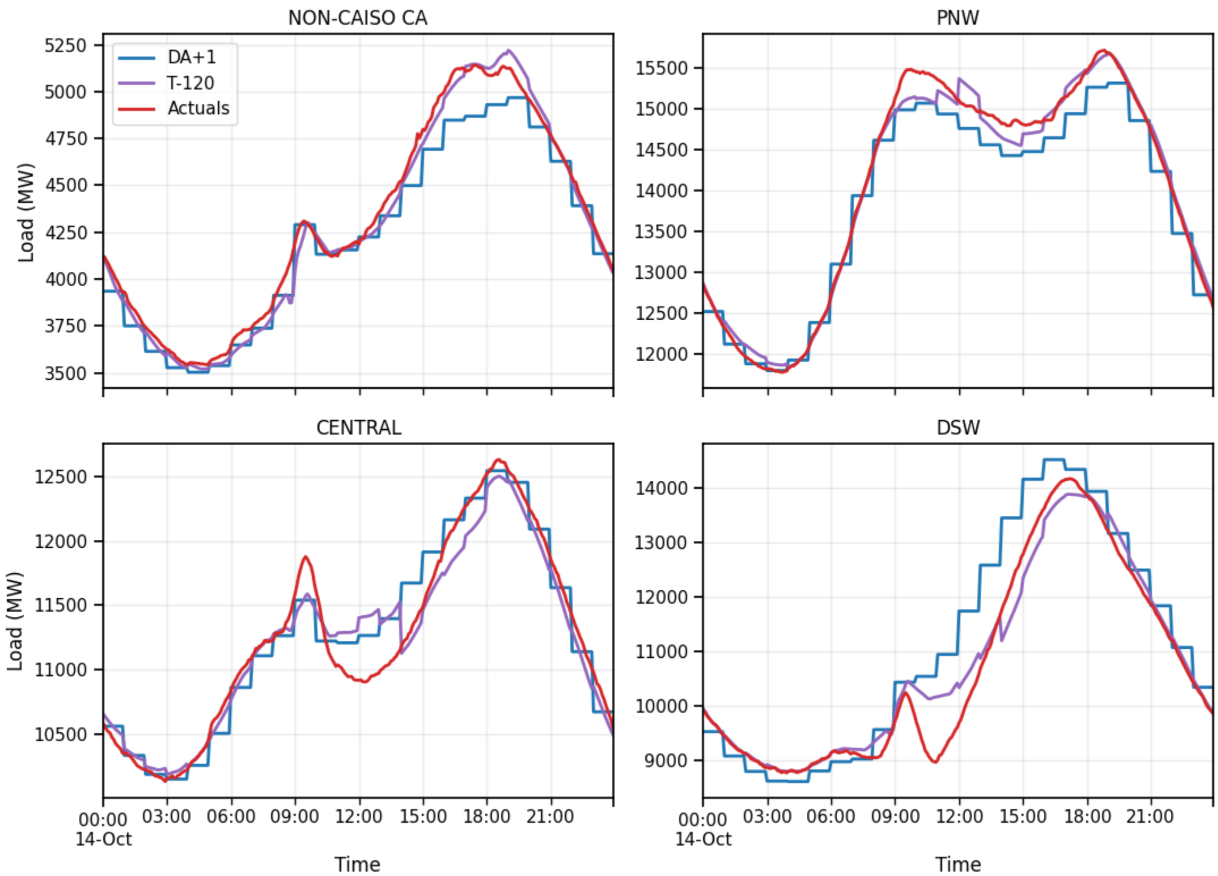
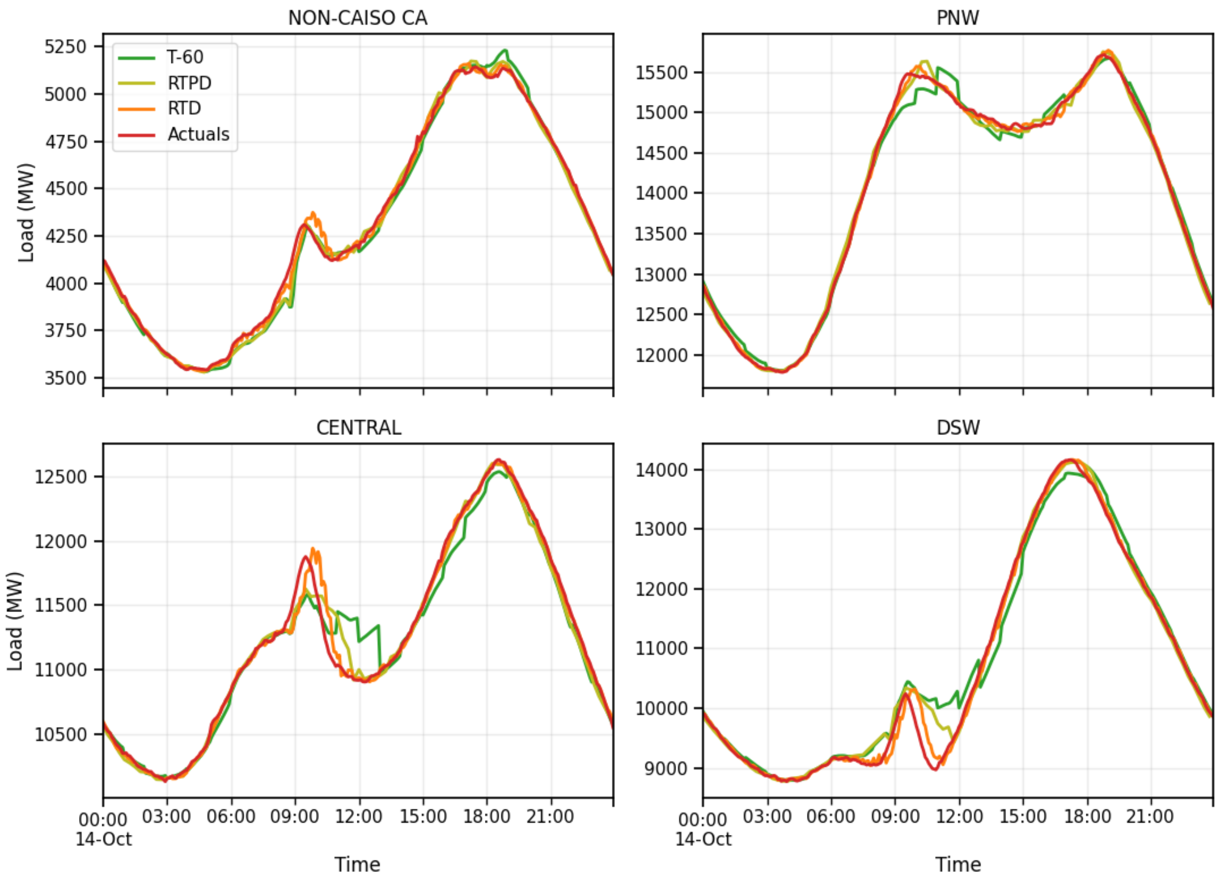


Figure 16 WEIM regional T-60 through RTD forecasts and load actuals



Model forecasts for WEIM regions generally performed better on the ramp-up period compared to the period immediately following the eclipse, when both real-time and longer-term forecasts remained elevated, particularly in the Central and Desert Southwest regions.

Table 6 WEIM observed load and ramping data during eclipse hours

	WEIM Region	Start Time	Load Start (MW)	Maximum Time	Maximum Load (MW)	Total Up Ramp (MW)	Average Up Ramp (MW/min)	Max Up Ramp (MW/min)
Ramp Up	Non-CAISO California	8:15	3,952	9:25	4,309	357	5.1	8.8
	Pacific Northwest[8]	--	--	--	--	--	--	--
	Central	8:15	11,287	9:30	11,879	592	7.9	14.1
	Desert Southwest	8:15	9,069	9:30	10,241	1,172	15.6	23.7

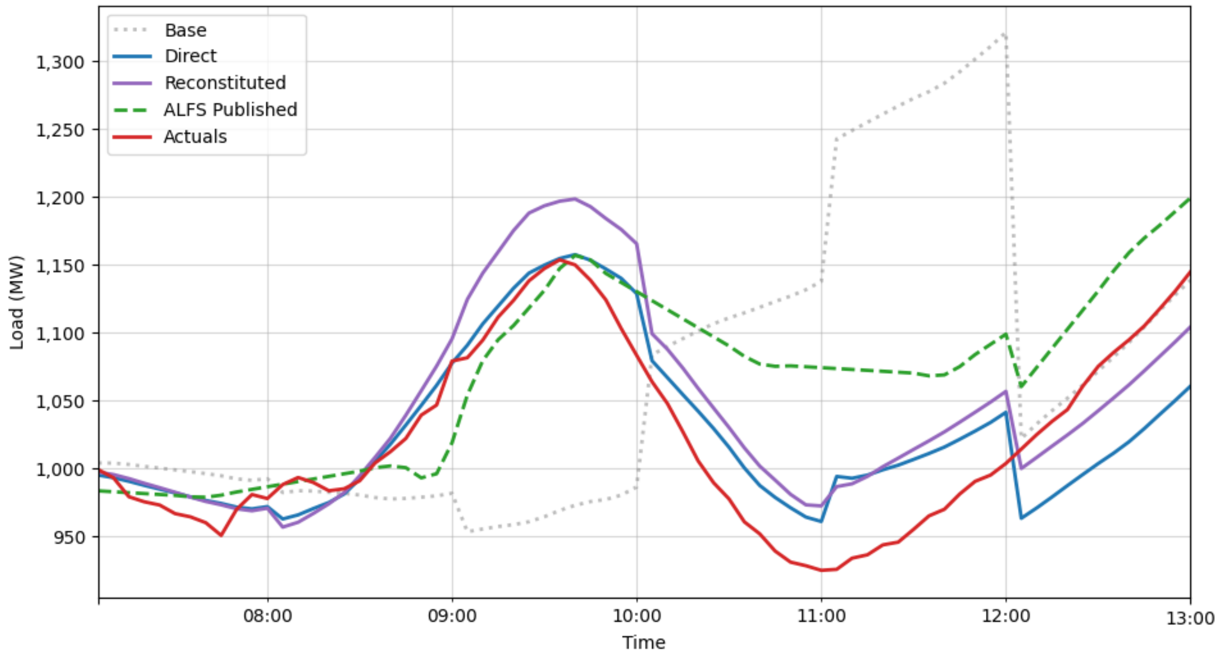
	WEIM Region	Maximum Time	Load Max (MW)	End Time	End Load (MW)	Total Down Ramp (MW)	Average Down Ramp (MW/min)	Max Down Ramp (MW/min)
Ramp Down	Non-CAISO California	9:25	4,309	10:45	4,120	-189	-2.4	-4.2
	Pacific Northwest	--	--	--	--	--	--	--
	Central	9:30	11,879	10:55	11,026	-853	-10.0	-17.6
	Desert Southwest	9:30	10,241	10:55	8,968	-1,273	-15.0	-25.2

WEIM Entity Case Study

A WEIM entity was selected for a case study to highlight model performance across different demand modeling methodologies. Figure 17 shows the T-60 forecast for the WEIM's model suite. As discussed in the CAISO forecast-zone case study, above, base models utilize a suite of weather data to predict gross load. Direct models utilize weather data in conjunction with BTM solar data to predict gross load. Reconstituted models utilize weather data to predict the sum of gross load and BTM Solar. The forecasted BTM solar is then subtracted from the predicted value, leaving a residual predicted gross load value. The Automated Load Forecast System (ALFS) published model seen in Figure 17, below, is a modified direct model. The direct model and ALFS published model successfully identified a relationship between BTM solar changes and actual loads for this entity. The reconstituted model also performed well for this WEIM entity, outperforming the ALFS published model on the tail end of the eclipse. This comparison supports direct and reconstituted models as viable model methodologies to handle future eclipse scenarios.

[8] Eclipse signal not strong enough in Pacific Northwest load profile to quantify impacts.

Figure 17 WEIM entity T-60 forecast performance across model suite



Uncertainty Requirements

RUC Adjustments

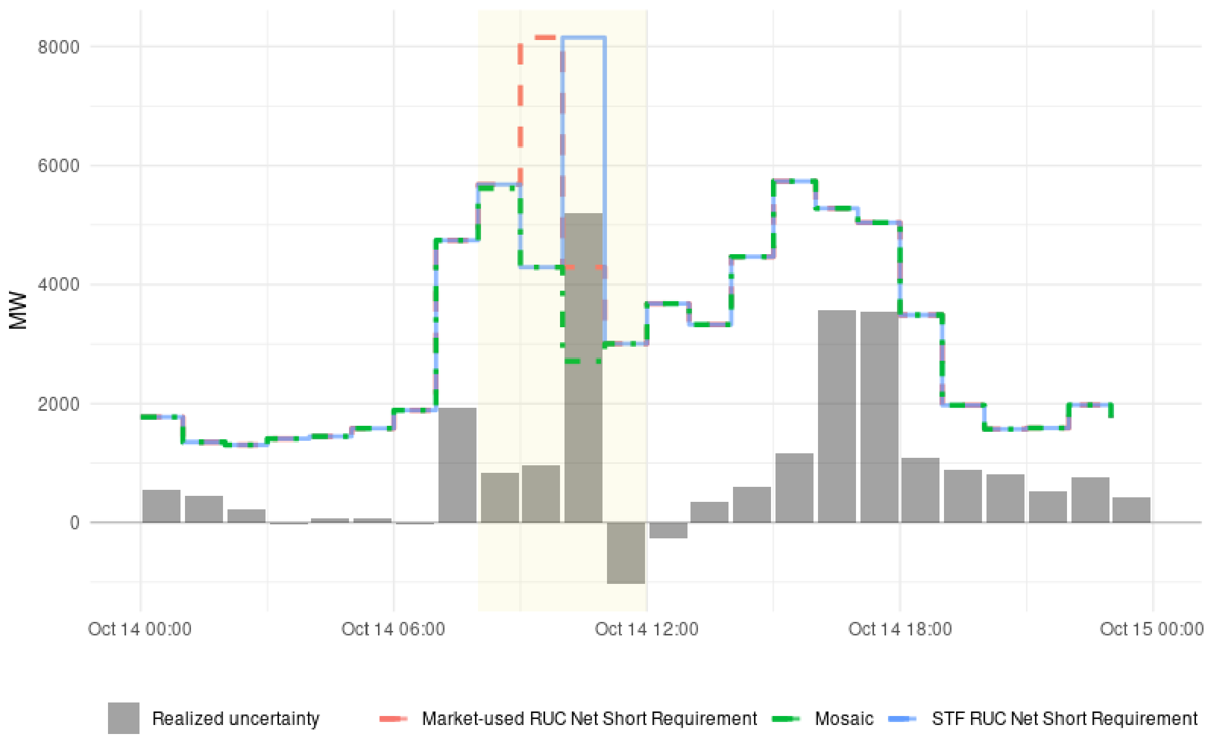
In some extreme situations, e.g. eclipses and hurricanes, historical data is not available to estimate uncertainty. For the solar eclipse, the estimation of uncertainty by the normal mosaic method was compared to the uncertainty forecasted within the 5 minute lowest confidence band values from renewable forecasts. The more conservative value between mosaic and lowest confidence band was taken. This enhanced methodology performed well in estimating the eclipse period with elevated uncertainty and limited historical information.

Figure 18 shows Residual Unit Commitment (RUC) net-short values compared to realized uncertainty. Here, uncertainty refers to the differences in day-ahead net load forecast to RTD binding net-load forecast. The adjusted estimates to RUC for the hour-ending (HE) 9 to 11 period with the largest upward adjustment in HE11. Those values are shown by the solid blue line in comparison to normal requirements estimated by the mosaic method, shown by the dash-dot green line. Ultimately, the higher requirement was applied to HE10 with the rationale that it was the period of maximum obscuration, and resources committed in HE10 could be extended to cover HE11. The red dashed line shows market-used RUC net short requirements, which are switch of HE10 and HE11 values from STF recommendation.

The gray bar columns in Figure 18 show realized uncertainty and the shaded yellow region highlights the eclipse period from 8am to 12pm PDT, also described as HE9 to HE12.

The upward adjustments to RUC, which were used to account for weather, load, and renewable forecast uncertainty, covered differences between day-ahead and real-time forecasts. Though the added bias in the hour-ending 9 and 10 period exceeded realized uncertainty, the added bias in hour-ending 11 helped bring RUC net-short close to realized uncertainty. In HE11, realized uncertainty of 5,209 MW exceeded the market-used RUC net-short requirement of 4,288 MW by 921 MW but fell below the original estimation of 8,153 MW by 2,944 MW.

Figure 18 RUC adjustments and realized uncertainty



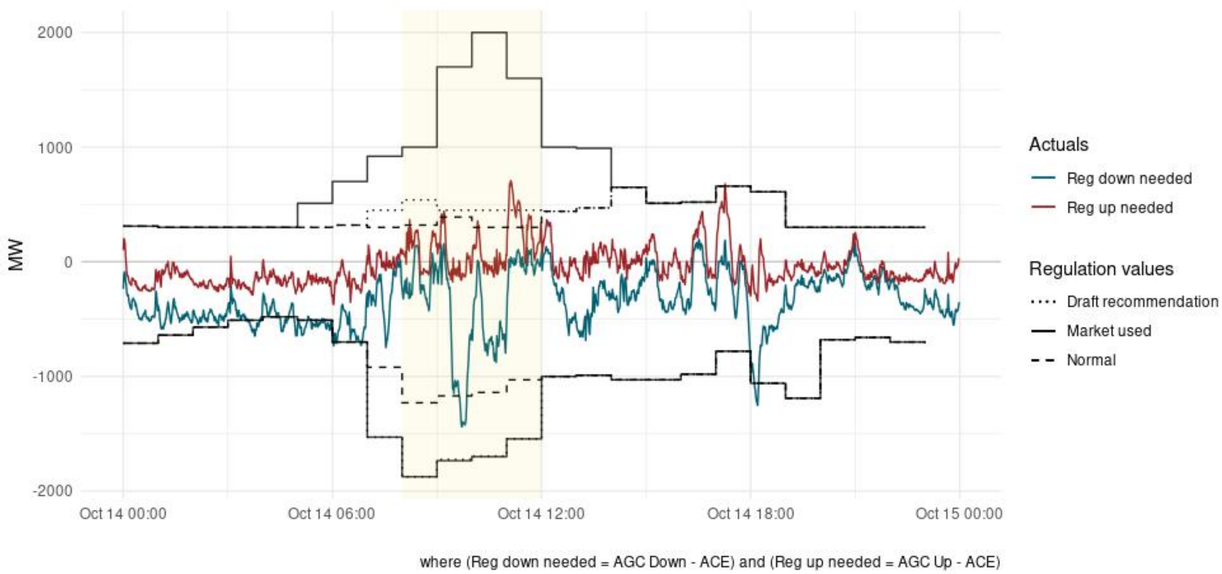
Regulation Requirements

Normal regulation up and down numbers, established for the month of October, were adjusted for the eclipse day with specific adjustments made in the HE8 to HE12 period in regulation down and the HE6 to HE14 period in regulation up. In Figure 19[9], the dashed stepped line shows the normal regulation up and down requirement values. The dotted stepped line indicates original forecasting recommended

[9] The actuals of total regulation needed (regulation dispatched – ACE) are shown at 1-minute granularity by the red and blue lines, respectively, in Figure 19.

adjustments from the solar eclipse draft report, and the solid stepped line shows the adjusted regulation requirement values used for October 14. Between the solar eclipse draft report and the eclipse day, regulation requirements saw minor changes in the negative direction and major increases in the positive direction. The eclipse adjustments, especially in the negative direction, helped cover the needed capacity for frequency regulation. Hourly regulation values are shown by the stepped line plot for normal conditions (dashed line) versus those recommended in the solar eclipse draft report (dotted line) versus market used (solid line). The ACE* variability high and ACE* variability low are shown inverted as regulation needed to compare to regulation down and regulation up procured respectively.

Figure 19 Comparison of regulation procured to regulation needed



Flex Ramp Product Requirements

The flex ramp product (FRP) is meant to capture uncertainty from advisory net-demand forecasts to binding net-demand forecasts, namely FMM materialized uncertainty (RTD binding versus FMM advisory) and RTD materialized uncertainty (RTD binding versus RTD advisory. The following four plots (Figure 20 to Figure 23) show the requirements held in FMM and RTD for the ISO (CISO) and the EIM area, separately. The eclipse period from HE9 to HE12 (8 a.m. to 12 p.m. PDT) is shown in a shaded yellow. Flex ramp up (FRU) and flex ramp down (FRD) products are shown by the solid dark line in either positive or negative uncertainty values, respectively. Because FMM to RTD is a longer time horizon than RTD advisory to binding, the uncertainty values are expectedly larger in the respective FMM plots compared to RTD plots.

Some elevated levels of uncertainty were observed in the eclipse period. FRP was better able to estimate and cover upward uncertainty than downward uncertainty. FRP performance recovered following the eclipse period so that coverage metrics for October 14 remain high overall. Table 7 and Table 8 give coverage metrics for the ISO and EIM BAAs for Oct 14 during the eclipse period, during the day overall, and for the preceding and following day.

Table 7 Flex ramp up coverage metrics for realized uncertainty Oct 13 through 15

FRU Coverage	CISO		EIM Area	
	FMM	**RTD**	**FMM**	**RTD**
Oct 14 during eclipse (HE9 - HE12)	1.00	0.96	0.97	0.92
Oct 14	1.00	0.97	0.98	0.97
Oct 13	1.00	0.98	1.00	0.99
Oct 15	0.98	0.96	0.97	0.94

Table 8 Flex ramp down coverage metrics for realized uncertainty Oct 13 through 15

FRD Coverage	CISO		EIM Area	
	FMM	**RTD**	**FMM**	**RTD**
Oct 14 during eclipse (HE9 - HE12)	0.35	0.86	0.51	0.80
Oct 14	0.82	0.96	0.86	0.92
Oct 13	1.00	0.98	0.96	1.00
Oct 15	0.90	0.99	0.91	0.96

Figure 20 FRP for CISO FMM market

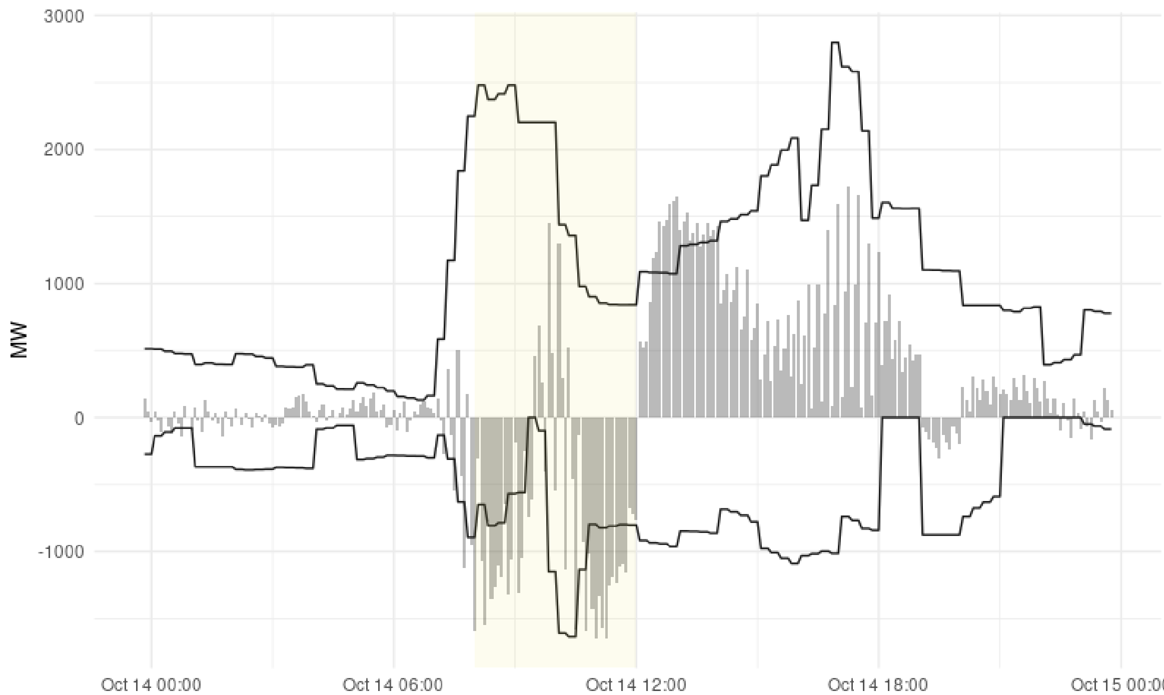


Figure 21 FRP for CISO RTD market

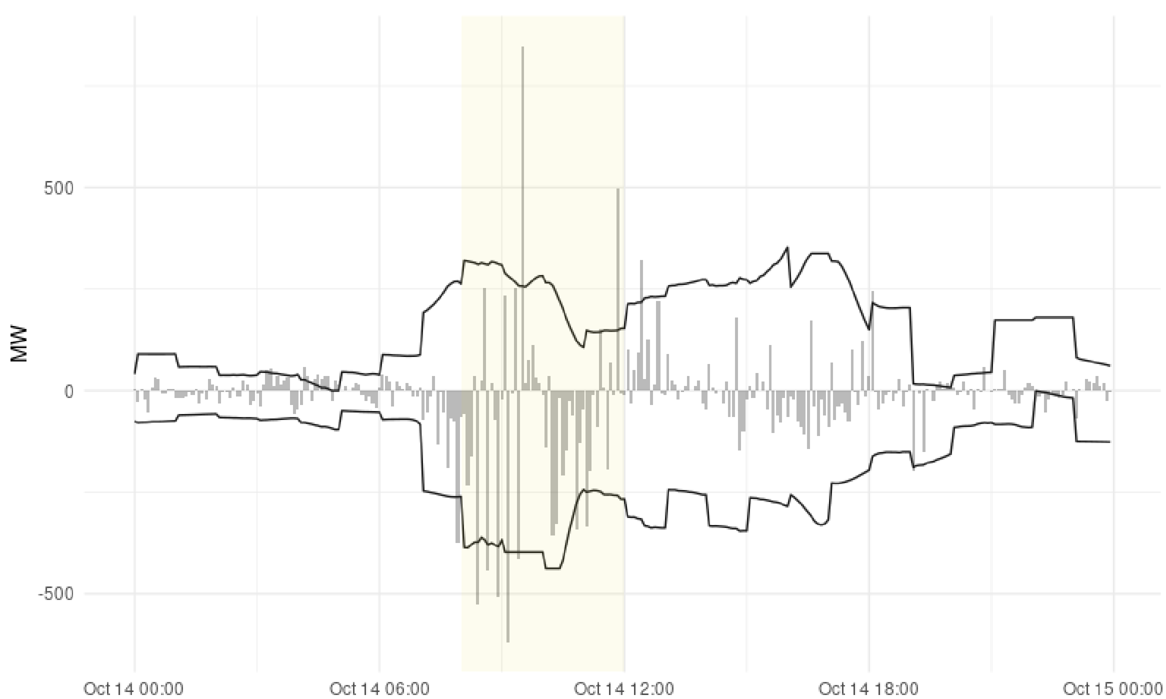


Figure 22 FRP for EIM BAA area in FMM market

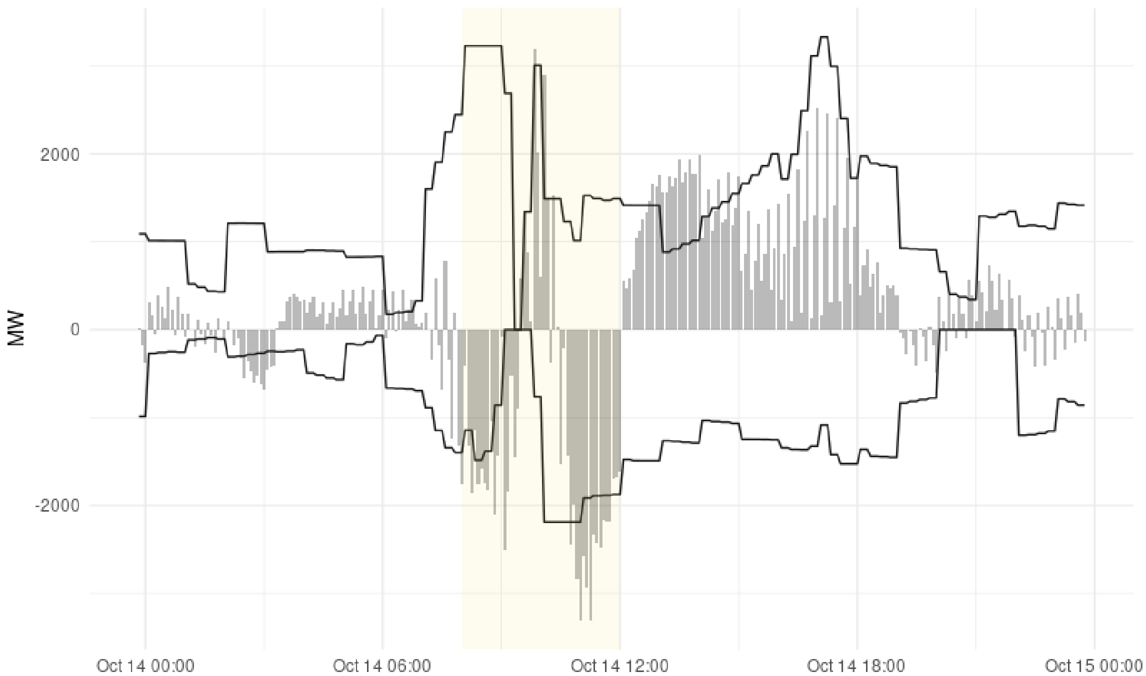
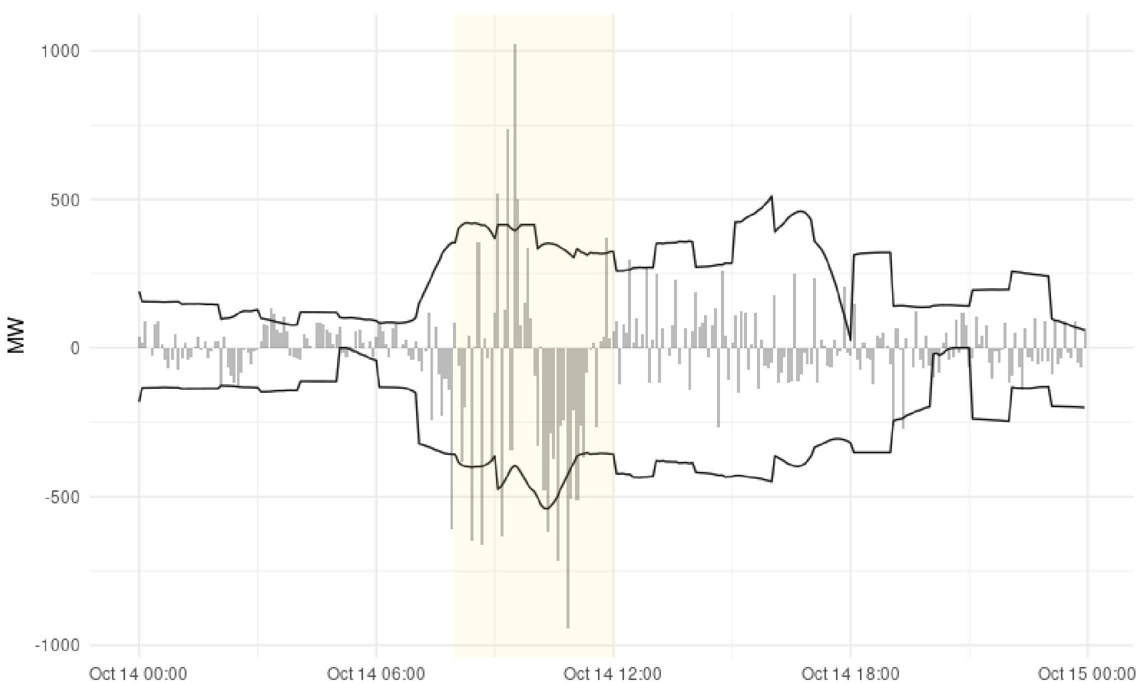


Figure 23 FRP for EIM BAA area in RTD market



Because the solar eclipse is an exceptional event, the data from the eclipse period has been marked for removal from future uncertainty calculations so that information from this event does not influence uncertainty estimations during normal conditions.

Market Performance

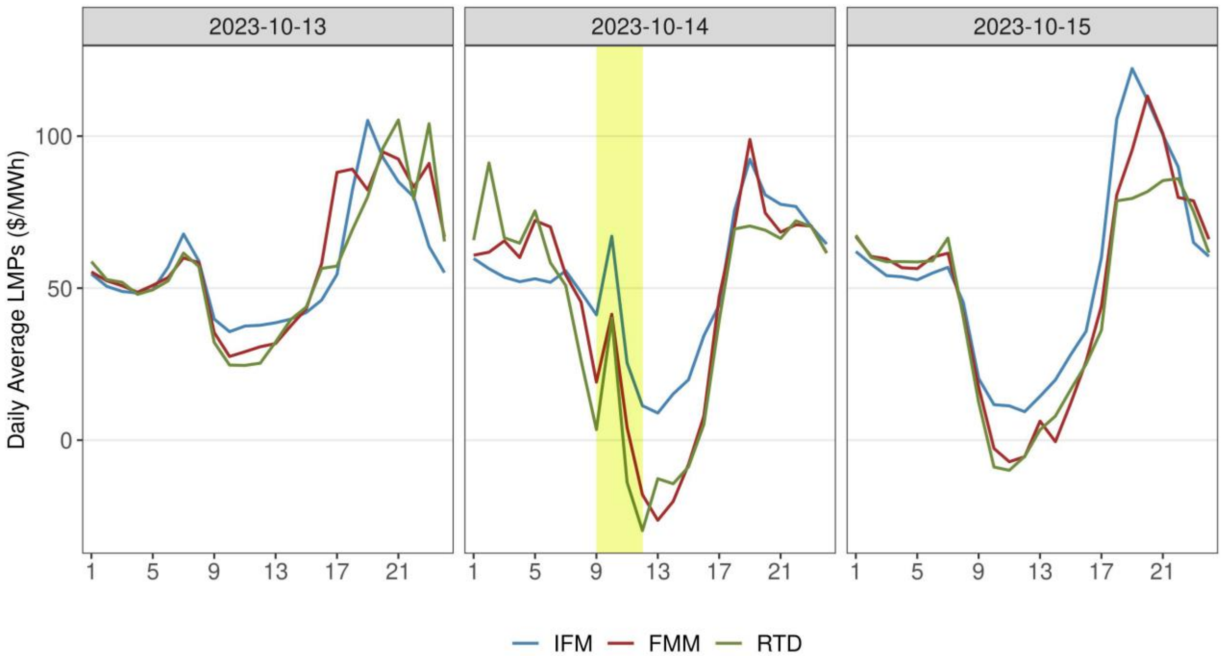
The first opportunity for the market to position the supply fleet for the eclipse is the day-ahead market, where the gross volume of energy is transacted. The day-ahead market is also the opportunity to commit long-start resources that otherwise cannot be committed in the real-time market. The real-time market is the last opportunity for the market to position resources in a shorter horizon. It can also procure additional imports and ancillary services as needed. The real-time dispatch determines optimal five-minute dispatches. Both markets rely on a forecast for solar and wind resources. During the eclipse, when solar generation decreases, other types of supply need to be ramped up to offset the loss of generation. Conversely, when the solar generation comes back and ramps to full production, other types of supply need to be ramped down to balance the change. Which resources and how much to ramp down and up is determined by the least-cost market solution achieved through optimization, based on the economic bids of available resources and by the physical and market limitations of the resources and the system.

Market prices

Figure 24 shows a comparison of CAISO prices[10] between markets for a three-day period surrounding the eclipse event. In this chart, the specific hours of the eclipse event, hours-ending 9 through 12, are highlighted in yellow. During the eclipse event, CAISO market prices are more divergent than neighboring days, with real-time market prices lower than the day-ahead integrated forward market (IFM) prices.

The metrics presented here are based on an average of the Default Load Aggregation Point (DLAP) prices within the CAISO area.

Figure 24 Hourly average DLAP prices by market



On October 14, when solar production was about to ramp up, the increase in supply production in combination with low load during the eclipse, resulted in negative energy prices. In response, solar generation was reduced through economic curtailments. By hour ending 12, solar output had fully ramped up to its maximum production, and prices normalized afterwards. In addition, Figure 26 shows a similar trend for hourly averages for WEIM Load Aggregation Point (ELAP) prices aggregated by geographical locations for the RTD market.

The figures below show hourly average ELAP prices for WEIM entities organized by geographic region for a three day period surrounding the eclipse event. Figure 25 and Figure 26 shows fifteen-minute market prices and real-time dispatch prices respectively, with the specific hours of the eclipse event, hours-ending 9 through 12, highlighted in yellow. During the eclipse event, prices for the California and Southwest regions dipped below prices for the Pacific Northwest and Central/Mountain regions. These prices eventually dropped below $0/MWh during the subsequent hours.

Figure 25. Hourly average WEIM ELAP prices by geographical region, FMM

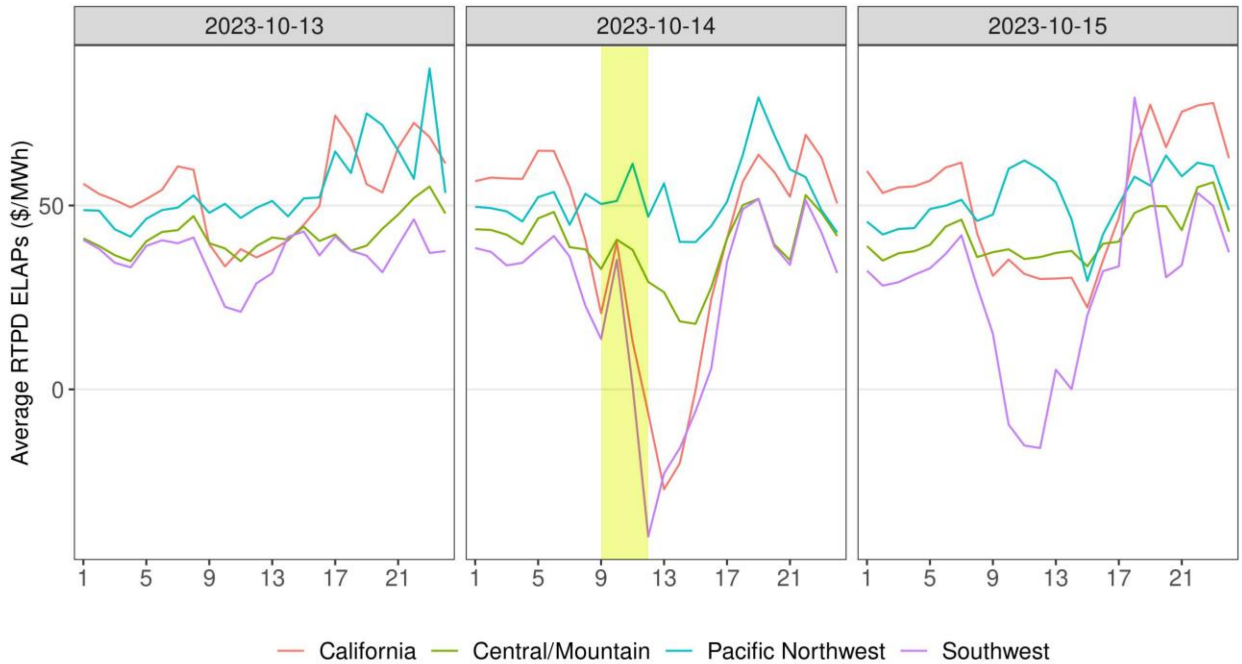
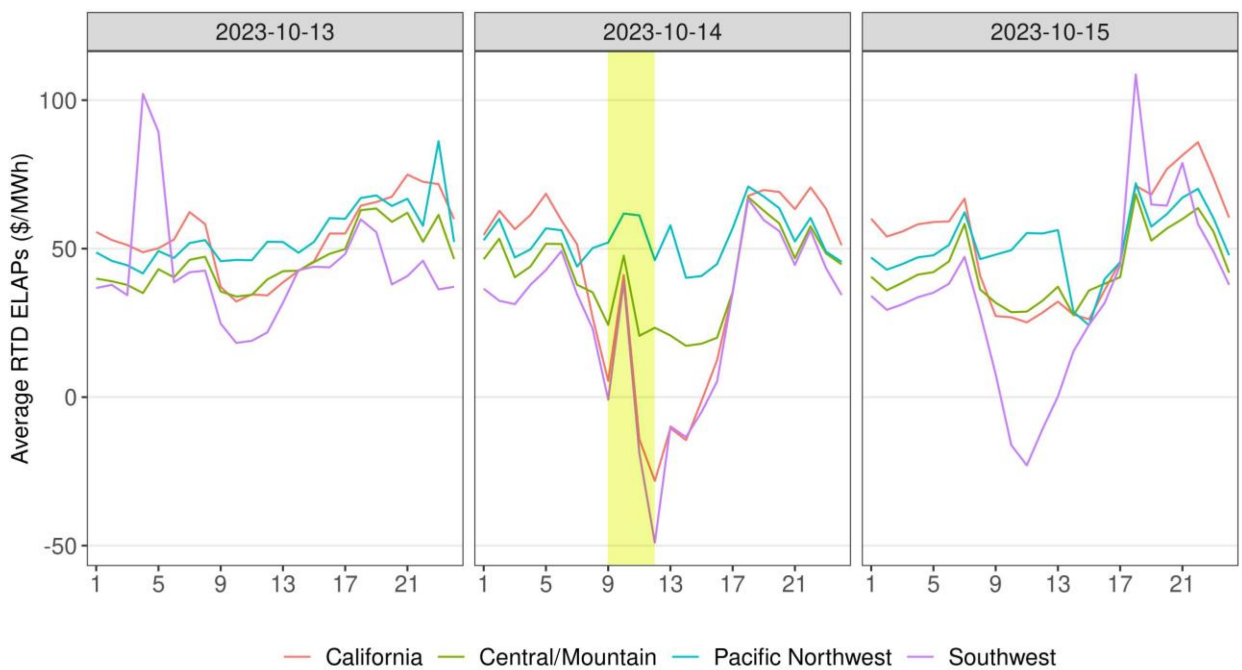


Figure 26. Hourly average WEIM ELAP prices by geographical region, RTD



Regulation

During the eclipse, regulation requirements were adjusted to better position the system to absorb the rapid changes in the generation mix. Regulation up was increased up to 2000 MW and regulation down was increased to 1875 MW. Figure 27 presents the CAISO regulation up requirement and prices in the day-ahead market (IFM). The eclipse event, hour ending 9 through 11, is shaded. The regulation up requirement during the day was noticeably higher on October 14, compared to October 13 and 15. Regulation up requirements and prices peaked during the eclipse hours. With the higher regulation requirements, the day ahead market saw an increase in prices for regulation up to about $20/MWh.

Figure 27 Regulation up (Ru) requirement and prices in day-ahead (IFM)

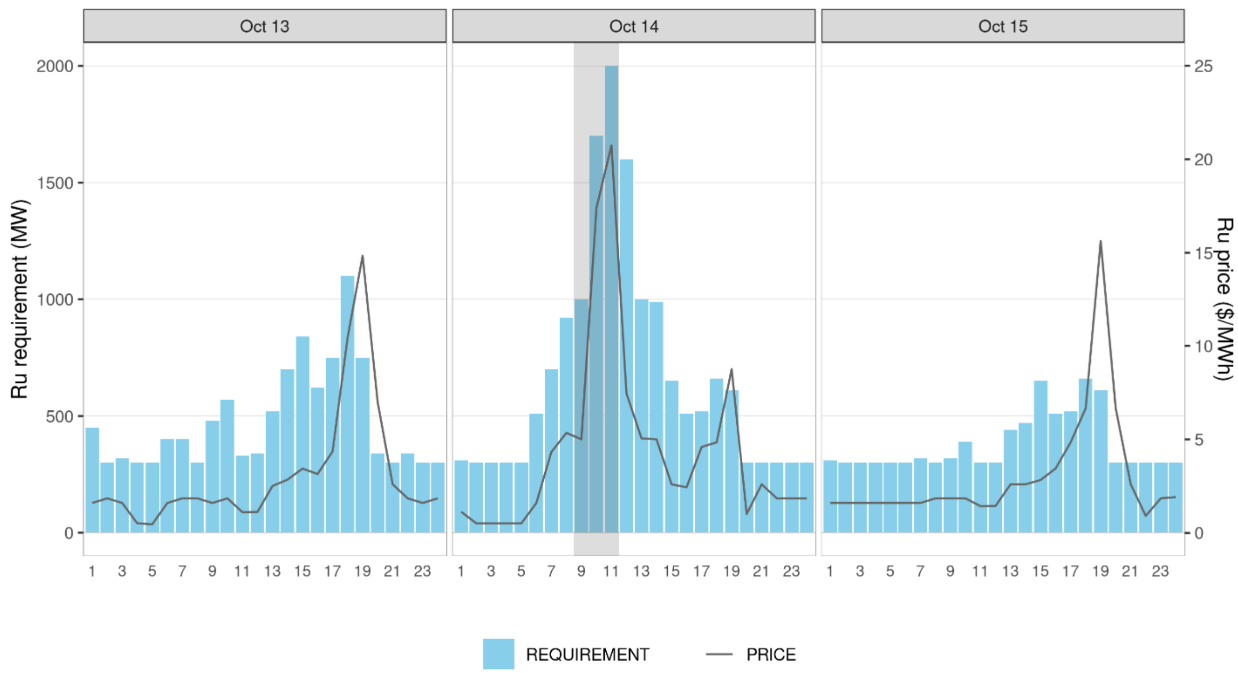
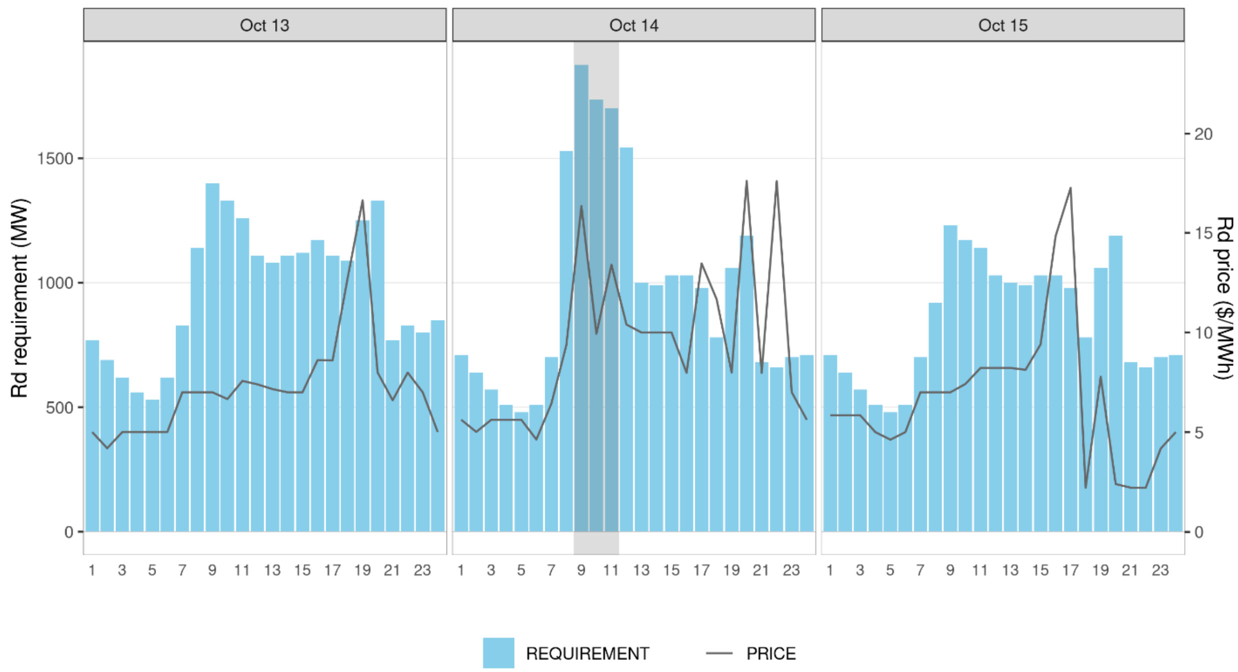


Figure 28 presents the CAISO regulation down requirement and prices in the day-ahead market. Regulation down requirements and prices from hour ending 8 through 12 are noticeably higher than a typical day.

Figure 28 Regulation down (Rd) requirement and prices in the day-ahead (IFM)



The objective is to procure all the regulation requirements through the day-ahead market. The real-time market can re-procure or procure incremental regulation. Figure 29 and Figure 30 show the regulation up and down requirements and prices in the FMM. On October 14th, the regulation up and down prices reached peaked right before the eclipse hours. Throughout the eclipse event, the prices remained low for both regulation up and down.

Figure 29 Regulation up (Ru) requirement and prices in real-time market (FMM)

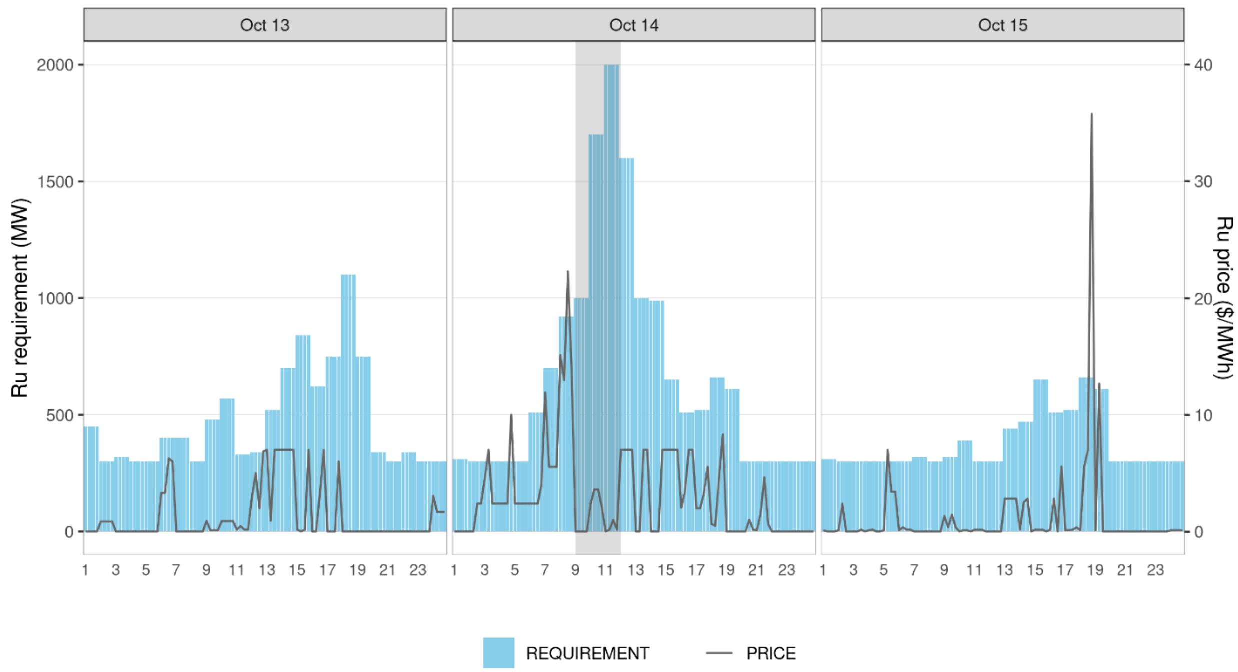


Figure 30 Regulation down (Rd) requirement and prices in real-time market (FMM)

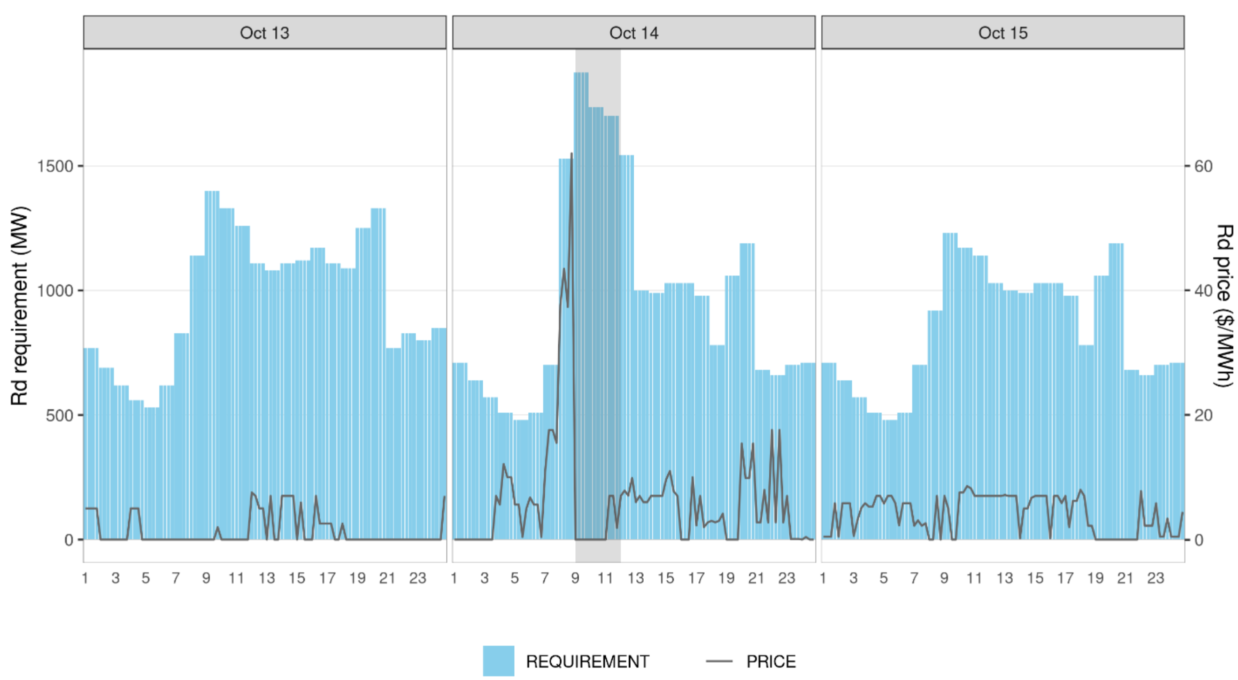


Figure 31 and Figure 32 below show the cost to procure regulation up and down in both day-ahead and real-time markets for a three-day period surrounding the eclipse event. The specific hours of the eclipse event are highlighted in yellow. Day-ahead regulation costs for the hours of the October 14 eclipse event (hours-ending 9 through 12) totaled approximately $55,000 across both upward and downward products. Real-time regulation costs for the same eclipse period totaled approximately $38,000. Day-ahead regulation costs were more distributed across hours over the three-day period, whereas real-time regulation costs were generally lower but spiked on October 14, hour-ending 8, just prior to when the eclipse event began.

Figure 31. Day-ahead regulation up and down costs

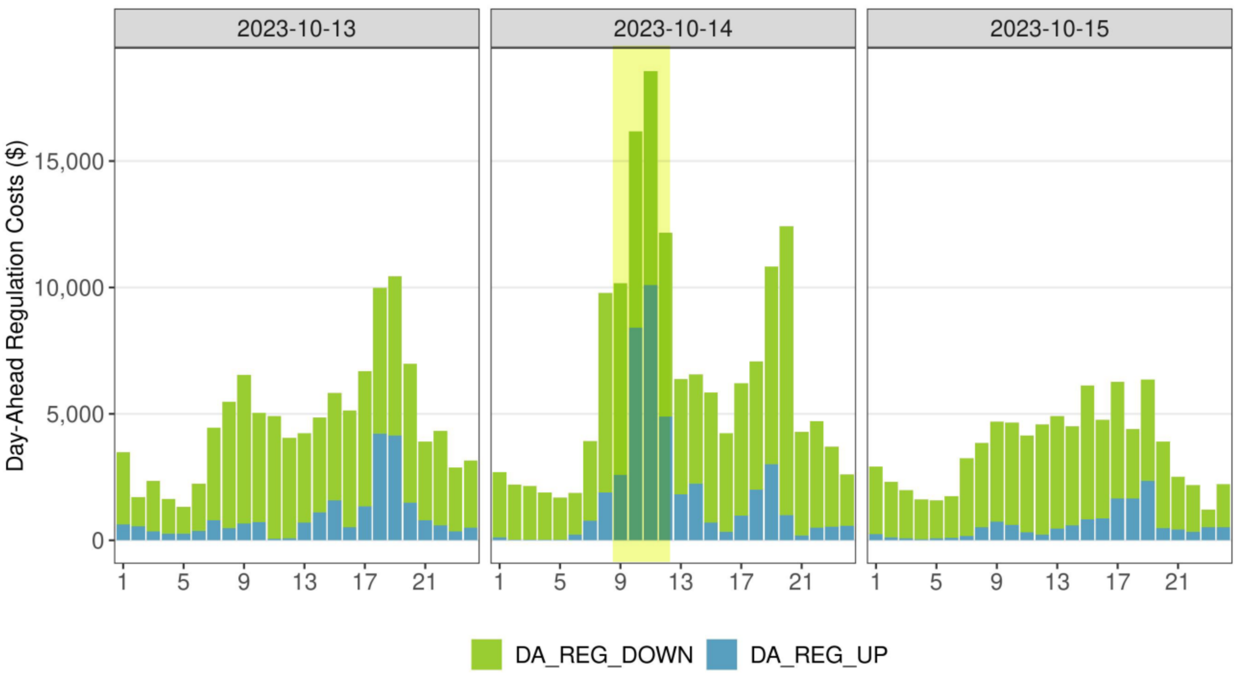


Figure 33 to 35 show a longer-term trend of regulation costs over a two-month span from September 1, 2023 through October 31, 2023. The day of the eclipse event is highlighted. The longer trend shows that regulation costs on the day of the eclipse event, October 14, were somewhat higher when compared to the surrounding days in both markets.

Figure 32. Real-time regulation up and down costs

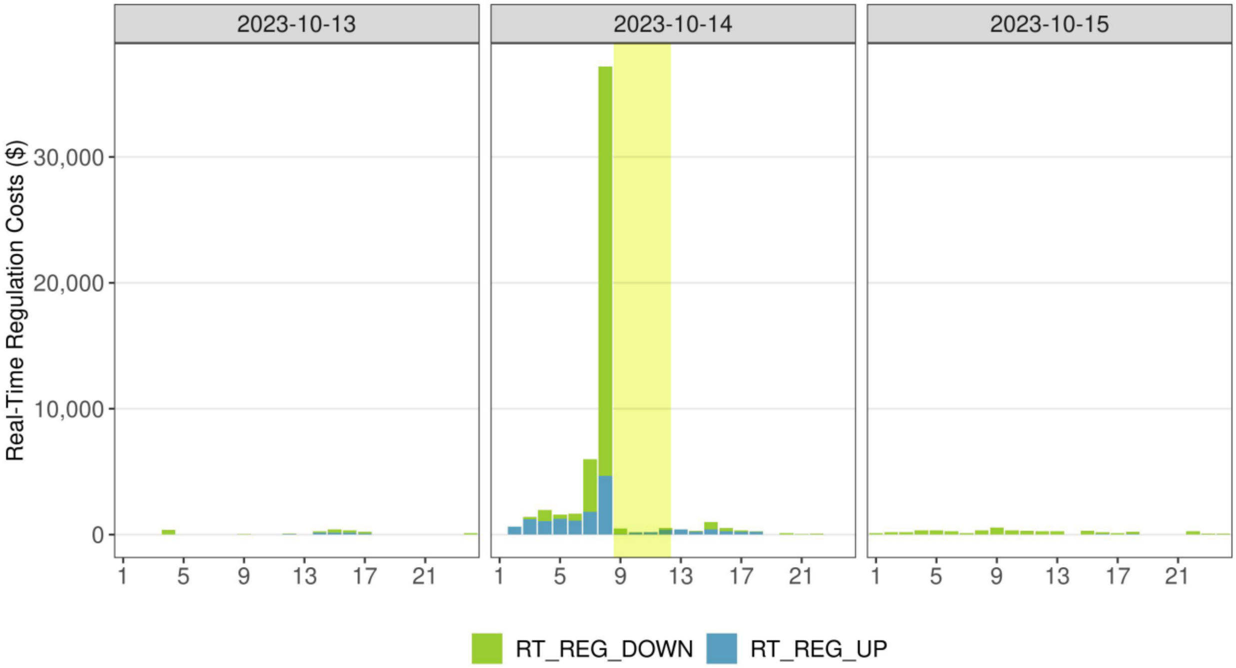


Figure 33. Day-ahead regulation costs, September 1 through October 31

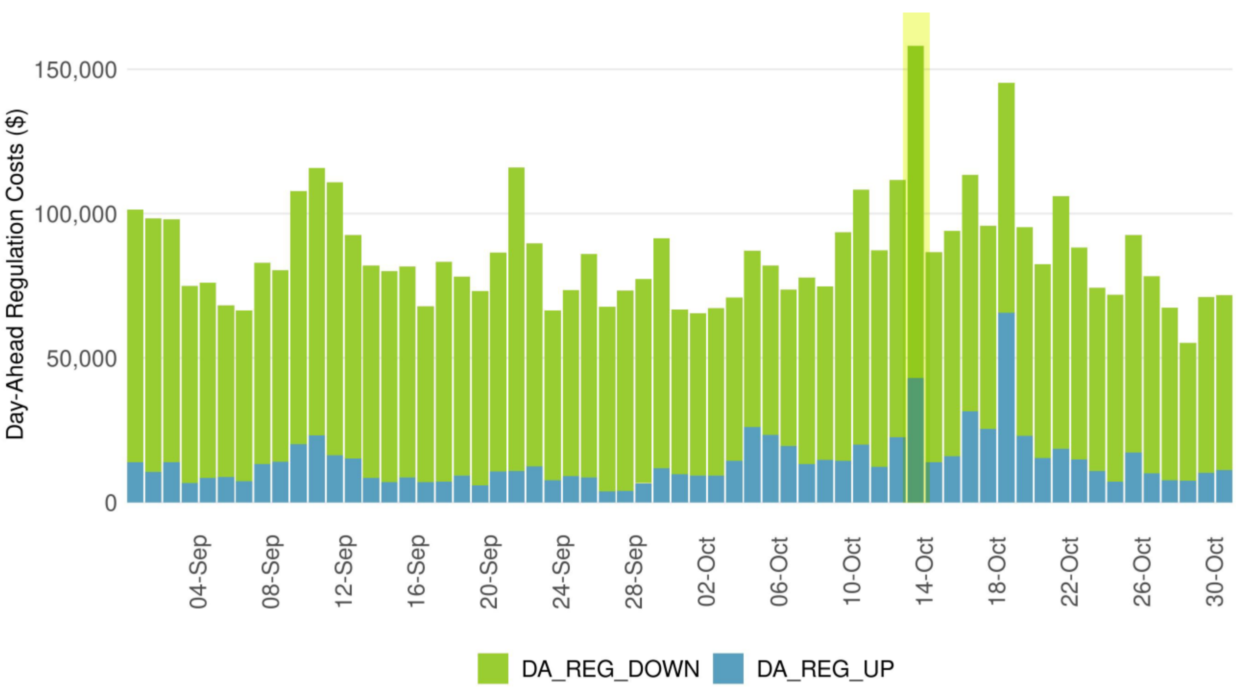


Figure 34. Real-time regulation costs, September 1 through October 31

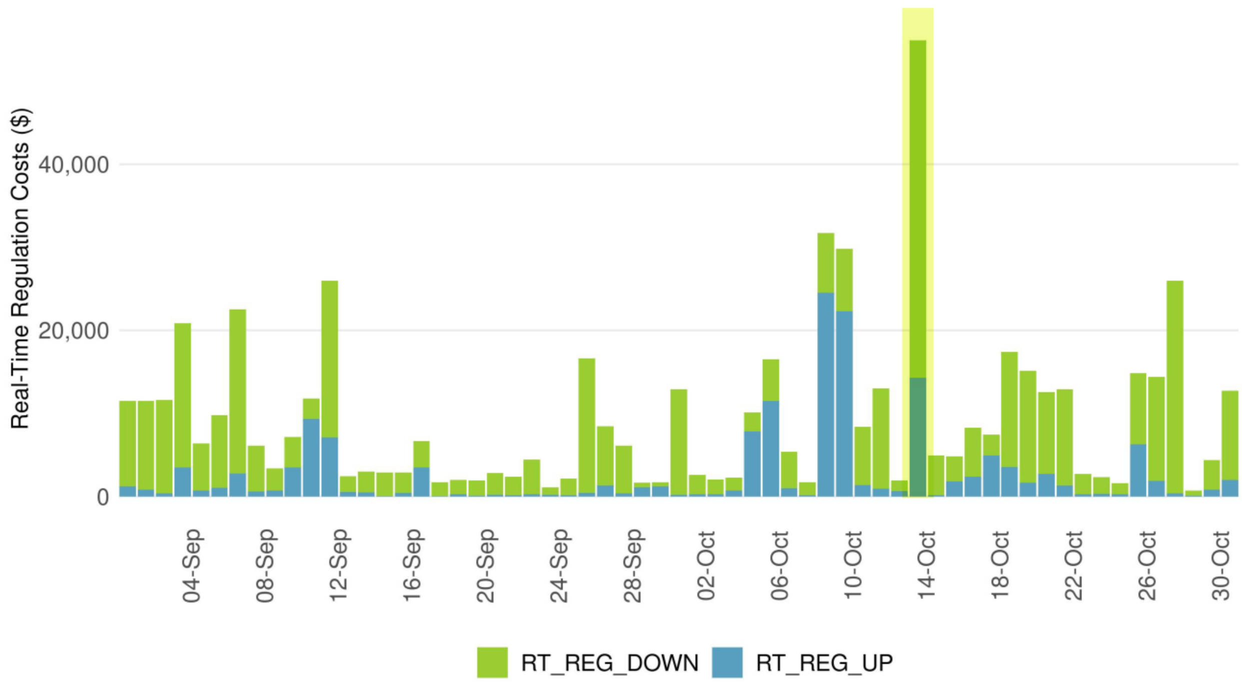
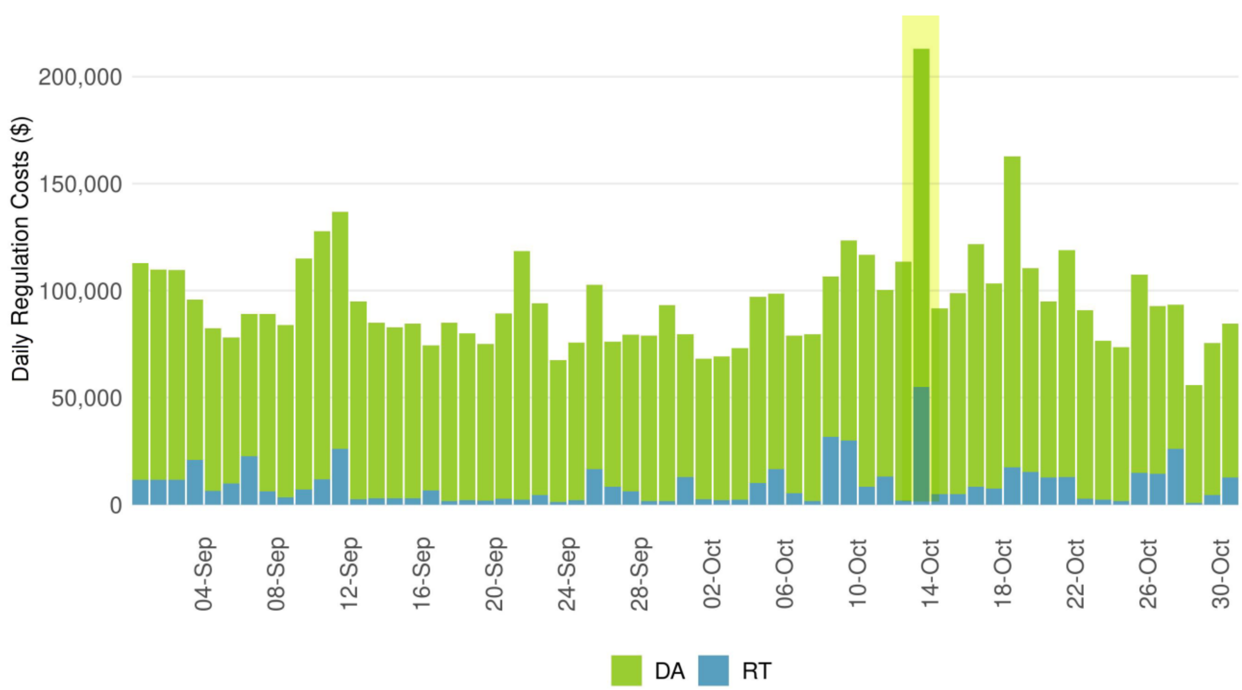


Figure 35. Daily regulation costs, September 1 through October 31

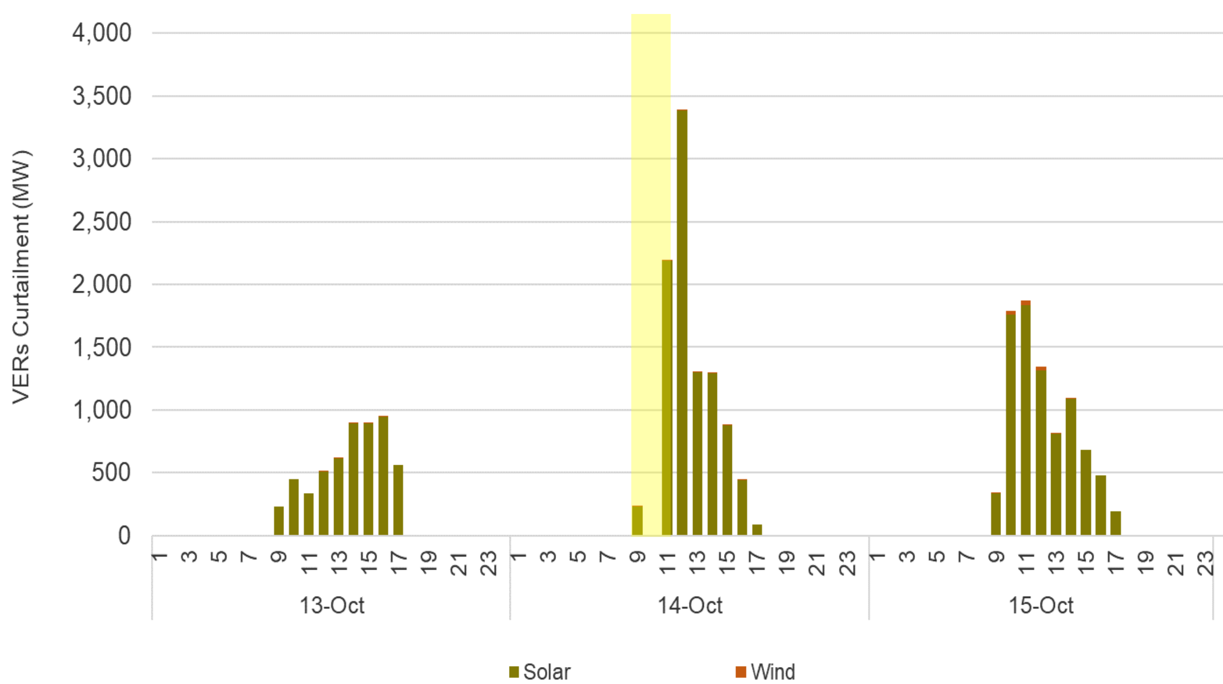


Curtailments

Under certain conditions, such as oversupply and congestion, the market solution may determine the need to curtail renewable dispatches below either the bid-in maximum output or forecasted value. The market will first reduce solar output based on the available economic bids, which reflect the willingness to reduce output. After all the economic bids are exhausted, the market will reduce the output of those resources that have self-scheduled their output to the level of their forecast. Curtailments are measured as the difference between a resource’s dispatch upper limit and its RTD schedule when the resource has an economic bid. They are further classified as economical when there is a bid present or self-schedules when the resource has a self-schedule.

Figure 36 below shows the VERs curtailment from October 13-15. The curtailment on these three days was mainly due to solar. On October 14, the solar curtailment was nearly 0 MW in HE 10 during the eclipse when the solar production was low. In HE 11 and HE 12, the solar curtailment increased when the solar eclipse waned, and the solar production ramped up at a faster rate than normal. Then the solar curtailment returned to a normal level since HE 13 compare with October 13 and 15.

Figure 36 Hourly average VERs curtailment comparing over three days



Resource performance

The dispatch operating target (DOT) values are the instructions the ISO market issues to resources. In order for the system to realize that optimal outcome, it is of paramount importance that resources follow the instructions. Requiring that all resources, including VERs such as wind and solar, follow the DOTs allows the market to optimize the overall solution and reduce burden on regulation that may have occurred if VER resources deviated from the DOTs.

Figure 37 shows the solar DOT (RTD schedules) and actual generation (metered generation). When the solar eclipse started in HE 9 on October 14, the solar DOT and actual generation both were lower than October 13 and October 15 for the same hour. In HE 10, solar production decreased by about 4,000 MW. That was much lower than the same hours on October 13 and 15, when solar production ranged between 11,000 MW and 12,000 MW. In HE 11 and HE 12, solar production started to recover, but it was still lower than the same time period on October 13 and 15. Solar production came back to a normal level in HE 13. During the solar eclipse, actual generation was lower than the DOTs, especially in HE 9 and HE 10.

Figure 38 shows the profile for solar actual production and actual load compared to the profile of VER curtailments. During intervals in hour ending 11, when solar generation was ramping back to full production, the load was reaching a low point and the market was reducing other types of supply. This led to a short period of oversupply in the market, which required VER curtailments of up to 5,500 MW in hour ending 11. Figure 39 shows the profile of solar and wind production compared to the load and net load for October 14. The solar and wind production does not include dynamic generation.

Figure 37 DOT vs actual production for solar production

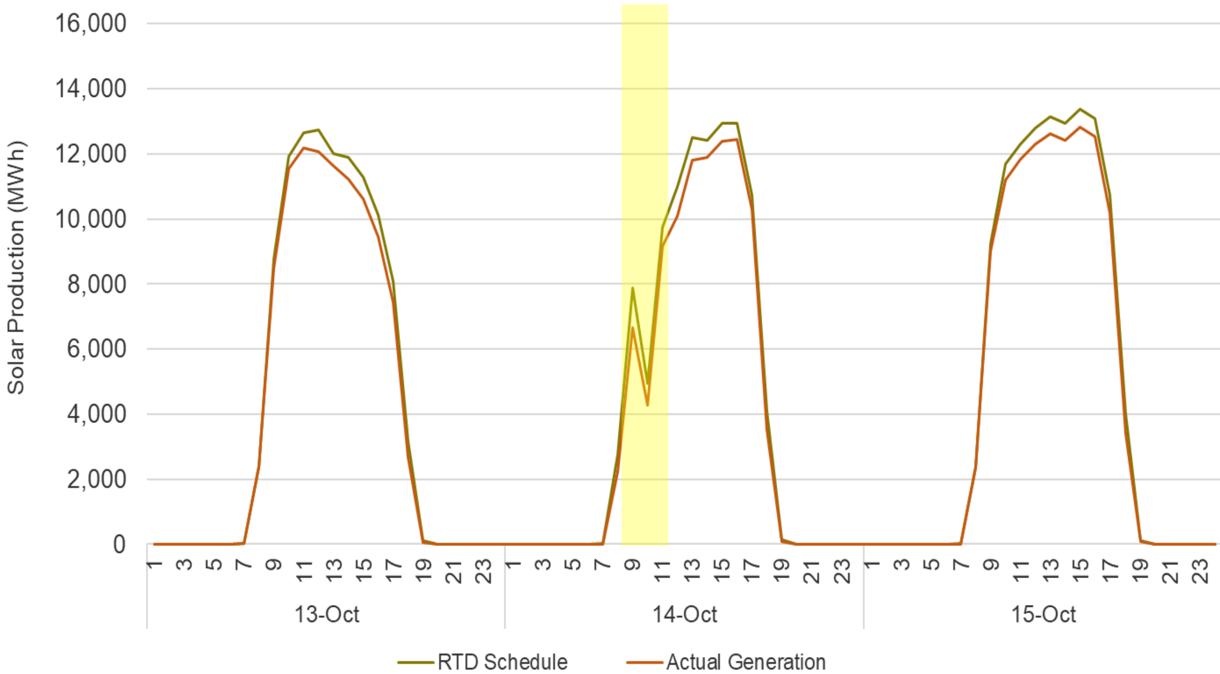


Figure 38 Solar production with curtailments vs load for October 14

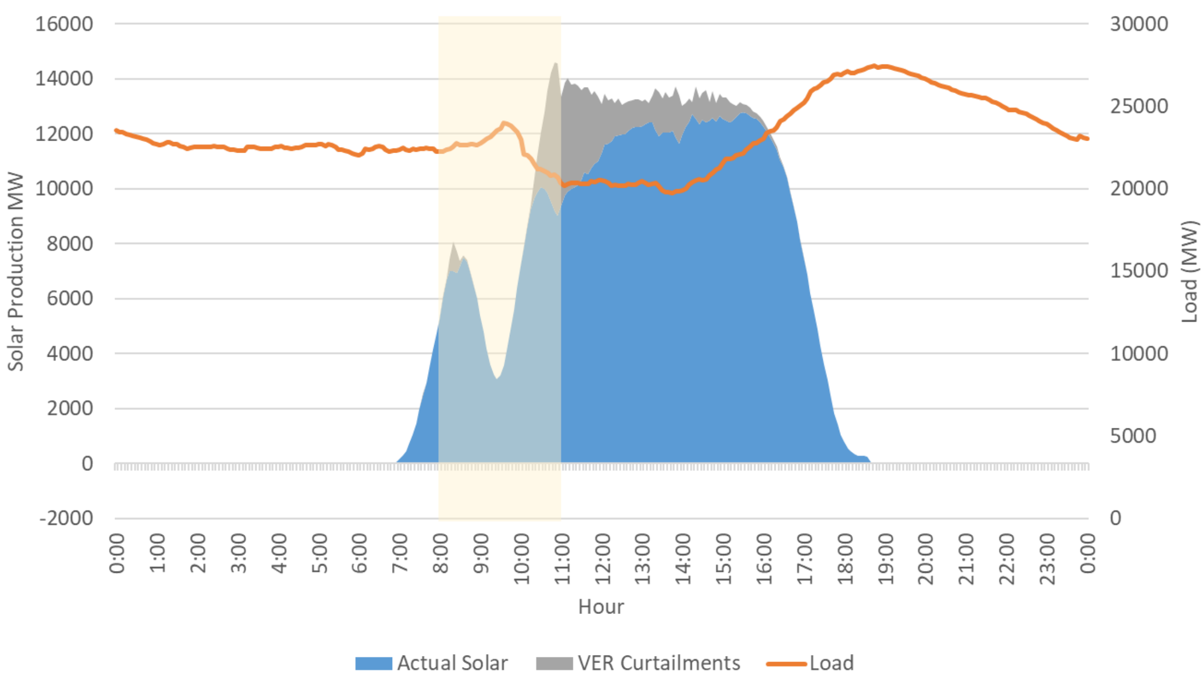
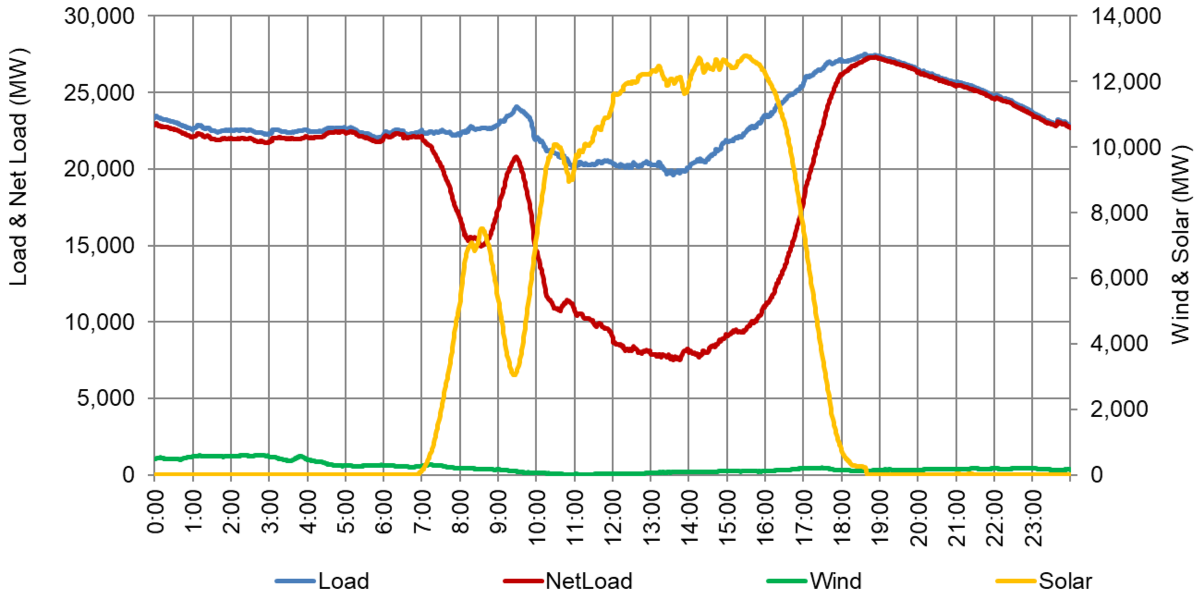


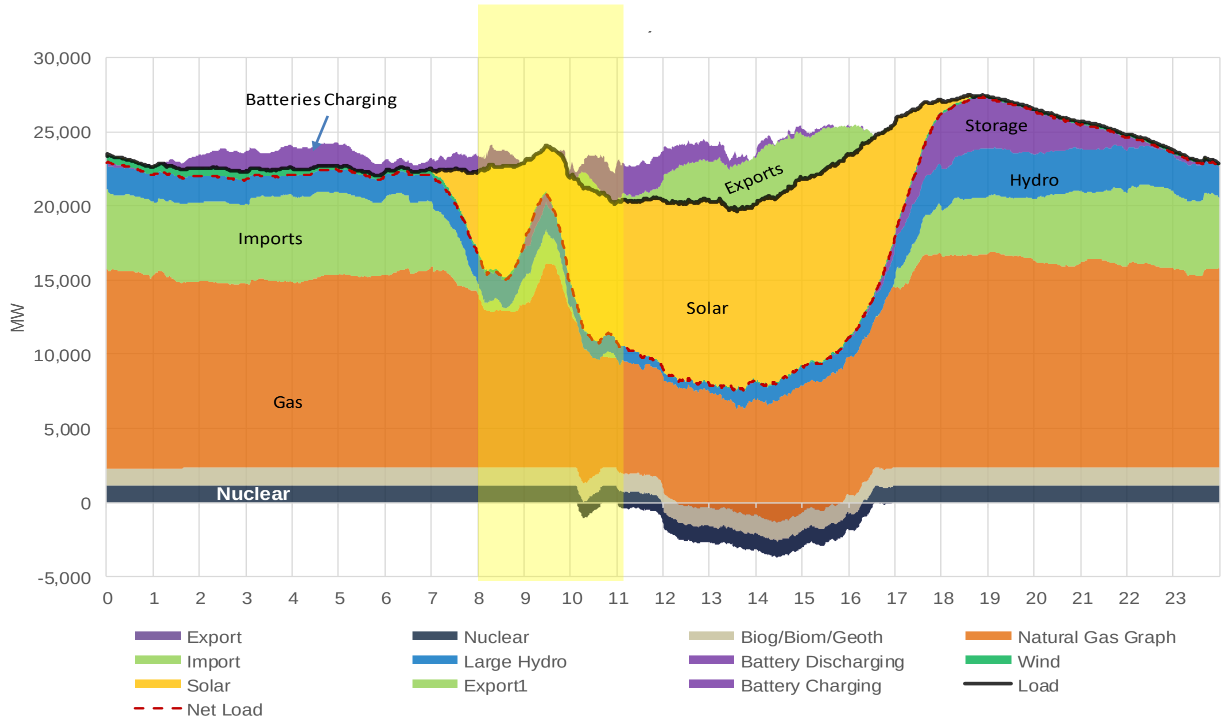
Figure 39 Comparison of Load, Net Load, Solar and Wind production for October 14



Generation Mix

Figure 40 shows the CAISO's resource breakdown on October 14 including the rapid changes in solar production during the eclipse hours that are compensated by other generation fuel types filling in. At about 8:32 a.m., as solar production began to decline, gas and hydro production as well as imports replaced the loss of solar production. To a smaller extent batteries without ancillary service awards were also dispatched up. After 9:25 a.m., as solar production began to increase, gas, hydro and imports were dispatched downwards to compensate for the increased in solar production. Batteries were charging during the morning hours so that they were ready to discharge during the solar eclipse. Also notable: Wind production was negligible during the solar eclipse.

Figure 40 Generation Mix of the energy produced



Storage Performance

On October 14, there were 83 storage resources actively participating in the ISO markets. Most storage resources participated in both the energy and ancillary service markets. This section presents the performance of the energy storage resources on October 14.

Figure 41 presents the aggregate state of charge (SOC) of the storage resources in the RUC process (day-ahead) and RTD (real-time) market. It presents the comparison of the aggregate state of charge spanning the three consecutive days. The overall state of charge pattern on October 14 was similar to the typical patterns observed for storage resources; state of charge peaked in the afternoon hours between hour ending 15 to 18. State of charge was generally higher in the RTD compared to the day-ahead market. During the eclipse hours highlighted for hours ending 9 to 11, a brief dip occurred in the trend, indicating the depletion of state of charge to compensate for the change in solar generation. The comparison of state of charge across the three days shows the market was aligning the storage resources in a way to be able to charge significantly during the morning so that they had enough state of charge to dispatch efficiently once the solar generation was ramping down.

Figure 41 State of charge, RUC vs. RTD

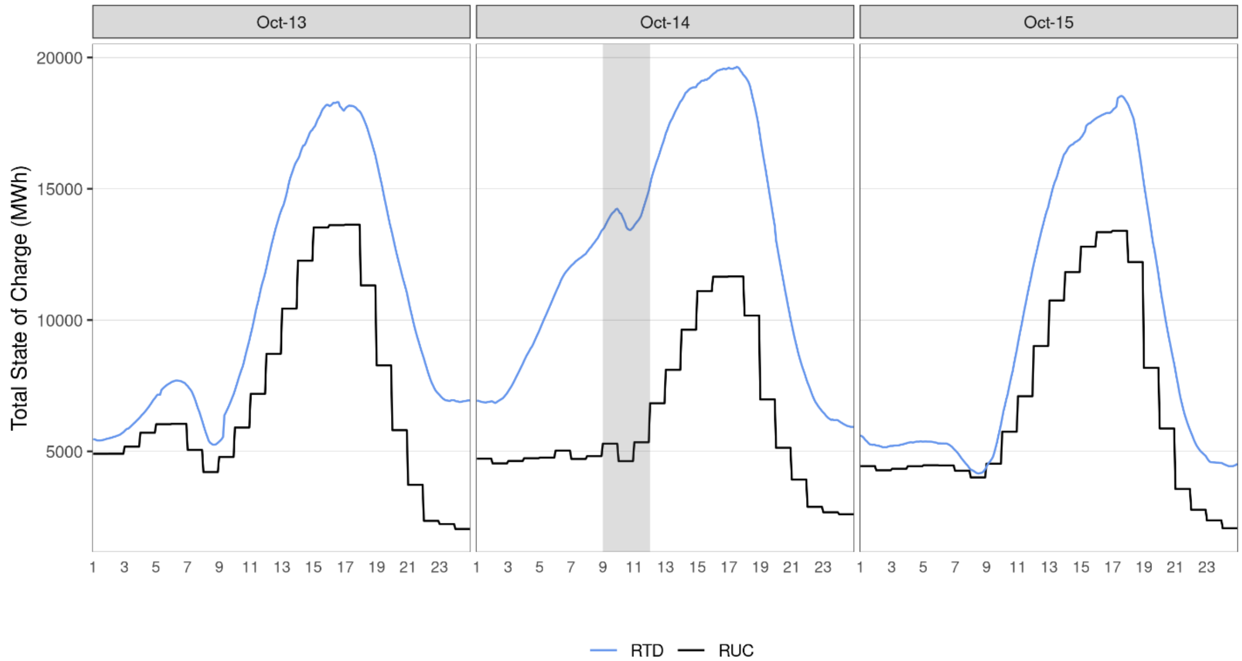


Figure 42 compares the aggregated energy schedules for storage resources in the DA and RTM. In both markets, the storage resources typically charged during peak solar hours of the day, and discharged in the evening peak net-load hours. It presents the comparison of the total energy schedule spanning the three consecutive days. On October 14, storage was charged in advance to prepare for the event, discharged during the eclipse hours, and subsequently recharged for later use.

Figure 42 Energy Schedules, RUC vs. RTD

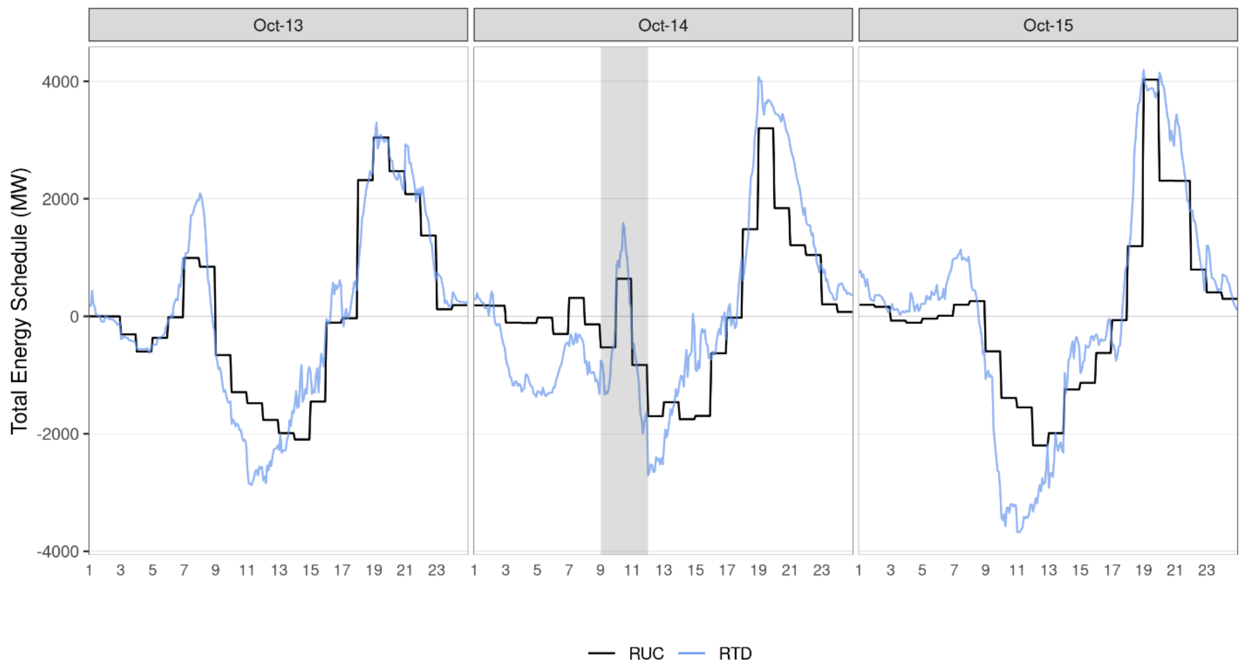


Figure 43 illustrates the energy awards for storage with prices in the RTD. The storage resources charged continuously through the morning peak hours, in anticipation of the eclipse event. During the eclipse hours, the storage resources discharged as prices reached the local peak, and charged in the midday hours after the event, when the real-time prices had turned negative.

Figure 43 RTD energy awards for storage resources and RTD SMEC

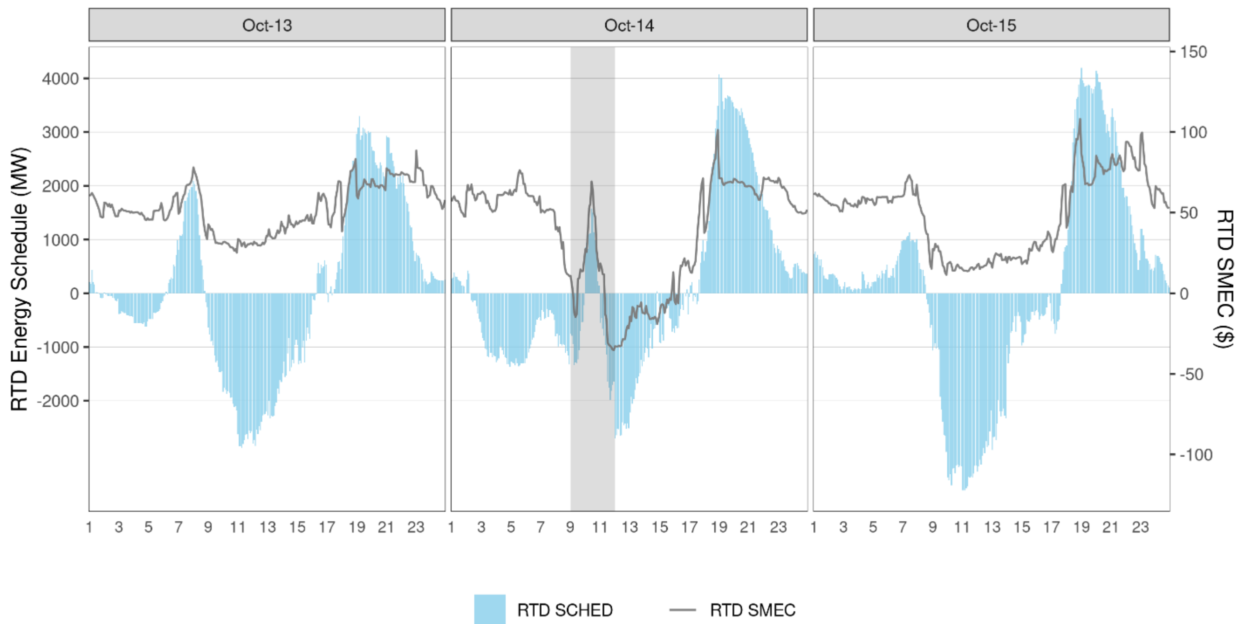
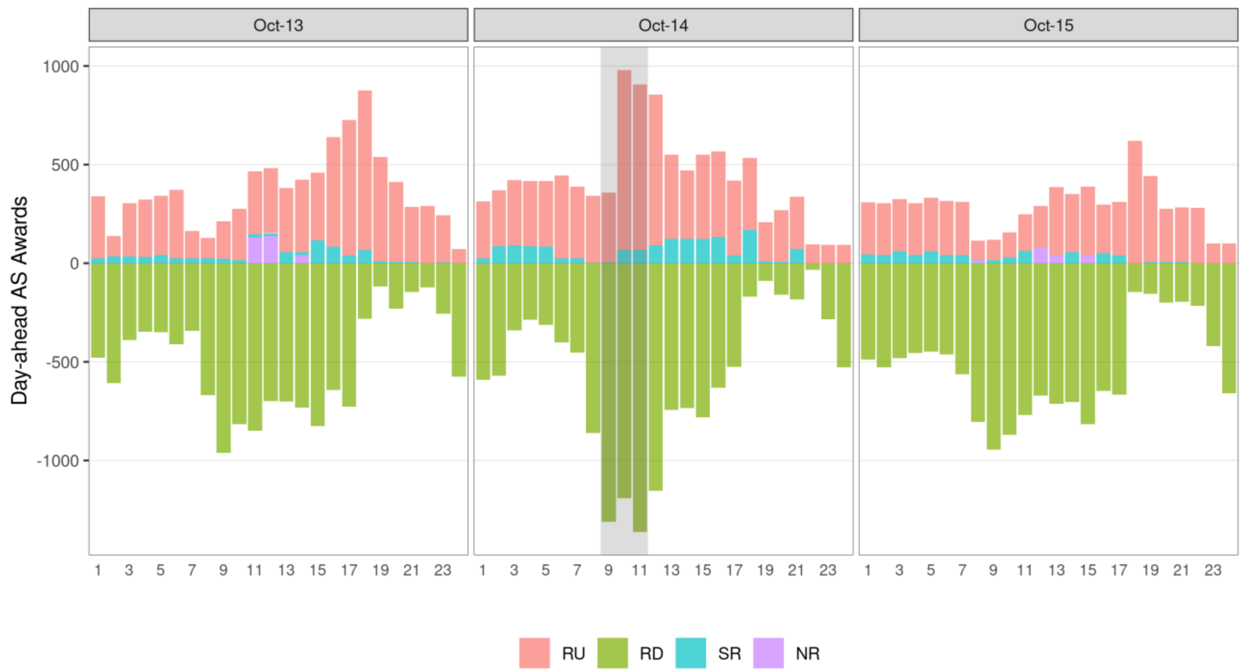


Figure 44 shows the hourly ancillary services (AS) awards for storage resources in the day-ahead market. Both upward AS (RU, SR, NR) and downward AS (RD) peaked during the eclipse hours. Storage resources contributed with a significant share of total regulation.

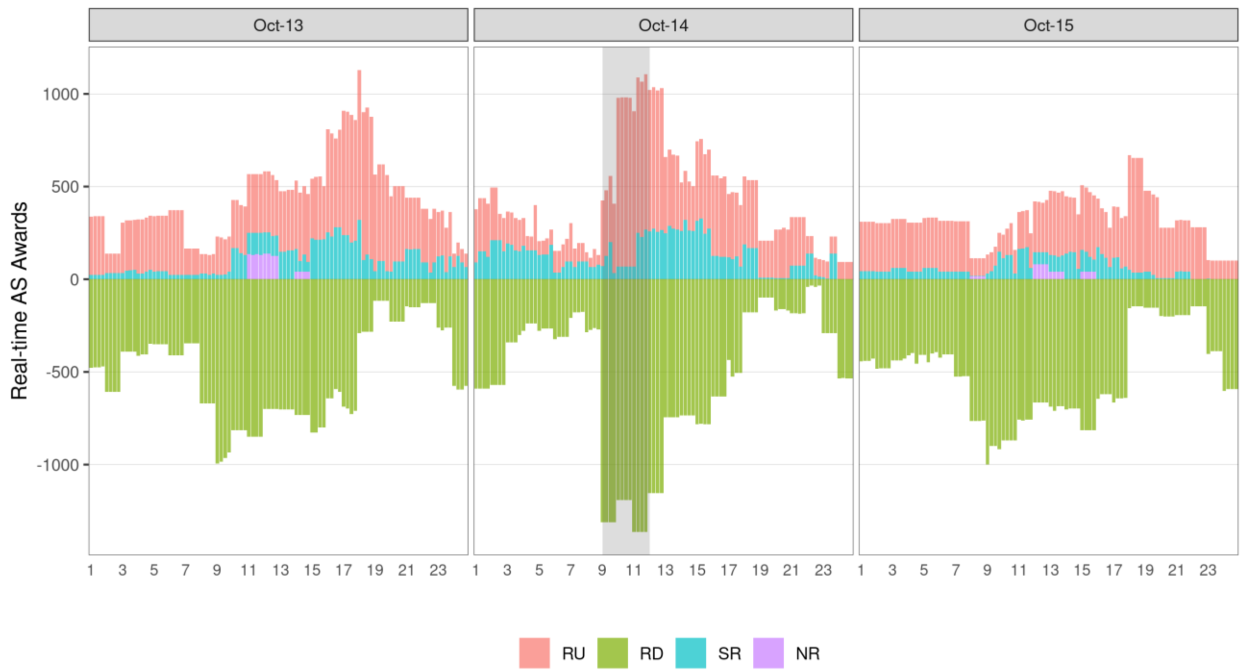
During the solar eclipse, the storage resources received the highest upward AS awards in hour ending 10, including 913 MW regulation up and 67 MW of spinning reserves in the FMM. The downward AS awards for storage resource reached a peak of 1362 MW in hour ending 11 for both FMM and IFM markets.

Figure 44 Day-ahead (IFM) AS awards



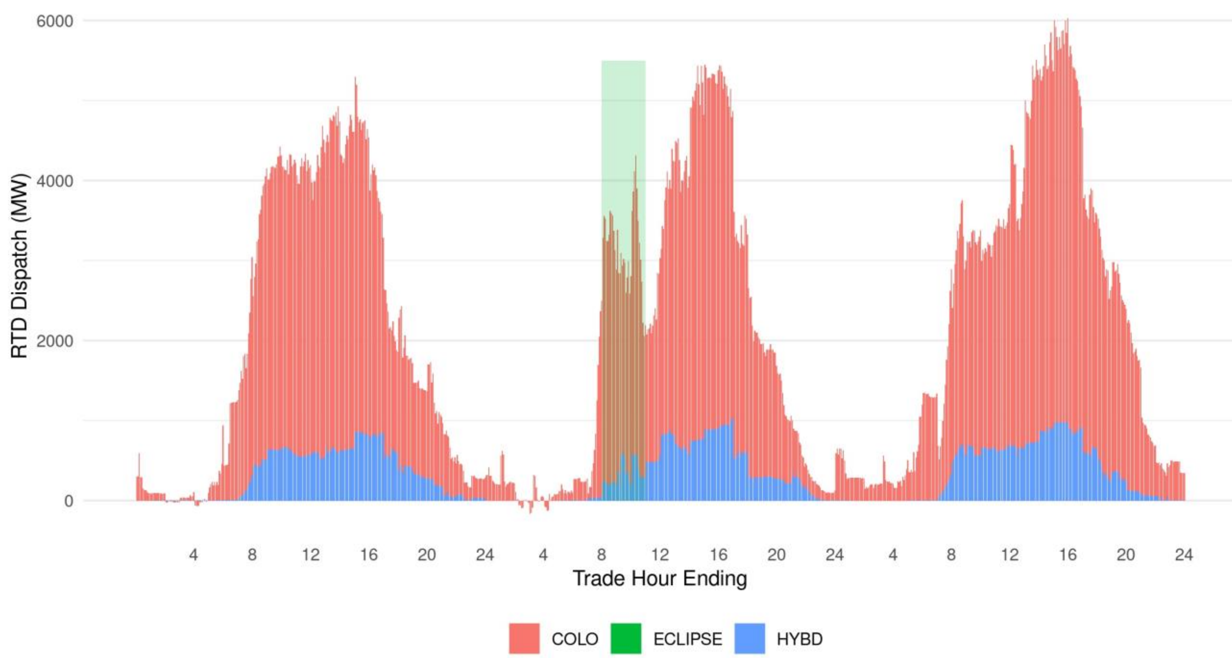
The majority of the AS requirements are procured through the day-ahead market. Given the changing conditions to the real-time operation, the RTM is the last opportunity to re-procure or procure incremental AS. Figure 45 presents the total ancillary service awards in real-time for storage resources, showing a similar pattern to the day-ahead.

Figure 45 Real Time (FMM) AS awards



The CAISO market provides two different participation models for mixed-fuel resources: the co-located model and the hybrid model. Figure 46 shows the performance of mixed-fuel resources from October 13-15. Resources using the co-located model are shown in red and resources using the hybrid model are shown in blue. The approximate time of the eclipse is shown in light green. October 13 shows a more typical pattern for the performance of mixed-fuel resources; the schedules follow the solar ramp in the morning and have some small variations during midday, when the battery component charges from inexpensive solar. During the solar eclipse event, the hybrid and co-located resources reached a combined maximum of 4,311 MW in HE 11. The co-located resources had about 3,738 MW, whereas hybrid resources had about 573 MW in that interval.

Figure 46: Hybrid and co-located resource performance



The performance of mixed-fuel resources on October 14 differs from the typical pattern. While the resources' output did ramp up quickly before the eclipse began, their output decreased once the eclipse began, commensurate with the decreased levels of solar irradiance. As the eclipse peak passed during hour ending 11, the output quickly spiked and then quickly decreased again. That spike was due to increased solar irradiance causing increased output from solar components. This increased output lead to the need for the market to increase economic curtailments, which caused the output to dip once again.

Because of the unique configuration of mixed-fuel resources, some of this curtailment might have been avoided by having the battery component charge from the increased solar output. From a more granular review of the component-specific performance, this appears not to have happened because the battery components submitted charging bid prices near to the bid floor price of negative $150/MWh.

Flexible Ramping Product

With the redesign of Flexible Ramping Product (FRP) that was launched in February 2023, this section provides an overview of the FRP performance during the solar eclipse, which is relevant in situations when the system operates under tight supply conditions.

Figure 47 shows the FRU (Flexible Ramp Up) requirements versus procurements in the passing group in FMM. BAAs passing the capacity and flexible ramping tests collectively benefit from a passing group to procure FRP, leveraging BAA diversity. Those failing must individually fulfill their own requirements. The market will procure uncertainty requirements at that group level while respecting the transmission and WEIM transfer constraints. The FRU requirements were fulfilled for all intervals over the three days. During the solar eclipse hours, all WEIM BAAs passed both tests in the upward direction and group FRU requirements were fulfilled with no relaxation. FRU procurement reached maximum of 3230 MW in hour ending 9.

Figure 47 FRU passing group requirement vs. procurement

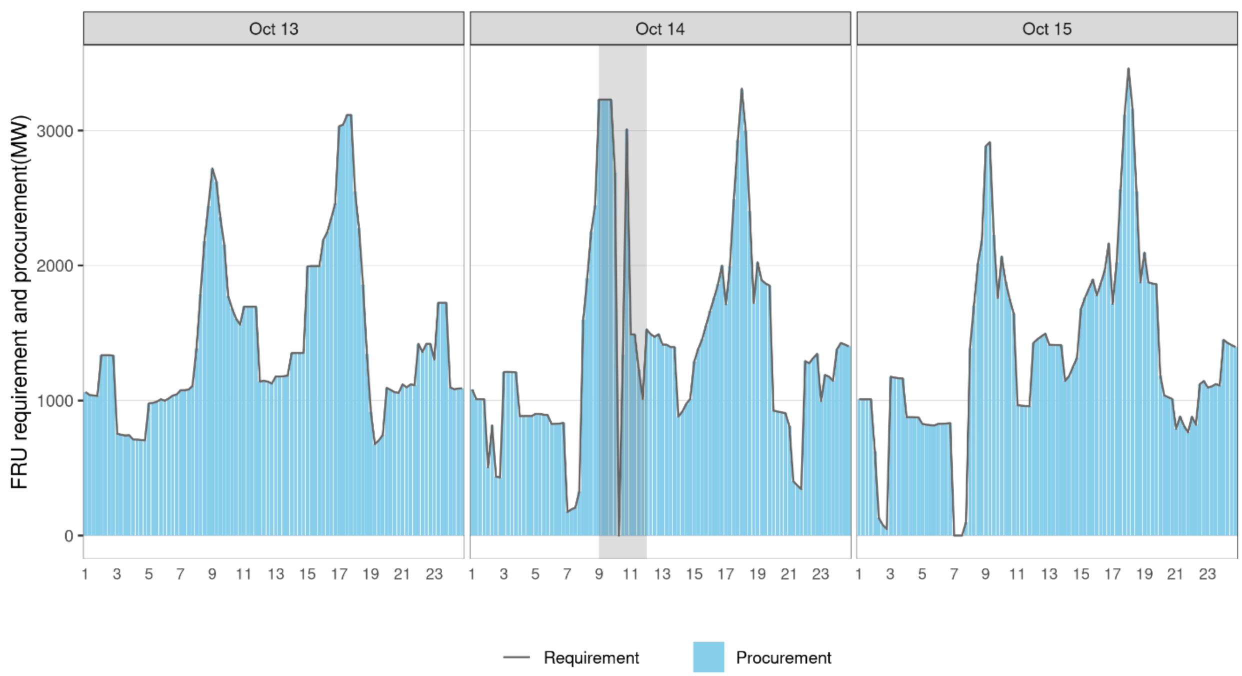


Figure 48 and Figure 49 presents the FRU procurement across the WEIM-wide area in the passing group. By region, FRU procurement primarily sourced from California and Pacific Northwest throughout the day, while during the majority of the solar eclipse hours, the procurement was sourced from Pacific Northwest region. By resource type, generic non-generating resources (GNRC), hydro, and storage resources were the main resource types getting FRU awards. During the eclipse hours, gas also became one of the main contributors.

Figure 48 FRU procurement by region

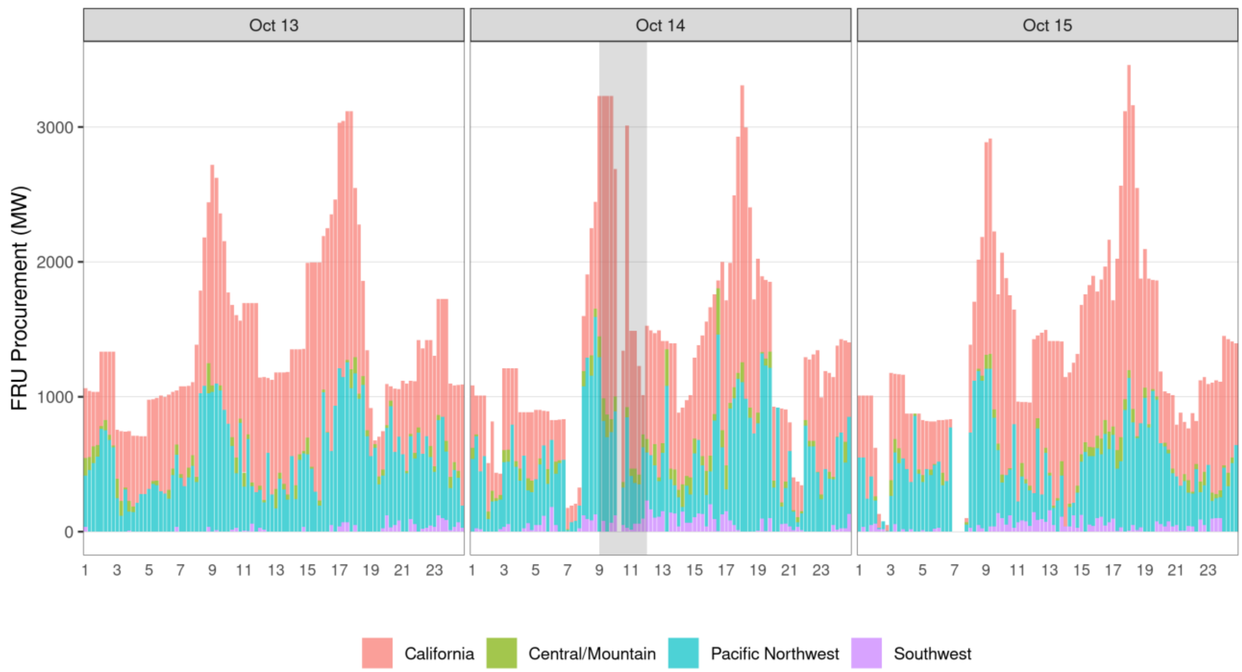


Figure 49 FRU procurement by resource type

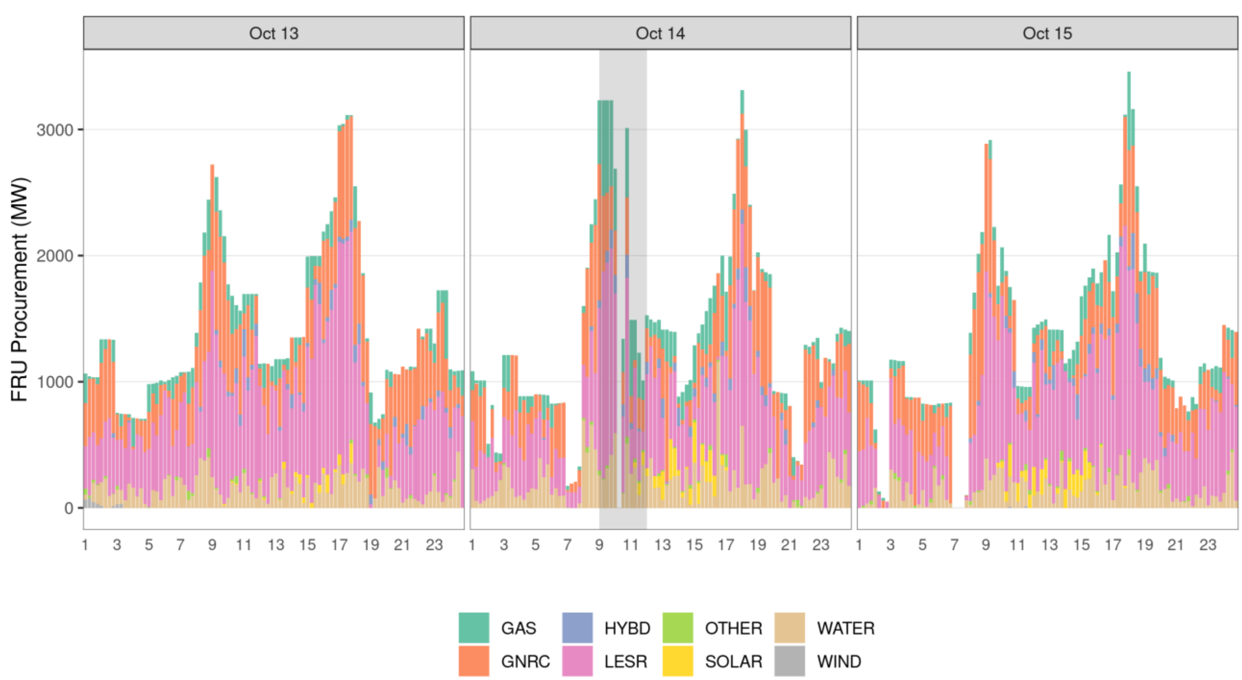


Figure 50 shows the FRD requirements versus procurements in the passing group in FMM. The FRD requirement dropped to its minimum in the middle of the solar eclipse period and reached its peak shortly afterward. The FRD requirements were generally fulfilled for all intervals over the three days. During the eclipse hours, all but one WEIM BAA passed both tests in the downward direction, and the group FRD requirements were fulfilled with no relaxation. FRD procurement reached a emaximum of 2189 MW in hour ending 11.

Figure 50 FRD requirement vs. procurement

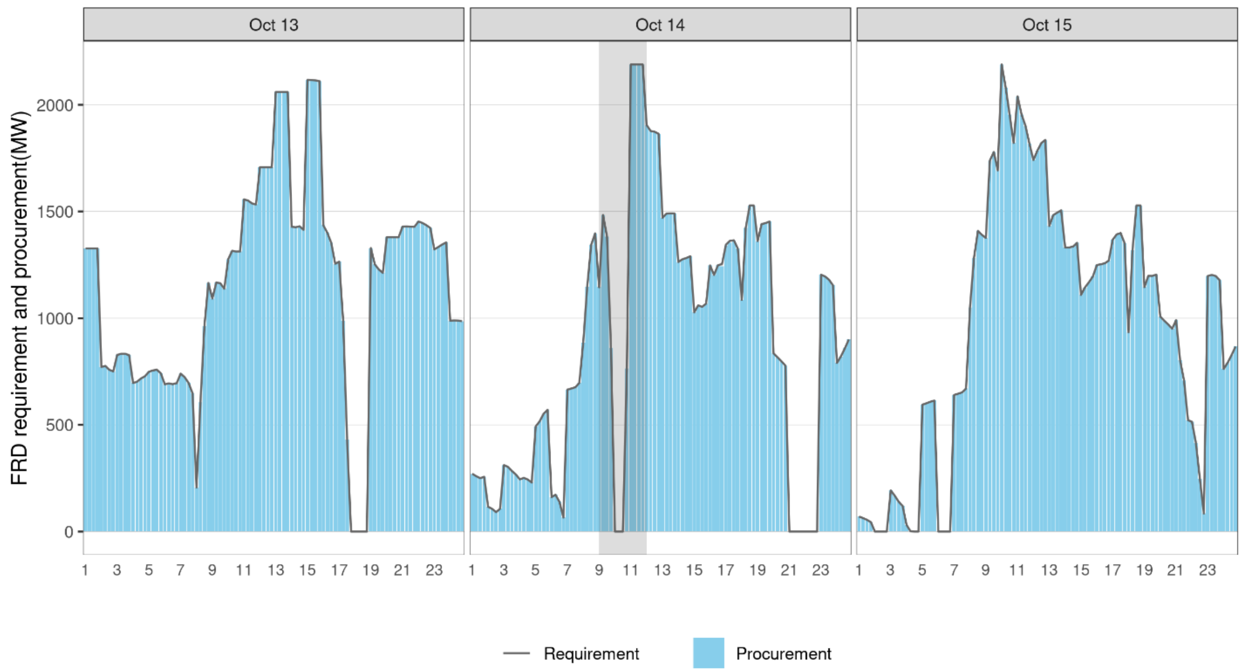


Figure 51 and Figure 52 present the FRD procurement breakdowns in the passing group. By region, FRD procurement was primarily sourced from California, the Southwest and the Pacific Northwest. By resource type, solar was the main contributor for the midday hours, while gas, hydro, and storage resources were the main sources for the remaining hours.

Figure 51 FRD procurement by region

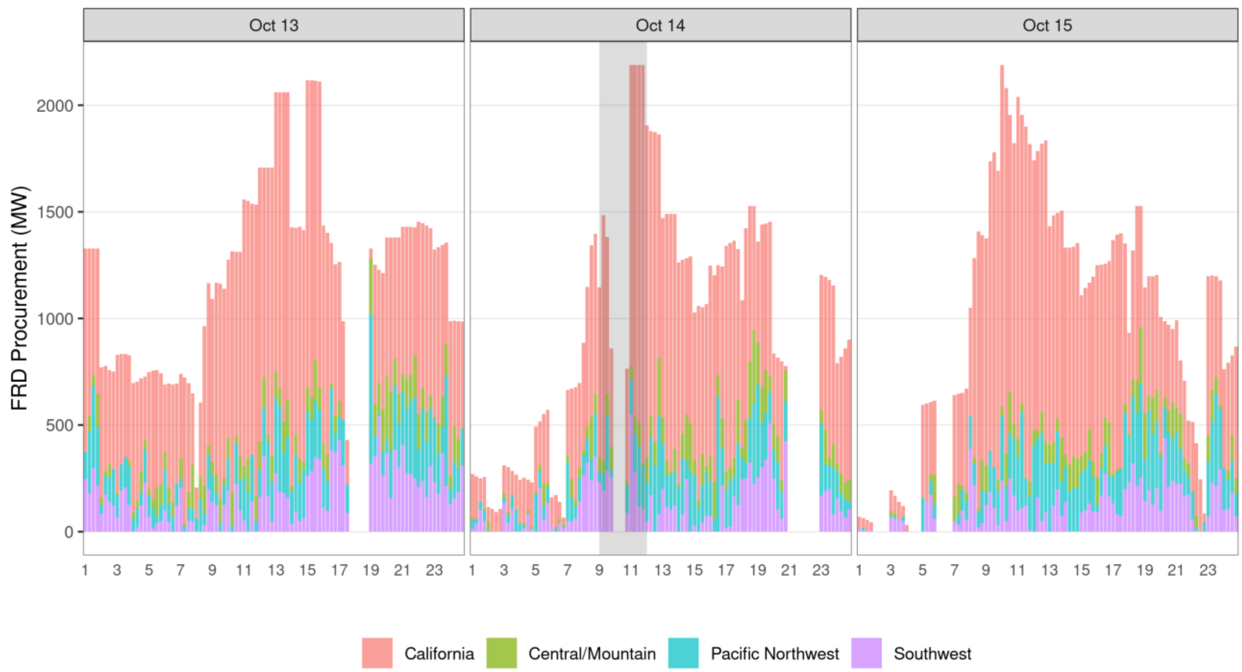
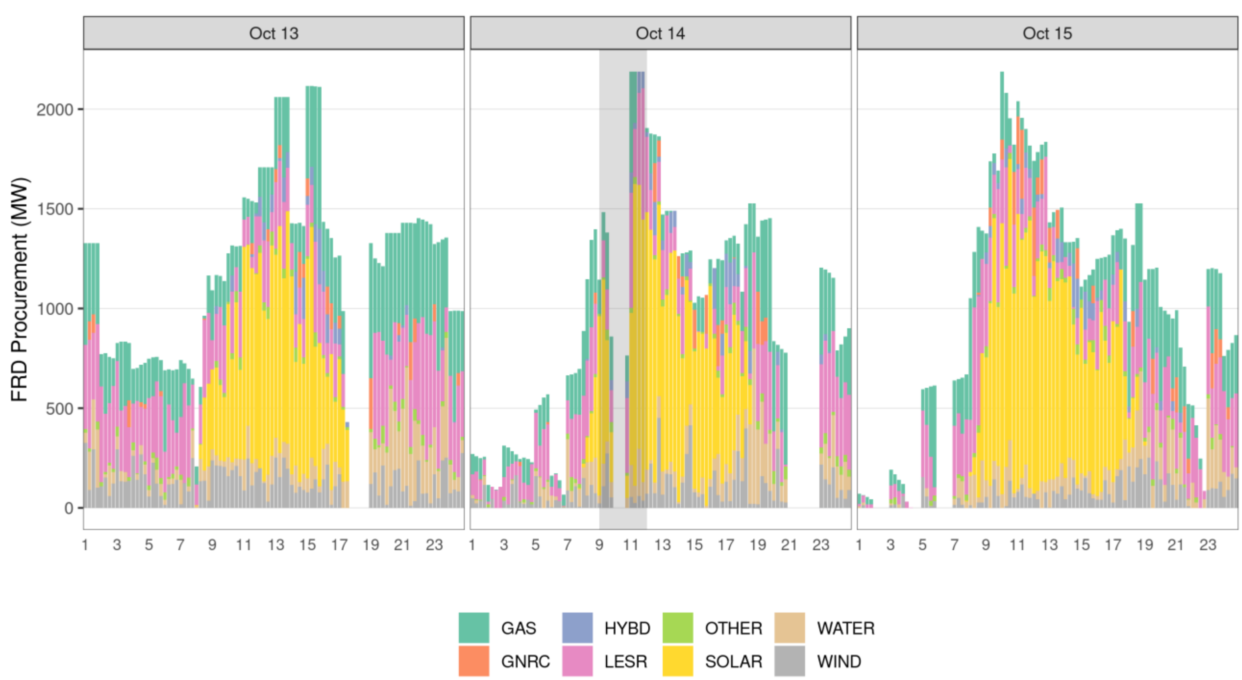


Figure 52 FRD procurement by resource type



Net Schedule Interchange

A pivotal aspect of the supply and demand mix within the ISO system is intertie transactions, encompassing static non-resource-specific imports, dynamic schedules on the supply side, and exports on the demand side. The net outcome of these three components yields the net schedule interchange.

Net schedule interchange (NSI) is the net import or export (i.e. gross imports minus gross exports) into or out of the ISO BAA. Figure 53 shows the NSI in the five-minute market for October 13-15. October 13 (shown in red) is an example of a more typical day when NSI decreases in the morning hours as CAISO begins increasing its exports of solar. The approximate time period of the eclipse is shown in light green.

On the day of the eclipse (October 14, shown in green) starting in hour-ending 9, NSI deviates from the typical pattern as the ISO BAA imported more to make up for lower solar output. The patterns across the three days for the fifteen-minute market and for the IFMare similar, so the associated charts are excluded for brevity's sake.

Figure 53: Net schedule interchange in RTD for October 13 through 15

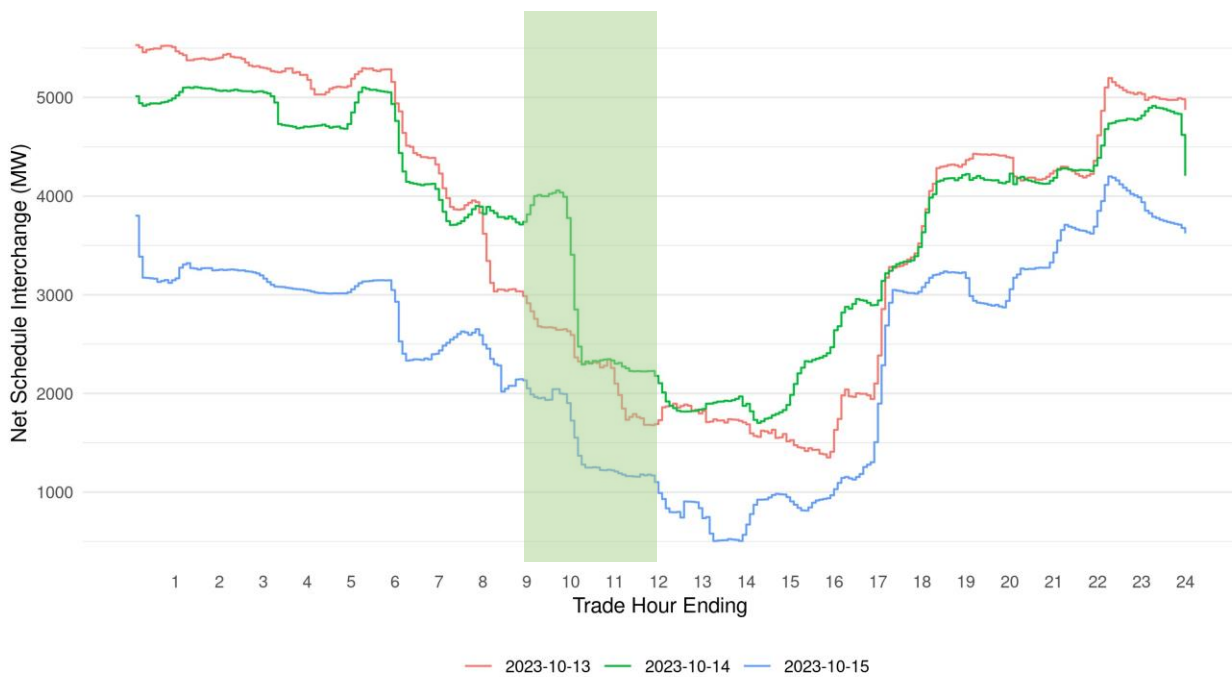


Figure 54 also shows the NSI trend but only focuses on October 14 and instead differentiates across three markets: IFM, FMM, and RTD. The approximate time period of the eclipse is shown in light green. The overall patterns across the three markets are relatively consistent, particularly around the timeframe of the eclipse. However, the most noticeable difference is that IFM was consistently lower than FMM and RTD prior to the beginning of the eclipse and during the eclipse. This was due to several large imports being awarded in FMM and RTD that were not awarded in the IFM. Many reasons exists for why an import may be awarded in FMM and RTD but not in IFM. For example in hour ending 9 on October 14, the largest import was not awarded in IFM because its bid prices were not economically competitive in IFM, but once the scheduling coordinator updated the price for its real-time bids, it became economic in the real-time markets.

Figure 54: Net schedule interchange by market for October 14

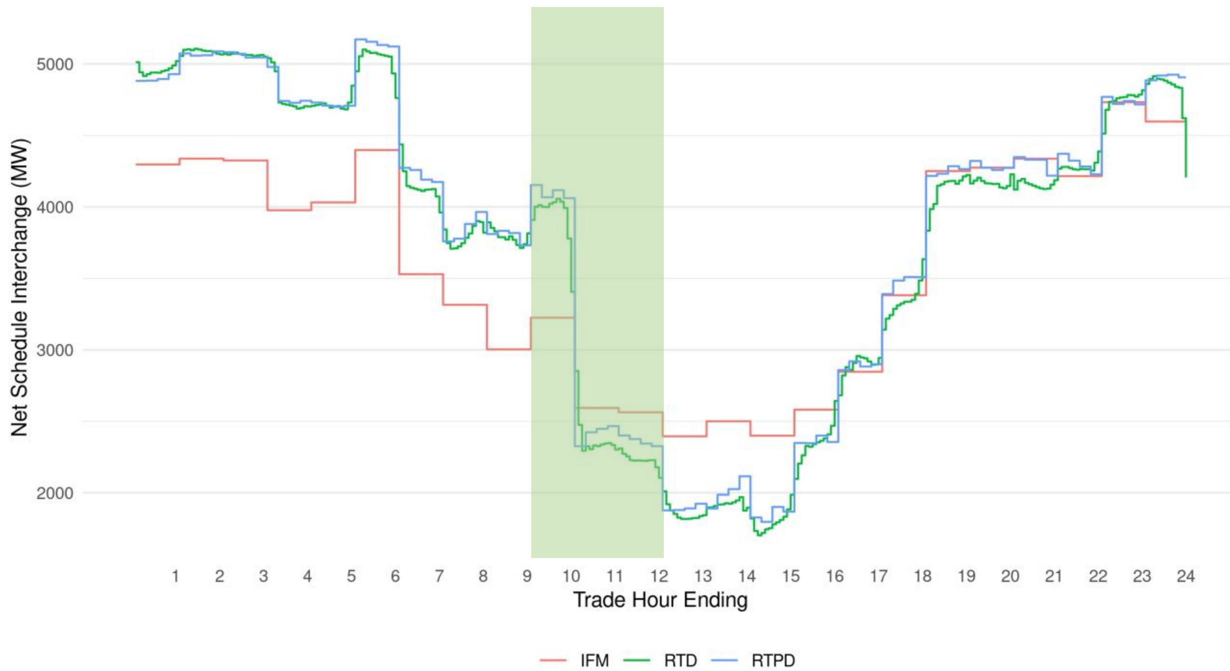
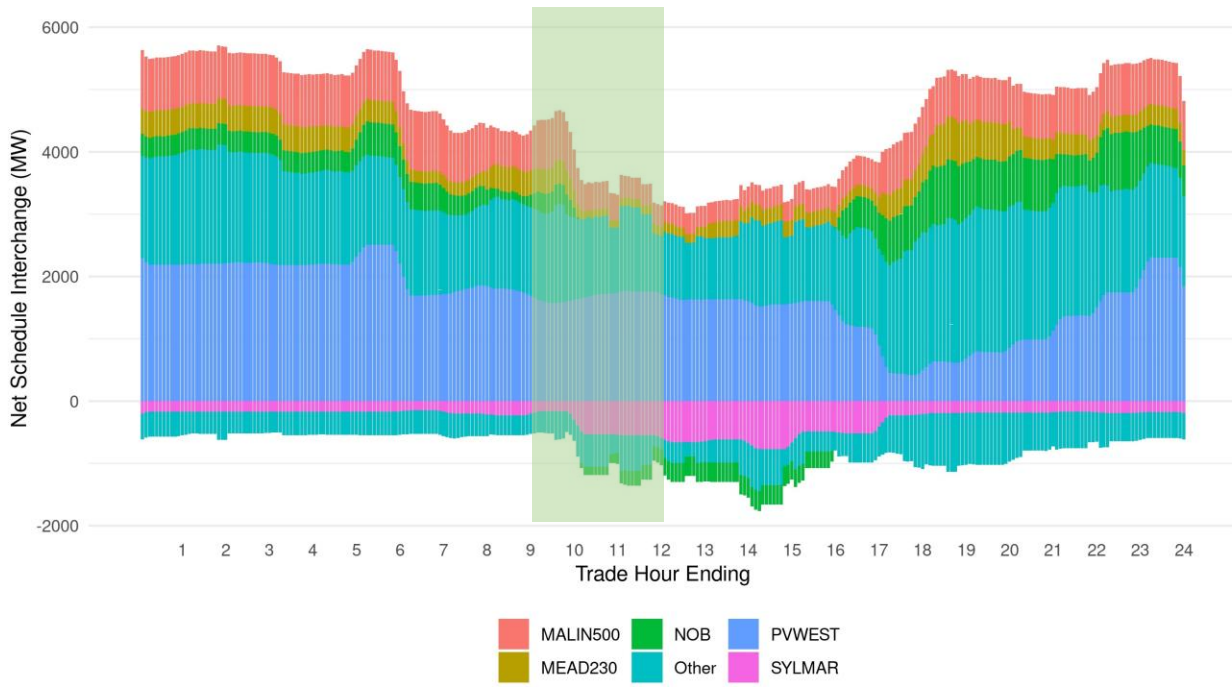


Figure 55 shows NSI on October 14 for RTD by major intertie point. The approximate time period of the eclipse is shown in light green. While there is no single intertie that drove the pattern of increased NSI during the time of the eclipse, PWVEST and MALIN500 were larger contributors.

Figure 55: Net schedule interchange in RTD by major intertie for October 14



WEIM Transfers

The centralized clearing process of the Western Energy Imbalance Market allows the market to attain an optimal solution across all balancing areas leveraging economical transfers among areas.

The following figures show the volume of dynamic WEIM transfers for the CAISO BAA for the day of the eclipse, October 14, and the day before and after. Figure 56 and 57 show the dynamic WEIM transfer volume in FMM and RTD, respectively. The specific hours of the eclipse event, hours ending 9 to 12, are highlighted in yellow. Negative values indicate net imports, while positive values indicate net exports.

At the onset of the eclipse event, dynamic WEIM transfers for CAISO in FMM and RTD showed higher net exports than the same hour the days before and after. During the eclipse event, the transfers experienced more volatility than the days before or after. Dynamic WEIM transfers for CAISO reached 3083 MW in FMM and 3185 MW in RTD during the hours of the eclipse.

Figure 56: Dynamic WEIM Transfer Volume for CAISO, FMM, October 13 to October 15

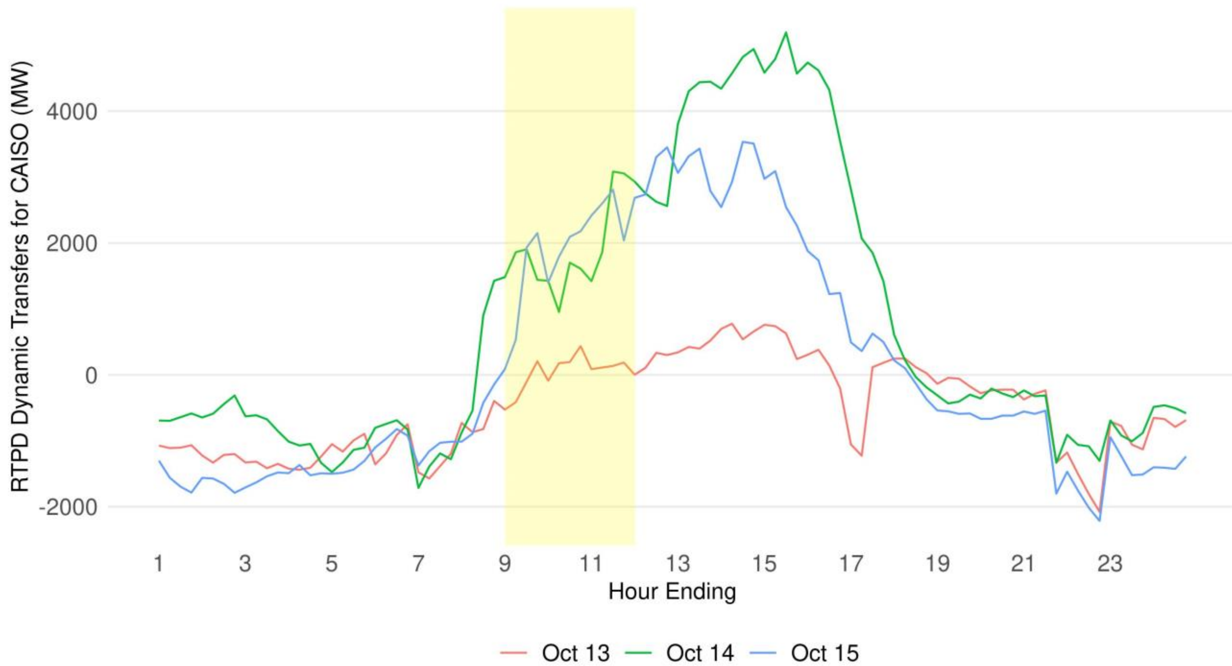


Figure 57: Dynamic WEIM Transfer Volume for CAISO, RTD, October 13 to October 15

The following figures show the volume of dynamic WEIM transfers for all WEIM participants for a three-day period surrounding the day of the eclipse. Figure 58 shows the dynamic WEIM transfers in FMM from October 13 to 15. The specific hours of the eclipse event, hours ending 9 to 12, are highlighted in yellow. Similarly, Figure 59 shows the dynamic WEIM transfers in RTD from October 13 to 15. Negative values indicate net imports; positive values indicate net exports.

At the onset of the eclipse event, dynamic WEIM transfers for WEIM entities in the California region showed higher net exports than the same hour the day before or after in FMM and RTD. During the eclipse event, dynamic WEIM transfers for California and the Southwest region's WEIM entities experienced more volatility than the day before or after in FMM and RTD. California and Southwest region's dynamic WEIM transfers during the eclipse event appeared to mirror each other. Dynamic WEIM transfers for the Central/Mountain and Pacific Northwest region's WEIM entities were relatively unaffected by the eclipse in both FMM and RTD.

Figure 58: Dynamic WEIM Transfer Volume for WEIM Participants by Region, FMM, October 13 to October 15

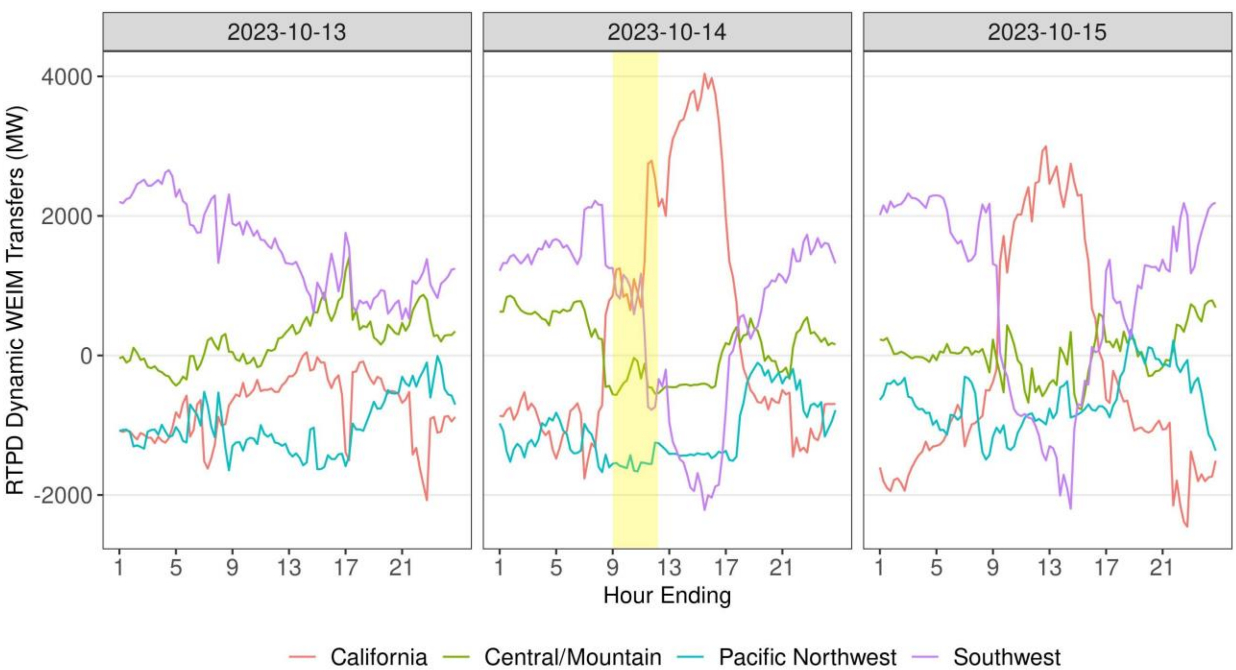
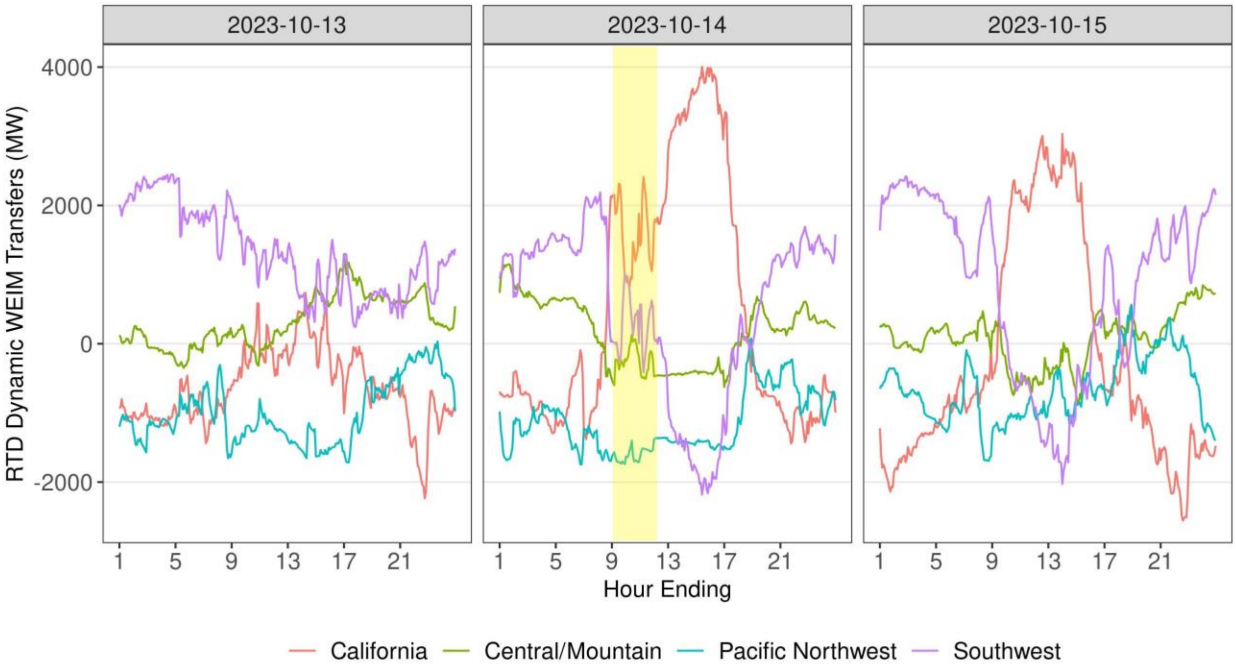


Figure 59: Dynamic WEIM Transfer Volume for WEIM Participants by Region, RTD, October 13 to October 15



Exceptional Dispatches

On the day of the eclipse, the CAISO issued exceptional dispatches for two main reasons: to ensure that battery resources had sufficient state of charge (SOC) to provide ramping capacity and meet energy needs and to position more traditional generating resources to provide ramping capacity. Both were needed to make up for the rapid decrease in solar generation during the onset of the eclipse.

Figure 60 shows the volume of exceptional dispatches by hour on October 14. The approximate time of the eclipse is shown in light green. The most noticeable pattern is that a substantial volume of state-of-charge exceptional dispatches were issued prior to the eclipse beginning. This was done to position the batteries to have sufficient SOC to discharge as the solar generation decreased during the beginning of the eclipse. Also noticeable is that a substantial amount of more traditional generation capacity was exceptionally dispatched to be available to provide ramping capacity during the onset of the eclipse.

Figure 60: Exceptional Dispatch volumes by hour on October 14

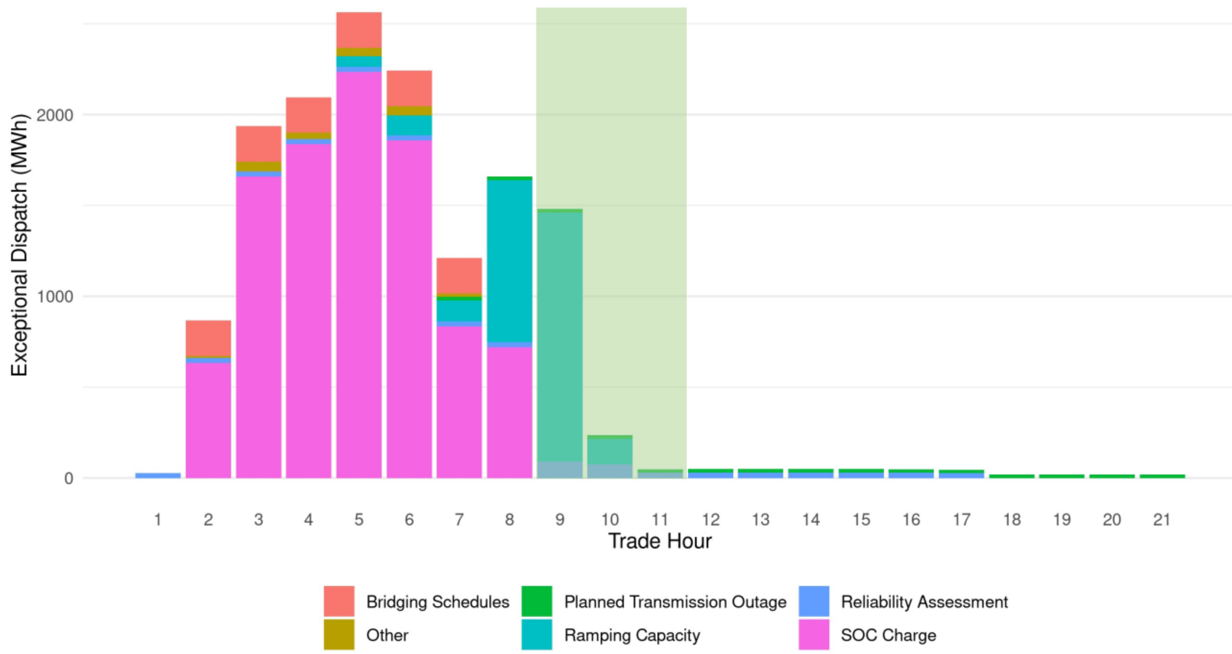
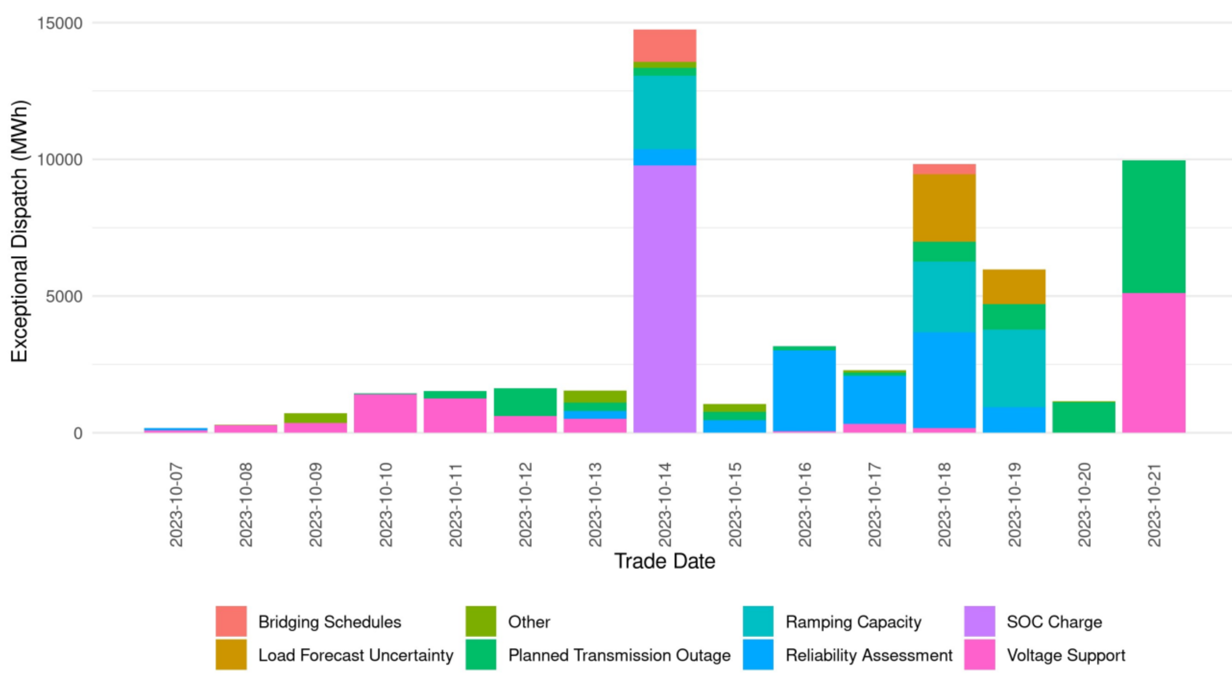


Figure 61 shows the volume of exceptional dispatches by day for the two weeks on each side of October 14. By looking at this longer period of time, it is clear that the exceptional dispatch volumes on October 14 were higher than usual. It is also apparent that the SOC exceptional dispatch was used much more than usual.

Figure 61: Exceptional Dispatch volumes by day from October 7 to 21



Operational Performance

The following section provides an explanation on the operational performance of the solar eclipse event. CAISO developed a team to study the potential impact of the October 14 solar eclipse. The team was able to forecast expected downward solar ramps at the beginning of the eclipse and the expected upwards solar ramps towards the end of the eclipse.

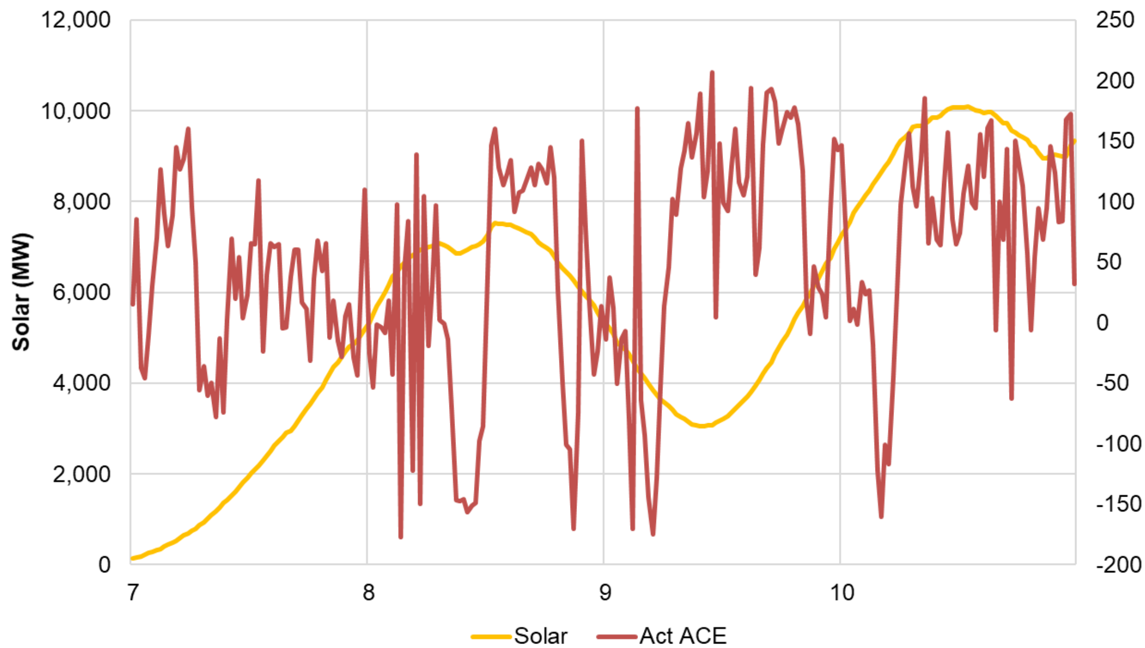
To account for uncertainty balancing supply and demand, the CAISO committed additional resources and procured additional ancillary services to ensure the operators had adequate flexible resources available for dispatch during the eclipse. This action allowed the operators to manage ACE between -177 MW to +207 MW in spite of the fluctuation in solar production. Also, the ISO ensured that solar resources followed their dispatch operating targets to minimize net load variability.

Overall, the ISO performed well based on NERC's CPS1 measure during and after the eclipse, achieving an overall CPS1 score of 161% for the day. Operationally, the ISO was able to meet the demand plus export energy to neighboring BAAs during the solar eclipse event. Figure 62 shows the system frequency (solid green curve) of the WECC interconnection during the eclipse. As shown, system frequency declined below 60 Hz as solar production began to decrease and exceeded the lower frequency dead band (dashed green line) below 60 Hz just prior to maximum solar obfuscation. As solar production began to increase after

9:25 a.m., system frequency began to increase and exceeded the upper frequency dead band (dashed green line) above 60 Hz.

Figure 62: Solar Production vs. Frequency

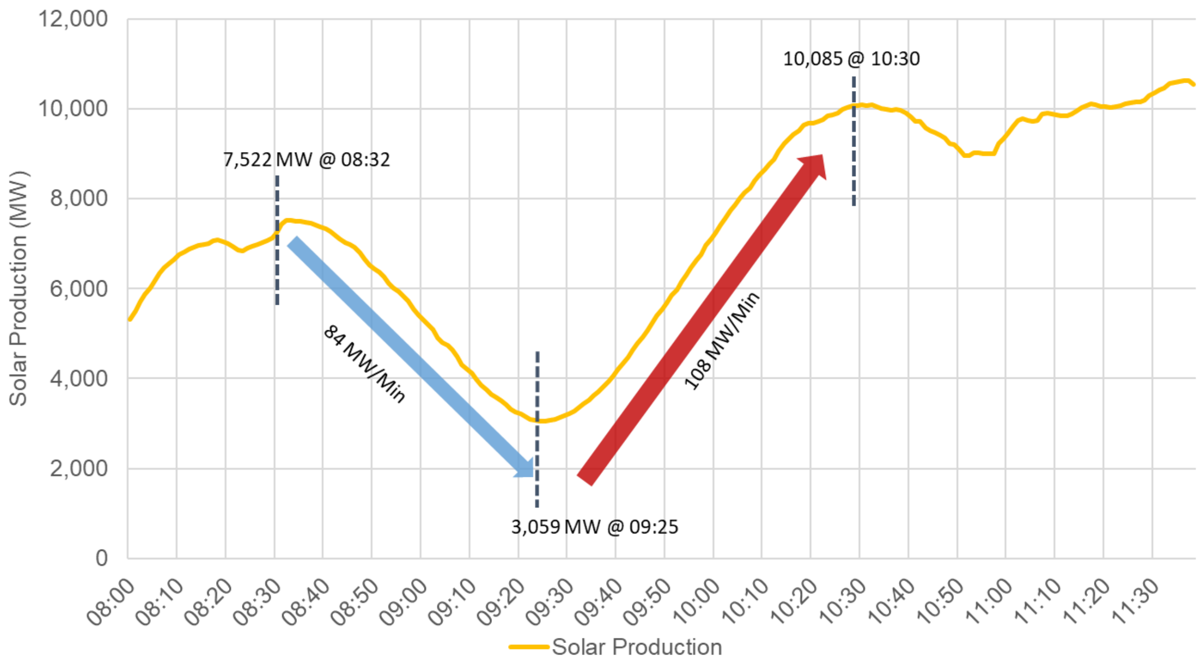
Figure 63: Solar Production vs. ACE



As shown in Figure 63, the ISO's ACE hovered between -177 MW to +207 MW during the eclipse,indicating that the ISO was able to maintain a very close balance between supply and demand.

Prior to the eclipse, the CAISO lowered its ACE dead band from ± 150 MW to ± 98 MW in order for units providing regulation to respond faster to changes in ACE outside the dead band. However, a high percentage of regulation up/down were procured from batteries, some of which have very high ramp rates. The fast response time of batteries to ACE deviations outside ± 98 MW resulted in system oscillations, which lasted for about 13 minutes. In response to the oscillations, the ACE dead bands were reverted back to ± 150 MW, which resolved the oscillation issue.

Figure 64: Solar Production During the Eclipse



As Figure 64 shows, around 8:32 a.m., solar production stood at 7,522 MW when it began to fall at a maximum rate of approximately 84 MW per minute for a period of 53 minutes. Around 9:25 a.m., solar production reached 3,059 MW for a total loss of 4,463 MW. After reaching maximum obscuration around 9:25 a.m., solar production began rapidly to increase for 65 minutes at a rate of about 108 MW per minute until 10:30 a.m., reaching 10,085 MW – an increase of 7,026 MW.

Figure 65: CAISO's Demand vs. Solar Production

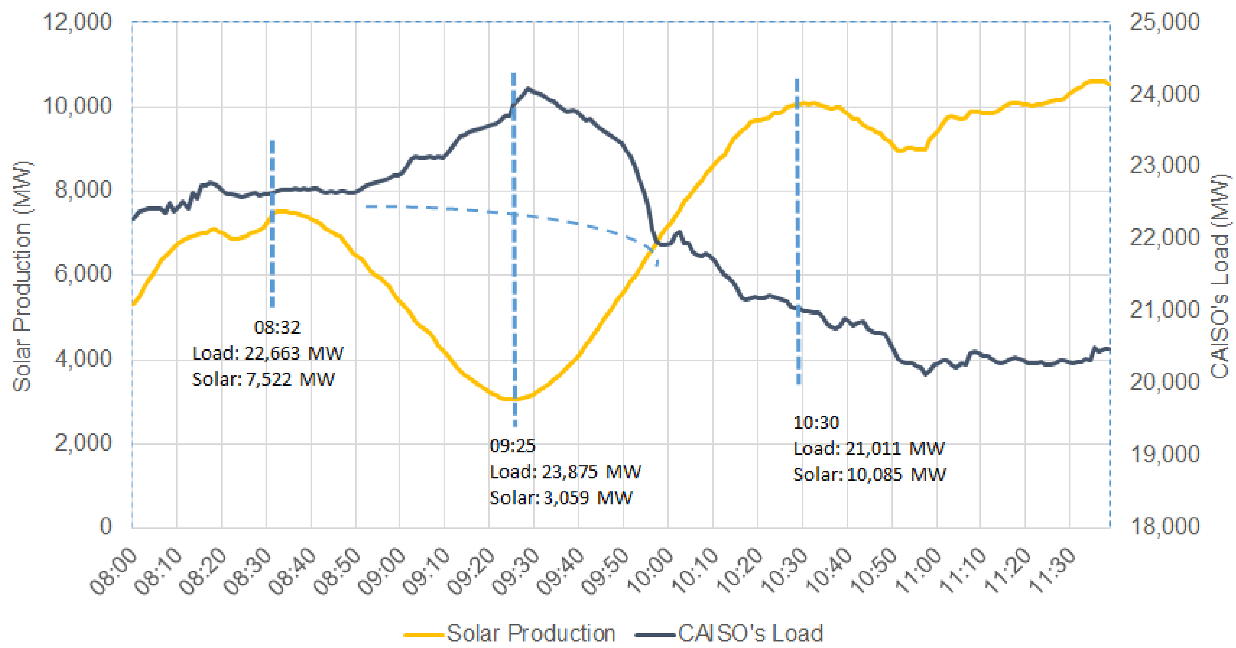


Figure 65 shows the relationship between load and solar production during the eclipse. Load increased from 22,663 MW to 23,875 MW, or by 1,212 MW as the solar production dropped off between 8:32 a.m. and 9:25 a.m.. As the eclipse progressed beyond the maximum obscuration around 9:25 a.m. and solar production started to increase, load dropped to about 21,021 MW at 10:30 a.m., a decline of 2,864 MW. This decline was primarily attributed to rooftop solar PV picking up distribution load and the cooling effect caused by the partially obscured sun.

Control Performance Standard (CPS1)

Figure 66 shows the trend of Control Performance Standard 1 (CPS1[11]) with respect to wind and solar production during the eclipse. Although the interconnection frequency was below 60 Hz prior to the eclipse, the ISO maintained a positive ACE prior to the eclipse, which resulted in the CPS1 score above 100%. The ISO evaluates its real-time control performance on an hourly basis in order to identify potential trends in poor performance as higher levels of renewables are integrated into its resource mix.

As shown, the blue bars indicate that the ISO contributed to supporting the interconnection frequency during the corresponding hours, while the red bars represent the hours the ISO leaned on the

[11] CPS1 is a statistical measure of the BA's area control error variability in combination with the interconnection frequency error from scheduled frequency. CPS1 is reported to NEREC on a monthly basis but is evaluated on a 12-month rolling average.

interconnection. The ISO's overall CPS1 score during the eclipse was above 100%, indicating the ISO supported the interconnection frequency during the eclipse. The ISO's overall CPS1 score for October 14 was 161% for the day.

Figure 66: CAISO's Solar Production vs. Control Performance Standard 1 (CPS1)

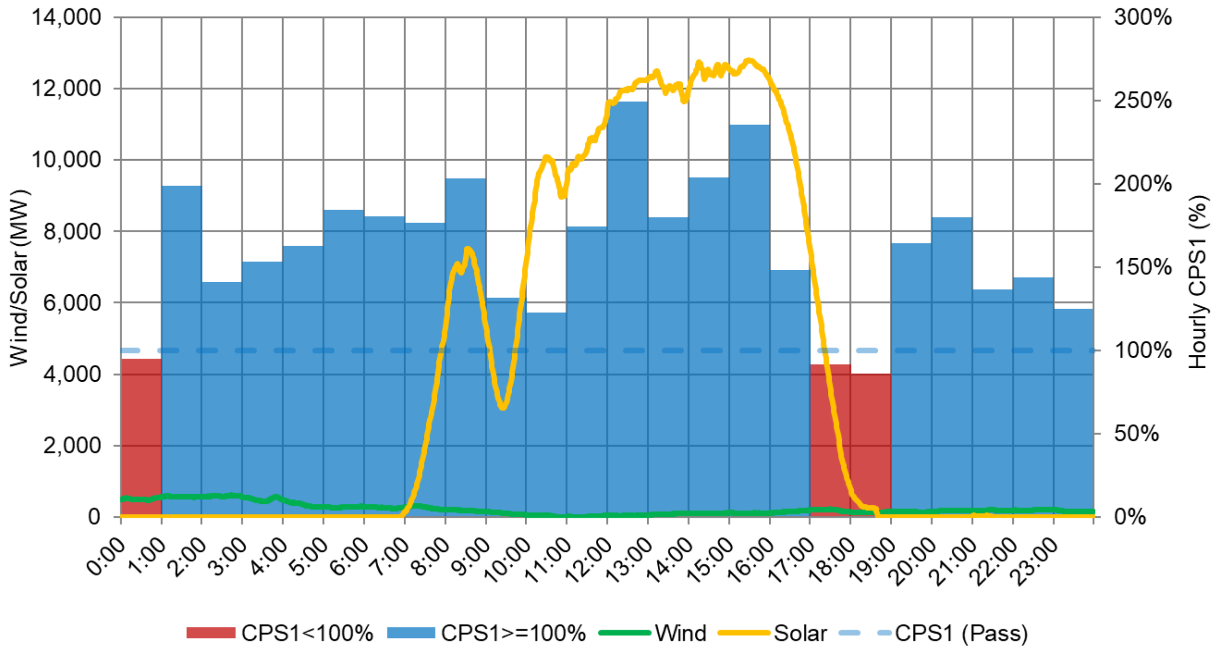
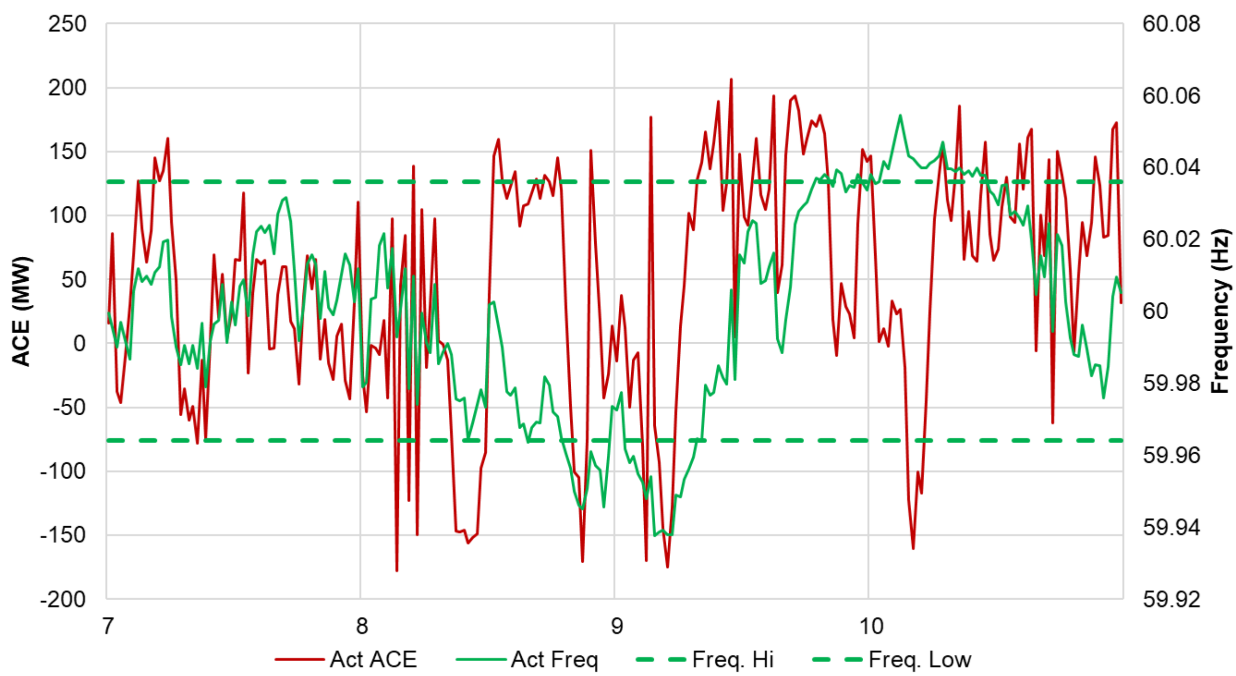


Figure 67: ACE vs Frequency



As shown in Figure 67, ACE hovered between -177 MW to +207 MW while system frequency hovered between 59.93 Hz and 60.05 Hz. As shown, the ISO was able to effectively dispatch resources on regulation to minimize ACE deviations outside ± 150 MW. This translated into an overall control performance measure of an average ACE * Delta Frequency of 1.1 MW-Hz between the hours of 8:00 a.m. and 11:00 a.m, another indication that the CAISO supported the interconnection frequency during the eclipse.