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-___

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

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I. INTRODUCTION

Pursuant to Rules 2.1 and 3.2, Public Utilities Code[1] section 712.8(h)(1), and California Public Utilities Commission ("Commission") decision ("D.") 23-12-036, Pacific Gas and Electric Company ("PG&E") respectfully submits this application for review and approval of forecast costs covering the period starting September 1, 2023 through December 31, 2025 (the "Record Period")[2] for Diablo Canyon Power Plant ("DCPP" or "Diablo Canyon") extended operations for inclusion in statewide rates starting on January 1, 2025.

PG&E's presentation of 2023 to 2025 forecast costs are shown in the table below and includes $1,225 million for DCPP costs, statutory fees, and substitution capacity expenses, which is offset by a net of forecast of $813 million for California Independent System Operator ("CAISO") market revenue received in the CAISO day-ahead market. After incorporating

[1] Unless indicated otherwise, all statutory sections in this application are to the Public Utilities Code.
[2] While extended operations for Unit 1 begins on November 3, 2024, costs for extended operations were incurred starting September 1, 2023.

certain fees, the resulting total net revenue requirement for ratesetting is $418.4 million for the 2025 calendar year.

TOTAL REVENUE REQUIREMENT FOR RATESETTING

Line No.		Chapter Cross Reference	Diablo Canyon Extended 2023-2025 Cost ($1000s)[a]		
			Statewide (A)	PG&E Specific (B)	Total (C)
1	**Total Forecast Cost**				
2	Operation & Maintenance Cost Forecast	Chapters 3 & 6	652,116		652,116
3	Management, Performance Fees, & Liquidated Damages	Chapters 6 & 7	417,517	79,805	497,322
4	Resource Adequacy Substitution Capacity	Chapter 4	76,444		76,444
5	**Total Forecast Cost (excluding FF&U)**		**1,146,077**	**79,805**	**1,225,882**
6	**DCPP Market Revenues**				
7	CAISO Energy Market Revenues	Chapter 8	(812,991)		(812,991)
8	**Total Net Forecast Cost (excluding FF&U)**		333,086	79,805	412,892
9	RF&U (PG&E) + FF&U (SCE) and FF&U (SDG&E)[b]	Chapter 12	4,618	897	5,516
10	**DCEO Revenue Requirement for Ratesetting**		**337,705**	**80,703**	**418,407**

Notes:
(a) Amounts in 2025 dollars ($s)
(b) SDG&E FF&U revenue for its DCNBC will be collected in Distribution Charge

The total Diablo Canyon revenue requirement for the Record Period is allocated to the three large investor-owned utilities ("IOU") as follows: (1) PG&E, $232.2 million; (2) Southern California Edison Company ("SCE"), $150.6 million; and (3) San Diego Gas & Electric Company ("SDG&E"), $35.6 million. Each of the IOUs independently calculate and present its respective Diablo Canyon Non-bypassable Charge ("DCNBC") in Chapter 12 based on its allocation of the total net revenue requirement presented in the table above.

PG&E's allocated revenue requirement for the calendar year 2025 results in a $2.07 per month bill impact for the average non-CARE residential customer. SCE's allocated revenue requirement for calendar year 2025 is estimated to result in a $1.25 per month bill impact for the average non-CARE residential customer. SDG&E's allocated revenue requirement is estimated to result in a $0.87 per month bill impact for average non-CARE residential customers.

This application supports PG&E's efforts to respond to the State's call to support electric reliability for all Californians and continuing operations at Diablo Canyon. As presented in Chapter 2, DCPP has additional value to the state and to customers that is not reflected in the total cost presentation. For example, on average, for the 2025 to 2030 extended operations cost recovery period, when accounting for the estimated imputed Resource Adequacy ("RA") attribute value, which would otherwise be realized through RA sales, DCPP extended operations results in approximately $192 million total net benefits. Further, as provided in Chapter 2, PG&E estimates the societal benefit of avoided greenhouse gas ("GHG") emissions associated with DCPP at approximately $371 million on average for the 2024 through 2030 extended operations period.[3]

Consistent with the Commission's directives in D.23-12-036, this application includes: (1) a forecast of costs of extended operations, (2) a forecast of market revenues for Diablo Canyon in the relevant ratemaking period, and (3) a proposal to establish the DCNBC applicable to all Commission jurisdictional customers based on forecast net costs and applicable amounts. In addition to the information supporting the proposed rate, PG&E provides cost- and benefit-related information that are required or addressed by D.23-12-036.

The forecast presented in this application updates the forecast presented in PG&E's May 19, 2023 testimony submitted in the Rulemaking 23-01-007. As directed by the Commission, this application also presents a forecast of the total operating costs for Diablo Canyon extended operations from 2022 to 2030.[4] However, PG&E requests cost recovery only for Record Period operating costs in this application.

This application also presents for Commission review and approval a plan for prioritizing the use of the section 712.8(f)(5) volumetric performance fees ("VPF") consistent with

[3] See Chapter 2, Table 2-3 for additional detail.
[4] D.23-12-036, pp. 60-61.

section 712.8(s)(1) and Decision (D.) 23-12-036.[5] PG&E presents its planned expenditures for 2025 VPFs[6] and its proposed accounting process. For future years, PG&E requests that the Commission consider utilizing a more efficient Tier 3 Advice Letter regulatory process for reporting VPFs, how the funds were spent, and prioritization plan.

Finally, PG&E proposes allocation of RA attributes and GHG-free energy attributes in consideration of the higher cost burden in PG&E's service territory consistent with section 712.8(q). Such adjustments would reflect the higher burden of cost responsibility established in SB 846 for customers in PG&E's service territory.

Similar to the rate recovery process in existence for the large IOUs for the Energy Resource Recovery Account ("ERRA") proceedings, PG&E will update its prepared testimony in October 2024 to include any updated forecast and recorded Diablo Canyon Extended Operations Balancing Account ("DCEOBA") balances prior to the issuance of the proposed decision ("Fall Update").[7] The schedule set forth in Section V.E below assumes the Commission will resolve this application by the first business meeting in December[8] to allow the IOUs to implement rate changes as of January 1, 2025. Timely approval is necessary to ensure that statewide rates accurately recover forecast extended operations costs from Commission-jurisdictional load serving entity ratepayers. When approval of this forecast application is delayed, the forecast revenues are misaligned to the recorded costs. As recorded extended operations cost begin to show up in the DCEOBA, they are matched to market revenues and

[5] PG&E submitted an Application for Rehearing ("AFR") of D.23-12-036 concerning the Commission's findings, legal conclusions, and orders relating to PG&E's use of VPFs provided to PG&E under section 712.8(f)(5) and the Commission's interpretation of Public Utilities Code Section 712.8(s)(1). The AFR is being litigated separately from this proceeding.
[6] The 2024 VPF revenues (starting on November 3, 2024 with Unit 1 extended operations) are included in the Record Period and will be collected as part of the 2025 non-bypassable charge.
[7] A subsequent true-up of the 2025 forecast revenue requirement and rates to actual costs, PG&E billed revenues, IOU remitted revenues, and CAISO market revenues for the Record Period will occur through an expedited Tier 3 advice letter process.
[8] During the R.23-01-007 rulemaking, D.23-12-036 authorized a schedule for the annual DCPP cost recovery proceeding resulting in a final decision by the last business meeting in November. However, as described below in Section V.E., this Application proposes a final decision by December 5, 2024 due to the schedules of the October 1, 2024 benchmark and Commission's voting meetings in 2024.

statewide customer rates in the form of PG&E billed revenues and SCE and SDG&E remitted revenues. The 12- month forecast of billed/remitted revenues must align to PG&E's 12 month forecast of record costs. Since there is no prior year's approved revenue requirement in place, the DCEOBA will likely carry an undercollection until the approved rates take effect.[9] Therefore, timely approval is essential to avoid a systemic mismatch in timing between the forecast period and the time at which the recorded costs, market revenues, and billed/remitted revenues are recovered in rates. PG&E requests this Commission's final decision set rates effective as of January 1, 2025.

II. LEGAL AND REGULATORY BACKGROUND

A. Senate Bill 846

On September 2, 2022, Governor Newsom signed Senate Bill (SB) 846 authorizing the potential extension of DCPP operations, California's only remaining nuclear power plant in operation, for up to five years beyond its current operating licenses.[10] This directive was effective immediately as SB 846 was passed as urgency statute. In authorizing the potential extension of Diablo Canyon operations, SB 846 states:

> Preserving the option of continued operations of the Diablo Canyon powerplant for an additional five years beyond 2025 may be necessary to improve statewide energy system reliability and to reduce the emissions of greenhouse gases while additional renewable energy and zero-carbon resources come online, until those new renewable energy and zero-carbon resources are adequate to meet demand. Accordingly, it is the policy of the Legislature that seeking to extend the Diablo Canyon powerplant's operations for a renewed license term is prudent, cost effective, and in the best interests of all California electricity customers. The Legislature anticipates that this stopgap measure will not be

[9] Any under- or over-collected DCEOBA balances would become part of the subsequent year revenue requirement, since D.23-12-036 does not contemplate a process for adjusting rates mid-year.
[10] Senate Bill 846, 2021-2022 Leg. Reg. Sess. (Cal. 2022) (hereinafter SB 846).

> needed for more than five years beyond the current expiration dates.[11]

Additionally, SB 846 tasked the Commission to direct and authorize PG&E to "take all actions … necessary to operate the powerplant beyond the current expiration dates, so as to preserve the option of extended operations…."[12] Subject to continued authorization to operate from the U.S. Nuclear Regulatory Commission ("NRC") and certain findings and conclusions from the Commission, the statute establishes new retirement dates of October 31, 2029 for Unit 1 and October 31, 2030 for Unit 2. In the months following the passage of SB 846, PG&E, acting at the direction and for the benefit of the state of California, took immediate and extensive action to effectuate the state's directives. Multiple state and federal agencies did the same to support continued operations at DCPP.

Two forms of government funding streams are identified in SB 846 to support extended operations at DCPP: a $1.4 billion loan through the California Department of Water Resources ("DWR") and funds awarded through the U.S. Departing of Energy ("DOE") Civil Nuclear Credit Program. The funds provided by the DOE will be used to repay the DWR loan. The government funding streams are intended to recover transition costs and costs supporting extended operations, but not the cost of extended operations. Costs that are covered by government funding streams are not included in PG&E's forecast or resulting rate request. The final Civil Nuclear Credit Award and Payment Agreement ("CAPA") between PG&E and the DOE was executed in the first quarter of 2024.

In implementing SB 846, the Commission adopted a broadly prescriptive cost recovery and approval process intended to fully recover the costs of Diablo Canyon operations and assign those costs to customers of all Commission-jurisdictional load-serving entities ("LSE").[13] This new regulatory process, similar to the IOUs' respective annual ERRA forecast proceedings, establishes a new DCNBC and provides that forecasted costs are trued up to actual recorded

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[11] Pub. Res. Code § 25548(b).
[12] Pub. Util. Code § 712.8(c)(1)(A).
[13] See generally Decision (D.) 23-12-036.

costs through an expedited Tier 3 advice letter process.[14] Section 712.8(h)(1) directs the Commission to authorize the recovery of all reasonable costs and expenses necessary to operate DCPP, and also that there will be no further review of costs provided that actual costs are below 115 percent of forecast costs.[15] This section does not allow PG&E to earn a rate of return on any of these costs, directing that "costs shall be recovered as an operating expense and shall not be eligible for inclusion in the operator's rate base."[16]

SB 846 established several costs and fees to be included in the extended operations forecast, including two distinct streams of performance and management fees to PG&E in lieu of the traditional rate-base return on capital investments. Specifically, PG&E receives a fixed management fee of $50 million per unit per year, as well as a VPF of $13.00 per megawatt-hour (MWh), in 2022 dollars, for the period of extended operations. The volumetric performance fee is split into two categories, with the first $6.50/MWh, in 2022 dollars, to be collected from all Commission-jurisdictional customers and an additional $6.50/MWh, in 2022 dollars, to be collected from customers in PG&E's service territory only. Section 712.8(s)(1) directs that the VPF revenues be spent, to the extent it is not needed for DCPP, to accelerate, or increase spending on, six public purpose priorities critical to advancing California's clean energy and decarbonization goals.[17] In addition, SB 846 provides for the funding of a liquidated damages account until the balance reaches $300 million to be used to offset the costs of any unplanned outages.[18] As described in Advice Letter 6870-E,[19] the Liquidated Damages Subaccount is a subaccount of the DCEOBA.

[14] Pub. Util. Code § 712.8(h)(1).
[15] Pub. Util. Code § 712.8(h)(1). Consistent with the framework adopted by D.23-12-036, future cost recovery applications, for DCPP extended operations may include certain year-end DCEOBA balances, including those actual expense project costs and operations and maintenance expenses that are at or below 115 percent of PG&E's forecast costs, be considered as part of the annual revenue requirement that is amortized in rates on January 1 of each year.
[16] Pub. Util. Code § 712.8(h)(1).
[17] Pub. Util. Code § 712.8(s)(1)(A) – (F).
[18] Pub. Util. Code §§ 712.8(g) and (i).
[19] PG&E Advice Letter 6870-E, submitted March 1, 2023.

In D.22-12-005, the Commission directed PG&E to take "all … actions that would be necessary" to preserve extended operations and to track costs associated with continued and extended operations.[20] The Commission also directed PG&E to establish the Diablo Canyon Power Plant Transition and Relicensing Memorandum Account ("DCTRMA") and the DCEOBA. The DCTRMA tracks costs and revenues associated with government funding streams for transitioning the plant to extended operations. The DCEOBA tracks the costs that will be recovered from all customers of all Commission-jurisdictional LSEs.

B. Decision 23-12-036

In D.23-12-036, the Commission authorizes new retirement dates for Diablo Canyon Units 1 and 2, subject to certain conditions.[21] The decision also adopts the ERRA-like application process to authorize forecast DCPP extended operations costs, with subsequent true-up to actual costs and market revenues for the prior calendar year,[22] of which this is the first instance. For this application, the decision directs PG&E to include the following:[23]

- Updated DCPP historical and forecast costs (2022 to 2030) presented using PG&E's existing General Rate Case ("GRC") cost structures.[24] This estimate shall include or be accompanied by:
    - All DCPP costs to be recovered from ratepayers over time, in a single analysis, including administrative and general costs ("A&G"), uncollectibles, associated taxes, all funds authorized under SB 846, etc. … The forecast analysis should include any and all costs expected to be recovered from utility ratepayers for DCPP extended operations.[25]
    - Costs associated with PG&E's 2023 license renewal application to the NRC, any Diablo Canyon Independent Safety Committee ("DCISC") recommendations on seismic safety upgrades or deferred maintenance, as well as any costs associated with NRC's conditions of license renewal. Costs associated with DCISC recommendations or NRC's conditions of license renewal shall only be included

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[20] D.22-12-005, p. 33, OP 2.
[21] D.23-12-036, p. 135, OP 1.
[22] D.23-12-036, p. 136, OP 4.
[23] See D.23-12-036, pp. 135-136, OPs 2 and 4.
[24] D.23-12-036, p. 60.
[25] D.23-12-036, p. 60.

to the extent there are actual recommendations and conditions from the DCISC and NRC.[26]

  - Any government-funded transition costs. The decision notes that these costs … are outside the Commission's purview and general mandate to ensure just and reasonable rates, and therefore will not be considered "costs" as part of any cost-effectiveness evaluation considered by the Commission. However, they should be identified in PG&E's DCPP forecast.[27]

  - A transparent comparison between PG&E's cost forecast and the Electric Utility Cost Group cost forecast presented in the R.23-01-007 proceeding to the best of PG&E's ability.[28]

- A copy of the California Energy Commission's ("CEC") final cost comparison report.[29]

- Detailed projections of all costs and revenues associated with DCPP extended operations, in a manner similar to PG&E's presentation in its GRC and ERRA Forecast proceedings;

- Quantification of the impact of DCPP's extended operations on its common costs relative to the amount approved in its 2023 GRC; and

- Demonstration that PG&E will not double count the common costs it proposes for recovery in its GRC and the DCPP Extended Operations Cost Forecast applications.[30]

- PG&E, SCE, and SDG&E are directed to provide joint testimony proposing an allocation among themselves of the statutorily defined DCPP extended operations costs applicable to all load serving entities, and the revenue associated with the $6.50 per megawatt hour volumetric fee under section 712.8(f)(5). PG&E, SCE, and SDG&E may use public load data to determine each electrical corporation's share of the 12 month coincident peak demand.[31]

- In addition, the proceeding should:

  - Determine the allocation of costs and benefits of DCPP extended operations among the large electrical corporations' service areas; and

  - Utilize a process that mirrors the Cost Allocation Mechanism ("CAM") process to determine the price of the volumetric non-bypassable charge to be charged by each of the large electrical corporations. Energy Division should utilize the CAM process to determine the allocation of RA benefits to SCE and SDG&E and

[26] D.23-12-036, p. 60.
[27] D.23-12-036, p. 61.
[28] D.23-12-036, p. 61.
[29] D.23-12-036, p. 127, COL 17. As of the timing of this filing, to PG&E's knowledge, the final cost comparison report has not been issued.
[30] D.23-12-036, pp. 132-133, Conclusion of Law ("COL") 54.
[31] D.23-12-036, pp. 136-137, OP 7.

> among the LSEs in each large electrical corporation's territory, and should endeavor to provide all LSEs with allocations of DCPP's RA benefits for the upcoming compliance year sufficiently in advance of the October 31 year-ahead RA compliance filing deadline.[32]

PG&E addresses each of D.23-12-036 requirements in this application, supporting testimony, and workpapers.

Following this application and its resolution, a true-up process will occur via a Tier 3 advice letter to request Commission authorization of true-up amounts for costs recorded to the DCEOBA, to the extent that such true-up amounts do not exceed 115 percent of the authorized forecast.[33] This advice letter process was described in PG&E's June 9, 2023 testimony in R.23-01-007[34] and adopted by D.23-12-036.[35] Prior to the resolution of the annual advice letter, PG&E's subsequent annual cost recovery applications could include certain year-end DCEOBA balances of the prior year, including actual expense project costs and operations and maintenance ("O&M") expenses that are at or below 115 percent of PG&E's forecasts.

In addition, the Commission provides direction on the benefits from extended operations, including RA and GHG-free benefits. Specifically, the Commission directs the allocation of RA "benefits of DCPP extended operations to each large electrical corporation service area on the basis of a 12-month coincident peak demand."[36] Decision 23-12-036 directs PG&E to "determine the allocation of costs and benefits of DCPP extended operations" among PG&E, SCE, and SDG&E.[37] To implement this, Energy Division should "utilize the CAM process to determine the allocation of RA benefits to SCE and SDG&E and among the LSEs in each large electrical corporation's territory, and should endeavor to provide all LSEs with allocations of DCPP's RA benefits for the upcoming compliance year sufficiently in advance of the October 31

[32] D.23-12-036, p. 133, COL 55.
[33] Pub. Util. Code § 712.8(h)(1). See also D.23-12-036, pp. 132-133, COL 51 and 57.
[34] R.23-01-007, PG&E-02, PG&E Prepared Testimony (June 9, 2023), p. 3-12, line 4 – p. 3-13, line 26.
[35] D.23-12-036, p. 136, OP 4.
[36] D.23-12-036, p. 130, COL 35.
[37] D.23-12-036, p. 133, COL 55.

year-ahead RA compliance filing deadline."[38] Thus, PG&E does not propose an allocation factor for RA benefits in this application, as Energy Division will allocate the RA benefits later this year to LSEs in each of the IOUs' service territories under the CAM process established in D.06-07-029 (e.g., where the Commission designated each IOU to procure new generation capacity in its own territory, with the costs and benefits allocated to all customers in the territory (including bundled and unbundled customers)). However, PG&E does propose a method of adjusting the existing Commission methodology of calculating RA allocations based on cost responsibility for DCPP extended operations, consistent with SB 846.

Finally, the Commission directed PG&E to present in an application its plan for use of the $13/MWh volumetric performance fees collected in 2025 (covering November 3, 2024 to December 31, 2025) and demonstrate that those plans are consistent with the critical public purpose priorities in section 712.8(s)(1) prior to expenditure of those funds.[39] PG&E may not use the VPFs until the Commission has reviewed and approved of the proposed use of funds. In this application, PG&E addresses the forecast amount of ratepayer funds to be collected during the Record Period and how PG&E plans to spend those funds. Some of the requirements associated with expenditure of the VPFs are met on a retrospective basis, e.g., reporting requirements including a declaration from PG&E's Chief Financial Officer, and a plan for prioritizing the uses of VPF revenues in the next year.[40] Given that VPF revenues have not yet been collected from customer rates, PG&E's application necessarily focuses on *planned* usage of VPF revenues.

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[38] D.23-12-036, p. 133, COL 55.
[39] D.23-12-036, p. 139, OP 15.
[40] D.23-12-036, pp. 111-116.

III. DESCRIPTION OF PG&E'S REQUESTED RELIEF IN THIS APPLICATION

A. Forecast Revenue Requirement for Record Period

The revenue requirement for the Record Period represents the forecast of costs of extended operations from September 1, 2023 to December 31, 2025, including O&M expense and project costs, fuel expense, tax expense, procurement costs associated with capacity and energy substitution for DCPP's planned and maintenance outages, and statutory costs associated with SB 846, netted with forecast market revenues. While Unit 1 begins extended operations on November 3, 2024 and Unit 2 begins extended operations on August 27, 2025, costs were incurred starting September 1, 2023 for extended operations.[41] As part of the operational costs, PG&E includes a request to amortize nuclear fuel over the years of extended operations. Fuel costs have increased over the past year due, in part, to market forces and geopolitical events outside of PG&E's control.[42] PG&E does not propose to recover common costs that were included in PG&E's 2023 GRC (which was submitted before the passage of SB 846), such as A&G costs in the rate established by this application. In addition, consistent with sections 712.8(f)(5) and 712.8(f)(6)(A), PG&E requests approval of an escalation rate and methodology for the fixed fee and VPF.

The table below expands on the table above, *Total Revenue Requirement for Ratesetting*, to show more cost component details of the Record Period revenue requirement. As shown below, line 2 includes costs to operate DCPP during this Record Period, including direct costs for O&M, support costs including taxes, benefits and standard PG&E overheads, employee retention, and regulatory compliance items discussed in Chapter 3. Line 3 includes a forecast for resource adequacy substitution capacity expenses, which is discussed in Chapter 4. Lines 8-11 provide additional detail regarding statutory charges and fees included in the cost forecast,

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[41] Specifically, the DCPP employee retention program directed by section 712.8(f)(2) began September 1, 2023. In addition, some planning costs were incurred in 2024 prior to November 3, 2024 (the Unit 1 extended operations start day), which are shown in supporting testimony.

[42] See, e.g., market forces and response from U.S. action from the Russian invasion of Ukraine in 2022, such as H.R. 1042. H.R. 1042, 118th Cong., 1st Sess. (2023), Prohibiting Russian Uranium Imports Act, https://www.govtrack.us/congress/bills/118/hr1042 (accessed Mar. 21, 2024).

including the performance and management fees, authorized in SB 846. Line 17 presents the 2023 employee retention costs, which were recorded to the DCEOBA as of December 31, 2023. Costs on line 13 plus the 2023 recorded costs on Line 17 total $1.225 million (the sum of line 13 and line 17). These costs are then netted against generation market revenues (line 15), resulting in approximately $412.9 million, (line 18), excluding Franchise Fees and Uncollectable (FF&U) revenues. The joint IOUs' FF&U revenues (line 20) are then added onto line 18, resulting in a net revenue requirement to be recovered in rates of approximately $418.4 million.

DETAILED TOTAL NET REVENUE REQUIREMENT FOR 2025 RATESETTING (THOUSANDS OF DOLLARS)

Line No.		Chapter Cross Reference	Diablo Canyon Extended Operations[a] 2023-2025 Cost ($1000s)		
			Statewide (A)	PG&E Specific (B)	Total (C)
1	Operational Revenue Requirement				
2	Operation and Maintenance Cost Forecast	Chapters 3 & 6	633,164		633,164
3	Resource Adequacy Substitution Capacity	Chapter 4	76,444		76,444
4					
5	**Subtotal Operational Revenue Requirement**		**709,608**		**709,608**
6					
7	Management, Performance Fees, and Liquidated Damages				
8	Management Fee	Chapters 6 & 7	112,711		112,711
9	Liquidated Damages	Chapters 6 & 7	225,000		225,000
10	Volumetric Performance Fee	Chapters 6 & 7	79,805		79,805
11	***PG&E Specific*** Volumetric Performance Fee	Chapters 6 & 7		79,805	79,805
12	**Subtotal Statutory Fees**		**417,517**	**79,805**	**497,322**
13	**Total Cost Forecast (Line 5 + Line 12)**		**1,127,125**	**79,805**	**1,206,930**
14	Offsetting Market Revenues				
15	CAISO Market Revenues	Chapter 8	(812,991)		(812,991)
16	Balancing Account Amortization				
17	DCEOBA	Chapter 10	18,953		18,953
18	Subtotal Net Cost (Line 13 + Line 15 + Line 17)		333,086	79,805	412,892
19					
20	RF&U (PG&E) + FF&U (SCE) and FF&U (SDG&E)[b]	Chapter 12	4,618	897	5,516
21	**DCEO Revenue Requirement for Ratesetting**		**337,705**	**80,703**	**418,407**

Notes:
(a) Amounts in 2025 dollars ($s)
(b) SDG&E FF&U revenue for its DCNBC will be collected in Distribution Charge

B. Diablo Canyon Allocation to the IOUs and DCNBC

As authorized by SB 846 and D.23-12-036, the DCNBC is a statewide charge that will apply to all Commission jurisdictional customers of electrical corporations, electric service providers, and Community Choice Aggregators, which will be billed through the CPUC jurisdictional IOUs.[43] To produce the DCNBC, the revenue requirement for the Record Period is allocated among the three large IOUs based on 12-month coincident peak demand using publicly available data.[44] Once the revenue requirement is allocated to each IOU, the DCNBC rate calculation by rate class utilizes a process that mirrors the CAM process. For each IOU, the DCNBC by rate class is presented in Chapter 12. The DCNBC rates will be included in their public purpose program ("PPP") rates.[45]

PG&E, SCE, and SDG&E present for Commission review the revenue requirements allocated to each IOU that support rate proposals for the DCNBC, a summary of those allocations is shown below:

[43] D.23-12-036, pp. 138-139, OP 14.
[44] D.23-12-036, pp. 136-137, OP 7.
[45] D.23-12-036, pp. 138-139, OP 14.

2025 DIABLO CANYON EXTENDED OPERATIONS COST ALLOCATION
(THOUSANDS OF DOLLARS)

Line No.		12-Month Coincident Peak Allocation[a] 2023-2025 Cost Allocation ($1000s)			
		45.0%	44.7%	10.3%	
		Pacific Gas & Electric	Southern California Edison	San Diego Gas & Electric	Total
1	Operational Revenue Requirement	(D)	(E)	(F)	(G)
2	Operation and Maintenance Cost Forecast	284,780	283,191	65,192	633,164
3	Resource Adequacy Substitution Capacity	34,383	34,191	7,871	76,444
4	SMJUs Revenue Credit and RA Reimbursement[b]	0			
5	**Subtotal Operational Revenue Requirement**	**319,163**	**317,382**	**73,063**	**709,608**
6					
7	Management, Performance Fees, and Liquidated Damages				
8	Management Fee	50,695	50,412	11,605	112,711
9	Liquidated Damages	101,199	100,634	23,167	225,000
10	Volumetric Performance Fee	35,894	35,694	8,217	79,805
11	***PG&E Specific* Volumetric Performance Fee**	79,805			79,805
12	**Subtotal Statutory Fees**	**267,593**	**186,740**	**42,989**	**497,322**
13	**Total Cost Forecast (Line 5 + Line 12)**	**586,756**	**504,122**	**116,052**	**1,206,930**
14	Offsetting Market Revenues				
15	CAISO Market Revenues	(365,662)	(363,621)	(83,708)	(812,991)
16	Balancing Account Amortization				
17	DCEOBA	8,525	8,477	1,951	18,953
18	Subtotal Net Cost (Line 13 + Line 15 + Line 17)	229,619	148,977	34,295	412,892
19	Uncollectibles, Franchise Fees, and SF Revenue Fee Factor[c]	1.1245%	1.1061%	3.7493%	
20	RF&U (Col. A = Col. D + Col. E + Col. F - Col. B) (Col. B = Col. A, Line 3 x Col. D, Line 23)	2,582	1,648	1,286	5,516
21	**DCEO Revenue Requirement for Ratesetting (Line 18 + Line 20) for PG&E and SCE (Line 18) for SDG&E**	**232,201**	**150,625**	**34,295**	**417,122**
22	**Distribution Revenue (SDG&E FF&U)**			**1,286**	**1,286**
23	**Volumetric Performance Fee (VPF) as a Percent of Net Costs[d] ((Line 10 + Line 11) / Line 18)**	**50.39%**	**23.96%**	**23.96%**	

Notes:
(a) Amounts in 2025 dollars ($s)
(b) D.23-12-036, OP8 and OP11
(c) SDG&E's revenues for its DCNBC will be collected in the Distribution Charge.
(d) VPF Revenue allocation for Revenue Reporting

customers in the operator's service area." The allocation processes established by D. 23-12-036 do not consider the higher costs to customers in PG&E's service area. Thus, PG&E proposes adjusting the allocation of RA and GHG-free energy to LSEs serving customers in PG&E's area to account for the higher cost burden borne by its customers. Such adjustments are consistent with the higher burden of cost responsibility established in SB 846 for customers in PG&E's service area.

PG&E proposes that these allocation ratios to the large IOU service areas be updated annually in this forecast application proceeding based on the allocation ratios of total forecasted costs. This proposal does not impact the revenue requirement or rates requested in this application. This allocation should occur with sufficient time to allow Commission staff to perform the allocation to LSEs in each service area using a process that mirrors CAM. If possible, the entirety of this RA allocation process should conclude prior to the RA year-ahead filing deadline in order to allow LSEs sufficient time to meet their RA compliance requirements.

PG&E proposes that for DCPP's GHG-free attribute allocation, the allocation ratio be based on each LSEs share of total forecast costs. This will better align LSE Power Content Label amounts associated with DCPP with those LSE customers' cost responsibility. PG&E service area customer's increased cost responsibility should also be reflected in the GHG-free energy allocation amounts. D.23-12-036 directs that "the existing process for voluntarily offering the GHG attributes of certain resources to LSEs, as adopted in D.22-06-066, should be used as a model."[46] Under that existing process, "PG&E offers LSEs within its service territory an allocated amount of GHG-free energy generated by specified facilities corresponding to each LSE's 'Allocation Ratio.'"[47]

D. Proposal to Address IRC Normalization Rules

PG&E includes a proposal to mitigate Internal Revenue Code ("IRC") Normalization violation concerns by including an additional amount for recovery in the results of operations ("RO") model. Under section 712.8(h)(1), costs are required to be recovered as an expense and not be included in PG&E's rate base, thereby requiring full expensing of "would-have-been" capitalized assets for financial statement ("book") purposes. For tax purposes, however, these remain capital assets that must be depreciated and cannot be expensed under the IRC. PG&E

[46] D. 23-12-036, p. 90. PG&E assumes this is a typographical error, and the intended reference is D. 23-06-006, a decision that addresses processes to allocate GHG-free attributes of large hydroelectric resources.
[47] D.23-12-036, p. 90.

must continue to follow the federal IRC rules to capitalize and depreciate the assets that were fully expensed for book purposes, resulting in a depreciation book-tax difference subject to the IRC Normalization rules. Thus, PG&E proposes that the RO Model include the revenue requirement equivalent of the Accumulated Deferred Income Taxes ("ADIT") for this depreciation book-tax difference to avoid an IRC Normalization violation.

E. Prioritization Plan for Expenditures of 2025 Volumetric Performance Fees

PG&E presents its plan for prioritizing the use of the VPF compensation[48] earned in 2025 (covering the period of November 3, 2024 to December 31, 2025) in this application for Commission approval in compliance with D.23-12-036. PG&E plans to focus its VPF expenditures on multiple section 712.8(s)(1) activities and potentially contribute to DCPP extended operations costs.

Additionally, PG&E presents its proposed pre- and post-accounting process for compliance with SB 846 and D.23-12-036. The Commission notes it "may revisit the direction to conduct its review through a formal application process if it determines, after having reviewed one or more of PG&E's applications, that the appropriate guidelines have been put into place."[49] For future years, PG&E requests that the Commission consider a more efficient regulatory process for reporting VPFs, how the funds were spent, and prioritization plan in an annual application. Instead, PG&E proposes utilizing the General Order 96-B process to present this information in an advice letter with a Tier 3 designation.

F. Summary of Requested Relief

PG&E requests that the Commission approve the following:

1. DCPP revenue requirement from the Record Period of $418.4 million to be effective in rates on January 1, 2025, including the following forecasts and their underlying financial assumptions and calculations, subject to updates in the Fall Update:

[48] Pub. Util. Code § 712.8(s)(1).
[49] D.23-12-036, p. 112.

a. Operations and maintenance costs (including expenses, project costs, and statutory costs and fees, as well as associated escalation),

b. Charges for the liquidated damages account pursuant to section 712.8(g),

c. Resource Adequacy substitution capacity costs,

d. Operating expenses that would be amortized through 2030 (i.e., nuclear fuel procurement),

e. Proposal to mitigate IRC Normalization violation concerns by allowing the additional recovery of the revenue requirement equivalent of the ADIT (for the Normalization depreciation book-tax difference) included in the RO model, and

f. Netting of CAISO revenues for the period from November 3, 2024 to December 31, 2025.

2. The statewide Diablo Canyon Non-Bypassable Charge.

3. PG&E's proposal for allocation of RA attributes and GHG-free energy allocation in consideration of the higher cost in PG&E's service territory.

4. PG&E's VPF plan and proposed spending priorities for the expenditures.

5. A modified regulatory process for PG&E to utilize a Tier 3 advice letter process for future years of VPF reporting, including how the funds were spent and a prioritization plan.

6. Finding that PG&E's testimony satisfies all the regulatory requirements set forth in D.23-12-036.

IV. OVERVIEW OF PREPARED TESTIMONY

In support of this application, PG&E contemporaneously serves direct testimony and workpapers to support its revenue requirement and ratemaking request. The testimony structure is modified and expanded from PG&E's proposal in R.23-01-007,[50] reflecting the directives from D.23-12-036 and through the testimony development process.

Chapter 1 (Introduction and Policy) summarizes the Legislature's and Governor's charge to the Commission in enacting SB 846 to establish new retirement dates. This policy chapter introduces and summarizes PG&E's proposals and summarizes PG&E's ratemaking requests for

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[50] R.23-01-007, PG&E-02, PG&E Prepared Testimony (June 9, 2023).

the Record Period. It also addresses benefits from the DCPP extended operations period.

Chapter 2 (Costs and Benefits of Diablo Canyon Power Plant Operations: 2022-2030) addresses the costs and benefits of DCPP extended operations through 2030, including benefits from RA and from GHG-free energy. It also addresses requirements from D.23-12-036 apart from the cost forecast and ratemaking proposal (which are addressed in other chapters), including presenting a single analysis showing DCPP's 2022 to 2030 historical and forecast costs, a comparison walk to PG&E's EUCG forecast presented in R.23-01-007,[51] and demonstration that common costs will not be double counted.[52] In addition, PG&E presents its RA attributes allocation proposal.

Chapter 3 (2023-2025 Forecast Operations and Maintenance Costs to be Recovered in Rates) contains PG&E's forecast of costs for the Record Period, incremental to those authorized in PG&E's 2023 GRC, to be collected in customer rates effective January 1, 2025. In this chapter, PG&E provides costs by Major Work Category ("MWC"), consistent with PG&E's presentation of nuclear operating costs in its GRC proceedings. This chapter also includes proposed expense projects, similar to those capital project forecasts historically addressed in PG&E's GRC. Execution of these projects is necessary to ensure safety and equipment reliability are maintained during extended operation of DCPP to meet the needs of all Californians. PG&E proposes to amortize nuclear fuel costs for the purpose of reducing rate volatility, presented in Attachment A of Chapter 3. This is also consistent with section 712.8(h)(2), permitting amortization for significant one-time expense project expenditures during the extended operation period, for the purpose of reducing rate volatility, at an amortization rate determined by the Commission.

Chapter 4 (Generation Forecast and Resource Adequacy Substitution Capacity Forecast) presents the amount of forecast generation of DCPP and requirements under the Commission's RA program. PG&E forecasts the procurement of replacement capacity during DCPP planned

[51] D.23-12-036, pp. 60-61.
[52] D.23-12-036, pp. 132-133, COL 54.

and unscheduled outages, and substitution capacity procurement costs that are necessary to meet the state's reliability needs. This chapter also discusses the Commission's directive that PG&E retain responsibility for procuring RA substitution capacity during DCPP outages on behalf of LSEs as D.23-12-036 determined it is reasonable for all LSEs that are allocated RA benefits to share in reasonable administrative and procurement costs associated with meeting DCPP substitution capacity obligations, including associated penalties and costs borne by non DCPP resources.

Chapter 5 (Internal Revenue Code Normalization Requirements and Taxes) explains PG&E's assumptions used in the revenue requirement model to estimate income taxes, the significant IRC Normalization tax implications that arise from SB 846's mandate to expense all costs[53] and presents a proposal to address the Normalization requirements. PG&E also discusses its methodology for property tax and explains that it does not expect to receive any production tax credits from DCPP extended operations.

Chapter 6 (Operational Revenue Requirement) contains the operational revenue requirements of the incremental costs associated with DCPP continued operations for the Record Period in Chapter 3, as well as costs in Chapter 4 and Chapter 5, for recovery in rates in 2025. The costs in the revenue requirement are incremental to authorized 2023 GRC revenues and are not eligible for government funding.

Chapter 7 (Statutory Costs) presents forecasts of the volumetric performance fees (including the statewide and PG&E-only fee),[54] associated escalation from 2022 dollars,[55] and fixed payments.[56] The chapter also addresses the liquidated damages sub-account [57] funding forecast and request. Statutory costs related to DCPP operations are also reflected in Chapters 2 and 3.

[53] Pub. Util. Code § 712.8(h)(1).
[54] Pub. Util. Code § 712.8(f)(5).
[55] Pub. Util. Code §§ 712.8(f)(5) and (f)(6).
[56] Pub. Util. Code § 712.8(f)(6).
[57] Pub. Util. Code § 712.8(g).

Chapter 8 (California Independent System Operator Corporation Market Revenues) presents a forecast of CAISO market revenues for the period of November 3, 2024 to December 31, 2025 in a manner similar to its ERRA Forecast proceeding. The forecasted generation revenues represent a significant offset to the plant's operation and fixed costs, reducing the total revenue requirement recovered from statewide customers. These generation revenues will be recorded monthly to the DCEOBA (e.g., consistent with the CAISO settlement of market revenues PG&E earns as scheduling coordinator of non-nuclear resources), as the costs presented in other chapters are also recorded monthly in the balancing account. PG&E anticipates that in its Fall Update, its generation revenue forecast will be based upon the Energy Index Market Price Benchmark produced by the Commission's Energy Division on October 1 of each year pursuant to D.22-01-023.

Chapter 9 (Planned Usage of Funds from Volumetric Performance Fees) presents PG&E's planned use of volumetric performance fees collected in 2025 rates (covering the period of November 3, 2024 to December 31, 2025) and demonstrates how these uses are consistent with the categories identified in section 712.8(s)(1). This is consistent with D.23-12-036, which directs PG&E to file an application setting forth planned use of the performance based fee revenues prior to making any expenditures. Subsequent showings will include an explanation of how funds were spent the year prior (including reporting on the amount of the funds collected, how it was spent, a demonstration that no funds were paid out to shareholders, and a demonstration that PG&E shareholders did not earn any return). PG&E requests that after this initial application, PG&E be permitted to submit a Tier 3 advice letter presenting the information required by section 712.8(s)(1).

Chapter 10 (Diablo Canyon Extended Operations Balancing Account) addresses the subaccount contents of the DCEOBA, which is consistent with modifications submitted on March 14, 2024 in PG&E's Advice 7204-E (in compliance with D.23-12-036 directives). It also addresses the revision and true-up process, as well as recorded activity.

Chapter 11 (Net Revenue Requirement for Ratesetting) presents a net revenue requirement for ratesetting purposes which consolidates the cost information presented in Chapters 3 to 7 against the forecast of market revenues in Chapter 8, to determine the net revenue requirement that will be recovered via the statewide DCNBC presented in Chapter 12.

Chapter 12 (Joint Investor-Owned Utility Non-Bypassable Charge Proposal) is co-sponsored by PG&E, SCE and SDG&E, and presents the ratemaking mechanism for the DCNBC. The chapter presents the allocation of costs of the DCPP extended operations among the three large IOUs based on public load data, specifically the 2024 Forecast of 12-Month CP Load. Each IOU sponsors its own testimony on allocating the share of revenue requirement among its customer classes using a process that mirrors the existing CAM methodology for system reliability resources. Chapter 12 presents the illustrative DCNBC rates applicable to customers in each utility's service area based on the methodology adopted by D.23-12-036. The rates presented in Chapter 12 are illustrative and subject to updates in the October Update and in each utility's January 1, 2025 consolidated rate change process.

With respect to the three small multi-jurisdictional utilities ("SMJU")—Liberty Utilities/CalPeco Electric; Bear Valley Electric Service, a division of Golden State Water Company; and Pacific Power, a division of PacifiCorp—the chapter describes the fixed amount of the non-bypassable charge for each, along with a reimbursement for RA attributes.

V. COMPLIANCE WITH THE COMMISSION'S RULES OF PRACTICE AND PROCEDURE

A. Statutory and Other Authority (Rule 2.1)

PG&E files this Application pursuant to Rules 2.1 and 3.2, as well as Rule 2.2, section 712.8(h)(1) and D.23-12-036.

B. Legal Name and Principal Place of Business (Rule 2.1(a))

The legal name of the Applicant is Pacific Gas and Electric Company. PG&E's principal place of business is 300 Lakeside Drive, Oakland, California 94612. PG&E is duly organized under the State of California.

C. Correspondence and Communications (Rule 2.1(b))

All correspondence, communications, and service of papers regarding this Application should be directed to:

Lillian Rafii
Pacific Gas and Electric Company
300 Lakeside Drive
Attn: Law Department
Oakland, CA 94612

Telephone: (510) 203-0749
E-Mail: Lillian.Rafii@pge.com

Thomas Jarman
Pacific Gas and Electric Company
300 Lakeside Drive
Attn: Regulatory Affairs Department
Oakland, CA 94612

E-mail: Thomas.Jarman@pge.com

D. Categorization, Hearings, And Issues To Be Considered (Rule 2.1(c))

1. **Proposed Categorization**

This application should be categorized as a "ratesetting" proceeding.

2. **Need for Hearings**

PG&E anticipates that evidentiary hearings may be requested by other parties to this proceeding, but the need for evidentiary hearings will depend on the degree to which and grounds on which other parties might contest the proposals contained in this application. PG&E hopes to resolve the issues raised in this application without hearings, such as through more informal procedures, including discovery.

3. **Issues to Be Considered**

The issues presented in this application are as follows:

1. Whether PG&E's forecast cost of operations and revenue requirement over the Record Period for DCPP is just and reasonable?

2. Whether the calculation of the non-bypassable charge and rate proposals by PG&E, SCE, and SDG&E comply with D.23-12-036?

3. Whether to adopt PG&E's proposal for allocation of RA attributes and GHG-free energy allocation in consideration of the higher cost in PG&E's service area?

4. Whether PG&E's planned expenditure of VPFs during the November 3, 2024 to December 31, 2025 period comply with section 712.8(s)(1) requirements?

5. Whether PG&E's proposal to utilize a Tier 3 advice letter process reporting VPFs, how the funds were spent, and prioritization plan properly implements section 712(f)(5) and 712(s)(1)?

E. Procedural Schedule

PG&E proposes the following procedural schedule for this proceeding, which is modeled after the illustrative schedule presented in PG&E's June 9, 2023 testimony[58] in R.23-01-007 and adopted in D.23-12-036.[59] Modifications to the illustrative schedule were made in part due to the 2024 Commission voting calendar and the timing of the Commission's issuance of the Market Benchmark on October 1. While the illustrative schedule contemplated a final decision in November 2024 to facilitate the ratemaking process among the statewide IOUs, the only Commission voting meeting in November 2024 is on November 7, 2024. This would not allow for processing the Commission's Market Price Benchmark, to be issued by no later than October 1 of each year pursuant to D.22-01-023.[60] Hence, PG&E proposes a final decision at the first voting meeting in December, which is December 5, 2024. PG&E's proposed schedule also

[58] R.23-01-007, PG&E-02, PG&E Prepared Testimony (June 9, 2023), p. 3-10, Table 3-1.
[59] While D.23-12-036 stated that it does not require the specific schedule proposed by PG&E in its June 9, 2023 testimony in R.23-01-007, it overall found PG&E's proposal to comply with its statutory obligation and recommended its adoption. D.23-12-036, p. 102.
[60] D.22-01-023, p. 27, OP 1.

provides for both opening and reply comments on the Fall Update in combining the reply brief and reply comments to the Fall Update.

Date	Event
March 29, 2024	PG&E files Application
April 1, 2024	Notice of Application appears in Daily Calendar
+ 30 days after Notice	Protests filed
+ 10 days after Protests/ Responses	Reply filed
By May 15, 2024	Prehearing Conference
July 8, 2024	Intervenor testimony served
August 6, 2024	Rebuttal testimony served
August 16, 2024	Rule 13.9 Meet and Confer
August 29, 2024	Evidentiary Hearings (if needed)
September 27, 2024	Opening Briefs
October 1, 2024	Market Price Benchmarks issued
By October 8, 2024	Update to Prepared Testimony served
October 21, 2024	Comments to Update to Prepared Testimony
November 21, 2024	Reply briefs and Reply comments to Update to Prepared Testimony served; proceeding submitted
November 2024	Proposed Decision issued 20 days before Commission voting meeting
+ 5 days after Proposed Decision[a]	Comments on Proposed Decision
+ 3 days after Comments on Proposed Decision[a]	Reply Comments
December 5, 2024	Final Decision

(a) Rule 14.6(b) allows the parties in the proceeding to stipulate to a shortened comment period. In the past, parties to PG&E's annual ERRA Forecast proceedings have stipulated to a shortened comment period given the timing constraints between the anticipated Proposed Decision date and the need for a January rate change.

The proposed schedule adheres to D.23-12-036 and is consistent with the ERRA Forecast schedules, which it is modeled after.

F. Articles of Incorporation (Rule 2.2)

PG&E is, and since October 10, 1905, has been, an operating public utility corporation organized under California law. It is engaged principally in the business of furnishing electric and gas services in California. A certified copy of PG&E's Amended and Restated Articles of Incorporation, effective June 22, 2020, was filed with the Commission on July 1, 2020, with PG&E's Application 20-07-002. These articles are incorporated herein by reference pursuant to Rule 2.2 of the Commission's rules.

A. Authority to Increase Rates (Rule 3.2)

PG&E is providing material in this Application that complies with Rule 3.2. This Application is not a general rate increase application, so Rule 3.2(a) applies, except for subsections (4), (7), and (9).

B. Balance Sheet and Income Statement (Rule 3.2(a)(1))

PG&E's most recent balance sheet and income statement for the period ended December 31, 2023, was filed with the Commission on March 1, 2024, in amended Application (A.) 22-09-006, and is incorporated herein by reference.

C. Statement of Presently Effective Rates (Rule 3.2(a)(2))

PG&E's presently effective electric rates were filed with the Commission on March 14, 2024, in A.24-03-011, and are incorporated herein by reference.

D. Statement of Proposed Increases or Changes In Rates (Rule 3.2(a)(3))

The proposed changes in electric rates are set forth in Attachment A.

E. Summary of Earnings (Rule 3.2(a)(5) and (a)(6))

A summary of recorded 2022 revenues, expenses, rate bases, and rate of return for PG&E's Electric and Gas Departments was filed with the Commission on July 28, 2023, in A.23-07-012, and is incorporated herein by reference.

F. Most Recent Proxy Statement – Rule 3.2(a)(8)

PG&E's most recent proxy statement was filed with the Commission on May 2, 2023, in A.23-05-005. This proxy statement is incorporated herein by reference.

G. Type of Rate Change Requested (Rule 3.2(a)(10))

The rate changes sought in this application pass through to PG&E, SCE, and SDG&E customers in their respective PPP rates as a non-bypassable charge.

H. Service and Notice of Application (Rule 3.2(b)-(d))

PG&E is serving this Application and its prepared testimony on the service lists in: *Order Instituting Rulemaking to Consider Potential Extension of Diablo Canyon Power Plant Operations in Accordance with Senate Bill 846*, R.23-01-007 and *Application of Pacific Gas and Electric Company for Approval of Modifications to the Diablo Canyon Power Plant Employee Retention Program*, A.23-10-009. Within 20 days after filing this Application, PG&E will mail a notice stating in general terms the proposed revenues, rate changes and rate making mechanisms requested in this Application to the parties listed in Attachment C of this Application, including the State of California and cities and counties served by PG&E. Within 20 days, PG&E will also publish in newspapers of general circulation in each county in its service territory a notice of the filing of this Application and any proposed changes in rates. Within 45 days after filing this Application, PG&E will also include notices of proposed changes in rates with the regular bills mailed or emailed to all customers affected by the proposed changes.

I. Safety (Rule 2.1(c))

In D.16-01-017, the Commission adopted an amendment to Rule 2.1(c) requiring applications to clearly state the "relevant safety considerations." The Commission has previously explained that the "safe and reliable provisions of utilities at predictable rates promotes public safety"[61] As demonstrated in this application and the prepared testimony, the proposals in this proceeding support the directives provided in SB 846, which find that extending DCPP operations is "prudent, cost effective, and in the best interests of all California electricity customers."[62] PG&E is providing detailed testimony and workpapers supporting its revenue requirement for the Record Period. The rate proposals contained in this application are co-sponsored by PG&E, SCE, and SDG&E pursuant to D.23-012-036. The proposals in this proceeding will promote the safe and reliable provision of electric service and establish predictable rates, all of which can help facilitate public safety.

VI. AFFORDABILITY METRICS

On August 4, 2022, the Commission adopted D.22-08-023, which directs when and how the affordability metrics adopted in D.20-07-032 will be applied in Commission energy, water, and communications proceedings and further develops the tools and methodologies used to calculate the affordability metrics. D.22-08-023 requires that PG&E include the affordability metrics in any initial filing or proceeding "with a revenue increase estimated to exceed one percent of currently authorized revenues systemwide for a single fuel."[63] Because the revenue requirements set forth in this Application exceed one percent of PG&E's currently authorized

[61] D.14-12-053, pp. 12-13.
[62] Pub. Res. Code § 25548(b).
[63] D.22-08-023, p. 84, OP 5.

revenues systemwide, PG&E introduces the Affordability Ratio 20 (AR20) by climate zone, Affordability Ratio 50 (AR50) by climate zone, and Hours-at-Minimum-Wage (HM) associated with revenues in effect at the time of the filing.[64] The revenue requirements in this proceeding may be subsequently modified by PG&E's Fall Update. Pursuant to D.22-08-023, PG&E is also required to include "[e]ssential usage bills by climate zone, underlying the affordability metrics associated with revenues in effect at the time of the filing; [a]verage usage bills by climate zone associated with revenues in effect at the time of the filing; [and, f]or climate zones with Areas of Affordability Concern (AAC) as defined in the most recent annual Affordability Report, AR20 by climate zones subdivided by Public Use Microdata Area."[65]

In addition, PG&E is required to produce the aforementioned metrics along with changes in the AR20 by climate zone, AR50 by climate zone, and HM "associated with the proposed new revenue requested annually for each year in which the new revenues are proposed."[66] Attachment B includes the required affordability metrics. Because the impact of the rate increase is expected to be limited to 2025, PG&E is only including metrics associated with that year.

VII. ATTACHMENTS

The following attachments are included in this Application:

- Attachment A – Proposed rate increase;
- Attachment B – Affordability metrics; and
- Attachment C - City and county mailing list.

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[64] D.22-08-023, p. 84, OP 5.
[65] D.22-08-023, p. 84, OP 5.
[66] D.22-08-023, pp. 84-85, OP 6.

VIII. CONCLUSION

PG&E respectfully requests that the Commission issue an order in this application to authorize the following:

1. DCPP revenue requirement from the Record Period of $418.4 million to be effective in rates on January 1, 2025, including the following forecasts and their underlying financial assumptions and calculations, subject to updates in the Fall Update:

    a. Operations and maintenance costs (including expenses, project costs, and statutory costs and fees, as well as associated escalation),

    b. Charges for the liquidated damages account pursuant to section 712.8(g),

    c. Resource Adequacy substitution capacity costs,

    d. Operating expenses that would be amortized through 2030 (i.e., nuclear fuel procurement),

    e. Proposal to mitigate IRC Normalization violation concerns by allowing the additional recovery of the revenue requirement equivalent of the ADIT (for the Normalization depreciation book-tax difference) included in the RO model, and

    f. Netting of CAISO revenues for the period from November 3, 2024 to December 31, 2025.

2. The statewide Diablo Canyon Non-Bypassable Charge.

3. PG&E's proposal for allocation of RA attributes and GHG-free energy allocation in consideration of the higher cost in PG&E's service territory.

4. PG&E's VPF plan and proposed spending priorities for the expenditures.

5. A modified regulatory process for PG&E to utilize a Tier 3 advice letter process for future years of VPF reporting, including how the funds were spent and a prioritization plan.

6. Finding that PG&E's testimony satisfies all the regulatory requirements set forth in D.23-12-036.

Respectfully submitted,

By: *___/s/ Lillian Rafii___________*
LILLIAN RAFII

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Date: March 29, 2024

Attorney for Pacific Gas and Electric Company

ATTACHMENT A

Table 1
Pacific Gas and Electric Company
Illustrative Electric Revenue Increase and Class Average Rates (PG&E service area)
Wednesday, January 1, 2025

Line No.	Customer Class	Proposed Revenue Increase (000's)	Present Rates ($/kWh)	Proposed Rates ($/kWh)	Percentage Change	Line No.
	Bundled Service*					
1	Residential	$ 40,865	$ 0.37888	$ 0.38237	0.9%	1
2	Small Commercial	$ 8,789	$ 0.44196	$ 0.44487	0.7%	2
3	Medium Commercial	$ 6,618	$ 0.39964	$ 0.40225	0.7%	3
4	Large Commercial	$ 9,405	$ 0.34504	$ 0.34766	0.8%	4
5	Streetlights	$ 153	$ 0.56468	$ 0.56675	0.4%	5
6	Standby	$ 1,289	$ 0.23219	$ 0.23551	1.4%	6
7	Agriculture	$ 10,393	$ 0.39569	$ 0.39826	0.6%	7
8	Industrial	$ 8,098	$ 0.24945	$ 0.25146	0.8%	8
9	Total	$ 85,611	$ 0.36614	$ 0.36906	0.8%	9
	Direct Access and Community Choice Aggregation Service**					
10	Residential	$ 60,894	$ 0.23784	$ 0.24165	1.6%	10
11	Small Commercial	$ 14,841	$ 0.28178	$ 0.28471	1.0%	11
12	Medium Commercial	$ 14,147	$ 0.22259	$ 0.22520	1.2%	12
13	Large Commercial	$ 27,360	$ 0.18123	$ 0.18384	1.4%	13
14	Streetlights	$ 371	$ 0.33558	$ 0.33764	0.6%	14
15	Standby	$ 462	$ 0.12886	$ 0.13218	2.6%	15
16	Agriculture	$ 3,778	$ 0.22776	$ 0.23033	1.1%	16
17	Industrial	$ 20,866	$ 0.11471	$ 0.11673	1.8%	17
18	Total	$ 142,719	$ 0.20233	$ 0.20524	1.4%	18
	Departing Load***					
19	Residential	$ 7			2.1%	19
20	Small Commercial	$ 30			7.6%	20
21	Medium Commercial	$ 186			9.1%	21
22	Large Commercial	$ 263			9.2%	22
23	Streetlights	$ -			0.0%	23
24	Standby	$ -			0.0%	24
25	Agriculture	$ 75			9.3%	25
26	Industrial	$ 3,161			8.5%	26

* Customers who receive electric generation as well as transmission and distribution service from PG&E.

** Customers who purchase energy from non-PG&E suppliers.

*** Customers who purchase their electricity from a non-utility supplier and receive transmission and distribution service from a publicly owned utility or municipality. A rate comparison cannot be provided for Departed Load as the applicable rates vary by specific departed load customer categories and any average rate that could be derived, would not be representative of any particular departed load category.

ATTACHMENT B

Summary of Affordability Metric Impacts			
	Affordability Ratio 20 CARE/Non-CARE	Hours at Minimum Wage CARE/Non-CARE	Affordability Ratio 20 in Areas of Affordability Concern (Portions of Lake & Mendocino, Nevada & Sierra, Madera, Fresno, Tulare, Contra Costa, Merced, Colusa, Humboldt, and Kern Counties) CARE/Non-CARE
PG&E Proposal, Lowest-Highest Affordability Impact by Climate Zone	(0.0-0.1%)/(0.1-0.2%)	(0.0-0.1)/(0.1) hours	(0.1-0.2%)/(0.2-0.3%)

Summary of Results:

As a result of PG&E's request in this application, the AR20 metric by climate zone would increase by 0.1 percent or less if based on CARE essential usage bills, and would increase by a range of 0.1 to 0.2 percent if based on non-CARE essential usage bills. This means that the proposed revenue request would increase the portion of a customer's discrentionary household income contributed towards essential electric service by an average of 0.2 percent or less for customers within the 20th percentile of income. As a result of PG&E's request in this application, the hours at minimum wage metric, assuming a minimum wage amount of $16 per month, would increase by less than 0.1 hours of work per month.

CARE Monthly Electric Essential Use Bills				
Climate Zone	3/1/2024	1/1/2025		
	Bill ($)	Bill ($)	Change from Present ($)	%
Territory P	$ 98.52	$ 99.41	$ 0.89	0.9%
Territory Q	$ 88.25	$ 89.05	$ 0.80	0.9%
Territory R	$ 106.85	$ 107.82	$ 0.97	0.9%
Territory S	$ 98.24	$ 99.13	$ 0.89	0.9%
Territory T	$ 59.67	$ 60.21	$ 0.54	0.9%
Territory V	$ 64.66	$ 65.25	$ 0.59	0.9%
Territory W	$ 107.68	$ 108.66	$ 0.98	0.9%
Territory X	$ 81.04	$ 81.77	$ 0.73	0.9%
Territory Y	$ 90.75	$ 91.57	$ 0.82	0.9%
Territory Z	$ 59.67	$ 60.21	$ 0.54	0.9%

Non-CARE Monthly Electric Essential Use Bills				
Climate Zone	3/1/2024	1/1/2025		
	Bill ($)	Bill ($)	Change from Present ($)	%
Territory P	$ 151.54	$ 152.91	$ 1.37	0.9%
Territory Q	$ 135.74	$ 136.97	$ 1.23	0.9%
Territory R	$ 164.34	$ 165.83	$ 1.49	0.9%
Territory S	$ 151.11	$ 152.48	$ 1.37	0.9%
Territory T	$ 91.78	$ 92.61	$ 0.83	0.9%
Territory V	$ 99.46	$ 100.36	$ 0.90	0.9%
Territory W	$ 165.62	$ 167.13	$ 1.50	0.9%
Territory X	$ 124.64	$ 125.77	$ 1.13	0.9%
Territory Y	$ 139.58	$ 140.85	$ 1.27	0.9%
Territory Z	$ 91.78	$ 92.61	$ 0.83	0.9%

**Essential Use Bills are for customers with basic end-use. Bills do not include the biannual California Climate Credit.*

CARE Monthly Electric Average Use Bills				
Climate Zone	3/1/2024	1/1/2025		
	Bill ($)	Bill ($)	Change from Present ($)	%
Territory P	$ 157.90	$ 159.31	$ 1.41	0.9%
Territory Q	$ 131.64	$ 132.82	$ 1.18	0.9%
Territory R	$ 169.50	$ 171.02	$ 1.51	0.9%
Territory S	$ 154.03	$ 155.40	$ 1.38	0.9%
Territory T	$ 85.33	$ 86.10	$ 0.76	0.9%
Territory V	$ 97.30	$ 98.17	$ 0.87	0.9%
Territory W	$ 169.49	$ 171.01	$ 1.51	0.9%
Territory X	$ 110.07	$ 111.06	$ 0.99	0.9%
Territory Y	$ 155.12	$ 156.50	$ 1.38	0.9%
Territory Z	$ 97.16	$ 98.02	$ 0.87	0.9%
Average	$132.75	$133.94	$1.19	0.9%

Non-CARE Monthly Electric Average Use Bills				
Climate Zone	3/1/2024	1/1/2025		
	Bill ($)	Bill ($)	Change from Present ($)	%
Territory P	$ 206.32	$ 208.17	$ 1.85	0.9%
Territory Q	$ 197.25	$ 199.02	$ 1.77	0.9%
Territory R	$ 240.95	$ 243.11	$ 2.16	0.9%
Territory S	$ 218.99	$ 220.95	$ 1.96	0.9%
Territory T	$ 123.00	$ 124.10	$ 1.10	0.9%
Territory V	$ 139.73	$ 140.98	$ 1.25	0.9%
Territory W	$ 235.88	$ 238.00	$ 2.11	0.9%
Territory X	$ 176.55	$ 178.14	$ 1.58	0.9%
Territory Y	$ 151.79	$ 153.16	$ 1.37	0.9%
Territory Z	$ 94.44	$ 95.30	$ 0.85	0.9%
Average	$178.49	$180.09	$1.60	0.9%

**Average Bills are based on 2023 recorded usage. Bills do not include the biannual California Climate Credit.*

CARE Electric - Hours at Minimum Wage			
Climate Zone	3/1/2024	1/1/2025	
	Hours	Hours	Change from Present (hours)
Territory P	6.2	6.2	0.1
Territory Q	5.5	5.6	0.0
Territory R	6.7	6.7	0.1
Territory S	6.1	6.2	0.1
Territory T	3.7	3.8	0.0
Territory V	4.0	4.1	0.0
Territory W	6.7	6.8	0.1
Territory X	5.1	5.1	0.0
Territory Y	5.7	5.7	0.1
Territory Z	3.7	3.8	0.0

Non-CARE Electric - Hours at Minimum Wage			
Climate Zone	3/1/2024	1/1/2025	
	Hours	Hours	Change from Present (hours)
Territory P	9.5	9.6	0.1
Territory Q	8.5	8.6	0.1
Territory R	10.3	10.4	0.1
Territory S	9.4	9.5	0.1
Territory T	5.7	5.8	0.1
Territory V	6.2	6.3	0.1
Territory W	10.4	10.4	0.1
Territory X	7.8	7.9	0.1
Territory Y	8.7	8.8	0.1
Territory Z	5.7	5.8	0.1

**Hours at Minimum Wage metrics are calculated using a statewide minimum wage of $16 per hour.*

Electric-AR20 (NON-CARE)			
Climate Zone	3/1/2024	1/1/2025	
	AR20	AR20	Change from Present (%)
	(A)	(C)	(C) - (A)
Territory P	16.8%	16.9%	0.2%
Territory Q	8.1%	8.2%	0.1%
Territory R	20.1%	20.3%	0.2%
Territory S	11.5%	11.6%	0.1%
Territory T	8.1%	8.2%	0.1%
Territory V	14.0%	14.1%	0.1%
Territory W	13.4%	13.5%	0.1%
Territory X	5.9%	6.0%	0.1%
Territory Y	16.6%	16.7%	0.2%
Territory Z	9.9%	10.0%	0.1%

Electric-AR20 (CARE)			
Climate Zone	3/1/2024	1/1/2025	
	AR20	AR20	Change from Present (%)
	(A)	(C)	(C) - (A)
Territory P	10.9%	11.0%	0.1%
Territory Q	5.3%	5.3%	0.0%
Territory R	13.1%	13.2%	0.1%
Territory S	7.5%	7.5%	0.1%
Territory T	5.3%	5.3%	0.0%
Territory V	9.1%	9.2%	0.1%
Territory W	8.7%	8.8%	0.1%
Territory X	3.9%	3.9%	0.0%
Territory Y	10.8%	10.9%	0.1%
Territory Z	6.5%	6.5%	0.1%

Electric-AR50 (NON-CARE)			
Climate Zone	3/1/2024	1/1/2025	
	AR50	AR50	Change from Present (%)
	(A)	(C)	(C) - (A)
Territory P	4.2%	4.3%	0.0%
Territory Q	2.8%	2.8%	0.0%
Territory R	4.2%	4.2%	0.0%
Territory S	2.9%	2.9%	0.0%
Territory T	1.5%	1.5%	0.0%
Territory V	3.4%	3.4%	0.0%
Territory W	4.3%	4.3%	0.0%
Territory X	1.6%	1.6%	0.0%
Territory Y	4.5%	4.5%	0.0%
Territory Z	2.8%	2.8%	0.0%

CARE AR20 - Areas of Affordability Concern					
PUMA	***County/City***	***Electric Climate Zone***	***# Housing Units***	***3/1/2024***	***1/1/2025***
03300	Lake & Mendocino Counties PUMA	PG&E P	34,621	13.31%	13.43%
05700	Nevada & Sierra Counties PUMA	PG&E P	28,517	12.56%	12.68%
03900	Madera County--Madera City PUMA	PG&E R	46,577	14.65%	14.78%
01903	Fresno County (Central)--Fresno City (East Central) PUMA	PG&E R	66,599	23.39%	23.60%
01904	Fresno County (Central)--Fresno City (Southwest) PUMA	PG&E R	111,927	16.90%	17.05%
01905	Fresno County (Central)--Fresno City (Southeast) PUMA	PG&E R	55,888	16.89%	17.04%
10703	Tulare County (Outside Visalia, Tulare & Porterville Cities) PUMA	PG&E Y	121	12.87%	12.99%
01308	Contra Costa County (Northeast)--Antioch City PUMA	PG&E S	39,137	15.40%	15.54%
04702	Merced County (Northeast)--Merced & Atwater Cities PUMA	PG&E R	5,956	15.41%	15.55%
04701	Merced County (West & South)--Los Banos & Livingston Cities PUMA	PG&E R	23,731	21.55%	21.75%
01100	Colusa, Glenn, Tehama & Trinity Counties PUMA	PG&E S	19,319	14.41%	14.54%
02300	Humboldt County PUMA	PG&E Y	13,357	15.55%	15.69%
02903	Kern County (Central)--Bakersfield City (Northeast) PUMA	PG&E R	894	13.36%	13.48%

Non-CARE AR20 - Areas of Affordability Concern					
PUMA	***County/City***	***Electric Climate Zone***	***# Housing Units***	***3/1/2024***	***1/1/2025***
03300	Lake & Mendocino Counties PUMA	PG&E P	34,621	20.48%	20.66%
05700	Nevada & Sierra Counties PUMA	PG&E P	28,517	19.32%	19.50%
03900	Madera County--Madera City PUMA	PG&E R	46,577	22.53%	22.73%
01903	Fresno County (Central)--Fresno City (East Central) PUMA	PG&E R	66,599	25.97%	26.21%
01904	Fresno County (Central)--Fresno City (Southwest) PUMA	PG&E R	111,927	25.99%	26.22%
01905	Fresno County (Central)--Fresno City (Southeast) PUMA	PG&E R	55,888	35.98%	36.30%
10703	Tulare County (Outside Visalia, Tulare & Porterville Cities) PUMA	PG&E Y	121	19.80%	19.98%
01308	Contra Costa County (Northeast)--Antioch City PUMA	PG&E S	39,137	23.69%	23.91%
04702	Merced County (Northeast)--Merced & Atwater Cities PUMA	PG&E R	5,956	23.70%	23.91%
04701	Merced County (West & South)--Los Banos & Livingston Cities PUMA	PG&E R	23,731	33.15%	33.45%
01100	Colusa, Glenn, Tehama & Trinity Counties PUMA	PG&E S	19,319	22.07%	22.26%
02300	Humboldt County PUMA	PG&E Y	13,357	23.92%	24.14%
02903	Kern County (Central)--Bakersfield City (Northeast) PUMA	PG&E R	894	20.55%	20.74%

**Areas of Affordability Concern (AAC) are denoted by the 2022 Annual Affordability Report published by the CPUC.*

ATTACHMENT C

SERVICE OF NOTICE OF APPLICATION

In accordance with Rule 3.2(b), Applicant will mail a notice to the following, stating in general terms its proposed change in rates.

State of California

To the Attorney General and the Department of General Services.

State of California
Office of Attorney General
1300 I St Ste 1101
Sacramento, CA 95814

and

Director of General Services
State of California
707 3rd St
West Sacramento, CA 95605

Counties

To the County Counsel or District Attorney and the County Clerk in the following counties:

Alameda
Alpine
Amador
Butte
Calaveras
Colusa
Contra Costa
El Dorado
Fresno
Glenn
Humboldt
Kern
Kings
Lake
Lassen
Madera
Marin
Mariposa
Mendocino
Merced
Modoc
Monterey
Napa
Nevada
Placer
Plumas
Sacramento
San Benito
San Bernardino
San Francisco
San Joaquin
San Luis Obispo
San Mateo
Santa Barbara
Santa Clara
Santa Cruz
Shasta
Sierra
Siskiyou
Solano
Sonoma
Stanislaus
Sutter
Tehama
Trinity
Tulare
Tuolumne
Yolo
Yuba

Municipal Corporations

To the City Attorney and the City Clerk of the following municipal corporations:

Alameda
Albany
Amador City
American Canyon
Anderson
Angels Camp
Antioch
Arcata
Arroyo Grande
Arvin
Atascadero
Atherton
Atwater
Auburn
Avenal
Bakersfield
Barstow
Belmont
Belvedere
Benicia
Berkeley
Biggs
Blue Lake
Brentwood
Brisbane
Buellton
Burlingame
Calistoga
Campbell
Capitola
Carmel
Ceres
Chico
Chowchilla
Citrus Heights
Clayton
Clearlake
Cloverdale
Clovis
Coalinga
Colfax
Colma
Colusa
Concord
Corcoran
Corning
Corte Madera
Cotati
Cupertino
Daly City
Danville
Davis
Del Rey Oakes
Dinuba
Dixon
Dos Palos
Dublin
East Palo Alto
El Cerrito
Elk Grove
Emeryville
Escalon
Eureka
Fairfax
Fairfield
Ferndale
Firebaugh
Folsom
Fort Bragg
Fortuna
Foster City
Fowler
Fremont
Fresno
Galt
Gilroy
Gonzales
Grass Valley
Greenfield
Gridley
Grover Beach
Guadalupe
Gustine
Half Moon Bay
Hanford
Hayward
Healdsburg
Hercules
Hillsborough
Hollister
Hughson
Huron
Ione
Isleton
Jackson
Kerman
King City
Kingsburg
Lafayette
Lakeport
Larkspur
Lathrop
Lemoore
Lincoln
Live Oak
Livermore
Livingston
Lodi
Lompoc
Loomis
Los Altos
Los Altos Hills
Los Banos
Los Gatos
Madera
Manteca
Maricopa
Marina
Mariposa
Martinez
Marysville
McFarland
Mendota
Menlo Park
Merced
Mill Valley

Millbrae
Milpitas
Modesto
Monte Sereno
Monterey
Moraga
Morgan Hill
Morro Bay
Mountain View
Napa
Newark
Nevada City
Newman
Novato
Oakdale
Oakland
Oakley
Orange Cove
Orinda
Orland
Oroville
Pacific Grove
Pacifica
Palo Alto
Paradise
Parlier
Paso Robles
Patterson
Petaluma
Piedmont
Pinole
Pismo Beach
Pittsburg
Placerville
Pleasant Hill
Pleasanton
Plymouth
Point Arena
Portola
Portola Valley
Rancho Cordova
Red Bluff
Redding
Redwood City
Reedley
Richmond
Ridgecrest
Rio Dell
Rio Vista
Ripon
Riverbank
Rocklin
Rohnert Park
Roseville
Ross
Sacramento
Saint Helena
Salinas
San Anselmo
San Bruno
San Carlos
San Francisco
San Joaquin
San Jose
San Juan Bautista
San Leandro
San Luis Obispo
San Mateo
San Pablo
San Rafael
San Ramon
Sand City
Sanger
Santa Clara
Santa Cruz
Santa Maria
Santa Rosa
Saratoga
Sausalito
Scotts Valley
Seaside
Sebastopol
Selma
Shafter
Shasta Lake
Soledad
Solvang
Sonoma
Sonora
South San Francisco
Stockton
Suisun City
Sunnyvale
Sutter Creek
Taft
Tehama
Tiburon
Tracy
Trinidad
Turlock
Ukiah
Union City
Vacaville
Vallejo
Victorville
Walnut Creek
Wasco
Waterford
Watsonville
West Sacramento
Wheatland
Williams
Willits
Willows
Windsor
Winters
Woodland
Woodside
Yountville
Yuba City

VERIFICATION

I, the undersigned, say:

I am an officer of Pacific Gas and Electric Company, a corporation, and am authorized, pursuant to Rule 2.1 and Rule 1.11 of the Rules of Practice and Procedure of the Commission, to make this Verification for and on behalf of said Corporation, and I make this Verification for that reason. I have read the foregoing Application, and I am informed and believe that the matters therein concerning Pacific Gas and Electric Company are true.

I declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct to the best of my knowledge.

Executed on March 29, 2024, at Avila Beach, California.

By: *<u>/s/ Maureen Zawalicki</u>*
Maureen Zawalick
Vice President, Business & Technical Services