

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 1

INTRODUCTION AND POLICY

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1 **PACIFIC GAS AND ELECTRIC COMPANY**
2 **CHAPTER 1**
3 **INTRODUCTION AND POLICY**

4 **A. Introduction**

5 Pacific Gas and Electric Company's (PG&E) Diablo Canyon Power Plant
6 (DCPP or Diablo Canyon) is continuing to deliver on its commitment to safely
7 serve California hometowns with clean, reliable, and affordable energy.
8 Annually, Diablo Canyon produces approximately 18,000 gigawatt-hours of
9 electricity – that is enough to serve more than 4 million Californians.

10 DCPP's electric reliability continues to hold strong, helping to provide
11 electric grid stability and reliability in a time of increasing electricity demand
12 across California. Indeed, the California Energy Commission (CEC) continues
13 to forecast strong mid- to long-term electric demand growth with their electric
14 peak demand forecast growing by 20 gigawatts by 2045. That is nearly nine
15 Diablo Canyons.

16 DCPP's strong operational reliability and focus on delivering safe and
17 affordable energy results in a forecast gross cost per megawatt-hour (MWh) of
18 \$73¹ as of this application for 2027, down from \$80 per MWh² (a reduction of
19 nearly 10 percent). In addition, the CEC's 2025 Electric Reliability Report finds
20 that "system reliability is expected to continue to significantly improve due to
21 [several factors that include] the near-term retention of Diablo Canyon Power."³

22 DCPP's key accomplishments in the last year include:

- 23 • Achieving "Column One" Status: The U.S. Nuclear Regulatory
24 Commission's (NRC) highest performance category. This ranking continues
25 to place DCPP among the top performing plants in the industry; and
- 26 • Achieving an 89.7 Percent Capacity Factor for Units 1 and 2 in 2025: The
27 second-highest generation total ever in a double refueling outage year. In

1 A.26-03-XXX, \$1,335 million (Prepared Testimony Chapter 1, Table 1-1 Line 19, Year 2027)/18.288 gigawatt hours (Prepared Testimony Chapter 3, p. 3-2, line 4).

2 A.24-03-018, \$1,455 million (Fall Update Confidential Chapter 2 Attachment A, Line 86, Year 2027)/18.268 gigawatt hours (Fall Update Confidential Workpapers Supporting Chapter 4, Year 2027). The files are no longer confidential.

3 California Energy Resource and Reliability Outlook, 2025, p. C-1, Link: [California Energy Resource and Reliability Outlook, 2025 | California Energy Commission](#).

1 fact, the capacity factor for 2025 missed setting a new record by
2 25,000 MWh—less than one day of one unit’s generation—due to ramp
3 downs on Unit 2 as a result of the Gifford and Madre wildfires’ proximity to
4 the transmission lines that export Diablo Canyon’s electricity to the larger
5 California electric grid.

6 In its most recent Integrated Resource Planning proceeding final decision
7 (D.26-02-057), the California Public Utilities Commission’s (Commission) issued
8 a zero-emitting generation procurement order of 6,000 megawatts by 2032.
9 Although DCPD is statutorily ineligible to fill this order, if it were eligible, it could
10 save additional costs for electric customers across the state of California.⁴

11 The economic benefits of DCPD to its surrounding communities cannot be
12 understated. DCPD remains San Luis Obispo (SLO) County’s largest private
13 employer, providing jobs for more than 1,200 dedicated nuclear professionals,
14 not including the 1,000 additional workers who support planned refueling
15 outages for its two reactors every 18 months. Since 2018, PG&E has paid more
16 than \$185 million in taxes to SLO County, including the \$85 million Community
17 Impact Mitigation Program directly benefiting local schools and communities.
18 PG&E and its employees provide hundreds of thousands of dollars in grants and
19 donations every year to Central Coast organizations and volunteer thousands of
20 hours of personal time each year to various groups.

21 DCPD’s extended operations also represent a substantial statewide benefit
22 in GHG emissions reductions. Specifically, DCPD’s extended operations
23 through 2030 are expected to reduce GHG emissions from natural gas
24 generation and imported energy by 34.5 million metric tons. Diablo Canyon’s
25 extended operations through 2030 are expected to annually reduce GHG
26 emissions equivalent to carbon dioxide emissions of 1.6 million cars.⁵

27 PG&E is proud of the strong results that it continues to deliver on its triple
28 bottom line approach of serving people, the planet, and California’s prosperity.

4 PG&E’s Opening Comments on the Administrative Law Judge’s Ruling Seeking
Comments on the 2026-2027 Transmission Planning Process and Need for Additional
Reliability Procurement, pp. 14-15.

5 See U.S. Environmental Protection Agency Greenhouse Gas (GHG) Equivalencies
Calculator:
<https://www.epa.gov/energy/greenhouse-gas-equivalencies-calculator#results>.

1 **B. Summary of Request**

2 This Application presents for the Commission’s review and approval of
3 recovery in customer rates of DCPP’s January 1, 2027 to December 31, 2027
4 extended operations period costs (Record Period). This Application also
5 presents for Commission review and approval a plan for prioritizing the uses of
6 the Public Utilities Code (Pub. Util. Code) Section 712.8(f)(5) volumetric
7 performance fees (VPF) consistent with Section 712.8(s)(1) and
8 Decision (D.) 23-12-036.

9 The total Diablo Canyon extended operations net revenue requirement, the
10 cost of DCPP less DCPP’s electric generation market revenues, is \$595 million.
11 This amount is allocated to the three large investor-owned utilities (IOU) as
12 follows: (1) PG&E, \$340 million; (2) Southern California Edison Company
13 (SCE), \$208 million; and (3) San Diego Gas & Electric Company (SDG&E),
14 \$47 million. Each of the IOU’s independently calculate and present its
15 respective Diablo Canyon Non-Bypassable Charge (DCNBC) in Chapter 10
16 based on its allocation of the total net revenue requirement presented in
17 Table 1-3 below.

18 Consistent with the Commission’s directives in D.23-12-036, PG&E’s
19 presentation supporting the proposed rate includes: (1) a forecast of costs of
20 extended operations, (2) forecast of market revenues for Diablo Canyon in the
21 relevant ratemaking period, and (3) a proposal to establish the DCNBC
22 applicable to all Commission-jurisdictional customers based on forecast net
23 costs and applicable true-up amounts. PG&E also provides additional
24 cost-related information as required by D.24-12-033 and D.25-12-007.

25 **1. DCPP Extended Operations Period Total Benefits**

26 Table 1-1 below provides the total statewide customer net benefit of
27 DCPP’s extended operations.

TABLE 1-1
DCPP 2023–2030 EXTENDED OPERATIONS COSTS, REVENUE CREDITS, AND RA BENEFITS
(MILLIONS OF DOLLARS)

Line No.	Forecast Item	2023A	2024A	2025A	2026A	2027F	2028F	2029F	2030F
1	<u>DCPP Direct Costs (Ch. 2)</u>								
2	Expense operations and maintenance (O&M) and Projects (Excludes Nuclear Fuel Procurement)	\$17,025	\$63,586	\$417,724	\$563,935	\$637,945	\$629,541	\$439,444	\$371,050
3	Nuclear Fuel Expense Amortization (Ch. 2)	–	–	\$134,002	\$135,734	\$118,454	\$118,454	\$118,454	\$118,454
4	Spent Nuclear Fuel Management Department of Energy (DOE) Litigation Balancing Account Proceeds	–	–	–	\$(12,587)	\$(11,440)	\$(10,514)	\$(23,462)	\$(3,430)
5	<u>Statutory Fees (Ch. 5)</u>								
6	Fixed Management Fee	–	\$7,869	\$66,479	\$113,997	\$117,163	\$119,935	\$117,167	\$57,108
7	VPF	–	\$19,467	\$147,638	\$266,567	\$274,094	\$265,957	\$277,622	\$114,171
8	<u>Results of Operations Items (Ch.4)</u>								
9	Administrative and General (A&G) Allocation	–	–	–	–	\$153,618	\$157,317	\$112,037	\$51,913
10	Taxes	\$1,928	\$5,211	\$17,573	\$23,659	\$25,413	\$27,499	\$21,880	\$19,917
11	Revenue Fees and Uncollectibles	\$271	\$787	\$8,823	\$7,562	\$10,805	\$8,847	\$3,965	\$1,562
12	Debt Financing Costs (Excluding Nuclear Fuel Debt Financing)	–	\$173	\$2,925	\$2,918	\$(2,098)	\$(2,194)	\$(1,971)	\$(1,542)
13	<u>Nuclear Generation-Related Benefits</u>								
14	DCPP Generation Market Revenues (Ch. 6)	–	\$(80,044)	\$(544,205)	\$(842,676)	\$(750,559)	\$(770,120)	\$(814,101)	\$(340,613)

Note: "A" in the header row refers to amounts adopted in D.24-12-033 and D.25-12-007 and "F" refers to amounts forecast in this application. Totals may not sum exactly due to rounding.

TABLE 1-1
DCPP 2023-2030 EXTENDED OPERATIONS COSTS, REVENUE CREDITS, AND RA BENEFITS
(MILLIONS OF DOLLARS)
(CONTINUED)

Line No.	Forecast Item	2023A	2024A	2025A	2026A	2027F	2028F	2029F	2030F
15	Resource Adequacy (RA) Substitution (Ch. 3)	-	\$14,968	\$50,388	\$26,288	\$16,451	\$32,903	-	\$16,451
16	RA Capacity Benefit (Ch. 1)	-	\$(59,873)	\$(183,814) \$(204,470)	\$(275,720) \$(315,461)	\$(275,720) \$(315,461)	\$(275,720) \$(315,461)	\$(252,744) \$(289,172)	\$(114,884) \$(131,442)
17	Other Costs	-	-	-	-	-	-	-	-
18	Liquidated Damages Subaccount (Ch. 5)	-	\$25,000	\$200,000	\$75,000	--	-	-	\$(300,000)
19	Total Extended Operations Gross Revenue Requirement	\$19,224	\$137,061	\$1,045,553	\$1,203,071	\$1,335,980	\$1,347,746	\$1,065,138	\$445,654
20	Total Extended Operations Net Revenue Requirement	\$19,224	\$57,018	\$501,348	\$360,396	\$585,420	\$577,625	\$251,037	\$105,041
21	Total Annual Cost Including RA Capacity Benefit	\$19,224	\$(2,855)	\$347,534 \$296,877	\$84,675 \$44,935	-\$309,700 \$269,960	-\$304,905 \$262,165	-\$4,707 \$(38,136)	\$(9,842) \$(26,401)

Note: "A" in the header row refers to amounts adopted in D.24-12-033 and D.25-12-007 and "F" refers to amounts forecast in this application. Totals may not sum exactly due to rounding.

**** Row 19 reflects the DCEOBA credit of \$4.425 million for forecast year 2027. This credit cascades into rows 20 and 21 for forecast year 2027.

1 **C. Organization of the Remainder of This Chapter**

2 The remainder of this chapter is organized as follows:

- 3 • Section D – Legislative and Regulatory Background;
- 4 • Section E – Avoided Resource Adequacy Costs;
- 5 • Section F – DCPD GHG Attributes Allocation;
- 6 • Section G – Forecast Costs for DCPD for the 2027 Record Period;
- 7 • Section H – Customer Rates Through the Diablo Canyon Extended
- 8 Operations Balancing Account;
- 9 • Section I – Non-Bypassable Charge Proposal;
- 10 • Section J – Fall Update;
- 11 • Section K – 2027 Planned Expenditures of VPFs;
- 12 • Section L – Testimony Overview; and
- 13 • Section M – Compliance with Prior Decisions.

14 **D. Legislative and Regulatory Background**

15 On September 2, 2022, Senate Bill (SB) 846 was signed into law, directing
16 PG&E to pursue extended operations at DCPD up to an additional five years
17 beyond its current license period in 2024 and 2025. The Legislature found that
18 extending DCPD operations “is prudent, cost effective, and in the best interests
19 of all California electricity customers.”⁶ The Governor, state agencies, and
20 lawmakers took this significant action to improve statewide energy system
21 reliability and to minimize GHG emissions as California transitions to additional
22 clean energy resources. As the state of California’s largest single source of
23 clean energy, DCPD currently supplies approximately 17 percent of California’s
24 zero-carbon electricity supply and serves more than 4 million (10 percent of)
25 Californians, 365 days a year, 24/7, rain or shine. The legislation directed all
26 relevant state agencies and PG&E as the plant operator to act quickly and to
27 coordinate on the necessary and prudent actions to extend plant operations.⁷

28 Since SB 846 was signed into law, PG&E has answered the state of
29 California’s call to ensure electric reliability for all Californians by accomplishing
30 several critical milestones in support of DCPD’s extended operations.

6 Public Resources Code (PRC) § 25548(b).

7 PRC § 25548(f).

1 Consistent with the legislation, PG&E secured funding from the California
2 Department of Water Resources (DWR) through a \$1.4 billion loan—PG&E has
3 received the entire DWR Loan with the final disbursement received in
4 September 2024; applied for and executed an agreement with the DOE for the
5 Civil Nuclear Credit Program to repay the DWR loan; and submitted its license
6 renewal application (LRA) to the NRC seeking to renew the current operating
7 licenses for DCPD Units 1 and 2 beyond 2024 and 2025, respectively.

8 In Rulemaking 23-01-007 implementing SB 846, the Commission
9 considered specific inputs necessary to establish new retirement dates for
10 DCPD and approved a cost recovery mechanism for extended operations. The
11 Commission issued D.23-12-036 on December 15, 2023, conditionally approving
12 new retirement dates of October 31, 2029, and 2030 for DCPD Units 1 and 2,
13 respectively,⁸ which also outlined the regulatory process PG&E will follow to
14 submit forecast extended operations costs to recover those costs through
15 statewide customer rates. This includes an annual planning process for PG&E's
16 use of VPFs.

17 In PG&E's first DCPD extended operations cost recovery
18 Application 24-03-018, the Commission issued D.24-12-033 approving, in part,
19 PG&E's 2023-2025 record period net revenue requirement request and
20 implementing additional requirements for future cost recovery Applications.

21 Finally, in December 2025, the Commission approved D.25-12-007,
22 authorizing, among other things, PG&E's net revenue requirement request and
23 its plan for use of 2026 VPFs. Additional directives from D.25-12-007 are
24 provided in Table 1-4.

25 As of February 2026, PG&E has obtained all state of California permit
26 approvals and completed all activities and regulatory submissions required by
27 the NRC in its review of DCPD's 20-year LRA. PG&E is awaiting a final
28 determination from the NRC on DCPD's LRA.

29 **E. Avoided Resource Adequacy Costs**

30 In D.23-12-036, the Commission determined that an allocation of DCPD's
31 RA capacity attributes should occur. This is primarily based on the
32 Commission's findings that:

8 D.23-12-036, p. 135, Ordering Paragraph (OP) 1.

1 RA benefits constitute a substantial financial value and are already
2 attributed to DCPD operations. Those ratepayers that are paying for
3 extended operations at DCPD should, as a matter of equity, realize the
4 financial benefits of those extended operations, and those benefits should
5 be distributed to each utility in the same manner of DCPD extended
6 operations costs.⁹

7 Consistent with this decision, DCPD's RA capacity for 2024, 2025, and 2026
8 was allocated by the Commission to load-serving entities (LSE) bearing cost
9 responsibility for extended operations at DCPD. Given the Commission's
10 conclusions and the actual allocation of DCPD's RA capacity, PG&E is providing
11 an updated calculation of the "financial value" (i.e., avoided costs or cost
12 savings) of providing DCPD's RA capacity attributes to all
13 Commission-jurisdictional LSEs to meet their respective RA compliance
14 obligations.

15 PG&E calculated the estimated cost savings using a forecast of the monthly
16 RA capacity amounts that are expected to be allocated to all benefiting LSEs
17 through 2030. Specifically, these monthly RA capacity amounts were multiplied
18 by a reference price benchmark. PG&E utilized the 2024, 2025, and 2026
19 Power Charge Indifference Adjustment system RA market price benchmarks
20 (MPB) as they are the most recent available reference prices published by the
21 Commission.

22 Based on these calculations, the estimated benefit associated with
23 allocating DCPD's RA capacity attributes are:

⁹ D.23-12-036, pp. 81-82.

**TABLE 1-2
DCPP RESOURCE ADEQUACY BENEFIT**

Line No.	Year	(A) Net Qualifying Capacity per Unit (MW)	(B) Number of Months RA is Expected to be Allocated ^(a)	(C) Market Price Benchmark (\$/kW-Month)	(D) = (A) * (B) * (C) Cost Savings \$000
1	2024	1,140	2	\$26.26	\$59,873
2	2025	1,140	16	\$11.21	\$204,470
3	2026	1,140	24	\$11.53	\$315,461
4	2027	1,140	24	\$11.53	\$315,461
5	2028	1,140	24	\$11.53	\$315,461
6	2029	1,140	22	\$11.53	\$289,172
7	2030	1,140	10	\$11.53	\$131,442

(a) Based on the total number of months that RA has been or is expected to be allocated. For example, in 2025, the RA capacity from Unit 1 and Unit 2 has been allocated out for 12 months (Unit 1) and 4 months (Unit 2), respectively.

F. DCPG Greenhouse Gas Attributes Allocation

D.23-12-036 directed PG&E to offer to LSEs that are paying for extended operations of DCPG the ability to use their share of DCPG’s GHG-free energy attributes towards their respective power content label.¹⁰ In compliance with this decision, PG&E submitted Advice 7295-E/E-A proposing modifications to its Commission-approved BPP – Appendix P to establish an allocation process for DCPG’s GHG-free energy during extended operations.¹¹ Consistent with D.24-12-033, D.23-12-036, and the approved BPP modifications, PG&E allocated DCPG’s 2025 GHG-free energy to opt-in LSEs in late 2024 and early 2025. Additionally, PG&E allocated DCPG’s 2026 GHG-free energy to opt-in LSEs in late 2025. The transactions reflecting these allocations were included in PG&E’s annual true-up advice letter, submitted on March 18, 2026.¹² Finally, PG&E will continue allocating DCPG’s GHG-free energy on an annual basis consistent with its Commission-approved BPP.

G. DCPG Forecast Costs for the 2027 Record Period

Table 1-3, Total Net Revenue Requirement for Ratesetting, presents the 2027 Record Period cost components in greater detail. Table 1-3, line 2

¹⁰ D.23-12-036, Conclusion of Law (COL) 42.

¹¹ PG&E Advice 7295-E/E-A, effective September 29, 2024.

¹² PG&E Advice 7860-E.

1 includes costs to operate DCPD during this 2027 Record Period, including direct
2 costs for O&M, support costs including taxes, benefits and standard PG&E
3 overheads, employee retention, and regulatory compliance items discussed in
4 Chapter 2. Line 3 includes A&G amounts allocated to Diablo Canyon extended
5 operations, which is discussed in Chapter 4. Line 4 provides a summary of the
6 statutory charges and fees included in the cost forecast, including the volumetric
7 performance and management fees, authorized in SB 846. Line 5 includes a
8 forecast for RA substitution capacity expenses, which is discussed in Chapter 3.
9 Line 6 provides a total cost for extended operations in 2027.

10 Line 8 provides PG&E's forecast of expected California Independent System
11 Operator (CAISO) Market Revenues and Line 9 is the Total Net Forecast Costs
12 for 2027, which sums Line 6 and Line 8 and is \$590.5 million.

13 Line 11 provides an expected end-of-year Diablo Canyon Extended
14 Operations Balance Account (DCEOBA) balance for 2026 and Line 12 is the
15 Total Net Forecast Costs for 2027, including amortization of the DCEOBA
16 balance, which totals to \$586.1 million.

17 The Joint Utilities' Franchise Fees and Uncollectibles Revenues (Line 13)
18 are then added to Line 12, Total Net Forecast Costs and DCEOBA amortization,
19 resulting in a Net Revenue Requirement to be recovered in rates of
20 approximately \$595.0 million.

**TABLE 1-3
DETAILED TOTAL NET REVENUE REQUIREMENT FOR RATESETTING**

Line No.	Chapter Cross Reference	Diablo Canyon Extended Operations ^a 2027 Cost (\$1000s)		
		Statewide	PG&E Specific	Total
1	Total Forecast Costs	(A)	(B)	(C)
2	Operation and Maintenance Cost Forecast	779,713		779,713
3	Administrative and General	153,618		153,618
4	Management, Performance Fees, & Liquidated Damages	254,210	137,047	391,257
5	Resource Adequacy Substitution Capacity	16,451		16,451
6	Total Cost Forecast (excluding FF&U)	1,203,993	137,047	1,341,040
7	D CPP Market Revenues			
8	CAISO Market Revenues	(750,559)		(750,559)
9	Total Net Forecast Costs (excluding FF&U)	453,433	137,047	590,480
10	Balancing Account Amortization			
11	DCEOBA	(4,425)		(4,425)
12	Total Net Forecast Costs and DCEOBA amortization	449,009	137,047	586,056
13	RF&U (PG&E) + FF&U (SCE) and FF&U (SDG&E) ^b	7,082	1,864	8,947
14	DCEO Revenue Requirement for Ratesetting	456,091	138,911	595,002

Notes:

- (a) Amounts in 2027 dollars (\$s)
- (b) SDG&E's FF&U revenue for its DCNBC will be collected in the its Distribution Charge.

H. Customer Rates Through the Diablo Canyon Extended Operations Balance Account

The Commission issued D.22-12-005 on December 6, 2022, directing PG&E to take “all actions that would be necessary” to preserve the option of extended operations at D CPP and to track and record all costs associated with continued operations. Pursuant to D.22-12-005, PG&E established the DCEOBA to track costs that will be recovered from the customers of all Commission-jurisdictional LSEs.¹³ The DCEOBA is intended to record and recover expenses related to the operations of D CPP Units 1 and 2 beyond the current license expiration dates of November 2, 2024, and August 26, 2025, respectively. The DCEOBA is comprised of three subaccounts: (1) the Extended Operations Subaccount, (2) the Liquidated Damages Subaccount, and (3) the VPF Subaccount. Additional information on the DCEOBA is provided in Chapter 8.

¹³ See PG&E Advice 7067-E; hyperlink at: https://www.pge.com/tariffs/assets/pdf/adviceletter/ELEC_7067-E.pdf (effective November 15, 2023).

1 **I. Non-Bypassable Charge Proposal**

2 Through jointly sponsored testimony, PG&E, SCE, and SDG&E set forth for
3 Commission review the rate proposals for the DCNBC. The DCNBC will consist
4 of a statewide charge applicable to all customers through the Public Purpose
5 Program (PPP) rates of the Commission-jurisdictional IOUs. PG&E requests
6 that the Commission approve the DCNBC described in this application and
7 testimony.

8 **J. Fall Update**

9 Consistent with the IOUs' respective Energy Resource Recovery Account
10 (ERRA) Forecast proceeding schedules over many years and as approved in
11 D.23-12-036, PG&E proposes to update its generation revenue forecast after
12 Energy Division staff releases its Energy Index MPB on October 1, 2026. The
13 Fall Update will incorporate the new Energy Index to reflect market conditions
14 closer to the time when 2027 rates go into effect, as well as other potential cost
15 updates. PG&E also proposes to update certain forecasts in this application and
16 testimony using the Energy Index and applicable RA MPBs. PG&E also will
17 present the amortization for 2026 balancing account balances into rates as of
18 January 1, 2027. The over or undercollection of 2026 rates will be included in
19 the December 2026 Annual Electric True-Up for ratesetting purposes. Finally,
20 PG&E proposes to update its 2027 Record Period revenue requirement to reflect
21 DOE settlement claims proceeds for DCPD spent fuel management activities
22 funded through the DCEOBA as appropriate.

23 **K. 2027 Planned Expenditures of VPFs**

24 PG&E also requests the Commission review and approve PG&E's 2027
25 VPF plan in Chapter 7. The Commission directed PG&E to present in an annual
26 application its plan for use of the \$13/MWh VPFs collected in 2026 and
27 demonstrate that those plans are consistent with the critical public purpose
28 priorities in Section 712.8(s)(1) prior to expenditure of those funds.¹⁴ PG&E
29 presents its planned use of VPFs collected in 2027 for the Commission's review
30 and demonstrates how these uses are consistent with the critical public purpose
31 priorities identified in Section 712.8(s)(1). Chapter 7 also describes how each

14 D.23-12-036, p. 139, OP 15.

1 program promotes affordability as a guiding principle and how they provide
2 benefits to ratepayers, among other items.

3 **L. Testimony Overview**

4 As directed in D.23-12-036 and consistent with Section 712.8(h)(1) of the
5 Pub. Util. Code, PG&E's testimony proposes a structure for a cost and revenue
6 requirement forecast of DCP's extended operations costs and revenues to
7 establish a statewide DCNBC that is modeled after the annual ERRA Forecast
8 proceeding.

9 Chapter 1 provides the introduction and underlying policy of the proceeding,
10 including the Legislature and the Governor's charge to the Commission in
11 SB 846 to establish new retirement dates for DCP, which became the basis for
12 D.23-12-036. This chapter summarizes PG&E's ratemaking requests for the
13 Record Period, addresses the costs and benefits of DCP's extended
14 operations through 2030, including benefits from RA and GHG-free energy and
15 demonstration that common costs will not be double counted.

16 Chapter 2 contains PG&E's 2027 Record Period forecast of O&M costs.
17 In this chapter, PG&E presents costs by Major Work Category, consistent with
18 PG&E's historical General Rate Case (GRC) testimony for nuclear operating
19 costs, which will describe categories of forecast costs.

20 Chapter 2 also includes proposed expense projects, similar to what would
21 have been capital project forecasts historically addressed in PG&E's GRC.
22 Execution of these projects is necessary to ensure safe and reliable extended
23 operations to meet the needs of all Californians. In addition, in compliance with
24 D.25-12-007, PG&E presents transition and license renewal costs identified in
25 PG&E's Transition and License Renewal Expenditure Summary (TLRES or
26 federal court affidavit) originally proposed to be recovered through the Diablo
27 Canyon Transition Memorandum Account that are proposed in this application
28 as recoverable through the DCEOBA. None of these costs are for activities
29 required as a result of NRC requirements for PG&E's LRA, consistent with SB
30 846 requirements.

31 Chapter 2 also presents PG&E's proposal for straight-line amortization for
32 cost recovery of nuclear fuel over the period of 2025 through 2030 which is
33 consistent with Pub. Util. Code Section 712.8(h)(2), which provides that for any
34 significant one-time expense project expenditures during the extended

1 operations period, PG&E may propose an amortization period for such
2 expenditures over a period of greater than one year for the purpose of reducing
3 rate volatility, at an amortization rate determined by the Commission. PG&E
4 proposes the Commission approve the same methodology that was adopted in
5 D.24-12-033 and D.25-12-007.

6 In Chapter 3, PG&E provides testimony regarding the amount of forecast
7 generation from extended operations for the Record Period, addresses
8 requirements under the Commission's RA Program, PG&E's procurement of
9 replacement capacity during DCPD planned and unscheduled outages, and
10 substitution capacity procurement costs that are necessary to meet the state's
11 reliability needs. Prior to SB 846, these issues were addressed in other
12 proceedings. This chapter also discusses the Commission's directive that
13 PG&E retain responsibility for obtaining substitution capacity during DCPD
14 outages as D.23-12-036 determined it is reasonable for all LSEs that are
15 allocated RA benefits to share in reasonable administrative and procurement
16 costs associated with meeting DCPD's RA substitution capacity obligations,
17 including associated penalties and costs borne by non-DCPD resources.

18 Chapter 4 contains cost inputs discussed in Chapter 2 ~~as well as costs from~~
19 ~~Chapter 3,~~ and Chapter 5 in order to calculate the forecast revenue requirement
20 request for DCPD Units 1 and 2 for the 2027 Record Period. Chapter 4 also
21 explains PG&E's assumptions used in the revenue requirement model.
22 Pub. Util. Code Section 712.8(h)(1) requires that all extended operations costs
23 shall be recovered as an operating expense and shall not be eligible for
24 inclusion in PG&E's rate base.

25 Pursuant to Section 712.8(h)(1), PG&E's cost recovery for extended
26 operations will be net of market revenues for those operations and any
27 production tax credits of the operator.

28 Chapter 5 presents statutory fees, including the statewide VPF pursuant to
29 Section 712.8(f)(5), PG&E service territory's VPF pursuant to
30 Section 712.8(f)(5), the fixed management fee for PG&E's operation of DCPD in
31 lieu of a rate-base return pursuant to Section 712.8(f)(6)(A), and liquidated
32 damages subaccount funding pursuant to Section 712.8(g). PG&E calculated
33 escalation of the fixed management fee using the methodology adopted in
34 D.25-12-007.

1 Chapter 6 presents a forecast of the CAISO market revenues for the period
2 of January 1, 2027, to December 31, 2027, in a manner similar to PG&E's ERRRA
3 Forecast proceeding, which is based on a weighted average of on- and off-peak
4 forward prices for the Test Year. PG&E anticipates that in its Fall Update, its
5 generation revenue forecast will be based upon the Energy Index on- and
6 off-peak prices provided by the Commission's Energy Division on October 1 of
7 each year pursuant to D.22-01-023.

8 In Chapter 7, PG&E presents its planned usage and programs for spending
9 the 2027 VPFs pursuant to statutorily mandated public purpose priorities.¹⁵ For
10 each proposed program, PG&E provides a description of planned activities, how
11 it promotes affordability as a guiding principle, program benefits, as well as
12 information required by D.25-06-002.

13 Chapter 8 addresses the subaccount contents of the DCEOBA, which is
14 consistent with PG&E's Advice 7509-E, which has an effective date of
15 February 18, 2025, and modifications submitted and still pending further
16 disposition, including: (a) Advice 7204-E submitted on March 14, 2024 in
17 compliance with D.23-12-036 directives, as further amended by
18 Advice 7204-E-A submitted on February 12, 2025;¹⁶ and (b) Advice 7531-E
19 submitted on March 10, 2025 in compliance with D.25-01-043.¹⁷

20 Chapter 9 presents the net revenue requirement for consideration in this
21 proceeding, which nets the forecast market revenues with Total DCPD Results
22 of Operations Costs presented in Chapter 4 over the Record Period.

23 Chapter 10 is co-sponsored by PG&E, SCE, and SDG&E and presents the
24 ratemaking mechanism for the statewide NBC applicable to all
25 Commission-jurisdictional customers through the PPP rates of the
26 Commission-jurisdictional IOUs. PG&E, SCE, and SDG&E jointly present

¹⁵ Pub. Util. Code § 712.8(s)(1).

¹⁶ See PG&E Advice 7204-E; hyperlink at:
https://www.pge.com/tariffs/assets/pdf/adviceletter/ELEC_7204-E.pdf (effective May 30,
2025); see also, PG&E Advice 7204-E-A; hyperlink at:
https://www.pge.com/tariffs/assets/pdf/adviceletter/ELEC_7204-E-A.pdf (also effective
May 30, 2025).

¹⁷ See PG&E Advice 7531-E; hyperlink at:
https://www.pge.com/tariffs/assets/pdf/adviceletter/ELEC_7531-E.pdf (effective
March 10, 2025).

1 testimony to allocate the net revenue requirement for the record period amongst
2 themselves using the CEC’s published 2025 peak load forecast that is
3 developed for use in the Commission’s RA Program. Each utility sponsors its
4 own testimony on allocating its share of the revenue requirement among its
5 customer classes using a process that mirrors the existing Cost Allocation
6 Methodology for system reliability resources.

7 Chapter 10 also presents the allocation of the DCPD Extended Operations
8 revenue requirement to PG&E, SCE, and SDG&E and illustrative DCNBC rates
9 applicable to customers in each utility’s service area based on the methodology
10 adopted by D.23-12-036. The rates presented in Chapter 10 are illustrative and
11 subject to updates in the Fall Update and in each utility’s January 1, 2027,
12 consolidated rate change process.

13 Appendix A includes the statements of qualification for PG&E, SCE, and
14 SDG&E witnesses sponsoring Prepared Testimony.

15 **M. Compliance With Prior Decisions**

16 Table 1-4 presents the specific requirements from D.23-12-036,
17 D.24-12-033, and D.25-12-007 that are applicable to this application and
18 PG&E’s compliance with each requirement. Compliance items from the above
19 decisions completed prior to this application or to be addressed outside of this
20 application are not included in Table 1-4.

**TABLE 1-4
COMPLIANCE WITH PRIOR DECISIONS**

Line No.	Action Required	Decision Reference	Compliance Action
1	D.23-12-036	OP 4	See PG&E application, filed on March 27, 2026
2	PG&E's proposed ERRA-like process to authorize forecast DCPPE extended operations costs, with a subsequent true-up to actual costs and market revenues for the prior calendar year via an expedited Tier 3 AL process, is approved as modified by this decision. PG&E shall file the first of these DCPPE Extended Operations Cost Forecast applications no later than March 29, 2024, and shall file subsequent annual DCPPE Extended Operations Cost Forecast applications no later than March 31 beginning in 2025, and ending the year before extended operations are complete.		
3	<p>As part of its annual DCPPE Extended Operations Cost Forecast Applications, PG&E should:</p> <ul style="list-style-type: none"> a) Provide detailed projections of all costs and revenues associated with DCPPE extended operations, in a manner similar to PG&E's presentation in its GRC and ERRA Forecast proceedings; b) Quantify the impact of DCPPE's extended operations on its common costs relative to the amount approved in its 2023 GRC; and c) Demonstrate it will not double count the common costs it proposes for recovery in its GRC and DCPPE Extended Operations Cost Forecast applications. 	COL 54	<p>Item 2-(a) Expense O&M and Projects Costs – See Chapter 2; Revenues – See Chapter 4</p> <p>Items 2-(b) and 2-(c) – No longer applicable. The 2023 GRC set revenues for the period 2023 through 2026 only.</p> <p>Item 2-e – See Chapter 4</p>
4	PG&E, SCE, and SDG&E are directed to provide joint testimony proposing an allocation among themselves of the statutorily-defined DCPPE extended operations costs applicable to all LSE, and the revenue associated with the \$6.50 per MWh volumetric fee under Pub. Util. Code Section 712.8(f)(5). PG&E, SCE, and SDG&E may use public load data to determine each electrical corporation's share of the 12-month coincident peak demand.	OP 7	See Chapter 10
5	<p>The Diablo Canyon Extended Operations Cost Forecast proceeding should:</p> <ul style="list-style-type: none"> a) Determine the allocation of costs and benefits of DCPPE extended operations among the large electrical corporations' service areas; and b) 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 LSEs in each large electrical corporation's territory, and should endeavor to provide all LSEs with allocations of DCPPE's RA benefits for the upcoming compliance year sufficiently in advance of the October 31 year-ahead RA compliance filing deadline. 	COL 55	See Chapter 10

**TABLE 1-4
COMPLIANCE WITH PRIOR DECISIONS
(CONTINUED)**

Line No.	Action Required	Decision Reference	Compliance Action
6	D.23-12-036		
7	PG&E is directed to file an annual application, as described in this decision, no later than March 1, 2026, until the retirement of DCCPP Unit 1 and Unit 2, to report the amount of compensation earned under California Pub. Util. Code Section 712.8(f)(5), how it was spent, and a plan for prioritizing the uses of such compensation the next year. PG&E is not prohibited from filing an application earlier than March 1, 2026, to request an earlier approval of its plan for prioritizing the uses of funds collected under California Pub. Util. Code Section 712.8(f)(5). PG&E's application may also include one or more proposals that would allow PG&E to spend the performance-based fees while ensuring sufficient funding for the true-up process, as discussed elsewhere in this decision.	OP 15	See Chapter 7
8	D.24-12-033		
9	PG&E must provide the following information in the next DCCPP cost forecast proceeding: (a) Detailed project summaries for all projects over \$1 million, instead of all projects over \$3 million; (b) Total cost of DCCPP extended operations through 2030; (c) Updated A&G costs for 2025 and beyond.	OP 10	(a) See Workpapers Supporting Chapter 2 (b) See Chapter 1 Table 1-1 (c) See Chapter 4
10	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 DCCPP; all plant and equipment improvement and investment costs; spent fuel storage capacity costs; and any related taxes or other revenue requirements." 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.	pp. 18-19 <u>p. 23</u>	(a) See Chapter 2 (b) Strike-through is a directive in D.22-12-005 that was subsequently eliminated by the Commission in D.25-12-007.
11	D.25-12-007		
12	In D.25-12-007, the Commission concluded that PG&E's "methodology for escalating the annual Fixed Management Fee using the all-urban consumer price index is approved. We direct PG&E to use the same consumer price index methodology to adjust the Fixed Management Fee in future DCCPP cost recovery applications to incrementally escalate the Fixed Management Fee approved in the previous year's DCCPP application."	<u>OP 4</u>	See Chapter 5, Section <u>DC</u>
13	PG&E must disclose whenever any transition and license renewal costs that were part of the amounts detailed in the TLRES in PG&E witness Brian Ketelsen's sworn federal court affidavit are proposed for recovery in any future DCCPP forecast proceedings for DCCPP extended operations, along with explanations for why those costs were originally proposed as transition and license renewal costs and why those costs are now eligible for recovery for extended operations.	<u>OP 5</u>	See Chapter 2

1 In addition, the Commission concluded that:

2 [T]he intent of the Legislature was to assign broad responsibility for the
 3 costs of extended operations of DCPD to ratepayers of all LSEs subject to
 4 the Commission’s jurisdiction, as outlined in Section 712.8(l)(1), [but certain
 5 costs are to only be paid by PG&E ratepayers].¹⁸

6 Pages 67-69 of D.23-12-036 lists the costs to be recovered by customers,
 7 replicated below in Table 1-5.

**TABLE 1-5
 SB 846 COST RECOVERY ITEMS**

Line No.	Pub. Util. Code Section 712.8	Cost	Payer
1	Subsection (f)(1)	Reasonable costs incurred to prepare for the retirement of Diablo Canyon Unit 1 and Unit 2.	PG&E ratepayers—bundled and unbundled—via an NBC.
2	Subsection (f)(1)	Any reasonable additional costs associated with decommissioning planning resulting from the LRAs or license renewals.	Ratepayers of all LSEs subject to the Commission’s jurisdiction—via an NBC
3	Subsection (f)(2)	Funding for the employee retention program approved in D.18-11-024, as modified to incorporate 2024, 2025, and additional years of extended operations, on an ongoing basis until the end of operations of both units.	Not specified in subsection (f)(2), so presumed to be ratepayers of all LSEs subject to the Commission’s jurisdiction—via an NBC—per subsection (l)(1).
4	Subsection (f)(4)	Reasonable costs incurred to prepare for, respond to, provide information to, or otherwise participate in or engage the independent peer review panel under Section 712.	Not specified in subsection (f)(4), so presumed to be ratepayers of all LSEs subject to the Commission’s jurisdiction—via an NBC—per subsection (l)(1).
5	Subsection (f)(5)	Payment in lieu of a rate-based return on investment (volumetric).	\$6.50 (2022 dollars) per MWh to be paid by PG&E ratepayers—bundled and unbundled—via an NBC. Plus \$6.50 (2022 dollars) per MWh to be paid by ratepayers of all LSEs subject to the Commission’s jurisdiction (including PG&E’s bundled).
6	Subsection (f)(6)(A)	Payment in lieu of a rate-based return on investment in acknowledgment of the greater risk of outages in an older plant (lump sum).	Not specified in subsection (f)(6)(A), so presumed to be ratepayers of all LSEs subject to the Commission’s jurisdiction—via an NBC—per subsection (l)(1).

¹⁸ D.23-12-036, p. 66.

**TABLE 1-5
SB 846 COST RECOVERY ITEMS
(CONTINUED)**

Line No.	Pub. Util. Code Section 712.8	Cost	Payer
7	Subsection (g)	Diablo Canyon Extended Operations liquidated damages balancing account. ^(a)	Ratepayers of all LSEs subject to the Commission's jurisdiction—via an NBC.
8	Subsection (h)(1)	All reasonable costs and expenses necessary to operate Diablo Canyon Unit 1 and Unit 2 beyond the current expiration dates, including those in subsections (f) and (g), net of market revenues for those operations and any production tax credits of the operator.	Not specified in subsection (h)(1), so presumed to be ratepayers of all LSEs subject to the Commission's jurisdiction—via an NBC—per subsection (l)(1).
9	Subsection (h)(2)	Any significant one-time capital expenditures during the extended operation period amortized over more than one year for the purpose of reducing rate volatility.	Not specified in subsection (h)(2), so presumed to be ratepayers of all LSEs subject to the Commission's jurisdiction—via an NBC—per subsection (l)(1).
10	Subsection (i)(1)	Reasonable replacement power costs, if incurred, associated with DCPD unplanned outage periods.	Not specified in subsection (i)(1), so presumed to be ratepayers of all LSEs subject to the Commission's jurisdiction—via an NBC—per subsection (l)(1).
<hr style="width: 20%; margin-left: 0;"/> <p>(a) The Liquidated Damages Subaccount is a subaccount of the DCEOBA.</p>			