STATE OF CALIFORNIA GAVIN NEWSOM, *Governor*

PUBLIC UTILITIES COMMISSION
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SAN FRANCISCO, CA 94102-3298

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TO PARTIES OF RECORD IN APPLICATION 24-03-018:

This is the proposed decision of Administrative Law Judge Nilgun Atamturk. Until and unless the Commission hears the item and votes to approve it, the proposed decision has no legal effect. This item may be heard, at the earliest, at the Commission's December 19, 2024 Business Meeting. To confirm when the item will be heard, please see the Business Meeting agenda, which is posted on the Commission's website 10 days before each Business Meeting.

Parties of record may file comments on the proposed decision as provided in Rule 14.3 of the Commission's Rules of Practice and Procedure.

The Commission may hold a Ratesetting Deliberative Meeting to consider this item in closed session in advance of the Business Meeting at which the item will be heard. In such event, notice of the Ratesetting Deliberative Meeting will appear in the Daily Calendar, which is posted on the Commission's website. If a Ratesetting Deliberative Meeting is scheduled, *ex parte* communications are prohibited pursuant to Rule 8.2(c)(4).

/s/ MICHELLE COOKE
Michelle Cooke
Chief Administrative Law Judge

MLC:jnf
Attachment

Decision **PROPOSED DECISION OF ALJ ATAMTURK**
(Mailed 11/14/2024)

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. (U39E.)	Application 24-03-018

DECISION ON PACIFIC GAS AND ELECTRIC COMPANY'S REVENUE REQUIREMENT TO SUPPORT EXTENDED OPERATION OF DIABLO CANYON POWER PLANT AND 2025 VOLUMETRIC PERFORMANCE FEES PROPOSAL

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DECISION ON PACIFIC GAS AND ELECTRIC COMPANY'S REVENUE REQUIREMENT TO SUPPORT EXTENDED OPERATION OF DIABLO CANYON POWER PLANT AND 2025 VOLUMETRIC PERFORMANCE FEES PROPOSAL

Summary

This decision approves Pacific Gas and Electric Company's (PG&E's) 2024 Diablo Canyon Power Plant (DC) extended operations revenue requirement of $723 million, reducing PG&E's requested revenue requirement of $761 million by approximately $38 million, to account for the Tax Gross Up adjustment ($33.63 million), Fixed Management Fee Escalation adjustment ($4.248 million), and the Internal Revenue Code Normalization adjustment ($0.051 million). The revenue requirement is allocated to PG&E, Southern California Edison Company, and San Diego Gas & Electric Company using the allocation factors 44.9 percent, 45.3 percent, and 9.8 percent, respectively.

This decision also makes the following determinations:

1) The investor-owned utilities' joint proposal to establish the DC non-bypassable charge applicable to all Commission jurisdictional customers based on the approved net costs is approved.
2) PG&E's proposal to modify the methodology adopted in Decision 23-12-036 for allocating resource adequacy attributes and greenhouse gas-free energy attributes is denied.
3) PG&E's 2025 Volumetric Spending Plan is denied without prejudice.

This proceeding is closed.

1. Regulatory Background

Senate Bill (SB) 846 (Dodd, 2022)[1] (SB 846) allows for the potential extension of operations at Diablo Canyon Power Plant (DCPP or DC) beyond the current federal license retirement dates, (2024 for Unit 1 and 2025 for Unit 2), up to five additional years, under specified conditions.

Pursuant to SB 846, Decision (D.) 23-12-036, directs and authorizes extended operations at DCPP until October 31, 2029 (Unit 1) and October 31, 2030 (Unit 2). The approval in D.23-12-036 is subject to the following conditions: (1) the United States Nuclear Regulatory Commission (NRC) continues to authorize DCPP operations; (2) the $1.4 billion loan agreement authorized by SB 846 is not terminated; and (3) the Commission does not make a future determination that DCPP extended operations are imprudent or unreasonable.[2]

Further, D.23-12-036 allocates the costs and benefits of extended DCPP operations among all load-serving entities subject to the Commission's jurisdiction; creates a new non-bypassable charge (NBC) and associated processes to collect DCPP extended operations costs; and provides further direction on the use of surplus performance-based fees. In D.23-12-036, the Commission also establishes an application process, similar to the annual Energy Resource Recovery Account (ERRA) proceedings, to review and authorize forecasted DCPP extended operations costs, with subsequent true up to actual costs and market revenues for the prior calendar year.[3]

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[1] SB 846 (Dodd, 2021-2022 Reg. Sess.) Diablo Canyon powerplant: extension of operations, codified as Public Resources (Pub. Res.) Code Sections 25233, 25233.2, 25302.7, 255548, and 25548.1 7; Public Utilities (Pub. Util.) Code Sections 454.52, 454.53, 712.1, and 712.8; and Water Code Section 13193.5.

[2] D.23-12-036 at Ordering Paragraph (OP) 1.

[3] D.23-12-036 at OP 4.

In D.23-12-036, the Commission expressly directs Pacific Gas & Electric Company (PG&E) to include in its application the following:

1. Updated DCPP historical and forecast costs (2022 to 2030) presented using PG&E's existing General Rate Case (GRC) cost structures.[4] This estimate will include or be accompanied by:

    a. 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 PG&E expects to be recovered from utility ratepayers for DCPP extended operations.[5]

    b. 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 to the extent there are actual recommendations and conditions from the DCISC and NRC.[6]

    c. Any government-funded transition costs. D.23-12-036 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.[7]

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[4] D.23-12-036 at 60.

[5] D.23-12-036 at 60.

[6] D.23-12-036 at 60.

[7] D.23-12-036 at 61.

d. 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.[8]

2. A copy of the California Energy Commission's (CEC) final cost comparison report.[9]

3. 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.[10]

4. Quantification of the impact of DCPP's extended operations on its common costs relative to the amount approved in its 2023 GRC.[11]

5. 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.[12]

6. 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 (VPF) 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 (12-CP) demand.[13]

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[8] D.23-12-036 at 61.

[9] D.23-12-036 at COL 17.

[10] D.23-12-036 at COL 54.

[11] D.23-12-036 at COL 54.

[12] D.23-12-036 at 132-133 and COL 54.

[13] D.23-12-036 at OP 7.

In addition, D.23-12-036 directed that this proceeding should:

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

2) Utilize a process that mirrors the Cost Allocation Mechanism (CAM) process to determine the price of the volumetric NBC 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 among the load-serving entities (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.[14]

2. Procedural Background

In compliance with D.23-12-036, on March 29, 2024, PG&E filed the *Application of the Pacific Gas & Electric Company (U39 E) to Recover in Customer Rates the Costs to Support Extended Operation of DCPP from September 1, 2023, through December 31, 2025 and for Approval of Planned Expenditure of 2025 Volumetric Performance Fees* (Application) and served associated testimony. PG&E filed its Amended Application on April 8, 2024.[15]

On April 18, 2024, Resolution ALJ 176-3544 preliminarily determined that this proceeding was categorized as ratesetting.

On May 8, 2024, protests were filed by Alliance for Nuclear Responsibility (A4NR), California Community Choice Association (CalCCA), CAlifornians for Renewable Energy, Inc. (CARE), Direct Access Customer Coalition and Alliance

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[14] D.23-12-036 at OP 9.

[15] In its Amended Application, PG&E corrected a clerical error, heading numbering errors, and officer name misspelling.

for Retail Energy Markets jointly (DACC/AReM), Public Advocates Office at the Commission (Cal Advocates), Southern California Edison Company (SCE), and The Utility Reform Network (TURN). Responses were filed by the Coalition of California Utility Employees (CUE), Green Power Institute (GPI), San Diego Gas & Electric Company (SDG&E), and Small Business Utility Advocates (SBUA). Women's Energy Matters, San Luis Obispo Mothers for Peace (SLO), and Energy Producers and Users Coalition (EPUC) were granted party status in response to their motions filed May 17, June 13, and June 28, 2024, respectively.

On May 20, 2024, PG&E filed a reply to the protests and responses. On May 21, 2024, PG&E filed its amended reply.[16]

A prehearing conference was held on May 31, 2024, to discuss the scope of the proceeding, address the need for hearing and the schedule for managing the proceeding. On June 18, 2024, the assigned Commissioner issued a Scoping Memo and Ruling (Scoping Memo).

PG&E submitted its written prepared testimony on March 29, 2024, and the parties to this proceeding submitted testimony on July 29, 2024, followed by the submission of concurrent rebuttal testimonies on August 20, 2024.

The parties submitted their Joint Report of Meet and Confer and List of Stipulated and Disputed Facts on September 3, 2024, and participated in evidentiary hearings on September 11-12, 2024.

Opening briefs were filed by A4NR, Cal Advocates, CARE, CalCCA, CGNP, CUE, EPUC, GPI, PG&E, SBUA, SCE, SDG&E, SLO, and TURN on

[16] *Amendment to Reply of Pacific Gas and Electric Company to Protests* replaced the *Reply of Pacific Gas and Electric Company to Protests*, which, according to PG&E's note served to the service list of this proceeding on May 21, 2024, contained significant typographical and substantive errors that occurred during the word processing and filing process.

October 1, 2024, and reply briefs were filed by A4NR, CARE, CalCCA, CGNP, CUE, EPUC, GPI, PG&E, SBUA, SCE, SDG&E, SLO, and TURN on October 21, 2024.

In accordance with the October 4, 2024, ALJ Ruling, PG&E updated its prepared testimony on October 11, 2024, to include any updated forecast and recorded Diablo Canyon Extended Operations Balancing Account (DCEOBA) balances (Fall Update). Comments to the update were filed by A4NR, TURN, and CGNP on October 18, 2024, and replies were filed by A4NR, CalCCA, PG&E on October 24, 2024.

2.1. Submission Date

This matter was submitted on November 8, 2024, upon the issuance of an ALJ Ruling admitting updated and confidential testimony into the record of this proceeding and granting motions for leave to file briefs under seal.

3. PG&E's Revenue Requirement Request with the Fall Update

PG&E filed its application for Commission review and approval of its forecasted costs covering the period starting from September 1, 2023 through December 31, 2025 (the Record Period) to support DCPP extended operations. These forecasted costs will be reflected in statewide rates starting on January 1, 2025.

Consistent with the Commission's directives in D.23-12-036, PG&E's application includes: (1) a forecast of costs of extended operations, (2) a forecast of market revenues for DCPP for the Record Period, and (3) a proposal to establish the DC NBC applicable to all Commission jurisdictional customers based on the forecasted net costs.

PG&E filed and served its Fall Update on October 11, 2024. PG&E's Fall Update includes updated market and generation production information, and updated allocation of the statewide 2025 DC NBC applicable to the investor-owned utilities (IOUs). These updates are based on the updates to the CEC load forecast, and updates to the Energy Index and Resource Adequacy (RA) market price benchmarks (MPB) issued by the Commission's Energy Division on October 2, 2024, and on October 4, 2024.[17]

In the Fall Update, PG&E reports that PG&E's forecast of operations and maintenance (O&M) cost presented in its Opening Prepared Testimony, as corrected in the June 28, 2024 errata and supplemental testimony, remains unchanged. Due to the fewer scheduled outage days during Unit 1 and Unit 2 refueling outages in 2025, the generation production forecast increases, which in turn increases the Volumetric Performance Fee (VPF) revenue forecast. The generation production forecast also impacts the generation revenue forecast.

As a result of the updates, for the Record Period, PG&E estimates $1,356.2 million for DCPP costs, statutory fees, and substitution capacity expenses, with an offsetting $624.2 million of California Independent System Operator (CAISO) net forecasted market revenue, for a net revenue requirement of $761 million.[18]

If authorized as proposed, the requested revenue requirement would be allocated to the IOUs as follows: (1) PG&E, $387.5 million; (2) Southern California Edison Company (SCE), $305.7 million; and (3) San Diego Gas & Electric Company (SDG&E), $65.4 million.[19]

PG&E estimates that the requested revenue requirement, if approved, would result in a system average bundled service rate increase by approximately

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[17] *See* PG&E Fall Update at 2-3 for the updated MPB provided by the Commission.

[18] PG&E Fall Update at 7, Table 11-4.

[19] PG&E Fall Update at 11.

1.4 percent to 35.4 cents per kWh when compared to the present system average bundled service rate of 34.9 cents per kWh. The system average rate for Direct Access (DA) and Community Choice Aggregation (CCA) customers would increase by approximately 2.4 percent to 20.9 cents per kWh,[20] when compared to the present system average rate for DA and CCA customers of 20.4 cents per kWh.[21] Similarly, SCE's system average bundled service rate would increase by approximately 1.4 percent to 27.6 cents per kWh.[22] SDG&E's system average bundled service rate would increase by 1.9 percent to 18.6 cents per kWh.[23]

4. Issues Before the Commission

Pursuant to the Scoping Memo, dated June 18, 2024, the issues to be determined in this proceeding are as follows:

1) Whether PG&E's forecasted cost of operations and requested revenue requirement of $418 million over the Record Period for DCPP is reasonable, including the following forecasts and their underlying financial assumptions and calculations, subject to PG&E updating these forecasts in the Fall Update:
   a) Operations and maintenance costs (including expenses, project costs, and statutory costs and fees, as well as associated escalations);
   b) Charges for the liquidated damages account pursuant to Pub. Util. Code section 712.8(g);
   c) Resource Adequacy (RA) substitution capacity forecast costs;

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20 Average rates for DA and CCA customers exclude generation charges that are provided by third-party service providers.

21 PG&E Fall Update at 12.

22 PG&E Fall Update at 15.

23 PG&E Fall Update at 18.

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

   e) PG&E's proposal to mitigate Internal Revenue Code (IRC) Normalization violation concerns by allowing the additional recovery of the revenue requirement equivalent of the Accumulated Deferred Income Taxes (ADIT) (for the normalization depreciation book-tax difference) included in the Results of Operation (RO) model;

   f) Federal and state income tax gross up of fixed management fees; and

   g) Netting of California Independent System Operator revenues for the period from November 3, 2024, to December 31, 2025.

2) Whether the calculation of the NBC and rate proposals by PG&E, SCE, and SDG&E comply with D.23-12-036 and should be approved.

3) Whether PG&E's proposal complies with the implementation of the methodology established by D.23-12-036 for allocating the RA attributes and greenhouse gas (GHG)-free energy associated with DCPP's extended operations.

4) Whether PG&E's proposed VPFs spending plan for the November 3, 2024 to December 31, 2025 period complies with Pub. Util. Code section 712.8(s)(1) requirements and should be approved.

5) Whether PG&E's proposed modified regulatory process for it to utilize a Tier 3 advice letter for reporting on the amount of VPF, how the funds were spent and a plan for prioritizing the uses of such funds pursuant to Pub. Util. Code Sections 712.8(f)(5) and 712.8(s)(1), is reasonable and should be approved.

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

The Commission highlights that in D.23-12-036 the Commission concluded that it will not revisit issues concerning the electric system reliability need for DCPP.[24] Ongoing long-term system reliability needs are already considered and addressed through the Commission's IRP proceeding. Hence, they are out of scope for this proceeding.

5. Burden of Proof and Evidentiary Standard

Pub. Util. Code Section 451 requires that "all charges demanded or received by any utility…shall be just and reasonable." As the applicant, PG&E bears the burden of establishing reasonableness of all issues within the scope of this proceeding as listed in Section 5 of this decision.

The Commission has held that the standard of proof the applicant must meet in rate cases is that of a preponderance of the evidence.[25] Preponderance of the evidence is usually defined "in terms of probability of truth, *e.g.* 'such evidence as, when weighed with that opposed to it, has more convincing force and the greater probability of truth."[26]

6. PG&E's Forecasted Cost and Requested Revenue Requirement

The Commission approves PG&E's 2024 DCPP extended operations revenue requirement of $723 million, reducing PG&E's requested revenue requirement of $761 million to account for the Tax Gross Up adjustment ($33.63 million), Fixed Management Fee Escalation adjustment ($4.248 million), and the IRC Normalization adjustment ($0.051 million). Forecasted cost categories and modifications are discussed in Sections 6.1 through 6.7. Working

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[24] D.23-12-036 at 64.

[25] D.19-05-020 at 7; D.15-11-021 at 8-9; D.14-08-032 at 17.

[26] D.08-12-058 at 19, citing Witkin, Calif. Evidence, 4th Edition, Vol. 1 at 184.

cash is discussed in Section 6.8 and netting of CAISO revenues is discussed in Section 6.9.

6.1. Operations and Maintenance Costs

The Commission approves PG&E's request to recover $498.34 million in O&M costs for the period September 1, 2023 to December 31, 2025.

6.1.1. PG&E's Forecasted O&M Costs

In its Application with the Fall Update, PG&E requests the Commission adopt its forecast for total extended operations and maintenance expense of $498.34 million for the period September 1, 2023 to December 31, 2025.[27] PG&E's forecasted O&M expense includes the base O&M expense, projects expense, and employee retention program expense.

In D.23-12-036, the Commission directed that "costs associated with DCISC recommendations or NRC's conditions of license renewal shall only be included to the extent there are actual recommendations and conditions from the DCISC and NRC.[28] PG&E reports that there are no actual or known forecastable costs for NRC license renewal conditions or any DCISC recommendations during the record period.[29]

In its Application, PG&E explains that similar to PG&E's GRC cost structure, the forecasted costs are presented in the Major Work Category (MWC) level.[30] An overview of PG&E's O&M cost forecast is shown below in Table 1.[31]

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[27] PG&E Opening Brief at 6; Exhibit (Ex.) PG&E-01-E at 3-2.

[28] D.23-12-036 at 60.

[29] Ex. PG&E-01 at 3-1; Ex. PG&E-01-E at 3-2.

[30] Ex. PG&E-01 at 3-16 through 3-25.

[31] Ex. PG&E-01-E at 3-1, Table 3-1. Fuel expense is confidential market sensitive information and is excluded from the tables in public version of the testimony. *See* Ex. PG&E-01 at 3-15 for description of the PG&E's estimation method and WPs Supporting Chapter 3, at 3-35 to 3-36.

Table 1: PG&E's O&M Cost Forecast (thousands of nominal dollars)

Cost Type	2023 Recorded	2024 Forecast	2025 Forecast	Total Period Forecast
O&M Expense	-	$6,121	$298,484	304,605
Project Expense	-	$2,197	$63,030	65,227
Retention Program Expense	$17,025	$55,277	$56,210	$128,512
Total O&M Expense (excluding nuclear fuel procurement)	$17,025	$63,596	$417,724	$498,344

PG&E states that the first component, the base O&M expense, reflects the incremental costs in excess of the 2023 GRC O&M costs approved in D.23-11-069 and those funded by the Department of Water Resources (DWR) loan for the period November 3, 2024 through December 31, 2025.[32] The O&M expense covers labor costs and non-labor costs (materials, contracts, and other costs).

Regarding the second component, the project expense, PG&E provides the following information:

a) The projects expense forecast reflects projects that historically would have been classified as either capital or expense depending on the project scope.[33]

b) PG&E defines project expenses as those for a project that is required as part of NRC's license renewal process or as a condition of PG&E's license renewal application and (1) is expected to be placed in service on or after January 1, 2027 and/or (2) the project scoping, design, engineering, procurement and implementation efforts generally begin after the original Unit 1 license expiration date of November 2, 2024.[34]

c) Discrete scopes of work have been identified with planned implementation schedules and cost estimates

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32 Ex. PG&E-01-E at 3-1.

33 Ex. PG&E-01 at 3-2, 3-3.

34 P&E Opening Brief at 10; Ex. PG&E-02 at 2-11.

for each project.[35] The projects included in this extended operations application have the bulk of the expense incurred after November 3, 2024; and projects with most of the expense prior to November 2024 have been included in the Diablo Canyon Transition and Relicensing Memorandum Account (DCTRMA) and are not part of the application.

d) The projects identified by PG&E include work related to instruments and control systems; intake pumps, motors and equipment; main generator turbine; motors; other electric equipment, cable and systems; other mechanical equipment and piping systems; reactor vessel and radiological control projects; and security infrastructure.[36]

The third component, the retention program expense, reflects the proposed DCPP retention program established to retain the personnel necessary for safe and reliable operation of the plant through the record period. In D.24-09-002, the Commission approved an uncontested settlement agreement in which the settling parties agreed that a reasonable total cost estimate for the employee retention program for September 1, 2023, through November 1, 2030 is $390 million. $128.5 million of $390 million is included in the O&M expense and will be recovered during the Record Period.

6.1.2. Distinction Between Preparatory/Transition Costs and Extended Operation Costs

Several parties dispute PG&E's forecasted O&M cost components and argue that these cost components support activities in preparation or transition to operation, and therefore, they should not be recovered from ratepayers and should instead be covered by government funding. For example, A4NR

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35 Exh.PG&E-01-E at 3-2 and 3-3.

36 Ex. PG&E-01-E at 3-26 through 3-30.

questions the ineligibility of the O&M Project Expense for recovery under PG&E's executed agreements with DWR or the DOE Civil Nuclear Credit program. A4NR asserts that because the O&M Project Expense would pay for the preparation for extended operations, the Commission is precluded by Pub. Util. Code Section 712.8(c)(1)(C) from approving its inclusion in PG&E's revenue requirement.[37] PG&E does not agree with A4NR's assertion and states that to ensure compliance with Pub. Util. Code Section 712.8(c)(1)(C), PG&E has requested approval and cost recovery only for projects not required by the NRC license renewal process or as a condition of license renewal and: (1) that are expected to be placed in service on or after January 1, 2027 and/or (2) the project scoping, design, engineering, procurement and implementation efforts generally begin after the original Unit 1 license expiration date of November 2, 2024.[38] PG&E further states that the project expenses included here "are not projects PG&E is undertaking in preparation for extended operations[,]" but rather they are "necessary to support safe and reliable operation through 2029 and 2030."[39]

Similarly, CARE argues that PG&E is attempting to cost-shift over $149 million in O&M expenses onto ratepayers. In CARE's view, this amount should be construed as a transition cost, and therefore, its recovery is "contrary to Pub. Util. Code Section 712.8(d), DCISC recommendations in their reports, and the DWR contract which specifies that these transitional costs should be funded by the DWR loan."[40] PG&E disagrees with CARE's arguments and reasons that if all costs were considered as transition costs, then PG&E would not be able to

[37] A4NR Opening Brief at 11-12; A4NR Reply Brief at 4-6.

[38] PG&E Opening Brief at 12-13.

[39] PG&E Opening Brief at 12-13.

[40] CARE Opening Brief at 10.

recover any of its project costs from customers, which, in PG&E's view, is a result neither prescribed nor intended by Pub. Util. Code Section 712.8(c)(1)(C) and contravenes the language of Pub. Util. Code Section 712.8(h)(1).[41]

Upon review of the testimony on this matter, the Commission finds PG&E's approach to distinguishing between transition costs and extended operations costs for the purpose of tracking costs in the DCTRMA for recovery via government funding and recording costs to DCEOBA for recovery in customer rates reasonable and consistent with the intent of SB 846 and compliant with Commission decisions.

The distinction between transitional or preparatory costs versus extended operations costs has not been clearly made by the relevant statute. However, PG&E notes, and we agree, that Pub. Util. Code Section 712.8(d) refers to "O&M expense" as that term is used in traditional cost of service ratemaking and is meant to preclude recovery of additional/incremental costs to those authorized in PG&E's 2023 GRC, which assumed DCPP retirement dates of 2024 and 2025. PG&E adds, "The same section does not preclude recovery of extended operations period costs incurred in 2023, 2024, and 2025 through the DC NBC. Given that all costs of DCPP extended operations must be recovered as O&M expense (i.e., none of the costs can be capitalized or rate-based) any other interpretation of Pub. Util. Code Section 712.8(d) renders moot Pub. Util. Code Sections 712.8(h)(1), (f)(2), (f)(5) and (f)(6)."[42]

The Commission finds that A4NR's interpretation of "preparation" is overly broad resulting in precluding almost all costs as preparatory, even though

41 PG&E Opening Brief at 13-15.

42 PG&E Reply Brief at 11.

the legislature clearly contemplated that some DCPP costs would be preparatory, and others would be for ongoing operations. Overall, PG&E proposes a workable and reasonable framework by requesting ratepayer recovery "for projects not recovered by the NRC license renewal process or as a condition of license renewal and (1) that are expected to be placed in service on or after January 1, 2027 and/or (2) the project scoping, design, engineering, procurement and implementation efforts generally begin after the original Unit 1 license expiration of November 2, 2024."

Even though PG&E provided a workable framework to distinguish transitional costs from extended operations costs, PG&E failed to provide in its application a detailed explanation why PG&E did not seek government funding, or was otherwise unable to anticipate the need for the investments and activities at the time government funding was being requested. In D.22-12-005, the Commission concluded that "PG&E should attempt to recover the following transition and extended operations costs using government funding to the greatest extent possible: all costs associated with preserving the option of extended operations at DCPP; all plant and equipment improvement and investment costs; spent fuel storage capacity costs; and any related taxes or other revenue requirements."[43] The Commission also stated that "In the event PG&E…records any of these costs directly to the DCEOBA without seeking government funding, PG&E should be prepared to explain why it did not seek government funding, or was otherwise unable to anticipate the need for the investments and activities at the time government funding was being

[43] D.22-12-005 at CoL 17.

requested."[44] Therefore, in its next application, PG&E must provide this information as directed by the Commission in D.22-12-005.

6.1.3. Level of Details for Project Costs

Cal Advocates does not dispute the eligibility of the project costs for recovery from ratepayers, but Cal Advocates asserts that PG&E has submitted $38.5 million under the category "Other Expenses" in incomplete cost estimates for future project costs. Cal Advocates requests that the Commission decline PG&E's recovery of such forecasted costs until these project costs are better documented.[45]

In response, PG&E explains that it presented the total project expense forecast for the Record Period broken down by MWC in its direct testimony and by MWC and cost group in supporting workpapers. These cost groups include: Labor, Burden, Contract, Material and Other.[46] PG&E explains that of the projects in dispute, "13 projects and 84.3 percent of the dollars have detailed project summaries, supporting that all forecast project costs were approved through PG&E processes as required to implement the project. For the remaining 15.7 percent of the dollars, PG&E witness Brian Ketelsen testified that, consistent with PG&E's approach in GRC proceedings, PG&E provided detailed project summaries only for projects over $3 million,"[47] which PG&E argues, is in line with the practice in prior GRCs.

[44] D.22-12-005 at 17.

[45] Cal Advocates Opening Brief at 5; Ex. PAO-01 at 8.

[46] PG&E Opening Brief at 11.

[47] Tr. Vol. 1, 75: 2-4.

Because PG&E properly followed the common practice in GRCs, as directed by D.23-12-036,[48] and presented project summaries for projects over $3 million, and given the sufficient level of project detail provided by PG&E, we do not find it necessary to reduce the requested funding. However, in the interest of transparency, PG&E must provide detailed information for all projects with costs more than $1 million in its next filing.

6.1.4. Costs Compared to Industry Norms

SBUA asserts that the overall cost forecast for DCPP extended operations remains significantly excessive. Specifically, SBUA considers the $15.9 million in projected labor overhead costs under Major Work Category BP and the $80 million projected for license renewal implementation under the Major Work Category (Maintain DCPP Plant Assets), to exceed industry norms.[49]

In response, PG&E states that SBUA's recommendation overlooks PG&E's explanation regarding the 2024 updates to overhead costs accounting changes implemented in 2024. PG&E adds that aside from the accounting changes, the main driver of annual forecast changes is headcount increases needed to support extended operations and the related cost escalation or inflation.[50]

SBUA's arguments are not well supported and do not provide sufficient details for the Commission to consider the reductions being proposed by SBUA.

6.1.5. Employee Retention Program Costs

A4NR, CARE, and EPUC disagree with PG&E's cost recovery proposal for employee retention program costs. A4NR does not dispute the aggregate amount of the employee retention program costs for the employee retention program, but

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[48] D.23-12-036 at FoF 57.

[49] SBUA Opening Brief at 6-7.

[50] PG&E Opening Brief at 9.

it contests the allocation of the employee retention program costs between utility service territories.[51] A4NR states that "…although PG&E's Application would charge the SCE and SDG&E service territories for the costs of the employee retention program for the entire Record Period, customers in those service territories will only be able to receive DCNPP electricity (and be charged for other DCPP operating costs) for less than one-third of this period."[52]

EPUC posits that 2023 employee retention costs are not recoverable in the DC NBC, but should instead be assumed recoverable from 2023 CAISO market revenues or via other revenue streams.[53] In response, PG&E states that the 2023 employee retention costs could not be offset by CAISO market revenues from 2023, because there was no extended operations generation at DCPP in 2023; PG&E was not authorized to use 2023 CAISO market revenues for offsetting extended operations costs, and D.22-12-005 directed these costs to be recorded in the DCEOBA and reviewed in this initial application.[54]

In D.24-09-002, the Commission adopted the Settlement Agreement of PG&E, CUE, and Community Legal Services on PG&E's extended operations period employee retention program.[55] The settlement agreement approved by D.24-09-002 specifies that the $390 million covers the direct costs of the employee retention program. These costs will be adjusted for payroll tax and Revenue Fees and Uncollectibles before being recovered through the Commission-approved cost recovery mechanism. Hence, PG&E's request to recover $128.5 million in

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[51] A4NR Opening Brief at 21-24; Reply Brief at 9.

[52] A4NR Reply Brief at 10.

[53] EPUC Opening Brief at 11.

[54] PG&E Opening Brief at 15-17.

[55] D.24-09-002 at OP 1.

employee retention costs for the Record Period in the DC NBC is consistent with Pub. Util. Code Section 712.8(f)(2), D.22-12-005 and Resolution E-5299, D.23-12-036, and D.24-09-002,[56] and is approved.

6.1.6. Contingencies

SLO alleges that PG&E's cost forecasts exclude several expenses related to DCPP operations. Specifically, SLO argues that the forecast omits a contingency factor, the annealing or replacement of the Unit 1 reactor pressure vessel, modifications to the Independent Spent Fuel Storage Installation (ISFSI) and related conditions, seismic upgrades, and compliance with the California Coastal Act's coastal development permit and federal consistency certification requirements.[57] In response, PG&E states that PG&E's cost forecast reflects risks that PG&E knows may occur, e.g., outage delays and vendor delays, but not those with higher level of uncertainty.[58] With respect to the costs of a project that would have modified the DC ISFSI to accommodate a new dry cask storage system and the costs to implement conditions the CCC required for its approval of an amendment to the DC ISFSI CDP, PG&E states that it has yet to decide if or when it will proceed with the ISFSI pad modifications allowed by the permit amendment from the CCC.[59] PG&E adds that if PG&E does not proceed with the project within two years of permit's issuance, the amendment and associated conditions will expire.[60]

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[56] D.23-12-036 at 67, D.24-09-002 at OP 2.

[57] SLO Opening Brief at 15.

[58] PG&E Reply Brief at 7.

[59] PG&E Reply Brief at 8, citing Ex. PG&E-03 at 3.

[60] PG&E Reply Brief at 8.

The Commission finds that it is reasonable for PG&E to exclude speculative costs in this application. As noted in the August 15, 2024, Administrative Law Judge's ruling, "the Commission has not received any new recommendations from the DCISC and there have not been any changes in NRC's conditions of license renewal. In the absence of any new information, asserting that certain safety risks have associated costs is highly speculative. In the event the DCISC or NRC provides new recommendations that may affect PG&E's cost forecast, then the Commission may consider the new or updated information, as appropriate, in this proceeding or a future proceeding."[61]

6.1.7. Conclusion - O&M Costs

Upon consideration and based on the discussion presented in Section 6, the Commission finds that PG&E's forecasted O&M costs comply with the applicable statute and Commission orders, are reasonable, and should be approved. In its next Application, PG&E must: (1) provide detailed information for all projects with costs more than $1 million; and (2) provide a detailed account of why it did not seek government funding for the costs being requested to be recovered from ratepayers, or was otherwise unable to anticipate the need for the investments and activities at the time government funding was being requested.

6.2. Statutory Fees

The Commission approves the following statutory fees authorized by SB 846 and requested by PG&E for the extended operations period of November 3, 2024 through December 31, 2025: (1) $167.1 million in VPFs; and (3) $225 million

[61] E-Mail Ruling Granting Pacific Gas and Electric Company's Motion to Strike Testimony, August 15, 2024, at 3.

to be recorded to the liquidated damages subaccount of the DCEOBA.[62] PG&E's request for $112.7 million in fixed management fees, including associated escalation factors and before taxes, is reduced by $4.248 million, to reflect the modified escalation method.

6.2.1. Fixed Management Fees

The Commission approves PG&E's fixed management fees in the amount of $108.5 million, reduced from $112.7 million due to the modified escalation rate.

SB 846 authorizes PG&E to collect a fixed payment of $50 million per unit per year of extended operations.[63] The Commission determined that the Fixed Management Fee, referred to in statute as a "fixed payment," would be recovered from ratepayers of all LSEs through the DC NBC.[64]

In its Application, in order to account for inflation, PG&E proposes to apply an escalation factor of 3.66 percent to the 2024 fixed management fee and an escalation factor of 4.9 percent to the 2025 fixed management fee. These escalation factors are the annual average product of the gas distribution, gas storage, electric distribution, electric transmission, nuclear generation, hydro generation, fossil generation, and common plant annual cumulative escalation factors. PG&E considers this approach reasonable because it utilizes an average of all functional areas' cumulative capital escalation factors.[65]

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[62] Ex. PG&E-01-E at 7-1.

[63] Pub. Util. Code § 712.8(f)(6).

[64] D.23-12-036 at 67.

[65] Opening Brief at 18-19.

Several parties challenge PG&E's escalation rates. EPUC objects to escalating fixed management fees.[66] In response, PG&E argues that EPUC's recommendation conflicts with the intent of Pub. Util. Code Section 712.8(f)(6)(A). Additionally, EPUC's recommendation overlooks inflation's impact and disregards the role of cost escalation in utility ratemaking.[67]

TURN does not dispute PG&E's use of an escalator but disagrees with PG&E's proposed escalation rates. TURN urges the Commission to restrict the methodology to focus on electric generation capital costs, only.[68] TURN's approach would lower the fixed management fee forecast by approximately $4.25 million in 2025 compared to PG&E's method, resulting in cumulative savings of $37.7 million through 2030.[69]

As TURN framed it, the relevant question is whether the escalation rate should consider capital expenditures in all functional areas or just electric generation. Since DCPP is a generation asset and the purpose of the Fixed Management Fee is to compensate PG&E shareholders for the risks associated with generation assets, the use of a generation-specific escalator is reasonable and appropriate. Hence, PG&E's proposed escalation rate is not approved. PG&E must update the fixed management fees escalation rates using TURN's proposed escalation rate.

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66 Ex. EPUC-01 at 2.

67 PG&E Opening Brief at 19.

68 Turn Opening Brief at 13.

69 TURN Opening Brief at 2.

6.2.2. Volumetric Performance Fees

Pub. Util. Code Section 712.8(f)(5) established VPFs for recovery in rates. PG&E requests the Commission's approval to recover a total combined VPF of $167.2 million for the extended operations period.

Several parties disputed PG&E's proposed use of the VPF revenues, but no party objected to PG&E's methodology for calculating the VPFs or the escalation factors applied to the total. PG&E's VPF request of approximately $167.2 million is reasonable and approved.

6.2.3. Liquidated Damages Fund

PG&E's liquidated damages funding request of $225 million complies with the statute, is reasonable, and should be approved.

Pub. Util. Code Section 712.8(g) establishes the liquidated damages fund:

> The commission shall authorize and fund as part of the charge under paragraph (1) of subdivision (l), the Diablo Canyon Extended Operations liquidated damages balancing account in the amount of twelve million five hundred thousand dollars ($12,500,000) each month for each unit until the liquidated damages balancing account has a balance of three hundred million dollars ($300,000,000).

Pub. Util. Code Section 712.8(i)(1) provides that the purpose of this liquidated damages funding is to offset potential replacement power costs resulting from an unplanned outage at DCPP when the Commission determines PG&E failed to meet the reasonable manager standard:

> During any unplanned outage periods, the commission shall authorize the operator to recover reasonable replacement power costs, if incurred associated with Diablo Canyon powerplant operations. If the commission finds that replacement power costs incurred when a unit is out of service due to an unplanned outage are the result of a failure of the operator to meet the reasonable manager standard, then the commission shall authorize payment of the replacement power costs from the Diablo Canyon Extended

Operations liquidated damages balancing account described in subdivision (g).

In the event it is not necessary to use the liquidated damages funding to offset replacement power costs as provided in Pub. Util. Code Section 712.8(i)(1), the funds will be returned to customers in PG&E's service territory, as required by Pub. Util. Code Section 712.8(t). Rather than creating a new balancing account for the liquidated damages fund, the Commission approved in Resolution 5299-E PG&E's request to include a subaccount in the DCEOBA to record the liquidated damages amounts and recover them in customer rates.

In its Application, PG&E requests that the Commission approve its requested total combined liquidated damages funding forecast of $225 million for the Record Period. This total request is the sum of: (1) the DCPP Unit 1 liquidated damages funding in the amount of $175 million for the DCPP Unit 1 extended operations period of November 3, 2024 through December 31, 2025, and (2) the DCPP Unit 2 liquidated damages funding in the amount of $50 million for the Unit 2 extended operations period of August 27, 2025, through December 31, 2025.

Most intervenors did not object to PG&E's calculations. Even though SBUA agrees that PG&E's cost recovery request is "correct and appropriate,"[70] SBUA requests that PG&E be required to supplement its testimony or file a new application to specify how liquidated damage funds will be used and how they will be returned to customers.

EPUC recommends the Commission approve $200 million in funding for liquidated damages for the record period, based on its belief that DCPP units 1

[70] Ex. SBUA-01, at 10 and 13.

and 2 will have only 16 months of combined extended operations by the end of 2025.[71] PG&E considers EPUC's proposal incorrect, because including the period from November 2, 2024 through December 2024 for Unit 1, whose operating license expires November 2, 2024, the correct total for extended operations across both units is 18 months during the Record Period.[72]

The Commission agrees with PG&E and finds that EPUC's calculation is incorrect. PG&E's liquidated damages funding request of $225 million complies with the statute, is reasonable and should be approved.

With respect to the SBUA's recommendation for a supplement or a new application, the Commission does not think it is appropriate to delay the proceeding schedule for PG&E to prepare a supplement or file a new application, but in its next DCPP cost forecast filing, PG&E should include its detailed plans on how the liquidated damage funds will be used and how they will be returned to customers.

6.3. RA Substitution Capacity Costs

PG&E's RA substitution capacity cost forecast of $210 million for the extended operations period of November 3, 2024, through December 31, 2025, is approved.

6.3.1. Background

In D.23-12-036, the Commission determined that PG&E would retain the responsibility, as the scheduling coordinator, to procure substitution RA capacity during periods when the DCPP units are on planned outages.[73] The Commission further specified that to ensure against potential cost shifts to PG&E's bundled

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71 Ex. EPUC-01 at 2.

72 PG&E Opening Brief at 25, citing Ex. PG&E-02 at 7-7.

73 D.23-12-036 at 86-87.

service customers, PG&E would be authorized to recover from all load-serving entities the administrative and procurement costs associated with meeting DCPP's substitution RA capacity obligations, including associated penalties and costs borne by non-DCPP resources.[74]

Pursuant to D.23-12-036, PG&E included as part of the forecasted DCPP revenue requirements an estimate of the RA substitution capacity costs covering the last two months of 2024 when Unit 1 will begin its period of extended operations and all of 2025 when Unit 1 is in its period of extended operations and the last four months of 2025 when Unit 2 begins its period of extended operations.[75]

6.3.2. PG&E's Proposal

To develop its RA substitution capacity cost forecast, PG&E first determines the amount of RA substitution capacity needed during times when Diablo Canyon is expected to be offline or curtailed due to planned outages, tunnel cleaning, and/or other short-term curtailment events. This required capacity is then multiplied by a market reference price to estimate the total procurement costs for meeting DCPP's RA substitution capacity obligations. PG&E uses the outage and curtailment schedules from the generation forecast and multiplies that amount with the 2024 Power Charge Indifference Adjustment (PCIA) system RA MPB, similar to the practice used in the ERRA Forecast proceeding. PG&E notes that its forecast does not include any additional administrative costs or potential compliance penalties costs and/or costs borne due to non-DCPP resources within PG&E's generation portfolio.[76]

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[74] D.23-12-036 at 87.

[75] Ex. PG&E-01 at 4-1.

[76] PG&E Opening Brief at 26.

As a result, PG&E seeks recovery from ratepayers of forecast RA Substitution Capacity Costs of $210.1 million for 2024 – 2025, as shown in Table 2.[77] Due to the increase in the system RA MPB, the forecasted RA substitution capacity costs increased from $78 million to $210 million in the Fall Update.

Table 2: RA Substitution Capacity Cost Forecast

Year	Total
2024	$16,340,100
2025	$193,800,800
Total	**$210,140,000**

6.3.3. Discussion

A4NR disputes the method PG&E uses to calculate its forecasted RA substitution capacity cost. A4NR prefers the use of data based on current market transactions over a weighted average of historic prices obtained retrospectively from past market transactions. A4NR argues that PG&E's confidential data response to CalCCA, when compared with the 2024 – 2025 scheduled outage months listed in PG&E's confidential workpapers (all non-peak RA months), indicates that PG&E actually projects it could secure system RA offers for four out of five of those months at prices that are significantly lower than the current $15.23/kW-Month PCIA market price benchmark.[78] As a result, according to A4NR, PG&E's choice to use the current $15.23/kW-Month PCIA market price benchmark instead of its own forward price estimates overstates its revenue requirement for system RA replacement capacity by $31,636,461 during 2024-2025.[79] For that reason, A4NR recommends capping the revenue requirement at

[77] PG&E Fall Update at 5.

[78] A4NR Opening Brief at 17.

[79] A4NR Opening Brief at 18.

$44.8 million to satisfy the "just and reasonable" requirement of Pub. Util. Code Section 451. Given the increase in PG&E's Fall Update, A4NR's recommended disallowance of RA substitution capacity costs has increased to $165.3 million.[80]

Similarly, TURN opposes the use of RA MPB for updating the RA substitution capacity cost forecast for 2025 and states the following.[81]

> For purposes of calculating Diablo Canyon resource capacity substitution costs in 2024 and 2025, the MPB is inappropriate due to the mismatch between the peak summer pricing that drives the annual average and the timing of Diablo Canyon outages. As pointed out in A4NR's testimony, PG&E's own forecasts of short-term system RA costs show massive differences between pricing in summer months versus all other times during the year. In its release of the MPBs, the Energy Division provided data showing higher transaction volumes in peak summer months but did not show pricing by month. Applying the average annual price to the months of the Diablo Canyon outages would result in a significant overcollection relative to expected real-world costs.[82]

Given the disconnect between expected monthly pricing of system RA and the timing of Diablo Canyon outages, TURN recommends that the Commission decline the use of the MPBs for purposes of setting revenue requirements and instead rely on either PG&E's own internal monthly forward RA price curves or the average actual cost of system RA capacity in PG&E's own portfolio that would be used to provide substitution during the outage periods.[83]

PG&E disagrees and argues that PG&E's use of the PCIA RA benchmark price is appropriate, as the Commission recently determined that, "using a

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80 A4NR Comments on the Fall Update, October 18, 2024, at 2.

81 TURN Comments on the Fall Update, October 18, 2024, at 1.

82 TURN Comments on the Fall Update, October 18, 2024, at 1, referring to Ex. A4NR-1, Confidential Appendix 8.

83 TURN Comments on the Fall Update, October 18, 2024, at 2.

process that mirrors the CAM process to distribute RA benefits to LSEs will account for the substitution capacity costs cited by PG&E." In PG&E's view, this suggests that the distribution of benefits and cost recovery should align with the guidance for CAM resources. Given this guidance and PG&E's historical use of resources within its portfolio to provide substitution for DCPP, PG&E recommends using the PCIA MPB as the most reasonable and defensible price available.[84]

The Commission is cognizant of the pros and cons of the use of a PG&E estimated benchmark versus an administratively set price benchmark as offered by the party testimony. However, the Commission has already determined that the use of RA MPB is appropriate.[85] The use of PCIA benchmarks is more transparent and aligns with the regulatory precedent, e.g., ERRA. Therefore, it is reasonable and consistent choice to use in this proceeding.

As noted in PG&E's Fall Update, the Administrative Law Judge in PG&E's ERRA Forecast proceeding, A.24-05-009, issued a ruling on October 8, 2024, noting that the 2025 forecast system RA MPB issued on October 4, 2024, is nearly three times higher than the 2024 forecast system RA MPB and requested party comments. If, based on those comments, the Commission adopts measures to mitigate excessive over- or under- collections in the ERRA balancing account, PG&E must incorporate those measures into the DC NBC via a Tier 1 advice letter and implement those changes in the next consolidated electric rate change filing with the Commission.

[84] PG&E Opening Brief at 26.

[85] D.24-06-004 at 15.

6.4. Nuclear Fuel Cost

PG&E's nuclear fuel cost forecast and straightline amortization proposal are reasonable, comply with Pub. Util. Code Section 712.8(c)(1)(C), 712.8(h)(1) and Commission decisions and resolutions interpreting those statutory sections, and are approved.

PG&E requests that the Commission adopt its nuclear fuel expense forecast for 2025. PG&E explains that these expenses stem from the contracted purchases of nuclear materials to support the nuclear fuel reload needs for each unit and cover the costs of uranium, conversion services, enrichment services, fabrication, and sales and use taxes, for the specific core design. Additionally, there are miscellaneous engineering expenses associated with the core nuclear fuel analysis.[86]

In addition to its forecast, PG&E requests that the Commission approve a straightline amortization method for recovering nuclear fuel expenses over the 2025-2030 period. PG&E presents both the 2024 through 2030 as-spent nuclear fuel expenditures as well as PG&E's 2025 through 2030 straightline amortization cost recovery proposal. According to PG&E, straight-line amortization offers the lowest financing cost compared to as-spent recovery and smooths rates for all California electric customers during the extended operations period. Consistent with D.22-12-031, PG&E also proposes that PG&E's proposed yield spread adjustment (YSA) mechanism be applied to the financing rate for the amortization period, pending a ruling on PG&E's YSA proposal in the Cost of Capital proceeding.[87]

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[86] PG&E Opening Brief at 27.

[87] PG&E Opening Brief at 27-28.

A4NR questions PG&E's inclusion of nuclear fuel procurement costs in the requested revenue requirement.[88] A4NR contends that these costs are transition costs incurred "in preparation for extended operations" and consequently subject to the ratepayer protections of Pub. Util. Code Section 712.8(c)(1)(C).[89]

CARE argues that PG&E's loan agreement with DWR specifies that nuclear fuel expense is to be covered by the DWR loan,[90] and that PG&E has already recovered $5,639,557 from DWR for 2023 fuel and transition costs.[91] Noting that PG&E's fuel costs are confidential, CARE states that it is impossible to determine the dollar amount of the nuclear fuel expense that should be eliminated from PG&E's rate recovery in this proceeding.

PG&E disagrees with both CARE and A4NR. As noted by PG&E, the Commission recently reviewed similar claims from both parties, which asserted that SB 846, D.22-12-005, and Pub. Util. Code Section 451 preclude recording fuel costs in the DCEOBA. The Commission concluded in Resolution E-5299 that, ". . . there is no indication in this statutory language, nor elsewhere in SB 846, that the legislature intended to categorically deny recovery of incremental fuel costs in the DCEOBA or limit its recovery to the DCTRMA."[92] Furthermore, the Commission clarified that under its review of Pub. Util Code section 712.8(c)(1)(C) and 451, PG&E may need to justify the transfer of SB 846 costs between the two accounts, signifying a need for flexibility when considering all

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[88] A4NR Opening Brief at 19-20.

[89] A4NR Reply Brief at 8.

[90] CARE Opening Brief at 17; CARE-01 at 3; CARE Reply Brief at 16.

[91] CARE Opening Brief at 18 citing PG&E Advice Letter 7068-E at Footnote 63.

[92] Res. E-5299 at 10.

SB 846 costs, including incremental fuel costs.[93] The Commission found that "Whether incremental fuel costs are considered a necessary preparation for extended operations under [Pub. Util. Code Section] 712.8(c)(1)(C) and whether those costs are just and reasonable under [Pub. Util. Code Section] 451 will be addressed … in PG&E's annual Diablo Canyon Extended Operations Cost Forecast application."[94] The Commission also found that the DCTRMA and the DCEOBA as proposed by PG&E comply with D.22-12-005.[95]

PG&E also disagrees with CARE's assertion that the DWR Loan Agreement requires that all nuclear fuel costs be recovered solely from government sources. The agreement allows loan proceeds to cover furl costs but does not restrict cost recovery to these funds.[96]

Upon review, the Commission finds PG&E's request to recover nuclear fuel costs reasonable and in alignment with the relevant statute. We note that the costs that are already attributed to the DWR Loan are considered incremental as they were needed to pay for the extension of the existing fuel cycle, whereas the nuclear fuel costs sought herein are outside of the transition window and part of ongoing operations during the extension and are necessary for the operation of the plant. This treatment aligns with the Commission's historical treatment of nuclear fuel costs where these costs were recovered annually in rates through the ERRA Forecast proceeding.

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93 Res. E-5299 at 10.

94 Res E-5299 at Finding 5.

95 Res E-5299 at Finding 5.

96 PG&E Reply Brief at 18.

6.5. The Internal Revenue Service (IRS) Tax Law Normalization Requirements

PG&E's alternate proposal to mitigate concerns regarding violation of the IRS tax law normalization requirements is approved. Accordingly, PG&E will: (1) track the amounts at issue in a memorandum account to enable it to cure any violation retrospectively; (2) seek a private letter ruling with the IRS on this issue and (3) adjust rates as soon as practicable via the General Order 96-B process if PG&E receives an IRS ruling confirming that excluding recovery for the amounts is a normalization violation. The costs to prepare and file this IRS Private Letter Ruling (PLR) may be recovered in a future rate case through the DCEOBA, since the need for this PLR arises due to SB 846 and this rate case.

6.5.1. An Overview of Normalization Method

The Economic Recovery Tax Act of 1981 made changes to the tax laws that had significant implications for ratemaking.[97] It required that utilities subject to cost-of-service regulation should account for the tax benefit of certain expenditures by using a Normalization method of accounting. The Commission issued Order Instituting Investigation (OII) 24, and later adopted Normalization accounting, and has addressed compliance with federal Normalization rules in various decisions.[98]

Utilities account for depreciation expenses using the straight-line depreciation method for ratemaking purposes and the accelerated depreciation method for tax purposes. While straight-line depreciation reduces the value of an asset by the same annual amount over the life of the asset, accelerated

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[97] *See* D.93848 issued on December 15, 1981, in OII 24, for a discussion of the implications.

[98] *See* D.93848, D.84-05-036, D.19-08-021, D.19-08-023.

depreciation allows a utility to reduce that value by larger amounts early in the life of the asset, and lower amounts in later years.

Normalization rules require that, for ratemaking purposes, the same asset be depreciated over the entire useful life of the asset, applying the straight-line depreciation method. As a result of the normalization requirement, customer rates collect more taxes than the utility pays the IRS in the early years of the underlying asset, but less taxes than necessary in later years. The utility establishes a deferred tax reserve account to record the difference between the straight-line depreciation expense and the accelerated depreciation expense. These funds are labeled ADIT. The utility then draws down that reserve as the accelerated depreciation benefits for a particular asset reverse. Because DCPP extended operations is not a traditional cost-of-service and rate-based rate of return model, there is no rate base for an ADIT adjustment.

PG&E highlights that "if a utility fails to comply with the Normalization rules, then the Utility loses the right to use accelerated tax depreciation under IRC Section 168 for the whole company (not limited to the offending rate case), all deferred taxes would become due to the IRS immediately and additionally, in future rate cases, there would be no more rate base adjustments for the ADIT for book-tax depreciation differences, which would generally increase rates."[99] That is, a normalization violation harms ratepayers as well as utilities.

99 Ex. PG&E-01 at chapter 5.

6.5.2. PG&E Proposal

PG&E asserts that the SB 846 requirement that all costs associated with Diablo Canyon be expensed within the same year,[100] and the prohibition on capitalizing any such costs, conflicts with federal tax depreciation rules applicable to these assets. To remedy, PG&E proposes two options. PG&E's first proposal is to "calculate the ADIT related to the book-tax difference for DCPP depreciation and convert this amount to a revenue requirement that would be recovered from ratepayers."[101] PG&E's alternative option is to track these amounts in a memorandum account and seek a private letter ruling from the IRS to determine if excluding recovery of these amounts from rates constitutes a normalization violation.[102]

PG&E proposes to implement the first proposal by including an additional revenue requirement based on the debt financing cost associated with the ADIT for the Normalization book/tax difference. The Normalization ADIT will be trued-up to actual once the information is available, as part of the true-up process. At the end of DCPP extended operations, the Normalization ADIT will reverse because the assets can no longer be used in a trade or business for tax purposes, which will balance out the book/tax difference and this adjustment.[103] The 2025 forecast amount for this Normalization adjustment is approximately $51,000 and does not result in additional income taxes.[104]

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[100] Pub. Util. Code Section 712.8(h)(1) requirement that all extended operations costs "shall be recovered as an operating expense and shall not be eligible for inclusion in the operator's rate base."

[101] Ex. PG&E-01 at 5-7.

[102] Ex. PG&E-01 at 5-10.

[103] Ex. PG&E-01-E, p. 5-8, 5-9.

[104] Ex.PG&E-01 at 6-4.

SBUA opposes PG&E's proposal to include an additional revenue requirement in the RO Model to mitigate for the potential Normalization violation.[105] SBUA argues that "how PG&E deals with the tax rules is up to PG&E" and that PG&E's proposal amounts to "double depreciation."[106]

In disagreement with SBUA, first, PG&E notes that the IRC Normalization rules must be reflected in ratemaking and that PG&E has a duty as a regulated utility to avoid Normalization violations and could not submit a cost recovery application without trying to mitigate the issue. Second, PG&E argues that SBUA's assertion of "double depreciation" is the opposite of PG&E's situation, since PG&E has not realized the full "tax benefits" for DCPP. PG&E adds that the no-rate base framework of SB 846, where book depreciation is accelerated faster than tax depreciation, results in greater upfront tax liability considering the significant amount of DCPP assets in extended period.[107]

TURN's testimony offers support for PG&E's alternative option.[108] TURN notes that the amount PG&E proposes to recover in 2025 rates is not large ($0.051 million) if PG&E's first proposal is adopted, but PG&E forecasts that approximately $8.2 million may need to be collected from ratepayers to address this issue through 2030.[109] PG&E witness Hayashida estimates that the cost of seeking a private letter ruling from the IRS is expected to cost between $0.1 and $0.12 million. Therefore, pursuing the alternative option will result in near-term

[105] Ex. SBUA-01 at 19.

[106] Ex. SBUA-01 at 20-21.

[107] PG&E Opening Brief at 33.

[108] TURN Opening Brief at 20; TURN-01 at 35.

[109] Ex. TURN-01, Attachments, PG&E response to TURN Data Request 1, Q28.

ratepayer savings until PG&E is able to clarify the applicability of the normalization requirements to Diablo Canyon.[110]

As TURN suggests, submitting a request for a Private Letter Ruling provides an opportunity to assess whether VPFs qualify for nontaxable treatment. Even if considered gross income, the IRS may offer guidance that allows modifications to the VPF mechanism to meet relevant IRS requirements for nontaxable treatment. This guidance could inform recommendations to the Legislature to amend the relevant statutory provisions, facilitating nontaxable treatment, aligning with SB 846 goals, and benefitting ratepayers.[111]

PG&E's alternative proposal to track potential deferred taxes in a memorandum account relating to SB 846 ratemaking, and seek a private letter ruling from the IRS, would result in near term ratepayer savings and clarify the applicability of the normalization requirement to DCPP. Hence, it should be adopted.

6.6. Federal and State Income Tax Gross-Up on Fixed Management Fees

In its Application, PG&E proposes to collect a state and federal tax gross-up applied to the fixed management fee. PG&E proposes to use the federal corporation income tax rate of 21 percent and California corporation state income tax rate of 8.84 percent for a combined tax rate of rate of 29.84 percent for the revenue requirement modeling purposes, consistent with past rate cases.[112] PG&E argues that a tax gross-up is required to account for the iterative effect on revenue for cost recovery of taxes. In PG&E's view, the tax gross-up rate will

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[110] TURN Opening Brief at 21, referring to Transcript, September 12, page 229.

[111] TURN Opening Brief at 29.

[112] Ex. PG&E-01-E at 5-2.

provide the appropriate income tax expense and related revenue requirement to allow PG&E to recover the authorized after-tax return allowed by SB 846.[113]

A4NR, EPUC, SBUA, and TURN oppose authorizing PG&E to include federal and state income taxes and the related tax gross up, noting that Section 712.8(f)(6) does not expressly mention or authorize the recovery of taxes and does not specify whether the fixed management fees are pre-tax or after-tax.[114] TURN opposes authorizing any tax gross-up on the fixed management fee,[115] for it would add 42.53 percent to the cost of the fixed management fee or $33.63 million to the 2024-2025 revenue requirement.[116] The cumulative tax gross-up on the fixed management fee is forecasted to amount to $231.8 million.

TURN notes that the plain language of SB 846 does not allow for a tax gross-up on incentive payments collected from ratepayers. For the fixed management fee, Public Utilities Code Section 712.8(f)(6)(A) only allows PG&E to recover in rates $50 million (adjusted to 2022 dollars) per DCPP unit annually during extended operations. While the statute expressly references escalation of that payment, it does not authorize PG&E to collect additional tax obligations through a gross up mechanism.[117]

PG&E does not deny that there is no language in SB 846 that expressly authorizes the gross up but points to language stating that the fixed management fee is provided "in lieu of a rate-based return on investment" claiming that this

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113 Ex.PG&E-01-E at 5-3.

114 Ex. TURN-01 at 32-34; Ex. EPUC-01 at 15; and Ex. SBUA-01 at 15.

115 TURN Opening Brief at 14.

116 TURN Opening Brief at 2, 14.

117 TURN Opening Brief at 14.

provision should be understood to reference the Commission's traditional ratemaking treatment for authorized return on equity.[118]

The Commission notes that typically in a GRC the use of a Net-to-Gross (NTG) multiplier is allowed to "gross up" net revenues which are after income taxes, to become gross revenues before income taxes. This is generally only applied to the shareholder equity return on rate base portion of the revenue requirement (the debt portion is not included, because the interest expense is tax-deductible). Without this treatment, the utility shareholders would not actually achieve the authorized rate of return on rate base investment, because income taxes would otherwise reduce some of that return. That is, the NTG multiplier adds more money into the revenue requirement to pay the income taxes on the shareholder's return on the investment in rate base. However, the management fee is not the same as an authorized return on rate base. The Commission has no reason to think the management fee is akin to an income generating investment in capital expenditures. It is more akin to an expense (which is deducted from taxable income), not a return on investment (which generates taxable income). Hence, there is no reason to allow a "gross up" on a fixed management fee.

Furthermore, as TURN noted, Pub. Util. Code Section 712.8(c)(4) states that, "except as authorized by this section, customers or load-serving entities shall have no other financial responsibility for the costs of the extended operations of the Diablo Canyon powerplant." The intent of the Legislature clearly aims to prevent ratepayers from being charged for items not explicitly referenced in SB 846.

[118] PG&E-02 at 5-3 and 5-4.

The Commission also notes that TURN raised this issue in R.23-01-007. In D.23-12-036, the Commission agreed with TURN's concern regarding the gross up, stating, "It is this decision's holding that the general prohibition on cost recovery from ratepayers outlined in Section 712.8(c)(4) is meant to apply to costs outside of those delineated in Section 712.8, as the prohibitionary language applies to "other financial responsibility for the costs of the extended operations of the Diablo Canyon powerplant" (emphasis added). For example, such excluded costs could include the tax payments due on lump sum performance payments highlighted by TURN."[119]

Based on our practice in GRCs, statutory intent, and the Commission's prior holding, we conclude that any incremental tax liabilities on fixed management fees should be born exclusively by PG&E and its shareholders. PG&E is not authorized to recover any tax gross-up on the fixed management fee.

6.7. PG&E's Generation and Generation Revenue Forecasts

The Commission finds PG&E's methodology to calculate forecast CAISO energy market revenues reasonable and approves it.

6.7.1. PG&E's Methodology

In its Application, PG&E describes the methodology used to forecast CAISO energy market revenues as follows: The forecast for generation volumes is multiplied by a market reference price to produce the energy market revenue forecast. PG&E uses a market reference price that is analogous to the PCIA energy index benchmark used in the ERRA forecast proceeding, using a portfolio

[119] TURN Opening Brief at 16, citing D.23-12-036 at 69-70.

weighting factor calculation based on actual DCPP CAISO generation and revenue data as opposed to the entire PCIA-eligible portfolio.[120]

PG&E updated the market reference price calculation in the Fall Update using the latest NP15 Platts price curves provided by the Commission as part of its standard PCIA energy index benchmark updating process. PG&E's forecast of CAISO energy market revenues is as follows:[121]

Table 3: Forecast of CAISO Energy Market Revenues

Year	Total generation (GWh)	CAISO Market Reference Price ($/Megawatt-Hour)	Generation Revenues $000
2024	1,442	55.52	80,044
2025	10,753	50.61	544,205

The generation energy market revenue forecast serves to offset the costs of DCPP's extended operations.

6.7.2. Party Comments and Discussion

Party positions vary on this matter. A4NR does not challenge PG&E's granular generation forecast for the near-term period from November 3, 2024, to December 31, 2025.[122] In contrast, EPUC asserts that PG&E's generation revenue forecast is too low due to PG&E's application of a resource weighting factor adjustment to the average forward price PG&E used to derive the market benchmark.[123]

[120] PG&E-01-E at 8-2.

[121] Fall Update at 4.

[122] A4NR Opening Brief at 24-25.

[123] EPUC Opening Brief at 5.

Upon review, the Commission finds PG&E's forecasted CAISO energy market revenues reasonable and approves them.

6.8. Working Cash Adjustment

PG&E's $761 million revenue requirement for the Record Period reflects a $3.098 million working cash adjustment included as part of the Results of Operation model.[124] Working cash consists of two elements: (1) amounts required for daily operations such as cash for processing in-person payments at customer service centers; and (2) amounts needed to cover operating expenses paid in advance of customer payments, including insurance and other contracts. PG&E states that PG&E's working cash adjustment account for only the carrying cost of financing working cash funds and is identical to the working cash adjustment in PG&E's GRC with one notable difference: the DCPP application requests a lower return rate on financing working cash balances.[125]

TURN considers PG&E's carrying cost adjustment for working cash to be too high and proposes that PG&E recover working cash on a "cash basis" by estimating PG&E's annual working cash requirements and recovering those costs in the revenue requirement rather than assuming it will finance those costs by issuing debt.[126] In response, PG&E argues that TURN's proposal would involve recovering each year's working cash requirement as an expense, increasing costs to customers compared to PG&E's proposal to finance the working cash requirement.[127]

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[124] Ex. PG&E-01-E, p.6-4, lines 17-20.

[125] PG&E Opening Brief at 40.

[126] Ex. TURN-01 at 36.

[127] PG&E Opening Brief at 40, citing Ex. PG&E-02 at 4-4.

Upon review, the Commission finds PG&E's proposed working cash adjustment proposal reasonable since TURN's working cash proposal is not based on Commission precedent and may increase customer costs compared to the alternate proposal. Thus, the Commission authorizes PG&E's adjustment to working cash.

6.9. Netting of CAISO Revenues

PG&E requests that the Commission approve the consolidated net revenue requirement of $761 million that will be used to allocate costs to the three large IOUs and will be the basis for setting rates. The Commission approves a consolidated net revenue requirement of $723 million. The reduction reflects the changes made by this decision.

In its Fall Update, PG&E consolidates PG&E's Diablo Canyon Extended Operations cost updates, DCPP Electric Generation Revenue Forecast Update, Volumetric Performance Fee Forecast Update, Resource Adequacy Substitution Cost Forecast with the unchanged cost forecasts presented in PG&E's June 28, 2024 errata testimony. Then, the DCEOBA balance from the end of year 2023 and Revenue Fees and Uncollectibles (RF&U) and the Franchise Fee and Uncollectibles (FF&U) amounts are included for developing the Diablo Canyon extended operations revenue requirement for ratesetting.[128]

No party disputed the computation of netting the CAISO revenues. However, TURN and A4NR disputed the inflated CAISO revenues and the impact on the net revenue requirement.[129]

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[128] Fall Update at 7.

[129] A4NR Reply Brief at 13-14.

Upon review, a consolidated net revenue requirement of $723 million is approved. The reduction from the requested amount reflects the changes made by this decision.

7. NBC

The Commission finds that the IOUs' proposal for allocation of the DCPP extended operations cost is consistent with the direction provided in D.23-12-036 and approves it.

7.1. Background and the IOUs' Joint Proposal

Pursuant to SB 846, in D.23-12-036, the Commission authorized PG&E, SCE, SDG&E; Liberty Utilities/CalPeco Electric (Liberty); Bear Valley Electric Service, a division of Golden State Water Company (Bear Valley); and Pacific Power, a division of PacifiCorp to establish a new NBC to collect Diablo Canyon Nuclear Power Plant extended operations costs.[130] The Commission required the three utilities "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 Pub. Util. Code Section 712.8(f)(5), in each of PG&E's DCPP Extended Operations Cost Forecast application proceedings[.]"[131] In compliance with the requirements, the IOUs, jointly, presented their proposed allocation of the DCPP extended operations costs and the DC NBC rates applicable to each utility's customers.[132]

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130 D.23-12-036 at 138-139, OP 14.

131 D.23-12-036 at OP 7.

132 Ex. PG&E-01 at Chapter 12.

The IOUs propose allocating the DCPP extended operations costs using a 12-month CP load forecast, as required by D.23-12-036.[133] They utilize the CEC's peak load forecast developed for use in the Commission's RA program.[134] Then, the utilities develop allocation factors by dividing each utility's peak load forecast by the total. The IOUs updated the allocation of DCPP extended operations costs based on the more recent 2025 CEC 12-CP load forecast in the Fall Update, as shown below.[135]

Table 4. 12-CP Load Allocation Factors

IOU	MW	Percent
PG&E	172,488	44.9
SCE	173,915	45.3
SDG&E	37,552	9.8
Total	**383,955**	**100**

With respect to the three small multi-jurisdictional utilities (Bear Valley, Liberty, and PacifiCorp), the Commission set a fixed amount, $10,000 per SMJU, of DCPP extended operations costs and benefits to be recovered from SMJU customers. The rates to be collected from customers of the three SMJUs is based on an equal cents per kilowatt hour (kWh) charge. The $30,000, in total, to be collected from Bear Valley, Liberty, and PacifiCorp will be subtracted from PG&E's allocated portion of the statewide revenue requirement. In addition, to reimburse the SMJUs on an annual basis, $30,000 in financial benefits from PG&E's portion of the RA attributes from DCPP are set aside for the SMJU. PG&E is required to distribute $10,000 annually to each of Bear Valley, Liberty, and PacifiCorp in consideration of the RA attributes they would have received

133 D.23-12-036 at COL 30, OP 14.

134 PG&E-01 at 12-3.

135 Fall Update at 8.

had they been required by the Commission to procure RA capacity. This reimbursement to the SMJUs will be made as a debit entry to PG&E's Extended Operations Subaccount.[136]

7.2. Party Positions

Overall, parties do not object to the calculation of the statewide fees. A4NR states that, if modified to reflect A4NR's recommended reductions, the NBC and rate proposals would comply with D.23-12-036, be consistent with the requirements of Pub. Util. Code Section 451 and could be approved.[137]

SBUA proposes in its testimony to modify the methodology established in D.23-12-036 to replace the 12-CP demand-based allocation with an allocation based on future GRC marginal costs. SBUA "recommends that the proposed rates be altered to reflect whatever the new equal percentage of marginal cost will be in the future [GRCs] of SCE, PG&E, and SDG&E."[138]

In response, SDG&E states that the generation revenue allocation factors based on the marginal costs of generation approved in the GRC are not applicable to the revenue allocation and rate design of the DC NBC. Noting that SBUA does not explain how this proposal complies with the requirements of D.23-12-036, SDG&E characterizes SBUA's proposal as unsupported, outside the scope of the instant proceeding, and an impermissible collateral attack on D.23-12-036.[139]

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[136] There is a pending petition to modify D.23-12-036 (PFM) filed by SMJUs. The PFM will be addressed in Rulemaking 23-10-009 in due time.

[137] A4NR Opening Brief at 25.

[138] Ex. SBUA-01 at 25.

[139] SDG&E Opening Brief at 1.

7.3. Discussion

In D.23-12-036, the Commission established a two-step process for allocating net statewide DCPP extended operations costs to the LSEs in each IOU service area. The first step involves allocation of DCPP costs between the three large IOUs based on each IOU's share of 12-CP load. The Commission explained, "[g]iven that ensuring system reliability is a key legislative rationale for the billions of ratepayer dollars that may be spent to keep DCPP operating, it follows that allocating the costs of those extended operations based on an IOU's share of a [12-CP] is fair and equitable."[140]

The second step in the process established in D.23-12-036 allocates each IOU's DCPP Cost revenue requirement among the customers within its distribution service territory based on 12-CP demand. The Commission directed that "[t]he process for allocating these eligible costs to the LSEs *within* each IOU's territory should mirror the Cost Allocation Mechanism (CAM)," which, as the decision points out, utilizes the 12-CP demand allocation approach. The Commission reasoned that "[b]ecause LSEs are familiar with the CAM and it is a proven mechanism for allocating costs among the LSEs in a large electrical corporation's territory, it is reasonable to use a process that mirrors the CAM process to allocate DCPP extended operations costs within each IOU's territory."[141]

After reviewing the IOUs' proposed methodology, the Commission concludes that the IOUs' proposed methodology and rate design for allocating

[140] D.23-12-036 at 73-74.

[141] D.23-12-036 at 75.

the DCPP costs, complies with the Commission's directives in D.23-12-036, and therefore, is approved.

8. RA Attributes and GHG-Free Energy

PG&E's proposal to modify the methodology adopted in D.23-12-036 for allocating resource adequacy RA attributes and GHG-free energy attributes is denied. PG&E must follow the direction provided in D.23-12-036, update its calculations, and submit a Tier 3 Advice Letter showing compliance within 30 days of the issuance of this decision.

8.1. Background

D.23-12-036 establishes a process for allocating RA attributes and GHG-free energy benefits. Accordingly, RA benefits associated with DCPP's extended operations must be allocated among PG&E, SDG&E, and SCE service areas based on the 12-CP. This allocation is to occur in each of PG&E's annual Diablo Canyon Nuclear Power Plant Extended Operations Cost Forecast applications. The benefits will then be further allocated to the LSEs in each service area as a load decrement using a process similar to the CAM process.[142] D.23-12-036 also directs PG&E to propose an allocation methodology based upon the process outlined in Resolution E-5111.[143] Resolution E-5111 methodology requires PG&E to offer LSEs within its service territory an amount of GHG-free energy attributes from certain eligible resources within its PCIA-eligible portfolio on an annual basis. LSEs are offered an allocation that corresponds to each LSE's Allocation Ratio; LSEs that accept their allocation amounts must execute a sales agreement. The allocation ratio for each LSE is based on the LSE's load relative to total eligible statewide load. Consistent with this process, the D.23-12-036 directs PG&E to

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[142] D.23-12-036 at OP 9.

[143] D.23-12-036 at 90-91.

calculate DCPP's GHG-free generation separately from other resources in its portfolio and offer an allocation to all California LSEs paying for DCPP extended operation costs.[144]

In D.23-12-036, the Commission also directed PG&E to offer LSEs that are paying for DCPP extended operations the ability to use their share of DCPP's GHG-free attributes for their power content labels using a load-based allocation.[145]

8.2. PG&E's Proposal

Instead of allocating DCPP's RA attributes among the IOUs' service areas based on 12-month CP load share, as required by D.23-12-036, PG&E proposes that the Commission allocate DCPP's RA attributes among the IOUs' service areas based on the allocation ratios of total forecasted costs, to be updated annually in the forecast application proceedings. The purpose of PG&E's proposed adjustment to the allocation of RA and GHG-free energy is "to account for the higher cost burden borne by its customers."[146]

8.3. Party Positions

In support of PG&E's proposal, SBUA argues that the proposed adjustment recognizes the disproportionate financial burden borne by PG&E's customers for the extended operations of DCPP.[147] GPI also supports PG&E's proposal.[148]

[144] D.23-12-036 at 91.

[145] D.23-12-036 at 88-92, 138, and OP 10.

[146] Ex. PG&E-01 at 1-11; Ex. PG&E-01 at 2-15 through 2-19.

[147] SBUA Opening Brief at 4-5.

[148] GPI Opening Brief at 6.

Several parties object to PG&E's proposal on procedural as well as substantial grounds. A4NR criticizes PG&E for not seeking changes in the allocation of RA and GHG attributes by filing a Petition for Modification of D.23-12-036.[149]

CalCCA recommends that the Commission reject PG&E's proposal for three reasons. First, PG&E's proposal does not correctly implement the methodologies the Commission established in Decision 23-12-036. Second, the Commission already considered, and did not adopt, PG&E's proposed allocation methodology in Phase 1 of the DCPP Rulemaking where that methodology was proposed by Cal Advocates. Third, as several parties already explained in Phase 1 of the DCPP Rulemaking, the statutory framework provides certain benefits solely to customers in PG&E's service territory, and thus PG&E's proposal to modify attribute allocations is neither necessary nor justified.[150]

Similarly, CARE asserts that PG&E is ignoring the benefits to its ratepayers, that any excess market revenues will accrue to PG&E, and that only the PG&E service territory will benefit from refunded liquidated damages.[151] In CARE's view, while PG&E customers pay more they benefit more.

SCE also opposes PG&E's proposed adjustment on procedural and substantial grounds. SCE states that the proposal is outside the scope of this proceeding, which is limited to consideration of whether PG&E's proposed allocation of RA attributes and GHG-free energy "complies with the implementation of the methodology established by D.23-12-036," as identified in the Scoping Memo. SCE adds that PG&E offers no justification for adjusting the

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149 A4NR Opening Brief at 25.

150 CalCCA Opening Brief at 2-3.

151 CARE Opening Brief at 18-19.

Commission's direction in D.23-12-036 soon after the decision was issued. Similar to CalCCA's comments, SCE notes that PG&E's proposal is similar to the proposal made by Cal Advocates in R.23-01-007, which the Commission considered and rejected.[152] SDG&E agrees.

For the same reasons regarding PG&E's RA allocation proposal, SCE recommends that the Commission reject PG&E's allocation proposal for GHG-free energy allocation proposal, because it does not comply with D.23-12-036. The two allocation proposals use different methodologies – allocation based on 12-CP or load share versus total cost allocation - and lead to different outcomes.

Finally, SCE argues that the policy reason for not allocating the DCPP RA attributes and GHG-free energy benefits in the same way as extended operations costs are allocated lies in the fact that customers in PG&E's service area already receive significant benefits from the higher volumetric fees they pay for DCPP extended operations- benefits that are not available to customers outside PG&E's service area.[153]

8.4. Discussion

Upon review, the Commission concludes that PG&E's proposal does not comply with implementation of the RA allocation methodology adopted in D.23-12-036, and therefore, it is rejected.

In D.23-12-036, the Commission expressly determined that, with the exception of SMJUs, the RA benefits associated with DCPP extended operations must be allocated among the PG&E, SCE, and SDG&E service areas "on the basis of [12-CP] load in each of PG&E's annual Diablo Canyon Nuclear Power Plant

[152] SCE Opening Brief at 6.

[153] SCE Opening Brief at 12-14.

Extended Operations Cost Forecast applications," and Energy Division will then allocate the RA benefits among all LSEs subject to the Commission's jurisdiction in each utility's service area, including SCE and SDG&E, "as a load decrement using a process that mirrors the [CAM] process.[154] It also directed PG&E to offer LSEs that pay for DCPP extended operations the ability to accept a share of DCPP's GHG-Free attributes, allocated according to each LSE's proportionate share of customer load.[155]

Instead of allocating DCPP's RA attributes among the IOUs' service areas based on 12-CP load share as required by D.23-12-036, PG&E allocates DCPP's RA attributes among the IOUs' service areas based on the allocation ratios of total forecasted costs, to be updated annually in these forecast application proceedings. As noted by parties, these are two different RA allocation methodologies that produce different results.[156]

Under Pub. Util. Code Section 712.8(q), the Commission can consider the higher costs to customers in PG&E's service area in benefit allocation. PG&E asserts that the Commission did not consider in R.23-01-007 whether a greater portion of RA and GHG-free energy attributes should be allocated to LSEs in PG&E's service area. As several parties noted, this allocation approach was proposed in R.23-01-007 and addressed by multiple parties, including PG&E, but was ultimately not adopted by the Commission.

For the reasons stated above, the Commission finds that PG&E's proposal does not comply with implementation of the RA allocation methodology adopted in D.23-12-036 and is rejected. PG&E must follow the direction provided

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[154] D.23-12-036 at OP 9.

[155] D.23-12-036 at COL 42.

[156] SDG&E Opening Brief at 10.

in D.23-12-036, update its calculations, and submit a Tier 3 Advice Letter showing compliance within 30 days of the issuance of this decision.

9. Volumetric Performance Fees Spending Plan

The Commission is unable to determine whether PG&E's VPF spending plan is consistent with Section 712.8(s) requirements, because PG&E's proposed spending plan lacks sufficient detail. Therefore, PG&E's request for approval of its VPF spending plan is denied without prejudice. PG&E may resubmit the proposal, provided that PG&E presents further detail as described in Section 9.3. Until then, the VPFs collected by PG&E must be held in the VPF Subaccount of the DCEOBA.

9.1. Background

Cal. Pub. Util. Code Section 712.8(s) provides the following:

> (1) The operator shall submit to the commission for its review, on an annual basis the amount of compensation earned under paragraph (5) of subdivision (f), how it was spent, and a plan for prioritizing the uses of such compensation the next year. Such compensation shall not be paid out to shareholders. Such compensation, to the extent it is not needed for Diablo Canyon, shall be spent to accelerate, or increase spending on, the following critical public purpose priorities:
>
> (A) Accelerating customer and generator interconnections.
>
> (B) Accelerating actions needed to bring renewable and zero carbon energy online and modernize the electrical grid.
>
> (C) Accelerating building decarbonization.
>
> (D) Workforce and customer safety.
>
> (E) Communications and education.
>
> (F) Increasing resiliency and reducing operational and system risk.
>
> (2) The operator shall not earn a rate of return for any of the expenditures described in paragraph (1) so that no profit shall be

> realized by the operator's shareholders. Neither the operator nor any of its affiliates or holding company may increase existing public earning per share guidance as a result of compensation provided under this section. The commission shall ensure no double recovery in rates.

In D.23-12-036, the Commission directed PG&E to file an annual application for review of its planned use of Section 712.8(f)(5) revenues to confirm its proposed plan is consistent with Section 712.8(s), as well as to review PG&E's past use of funds.[157] The Commission stated that "while we interpret Section 712.8(s) as providing PG&E some amount of discretion on the use of surplus performance based fees, subject to the statutory conditions and review discussed below, in the event actual recorded costs are more than 15 percent above PG&E's approved forecast then PG&E must first use the volumetric performance based fees to offset any costs above that amount before they be used for another purpose."[158]

In compliance with D.23-12-036, PG&E seeks the Commission's approval of its plan for 2025 VPF expenditures covering the Record Period pursuant to the public purpose priorities identified in Section 712.8(s)(1). In its application, PG&E proposes a "waterfall" of priority uses, starting with defined customer-benefitting programs, followed by an allocation of contingency funds for key risk and safety programs, and then contribution of any remaining funds to offset Diablo Canyon operating costs.[159] In this way, according to the proposal, all of the VPFs will be first spent on critical public purpose priorities. However, in the event PG&E earns less than the forecasted amount of volumetric fees in 2025,

[157] D.23-12-036 at OP 15.

[158] D.23-12-036 at 110-111.

[159] Ex. PG&E-01-E at 9-1.

PG&E will not allocate 100 percent of the funds for defined uses, so less would be available for use as contingency.[160]

The total forecast for the VPFs collected in 2025 (covering the period of November 3, 2024 to December 31, 2025) is $159.6 million and the proposal includes the following programs.[161]

1. Accelerated enhancements of Hydro Asset Management, Inspection, and Maintenance ($20 - 40 million) aims to address gaps identified during PG&E's ISO 55001 certification process, incorporate corrective actions stemming from recent asset failures sooner, and implement new, industry-leading practices for proactively managing asset lifecycle and reducing risk.[162]
2. Accelerating Interconnections and Actions to Reduce Operational Risk and Modernize the Grid More Efficiently Through Operating System Enhancements ($20-$30 million) aims to enable a more efficient work production system to streamline processes resulting in expedited timeline for customer interconnections, accelerate work to modernize the grid more efficiently, and increase resiliency, as well as other customer-benefitting programs.[163]
3. Batteries for Resiliency ($5-$15 million) aims to expand an existing program, the wildfire-related, Behind-the-Meter Batteries for Resiliency, to target customers outside of high fire risk areas.[164]

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160 Ex. PG&E-01 at 9-1.

161 Ex. PG&E-01-E Chapter 9.

162 Ex. PG&E-01-E at 9-7 through 9-9; and Opening Brief at 51.

163 Ex. PG&E-01-E at 9-9 through 9-11.

164 Ex. PG&E-02 at 8-19.

4. Electric Vehicle Detection for Forecasting and Vehicle Grid Integration ($250,000-$750,000) aims to improve EV detection and data gathering.[165]
5. Electrification Customer Experience ($5-$17 million) aims to streamline transportation and building electrification customer experiences and expand existing programs to broaden building electrification weatherization support.[166]
6. Programs to support building decarbonization for small businesses (at least $2 million) aims to support new or expanded programs to support small business in pursuing building decarbonization objectives.[167]
7. PG&E Contingency Uses for Safety and Risk ($40-$60 million) is intended to cover any unforeseen key critical risk and safety work that falls within one or multiple of the MWCs and exceeds imputed GRC authorized amounts for 2025. These categories include areas where emergencies may occur, such as in response to storm or wind events, landslides, or other unanticipated operational conditions.[168]

9.2. Party Positions

Several parties, including A4NR, GPI, and TURN, oppose PG&E's proposed plan, while CUE, CGNP, and SBUA support it. CalCCA neither opposes nor supports the program as is but suggests applying principles to guide program selection and as a result of applying these guidelines, CalCCA recommends modifications to PG&E's proposal.

Some parties recommend that the Commission refrain from taking any action at this time. CARE requests that because PG&E is currently litigating the

[165] Ex. PG&E-02 at 8-19 and 8-20.

[166] Ex. PG&E-02 at 8-20 through 8-22.

[167] Ex. PG&E-02 at 8-19.

[168] Ex. PG&E-01-E at 9-12 through 9-15, line 1 (removing the projects related to gas system resiliency). *See* Ex. PG&E-02, p. 8-14, lines 5-13.

use of VPFs in *PG&E v. Commission*, Court of Appeal Case Number A170833, the Commission wait until that litigation is resolved to decide whether PG&E's proposed spending plan should be approved.[169] Similarly, A4NR argues that PG&E failed to address the combined effect of the party comments in Phase 2 of R.23-01-007 on post-2024 use of VPFs; the material change in circumstances between 2024, when no VPFs are expected, and 2025, when PG&E proposes to collect $159.6 million in VPFs; and the preemptive effect of PG&E's July 3, 2024 petition for writ of review of D.23-12-036 by the First Appellate District of the Court of Appeal on party comments and Commission authority regarding post-2024 use of VPFs.[170] Therefore, in the interim, A4NR recommends that the VPFs collected by PG&E be invested and held in a separate account, *i.e.*, the VPF Subaccount of the DCEOBA.[171]

In support of PG&E's proposal, CUE suggests that the Commission's review of PG&E's plan focus on determining whether: (1) the proposed spending accelerates or increases spending on programs or projects that align with categories specified in Pub. Util. Code Section 712.8(s)(1); and (2) "the spending would not result in double recovery in rates, cause compensation to be paid out to PG&E shareholders, or cause PG&E to earn a rate of return on any of the expenditures."[172] Aside from verifying that these criteria are met, in CUE's view, PG&E does not need to "justify how it intends to allocate surplus funds among the listed categories" of critical public purpose priorities. Therefore, CUE concludes, PG&E's VPF spending plan satisfies these requirements and should

[169] CARE Opening Brief at 19.

[170] A4NR Opening Brief at 26.

[171] A4NR Opening Brief at 27, A4NR Reply Brief at 18.

[172] CUE Opening Brief at 4.

be approved.[173] SBUA also supports PG&E's proposal. Specifically, SBUA recommends that the Commission adopt SBUA's proposal for Volumetric Performance Fee allocation to fund decarbonization programs, which PG&E has agreed to implement. SBUA supports PG&E's proposal to reallocate funds of $30-$60 million previously allocated to the Customer Programs Investment (CPI) Program toward accelerating the integration of renewable energy, modernizing the grid, and supporting customer education around building electrification and electric vehicles, because these areas align with SBUA's own recommendations to prioritize actions that benefit small business customers.

CalCCA asserts that it identified the following flaws in PG&E's planning of VPF use:

1) PG&E's process does not explicitly consider whether the selected projects will maximize the number of benefiting customers.
2) PG&E's proposed process allows VPF revenues to be used for projects from any part of its utility business, including its gas department, which risks diverting VPF revenue paid by electric customers to fund projects that would otherwise be paid for by PG&E's gas customers.
3) PG&E's proposed process does not include guardrails to avoid competitive issues with other LSEs in its service territory. To the extent PG&E spends VPF funds paid by customers of other LSEs to enhance PG&E's generation fleet or offset the cost of PG&E's generation service as proposed, PG&E could gain an unfair competitive advantage over those LSEs.[174]

[173] CUE opening Brief at 4.

[174] CalCCA Opening Brief at 3 and 25-26.

To remedy these flaws, CalCCA requests that the Commission adopt the following clarifications and principles:

1. PG&E can only use VPF revenues to cover costs that would otherwise be recovered only from PG&E's electric customers.
2. VPF funds should be used on projects providing benefits to the largest number of customers possible, including bundled and unbundled customers.
3. VPF funds should be used first on projects related to electric distribution to help reduce upward pressure on distribution rates.
4. VPF funds should not be used on projects that benefit PG&E's generation assets.

In CalCCA's view, if their proposed principles are applied, the Commission should reject PG&E's proposal to spend 2025 VPF revenues on its hydroelectric generation infrastructure. TURN agrees with CalCCA.[175] CalCCA is unable confirm whether, under PG&E's proposal, VPF funds will be used in a way that increases output from its hydroelectric generation assets or effectively extends the life of those assets. If either result occurs, CalCCA argues, PG&E's use of VPF funds would raise complex issues regarding the set of customers on whose behalf PG&E's investments were made.[176] In response, PG&E states that its proposed activities are expected to increase the resiliency and reliability of the assets rather than extend the life of the asset, and therefore satisfies section 712.8(s)(1)(F); and the spending is focused on accelerating safety-driven work necessary for safe and reliable operations, not on development of new generation

[175] TURN Opening Brief at 32; CalCCA Opening Brief at 28-31.

[176] CalCCA Opening Brief at 29.

assets.[177] Finally, CalCCA recommends that the Commission direct PG&E to explain how it satisfied the spending principles it adopts here and to identify the stakeholders that will benefit from the projects it selects when presenting proposed VPF spending plans.

GPI also makes several recommendations for the use of VPFs as follows:

1) Without an auditing process there is a risk that the funds could be used to cover cost overruns for existing programs, i.e. a slush fund.
2) For proposed pole inspection program, GPI requests a more thorough explanation to ensure this is separate from the inspections requested through PG&E's Wildfire Mitigation Plan process.
3) GPI requests a maximum 20 percent allocation to the VPF contingency fund with annual rollover of unused funds.
4) GPI argues that costs below the 115% threshold should be eligible to offset DCPP operating costs.

The most detailed critique of PG&E's proposal was offered by TURN. TURN recommends that the Commission decline to authorize the new priority programs and spending initiatives PG&E proposes to finance with VPFs since "they lack key details, were hastily developed, offer questionable ratepayer value, would relieve shareholders of spending obligations and are not accompanied by any cost-benefit analysis or enforceable metrics. Additionally, some of the proposed work does not fall within the definition of a critical public purpose priority."[178] TURN urges the Commission to reject PG&E's proposed plan and adopt an alternative that directs surplus VPF revenue to offset already spent or authorized funds.

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[177] PG&E Reply Brief at 21-22.

[178] TURN Opening Brief at 2-3.

In TURN's view, there are several issues that were not addressed in R.23-01-007. Therefore, TURN requests that the Commission provide direction and clarification on the following issues:

1) TURN requests that the Commission clarify that VPFs cannot be used to pay for Diablo Canyon costs in excess of 115% of forecasted amounts if the additional costs are attributable to imprudence that would otherwise be absorbed by shareholders.[179]
2) TURN requests that the Commission affirm that SB 846 prevents VPFs from being used to provide any direct benefit to PG&E's shareholders.[180]

CUE objects to TURN's alternate VPF spending plan directing surplus VPF revenue to offset already spent or authorized funds. In CUE's belief, TURN's proposal fails to accelerate or increase spending on critical public purpose priorities and is inconsistent with Section 712.8(s)(1). CUE objects to TURN asking the Commission to change the relevant standard of review set in D.23-12-036, which CUE asserts, is out of the scope of this proceeding. In CUE's view, TURN's proposal is based on a flawed ratepayer impact analysis that fails to consistently account for VPF costs and overlooks the value of accelerating and increasing spending on critical public purpose priorities.[181] CUE argues that these flaws hinder a fair comparison between TURN's and PG&E's proposals and exaggerate the advantages of TURN's proposal over PG&E's.[182]

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[179] TURN Opening Brief at 22.

[180] TURN Opening Brief at 23.

[181] CUE Opening Brief at 5.

[182] CUE Opening Brief at 10-12.

9.3. Conclusion

In D.23-12-036, the Commission directed PG&E to file an annual application for review of its planned use of Section 712.8(f)(5) revenues to confirm its proposed plan is consistent with Section 712.8(s). In D.23-12-036, the Commission noted that SB 846 "[d]oes not rank or prioritize the critical public policy priorities." The Commission directed: "Accordingly, while the Surplus Performance-Based Fees Application shall detail PG&E's spending proposals, PG&E is not required to justify how it intends to allocate surplus funds among the listed categories. The Commission's review of PG&E's Application will be focused on determining whether the proposed spending properly falls within one or more of the categories identified in Section 712.8(s)(1), and that the spending would not result in double recovery in rates, cause compensation to be paid out to PG&E shareholders, or cause PG&E to earn a rate of return on any of the expenditures."[183] The Commission also stated that, "There would be no purpose in having the Commission review PG&E's proposed usage of funds if the Commission did not also have the ability to modify or reject PG&E's proposed spending, as needed.[184]

Upon review of the proposed plan and testimony, because PG&E's proposed plan lacks concrete as well as conceptual details, the Commission cannot conclusively determine whether the proposed spending plan satisfies Section 712.8(s) requirements.

While several programs outlined in PG&E's spending plan may have the potential to align with the State's goals for reliability and decarbonization, the

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[183] D.23-12-036 at 114.

[184] D.23-12-036 at 111.

Commission agrees with the parties that the spending plan lacks the detail necessary for the Commission to conclude that the projects: (1) fall within the required (s)(1) categories and (2) will not increase shareholder profits, consistent with (s)(2). Given is the projects total over one hundred million dollars, it is incumbent on PG&E to make a sufficient showing in its spending plan, clearly demonstrating how the plan satisfies Section 712.8(s) requirements.

In conclusion, PG&E's request for approval of its VPF spending plan is denied without prejudice. PG&E may resubmit the proposal, provided that, at a minimum, PG&E presents further project details to support a showing that the expenditures in its plan properly fall within the Section 712.8(s)(1) categories. Additionally, PG&E's request must demonstrate compliance with Section 712.8(s)(2), including that (a) a rate of return will not be earned for projects funded by the expenditures so that no profit will be realized by shareholders, and (b) the expenditures will not lead to double recovery from ratepayers, including, if applicable, the proposed accounting and/or auditing measures that will be put in place to confirm that no double counting has occurred and no shareholder profits were received. Pending approval, the VPFs collected by PG&E must be held in the Volumetric Performance Fees Subaccount of the DCEOBA.

10. Regulatory Process for Reporting VPF

PG&E's request to utilize a Tier 3 advice letter process for reporting VPF revenue spending for future annual plans and retrospective reporting of section 712.8(s) requirements is denied without prejudice.

10.1. PG&E's Proposal

PG&E seeks authorization to use an advice letter process for future annual plans submittal and retrospective reporting of Pub. Util. Code Section 712.8(s)(1) funding.[185] In PG&E's view, a Tier 3 advice letter will allow for stakeholder input on proposed uses with less administrative burden. PG&E notes that D.23-12-036 left the possibility of revisiting "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 in place."[186]

10.2. Party Positions

A4NR states that with pivotal questions of statutory interpretation pending before the First District Court of Appeal, the Commission should not approve PG&E's proposed modifications to the review process established in D.23-12-036.[187] GPI also recommends that the Commission reject PG&E's proposal to move VPF Plan approval to a Tier 3 AL process.[188]

10.3. Conclusion

Upon review, we decline to adopt PG&E's proposal to submit future plans via Tier 3 advice letter without prejudice. This matter can be reconsidered in the next application. The VPF program is a new program. Until we gain a reasonable amount of experience with the program, it is appropriate to consider the program annually through an application process.

11. Regulatory Requirements Established by D.23-12-036

PG&E addressed in its application the compliance requirements established by D.23-12-036 and how the application addressed these requirements.[189] Upon review of the Application, except for the proposal to

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185 Ex. PG&E-01-E at 9-18.

186 D.23-12-036 at 112.

187 A4NR Opening Brief at 28-29.

188 GPI Opening Brief at 12.

189 PG&E testimony 2-1, 2-2.

allocate RA benefits, which is discussed in Section 8, the VPF spending proposal, which is discussed in Section 9, and the missing A&G costs, which is discussed below, the Commission concludes that PG&E's application complied with the requirements established by the Commission in D.23-12-036.

CARE argues that despite D.23-12-036's direction, PG&E does not provide an update to the A&G costs from the transition period in the Application.[190] TURN also pointed out that PG&E's forecast includes declining A&G costs for DCPP in 2025, and none for 2026.[191] In response, PG&E argues that adjusting the DCPP A&G is unnecessary, as this issue will be appropriately addressed in PG&E's 2027 GRC, anticipated for filing in seven months.[192]

The Commission finds TURN and CARE's request reasonable. Due to the timing of the DCPP extension, PG&E's last GRC and its "post-decision compliance" reflect cost assumptions for A&G that DCPP will close in November 2024 (Unit 1) and August 2025 (Unit 2). In D.23-12-036, the Commission expressly directed PG&E to include A&G costs in its DCPP cost forecast application.[193] Because this application was filed in March 2024, PG&E has no excuse for not accounting for A&G for 2025 and beyond in this application. With the next DCPP cost forecast application due in March 2025, which is earlier than the anticipated GRC filing date, PG&E must include the A&G costs in its next DCPP cost forecast application.

In conclusion, for future forecast and cost recovery proceedings, PG&E must:

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[190] CARE Opening Brief at 20-21.

[191] TURN Opening Brief 69-70.

[192] PG&E Reply Brief at 39-41.

[193] D.23-12-036 at 60.

1) Provide detailed project summaries for all projects over $1 million, instead of all projects over $3 million as PG&E did in this application as modeled after the GRC.
2) Provide the total cost of DCPP extended operations through 2030 in each annual application for informational purposes.
3) Provide updated A&G costs for 2025 and beyond.
4) Provide a detailed account of why PG&E did not seek government funding for the costs being requested to be recovered from ratepayers, or was otherwise unable to anticipate the need for the investments and activities at the time government funding was being requested.

12. Other Concerns and Requests

12.1. Confidentiality

Expressing concerns with PG&E's confidentiality practices, TURN requests that PG&E be directed "to present forecasted Diablo Canyon costs in a manner that limits confidentiality, yields greater public transparency, and results in public disclosure of both total annual costs and expected annual generation."[194] According to TURN, the availability of this information will not harm PG&E's competitive interests but will enable legitimate public debate over the costs of the plant. TURN urges the Commission to adopt this requirement in this proceeding and require PG&E to comply no later than its next cost recovery application. In addition, the Commission should direct PG&E to revise its showing in this proceeding to disclose total costs and costs/MWh for both 2024 and 2025.[195]

194 TURN Opening Brief at 1; Ex. TURN-01 at 6-8.

195 TURN Opening Brief at 8.

In response, PG&E states that it will strive to minimize the amount of confidential information in the next annual application, while still protecting any market-sensitive data.[196]

The underlying principle of confidentiality is about making information publicly accessible to the greatest extent possible while protecting certain market-sensitive information. As such, the party seeking confidentiality bears the burden of proof while seeking confidentiality protection for any data. PG&E must minimize the amount of confidential information in the next annual application and protect only market-sensitive data, as permitted by the Commission decisions.

12.2. DWR Loan Review Process

In D.23-12-036, the commission directed PG&E to include in its cost recovery application "any government-funded transition costs" to ensure that costs funded by this source are not also recovered from ratepayers. The primary source of government funding is the $1.4 billion "loan" from the DWR used to support costs related to DCPP and $300 million in "Performance-Based Disbursements" for spending unrelated to DCPP. PG&E's testimony provides little information about this source of funding. Asserting that TURN's testimony identified weaknesses in the current review process for these funds and offering recommendations to promote transparency, TURN requests that the Commission: (1) open the semi-annual true-up process for the DWR loan to participation by parties other than PG&E, (2) require PG&E to publicly identify in the annual cost recovery proceeding each specific project funded via the DWR loan, (3) prohibit PG&E from claiming that the use of DWR loan proceeds to any

[196] PG&E Reply Brief at 43.

program represents a contribution from shareholders, (4) require PG&E to proactively disclose expenditures of Performance-Based Disbursements on costs unrelated to DCPP to prevent double recovery.[197]

In the interest of administrative efficiency, the Commission declines to adopt TURN's proposal. There is already a public review process established and DWR and the Commission have the authority and capability of review of these expenses.

12.3. Additional Analysis

CalCCA requests a finding in this proceeding requiring PG&E to: (1) prepare a DCEOBA variance analysis, including workpapers with DCEOBA detail by tariff line item, including dollar amounts and underlying volumes; and (2) provide certain itemized information with each filing.[198]

In CalCCA's view, understanding the cause of the variations in the DCEOBA is critical for cost recovery purposes. For example, if higher retail sales volumes cause an over-collected balance in the DCEOBA, the balance can be returned to all customers causing the over-collection. However, if an over-collection is caused by excess CAISO market revenue, the balance can only be returned to customers in PG&E's service territory. For that reason, CalCCA recommends that the Commission require PG&E to demonstrate the drivers of under- or over-collected balances in DCEOBA each time it files a DCPP Forecast application and the annual Tier 3 Advice Letter true-up, with information parallelling what PG&E presents in its annual ERRA Forecast and Compliance applications.[199]

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[197] TURN Opening Brief at 1.

[198] CalCCA Opening Brief at 36.

[199] CalCCA Opening Brief at 4-5.

In response, PG&E recommends that the Commission reject CalCCA's request for a Commission order detailing the supporting information to be provided for the Tier 3 True Up Advice letter process. In PG&E's view, CalCCA attempts to expand the scope of that filing. Moreover, PG&E expresses its intention to present all recorded costs and an analysis of the drivers of over- and under collections.[200] PG&E adds that CalCCA's proposal does not identify any information PG&E does not already provide in the ERRA compliance proceedings. PG&E does not object to providing the information requested by CalCCA but does not think it is necessary for the Commission to make a determination about the content of the filing.

The Commission disagrees. Given that the costs approved in this decision are recorded in DCEOBA and its subaccounts, and that the requested information is similar to how ERRA compliance reviews are presented, it is reasonable to direct PG&E to provide the same type of information and analysis in its true-up filing for the expenses approved in this decision. Accordingly, PG&E should in its true up filing provide the following information:

1. Workpapers supporting the final (e.g., the October update) forecast revenue requirement and rates from the DCPP Forecast case and any implementing advice letters for the record year.
2. Workpapers demonstrating monthly recorded costs and revenue for each tariff line item in the DCEOBA.
3. DCPP monthly generation volume by unit.
4. DCPP monthly CAISO revenue and costs.
5. Monthly retail revenue recorded for bundled, CCA and direct access customers, for PG&E, SCE, and SDG&E.

[200] PG&E Reply Brief at 44.

6. Monthly billed retail sales volumes for bundled, CCA and direct access customers, for PG&E, SCE, and SDG&E.
7. A DCEOBA variance analysis (forecast vs. actual), with explanations of material variances from forecast.

13. CARE's Requests for Official Notice

On September 30, 2024, CARE filed a motion requesting that the Commission take official notice of the "March 13, 2024, letter from the Department of Finance to Joint Legislative Budget Committee Senate Budget and Fiscal Review Committee responding to a request for additional information regarding Diablo Canyon Power Plant." CARE claims this letter demonstrates that PG&E is seeking performance-based distributions from both DWR and the ratepayers, suggesting potential "double-dipping" in this proceeding. It also provides information on which expenses DWR is reimbursing, thereby identifying costs that are not the responsibility of ratepayers.[201] No party responded to CARE's motion.

While relevant, CARE does not provide specifics in the motion substantiating this claim with examples and references to the letter. However, CARE referenced the letter in its September 29, 2024 opening brief.[202] Therefore, CARE's motion for official notice is granted.

On October 14, 2024, CARE filed a second motion requesting that the commission take official notice of: (1) the September 14, 2024, letter from Tom Luster of the California Coastal Commission, Energy, Ocean Resources, and Federal Consistency Division to Mr. Tom Jones, Senior Director – Regulatory,

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[201] CARE Motion, September 9, 2024, at 2.

[202] CARE Opening Brief at 12-13.

Environmental and Repurposing, Pacific Gas & Electric Company, Diablo Canyon Power Plant; and (2) October 9, 2024, Summary of Compliance with Integrated Resource Planning (IRP) Order D.19-11-016 and Mid Term Reliability (MTR) D.21-06-035 Procurement December 2023 Data Filings Energy Division Staff Recommendations.

These documents concern reliability issues. The Commission previously found that the Legislature did not intend for the Commission to continually re-evaluate the reliability need for Diablo Canyon based on specific requirements in SB 846 — including the requirement that new renewable and zero-carbon resources be interconnected by the end of 2023. Further, reliability issues are out of the scope of this proceeding and considered in the IRP proceeding. As such, CARE's request is denied.

14. Summary of Public Comment

Rule 1.18 allows any member of the public to submit written comment in any Commission proceeding using the "Public Comment" tab of the online Docket Card for that proceeding on the Commission's website. Rule 1.18(b) requires that relevant written comment submitted in a proceeding be summarized in the final decision issued in that proceeding.

In this proceeding, 47 members of the public submitted comments opposing the requested rate increase.

15. Procedural Matters

This decision affirms all rulings made by the Administrative Law Judge and assigned Commissioner in this proceeding. All motions not ruled on are deemed denied.

16. Comments on Proposed Decision

The proposed decision of ALJ Nilgun Atamturk in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed on __________, and reply comments were filed on _____________ by ________________.

17. Assignment of Proceeding

Karen Douglas is the assigned Commissioner and Nilgun Atamturk is the assigned Administrative Law Judge in this proceeding.

Findings of Fact

1. D.23-12-036 specified what PG&E must include in its forecast DCPP extended operations cost application.

2. In compliance with D.23-12-036, PG&E timely filed its application for Commission review and approval of its forecasted costs covering the period starting from September 1, 2023 through December 31, 2025 to support DCPP extended operations.

3. Consistent with the Commission's directives in D.23-12-036, PG&E's application includes: (1) a forecast of costs of extended operations, (2) a forecast of market revenues for DCPP for the Record Period, and (3) a proposal to establish the DC NBC applicable to all Commission jurisdictional customers based on the forecasted net costs.

4. PG&E estimates $1,356.2 million for DCPP costs, statutory fees, and substitution capacity expenses, with an offsetting $624.2 million of CAISO net forecasted market revenue, for a net revenue requirement of $761 million.

5. PG&E's forecasted O&M expense includes the base O&M expense, projects expense, nuclear fuel expense, and employee retention program expense.

6. There are no actual or known forecastable costs for NRC license renewal conditions or any DCISC recommendations during the Record Period.

7. PG&E provided a workable framework to distinguish transitional costs from extended operations costs.

8. PG&E failed to provide a detailed explanation in its application for why it did not seek government funding, or was otherwise unable to anticipate the need for the investments and activities at the time government funding was being requested.

9. PG&E properly followed the common practice in GRCs, as directed by D.23-12-036, and presented summaries for projects over $3 million.

10. PG&E's request to recover $128.5 million in employee retention costs for the Record Period in the DC NBC is consistent with Pub. Util. Code Section 712.8(f)(2), D.22-12-005, Resolution E-5299, D.23-12-036, and D.24-09-002.

11. DCPP is a generation asset and the purpose of the Fixed Management Fee is to compensate PG&E shareholders for the risks associated with generation assets.

12. PG&E's liquidated damages funding calculation is correct.

13. Due to the increase in the system RA MPB, the forecasted RA substitution capacity costs increased from $78 million to $210 million in the Fall Update.

14. The use of PCIA benchmarks to calculate RA substitution cost is more transparent and aligns with the regulatory precedent.

15. Costs that are already attributed to the DWR Loan are considered incremental as they were needed to pay for the extension of the existing fuel cycle, whereas the nuclear fuel costs sought herein are outside of the transition window and part of ongoing operations during the extension and are necessary for the operation of the plant.

16. The treatment of nuclear fuel expense aligns with the Commission's historical treatment of nuclear fuel costs where these costs were recovered annually in rates through the ERRA Forecast proceeding.

17. PG&E's alternative proposal to track potential deferred taxes in a memorandum account relating to SB 846 ratemaking, and seek a private letter ruling from the IRS, would result in near term ratepayer savings and clarify the applicability of the normalization requirement to DCPP.

18. The Commission has no reason to think the management fee is akin to an income generating investment in capital expenditures. It is more akin to an expense (which are deducted from taxable income), not a return on investment (which generates taxable income).

19. TURN's working cash proposal is not based on Commission precedent and may increase customer costs compared to the alternate proposal.

20. The computation of netting the CAISO revenues is undisputed by the parties.

21. D.23-12-036 establishes a process for allocating RA attributes and GHG-free energy benefits.

22. Instead of allocating DCPP's RA attributes among the IOUs' service areas based on 12-month CP load share, as required by D.23-12-036, PG&E proposed an allocation method based on the allocation ratios of total forecasted costs.

23. PG&E's VPF spending plan lacks detail.

24. The Commission cannot conclusively determine whether PG&E's VPF Spending Plan is consistent with Section 712.8(s)(1).

25. The VPF program is a new program and there is a need to gain a reasonable amount of experience with the program.

26. PG&E did not provide updated A&G expenses.

27. There is already a public review process established; and DWR and the Commission have the authority and capability of reviewing these expenses.

28. Reliability issues are out of the scope of this proceeding and considered in the IRP proceeding.

Conclusions of Law

1. PG&E's 2024 DCPP extended operations revenue requirement of $723 million, reducing PG&E's requested revenue requirement of $761 million to account for the Tax Gross Up adjustment ($33.63 million), Fixed Management Fee Escalation adjustment ($4.248 million), and the IRC Normalization adjustment ($0.051 million) should be approved.

2. The approved costs should be reflected in statewide rates starting on January 1, 2025.

3. PG&E's request to recover $498.34 million in O&M costs for the period September 1, 2023 to December 31, 2025 is reasonable.

4. PG&E's request to recover $128.5 million in employee retention costs for the Record Period in the DC NBC should be approved.

5. PG&E should provide detailed information for all projects with costs more than $1 million in its next filing.

6. PG&E's request for $167.1 million in VPFs; and $225 million to be recorded to the liquidated damages subaccount of the DCEOBA should be approved.

7. The requested $112.7 million in fixed management fees, including associated escalation factors and before taxes, should be reduced by $4.248 million, based on the modified escalation method.

8. The use of a generation-specific escalator for fixed management fees is reasonable and appropriate.

9. PG&E's liquidated damages funding request of $225 million complies with the Pub. Util. Code Section 712.8(g), is reasonable, and should be approved.

10. In its next DCPP cost forecast filing, PG&E should include its detailed plans on how the liquidated damage funds will be used and how they will be returned to customers.

11. PG&E's RA substitution capacity cost forecast of $210 million for the extended operations period of November 3, 2024, through December 31, 2025, should be approved.

12. The use of the RA MPB is appropriate and should be approved.

13. If the Commission adopts measures to mitigate excessive over- or under-collections in the ERRA balancing account, PG&E should incorporate those measures into the DC NBC via a Tier 1 advice letter and implement those changes in the next consolidated electric rate change filing with the Commission.

14. PG&E's nuclear fuel cost forecast and straightline amortization proposal are reasonable, comply with Pub. Util. Code Sections 712.8(c)(1)(C), 712.8(h)(1) and Commission decisions and resolutions interpreting those statutory sections, and should be approved.

15. PG&E's alternate proposal to mitigate concerns regarding violation of the IRS tax law normalization requirements should be approved.

16. Any incremental tax liabilities on fixed management fees should be born exclusively by PG&E and its shareholders.

17. PG&E's methodology to calculate forecast CAISO energy market revenues reasonable and should be approved.

18. PG&E's proposed working cash adjustment proposal is reasonable.

19. The IOUs' proposal for allocation of the DCPP extended operations cost is consistent with the direction provided in D.23-12-036 and should be approved.

20. PG&E's proposal to modify the methodology adopted in D.23-12-036 for allocating resource adequacy RA attributes and GHG-free energy attributes should be denied.

21. PG&E's request for approval of its VPF spending plan should be denied without prejudice.

22. It is appropriate to consider the VPF spending plan annually through an application process.

23. PG&E's request to utilize a Tier 3 advice letter process for reporting VPF revenue spending for future annual plans and retrospective reporting of section 712.8(s) requirements should be denied without prejudice.

24. PG&E should provide updated A&G costs for 2025 and beyond in its next DCPP cost forecast filing.

25. PG&E should minimize the amount of confidential information in the next annual application and protect only market-sensitive data.

26. PG&E's testimony satisfied all the regulatory requirements set forth in D.23-12-036 except for the deficiencies discussed in this decision.

27. All rulings issued by the assigned Commissioner and the assigned ALJ should be confirmed.

28. CARE's motion, dated September 30, 2024, to take official notice of the "March 13, 2024, letter from the Department of Finance to Joint Legislative Budget Committee Senate Budget and Fiscal Review Committee responding to a request for additional information regarding Diablo Canyon Power Plant" should be granted.

29. CARE's motion, dated October 14, 2024, to take official notice of reliability related documents should be denied.

30. All motions not specifically addressed herein or previously addressed by the assigned Commissioner or ALJ, should be denied.

31. This application should be closed.

O R D E R

IT IS ORDERED that:

1. Pacific Gas and Electric Company is authorized to recover a revenue requirement of $723 million covering the extended operations costs from September 1, 2023 to December 31, 2025, which includes operations and maintenance costs; resource adequacy substitution capacity forecast; generation forecast and generation revenues forecast methodology and calculation; amortized fuel expense cost for fuel over the 2025 through 2030 period; and netting of California Independent System Operator revenues of the period of November 3, 2024 to December 31, 2025.

2. The methodology for calculation of the Diablo Canyon Power Plant non-bypassable charge and rate proposals by Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas and Electric Company, complies with Decision 23-12-036 and is adopted. Final rates should reflect the revenue requirement adopted in this decision.

3. Pacific Gas and Electric Company's proposal to allocate Resource Adequacy and greenhouse gas-free energy attributes does not comply with the methodology established by Decision 23-12-036 and is denied.

4. Pacific Gas and Electric Company must submit a Tier 2 Advice Letter to allocate resource adequacy and greenhouse gas-free energy attributes as directed by Decision 23-12-036.

5. Pacific Gas and Electric Company's proposed volumetric performance fees spending plan for the November 3, 2024 to December 31, 2025 period is denied without prejudice.

6. Pacific Gas and Electric Company's (PG&E's) proposed modified regulatory process for it to utilize a Tier 3 Advice Letter for reporting on the amount of volumetric performance fee, how the funds were spent, and a plan for prioritizing the uses of such funds pursuant to Public Utilities Code Sections 712.8(f)(5) and 712.8(s)(1) for future years is denied without prejudice.

7. Pacific Gas and Electric Company's testimony satisfies all the regulatory requirements set forth in Decision 23-12-036 except for the proposal to allocate resource adequacy benefits and the administrative and general costs.

8. Pacific Gas and Electric Company must file a Tier 1 Advice Letter and revised tariff sheets within 30 days of the issuance of this decision to implement this Decision.

9. Pacific Gas and Electric Company must provide the following information in the next Diablo Canyon Power Plant cost forecast proceeding:

   a) Detailed project summaries for all projects over $1 million, instead of all projects over $3 million.

   b) Total cost of Diablo Canyon Power Plant extended operations through 2030.

   c) Updated Administrative and General costs for 2025 and beyond.

10. CAlifornians for Renewable Energy, Inc.'s motion, dated September 30, 2024, to take official notice of the "March 13, 2024, letter from the Department of Finance to Joint Legislative Budget Committee Senate Budget and Fiscal Review

Committee responding to a request for additional information regarding Diablo Canyon Power Plant is granted.

11. CAlifornians for Renewable Energy, Inc.'s motion, dated October 14, 2024, to take official notice of the September 14, 2024, letter from Tom Luster of the California Coastal Commission, Energy, Ocean Resources, and Federal Consistency Division to Mr. Tom Jones, Senior Director – Regulatory, Environmental and Repurposing, Pacific Gas & Electric Company, Diablo Canyon Power Plant; and October 9, 2024, Summary of Compliance with Integrated Resource Planning Order Decision (D.) 19-11-016 and Mid Term Reliability D.21-06-035 Procurement December 2023 Data Filings Energy Division Staff Recommendations is denied.

12. All rulings issued by the assigned Commissioner and the assigned Administrative Law Judge (ALJ) are affirmed; and all motions not specifically addressed herein or previously addressed by the assigned Commissioner or ALJ are denied.

13. Application 24-03-018 is closed.

This order is effective today.

Dated _____________________________, at San Francisco, California