California ISO

2025 SUMMER LOADS AND RESOURCES ASSESSMENT

TECHNICAL APPENDIX

May 5, 2025

Table of Contents

Acronyms

BAA	Balancing Authority Area
CAISO	California Independent System Operator
CEC	California Energy Commission
COD	Commercial Operation Date
CPUC	California Public Utilities Commission
DEBA	Distributed Electricity Backup Assets Program
DSGS	Demand Side Grid Support Program
DWR	Department of Water Resources
EEA	Energy Emergency Alert
ELCC	Effective Load Carrying Capability
ELRP	Emergency Load Reduction Program
ESSRRP	Electricity Supply Strategic Reliability Reserve Program
EUE	Expected Unserved Energy
F	Fahrenheit
HE	Hour Ending
IEPR	Integrated Energy Policy Report
IOU	Investor-Owned Utility
IRP	Integrated Resource Planning
LOLE	Loss-of-Load Expectation
LOLH	Loss-of-Load Hours
LSE	Load Serving Entity
MW	Megawatt
MWh	Megawatt-hour
NERC	North American Electric Reliability Corporation
NQC	Net Qualifying Capacity
OASIS	Open Access Same-Time Information System
OOS	Out Of State
OR	Operating Reserves
OTC	Once-Through-Cooling
PDR	Proxy Demand Response
PG&E	Pacific Gas and Electric
PRM	Planning Reserve Margin
PSP	Preferred System Plan
PDT	Pacific Daylight Time
PST	Pacific Standard Time
PTO	Participating Transmission Owner
NQC	Net Qualifying Capacity
RA	Resource Adequacy
RDRR	Reliability Demand Response Resource
SCE	Southern California Edison
SDG&E	San Diego Gas and Electric
SOC	State of Charge
WECC	Western Electricity Coordinating Council
WEIM	Western Energy Imbalance Market

List of Figures

List of Tables

1 Loads and Resources

In this chapter, the CAISO provides details on resource development and load forecasts that support the analysis presented in Chapter 1 of the 2025 Summer Assessment report.[1] Section 1.1 provides an update on existing and expected resources available for summer 2025. Section 1.2 shows the CAISO's near-term load projections based on the CEC's 2024 IEPR demand forecast.

1.1 Supply Conditions for 2025

In this assessment, the CAISO considers both existing and in-development resources expected to be available to serve demand during the forecasted summer peak in 2025. For existing resources, the CAISO reports resource capacity based on their Net Qualifying Capacity (NQC)[2] and Net Dependable Capacity (NDC)[3] or installed capacity. The CAISO identifies new resources as those projects in the late stages of the interconnection process that are estimated to be near to achieving commercial operation (COD). The CAISO expects about 2,163 MW of NDC to be added to the grid by June 30, including 1,654 MW of battery and 354 MW of solar.[4]

1.1.1 Existing Resources

Table 1.1 shows existing resource capacity by fuel type with their corresponding NQC and NDC totals and the amounts of each resource type by deliverability status. The table excludes pseudo-tie and dynamic import resources outside of the CAISO BAA, which total around 9,500 MW. Deliverability is a measure of the transmission system's ability to deliver energy to the grid in times of critical system need. The study process results in each resource being assigned either Full Capacity, Interim Deliverability, Partial Deliverability or Energy Only deliverability statuses.[5]

---

1 2025 Summer Loads and Resource Assessment, May 5, 2025: https://www.caiso.com/library/seasonal-assessments

2 Each resource has a qualifying capacity (QC) and net qualifying capacity (NQC). Qualifying capacity values are fuel-type specific and are set using methodologies determined by the appropriate local regulatory authority (LRA). The NQC value is resource-specific and is determined by the CAISO based on the QC and the deliverability status of the resource. NQC provides a reasonable estimation of a resource's capability to serve system needs in critical hours.

3 Net dependable capacity is the maximum continuous net output of a generating unit (net of auxiliary load), considering seasonal de-rates.

4 Expected new resources are calculated relative to existing resources in Table 1.1 as of March 2025 NQC list.

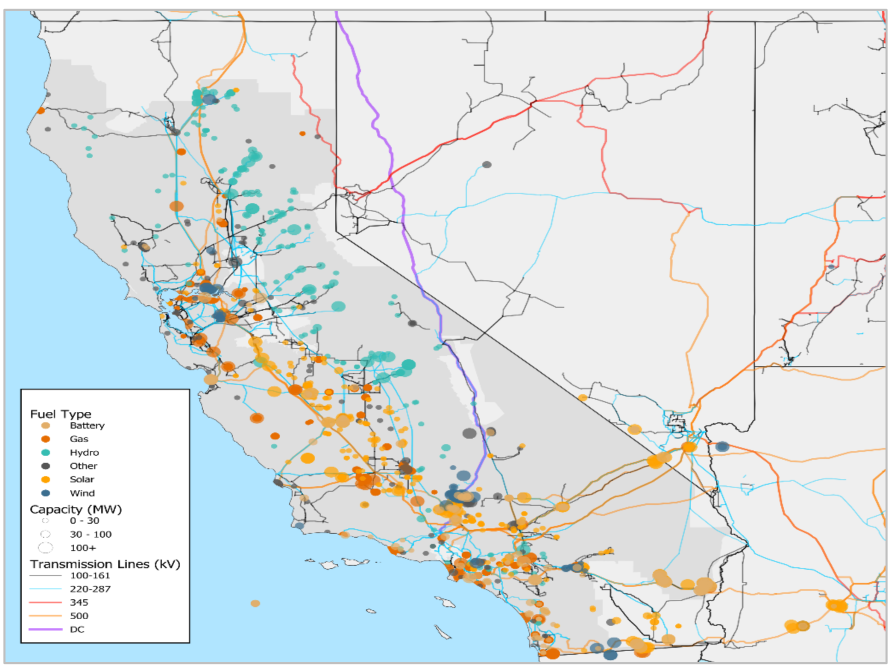
5 *Full Capacity* deliverability status entitles a generating facility to a NQC amount that could be as large as its QC amount and may be less pursuant to the assessment of its Net Qualifying Capacity by the CAISO.
Interim Deliverability allows an interconnection customer that has requested Full Capacity or Partial Capacity deliverability status to obtain non-zero NQC pending the in-service date of all the required network upgrades required for its requested deliverability status.
Partial Capacity deliverability status entitles a generating facility to a NQC amount that cannot be larger than a specified fraction of its QC amount, and may be less pursuant to the assessment of its NQC amount by the CAISO.
Energy only is a condition elected by an interconnection customer for a generating facility interconnected with the CAISO-controlled grid where the generating facility will be deemed to have a NQC of zero, and, therefore, cannot be considered a resource adequacy resource.

The technology factor is based on historical performance by fuel type during each month of the year and results in a resource being assigned a NQC value. For dispatchable resources like battery and natural gas plants, the NQC value is typically near its NDC or installed capacity. For intermittent resources like wind and solar, NQC values are typically lower because the output of these resources are weather-dependent.

Table 1.1 Existing resources by fuel type and deliverability status (excludes tie-generators)[6]

Deliverability	Full Capacity		Interim Deliverability		Partial Deliverability		Energy Only		Total	
Fuel Type	NDC	NQC	NDC	NQC	NDC	NQC	NDC	NQC	NDC	NQC
Battery	7,062	6,986	2,886	2,811	476	325	84	0	10,507	10,122
Biogas	232	170	0	0	0	0	19	0	251	170
Biomass	421	324	0	0	0	0	5	0	426	324
Distillate	110	110	0	0	0	0	0	0	110	110
Geothermal	1,297	1,155	0	0	162	102	0	0	1,459	1,257
Hybrid	576	396	1,437	969	8	7	0	0	2,021	1,372
Hydro	9,060	6,449	0	0	2	0	17	0	9,079	6,449
Natural Gas	25,885	24,939	417	414	704	624	4	0	27,010	25,977
Nuclear	2,300	2,280	0	0	0	0	0	0	2,300	2,280
Other	273	26	0	0	0	0	0	0	273	26
Solar	12,106	4,808	2,744	1,029	2,568	547	1,986	0	19,405	6,385
Waste Heat	35	24	0	0	0	0	0	0	35	24
Wind	6,059	1,338	230	57	0	0	6	0	6,295	1,394
Total	**65,415**	**49,005**	**7,714**	**5,280**	**3,920**	**1,605**	**2,120**	**0**	**79,170**	**55,891**

Figure 1.1 CAISO balancing area existing resources as of February 12, 2025



[6] Existing resources data is sourced from the more recent March 2025 NQC list. The expected new resources are always calculated relative to existing resources and captures any changes in resource status (e.g. declared COD). This way the total modeled capacity for existing and new resources is accounted for accurately.

September NQC values are used and installed capacity in NDC calculated as of April 1, 2025 from Master file.

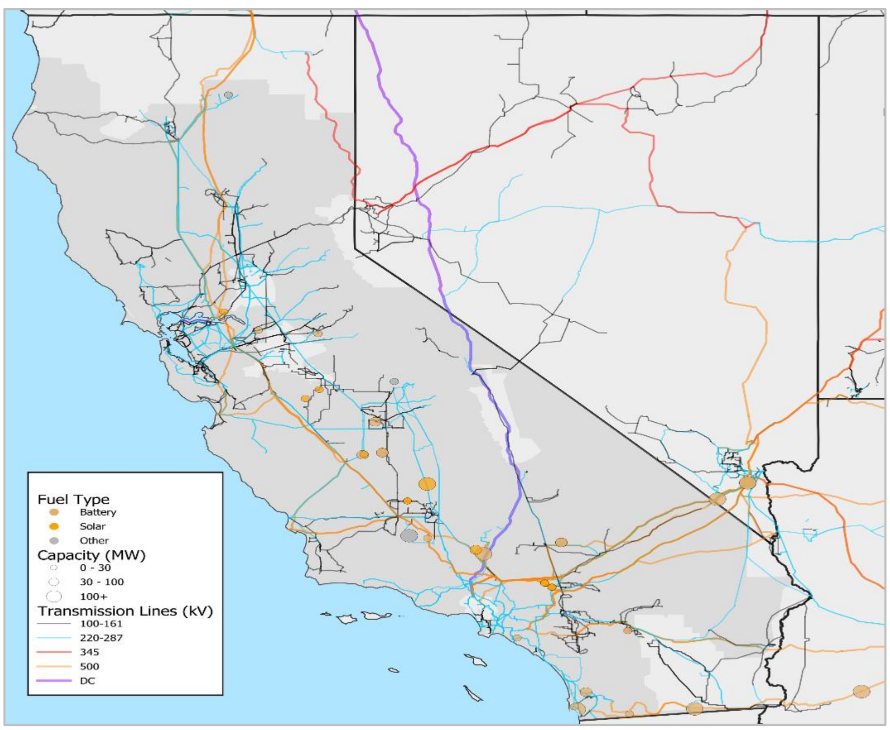
1.1.2 Expected Resources

In addition to existing resources, the CAISO expects several in-development resources to come online by June 30, 2025. As shown in Table 1.2, there are about 1,654 MW of battery, 354 MW of solar, 150 MW of hybrid, and 5 MW of other Biofuel resources (NDC values) have a high likelihood of declaring commercial operation by June 30, 2025. The CAISO used a set of criteria based on New Resource Implementation (NRI) status and target COD to determine whether to count a project as available for the summer. NRI status indicates the development stage of a resource as it progresses through construction and testing towards being fully commercially available. Notable NRI status labels are Active (under construction), SYNC (permission to connect to the grid and begin to test injecting energy at the point of interconnection), COMX (a resource at partial capacity may begin to participate in the market before full capacity is available), and COD (fully commercially online). All SYNC and COMX resources with target COD's before June 30, 2025 count as available in this assessment, while only those Active resources on the CAISO NQC list as of April 1, 2025 are counted.

Table 1.2 Expected additions from April 1, 2025 through June 30, 2025 (MW)[7]

Category	Battery	Solar	Biofuel	Hybrid	Total Nameplate Capacity (MW)
Expected additions by June 30 (as of April 1, 2025)	1,654	354	5	150	**2,163**

Figure 1.2 CAISO balancing area expected new resources by June 30, 2025



[7] Expected new resources are calculated relative to existing resources in Table 1.1 as of March 2025 NQC list.

1.2 CEC's Near-Term Load Projections

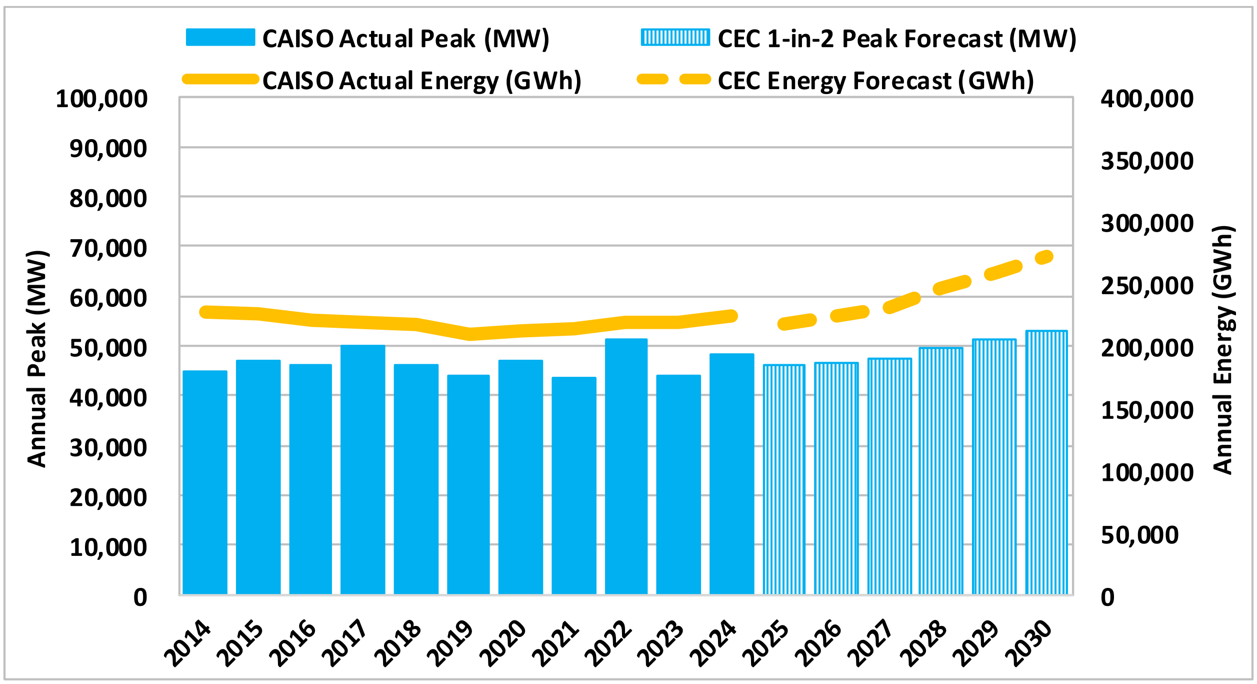
The CAISO's near-term load projections rely on the CEC's 2024 IEPR demand forecast using the managed load from 1-in-2 planning forecast. The planning forecast is used by the CAISO and state agencies for electricity system-level planning activities. It represents the CEC's estimates of baseline economic, demographic, and price scenarios, as well as "mid-level" impacts of energy efficiency, building electrification, and transportation electrification.[8] Table 1.3 shows 2025 summer monthly peak load forecasts for the CAISO BAA. The table shows that CEC forecasted peak load for 2025 occurs in September.

Table 1.3 Monthly peak load forecast (May 2025 – October 2025)

Month	May	June	July	August	September	October
Monthly peak load forecast (MW)	31,026	41,047	45,568	44,896	46,094	37,568

Figure 1.3 shows that from 2014 to 2024, CAISO's actual annual peak demand fluctuated between 43,789 MW and 51,479 MW while its actual annual energy consumption varied from 209,429 GWh to 227,309 GWh. The figure also shows CEC's CAISO 1-in-2 peak demand forecast[9] of 46,094 MW in 2025 increases gradually by 15 percent to 52,940 MW in 2030. In addition, the CEC is also projecting CAISO's annual energy in 2025 to be 217,686 GWh with an increase to 271,992 GWh by 2030.

Figure 1.3 CAISO historical and projected annual peak load and energy (2014 – 2030)



[8] CEC, 2024 Integrated Energy Policy Report, Hourly Demand Forecast Files (corrected), Mar 21, 2025: https://docketsearch.energy.ca.gov/Pages/results.aspx?k=*&a=IsDocument%3a1+DocketNumber%3a24-IEPR-03&docketnumber=24-IEPR-03

[9] A 1-in-2 forecast assumes there is a 50 percent probability that the forecasted peak will be less than actual peak load and a 50 percent probability that the forecasted peak will be greater than actual peak load.

2 Probabilistic Modeling Assumptions

This chapter discusses probabilistic assessment's resource portfolio capacity assumptions as well as resource modeling considerations, operational attributes/constraints, stochastic profiles (solar, wind, load and outages), and details on ancillary services modeling.

2.1 Capacity Assumptions

Table 2.1 shows modeled capacity by month and fuel type in CAISO's probabilistic assessment of summer 2025. Existing resource capacities are based on final net qualifying capacity (NQC) list published on February 12, 2025. Expected new resources are sourced from CAISO's NRI database using criteria previously discussed in section 1.1.2. Following are capacity assumptions by fuel type considered in Table 2.1:

1. Natural gas and battery resources are modeled at their nameplate capacities.
2. For solar, wind and hydro resources, the table lists nameplate capacity. For solar and wind resources, the study uses nameplate capacities in the creation of stochastic profiles for the simulation. Hydro resources use an average hydro year profile based on 2018 EMS data.
3. Hybrid and co-located resource components are modeled individually with corresponding Pmax and aggregate capability constraints enforced, respectively.
4. For QFs, CHP, cogeneration facilities, must-take, geothermal and bio fuel resources, NQC value is modeled consistent with their bidding levels in the market.
5. Demand response (DR) category includes projected capacity from CPUC-jurisdictional utility-scale DR programs as well as NQC values for third party supply plan DR.
6. Partial deliverable resources have their capacity scaled down based on their deliverable MW.[10]
7. "Energy-only" solar resources that are co-located with "fully-deliverable" battery resources that support onsite charging are included.[11]

Since the NQC list does not have information on external tie-generators, the table excludes pseudo-tie and dynamic import resources outside of the CAISO BAA, which total around 9,000 MW. However, these resources are subject to the net import limit of 5,500 MW from June through September during hours 16 – 22. In all other hours, the net import limit is 11,665 MW.

[10] *Partial Capacity* deliverability status entitles a generating facility to a NQC amount that cannot be larger than a specified fraction of its QC amount, and may be less pursuant to the assessment of its NQC amount by the CAISO.

[11] *Energy only* is a condition elected by an interconnection customer for a generating facility interconnected with the CAISO controlled grid where the generating facility will be deemed to have a NQC of zero, and, therefore, cannot be considered a resource adequacy resource.

Table 2.1 2025 summer probabilistic assessment modeled capacity (MW) by month and fuel type

Fuel type	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Battery	10,293	10,574	10,906	11,994	12,202	12,202	12,322	12,391	12,391	12,391	12,391	12,391
Biogas	172	174	172	168	173	170	168	168	170	167	168	170
Biomass	310	303	298	279	326	337	338	328	330	317	304	314
Distillate	110	110	110	110	110	110	110	110	110	110	110	110
Geothermal	1,260	1,265	1,262	1,246	1,249	1,252	1,254	1,255	1,257	1,249	1,267	1,267
Hybrid	2,020	2,020	2,020	2,170	2,170	2,170	2,170	2,170	2,170	2,170	2,170	2,170
Hydro	10,871	10,871	10,871	10,877	10,877	10,877	10,877	10,877	10,877	10,877	10,877	10,877
Natural Gas	26,488	26,474	26,307	26,373	26,370	26,397	26,419	26,428	26,405	26,368	26,363	26,374
Nuclear	2,280	2,280	2,280	2,280	2,280	2,280	2,280	2,280	2,280	2,280	2,280	2,280
Other	39	36	39	31	33	45	37	36	27	29	40	41
Demand Response	598	670	508	691	957	1,116	1,107	1,083	1,073	964	787	688
Solar	16,548	16,548	16,592	16,908	16,920	16,920	16,920	16,920	16,920	16,920	16,920	16,920
Waste	45	25	24	23	17	24	24	24	24	23	22	25
Wind	6,289	6,316	6,316	6,316	6,316	6,316	6,316	6,316	6,316	6,316	6,316	6,316
Total	**77,324**	**77,667**	**77,705**	**79,466**	**79,999**	**80,216**	**80,343**	**80,386**	**80,350**	**80,182**	**80,016**	**79,943**
Net Import Limit	11,665	11,665	11,665	11,665	11,665	5,500	5,500	5,500	5,500	11,665	11,665	11,665

2.2 Thermal Generators Modeling

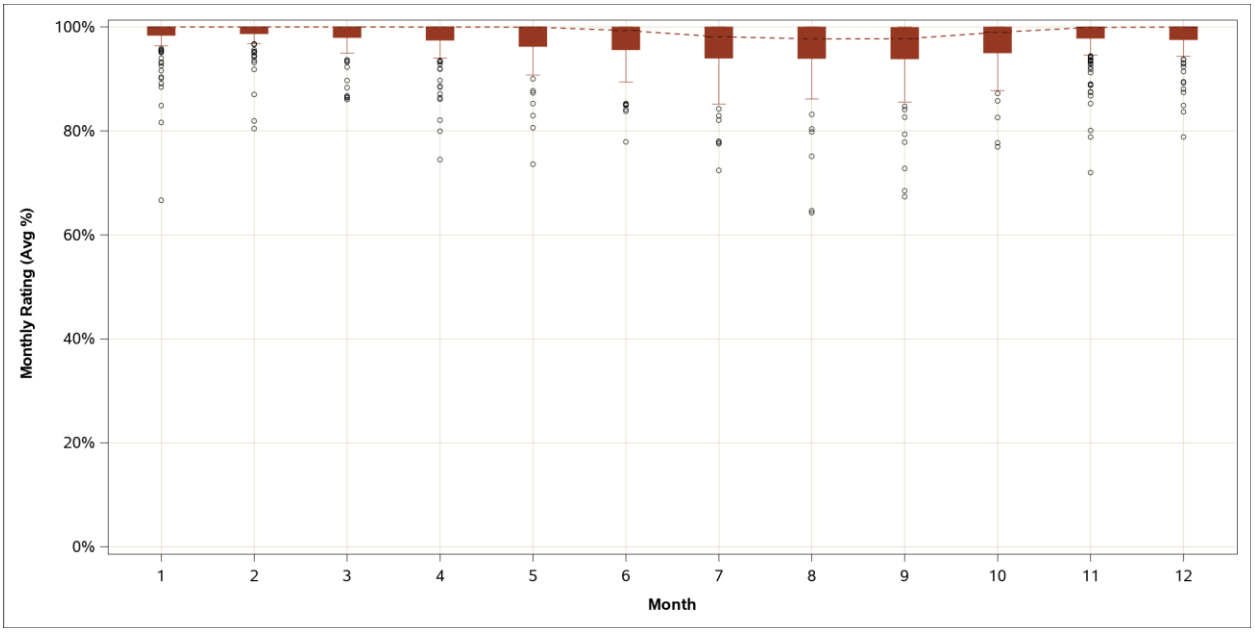
Thermal generators are modeled at a unit level in this study. The CPUC's Integrated Resource Planning (IRP) process is the source for the fuel prices for these units. Diablo Canyon nuclear plant is modeled as available through 2029 (Unit 1) and 2030 (Unit 2) based on SB 846 ruling. As shown in Table 2.2, operating characteristics that constrain unit commitment and dispatch of thermal resources (natural gas, distillate, and nuclear resources etc.) include maximum and minimum capacity, minimum up and down times, ramp up and down times, start-up times, start fuel and start-up cost, heat rate curve, and variable operations and maintenance (VOM) cost. The CAISO's Master File is the primary source for these operating characteristics on a technology level and the model uses group averages to preserve confidentiality.

Table 2.2 Thermal resource modeling attributes

PLEXOS Modeling Attribute	Methodology	Source
Max Capacity	Resource-specific values	CAISO Master File
Min Stable Level		
Heat Rate	Class Averages - Grouped by Average Heat Rate, Max Ramp Rate	
VO&M Charge		
Start Cost Time (Cold, Warm and Hot)		
Offtake at Start		
Start Cost		
Run up rate (Zero to Pmin)		
Max Ramp Up/Down		
Min Up/Down time		
Forced Outage Rate	Resource-specific values	CAISO OMS
Maintenance Rate		
Mean Time to Repair		

Ambient due to temp derates for thermal resources were also reflected in the PLEXOS model. Figure 2.1 shows a distribution of monthly resource-specific rating factor for modeled thermal units. Each data point corresponds to a monthly average rating of one unit calculated using ambient due to temp derates from OMS data between 2022 and 2024. For example, a monthly rating of 80 percent for a unit means that the specific unit will be modeled at 80 percent of its Max Capacity during that month in the model. The dotted line in the figure represents the median. The figure shows that in July, half of the thermal units modeled have a rating greater than 98 percent.

Figure 2.1 Distribution of average monthly rating for thermal units with ambient derates (2022-2024)



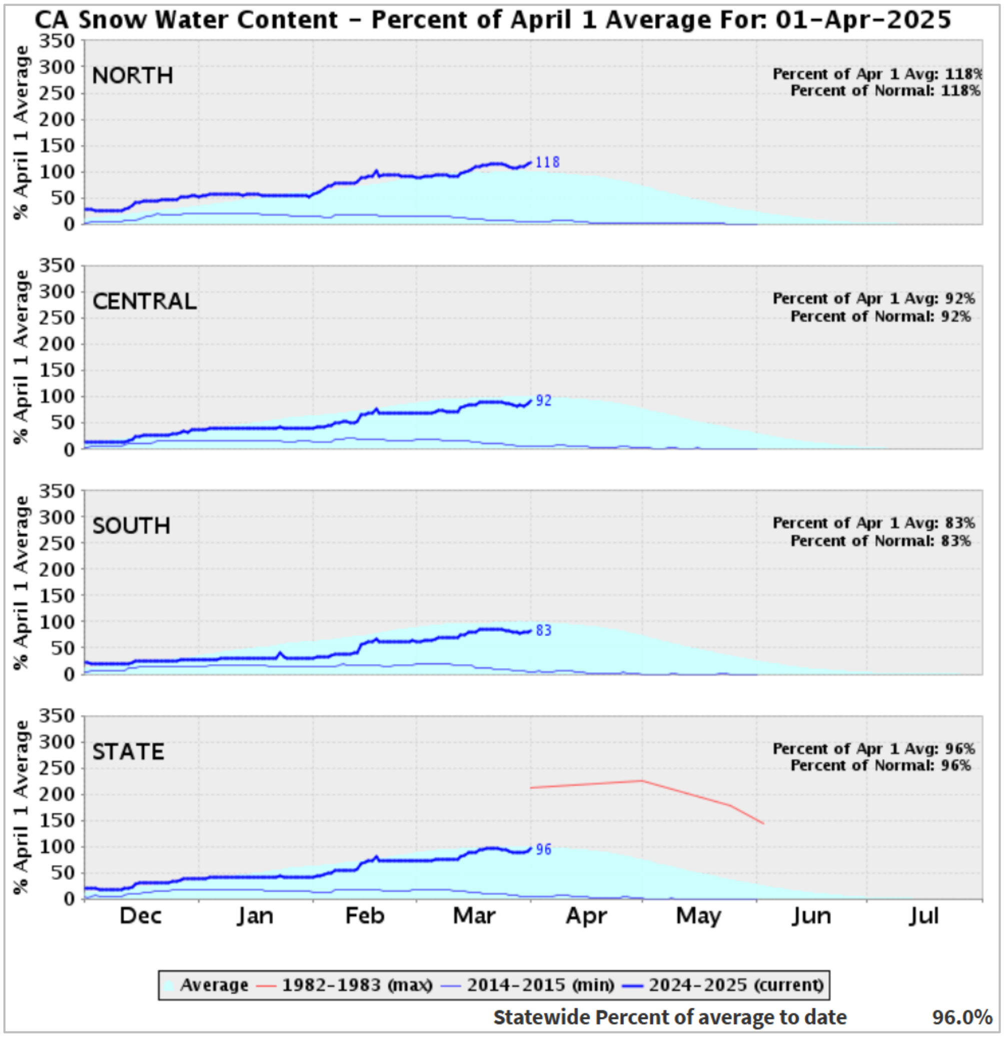
With respect to ancillary services and load-following reserve modeling, the model includes relevant properties that determine each generator's reserve provision in proportion to its ramping capabilities. That is, in upward direction, its total provision of ancillary services cannot exceed its 10-minute ramping capability and any unused capacity. Total provision of ancillary services and load following cannot exceed its 20-minute ramping capability and any unused capacity. In addition, the sum of energy ramping and provision of ancillary services and load following cannot exceed its 60-minute ramping capability and any unused capacity.

2.3 Hydro and Pumped Storage Modeling

Hydro generation is modeled on an aggregated basis as two types: non-dispatchable run-of-river and dispatchable hydro generation. Run-of-river hydro generation is modeled as a fixed generation profile. These resources cannot provide ancillary services or load following. As shown in Figure 2.2, on a statewide basis, the snow water content is trending slightly below average as of April 1, 2025. Storage levels in California's major reservoirs provides a better indication of water supply conditions for the coming year. As of April 3, 2025, California's major reservoir storage levels ranged between 95 to 138 percent of historical average.[12]

[12] California Department of Water Resources, Daily Reservoir Storage Summary: https://cdec.water.ca.gov/resapp/RescondMain

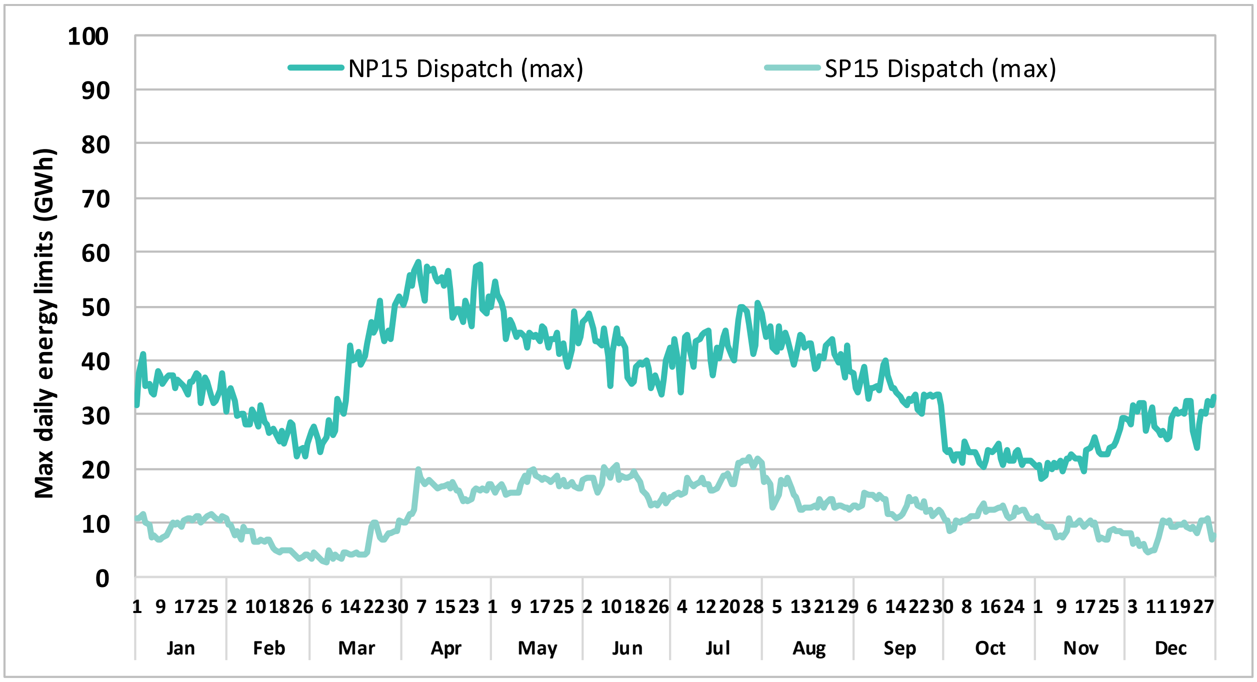
Figure 2.2 California snow water content for water years 2024-25, 1982-83 & 2014-15[13]



Dispatchable hydro generation is optimized subject to daily maximum energy limits as shown in Figure 2.3. These energy limits are derived from historical generation data where snowpack and reservoir conditions that most closely resemble an average hydro year. The model in this analysis for an "average hydro" year was based on the 2018 hydro year. Dispatchable hydro generation can provide system capacity, ancillary service and load following. The hydro resources are aggregated by zone in the model. They do not have outages since the outages are already reflected in the hydro generation profile.

13 California Department of Water Resources, California Data Exchange Center, CA Snow Water Content – Percent of April 1 average: http://cdec.water.ca.gov/snowapp/swcchart.action

Figure 2.3 Dispatchable hydro daily energy limits (2025)



For pumped storage resources, pumping and generation schedules are optimized with constraints on storage capacity, water inflow and target limits, reservoir storage volume and cycling efficiencies. In generation mode, pumped storage resources can provide all ancillary services and load following. Pumped storage have defined forced and maintenance outages.

2.4 Battery Energy Storage Modeling

Battery energy storage resources are modeled at a unit level in PLEXOS with resource-specific operating parameters such as energy capacity, power rating, round-trip efficiency, and ramp rates as shown in Table 2.3. The CAISO's Master File is the primary source for these operating characteristics and the model uses group averages to preserve confidentiality. The model treats batteries as bi-directional resources and co-optimizes battery charging and discharging across time intervals to minimize system costs or meet specified objectives (such as minimizing depth verses duration of shortfalls), while adhering to operational constraints. State-of-charge limits are captured in modeled outage rates calculated using CAISO OMS data. Currently, there is no constraint enforced on the number of cycles a battery resource can undergo in a day. Battery storage resources can provide ancillary services and load following in both charging and discharging modes.

Storage components of hybrid and co-located resources are modeled individually and are subject to their respective Pmax and aggregate capability constraints, respectively.

Table 2.3 Battery storage modeling attributes

PLEXOS Modeling Attribute	Methodology	Source
Max Power (Installed Cap, MW)	Resource-specific values	CAISO Master File
Capacity (Energy, MWh)	Class Averages - Grouped by Energy Limit, Max Ramp Rate	
Charge Efficiency		
Max Ramp Up Rate		
Forced Outage Rate	Resource-specific values	CAISO OMS
Maintenance Rate		
Mean Time to Repair		

2.5 Demand Response Modeling

Demand response (DR) capacity in the market includes CPUC-jurisdictional utility (IOU) DR, non-CPUC jurisdictional DR, and third party DR. Utility demand response includes reliability demand response resources (RDRR) and proxy demand resources (PDR) and accounts for majority of demand response used to meet resource adequacy requirements. RDRR capacity represents a major portion of utility demand response capacity. This capacity can be economically scheduled in the day-ahead market but can only be dispatched in real-time if the CAISO is in an EEA Watch. Table 2.4 shows the amount of utility, third party, and non-CPUC DR capacity modeled for 2025 summer assessment. Utility DR capacity values are based on CPUC's Slice of Day hourly ex-ante load impacts from hour ending 17 to 21 for January to February and June to December and from hour ending 18 to 22 for March to May at the portfolio level on monthly worst load days under 1-in-2 utility weather year conditions.[14] Third party or supply plan DR capacity values are based on CAISO's February 2025 net qualifying capacity list. Non-CPUC jurisdictional load serving entities (municipal utilities) DR values are sourced from DMM's 2024 DR issues and performance report[15]. As shown in the table, DR capacity is available only to be dispatched during net load peak hours of 17 through 22 in the model.

In the PLEXOS model, demand response resources are represented as supply resources with high triggering prices calculated based on a 1,000 BTU/kWh heat rate and a high fuel price. When the energy price reaches the triggering price, the demand response resources' loads are dropped. The triggering prices are high enough so that the demand response resources are not be triggered more frequently than is realistic. Demand response resources cannot provide ancillary services or load following reserves.

[14] CPUC Resource Adequacy Compliance Materials, 2025 – 2027 IOU DR projections: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/resource-adequacy-homepage/resource-adequacy-compliance-materials

[15] DMM 2024 DR Issues and Performance report, Table 2.1: https://www.caiso.com/documents/demand-response-issues-and-performance-2024-mar-14-2025.pdf

Table 2.4 Monthly utility, third party, and non-CPUC demand response capacity (MW)

Demand Response type	Hour	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
PG&E Utility DR Programs	17	126	140				381	400	396	370	245	144	135
	18	126	140	134	174	293	319	334	330	308	227	143	133
	19	125	140	135	168	258	275	286	283	266	216	142	133
	20	124	139	135	164	231	254	263	261	246	212	142	132
	21	125	140	136	162	211	133	119	116	113	146	142	133
	22			140	150	143							
SCE Utility DR Programs	17	387	435				708	704	722	731	686	578	415
	18	444	497	388	588	598	714	697	713	721	694	615	476
	19	443	501	435	617	615	686	658	675	684	667	582	479
	20	446	505	437	578	579	652	616	637	642	627	557	480
	21	449	505	438	555	560	637	599	614	621	607	544	475
	22			457	608	617							
SDG&E Utility DR Programs	17						3	4	4	4	4		
	18					3	3	3	3	3	3		
	19					2	2	2	2	2	2		
	20					2	2	2	2	3	3		
	21					2	2	3	3	3	3		
	22					2							
3rd Party DR (Supply Plan DR)	17	43	47	4	16	271	321	326	290	287	241	189	189
	18	44	48	48	90	271	321	326	290	287	241	189	189
	19	44	47	48	87	271	321	326	290	287	241	189	189
	20	44	47	49	86	271	321	326	290	287	241	189	189
	21	19	20	48	83	271	321	326	290	287	241	189	189
	22			17	25	271	321	326	290	287	241	189	189
Non-CPUC DR	17							89	58	81			
	18							89	58	81			
	19							89	58	81			
	20							89	58	81			
	21							89	58	81			
	22							89	58	81			
Total Modeled DR	17	557	622	4	16	271	1,413	1,523	1,470	1,473	1,176	912	739
	18	614	685	571	852	1,164	1,356	1,448	1,393	1,401	1,165	946	798
	19	613	688	618	871	1,146	1,283	1,360	1,308	1,321	1,126	913	801
	20	615	691	621	828	1,082	1,229	1,295	1,248	1,259	1,083	888	801
	21	593	665	623	800	1,044	1,092	1,135	1,080	1,105	997	875	797
	22	0	0	615	782	1,033	321	415	348	368	241	189	189
Total Modeled DR (Average)	**17-22**	**598**	**670**	**508**	**691**	**957**	**1,116**	**1,196**	**1,141**	**1,154**	**964**	**787**	**688**

2.6 Stochastic Solar and Wind Profiles

The CAISO's model has stochastic variables for solar generation, wind generation, outages, and load. The solar variable is the aggregate solar generation of behind-the-meter PV, solar resources inside the CAISO and from out-of-state (tie-generators). The wind variable is the aggregate wind generation by wind resources inside the CAISO and out-of-state (tie-generators).

For solar and wind resources, their respective nameplate capacities shown in Table 2.5 are used as an input into creating 500 stochastic profiles for 2025. The table excludes solar and wind capacity from hybrid resources but are used in developing the respective stochastic profiles. Solar and wind components of hybrid and co-located resources are modeled individually and are subject to their respective Pmax and aggregate capability constraints. In the simulations, the stochastic values of solar and wind generation are distributed to the five zones - PG&E Bay, PG&E Valley, SCE, SDG&E, and the external zone by ratios calculated based on their respective base profiles.

Table 2.5 2025 Solar and wind nameplate capacities (MW)

FUEL_TYPE	Type	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Solar	GEN	16,548	16,548	16,592	16,908	16,920	16,920	16,920	16,920	16,920	16,920	16,920	16,920
Solar	TG	982	982	982	982	982	982	982	982	982	982	982	982
Wind	GEN	6,289	6,316	6,316	6,316	6,316	6,316	6,316	6,316	6,316	6,316	6,316	6,316
Wind	TG	2,051	2,051	2,051	2,051	2,051	2,051	2,051	2,051	2,051	2,051	2,051	2,051

Solar and wind base profiles are used as an input into the CAISO's mean reversion stochastic model.[16] Utility scale solar base profile is based on CPUC's most recently adopted Preferred System Plan (PSP).[17] The wind base profile comes from a 5-year (2019 – 2023) average of actual CAISO EMS data normalized by annual installed capacity. Mean reversion ratios of solar and wind are calculated with a regression model using historical wind (2007 – 2014) and solar (2010 – 2021) data sourced from the National Renewable Energy Laboratory (NREL). The CAISO then applied these ratios to the solar and wind base profiles to generate 500 stochastic samples for solar and wind generation. Figure 2.4 and Figure 2.5 show hourly distribution of solar (excludes behind the meter PV generation) and wind profiles for each month of 2025 based on capacities listed in Table 2.5.

Stochastic profiles for solar and wind are based on respective generation potential and do not include outages. Table 2.6 shows capacity-weighted rating factors applied to solar and wind by zone, which represents capacity not on outage each month. These values are calculated from OMS data (2022-2024) using same planned and forced outage natures of work used to calculate outage rates for other resource types.

Table 2.6 Solar and wind rating factors by zone (2025)

Resource type	Zone	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
SOLR	PG&E Bay	96.4%	95.8%	94.4%	95.6%	91.2%	91.7%	93.7%	92.6%	97.2%	96.4%	95.6%	94.6%
SOLR	PG&E Valley	96.8%	96.1%	97.1%	96.8%	96.5%	95.9%	95.5%	96.4%	96.7%	95.8%	96.3%	96.0%
SOLR	SCE	96.8%	96.9%	98.0%	97.6%	97.3%	97.8%	97.5%	96.7%	97.4%	97.5%	97.6%	98.1%
SOLR	SDG&E	97.6%	98.3%	98.2%	98.4%	98.6%	98.9%	97.9%	96.9%	97.2%	97.5%	97.6%	97.7%
WIND	PG&E Bay	94.0%	91.0%	92.8%	91.0%	92.2%	93.6%	91.6%	93.1%	92.9%	88.4%	91.2%	91.3%
WIND	PG&E Valley	97.6%	96.3%	96.6%	98.1%	98.4%	99.7%	99.4%	99.6%	99.6%	99.3%	98.0%	96.0%
WIND	SCE	96.0%	95.6%	95.2%	95.1%	95.2%	94.7%	95.0%	94.8%	95.3%	94.5%	93.9%	93.9%
WIND	SDG&E	90.8%	93.9%	92.4%	91.6%	89.6%	88.6%	93.3%	92.8%	93.4%	95.0%	94.0%	96.3%

16 The methodology was filed as part of CAISO's expert testimony in the CPUC Long-Term Procurement Plan (LTPP) proceeding, Appendix A, pg. 5 – 19, Nov 20, 2014: https://www.caiso.com/documents/nov20_2014_liu_stochasticstudytestimony_ltpp_r13-12-010.pdf

17 CPUC, 2023 Preferred System Plan Proposed Decision, Modeling & Analysis, pp. 13, January 12, 2024: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-longterm-procurement-plan-irp-ltpp/2023-irp-cycle-events-and-materials/2024-01-12-presentation-summarizing-updatedservm-and-resolve-analysis.pdf

Solar base profile is downscaled to 85.4 percent of the existing profile, which is maximum hourly capacity factor observed for solar, averaged across 2022-2024. Solar stochastic profiles are capped at maximum hourly value at 112.18 percent of the base profile peak. This is the maximum observed hourly capacity factor since 2016, adjusted relative to the base profile peak.

Figure 2.4 Hourly utility scale solar stochastic sample distribution by month (2025)

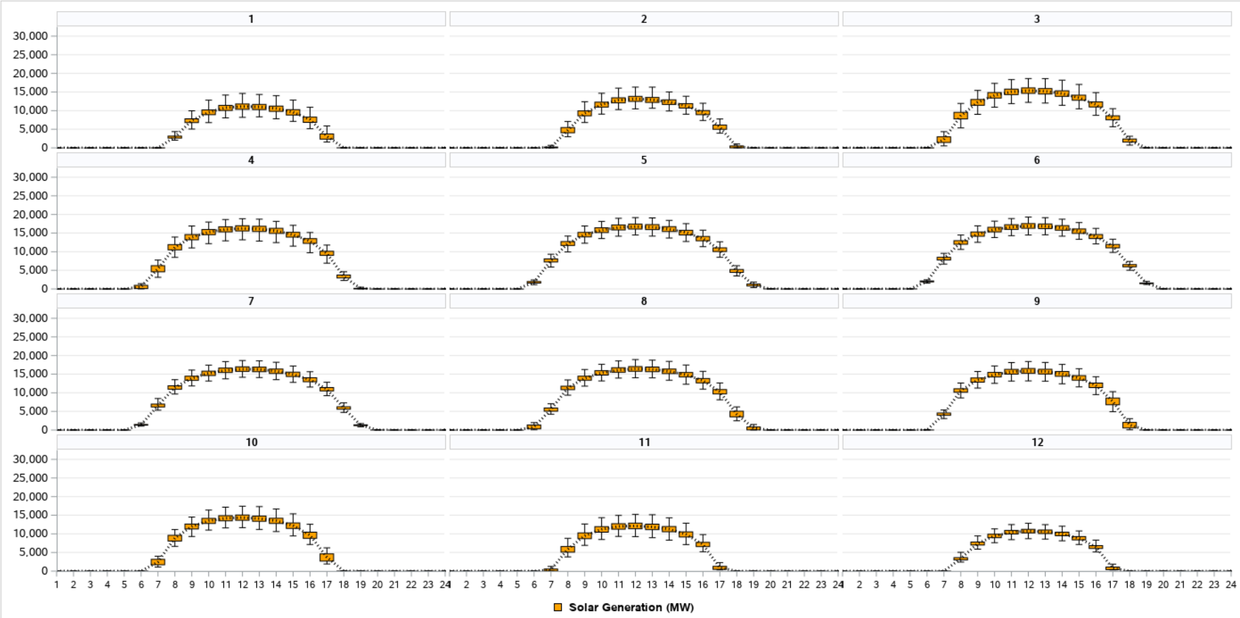
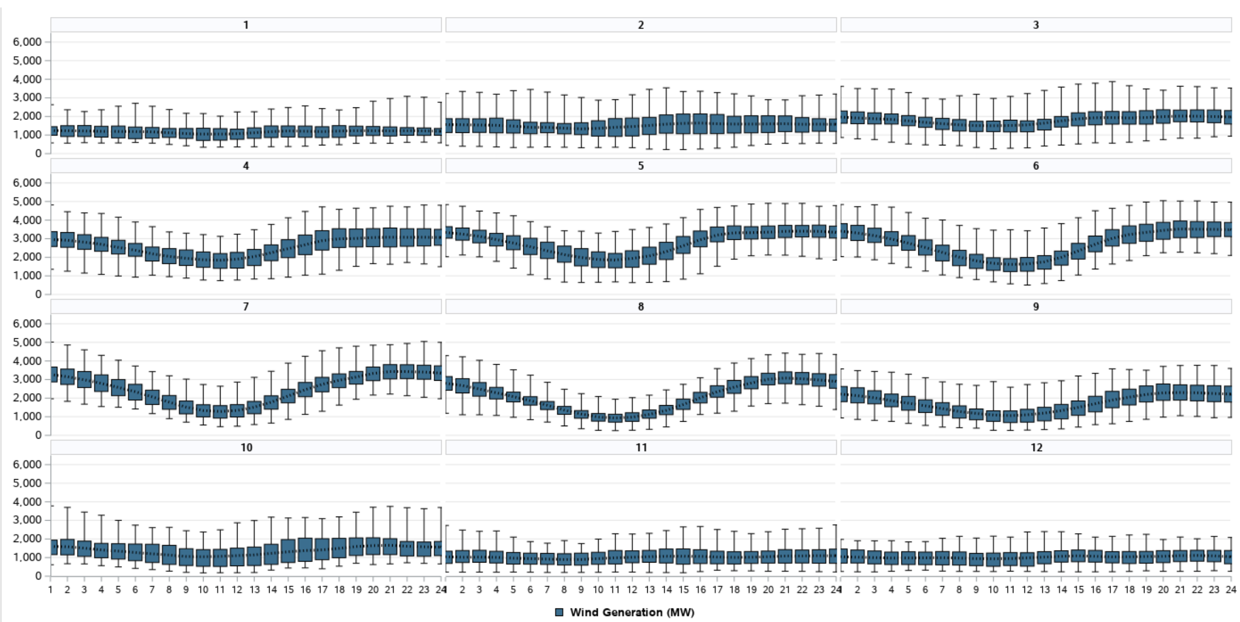


Figure 2.5 Hourly wind stochastic sample distribution by month (2025)



2.7 Stochastic Generator Outage Profiles

Annual forced outage rate, maintenance rate and mean time to repair generator properties are used to create 500 independent outage samples for each generator using the converged Monte Carlo method. PLEXOS' PASA simulation phase is used to create outage events that can be used as an input into subsequent hourly chronological simulations. The converged Monte Carlo method is used in generating the forced outages so that the percent of hours with forced outage is close to the forced outage rates of the resources. Planned maintenance factor on a region level (PG&E Bay, PG&E Valley, SCE and SDG&E) is used to schedule outages by month. It is a profiling factor used by PASA to 'shape' maintenance events into appropriate periods of high capacity reserves. As mentioned earlier, the outage stochastic variable is independent of any other stochastic variables in the model.

Table 2.7 shows the natures of work used for calculating resource-specific planned and forced outage rates. CAISO OMS data from 2022 to 2024 was used to update annual outage rates in the model. Ambient due to temp forced outages are separated and applied as a monthly derate to each thermal resource as shown in Figure 2.1. Outages outside of management control such as ambient not due to temp/fuel insufficiency are not included. Historical forced outage data from these categories show outage rates are generally low for gas and storage resources.

Table 2.7 Planned and forced outage natures of work

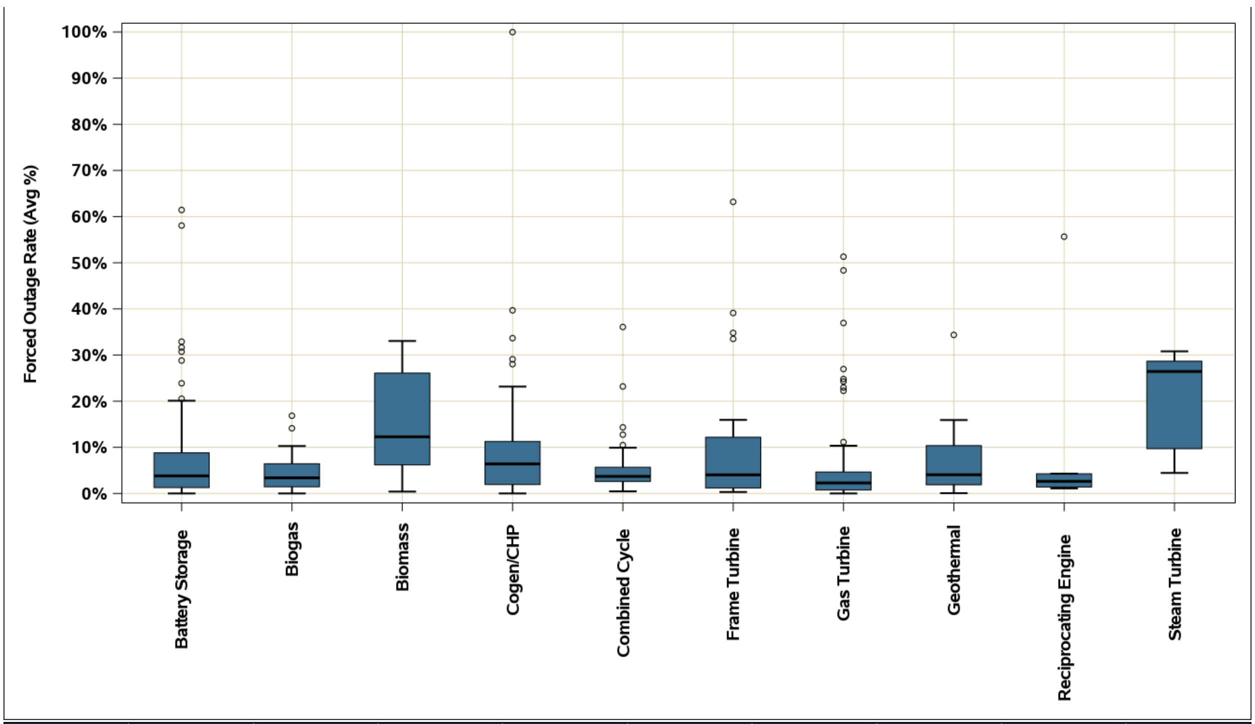
Nature of Work Type	Nature of Work	Included in Forced Outages?
Equipment failure/unavailability	Plant Maintenance	Yes
Equipment failure/unavailability	Plant Trouble	Yes
Equipment failure/unavailability	Power System Stabilizer	Yes
Equipment failure/unavailability	Metering/ Telemetry	Yes
Equipment failure/unavailability	RTU/RIG	Yes
Equipment failure/unavailability	ICCP	Yes
Equipment failure/unavailability	AVR/Exciter	Yes
Market model-related	Technical Limitations not in Market Model	Yes
Market model-related	Transitional Limitation	Yes
Use limitation	Environmental Restrictions	Yes
Transmission outage	Transmission Induced	No
Market model-related	Unit Supporting Startup	No
Fuel insufficiency	Ambient Not Due to Temp	No
Fuel insufficiency	Ambient due to Fuel insufficiency	No
Testing/onboarding	New Generator Test Energy	No
Testing/onboarding	Unit Testing	No
Testing/onboarding	RIMS Outage	No
Testing/onboarding	RIMS Testing	No
Market model-related	Ramp Rate	No
Market model-related	Contingency Reserves Management	No
Market model-related	MSS_Reservable	No
Use limitation	Annual use limit reached	No
Use limitation	Monthly use limit reached	No
Use limitation	Other Use Limit reached	No
Use limitation	Short term use limit reached	No
Situational derates	Ambient Due to Temp	No

Figure 2.6 and Figure 2.7 show a distribution of resource-specific average forced and planned outage rates, respectively. These rates are calculated using natures of work listed above using CAISO OMS data from 2022 to 2024. Each data point in these distributions corresponds to an average forced or planned outage rate of one resource. The respective rates are calculated based on unavailable capacity for each outage type divided by nameplate capacity of the resource. Unavailable capacity includes both partial derates and full outages.

The median of the distribution in these figures is represented as a horizontal line within each box. For example, on an annual basis, half of the battery storage resources have a forced outage rate higher than 4 percent (Figure 2.6). Similarly, half of the combined cycle resources have an annual planned outage rate higher than 4.3 percent (Figure 2.7). Forced and planned outage mean time to repairs are modeled separately for each individual resource and calculated as total time on outage divided by number of repairs.

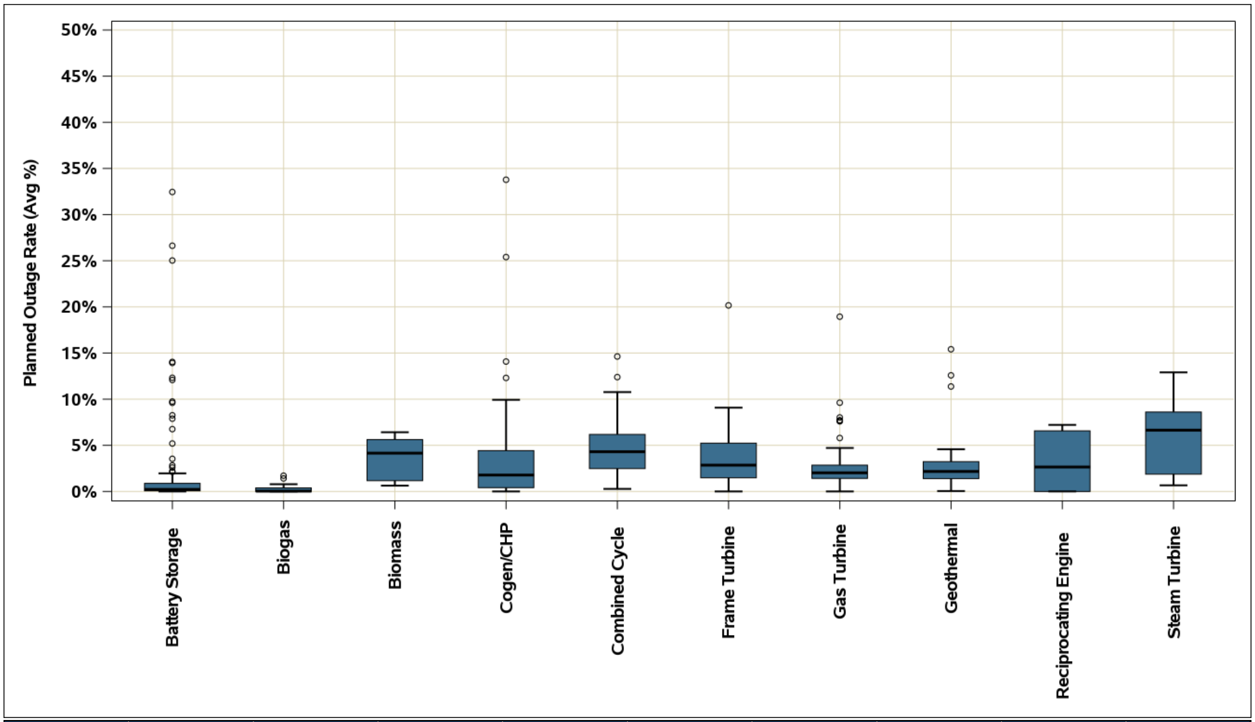
For new resources without outage data, capacity weighted class-average rates shown below respective figures are used to model forced and planned outage rates. These rates are used for any resources modeled on an aggregated basis (non-dispatchable biofuels, CHP). For nuclear units (Diablo 1 and 2), annual forced outage rate of 2 percent is used. Planned nuclear maintenance for refueling is sourced from publicly available sources. For solar and wind stochastic profiles, a static monthly derate is applied based on historical outages (see Table 2.6).

Figure 2.6 Distribution of resource-specific forced outage rate by fuel/technology type



Capacity-weighted average Forced Outage Rate (%)	Battery Storage	Biogas	Biomass	Cogen/CHP	Combined Cycle	Gas Turbine	Geothermal	Reciprocating Engine	Steam Turbine
	5.4%	6.1%	19.1%	8.3%	4.5%	6.1%	7.5%	3.7%	22.3%

Figure 2.7 Distribution of resource-specific planned outage rate by fuel/technology type



Capacity-weighted average Planned Outage Rate (%)	Battery Storage	Biogas	Biomass	Cogen/CHP	Combined Cycle	Gas Turbine	Geothermal	Reciprocating Engine	Steam Turbine
	0.9%	0.5%	4.5%	6.2%	4.9%	2.7%	3.1%	4.3%	6.9%

2.8 Stochastic Load Profiles

The CEC baseline managed hourly demand forecast from the CEC's 2024 IEPR[18] was an input to CAISO's mean reversion load forecast model.[19] This model has two processes: the first process uses CAISO's historical load profiles to calculate the mean reversion ratios with a regression model. The second process applies the calculated mean reversion ratios to CEC's baseline hourly demand forecast plus behind-the-meter solar generation to generate 500 stochastic hourly gross load profiles. The managed hourly load was calculated by subtracting behind the meter solar from the projected 500 stochastic gross load profiles. Figure 2.8 shows the frequency distribution of hourly managed loads used in the stochastic model. Figure 2.9 shows hourly distribution of managed load profiles for each month of 2025.

[18] CEC, 2024 Integrated Energy Policy Report, Hourly Demand Forecast Files (corrected), Mar 21, 2025: https://docketsearch.energy.ca.gov/Pages/results.aspx?k=*&a=IsDocument%3a1+DocketNumber%3a24-IEPR-03&docketnumber=24-IEPR-03

[19] The methodology was filed as part of CAISO's expert testimony in the CPUC Long-Term Procurement Plan (LTPP) proceeding, Appendix A, pg. 5 – 19, Nov 20, 2014: https://www.caiso.com/documents/nov20_2014_liu_stochasticstudytestimony_ltpp_r13-12-010.pdf

Figure 2.8 Frequency distribution of hourly load samples (2025)

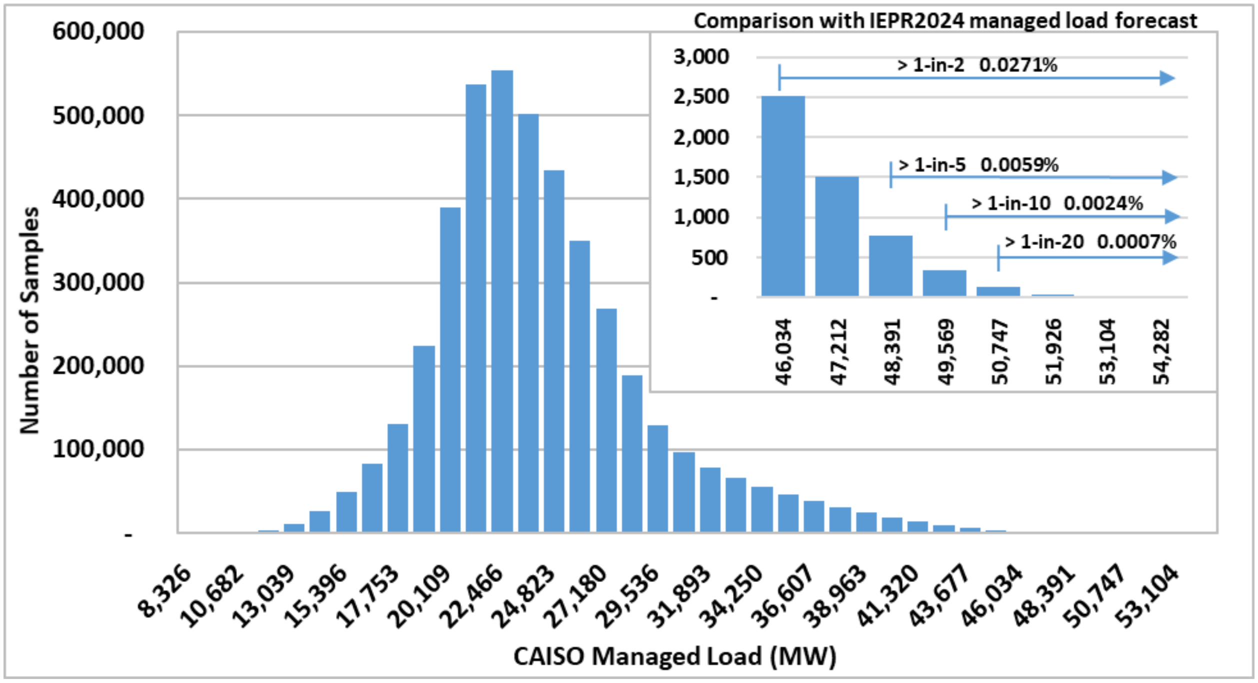
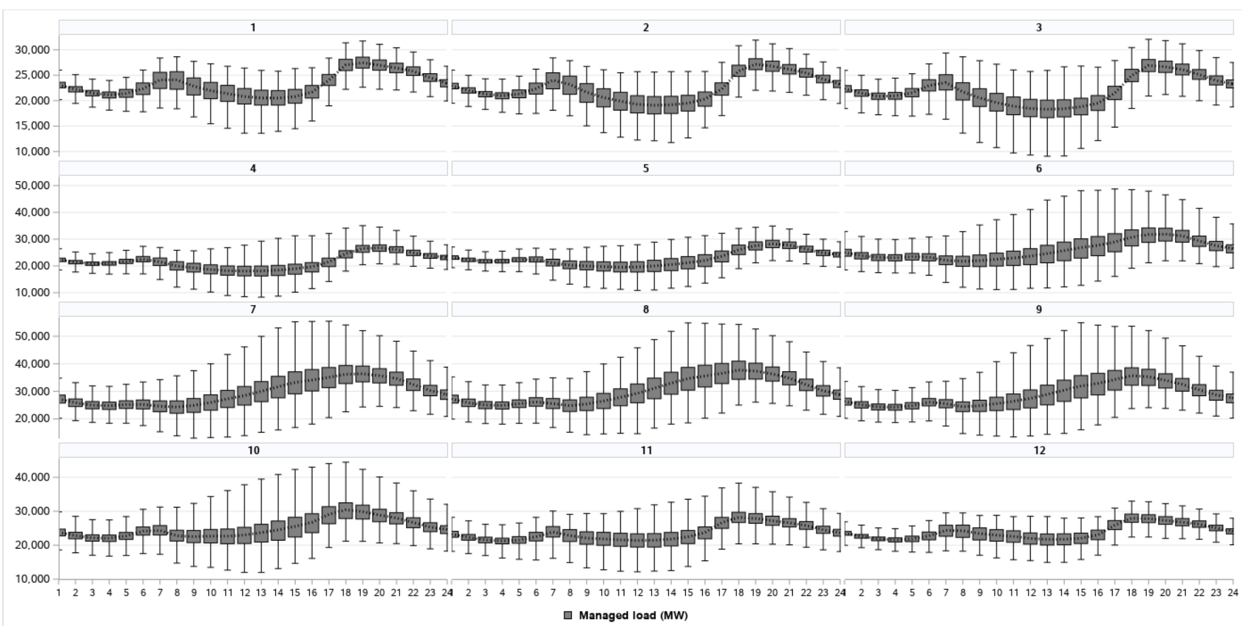


Figure 2.9 Hourly managed load stochastic sample distribution by month (2025)



2.9 Ancillary Services Modeling

CAISO zones defined in the production cost model also have ancillary services and load following requirements, either as fixed profiles or as a certain percent of their loads. The CAISO has total ancillary service and load following requirements for PG&E, SCE, and SDG&E zones together. Internal resources and resources outside the zone as designated in the model may meet the ancillary service and load following requirements.

Individual gas and battery resources providing a specific reserve product in the model are selected based on top "x" MW of capacity capable of providing a specific reserve, where x = total gas or battery capacity certified to provide a specific AS product according to Master File data.[20]

Regulation and Spinning/Non-Spinning Requirements

Regulation requirements enforced in the market did not change significantly year over year (based on day-ahead market values from 2022 to 2024). Hence, regulation up and down requirements in the 2025 model are based on actual 2025 requirements for January through March 2025 and actual 2024 requirements for April through December 2025. All 500 iterations use a single set of deterministic regulation up and down requirements. Figure 2.10 and Figure 2.11 show hourly distributions of regulation up and down requirements for each month of 2025.

Spinning and non-spinning reserve requirements are each held at 3 percent of load, respectively. Because load is a stochastic variable, the hourly values of spinning and non-spinning reserve requirements vary in each iteration. Minimum spin provision is also enforced in the model and is equal to maximum capacity of single unit of Diablo Canyon power plant.

[20] For non-spin, fast start gas resources are selected based on a 10-minute or less cold startup time.

Figure 2.10 Hourly distribution of regulation up requirements (2025)

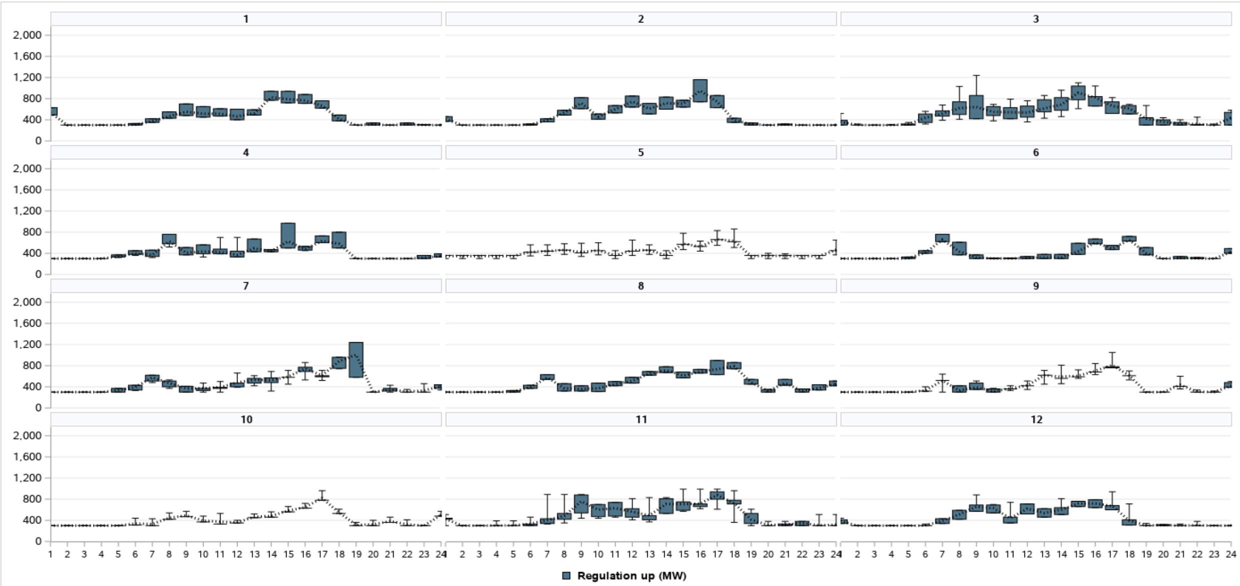
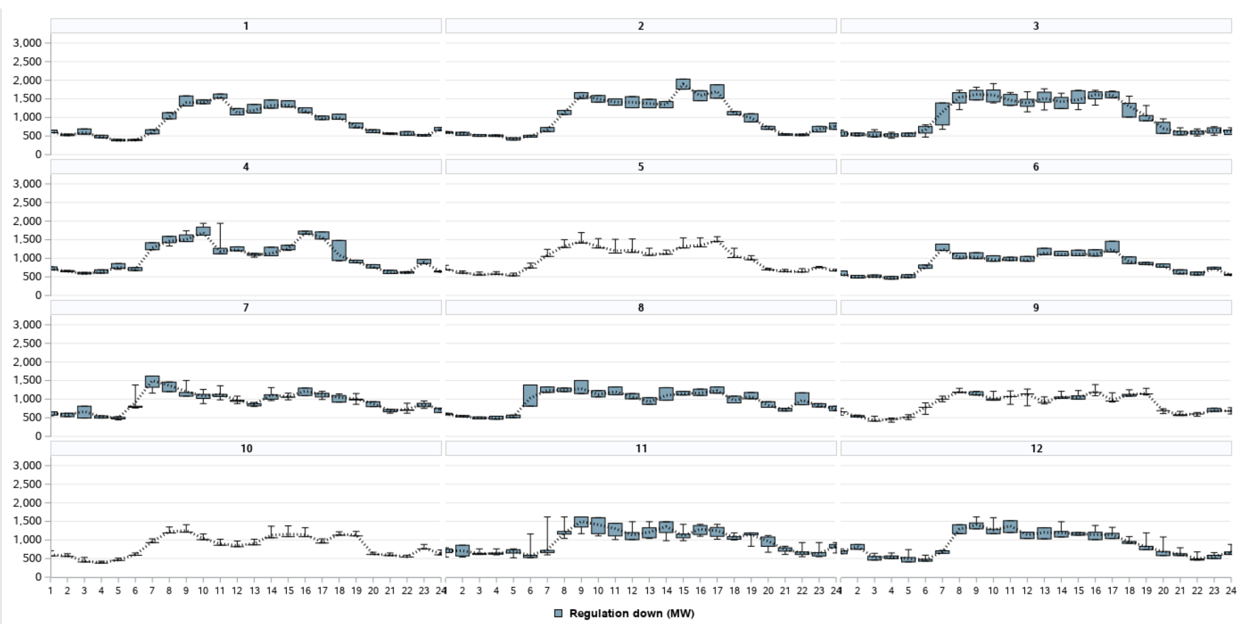


Figure 2.11 Hourly distribution of regulation down requirements (2025)



Load Following Requirements

The load-following up or down requirement is the maximum of net load differences between the 5-minute and hourly forecast values within the hour in an upward or downward direction. All 500 iterations use a single set of deterministic load following up and down requirements. Figure 2.12 and Figure 2.13 show hourly distributions of load following up and down requirements for each month of 2025.

In addition to ancillary service and load-following requirements, the model also enforces a frequency response reserve with a minimum provision of 376 MW to satisfy a NERC requirement. The model enforces a constraint such that only internal combined cycle and battery energy storage resources provide this reserve. This reserve product requires that generators providing it be able to maintain the required response for 30 minutes.

Figure 2.12 Hourly distribution of load following up requirements (2025)

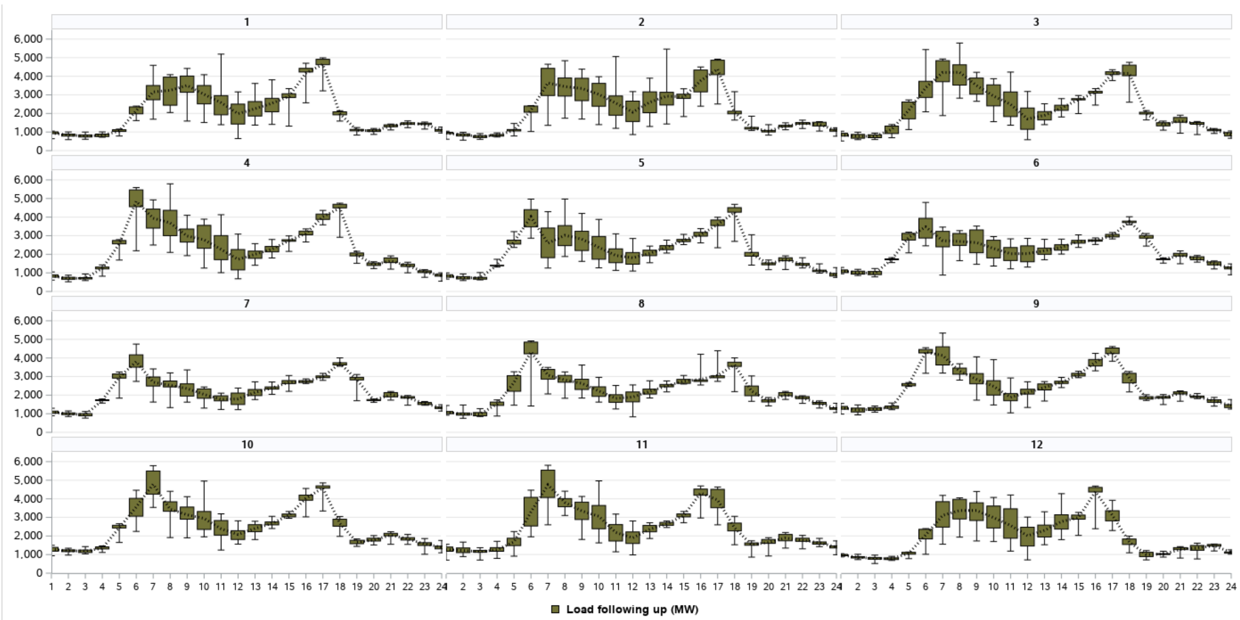


Figure 2.13 Hourly distribution of load following down requirements (2025)