PUBLIC UTILITIES COMMISSION
505 Van Ness Avenue
San Francisco CA 94102-3298

Pacific Gas & Electric Company
ELC (Corp ID 39)
Status of Advice Letter 6636E
As of November 15, 2022

Subject: Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company's Effective Load Carrying Capability Study Submission

Division Assigned: Energy

Date Filed: 07-01-2022

Date to Calendar: 07-08-2022

Authorizing Documents: D1909043

Disposition:	**Accepted**
Effective Date:	**07-31-2022**

Resolution Required: No

Resolution Number: None

Commission Meeting Date: None

CPUC Contact Information:

edtariffunit@cpuc.ca.gov

AL Certificate Contact Information:

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PGETariffs@pge.com

PUBLIC UTILITIES COMMISSION
505 Van Ness Avenue
San Francisco CA 94102-3298

To: Energy Company Filing Advice Letter

From: Energy Division PAL Coordinator

Subject: Your Advice Letter Filing

The Energy Division of the California Public Utilities Commission has processed your recent Advice Letter (AL) filing and is returning an AL status certificate for your records.

The AL status certificate indicates:

Advice Letter Number
Name of Filer
CPUC Corporate ID number of Filer
Subject of Filing
Date Filed
Disposition of Filing (Accepted, Rejected, Withdrawn, etc.)
Effective Date of Filing
Other Miscellaneous Information (e.g., Resolution, if applicable, etc.)

The Energy Division has made no changes to your copy of the Advice Letter Filing; please review your Advice Letter Filing with the information contained in the AL status certificate, and update your Advice Letter and tariff records accordingly.

All inquiries to the California Public Utilities Commission on the status of your Advice Letter Filing will be answered by Energy Division staff based on the information contained in the Energy Division's PAL database from which the AL status certificate is generated. If you have any questions on this matter please contact the:

Energy Division's Tariff Unit by e-mail to
edtariffunit@cpuc.ca.gov

Pacific Gas and Electric Company®

Sidney Bob Dietz II
Director
Regulatory Relations

Pacific Gas and Electric Company
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July 1, 2022

Advice 6636-E
(Pacific Gas and Electric Company ID U 39 E)

Advice 4825-E
Southern California Edison company (U 338-E)

Advice Letter 4016-E
San Diego Gas & Electric (U 902-E)

Public Utilities Commission of the State of California

Subject: **Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company's Effective Load Carrying Capability Study Submission**

Purpose

Pursuant to Ordering Paragraph (OP) 2 of Decision (D.) 19-09-043, Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E), and Southern California Edison Company (SCE), (collectively, the Joint IOUs) submit the 2022 Effective Load Carrying Capability (ELCC) Study Report (Report).[1/] The Report includes the study methodology, assumptions, and marginal ELCC values for the following generating facilities: fixed axis solar photovoltaic (PV), tracking solar PV, tracking solar PV paired with storage, distributed solar PV, wind, and wind paired with storage.

Background

As ordered in D. 19-09-043, the Joint IOUs performed a study to assess the ELCC values used in Renewables Portfolio Standard (RPS) evaluations. The Decision required using a specific dataset, software, and methodology including the following:

- The Joint IOU study shall use the Strategic Energy and Risk Valuation Model (SERVM).

1/ On May 31, 2022 the Executive Director of the Commission granted the Joint IOUs' request for a one-month extension to comply with OP 2 of D. 19-09-043. The Joint IOUs submitted such request pursuant to Rule 16.6 of the California Public Utilities Commission's Rules of Practice and Procedure. Accordingly, this advice letter and accompanying Report is timely.

- Behind the Meter (BTM) solar PV must be treated as a supply-side resource.
- An annual loss of load expectation (LOLE) study must be conducted using a 0.1 LOLE metric.
- Annual, marginal ELCC values must be determined.
- The most recently updated base portfolio from the Integrated Resource Plan (IRP)[2/] proceeding must be used with study years of subsequent four-year increments.
- The study shall analyze the following resources: fixed axis solar PV, tracking solar PV, tracking solar PV paired with storage, distributed solar PV, wind, and wind paired with storage.
- The study shall be performed across seven regions, four in the California Independent System Operator (CAISO) area and three outside of the CAISO area.
- The Joint IOUs must continue to update the joint ELCC study annually until directed otherwise.

To fulfill the joint study and its associated requirements, the Joint IOUs hired Astrapé Consulting to perform the analysis.

Methodology Concerns

During the 2022 ELCC report development process, the Joint IOUs identified several issues regarding the ELCC Report assumptions that are ordered by the Commission. These issues and their impact on the marginal ELCC values are described below.

Although the methodology used in the 2022 ELCC Report is the same as the methodology used in the past Joint IOU ELCC studies, the issues identified below have a more noticeable impact on the marginal ELCC values, given the Preferred System Plan (PSP) portfolio used for the Report. The Joint IOUs have concerns about adopting the marginal ELCC values in the Final 2022 ELCC Report because of methodology issues discussed below.

- **The methodology constraints to calibrate the SERVM model to 0.1 Loss of Load Expectation (LOLE) biases the Report results.**

Specifically, D.19-09-043 ordered the Joint IOUs to determine the ELCCs of several renewable and renewable with battery storage technologies based on the resource portfolio from the IRP's PSP portfolio. The decision also requires the SERVM model to be calibrated to a 0.1 LOLE for marginal ELCC calculations.[3] The Joint IOUs are

2/ Rulemaking (R.) 20-03-007
3/ D. 19-09-043, OP 1.

concerned that the combined use of the PSP portfolio and the prescribed methodology[4/] results in marginal ELCC values that are not reflective of their reliability contributions. As demonstrated by the CPUC's PSP reliability analysis[5], the PSP results in a CAISO system LOLE significantly lower than 0.1 LOLE. This demonstrates that the PSP is overbuilt and includes resources in excess of capacity needed to achieve 0.1 LOLE.[6] To be compliant with the decision, and since the Joint IOUs are unable to remove resource capacity from the PSP to calibrate to 0.1 LOLE, the ELCC SERVM modeling of the PSP required significant load additions to calibrate the portfolio to a 0.1 LOLE.

The use of hourly load scaling to achieve 0.1 LOLE, combined with the requirement to calculate marginal ELCC values using the PSP as the resource baseline, results in in marginal ELCC values that are likely distorted by the significant amount of artificial load that had to be added to the model.[7] Since the marginal capacity is primarily batteries, overbuilding the battery portfolio, relative to the 0.1 LOLE standard, and adding load begins to exhaust the potential for batteries to supply resource adequacy (RA) earlier which means the ELCC of incremental batteries will be much lower than if the starting battery portfolio was properly sized to achieve a 0.1 LOLE. Conversely, renewable ELCCs are likely higher than reasonable. In the modeled CAISO scenario with the LOLE significantly below 0.1, renewable resources provide energy during pre-peak hours to fully charge and delay the discharge of batteries to hours having the highest reliability need. As a result, the marginal ELCC values are likely not reflective of the reliability contributions of the PSP resources. In addition, since D.19-09-043 requires the Joint IOU ELCC Report to calculate marginal ELCC values for resources incremental to the PSP resource portfolio, in the Joint IOUs' view, the marginal ELCCs produced are not useful for guiding procurement decisions intended to implement the PSP or for achieving any particular level of overall supply reliability.

The approach of basing the 2022 ELCC Report on the PSP resource portfolio, and the prescribed methodology, results in significantly inflated solar ELCCs and suppressed

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4/ D. 19-09-043, OP 1, requires the "installed capacities from the Integrated Resource Planning proceeding's most recently updated base portfolio must be used" for the purpose of calculating marginal ELCC values of resources above the resources already in the PSP. The methodology also requires the SERVM model to be calibrated to a 0.1 LOLE for marginal ELCC calculations.

5/ D. 20-05-003 pg. 103

6/ The IOUs recognize that the CAISO system LOLE is significantly lower than the industry standard 0.1 LOLE. The found LOLE is driven by the PSP SERVM model assumptions, some assumptions have since changed which could increase the LOLE to closer than 0.1. The IOUs also recognize that some resources may be built for system constraints other than reliability.

battery storage ELCCs (16.5% for CA-S[8/] tracking solar PV and 68.7% for 4-hour tracking solar PV with storage hybrid in 2032).[9]

- **Given the issues identified above, the Joint IOUs do not support the use of the marginal ELCC values provided in this report to guide procurement decisions.**

As the Commission recognized in D.19-10-043, a standardized ELCC methodology will facilitate planning and analysis by the stakeholders and the Commission.[10] In general, the Joint IOUs view accurate ELCC values as providing an important signal to the market about the ability of new resources to contribute to system reliability given the portfolio of resources assumed to be online. The inflated solar ELCCs and suppressed battery storage ELCCs shown in the Report will send an incorrect signal to the market, may lead to an unreliable or unnecessarily costly resource portfolio, and could ultimately delay California's path toward decarbonization.

The Joint IOUs recommend that the ELCC values provided in the Report not be used to guide the procurement decisions and/or Commission Orders in the RPS proceeding or in any other proceedings, such as RA and IRP proceedings.

For the upcoming procurement, the Joint IOUs plan to use the compliance ELCC values provided by the Commission. For example, for the IRP's mid-term reliability procurement, the Commission asked all load serving entities (LSEs) to use specific marginal ELCC values develop by the CPUC. [11]

- **Changes will be required to align future long-term reliability planning with a new RA framework.**

ELCC is a methodology used to assess a resource's annual contribution to reliability relative to perfect capacity. The annual ELCC numbers do not specifically represent the reliability contribution of resources during critical hours. With the increasing penetration of renewables and storage resources in the California system, changes have been made in the RA proceeding to assess reliability at a more granular level.[12] A new RA framework, with 24-hourly slices, has been adopted by the Commission to consider the reliability contribution of all resources including use/energy-limited resources. Long-term planning

8/ CA-S is defined as Southern California in the Report.

9/ The 2022 Report includes a sensitivity which demonstrates the impact of different methodologies for calibrating towards a 0.1 LOLE in ELCC analysis. Removing storage as the marginal resource to calibrate the portfolio to a 0.1 LOLE results in a decrease of three percentage points in CA-S tracking solar PV and an increase of twenty-seven percentage points in 4-hr standalone storage.

10/ D. 19-09-043, Finding of Fact 6.

11/ D. 20-05-003.

12 / See D. 21-07-014 (adopting a slice-of-day RA framework).

will require changes across the different proceedings, including RPS and IRP, to ensure the correct signals are sent to the market and that California builds a mix of resources that effectively and efficiently achieves electricity system reliability and environmental objectives.

Study Results

Tables ES1 – ES6 provide the ELCC values by technology and region for the study years 2026, 2030, and 2032. A detailed discussion of study results is included in the Simulation Results section of the ELCC study report.

As mentioned above, the Joint IOUs faced a methodology constraint in developing the report. Given the PSP assumptions, the reliability of the system in each study year before calculating ELCCs is significantly better than the industry standard 0.1 Loss of Load Expectation (LOLE).[13] The methodology constraint created a challenge for establishing the base cases in SERVM since capacity value is typically only measured when reliability is at or near the industry standard 0.1 LOLE target. D.19-09-043 also requires that the ELCC values be calculated with the system at 0.1 LOLE. In order to meet this requirement while utilizing the resource mix outlined in the PSP, the only option was to increase loads dramatically to tune reliability to 0.1 LOLE. The approach of basing the 2022 ELCC Report on the PSP resource portfolio, and the prescribed methodology, results in significantly inflated solar ELCCs and suppressed battery storage ELCCs

Table ES1. 2026 Study Wind and Solar Results (expressed as a percentage of assumed interconnection capability)

Technology	BTM PV	Fixed PV	Tracking PV	Wind
CA-N	8.8%	9.3%	10.2%	10.2%
CA-S	7.7%	8.3%	9.3%	7.5%
AZ APS	N/A	8.8%	9.9%	13.9%
NM EPE	N/A	7.9%	8.9%	19.4%
BPA	N/A	N/A	N/A	11.8%

Table ES2. 2026 Study Storage and Hybrid Results (expressed as a percentage of assumed interconnection capability)

Technology	1-Hour Storage	2-Hour Storage	4-Hour Storage	1-Hour PV Hybrid	2-Hour PV Hybrid	4-Hour PV Hybrid	1-Hour Wind Hybrid	2-Hour Wind Hybrid	4-Hour Wind Hybrid
CA-N	24.8%	33.9%	57.6%	34.3%	43.4%	65.0%	35.7%	26.8%	23.9%
CA-S	24.8%	33.9%	57.6%	33.4%	41.8%	63.3%	34.7%	24.1%	21.2%

13/ The at found LOLE for each study year utilizing the 2021 PSP was 0.

AZ APS	N/A	N/A	N/A	34.0%	43.1%	64.7%	38.1%	30.5%	27.6%
NM EPE	N/A	N/A	N/A	33.1%	42.2%	63.7%	43.5%	36.0%	33.1%
BPA	N/A	N/A	N/A	N/A	N/A	N/A	36.0%	28.5%	25.6%

Table ES3. 2030 Study Wind and Solar Results (expressed as a percentage of assumed interconnection capability)

Technology	BTM PV	Fixed PV	Tracking PV	Wind
CA-N	12.7%	14.0%	16.7%	14.4%
CA-S	10.2%	13.8%	15.6%	13.4%
AZ APS	N/A	10.7%	14.7%	16.5%
NM EPE	N/A	10.4%	12.6%	24.5%
BPA	N/A	N/A	N/A	15.4%

Table ES4. 2030 Study Storage and Hybrid Results (expressed as a percentage of assumed interconnection capability

Technology	1-Hour Storage	2-Hour Storage	4-Hour Storage	1-Hour PV Hybrid	2-Hour PV Hybrid	4-Hour PV Hybrid	1-Hour Wind Hybrid	2-Hour Wind Hybrid	4-Hour Wind Hybrid
CA-N	24.1%	32.6%	57.9%	38.0%	44.6%	70.1%	35.7%	28.3%	27.7%
CA-S	24.1%	32.6%	57.9%	37.9%	44.0%	70.9%	34.7%	27.3%	26.7%
AZ APS	N/A	N/A	N/A	31.8%	42.6%	68.1%	37.8%	30.4%	29.8%
NM EPE	N/A	N/A	N/A	34.0%	40.6%	66.1%	45.8%	38.5%	37.9%
BPA	N/A	N/A	N/A	N/A	N/A	N/A	36.7%	29.3%	28.7%

Table ES5. 2032 Study Wind and Solar Results (expressed as a percentage of assumed interconnection capability)

Technology	BTM PV	Fixed PV	Tracking PV	Wind
CA-N	15.3%	16.9%	17.3%	19.8%
CA-S	12.7%	14.2%	16.5%	14.2%
AZ APS	N/A	14.7%	16.9%	18.0%
NM EPE	N/A	13.9%	16.3%	27.4%
BPA	N/A	N/A	N/A	18.3%

Table ES6. 2032 Study Storage and Hybrid Results (expressed as a percentage of assumed interconnection capability)

Technology	1-Hour Storage	2-Hour Storage	4-Hour Storage	1-Hour PV Hybrid	2-Hour PV Hybrid	4-Hour PV Hybrid	1-Hour Wind Hybrid	2-Hour Wind Hybrid	4-Hour Wind Hybrid

CA-N	23.6%	30.5%	55.8%	36.1%	42.0%	67.2%	38.6%	32.1%	32.3%
CA-S	23.6%	30.5%	55.8%	35.7%	43.5%	68.7%	33.0%	26.5%	26.6%
AZ APS	N/A	N/A	N/A	32.8%	41.6%	66.8%	38.6%	30.4%	30.5%
NM EPE	N/A	N/A	N/A	35.1%	41.0%	66.2%	33.0%	39.7%	39.9%
BPA	N/A	N/A	N/A	N/A	N/A	N/A	37.1%	30.6%	30.7%

Joint IOU Recommendations

As noted above, given the issues identified above, the Joint IOUs do not support the use of the marginal ELCC values provided in the attached Report to guide procurement decisions.

The IOUs recommend that the CPUC begin a process to consider aligning resource reliability contribution counting in the various proceedings such as RPS, RA, and IRP.

Request For Commission Approval

Joint IOUs are requesting Commission approval of this Report to affirm compliance with D. 19-09-043.

Appendices

This advice letter contains one Appendix as listed below.

Appendix A: 2022 Effective Load Carrying Capacity (ELCC) Study Report

Tier Designation

Pursuant to D.19-09-043, OP 2, this advice letter is submitted with a Tier 2 designation.

Effective Date

The Joint IOUs believes this submittal is subject to Energy Division disposition and should be classified as Tier 2 (effective after staff approval) pursuant to GO 96-B. The Joint IOUs respectfully requests that the Commission approve this advice letter no later than July 31, 2022, which is 30 days from the date of this submittal.

Protests

Anyone wishing to protest this submittal may do so by letter sent electronically via E-mail, no later than July 21, 2022, which is 20 days after the date of this submittal. The Joint IOUs recommend that the protest period be reopened following the submittal of a supplemental advice letter containing the Final 2022 ELCC Report.

Protests must be submitted to:

CPUC Energy Division
ED Tariff Unit
E-mail: EDTariffUnit@cpuc.ca.gov

The protest shall also be electronically sent to the Joint IOUs via E-mail at the address shown below on the same date it is electronically delivered to the Commission:

For PG&E: Sidney Bob Dietz II
Director, Regulatory Relations
c/o Megan Lawson
E-mail: PGETariffs@pge.com

Maria V. Wilson, Counsel
E-mail: Maria.Wilson@pge.com

For SCE: Connor Flanigan
Managing Director, State Regulatory Operations
E-mail: AdviceTariffManager@sce.com

Tara S. Kaushik
Managing Director, Regulatory Relations
c/o Karyn Gansecki
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Carol Schmid-Frazee
Senior Attorney
E-mail: Carol.Schmidfrazee@sce.com

For SDG&E: Attn: Greg Anderson
Regulatory Tariff Manager
8330 Century Park Ct., CP31F
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E-mail: GAnderson@sdge.com

Paul A. Szymanski
Senior Attorney
Email: pszymanski@sdge.com

Any person (including individuals, groups, or organizations) may protest or respond to an advice letter (General Order 96-B, Section 7.4). The protest shall contain the following information: specification of the advice letter protested; grounds for the protest; supporting factual information or legal argument; name and e-mail address of the protestant; and statement that the protest was sent to the utility no later than the day on which the protest was submitted to the reviewing Industry Division (General Order 96-B, Section 3.11).

Notice

In accordance with General Order 96-B, Section IV, a copy of this advice letter is being sent electronically to parties shown on the attached list and the parties on the service list for Rulemaking 18-07-003. Address changes to the General Order 96-B service list should be directed to PG&E at email address PGETariffs@pge.com. For changes to any other service list, please contact the Commission's Process Office at (415) 703-2021 or at Process_Office@cpuc.ca.gov. Send all electronic approvals to PGETariffs@pge.com. Advice letter submittals can also be accessed electronically at: http://www.pge.com/tariffs/.

/S/

Sidney Bob Dietz II
Director, Regulatory Relations

Attachments

cc: Rulemaking 18-07-003

California Public Utilities Commission

ADVICE LETTER SUMMARY

ENERGY UTILITY

MUST BE COMPLETED BY UTILITY (Attach additional pages as needed)

Company name/CPUC Utility No.: Pacific Gas and Electric Company (ID U39 E)

Utility type:

- ☑ ELC
- ☐ GAS
- ☐ WATER
- ☐ PLC
- ☐ HEAT

Contact Person: Kimberly Loo
Phone #: (415)973-4587
E-mail: PGETariffs@pge.com
E-mail Disposition Notice to: KELM@pge.com

EXPLANATION OF UTILITY TYPE

ELC = Electric GAS = Gas
PLC = Pipeline HEAT = Heat
WATER = Water

(Date Submitted / Received Stamp by CPUC)

Advice Letter (AL) #: 6636-E, et al.

Tier Designation: 2

Subject of AL: Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company's Effective Load Carrying Capability Study Submission

Keywords (choose from CPUC listing): Compliance

AL Type: ☐ Monthly ☐ Quarterly ☐ Annual ☑ One-Time ☐ Other:

If AL submitted in compliance with a Commission order, indicate relevant Decision/Resolution #:
D.19-09-043

Does AL replace a withdrawn or rejected AL? If so, identify the prior AL: No

Summarize differences between the AL and the prior withdrawn or rejected AL:

Confidential treatment requested? ☐ Yes ☑ No

If yes, specification of confidential information:
Confidential information will be made available to appropriate parties who execute a nondisclosure agreement. Name and contact information to request nondisclosure agreement/ access to confidential information:

Resolution required? ☐ Yes ☑ No

Requested effective date: 7/31/22

No. of tariff sheets: 0

Estimated system annual revenue effect (%): N/A

Estimated system average rate effect (%): N/A

When rates are affected by AL, include attachment in AL showing average rate effects on customer classes (residential, small commercial, large C/I, agricultural, lighting).

Tariff schedules affected: N/A

Service affected and changes proposed[1]: N/A

Pending advice letters that revise the same tariff sheets: N/A

[1]Discuss in AL if more space is needed.

Clear Form

Protests and correspondence regarding this AL are to be sent via email and are due no later than 20 days after the date of this submittal, unless otherwise authorized by the Commission, and shall be sent to:

California Public Utilities Commission
Energy Division Tariff Unit Email:
EDTariffUnit@cpuc.ca.gov

Contact Name: Sidney Bob Dietz II, c/o Megan Lawson
Title: Director, Regulatory Relations
Utility/Entity Name: Pacific Gas and Electric Company

Telephone (xxx) xxx-xxxx:
Facsimile (xxx) xxx-xxxx:
Email: PGETariffs@pge.com

Contact Name:
Title:
Utility/Entity Name:

Telephone (xxx) xxx-xxxx:
Facsimile (xxx) xxx-xxxx:
Email:

CPUC
Energy Division Tariff Unit
505 Van Ness Avenue
San Francisco, CA 94102

Clear Form

Attachment 1

Joint IOU ELCC Study

2022 Effective Load Carry Capacity (ELCC) Study Report

Final Report

7/01/2022

PREPARED FOR

California Investor-Owned Utilities
Southern California Edison Company
Pacific Gas and Electric Company
San Diego Gas & Electric Company

PREPARED BY

Kevin Carden
Alex Krasny Dombrowsky
Cole Benson
Astrapé Consulting

Disclaimer: This report was prepared by the authors for the California Investor-Owned Utilities (CA IOUs) which include San Diego Gas & Electric Company, Southern California Edison Company, and Pacific Gas and Electric Company. It is provided as is, and Astrapé Consulting and CA IOUs disclaim any and all express or implied representations or warranties of any kind relating to the accuracy, reliability, completeness, or currency of the data, conclusions, forecasts or any other information in this report. Readers of this report should independently verify the accuracy, reliability, completeness, currency, and suitability for any particular purpose of any information in this report.

Furthermore, this report is not intended, nor should it be read as either comprehensive or fully applicable to any specific opportunity in the CAISO market, as all opportunities have idiosyncratic features that will be impacted by actual market conditions. Readers of this report should seek independent expert advice regarding any information in this report and any conclusions that could be drawn from this report. The report itself in no way offers to serve as a substitute for such independent expert advice.

To the fullest extent permitted by law, Astrapé Consulting and CA IOUs, along with their respective directors, officers, and employees, shall not be liable for any errors, omissions, defects, or misrepresentations in the information contained in this report, whether intentional or unintentional, or for any loss or damage suffered by persons who use or rely on such information or any conclusions that could be drawn from the report that turn out to be inaccurate (including by reason of negligence, negligent misstatement, or otherwise).

By reviewing this report, the reader agrees to accept the terms of this disclaimer.

Acknowledgement: We acknowledge the valuable contributions of many individuals to this report and to the underlying analysis, including peer review and input offered by the CA IOUs staff. We especially would like to acknowledge the analytical, technical, and conceptual contributions of Matt O'Connell, Matthew Kawatani, Daniel Hopper, Effat Moussa, Habibou Maiga, Jan Strack, Anupama Pandey, Grace Li, Joseph Yan, James Elias, Alan Soe, James Barrios, and Amy Li.

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AZ APS	Arizona Public Service
BANC	Balancing Authority of Northern California
BCHA	British Columbia Hydro Authority
BPA	Bonneville Power Administration
BTM PV	Behind the Meter PV
CAISO	California Independent System Operator
CA-N	Northern California (PGE Valley and PGE Bay)
CA-S	Southern California (SDGE and SCE)
CFE	Comisión Federal de Electricidad
CPUC	California Public Utilities Commission
Decision	Decision Adopting Modeling Requirements to Calculate Effective Load Carrying Capability Values for Renewables Portfolio Standard Procurement
EE	Energy Efficiency
EFOR	Equivalent Forced Outage Rate
EIA	Energy Information Administration
ELCC	Effective Load Carrying Capability
EV	Electric Vehicle
GW	Gigawatts
IEPR	Integrated Energy Policy Report
IID	Imperial Irrigation District
ILR	Inverter Loading Ratio
IOUs	California Investor-Owned Utilities
IPCO	Idaho Power Company
IRP	Integrated Resource Plan
LADWP	Los Angeles Department of Water and Power
LOLE	Loss of Load Expectation
MW	Megawatts
NEVP	Nevada Power Company
NM EPE	New Mexico Area and El Paso Electric
NWMT	NorthWestern Energy
NREL	National Renewable Energy Laboratory
PACE	PacifiCorp East

PACW	PacifiCorp West
PGE Bay	Pacific Gas and Electric Bay
PGE Valley	Pacific Gas and Electric Valley
PSCO	Public Service Company of Colorado
PSP	Preferred System Plan
PV	Photovoltaic
SAM	System Advisor Model
SCE	Southern California Edison
SDGE	San Diego Gas & Electric
SERVM	Strategic Energy and Risk Valuation Model
SRP	Salt River Project
TEPC	Tucson Electric Power Company
TIDC	Turlock Irrigation District
TOU	Time-of-Use
WACM	Western Area Power Administration – Colorado/Missouri Region
WALC	Western Area Power Administration – Lower Colorado Region

EXECUTIVE SUMMARY

As directed in the "Decision Adopting Modeling Requirements to Calculate Effective Load Carrying Capability Values for Renewables Portfolio Standard Procurement" ("Decision") on October 3rd, 2019, in California Public Utilities Commission's ("CPUC" or "Commission") Renewables Portfolio Standard ("RPS") Proceeding Rulemaking. 18-07-003, the Commission ordered the California Investor-Owned Utilities ("IOUs"), which comprise of Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company, to perform an annual Effective Load Carrying Capability ("ELCC") study.[1]

In accordance with the Decision, Astrapé Consulting, acting as contractor, provided to the IOUs a report that updates the ELCC values for the resource classes and class subtypes located in, or deliverable to, the CAISO Balancing Authority Area, based on an assumed baseline resource list, details the input assumptions (e.g., load, installed capacity), explains the methodology used to calculate the ELCC values, and compares the impact of the different locations on the same technology types.[2]

As directed in the Decision, the 2021 IRP's Preferred System Plan ("PSP") was used for the baseline resource list for the analysis presented here.

The marginal ELCC values presented in this report are reflective of the system studied and are not applicable to a system with a substantially different load and resource mix. The marginal ELCC values in this report represent the annual contribution towards reliability of a given increment of generation capacity.

This report is being provided with one important caveat:

> **PSP reserves in excess of what is needed for reliability deflate the value of storage and inflate the value of renewables.** The reliability of the system in each study year before calculating ELCCs is significantly better than the industry standard 0.1 Loss of Load Expectation (LOLE).[3] This created a challenge for establishing the base cases in SERVM since capacity value is typically only measured when reliability is at or near target. The Decision also requires that the ELCC values be calculated with the system at 0.1 LOLE.[4] In order to meet this requirement while utilizing the resource mix outlined in the PSP, the only option was to increase loads dramatically to tune reliability to 0.1 LOLE. The load adjustment was applied as a scaler and ranged from 3.6 GW in 2026 to 5.9 GW in 2032. This then becomes the starting point for analyzing ELCCs. The size of the load adjustment is approximately equal to the amount by which resources in the PSP exceed what is required to achieve a 0.1 LOLE. Since marginal capacity is primarily batteries, the system in 2032 has over 5GW more battery capacity than what is required to achieve a 0.1 LOLE. Overbuilding the battery portfolio begins to exhaust the potential for batteries to supply resource adequacy which means

[1] See Decision at Ordering Paragraph 1 (adopting modelling requirements applicable to the Report) and Ordering Paragraph 2 (ordering an annual report unless directed otherwise) 2. The Decision is available at http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M316/K882/316882092.PDF

[2] Pacific Gas and Electric Bay, Pacific Gas and Electric Valley, Southern California Edison, San Diego Gas & Electric, Arizona Public Service, New Mexico Area and El Paso Electric, and Bonneville Power Administration, respectively.

[3] The at found LOLE for each study year utilizing the 2021 PSP was 0.

[4] D. 19-09-043

the ELCC of incremental batteries will be much lower than if the starting battery portfolio was properly sized to meet reliability objectives.[5]

Conversely, renewable ELCCs are likely higher than reasonable. When batteries are overbuilt, the ELCC modeling values resources that produce energy to charge the batteries (the model is then better able to optimize the dispatch of those overbuilt batteries to provide grid reliability**)**. An increment of renewable resources (which are added to the PSP to determine the renewable resources' ELCC values) thereby produces an artificially large contribution to grid reliability. As such, renewable ELCCs are likely inflated, while the battery and hybrid ELCCs are deflated relative to what they would be had the PSP been developed to meet, but not exceed, the 0.1 LOLE standard.

Based on the prescribed methodology and notwithstanding the reservation discussed above, the major findings of this study are:

- **Due to a number of input assumption changes and a significantly higher storage penetration, relative to previous studies, the marginal ELCC of hybrid resources has declined:** As outlined in the Input Assumptions section of this report, compared to the 2021 study, the storage penetration of all study years has increased along with thermal resources retiring. The 2026 portfolio in this study has approximately 2GW of additional storage compared to the 2030 assumptions in last year's study. This study also included a 5% forced outage rate on batteries and a reduction in the late afternoon import limit from 5GW to 4GW. In last year's study, the batteries were not modeled with a forced outage rate. The effect of these portfolio changes is a reduction in the marginal ELCC of storage resources and subsequently, hybrid resources. Standalone storage ELCCs in the first study year are less than 60%. Figure ES1 below shows why this reduction in the marginal ELCC of storage is to be expected. Figure ES1 contains an illustrative dispatch of the 2030 battery amounts from the 2021 study and the 2022 study on a high net load day.[6] The increased battery penetration increases the duration and volume of both charging and discharging, meaning incremental storage additions would be expected to operate for significant periods of the day. While anecdotal, this observation is confirmed by the SERVM simulations which demonstrate meaningfully lower ELCCs for short duration storage.
    - **Sensitivity results clearly indicate the challenge in establishing the base case as caveated above and their subsequent impact on ELCC results.** A sensitivity was run with 4 GW less short duration battery to estimate ELCCs if significantly less storage capacity is built by 2026.[7,8] This increased the ELCC for marginal storage resources from

[5] Given the PSP assumptions and methodology, the overbuilt PSP portfolio creates issues in the ELCC calculation for various resources. The root cause of the overbuild is the RESOLVE capacity expansion modeling in the IRP process which relies on the PRM, a capacity requirement not supported by LOLE modeling and an uncalibrated ELCC surface. With a high penetration of energy limited resources such as energy storage, solar and wind resources to meet California's decarbonization objectives, a more rigorous IRP modeling approach is required to ensure that both capacity constraints and energy sufficiency in the capacity expansion and production cost modeling are appropriately accounted for in developing a PSP that meets, but does not exceed, the 0.1 LOLE reliability requirement used in the IRP proceeding.

[6] Unless noted otherwise, net load will be defined as gross load less BTM PV, utility scale solar PV, and wind generation.

[7] Battery capacity removed was all 4-hour duration.

[8] The LOLE of this base case was approximately 0.04. In order to calibrate the system to 0.1 LOLE, Astrapé estimates another 1 GW of storage would need to be removed.

less than 60% to above 80% and decreased the ELCCs for marginal solar and marginal wind by approximately 5%.

- **Conversely, the resulting energy-constrained environment from the increased storage penetration means that the renewable technologies in this report show increased ELCC values relative to other ELCC studies.** This is largely in part because these renewable resources provide the energy during pre-peak hours to fully charge and delay the discharge of batteries to hours having the highest reliability need. The resulting improvement in grid reliability is attributable to renewable technologies that provide the charging energy.
- **Hybrid ELCCs no longer show a maximum reliability value.** In the 2021 study, hybrid resources were effectively showing the maximum reliability value for a resource that is not forced to run in all hours in which it is available.[9] This is because reliability events were not primarily driven by energy constraints. Four-hour duration batteries were not getting exhausted, and the system was able to use 1–2-hour batteries to serve ancillary service needs during emergencies, so the battery contribution to reliability was significant. Since the modeled maximum output of the hybrid facility was the same size as the battery, no additional reliability value was shown for the associated renewable energy. The ELCCs for 1-4-hour wind and solar hybrids were 85-90% in most years.[10] In this study, reliability is primarily driven by exhaustion of storage resources, so the reliability value of hybrids reflects additive value from the energy of the renewable and the capacity of the battery. The ELCCs for the hybrid resources are essentially equivalent to the sum of the renewable and battery ELCCs.[11] This heuristic is applied to develop ELCCs for out-of-state hybrid resources.
- **Out-of-state wind ELCCs continue to reflect the challenges with finding dependable data that have been identified in prior reports.** While the California wind projects are calibrated to historical production data and reflect observed lower output during extreme weather, the out-of-state wind profiles are constructed from public data sets that cannot be readily validated against production data. The out-of-state wind ELCCs are modestly higher than the values provided in the 2021 study. The values in aggregate are likely reasonable, however the regional distinctions may not reflect actual reliability differences.
- **Hybrid wind resource ELCCs show a significant decline due to new wind profiles and system energy constraints.** Wind profiles included in this study combined with the more prevalent energy constraints on the system reduced the potential for wind hybrids that must be charged from on-site wind energy to supply reliability value. On particular reliability-constrained days, the daily available wind energy prior to the net load peak represents only 1 hour of on-site battery energy. storage capability. This means that for wind hybrid facilities to maximize the reliability contribution of batteries, the batteries could only be sized at a maximum ratio of 1 MWh of battery to 4 MW of wind. This is a more stringent requirement than has been identified in prior studies which suggested that 1:1 or 1:2 ratios would be adequate to supply reliability.
  - This sizing constraint influences the heuristic that should be used to calculate wind hybrid ELCCs. The wind hybrid ELCCs included in this report reflect the heuristic of 1 MWh battery: 4 MW wind. This results in less battery capacity for longer duration

[9] The 2021 Study is available for download at https://www.astrape.com/?ddownload=9255

[10] In that study, the reliability contribution was compared to the effects of flat load adders in every hour. Since the hybrids were only dispatched in emergencies, other conventional units had to operate more to cover the load adder which produced additional generator outages, reducing the overall reliability contribution of the hybrid which resulted in ELCCs of 85-90%.

[11] All PV hybrid technologies show a 1-4% less value than the sum of the battery and solar portions. This is due to both the solar charging constraint and the interconnection size.

configurations, and thus declining ELCCs when measured as a percentage of interconnection size.[12]

Figure ES1. Storage Illustrative Dispatch

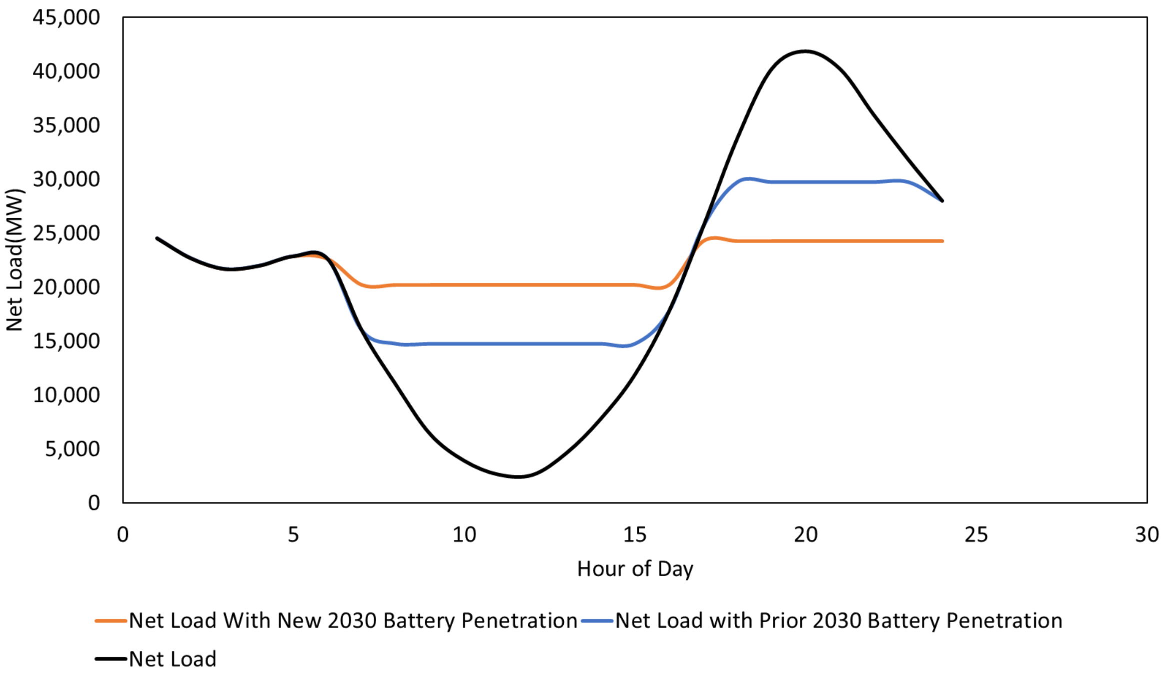


Table ES1. 2026 Study Wind and Solar Results (expressed as a percentage of assumed interconnection capability)

Technology	BTM PV	Fixed PV	Tracking PV	Wind
CA-N	8.8%	9.3%	10.2%	10.2%
CA-S	7.7%	8.3%	9.3%	7.5%
AZ APS	N/A	8.8%	9.9%	13.9%
NM EPE	N/A	7.9%	8.9%	19.4%
BPA	N/A	N/A	N/A	11.8%

[12] Wind hybrid example ELCC calculation:

Installed Wind Capacity (MW)	Installed Battery Capacity (MW)	Battery Duration (Hours)	Wind ELCC (MW)	Battery ELCC (MW)	Combined ELCC (MW)	Combined ELCC (% of Interconnection)
500	500	1	51	124	175	34.9%
500	250	2	51	85	135	27.1%
500	125	4	51	72	123	24.6%

Table ES2. 2026 Study Storage and Hybrid Results (expressed as a percentage of assumed interconnection capability)

Technology	1-Hour Storage	2-Hour Storage	4-Hour Storage	1-Hour PV Hybrid	2-Hour PV Hybrid	4-Hour PV Hybrid	1-Hour Wind Hybrid	2-Hour Wind Hybrid	4-Hour Wind Hybrid
CA-N	24.8%	33.9%	57.6%	34.3%	43.4%	65.0%	35.7%	26.8%	23.9%
CA-S	24.8%	33.9%	57.6%	33.4%	41.8%	63.3%	34.7%	24.1%	21.2%
AZ APS	N/A	N/A	N/A	34.0%	43.1%	64.7%	38.1%	30.5%	27.6%
NM EPE	N/A	N/A	N/A	33.1%	42.2%	63.7%	43.5%	36.0%	33.1%
BPA	N/A	N/A	N/A	N/A	N/A	N/A	36.0%	28.5%	25.6%

Table ES3. 2030 Study Wind and Solar Results (expressed as a percentage of assumed interconnection capability)

Technology	BTM PV	Fixed PV	Tracking PV	Wind
CA-N	12.7%	14.0%	16.7%	14.4%
CA-S	10.2%	13.8%	15.6%	13.4%
AZ APS	N/A	10.7%	14.7%	16.5%
NM EPE	N/A	10.4%	12.6%	24.5%
BPA	N/A	N/A	N/A	15.4%

Table ES4. 2030 Study Storage and Hybrid Results (expressed as a percentage of assumed interconnection capability

Technology	1-Hour Storage	2-Hour Storage	4-Hour Storage	1-Hour PV Hybrid	2-Hour PV Hybrid	4-Hour PV Hybrid	1-Hour Wind Hybrid	2-Hour Wind Hybrid	4-Hour Wind Hybrid
CA-N	24.1%	32.6%	57.9%	38.0%	44.6%	70.1%	35.7%	28.3%	27.7%
CA-S	24.1%	32.6%	57.9%	37.9%	44.0%	70.9%	34.7%	27.3%	26.7%
AZ APS	N/A	N/A	N/A	31.8%	42.6%	68.1%	37.8%	30.4%	29.8%
NM EPE	N/A	N/A	N/A	34.0%	40.6%	66.1%	45.8%	38.5%	37.9%
BPA	N/A	N/A	N/A	N/A	N/A	N/A	36.7%	29.3%	28.7%

Table ES5. 2032 Study Wind and Solar Results (expressed as a percentage of assumed interconnection capability)

Technology	BTM PV	Fixed PV	Tracking PV	Wind
CA-N	15.3%	16.9%	17.3%	19.8%
CA-S	12.7%	14.2%	16.5%	14.2%
AZ APS	N/A	14.7%	16.9%	18.0%
NM EPE	N/A	13.9%	16.3%	27.4%
BPA	N/A	N/A	N/A	18.3%

Table ES6. 2032 Study Storage and Hybrid Results (expressed as a percentage of assumed interconnection capability)

Technology	1-Hour Storage	2-Hour Storage	4-Hour Storage	1-Hour PV Hybrid	2-Hour PV Hybrid	4-Hour PV Hybrid	1-Hour Wind Hybrid	2-Hour Wind Hybrid	4-Hour Wind Hybrid
CA-N	23.6%	30.5%	55.8%	36.1%	42.0%	67.2%	38.6%	32.1%	32.3%
CA-S	23.6%	30.5%	55.8%	35.7%	43.5%	68.7%	33.0%	26.5%	26.6%
AZ APS	N/A	N/A	N/A	32.8%	41.6%	66.8%	38.6%	30.4%	30.5%
NM EPE	N/A	N/A	N/A	35.1%	41.0%	66.2%	33.0%	39.7%	39.9%
BPA	N/A	N/A	N/A	N/A	N/A	N/A	37.1%	30.6%	30.7%

INPUT ASSUMPTIONS

STUDY REQUIREMENTS

Astrapé Consulting was contracted by the California Investor-Owned Utilities to examine the annual marginal ELCC values for the resource classes and locations found in Table 1 for 3 study years (2026, 2030, and 2032). For this report, all values are aggregated to the CAISO level until further analysis can be performed to more accurately disaggregate the reliability contribution of resources in each zone.

Table 1. Resource Class and Location Combinations Calculated

Technology	CA-N	CA-S	AZ APS	NM EPE	BPA
BTM PV	X	X			
Fixed PV	X	X	X	X	
Tracking PV	X	X	X	X	
1-Hour Tracking PV Hybrid	X	X	X	X	
2-Hour Tracking PV Hybrid	X	X	X	X	
4-Hour Tracking PV Hybrid	X	X	X	X	
Wind	X	X	X	X	X
1-Hour Wind Hybrid	X	X	X	X	X
2-Hour Wind Hybrid	X	X	X	X	X
4-Hour Wind Hybrid	X	X	X	X	X
1-Hour Standalone Storage	X	X			
2-Hour Standalone Storage	X	X			
4-Hour Standalone Storage	X	X			

Astrapé performed simulations to determine the ELCC values using the Strategic Energy and Risk Valuation Model (SERVM). The base database was constructed using the 2021 Preferred System ("PSP") as directed in the "Decision Adopting Modeling Requirements to Calculate Effective Load Carrying Capability Values for Renewables Portfolio Standard Procurement' ("Decision") on October 3rd, 2019, in California Public Utilities Commission's ("CPUC's") RPS Proceeding Rulemaking. 18-07-003.[13,14] A base case of the system was first established by calibrating the CAISO region to a reliability level of 0.1 Loss of Load Expectation (LOLE) for each of the three study years (2026, 2030, and 2032) by scaling the hourly loads of each study year. LOLE was determined as the expected number of days per year where load and ancillary service requirements exceeded available generation, as measured over thousands of hourly chronological simulations. Using the base case from each respective study year, multiple technology and locational ELCC values were studied. Table 2 contains the resource mix from the 2021 PSP.

[13] https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M449/K173/449173804.PDF

[14] The Decision is available at http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M316/K882/316882092.PDF

Table 2. Study Year Resource Mix

Unit Category	Total Capacity by Year (MW)		
	2026	2030	2032
Battery Storage	**11,908**	**12,926**	**13,984**
2-Hour	150	150	150
4-Hour	8,362	9,633	9,633
6-Hour	3,396	3,143	4,201
BTM Battery Storage	**1,687**	**2,592**	**2,592**
Thermal	**26,158**	**26,158**	**25,797**
Nuclear	**635**	**635**	**635**
DR/EE	**7,657**	**8,889**	**9,428**
EV	**-2,505**	**-3,169**	**-3,676**
Hydro	**6,619**	**6,619**	**6,619**
PSH	**2,099**	**3,099**	**3,099**
Other Renewable	**2,667**	**3,664**	**3,664**
Wind	**10,867**	**12,442**	**13,955**
BTM PV	**19,297**	**23,741**	**26,023**
Solar Thermal	**997**	**997**	**997**
Solar Fixed	**12,585**	**12,585**	**12,585**
Solar Tracking	**11,118**	**14,119**	**17,280**
Hybrid	**2,742**	**3,008**	**3,008**
Hybrid Storage	**1,203**	**1,310**	**1,310**
Total	**94,276**	**105,339**	**117,944**

** Other Renewable includes biogas, biomass, and geothermal units*

As shown in Table 2, the SERVM database populated by CPUC with PSP data showed a significant portion of the battery capacity in all three years to have longer than 4-hours of duration. If this duration is longer than the duration of the resources that are actually built, the storage reliability contribution of marginal 4-hour batteries would be less than what is shown in this report.

Table 3 shows the differences for battery, wind, and solar capacities between the 2021 and 2022 studies for each study year.[15] The PSP reflects significant additions of capacity across several technologies.

Table 3. Study Year Battery, Wind, and Solar Capacity Differences Between 2021 and 2022 Study

Unit Category	Total Capacity Delta by Year (MW)*	
	2026	2030
Battery Storage*	**2,842**	**788**
1-Hour	-68	-68
2-Hour	-869	-1,195
4-Hour	383	-1,092

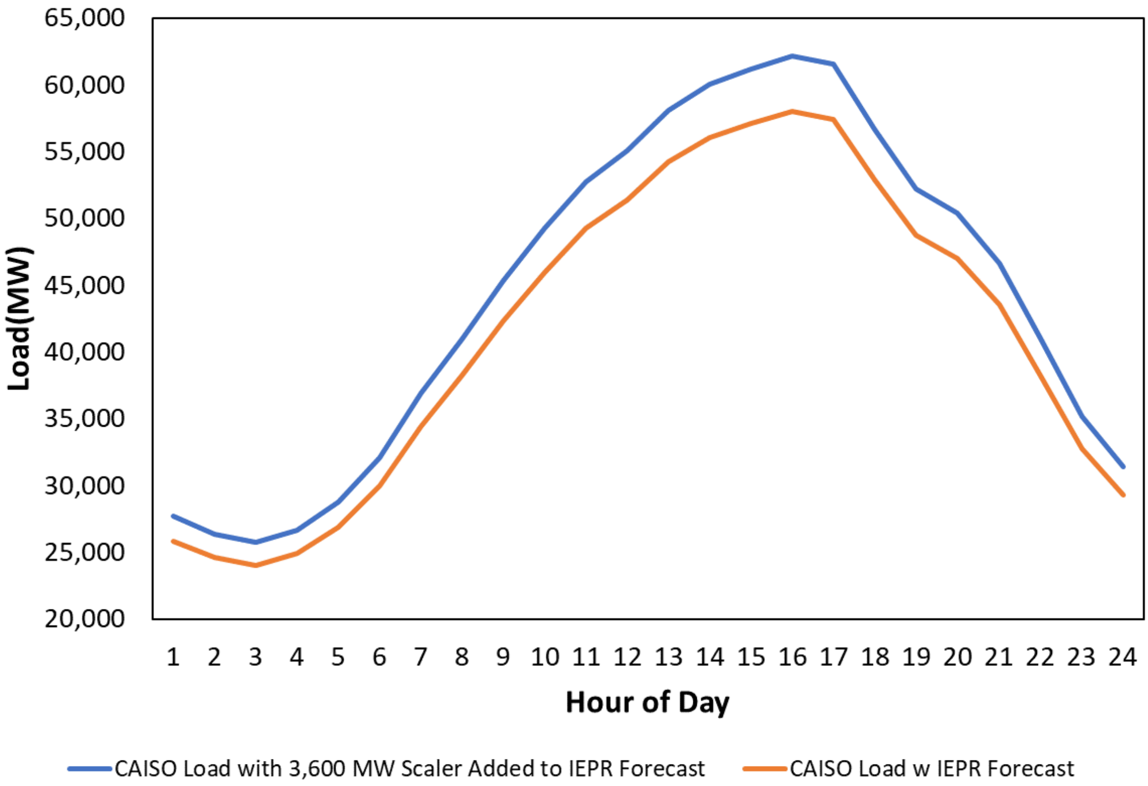
[15] The 2022 capacity delta calculations include 6-Hour battery storage, BTM Battery Storage, Hybrid, and Hybrid storage which were unit categories that were not utilized in the 2021 study.

6-Hour	3,396	3,143
BTM Battery Storage*	**1,687**	**2,592**
Wind	**679**	**1,548**
BTM PV	**3,141**	**3,683**
Solar Thermal	**-240**	**-240**
Solar Fixed	**-664**	**-1,418**
Solar Tracking	**2,719**	**3,457**
Hybrid*	**2,742**	**3,008**
Hybrid Storage*	**1,203**	**1,310**
PSH	**-473**	**527**
Total	**16,479**	**16,043**

*Positive values represent an increase in capacity. The BTM Battery Storage, Hybrid, and Hybrid Storage categories were not used in the previous study.

Load was added in the 2022 study each year to achieve 0.1 LOLE. Instead of adding load uniformly across all hours as was done in previous studies, the load adjustment was applied by increasing the load forecast. The load forecast is applied in SERVM by scaling the median peak of the 1998-2017 load seed shapes so that it is equal to the load forecast. The resulting multiplier to scale each weather year's peak is then applied to the rest of the hours of every year. Since a multiplier is used to scale, all hours less than the median will increase by less than the peak load forecast change and hours above the median peak forecast will increase by slightly more than the peak load forecast change. Figure 1 below shows the difference from the peak load day in 2017 after the base IEPR load forecast and the IEPR load forecast with a 3,600 MW adjustment are applied.

Figure 1. Load Scaling Illustration



The peak load adjustments are shown in Table 4.

Table 4. Peak Load Adjustment to Achieve 0.1 LOLE

Study Year	Load Adjustment (MW)
2026	3,600
2030	6,100
2032	5,900

MARGINAL ELCC METHODOLOGY

As part of the reliability calibration, a perfect 500 MW resource was also included in the simulations to perform the ELCC calculation.[16] After calibrating the system, the study technology resource was added to the system. The following equation was used to calculate the marginal ELCC value:

$$ELCC = \frac{Perfect\ Capacity\ Removed\ (MW)}{Study\ Technology\ Resource\ Added^{17}\ (MW)} * 100\%$$

The process is as follows, using illustrative values and a solar resource:

1. Add a 500 MW solar resource to system calibrated to 0.1 LOLE
    a. LOLE decreases to 0.08, indicating an improvement in reliability
2. Remove 50 MW of load every hour
    a. LOLE increases to 0.1, indicating a return to original reliability

[16] Load was scaled by an additional 500 MW to accommodate the perfect resource for comparison.
[17] Limited by interconnection capability for combined hybrid projects.

3. The ELCC is calculated as the ratio of step 2 and step 1
    a. 50 MW / 500 MW = 10% ELCC

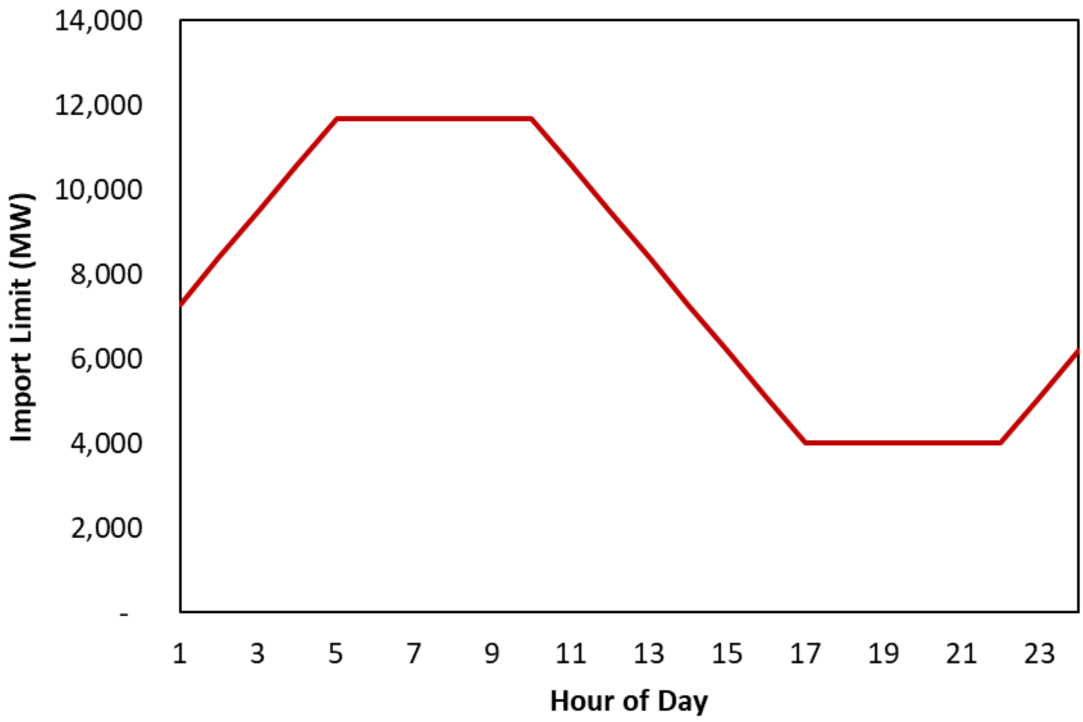
REGIONS

CAISO is separated into 4 distinct regions in SERVM: PGE Bay, PGE Valley, SCE, and SDGE. The following external regions were included in the study to incorporate the impact of imports on CAISO reliability:

- Arizona Public Service Company (AZ APS)
- Balancing Authority of Northern California (BANC)
- British Columbia Hydro Authority (BCHA)
- Bonneville Power Administration (BPA)
- Comisión Federal de Electricidad (CFE)
- Imperial Irrigation District (IID)
- Idaho Power Company (IPCO)
- Los Angeles Department of Water and Power (LADWP)
- Nevada Power Company (NEVP)
- NorthWestern Energy (NWMT)
- New Mexico Area and El Paso Electric (NM EPE)
- PacifiCorp East (PACE)
- PacifiCorp West (PACW)
- Portland General
- Public Service Company of Colorado (PSCO)
- Salt River Project (SRP)
- Tucson Electric Power Company (TEPC)
- Turlock Irrigation District (TIDC)
- Western Area Power Administration – Colorado/Missouri Region (WACM)
- Western Area Power Administration – Lower Colorado Region (WALC)

Imports from neighbors are constrained by both energy and transmission availability. These two constraints are represented by a consolidated profile. The base case energy availability assumption provided by the CPUC is that 4,000 MW will be available during hours ending 17 to 22. Historical data demonstrates that imports rarely ramp by more than 1,000 MW per hour, so the energy availability was scaled before and after this window by 1,000 MW per hour. The transmission availability is assumed to be 11,665 MW which sets the maximum import in other hours.

Figure 2. Modeled Maximum Import Limit



All external regions described above were not explicitly modeled, instead North and South neighbor assistance was modeled as a proxy unit. Table 5 defines which Tier 1 (one tie away) neighboring entities were classified as North and which neighbors were classified as South.

Table 5. Region Definitions for Proxy Neighbor Assistance

Region	Tier 1 Entity
North	BANC
	BPA
	PACW
	TIDC
South	AZ APS
	CFE
	IID
	LADWP
	NEVP
	SRP
	WALC

A time series of imports into CAISO was developed for North and South Tier 1 neighboring entities separately and was based on historic interchange as a function of CAISO net load by season, where net load is calculated as load minus the sum of wind, utility scale solar PV, and behind the meter PV ("BTM PV"). Supporting information for CAISO was retrieved from the Energy Information Administration

("EIA") website based on January 2020 to February 2021 actual data.[18] The relationship between net load and net imports was applied to all 20 weather years studied (1998 to 2017) so that each weather year included a unique profile of assistance from neighboring areas reflective of each year's renewable output and weather conditions.[19] While historical imports often showed more than 4 GW during peak net load hours, total imports were capped as shown in Figure 2 to match the expected future generation availability constraint of 4 GW between hours ending 17 and 22. The average hourly imports as a function of net load during hours ending 17 to 22 are provided in Figure 3. In most summer net load conditions, the available 4GW of external energy is fully utilized.

Figure 3. Average Hourly Imports by Zone

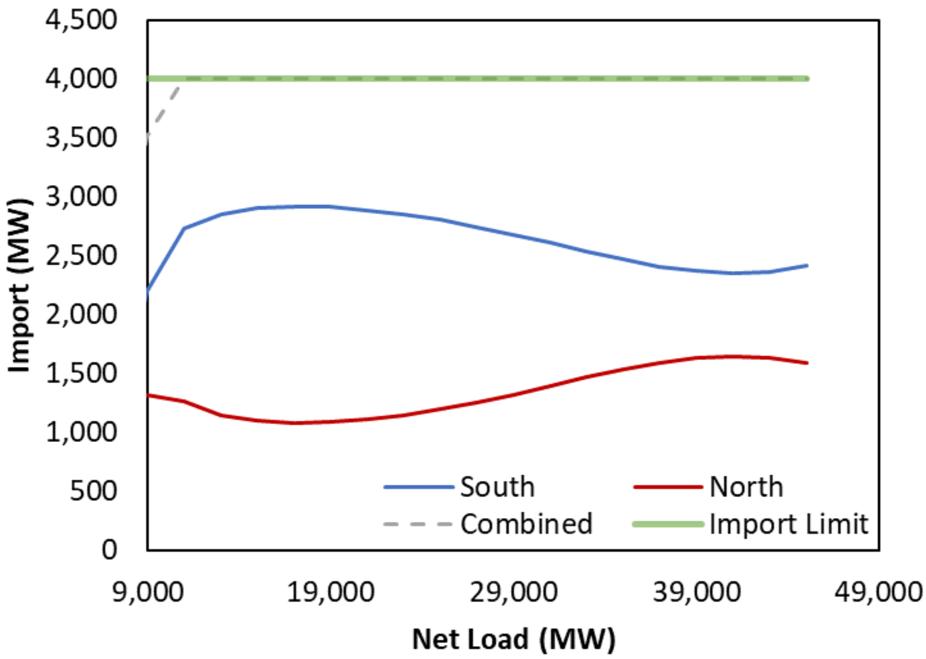
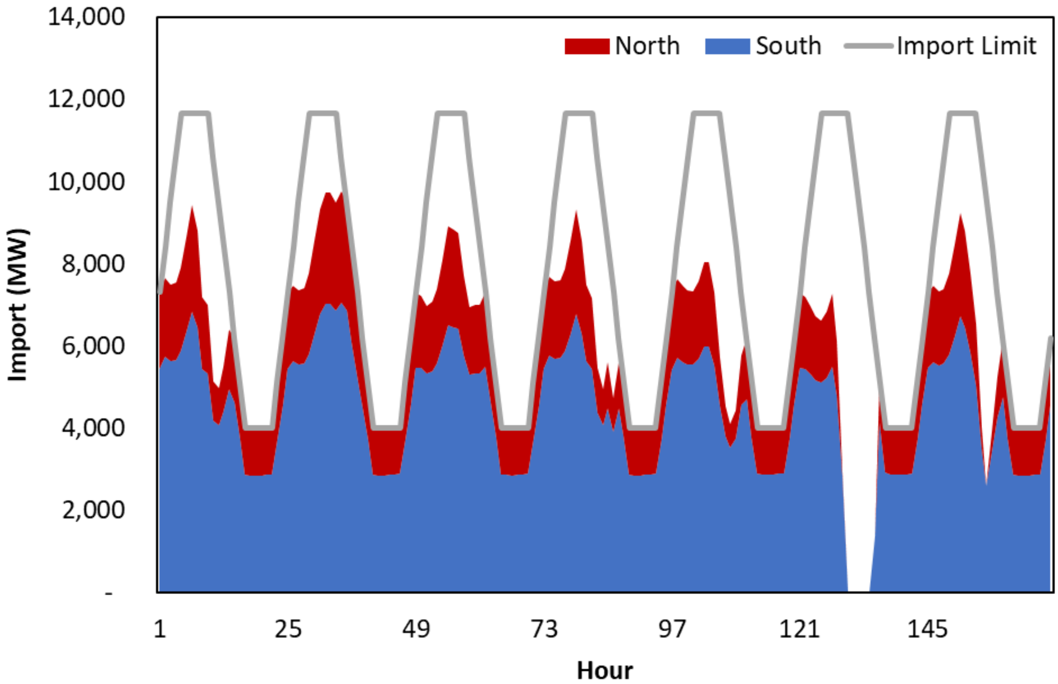


Figure 4 provides an illustrative example of a week of imports for both the North and South zones.

[18] Data is available at https://www.eia.gov/beta/electricity/gridmonitor/dashboard/electric_overview/balancing_authority/CISO

[19] Net imports are exports minus imports. The study simulations do not capture periods of net export, but as a resource adequacy study, those periods are not relevant for ELCC calculations.

Figure 4. Imports – 1 Week Illustrative Example



LOAD SHAPES

To capture the effects of weather uncertainty, synthetic load shapes were originally developed by CPUC for twenty historical weather years (1998 – 2017) to reflect the impact of weather on load for all four CAISO regions.[20] The synthetic load profiles represent expected load given customer electric use patterns in the study year if historic weather conditions were to occur. The synthetic shapes are scaled such that the median peak of all shapes matches the zonal 2020 IEPR load forecast with the load adjustment outlined above applied. The original forecast peak load by study year for each CAISO region is displayed in Table 6.

Table 6. Gross Peak Load by Weather Year and Region

Region	Peak Load (MW)		
	2026	2030	2032
PGE Bay	10,128	10,557	10,851
PGE Valley	14,723	15,264	15,656
SCE	27,447	28,383	28,978
SDGE	4,945	5,142	5,248
Non-Coincident CAISO	57,243	59,356	60,733
Coincident CAISO	55,402	57,414	58,761

Table 7 summarizes the differences in the peak load assumptions between the 2021 and 2022 studies.

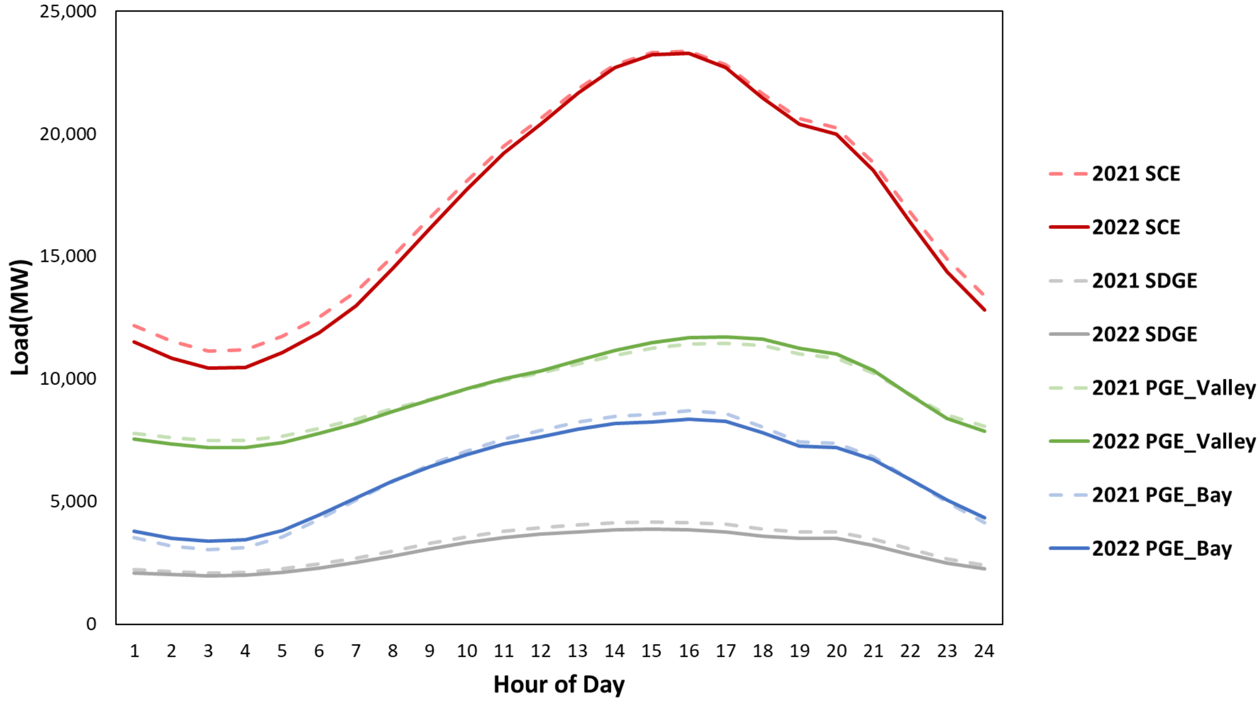
[20] https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/long-term-procurement-planning/2019-20-irp-events-and-materials/unified-ra-and-irp-modeling-datasets-2021

Table 7. Peak Load Delta between 2021 and 2022 Studies by Study Year and Region

Region	Peak Load Delta (MW)[21] 2026	2030
PGE Bay	-235	-221
PGE Valley	330	282
SCE	-188	-370
SDGE	-362	-375
CAISO	-455	-674

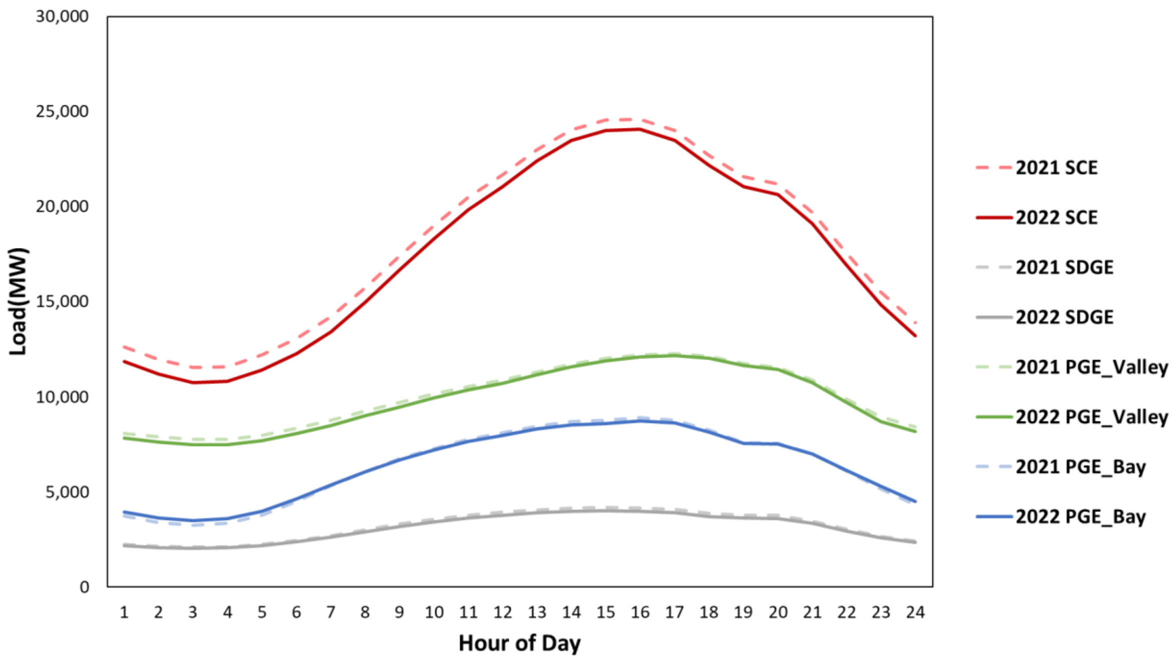
A comparison of the average August daily load shape for all study regions for the 2026 and 2030 study year from the 2021 and 2022 studies are provided in Figure 5 and Figure 6.

Figure 5. August Average Daily Shape Comparison for 2026 Study Year – Inclusive of Load Scaling



[21] Positive indicates higher values in 2021 study and negative indicates higher values in the 2020 study.

Figure 6. August Average Daily Shape Comparison for 2030 Study Year – Inclusive of Load Scaling



RENEWABLE PROFILES

The wind and solar shapes for all study locations are from the PSP and were developed by CPUC staff.

A representative set of renewable profiles was selected for the two California study regions (CA-N which is composed of PGE Bay and PGE Valley and CA-S which is composed of SCE and SDGE). For CAISO regions, marginal ELCC values were calculated for each of the following technologies: BTM PV, fixed PV, tracking PV, tracking PV hybrid, wind, wind hybrid, and standalone battery. For each case, 500 MW increments for each respective technology and location were added. The average annual capacity factor for the set of profiles used for each technology and region is provided in Table 8.

Table 8. Average Capacity Factor for Renewable Profiles Used

Region	BTM PV	Solar Fixed	Solar Tracking Single Axis	Wind
CA-N	19.01%	23.27%	30.70%	23.34%
CA-S	20.39%	24.53%	33.52%	29.23%
AZ APS	N/A	25.32%	33.83%	30.57%
NME PE	N/A	24.16%	32.59%	42.47%
BPA	N/A	N/A	N/A	28.47%
Average	**19.70%**	**24.32%**	**32.66%**	**30.82%**

The average annual capacity factor for the profiles used for each technology and region in the 2022 study and the delta from the 2021 study are presented in Table 9. In the 2021 study, Northern California (CA-N), was split into PGE Valley and PGE Bay regions, and Southern California (CA-S) was split into SDGE and SCE.

Table 9. Average Capacity Factor and Capacity Factor Differences from 2021 and 2022 Studies

	2021 Study				Delta[22]			
Region	BTM PV	Solar Fixed	Solar Tracking Single Axis	Wind	BTM PV	Solar Fixed	Solar Tracking Single Axis	Wind
CA-N	18.67%	23.76%	31.00%	29.36%	0.34%	-0.48%	-0.30%	-6.02%
CA-S	20.18%	24.73%	33.51%	26.62%	0.21%	-0.20%	0.01%	2.61%
AZ APS	N/A	25.33%	33.00%	25.32%	N/A	-0.01%	0.83%	5.25%
NME PE	N/A	24.81%	32.70%	29.09%	N/A	-0.65%	-0.11%	13.38%
BPA	N/A	N/A	N/A	37.45%	N/A	N/A	N/A	-8.98%
Average	**19.42%**	**24.65%**	**32.55%**	**29.57%**	**0.28%**	**-0.33%**	**0.11%**	**1.25%**

TECHNOLOGY ASSUMPTIONS

SOLAR TECHNOLOGIES

For each region, the PV units total 500 MW and used the corresponding technology weather stations and inverter loading ratios (ILR). The capacity was divided evenly across all corresponding weather stations for each region. As a result, multiple profiles were used for some regions and technologies. The weather shape, capacity, ILR, and capacity factor breakdowns for each region and technology are defined in Table 10.

Table 10. Solar Technology Assumptions

Region	Technology	Solar Shape	Capacity (MW)	Inverter Loading Ratio (ILR)	Capacity Factor (%)
CA-N	BTM PV	Solar_Fixed_CA__Monterey	62.5	1.1	17.96%

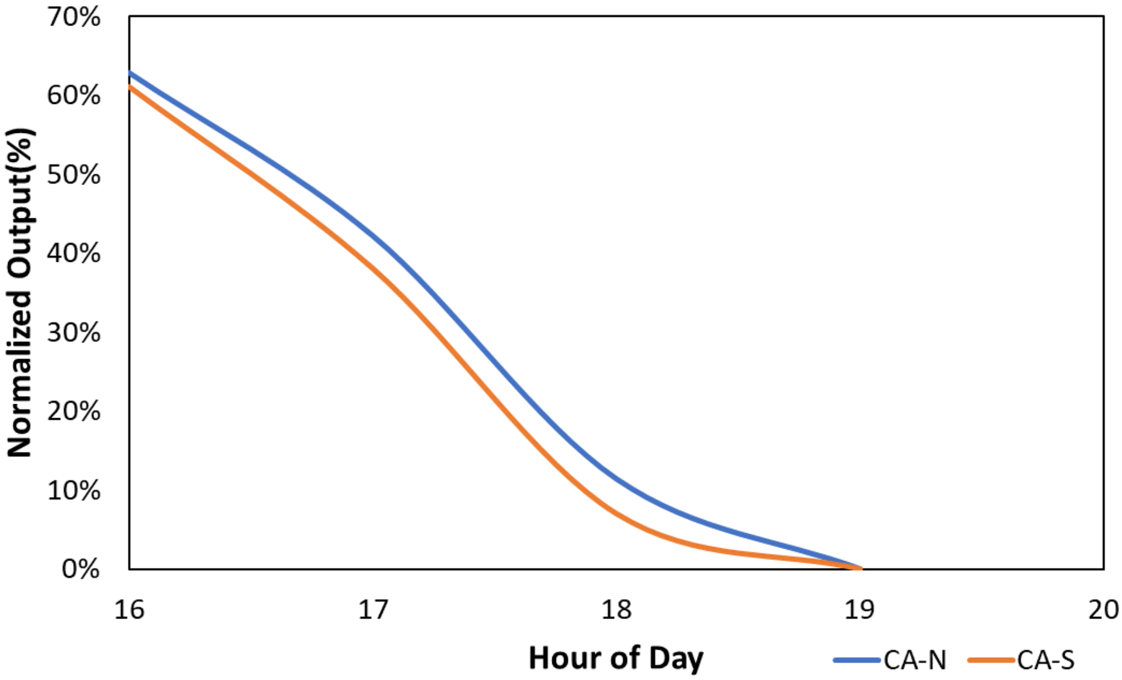
[22] Positive indicates higher values in 2022 study and negative indicates higher values in the 2021 study.

	BTM PV	Solar_Fixed_CA__Oakland	62.5	1.1	18.55%
	BTM PV	Solar_Fixed_CA__Chico	62.5	1.1	18.44%
	BTM PV	Solar_Fixed_CA__Fresno	62.5	1.1	19.74%
	BTM PV	Solar_Fixed_CA__Sacramento	62.5	1.1	19.12%
	BTM PV	Solar_Fixed_CA__SantaRosa	62.5	1.1	18.28%
	BTM PV	Solar_Fixed_CA_Kern_Bakersfield	62.5	1.1	20.25%
	BTM PV	Solar_Fixed_CA_Madera_Madera	62.5	1.1	19.76%
CA-S	BTM PV	Solar_Fixed_CA_LosAngeles_Lancaster	100	1.1	22.06%
	BTM PV	Solar_Fixed_CA_Riverside_Riverside	100	1.1	20.55%
	BTM PV	Solar_Fixed_CA_Kings_Stratford	100	1.1	23.61%
	BTM PV	Solar_Fixed_CA__LosAngeles	100	1.1	20.13%
	BTM PV	Solar_Fixed_CA__SanDiego	100	1.1	19.20%
CA-N	Solar Fixed	Solar_Fixed_CA__Oakland	125	1.3	18.55%
	Solar Fixed	Solar_Fixed_CA_Kern_LostHills	125	1.3	24.12%
	Solar Fixed	Solar_Fixed_CA_Kern_Rosamond	125	1.3	26.15%
	Solar Fixed	Solar_Fixed_CA_Placer_Roseville	125	1.3	22.27%
CA-S	Solar Fixed	Solar_Fixed_CA__LosAngeles	41.67	1.3	20.13%
	Solar Fixed	Solar_Fixed_CA_Riverside_Riverside	41.67	1.3	20.55%
	Solar Fixed	Solar_Fixed_CA_SanBernardino_AppleValley	41.67	1.3	26.04%
	Solar Fixed	Solar_Fixed_CA_Imperial_Ocotillo	41.67	1.3	26.08%
	Solar Fixed	Solar_Fixed_CA_Imperial_Calipatria	41.67	1.3	24.87%
	Solar Fixed	Solar_Fixed_CA_Kern_Bakersfield	41.67	1.3	20.25%
	Solar Fixed	Solar_Fixed_CA_Kern_LostHills	41.67	1.3	24.12%
	Solar Fixed	Solar_Fixed_CA_Kern_Rosamond	41.67	1.3	26.15%
	Solar Fixed	Solar_Fixed_CA_Kings_Stratford	41.67	1.3	23.61%
	Solar Fixed	Solar_Fixed_CA_LosAngeles_Lancaster	41.67	1.3	22.06%
	Solar Fixed	Solar_Fixed_CA_Madera_Madera	41.67	1.3	19.76%
	Solar Fixed	Solar_Fixed_CA_Placer_Roseville	41.67	1.3	22.27%
AZ APS	Solar Fixed	Solar_Fixed_AZ__Phoenix	250	1.3	25.03%
	Solar Fixed	Solar_Fixed_AZ_LaPaz_None	250	1.3	25.62%
NM EPE	Solar Fixed	Solar_Fixed_NM__Albuquerque	250	1.3	24.79%
	Solar Fixed	Solar_Fixed_NM_LosAlamos_LosAlamos	250	1.3	23.53%
CA-N	Solar 1Axis	Solar_1Axis_CA__Fresno	71.43	1.3	30.92%
	Solar 1Axis	Solar_1Axis_CA__Sacramento	71.43	1.3	30.02%
	Solar 1Axis	Solar_1Axis_CA__SantaRosa	71.43	1.3	28.24%
	Solar 1Axis	Solar_1Axis_CA_Kern_Bakersfield	71.43	1.3	31.67%
	Solar 1Axis	Solar_1Axis_CA_Kern_LostHills	71.43	1.3	32.01%
	Solar 1Axis	Solar_1Axis_CA_Kings_Stratford	71.43	1.3	31.26%
	Solar 1Axis	Solar_1Axis_CA_Madera_Madera	71.43	1.3	30.77%
CA-S	Solar 1Axis	Solar_1Axis_CA__LosAngeles	50	1.3	31.04%
	Solar 1Axis	Solar_1Axis_CA_Imperial_Calipatria	50	1.3	32.81%
	Solar 1Axis	Solar_1Axis_CA_Kern_Bakersfield	50	1.3	31.67%
	Solar 1Axis	Solar_1Axis_CA_Kern_Rosamond	50	1.3	34.98%
	Solar 1Axis	Solar_1Axis_CA_LosAngeles_Lancaster	50	1.3	34.63%
	Solar 1Axis	Solar_1Axis_CA_Riverside_Riverside	50	1.3	31.87%
	Solar 1Axis	Solar_1Axis_CA_SanBernardino_AppleValley	50	1.3	34.77%

	Solar 1Axis	Solar_1Axis_CA_Imperial_Calipatria	50	1.3	32.81%
	Solar 1Axis	Solar_1Axis_CA_Imperial_Ocotillo	50	1.3	34.60%
	Solar 2Axis	Solar_2Axis_CA_Imperial_Ocotillo	50	1.3	39.14%
AZ APS	Solar 1Axis	Solar_1Axis_AZ__Phoenix	250	1.3	33.00%
	Solar 1Axis	Solar_1Axis_AZ_LaPaz_None	250	1.3	34.05%
NM EPE	Solar 1Axis	Solar_1Axis_NM__Albuquerque	500	1.3	32.59%

Figure 7 illustrates the average September shape for hours 16 to 20 for all PV technologies (average of fixed, 1-axis, and BTM PV) between the two different CA study regions.

Figure 7. Average September PV Shape for Hours 16 to 20 for Two Different CA Study Regions



A comparison of the average August daily shapes for all PV technologies between the 2021 and 2022 studies is shown in Figure 8.

Figure 8. Average August PV Daily Shape Comparison

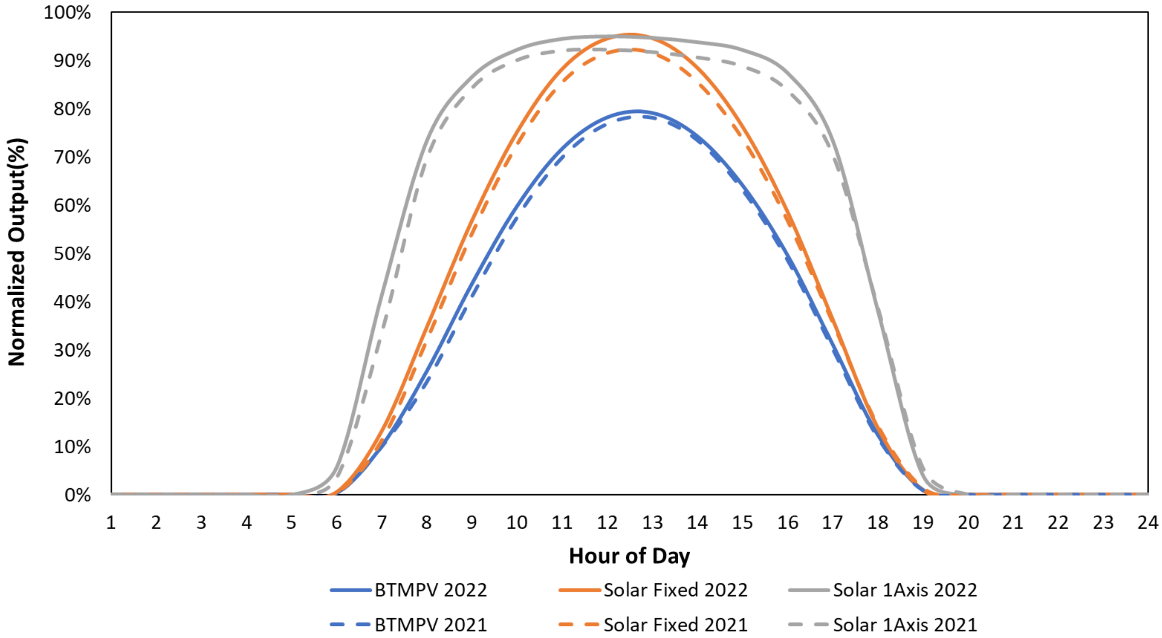


Figure 9 illustrates the average September shape for PV technologies (average of fixed and 1-axis) between the two CAISO study regions, NM EPE, and AZ APS. Figure 10 shows only hours 16 to 20 from Figure 9.

Figure 9. Average September Shape Comparison for CAISO, NM EPE, and AZ APS

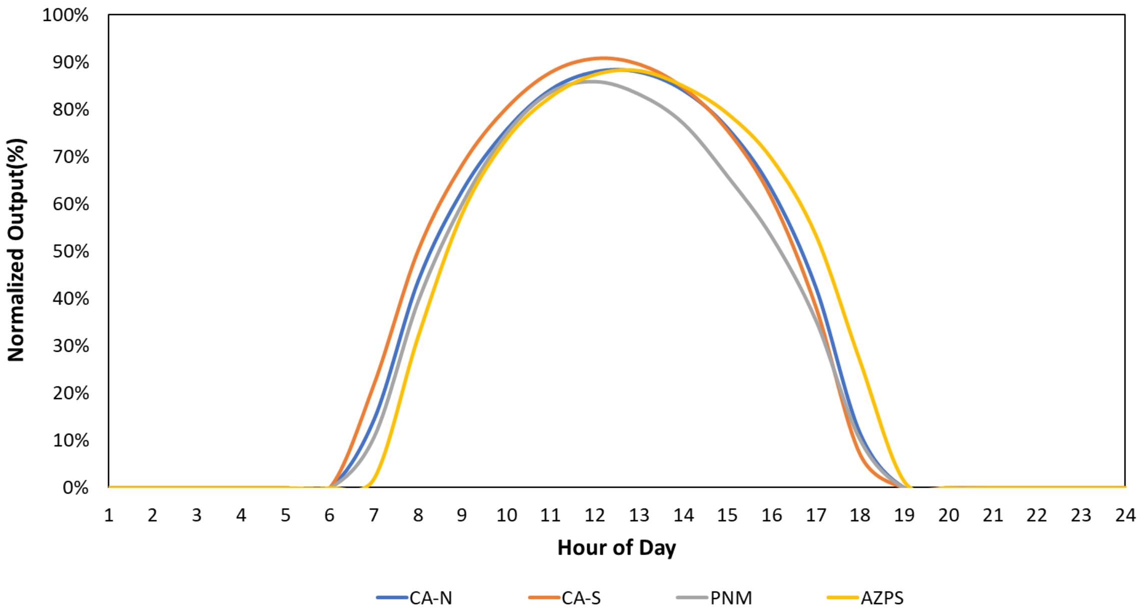
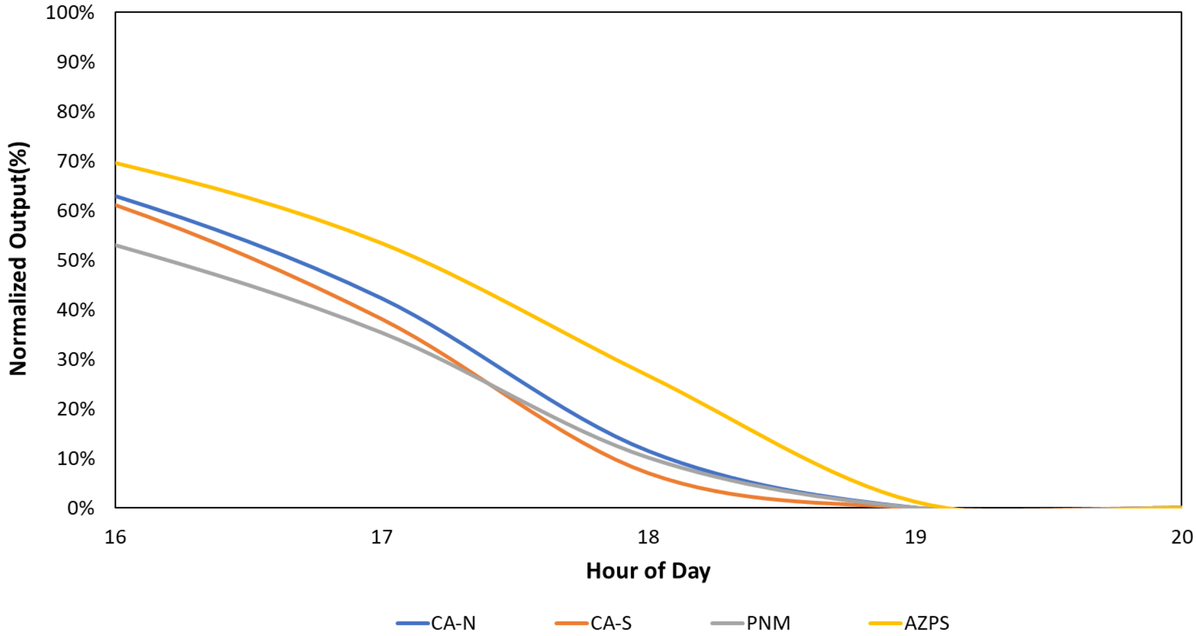


Figure 10. Average September Shape Comparison for Hours 16 to 20 for CAISO, NM EPE, and AZ APS



TRACKING PV HYBRID

The tracking PV hybrid units used the tracking PV solar shapes and capacities defined in Table 11 below.

Table 11. Tracking PV Technology Assumptions

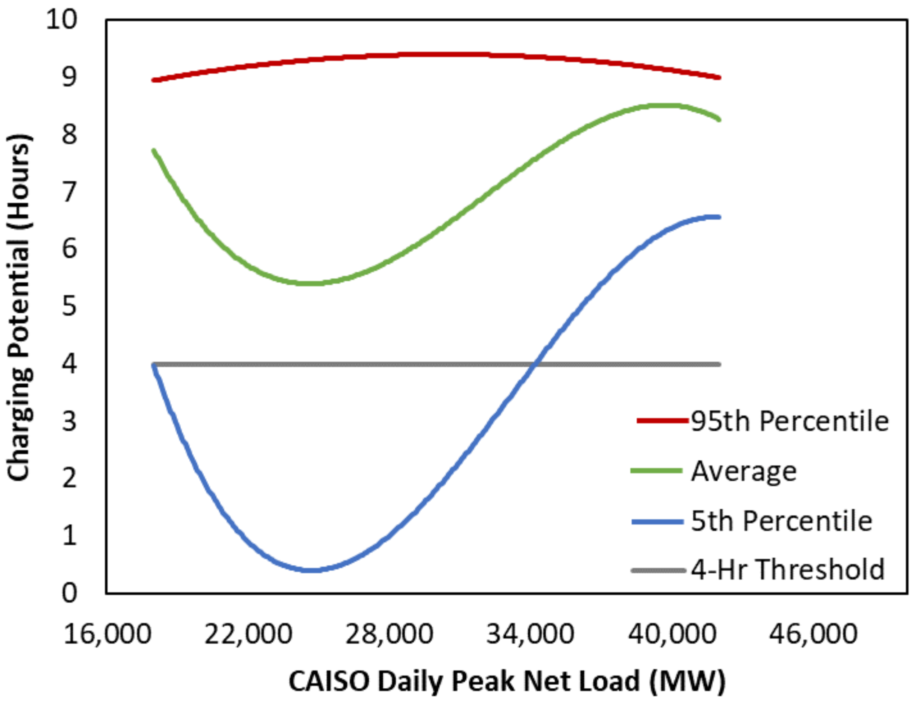
Region	Solar Shape	Capacity (MW)	Inverter Loading Ratio (ILR)	Capacity Factor (%)
CA-N	Solar_1Axis_CA__Fresno	71.43	1.3	30.92%
	Solar_1Axis_CA__Sacramento	71.43	1.3	30.02%
	Solar_1Axis_CA__SantaRosa	71.43	1.3	28.24%
	Solar_1Axis_CA_Kern_Bakersfield	71.43	1.3	31.67%
	Solar_1Axis_CA_Kern_LostHills	71.43	1.3	32.01%
	Solar_1Axis_CA_Kings_Stratford	71.43	1.3	31.26%
	Solar_1Axis_CA_Madera_Madera	71.43	1.3	30.77%
CA-S	Solar_1Axis_CA__LosAngeles	50	1.3	31.04%
	Solar_1Axis_CA_Imperial_Calipatria	50	1.3	32.81%
	Solar_1Axis_CA_Kern_Bakersfield	50	1.3	31.67%
	Solar_1Axis_CA_Kern_Rosamond	50	1.3	34.98%
	Solar_1Axis_CA_LosAngeles_Lancaster	50	1.3	34.63%
	Solar_1Axis_CA_Riverside_Riverside	50	1.3	31.87%
	Solar_1Axis_CA_SanBernardino_AppleValley	50	1.3	34.77%
	Solar_1Axis_CA_Imperial_Calipatria	50	1.3	32.81%
	Solar_1Axis_CA_Imperial_Ocotillo	50	1.3	34.60%
	Solar_2Axis_CA_Imperial_Ocotillo	50	1.3	39.14%

AZ APS	Solar_1Axis_AZ__Phoenix	250	1.3	33.00%
	Solar_1Axis_AZ_LaPaz_None	250	1.3	34.05%
NM EPE	Solar_1Axis_NM__Albuquerque	500	1.3	32.59%

Though solar shape allocation differed between hybrids, the tracking PV units and battery units totaled 500 MW each, yielding 1,000 MW of nameplate capacity with 500 MW maximum combined output based on an assumed 500 MW interconnection capability. The battery units were modeled with 1-, 2-, or 4-hour storage capability, 85% round trip efficiency, and used economic commitment and dispatch subject to the constraint that the battery could only charge from the corresponding tracking PV unit. As DC coupling of the solar PV and storage would be expected to result in higher ELCC than AC coupling when renewable energy charging constraints are binding, the tracking PV and battery units were assumed to be AC coupled to serve as a conservative estimate of hybrid configuration ELCC.

Figure 11 below was developed to determine if the solar profiles would provide adequate energy to consistently charge the paired energy storage resource. The charging potential of the PGE Bay solar shape describes the amount of energy produced prior to hour 18 by the solar plant, expressed in terms of hours of energy which could be stored within a 500 MW storage device. Hybrid ELCCs are highly dependent on the ability to fully charge prior to the highest net load peak periods. Figure 11 shows that during the highest CAISO net daily load peaks across the year 2022, the coupled solar PV tracking component should be able to consistently charge the studied storage devices (1-, 2-, or 4-hours) with a 90% confidence interval, with an average charging potential of roughly 8 hours. The 90% confidence interval is shown as the difference in the 95th percentile and 5th percentile curves. Because the PGE Bay solar shape exhibits the lowest annual capacity factor of hybrid resources studied, other configurations are assumed to also have enough energy to achieve a full charge.

Figure 11. Charging Potential of PGE Bay Tracking PV Hybrid



WIND

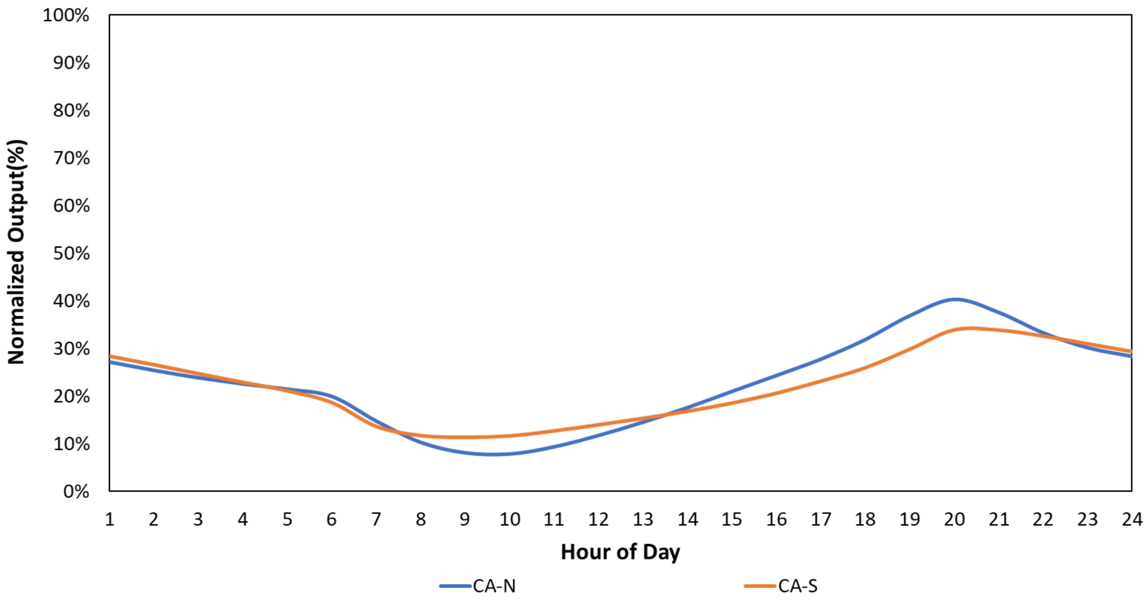
The wind units being studied totaled 500 MW for each region and used the wind weather stations in SERVM for each region. Prior to being imported into SERVM, the profiles were averaged for each region's 500 MW unit. Table 12 displays the wind shape and capacity breakdown for each region being tested.

Table 12. Wind Technology Assumptions

Region	Wind Shape	Capacity (MW)	Capacity Factor (%)	Capacity Factor on CAISO Net Peak (%)
CA-N	Wind_CA_Contracosta_Pittsburg_0	166.67	25.0%	12.7%
	Wind_CA_Merced_DosPalos_0	166.67	23.2%	12.7%
	Wind_CA_Shasta_Shingletown_0	166.67	21.6%	12.7%
CA-S	Wind_CA_Kern_Mojave_0	83.33	28.0%	12.1%
	Wind_CA_Riverside_None_0	83.33	26.3%	12.1%
	Wind _CA_SanBernardino_92332_0	83.33	32.8%	12.1%
	Wind _CA_ SanBernardino _Boron_0	83.33	31.8%	12.1%
	Wind _CA_ SanBernardino _None_0	83.33	26.6%	12.1%
	Wind_CA_SanDiego_None_0	83.33	29.6%	12.1%
BPA	Wind_WA_Columbia_Dayton_0	41.67	31.42%	24.6%
	Wind_WA_Grant_Royal_0	41.67	24.75%	19.0%
	Wind_WA_Yakima_Moxee_0	41.67	22.61%	17.7%
	Wind_ID_Bonneville_Idahofalls_0	41.67	30.80%	22.4%
	Wind_ID_Power_Americanfalls_0	41.67	29.34%	19.4%
	Wind_ID_Twinfalls_Castleford_0	41.67	34.40%	21.0%
	Wind_ID_Twinfalls_Kimberly_0	41.67	33.32%	19.4%
	Wind_OR_97843_Ione_0	41.67	34.42%	26.8%
	Wind_OR_Clatsop_Seaside_0	41.67	17.81%	11.4%
	Wind_OR_Malheur_Vale_0	41.67	21.53%	21.6%
	Wind_OR_Morrow_Heppner_0	41.67	32.13%	23.7%
	Wind_OR_Umatilla_Pilotrock_0	41.67	29.08%	18.3%
AZ APS	Wind_AZ_Apache_StJohns_0	166.67	31.1%	17.1%
	Wind_AZ_Cochise_Willcox_0	166.67	27.5%	23.9%
	Wind_AZ_Coconino_Ashfork_0	166.67	33.0%	15.6%
NM	Wind_NM_88030_Deming_0	100	35.3%	24.8%
	Wind_NM_88434_Glenrio_0	100	47.1%	31.4%
	Wind_NM_Cibola_Grants_0	100	37.7%	18.5%
	Wind_NM_Guadalupe_Vaughn_0	100	46.5%	25.5%
	Wind_NM_Torrance_Encino_0	100	45.8%	23.9%

Figure 12 illustrates the average August daily wind shape for the two California study regions.

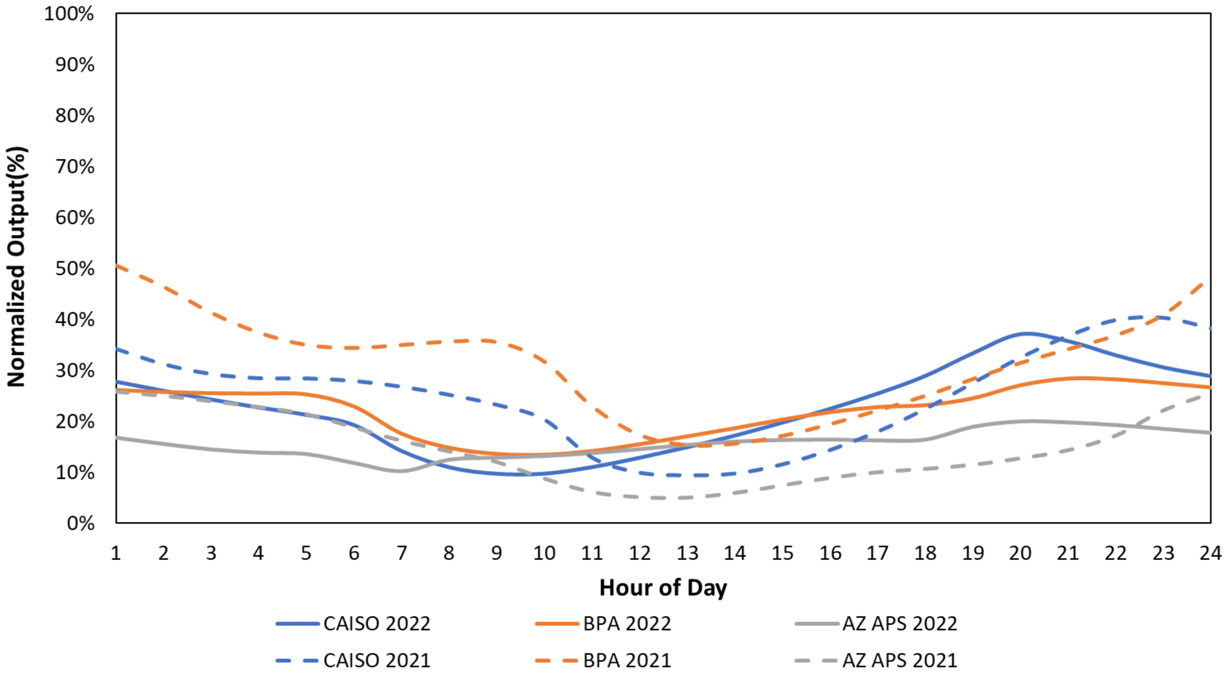
Figure 12. Average August Daily Wind Shape for CA-N and CA-S



A comparison of the average August daily wind shapes between the 2021 and 2022 studies for California, AZ APS, and BPA is shown in Figure 13. The methodology for developing wind profiles has changed significantly from that used for the 2021 study. The methodology used for the 2022 load shapes primarily relied on project level wind data. The wind profiles used in this study are heavily reliant on modeled data from the MERRA wind dataset.[23] However, neither methodology likely reflects location-specific resource adequacy contributions of actual and future wind projects accurately and thus further development work on wind shapes is warranted.

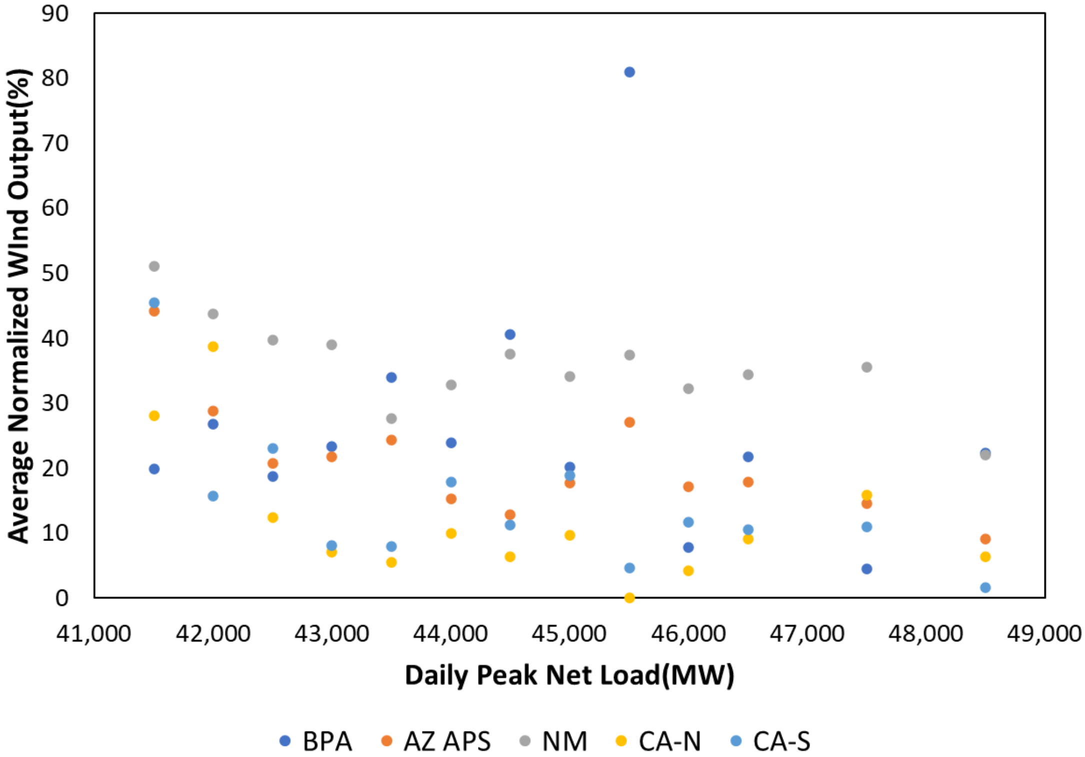
[23] https://gmao.gsfc.nasa.gov/reanalysis/MERRA/

Figure 13. Average August Daily Shape Comparison



To understand the characteristics of each wind shape and to validate ELCC results, the capacity factor during the expected CAISO net peak demand was calculated.[24] Figure 14 below illustrates each wind shape's generation during hours 18 to 20 for high demand periods across all weather years for the synthetic profiles.

Figure 14. Average Wind Output Hours 18 to 20 on Peak Net Load Days



[24] Considering all solar, wind, EE, and EV.

WIND HYBRID

The wind hybrid units used the wind shapes and capacities defined in Table 13 below.

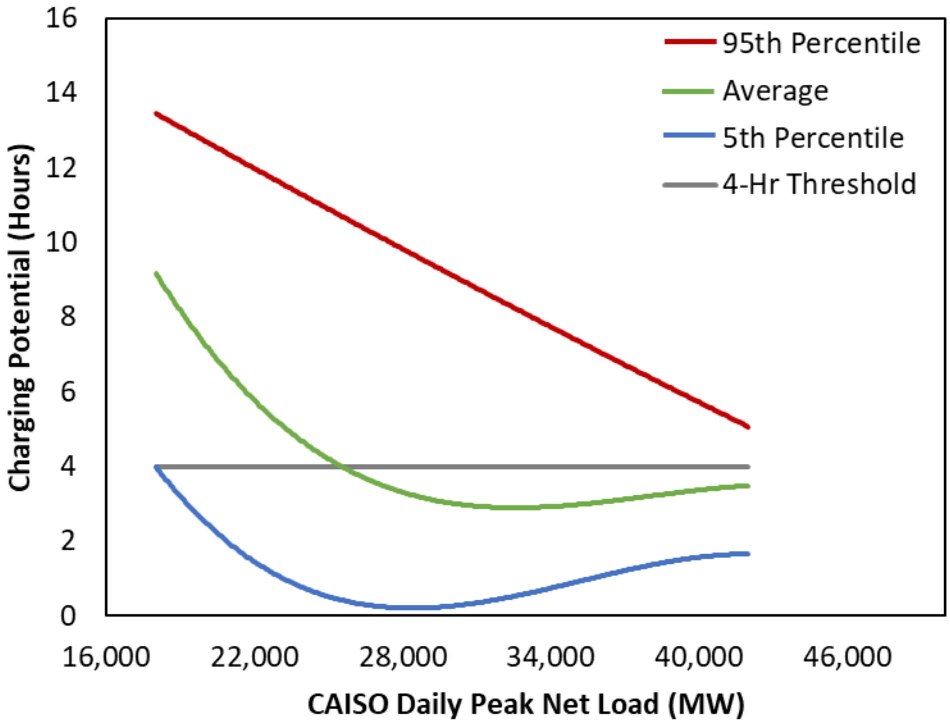
Table 13. Wind Technology Assumptions

Region	Wind Shape	Capacity (MW)	Capacity Factor (%)	Capacity Factor on CAISO Net Peak (%)
CA-N	Wind_CA_Contracosta_Pittsburg_0	166.67	25.0%	12.7%
	Wind_CA_Merced_DosPalos_0	166.67	23.2%	12.7%
	Wind_CA_Shasta_Shingletown_0	166.67	21.6%	12.7%
CA-S	Wind_CA_Kern_Mojave_0	83.33	28.0%	12.1%
	Wind_CA_Riverside_None_0	83.33	26.3%	12.1%
	Wind _CA_SanBernardino_92332_0	83.33	32.8%	12.1%
	Wind _CA_ SanBernardino _Boron_0	83.33	31.8%	12.1%
	Wind _CA_ SanBernardino _None_0	83.33	26.6%	12.1%
	Wind_CA_SanDiego_None_0	83.33	29.6%	12.1%
BPA	Wind_WA_Columbia_Dayton_0	41.67	31.42%	24.6%
	Wind_WA_Grant_Royal_0	41.67	24.75%	19.0%
	Wind_WA_Yakima_Moxee_0	41.67	22.61%	17.7%
	Wind_ID_Bonneville_Idahofalls_0	41.67	30.80%	22.4%
	Wind_ID_Power_Americanfalls_0	41.67	29.34%	19.4%
	Wind_ID_Twinfalls_Castleford_0	41.67	34.40%	21.0%
	Wind_ID_Twinfalls_Kimberly_0	41.67	33.32%	19.4%
	Wind_OR_97843_Ione_0	41.67	34.42%	26.8%
	Wind_OR_Clatsop_Seaside_0	41.67	17.81%	11.4%
	Wind_OR_Malheur_Vale_0	41.67	21.53%	21.6%
	Wind_OR_Morrow_Heppner_0	41.67	32.13%	23.7%
	Wind_OR_Umatilla_Pilotrock_0	41.67	29.08%	18.3%
AZ APS	Wind_AZ_Apache_StJohns_0	166.67	31.1%	17.1%
	Wind_AZ_Cochise_Willcox_0	166.67	27.5%	23.9%
	Wind_AZ_Coconino_Ashfork_0	166.67	33.0%	15.6%
NM	Wind_NM_88030_Deming_0	100	35.3%	24.8%
	Wind_NM_88434_Glenrio_0	100	47.1%	31.4%
	Wind_NM_Cibola_Grants_0	100	37.7%	18.5%
	Wind_NM_Guadalupe_Vaughn_0	100	46.5%	25.5%
	Wind_NM_Torrance_Encino_0	100	45.8%	23.9%

Though wind shape allocations differed between hybrids, the wind units and battery units totaled 500 MW each, yielding 1,000 MW of nameplate capacity with 500 MW maximum combined output based on the assumed interconnection capability. The battery units were modeled with 1-, 2-, or 4-hour storage capability, 85% round trip efficiency, used economic commitment and dispatch subject to the constraint that the battery could only charge from the corresponding wind unit.

Figure 15 was developed to determine if the wind profiles would provide adequate energy to consistently charge the coupled energy storage resource. The charging potential of the PGE Bay wind shape describes the daily amount of energy produced prior to hour 18 by the wind plant, expressed in terms of hours of energy which could be stored within a 500 MW storage device.[25] The Figure shows during the highest net daily peaks, the coupled wind would not be able to consistently charge a 500 MW storage device to 4 hours of energy in a 90% confidence interval. The coupled wind is even insufficient for 1- and 2-hour storage devices to consistently provide full charge, considering the 5th percentile is below 1 hour. The expected charging capability at the highest net load periods is expected to be less than 2 hours, with some days as low as a fraction of 1 hour. However, since this product is assumed to be capable of providing AS, and the system does not reach storage exhaustion in any study year, its ELCC remains elevated throughout the analysis. If battery ELCCs become constrained by energy duration because of system battery penetration in the future, the wind hybrid project ELCCs would begin to reflect the charging constraint effect. Wind hybrids exhibit characteristics of 1- and 2-hour battery storage resources which is consistent with the available charging energy distribution modeled. If penetration of 1- and 2-hour batteries in CAISO increased significantly, 1- and 2-hour standalone battery ELCCs would decline, and it is expected that wind hybrids would also see a commensurate decline in ELCCs due to the limited wind energy available for charging.

Figure 15. Charging Potential of PGE Bay Wind Hybrid



BATTERY COMPONENTS

The battery components of the hybrid resources were modeled with 500 MW of capacity, 1-, 2-, or 4-hour storage capability, 85% round trip efficiency, used economic commitment and dispatch, and were allowed to charge from the grid. The batteries were modeled with forced outage rates of 5%

[25] These hours represent the peak net load hours, considering all solar, wind, EE, and EV and serves as a proxy for timing of expected reliability events.

SIMULATION RESULTS

Astrapé performed simulations to determine the annual, marginal ELCC values for the defined resource classes and class subtype locations. The hybrid projects have total nameplate capacity of 1,000 MW (500 MW renewable and 500 MW battery), but the marginal ELCC is calculated as a percentage of the maximum possible simultaneous output from the facility, which is 500 MW based on the assumed interconnection capacity.[26,27] Additionally, the storage component cannot charge from the grid. Tables 14-19 define the results for all the resource classes for the 2026, 2030, and 2032 study years.

Table 14. 2026 Study Wind and Solar Results (expressed as a percentage of assumed interconnection capability)

Technology	BTM PV	Fixed PV	Tracking PV	Wind
CA-N	8.8%	9.3%	10.2%	10.2%
CA-S	7.7%	8.3%	9.3%	7.5%
AZ APS	N/A	8.8%	9.9%	13.9%
NM EPE	N/A	7.9%	8.9%	19.4%
BPA	N/A	N/A	N/A	11.8%

Table 15. 2026 Study Storage and Hybrid Results (expressed as a percentage of assumed interconnection capability)

Technology	1-Hour Storage	2-Hour Storage	4-Hour Storage	1-Hour PV Hybrid	2-Hour PV Hybrid	4-Hour PV Hybrid	1-Hour Wind Hybrid	2-Hour Wind Hybrid	4-Hour Wind Hybrid
CA-N	24.8%	33.9%	57.6%	34.3%	43.4%	65.0%	35.7%	43.4%	65.0%
CA-S	24.8%	33.9%	57.6%	33.4%	41.8%	63.3%	34.7%	40.7%	62.3%
AZ APS	N/A	N/A	N/A	34.0%	43.1%	64.7%	38.1%	47.1%	68.7%
NM EPE	N/A	N/A	N/A	33.1%	42.2%	63.7%	43.5%	52.6%	74.2%
BPA	N/A	N/A	N/A	N/A	N/A	N/A	36.0%	45.1%	66.7%

Table 16. 2030 Study Wind and Solar Results (expressed as a percentage of assumed interconnection capability)

Technology	BTM PV	Fixed PV	Tracking PV	Wind
CA-N	12.7%	14.0%	16.7%	14.4%
CA-S	10.2%	13.8%	15.6%	13.4%
AZ APS	N/A	10.7%	14.7%	16.5%
NM EPE	N/A	10.4%	12.6%	24.5%
BPA	N/A	N/A	N/A	15.4%

[26] These hours represent the peak net load hours, considering all solar, wind, EE, and EV and serves as a proxy for timing of expected reliability events.

[27] Given the wide range of possible configurations for hybrid facilities, multiple methods of accounting for their ELCC may need to be employed, but for simplicity and comparability, using maximum possible simultaneous output as the denominator was most appropriate for this draft report.

Table 17. 2030 Study Storage and Hybrid Results (expressed as a percentage of assumed interconnection capability)

Technology	1-Hour Storage	2-Hour Storage	4-Hour Storage	1-Hour PV Hybrid	2-Hour PV Hybrid	4-Hour PV Hybrid	1-Hour Wind Hybrid	2-Hour Wind Hybrid	4-Hour Wind Hybrid
CA-N	24.1%	32.6%	57.9%	38.0%	44.6%	70.1%	35.7%	42.3%	67.8%
CA-S	24.1%	32.6%	57.9%	37.9%	44.0%	70.9%	34.7%	41.3%	66.8%
AZ APS	N/A	N/A	N/A	31.8%	42.6%	68.1%	37.8%	44.4%	69.9%
NM EPE	N/A	N/A	N/A	34.0%	40.6%	66.1%	45.8%	54.4%	77.9%
BPA	N/A	N/A	N/A	N/A	N/A	N/A	36.7%	43.3%	68.8%

Table 18. 2032 Study Wind and Solar Results (expressed as a percentage of assumed interconnection capability)

Technology	BTM PV	Fixed PV	Tracking PV	Wind
CA-N	15.3%	16.9%	17.3%	19.8%
CA-S	12.7%	14.2%	16.5%	14.2%
AZ APS	N/A	14.7%	16.9%	18.0%
NM EPE	N/A	13.9%	16.3%	27.4%
BPA	N/A	N/A	N/A	18.3%

Table 19. 2032 Study Storage and Hybrid Results (expressed as a percentage of assumed interconnection capability)

Technology	1-Hour Storage	2-Hour Storage	4-Hour Storage	1-Hour PV Hybrid	2-Hour PV Hybrid	4-Hour PV Hybrid	1-Hour Wind Hybrid	2-Hour Wind Hybrid	4-Hour Wind Hybrid
CA-N	23.6%	30.5%	55.8%	36.1%	42.0%	67.2%	38.6%	44.5%	69.7%
CA-S	23.6%	30.5%	55.8%	35.7%	43.5%	68.7%	33.0%	38.9%	64.1%
AZ APS	N/A	N/A	N/A	32.8%	41.6%	66.8%	38.6%	42.7%	68.0%
NM EPE	N/A	N/A	N/A	35.1%	41.0%	66.2%	33.0%	53.2%	77.3%
BPA	N/A	N/A	N/A	N/A	N/A	N/A	37.1%	43.0%	68.2%

RESULTS DISCUSSION

Subject to the caveats described in the executive summary section, the results indicate that a rapid increase in storage penetration in the CAISO has significant consequences for the reliability value of not only incremental storage resources, but also for incremental solar and wind resources. When reliability is driven more by energy constraints than capacity constraints, any energy that solar and wind can supply during hours in which the storage portfolio is discharging can contribute directly to reliability. This occurs because the additional energy from the incremental solar and wind resources allows the ELCC modeling to better optimize the storage dispatch; i.e., allows storage energy to be saved for later in the day to address potential unserved energy events. The improved reliability is therefore attributable to the incremental solar and wind resources. A proxy for the marginal reliability contribution of the incremental wind and solar resources then is the average output of those resources respectively during those critical storage discharge hours. As shown in Figure 16 below, a 500 MW tracking solar project is producing at over 300 MW at the beginning of this period and even though the critical hours extend well past sunset, its average output during critical hours is still over 100 MW, suggesting an approximate ELCC of 20%. While this is a simple illustration from a single day and the actual ELCC calculations are the aggregate result of thousands of peak day simulations, this illustration comports with the simulation findings of tracking solar projects supplying up to 17% in 2032 as the severity of the energy constraint increases.

Figure 16. Solar Output on High Net Load Day (Illustrative Example)

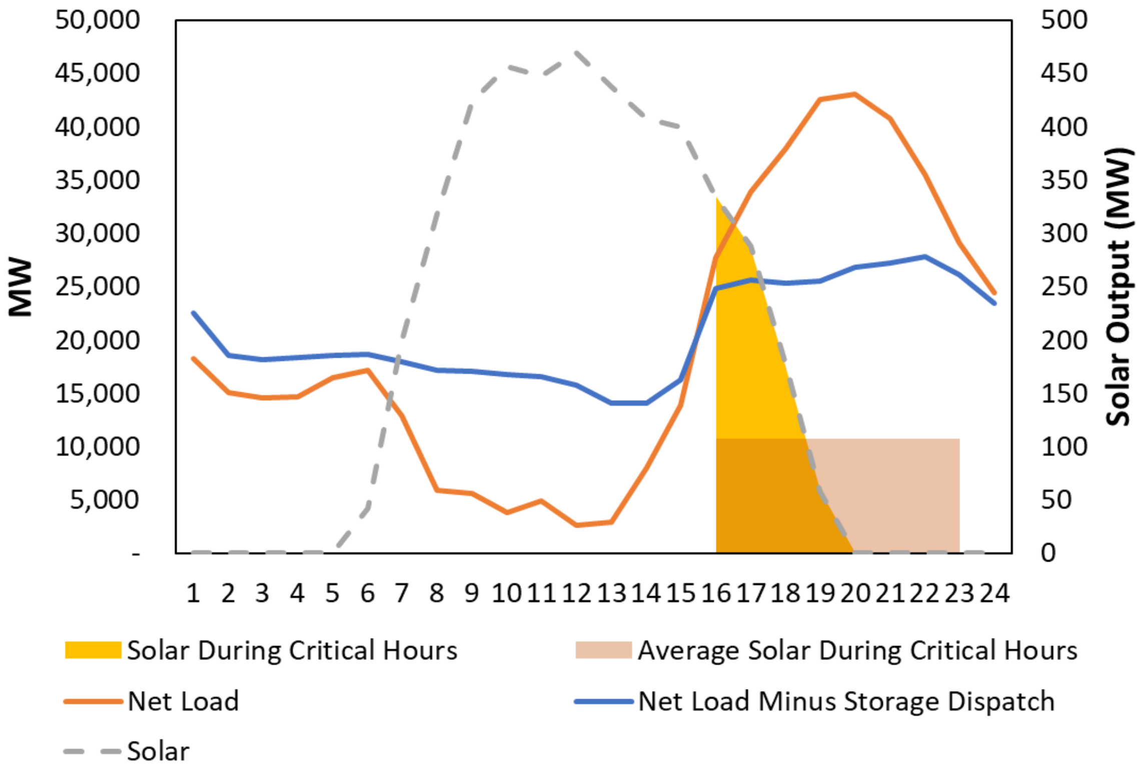
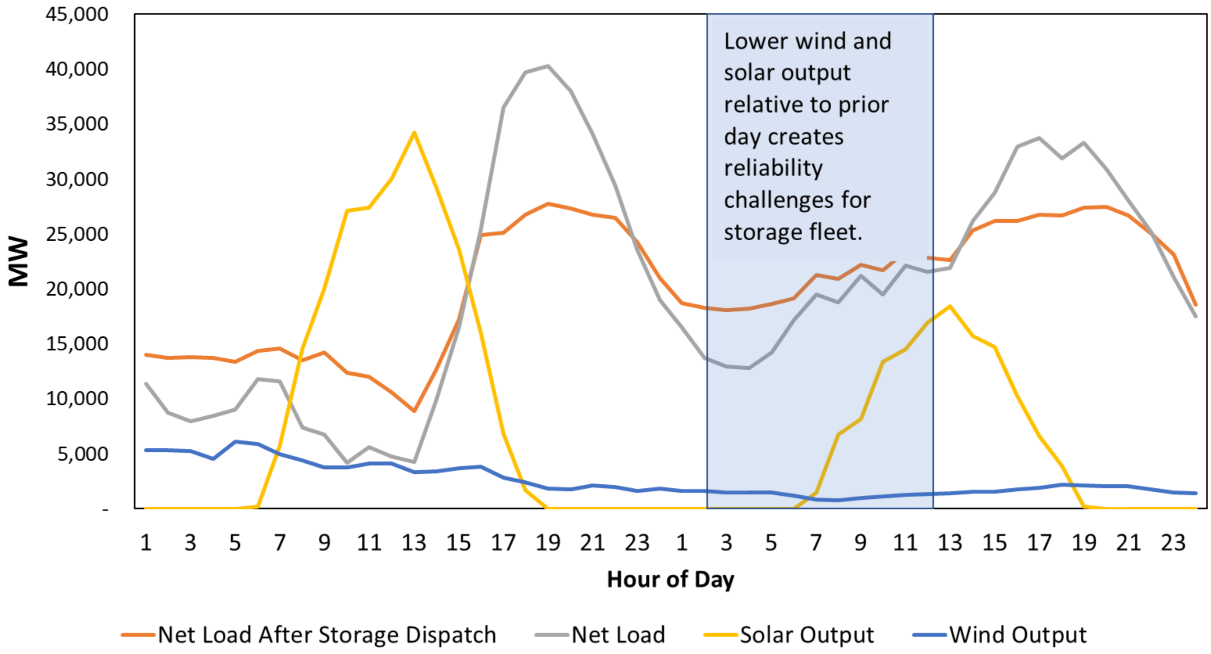


Figure 16 demonstrates a typical daily pattern but meeting reliability objectives often entails more complicated dynamics. Figure 17 shows a reliability constrained two-day period. The first day has robust wind and solar output but has higher loads. The second day has lower wind and solar output, but also lower load. Despite lower load – more than 5 GW – it is more difficult to avoid a load shed event during the second day because of the shape of the resulting net load profile. The lower wind and solar output in the second day results in the net load staying elevated throughout the day. And while the storage fleet is able to nearly fully charge, the initiation of the storage discharge happens two hours earlier (HE14 compared to HE16 the prior day). The high penetration of energy-limited and intermittent resources combined and the interaction between resource classes shifts the types of daily conditions that lead to reliability challenges away from a more simplistic load view, and drives the decline in the reliability value of storage and also increases the energy contribution of wind and solar to system reliability.

Figure 17. Reliability Constrained Two-Day Period Illustration



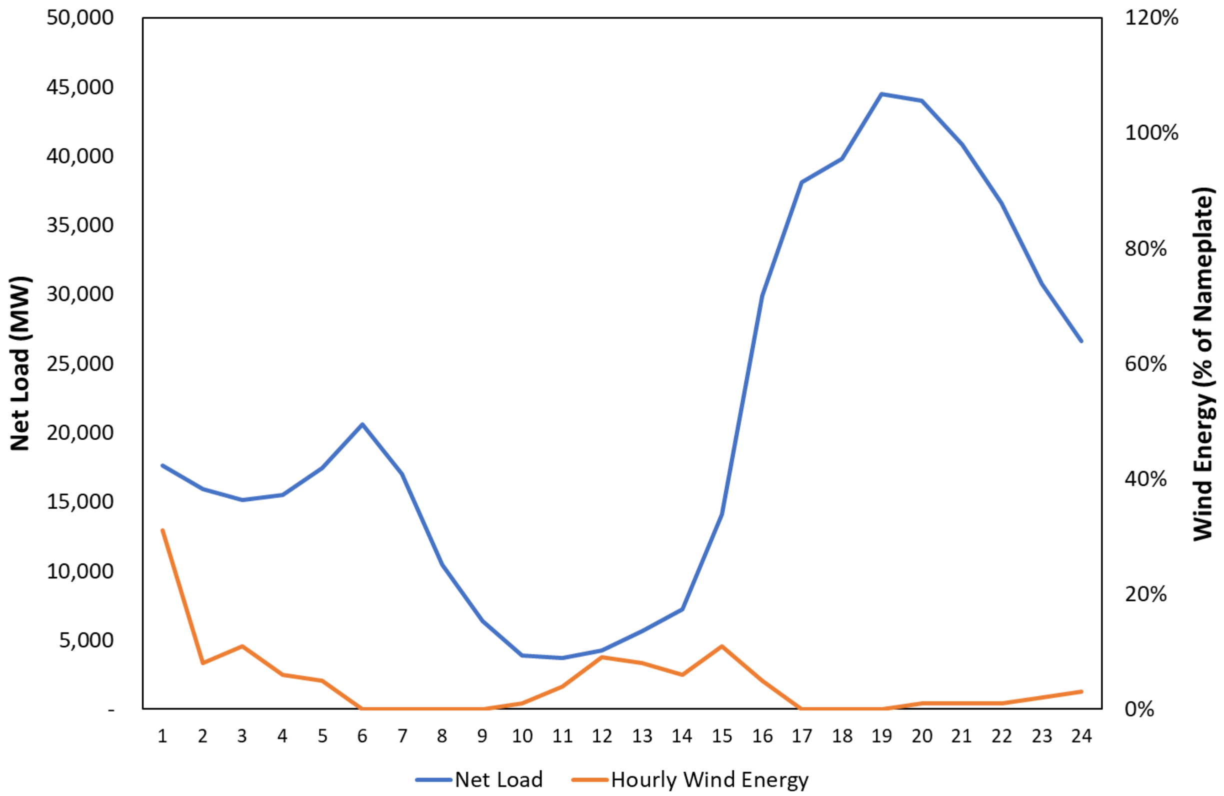
Comparing the results to the prior study, all technologies with a storage component declined while wind and solar only technology ELCCs increased with the exception of wind in 2026 as shown in Table 20.

Table 20. 2021 & 2022 CAISO Study Results Comparison

Study Year	Report	Tracking PV	Wind	4-Hour Hybrid Solar	4-Hour Hybrid Wind
2026	2021 Study	7%	14%	88%	88%
	2022 Study	9.7%	8.8%	64.2%	63.7%
	Delta	+2.7%	-5.2%	-23.8%	-14.3%
2030	2021 Study	6%	10%	82%	82.%
	2022 Study	16.1%	13.9%	70.5%	67.3%
	Delta	+10.1%	+3.9%	-11.5%	-14.7%
2032	2021 Study	NA	NA	NA	NA
	2022 Study	16.9%	17%	68.0%	66.9%

The wind profiles included in this study combined with the more prevalent energy constraints on the system reduced the potential for wind hybrids that must be charged from on-site wind energy to supply reliability value. On particular reliability-constrained days, the daily available wind energy prior to the net load peak represents only 1 hour of on-site storage capability based on the storage device's nameplate capacity.[28] An example is shown in Figure 18. This means that for wind hybrid facilities to maximize the reliability contribution of batteries, the batteries could only be sized at a maximum ratio of 1 MWh of batteries to 4 MW of wind. This is a more stringent requirement than has been identified in prior studies which suggested that 1:1 or 1:2 ratios would be adequate to supply reliability.

Figure 18. Wind Hybrid Charging Illustration



[28] The sum of all hourly energy values across the day is approximately equal to only one hour at full nameplate output

SENSITIVITY RESULTS

Given the differences between the 2022 study and 2021 study results, a sensitivity was run to better understand the effects of the underlying assumptions on the results.

STORAGE CAPACITY REDUCTION

One of the main drivers of the marginal ELCC's of the standalone storage is the high penetration of batteries included in the 2021 PSP. As shown in the input section of the report, the total battery capacity in 2026 is around 4,000 MW higher in the 2022 study compared to the 2021 study.[29] The increased battery penetration in the 2022 study flattens the net load shape and reduces the value of the marginal storage resource. A sensitivity was run to examine the impact of a 4,000 MW reduction in the battery capacity from the 2021 PSP. The sensitivity was run at the at found reliability of the 2026 study year and the marginal ELCC's for the CA-N wind, tracking solar, and 4-hour standalone storage. As expected, the removal of the 4,000 MW of storage increases the value of the standalone storage and reduces the value of the wind and tracking solar as shown in Table 21.

Table 21. 2026 Storage Capacity Reduction Sensitivity Results

Technology	ELCC (%)
CA-N Wind	8.0%
CA-S Tracking PV	6.0%
CA 4-Hr Standalone Storage	84.0%

[29] This battery capacity amount does not include BTM storage.

APPENDIX 1: 2021 PSP WIND PROFILES

While reviewing the 2021 PSP dataset, Astrapé Consulting encountered inconsistencies with the PSP wind generation shapes. Preliminary results review indicated that during the highest net load days, which are usually the most consequential days in resource adequacy analysis, the PSP dataset wind shapes showed consistently higher output than shapes based on historical production data. The differences in these profiles for CA-N and CA-S during the highest net load days are shown in Figure 19 and Figure 20 below.

Figure 19. CA-N Wind Output Comparison During High Net Load Days

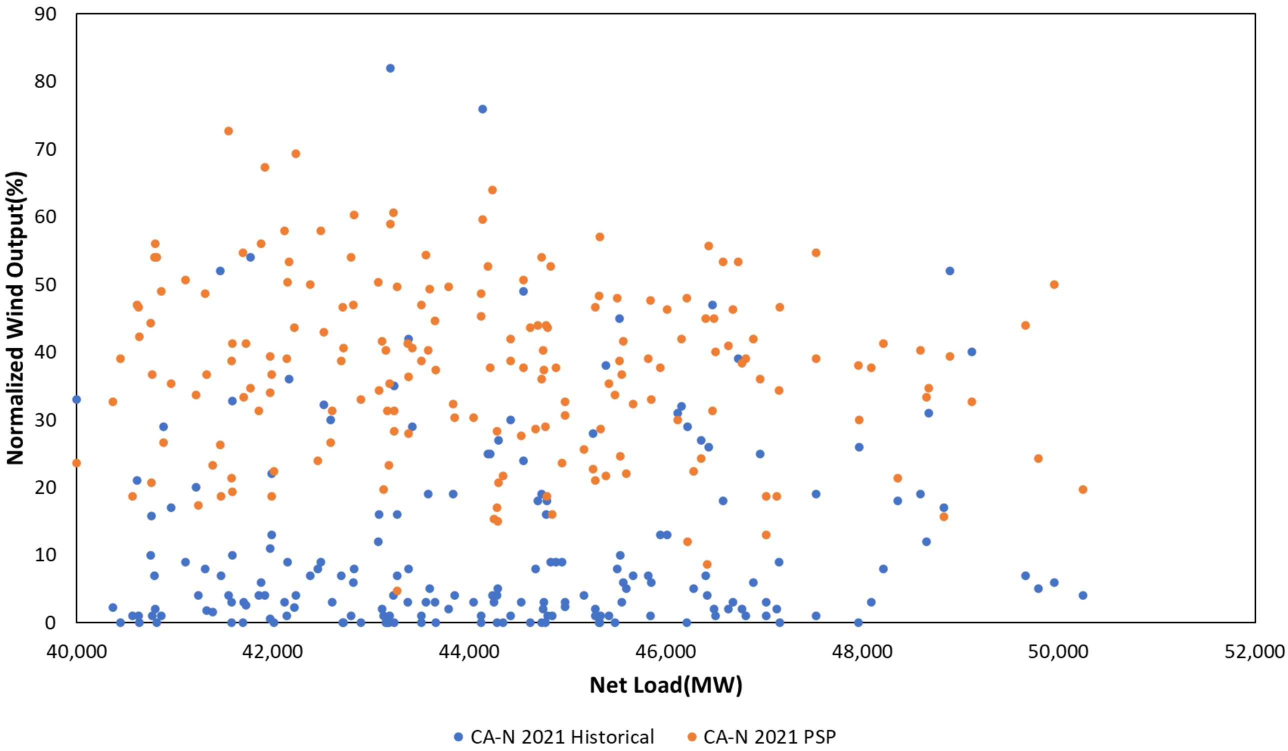
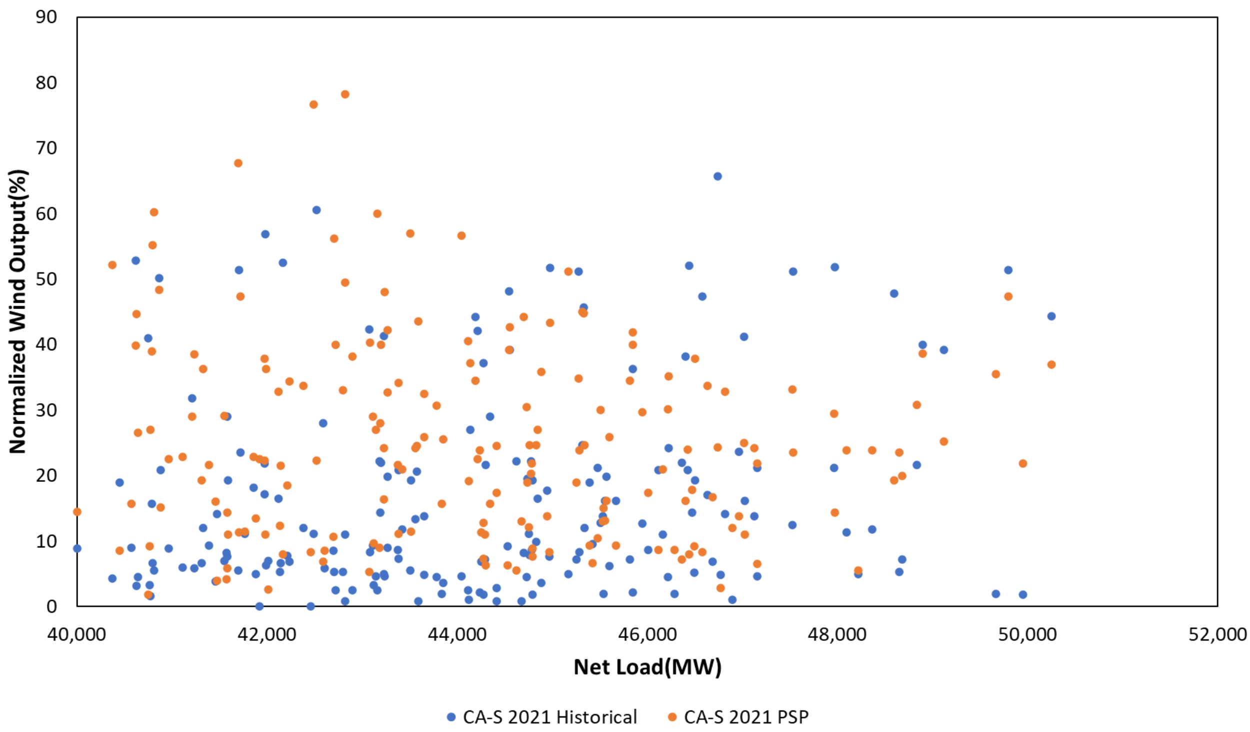


Figure 20. CA-S Wind Output Comparison During High Net Load Days



For this study, Astrapé used the 2021 PSP profiles and replaced the output on highest net load days with the historical output so as to not overstate the contribution of the wind resources during the analysis. Astrapé recommends that the wind modeling be revisited in the future.

APPENDIX 2: BTM STORAGE MODELING

In accordance with the 2021 PSP, BTM storage was modeled as a supply side resource and Table 22 lists the BTM storage numbers included in the simulations for each study year

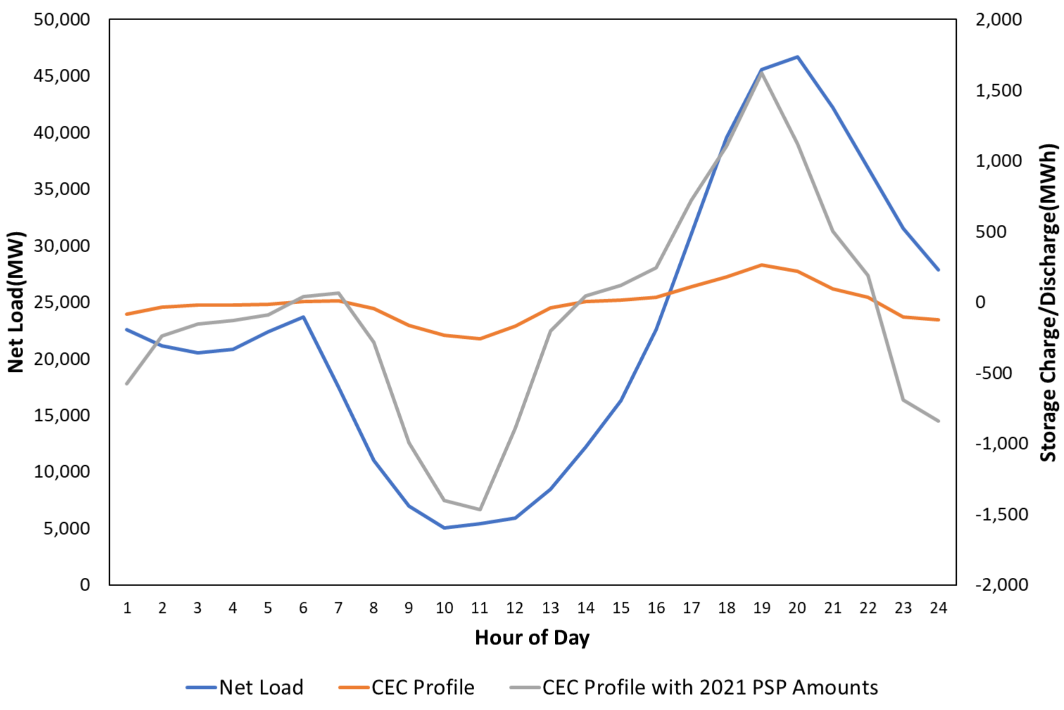
Table 22.BTM Storage Amounts

Study Year	BTM Storage (MW)
2026	1,687
2030	2,592
2032	2,592

The California Energy Commission (CEC) provides an hourly dispatch profile for BTM storage, in the past the CPUC has used this profile in PSP modeling. The resulting effect on this study of modeling BTM storage as a supply side resource is a further depressed marginal storage ELCC value for incremental storage resources compared to a study which models BTM battery storage with the CEC profile. The marginal storage ELCC in this study with BTM storage modeled on the supply side is lower because the BTM storage is dispatching at high output in the highest net load hours, pushing incremental storage resources to dispatch for longer periods and exhausting sooner.

It should be noted, the CEC profile reflects limited BTM storage dispatch. The profiles provided by the CEC dispatch at a maximum of 262 MW in the 2026 study year which is less than 20% of the amount modeled on the supply side during the 2026 study year in this study. This may be a reasonable assumption given that BTM storage resources are customer cited. Given the impact on results, this assumption may need further exploration. Figure 21 below shows the difference in discharge on a high net load day between modeling BTM storage as a dispatchable resource compared to using the profile provided by the CEC.

Figure 21 BTM Storage Discharge Profile Comparison



PG&E Gas and Electric
Advice Submittal List
General Order 96-B, Section IV

AT&T
Albion Power Company

Alta Power Group, LLC
Anderson & Poole

Atlas ReFuel
BART

Barkovich & Yap, Inc.
Braun Blaising Smith Wynne, P.C.
California Cotton Ginners & Growers Assn
California Energy Commission

California Hub for Energy Efficiency Financing

California Alternative Energy and Advanced Transportation Financing Authority
California Public Utilities Commission
Calpine

Cameron-Daniel, P.C.
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Leviton Manufacturing Co., Inc.

Los Angeles County Integrated Waste Management Task Force
MRW & Associates
Manatt Phelps Phillips
Marin Energy Authority
McClintock IP
McKenzie & Associates

Modesto Irrigation District
NLine Energy, Inc.
NRG Solar

OnGrid Solar
Pacific Gas and Electric Company
Peninsula Clean Energy

Pioneer Community Energy

Public Advocates Office

Redwood Coast Energy Authority
Regulatory & Cogeneration Service, Inc.
SCD Energy Solutions
San Diego Gas & Electric Company

SPURR
San Francisco Water Power and Sewer
Sempra Utilities

Sierra Telephone Company, Inc.
Southern California Edison Company
Southern California Gas Company
Spark Energy
Sun Light & Power
Sunshine Design
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Tecogen, Inc.
TerraVerde Renewable Partners
Tiger Natural Gas, Inc.

TransCanada
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Water and Energy Consulting Wellhead Electric Company
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