Docket No.: A.24-03-018
Date: August 6, 2024
Commissioner: Douglas ALJ: Atamturk
Witness: Rao Konidena

BEFORE THE PUBLIC UTILITIES COMMISSION OF

THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company to Recover in Customer Rates the Costs to Support Extended Operation of Diablo Canyon Power Plant from September 1, 2023 through December 31, 2025 and for Approval of Planned Expenditure of 2025 Volumetric Performance Fees (U 39 E)	Application 24-03-018 (Filed March 29, 2024)

<u>CORRECTED</u> OPENING TESTIMONY OF RAO KONIDENA ON BEHALF OF SAN LUIS OBISPO MOTHERS FOR PEACE

(Public Version)

Dated: August 6, 2024

Rao Konidena for SLOMFP
c/o
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VERIFICATION

The statements in the foregoing document are true and correct to the best of my knowledge. The facts presented in the forgoing document are true and correct to the best of my knowledge, and the opinions expressed therein are based on my best professional judgment. I declare under penalty of perjury under the laws of the state of California that the foregoing is true and correct.

Executed on 06/08/2024 in Roseville, MN,

Rao Konidena

Rao Konidena

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I. INTRODUCTION

Q. Please state your name, employer, title, and business address.

A. My name is Rao Konidena. I am the President of Rakon Energy LLC. My business address is 2309 Auerbach St, Roseville, MN, 55113.

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of San Luis Obispo Mothers for Peace ("SLOMFP").

Q. Please describe your current position and provide your education and professional experience related to this testimony.

A. I have been an independent energy consultant for the past five years, primarily focusing on wholesale market practices and policy. Before that, I was employed by Midcontinent Independent System Operator ("MISO") from September 2003 through May 2018. I started as an Applications Engineer for Planning, where I ran Loss of Load Expectation ("LOLE") studies used in the Planning Reserve Margin Requirement. I gained familiarity with MISO's Planning Resource Auction and Module E Capacity Tracking (MECT) tool in various roles at MISO. Specifically, in the Resource Forecasting department, I used peak demand and annual energy data from the MECT to run the resource forecasting model called the Electric Generation Expansion Analysis System (EGEAS), which is an Integrated Resource Planning software tool.

Before leaving MISO, my title was Principal Advisor in Transmission Asset Management. In that role, I was part of an internal subject matter expert team providing technical support to the legal team on how MISO should respond to the Federal Energy Regulatory Commission's Order 841, which compensates Electric Storage Resources and the Notice Of Proposed Rulemaking on aggregations of Distributed Energy Resources.

My CV is attached at the end of this testimony.

Q. Please describe the purpose of your testimony.

A. My testimony focuses on three areas: First, I provide a basis for my expertise in forecasting energy market revenues. Second, my testimony shows that PG&E's CAISO market revenue forecasts are likely inflated. Third, I analyze the need for DCPP extended

operations based on the new resource information. Fourth, I provide a summary of my conclusions.

II. BASIS FOR TESTIMONY ON CAISO MARKET REVENUES

Q. Are you familiar with forecasts of purchase and sale transactions of energy in CAISO's wholesale Energy Market?

A. Yes.

Q. How did you acquire your expertise in this field?

A. In my previous job working for the Midcontinent Independent System Operator (MISO), I was responsible for the PowerBase database that was an input to the energy market price forecasting software tool. The Energy Market forecasts are an output of this software tool. These energy market forecasts were utilized to conduct benchmark studies of the MISO market. Additionally, these energy market forecasts were utilized to evaluate the economic benefits of transmission lines in the MISO Transmission Expansion Plan (MTEP). As an independent consultant, I regularly download Energy Market data from ISO websites to answer various client needs.

III. METHODOLOGY FOR CAISO ENERGY MARKET FORECASTS

Q. What are the different methodologies that are used to forecast CAISO energy market revenues?

A. There are different methodologies used to forecast energy market revenues in general. Primarily, I am familiar with the following methodologies:

- Time Series Analysis – In this method, historical energy market revenues are used to forecast energy market revenues. A time series analysis is typically deployed in load forecasting when the load forecast is not complicated with estimates of future technologies such as electric vehicles. But history is not always an accurate predictor of the future when it pertains to the energy market because of several factors, such as variable renewable energy, fluctuating electric demand due to weather and loss of major transmission lines during natural disasters such as hurricanes and wildfires. So, a time series analysis for forecasting energy market revenues is not completely risk-free.

- Statistical Regression Analysis – In this statistical method, the energy market revenue is the dependent variable, and the independent variables are the generating units, the demand, weather and transmission. Statistical regression analysis is also used in load forecasting or to understand simple energy market revenues in a small power system with few generators and demand.
- Monte Carlo Simulations – In this method, hourly simulations are conducted using both statistical and random sampling techniques. This Monte Carlo simulation method is most widely used for forecasting energy market revenues. I discuss this method in more detail below.

Q. Please explain how production cost modeling software is used to forecast CAISO energy market revenues.

A. I am most familiar with PROMOD IV, a production cost modeling software that calculates Locational Marginal Price (LMP). LMP at each location/transmission node in CAISO shows the price of serving the next Megawatt (MW) and includes 3 components – Energy, Congestion and Loss. Hence, in each LMP, there is a price of serving energy, the congestion price and a price for losses incurred for that location.

A software tool like PROMOD IV mimics the security-constrained unit commitment and security-constrained economic dispatch functions performed by an Independent System Operator like CAISO. As another ISO – PJM Interconnection indicates, "PROMOD IV is a production costing software application that simulates the hourly commitment and dispatch of generation to meet input load while recognizing and maintaining transmission system security limits[1]."

To provide a simple explanation, a PROMOD IV simulation is run with various inputs such as currently available generators, expected load forecasts and available transmission support for the study region like CAISO. In order to forecast energy market revenue from a large generator such as the Diablo Canyon Power Plant (DCPP), PROMOD IV

[1] https://www.pjm.com/-/media/committees-groups/committees/teac/2022/20221004/informational-only---market-efficiency-analysis-assumptions.ashx

simulations are run with and without DCPP extended operations. In each of the simulations, a metric called "adjusted production cost" is calculated for each hour in a year for each utility, e.g., PG&E in the CAISO study region.

An "Hourly PG&E Adjusted Production Cost" = PG&E Production Cost + PG&E Fixed Transaction Cost + PG&E Emergency Energy Cost + PG&E Interpool Transaction Cost + PG&E Withinpool Transaction Cost[2].

Q. Please explain how the hourly PG&E adjusted production cost is calculated in the PROMOD IV software.

A. As mentioned above, there are 5 components. I will explain each below:

- Production Cost – This cost represents the cost of operating PG&E's thermal fleet, including fuel costs, start-up costs, emission costs and variable operations and maintenance costs.
- Fixed Transaction Cost – This cost represents the cost of operating PG&E's non-thermal fleet such as wind and solar, which do not have fuel costs.
- Emergency Energy Cost – This cost represents the cost of providing energy during CAISO-declared emergency events. Typically, the emergency energy cost is $1000 per MWh.
- Interpool Transaction Cost – Recognizing that PG&E is not the sole transmission utility in the CAISO region, this interpool transaction cost provides the total cost of purchases and sales of energy that PG&E engaged with other utilities in CAISO located outside the CAISO balancing authority.
- Withinpool Transaction Cost – Any energy transactions PG&E has within its "pool," which could be defined as all transmission utilities within a single balancing authority, are captured in this withinpool transaction cost.

Q. What methodology do you utilize to forecast CAISO energy market revenues relating to extended operations of DCPP?

[2] https://cdn.misoenergy.org/20210427%20PSC%20Item%2007%20MISO%20APC%20Calculation%20Methodology%20Whitepaper544059.pdf

A. To forecast CAISO energy market revenues relating to the extended operations of DCPP, I need access to PROMOD IV simulation data results that show the hourly adjusted production cost value for PG&E with and without extended operations of DCPP. This information was not provided in the responses to the data requests SLOMFP issued.

Q. What is a market reference price in terms of CAISO market revenue forecasts?

A. Typically, the market reference price is calculated at a "trading hub." CAISO has 3 trading hubs – NP15, SP15 and ZP26[3]. Since DCPP is located close to North Path 15 (NP15), the market reference price would be the NP15 trading hub price.

Q. Is it true that the Public Utilities Commission does not identify a specific market reference price to be used in this context?

A. Yes. PG&E states, "Since the California Public Utilities Commission (Commission) does not identify a specific market reference price to be used in this context[4]."

Q. Is PG&E's use of the Power Charge Indifference Adjustment Energy Index Benchmark used in the ERRA proceeding ("PCIA Benchmark") an appropriate methodology for calculating CAISO market revenue forecasts for DCPP?

A. According to PG&E, the Power Charge Indifference Adjustment (PCIA) is "intended to ensure that any above-market costs of electric resources PG&E procured on behalf of customers who switch to another electric generation provider are not transferred to remaining PG&E electric supply customers. PG&E collects above-market costs from customers who receive their electric supply from PG&E in their bundled generation rate[5]."

Whether PG&E customers switch to another electric generation provider or not, the CAISO continues to be the market operator for PG&E. In that sense, it is a zero-sum game whether customers switch from PG&E and enter into a contract with another electric generation provider because CAISO is still the responsible Transmission Provider to provide transmission for those customers who have switched from PG&E.

[3] http://oasis.caiso.com/oasisapi/prc_hub_lmp/PRC_HUB_LMP.html
[4] PG&E Prepared Testimony, 8-2, Lines 5-6.
[5] https://pgesupport.zendesk.com/hc/en-us/articles/360057073531-What-is-the-Power-Charge-Indifference-Adjustment-PCIA-on-my-bill

Finally, PG&E states that it has chosen to use PCIA for calculating the Resource Adequacy (RA) system benchmark price because the Commission does not identify a specific market reference price[6].

Q. Is there a methodology that is better suited for calculating CAISO market revenue forecasts for DCPP besides the PCIA Benchmark?

A. Yes, PG&E should run a PROMOD IV simulation study to calculate CAISO market revenue forecasts for DCPP besides the PCIA Benchmark.

Q. Is PG&E's description of the various components required to calculate market revenue forecasts (i.e. generation volume, NP15, single annual price and portfolio weighting factor) accurate or is the formula missing a component or has the formula included a component which should be removed?

A. PG&E's description of the various components required to calculate market revenue forecasts appears to be accurate. However, I am unable to replicate the generation volumes forecasted because PG&E is using CAISO forecasted values instead of using CAISO actual generation values before the extended period of operations.

For example, "PG&E forecasts that DCPP's Unit 1 extended operations period of November 3, 2024, to December 31, 2024, is [redacted] megawatt-hours (MWh)[7]." The Maximum Dependable Capacity is 1,122 MW for Unit 1[8].

I understand that the Maximum Dependable Capacity is reduced to 25 percent on 2 days during November 3 - December 31, 2024, "The annual generation forecast includes a one-day curtailment to 25 percent power in November and a 1-day curtailment in December due to severe storms.[9]"

[6] PG&E Prepared Testimony, p. 4-4, Line 13.
[7] PG&E Prepared Testimony, p. 4-1, Line 27, but marked as confidential in Workpaper 10_DCPP-ExtendedOperations2025-Forecast_WP_PGE_20240329-Ch04_Generation Forecast-CONF_X.
[8] PG&E Prepared Testimony, p. 4-2, Line 5.
[9] PG&E Prepared Testimony, p. 4-2, Line 8.

Based on these assumptions, I calculate [redacted] megawatt-hours for Unit 1 generation forecast in 2024, lower than the PG&E [redacted] megawatt-hours value for the period of extended operations[10]. Similarly, I calculate [redacted] megawatt-hours for Unit 1 and Unit 2 generation forecast in 2025 for the period of extended operations, lower than the PG&E [redacted] megawatt-hours value.[11]

Q. Do you take any issue with the generation forecasts made by PG&E in Chapter 4, i.e. are those figures inflated?

A. Yes, I have the following concerns with the generation forecasts made by PG&E in Chapter 4 of its Prepared Testimony.

First, PG&E does not provide an explanation as to why the Actual CAISO Generation is lower than the CAISO – Actuals/Forecast values for both Units 1 and 2 in 2022 before period extended of operations. Without a reasonable explanation, I observe that Unit 1 ran [redacted] less than forecasted and Unit 2 ran [redacted] less than 2022 forecasted values.[12] The lower Actual CAISO Generation in 2022 before period extended of operations could occur again during the period of extended operations. Hence, there is a concern that the generation forecasts for Unit 1 and Unit 2 could be inflated by [redacted] and [redacted] respectively.

Second, due to refueling outage and tunnel cleaning, PG&E is forecasting reduction in DCPP production of 100% and 50%, respectively. It is unclear how PG&E is calculating the replacement costs – the cost of power to replace the DCPP power production reductions due to refueling outage and tunnel cleaning. Without a reasonable explanation for the calculation of replacement capacity costs, there is a concern that the cost of replacement power could be higher depending upon the time of the day and the season in the CAISO market. For example, during October and November 2023 – months in which refueling and tunnel cleaning is most likely to occur, the average energy price at NP15

[10] E.g. PG&E Prepared Testimony, Chapter 4; see also DCPP-ExtendedOperations2025-Forecast_Test_PGE_20240329_788417 [Workpapers for Chpt 3-4 and 6-8, p. 4-1]; Workpaper 10_DCPP-ExtendedOperations2025-Forecast_WP_PGE_20240329-Ch04_Generation Forecast-CONF_X.
[11] *Ibid*.
[12] *Ibid*.

was [redacted] per MWh[13]. This [redacted] price is 4 times the PG&E assumed replacement power price of [redacted] per MWh.

Additionally, it is not clear whether tunnel cleaning is part of either refueling (planned) outages or maintenance outages[14].

Third, PG&E shows replacement capacity only for the refueling outages and tunnel cleaning in the workpapers supporting Chapter 4 but does not include replacement capacity needed for maintenance outages, forced outages and curtailments. As PG&E mentions, during "a maintenance outage, a unit's energy production is also reduced to zero and the unit is taken offline."[15] Similarly, during forced outages and curtailments, DCPP's energy production will be "reduced to zero" and the DCPP unit is taken offline.[16] Hence, there is a concern that replacement capacity costs could be higher when compared to PG&E's estimates.

Q. Have you reviewed Appendix B to D.23-06-006 referenced by PG&E's testimony?

A. Yes.

Q. Have you reviewed the work papers supporting Chapter 8 of PG&E's testimony?

A. Yes.

Q. Has PG&E provided the data necessary to independently calculate the CAISO market revenue forecast using PG&E's PCIA Benchmark methodology? If not, what data is missing?

A. No, PG&E did not provide all the data necessary to calculate the CAISO market revenue forecast using the PCIA Benchmark methodology. The following data is missing:

- The Assumptions behind the Platts on- and off-peak NP15 monthly forward prices.
- Actual CAISO Generation values for Unit 1 and Unit 2 in 2021.
- Explanation of values in the numerator of the 3-year DCPP Ratio

[13] Historic NP-15 Tab in the 15_DCPP-ExtendedOperations2025-Forecast_WP_PGE_20240329-Ch08_Forward Power Price Derivation-CONF.
[14] PG&E Prepared Testimony, p. 4-2, Line 23.
[15] PG&E Prepared Testimony, p. 4-3, Lines 7-8.
[16] PG&E Prepared Testimony, p. 4-3, Lines 14-15 and 22-30.

- SLOMFP submitted data requests to clarify this information and PG&E merely pointed back to the data already contained in its workpapers.

Q. Please explain.

A. The CAISO energy market revenue forecast for any given year (2024/2025) is the product of the total generation forecast and the CAISO market reference price. Since I have already discussed my concerns with the total generation forecast, I focus here on how PG&E arrived at the CAISO market reference price.

As mentioned above, since the Commission did not identify a specific market reference price to be used in this proceeding, PG&E constructed a standard Power Charge Indifference Adjustment (PCIA) Energy Index Benchmark for the time period starting from November 2024 and ending in October 2030 using the "time-weighted Platts on- and off-peak North of Path 15 (NP15) monthly forward prices."[17] I was unable to replicate this Platts on- and off-peak NP15 monthly forward prices.

The off-peak prices and on-peak Platts prices were time-weighted to account for the major holidays.

Next, to arrive at the average monthly price curve during November 2024 - October 2030, the on-peak price was multiplied by the time-weight for on-peak and the off-peak price was multiplied by the time-weight for off-peak and added together.[18] I was able to replicate this calculation.

Next, for each year in the 2024-2030 time period, an average price was calculated by calculating a straight average of all the monthly values.[19] I was able to replicate this calculation.

[17] PG&E Prepared Testimony, p. 8-2.
[18] *Ibid.*
[19] PG&E Prepared Testimony, Chapter 8-2.

This average annual price for each year in the 2024-2030 time period was adjusted with a "DCPP Weight". The DCPP Weight is calculated by dividing the 3-Year DCPP Ratio by the 3-Year Average NP15 Price.[20]

I was unable to replicate the 3-Year DCPP Ratio because I was unable to reconcile the Actual CAISO Generation values for 2022 for Units 1 and 2. I was only able to reconcile 2023 values. Additionally, PG&E did not provide the 2021 Actual CAISO Generation in the workpapers supporting Chapter 4.

The DCPP Weight is critical because PG&E states, "The single annual price is then further adjusted by a portfolio weighting factor that reflects the average historical variance between generation revenues received by PCIA-eligible resources and actual average NP15 prices calculated over the prior 3-year period[21]." If the portfolio weighting factor reflects the average historical variance between the generation revenues received by PCIA-eligible resources and actual average NP15 prices, then, according to my calculations, with the limited data available (2022 and 2023 Actual CAISO Generation, not 2021), I observe a lower variance because I calculate 0.78[22] for DCPP Weight lower than the 0.93 that PG&E calculated[23].

With an updated DCPP Weight, the 2024 and 2025 CAISO Market Reference Prices are $65.54 and $57.29 respectively.[24] Hence, the forecasted Generation Revenues are $94,508,680 and $584,759,030 respectively. These values are lower - $18,601,800 (in 2024) and $115,134,960 (in 2025) - than the PG&E forecasted generation revenues.[25]

Q. Why is it critical for this information to be provided?

A. The DCPP Weight is a key piece of information in the PG&E forecast of CAISO market revenue. This DCPP Weight is critical because it signifies the average historical variance

[20] *Ibid*.
[21] *Id*. at line 13.
[22] Attachment A [SLOMFP Forward Power Price Derivation].
[23] DCPP-ExtendedOperations2025-Forecast_Test_PGE_20240329_788417[Workpapers for Chpt 3-4 and 6-8, p. 8-3].
[24] Attachment B [SLMOFP Market Revenue Calculations].
[25] See Attachment B [SLMOFP Market Revenue Calculations]; DCPP-ExtendedOperations2025-Forecast_Test_PGE_20240329_788417[Workpapers for Chpt 3-4 and 6-8, p. 8-2].

between the generation revenues received by Power Charge Indifference Adjustment (PCIA) eligible resources and actual average NP15 prices. Hence it is critical to understand the drivers behind the historical variance to understand the DCPP Weight.

Q. Can you replicate PG&E's forecasts of CAISO market revenue without this information?

A. Yes, I was able to replicate PG&E's forecasts of CAISO market revenue without this information.

Q. Does PG&E's show how it reached the single annual price for its PCIA Benchmark calculation methodology?

A. Yes.

Q. Does PG&E's show how it calculated the portfolio weighting factor for its PCIA Benchmark calculation methodology?

A. Yes.

Q. Do the workpapers for Chapter 8 of PG&E's testimony provide the required information to allow independent vetting of the accuracy of the CAISO market revenue forecasts?

A. No. As mentioned above, the workpapers for Chapter 8 of PG&E's testimony do not provide the required information for DCPP Weight and underlying assumptions behind the Platts forecast. Additionally, the 2021 Actual CAISO Generation for Units 1 and 2 were not provided by PG&E.

Q. What is your opinion, based on the information made available, as to the accuracy of PG&E's forecast of CAISO market revenues?

A. At this time, it appears that PG&E's forecast of CAISO market revenues are higher based on unexplained generation revenues received by Power Charge Indifference Adjustment (PCIA) eligible resources, which are a key input for the DCPP Weight.

Q. Are PG&E's CAISO market revenue forecasts inflated?

A. Yes, it appears so.

Q. What are the impacts of an inflated forecast of CAISO market revenues on the revenue requirement that will be recovered from statewide customers?

A. A lower revenue may mean less of an offset against the cost of extended operations at DCPP. Therefore, higher costs will be recovered from and paid by ratepayers in California.

III. ANALYSIS OF NEW RELIABILITY INFORMATION

Q: Can California maintain power reliability without the 2,240 MW from DCPP, even during extreme heat events?

A. Yes. California can maintain power reliability without the 2,240 MW from DCPP even during extreme heat events. This conclusion is based on three data points.

First, CAISO currently has more than ~~8,500~~10,000 MW of energy storage capacity, with additional storage being added annually. Additionally, there is up to 5,000 MW of demand response available. This combined capacity is more than sufficient to ensure grid reliability even during extreme heat events.

Second, by the end of ~~2023~~2024, California ~~had~~ is scheduled to have at least ~~5,424~~10,522 MW of excess capacity.[26] This excess capacity takes into account only the amount of capacity that can be counted towards meeting resource adequacy requirements in the CPUC's RA program. ~~projects that have already been constructed and interconnected.~~

Finally, California's battery storage capacity has been increasing each year, from 500 MW in 2018 to over 10,300 MW in 2023. By the end of 2024, an additional 3,800 MW is planned to come online. California projects a need for 52,000 MW of battery storage by 2045[27]. Given the historical growth rate (10,000 MW in 5 years), California is likely to meet this projection well before 2045.[28]

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[26] Attachment D [Joint Agency Reliability Planning Assessment SB 846 Combined Second and Third Quarterly Report 2024, dated August 5, 2024, see Tables 4, 8 and 10] ~~Attachment C [Konidena, R., *California has enough power to keep the lights on without DCPP* (July 17, 2024)].~~

[27] See California Energy Storage Survey here on the California Energy Commission website updated as of April 15, 2024 - https://www.energy.ca.gov/data-reports/energy-almanac/california-electricity-data/california-energy-storage-system-survey.

[28] Attachment C [Konidena, R., *California has enough power to keep the lights on without DCPP* (July 17, 2024)].

V. SUMMARY AND CONCLUSION

Q. Please summarize your conclusions?

A. Yes, my conclusions are as follows:

- The PROMOD IV simulation study is a better methodology than the ERRA Benchmark for calculating CAISO market revenue forecasts for DCPP.
- PG&E's description of the various components required to calculate market revenue forecasts appears to be accurate but I was unable to replicate the generation volumes forecasted because PG&E is using CAISO forecasted values instead of using CAISO actual generation values before the extended period of operations.
- There are concerns with PG&E's generation forecasts in Chapter 4, which lead me to conclude that replacement capacity costs could be higher than PG&E's estimates.
- PG&E did not provide all the data necessary to calculate the CAISO market revenue forecast using the ERRA Benchmark methodology. For instance, the workpapers for Chapter 8 of PG&E's testimony do not provide the required information for DCPP Weight and underlying assumptions behind the Platts forecast. Additionally, the 2021 Actual CAISO Generation for Units 1 and 2 was not provided and therefore PG&E's CAISO market revenue forecasts are questionable.
- As a result, PG&E's forecast of CAISO market revenues appears to be higher based on unexplained generation revenues received by Power Charge Indifference Adjustment (PCIA) eligible resources, which are a key input for the DCPP Weight.
- If DCPP's operations are not extended past 2025, California will still not experience an energy reliability problem even in times of excessive heatwaves.

Q. Does this conclude your testimony?

A. Yes, it does.

ATTACHMENT A

PACIFIC GAS AND ELECTRIC COMPANY

DIABLO CANYON POWER PLANT 2025 COST RECOVERY FORECAST TO SUPPORT OPERATIONS AS DIRECTED BY THE STATE TO ENSURE ELECTRIC RELIABILITY AND TO REDUCE GREENHOUSE GAS EMISSIONS FOR ALL CALIFORNIANS

WORKPAPERS SUPPORTING CHAPTER 8
CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION MARKET REVENUES
FORWARD POWER PRICE DERIVATION

Year	Month	Date	Avg Price
2024	11	11/01/24	[redacted]
2024	12	12/01/24	
2025	1	01/01/25	
2025	2	02/01/25	
2025	3	03/01/25	
2025	4	04/01/25	
2025	5	05/01/25	
2025	6	06/01/25	
2025	7	07/01/25	
2025	8	08/01/25	
2025	9	09/01/25	
2025	10	10/01/25	
2025	11	11/01/25	
2025	12	12/01/25	
2026	1	01/01/26	
2026	2	02/01/26	
2026	3	03/01/26	
2026	4	04/01/26	
2026	5	05/01/26	
2026	6	06/01/26	
2026	7	07/01/26	
2026	8	08/01/26	
2026	9	09/01/26	
2026	10	10/01/26	
2026	11	11/01/26	
2026	12	12/01/26	
2027	1	01/01/27	
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2029	10	10/01/29	
2029	11	11/01/29	
2029	12	12/01/29	
2030	1	01/01/30	
2030	2	02/01/30	
2030	3	03/01/30	
2030	4	04/01/30	
2030	5	05/01/30	
2030	6	06/01/30	
2030	7	07/01/30	
2030	8	08/01/30	
2030	9	09/01/30	
2030	10	10/01/30	

Row Labels	Average of Avg Price	Adjusted Price
2024	84.02	65.54
2025	73.45	57.29
2026	73.69	57.47
2027	72.37	56.45
2028	70.51	55.00
2029	71.04	55.41
2030	67.90	52.96
Grand Total	**71.94**	

DCPP Weight

0.78

PACIFIC GAS AND ELECTRIC COMPANY
DIABLO CANYON POWER PLANT 2025 COST RECOVERY FORECAST TO SUPPORT OPERATIONS AS DIRECTED BY THE STATE TO ENSURE ELECTRIC RELIABILITY AND TO REDUCE GREENHOUSE GAS EMISSIONS FOR ALL CALIFORNIANS

WORKPAPERS SUPPORTING CHAPTER 8
CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION MARKET REVENUES
FORWARD POWER PRICE DERIVATION - PG&E CALCULATION

Row Labels	DIABLO_7_UNIT 1	DIABLO_7_UNIT 2	Grand Total
2021	$ (478,499,345.20)	$ (334,477,264.90)	$ (812,976,610.09)
2022	$ (757,381,763.70)	$ (727,791,708.73)	$ (1,485,173,472.43)
2023	$ (449,952,876.59)	$ (526,105,715.76)	$ (976,058,592.35)
Grand Total	$ (1,685,833,985.49)	$ (1,588,374,689.39)	$ (3,274,208,674.88)

MWh

Row Labels	DIABLO_7_UNIT 1	DIABLO_7_UNIT 2	Grand Total
2021	9,854,371.70	6,651,740.14	16,506,111.85
2022	8,915,481.58	8,729,836.67	17,645,318.25
2023	8,196,055.07	9,543,051.47	17,739,106.54
Grand Total	26,965,908.36	24,924,628.29	51,890,536.64

3-Year DCPP Ratio	63.10
3-year Avg NP15 Price	67.59
DCPP weight	0.93

2021 Row Label/MWh	[redacted]
2022 Row Label/MWh	
2023 Row Label/MWh	

PACIFIC GAS AND ELECTRIC COMPANY
DIABLO CANYON POWER PLANT 2025 COST RECOVERY FORECAST TO SUPPORT OPERATIONS AS DIRECTED BY THE STATE TO ENSURE ELECTRIC RELIABILITY AND TO REDUCE GREENHOUSE GAS EMISSIONS FOR ALL CALIFORNIANS

WORKPAPERS SUPPORTING CHAPTER 8
CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION MARKET REVENUES
FORWARD POWER PRICE DERIVATION - SLOMFP CALCULATION

Row Labels	DIABLO_7_UNIT 1	DIABLO_7_UNIT 2	Grand Total
2021	$ (478,499,345.20)	$ (334,477,264.90)	$ (812,976,610.09)
2022	$ (179,569,898.55)	$ (117,235,706.68)	$ (296,805,605.23)
2023	$ (449,952,876.59)	$ (526,105,715.76)	$ (976,058,592.35)
Grand Total	$ (1,685,833,985.49)	$ (1,588,374,689.39)	$ (2,085,840,807.68)

MWh

Row Labels	DIABLO_7_UNIT 1	DIABLO_7_UNIT 2	Grand Total
2021	9,854,371.70	6,651,740.14	16,506,111.85
2022	3,264,907.25	2,131,558.30	5,396,465.55
2023	8,196,055.07	9,543,051.47	17,739,106.54
Grand Total	26,965,908.36	24,924,628.29	39,641,683.94

3-Year DCPP Ratio	52.62
3-year Avg NP15 Price	67.59
DCPP weight	0.78

ATTACHMENT B

PG&E Calculation				
		Total	CAISO Market	Generation
		Generation	Reference Price	Revenues
Line No	Year	GWh	$/Megawatt-hour	
1	2024	[redacted]	78.44	$ 113,110,480
2	2025	[redacted]	68.57	$ 699,893,990
SLOMFP Calculation				
		Total	CAISO Market	Generation
		Generation	Reference Price	Revenues
Line No	Year	GWh	$/Megawatt-hour	
1	2024	[redacted]	65.54	$ 94,508,680
2	2025	[redacted]	57.29	$ 584,759,030
			Difference - 2024	$ 18,601,800
			Difference - 2025	$ 115,134,960

ATTACHMENT C

California has enough power to keep the lights on without DCPP.

Prepared by Rao Konidena, Rakon Energy LLC[1]
On Behalf of San Luis Obispo Mothers for Peace
July 17, 2024

Summary of Key Points

- **California has enough power (including storage) to keep the lights on** – without the 2,200 MW of Diablo Canyon Power Plant (DCPP) – **even during extreme heat events.**
    - **The California Independent System Operator (CAISO) now has more than 8,500 MW of energy storage capacity** (with more being added each year), **plus up to 5,000 MW of demand response, which is more than sufficient to ensure grid reliability.**
    - Even if we focus only on "have already been constructed and interconnected" by the end of 2023, as does the Proposed Decision in the California Public Utilities Commission Rulemaking (October 26, 2023), **California will have at least 5,424 MW of excess capacity by the end of 2024.**
    - **California** battery capacity increases every year: **from 500 megawatts (MW) in 2018 to more than 10,300 MW in 2023, with an additional 3,800 MW planned to come online by the end of 2024. The state projects 52,000 MW of battery storage will be needed by 2045 (*i.e.,* an additional 40,000 MW in 20 years). Given the historical growth of battery storage (10,000 MW in 5 years), California is likely to meet the projection well before 2045.**
- This data comes from the CPUC and the California Energy Commission (CEC), reliable sources. Inexplicably, however, the CEC staff's draft September 2023 report omitted over 10,000 MW of renewables from its analysis of whether continued operation of the DCPP is needed to ensure grid reliability. (This is the last available report from the CEC, and only a draft.[2]

- The CEC staff's erroneous analysis is bad for California's clean energy future because:
    - DCPP's high cost and inflexibility hinders deployment of more renewables and storage.
    - Favoring DCPP as an inflexible electricity supplier will drive out flexible renewables ***and thereby increase the danger of blackouts.***

[1] Mr. Konidena is an independent energy consultant, focusing on wholesale market practices and policy. From 2003 to 2018, he was employed by the Midcontinent Independent System Operator (MISO), where he used a range of software tools for resource forecasting and planning, including MISO's Planning Resource Auction and Module E Capacity Tracking (MECT) tool and the Electric Generation Expansion Analysis System (EGEAS). Before leaving MISO in 2018, his title was Principal Advisor in Transmission Asset Management.

[2] Other than CEC updates to the energy storage installation numbers from the California Energy Storage System Survey (https://www.energy.ca.gov/data-reports/energy-almanac/california-electricity-data/california-energy-storage-system-survey), I have not seen any CEC report that includes the latest energy storage capacity.

Technical Analysis

In June 2023, I testified in a CPUC proceeding that the retirement of DCPP in 2024 and 2025, as previously planned, will not have an adverse impact on local reliability of San Luis Obispo and that it would impede the development of other low or zero-carbon alternatives. Since then, two reports from the CPUC and the CEC show that California's renewable electricity capacity has continued to grow at an unprecedented and unexpected rate, such that California has enough power to keep the lights on – without the 2,200 MW of DCPP – even during extreme heat events. These two reports are the following:

First, from the Joint Agency (CPUC + CEC) report "Joint Reliability Planning Assessment - Fourth Quarterly Report" issued in December 20233, it is clear that the need for contingency resources did not worsen since March 2023:

> "Through summer 2023, analysis indicates that the state maintained surplus capacity under average weather conditions. Under extreme weather conditions, such as those witnessed in the August 2020 heat wave (2020 equivalent event) and the September 2022 heat wave (2022 equivalent event), projected need for contingency resources did not worsen compared to the February 2023 first quarterly report."[4]

Even though the report projects a shortfall of 2,606 MW for a 2022 equivalent extreme event[5], that can be easily handled by the 2,444 MW of available contingency reserves[6], plus 4,800 MW of demand response[7].

Additionally, Table 1, which is copied from the Joint Agency report, estimates the addition of 5,499 MW as a "net qualifying capacity" in September 2023.

[3] Yee Yang, Chie Hong (CEC) and Sarah Goldmuntz (CPUC). December 2023. Joint Agency Reliability Planning Assessment. California Energy Commission. Publication Number: CEC-200-2023-015.

[4] Executive Summary, Ibid.

[5] Table 5, Ibid.

[6] Table 6, Ibid.

[7] https://www.canarymedia.com/articles/nuclear/california-faces-big-power-challenges-even-if-diablo-canyon-stays-open

Table 1: Cumulative Resource Additions, January 2020 Through August 30, 2023

Technology Type	Nameplate Capacity (MW)	Estimated Sept. Net Qualifying Capacity (NQC) MW	Number of Projects*
Storage	4,919	4,556	69
Solar	3,993	345	64
Hybrid (Storage/Solar)	1,034	464	17
Wind	783	103	20
Geothermal	41	31	1
Biogas, Biomass, Hydro	36	1	9 (2,3,4)
Subtotal SB 100 Resources, In-California Independent System Operator	10,806	5,499	180
Natural Gas, incl. Alamitos & Huntington Beach	1,477	1,474	12
Total Resources, In-California Independent System Operator	12,282	6,973	192
New Imports, Pseudo-Tie[2] or Dynamically Scheduled	1,689	727	13
Total Resources, Including Imports	13,971	7,701	205

Source: CPUC staff[3]

This 5,499 MW additional capacity includes 4,556 MW of energy storage available during the top summer demand hours, reducing the risk of blackouts in California. But this number is too low. In fact, CAISO has released a statement[8] that CAISO has more than 5,000 MW of energy storage capacity as of July 2023. This 5,000 MW of energy storage will be available to reduce the blackout risk in California due to wildfires or other issues.

I also note that, according to the "California Energy Storage System Survey" results posted on the CEC website[9], CA now has 10,383 MW of battery storage capacity, of which 1,076 MW is from the residential customer, 571 MW from the commercial customer and 8,736 MW from the utility customer sector. The Survey notes an additional 3,800 MW is still planned to come online by the end of 2024. Hence, as of December 31, 2024, the CEC projects that California will have 14,100 MW total of energy storage capacity available to reduce the blackout risk, with more coming online every year.

Additional tables in the Joint Agency report show the quarter-by-quarter estimate of new resources coming online in California based on the CPUC data. I have compiled the data from these tables into Table A below, which shows that California added 2,076 MW by August 1, 2023, and will add nearly 5,000 MW more before June 1 every year during 2024-2026 for a total of 18,500 MW by June 2026. This is greatly in excess of the 11,500 MW required by the CPUC in Decision D.21-06-035 (2021). Thus, California is overbuilding renewable capacity by at least 7,000 MW, three times the capacity of DCPP.

[8] "Storage surpasses 5,000 MW on the CAISO grid." http://www.caiso.com/about/Pages/Blog/Posts/Storage-surpasses-5000-MW-on-the-CAISO-grid.aspx

[9] https://www.energy.ca.gov/data-reports/energy-almanac/california-electricity-data/california-energy-storage-system-survey

Table A- California is overbuilding capacity by at least 7,000 MW.

Required Date	**D.21-06-035 Requirements (PG&E recommended baseline)**	**SB 846 Fourth Quarterly Report**	**Extra Capacity Built**
August 1, 2023	2,000 MW	2,076 MW (Source – Table 3, 2023 Q3 value)	76 MW
June 1, 2024	6,000 MW	5,398 MW (Source – Table 3, 2024 Q2 value of 7,474 MW minus 2,076 MW)	-602 MW (deficit)
June 1, 2025	1,500 MW	4,800 MW (Source – Table 4, 2025 Q2 value of 10,198 MW minus 5,398 MW)	3,300 MW
June 1, 2026	2,000 MW	6,226 MW(Source – Table 4, 2026 Q2 value of 11,026 MW minus 6,226 MW)	4,226 MW
Total	**11,500 MW**	**18,500 MW** (Sum of 2076, 5398, 4800, and 6226)	**7,000 MW**

Second, after the Joint Agency third quarterly report was issued in August[10], the CEC staff issued a draft report[11] in September. In addition to the Joint Agency report that documented an expectation of 10,230 MW of renewable capacity to be online by 2026, the draft CEC report shows an improved resource picture due to acknowledgment of the role of demand response in keeping the lights on. The CEC staff estimated additional potential for 3,600 MW of demand response by 2025. While I believe this figure is too low by 1,200 MW (see below), the combined significant volume of new renewable capacity predicted by the Joint Agency and the significant demand response predicted by the CEC staff greatly increase California's likelihood of staying reliable during peak summer conditions. See Table B below.

[10] Kootstra, Mark (CEC) and Nathan Barcic (CPUC). 2023. Joint Agency Reliability Planning Assessment. California Energy Commission. Publication Number: CEC-200-2023-011.

[11] Erne, David and Chie Hong Yee Yang. September 2023. Draft SB 846 Diablo Canyon Power Plant Extension Cost Comparison. California Energy Commission. Publication Number: CEC-200-2023-013-SD.

Table B - Expected Cumulative New September Net Qualifying Capacity (MW) from Joint Agency Fourth Quarterly report.

Resource Type	2023 Q1	2023 Q2	2023 Q3	2023 Q4	2024 Q1	2024 Q2	2024 Q3	2024 Q4
Solar	7	26	101	150	182	318	321	331
Battery	654	810	1,302	1,825	2,504	5,199	5,528	5,538
Paired /Hybrid	395	473	638	1,280	1,446	1,847	1,856	2,324
Wind	-	14	14	14	14	14	14	14
Geothermal	21	21	21	21	21	74	74	92
Biomass /Biogas	-	-	-	3	22	22	22	25
Total	1,076	1,344	2,076	3,293	4,188	7,474	7,814	8,324

Source: CPUC staff, data as of August 2023

Resource Type	2025 Q1	2025 Q2	2025 Q3	2025 Q4	2026 Q1	2026 Q2	2026 Q3	2026 Q4
Solar	441	459	459	459	462	462	462	462
Battery	5,972	6,743	6,743	6,743	6,865	7,221	7,221	7,221
Paired /Hybrid	2,498	2,815	2,929	2,993	3,001	3,061	3,061	3,061
Wind	14	31	31	31	31	60	60	60
Geothermal	93	122	143	144	160	195	195	200
Biomass /Biogas	25	28	28	28	28	28	28	28
Total	9,043	10,198	10,333	10,398	10,546	11,026	11,026	11,030

Even limiting the analysis to resources that "have already been constructed and interconnected" by the end of 2023, as does the Proposed Decision adopted by the CPUC today[12], California still has at least 1,075 MW surplus capacity by the end of 2023. (As shown below in Table C, the "Net Gain" exceeds the "Net Shortfall" by 1,075 MW).

[12] PROPOSED DECISION OF ALJ SEYBERT (Mailed 10/26/2023).

Table C - California has at least 5,424 MW of excess capacity by the end of 2024, based on Joint Agency Fourth Quarterly report and California Energy Storage System Survey.

Category	Capacity (MW)
DCPP	2,200
3,293 constructed & Interconnected by 2023 + 549 MW installed Battery Energy Storage System (BESS) as of 04/15/24 + 3,800 MW planned BESS online by 12/31/24	7,642
Net Gain if DCPP were retired	5,442
Contingency Reserves	2,588
2022 Equivalent Event shortfall	-2,606
Net Shortfall	18
Bottomline by the end of 2023	5,424

However, it is important to note that a number of significant improvements shown above are not credited in the CEC staff's analysis. Most significantly, the CEC staff report excludes almost all of the 10,230 MW of renewables because they supposedly "compete with the Integrated Resource Planning procurement orders." The 10,230 MW of excluded resources has increased to 11,030 MW in the Joint Agency fourth quarterly report, which are listed in Table B. The CEC staff's failure to credit these renewable resources does not make sense because they are being built in California for the purpose of building capacity and because they can substantially reduce the likelihood of blackouts in California. This substantial volume of renewable capacity should be counted in agency forecasts, not ignored.
In addition to excluding 10,230 MW of renewables (which has increased to 11,030 MW in the Joint Agency fourth quarterly report), the draft September CEC staff's analysis only recognizes 3,600 MW potential for Demand Response in CA by 2025. But when the California Governor initiated Emergency Alerts13 on September 6, 2022, 4,800 MW of demand was reduced.14 Therefore, potential demand response should be increased by at least 1,200 MW.

The draft September CEC staff report also assumes it takes 6 years for new resources to interconnect when new and improved interconnection reforms at other grid operators estimate 1-2 years. Based on new requirements from the Federal Energy Regulatory Commission (FERC) and recent experience, new renewable resources should be expected to be online much sooner.

[13] https://www.gov.ca.gov/2022/09/06/as-record-heat-wave-intensifies-governor-newsom-extends-emergency-response-to-increase-energy-supplies-and-reduce-demand/

[14] https://www.canarymedia.com/articles/nuclear/california-faces-big-power-challenges-even-if-diablo-canyon-stays-open

Finally, the draft CEC staff report is hampered by including the inflexible and expensive 24/7 DCPP operation, when California needs flexible resources to provide reliable, low cost electricity sources. The 2022 rolling blackouts provide an illustration of this phenomenon. CAISO has to maintain 26% planning reserve margin at all times, including covering the threat of loss of the largest power generator on the grid. Thus, one of the contributing factors to the 2020 rolling blackouts was the fact that CAISO needed an additional reserve margin of 2200 MW, just in case DCPP unexpectedly went off-line during the two-hour demand peak.[15] In short, the operation of DCPP increased the blackout risk rather than reducing it.

Therefore, it is important to evaluate the data presented by the CEC and the Joint Agency, rather than relying on the CEC's distorted analysis. The data strongly show that CA has enough energy to keep the lights on without extended operation of DCPP.

[15] https://calmatters.org/commentary/2022/07/the-diablo-canyon-power-plant-wont-stop-power-outages/

ATTACHMENT D

DOCKETED	
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Joint Agency Reliability Planning Assessment

SB 846 Combined Second and Third Quarterly Report 2024

August 2024 | CEC-200-2024-015

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ABSTRACT

The *Joint Agency Reliability Planning Assessment* addresses requirements for electric system reliability reporting in Senate Bill 846 (Dodd, Chapter 239, Statutes of 2022). This report provides the 2024 combined second and third quarterly review of the supply forecast and risks to reliability in the California Independent System Operator territory for 2024 and includes an updated analysis for summer 2024.

Keywords: Reliability, Reliability Planning Assessment, Diablo Canyon, SB 846, California ISO, CEC, CPUC, California, electricity, supply and demand, extreme weather, electricity system planning, stack analysis, summer reliability, resource procurement

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EXECUTIVE SUMMARY

Senate Bill 846 (Dodd, Chapter 239, Statutes of 2022) mandated the California Energy Commission (CEC) and California Public Utilities Commission (CPUC) to develop and provide to the Legislature quarterly joint agency reliability planning assessments beginning on or before December 15, 2022. These assessments include updates on electric system demand and supply for the next 5- and 10-year period, as well as an assessment of electric system reliability under different risk scenarios. The report is also required to provide information on the status of new resources and any delays or barriers to the resources being available to support reliability.

This assessment is the second and third combined quarterly report of 2024 and provides an update to the May 2024 first quarterly *Joint Agency Reliability Planning Assessment* on the status of demand and electricity supply for summer 2024 for the California Independent System Operator (California ISO) balancing area. This report does not update the 5- and 10-year-forward projections of system reliability or provide any recommendations to the Legislature because the assumptions are not updated until the end of calendar year.

Projected system conditions for this summer have improved from the first to the third quarter as new resource projects continue to come online. For August and September, the analysis shows surplus capacity under average and extreme weather conditions, such as those witnessed in the 2020 heat wave (2020 equivalent event) and the 2022 heat wave (2022 equivalent event).

For September, improvements in supply build and system conditions led to an increase in the surplus of resources expected under average conditions, up to 4,700 megawatts (MW). Under a 2020 equivalent event, the September surplus is 2,200 MW. In a 2022 equivalent event, the September projected shortfall turns into a surplus of 655 MW. Under similar extreme conditions, this summer could likely be managed with contingency resources and additional real-time market procurements projected for July through September. However, if there is a coincident fire that impacts transmission assets and results in reduced electricity imported to the California ISO balancing area, the state could face up to a 4,000 MW loss of resources. Such an event could lead to the dispatch of contingency resources and calls for energy conservation measures across the state.

CHAPTER 1:
Combined Second and Third Quarterly Report

Introduction

This report provides an update to reliability-related activities and developments since the May 2024 first quarterly *Joint Agency Reliability Planning Assessment*[1] was published. This report provides updates for topics required by Senate Bill 846 (Dodd, Chapter 239, Statutes of 2022) (SB 846).

Supply Forecast

New Megawatts Online Through May 2024

Throughout the state, over 20,000 MW of new nameplate capacity have come online from January 2020 to May 2024. In this year alone, as shown by Table 1, California continues to experience rapid growth in renewable resources, particularly solar photovoltaics (PV) and energy storage. In 2023 alone, over 5,000 MW of solar PV and energy storage nameplate capacity were added to the electric grid. The CPUC staff estimate that new generation and storage investments represent approximately $7 billion in new infrastructure investment in California in 2022 and 2023.

This growth took place despite challenges outlined in previous reports including permitting, construction, and the interconnection processes. Increased transmission development, approved by the California ISO, should increase the amount of both in-state and out-of-state project development in the coming years.

1 CEC and CPUC May 2024 first quarterly *Joint Agency Reliability Planning Assessment* available at https://www.energy.ca.gov/publications/2024/joint-agency-reliability-planning-assessment-covering-requirements-sb-846-first

Table 1: New Resource Additions Since January 1, 2024

Technology Type	Nameplate Capacity (MW)	Estimated Sept. Net Qualifying Capacity (NQC) MW[2]	Number of Projects
	January 1, 2024-May 28, 2024	**January 1, 2024-May 28, 2024**	**January 1, 2024-May 28, 2024**
Storage	1,345	1,255	21
Solar	921	29	18
Hybrid (storage/solar)	153	95	2
Wind	230	0	1
Geothermal	0	0	0
Biomass, Biogas, Hydro	0.6	0	1
Subtotal Total New SB100 Resources, In-California ISO	**2,650**	**1,379**	**43**
Natural Gas, including Alamitos and Huntington Beach	0	0	0
Total New Resources, In-California ISO	**2,650**	**1,379**	**43**
New Imports, Pseudo-Tie or Dynamically Scheduled	0	0	0
Total New Resources, including Imports	**2,650**	**1,379**	**43**

Source: CPUC staff, California ISO data through May 2024

Note: Data shown here includes new resources added to the California ISO grid since the May 2024 first quarterly *Joint Agency Reliability Planning Assessment* that have been verified online in the California ISO Generator Interconnection Resource ID Report as of May 28, 2024. CEC resource stack assumptions include additional resources with 2024 Commercial Operations Dates that are not included in the California ISO Generator Interconnection Resource ID Report at this time.

Compliance with CPUC's Procurement Orders

In April 2024, California Public Utilities Commission (CPUC) staff released the Summary of Compliance with Integrated Resource Planning (IRP) Order D.19-11-016 and Mid-Term Reliability (MTR) D.21-06-035 Procurement using the August 2023 data filing. All of the data released shows claimed procurement by load serving entities (LSEs) towards the MTR. A supplemental MTR Decision (D.23-02-040) was issued in March 2023, and procurement efforts by the LSEs are ongoing.

2 New projects have not yet made it onto the CPUC's monthly NQC list and have not yet been assigned NQC. Future quarterly SB 846 reports will include updated NQC amounts for these resources.

CPUC staff are monitoring LSE Procurement Progress with IRP Procurement orders. As of the August 1, 2023, CPUC IRP Compliance Filings, LSEs are reporting:

- 3,466 MW net qualifying capacity[3] (NQC) of total new procurement (validated by CPUC staff as online by August 1, 2023), collectively exceeding the D.19-11-016 3,300 MW procurement obligation.
- 2,978 MW NQC eligible for IRP procurement orders (validated by CPUC staff as online by August 1, 2023), collectively exceeding the 2,000 MW of MTR Tranche 1 Obligation.
- 11,052 MW NQC of procurement as under contract and forecasted to be online by June 1, 2027, as progress towards the 13,500 MW NQC MTR and supplemental MTR procurement order.

More comprehensive information about compliance with IRP procurement orders can be found in the CPUC's report.[4]

Estimates of Planned Resources

This section updates the estimated new capacity under contract to CPUC-jurisdictional LSEs through 2027. Tables 2 through 5 include resources being developed for compliance with IRP procurement orders as well as procurement for LSE compliance with Renewables Portfolio Standard and procurement the CPUC approved in the Emergency Reliability proceeding.

All totals provided below represent the cumulative LSE-reported September NQC under contract to CPUC-jurisdictional LSEs. The data underlying the expected projects can be challenging to track due to:

- Changes in project names throughout the lifecycle of project development.
- Frequent on-line date changes that can be reported on differently in different data sets
- Multiple load-serving entities can contract as off-takers for each project.
- Different on-line dates for different phases of a project.
- Projects with multiple technologies at the same site in various configurations.
- Projects with changes to project sizing, or initial phases that are subsets of the total project size.
- Projects with a single interconnection queue position can result in multiple project resource identification numbers, once they come on-line with interconnection at the California ISO (i.e., each California ISO queue position can have multiple California ISO resources IDs).
- Projects can be developed and interconnected via either wholesale interconnection tariffs governed by California ISO interconnection tariffs (known as Large Generator

3 NQC values listed for compliance with IRP procurement orders are based on IRP's effective load carrying capabilities (ELCCs). More information about ELCCs for use in IRP's Procurement Track are available here: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/long-term-procurement-planning/more-information-on-authorizing-procurement/irp-procurement-track

4 Summary of Compliance with Integrated Resource Planning (IRP) Order D.19-11-016 and Mid Term Reliability (MTR) D.21-06-035 Procurement, available at https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/publicirpcompliancereport080123.pdf

Interconnection Agreements) or wholesale interconnection tariffs governed by distribution utility tariffs (known as Wholesale Distribution Access Tariffs)

LSE procurement is ongoing to meet CPUC IRP procurement orders; some of the existing contracts will be delayed, and other contracts will be added, which is consistent with the cycle of energy project development. The CPUC staff emphasizes that Tables 2 through 5 represent resources known to be under contract to CPUC-jurisdictional LSEs between 2023 and 2027, as of March 2024. Tables 2 through 5 do not comprehensively track all new MW already on-line and, instead, track CPUC Jurisdictional LSEs' reporting of their contracts that came online in 2023 and are forecasted to come online through 2027, inclusive of procurement beyond the scope of IRP. Since the May 2024 first quarterly *Joint Agency Reliability Planning Assessment* was released, the CPUC is reporting more expected MW as its jurisdictional LSEs continue to sign additional contracts to meet IRP procurement orders. These totals are subject to change as the CPUC receives new data from LSEs, conducts field calls with developers and investor-owned utility (IOU) interconnection departments, and continues to evaluate the data.

Table 2: Estimated September NQC[5] (MW) by Transmission Access Charge (TAC) Area 2024 through 2025

TAC Area	2024 Q1	2024 Q2	2024 Q3	2024 Q4	2025 Q1	2025 Q2	2025 Q3	2025 Q4
East-Central	1,917	3,706	4,294	4,687	5,129	5,322	5,340	5,340
North	1,070	1,836	1,933	1,967	2,377	2,870	3,035	3,035
South	120	224	275	275	689	806	920	920
Other	411	815	815	853	853	1,738	1,903	1,952
Total	**3,518**	**6,580**	**7,317**	**7,782**	**9,048**	**10,736**	**11,198**	**11,247**

Source: CPUC Staff Aggregation of March 2024 LSEs' Procurement Status Reports

Table 3: Estimated September NQC (MW) by TAC Area 2026 through 2027

TAC Area	2026 Q1	2026 Q2	2026 Q3	2026 Q4	2027 Q1	2027 Q2	2027 Q3	2027 Q4
East Central	5,601	6,762	6,762	6,762	6,762	7,255	7,255	7,255
North	3,186	3,597	3,600	3,667	3,667	4,007	4,007	4,007
South	920	970	970	1,029	1,029	1,029	1,029	1,029
Other	2,038	2,547	2,575	2,834	2,834	2,884	3,334	3,340

5 Values here also represent NQC per IRP's Procurement Track ELCCs. More information is available here: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/long-term-procurement-planning/more-information-on-authorizing-procurement/irp-procurement-track.

TAC Area	2026 Q1	2026 Q2	2026 Q3	2026 Q4	2027 Q1	2027 Q2	2027 Q3	2027 Q4
Total	**11,745**	**13,876**	**13,907**	**14,291**	**14,291**	**15,175**	**15,625**	**15,630**

Source: CPUC Staff Aggregation of March 2024 LSEs' Procurement Status Reports

Table 4: Estimated September NQC (MW) by Resource Type 2024 through 2025

Resource Type	2024 Q1	2024 Q2	2024 Q3	2024 Q4	2025 Q1	2025 Q2	2025 Q3	2025 Q4
Solar	214	299	304	323	326	361	361	361
Battery	2,089	4,371	5,082	5,239	6,260	7,622	7,787	7,787
Paired/ hybrid	1,123	1,812	1,820	2,103	2,345	2,624	2,899	2,927
Wind	64	64	64	64	64	64	64	64
Geothermal	21	28	28	28	28	38	57	87
Biomass/ biogas	21	28	28	28	28	38	57	78
Total	**3,518**	**6,580**	**7,317**	**7,782**	**9,048**	**10,736**	**11,198**	**11,247**

Source: CPUC Staff Aggregation of March 2024 LSEs' Procurement Status Reports

Table 5. Estimated September NQC (MW) by Resource Type 2026 through 2027

Resource Type	2026 Q1	2026 Q2	2026 Q3	2026 Q4	2027 Q1	2027 Q2	2027 Q3	2027 Q4
Solar	363	363	363	363	363	363	363	363
Battery	7,981	9,871	9,871	9,938	9,938	10,640	11,090	11,090
Paired/ hybrid	3,143	3,243	3,245	3,304	3,304	3,334	3,334	3,334
Wind	64	157	186	374	374	424	424	424
Geothermal	163	212	212	282	282	382	382	388
Biomass/ biogas	31	31	31	31	31	31	31	31
Total	**11,745**	**13,876**	**13,907**	**14,291**	**14,291**	**15,175**	**15,625**	**15,630**

Source: CPUC Staff Aggregation of March 2024 LSEs' Procurement Status Reports

CPUC Rulemaking (R.23-01-007) Related to the Diablo Canyon Power Plant Extension

On January 12, 2023, the CPUC adopted Order Instituting Rulemaking (R.) 23-01-007 to implement the provisions of SB 846. In August 2023, the CPUC approved Decision D.23-08-004 for Phase 1, Track 1 of R.23-01-007, addressing funding issues for the Diablo Canyon Independent Safety Committee (DCISC). Ongoing SB 846-related items in the rulemaking include the following:

- In February 2024, Phase 2 of R.23-01-007 commenced during which the CPUC will consider whether Pacific Gas and Electric (PG&E) should:
    - provide upfront reasonable manager showings for CPUC review and approval.[6]
    - determine the process for Diablo Canyon Power Plant (DCPP) cost review and true-up to actual costs and market revenues for the prior year.
    - establish the process for submittal and review of an annual compensation report and spending plan.
- On February 21 and 22, 2024, the DCISC held its first meeting of the year at which it reviewed DCPP safety, seismic, and operational issues, and presented on their fact-finding efforts. The Fact-Finding Report and informational presentations can be downloaded from the DCISC webpage.[7] Some of the key conclusions from the report are:
    - DCPP's Refueling Outage 1R24 was successfully performed. All planned scope of work was completed, and all performance goals were met except for radiation dose and post-outage reliability. The DCISC should follow up on reviewing the causes and corrective actions for Maintenance Outage 1X25 (Pressurizer Safety Valve repair) which occurred about one month after the end of the Refueling Outage.
    - The DCPP team successfully completed a total of approximately 182 Aging Management Program inspections during Refueling Outage 1R24 in support of license renewal. Overall, there were no findings of aging-related challenges to any structure, system or component's ability to perform its intended functions. The DCISC considered these results to be an indicator of excellent performance and a strong assurance of continued safety during a period of extended operations.

PG&E provided information on past Unit 1 Reactor Vessel weld inspection results along with answers to questions related to vessel embrittlement. The DCPP team was unable to withdraw the Capsule B weld material specimen from the Unit 1 Reactor Vessel during Refueling Outage 1R24 due to tool fitment problems. The DCPP team will retry this procedure and other approaches in Refueling Outage 1R25 with the Reactor Vessel core barrel removed, which should enable better access. The DCISC's evaluations of Unit 1's Reactor Pressure Vessel embrittlement is ongoing and will be completed at a future Public Meeting. The DCISC has

6 Upfront reasonable manager showings mean the utility's procurement expenses are found to be reasonable before incurring the costs rather than after. Typically this looks like establishing regulatory (balancing accounts) that have a revenue requirement approved through a proceeding on a forecast basis.

7 Past Public Meetings. Available here: https://www.dcisc.org/event-public-meeting_43.htm

published two embrittlement reports and presented the information in two public meetings while accepting and addressing public comments. The DCISC has indicated it will likely vote on whether to endorse the report's conclusions at their October 2024 public meeting. Additionally, the NRC Atomic Safety and Licensing Board considered a petition for hearing on the topic of embrittlement from San Luis Obispo Mothers for Peace, Friends of the Earth, and Environmental Working Group. On July 3, 2024, the NRC Administrative Judges concluded that embrittlement testing was in line with NRC regulations, denying the request for hearing and terminating the proceeding. On March 29, 2024, PG&E filed Application (A.)24-03-018[8], its first DCPP Extended Operations Cost Forecast application with the CPUC, as ordered in D.23-12-036.

- The Nuclear Regulatory Commission continues its review of PG&E's license renewal application for DCPP.
- On May 30, 2024, the Diablo Canyon Independent Peer Review Panel met to discuss the findings of geological studies done on the faults around Diablo Canyon.

Tracking Project Development

The Tracking Energy Development (TED) Task Force, comprised of the CEC, CPUC, Governor's Office of Business Development (GO-Biz) and California ISO, continues to track energy projects under development and help to navigate challenges and barriers where appropriate. Table 6 lists the TED Task Force tracking efforts and its frequency.

Table 6: TED Task Force Tracking Efforts and Frequencies

Frequency	Action
Ongoing	TED Task Force conducts outreach to developers with many projects under development to review status of projects and issues, if any.
Ongoing	Ad-hoc meeting with developers and others about specific project challenges.
Weekly	TED Task Force meets weekly to review issues, developer requests for assistance and provide updates.
Monthly	CPUC receives and compiles submitted data from LSEs on resources under contract for the near-term.
Monthly	CPUC compiles data on new MW online.
Monthly	CPUC hold calls with investor-owned utility interconnection teams to review projects, pinpoint discrepancies, and identify operational areas for improvement.
Quarterly	TED Task Force provides updates to Joint Agency Reliability Planning Assessments.
Biannual	California ISO, in conjunction with CPUC, hosts the Transmission Development Forum to provide status updates and discuss delays to transmission projects, including network upgrades.

Source: GO-Biz

8 Application of Pacfiic Gas and Electric Company to Recover in Customer Rates the Costs to Support Extended Operations of Diablo Canyon Power Plant From September 1, 2023, Through December 31, 2025, and for Approval of Planned Expenditure of 2025 Volumetric Performance Fees. Available at https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M528/K454/528454317.PDF

In the first quarter of 2024, 19 renewable energy projects totaling 1,188 MW were added to the California grid. The TED Task Force is working to assist more projects to come online timely to support the state's energy reliability needs. With improved coordination amongst member agencies, the TED Task Force has increased engagement with renewable energy project developers as well as other stakeholders including utility companies and permitting agencies. This has allowed the TED Task Force to monitor and understand the successes and challenges experienced throughout project development. The major barriers to energy project deployment remain the same as previously reported: supply chain challenges, interconnection issues (including network upgrades), and permitting challenges. These issues are complex, interrelated, and cannot be resolved with a single solution. Recent activities that members of the TED Task Force have taken, individually or collectively, to help address some of these issues are outlined below.

Leveraging Federal Funding to Accelerate Energy Project Development

The passage of the federal Inflation Reduction Act of 2022 and the Infrastructure Investment and Jobs Act provided billions of dollars for clean energy projects and climate initiatives over the next 10 years, including projects to modernize the grid, improve energy efficiency, speed up the interconnection process and increase transmission capacity.

Most of these funds are available through a competitive application process. In January 2022, CPUC President Alice Reynolds sent a letter to the utilities in California encouraging them to apply for suitable federal funding opportunities that will advance innovative approaches to reduce the cost of energy.[9]

Further, GO-Biz assisted many businesses and organizations into securing federal funds by providing support letters. When appropriate, members of the TED Task Force partnered with private entities to directly apply for funding of critical projects that will assist with improvements and address the issues that regularly plague deployment of utility-scale energy projects.

In April 2024, TED Task Force members worked with utility partners to apply for funds from the U.S. Department of Energy's Grid Resilience and Innovation Partnerships (GRIP) Program Round 2 Funding Opportunity.[10] The proposal would implement projects that will address two challenges – transmission capacity and interconnection system upgrade needs. The "California Harnessing Advanced Reliable Grid Enhancing Technologies for Transmission" (CHARGE 2T) proposal would utilize advanced conductors and grid enhancing technologies which would help to increase the capacity of current transmission lines. Additionally, by streamlining the interconnection process through bridging critical data gaps and increasing transparency for developers and utilities, this proposal will greatly assist in the state's effort to connect more clean energy projects to the California grid. CHARGE 2T projects would aid in the state's efforts to reach its energy and carbon neutrality goals set out in Senate Bill 100 (de León,

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9 Letter available here: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/office-of-governmental-affairs-division/documents/federal-funding/january-2022-letter-from-cpuc-president-reynolds-to-electric-and-gas-ious.pdf?sc_lang=en&hash=1776D6C63D6310697A34CDA849700EE7

10 PG&E Press Release related to grant application. PG&E Corporation - Statewide Partnership Aims to Deliver More Clean Energy Faster to Californians and Support State Climate Goals (pgecorp.com)

Chapter 312, Statutes of 2018) and the 2022 California Air Resources Board Scoping Plan. The TED Task Force members will remain in partnership with project sponsors to ensure successful project implementation if funded.

Additionally, the CEC partnered with an energy developer to apply for GRIP funding for the "California Enabling Grid Reliability with Energy Storage Technology" project, which aims to deploy new multiday energy storage assets in California's Central Valley. If funded, these assets will promote higher levels of renewable energy projects and help the state decarbonize the grid.

Continued Stakeholder Engagement on Battery Energy Storage Safety

Battery energy storage systems (BESS) play an enormous role in providing reliable power and helping California reach its energy decarbonization goals. In April 2024, California reached a milestone of deploying 10,000 MW of battery energy storage, including over 8,000 MW of wholesale energy storage. In the coming years, more than half of the capacity expected to come online to serve the wholesale electricity market are BESS systems.

While the state has deployed many BESS projects, the technology is fairly new compared to other resources. There are public concerns around the impacts on the communities near and around where the projects are built, including safety risks and in particular, fire risks. In the first quarter of 2024, the CEC, in conjunction with other members of the TED Task Force, hosted a staff workshop on BESS safety, siting and permitting best practices. The workshop highlighted the importance for stakeholders to work collaboratively to develop a common understanding of how BESS can be designed and installed to operate safely and reliably. Following the workshop, GO-Biz engaged with stakeholders to partner and develop a forum to exchange information needed as cities and counties revise planning documents and determine how BESS best fits within their communities. Considering the nascency of BESS, forums such as this, as well as education and training will be critical to develop best practices.

Reliability Assessment

The reliability assessment approach used for this report is consistent with the Summer Resource Stack Analysis for 2024–2034 published by the CEC in the May 2024 first quarterly *Joint Agency Reliability Planning Assessment*. A change worth noting is the addition of new logic, shown in Table 7, built into the analysis to better track the development of new projects and account for uncertainty. The assessment compares an hourly projection of anticipated supply, against the projected hourly demand plus the reserve margin, for the peak day of each month (July through September). A 17 percent planning reserve margin (current resource adequacy planning standard) is equivalent to average conditions, while 22.5 and 26 percent planning reserve margins are comparable to 2020 and 2022 equivalent events, respectively.

Generally, the Summer Resource Stack Analysis conservatively identifies the maximum hourly need for contingencies in summer 2024 for each equivalent event. There is no projected need for contingency resources in July and August and as such, this section will report on September, which is typically the most challenging summer month for reliability.

Comparison Matrix

As part of an ongoing effort to align inputs and assumptions for various energy entities, CEC staff collaborated with California ISO and CPUC staff to develop a comparison matrix that shows the similarities and differences. As shown in Table 7, the CEC and California ISO inputs for stack analyses are generally aligned with few minor differences in solar and wind profiles methodologies.

Table 7: CEC and California ISO Comparison of Inputs and Assumptions

Input	CEC stack	California ISO Stack[11]
Horizon	Near term, year ahead, 2024	Near term, year ahead, 2024
Planning reserve margin (PRM)/ Reserve margin	17%, 22.5%, 26% PRM	18.5% Reserve margin
Base demand	2023 IEPR California Energy Demand Forecast (CED) - Planning	2023 IEPR CED - Planning[12]
Existing supply	• California ISO NQC list - monthly update • CPUC NQC list	California ISO NQC list - monthly update
New supply	• California ISO queue data • CPUC Procurement Orders Apply logic for projects with online dates in the past: • If the project is ACTIVE then add 3 months to the online date • If the project is SYNC OK then add 2 months to the online date • If the project is COMX then add 1 months to the online date	California ISO queue data. Criteria for revised commercial operations dates to reflect potential project delays: • If the project is not active in Resource Interconnection Management System (RIMS) then add 6 months • If the project is active in RIMS without a resource ID then add 4 months • If the project is active in RIMS and has a resource ID then add 3 months • If the project is SYNC OK in RIMS and has a resource ID then add 2 months

11 2024 Summer Loads and Resources Assessment. Available at: https://www.caiso.com/Documents/2024-Summer-Loads-and-Resources-Assessment.pdf

12 2023 Integrated Energy Policy Report (IEPR) California Energy Demand Forecast (CED) - Planning available at https://efiling.energy.ca.gov/GetDocument.aspx?tn=254234&DocumentContentId=89587

Input	CEC stack	California ISO Stack[11]
		• If the project is COMX in RIMS and has a resource ID then add 1 month Additional information[13]
Imports (resource adequacy)	Average of 2015-2022 Import RA[14]	Average of past 8 years import resource adequacy (2016-2023)[15]
Hybrids	• NQC value; When no NQC, ignore variable energy resource (VER) component. • Battery nameplate and assume a discharge profile (4 hours across peak)	• Apply solar and wind profile factors to the VER component, and • Apply standalone assumptions for battery component; the sum of these two is constrained by net MW at point of interconnection
Solar	Nameplate capacity using solar shapes[16]	• CPUC exceedance value approach using 8 years of rolling data (2016-2023) • Net dependable capacity multiplying solar profiles[17]
Wind	Nameplate capacity using wind shapes	• Exceedance value approach using 8 years of rolling data (2016-2023): • Net dependable capacity using wind profiles[18]

13 Expected new resources are those that are not on the California ISO NQC list, but are expected to be online by June 30, 2024; If the new resource has an NQC then use NQC; If no NQC - use technology factors (e.g., effective load carrying capability) to discount maximum operating level; Solar profile based on 70% exceedance value; Wind profile based on 80% exceedance value for summer months (June to October) and 65% for non-summer months; batteries are at 90% of maximum operating level. New resources are units in California ISO systems in the New Resource Implementation process and are selected based on the following methodology: Push out online dates for delayed projects, include all SYNC OK and COMX in NRI, Include Active status NRI projects that are on the California ISO NQC list.

14 Non-resource specific plus tie generator, no liquidated damages credits for month of September

15 Non-resource specific plus pseudo-tied import resources; liquidated damages credits are included separately.

16 Profiles based on high load days and weighting 2014-2023 load data (OASIS); generation data from meter data

17 Profiles based on 70% exceedance, California ISO historical demand meter data for the top 5 load days, and generation meter data

18 Profiles based on 80% exceedance for summer months (June to October) and 65 percent for non-summer months, California ISO historical demand meter data for the top 5 load days, and generation meter data

Input	CEC stack	California ISO Stack[11]
Projected demand response	Demand Response CPUC load impact protocol 2024	NQC plus demand response resource adequacy credits
Hydro	NQC value	NQC value, or technology factor to discount net dependable capacity if no NQC
Cogen/Biomass/Biogas/Geothermal	NQC value	NQC value, or technology factor to discount net dependable capacity if no NQC
Once Through Cooling (OTC)	Not included in 2024 and beyond, as OTCs will be in the Strategic Reliability Reserve (SRR)	Not included in 2024 and beyond, as OTCs will be in the SRR
Diablo Canyon Power Plant	• Included in 2024 and beyond stack • Retired beginning 2031.	Included in 2024 stack

Source: CEC staff with input from California ISO staff

California ISO Area: Updated Resource Stack Analysis Results for Summer 2024

As shown in Table 8, there were various changes to the resource stack since the release of the May 2024 first quarterly *Joint Agency Reliability Planning Assessment*. Notably, over 2,000 MW of NQC were added that will now be available to support summer net peak demand. The new NQC consists of standalone battery, geothermal, hybrid, and solar resources. The effect of adding 2000 MW of NQC can be seen in the need for contingencies, in Table 8, where surpluses continue to improve. Other changes to note, in Table 8, include changes to demand response resources and expected new battery capacity for September. CEC staff removed a 6 percent demand response PRM adder to align with CPUC demand response program changes.[19] The decrease, in the New Batteries Nameplate, is due to the net impact of battery projects coming online, moving to the Existing Resources category, and projects delayed.

In the May 2024 first quarterly *Joint Agency Reliability Planning Assessment*, surpluses of 4,000 MW and 1,500 MW were reported under average conditions and 2020 equivalent event conditions, respectively. However, there was a 90 MW need if the state were to experience a 2022 equivalent event. As shown in Table 8, the resource stack analysis identified improvements from the average conditions through all extreme events.

While improvements can be seen in all conditions, it is important to note that improvements are forecasted results based on the assumed full build out of resources planned for the year. More specifically, the resource stack analysis in this report assumes that 2,102 MW of batteries

19 2022 Filing Guide for System, Local and Flexible Resource Adequacy Compliance Filings. Available at https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/final-2022-ra-guide-clean-101821.pdf

will fully be online before August 31, 2024, to support reliability in the month of September 2024. Any delays to the battery storage build out could create challenges under extreme events.

Table 8: Comparison of Summer Assessment Results for September 2024

	2024 1st Quarterly Report	2024 2nd and 3rd Quarterly Reports	Change Since Last Update
Supply			
Demand Response	1,115	1,052	▼**63**
Existing Resources*	43,556	45,643	▲**2087**
New Batteries Nameplate**	3,327	2,102	▼**1225**
Wind	1,382	1,325	▼ **57**
Solar	1,643	1,745	▲**102**
Resource Adequacy Imports	6,000	6,000	–**0**
Total (MW)	**57,022**	**57,867**	▲**844**
Demand			
2023 CEC Demand Forecast – 2024 Sept. Peak Demand	**45,972**	**45,972**	–**0**
Surplus/Shortfalls			
Planning Standard	4,000	4,765	▲**765**
2020 Equivalent Event	1,500	2,253	▲**753**
2022 Equivalent Event	-90	655	▲**745**

Source: CEC staff with California ISO data
*Increase in this category is due to all types of resources coming online. Values are in RA NQC MW.
**Decrease in this category means that resources have come online or have an updated online date but generally means they are no longer considered new and have been moved to Existing Resources.

Table 9 shows the impact of 20 percent and 40 percent resource delays to the need for contingencies. The delay percentage is applied across all resources but solar and wind contributions to reliability at net peak are minor. Therefore, the biggest new resource supporting reliability is BESS. As shown in

Table 9, a 40 percent delay to new BESS resources could swing a 2022 equivalent event system condition from a 655 MW surplus to a 318 MW need for contingency.

Table 9: Impact of Delay on Reliability

Delay	Battery capacity online by 8/31/2024	System conditions	Surplus/Shortfalls
20 percent	1,680 MW	2020 equivalent event	168 MW
40 percent	1,260 MW	2022 equivalent event	-318 MW

Source: CEC staff

Contingency Resources

The agencies and the California ISO are continuing to track contingency resources to provide support during an extreme event. The updated contingency list for 2024 includes the addition of 2,859 MW of OTC resources to the Electricity Supply Strategic Reliability Reserve Program. Contingency resources, identified in **Table 10**, are expected to provide up to 4,200 MW during extreme events and may be called upon to cover contingency needs identified in real time grid operations.

Table 10: **Contingency Resources for Summer 2024**

Type	Contingency Resource	Available MW July	Available MW August	Available MW September
SRR [20]	DWR Electricity Supply Strategic Reliability Reserve Program	3,130	3,150	3,150
SRR	Demand Side Grid Support	393	444	450
SRR	Distributed Electricity Backup Assets (under development)	0	0	0
CPUC	Ratepayer Programs (Emergency Load Reduction Program, Smart Thermostats, etc.)	217	209	202
CPUC	Imports Beyond Stack*	25	25	25
CPUC	Capacity at Co-gen or Gas Units Above Resource Adequacy *	159	186	93
Non-Program	Balancing Authority Emergency Transfers	300	300	300
Non-Program	Thermal Resources Beyond Limits: Gen Limits	40	40	40
Non-Program	Thermal Resources Beyond Limits: Gen Limits Needing 202c[21]	25	25	25
	Total	4,289	4,379	4,285

*Estimates based on IOU excess procurement reports from 2024.
Source: CEC staff with California ISO, DWR, and CPUC data

20 Strategic Reliability Reserve

21 Federal Power Act Section 202(c) - emergency order authorizing specific electric generating units located within a service territory to operate at their maximum generation output levels in order to preserve the reliability of the bulk electric power system due to ongoing wildfires, extreme heat, and droughts causing a diminished ability to generate hydropower resulting in higher than usual electricity demand.

Additional recent activities related to the SRR include the following:

- On May 8, 2024, the CEC adopted the Third Edition of the guidelines for its Demand Side Grid Support (DSGS) program in time for the 2024 summer season, continuing to streamline participation and incorporating bi-directional electric vehicle chargers as an eligible resource providers can include in the virtual power plant option in the DSGS program.
- The CEC released a Notice of Proposed Awards on April 22, 2024, for 9 projects selected among the applications submitted in response to the first solicitation issued under the Distributed Electricity Backup Assets program (referred to as Bulk Grid Assets Enhancements for Grid Reliability Grant Funding Opportunity). The selected projects requested $123 million funding to add ~297 MW of new capacity by 2027 to increase California's grid reliability. The CEC is expected to approve executed project agreements in the second half of 2024.
- The CEC released a draft concept proposal for the second grant funding opportunity focused on distributed energy resources in February 2024 under its Distributed Electricity Backup Assets program.

Summer 2024 Outlook

The CEC hosted a Summer Reliability Workshop on May 29, 2024. The following were the key takeaways for the Summer 2024 Outlook:

- The weather forecast indicated cooler temperatures in June and July, with a significant increase expected from August onward, particularly in interior areas of the Western U.S. The Desert Southwest and Rockies regions have the highest probability of above-average temperatures, while coastal California is expected to remain cooler. There is a need to monitor weather patterns closely as shifts could lead to widespread heatwaves.
- The fire outlook suggested that California remains at risk, particularly due to the robust herbaceous growth from the past two years, which provides ample fuel for potential fires.
- The resource adequacy outlook for the Western Interconnection was generally positive, with sufficient resources under expected conditions. However, extreme weather events, ongoing droughts, and wildfires could elevate reliability risks. Efforts to expedite resource builds and delay retirements have been beneficial, but challenges such as supply chain issues could impact these improvements.
- The Sacramento Municipal Utility District reported a cautiously optimistic outlook for summer 2024, with no significant planned transmission or generation outages and sufficient operating margins to meet a 1-in-10 year load forecast. The Los Angeles Department of Water and Power expects stable loads compared to previous years, with a forecasted peak load of 5,727 MW for 2024 and plans to add 200 MW of solar and 150 MW of battery storage by the end of summer. The Imperial Irrigation District emphasized enhanced grid resilience using mobile generators for emergency responses in rural areas, and the critical role of energy storage in maintaining grid stability. Collaborative planning with the California ISO and other balancing authorities, as well as reconductoring transmission lines with advanced conductors to withstand higher temperatures, were also highlighted as essential strategies for ensuring summer reliability.

- California's new energy resource build out has seen significant developments, including a record addition of clean energy capacity, primarily from solar and battery projects. These advancements are crucial for meeting energy demands during peak periods. The state's hydro resources are managed with improved flexibility, thanks to favorable water and reservoir conditions. Demand-side programs, such as the Emergency Load Reduction Program and the Distributed Electricity Backup Assets Program, are expanding participation and providing additional support for reliability. Additionally, the Stack Analysis indicated a surplus of 4,000 MW under average conditions, though contingencies may be necessary in extreme scenarios. Overall, the workshop emphasized the importance of continued monitoring and proactive measures to ensure grid reliability throughout the summer.

Recent and Upcoming Activities

The following activities occurred recently or are projected for the next quarter:

- The CEC is targeting to release the final version of the grant funding opportunity focused on distributed energy resources under its Distributed Energy Backup Assets program pending the final budget adopted for fiscal year 2024-2025 and review of stakeholder comments.
- DSGS Program staff plan to continue the stakeholder process this summer to explore changes to the DSGS program guidelines that would be implemented in 2025, such as a potential incentive option for market-aware demand response and real-time emergency triggers for virtual power plants.
- In quarters three and four of 2024, the CPUC's Resource Adequacy Proceeding (R.23-10-011) will consider modifications to the PRM for compliance years 2026 and 2027, including the results of Energy Division's annual Loss of Load Expectation study to be published in July 2024.[22]
- In April 2024, the IRP Proceeding (R.20-05-003) issued an amended Scoping Memo, which established timelines for key items in the proceeding. Among those items was CPUC's work toward implementing Assembly Bill 1373 (Garcia, Chapter 367, Statutes of 2023) and, in support of that implementation, the CPUC issued an Administrative Law Judge Ruling Seeking Comments on Need and Process for Centralized Procurement of Specified Long Lead-Time Resources, including some supporting material, and held a workshop on the Ruling.

22 Available here: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M534/K332/534332050.PDF

APPENDIX A:
Acronyms and Abbreviations

BESS – Battery energy storage system

California ISO – California Independent System Operator

CEC – California Energy Commission

CED – California Energy Demand Forecast

CHARGE 2T - California Harnessing Advanced Reliable Grid Enhancing Technologies for Transmission

CPUC – California Public Utilities Commission

DCISC - Diablo Canyon Independent Safety Committee

DCPP – Diablo Canyon Power Plant

DSGS – Demand Side Grid Support

DWR – Department of Water Resources

ELCC - Effective load carrying capability

GO-Biz – Governor's Office of Business and Development

GRIP - Grid Resilience and Innovation Partnerships Program

IRP – Integrated Resource Planning

LSE – Load-serving entity

MTR – Mid-term reliability

MW - Megawatts

NQC – Net qualifying capacity

OTC – Once through cooling

PG&E – Pacific Gas and Electric

PV - Photovoltaics

RIMS – Resource Interconnection Management System

SRR – Strategic Reliability Reserve

TED – Tracking Energy Development

TED Task Force – Tracking Energy Development Task Force

VER – Variable energy resource

APPENDIX B:
Glossary

For additional information on commonly used energy terminology, see the following industry glossary links:

- California Air Resources Board Glossary, available at https://ww2.arb.ca.gov/about/glossary
- California Energy Commission Energy Glossary, available at https://www.energy.ca.gov/resources/energy-glossary
- California Independent System Operator Glossary of Terms and Acronyms, available at http://www.caiso.com/Pages/glossary.aspx
- California Public Utilities Commission Glossary of Acronyms and Other Frequently Used Terms, available at https://www.cpuc.ca.gov/glossary/
- Federal Energy Regulatory Commission Glossary, available at https://www.ferc.gov/about/what-ferc/about/glossary
- North American Electric Reliability Corporation Glossary of Terms Used in NERC Reliability Standards, available at: https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf
- US Energy Information Administration Glossary, available at https://www.eia.gov/tools/glossary/

Integrated Energy Policy Report (IEPR)

Senate Bill 1389 (Bowen, Chapter 568, Statutes of 2002) requires the California Energy Commission to prepare a biennial integrated energy report. The report, which is crafted in collaboration with a range of stakeholders, contains an integrated assessment of major energy trends and issues facing California's electricity, natural gas, and transportation fuel sectors. The report provides policy recommendations to conserve resources, protect the environment, ensure reliable, secure, and diverse energy supplies, enhance the state's economy, and protect public health and safety. For more information, see the CEC Integrated Energy Policy Report Web page.

Investor-owned utility (IOU)

Investor-owned utilities (IOUs) provide transmission and distribution services to all electric customers in their service territory. The utilities also provide generation service for "bundled" customers, while "unbundled" customers receive electric generation service from an alternate provider, such as a community choice aggregator. California has three large IOUs offering electricity service: Pacific Gas and Electric, Southern California Edison, and San Diego Gas & Electric.

Load-serving entity (LSE)

A load-serving entity is defined by the California Independent System Operator as an entity that has been "granted authority by state or local law, regulation or franchise to serve [their] own load directly through wholesale energy purchases."

Nameplate capacity

The maximum amount of electricity that a generating station (also known as a power plant) can produce under specific conditions designated by the manufacture.

Net qualifying capacity (NQC)

The amount of capacity that can be counted towards meeting resource adequacy requirements in the CPUC's RA program. It is a combination of the CPUC's qualifying capacity counting rules and the methodologies for implementing them for each resource type, and the deliverability of power from that resource to the California ISO system. CPUC IRP procurement orders (D.19-11-016, D.21-06-035, D.23-02-040) also require counting of resources for compliance using the associated NQCs, which can be different to those used in the RA program, depending on the resource type and order.

Planning reserve margin

Planning reserve margin (PRM) is used in resource planning to estimate the generation capacity needed to maintain reliability given uncertainty in demand and unexpected capacity outages. A typical PRM is 15 percent above the forecasted 1-in-2 weather year peak load, although it can vary by planning area.

Power plant

A centralized facility that generates and stores electricity to meet the energy demands of a specific area or grid. It includes generating units and storage resources to produce and supply electrical energy effectively.

Real-Time Market

The competitive generation market controlled and coordinated by the ISO for arranging real-time imbalance energy.

Renewables Portfolio Standard (RPS)

The Renewables Portfolio Standard, also referred to as RPS, is a program that sets continuously escalating renewable energy procurement requirements for California's load-serving entities. The generation must be procured from RPS-certified facilities (which include solar, wind, geothermal, biomass, biomethane derived from landfill and/or digester, small hydroelectric, and fuel cells using renewable fuel or qualifying hydrogen gas). More information can be found at the CEC Renewables Portfolio Standard web page and the CPUC RPS Web page.

Reserve margin

The differences between the dependable capacity of a utility's system and the anticipated peak load for a specified period.

Resource adequacy

Resource adequacy ensures there is enough capacity and reserves for the grid operator to maintain a balanced supply and demand across the electric system.

Transmission Planning Process (TPP)

The California Independent System Operator's annual transmission plan, which serves as the formal roadmap for infrastructure requirements. This process includes stakeholder and public input and uses the best analysis possible (including the CEC's annual demand forecast) to assess short- and long-term transmission infrastructure needs. For more information, see the California ISO Transmission Planning Web page.

RAO KONIDENA

ENERGY MARKET EXPERTISE IN DISTRIBUTED ENERGY RESOURCES

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Rao Konidena is an independent energy consultant. He worked at the Midcontinent Independent System Operator (MISO) for 15 years. Before he left MISO, he was the Principal Advisor for Policy Studies, working on energy storage and distributed energy resources. At MISO, Rao worked in management and non-management roles around resource adequacy, economic planning, business management, and policy functions.

Rao is the President of the Finnish American Chamber of Commerce – Minnesota (FACC-MN) and sits on the Board of Ever Green Energy and Minnesota Solar Energy Industries Association (MnSEIA).

EXPERIENCE

RAKON ENERGY LLC, Roseville, MN
President & Chief Executive Officer (CEO) May 2018 – Present

Providing consulting services related to Federal and state energy policies focusing on energy storage and distributed energy resources

- A renewable energy developer engaged Rakon Energy to provide MISO expertise for their renewable energy project portfolio in various stages and study cycles of the Generator Interconnection Queue and the capacity credit impact from MISO's seasonal capacity construct.
- An Independent Power Producer engaged Rakon's services to understand MISO's seasonal resource adequacy construct and its impact on Power Purchase Agreement negotiations with a MISO utility.
- An aggregator engaged Rakon Energy as part of the team to represent their interests at RTO stakeholder committees on FERC Order 2222.
- Rakon Energy was part of the team engaged by a technology company to represent their interests at the PJM RTO. Another similar company hired Rao to navigate MISO's market rules for data center interconnection.
- Advanced Energy Economy and the Natural Resources Defense Council's Sustainable FERC Project engaged Rakon to monitor MISO's FERC Order 2222 implementation process.
- The Commonwealth of Pennsylvania's Office of Consumer Advocate engaged Rakon Energy LLC to support OCA's response to the questions posed by the Pennsylvania Public Utility Commission's Secretary in the policy proceeding - Utilization of Storage Resources as Electric Distribution Assets.
- A prominent solar advocacy group currently engaged Rao for expert testimony work in Nevada and Minnesota IOUs IRP filing.
- He submitted comments to Minnesota and Colorado Public Utilities Commission on Integrated Distribution Planning dockets.
- He has provided expert testimony support for Environmental Law and Policy Center (ELPC) at the Public Service Commission of Wisconsin (PSCW) on the MISO Multi-Value Project (MVP) line in Wisconsin.
- He provided affidavit support for the Office of the People's Counsel of the District of Columbia (OPC-DC) at the Federal Energy Regulatory Commission (FERC) on PJM's Reserves Pricing Proposal and municipal utilities in Wisconsin and Missouri at FERC on MISO's Resource Adequacy construct.
- He provided advocacy support for Energy Storage Association (ESA) at MISO on FERC Order 841 Compliance.
- He provided training as part of the Tuatara team on DERs to Colombia's grid operator XM and the ESTA International team on energy storage benefits to Mexican regulator CRE.

Advisor, Volunteer, Pro-Bono assignments

- Rao presented on Distributed Energy Resources (DER) and peer-reviewed Demand Side Management and DER plans for Central American regulators, as part of NARUC International Peer Review.
- Rao presented and shared best practices around the impact of provisioning ancillary services. At an Eastern Africa regional workshop organized by the United States Energy Agency (USEA), the United

States Agency for International Development (USAID) and the Power Africa initiative.

MIDCONTINENT INDEPENDENT SYSTEM OPERATOR (MISO), Eagan, MN
Principal Advisor, Policy Studies Aug 2015 – May 2018

- Recognized as an expert on all thing's energy storage and distributed energy resources from an economic transmission planning perspective
- Project manager for long term independent load forecast and demand response/energy efficiency/distributed generation potential study.
- MISO representative on Department of Energy (DOE) US DRIVE Grid Interaction Technical Team

Senior Manager, Transmission Asset Management Operations Feb 2013 – July 2015
- He engaged the division lead in the development of strategic initiatives and operating plans.
- Rao chaired the Economic Modeling Framework Working Group of international Grid operators GO-15.

Manager, Resource Forecasting (started at Engineer II) Sep 2003 – Jan 2013
- ***Main Accomplishments***
  - In this role, I directed the Demand Response & Energy Efficiency potential study for MISO, with the support of Global Energy Partners consultants.
  - Directed the MISO Energy Storage Study identifying the economic potential for grid-scale energy storage in MISO footprint, providing strategic consulting services to investor-owned utilities, public power utilities, asset owners, and investors.
- ***Regulatory Experience***
  - Responsible for analytical assessments that meet MISO's Federal Energy regulatory compliance obligations as well as our Transmission Owners (e.g., FERC Market-based rates).
  - Responsible for supporting state regulators and MISO Board of Directors with technical analysis related to policy drivers.

PWRSOLUTIONS, Inc., Dallas, TX (Consulting) May 2001 – August 2003
Student Intern and Electrical Engineer
- Rao executed generator interconnection studies for Independent Power Producers (IPPs) clients.
- Analyzed future generator and transmission needs in the Eastern Interconnection.

EDUCATION

THE UNIVERSITY OF MINNESOTA, Minneapolis, Minnesota
Carlson School of Management
Master of Business Administration, Global Executive Program May 2011
Emphases: Strategic Management, International Business

- Responsible for all financial aspects of marketing mobile charging services for Electric vehicles in the Singapore market.

UNIVERSITY OF TEXAS AT ARLINGTON, Arlington, Texas
Energy Systems Research Center (ESRC)
Master of Science in **Electrical Engineering** May 2002

- Master's Thesis in Economic Analysis of Distributed Generation (Photovoltaics (P.V.) and Fuel Cells)

BLOG POSTING, PUBLICATIONS & PRESENTATIONS

1. Co-Author for a graduate level textbook titled "Modern Electricity Systems: Engineering, Operations, and Policy to address Human and Environmental Needs". Release date - August 2022 with Wiley.
2. **He has authored multiple publications in Electricity Journal, Renewable Energy World (blog), and other peer-reviewed industry journals.**

BOARD & VOLUNTEER ACTIVITIES

- Board of Directors, Ever Green Energy. Sep 2019 – present

- Board of Directors, Minnesota Solar Energy Industries Association. Sep 2020 - present
- President, Finnish American Chamber of Commerce – Minnesota (FACC-MN). Jan 2016 - present