Western Energy Imbalance Market Resource Sufficiency Evaluation Metrics Report covering June 2023

August 1, 2023

Prepared by: Department of Market Monitoring

California Independent System Operator

1 Report overview

As part of the Western Energy Imbalance Market (WEIM) resource sufficiency evaluation enhancements stakeholder initiative, DMM is providing additional information and analysis about resource sufficiency evaluation performance, accuracy, and impacts in regular monthly reports.[1] This report provides metrics and analysis covering June 2023 and is organized as follows:

- Section 2 provides an overview of the flexible ramp sufficiency and bid-range capacity tests.
- Section 3 summarizes the frequency and size of resource sufficiency evaluation failures.
- Section 4 provides an overview of the quantile regression method for calculating uncertainty in the resource sufficiency evaluation. This method was implemented on February 1.
- Section 5 summarizes WEIM import limits and transfers following a resource sufficiency evaluation failure.
- Section 6 summarizes load conformance and provides some context with how it interacts with the resource sufficiency evaluation.

DMM continues to welcome feedback on existing or additional metrics and analysis that WEIM entities and other stakeholders would find most helpful. Comments and questions may be submitted to DMM via email at DMM@caiso.com.

[1] California ISO, *EIM Resource Sufficiency Evaluation Enhancements Straw Proposal*, August 16, 2021: http://www.caiso.com/InitiativeDocuments/StrawProposal-ResourceSufficiencyEvaluationEnhancements.pdf

2 Overview of the flexible ramp sufficiency and capacity tests

As part of the Western Energy Imbalance Market (WEIM) design, each balancing area (including the California ISO) is subject to a resource sufficiency evaluation. 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 flexible ramp sufficiency test, and the bid range capacity test.

The market software automatically limits transfers into a balancing area from other WEIM areas if a balancing area fails either of the following two tests:

- **The flexible ramp 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.
- **The bid range capacity test (capacity test)** requires that each area provides incremental bid-in capacity to meet the imbalance between load, intertie, and generation base schedules.

If an area fails either the flexible ramp sufficiency test or bid range capacity test in the *upward* direction, WEIM transfers into that area cannot be *increased*.[2] Similarly, if an area fails either test in the *downward* direction, transfers out of that area cannot be *increased*.

Flexible ramp sufficiency test

The *flexible ramp sufficiency test* requires that each balancing area has enough ramping resources to meet expected upward and downward ramping needs in the real-time market without relying on transfers from other balancing areas. Each area must show sufficient ramping capability from the start of the hour to each of the four 15-minute intervals within the hour.

Equation 1 shows the different components and mathematical formulation of the flexible ramp sufficiency test. As shown in Equation 1, the requirement for the flexible ramp sufficiency test is calculated as the *forecasted change in load* plus the *uncertainty component* minus two components: (1) the *diversity benefit* and (2*) flexible ramping credits.* Any undersupply infeasibility in the last 15-minute market interval is also accounted for in the flexibility test requirement as of June 1, 2022.

Equation 1. Flexible Ramp Sufficiency Test Formulation

$$Up\ Requirement = \Delta Load + Up\ uncertainty - \min\begin{bmatrix} Net\ import\ capability, \\ Diversity\ benefit + Up\ credit \end{bmatrix} + Undersupply\ infeasibility$$

$$Down\ Requirement = \underbrace{-\Delta Load}_{\text{Change in load forecast}} + \underbrace{Down\ uncertainty}_{\text{Net load uncertainty}} - \underbrace{\min\begin{bmatrix} Net\ export\ capability, \\ Diversity\ benefit + Down\ credit \end{bmatrix}}_{\text{Discounts: diversity benefit and credit reduction capped by transfer capability}} - \underbrace{Undersupply\ infeasibility}_{\text{Undersupply infeasibility in last 15-minute market interval, excluding imbalance conformance}}$$

The diversity benefit reflects that system-level flexible ramping needs are typically smaller than the sum of the needs of individual balancing areas because of reduced uncertainty across a larger footprint. As a result, balancing areas receive a prorated diversity benefit discount based on this proportion.

The flexible ramping credits reflect the ability to reduce exports from a balancing area to increase upward ramping capability or to reduce imports to increase downward ramping capability.

[2] If an area fails either test in the upward direction, net WEIM imports during the interval cannot exceed the greater of either the base transfer or transfer from the last 15-minute interval prior to the hour.

As shown in Equation 1, the reduction in the flexibility test requirement because of any diversity benefit or flexible ramping credit is capped by the area's net import capability for the upward direction, or net export capability for the downward direction.

Last, as part of phase 1 of *resource sufficiency evaluation enhancements*, the flexibility test requirement now includes any undersupply infeasibility (power balance constraint relaxation) from the 15-minute market solution immediately prior to the resource sufficiency evaluation hour. This amount excludes any operator imbalance conformance.

As of February 1, 2023, the uncertainty component used in the flexible ramp sufficiency test is calculated using a regression method which considers forecasted net load currently on the system.[3] The measured uncertainty reflects extreme historical net load errors (95 percent confidence interval) adjusted to reflect forecasted conditions. The net load error observations used to calculate uncertainty in the resource sufficiency evaluation are measured from the difference between (1) binding 5-minute market net load forecasts and (2) the corresponding advisory 15-minute market net load forecast.

Bid range capacity test

The *bid range capacity test* requires that each area provide incremental (or decremental) bid-in capacity to meet the imbalance between load, intertie, and generation base schedules. Equation 2 shows the different components and mathematical formulation of the bid range capacity test. As shown in Equation 2, the requirement for the bid range capacity test is calculated as the *load forecast* plus *export base schedules* minus *import and generation base schedules*. Intertie uncertainty was removed on June 1, 2022.

Equation 2. Bid Range Capacity Test Formulation

$$Requirement = \underbrace{Load}_{\text{Load forecast}} + \underbrace{Export_{base} - Import_{base} - Generation_{base}}_{\text{Intertie and generation base schedules}}$$

If the requirement is positive, then the area must show sufficient incremental bid range capacity to meet the requirement, and if the requirement is negative, then sufficient decremental bid range capacity must be shown.

The bid range capacity used to the meet the requirement is calculated relative to the base schedules. For the California ISO (CAISO), the "base" schedules used in the requirement are the advisory schedules from the last binding 15-minute market run. For all other WEIM areas, the export, import, and generation schedules used in the requirement are the base schedules submitted as part of the hourly resource plan.

[3] California ISO, *Flexible Ramping Product Refinements Final Proposal*, August 31, 2020: http://www.caiso.com/InitiativeDocuments/FinalProposal-FlexibleRampingProductRefinements.pdf

Since the bid range capacity is calculated relative to the base schedules, the upward capacity test can generally be expressed as follows:[4]

$$\underbrace{Generation_{maximum} + Net\ Import_{maximum}}_{\text{Upward capacity}} \geq \underbrace{Load}_{\substack{\text{Load forecast} \\ \text{(requirement)}}}$$

Incremental bid-in generation capacity is calculated as the range between the generation base schedule and the economic maximum, accounting for upward ancillary services and any de-rates (outages). Other resource constraints including start-times and ramp rates are not considered in the capacity test; 15-minute dispatchable imports and exports are included as bid range capacity.

[4] DMM has identified cases when the existing incremental approach for the capacity test relative to base schedules does not equal maximum capacity expected under a total approach. The incremental bid-range capacity can be positive only. If maximum capacity at the time of the test run is below base schedules, this difference will not be accounted for in the test. For more information see DMM's *Comments on EIM Resource Sufficiency Evaluation Enhancements Issue Paper,* September 8, 2021: https://stakeholdercenter.caiso.com/Common/DownloadFile/25df1561-236b-4a47-9b1c-717b4a9cf9f0

3 Frequency of resource sufficiency evaluation failures

This section summarizes the frequency and shortfall amount for bid-range capacity test and flexible ramping sufficiency test failures.[5] If a balancing area fails either (or both) of these tests, then transfers between that and the rest of the WEIM areas are limited.

Figure 3.1 through Figure 3.4 show the percent of 15-minute intervals in which each WEIM area failed the upward capacity or the flexibility tests as well as the average shortfall of those test failures.[6] Figure 3.5 through Figure 3.8 provide the same information for the downward direction. The dash indicates that the area did not fail the test during the month. Of note in June, El Paso Electric failed the downward flexibility test during 1.8 percent of intervals.

Net load uncertainty — which is added to the flexibility test requirement — was adjusted on February 1, 2023 as part of flexible ramping enhancements. The uncertainty was adjusted to incorporate current load, solar, and wind forecast information using a technique called *mosaic quantile regression*. This regression combines both histogram and quantile regression models to estimate the lower and upper extremes of uncertainty that might materialize. For more information on this regression, see Section 3. The capacity test currently does not include any net load uncertainty adder in the requirement.

Figure 3.9 summarizes the overlap between failure of the upward capacity and the flexibility tests during the month. The black horizontal line (right axis) shows the number of 15-minute intervals with either a capacity or a flexibility test failure for each WEIM area. The areas are shown in descending number of failure intervals. The bars (left axis) show the percent of the failure intervals that meet the condition.

Figure 3.10 shows the same information for the downward direction. Areas that did not fail either the capacity or the flexibility tests during this period were omitted from the figure. Across both directions, the flexibility test was more often the source of the resource sufficiency evaluation failure.

[5] Results in this section exclude known invalid test failures. These can occur because of a market disruption, software defect, or other errors.

[6] Results in these figures reflect the final resource sufficiency evaluation (40 minutes prior to the evaluation hour).

Figure 3.1 Frequency of upward capacity test failures (percent of 15-minute intervals)

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

Figure 3.2 Average shortfall of upward capacity test failures (MW)

	2022 Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	2023 Jan	Feb	Mar	Apr	May	Jun
Arizona Publ. Serv.	3	—	—	—	—	—	—	—	32	316	41	817	637	35	192
Avangrid													1	—	—
Avista	1	—	6	27	5	—	—	—	9	—	—	—	20	1	—
BANC	—	—	—	—	37	264	—	—	—	—	—	—	—	—	—
BPA		—	81	—	8	336	—	—	68	—	—	—	55	—	238
California ISO	—	—	—	—	—	141	—	—	—	—	—	—	—	—	—
El Paso Electric													6	8	88
Idaho Power	—	—	—	—	60	37	—	—	—	—	—	—	23	12	—
LADWP	—	—	—	0	—	—	—	—	—	49	—	—	—	—	—
NorthWestern En.	1	—	—	—	86	64	—	91	40	56	68	—	—	—	—
NV Energy	37	67	2	36	—	—	—	—	—	—	—	—	—	53	—
PacifiCorp East	—	—	—	—	—	124	—	—	293	—	—	—	—	—	—
PacifiCorp West	3	11	50	24	36	4	—	17	16	9	84	—	—	—	—
Portland Gen. Elec.	—	—	—	—	1	—	—	25	—	—	38	13	1	19	12
Powerex	364	—	—	—	142	—	—	50	—	—	—	—	—	131	—
PSC of New Mexico	—	—	—	—	—	—	—	—	—	—	—	52	24	106	5
Puget Sound En.	13	1	27	—	—	13	24	5	—	—	15	22	—	26	45
Salt River Proj.	50	44	51	41	214	132	30	17	26	44	44	54	30	38	1
Seattle City Light	—	—	—	15	9	7	5	2	16	2	16	—	—	—	—
Tacoma Power	77	2	1	3	6	0	—	—	—	0	5	0	—	2	—
Tucson Elec. Pow.		—	—	—	20	—	—	—	—	65	1	—	—	—	—
Turlock Irrig. Dist.	—	—	104	—	—	—	—	—	1	—	—	—	2	—	—
WAPA DSW													133	74	5

Figure 3.3 Frequency of upward flexibility test failures (percent of 15-minute intervals)

	2022									2023					
	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun
Arizona Publ. Serv.	—	—	—	0.0	0.1	—	—	0.1	0.4	0.9	1.8	2.5	1.1	0.2	0.1
Avangrid													1.0	0.7	0.1
Avista	0.2	0.5	1.0	0.5	0.1	—	0.1	—	0.1	—	0.0	0.0	0.2	0.2	0.0
BANC	—	—	—	—	—	0.3	—	—	—	—	—	—	—	0.1	—
BPA		0.9	3.1	3.3	1.0	1.1	0.2	0.1	0.4	—	0.1	0.6	0.2	1.2	0.3
California ISO	—	—	—	—	0.1	0.5	0.0	—	—	—	—	—	—	—	—
El Paso Electric													0.8	0.7	0.3
Idaho Power	—	—	—	0.2	0.2	0.5	—	0.1	—	0.0	0.1	0.3	0.3	0.5	0.1
LADWP	—	—	—	—	—	0.1	0.1	—	—	—	0.3	—	0.1	0.0	0.1
NorthWestern En.	0.3	—	0.1	0.3	1.0	0.2	—	0.5	0.8	0.3	0.1	0.2	0.8	0.3	0.2
NV Energy	1.0	0.8	0.2	—	0.1	0.1	0.1	0.2	0.0	0.1	0.3	0.0	0.1	0.1	0.0
PacifiCorp East	0.1	0.1	0.1	0.2	0.1	—	0.1	—	0.0	0.1	—	0.0	0.1	—	0.0
PacifiCorp West	0.2	0.1	0.0	—	0.1	0.1	—	0.1	—	0.1	0.1	—	0.1	0.6	0.0
Portland Gen. Elec.	—	—	0.0	0.4	0.1	0.1	0.2	1.0	0.1	0.0	0.1	0.0	0.1	1.5	0.7
Powerex	0.1	—	—	—	0.3	0.1	—	—	—	—	0.2	—	—	—	—
PSC of New Mexico	0.0	0.1	—	0.4	—	0.0	0.2	0.1	0.8	0.2	—	1.2	5.1	0.9	0.6
Puget Sound En.	0.1	—	0.1	0.4	0.2	0.3	—	0.0	—	—	0.1	0.8	0.2	1.0	0.6
Salt River Proj.	0.5	0.2	0.5	0.6	1.1	0.6	0.6	0.5	0.8	3.5	1.2	1.7	2.0	0.6	0.2
Seattle City Light	—	—	—	0.2	0.0	0.2	—	0.1	0.0	—	0.1	—	—	—	—
Tacoma Power	—	0.1	0.1	0.0	0.1	0.1	—	0.2	—	0.2	0.1	0.2	—	0.1	—
Tucson Elec. Pow.		0.1	—	—	—	0.4	0.0	—	0.2	0.3	0.3	0.3	0.1	0.1	—
Turlock Irrig. Dist.	—	—	—	—	—	0.1	—	—	1.2	—	—	—	0.0	—	—
WAPA DSW													2.7	0.7	0.8

Figure 3.4 Average shortfall of upward flexibility test failures (MW)

	2022									2023					
	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun
Arizona Publ. Serv.	—	—	—	28	28	—	—	15	65	154	77	288	119	36	76
Avangrid													79	13	9
Avista	18	29	26	19	30	—	5	—	11	—	13	12	35	14	4
BANC	—	—	—	—	—	237	—	—	—	—	—	—	—	64	—
BPA		68	71	50	56	232	43	42	114	—	36	62	99	82	164
California ISO	—	—	—	—	684	671	53	—	—	—	—	—	—	—	—
El Paso Electric													24	15	123
Idaho Power	—	—	—	13	34	45	—	14	—	5	51	28	42	24	46
LADWP	—	—	—	—	—	36	9	—	—	—	45	—	21	30	56
NorthWestern En.	20	—	10	15	22	83	—	45	30	44	16	40	14	33	11
NV Energy	61	66	89	—	80	88	41	91	69	60	69	29	164	59	24
PacifiCorp East	83	77	9	34	43	—	16	—	13	53	—	101	47	—	18
PacifiCorp West	58	24	5	—	31	28	—	62	—	14	79	—	30	146	2
Portland Gen. Elec.	—	—	8	72	25	16	19	46	12	39	16	9	61	49	37
Powerex	366	—	—	—	318	101	—	—	—	—	86	—	—	—	—
PSC of New Mexico	23	33	—	70	—	22	38	39	36	19	—	45	47	26	21
Puget Sound En.	32	—	49	46	17	21	—	29	—	—	45	46	29	59	48
Salt River Proj.	36	43	89	45	156	72	61	38	67	47	39	48	54	72	53
Seattle City Light	—	—	—	17	2	8	—	4	6	—	23	—	—	—	—
Tacoma Power	—	206	6	3	5	3	—	16	—	6	3	6	—	21	—
Tucson Elec. Pow.		22	—	—	—	44	5	—	97	67	28	31	36	30	—
Turlock Irrig. Dist.	—	—	—	—	—	3	—	—	6	—	—	—	1	—	—
WAPA DSW													71	122	21

Figure 3.5 Frequency of downward capacity test failures (percent of 15-minute intervals)

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

Figure 3.6 Average shortfall of downward capacity test failures (MW)

	2022 Apr	2022 May	2022 Jun	2022 Jul	2022 Aug	2022 Sep	2022 Oct	2022 Nov	2022 Dec	2023 Jan	2023 Feb	2023 Mar	2023 Apr	2023 May	2023 Jun
Arizona Publ. Serv.	—	33	19	—	—	—	—	—	146	—	—	210	—	—	—
Avangrid													—	—	—
Avista	—	—	—	52	—	—	14	—	—	—	—	—	2	—	—
BANC	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
BPA		—	—	—	—	31	—	—	—	—	435	—	12	99	—
California ISO	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
El Paso Electric													91	8	11
Idaho Power	—	7	—	—	—	—	—	—	—	—	—	—	—	—	4
LADWP	—	34	—	—	—	—	—	—	—	16	—	—	—	—	19
NorthWestern En.	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
NV Energy	—	53	41	—	—	—	—	—	—	—	—	—	14	42	124
PacifiCorp East	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
PacifiCorp West	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Portland Gen. Elec.	—	—	23	—	—	—	—	—	—	—	—	—	—	—	—
Powerex	—	175	—	—	13	—	—	12	—	—	—	—	—	—	—
PSC of New Mexico	—	6	—	—	—	—	—	—	—	—	—	9	233	—	—
Puget Sound En.	—	61	31	19	—	—	—	—	—	—	—	—	—	26	—
Salt River Proj.	—	41	46	8	72	27	11	14	—	15	15	6	79	27	35
Seattle City Light	—	—	2	7	—	6	—	—	—	—	7	—	—	—	—
Tacoma Power	29	3	—	5	8	—	33	—	2	—	4	7	—	—	—
Tucson Elec. Pow.		—	6	—	—	—	—	—	—	—	—	—	—	—	—
Turlock Irrig. Dist.	3	—	—	—	—	—	—	—	—	—	0	—	—	—	—
WAPA DSW													9	—	12

Figure 3.7 Frequency of downward flexibility test failures (percent of 15-minute intervals)

	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
Arizona Publ. Serv.	0.3	0.5	0.2	—	—	0.1	0.2	0.2	0.1	0.9	0.5	2.1	0.7	1.2	0.1
Avangrid													0.1	—	—
Avista	—	—	0.1	—	—	0.1	0.2	—	0.0	—	—	0.1	0.1	0.1	—
BANC	0.0	0.1	0.1	—	—	—	—	—	—	—	—	—	—	—	—
BPA		0.1	0.2	—	0.0	0.3	—	0.2	0.2	—	0.0	0.1	0.6	5.5	0.0
California ISO	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
El Paso Electric													0.2	0.9	1.9
Idaho Power	0.3	0.4	—	—	0.0	—	—	—	—	—	—	0.9	0.2	—	—
LADWP	—	—	—	—	—	—	—	—	—	0.1	—	—	—	—	—
NorthWestern En.	—	0.5	1.9	0.2	—	—	—	0.0	0.1	—	0.0	—	—	0.2	0.2
NV Energy	3.2	1.3	2.0	0.6	0.2	0.5	0.5	0.6	0.1	0.1	0.1	0.1	0.0	0.1	0.4
PacifiCorp East	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
PacifiCorp West	0.0	0.1	0.4	0.5	—	—	0.1	—	0.0	—	—	—	0.0	0.2	0.0
Portland Gen. Elec.	—	—	0.2	—	—	—	—	—	—	—	—	—	—	—	—
Powerex	0.0	0.3	0.2	—	0.1	0.1	0.1	—	—	0.1	0.1	—	0.2	—	—
PSC of New Mexico	0.3	1.8	0.7	0.0	0.0	0.2	0.2	0.1	—	0.0	—	0.4	1.6	2.1	—
Puget Sound En.	—	0.2	2.3	0.1	—	—	0.1	—	—	—	—	—	—	0.8	—
Salt River Proj.	0.2	0.4	0.5	0.2	0.2	1.0	0.2	0.9	0.3	1.4	3.3	1.0	0.3	0.1	0.1
Seattle City Light	0.1	0.1	0.3	0.1	0.8	0.3	—	0.2	0.6	0.1	0.2	0.0	0.3	0.0	0.3
Tacoma Power	0.4	0.3	—	0.5	0.2	—	—	—	0.1	—	0.2	0.1	—	—	—
Tucson Elec. Pow.		—	—	—	—	—	—	0.0	—	—	—	—	—	—	—
Turlock Irrig. Dist.	0.6	0.1	0.5	0.1	0.1	—	—	0.1	—	0.1	0.1	0.1	0.1	0.4	—
WAPA DSW													2.7	0.5	0.7

Figure 3.8 Average shortfall of downward flexibility test failures (MW)

	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
Arizona Publ. Serv.	54	58	33	—	—	81	20	28	31	46	45	49	33	64	14
Avangrid													13	—	—
Avista	—	—	20	—	—	11	20	—	26	—	—	16	12	29	—
BANC	7	5	15	—	—	—	—	—	—	—	—	—	—	—	—
BPA		212	55	—	4	149	—	77	191	—	72	78	102	741	27
California ISO	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
El Paso Electric													8	15	30
Idaho Power	18	55	—	—	13	—	—	—	—	—	—	31	11	—	—
LADWP	—	—	—	—	—	—	—	—	—	34	—	—	—	—	—
NorthWestern En.	—	12	27	14	—	—	—	2	16	—	17	—	—	39	16
NV Energy	86	49	98	151	59	58	43	28	62	83	104	90	22	13	96
PacifiCorp East	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
PacifiCorp West	15	55	28	11	—	—	12	—	22	—	—	—	6	44	7
Portland Gen. Elec.	—	—	18	—	—	—	—	—	—	—	—	—	—	—	—
Powerex	3	257	244	—	87	62	86	—	—	23	30	—	48	—	—
PSC of New Mexico	40	144	34	3	9	40	16	15	—	16	—	115	112	75	—
Puget Sound En.	—	54	33	47	—	—	11	—	—	—	—	—	—	38	—
Salt River Proj.	74	62	34	54	155	42	42	113	38	52	54	84	45	49	23
Seattle City Light	6	7	11	10	21	10	—	24	39	10	28	6	6	30	15
Tacoma Power	5	14	—	5	4	—	—	—	8	—	3	4	—	—	—
Tucson Elec. Pow.		—	—	—	—	—	—	14	—	—	—	—	—	—	—
Turlock Irrig. Dist.	20	5	6	3	2	—	—	5	—	6	6	14	8	4	—
WAPA DSW													55	8	16

Figure 3.9 Upward capacity/flexibility test failure intervals by concurrence (June 2023)

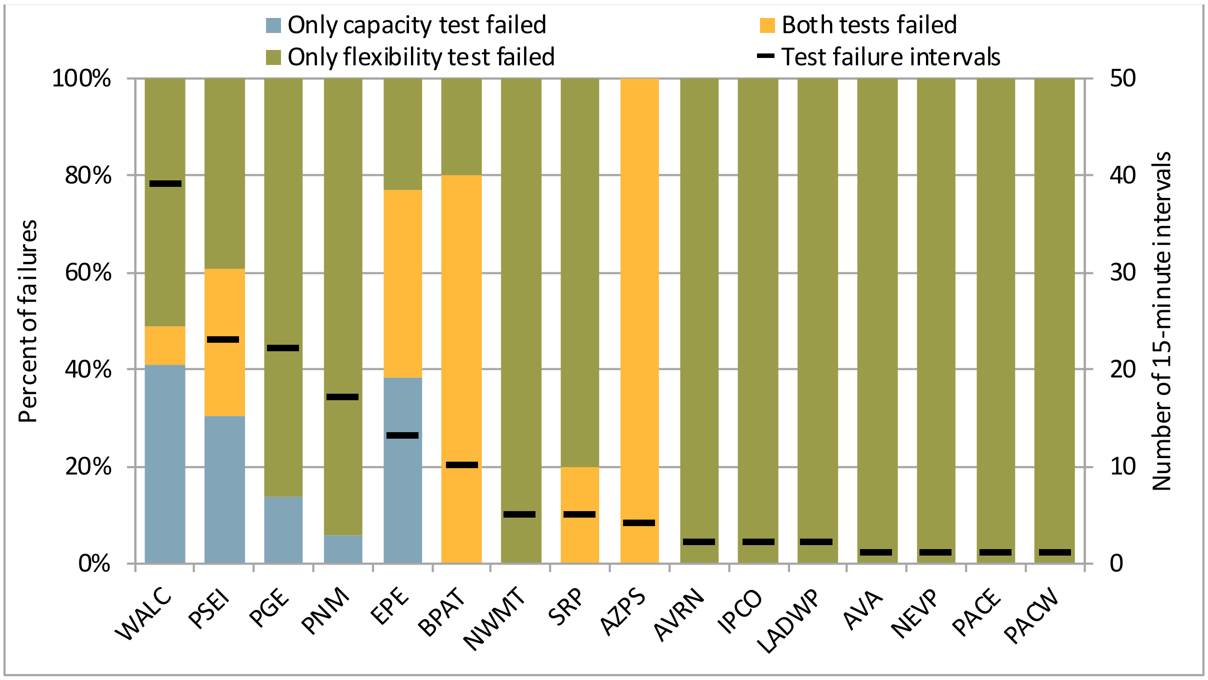
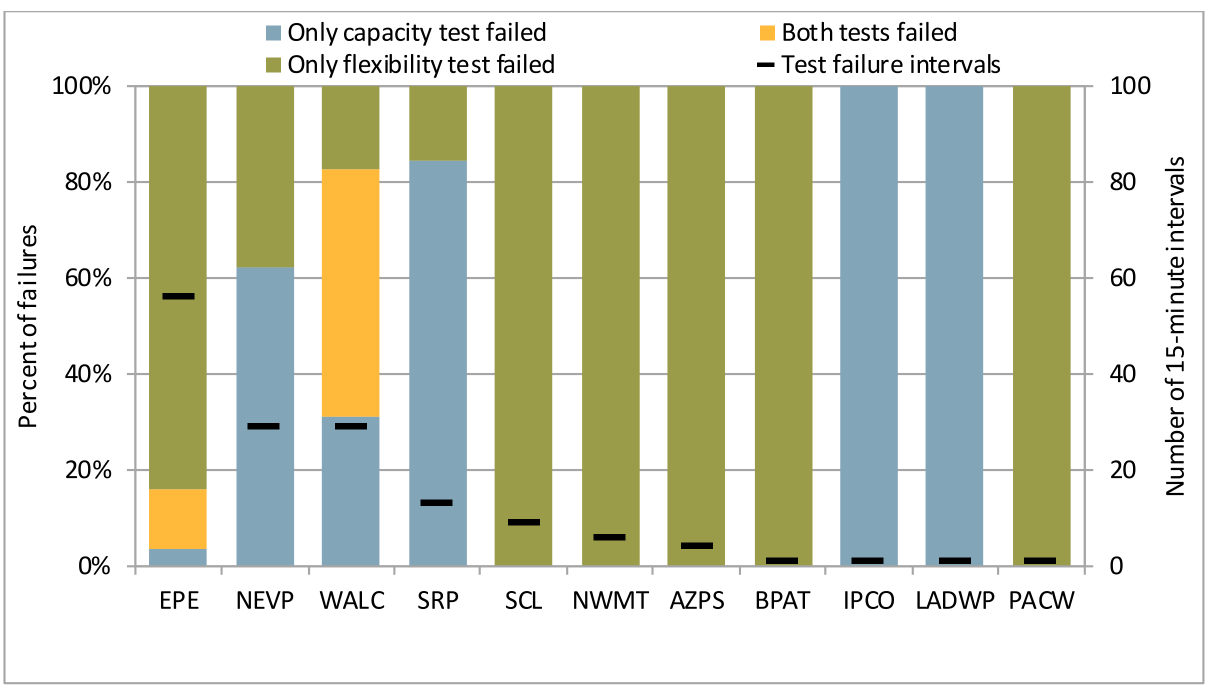


Figure 3.10 Downward capacity/flexibility test failure intervals by concurrence (June 2023)



Impact of earlier runs of the resource sufficiency evaluation on market results

There are three runs of the resource sufficiency evaluation, at 75 minutes (first run), 55 minutes (second run), and 40 minutes (final run) prior to each evaluation hour. The first and second runs are sometimes considered the *advisory runs* with the results of the final evaluation at 40 minutes prior considered the *binding run*. The previous section summarized the frequency of resource sufficiency evaluation failures in the final run. However, the results in the earlier runs of the resource sufficiency evaluation can also impact binding market results in several key ways. These are discussed below.

Nodal flexible ramping capacity procurement in the first 15-minute interval of each hour

Flexible ramping product nodal procurement in the first 15-minute market interval of each hour is dependent on the second run of the resource sufficiency evaluation at 55 minutes prior to the evaluation hour.

The results of the resource sufficiency evaluation are used as an input for the flexible ramping product. As part of the enhancements implemented on February 1, the real-time market will enforce an area-specific uncertainty target for balancing areas that fail the resource sufficiency evaluation. This target can only be met by flexible capacity within that area. In contrast, flexible capacity for the group of balancing areas that pass the resource sufficiency evaluation are pooled together to meet the uncertainty target for the rest of the system.

Deliverable flexible capacity awards are 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. This ensures that upward and downward flexible capacity awards do not violate transmission or transfer constraints. A consequence of this is that binding flex ramp awards in the first 15-minute market interval of each hour are now dependent on the second run of the resource sufficiency evaluation at 55 minutes prior to the evaluation hour — based on the latest information available at the time of this market run.

Figure 3.11 and Figure 3.12 summarizes the first interval of each evaluation hour during the month with a failure in the second (T-55) or final (T-40) resource sufficiency evaluation.[7] This reflects failure of *either* the flexibility or capacity test in the second or final run. The red and yellow bars show intervals with a failure in the second evaluation (T-55) and whether the balancing area ultimately failed or passed in that interval based on the final evaluation results at 40 minutes prior to the hour. The dashed blue region instead shows cases in the first interval of the hour when the balancing area passed the second evaluation (T-55) but failed the final evaluation (T-40). In these intervals, the balancing area would have been included in the pass-group for the purpose of procuring flexible ramping capacity. The pass-group uncertainty requirement includes any diversity benefit of reduced uncertainty over a larger footprint.

[7] Areas that did not fail in the first interval of a resource sufficiency evaluation at T-55 or T-40 during this period were omitted from these figures.

Figure 3.11 Upward resource sufficiency evaluation failures in first 15-minute interval of hour (June 2023)

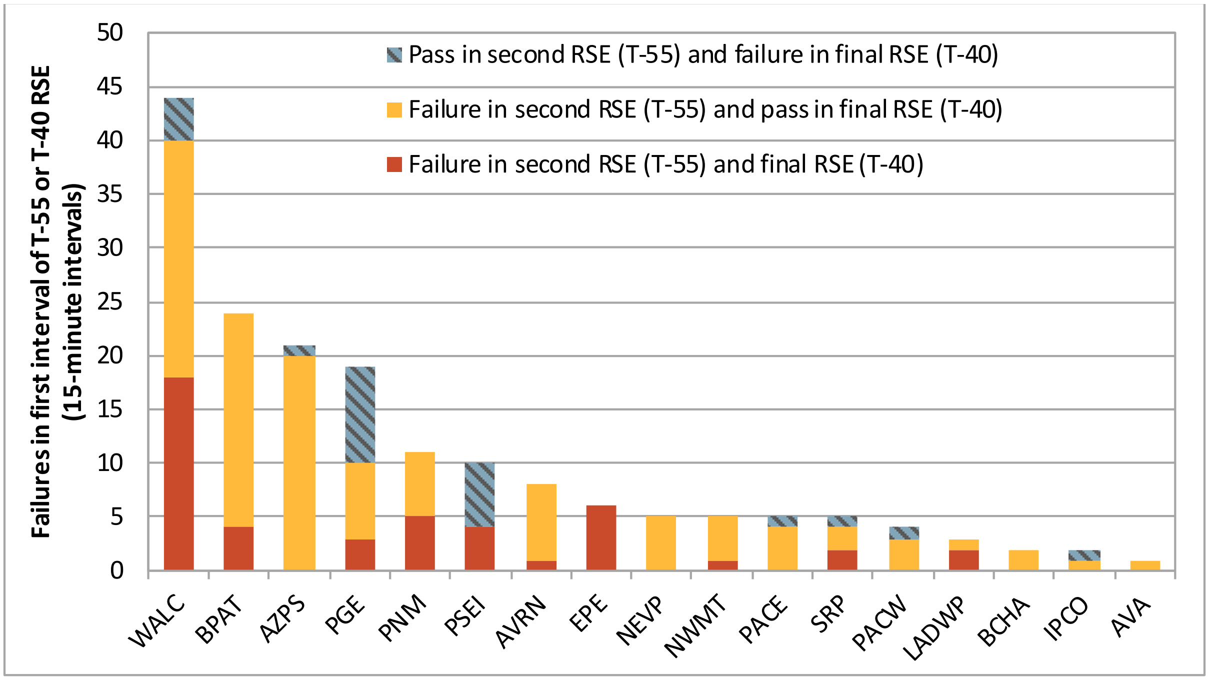
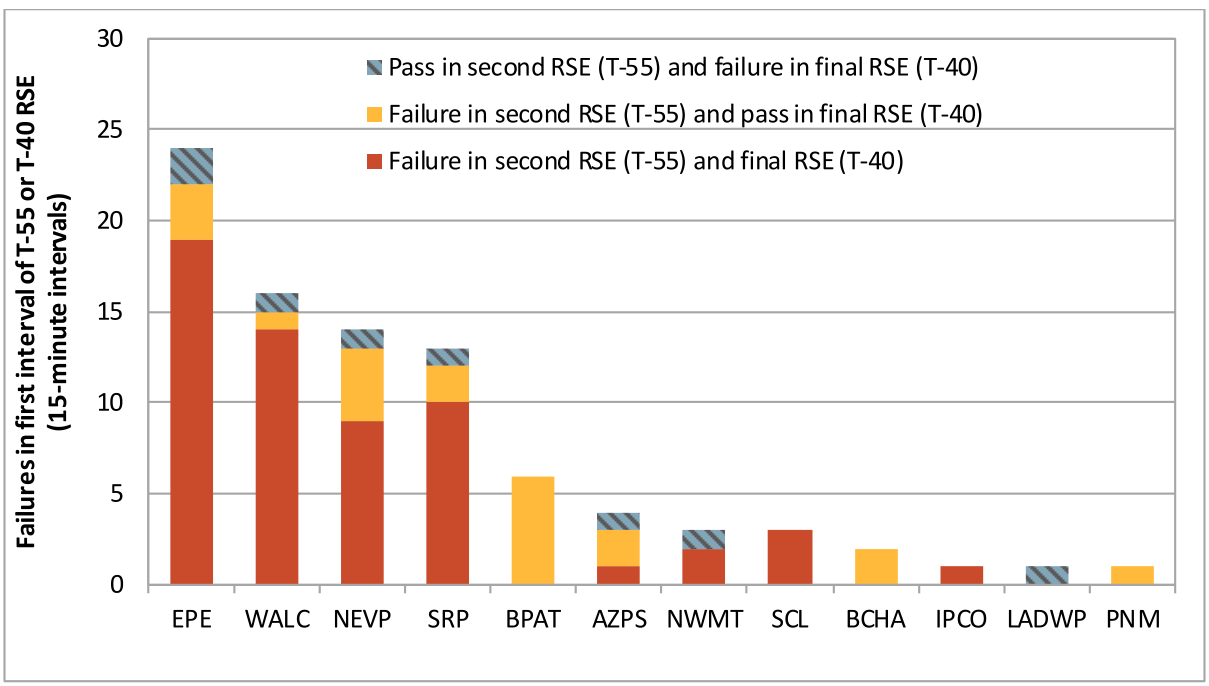


Figure 3.12 Downward resource sufficiency evaluation failures in first 15-minute interval of hour (June 2023)



Calculating uncertainty for balancing areas passing the resource sufficiency evaluation

Uncertainty estimates created for the group of balancing areas that pass the resource sufficiency evaluation in the *first and second* interval of each hour are based on earlier test results.

As part of the enhancements implemented on February 1, uncertainty is now calculated based on regression results that use historical data to predict uncertainty relative to load, solar, and wind forecasts.[8] Once all of the regressions are complete, the regression outputs can be combined with current forecast information to calculate uncertainty for each interval.

For a single balancing area that failed the resource sufficiency evaluation, these regressions can be performed in advance and local uncertainty targets can be readily determined based on current forecast information. However, for instead the group of balancing areas that pass the resource sufficiency evaluation (known as the pass-group), the regression 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 to through 4. Table 3.1 summarizes this inconsistency by showing which resource sufficiency evaluation run is used for each interval and process.

Table 3.1 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)

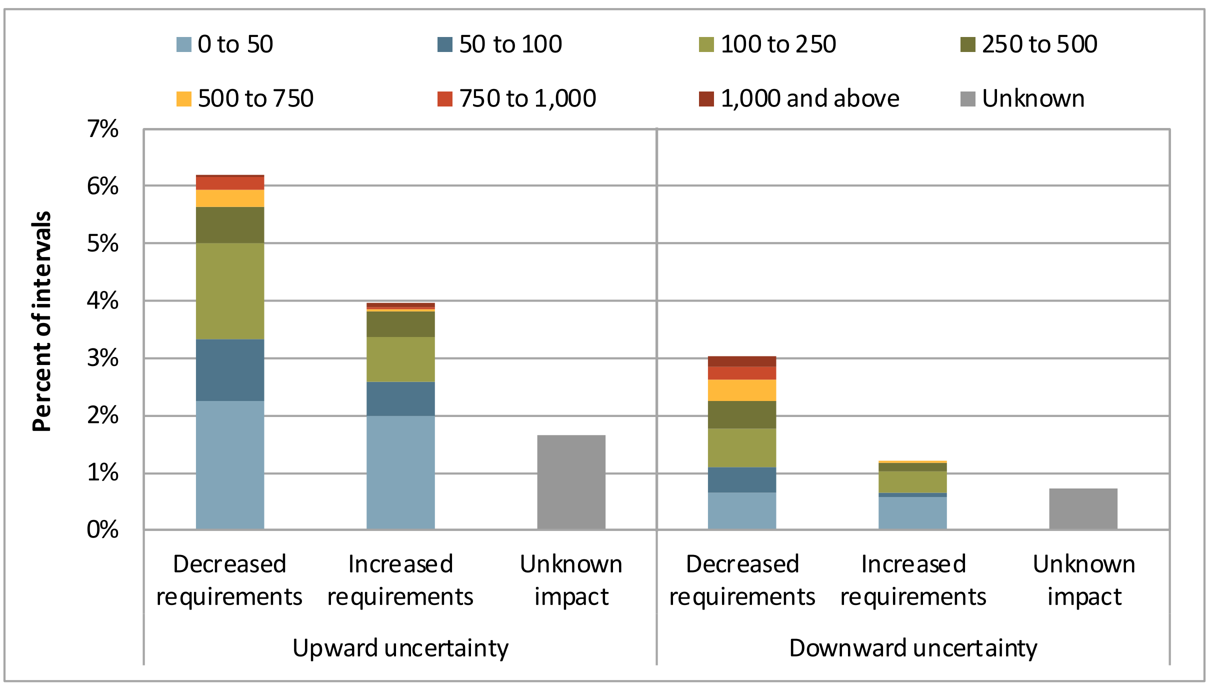
Using an inconsistent composition of balancing areas in the pass-group between the forecast and regression information can create significant swings in the calculated uncertainty for this group. For example, if you have a model to predict uncertainty based on forecast information of all but one balancing 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.

[8] The calculation of uncertainty is described in more depth in the following section.

During about 17 percent of intervals during the month, the composition of balancing areas in the pass-group between the current forecast information and regression information were inconsistent for either upward or downward uncertainty. Figure 3.13 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. Figure 3.13 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.[9] 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.
- **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 3.13 Impact of pass-group inconsistency on uncertainty requirements (June 2023)



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

Additional impacts of earlier resource sufficiency evaluation failures on market results

Each real-time market run will use the latest resource sufficiency evaluation results available to optimize resources and energy transfers in the WEIM accordingly. This includes future advisory intervals that can be impacted by earlier runs of the resource sufficiency evaluation. In particular, the hour-ahead market includes resources and transfers in the WEIM footprint with transfer limits potentially impacted from test failures from the first run of the resource sufficiency evaluation at 75 minutes prior to the evaluation hour.

4 Net load uncertainty in the resource sufficiency evaluation

Net load uncertainty is 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. This calculation was adjusted on February 1 using a method called *mosaic quantile regression*. This section summarizes how uncertainty is currently calculated, the results of the uncertainty calculation, and how it compares with actual error between forecasts used in the tests and in the real-time market.

Calculating net load uncertainty in the resource sufficiency evaluation

Histogram method

Uncertainty used in the resource sufficiency evaluation was previously calculated by selecting the 2.5th and 97.5th percentile of observations from a distribution of historical net load forecast errors. This is known as the *histogram method*. The historical error observations in the distribution were the difference between binding 5-minute market net load forecasts and corresponding advisory 15-minute market net load forecasts.[10] Prior to February 1, 2023, the weekday distributions used data for the same hour from the previous 40 weekdays while weekend distributions instead used same-hour observations from the previous 20 weekend days. The histogram approach did not factor in any current load, solar, or wind forecast information. Under this approach, uncertainty could have been set by historical outlier observations uncorrelated with current market conditions such as an extreme historical observation in which wind forecasts were significant while wind forecasts in the evaluation hour were minimal.

Mosaic quantile regression method

The calculation for net load uncertainty was adjusted on February 1, 2023 as part of flexible ramping enhancements. The uncertainty was adjusted to incorporate current load, solar, and wind forecast information using a method called *mosaic quantile regression*.

Regression is a statistical method used to study the relationship between two or more variables, such as the relationship between the load or renewable forecasts (independent variables) and uncertainty (dependent variable). Ordinary Least Squares is widely used to estimate the *mean* relationship between these variables (i.e. the average value of the dependent variable as a function of the independent variable). In contrast, quantile regression is a variation of regression that is useful when interested in the relationship between the independent variable(s) and different *percentiles* of the dependent variable. For example, the relationship between the load or renewable forecasts and the 97.5th percentile of uncertainty.

[10] In comparing the 15-minute observation to the three corresponding 5-minute observations, the minimum and maximum net load errors were used as a separate observation in the distribution.

The chosen regression method is a two-step procedure to forecast the lower and upper extremes of net load uncertainty that might materialize. The initial quantile regressions determine the relationship between the forecasts (load, solar, and wind) and the extremes of uncertainty (load, solar, and wind). In a simple linear regression, the relationship between the dependent variable Y and the independent variable X takes the basic form of $Y = bX$ where the outcome of the regression, b, explains how much Y changes for every one unit increase in X (e.g. If b is two, then y is predicted to be twice X). For calculating uncertainty as a function of the forecast, the quantile regressions are instead defined in the quadratic form ($Y = aX^2 + bX + c$). The initial regressions are shown below for upward net load uncertainty.[11]

Equation 1. Initial quantile regressions for upward net load uncertainty

$$
\begin{aligned}
Load\ uncertainty^{max} &= a_l^{97.5}(load)^2 + b_l^{97.5}(load) + c_l^{97.5} + \varepsilon && (\tau = 0.975) \\
Solar\ uncertainty^{min} &= a_s^{2.5}(solar)^2 + b_s^{2.5}(solar) + c_s^{2.5} + \varepsilon && (\tau = 0.025) \\
Wind\ uncertainty^{min} &= a_w^{2.5}(wind)^2 + b_w^{2.5}(wind) + c_w^{2.5} + \varepsilon && (\tau = 0.025)
\end{aligned}
$$

Dependent variable: load, solar, and wind uncertainty — minimum or maximum difference between binding 5-minute market forecasts and advisory 15-minute market forecasts in each 15-minute market interval

Independent variable: advisory 15-minute market forecasts for load, solar, and wind in each interval

Error term (ε): variation in dependent variable that is not explained by independent variable

Quantile parameter (τ): determines the level of the quantile regression being estimated (high: 97.5 percentile, low: 2.5 percentile)

The uncertainty regressions use a distribution of historical forecast observations from the previous 180 days — separate for each balancing area, hour, and day-type (weekday or weekend/holiday). For the resource sufficiency evaluation, uncertainty in the distributions is the difference between binding 5-minute market forecasts and corresponding advisory 15-minute market forecasts.[12] The outcome of these regressions are the coefficients *a*, *b*, and *c*, that define the relationships between the forecasts and the extreme end of uncertainty that might materialize.[13] These coefficients can then be combined with the historical 15-minute forecast data to create a distribution of predicted values for load, solar, and wind uncertainty which is needed for the second step of the calculation. This is shown below for upward net load uncertainty.

[11] Equations 1 to 5 are for calculating *upward* net load uncertainty. *Downward* net load uncertainty is instead based on the lower end of load uncertainty, and upper end of solar and wind uncertainty that might materialize.

[12] In comparing the 15-minute observation to the three corresponding 5-minute observations, the maximum load errors and minimum wind and solar errors are used to calculate upward net load uncertainty. Or, minimum load errors and maximum wind and solar errors for downward net load uncertainty.

[13] The coefficient *c* is also known as the intercept. It shows the value of the dependent variable when all independent variables are equal to zero.

Equation 2. Predicted values for upward net load uncertainty

$$\underbrace{\hat{L}_Q^{97.5}}_{} = a_l^{97.5}(load)^2 + b_l^{97.5}(load) + c_l^{97.5}$$
$$\hat{S}_Q^{2.5} = a_s^{2.5}(solar)^2 + b_s^{2.5}(solar) + c_s^{2.5}$$
$$\widehat{W}_Q^{2.5} = a_w^{2.5}(wind)^2 + b_w^{2.5}(wind) + c_w^{2.5}$$

Predicted values: predicted 97.5th percentile of load uncertainty and 2.5th percentile of solar and wind uncertainty based on regression coefficients and historical distribution

***Regression coefficients*:** parameters “a”, “b” and “c” that define the relationship between the forecasts and the extreme end of uncertainty that might materialize

The *mosaic* element of the regression combines the predicted forecasts above with the histogram method. For the histogram estimates, the 180-day distributions are again used to calculate the lower and upper ends of uncertainty, based on the 2.5th and 97.5th percentiles in the distribution. The combination of the predicted values and the histograms extremes in the mosaic variable are intended to capture the incremental weather effect of using predicted information relative to the histogram approach. Here, the calculation modifies the histogram net load by adding the predicted values and subtracting the histogram outcomes for each uncertainty type individually.[14] This is shown below for upwards net load uncertainty:

Equation 3. Mosaic variable for upward net load uncertainty

$$\underbrace{mosaic^{97.5}}_{} = \underbrace{NL_H^{97.5}}_{} + \left(\left(\hat{L}_Q^{97.5} - L_H^{97.5}\right) - \left(\hat{S}_Q^{2.5} - S_H^{2.5}\right) - \left(\widehat{W}_Q^{2.5} - W_H^{2.5}\right)\right)$$

***Upward mosaic variable*:** intermediate variable for final regression

97.5th percentile of net load uncertainty from histogram

Predicted values: predicted load, solar, and wind uncertainty from initial quantile regressions (using historical distribution)

Load, solar, and wind uncertainty from histograms

Once the mosaic variable is calculated for each interval in the distribution, the software runs a final regression to predict net load uncertainty. Again, the quantile regression method looks for the extreme values of the data (at the 2.5th and 97.5th percentiles) such that the output reflects the upper and lower boundaries of the future uncertainty. Therefore, the predicted values obtained from the quantile regression models are expected to estimate the range in which net load uncertainty is likely to materialize. The final regression is shown below:

[14] The mosaic variable can be thought of as the modified net load.

Equation 4. Mosaic regression for upward net load uncertainty

$$\underbrace{Net\ load\ uncertainty^{max}}_{\text{Dependent variable}} = a_m^{97.5}(\underbrace{mosaic^{97.5}}_{\text{Independent variable}})^2 + b_m^{97.5}(mosaic^{97.5}) + c_m^{97.5} + \underbrace{\varepsilon}_{\text{Error term}} \qquad \underbrace{(\tau = 0.975)}_{\text{Quantile parameter}}$$

Dependent variable: net load uncertainty — maximum difference between binding 5-minute market forecasts and advisory 15-minute market forecasts in each 15-minute market interval

Independent variable: mosaic variable in each 15-minute market interval (from previous step)

Error term (ε): variation in dependent variable that is not explained by independent variable

Quantile parameter (τ): determines the level of the quantile regression being estimated (high: 97.5 percentile)

Once all of the regressions are complete, the regression output coefficients can be combined with current forecast information to calculate uncertainty for each interval. For the flexibility test, this forecast information is the same load, solar, and wind forecasts which are considered in the resource sufficiency evaluation for calculating ramping capacity and test requirements. The latest forecasts at the time of the second pass of the resource sufficiency evaluation at 55 minutes prior to the evaluation hour are held constant for the final test at 40 minutes prior to the hour. The final equations for combining the current forecast information with the regression coefficients and histogram extremes to calculate upward uncertainty for each interval are shown below.

Equation 5. Calculation of upward uncertainty from current forecast information

$$\hat{L}^{97.5}_{current} = a_l^{97.5}(load_{current})^2 + b_l^{97.5}(load_{current}) + c_l^{97.5}$$
$$\hat{S}^{2.5}_{current} = a_s^{2.5}(solar_{current})^2 + b_s^{2.5}(solar_{current}) + c_s^{2.5}$$
$$\hat{W}^{2.5}_{current} = a_w^{2.5}(wind_{current})^2 + b_w^{2.5}(wind_{current}) + c_w^{2.5}$$

$$mosaic^{97.5}_{current} = NL_H^{97.5} + \left(\left(\hat{L}^{97.5}_{current} - L_H^{97.5}\right) - \left(\hat{S}^{2.5}_{current} - S_H^{2.5}\right) - \left(\hat{W}^{2.5}_{current} - W_H^{2.5}\right)\right)$$

$$Net\ load\ uncertainty^{97.5}_{current} = a_m^{97.5}\left(mosaic^{97.5}_{current}\right)^2 + b_m^{97.5}\left(mosaic^{97.5}_{current}\right) + c_m^{97.5}$$

The performance of the mosaic quantile regression method depends on whether there is a meaningful relationship between net load uncertainty and the mosaic variables created from historical and predicted values. DMM is currently in the process of evaluating whether there is a strong relationship between these variables.

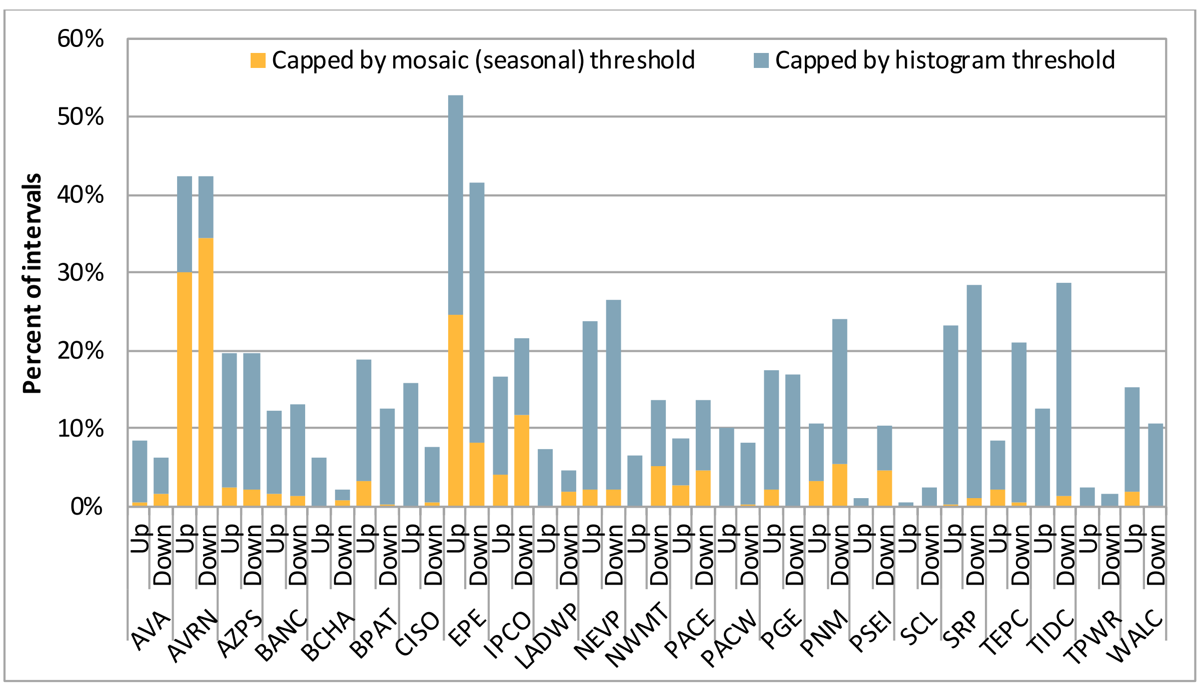
Thresholds for capping uncertainty

Uncertainty calculated from the quantile regressions are 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.[15] The *mosaic* (or seasonal) threshold is updated each quarter and is calculated based on the 1st and 99th percentile using the quantile regression method and observations over the previous 90 days. Here, each 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.

Figure 4.1 shows the percent of test intervals in which the upward or downward uncertainty calculated by the quantile regression was capped by either the mosaic or histogram threshold during the month. During June, the mosaic threshold frequently capped Avangrid calculated uncertainty, during 30 percent of intervals for upward uncertainty and 35 percent of intervals for downward uncertainty. For all other balancing areas, the histogram threshold capped the calculated uncertainty more frequently compared to the mosaic threshold.

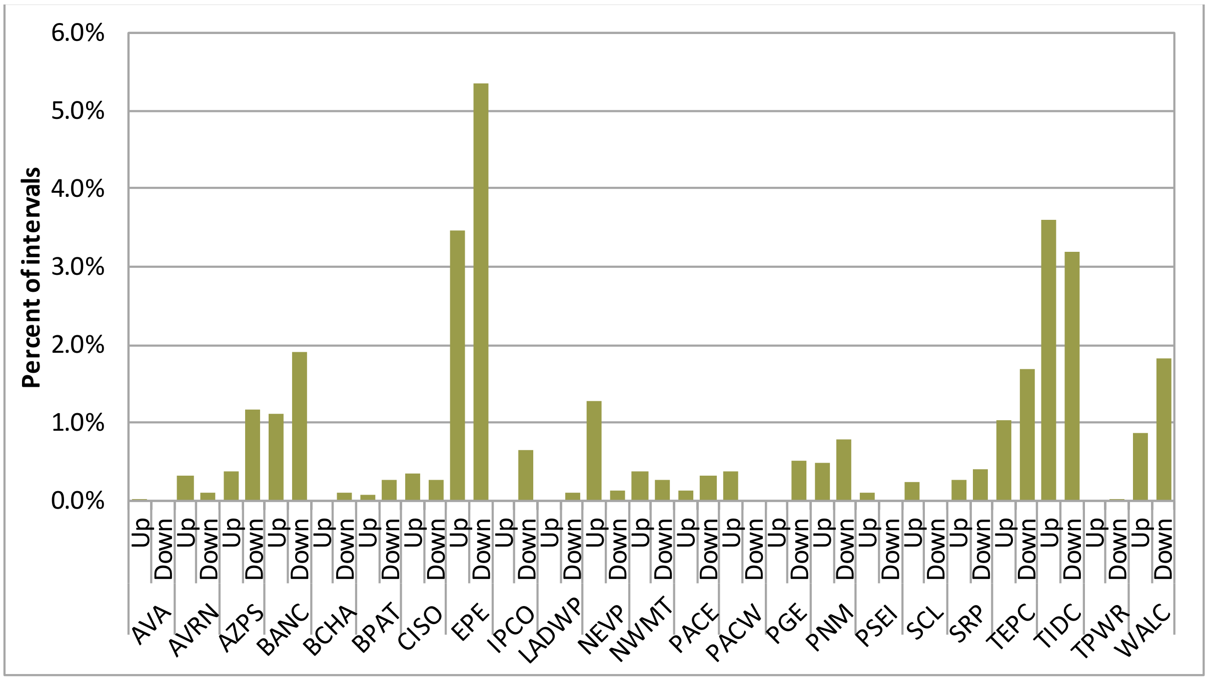
A threshold is also in place that sets the *floor* for uncertainty at 0.1 MW in both directions. The upward and downward uncertainty is therefore set near zero when the uncertainty calculated from the quantile regression would be negative. Figure 4.2 shows the percent of test intervals in which the quantile regression uncertainty was set near zero by this threshold during the month. In particular, the floor set the downward uncertainty for El Paso Electric near zero during around 5 percent of intervals.

Figure 4.1 Quantile regression uncertainty capped by mosaic or histogram thresholds (June 2023)



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

Figure 4.2 Quantile regression uncertainty set near zero by mosaic threshold (June 2023)



Using uncertainty concepts from the flexible ramping product in the resource sufficiency evaluation

The calculation of uncertainty in the flexibility test continues to be measured similarly to the 15-minute market flexible ramping product — based on the difference between binding 5-minute market forecasts and corresponding advisory 15-minute market forecasts. The quantile regression uses the historical sample of 5-minute and 15-minute market observations to create hourly coefficients that define the relationship between the forecasts and uncertainty. The resource sufficiency evaluation and flexible ramping product uncertainty calculations for a single balancing area use the same hourly coefficients, but are combined with the current forecast information for each time horizon.[16]

The calculated uncertainty is based on the 2.5th and 97.5th percentile for downward and upward uncertainty, respectively. The 95 percent confidence interval for the uncertainty requirement in the flexible ramping product was designed to capture the upper end of uncertainty needs, such that it could 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 constraint relaxation. In the resource sufficiency evaluation, this trade-off is not considered, and the upper end of uncertainty is instead required in full

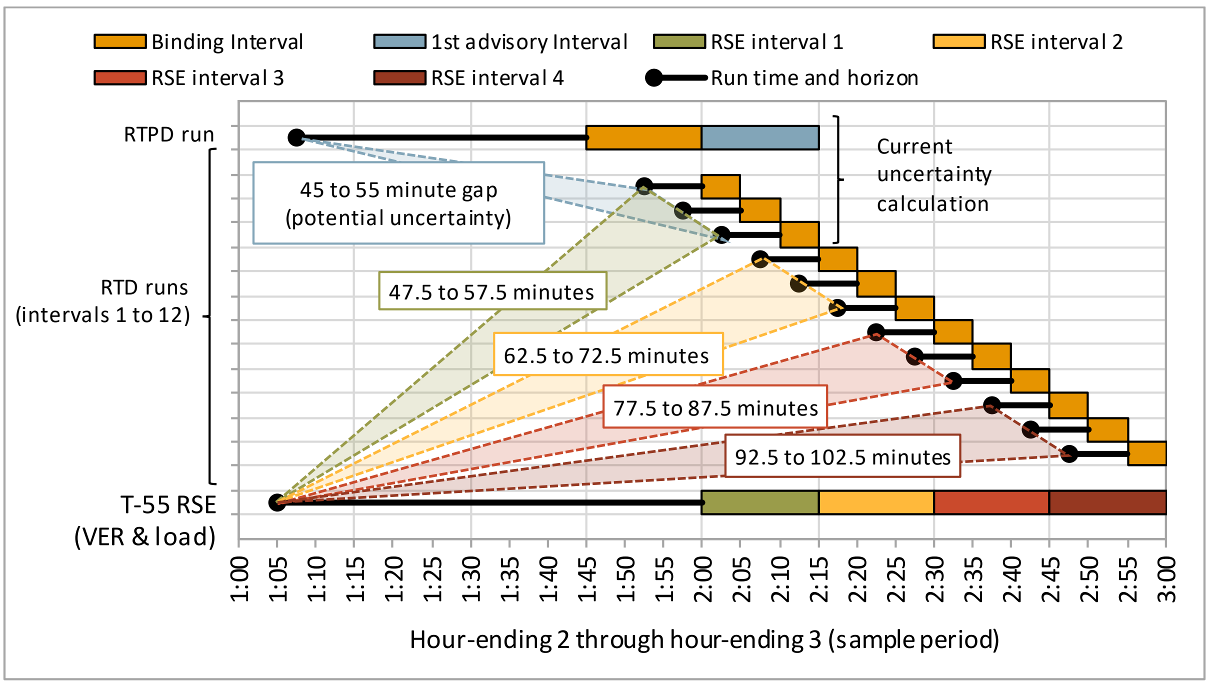
[16] A balancing-area-specific flexible ramping product uncertainty requirement will be enforced for any balancing area that failed the resource sufficiency evaluation.

to pass both tests. DMM has asked the CAISO and stakeholders to consider whether the 95 percent confidence interval, or another, is most appropriate for the tests.[17]

Further, the resource sufficiency evaluation occurs in a different timeframe than the 15-minute market. Figure 4.3 illustrates the current uncertainty calculation — based on net load error between an advisory 15-minute market interval and corresponding binding 5-minute market intervals — as well as how it compares with the timeframe of the resource sufficiency evaluation. The current uncertainty calculation captures 45 to 55 minutes of potential uncertainty from the 15-minute market run to three corresponding 5-minute market runs. In contrast, when comparing the VER and load forecast values used in each interval of the resource sufficiency evaluation to corresponding 5-minute intervals, there exists a larger gap for uncertainty to materialize.[18]

In comparing the first 15-minute test interval to corresponding 5-minute market intervals, the timeframe and potential for net load uncertainty is similar to the timeframe of the 15-minute market flexible ramping product uncertainty calculation. In the later test intervals, the gap between the predicted forecasts at the time of the resource sufficiency evaluation and the real-time forecasts widens, reaching above 100 minutes.

Figure 4.3 Comparison of current uncertainty calculation to the timeframe of the RSE



[17] Department of Market Monitoring, *Comments on EIM Resource Sufficiency Evaluation Enhancements Issue Paper*, September 8, 2021: http://www.caiso.com/Documents/DMM-Comments-on-EIM-Resource-Sufficiency-Evaluation-Enhancements-Issue-Paper-Sep-8-2021.pdf

[18] The figure shows the resource sufficiency evaluation run time at 55 minutes prior to the hour. While the financially binding test is run at 40 minutes prior to the hour, the VER and load forecasts used in the final test are pulled from the advisory test performed at T-55.

Results of quantile regression uncertainty in the resource sufficiency evaluation

Figure 4.4 summarizes the histogram uncertainty (pulled from the 2.5th and 97.5th percentile of observations in the hour from the previous 180 days) and the final uncertainty from the mosaic quantile regression during the month for CAISO. 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 in Figure 4.4 show the average histogram and mosaic thresholds, respectively, during the month.

Figure 4.5 summarizes actual error between net load forecasts used in the resource sufficiency evaluation and those used in the 5-minute market for CAISO during the month. The distributions in each interval were created from the difference between 5-minute market net load and *net load in the corresponding test interval*. Here, a higher net load error reflects higher load (or lower renewables) in real-time, relative to the tests.

For comparison, the blue lines in Figure 4.5 show the average upward and downward uncertainty used in the tests during the same period (per the quantile regression output). Again, the blue areas around the lines show the minimum and maximum amounts for each hour. This metric therefore highlights net load error from the time horizon of the resource sufficiency evaluation and how well it fits within the current construct of uncertainty.

Figures covering the same information for all WEIM entities are provided further below. Overall, uncertainty calculated from the quantile regression approach were often comparable to those calculated with the histogram approach, though with the quantile regression approach tending to be lower across most hours and balancing areas.

Figure 4.4 CAISO resource sufficiency evaluation uncertainty requirements (weekdays, June 2023)

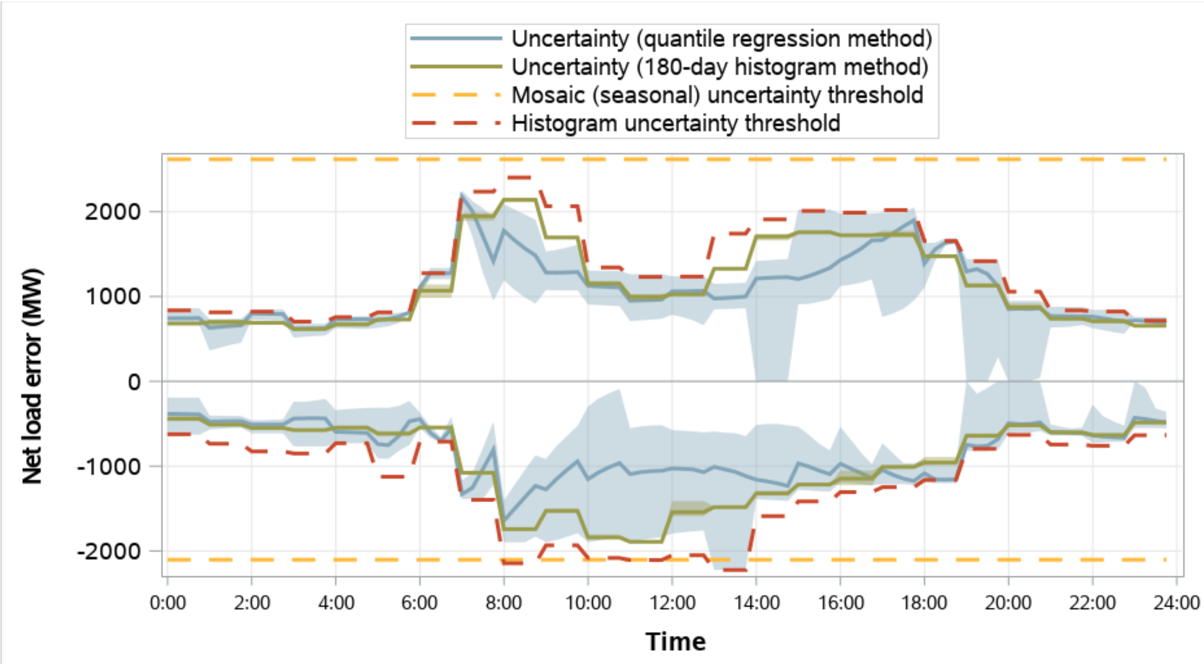


Figure 4.5 CAISO distribution of RSE and RTD net load error and comparison to RSE uncertainty (weekdays, June 2023)

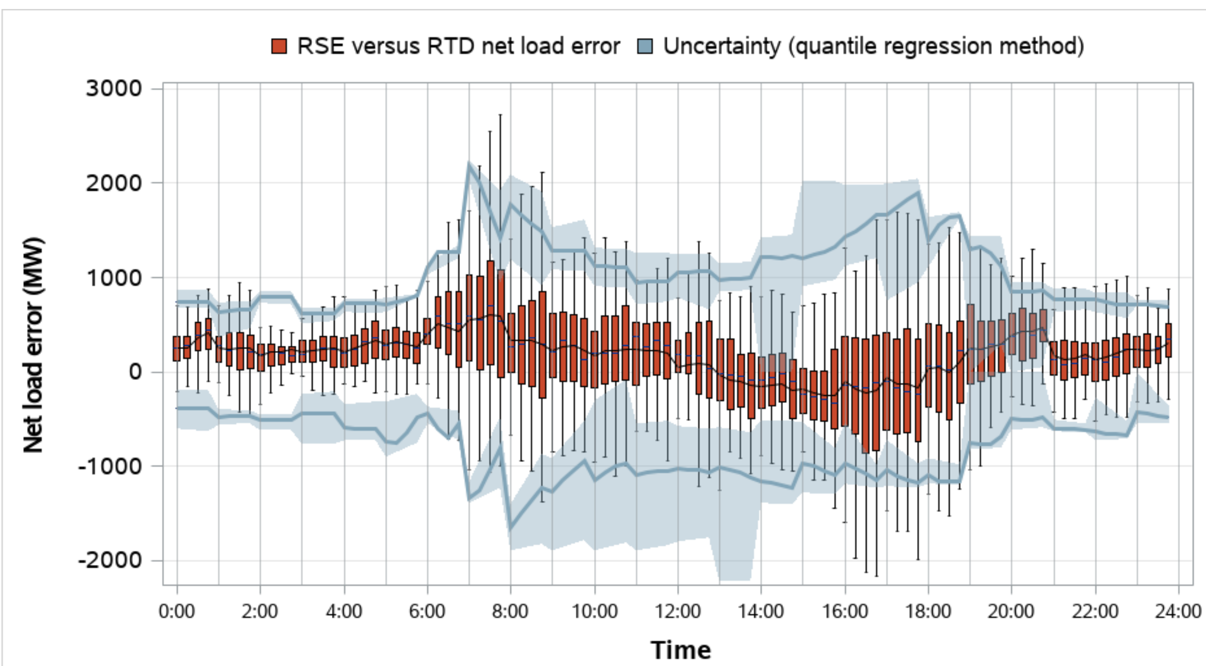


Figure 4.6 Arizona Public Service resource sufficiency evaluation uncertainty requirements (weekdays, June 2023)

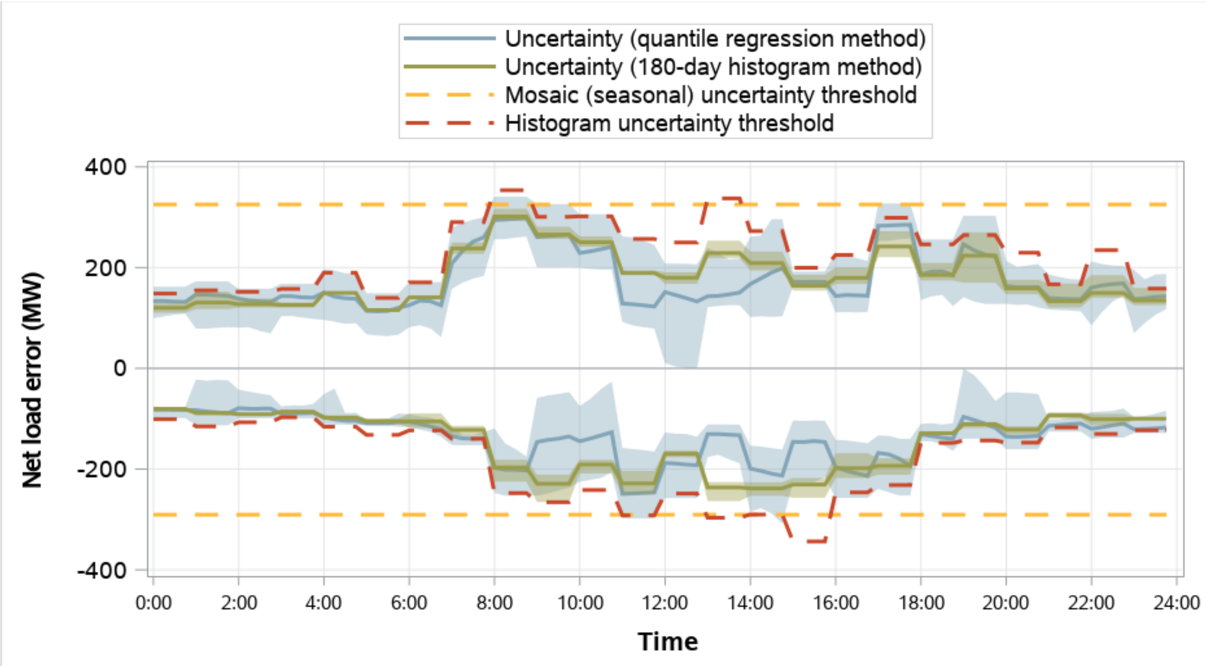


Figure 4.7 Arizona Public Service distribution of RSE and RTD net load error and comparison to RSE uncertainty (weekdays, June 2023)

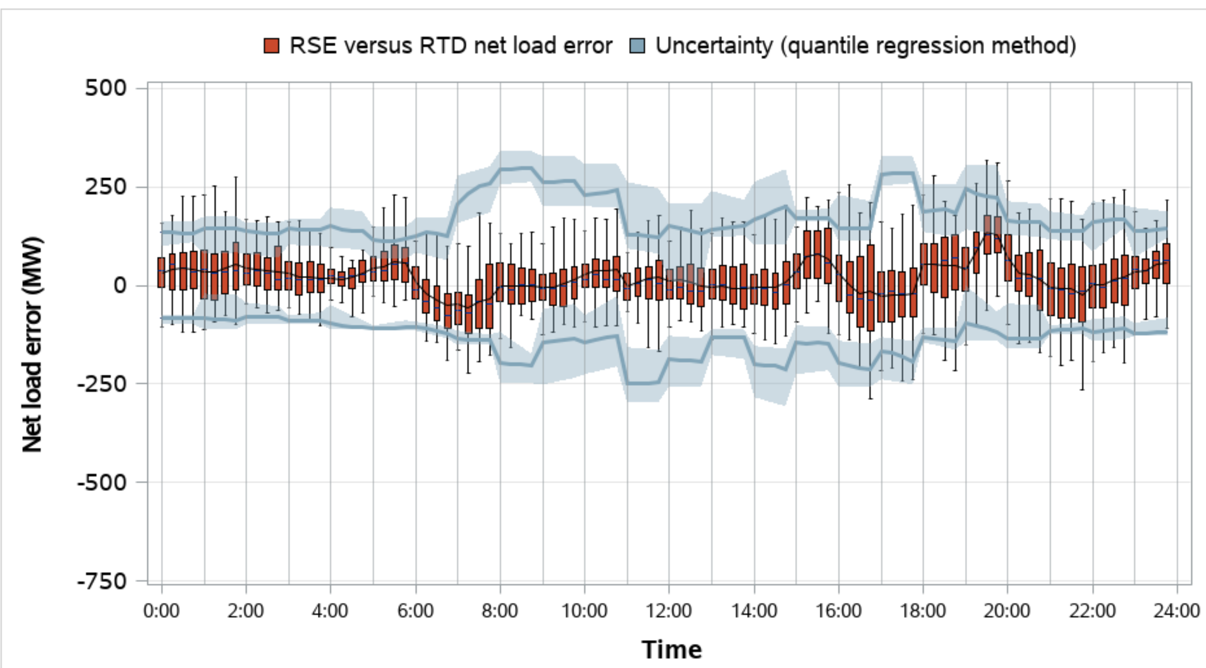


Figure 4.8 Avangrid resource sufficiency evaluation uncertainty requirements (weekdays, June 2023)

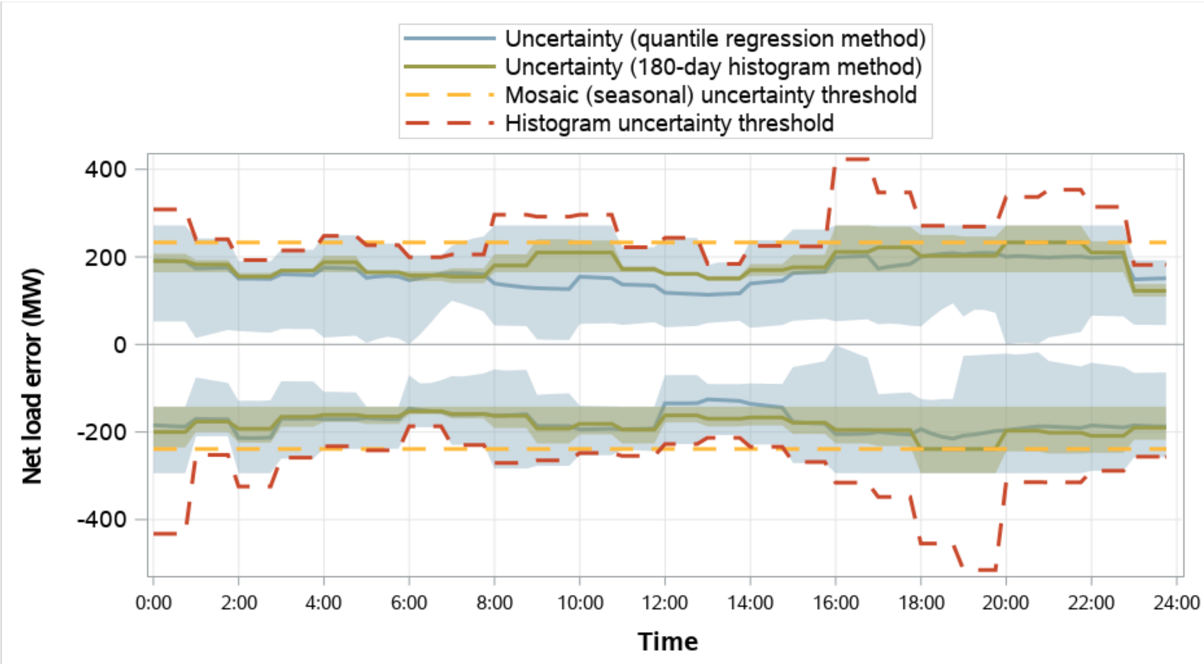


Figure 4.9 Avangrid distribution of RSE and RTD net load error and comparison to RSE uncertainty (weekdays, June 2023)

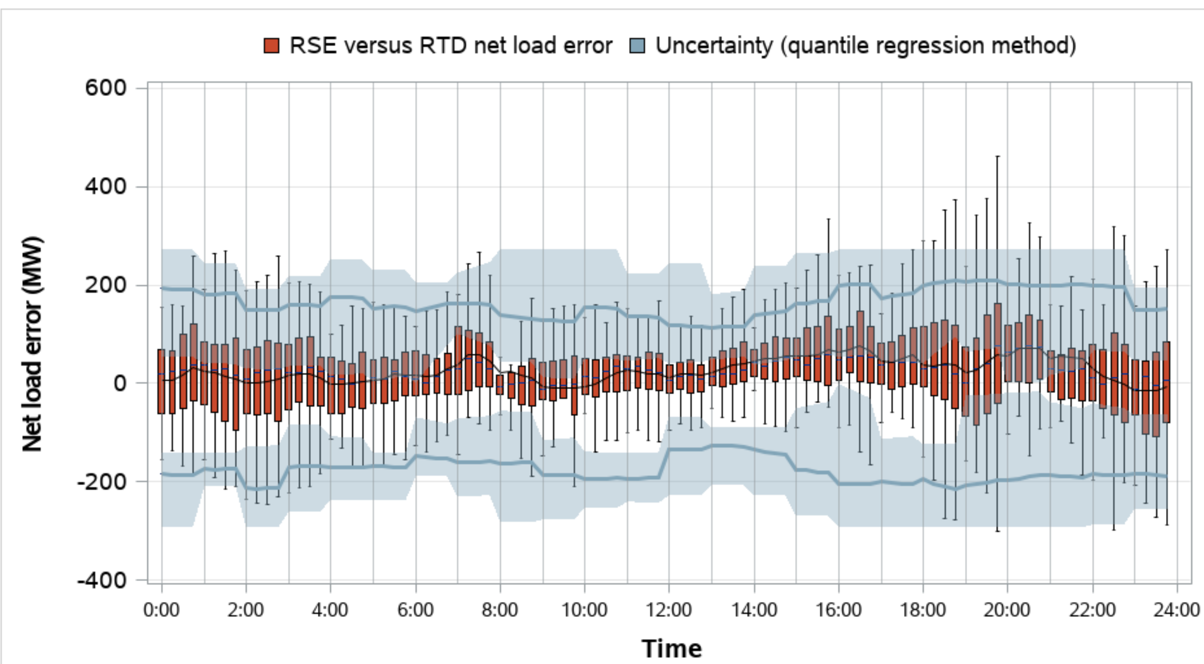


Figure 4.10 Avista resource sufficiency evaluation uncertainty requirements (weekdays, June 2023)

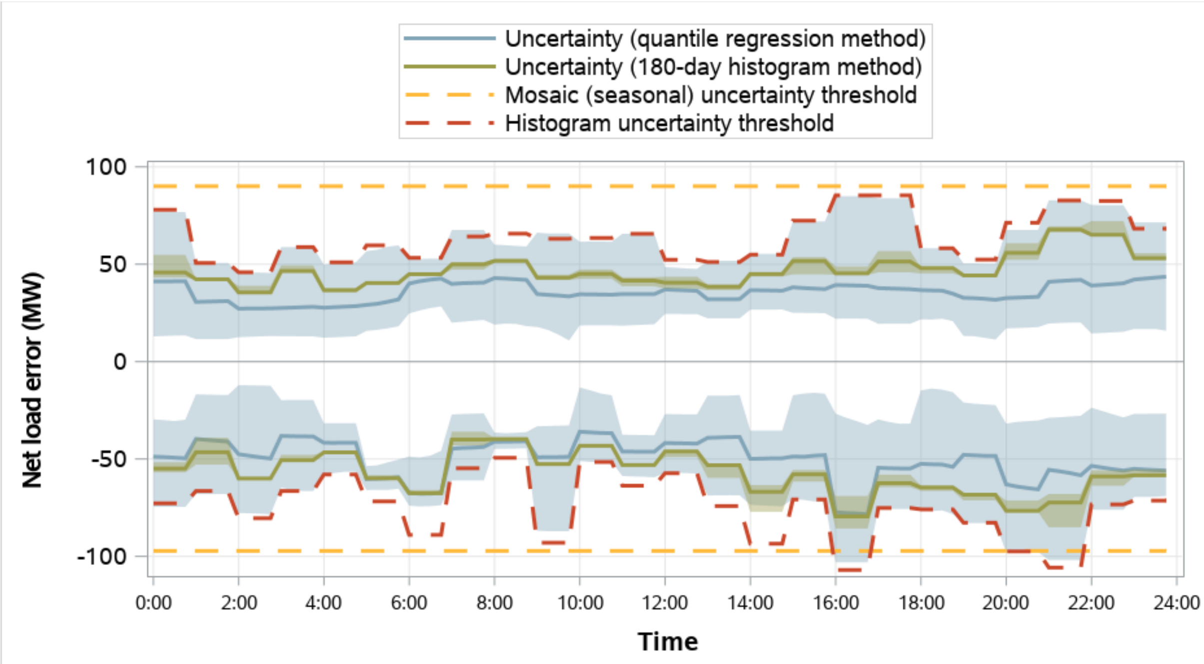


Figure 4.11 Avista distribution of RSE and RTD net load error and comparison to RSE uncertainty (weekdays, June 2023)

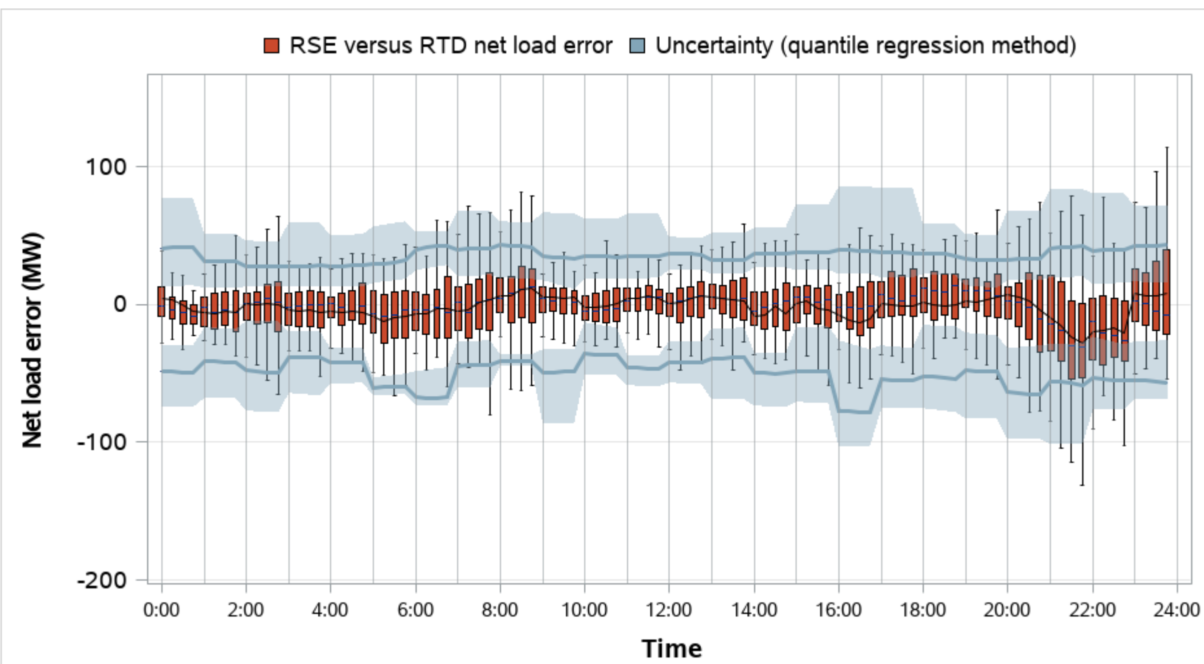


Figure 4.12 BANC resource sufficiency evaluation uncertainty requirements (weekdays, June 2023)

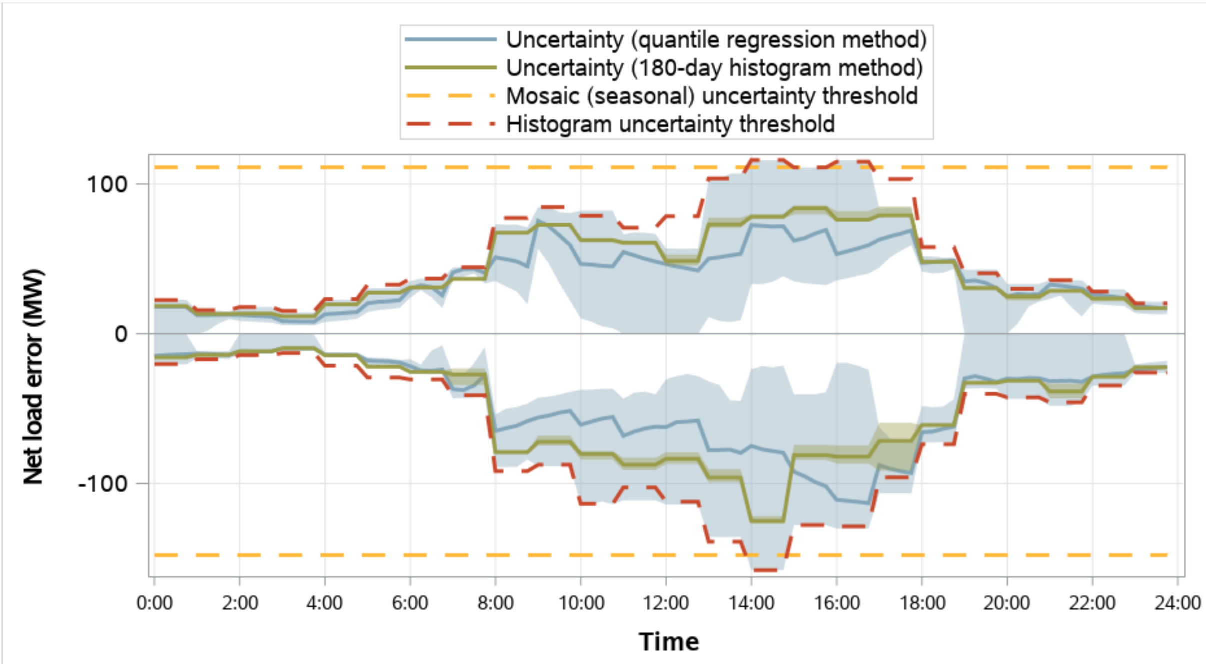


Figure 4.13 BANC distribution of RSE and RTD net load error and comparison to RSE uncertainty (weekdays, June 2023)

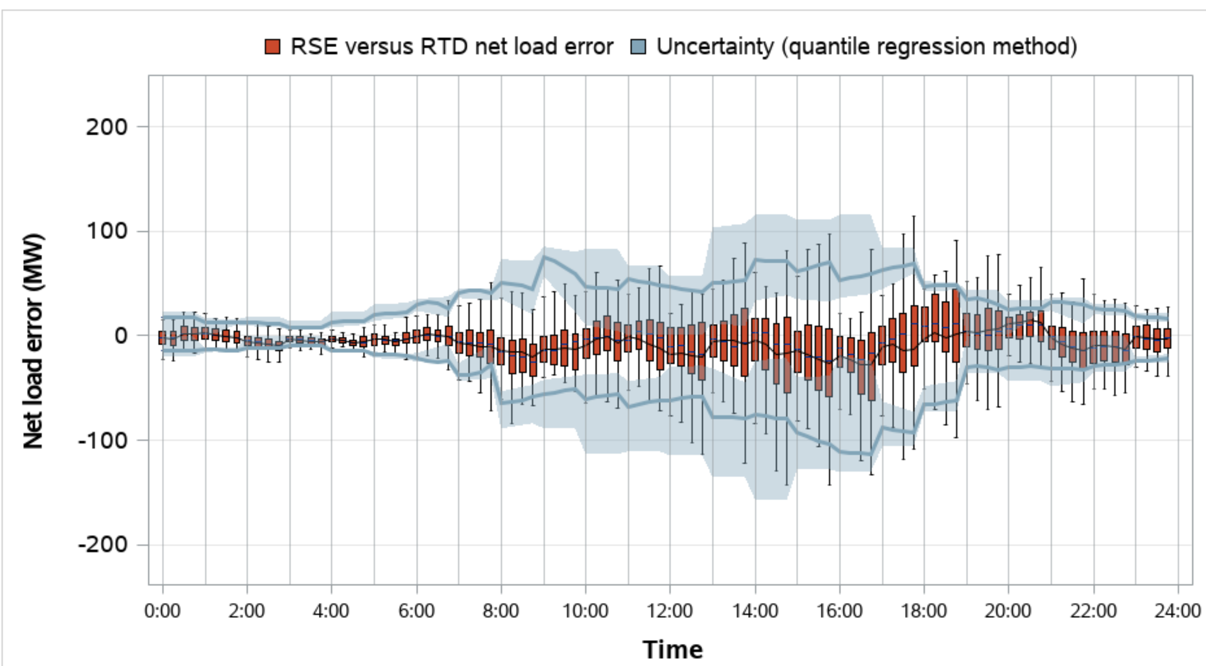


Figure 4.14 BPA resource sufficiency evaluation uncertainty requirements (weekdays, June 2023)

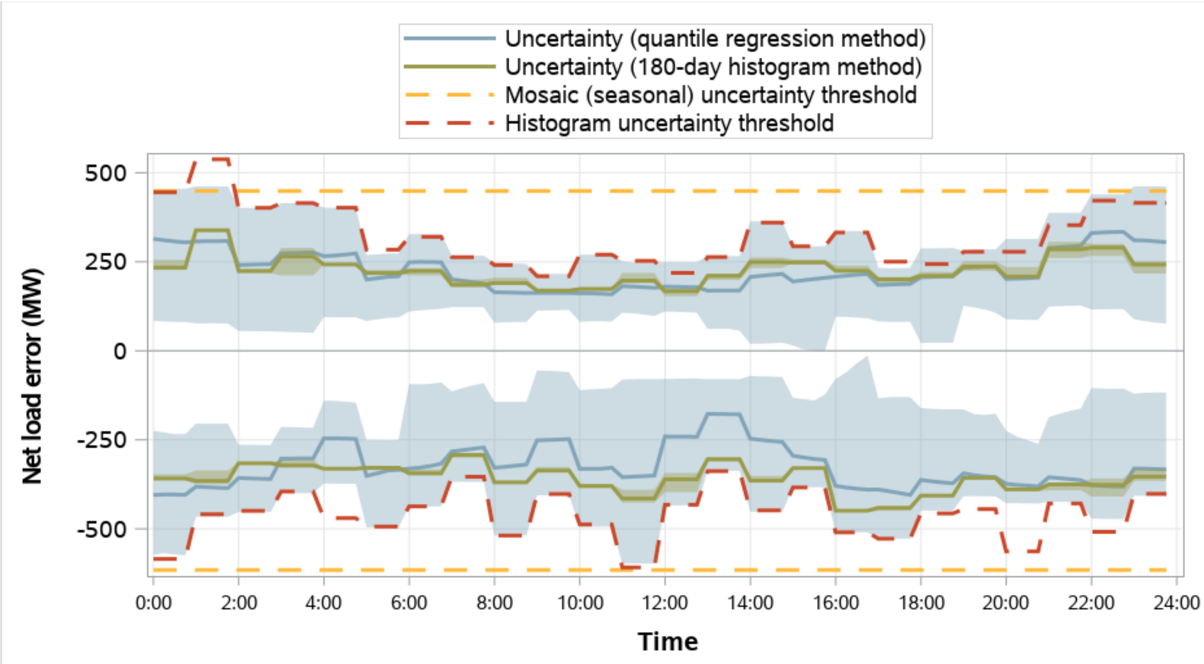


Figure 4.15 BPA distribution of RSE and RTD net load error and comparison to RSE uncertainty (weekdays, June 2023)

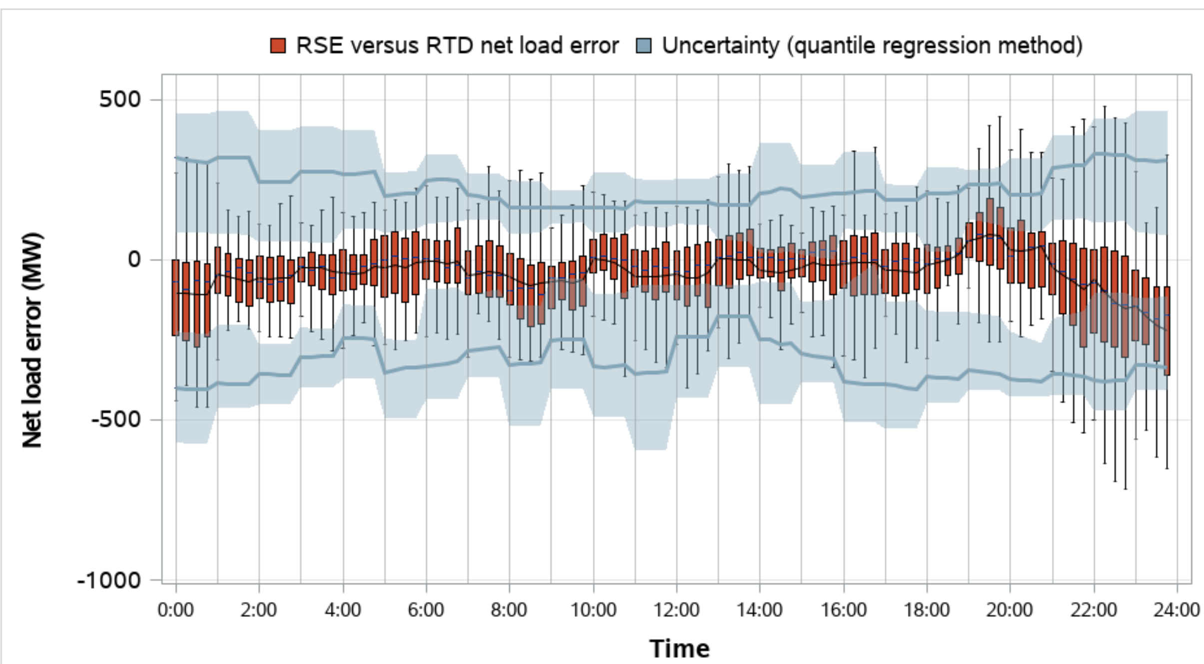


Figure 4.16 El Paso Electric distribution resource sufficiency evaluation uncertainty requirements (weekdays, June 2023)

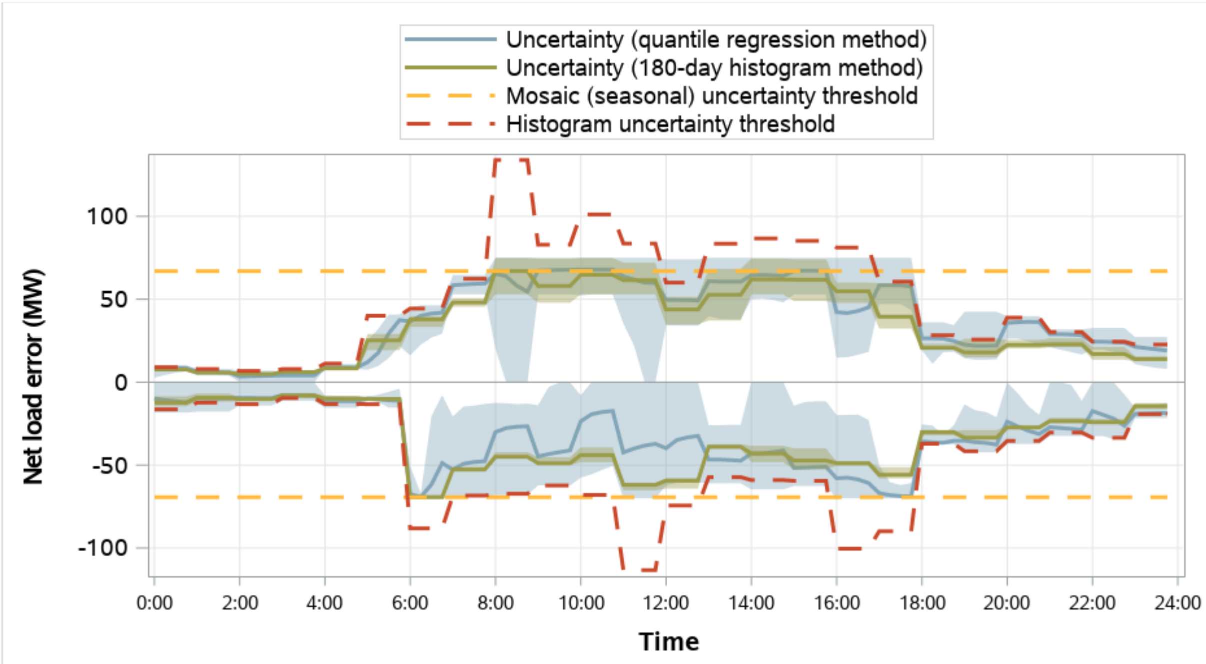


Figure 4.17 El Paso Electric distribution of RSE and RTD net load error and comparison to RSE uncertainty (weekdays, June 2023)

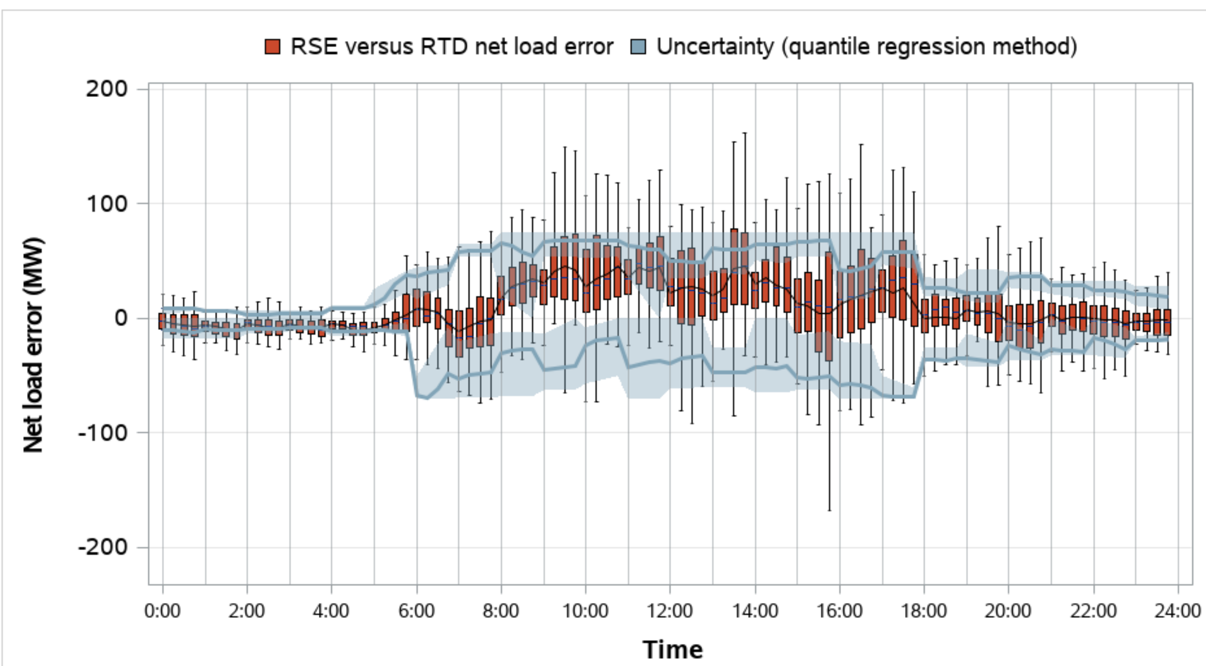


Figure 4.18 Idaho Power distribution resource sufficiency evaluation uncertainty requirements (weekdays, June 2023)

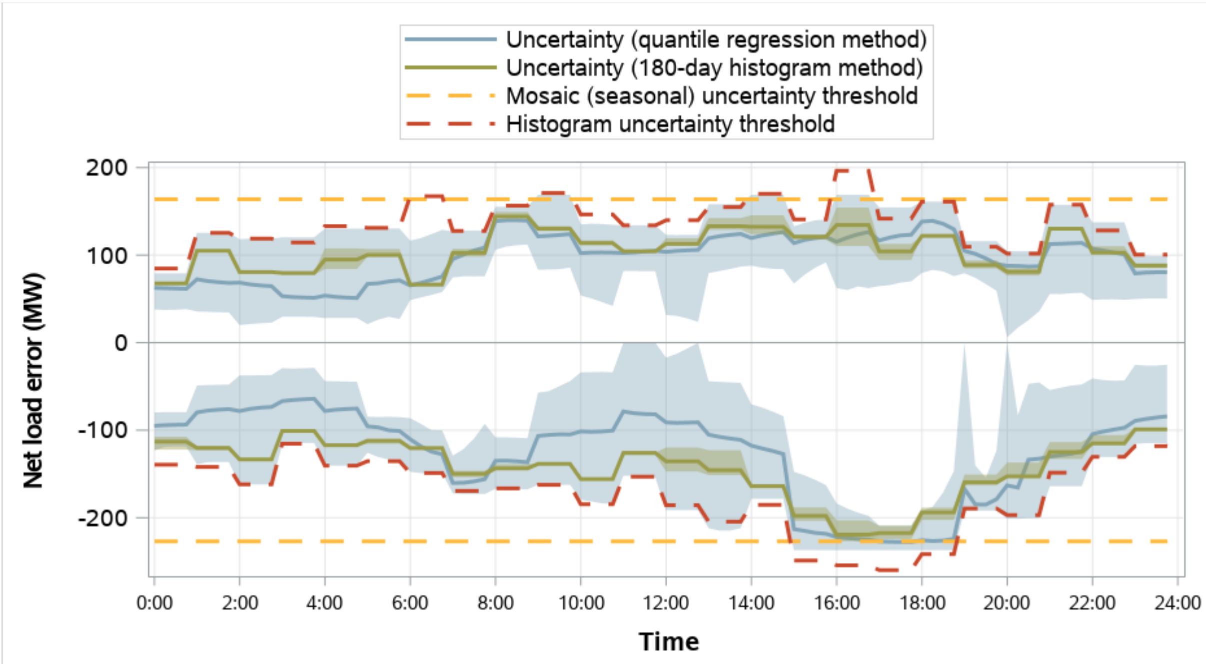


Figure 4.19 Idaho Power distribution of RSE and RTD net load error and comparison to RSE uncertainty (weekdays, June 2023)

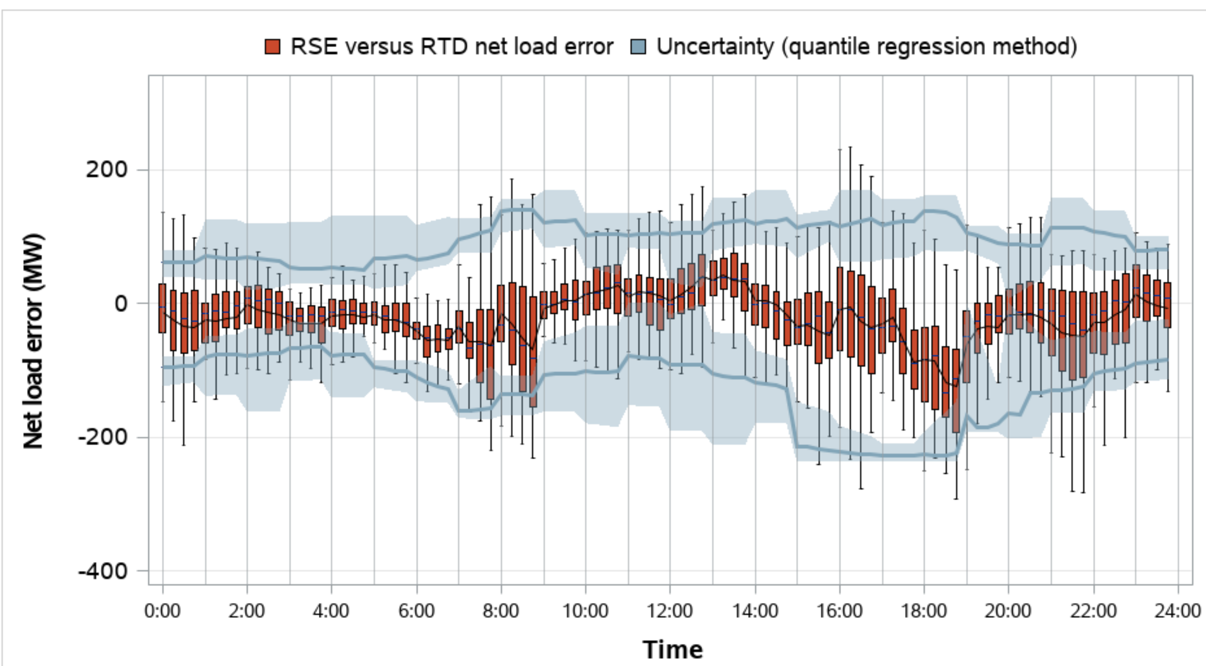


Figure 4.20 LADWP resource sufficiency evaluation uncertainty requirements (weekdays, June 2023)

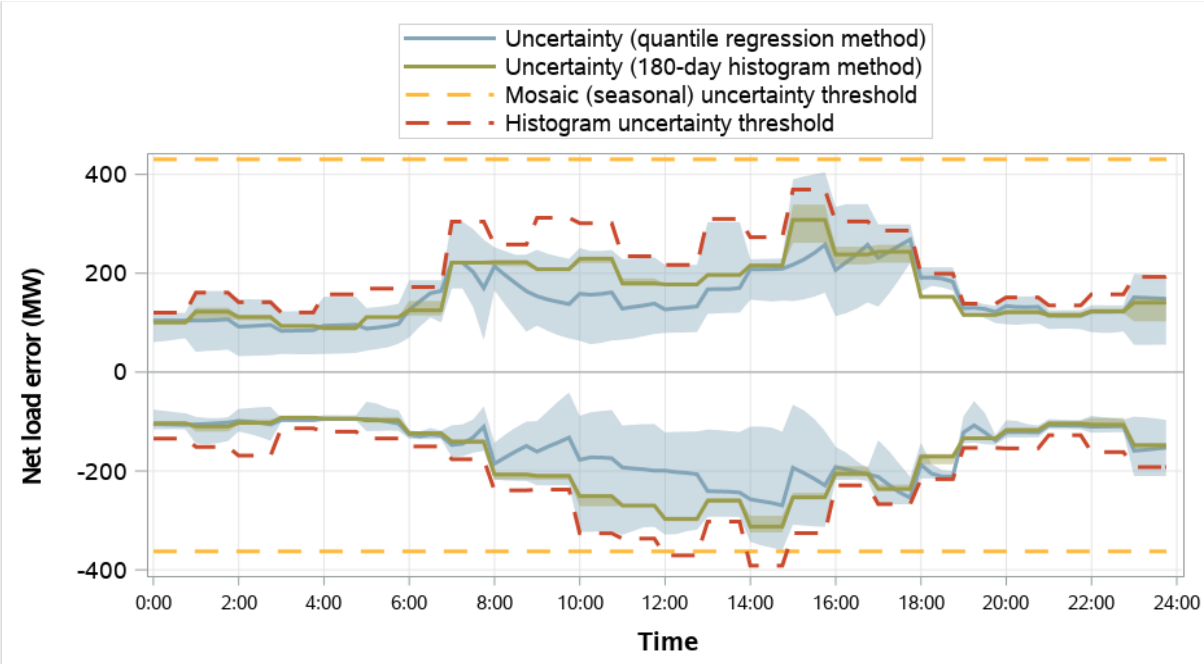


Figure 4.21 LADWP distribution of RSE and RTD net load error and comparison to RSE uncertainty (weekdays, June 2023)

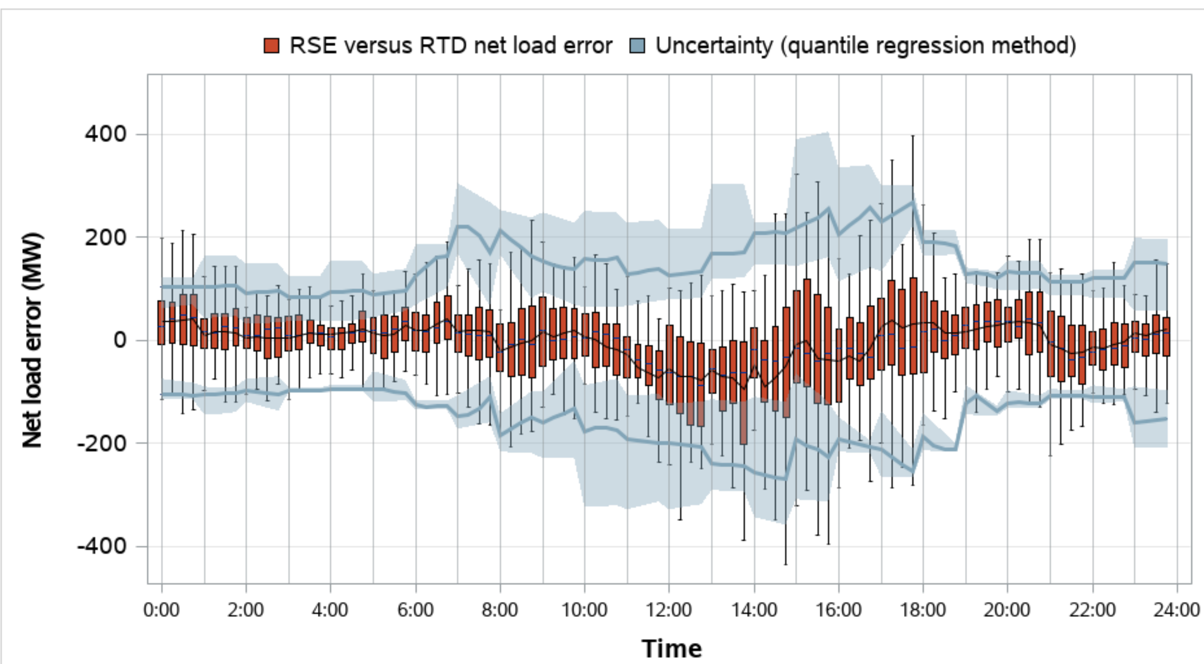


Figure 4.22 NorthWestern Energy average uncertainty by component (weekdays, June 2023)

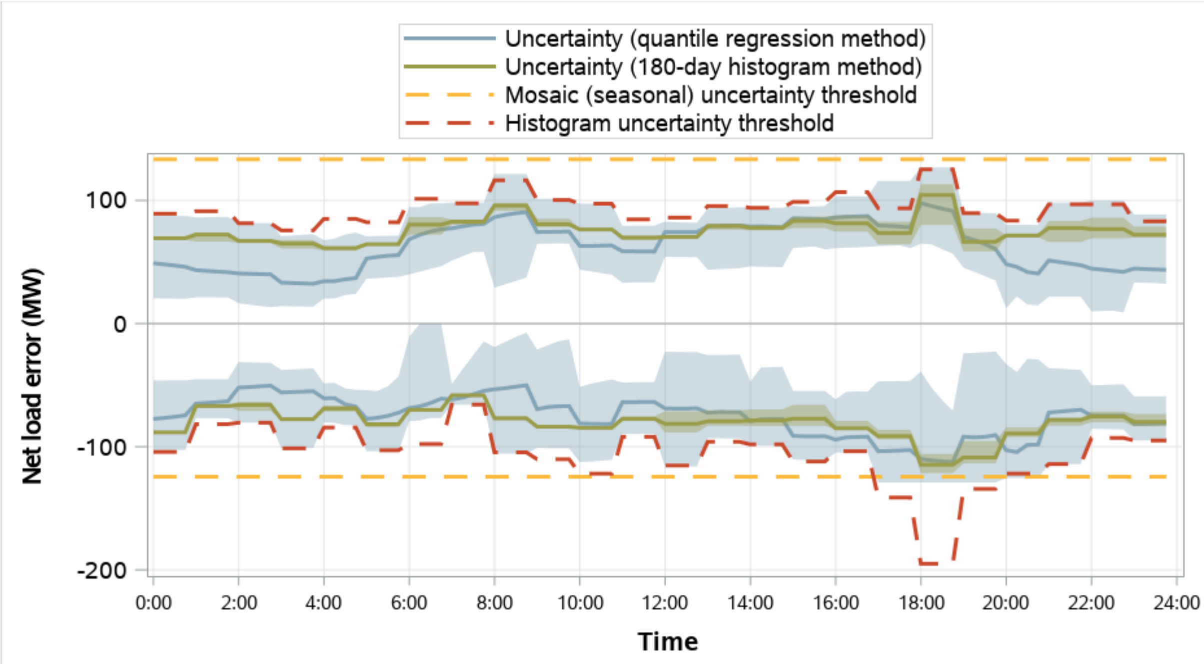


Figure 4.23 NorthWestern Energy distribution of RSE and RTD net load error and comparison to RSE uncertainty (weekdays, June 2023)

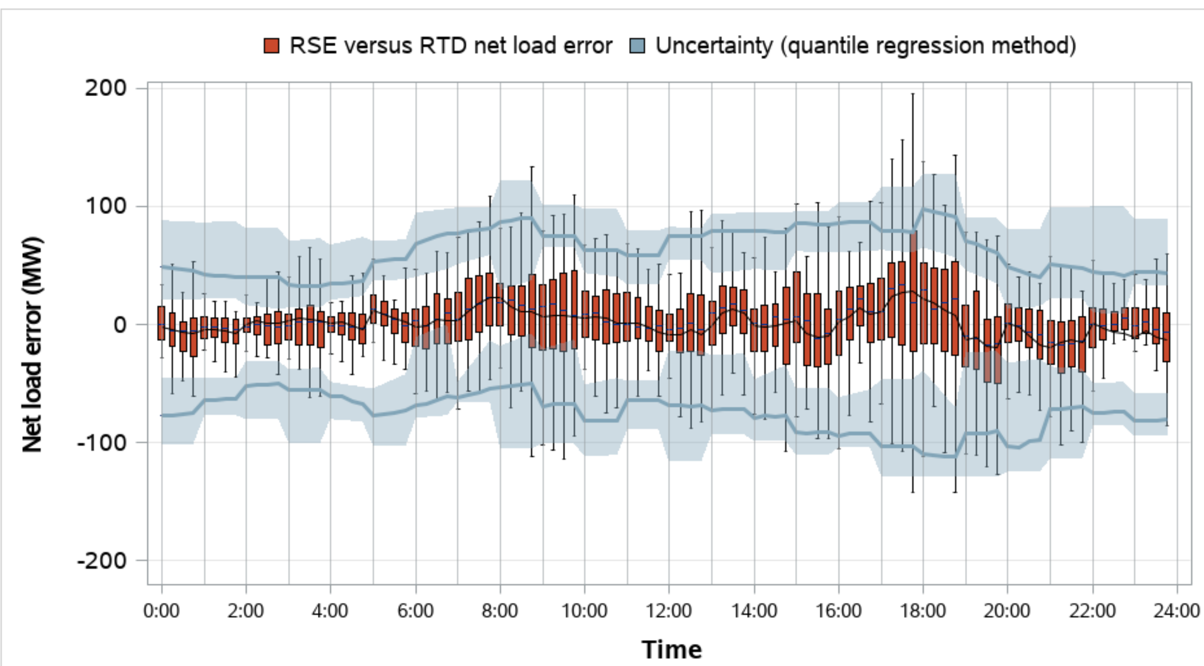


Figure 4.24 NV Energy resource sufficiency evaluation uncertainty requirements (weekdays, June 2023)

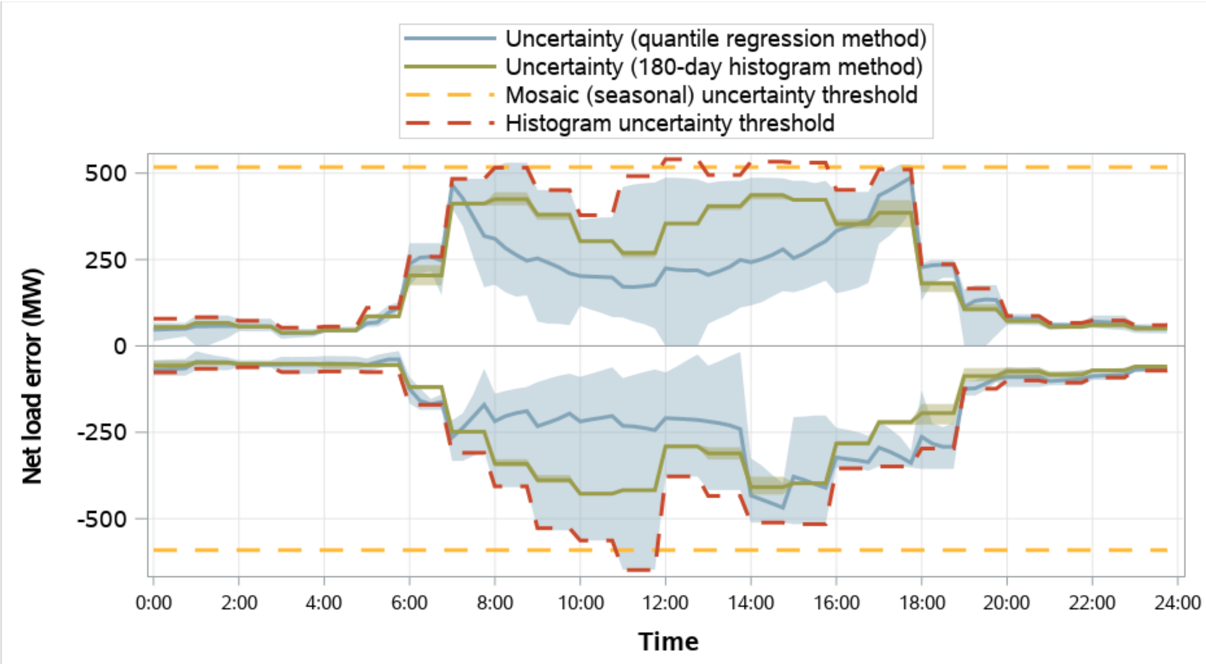


Figure 4.25 NV Energy distribution of RSE and RTD net load error and comparison to RSE uncertainty (weekdays, June 2023)

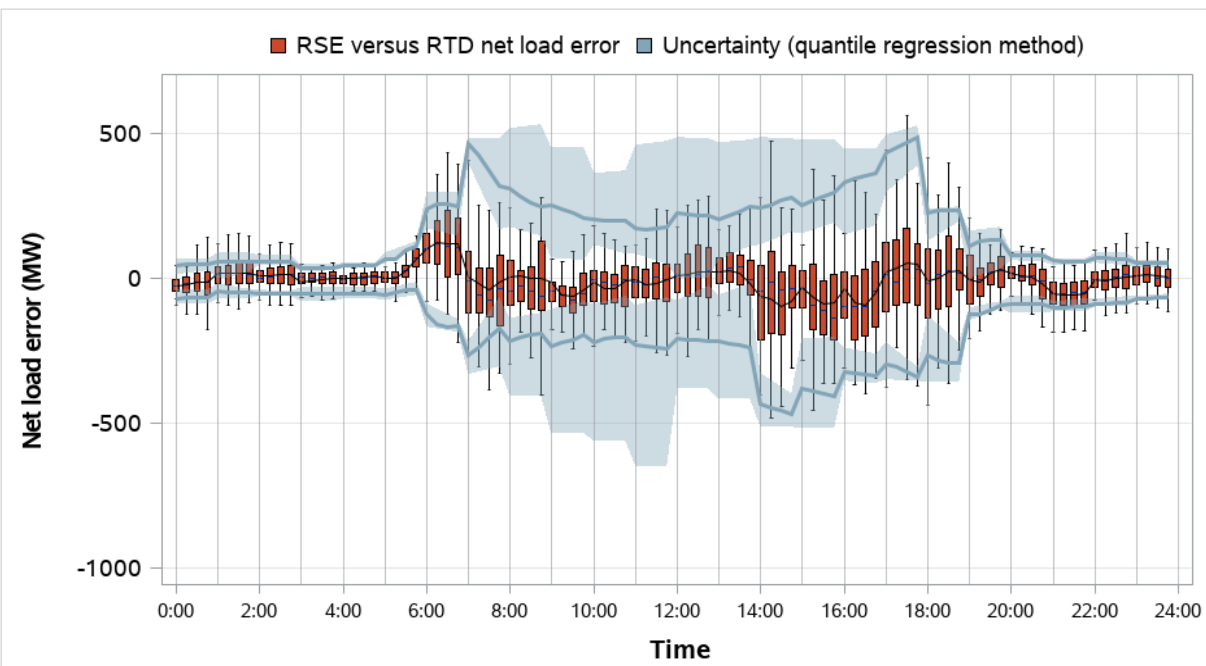


Figure 4.26 PacifiCorp East resource sufficiency evaluation uncertainty requirements (weekdays, June 2023)

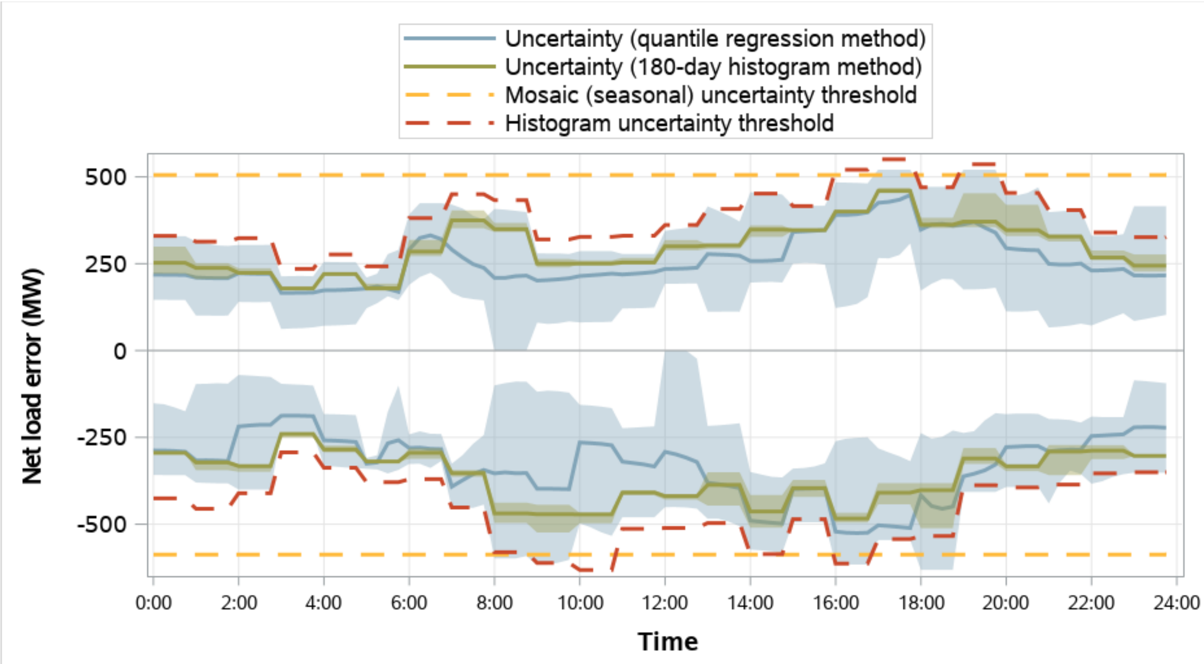


Figure 4.27 PacifiCorp East distribution of RSE and RTD net load error and comparison to RSE uncertainty (weekdays, June 2023)

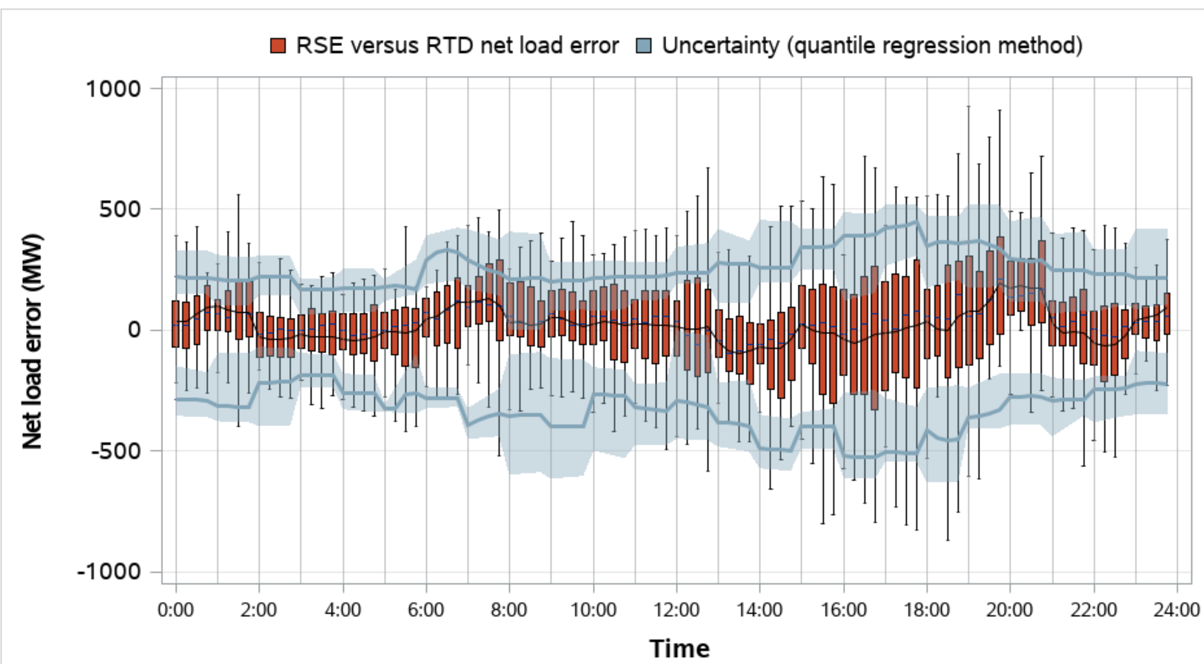


Figure 4.28 PacifiCorp West resource sufficiency evaluation uncertainty requirements (weekdays, June 2023)

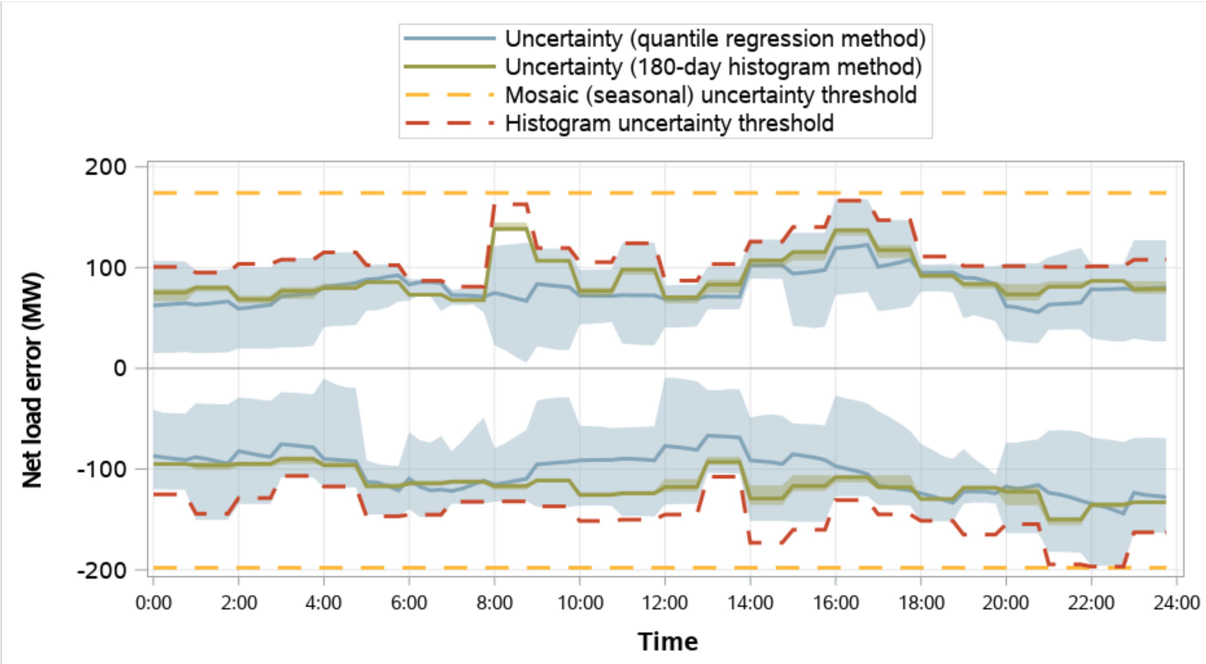


Figure 4.29 PacifiCorp West distribution of RSE and RTD net load error and comparison to RSE uncertainty (weekdays, June 2023)

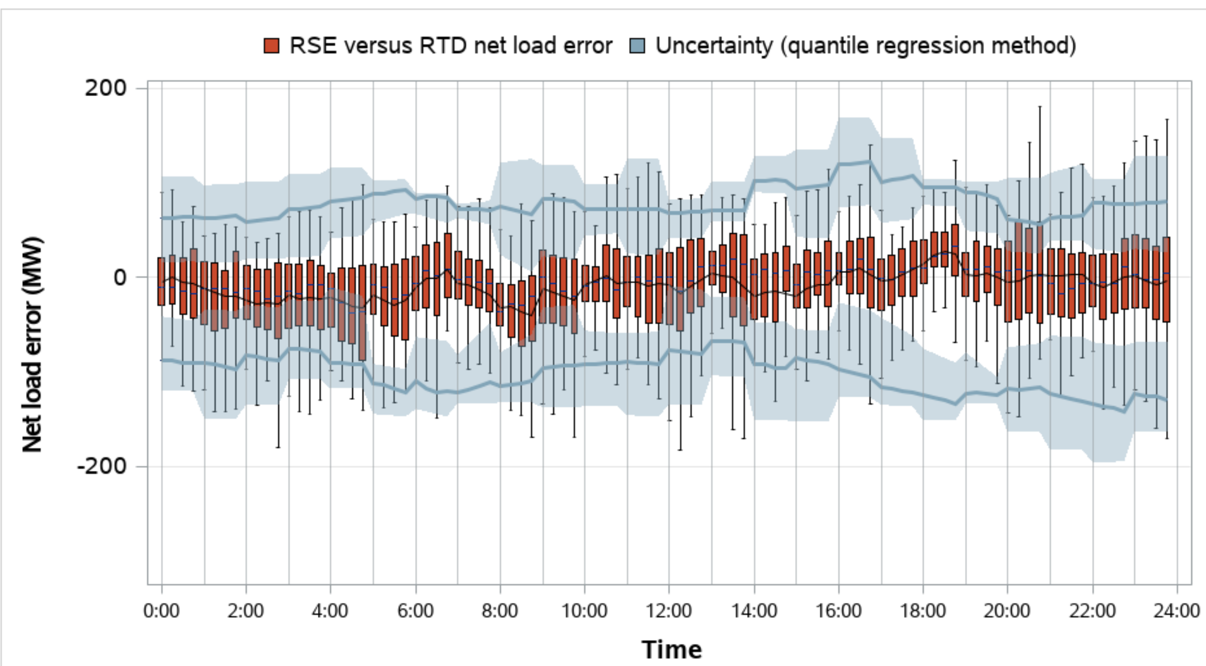


Figure 4.30 Portland General Electric resource sufficiency evaluation uncertainty requirements (weekdays, June 2023)

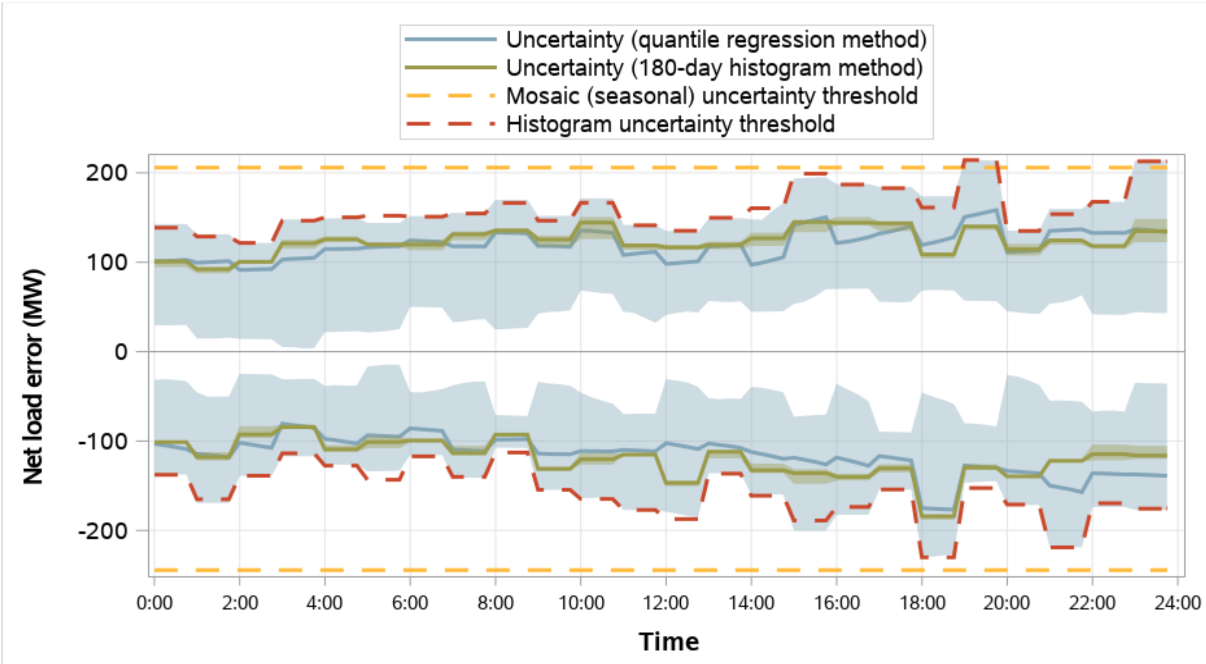


Figure 4.31 Portland General Electric distribution of RSE and RTD net load error and comparison to RSE uncertainty (weekdays, June 2023)

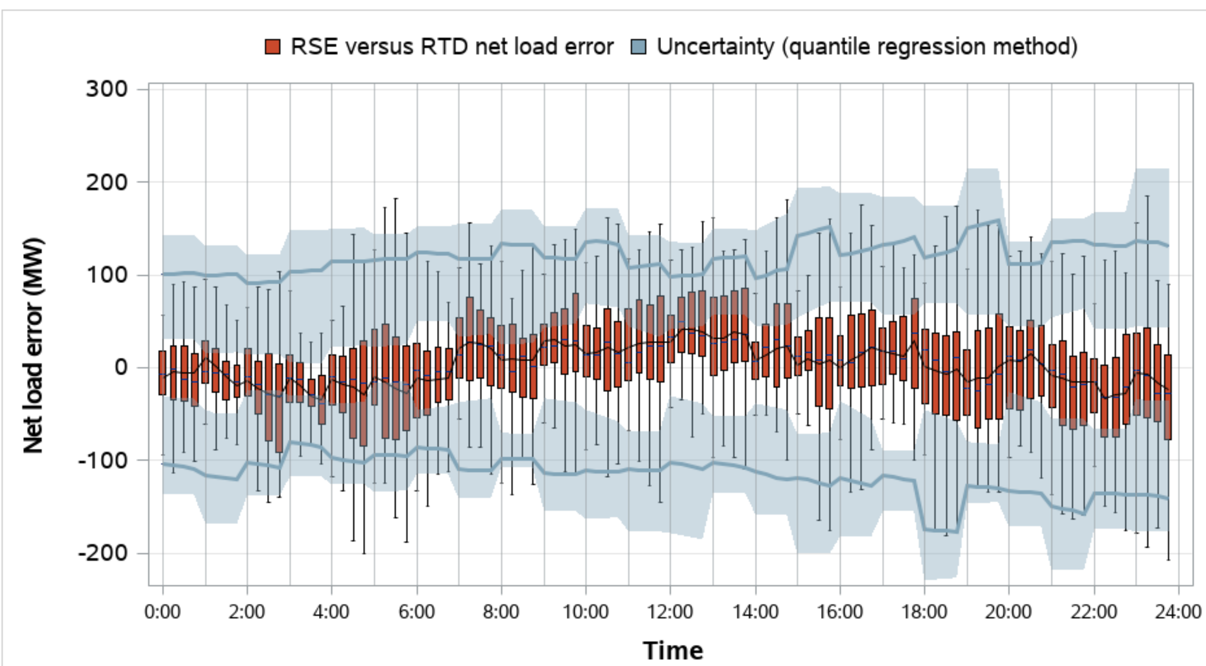


Figure 4.32 Powerex resource sufficiency evaluation uncertainty requirements (weekdays, June 2023)

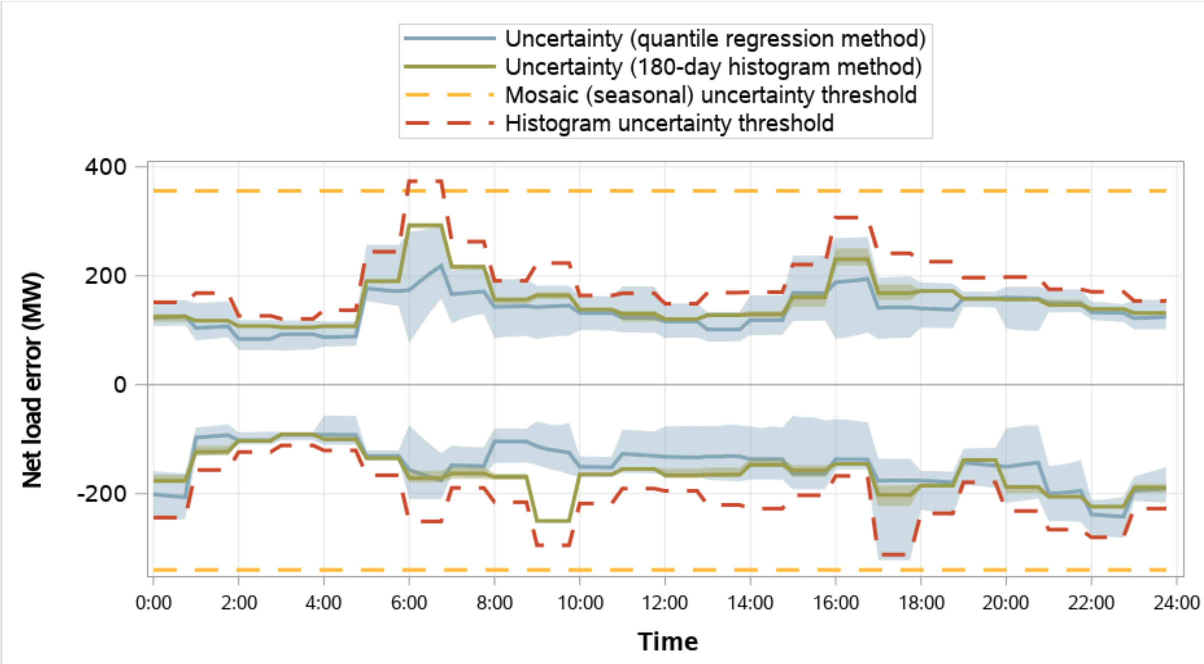


Figure 4.33 Powerex distribution of RSE and RTD net load error and comparison to RSE uncertainty (weekdays, June 2023)

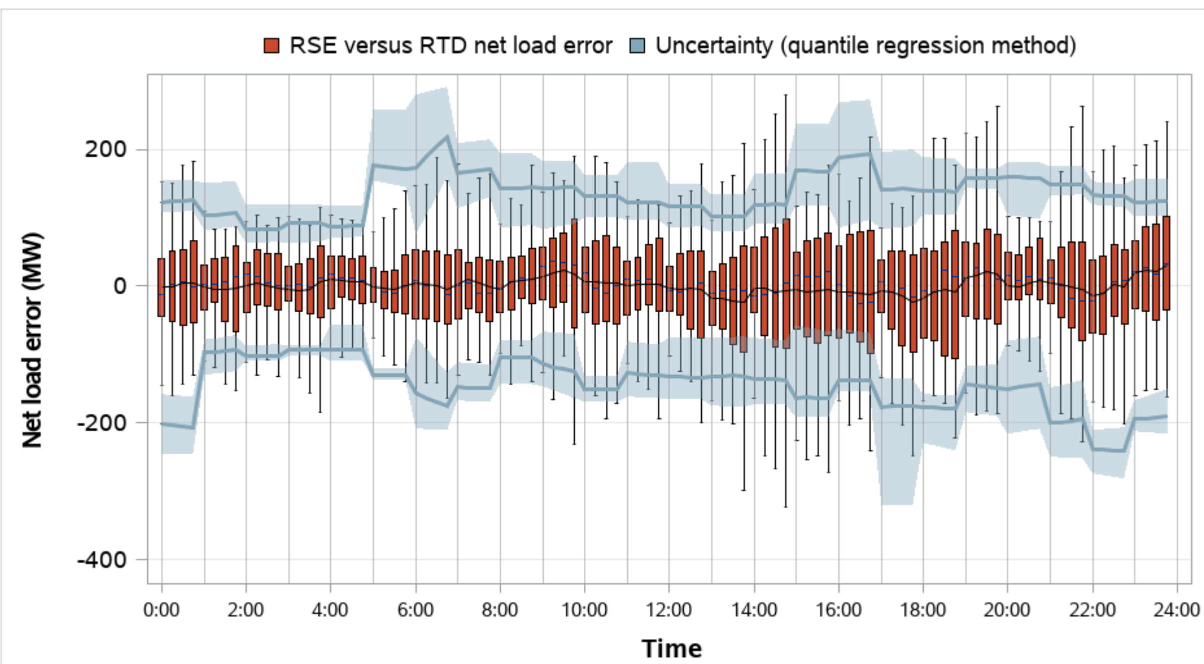


Figure 4.34 PNM resource sufficiency evaluation uncertainty requirements (weekdays, June 2023)

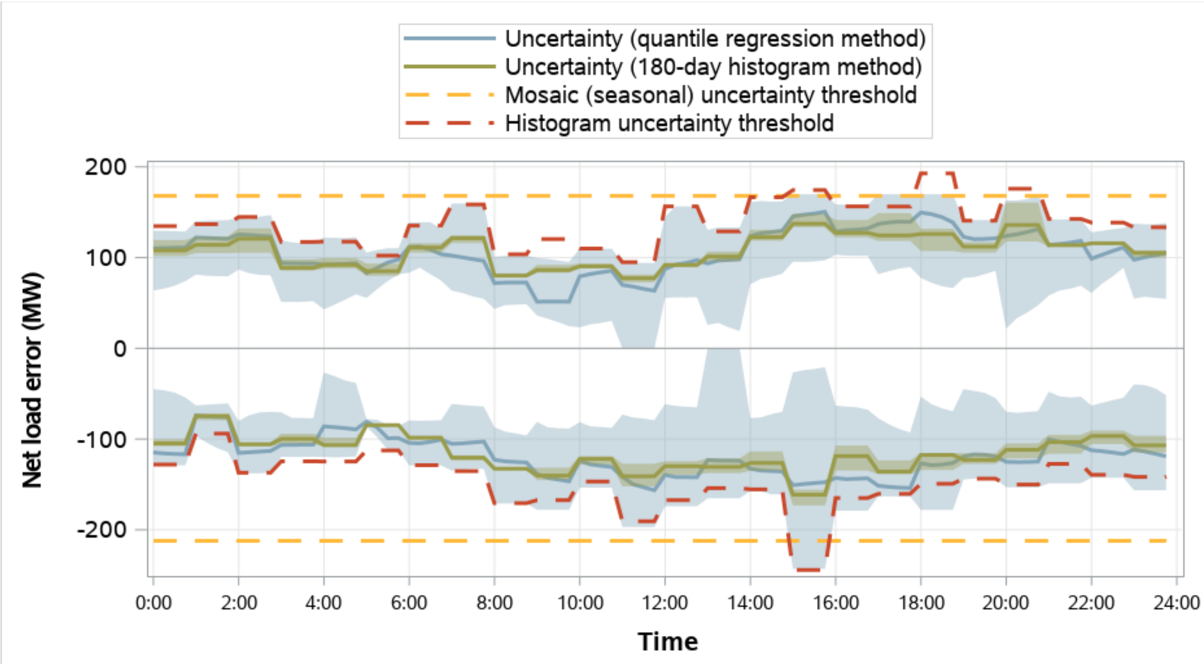


Figure 4.35 PNM distribution of RSE and RTD net load error and comparison to RSE uncertainty (weekdays, June 2023)

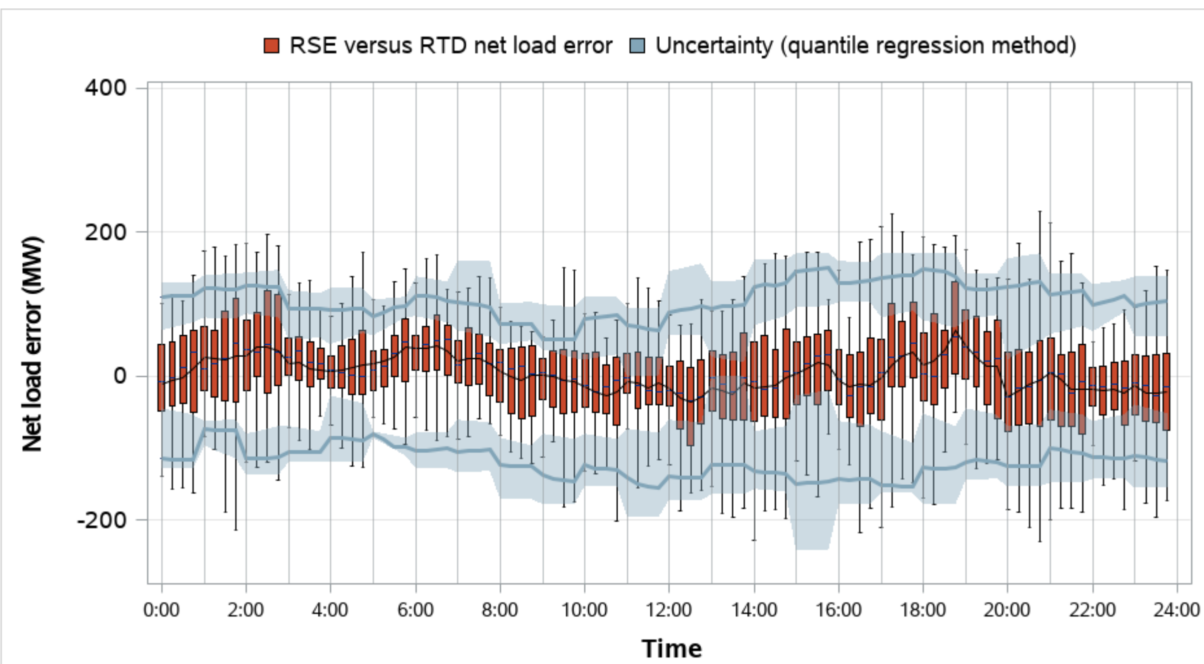


Figure 4.36 Puget Sound Energy resource sufficiency evaluation uncertainty requirements (weekdays, June 2023)

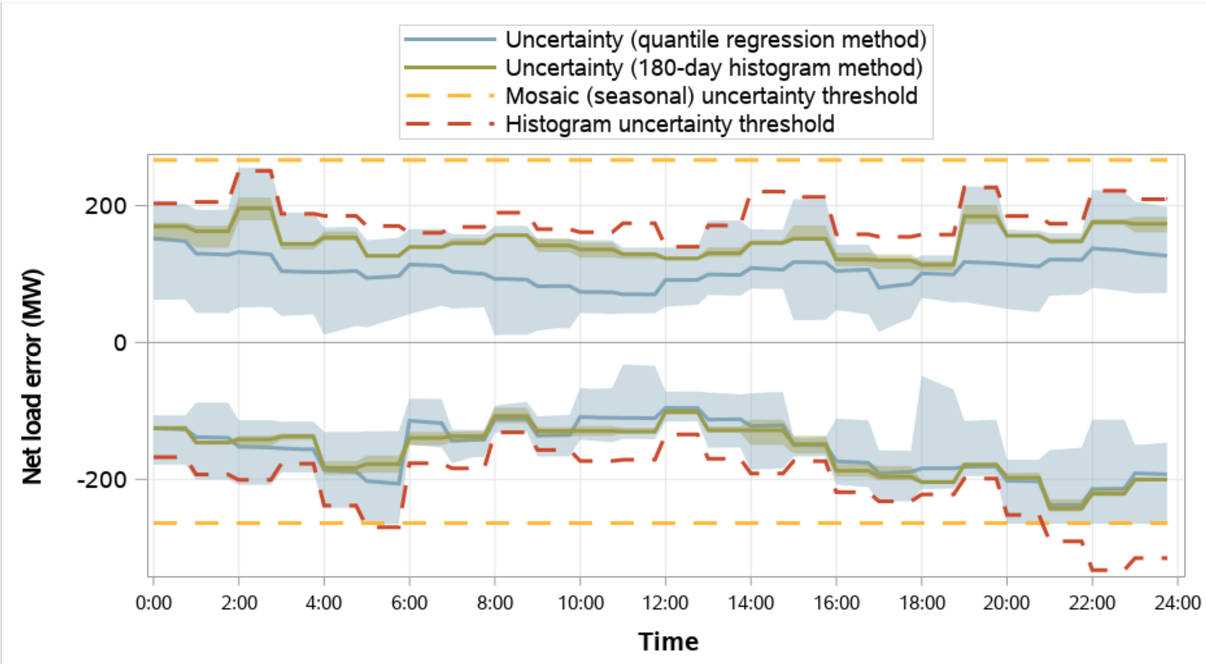


Figure 4.37 Puget Sound Energy distribution of RSE and RTD net load error and comparison to RSE uncertainty (weekdays, June 2023)

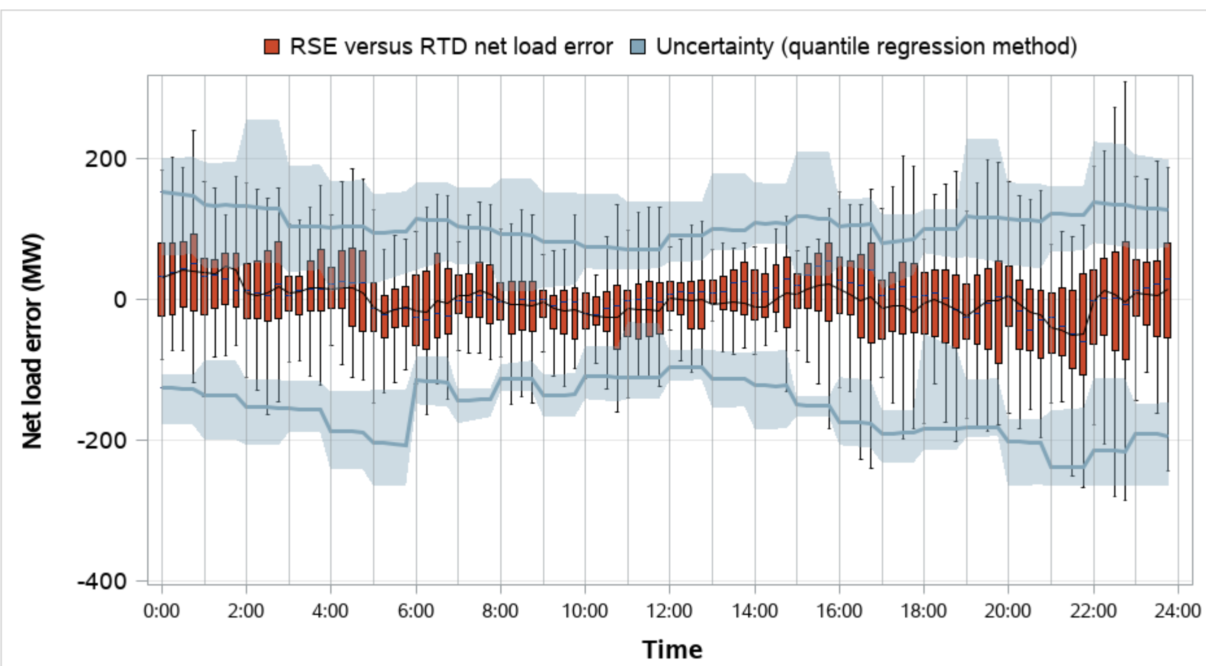


Figure 4.38 Salt River Project resource sufficiency evaluation uncertainty requirements (weekdays, June 2023)

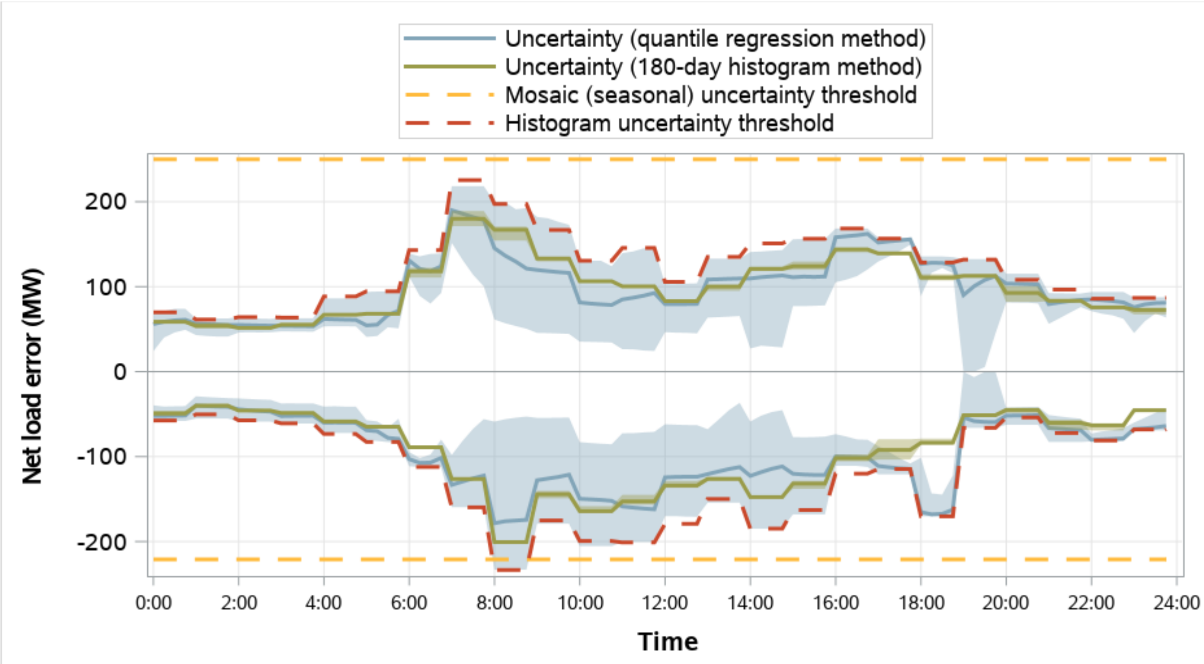


Figure 4.39 Salt River Project distribution of RSE and RTD net load error and comparison to RSE uncertainty (weekdays, June 2023)

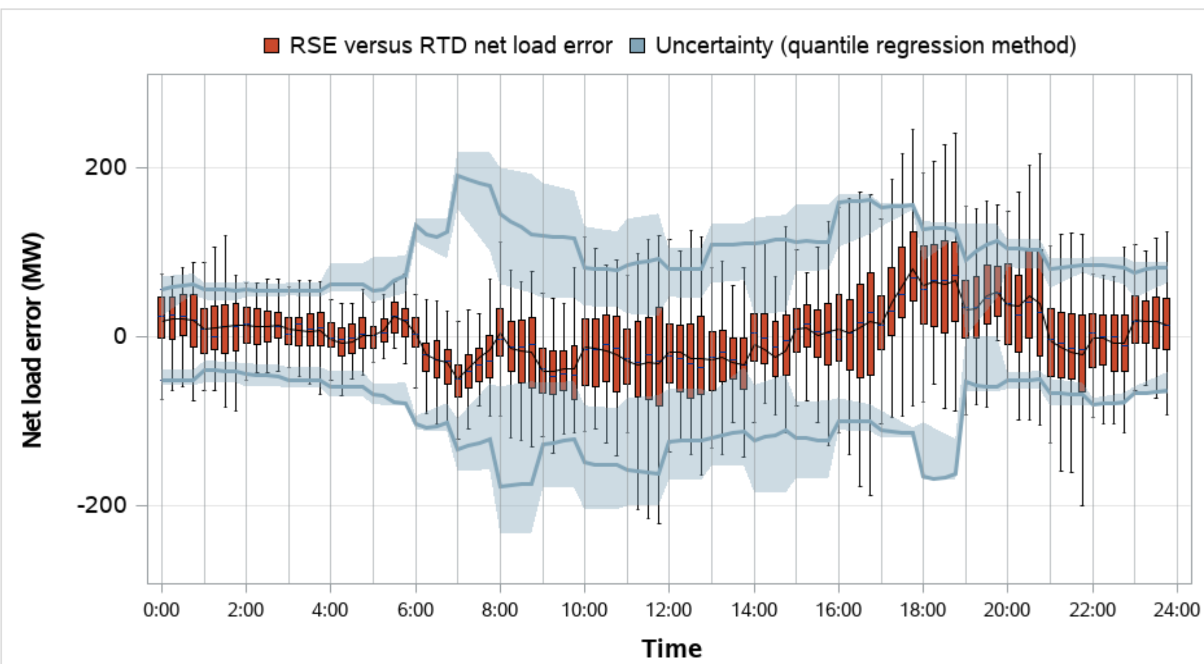


Figure 4.40 Seattle City Light resource sufficiency evaluation uncertainty requirements (weekdays, June 2023)

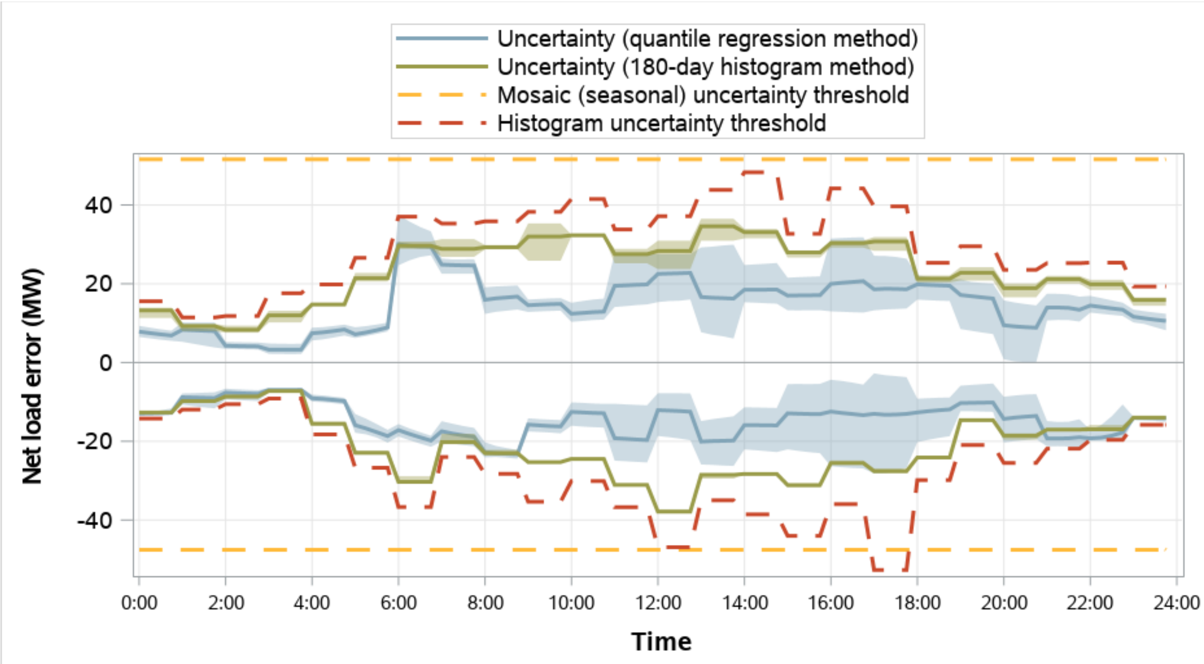


Figure 4.41 Seattle City Light distribution of RSE and RTD net load error and comparison to RSE uncertainty (weekdays, June 2023)

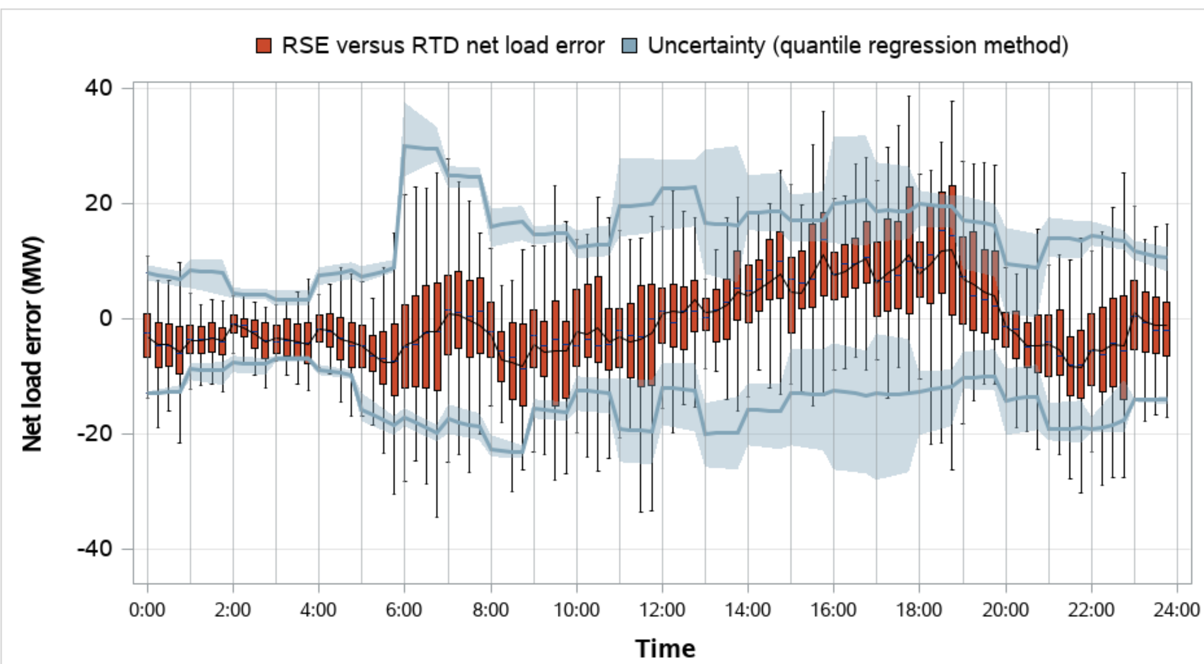


Figure 4.42 Tacoma Power resource sufficiency evaluation uncertainty requirements (weekdays, June 2023)

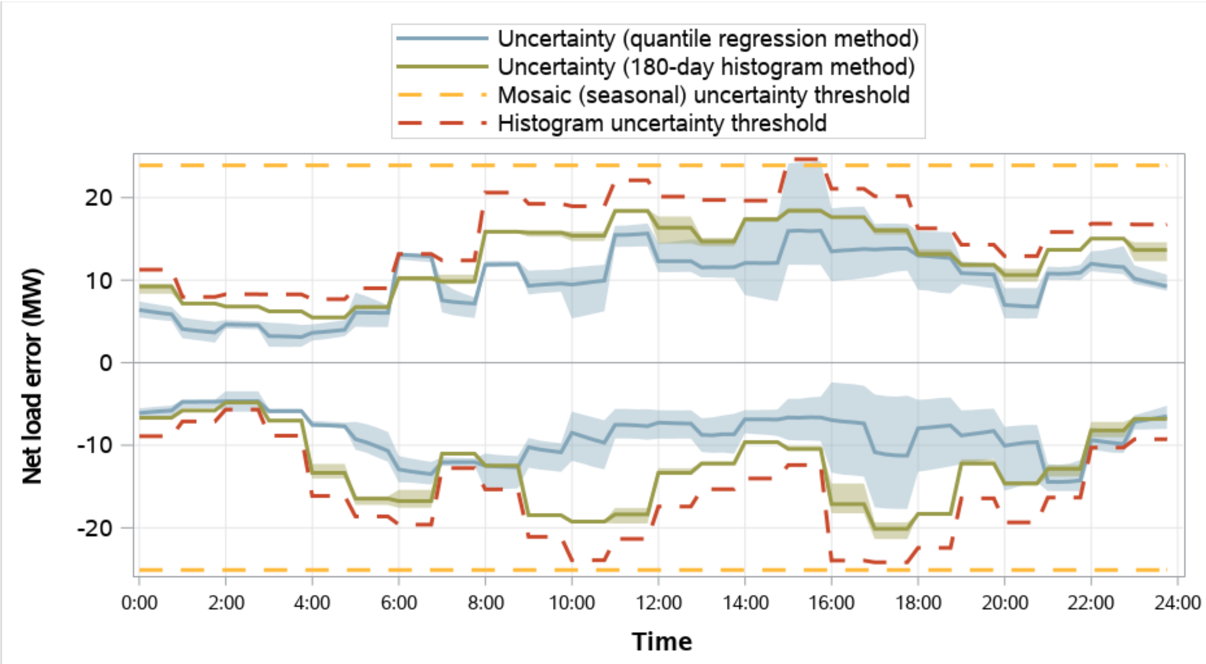


Figure 4.43 Tacoma Power distribution of RSE and RTD net load error and comparison to RSE uncertainty (weekdays, June 2023)

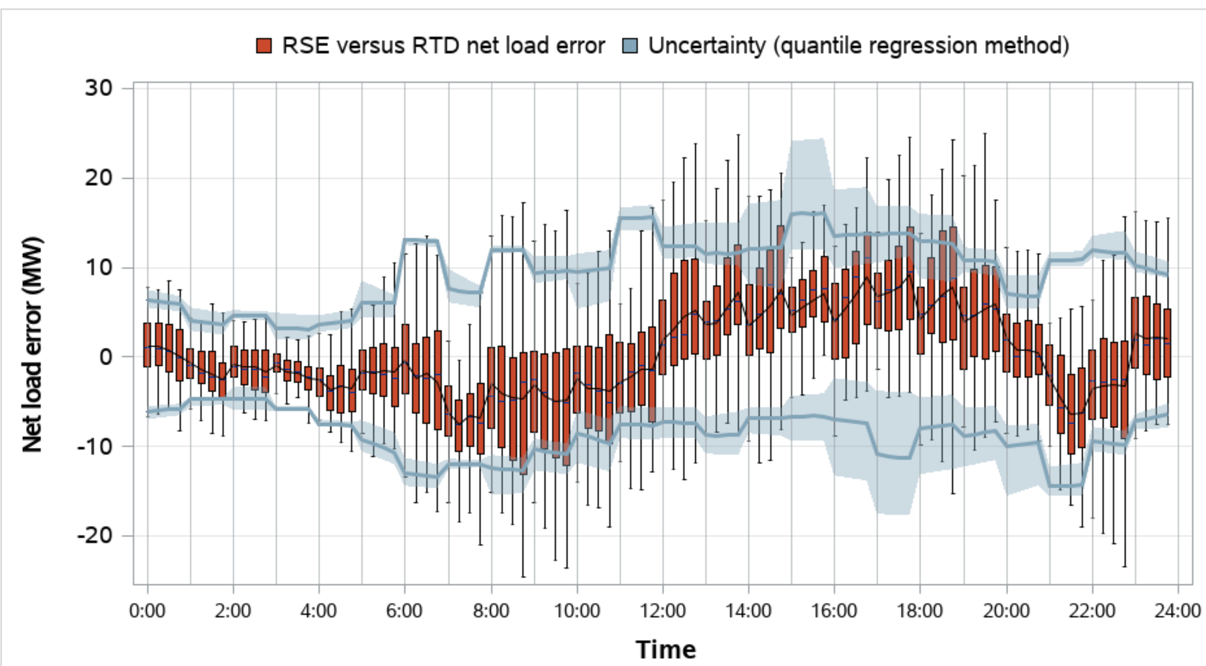


Figure 4.44 Tucson Electric Power resource sufficiency evaluation uncertainty requirements (weekdays, June 2023)

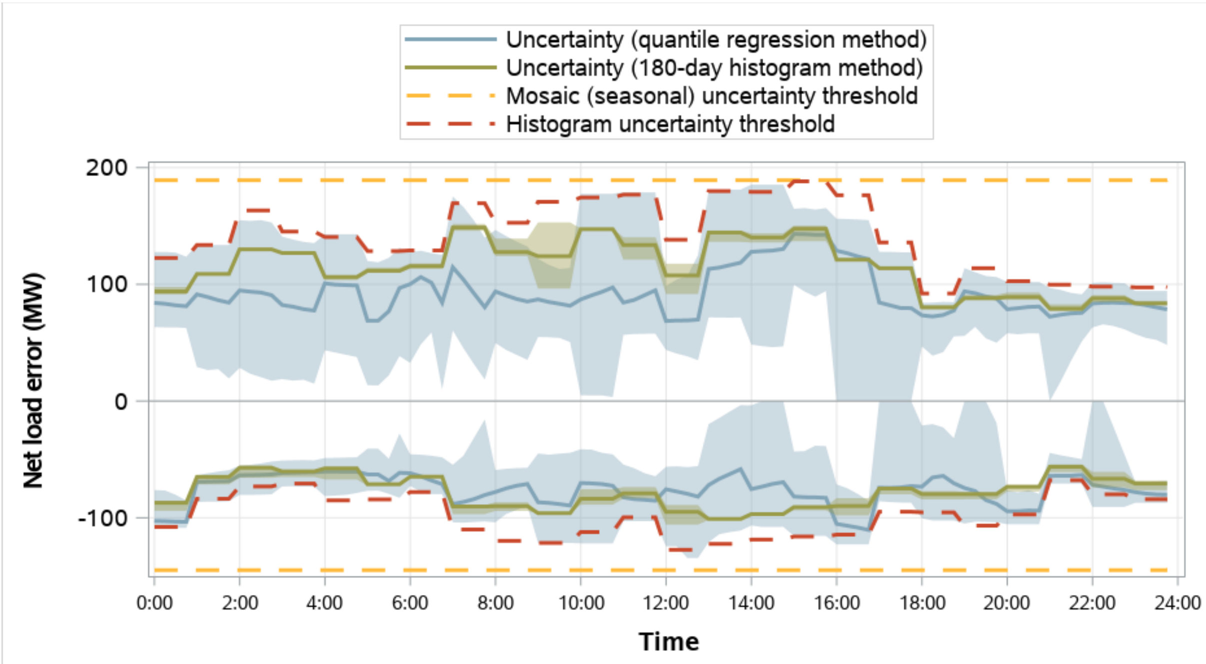


Figure 4.45 Tucson Electric Power distribution of RSE and RTD net load error and comparison to RSE uncertainty (weekdays, June 2023)

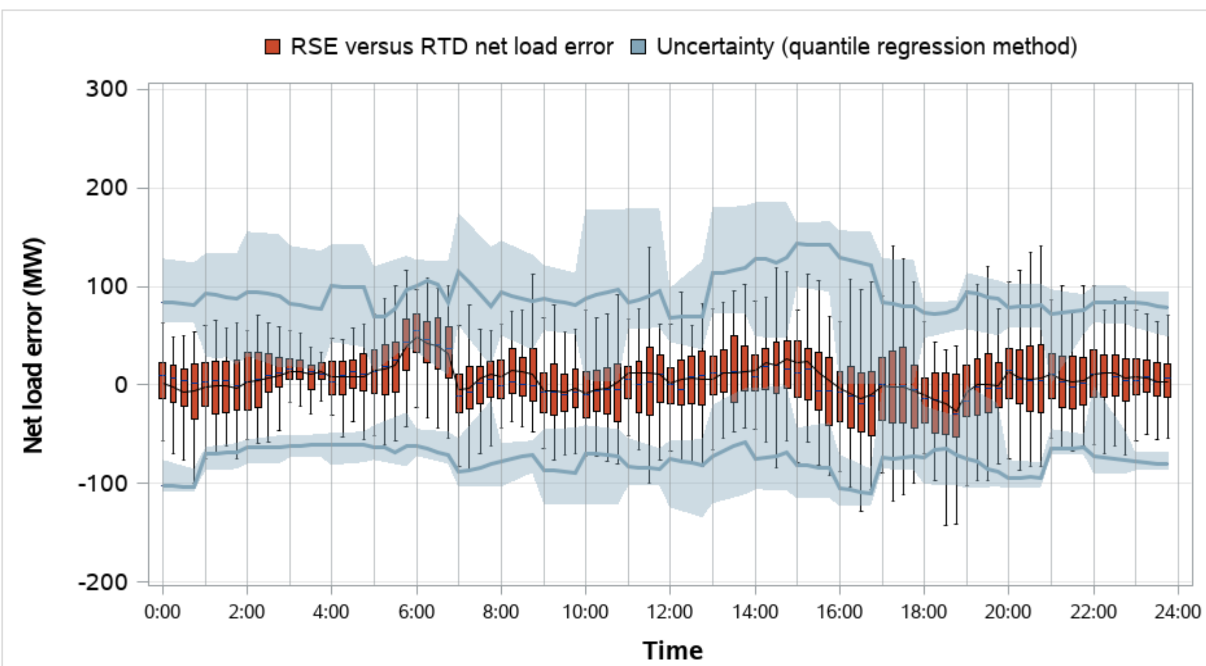


Figure 4.46 Turlock Irrigation District resource sufficiency evaluation uncertainty requirements (weekdays, June 2023)

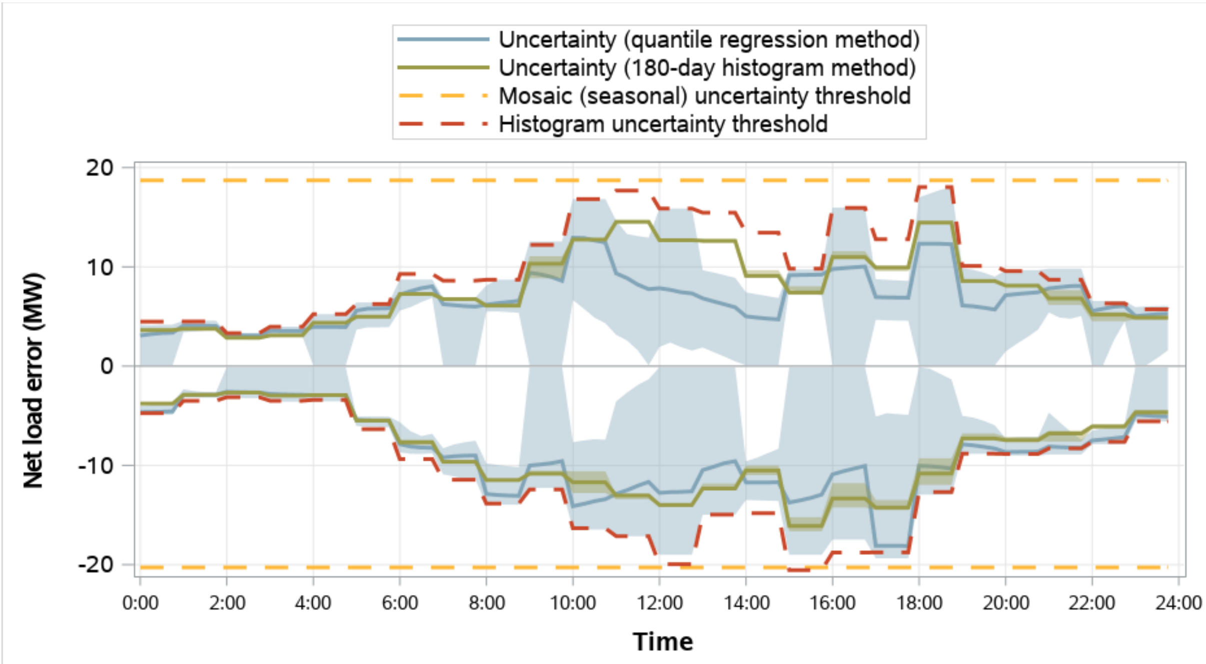


Figure 4.47 Turlock Irrigation District distribution of RSE and RTD net load error and comparison to RSE uncertainty (weekdays, June 2023)

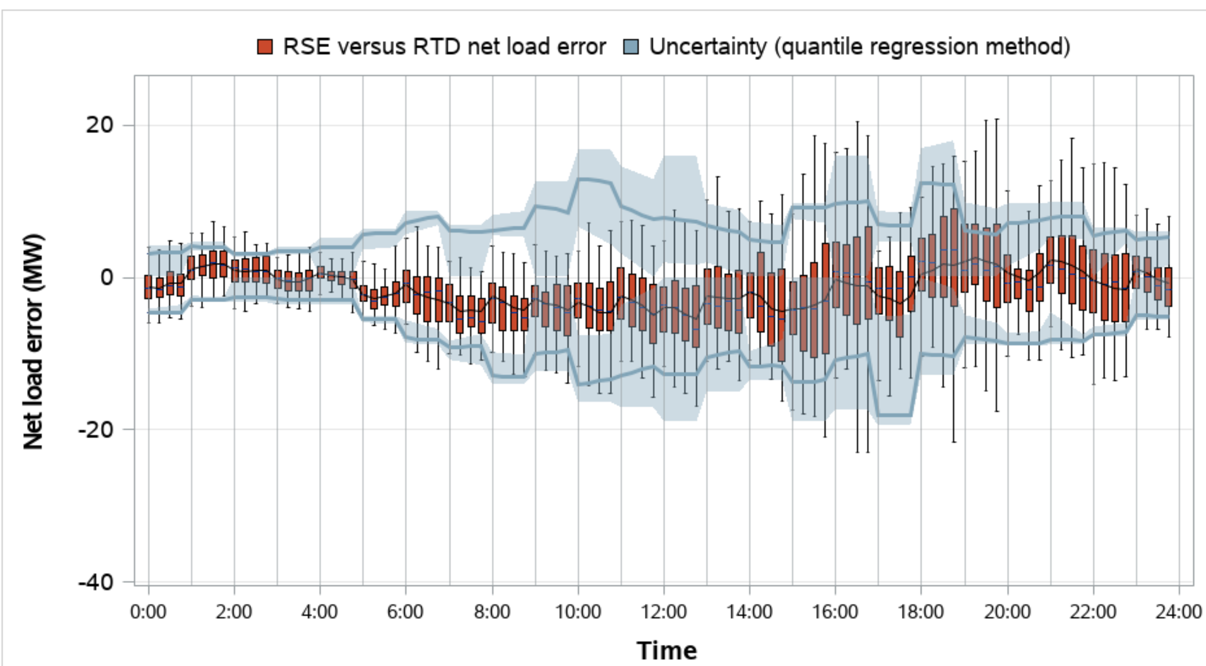


Figure 4.48 WAPA Desert Southwest resource sufficiency evaluation uncertainty requirements (weekdays, June 2023)

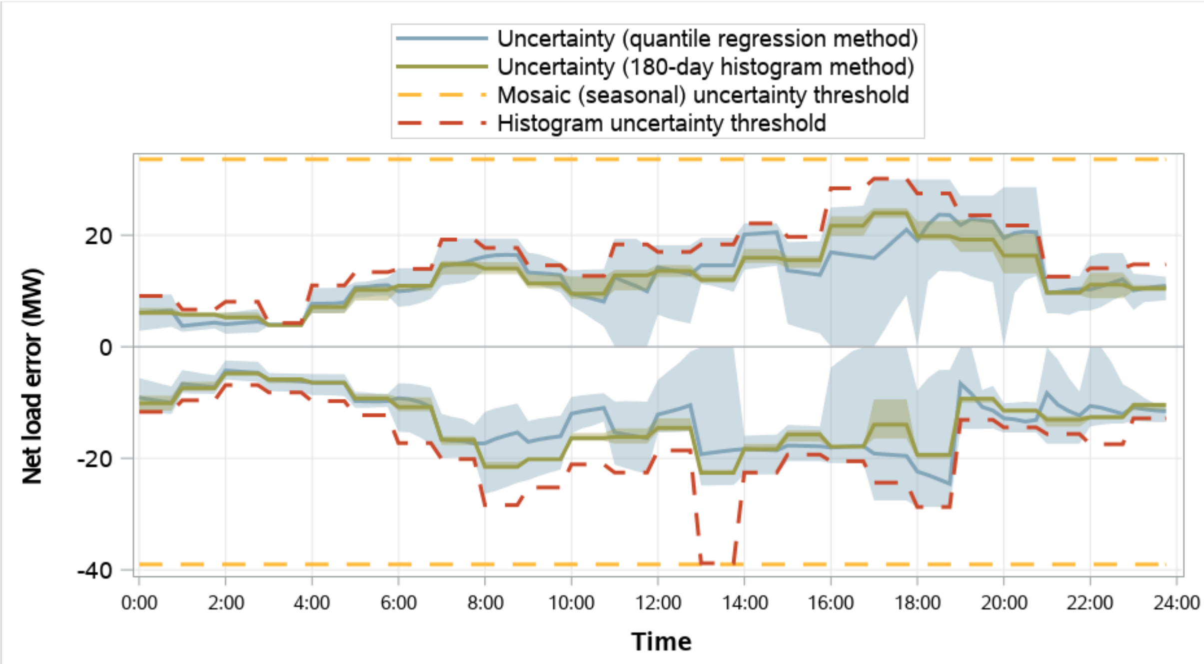
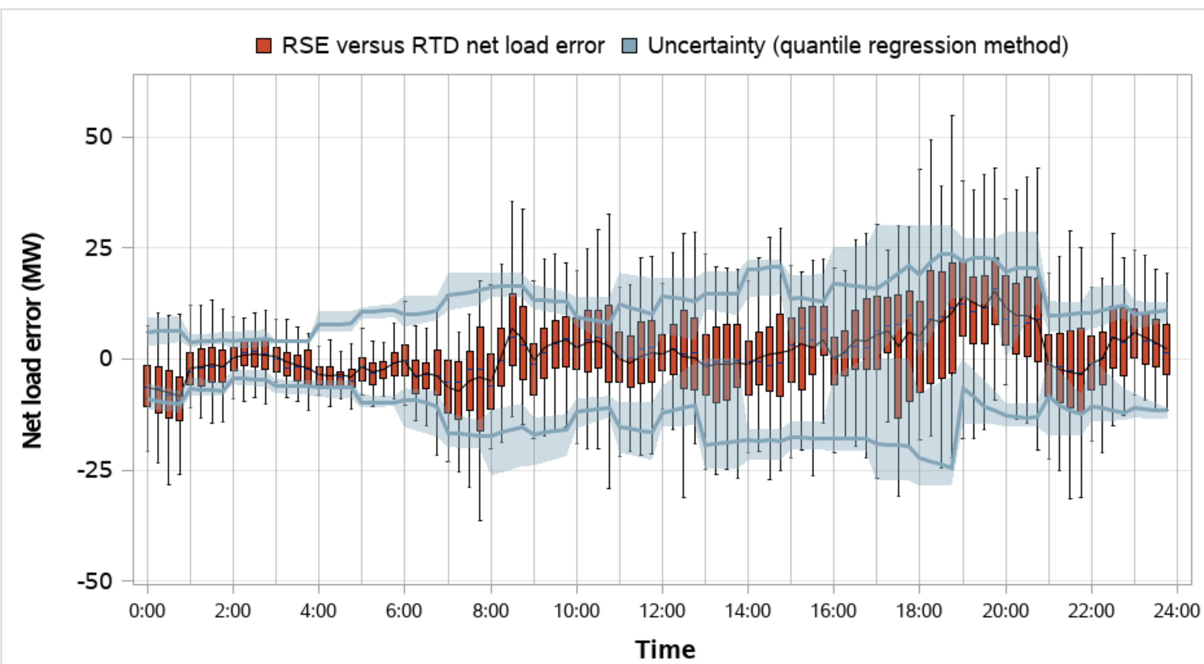


Figure 4.49 WAPA Desert Southwest distribution of RSE and RTD net load error and comparison to RSE uncertainty (weekdays, June 2023)



Performance measurements of quantile regression uncertainty

Table 4.1 summarizes the average requirements calculated using both the histogram and mosaic quantile regression methods. On average across all hours, the uncertainty calculated from the regression method was less than the histogram method for most of the balancing areas. The exceptions were El Paso Electric, WAPA Desert Southwest, PNM, and Salt River Project, where uncertainty from the regression method was slightly higher than the histogram method on average for upward or downward uncertainty.

Table 4.2 summarizes the *actual net load error* — as measured by the difference between binding 5-minute market net load forecasts and *net load forecasts in the resource evaluation* — and how that compares to the mosaic regression uncertainty requirements for the same interval.[19] The left side of the table summarizes the closeness of the actual net load error to the uncertainty requirements when the actual net load error was within (or covered) by the upward and downward requirements.[20] For El Paso Electric, the calculated uncertainty from the mosaic regression covered only 66 percent of actual net load error. For WAPA Desert Southwest, the calculated uncertainty from the mosaic regression covered 73 percent of actual net load error. For all other balancing areas, the mosaic regression requirements covered 79 to 92 percent of actual net load errors. The right side of the table summarizes when the actual net load error instead exceeded upward or downward uncertainty requirements.

Table 4.3 shows the same information except with requirements calculated from the histogram method. Coverage from the histogram method was typically more than the mosaic method.

[19] In comparing the 15-minute resource sufficiency evaluation forecasts to the three corresponding 5-minute forecasts, all three observations of error were used as a separate observation for calculating coverage, closeness, and exceedance.

[20] To the extent that the actual net load error averages around zero MW, this measurement largely matches the upward and downward uncertainty requirements.

Table 4.1 Average uncertainty requirements in the resource sufficiency evaluation (June 2023)

	Upward uncertainty			Downward uncertainty		
Balancing area	**Histogram**	**Mosaic**	***Difference***	**Histogram**	**Mosaic**	***Difference***
Arizona Public Service	175.5	169.9	-5.5	-145.0	-133.2	11.8
Avangrid	182.4	161.1	-21.3	-180.4	-171.2	9.2
Avista	47.8	35.5	-12.3	-57.9	-50.0	7.9
BANC	43.9	38.4	-5.5	-49.7	-46.0	3.7
Bonneville Power Admin.	223.2	216.8	-6.4	-362.5	-311.2	51.2
California ISO	1,177.7	1,078.9	-98.8	-953.2	-827.8	125.4
El Paso Electric	33.0	35.8	2.9	-33.4	-30.6	2.8
Idaho Power	105.9	98.2	-7.8	-145.0	-125.4	19.6
LADWP	165.6	150.2	-15.4	-172.4	-153.5	19.0
NorthWestern Energy	75.7	62.3	-13.4	-79.0	-72.4	6.5
NV Energy	208.2	172.8	-35.4	-194.2	-167.1	27.1
PacifiCorp East	295.9	260.3	-35.7	-357.2	-319.8	37.4
PacifiCorp West	90.4	80.4	-10.0	-117.6	-101.4	16.1
Portland General Electric	120.5	115.0	-5.5	-127.4	-119.1	8.4
Powerex	155.2	138.1	-17.1	-162.8	-147.4	15.3
PNM	106.3	103.3	-3.0	-116.7	-117.3	-0.5
Puget Sound Energy	145.1	107.4	-37.7	-165.1	-156.4	8.7
Salt River Project	99.0	97.4	-1.6	-93.2	-94.5	-1.3
Seattle City Light	23.0	14.1	-8.9	-21.4	-13.9	7.4
Tacoma Power	12.5	9.5	-3.1	-12.6	-8.4	4.2
Tucson Electric Power	112.8	92.8	-20.0	-81.4	-77.2	4.2
Turlock Irrigation District	7.9	6.5	-1.4	-8.3	-8.3	0.0
WAPA Desert Southwest	12.2	12.3	0.1	-13.1	-12.5	0.6

Table 4.2 Actual net load error compared to mosaic regression uncertainty requirements (June 2023)

	Actual net load error falls within calculated uncertainty requirements			Actual net load error exceeds ...			
				upward requirement		downward requirement	
Balancing area	Percent of intervals	Distance to up requirement (MW)	Distance to down requirement (MW)	Percent of intervals	Amount (MW)	Percent of intervals	Amount (MW)
Arizona Public Service	88%	158.2	151.8	7%	51.6	4%	44.6
Avangrid	86%	148.5	189.2	9%	68.8	5%	60.7
Avista	87%	36.4	49.2	7%	13.6	6%	26.1
BANC	86%	45.1	41.5	6%	21.3	8%	24.1
Bonneville Power Admin.	92%	255.4	273.9	3%	73.1	5%	84.7
California ISO	92%	914.4	1,012.9	5%	195.3	3%	270.6
El Paso Electric	66%	32.0	40.8	18%	23.7	16%	11.8
Idaho Power	88%	114.2	110.0	4%	40.6	8%	40.7
LADWP	91%	152.6	150.2	4%	37.1	4%	54.9
NorthWestern Energy	91%	61.4	74.4	4%	20.5	5%	30.8
NV Energy	84%	189.5	163.6	8%	54.7	8%	58.1
PacifiCorp East	79%	256.5	328.9	13%	117.3	9%	160.8
PacifiCorp West	90%	86.1	95.6	4%	28.5	6%	34.7
Portland General Electric	91%	111.8	124.1	4%	25.9	5%	24.4
Powerex	92%	136.6	151.0	4%	35.8	4%	48.0
PNM	84%	100.3	122.6	9%	34.3	7%	36.8
Puget Sound Energy	90%	110.4	154.5	6%	36.2	4%	56.9
Salt River Project	89%	98.2	96.9	6%	32.6	5%	31.0
Seattle City Light	85%	14.4	13.9	6%	4.2	8%	4.5
Tacoma Power	83%	9.1	8.8	8%	3.1	10%	3.6
Tucson Electric Power	92%	87.6	85.6	4%	26.7	4%	30.4
Turlock Irrigation District	81%	8.1	7.5	9%	3.5	10%	4.0
WAPA Desert Southwest	73%	12.4	13.6	15%	6.1	12%	5.5

Table 4.3 Actual net load error compared to histogram uncertainty requirements (June 2023)

	Actual net load error falls within calculated uncertainty requirements			Actual net load error exceeds ...			
				upward requirement		downward requirement	
Balancing area	Percent of intervals	Distance to up requirement (MW)	Distance to down requirement (MW)	Percent of intervals	Amount (MW)	Percent of intervals	Amount (MW)
Arizona Public Service	89%	161.9	164.6	7%	49.7	4%	39.1
Avangrid	88%	167.2	198.4	7%	83.6	5%	62.3
Avista	92%	48.9	57.0	4%	23.4	4%	29.5
BANC	87%	50.1	45.6	5%	18.7	8%	24.2
Bonneville Power Admin.	93%	265.9	319.6	3%	100.7	3%	102.5
California ISO	93%	1,014.8	1,145.8	5%	171.1	2%	361.1
El Paso Electric	64%	29.3	40.9	20%	23.8	16%	11.5
Idaho Power	90%	121.8	129.3	4%	48.7	6%	43.9
LADWP	92%	171.1	168.6	4%	46.2	3%	65.8
NorthWestern Energy	93%	74.1	80.7	3%	27.3	4%	31.5
NV Energy	86%	227.1	196.8	6%	60.3	8%	63.8
PacifiCorp East	84%	282.1	369.9	9%	134.9	7%	171.9
PacifiCorp West	92%	95.7	112.8	3%	33.9	5%	42.4
Portland General Electric	92%	117.4	131.5	4%	34.8	4%	27.9
Powerex	94%	154.2	165.9	3%	38.8	3%	45.4
PNM	86%	100.8	123.1	8%	37.5	7%	41.3
Puget Sound Energy	94%	144.6	165.6	3%	51.9	3%	56.6
Salt River Project	89%	101.1	94.1	6%	29.1	5%	30.4
Seattle City Light	95%	23.3	21.4	1%	3.4	3%	3.9
Tacoma Power	92%	12.2	13.0	3%	3.3	5%	3.1
Tucson Electric Power	96%	105.9	88.7	2%	35.5	2%	18.5
Turlock Irrigation District	86%	9.3	7.2	6%	3.1	7%	3.2
WAPA Desert Southwest	76%	12.0	13.7	14%	5.7	10%	5.0

5 WEIM limits and transfers following test failure

This section summarizes the import limits that are imposed when a WEIM entity fails either the bid-range capacity or the flexible ramping sufficiency test in the upward direction. These limits are also compared against actual WEIM transfers during these insufficiency periods.

This section summarizes the import limits that are imposed when a WEIM entity fails either the bid-range capacity or the flexible ramping sufficiency test in the upward direction. These limits are also compared against actual WEIM transfers during these insufficiency periods.

WEIM import limits following test failure

When either test fails in the upward direction, imports will be capped at the greater of (1) the base transfer or (2) the transfer from the last 15-minute market interval. Figure 5.1 summarizes the import limits after failing either test by the source of the limit. The black horizontal line (right axis) shows the number of 15-minute intervals with either a capacity or a flexibility test failure while the bars (left axis) show the percent of failure intervals in which the WEIM import limit was capped by either the base transfer or the last 15-minute market transfer. In some cases, the import limit after failing the test (i.e. the greater of the base transfer or last 15-minute interval transfer) is at or above the unconstrained total import capacity. In these cases, the import limit imposed after failing the test has no impact.

Figure 5.1 Upward capacity/flexibility test failure intervals by source of import limit (June 2023)

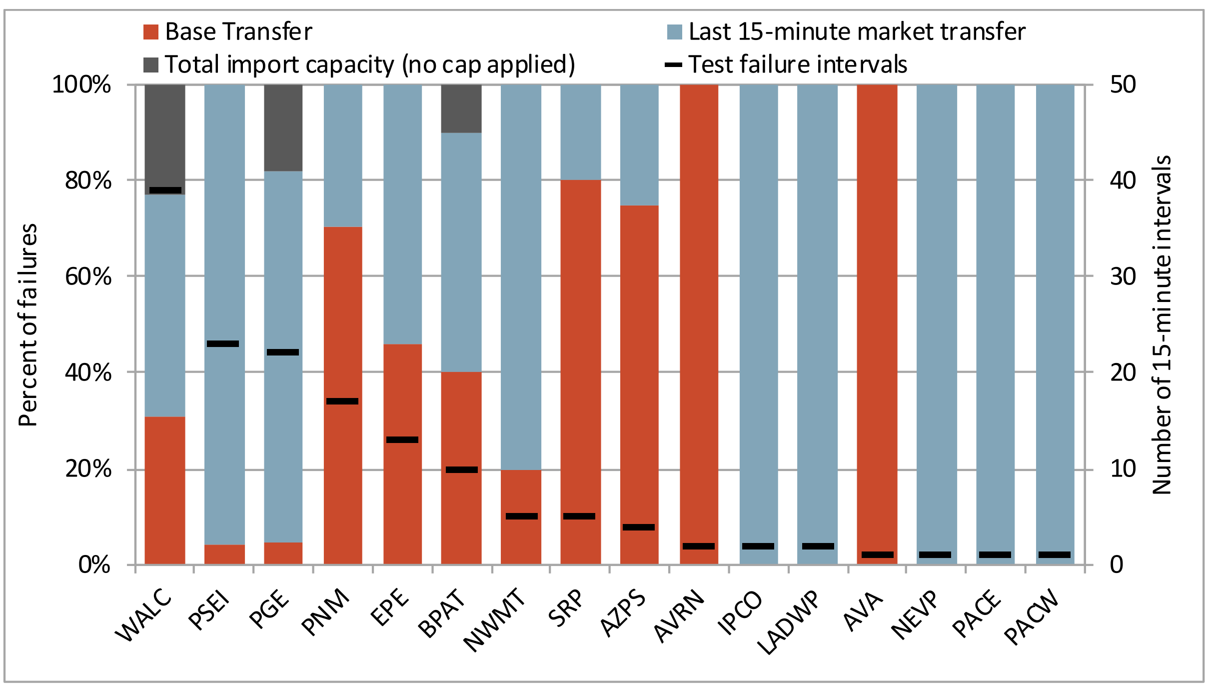
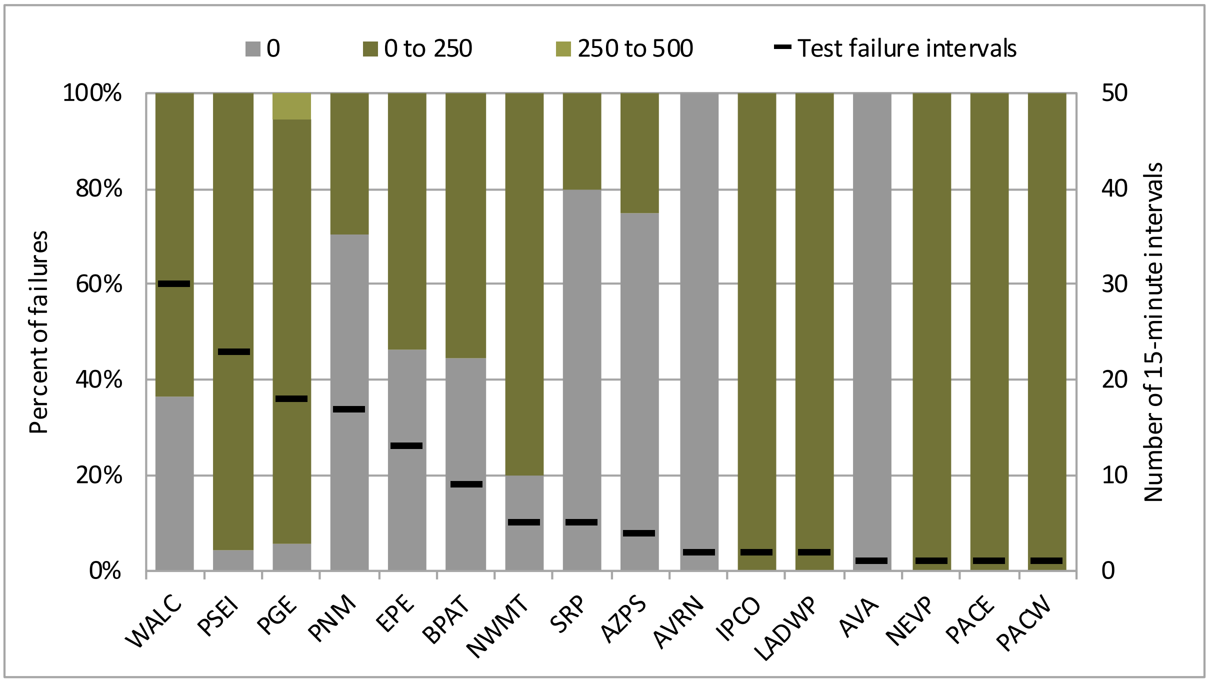


Figure 5.2 summarizes dynamic WEIM import limits above base transfers (fixed bilateral transactions between WEIM entities) after failing either test in the upward direction.[21] From this perspective, the incremental WEIM import limit after a test failure is set by the greater of (1) zero or (2) the transfer from

[21] Test failure intervals in which an import limit was not imposed because it was at or above the unconstrained total import capacity were excluded from this summary.

the last 15-minute market interval minus the current base transfer. Therefore, the dynamic import limits show the incremental flexibility available through the WEIM after a resource sufficiency evaluation failure. The black horizontal line (right axis) shows the number of 15-minute intervals with an import limit imposed after a test failure. Areas without any upward test failures during the month were excluded.

Figure 5.2 Upward capacity/flexibility test failure intervals by dynamic import limit (June 2023)



WEIM transfers following a test failure

The previous section looked at WEIM import limits imposed following a resource sufficiency evaluation failure. This section instead summarizes optimized WEIM transfers during these failure periods.

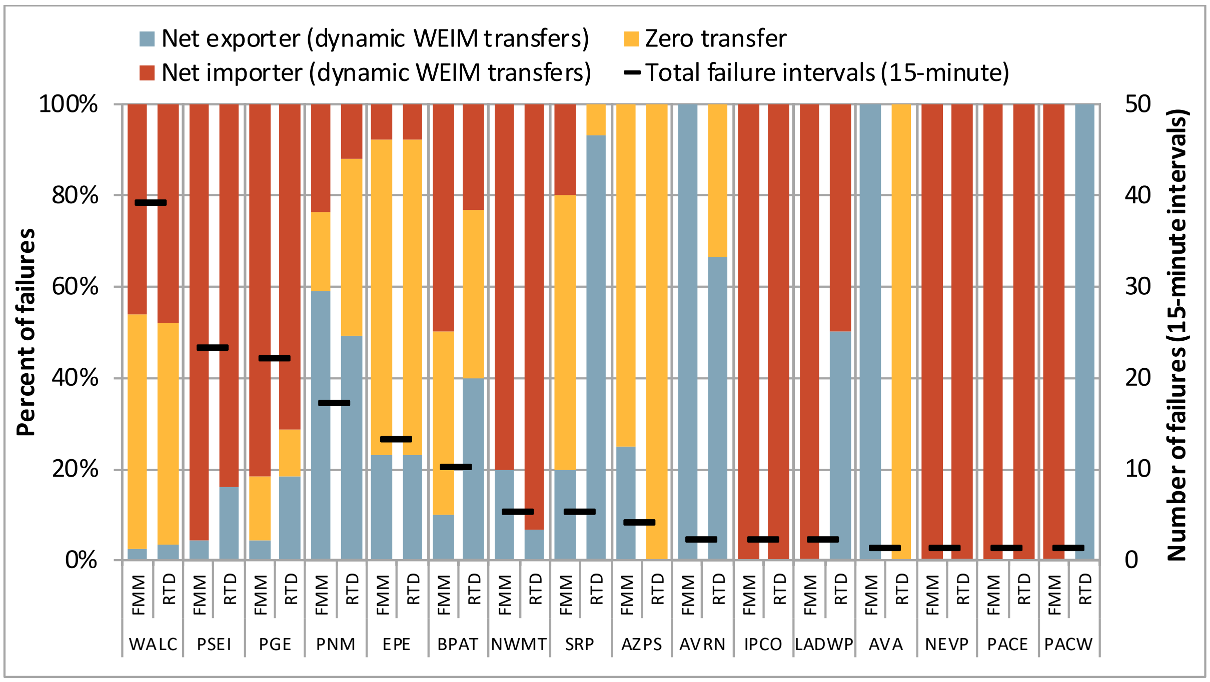
Figure 5.3 summarizes dynamic WEIM transfers (excluding any base transfer) on net for each area during an upward resource sufficiency evaluation failure in the month. Again, the black horizontal line (right axis) shows the number of 15-minute intervals with either a capacity or a flexibility test failure while the bars (left axis) show the percent of failure intervals in which the balancing area was a net importer or net exporter in the corresponding real-time market interval. Figure 5.4 summarizes the same information with the net transfer quantity categorized by various levels.

As shown by Figure 5.3, WEIM balancing areas were commonly optimized as a net exporter during the month despite failing the resource sufficiency evaluation. This result is in part driven from net load uncertainty that is included in the flexibility test. In some cases, the balancing area would fail the resource sufficiency evaluation in part because of the uncertainty component, but then in the real-time market it could then be economically optimal to export if that uncertainty does not materialize.

Other factors can also contribute to this outcome as a net exporter. First, a decrease in the load forecast (or increase in wind or solar forecasts) from the resource sufficiency evaluation to the real-time market run can lead to greater resource sufficiency and WEIM exports. A negative imbalance conformance adjustment entered by WEIM operators can also be included in the market run as effectively lower load, but will not be included in the resource sufficiency evaluation.

Figure 5.5 summarizes whether the import limit that was imposed after failing either test in the upward direction ultimately impacted market transfers.[22] It shows the percent of failure intervals in which the resulting transfers are constrained to the limit imposed after failing the test. These results are shown separately for the 15-minute (FMM) and 5-minute (RTD) markets.

Figure 5.3 Upward test failure by dynamic net WEIM transfer status (June 2023)



[22] Again, test failure intervals in which an import limit was not imposed because it was at or above the unconstrained total import capacity were excluded from this summary.

Figure 5.4 Upward test failure by dynamic net WEIM transfer amount (June 2023)

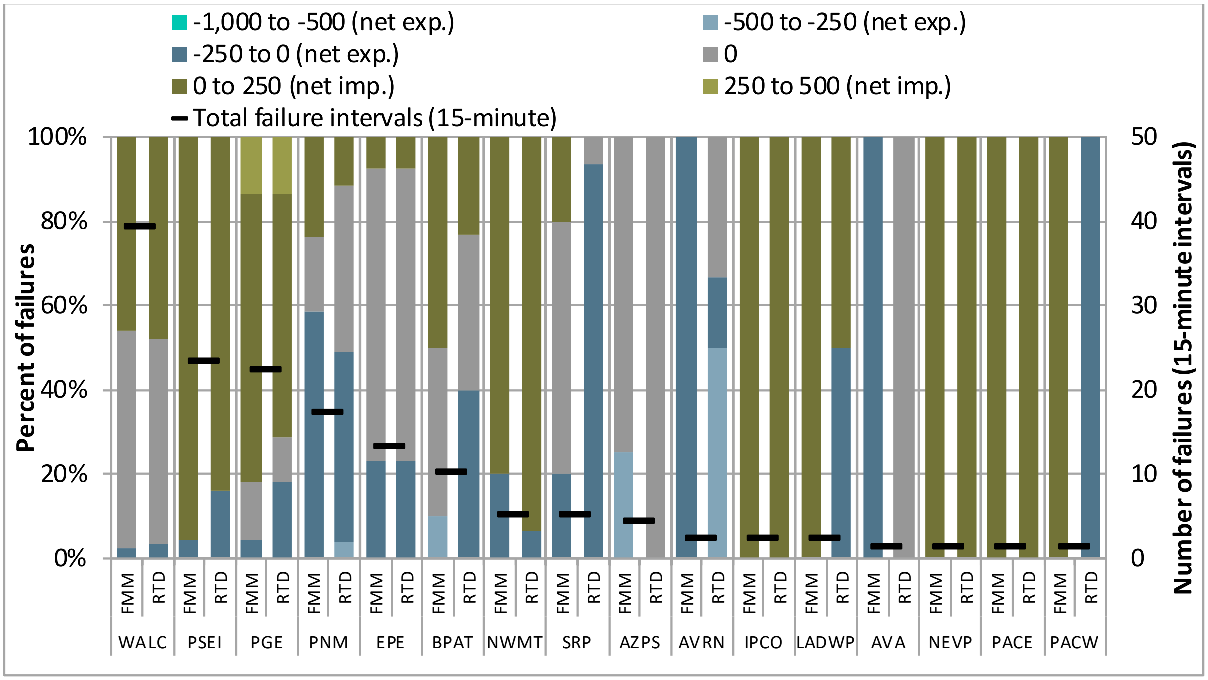
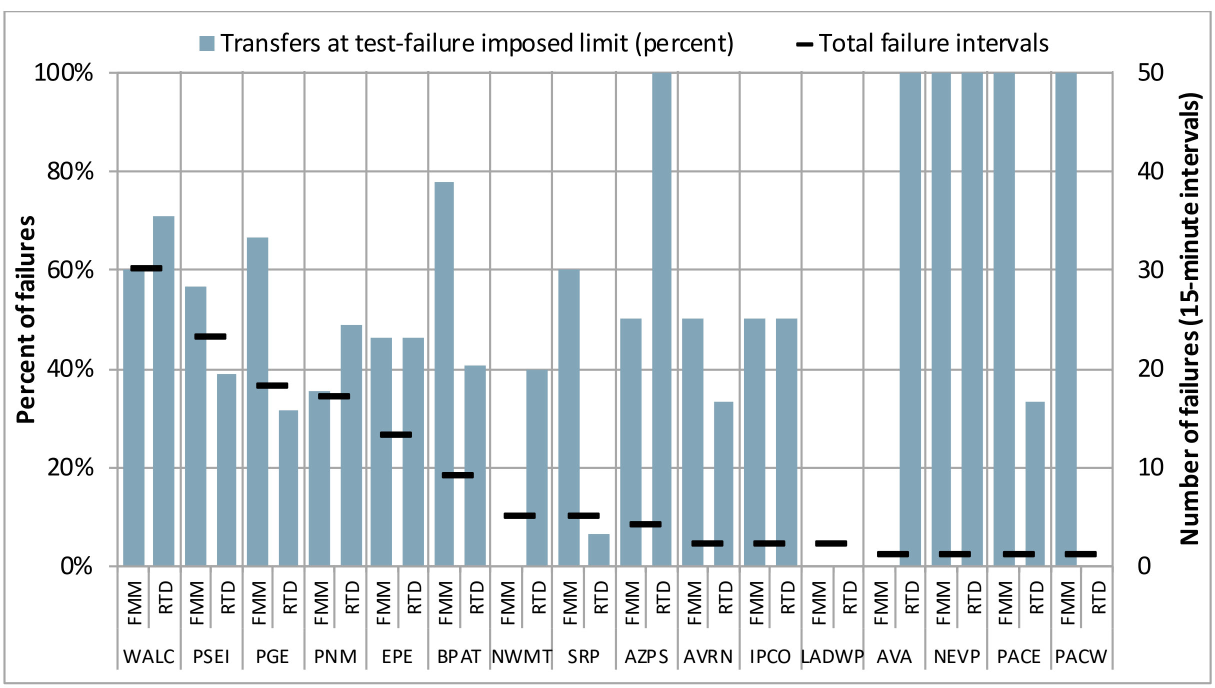


Figure 5.5 Percent of upward test failure intervals with market transfers at the imposed cap (June 2023)



6 Load conformance in the Western Energy Imbalance Market

Operators in every balancing area of the Western Energy Imbalance Market, including the California ISO, can manually adjust the load through load conformance adjustments. These adjustments, sometimes referred to as *load bias* or *imbalance conformance,* are not used directly in either the bid range capacity or the flexible ramp sufficiency tests; however, they can indirectly impact test results in several ways.

- The flexible ramp sufficiency test measures ramping capacity from the start of the hour (*i.e. last binding 15-minute interval*) compared to the load forecast. Here, imbalance conformance adjustments entered prior to the test-hour can impact internal generation at the initial reference point and ramping capacity measured from that point.
- The bid-range capacity test requirement includes all import and export base schedules.[23] Additional imports and exports (relative to these base schedules) that are *15-minute-dispatchabale* are then included as incremental or decremental capacity. Thus, the maximum of 15-minute-dispatchable imports would be included in the capacity test regardless of the dispatch. However, imbalance conformance adjustments made by the CAISO operators in the hour-ahead market can impact non-15-minute dispatchable import and export schedules included in the requirement.
- The penalty for failing either the upward capacity or the flexibility test is that WEIM transfers are capped by the greater of the transfer in the last 15-minute interval prior to the hour or base transfers. Due to this, a higher imbalance conformance adjustment entered prior to the hour can increase transfers into the balancing area, resulting in higher transfer limits following a failure than would have occurred otherwise.

The CAISO is not proposing any changes in the *WEIM resource sufficiency evaluation* to account for operator imbalance conformance.[24]

Figure 6.1 summarizes average hour-ahead and 15-minute market imbalance conformance adjustments entered by the CAISO operators during the month. Figure 6.2 shows the hourly distribution of 15-minute market imbalance conformance.

Figure 6.3 shows imbalance conformance adjustments for WEIM entities with substantial imbalance conformance and Figure 6.4 shows adjustments as a percent of total load.[25]

Table 6.1 summarizes the average frequency and size of 15-minute and 5-minute market imbalance conformance for all balancing authority areas.

[23] For the CAISO, the base schedules used in the requirement are the advisory schedules from the last 15-minute market run.

[24] California ISO, *EIM Resource Sufficiency Evaluation Enhancements Phase 2 Straw Proposal*, July 1, 2022. http://www.caiso.com/InitiativeDocuments/StrawProposal-WEIMResourceSufficiencyEvaluationEnhancementsPhase2.pdf

[25] WEIM entities with an average absolute 15-minute market imbalance conformance of less than 1 MW or less than 0.1 percent of load were omitted from the chart.

Figure 6.1 Average CAISO hour-ahead and 15-minute market load conformance (June 2023)

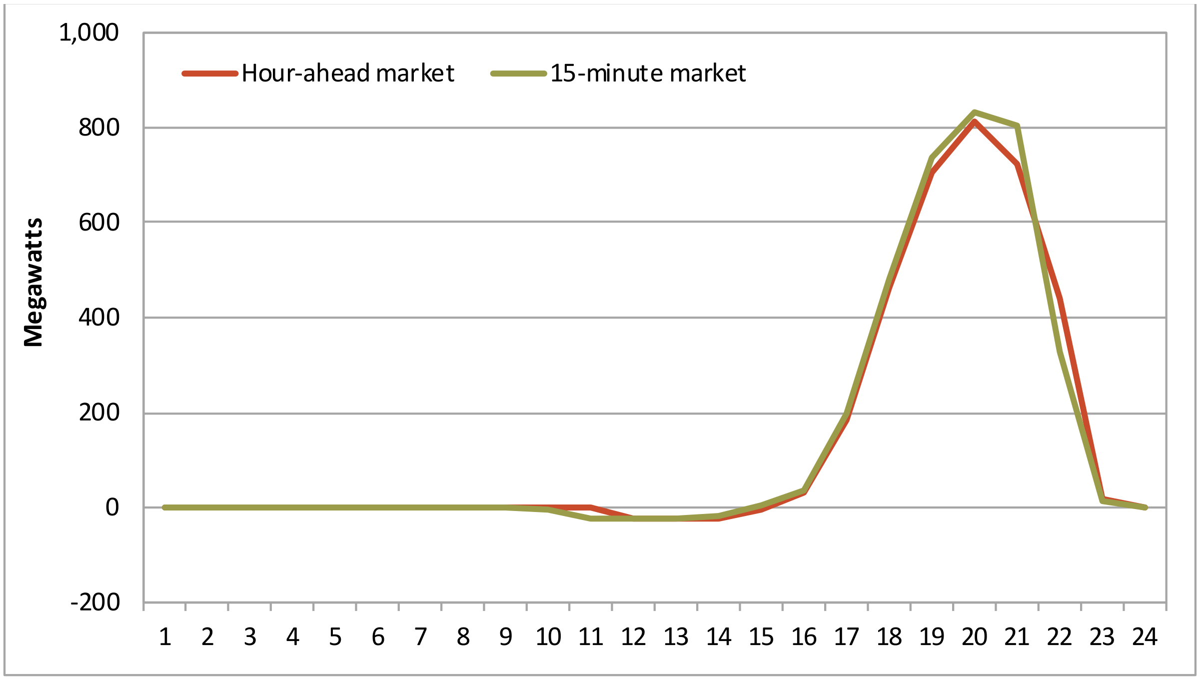


Figure 6.2 Distribution of CAISO load conformance (June 2023)

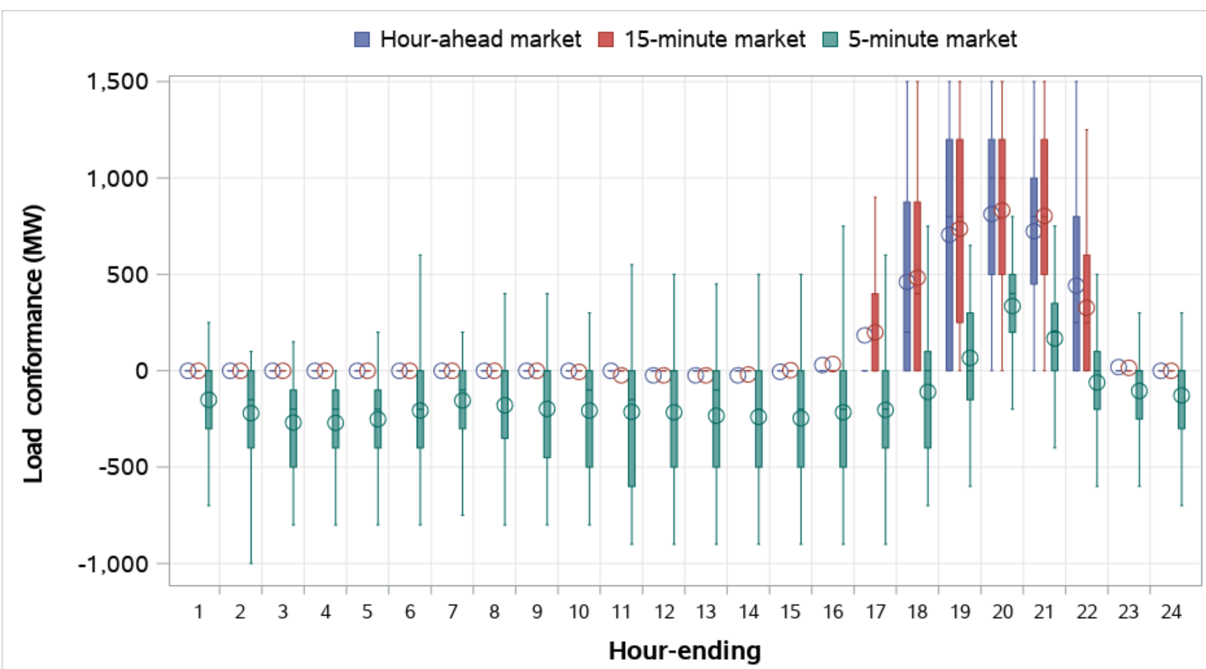


Figure 6.3 Average hourly 15-minute market load conformance (June 2023)

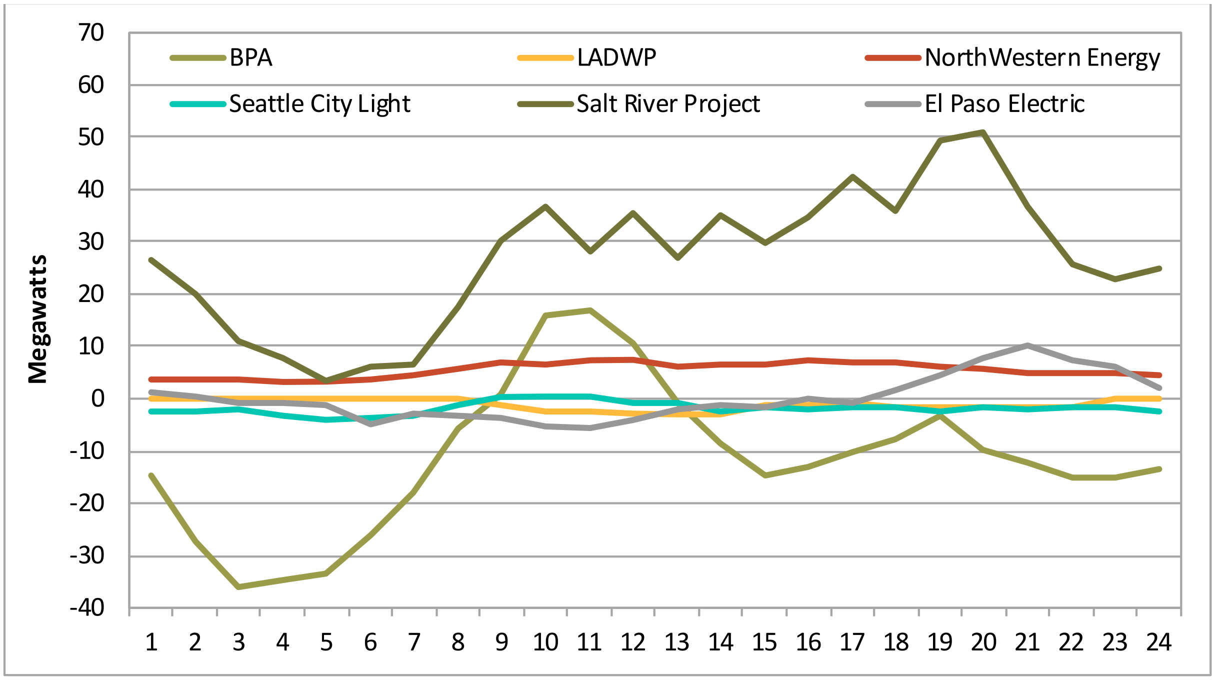


Figure 6.4 Average hourly 15-minute market load conformance *as a percent of load* (June 2023)

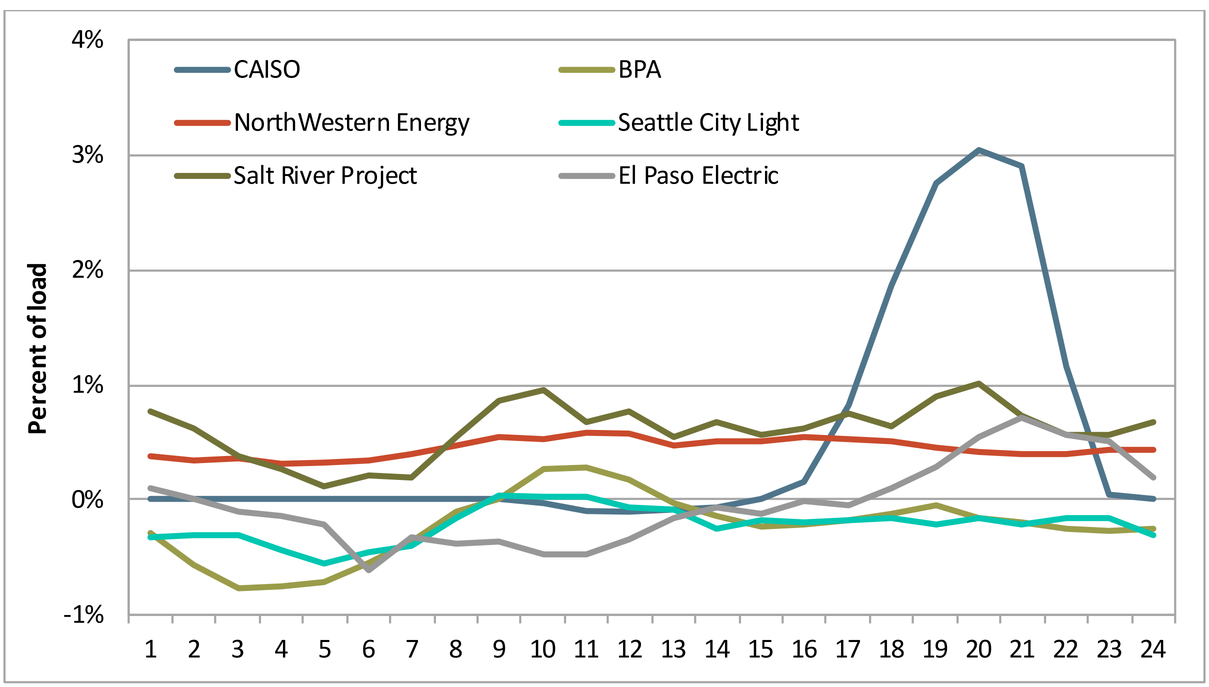


Table 6.1 Average frequency and size of load conformance (June 2023)

		Positive load conformance			Negative load conformance			Average hourly adjustment MW
Balancing area	***Market***	Percent of intervals	Average MW	Percent of total load	Percent of intervals	Average MW	Percent of total load	
Arizona Public Service	15-minute market	0%	N/A	N/A	0%	N/A	N/A	0
	5-minute market	52%	69	1.7%	18%	-60	1.6%	26
Avangrid	15-minute market	0%	N/A	N/A*	0%	N/A	N/A*	0
	5-minute market	49%	43	N/A*	11%	-34	N/A*	17
Avista	15-minute market	0.2%	36	2.7%	2%	-32	2.9%	-1
	5-minute market	3%	20	1.6%	29%	-22	2.1%	-6
Balancing Authority of Northern California	15-minute market	0.1%	30	1.4%	0%	N/A	N/A	0
	5-minute market	0.2%	30	1.4%	0.1%	-50	2.2%	0
Bonneville Power Administration	15-minute market	36%	23	0.4%	63%	-31	0.6%	-12
	5-minute market	36%	24	0.4%	63%	-32	0.6%	-11
California ISO	15-minute market	17%	861	3.2%	0.6%	-671	2.7%	139
	5-minute market	20%	288	1.2%	50%	-405	1.8%	-146
El Paso Electric	15-minute market	27%	15	1.2%	26%	-15	1.3%	0
	5-minute market	29%	17	1.2%	28%	-17	1.5%	0
Idaho Power	15-minute market	0%	N/A	N/A	0%	N/A	N/A	0
	5-minute market	11%	58	2.4%	28%	-60	2.8%	-10
Los Angeles Department of Water and Power	15-minute market	0%	N/A	N/A	2%	-64	2.6%	-1
	5-minute market	15%	37	1.7%	25%	-44	1.9%	-6
NorthWestern Energy	15-minute market	39%	14	1.2%	0%	-37	3.1%	5
	5-minute market	73%	15	1.2%	0.4%	-47	3.9%	11
NV Energy	15-minute market	0.03%	300	5.5%	0%	N/A	N/A	0
	5-minute market	41%	108	2.3%	9%	-94	2.1%	36
PacifiCorp East	15-minute market	0%	N/A	N/A	0%	N/A	N/A	0
	5-minute market	14%	92	1.7%	45%	-104	2.0%	-34
PacifiCorp West	15-minute market	0%	N/A	N/A	0%	N/A	N/A	0
	5-minute market	8%	30	1.2%	18%	-42	2.0%	-5
Portland General Electric	15-minute market	0%	N/A	N/A	0%	N/A	N/A	0
	5-minute market	8%	31	1.2%	1%	-38	1.7%	2
Public Service Company of New Mexico	15-minute market	0%	N/A	N/A	0%	N/A	N/A	0
	5-minute market	40%	71	4.6%	14%	-63	4.2%	20
Puget Sound Energy	15-minute market	0%	N/A	N/A	0%	N/A	N/A	0
	5-minute market	3%	31	1.4%	49%	-33	1.3%	-15
Salt River Project	15-minute market	28%	97	2.1%	0.1%	-38	1.1%	27
	5-minute market	60%	98	2.2%	0.6%	-60	1.6%	58
Seattle City Light	15-minute market	2%	11	1.1%	12%	-17	1.9%	-2
	5-minute market	6%	15	1.6%	60%	-23	2.6%	-13
Tacoma Power	15-minute market	0%	N/A	N/A	0%	N/A	N/A	0
	5-minute market	5%	11	2.4%	6%	-18	4.8%	0
Tucson Electric Power	15-minute market	0%	N/A	N/A	0%	N/A	N/A	0
	5-minute market	10%	48	3.1%	15%	-43	3.2%	-2
Turlock Irrigation District	15-minute market	0%	N/A	N/A	0%	N/A	N/A	0
	5-minute market	0.05%	11	4.7%	0%	N/A	N/A	0
WAPA Desert Southwest	15-minute market	0%	N/A	N/A	0%	N/A	N/A	0
	5-minute market	64%	27	3.2%	4%	-17	2.3%	16

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