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Exhibit No.:
Date: March 28, 2025
Witness(es): Various

PACIFIC GAS AND ELECTRIC COMPANY

DIABLO CANYON POWER PLANT 2026 COST RECOVERY FORECAST TO SUPPORT OPERATIONS AS DIRECTED BY THE STATE TO ENSURE ELECTRIC RELIABILITY AND TO REDUCE GREENHOUSE GAS EMISSIONS FOR ALL CALIFORNIANS

PREPARED TESTIMONY

PACIFIC GAS AND ELECTRIC COMPANY
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TABLE OF ACRONYMS

Acronym	Full Name
12-CP	12-month coincident peak
A.	Application
A&G	administrative and general
AB	Assembly Bill
AET	Annual Electric True-Up
AL	Advice Letter
AMS	Advanced Metering Services
BE	Building Electrification
BESS	Battery Energy Storage System
BTM	Behind-the-Meter
CAISO	California Independent System Operator Corporation
CAM	Cost Allocation Mechanism
CAP	Corrective Action Plan
CAPA	Credit Award and Payment Agreement
CCA	Community Choice Aggregator or Community Choice Aggregation
CEC	California Energy Commission
CERP	Company Emergency Response Plan
CGI	Common, General, and Intangible
CPI-U	Consumer Price Index-All Urban
CM	corrective maintenance
CNC	Civil Nuclear Credit
CNO	Chief Nuclear Officer
COD	Cost of Debt
COL	Conclusion of Law
CPUC or Commission	California Public Utilities Commission
D.	Decision
DCEOBA	Diablo Canyon Extended Operations Balancing Account
DCISC	Diablo Canyon Independent Safety Committee
DCNBC	Diablo Canyon Nonbypassable Charge
DCTRMA	Diablo Canyon Transition and Relicensing Memorandum Account

TABLE OF ACRONYMS
(CONTINUED)

Acronym	Full Name
DCPP	Diablo Canyon Power Plant or Diablo Canyon
DOE	Department of Energy
DOJ	Department of Justice
DOELBA	DOE Litigation Balancing Account
DWR	California Department of Water Resources
EEI	Edison Electric Industry
EGI	Electric Generation Interconnection
ERRA	Energy Resource Recovery Account
EV	Electric Vehicle
EVSC	EV Savings Calculator
FICA	Federal Insurance Contribution Act
FOF	Finding of Fact
FUI	Federal Unemployment Insurance
GAAP	Generally Accepted Accounting Principles
GHG	greenhouse gas
GIS	Geographic Information System
GRC	General Rate Case
GWh	gigawatt-hour
HBPP	Humboldt Bay Power Plant
HFRA	High Fire Risk Areas
HVAC	heating, ventilation and air conditioning
IMT	Incident Management Teams
IOU	Investor-Owned Utility or Investor-Owned Utilities
IRC	Internal Revenue Code
IRS	Internal Revenue Service
ISFSI	Independent Spent Fuel Storage Installation
IT	Information Technology
kV	kilovolt
kWh	kilowatt-hour
LRA	License Renewal Application
LSE	load serving entity or load serving entities

TABLE OF ACRONYMS
(CONTINUED)

Acronym	Full Name
MACRS	Modified Accelerated Cost Recovery System
MDC	Maximum Dependable Capacity
MPB	Market Price Benchmark
MW	megawatt
MWC	Major Work Category
MWh	megawatt-hour
NBC	non-bypassable charge
NDAM	Nuclear Decommissioning Adjustment Mechanism
NEI	Nuclear Energy Institute
NEM	Net Energy Metering
NFPA	National Fire Protection Association
NP15	North of Path 15
NRC	U.S. Nuclear Regulatory Commission
NSOC	Nuclear Safety Oversight Committee
OASDI	Old Age, Survivors, and Disability Insurance
O&M	operations and maintenance
OII	Order Instituting Investigation
OIR	Order Instituting Rulemaking
OP	Ordering Paragraph
OSHA	Occupational Safety and Health Administration
OTC	Once Through Cooling
PABA	Portfolio Allocation Balancing Account
PCC	Provider Cost Center
PCIA	Power Charge Indifference Adjustment
PEO	Period of extended operations
PLR	Private Letter Ruling
PM	Preventative Maintenance
PMCR	Preventative maintenance change requests
PMO++	Preventative Maintenance Optimization Program ++
PPP	Public Purpose Program
PPPC	Public Purpose Program Charge

TABLE OF ACRONYMS
(CONTINUED)

Acronym	Full Name
PRC	Public Resources Code
PTC	production tax credit
Pub. Util. Code	Public Utilities Code
QA	Quality Assurance
QV	Quality Verification
R.	Rulemaking
RA	Resource Adequacy
REM	Roentgen Equivalent Man
Res.	Resolution
RF&U	Revenue Fees and Uncollectibles
RM	rad motor
RO	Results of Operations
ROP	Reactor Oversight Process
SA	Settlement Agreement
SB	Senate Bill
SBE	California State Board of Equalization
SCE	Southern California Edison Company
SDG&E	San Diego Gas & Electric Company
SLO	San Luis Obispo
SMJU	small multi-jurisdictional utilities
SSC	structures, systems, and components
SUI	State Unemployment Insurance
SVP	Senior Vice President
TO	Transmission Owner
TY	Test Year
UOG	Utility-Owned Generation
VGI	Vehicle-Grid Integration
VPF	Volumetric Performance Fee
WECC	Western Electric Coordinating Council
WP	Workpapers

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 1

INTRODUCTION AND POLICY

PACIFIC GAS AND ELECTRIC COMPANY
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INTRODUCTION AND POLICY

A. Introduction

Pacific Gas and Electric Company's (PG&E) Diablo Canyon Power Plant (DCPP or Diablo Canyon) is delivering on its commitment to serve California hometowns with safe, reliable, affordable, and clean energy. Annually, Diablo Canyon produces approximately 18,000 gigawatt-hours of safe and reliable greenhouse gas (GHG)-free energy to more than 3 million Californians annually.

DCPP's key accomplishments in the last year include:

- Achieving "Column One" status – the United States (U.S.) Nuclear Regulatory Commission's (NRC) highest performance category. This ranking continues to place DCPP among the top performing plants in the industry;
- Recognition for DCPP's excellent performance and safe operations by industry peers of nuclear oversight groups; and,
- Achieving a 99.5 percent capacity factor for Unit 1 in 2024.

Regarding statewide customer benefits and affordability, the net revenue requirement for 2026 represents a 42 percent net reduction to 2025 DCPP extended operations present authorized revenues. Likewise, the DCPP extended operations portion of the PG&E, Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E) bundled service electric customer bill is reduced by 31 percent, 58 percent, and 54 percent, respectively, as compared to the 2025 DCPP extended operations electric bundled service non-California Alternate Rates for Energy (CARE) customer bill impacts.

Additionally, DCPP extended operations total benefit to statewide customers is $540 million per year on average, as presented in Table 1-1 below.

The economic benefits of DCPP to its surrounding communities cannot be understated. DCPP remains San Luis Obispo (SLO) County's largest private employer, providing jobs for more than 1,300 dedicated nuclear professionals, not including the 1,200 temporary workers who support the refueling outage.

From 2023-2024, DCPP contributed more than $15.1 million in property taxes and Community Impact Mitigation Program funds in SLO County, directly benefiting local schools and communities. PG&E and its employees provide hundreds of thousands of dollars in grants and donations every year to Central Coast organizations and volunteer thousands of hours of personal time each year to various groups.

DCPP's extended operations also represents a substantial statewide benefit in GHG emissions reductions. Specifically, DCPP's extended operations through 2030 are expected to reduce GHG emissions from natural gas generation and imported energy by 34.50 million metric tons. An Average single refueling outage year of extended operations is expected to reduce GHG emissions by 6.98 million metric tons, or the equivalent of carbon dioxide emissions from 1.6 million cars per year.[1]

PG&E is proud of the progress made through working to deliver on its triple bottom line approach of serving people, the planet, and California's prosperity.

B. Summary of Request

This application presents for the California Public Utilities Commission's (CPUC or Commission) review and approval of recovery in customer rates of DCPP January 1, 2026 to December 31, 2026 extended operations period costs (Record Period). This application also presents for Commission review and approval a plan for prioritizing the uses of the Public Utilities Code (Pub. Util. Code) Section 712.8(f)(5) Volumetric Performance Fees (VPF) consistent with Section 712.8(s)(1) and Decision (D.) 23-12-036.

PG&E's presentation of 2026 Extended Operations Record Period forecast costs are shown in Table 1-3 below and includes $1,339.3 million for DCPP costs, statutory fees, and substitution capacity expenses, which is offset by a forecast of $934.9 million for California Independent System Operator (CAISO) Corporation market revenues received in the CAISO's energy market. The resulting total net revenue requirement, including revenue/franchise fees and

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[1] See U.S. Environmental Protection Agency Greenhouse Gas Equivalencies Calculator: https://www.epa.gov/energy/greenhouse-gas-equivalencies-calculator#results.

uncollectibles for ratesetting is $410.0 million for the 2026 Record Period[2] representing a $301 million (42 percent) decrease from the 2025 Commission-authorized total net revenue requirement of $711 million.

The total Diablo Canyon extended operations revenue requirement is allocated to the three large investor-owned utilities (IOU) as follows: (1) PG&E, $257.3 million; (2) SCE, $124.9 million; and (3) SDG&E, $27.8 million. Each of the IOU's independently calculate and present its respective Diablo Canyon Non-Bypassable Charge (DCNBC) in Chapter 10 based on its allocation of the total net revenue requirement presented in Table 1-3 below.

PG&E's allocated revenue requirement for calendar year 2026 results in a $0.98 per month bill decrease for the average non-CARE residential customer. SCE's allocated revenue requirement for calendar year 2026 is estimated to result in a $1.38 per month bill decrease for the average non-CARE residential customer. SDG&E's allocated revenue requirement is estimated to result in a $0.77 per month bill decrease for the average non-CARE residential customer.[3]

As presented further below, DCPP provides additional value to the state and to customers that is not reflected in the total cost presentation above. For example, on average, for the 2025 to 2030 extended operations cost recovery period, when accounting for the estimated imputed Resource Adequacy (RA) attribute value, which would otherwise be realized through RA sales, DCPP extended operations results in $540 million in total net benefits to statewide customers.

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

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[2] A detailed discussion of the consolidated net revenue requirement used for ratesetting and subsequent allocation of the net revenue requirement to the IOUs is presented in Chapters 9 and 10, respectively.

[3] A detailed discussion of the IOUs' DCNBC results are presented in Chapter 10.

1. DCPP Extended Operations Period Total Benefits

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

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

Line No.	Forecast Item	2023A	2024A	2025A	2026F	2027F	2028F	2029F	2030F	2024-2030 Extended Operations Period Annual Average
1	DCPP Direct Costs (Ch. 2)									
2	Expense O&M and Projects (Excludes Nuclear Fuel Procurement)	$17,025	$63,586	$417,724	$563,934	$551,866	$585,304	$429,956	$338,607	
3	Nuclear Fuel Expense Amortization (Ch. 2)	–	–	$134,002	$135,734	$135,734	135,734	$135,734	$135,734	
4	Spent Nuclear Fuel Management Department of Energy (DOE) Litigation Balancing Account Proceeds	–	–	–	$(12,587)	$(9,154)	$(18,287)	$(21,405)	$(1,796)	
5	Statutory Fees (Ch. 5)									
6	Fixed Payment	–	$7,869	$66,479	$113,884	$116,416	$118,541	$111,070	$51,604	
7	Volumetric Performance Fee	–	$19,467	$147,638	$263,379	$270,460	$262,182	$274,135	$113,086	
8	Results of Operations Items (Ch.4)									
9	Administrative and General (A&G) Allocation	–	–	–	–	$154,836	$160,104	$151,814	$71,416	
10	Taxes	$1,928	$5,211	$17,573	$23,659	$24,431	$26,939	$21,955	$18,782	
11	Revenue Fees and Uncollectibles	$271	$787	$8,823	$5,572	$5,620	$7,649	$2,227	$1,804	
12	Debt Financing Costs (Excluding Nuclear Fuel Debt Financing)	–	$173	$2,925	$2,918	–	–	–	–	
13	Nuclear Generation-Related Benefits									
14	DCPP Generation Market Revenues (Ch. 6)	–	$(80,043.587)	$(544,204.773)	$(934,925)	$(983,423)	$(946,892)	$(998,022)	$(388,375)	

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

Line No.	Forecast Item	2023A	2024A	2025A	2026F	2027F	2028F	2029F	2030F	2024-2030 Extended Operations Period Annual Average
15	RA Substitution (Ch. 3)	–	$14,968	$183,814	$160,837	$137,860	$206,790	$45,953	$91,907	
16	RA Capacity Benefit (Ch. 1)	–	$(59,873)	($735,254)	$(1,102,882)	$(1,102,882)	$(1,102,882)	$(1,010,975)	$(459,534)	
17	<u>Other Costs</u>									
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	$1,178,978	$1,332,330	$1,388,070	$1,484,957	$1,151,439	$521,144	
20	Total Extended Operations Net Revenue Requirement	$19,224	$57,018	$634,773	$397,405	$404,646	$538,065	$153,417	$132,770	
21	Total Extended Operations Net Benefits	$19,224	$(2,855)	$(100,481)	$(705,477)	$(698,235)	$(564,817)	$(857,557)	$(326,764)	$(539,494)

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

C. Organization of the Remainder of This Chapter

The remainder of this chapter is organized as follows:

- Section D – Legislative and Regulatory Background;
- Section E – Avoided Resource Adequacy Costs;
- Section F – DCPP Greenhouse Gas Attributes Allocation;
- Section G – Forecast Costs for DCPP for the 2026 Record Period;
- Section H – Funding Mechanisms for DCPP Extended Operations;
- Section I – Non-Bypassable Charge (NBC) Proposal;
- Section J – Fall Update;
- Section K – 2026 Planned Expenditures of VPFs;
- Section L – Testimony Overview;
- Section M – Compliance with Prior Decisions;
- Section N – No Double Recovery of Common Costs From GRC; and
- Section O – Conclusion.

D. Legislative and Regulatory Background

On September 2, 2022, Senate Bill (SB) 846 was signed into law, directing PG&E to pursue extended operations at DCPP up to an additional five years beyond its current license period in 2024 and 2025. The Legislature found that extending DCPP operations "is prudent, cost effective, and in the best interests of all California electricity customers."[4] The Governor, state agencies, and lawmakers took this significant action to improve statewide energy system reliability and to minimize GHG emissions as California transitions to additional clean energy resources. As the state of California's largest single source of clean energy, DCPP currently supplies approximately 17 percent of California's zero-carbon electricity supply and 8.6 percent of California's total electricity supply, or three million homes and businesses, 365 days a year, 24/7, rain or shine. The legislation directed all relevant state agencies and PG&E as the Plant Operator to act quickly and to coordinate on the necessary and prudent actions to extend plant operations.[5]

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

5 PRC § 25548(f).

Since SB 846 was signed into law, PG&E has answered the state of California's call to ensure electric reliability for all Californians by accomplishing several critical milestones in support of DCPP extended operations. Consistent with the legislation, PG&E secured funding from the California Department of Water Resources (DWR) through a $1.4 billion loan—PG&E has received the entire DWR Loan with the final disbursement received in September 2024; applied for and executed an agreement with the DOE for the Civil Nuclear Credit (CNC) Program to repay the DWR loan; and submitted the license renewal application to the U.S. NRC seeking to renew the current operating licenses for DCPP Units 1 and 2 beyond 2024 and 2025, respectively.

In Rulemaking 23-01-007 implementing SB 846, the Commission considered specific inputs necessary to establish new retirement dates for DCPP and approved a cost recovery mechanism for extended operations. The Commission issued D.23-12-036 on December 15, 2023, conditionally approving new retirement dates of October 31, 2029, and 2030 for DCPP Units 1 and 2, respectively,[6] which also outlined the regulatory process PG&E will follow to submit forecast extended operations costs to recover those costs through statewide customer rates. This includes an annual planning process for PG&E's use of the VPFs.

Finally, in December 2024, the Commission approved a final decision (D.24-12-033) on PG&E's first DCPP extended operations cost recovery Application (A.) 24-03-018, approving, in part, PG&E's 2023-2025 record period net revenue requirement request, and implementing additional requirements for future cost recovery applications as provided in Table 1-4 below.

E. Avoided Resource Adequacy Costs

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

> RA benefits constitute a substantial financial value and are already attributed to DCPP operations. Those ratepayers that are paying for extended operations at DCPP should, as a matter of equity, realize the financial benefits of those extended operations, and those benefits should

[6] D.23-12-036, p. 135, Ordering Paragraph (OP) 1.

be distributed to each utility in the same manner of DCPP extended operations costs.[7]

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

PG&E calculated the estimated cost savings using a forecast of the monthly RA capacity amounts that are expected to be allocated to all benefiting LSEs through 2030. This forecast is consistent with the calculation of the RA substitution capacity cost forecast contained in Chapter 4. Specifically, these monthly RA capacity amounts were multiplied by a reference price benchmark. PG&E utilized the 2024 and 2025 Power Charge Indifference Adjustment system RA market price benchmarks as they are the most recent available reference prices published by the Commission.

Based on these calculations, the estimated cost savings of allocating DCPP's RA capacity attributes are:

7 D.23-12-036, pp. 81-82.

TABLE 1-2
RESOURCE ADEQUACY COST SAVINGS

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	$40.31	$735,254
3	2026	1,140	24	$40.31	$1,102,882
4	2027	1,140	24	$40.31	$1,102,882
5	2028	1,140	24	$40.31	$1,102,882
6	2029	1,140	22	$40.31	$1,010,975
7	2030	1,140	10	$40.31	$459,534

(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. DCPP Greenhouse Gas Attributes Allocation

D.23-12-036 directed PG&E to offer to LSEs that are paying for extended operations of DCPP the ability to use their share of DCPP's GHG-free energy attributes towards their respective power content label.[8] In compliance with this Decision, PG&E filed Advice 7295-E/E-A proposing modifications to its Commission-approved BPP – Appendix P to establish an allocation process for DCPP's GHG-free energy during extended operations.[9] Consistent with D.24-12-033, D.23-12-036, and the approved BPP modifications, PG&E allocated DCPP's 2025 GHG-free energy to opt-in LSEs in late 2024 and early 2025. The transactions reflecting the allocations will be submitted on an informational-only basis in PG&E's Quarter 4, Quarterly Compliance Report and will be submitted for Commission review in March 2026. Finally, PG&E will continue allocating DCPP's GHG-free energy on an annual basis consistent with its Commission-approved BPP.

G. DCPP Forecast Costs for the 2026 Record Period

Table 1-3, Total Net Revenue Requirement for Ratesetting, presents the 2026 Record Period cost components in greater detail. Table 1-3, line 2 includes costs to operate DCPP during this 2026 Record Period, including direct

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

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

costs for operations and maintenance (O&M), support costs including taxes, benefits and standard PG&E overheads, employee retention, and regulatory compliance items discussed in Chapter 2. Line 3 includes a forecast for RA substitution capacity expenses, which is discussed in Chapter 3. Lines 6-10 provide additional detail regarding statutory charges and fees included in the cost forecast, including the performance and management fees, authorized in SB 846. Total costs on line 11, are netted against generation market revenues (line 12), resulting in approximately $404.4 million, (line 16), excluding Franchise Fees and Uncollectable (FF&U) revenues. The Joint Utilities' FF&U revenues (line 18) are then added onto line 19 (and 20), resulting in a Net Revenue Requirement to be recovered in rates of approximately $410.0 million.

TABLE 1-3
DETAILED TOTAL NET REVENUE REQUIREMENT FOR RATESETTING

Line No.		Chapter Cross Reference	2026 Cost Allocation ($1000s) 44.9% Pacific Gas & Electric	45.3% Southern California Edison	9.8% San Diego Gas & Electric	2026 Total
1	Operational Revenue Requirement		(D)	(E)	(F)	(G)
2	Operation and Maintenance Cost Forecast	Chapters 2 & 4	326,084	328,989	71,172	726,245
3	Resource Adequacy Substitution Capacity	Chapter 3	72,216	72,859	15,762	160,837
4	**Subtotal Operational Revenue Requirement**		**398,300**	**401,848**	**86,934**	**887,082**
5	Management, Performance Fees, and Liquidated Damages					
6	Management Fee	Chapters 4 & 5	51,134	51,589	11,161	113,884
7	Liquidated Damages	Chapters 4 & 5	33,675	33,975	7,350	75,000
8	Volumetric Performance Fee	Chapters 4 & 5	59,128	59,655	12,906	131,689
9	***PG&E Specific*** **Volumetric Performance Fee**	Chapters 4 & 5	131,689			131,689
10	**Subtotal Statutory Fees**		**275,626**	**145,219**	**31,416**	**452,262**
11	**Total Cost Forecast (Line 4 + Line 10)**		**673,926**	**547,068**	**118,350**	**1,339,344**
12	Offsetting Market Revenues					
13	CAISO Market Revenues	Chapter 6	(419,781)	(423,521)	(91,623)	(934,925)
14	Balancing Account Amortization					
15	DCEOBA	Chapter 8	0	0	0	0
16	Subtotal Net Cost (Line 13 + Line 15 + Line 17)		254,145	123,547	26,728	404,419
17	Uncollectibles, Franchise Fees, and SF Revenue Fee Factor[c]	Chapter 10	1.2520%	1.1061%	3.8314%	
18	RF&U (Col. A = Col. D + Col. E + Col. F - Col. B) (Col. B = Col. A, Line 3 x Col. D, Line 23)	Chapter 10	3,182	1,367	1,024	5,572.486
19	**DCEO Revenue Requirement for Ratesetting (Line 16 + Line 18) for PG&E and SCE (Line 16) for SDG&E**		**257,327**	**124,913**	**26,728**	**408,968**
20	**Distribution Revenue (SDG&E FF&U)**				**1,024**	**1,024**
21	**Volumetric Performance Fee (VPF) as a Percent of Net Costs[d]**		**75.08%**	**48.29%**	**48.29%**	

Notes:
(a) Amounts in 2026 dollars ($s)
(b) D.23-12-036, OP8 and OP11
(c) SDG&E's revenues for its DCNBC will be collected in the Distribution Charge.
(d) VPF Revenue allocation for Revenue Reporting

H. Funding Mechanisms for DCPP Extended Operations

Historically, PG&E has presented its nuclear operations costs in the General Rate Case (GRC) application, with the 2023 GRC A.21-06-021 being the last and final PG&E request to include these costs under the current operating licenses. The 2023 GRC included DCPP costs for O&M expense, capital, and related-balancing accounts through August 26, 2025 (i.e., Unit 2 license expiration).[10]

Relevant to this proceeding, D.23-12-036 directs PG&E to:

> [Q]uantify the impact of DCPP's extended operations on its common costs relative to the amount approved in its 2023 GRC, and demonstrate it will not double count the common costs it proposes for recovery in its GRC and DCPP Extended Operations Cost Forecast applications.[11]

PG&E provides its showing of costs that are presented for recovery in customer rates and incremental to PG&E's GRC further below and in Chapter 2.

Separately, historically PG&E has presented its nuclear fuel procurement (forecast and recorded) in its Energy Resource Recovery Account (ERRA) proceedings. Nuclear fuel procurement costs are presented in Chapter 2. The reimbursement of spent fuel storage costs from the DOE is also addressed in Chapter 2.

Since costs for DCPP will no longer be included in GRC or ERRA applications, PG&E will seek to recover costs through the funding mechanisms described below.

1. Government Funding Through the DWR and the U.S. DOE

There are two forms of government funding identified in SB 846 to support extended operations at DCPP: a $1.4 billion loan through DWR and funds awarded through the DOE CNC Program.

PG&E signed the "Loan Agreement for Diablo Canyon Nuclear Power Plant" with DWR on October 18, 2022, with the purpose of supporting DCPP extended operations and maintaining electrical reliability during the period of extended operations. Funds provided under this loan agreement are to cover incremental and transition costs and will not be used in cases where

10 On November 17, 2023, the Commission approved the 2023 GRC application in D.23-11-069.

11 D.23-12-036, p. 103.

expenses: (1) are authorized by the CPUC or other regulatory body for rate recovery, (2) will be included in a future proceeding for rate recovery from CPUC or other regulatory body, and (3) have been previously disbursed under the Reliability Reserve Reimbursement Agreement between PG&E and DWR.[12] PG&E has received the full $1.4 DWR Loan, with the final DWR Loan disbursement received in September 2024.

The DOE CNC Program is part of the 2021 Infrastructure Investment and Jobs Act to make federal funds available for a reactor that is scheduled to cease operations by September 30, 2026, due to economic factors. PG&E filed its application seeking up to $1.1 billion in credits through the CNC Program on September 2, 2022; and on November 21, 2022, the DOE issued the conditional award decision and certified PG&E to participate in the CNC Program. Final award of credits was contingent upon execution of the Credit Award and Payment Agreement (CAPA), which outlines the agreement terms and reporting structure for award of credits up to $1.1 billion to support extended operations at DCPP. PG&E and the DOE executed the CAPA on January 11, 2024. The funds provided by the DOE through the CNC Program will be used to repay the $1.4 billion loan from DWR with the first credits to be received in 2025 then annually thereafter. DOE CNC credits will cover costs to transition DCPP to extended operations for the period of January 1, 2023, through December 31, 2026, and do not cover the period of extended operations after expiration of the existing NRC licenses. These funding sources and the recorded spend are tracked to the Diablo Canyon Transition and Relicensing Memorandum Account (DCTRMA).

2. Customer Rates Through the Diablo Canyon Extended Operations Balancing 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

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[12] Agreement executed in August 2022 between PG&E and DWR under the Strategic Reliability Reserve Program, pursuant to Assembly Bill 180, where DWR will reimburse PG&E up to $75 million to preserve the option of continued operation of DCPP pending further legislation (i.e., passage of SB 846 and execution of the $1.4 billion Loan Agreement with DWR).

extended operations at DCPP and to track and record all costs associated with continued operations. Pursuant to D.22-12-005, PG&E established the Diablo Canyon Extended Operations Balancing Account (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 DCPP Units 1 and 2 beyond the current license expiration dates of November 2, 2024, and August 26, 2025, respectively, that are not eligible for government funding pursuant to SB 846, AB 180, or the DOE CNC Program.[14] The DCEOBA is comprised of three types of subaccounts: (1) the Extended Operations Subaccount, (2) the Liquidated Damages Subaccount, and (3) the Volumetric Performance Fee Subaccount. Additional information on the DCEOBA is provided in Chapter 8.

I. NBC Proposal

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

J. Fall Update

Consistent with the IOUs' respective ERRA Forecast proceeding schedules over many years and as approved in D.23-12-036, PG&E proposes to update its generation revenue forecast after Energy Division staff releases its Energy Index of the Market Pricing Benchmark (MPB) on October 1, 2025. The Fall Update will incorporate the new Energy Index to reflect market conditions closer to the time when 2026 rates go into effect, as well as other potential cost updates. PG&E also proposes to update certain forecasts in this application and testimony using the Energy Index and applicable RA MPBs. PG&E also will

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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).

14 See Chapter 2 Section D for the DCEOBA and DCTRMA accounting principles.

present the amortization of the for 2025 balancing account balances into rates as of January 1, 2026. The over or undercollection of 2025 rates will be included in the December 2025 AET for ratesetting purposes. Finally, PG&E proposes to update its 2026 Record Period revenue requirement to reflect $12.5 million DOE settlement claims proceeds for DCPP spent fuel management activities funded through the DCEOBA.

K. 2026 Planned Expenditures of VPFs

PG&E also requests the Commission review and approve PG&E's planned expenditure of 2026 VPFs. The Commission directed PG&E to present in an application its plan for use of the $13/megawatt-hour (MWh) VPFs collected in 2026 and demonstrate that those plans are consistent with the critical public purpose priorities in Section 712.8(s)(1) prior to expenditure of those funds.[15] PG&E presents its planned use of VPFs collected in 2026 and demonstrates how these uses are consistent with the critical public purpose priorities identified in Section 712.8(s)(1). Chapter 7 testimony is consistent with D.23-12-036, which directs PG&E to file an application setting forth planned use of the VPF revenues prior to making any expenditures.

L. Testimony Overview

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

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

Chapter 2 contains PG&E's 2026 Record Period forecast of O&M costs. In this chapter, PG&E presents costs by Major Work Category, consistent with

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[15] D.23-12-036, p. 112.

PG&E's historical GRC Testimony for Nuclear Operating Costs, which will describe categories of forecast costs.

Chapter 2 also includes proposed expense projects, similar to what would have been capital project forecasts historically addressed in PG&E's GRC. Execution of these projects is necessary to ensure safe and reliable extended operations to meet the needs of all Californians.

Chapter 2 also presents PG&E's proposal for straight-line amortization for cost recovery of nuclear fuel over the period of 2025 through 2030 which is consistent with Pub. Util. Code Section 712.8(h)(2), which provides that for any significant one-time expense project expenditures during the extended operations period, PG&E may propose an amortization period for such expenditures over a period of greater than one year for the purpose of reducing rate volatility, at an amortization rate determined by the Commission. PG&E proposes the Commission approve the same methodology that was adopted in D.24-12-033 for the 2025 DCPP extended operations forecast proceeding.

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

Chapter 4 contains cost inputs discussed in Chapter 2 that are incremental to the authorized 2023 GRC revenues, as well as costs from Chapter 3, and Chapter 5 in order to calculate the forecast revenue requirement request for DCPP Units 1 and 2 for the 2026 Record Period, and that are not eligible for government funding pursuant to SB 846, AB 180, or the DOE CNC Program. Chapter 4 also explains PG&E's assumptions used in the revenue requirement model. Pub. Util. Code Section 712.8(h)(1) requires that all extended operations costs shall be recovered as an operating expense and shall not be eligible for inclusion in PG&E's rate base.

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

Chapter 5 presents statutory fees, including the statewide VPF pursuant to Section 712.8(f)(5), PG&E service territory's VPF pursuant to Section 712.8(f)(5), the fixed management fee for PG&E's operation of DCPP in lieu of a rate-base return pursuant to Section 712.8(f)(6)(A), and liquidated damages subaccount funding pursuant to Section 712.8(g).

Chapter 6 presents a forecast of the CAISO market revenues for the period of January 1, 2026, to December 31, 2026, in a manner similar to PG&E's ERRA Forecast proceeding, which is based on a weighted average of on- and off-peak forward prices for the Test Year (TY). PG&E anticipates that in its Fall Update, its generation revenue forecast will be based upon the Energy Index on- and off-peak prices provided by the Commission's Energy Division on October 1 of each year pursuant to D.22-01-023.

In Chapter 7, PG&E presents its planned usage and programs for spending the 2026 VPFs pursuant to statutorily mandated public purpose priorities.[16] In addition, PG&E also presents its plan for post-spend compliance review in its annual compensation report, how PG&E will track the VPF project expenditures to ensure they are incremental, and actions PG&E will take to ensure compliance with the prohibitions in Section 712.8(s)(1) and (s)(2).

Chapter 8 addresses the subaccount contents of the DCEOBA, which is consistent with Advice Letter 7509-E, which has an effective date of February 18, 2025, and modifications submitted and still pending further disposition, including: Advice 7204-E submitted on March 14, 2024 in compliance with D.23-12-036 directives, as further amended by Advice 7204-E-A submitted on

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16 Pub. Util. Code § 712.8(s)(1).

February 12, 2025;[17] and Advice 7531-E submitted on March 10, 2025 in compliance with D.25-01-043.[18]

Chapter 9 presents the net revenue requirement for consideration in this proceeding, which nets the forecast market revenues with total DCPP Results of Operations costs presented in Chapter 4 over the record period.

Chapter 10 is co-sponsored by PG&E, SCE, and SDG&E and presents the ratemaking mechanism for the statewide NBC applicable to all Commission-jurisdictional customers through the PPP rates of the Commission-jurisdictional IOUs. PG&E, SCE, and SDG&E jointly present testimony to allocate the net revenue requirement for the record period amongst themselves using the California Energy Commission's (CEC) published 2025 peak load forecast that is developed for use in the Commission's RA program. Each utility sponsors its own testimony on allocating its share of the revenue requirement among its customer classes using a process that mirrors the existing Cost Allocation Methodology for system reliability resources.

Chapter 10 also presents the allocation of the DCPP Extended Operations revenue requirement to PG&E, SCE, and SDG&E and illustrative DCNBC rates applicable to customers in each utility's service area based on the methodology adopted by D.23-12-036. The rates presented in Chapter 10 are illustrative and subject to updates in the Fall Update and in each utility's January 1, 2026, consolidated rate change process.

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

M. Compliance With Prior Decisions

Table 1-4 presents the specific requirements from D.23-12-036 and D.24-12-033 that are applicable to this application and PG&E's compliance with

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17 See PG&E Advice 7204-E; hyperlink at: https://www.pge.com/tariffs/assets/pdf/adviceletter/ELEC_7204-E.pdf (pending CPUC approval); see also, PG&E Advice 7204-E-A; hyperlink at: https://www.pge.com/tariffs/assets/pdf/adviceletter/ELEC_7204-E-A.pdf (pending CPUC approval).

18 See PG&E Advice 7509-E; hyperlink at: https://www.pge.com/tariffs/assets/pdf/adviceletter/ELEC_7531-E.pdf (effective pending final CPUC approval); see PG&E Advice 7531-E; hyperlink at: https://www.pge.com/tariffs/assets/pdf/adviceletter/ELEC_7531-E.pdf (effective pending final CPUC approval).

each requirement. D.23-12-036 and D.24-12-033 compliance items completed prior to this application or to be addressed outside of this application are not included in Table 1-4.

TABLE 1-4
COMPLIANCE WITH PRIOR DECISIONS

<table>
<tr><th>Line No.</th><th>Action Required</th><th>Decision Reference</th><th>Compliance Action</th></tr>
<tr><td colspan="4">D.23-12-036</td></tr>
<tr><td>1</td><td>PG&E’s proposed ERRA-like process to authorize forecast DCPP extended operations costs, with a subsequent true-up to actual costs and market revenues for the prior calendar year via an expedited Tier 3 advice letter process, is approved as modified by this decision. PG&E shall file the first of these DCPP Extended Operations Cost Forecast applications no later than March 29, 2024, and shall file subsequent annual DCPP Extended Operations Cost Forecast applications no later than March 31 beginning in 2025, and ending the year before extended operations are complete.</td><td>OP 4</td><td>See PG&E Application, filed on March 28, 2025</td></tr>
<tr><td>2</td><td>As part of its annual DCPP Extended Operations Cost Forecast Applications, PG&E should:
a) Provide 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;
b) Quantify the impact of DCPP’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 DCPP Extended Operations Cost Forecast applications.</td><td>COL 54</td><td>Item 2.a
Expense O&M and Projects Costs – See Chapter 2
Revenues – See Chapter 4
Item 2.b – See Chapter 1 Section N
Item 2.c – See Chapter 1 Section N</td></tr>
<tr><td>3</td><td>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 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.</td><td>OP 7</td><td>See Chapter 10</td></tr>
<tr><td>4</td><td>The Diablo Canyon Extended Operations Cost Forecast proceeding should:
a) Determine the allocation of costs and benefits of DCPP 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 DCPP’s RA benefits for the upcoming compliance year sufficiently in advance of the October 31 year-ahead RA compliance filing deadline.</td><td>COL 55</td><td>See Chapter 10</td></tr>
</table>

TABLE 1-4
COMPLIANCE WITH PRIOR DECISIONS
(CONTINUED)

Line No.	Action Required	Decision Reference	Compliance Action
D.23-12-036			
5	PG&E is directed to file an annual application, as described in this decision, no later than March 1, 2026, until the retirement of Diablo Canyon Nuclear Power Plant 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
D.24-12-033			
6	PG&E must provide the following information in the next DCPP cost forecast proceeding: a) Detailed project summaries for all projects over $1 million, instead of all projects over $3 million; b) Total cost of DCPP 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 1, Section N
7	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." 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 requested." Therefore, in its next application, PG&E must provide this information as directed by the Commission in D.22-12-005.	pp. 18-19	See Chapter 2

In addition, the Commission concluded that:

> [T]he intent of the Legislature was to assign broad responsibility for the costs of extended operations of DCPP to ratepayers of all LSEs subject to the Commission's jurisdiction, as outlined in Section 712.8(l)(1), [but certain costs are to only be paid by PG&E ratepayers].[19]

Pages 67-69 of D.23-12-036 lists the costs to be recovered by customers, 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 license renewal applications 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).

19 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
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).
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 DCPP 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).

(a) The Liquidated Damages Subaccount is a subaccount of the DCEOBA.

N. No Double Recovery of Common Costs From GRC

Among other items, COL 54 requires that PG&E:

> [(1) Q]uantify the impact of DCPP's extended operations on its common costs relative to the amount approved in its 2023 GRC[, (2)] demonstrate it

will not double count the common costs it proposes for recovery in its GRC and [this application].[20]

For cost-of-service ratemaking purposes, A&G and Common General and Intangible Plant (CGI) common costs are allocated to PG&E's functional areas through the GRC. A&G and CGI Plant common cost recovery for the years 2023 through 2026 were resolved in PG&E's 2023 GRC D.23-11-069. As such, PG&E does not propose recovery of A&G or CGI costs for the years 2023 through 2026 in this application. The 2027-2030 DCPP A&G cost allocation forecast is presented in Table 1-6. This forecast reflects the current DCPP A&G allocation that will be presented in PG&E's 2027 GRC, which will be filed with the CPUC on May 15, 2025.

TABLE 1-6
ADMINISTRATIVE & GENERAL EXPENSE ESTIMATE AND ALLOCATION TO DCPP EXTENDED OPERATIONS
(MILLIONS OF DOLLARS)

Line No.		2025 Adopted (D.23-11-069)	2026 Adopted (D.23-11-069)	2027 Estimate	2028 Estimate	2029 Estimate	2030 Estimate
1	A&G Expenses Allocated to DCPP	–	–	$154.8	$160.1	$151.8	$71.4

D.24-12-033 directed PG&E to present A&G costs for 2025 and 2026 in this application. As described above, DCPP's A&G allocation was authorized in the 2023 GRC D.23-11-069. While the DCPP allocation amounts before the period of extended operations were already set by the Commission at $113 million for 2025 and $0 for 2026, PG&E understands the Commission's directive in D.24-12-033 to require PG&E to present illustrative A&G allocation values for 2025 and 2026 DCPP extended operations. With this understanding, the illustrative A&G allocation values associated with DCPP extended operations is $81.288 million for 2025 and $122.911 million for 2026. These illustrative A&G allocation values reflect the A&G allocation methodology that will be presented in PG&E's 2027 GRC, which will be filed with the CPUC on May 15, 2025.

Regarding CGI, PG&E does not propose to recover CGI costs in this application because CGI cost recovery for 2026 was determined in PG&E's

[20] D.23-12-036, pp. 132-133, COL 54.

2023 GRC final decision and because CGI is a capital rate base item and SB846 prohibits rate base treatment for DCPP extended operations costs.[21]

O. Conclusion

As described above and in subsequent chapters, PG&E requests that the Commission approve the following:

- DCPP revenue requirement from the Record Period of $410 million to be effective in rates on January 1, 2026, including the following forecasts and their underlying financial assumptions and calculations, subject to updates in the Fall Update:
  - Operations and maintenance costs (including expenses, project costs, and statutory costs and fees, as well as associated escalation);
  - Charges for the liquidated damages account pursuant to Section 712.8(g);
  - Resource Adequacy substitution capacity costs, including any updates from the results of R.25-02-005, or unless otherwise directed by the Commission;
  - Operating expenses that would be amortized through 2030 (i.e., nuclear fuel procurement), and
  - Netting of CAISO revenues for the period from January 1, 2026, to December 31, 2026.
- The statewide Diablo Canyon Non-Bypassable Charge;
- Modification of the DOELBA preliminary statement to create a sub-account for spent nuclear claim proceeds attributable to the DCEOBA, to be implemented in a Tier 1 advice letter within 60 days following the issuance of the decision;
- PG&E’s 2026 VPF plan and proposed spending priorities for the expenditures; and
- Find that PG&E's testimony satisfies all the regulatory requirements from D.23-12-036 and D.24-12-033.

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21 Pub. Util. Code § 712.8(h)(1).

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 2

2026 FORECAST OPERATIONS AND MAINTENANCE COSTS TO BE RECOVERED IN RATES

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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 2
2026 FORECAST OPERATIONS AND MAINTENANCE COSTS TO BE RECOVERED IN RATES

A. Introduction

1. Scope and Purpose

This chapter requests approval of Pacific Gas and Electric Company's (PG&E) Diablo Canyon Power Plant (Diablo Canyon or DCPP) Extended Operations' operations and maintenance (O&M) expense including base O&M expense, projects expense, nuclear fuel expense, and retention expense, as well as U.S. Department of Energy (DOE) settlement claims proceeds associated with DCPP spent fuel management for the period January 1, 2026 through December 31, 2026 ("record period") for the safe and reliable operation of DCPP to be recovered in customer rates. The chapter also proposes an update to the allocation of DOE settlement claims proceeds for the record period across the Nuclear Decommissioning Adjustment Mechanism (NDAM) for the Humboldt Bay Independent Spent Fuel Storage Installation (ISFSI), the Portfolio Allocation Balancing Account (PABA) for 2023 General Rate Case (GRC) funded DCPP spent fuel management costs and Diablo Canyon Extended Operations Balancing Account (DCEOBA) funded DCPP spent fuel management costs.

As described in Chapter 1, the California Public Utilities Commission (CPUC or Commission) has conditionally authorized extended operations at Diablo Canyon until the following retirement dates: (i) for Unit 1, October 31, 2029; (ii) for Unit 2, October 31, 2030.[1]

The forecasts presented in this chapter employ PG&E's GRC cost structure whereby costs are presented in the Major Work Category (MWC) view. Decision (D.) 23-12-036 also instructed that actual (or forecastable) costs associated with U.S. Nuclear Regulatory Commission (NRC) license renewal conditions and any Diablo Canyon Independent Safety Committee (DCISC) recommendations for seismic safety upgrades or related to

[1] D.23-12-036, p. 135, Ordering Paragraph 1.

deferred maintenance be included. There are no actual or known forecastable costs for NRC license renewal conditions or any DCISC recommendations during the record period.

Costs provided in this chapter are incremental costs to those authorized in PG&E's 2023 GRC D.23-11-023 and those funded by the California Department of Water Resources (DWR) loan and the DOE Credit Award and Payment Agreement of implementing DCPP extended operations. Costs presented in this chapter reflect what was known as of January 2025.

2. Summary of Request

a. Expense

PG&E requests the Commission adopt its total extended operations expense forecast, excluding nuclear fuel procurement, of $564 million for the period January 1, 2026 through December 31, 2026.[2] An overview of expense forecast components is shown below in Table 2-1.

TABLE 2-1
O&M EXPENSE
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Cost Type	2026 Forecast
1	O&M Expense	$449,286
2	Project Expense	60,496
3	Fuel Administration	1,092
4	Retention Program Expense	53,061
5	Total O&M Expense (Excludes Nuclear Fuel Procurement)	$563,934

b. O&M Expense

The O&M expense forecast reflects the incremental costs in excess of the DWR loan expenses for the period January 1, 2026 through December 31, 2026.

c. Projects Expense

The projects expense forecast reflects projects that historically would have been classified as either capital or expense depending on

[2] See Workpapers (WP) Supporting Chapter 2, p. 2-1 through 2-4.

the project scope. Discrete scopes of work have been identified with planned implementation schedules and cost estimates for each project.

d. Employee Retention Expense

The retention expense forecast reflects the proposed DCPP retention program needed to retain the plant personnel necessary for safe and reliable operation through the extended operations period. The program headcount and forecast amounts for 2026 have been updated to reflect adjusted headcount forecasts.[3]

B. DCPP Operations Overview

1. DCPP Background

Diablo Canyon is a 2,240 megawatt facility located 7.5 miles North of Avila Beach in San Luis Obispo (SLO) County, California. The site consists of approximately 12,000 acres of PG&E-owned land and the assets related to two nuclear units, including a power block and related facilities. See Figure 2-1 below.

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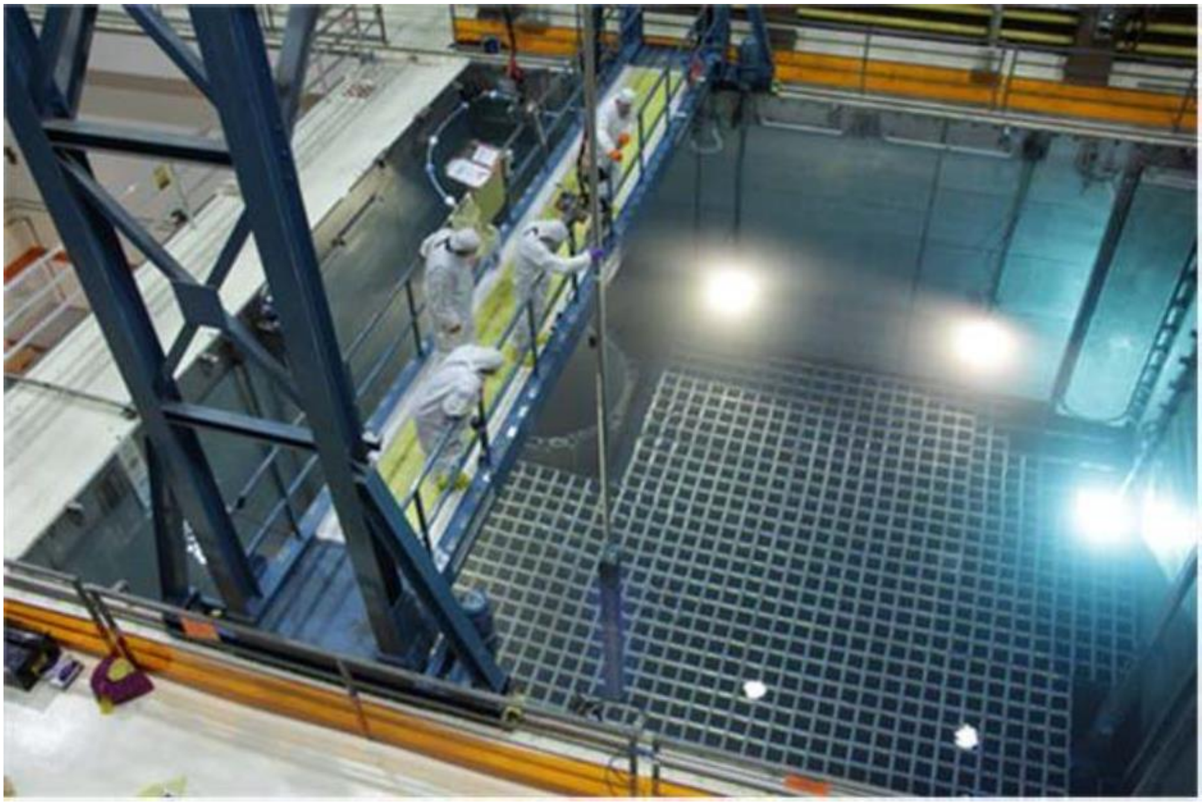
3 WP 2-10.

FIGURE 2-1
DIABLO CANYON POWER PLANT

The DCPP power block includes two nuclear units, each consisting of a Westinghouse four loop, pressurized water reactor coupled with a steam electric turbine generator, feed water systems and cooling water systems. In addition to the unit specific facilities, the common facilities include: a nuclear fuel handling building, a radioactive waste storage building, an auxiliary building containing emergency safety systems, and various support systems. See Figure 2-2 for a picture showing nuclear fuel offload at the spent nuclear fuel pool in the nuclear fuel handling building.

FIGURE 2-2
NUCLEAR FUEL OFFLOAD AT THE SPENT NUCLEAR FUEL POOL IN THE NUCLEAR FUEL HANDLING BUILDING



In addition to the power block described above, Diablo Canyon facilities include: an administrative building, a training building, maintenance shop buildings, ISFSI, Removed Steam Generator and Removed Reactor Vessel Head Storage Facility, and a warehouse. The warehouse holds consumables, spare parts, and complete spare replacements for key components, such as: a reactor coolant pump motor, main turbine rotors, and various safety system pumps. The site has multiple communications systems, a vehicle fleet, office equipment, and a high voltage switchyard.[4] See Figure 2-3 for a picture showing the 500 kilovolt (kV) switchyard.

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4 The 500 kV switchyard, into which the two electrical generators feed, is physically located on the Diablo Canyon site; however, the associated costs for this facility are included in electric transmission, which is not forecasted in this chapter.

FIGURE 2-3
500 KV SWITCHYARD

PG&E's primary responsibility as the owner and operator of DCPP is to generate power safely and reliably through cost efficient management of plant and related assets. PG&E's safety responsibility extends to the general public, as well as to its employees. Plant safety is essential to the successful operation of a nuclear power station.

An important element of maintaining high safety standards while continuously improving operations and managing costs is employee culture. DCPP employees maintain a questioning attitude when developing, reviewing, or making changes to plant Structures, Systems, and Components (SSC), programs and procedures. In addition to expecting employees to affirmatively participate in the process of developing, reviewing, implementing, and making changes to plant procedures and processes, all employees are expected to continuously assess and improve their performance. Employees critique their performance, compare their work to relevant industry best practices, participate in industry groups and conferences, share operational information with others, and implement changes when appropriate. Additionally, when necessary, employees solicit vendor expertise to help assure unexpected conditions are investigated, and important technical questions are answered.

In addition to employee culture, performance improvement is continuously emphasized and evaluated by leadership through the Performance Improvement Department. Performance improvement elements include problem identification and resolution via the Corrective Action Program (CAP), station improvement via operating experience, human performance, self-assessment, benchmarking, and the Employee Concerns Program.

2. Management Structure

PG&E's Nuclear Generation organization, led by the Senior Vice President (SVP) and Chief Nuclear Officer (CNO), is responsible for the overall safe and reliable operation of DCPP. The DCPP Site Vice President (VP), VP of Business and Technical Services, Director of Nuclear Quality Verification (QV), Director of Strategy and Policy, and Manager of Employee Concerns report directly to the SVP.

The Site VP is responsible for the overall safe operation of the station. The Station Senior Director, Director of Nuclear Training and Accreditation, Senior Director of Engineering, Projects, and Outages, and Director of Security report to the Site VP.

The Station Senior Director is responsible for O&M. The Directors of the Operations Services, Maintenance Services, and Nuclear Industry Relations report to the Station Director.

The Senior Director of Engineering, Projects and Outages reports to the Site VP and is responsible for providing Engineering services, Project management service, and Outage planning and execution services. The Director of each of these groups reports to the Senior Director.

The VP of Business and Technical Services reports to the CNO and is responsible for DCPP financial planning and management, Performance Improvement and Innovation, Risk and Compliance Management, Strategic Initiatives, License Renewal, Nuclear Fuel Procurement and Spent Fuel Management and Decommissioning/Trust Fund, and Regulatory

Proceedings. The Director of each of these groups reports to the VP of Business and Technical Services.

The Director, QV reports to the CNO and is responsible for management of the Quality Assurance (QA) Program and for assuring that the QA Program is implemented and complied with by all involved organizations, both internal and external to PG&E. The Director, QV is responsible for independent review and oversight of operations, corrective action, plant support, engineering, procurement, and maintenance activities performed by or for DCPP.

The Manager of Employee Concerns is responsible for managing DCPP's Employee Concerns Program which is a resource available to all nuclear generation employees that provides an independent and alternative method for reporting concerns related to nuclear safety, nuclear quality, and safety conscious work environment. The Manager of Employee Concerns reports to the SVP and CNO.

C. Key Metrics and Other Performance Measures

PG&E provides an explanation of its own key metrics and performance measures that it uses to ensure safe and reliable operations at DCPP.

1. Safety

a. Reactor Oversight Process

The safe operation of Diablo Canyon is PG&E's number one priority for the facility. Assigned NRC resident inspectors are located physically at DCPP and provide daily inspection activities of all nuclear activities. The NRC's Reactor Oversight Process (ROP) is the process through which the NRC measures nuclear safety, regulatory compliance, and recognition for compliance with safety requirements. The NRC initiated this process in April 2000 to: (1) evaluate the overall safety performance of the operating commercial nuclear reactors based on objective performance data and NRC inspections; and (2) communicate those results to plant management, the public and other government agencies. The process includes one strategic performance area, Reactor Safety, consisting of seven cornerstones. These seven cornerstones consist of one or more performance indicators as shown in

Table 2-2. In addition, the NRC conducts periodic inspections of the seven cornerstones. DCPP Units 1 and 2 have generally performed well in each of these seven areas.

Table 2-2 below shows PG&E's level of performance in the ROP Strategic Performance Area. Green, "Licensee Response Band," is the highest level of performance and indicates licensee performance is acceptable, and the cornerstone objectives are being met. PG&E reports Diablo Canyon Unit 1 and 2 performances for each of the 17 performance indicators to the NRC on a quarterly basis. DCPP Units 1 and 2 have a rating of "green" for each of the ROP Performance Indicators.

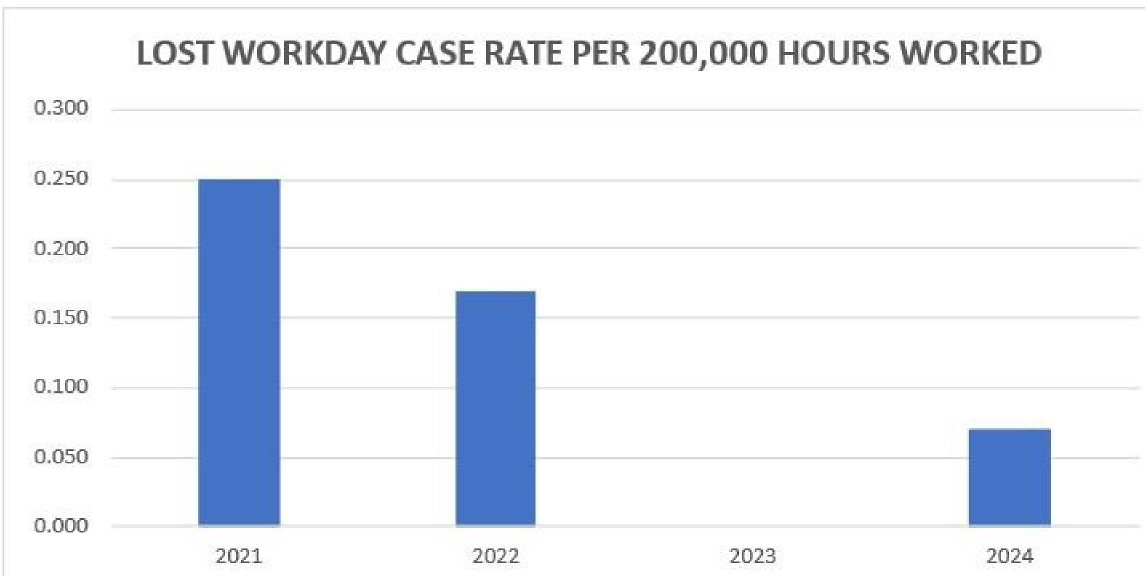
TABLE 2-2
NRC ROP – REACTOR SAFETY
(AS OF FOURTH QUARTER 2024)

Line No.	Seven Cornerstones	Performance Indicators	Current PG&E Performance
1	Initiating Events	Unplanned Reactor Trips	Green
2		Unplanned Power Changes	Green
3		Unplanned Reactor Trips with Complications	Green
4	Mitigating Systems	Safety System Functional Failures	Green
5		Emergency Alternating Current Power System	Green
6		High Pressure Injection System	Green
7		Heat Removal System	Green
8		Residual Heat Removal System	Green
9		Cooling Water System	Green
10	Barrier Integrity	Reactor Coolant System Activity	Green
11		Reactor Coolant System Leakage	Green
12	Emergency Preparedness	Drill/Exercise Performance	Green
13		Emergency Response Organization Drill Participation	Green
14		Alert and Notification System	Green
15	Occupational Radiation Safety	Occupational Exposure Control Effectiveness	Green
16	Public Radiation Safety	Radiation Effluent Technical Specifications/Offsite Dose Calculation Manual Radiological Effluents	Green
17	Security	Protected Area Equipment	Green

b. Personnel Safety

In addition to public safety, PG&E is also strongly focused on the safety of the PG&E employees and contractors working at Diablo Canyon. PG&E measures personnel safety at DCPP by the Occupational Safety and Health Administration (OSHA) lost workday rate. As shown in Figure 2-4 below, DCPP personal safety performance was 0.070 in the most recent recorded year, 2024.

FIGURE 2-4
DCPP
OSHA LOST WORKDAY CASE RATE

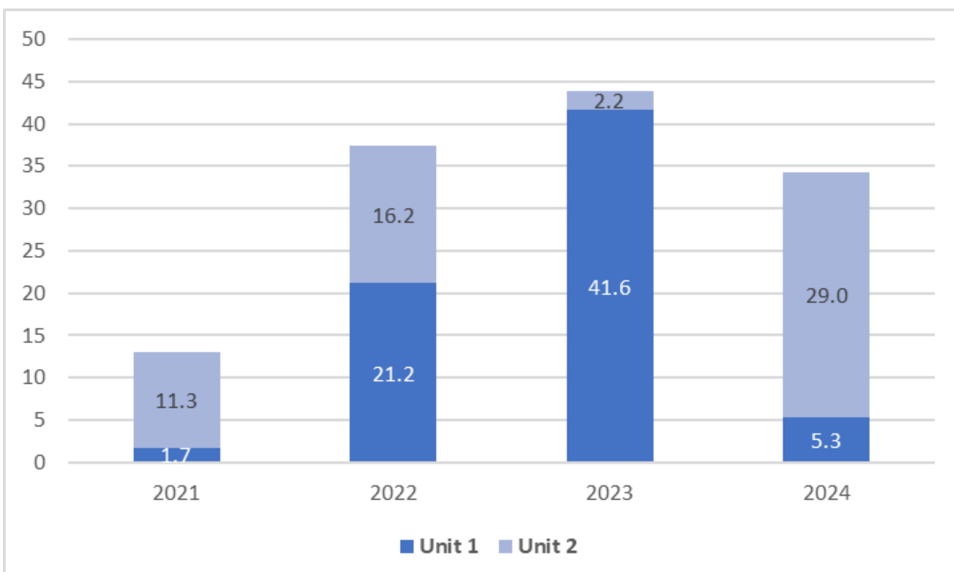


c. Radiation Protection

PG&E measures collective radiation exposure at DCPP by Person-REM (Roentgen Equivalent Man), a unit of absorbed doses of radiation, or the collective radiation exposure when summed across all site personnel. Figure 2-5 below shows DCPP's consistent performance for 2021-2024. The Unit 1 measurement for 2022 is greater than the 2021 measurement because of the nuclear refueling outage that occurred in Spring 2022, known as outage 1R23. There was no nuclear refueling outage for Unit 1 in 2021. The Unit 1 measurement for 2023 is greater than the 2021 and 2022 measurements due to the Unit 1 refueling outage that occurred in Fall 2023, known as outage 1R24. The

Unit 2 measurement for 2024 is greater than the 2021 and 2022 measurements due to the Unit 2 refueling outage that occurred in Spring 2024, known as outage 2R24. Work performed during 1R24 and 2R24 were greater in scope as compared to the 1R23 outage in 2022 as the 1R24 and 2R24 outages included additional inspections to extend the life of DCPP Units 1 and 2 to October 2029, and 2030, respectively, as required under the NRC's License Renewal Application (LRA) process. As a general matter, when comparing a Units' measurement between an outage year and a non-outage year, the measurement in an outage year is greater than a non-outage year due to hundreds of PG&E and contract employees performing work in the radiologically controlled area of the unit, which, outside of an outage, has very limited access.

FIGURE 2-5
DIABLO CANYON POWER PLANT
COLLECTIVE RADIATION EXPOSURE



d. Physical Security

DCPP is intensely dedicated to fulfilling the federal requirements of all nuclear power facilities by maintaining a security program committed to preventing radiological sabotage and the theft of special nuclear material. The Security Program and DCPP facility and its security features are periodically inspected by the NRC to assure compliance.

2. Reliability

PG&E strives to achieve maximum output from DCPP consistent with the safety priorities described above. DCPP is a significant supplier of electricity to PG&E's customers and tracks various reliability-based metrics including capacity factor and net generation. The net capacity factor of a power plant is the ratio of the actual output of a power plant over a period of time and its potential output if it had operated at full maximum dependable capacity the entire time. Figures 2-6 and 2-7 below provide the capacity factors for DCPP Units 1 and 2 between 2022 and 2024. In 2024 PG&E increased the capacity factor by 6.1 percentage points over 2023.

Net generation is the amount of electricity generated by a power plant that is transmitted and distributed for consumer use. Net generation is less than the total gross power generation as some power produced is consumed within the plant itself to power auxiliary equipment such as pumps and motors. Figure 2-8 shows DCPP net generation. In 2024 PG&E Increased net generation by 634 GWH over 2023.

FIGURE 2-6
CAPACITY FACTOR (PERCENT) – UNIT 1

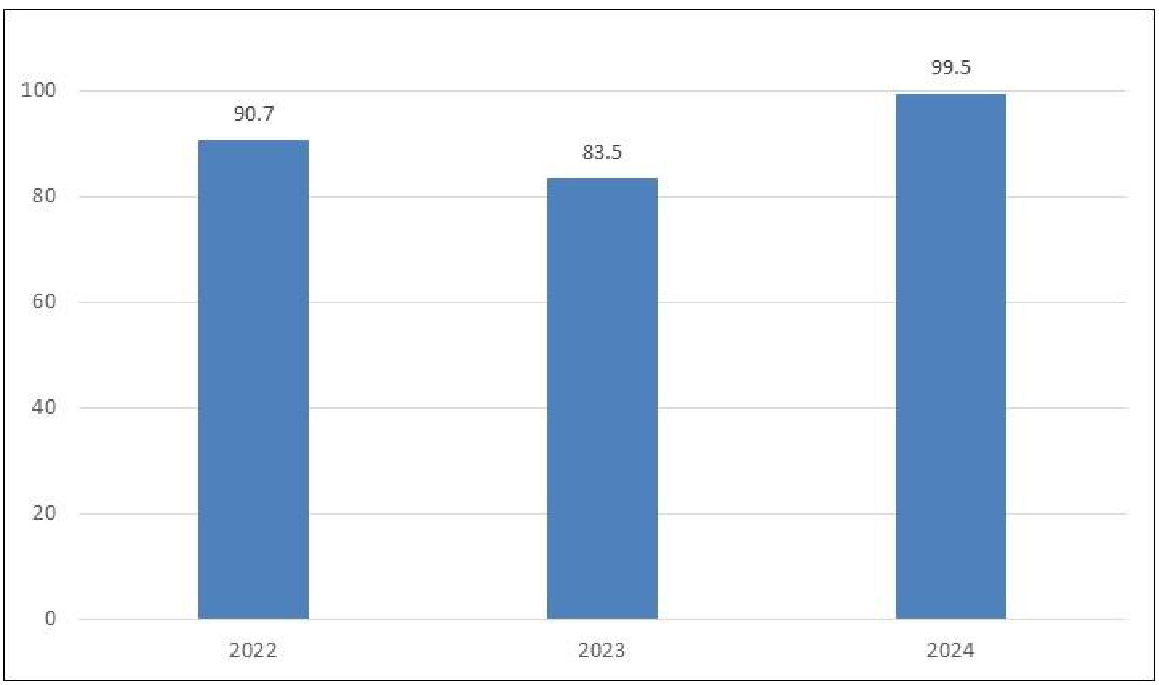


FIGURE 2-7
CAPACITY FACTOR (PERCENT) – UNIT 2

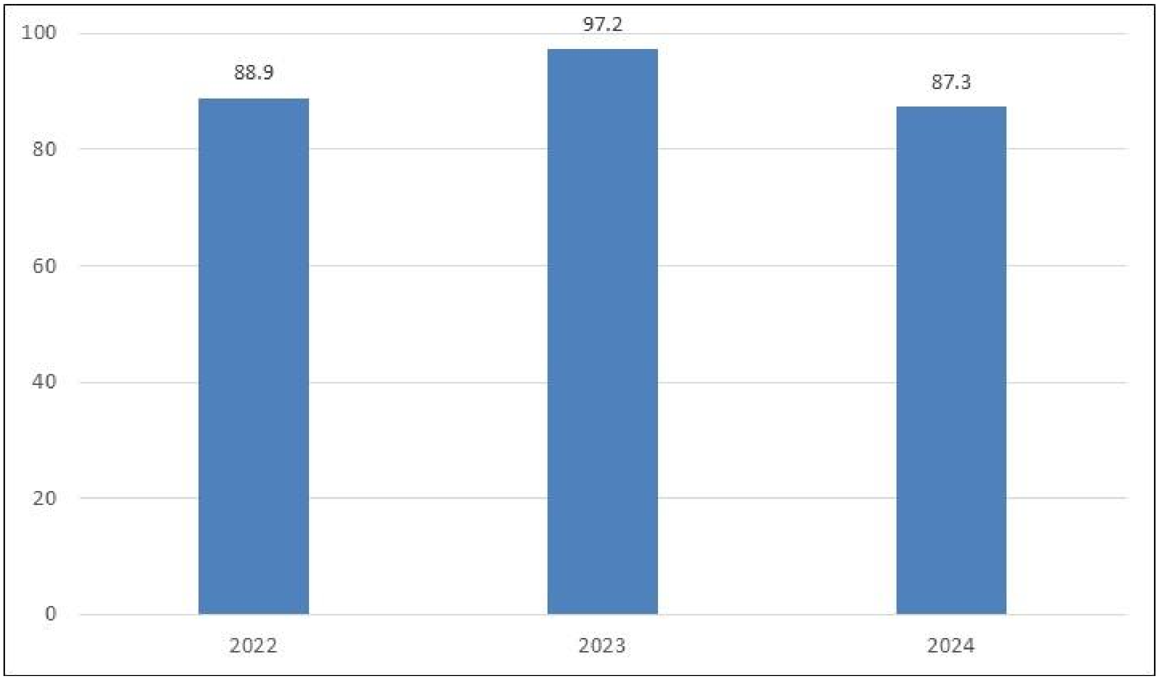
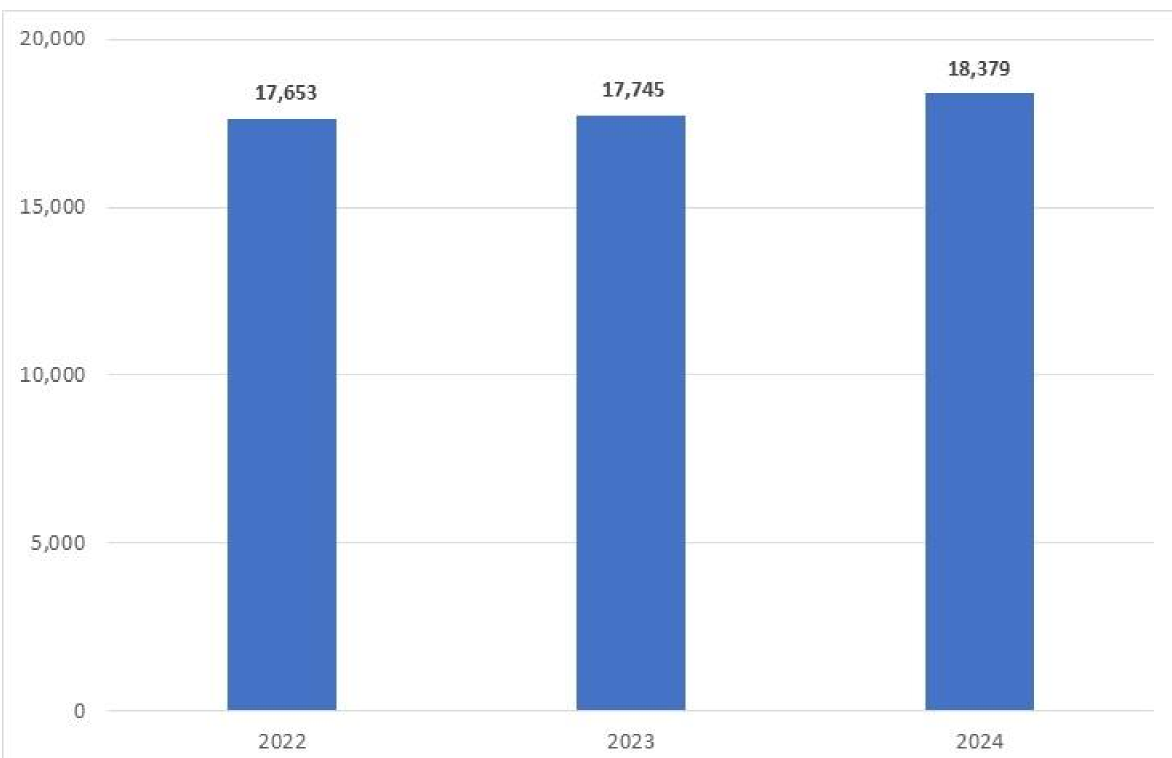


FIGURE 2-8
NET GENERATION (GIGAWATT-HOUR)



D. Extended Operations Forecast January 1, 2026-December 31, 2026

1. Estimating Method

a. Provider Cost Center Costs and Standard Labor Rates

PG&E developed its O&M forecast for 2026 by starting with recorded 2024 staffing and straight time labor costs by Provider Cost Center (PCC).[5] From recorded 2024 staffing, we then adjusted for changes in staffing with consideration given to the need for additional equipment preventive maintenance (PM), anticipated attrition from an aging workforce, incremental training needs for new hires, projects work scopes to assure equipment reliability and plant safety, and nuclear refueling outages for implementation of the projects and execution of the preventive equipment maintenance. The staffing plan is then converted to straight time hours. Overtime hours are based on a review of recorded 2023 and 2024 non-outage and outage overtime.[6] The outage incremental over time hours are determined for each PCC based on planned maintenance and support work for the upcoming outages.[7] The non-labor costs for each PCC consist of department materials and employee expenses. These costs are generally averaged for recent history, and escalation rates are applied to account for inflation. All hour projections are then converted to labor dollars by multiplying by the average pay for each job group. The summation of the straight time labor, overtime labor and non-labor PCC costs, are then divided by total productive (billable) hours to determine a standard rate for each PCC. This same process was repeated for each year.

The total work planned encompasses all base expense, plant upgrade projects, and non-earnings transition memorandum and balancing accounts. Non-Earnings transition memorandum account amounts are not included in this application. In addition, all 2026 O&M forecast costs in this chapter are incremental to the O&M funding

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5 See WPs Supporting Chapter 2, p. 2-8 to 2-9.

6 See WPs Supporting Chapter 2, p. 2-5, for hours required for all planned work.

7 See WPs Supporting Chapter 2, p. 2-6, for outage incremental costs (labor and non-labor).

provided in the final decision for PG&E's 2023 GRC for the 2026 forecast year and will be recovered through the DCEOBA. PG&E requested $0 for DCPP 2026 O&M expense in its 2023 GRC because the 2023 GRC forecast assumptions reflected a Unit 1 retirement date of November 2, 2024 and a Unit 2 retirement date of August 26, 2025.

2. O&M Expense

a. Expense Labor Costs

Expense O&M labor costs are determined by multiplying expense hours by the PCC standard rate to determine expense labor charges. The productive expense hours are developed by subtracting hours charged to non-expense orders from the total productive billable hours.

b. Expense Non-Labor Costs

Expense non-labor costs are comprised of materials, contracts and other costs. The O&M non-labor costs are charged directly to orders and are estimated based on a combination of trending and specifically identified non-recurring costs.

c. O&M Expense by MWC

1) MWC AK – Manage Environmental Operation

TABLE 2-3
O&M EXPENSE FORECAST – MWC AK MANAGE ENVIRONMENTAL OPERATION COSTS
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MWC	2026
1	AK	$3,903

The Environmental group manages the DCPP Environmental Protection Programs mandated by federal, state, and local regulations. These programs include air quality, pollution prevention, water quality, offshore monitoring, radiological environmental monitoring, and storage tank integrity. MWC AK includes non-labor costs for the Receiving Water Monitoring Program as a requirement of our water use permit, Operations support at the Intake facility, and waste treatment and disposal for hazardous, industrial, and mixed waste products. This MWC also includes various fees and permit costs to oversight groups including the Department of Fish and Game, National Pollution Discharge Elimination System, SLO County, and the state of California.[8]

2) MWC BP – Manage DCPP Business

TABLE 2-4
O&M EXPENSE FORECAST – MWC BP MANAGE DCPP BUSINESS
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MWC	2026
1	BP	$21,066

MWC BP includes labor costs for Facilities Maintenance, Risk and Compliance, General Administrative services, and Strategy and Policy departments. It also includes non-labor costs for STARS fees, DCISC member fees and related costs, INPO fees, Nuclear Energy Institute (NEI) fees, Edison Electric Industry (EEI) dues, and Nuclear Safety Oversight Committee (NSOC) fees.[9] STARS is an alliance of southwestern nuclear facilities. DCISC is a three-person Committee charged by the state of California with reviewing and making recommendations concerning the safety of operations at DCPP. INPO is a private nuclear industry oversight organization. NEI is a private nuclear education and policy organization. PG&E is requesting only 50 percent of the NEI fees in accordance with the cost recovery determinations of GRC outcomes. The other 50 percent of NEI fees are borne by PG&E shareholders as “Below-the-line” items. EEI is an association of U.S. shareholder-owned electric utilities. It provides public policy leadership, critical industry data, strategic business intelligence, and conferences and forums. NSOC is a regulatory required nuclear

8 See WPs Supporting Chapter 2, p. 2-1, for the forecast details. The Non-Earn Exp reflects Balancing Account Receiver Cost Center (BA_Rec_CC) 14356 (extended operations) request amount for non-fuel O&M.

9 See WPs Supporting Chapter 2, p. 2-1, for the forecast details.

oversight committee charged with reviewing and making recommendations concerning the safety of operations at DCPP. This MWC also includes charges for the Land Management Program and property leasing.

3) MWC BR – Operate DCPP Plant

TABLE 2-5
O&M EXPENSE FORECAST – MWC BR – OPERATE DCPP PLANT COSTS
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MWC	2026
1	BR	$105,777

MWC BR consists of the following groups: Operations Services, Chemistry Department, and Radiation Protection. Each of these groups and the work that they perform are described below.

Operations Services includes operation of the plant, radiation control, monitoring of plant chemistry, managing radioactive waste and hazardous waste generation, nuclear fuel movement and reactor physics testing.

The Chemistry Program includes plant chemistry control for Units 1 and 2, as well as radiological effluent monitoring and control for the DCPP site. Chemical control is the process of establishing and maintaining a prescribed set of chemical parameters to prevent or minimize corrosion and/or deposition on system components.

Radiation Protection provides oversight for control of radioactive material and support to plant workers on radiation safety. The primary focus of this section is to maintain radiation dose received by workers as low as reasonably achievable. This is accomplished by minimizing radiation levels in the plant through engineering controls, radiation shielding and controlling plant chemistry. Radiation Protection also provides oversight and guidance to plant workers to help assure work practices minimize radiation dose.

In addition to labor, this group also incurs fees for Once Through Cooling Mitigation fees to the State of California. DCPP maintains chemical parameters by using chemical additives or by minimizing the ingress of impurities into the systems. PG&E maintains chemical control of the Units 1 and 2 reactor coolant systems, the secondary systems including Steam Generators, and auxiliary systems, such as the service cooling water and component cooling water systems. In addition, PG&E generates all necessary water with an on-site reverse osmosis system for use in all plant systems. Finally, this MWC includes contract costs for radioactive waste monitoring and disposal, dosimetry analysis, and chemical analysis and disposal.[10]

4) MWC BQ – Loss Prevention

TABLE 2-6
O&M EXPENSE FORECAST – MWC BQ – LOSS PREVENTION COSTS
(THOUSANDS OF DOLLARS)

Line No.	MWC	2026
1	BQ	$59,845

The Loss Prevention MWC BQ is comprised of the Security and Emergency Planning departments. The Security Operations group: (1) implements NRC requirements; (2) formulates tactical responses; (3) implements searches; (4) assesses barriers; and (5) evaluates alarm monitoring to make certain that safeguards are effective on a continuous basis.

The Emergency Planning Department administers the Emergency Plan, which is a condition of the plant license. As such, Emergency Planning is a heavily-regulated program, with the basis for our emergency plan found in the 16 planning standards in 10 C.F.R. § 50.47(b), and NUREG-0654, Criteria for Preparation and Evaluation of Radiological Emergency Response Plans. This includes such things as plans, processes, procedures, facilities,

10 See WPs Supporting Chapter2, p. 2-2, for the forecast details.

equipment, training, and drills, all in support of protecting the health and safety of the public in the event of a radiological emergency.

In addition to labor, this MWC includes non-labor costs for weather forecasting and modeling, emergency plan public education, and emergency plan drill preparation and simulation. MWC BQ also includes various fees to the Office of Emergency Services and Federal Emergency Management Agency.[11]

5) MWC BS – Maintain DCPP Plant Assets

TABLE 2-7
O&M EXPENSE FORECAST – MWC BS – MAINTAIN DCPP PLANT ASSETS
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MWC	2026
1	BS	$165,787

The Manage DCPP Assets MWC BS includes groups and sections within the Maintenance Department, Outage Management Department, Business Operations, License Renewal, and Project Services group.

The Maintenance Department plans and performs PM, corrective maintenance (CM), and maintenance surveillance testing of DCPP mechanical, electrical, and Instrument and Control equipment. This MWC includes repair and maintenance services for all non-power block buildings and facilities and does minor project work. Expense projects included in MWC BS are concrete repairs, snubber maintenance, Radiation Protection instrument replacements and additional spare parts procurement required for extended operations in excess of the stranded inventory amounts being recovered through the Diablo Canyon Retirement Balancing Account. Due to new security and environmental demands, the group increasingly addresses land maintenance issues. In addition, this section manages a significant number of support service

11 See WPs Supporting Chapter 2, p. 2-1, for the forecast details.

contracts for such areas as: janitorial services, rental needs, trash collection for all offices and work areas, restrooms, cafeterias, sewer maintenance, and infrastructure maintenance. Costs for charges from other PG&E functional areas are also included in this MWC for transmission line and substation equipment maintenance.[12]

The Outage Services section provides consistent application of Project Management methodology for nuclear refueling outages including planning, scope alignment, scheduling services, cost estimation and monitoring, and resource adequacy evaluation.

The Business Operations section provides budget and forecast assistance and analysis for all Departments and Project Services and maintains forecast and governance financial tools, policies and procedures consistent with effective cost management practices.

The Project Services section provides consistent application of Project Management methodology for DCPP projects. Project Services assigns project managers that play a key role to proactively replace and/or maintain the original equipment of the plant. Additional considerations for assigning project managers are made if the project has implementation or financial risk, requires significant coordination, or involves regulatory commitments. Projects formerly included in Capital are now expensed and are also reflected in this MWC. See Projects Expense testimony and tables in section D.3 below.

6) MWC BT – Enhance DCPP Personnel Performance

TABLE 2-8
O&M EXPENSE FORECAST – MWC BT – NUCLEAR GENERATION FEES
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MWC	2026
1	BT	$41,131

[12] See WPs Supporting Chapter 2 pp. 2-2, for the forecast details excluding project costs detailed in section 3.a through 3.h below.

The Enhance DCPP Personnel Performance MWC BT consists of the Performance Improvement, Learning Services, QV, and Regulatory Services departments.

The Performance Improvement section has overall programmatic responsibility for performance improvement at DCPP. Performance improvement elements include problem identification and resolution via the CAP, station improvement via operating experience, human performance, self-assessment, benchmarking, and the Employee Concerns Program. They also maintain and trouble shoot business process system issues.

The Learning Services Department manages the preparation and delivery of employee training specific to the nuclear industry and manages training facilities. These training programs result in industry certification recognition for the Operators, Maintenance Workers, Technicians, and Engineers.

The QV Department has overall responsibility for independent quality oversight of DCPP plant operations, maintenance, radiation protection, chemistry, EP, environmental protection plan, fitness for duty, engineering, design, procurement, outage management, work control, and Strategic Projects. This includes independent QA audits, assessments, reviews, quality control inspections, welding non-destructive examinations, source assessments, and supplier audits.

The Regulatory Services section manages the process for maintaining the DCPP NRC facility operating licenses, including the preparation of all correspondence related to maintaining those licenses. This section also manages PG&E's participation in NRC inspection activities. They provide NRC inspectors with unfettered access to PG&E personnel and plant operation and design information and address any issues that may arise.[13]

[13] See WPs Supporting Chapter 2, p. 2-3, for the forecast details.

7) MWC BV – Maintain DCPP Plant Configuration

TABLE 2-9
O&M EXPENSE FORECAST – MWC BV – MAINTAIN DCPP PLANT CONFIGURATION COSTS
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MWC	2026
1	BV	$47,490

The Maintain Plant Configuration MWC BV consists of Engineering, Fuels Administration and Strategic Projects.

The Engineering Department's fundamental responsibility is to maintain the configuration of the plant. Configuration management is essential to continuing the health and regulatory compliance of the plant SSCs. Safe operations and NRC regulations require nuclear plants to examine all potential changes to plant SSCs. This ensures that plant operations will not be compromised, and complete, accurate, up-to-date records will be maintained.

The Fuels Administration is comprised of departmental labor and contracts for software tracking maintenance.

The Strategic Projects Department has only minor expense amounts, with its primary focus on implementation of long-term reliability (plant upgrade) projects funded in MWC BS.

In addition to labor, MWC BV includes non-labor costs for Electric Power Research Institute dues, Pressurized Water Reactor Owners Group dues, and various reactor equipment inspection contract costs.[14]

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[14] See WPs Supporting Chapter 2, p. 2-3, for the forecast details.

8) MWC EO – Provide Nuclear Support

TABLE 2-10
O&M EXPENSE FORECAST – MWC EO – PROVIDE NUCLEAR SUPPORT
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MWC	2026
1	EO	$957

The Provide Nuclear Support MWC EO consists of Supply Chain support labor and staff augmentation for procurement activities and system support.[15]

9) MWC IG – Manage Balancing Account Processes

TABLE 2-11
O&M EXPENSE FORECAST – MWC IG – MANAGE BALANCING ACCOUNT PROCESSES
(THOUSANDS OF DOLLARS)

Line No.	MWC	2026
1	IG	$4,422

The Manage Various Balancing Account Processes MWC IG consists of costs previously recorded to MWC IG and recovered through the Nuclear Regulatory Balancing Account. MWC IG historically consists of three expense projects and programs – Cyber Security, Fukushima (including Fragilities and Seismic Probabilistic Risk Assessment studies), and National Fire Protection Association (NFPA) 805.[16] These projects/programs were implemented to respond to the NRC's orders.

The Cyber Security project and program responded to the NRC-issued 10 C.F.R. § 73.54 (2013) (protection of digital computer and communication systems and networks), which required each nuclear licensee to make all necessary modifications and implement a program to provide high assurance that digital computer and

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15 See WPs Supporting Chapter 2, p. 2-3 to 2-4, for the forecast details.

16 See WPs Supporting Chapter 2, p. 2-4, for the forecast details.

communication systems and networks are adequately protected against cyberattacks. The project was completed in 2019. Compliance monitoring activities continue under the Cyber Security program.

Fukushima Phase 1 expense project responds to the NRC Order EA-12-049 issued on March 3, 2012, which required completing seismic and flooding reevaluations and walk-downs to identify any need for plant upgrades. Additionally, an update and upgrade of the DCPP Seismic Probabilistic Risk Analysis models to new standards as well to fragilities and seismic hazards documents was required to comply with this NRC order. The Fukushima project was completed in 2019. Finally, as a byproduct to the Fukushima Near-Term Task Force 2 rulemaking (SECY-15-0065) required licensees to mitigate beyond-design-basis events. The new rule made NRC Orders EA-12-049 and EA-12-051 generically applicable, establish regulatory requirements for an integrated response capability including supporting requirements for command and control, drills, training and change control, included requirements for enhanced on-site emergency response capabilities, and addressed several petitions for rulemaking submitted to the NRC following the March 2011 Fukushima Daiichi event. This project was completed in 2021. Compliance monitoring activities continue under the Fukushima program. NFPA 805 rulemaking compliance continues as requirements for the 2026 record period.

3. Projects Expense

a. Forecasting Overview

After an initial review of the projects needed for extended operations, each of our projects have been estimated using vendor inputs, subject matter expert input, standard PG&E labor hour estimates for various project classifications, and analogous historical projects. All projects are continuously monitored for scope, schedule, and cost and prioritized for continuous leadership review and decision making.

The strategic projects are summarized below and the accompanying Projects Summaries in Workpapers Supporting Chapter 2, for projects that are $1 million or greater in total cost project life cost.[17]

b. Extended Operations Projects Cost Accounting

PG&E defines Projects costs as extended operations costs to be recovered in customer rates through the DCEOBA if the project is not required as a condition of PG&E's NRC LRA, and meets the following criteria: it is expected to be placed in service on or after January 1, 2027; and/or the project scoping, design, engineering, procurement, and implementation efforts generally begin after the original Unit 1 license expiration date of November 2, 2024.

Projects costs forecast to be incurred earlier than November 3, 2024, not funded by revenues from the 2023 GRC, and forecast to be complete and in service earlier than December 31, 2026, are generally tracked to the Diablo Canyon Transition Memorandum Account and funded through the DWR Loan. This population of Projects includes all projects that are a required condition of PG&E's LRA request with the NRC.

This accounting framework is appropriate as it is anchored in the Public Utilities Code Section 712.8(c)(1)(C) prohibition against recovering any costs incurred by PG&E to satisfy the requirements of its LRA under review by the NRC through customer rates. More specifically, this section of the code states:

> Actions taken by the operator pursuant to the commission's actions under this paragraph, including in preparation for extended operations, shall not be funded by ratepayers of any load-serving entities, but may be funded by the loan provided for by Chapter 6.3 (commencing with Section 25548) of Division 15 of the Public Resources Code or other non-ratepayer funds available to the operator. The commission shall not allow the recovery from ratepayers of costs incurred by the operator to prepare for, seek, or receive any extended license to operate by the U.S. Nuclear Regulatory Commission.

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17 See WPs Supporting Chapter 2, p. 2-7 and pp. 2-12 through 2-4, for further information on these projects.

This accounting framework also reflects PG&E’s efforts to maximize external non-ratepayer funding sources.

D.24-12-033 p. 18 and 19 directs PG&E to make the following demonstration in this application request:

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

PG&E provides this information in the Projects Summaries in Workpapers Supporting Chapter 2.

c. Instrument and Control Systems

Scopes of work that support the reliable operations of the different instrumentation and control systems throughout the plant that manage nuclear instruments, plant control and protection systems, and other balance of plant systems. The projects in this group total 6.0 million and include the following:

TABLE 2-12
PROJECT COSTS - INSTRUMENT AND CONTROL SYSTEMS / INFORMATION TECHNOLOGY
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Item	Title	2026
1	5282338	U2 Tricon Control Systems Migration	$1,912
2	5286765	U2 Main Annunciator System	3,076
3	5286769	U2 Replace Flux Thimble Tubes 2R25	350
4	5286935	Install Sentinel 2.0 Upgrade	644
5	Total		$5,982

d. Intake Pumps, Motors, and Equipment

These Projects activities include work to enhance the reliability of the salt water system and associated cranes that provides cooling water required for the operation of the plant. The projects in this group total $4.0 million and include the following:

TABLE 2-13
PROJECTS FORECAST – INTAKE PUMPS, MOTORS AND EQUIPMENT COSTS
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Item	Title	2026
1	5283512	U1 CWP 1-1 Motor Stator Rewind	$2,573
2	5283515	U2 CWP 2-2 Motor Stator Rewind	893
3	5286753	COM: Intake Gantry Crane Overhaul	1,471
4	Total		$4,937

e. Main Generator Turbine

These Projects activities include work to maintain reliability of the main generator and turbines to generate electricity from the main steam system. The projects in this group total $4.3 million and include the following:

TABLE 2-14
PROJECTS FORECAST – MAIN GENERATOR TURBINE COSTS
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Item	Title	2026
1	5286755	U2 Generator Rotor Refurb	$3,388
2	5286757	U2 Stator Cooling Water (TM-84A)	367
3	5286766	U1 Stator Cooling Water Temp (TM-84A)	244
4	5287132	U2 Main Generator Relays Repl	257
5	Total		$4,256

f. Motors

These Projects activities include work that support larger motors throughout the site that service critical systems such as the primary loop system, circulating water pumps, or other systems. The projects in this group total $3.8 million for various Unit 1 and Unit 2 motors – all expense in 2026.

TABLE 2-15
PROJECTS FORECAST – MOTOR COSTS
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Item	Item title	2026
1	5283779	U1 RHR Motors Refurb Program	$1,550
2	5283781	U1 CCW Motors Refurb Program	2,050
3	5286055	U2 CWP Mech Seal Upgrade & Pump Overhaul	164
4	Total		$3,764

g. Other Electric Equipment, Cable, and Systems

These Projects activities include work that support other balance of plant electric equipment, cabling and systems that manage the balance of plant. These systems include the Condensate system, and 230 kV electrical system. The projects in this group total $2.0 million and include the following:

TABLE 2-16
PROJECTS – OTHER ELECTRIC EQUIPMENT, CABLE, AND SYSTEMS COSTS
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Item	Title	2026
1	5284874	COM 230 kv Tie-Line Breaker CB-212&Switch	$1,308
2	5286756	U2 Cond Pres Xmtr Rel Proj	50
3	5286763	COM 230 kV Tie-Line Relay 287 Repl	669
4	Total		$2,027

h. Other Mechanical Equipment and Piping Systems

These Projects activities include work that support the reliable operation of the mechanical related equipment and piping systems for the balance of plant required to produce energy. These systems include the condensate system, saltwater system, heating, ventilation and air conditioning (HVAC) system. The projects in this group total $22.1 million and include the following:

TABLE 2-17
O&M EXPENSE FORECAST – OTHER MECHANICAL EQUIPMENT PIPING SYSTEMS COSTS
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Item	Title	2026
1	5281655	U1 Condenser Waterbox & Tubesheet Coat PH2	$2,087
2	5281656	U2 Waterbox & Tubesheet Coatings PH 2	23
3	5281693	U1 Cond Booster Pump 1-2 Pedestal	1,645
4	5286761	U1 Cold Reheat Piping SS Cladding FAC	8,287
5	5287012	COM: R22 HVAC Unit Repl Group 1	3,574
6	5287013	COM: R22 HVAC Unit Repl Group 2	2,167
7	5287014	COM: R22 HVAC Unit Repl Group 3	1,968
8	5287692	U1 Main Condenser SW Exp Jnt Repl 1R26	1,457
9	Total		$21,208

i. Reactor Vessel and Radiological Control Projects Costs

These Projects activities include work to support the reliable operation of the main steam / steam generator system, rad monitor (RM) system, and primary system cranes. The efforts include upgrades to the RM 11 Skid and Monitor, Fuel Transfer Cart & Upender, and Steam Generator Snubbers. The projects in this group total $5.6 million and include the following:

TABLE 2-18
PROJECTS FORECAST – REACTOR VESSEL AND RADIOLOGICAL CONTROL PROJECTS COSTS
(THOUSANDS OF DOLLARS)

Line No.	Item	Title	2026
1	5282378	U2 RM-11/12 Skid and Monitor Repl	$420
2	5286839	U2 Fuel Transfer Cart & Upender Upgrade	1,186
3	5288172	U1 Steam Generator Snubbers Replacement	4,041
4	Total		$5,648

j. Dry Cask Storage

These Projects activities include work to offload spent nuclear fuel from the spent fuel pool due to space limitations as a result of extended operations. The projects in this group total $12.7 million and include the following:

TABLE 2-19
PROJECTS FORECAST – DRY CASK STORAGE
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Item	Title	2026
1	5283332	ISFSI Loading Campaign #9	$2,237
2	5285792	Procure Casks SNF Camp #9	10,437
3	Total		$12,674

4. Employee Retention Expense

The retention expense forecast reflects the DCPP retention program needed to retain the personnel necessary for safe and reliable operation of the plant through the extended operations period.

TABLE 2-20
O&M EXPENSE FORECAST – MWC IG – EMPLOYEE RETENTION COSTS
(THOUSANDS OF DOLLARS)

Line No.	MWC	2026
1	IG	$53,061

MWC IG is partially comprised of the costs for the employee retention. The amounts for 2026 have been updated in this application to reflect the headcount in this application for employees eligible for this retention payment.[18]

E. Nuclear Fuel Costs

PG&E requests the CPUC adopt its nuclear fuel expense forecast of $135.7 million for the year 2026. PG&E requests Commission approval for straight line amortization cost recovery over the period 2025-2030 for recovery of PG&E's nuclear fuel expense.[19] PG&E presents both the 2024-2030 as-spent nuclear fuel expenditures, as well as PG&E's 2025-2030 straight-line amortization cost recovery proposal.

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18 See WPs Supporting Chapter 2, p. 2-9 through 2-10 for year end 2024-2030 headcount.

19 PG&E's proposal is the continuation of PG&E's same proposal approved by the Commission in D.24-12-033, p. 33, and p. 82, Conclusion of Law 13.

The Nuclear Fuel expense forecast comprises the costs for procurement of Nuclear Fuel to operate Unit 1 and Unit 2 through the retirement dates in October 31, 2029, and October 31, 2030, respectively.

TABLE 2-21
O&M EXPENSE FORECAST – MWC IG –
NUCLEAR FUEL AS-SPENT RECORDED AND FORECAST
(THOUSANDS OF DOLLARS)

Line No.	MWC	2024R[(a)]	2025F[(b)]	2026F	2027F	2028F	2029F	2030F
1	IG	$158,624	$82,294	$313,700	$144,717	$55,299	–	–

(a) "R" identifies the financial data in the table column as recorded costs.
(b) "F" identifies the financial data in the table column is forecast costs.

TABLE 2-22
O&M EXPENSE FORECAST – MWC IG – NUCLEAR FUEL AMORTIZATION
(THOUSANDS OF DOLLARS)

Line No.	MWC	2024	2025A[(a)]	2026F	2027F	2028F	2029F	2030F
1	IG	–	$134,002	$135,734	$135,734	$135,734	$135,734	$135,734

(a) "A" identifies the cost as the adopted 2025 Nuclear Fuel Amortization forecast in D.23-12-033.

Nuclear Fuel Expense is recorded to MWC IG. These costs are based on contracted purchases of nuclear materials to support the nuclear fuel reload needs for each unit. This includes the costs of uranium, conversion services, enrichment services, fabrication, and sales and use taxes,[20] for the specific core design. Additionally, there are miscellaneous engineering expenses associated with the analysis of the core nuclear fuel as well. Table 2-21 presents the as-spent Nuclear Fuel procurement forecast.

Table 2-22 reflects the amortized expense forecast for nuclear fuel procurement. The amortized expense forecast is the sum of the total nuclear

20 Sales or Use Tax is assessed at certain points in the nuclear fuel procurement process including the Sales Tax during the fuel assembly fabrication process performed by PG&E's nuclear fuel fabrication vendor, and the Use Tax for nuclear fuel uranium, conversion and enrichment which is assessed when the nuclear fuel enters into California and is delivered to DCPP prior to a reload cycle.

fuel procurement recorded expenses and short-term debt financing cost for 2024 and the forecast expenses for the period 2025 through 2030 divided by six (the number of years the nuclear fuel amortization will occur over), plus PG&E's present annual short-term debt financing cost of 4.43 percent in each year for the positive or negative cash balance relative to the as-spent forecast.

PG&E requests CPUC approval to recover nuclear fuel costs via this straight-line amortization as it is an essential element to ensuring extended operations through 2030, provides the lowest financing cost compared to the alternative cost recovery on an as-spent basis, and provides for all California electric customer rate smoothing through the extended operations period.

F. Balancing Accounts

1. DCEOBA

The DCEOBA was approved by the Commission in D.23-12-036. The DCEOBA provides for the recovery of expenses related to the operations of DCPP Units 1 and 2 beyond the current license expiration dates of November 2, 2024 and August 26, 2025, respectively, that are not eligible for government funding pursuant to SB 846, Assembly Bill 180, or the DOE Civil Nuclear Credit Program. PG&E proposes no modifications to the effective DCEOBA preliminary statement.

2. Department of Energy Litigation Balancing Account

a. U.S. Department of Energy Litigation Refund

In September 2012, PG&E entered into a Settlement Agreement with the DOE to resolve litigation surrounding DOE's failure to perform under spent nuclear fuel disposal agreements for DCPP and Humboldt Bay Power Plant (HBPP). Under the terms of the SA, PG&E recovered a lump sum amount reimbursing PG&E for the costs of spent nuclear fuel storage at DCPP and HBPP through 2010. In addition, the settlement approved an annual administrative claims process that requires PG&E to document its costs of spent nuclear fuel storage in defined recoverable categories and submit an annual claim to be reviewed by DOE staff and approved by the U.S. Department of Justice (DOJ). The annual claim period is June 1st to May 31st with payment of DOE Determination received in March of the following year. The DOE proceeds will be credited to the DOE Litigation Balancing Account (DOELBA) in the year received. The DOELBA balance on December 31st of that year will be transferred annually, net of any outside litigation costs, to the corresponding accounts listed in Table 2-23 in the year following the receipt as part of the Annual Electric True-up advice letter filing. The annual claims process has been successful, and PG&E agreed to extend the administrative claims process through the end of 2025 in an addendum to the Settlement Agreement that was approved by the DOJ on April 12, 2022. PG&E's forecast for 2026 assumes that the annual claims process will continue.

Although the current Settlement Agreement with DOE is set to expire in 2025 and future recovery of the costs of storing spent nuclear fuel in dry casks at DCPP is uncertain, PG&E has included a forecast of continued revenues from DOE and proposes to continue the crediting process for DCPP, subject to true-up when actual proceeds are received. If the DOE settlement is not extended beyond 2025 PG&E will be required to file new lawsuits against DOE to recover the costs of spent nuclear fuel storage starting in 2026. This could significantly delay reimbursement from DOE of spent nuclear fuel storage costs at DCPP and HBPP.

In the 2014 GRC,[21] the Commission approved an agreement among PG&E, The Utility Reform Network and Marin Energy Authority (now Marin Clean Energy) to credit the proceeds of the DOE litigation settlement to generation rates (for reimbursement of spent fuel related storage costs for DCPP), and to nuclear decommissioning rates (for reimbursement of spent fuel related storage costs for HBPP).[22]

In the 2020 GRC SA, the parties agreed that a reasonable forecast of DOE settlement proceeds was $20.5 million per year, which reduced PG&E's forecasted revenue requirement.[23] Allocation between the two

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21 D.14-08-032.

22 D.14-08-032, Appendix F-5.

23 D.20-12-005, pp. 154-155; 2020 SA adopted in D.20-12-005, pp. 14-15, § 2.4.2.3.

nuclear plants was not specified in the Settlement Agreement. PG&E allocated 76.21 percent to DCPP and 23.79 percent to HBPP.

For the 2020 to 2022 period, PG&E calculated the allocation percentages based on the credit amount that was agreed to in the Settlement Agreement associated with implementing the Results of Operations for the 2020 GRC decision.[24] The result is that 76.21 percent of DOE litigation settlements are allocated to the PABA and 23.79 percent of the proceeds are credited to the NDAM. Using those allocation factors, DCPP Operations is allocated 76.21 percent and HBPP Decommissioning is allocated 23.79 percent of the proceeds.

For the period 2024 and 2025, as recently approved in the 2025 DCPP Forecast Extended Operations Application, the allocations as approved under D.24-12-033[25] are as follows:

TABLE 2-23
DCPP
ALLOCATION PERCENTAGE FOR DOE CREDITS

Line No.	Year	DCPP Allocation percentage to PABA	DCPP Allocation percentage to DCEOBA	HB ISFSI Allocation percentage to NDAM	Total DOE Settlement
1	2024	19.0%	0%	81.0%	100%
2	2025	15.0%	0%	85.0%	100%

For the extended operations forecast year 2026, PG&E proposes an updated allocation of DOE settlement proceeds as shown in Table 2-24 to refund the settlement proceeds according to cost causation principles.[26] Specifically, small and declining refund percentages to the PABA in 2026 and 2027 as these refunds are for costs funded through the 2023 GRC Generation Revenue requirements for years 2024 and 2025, respectively. PG&E proposes to revise the DOELBA to add an

[24] PG&E calculated the allocation percentages using amounts detailed in Section 2.4.2.3 of the SA ($20.5 million for PABA) and Table 3-5 of the original GRC filing ($6.4 million for NDAM).

[25] See D.24-12-033 p. 3-24, Table 3-22, for allocation percentage for DOE credits.

[26] See WPs Supporting Chapter 2, p. 2-11, for the allocation proposal details.

additional subaccount for DOE settlement proceeds attributable to DCEOBA funded activities. This proposal is addressed in Chapter 8.

For the 2026 record period in this proceeding, PG&E forecasts DOE settlement proceeds in the amount of $12.587 million directly attributable to spent fuel management costs funded through the DCEOBA for the 2024-2025 claim period. The forecast is based on PG&E's total estimate for DCPP spent fuel management and HB ISFSI management costs for the 2024-2025 claim period, allocated according to the allocation percentages provided in Table 2-24 below multiplied by 97.9%, the claim success percentage for the three most recent claim submissions to the DOE.[27]

PG&E proposes to add these estimated proceeds as a credit to the 2026 DCEOBA revenue requirement in the 2025 Fall Update for this proceeding. This credit would be subject to true up through the DOELBA for the final recorded payment from the DOE for the 2024-2025 claim.

TABLE 2-24
DCPP
ALLOCATION PERCENTAGE FOR DOE CREDITS

Line No.	Year	DCPP Allocation percentage to PABA	DCPP Allocation percentage to DCEOBA	HB ISFSI Allocation percentage to NDAM	Total DOE Settlement
1	2026	5.3%	52.2%	42.5%	100%
2	2027	1.7%	45.9%	52.4%	100%
3	2028	0.0%	62.2%	37.8%	100%
4	2029	0.0%	68.2%	31.8%	100%
5	2030	0.0%	15.2%	84.8%	100%

27 $12.857 million (DCEOBA-attributable costs)*.979 = $12.587 million.

G. Cost Tables

Table 2-25 shows forecasted costs by MWC for expense.

TABLE 2-25
MWC TOTAL DCPP O&M AND RETENTION EXPENSE FORECAST
(THOUSANDS OF DOLLARS)

Line No.	Expense Component	MWC	2026 Forecast
1	O&M Expense	AK	$3,903
2		BP	21,066
3		BR	105,777
4		BQ	59,845
5		BS	165,787
6		BT	41,131
7		BV	46,399
8		EO	957
9		IG	4,422
10		Subtotal	$449,286
11	Retention Expense		$53,061
12	Fuel Administration	BV	1,092
13	Nuclear Fuel Expense Amortization		135,734
14	O&M, Retention and Fuel Admin		$639,173

Table 2-26 shows forecasted costs by Projects for expense.

TABLE 2-26
DCPP PROJECTS EXPENSE FORECAST

Line No.	Project Name	2026 Forecast
1	Instrument & Control Systems	$5,339
2	Information Tech/Telecom	644
3	Intake Pumps, Motors & Equipment	4,937
4	Main Generator/Turbine	4,256
5	Other Elect Equip, Cable & Systems	2,027
6	Other Mech Equip & Piping Systems	21,208
7	Reactor Vessel & RCPs	1,606
8	Reactor Vessel & RCPs - Snubbers	4,041
9	Motors	3,764
10	Dry Cask Storage	12,674
11	Total	$60,496

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 3

GENERATION FORECAST AND RESOURCE ADEQUACY SUBSTITUTION CAPACITY COST FORECAST

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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 3
GENERATION FORECAST AND RESOURCE ADEQUACY SUBSTITUTION CAPACITY COST FORECAST

A. Introduction

In compliance with Decision (D.) 23-12-036, this chapter presents the Diablo Canyon Power Plant's (DCPP) electric generation forecast and Resource Adequacy (RA) substitution capacity cost forecast. The annual DCPP electric generation forecast estimates the anticipated electricity production from January 1 to December 31, 2026. The RA substitution capacity cost forecast uses the electric generation forecast to estimate the amount of RA substitution capacity to be included in the non-bypassable charge.

B. Direction From Decision 23-12-036

In D.23-12-036, the California Public Utilities Commission (Commission) determined that Pacific Gas and Electric Company (PG&E) would retain the responsibility, as the scheduling coordinator, to procure substitution RA capacity during periods when the DCPP units are on planned outage and in accordance with the California Independent System Operator Tariff provisions.[1] The Commission further specified that to ensure against potential cost shifts to PG&E's bundled service customers, PG&E would be authorized to fully recover—from all benefitting 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.[2] To that end, PG&E will include as part of the forecasted DCPP revenue requirements an estimate of the RA substitution capacity costs covering all of 2026 when Unit 1 and Unit 2 will operate in their period of extended operations.

C. DCPP Electric Generation Forecast

PG&E forecasts that DCPP's 2026 Unit 1 extended operations generation is 8,620,732 megawatt-hours (MWh), and 2026 Unit 2 extended operations

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[1] D.23-12-036, pp. 86-87.

[2] D.23-12-036, p. 87.

generation is 9,582,632 MWh for a combined total forecast of 18,203,364 MWh. The generation forecast is based on the Generation Forecast Methodology.[3]

Electric power generation unit performance calculations are based on the Maximum Dependable Capacity (MDC). The MDC values for DCPP Units 1 and 2 are 1,122 megawatts (MW) and 1,118 MW, respectively. MDC is the maximum amount of power that a unit can produce during average worst case natural operating conditions.

The annual generation forecast includes a one-day curtailment to 25 percent power in November and a 1-day curtailment in December due to severe storms, refueling outages planned during the year along with associated ramping down into the outage and ramping up to full power afterwards, a 50 percent power curtailment for ocean cooling water tunnel cleaning that is typically performed 8-12 months after a refueling outage, main output transformer efficiency losses, and an additional 0.50 percent reduction for thermal efficiency losses and minor equipment degradation.

DCPP is a baseload generation resource that operates at 100 percent (or full) power levels. There are a number of factors that can affect the MWh output of a nuclear facility, such as: scheduled refueling and maintenance outages, ocean cooling water system tunnel cleaning, curtailments, and forced outages as discussed below.

1. Outages and Curtailments

Nuclear generating facilities can experience reduced generation due to: (1) refueling (planned) outages; (2) maintenance outages; (3) forced outages; and (4) curtailments. Refueling outages and maintenance outages are both classified as scheduled outages. Each of these types of generation reductions are discussed in greater detail below.

a. Refueling Outages

Nuclear generating facilities are unique in that the facilities must be shut down periodically to be refueled. DCPP Unit 1 and Unit 2 each undergo a refueling outage approximately every 18 months. Unit 1 and Unit 2 outages do not occur simultaneously and are generally staggered between the Spring and Fall in a two-outage year. The planned duration

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3 See PG&E's Workpapers Supporting Chapter 3.

of a refueling outage is established based on the duration required to refuel the reactor, the scope of maintenance required for the specific outage, and the scope of projects required to be implemented for regulatory or plant improvement activities. During a refueling outage, a unit's energy production is reduced to zero and the unit is taken offline.

b. Maintenance Outages

During a maintenance outage, a unit's energy production is also reduced to zero and the unit is taken offline. Maintenance outages are scheduled when needed throughout the year to perform testing, routine maintenance, or non-emergency repairs when the repairs can be deferred beyond the end of the next weekend but require a capacity reduction before the next scheduled refueling outage.

c. Forced Outages

During a forced outage, a unit's energy production is reduced to zero and the unit is taken offline. Forced outages are generally the result of equipment malfunctions or unexpected ocean conditions that restrict the plant's ocean cooling water intake system. When a forced outage occurs, the primary objective is to repair the item that led to the outage or protect plant equipment from damage resulting from restricted ocean cooling water flow.

d. Curtailments

During a curtailment, a unit's energy production is reduced to below 100 percent. Curtailments occur for events such as required surveillance testing that must be performed at a power level less than 100 percent, routine maintenance that requires a unit to be less than 100 percent such as cleaning of the ocean cooling water system to remove biological growth, emergent maintenance items that require the unit to be at a reduced power level, or an operational decision to reduce power due to external influences such as significant ocean swells that could impact the ability of a unit to remain operational.

D. RA Substitution Capacity Cost Forecast

The following section describes PG&E's proposed methodology for forecasting the anticipated RA substitution capacity costs.

1. RA Substitution Capacity Cost Forecast Methodology

The RA substitution capacity costs forecast consists of determining the amount of capacity that will need to be acquired by PG&E during periods when DCPP is expected to be offline or curtailed due to planned outages, tunnel cleaning, and/or other short-term curtailment events as described above. Those RA substitution capacity amounts are then multiplied by a market reference price to estimate the total procurement costs associated with meeting DCPP's RA substitution capacity obligations, including any associated penalties and costs borne by non-DCPP resources substitution costs.

To operationalize the calculation, PG&E has quantified the needed RA substitution capacity using the outage and curtailment schedules embedded in the generation forecast described in Section C above. Consistent with D.24-12-033, PG&E uses the current 2025 Power Charge Indifference Adjustment (PCIA) system RA market price benchmark to calculate the total costs.[4] The 2025 system RA market price benchmark is the most recent PCIA-related benchmark that is currently available for use. Using the PCIA system RA market price benchmark mirrors established practice used in the traditional Energy Resource Recovery Account (ERRA) Forecast proceeding. Consistent with traditional ERRA Forecast modeling practices, PG&E will true-up the 2025 substitution capacity cost to reflect the final 2025 PCIA system RA market price benchmark and update the DCPP RA substitution capacity cost forecast in the Fall using the forecast 2026 PCIA system RA market price benchmark, unless otherwise directed by the Commission, once it is made available by the Commission.[5]

2. RA Substitution Capacity Cost Forecast

Table 3-1 below shows the forecasted RA substitution capacity costs for the period ending December 31, 2026, for DCPP Units 1 and 2. PG&E's forecasted costs do not include any incremental administrative costs or

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4 D.24-12-033, Findings of Fact 14.

5 In February 2025, the Commission adopted an *Order Instituting Rulemaking to Update and Reform Energy Resource Recovery Account and Power Charge Indifference Adjustment Policies and Processes*, Rulemaking 25-02-005. This Rulemaking may affect the final RA benchmark price, issued in October 2025.

costs associated with any expected compliance penalties and/or costs borne due to non-DCPP resources within PG&E's generation portfolio.

TABLE 3-1
RA SUBSTITUTION CAPACITY COST FORECAST (2026)

Line No.	Year	Total
1	2026	$160,836,900

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CHAPTER 4

OPERATIONAL REVENUE REQUIREMENT

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OPERATIONAL REVENUE REQUIREMENT

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CHAPTER 4
OPERATIONAL REVENUE REQUIREMENT

A. Introduction

The purpose of this chapter is to present the revenue requirement associated with the forecast incremental costs for the period of January 1, 2026 to December 31, 2026 for operations of Diablo Canyon Power Plant (DCPP or Diablo Canyon). Pacific Gas and Electric Company (PG&E) calculates the revenue requirement using the Results of Operations (RO) model. The RO model compiles operating costs to estimate the revenue that PG&E needs to recover for work presented in this application. The revenue requirement for these costs is described below in Section B and set forth in Table 4-1. The revenue requirement for the final cost recovery approved by the California Public Utilities Commission (CPUC or Commission) will be calculated using the same RO assumptions presented here, updated as appropriate for interest expense, authorized Cost of Debt (COD), and applicable tax parameters.

B. Summary of Request

In this application, PG&E seeks recovery of $1,178.5 million in total revenue requirement (excluding interest and Revenue Fees and Uncollectibles (RF&U)) for the period of January 2026 to December 2026. PG&E proposes to implement the approved revenue requirement in rates effective January 1, 2026. All revenues presented in this application are incremental and were not requested in the 2023 General Rate Cases (GRC) or other CPUC-approved funding. PG&E summarizes the revenue requirement requested in the application in Table 4-1 below.

TABLE 4-1
REVENUE REQUIREMENTS EXCLUDING RF&U
(THOUSANDS OF DOLLARS)

Line No.	Description	Total 2026
1	Total Revenue Requirements (excluding RF&U)	$1,178,507

1. Elements of the RO Calculation

The RO model computes the annual revenues that are needed (revenue requirement) from customers to recover the cost of service. The model calculates the revenue requirement based primarily on a forecast of Operations and Maintenance (O&M) expense as described in Chapter 2 and Statutory Fees as described in Chapter 5. The calculations are based on traditional cost-of-service ratemaking methods, which are consistent with the methods that PG&E uses in its CPUC cases. The revenue requirement is calculated using the RO model for separately funded rate case applications.

The forecast presented in this application excludes capital expenditures, and hence the revenue requirement is based solely on forecast expense costs. Accordingly, and consistent with Public Utilities Code (Pub. Util. Code) 712.8(h)(1), the requested revenue requirement excludes book depreciation and a return on rate base. Payroll taxes associated with the DCPP O&M labor costs and certain debt financing costs are also included consistent with the prior rate case.[1]

The RO model for the DCPP extended operations application computes the revenue requirement using the following formula:

$$RRQ = \text{Operating } Expenses + Taxes$$ [2]

a. O&M Expenses

The predominant contributors to the operating expense category in the RO calculation are the $699.7 million O&M expenses including Nuclear Fuel, DCPP Retention Expense, O&M expenses, and the Project Expenses. The O&M expenses are described further in Chapter 2.

Certain expense costs relate to Administrative and General (A&G) and Common, General, and Intangible (CGI) costs, and are typically shared among all functional areas within PG&E. In PG&E's 2023 GRC, these costs are allocated to different functional areas (Electric

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1 See Section B.1.b. below for further discussion.

2 This reference is to payroll taxes. No income taxes are included in the Forecast 2026 revenue requirements.

Distribution, Gas Distribution, Electric Generation, Gas Transmission and Storage, and Electric Transmission) using the 2023 GRC adopted O&M labor allocation factors. The revenue requirement presented in this chapter excludes allocated A&G and capital revenue requirement related to the CGI common capital over the period of 2026 because these revenue requirements are captured in the 2023 GRC. Please refer to Chapter 1 for additional details on common cost allocation.

b. Debt Financing Costs

The RO calculation includes a $2.9 million of Debt Financing Cost recovery item to compensate for necessary adjustments pertaining to Working Cash (see below).

The debt financing cost is calculated using the CPUC COD approved under Decision (D.) 24-10-008 for year 2026. In all cases, the debt financing cost is calculated using the authorized COD rate only and 100 percent debt structure. There is no return on equity calculated and requested in this application. PG&E believes that this approach is reasonable and comports with Senate Bill (SB) 846's prohibition on rate base, since there is no equity return and the debt financing costs are a real cost to PG&E for these items.

1) Working Cash Adjustment

The adoption of a working cash forecast is necessary to establish PG&E's cost of providing services from DCPP to customers. Working cash is composed of two elements: (1) amounts required for day-to-day operations (such as cash needed to process in-person payments at customer service centers); and (2) amounts used to pay operating expenses in advance of receiving customer payments (such as insurance contracts and other contracts that extend for a year or more). Generally, working cash cost recovery is a necessary component of revenue requirements to finance such operations. For 2026, the RO Model includes working cash revenue requirements consistent with D.24-12-033. More specifically, working cash for the year 2026 is forecasted to be the same as the amount approved in the 2023

GRC for Test Year 2023, as both units were planned to be in operation in 2023.

c. Statutory Fees

DCPP extended operations has unique income streams authorized under Pub. Util. Code Section 712.8 for 2026:

- Fixed Payment;[3]
- Volumetric Performance Fee (VPF);[4] and
- Liquidated Damages Subaccount funding amounts.[5]

Additional details on statutory fees listed above are provided in Chapter 5.

d. Payroll Taxes

$23.7 million of Payroll taxes are calculated based on DCPP O&M labor cost forecast, DCPP retention headcount and 2023 GRC adopted payroll tax factors. The payroll taxes include Social Security Tax (Old Age, Survivors, and Disability Insurance (OASDI)), Medicare Tax, Federal and State Unemployment Tax. Specifically, the RO model uses 2023 GRC adopted payroll tax factors to estimate the following elements of payroll tax:

1) Taxes associated with the Federal Insurance Contribution Act (FICA) (OASDI and Medicare) – FICA taxes are a function of taxable wages and the OASDI and Medicare tax rates, respectively;
2) Taxes associated with Federal Unemployment Insurance (FUI) – FUI taxes are a function of headcount, maximum per-capita FUI tax amount, and FUI tax rate; and
3) Taxes associated with State Unemployment Insurance (SUI) – SUI taxes are a function of headcount, maximum per-capita SUI tax amount, and SUI tax rate.

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3 Pub. Util. Code Section 712.8(f)(6).

4 Pub. Util. Code Section 712.8(f)(5).

5 Pub. Util. Code Section 712.8(g).

e. Income Taxes

1) Fixed Management Fees

Pursuant to D.24-12-033,[6] no federal or state income tax revenue requirements are included in this rate case related to the fixed management fees.

2) Production Tax Credits

There are no production tax credits (PTC) included as a reduction to revenue requirement in this Application.

Pub. Util. Code Section 712.8(h)(1) states that PG&E may recover reasonable costs and expenses to operate DCPP, however this amount is "net" of any PTCs of the operator. Additionally, Public Resources Code Section 25548.3(c)(10), provides that PG&E:

> …shall allocate all revenues received as a result of federal or state tax credits or incentives, excluding funds specifically allocated by a federal program for the costs of extending power plant operations, on a cost-share basis of 10 and 90 percent between the operator corporation (PG&E) and ratepayers…

Under the Inflation Reduction Act of 2022, Internal Revenue Code (IRC) Section 45U includes a PTC for qualifying zero-emission nuclear power production. Under IRC Section 45U, a nuclear operator is eligible for a credit equal to 0.3 cents per kilowatt-hour (kWh) of electricity generated in the United States and sold to unrelated person.[7] The credit is increased five-fold if certain prevailing wage requirements are satisfied.[8] However, as the price of power sold from a zero emission nuclear power plant increases, the Section 45U credit is reduced by operation of IRC Section 45U(a)(2). As power prices rise above a $25 per

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[6] D.24-12-033, Section 6.6; Conclusions of Law (COL) 1, 7, and 16. On January 21, 2025, PG&E filed an Application for Rehearing challenging the conclusions and orders of D.24-12-036 related to income tax recovery with respect to the fixed management fees.

[7] IRC Section 45U(a).

[8] IRC Section 45U(d)(1).

megawatt-hour index, the credit gradually begins to reduce.[9] The Nuclear PTC is available to existing nuclear plants for electricity produced or sold for taxable years beginning after December 31, 2023 through December 31, 2032.[10]

For forecast 2026 revenue requirements, PG&E expects that any IRC Section 45U PTC attributable to DCPP will be reduced to zero based on the mechanics of IRC Section 45U(a)(2).

Additionally, PG&E is not aware of any other PTCs, investment tax credits under IRC Sections 48 and 48E, or any other tax incentives that would be applicable for DCPP extended operations. PG&E will continue to monitor IRC Section 45U and any other tax credits and tax incentives that may be applicable for DCPP extended operations. To the extent credits or incentives are subsequently claimed, but were not included in the forecast, they will be captured in the rate case true-up to actual process when such information is available.

3) Volumetric Performance Fees

There are no federal and state income tax gross-up revenue requirements on VPFs because PG&E's 2026 forecast revenue requirements presume adoption of PG&E's all-expense VPF plan.

Pub. Util. Code Section 712.8(f)(5) authorizes PG&E to collect VPFs from customers during extended operations, which must be spent on DCPP operations and critical public purpose priorities.[11] The receipt of these VPFs constitutes taxable income[12]; however, PG&E is entitled to a tax deduction when it spends the VPF funds

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9 IRC Section 45U(b)(2) defines the reduction amount based on a threshold equal to 16 percent of the excess of the gross receipts from a facility over the product of 2.5 cents and the number of kWh hours of electricity produced and sold by the taxpayer.

10 IRC Section 45U(e).

11 Pub. Util. Code Section 712.8(s). Additionally, PG&E shareholders are not allowed to earn a rate of return or realize any profit related to the VPFs.

12 PG&E is in the process of preparing an IRS private letter ruling regarding whether the VPFs can be treated as non-taxable revenues, as ordered in D.24-12-033 on this matter.

on the required public purpose priorities. Therefore, the difference in the timing of the taxable VPF income receipt and related deductible tax expense (VPF spend) can result in tax liability.

PG&E's VPF proposal (discussed in Chapter 7) applies the VPFs to expense projects only. Since the timing of the receipt of the taxable VPF income and the VPF spend (tax deductions) should occur within the same year (or within close proximity to the same year), PG&E does not include any federal and state income taxes on the VPFs. PG&E's tax timing exposure, when VPFs are used for expense projects, is lessened enough to justify excluding income tax impacts for the VPFs, since DCPP operations is only authorized until 2030.

However, if the Commission adopts a proposal to use VPF funds for capital spend, then PG&E may modify its revenue requirement to include the appropriate amount of income taxes to compensate for this additional cost, which is not fully reversed through tax deductions by 2030.[13] The inclusion of income taxes in this scenario ensures that the full amount of authorized VPFs under SB 846 are used for the intended legislative purposes of accelerating public purpose priorities.

PG&E is in the process of preparing an Internal Revenue Service (IRS) private letter ruling request regarding the taxability of the VPFs.[14] Pursuant to D.24-12-033, PG&E will submit the draft ruling and final IRS ruling to the Commission via the General Order 96-B advice letter process.[15]

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13 This adjustment to revenue requirements to account for income taxes is dependent on the outcome of the IRS Private Letter Ruling (PLR) on the tax treatment of VPFs.

14 D.24-12-033, Section 16, p. 77.

15 D.24-12-033, Finding of Fact (FOF) 28 and Ordering Paragraph (OP) 12.

4) SB 846 Normalization Revenue Requirements

There are no revenue requirements included in this rate case related to SB 846 tax normalization deferred taxes.[16]

Under the IRC normalization rules, the book/tax difference for depreciation is required to be included in rate base to comply with these mandatory tax rules.[17] Therefore, SB 846's prohibition on rate base creates unique IRC tax normalization concerns.

The Commission acknowledged this potential risk and pursuant to D.24-12-033, allowed PG&E to: (1) track the amounts at issue in the Diablo Canyon Extended Operations Memorandum Account to enable curing of any normalization violation retroactively, (2) file an IRS ruling request on this issue, and (3) adjust rates as soon as practicable via the advice letter process upon the issuance of a ruling that confirms that the exclusion of these revenue requirements violated the normalization rules.[18] PG&E is in the process of preparing and filing this IRS PLR. Pursuant to D.24-12-033, PG&E will submit the draft ruling and final IRS ruling to the Commission via the advice letter process.[19]

f. Property Taxes

The California Constitution requires the California State Board of Equalization (SBE) to annually assess public utilities at Fair Market Value on the lien date of January 1. PG&E continues to own and uses the land at DCPP throughout the extended operations period and will be subject to appraisal by the SBE. SBE appraisers estimate the market value of PG&E's unitary land parcels using generally accepted appraisal methods. Property taxes are levied and collected in the same manner as county assessed properties. The 2026 property tax expense for

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16 In the 2025 Forecast filing last year, PG&E included debt financing cost revenue requirements to mitigate against potential tax normalization concerns arising from Senate Bill 846's no rate base cost recovery framework. As mentioned above, pursuant to D. 24-12-033, these amounts at issue are being tracked and PG&E will file an IRS ruling on the matter.

17 IRC Section 168(i)(9).

18 D.24-12-33, Section 6.5, FOF 17 and COL 14.

19 D.24-12-033, OP 12.

DCPP land is included in the 2023 GRC. Given this fact, the 2026 revenue requirement calculated under this filing excludes a property tax cost recovery component.

C. Conclusion

PG&E respectfully requests that the Commission adopt a total revenue requirement of $1,178.5 million (excluding interest and RF&U). The revenue requirement set forth in this filing is calculated using the RO model and is based on the incremental costs presented in other testimony submitted in this filing. The detailed revenue requirement calculation is provided in the workpapers supporting this chapter.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 5

STATUTORY FEES

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STATUTORY FEES

A. Introduction

The purpose of this chapter is to request approval of: (1) $113.9 million Diablo Canyon Power Plant (DCPP or Diablo Canyon) Units 1 and 2 Fixed Payment forecast,[1] (2) $263.4 million DCPP Units 1 and 2 Volumetric Performance Fees (VPF) forecast,[2] (3) the associated VPF and Fixed Payment escalation factors,[3] and (4) $75 million in the DCPP Liquidated Damages subaccount funding[4] for the extended operations period of January 1, 2026, through December 31, 2026 record period.

B. Organization of The Remainder of This Chapter

The remainder of this chapter is organized as follows:

- Section C – Fixed Payment Request;
- Section D – VPF Request;
- Section E – VPF and Fixed Payment Escalation Rates; and
- Section F – Liquidated Damages Subaccount Funding Request.

C. Fixed Payment

1. Fixed Payment Forecast Request

Pacific Gas and Electric Company (PG&E) requests the California Public Utilities Commission (CPUC or Commission) approval to recover a total combined Fixed Payment forecast for DCPP Units 1 and 2 in the amount of $113.9 million for the extended operations record period of January 1, 2026, through December 31, 2026. This total request is the sum of: (1) the DCPP Unit 1 Fixed Payment in the amount of $56.9 million for the period January 1, 2026, through December 31, 2026, and (2) the DCPP

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1 Public Utilities Code (Pub. Util. Code) Section 712.8(f)(6)(A).

2 Pub. Util. Code Section 712.8(f)(5).

3 Pub. Util. Code Section 712.8(f)(5) and 712.8(f)(6)(A).

4 Pub. Util. Code Section 712.8(g) and Pub. Util. Code Section 712.8 (i)(1).

Unit 2 Fixed Payment in the amount of $56.9 million for the period January 1, 2026, through December 31, 2026.

2. Fixed Payment Forecast Methodology

The DCPP Unit 1 Fixed Payment forecast for the 2026 extended operations year is the product of: (1) $50 million (2) multiplied by the 2026 cumulative escalation factor of 1.1388. The DCPP Unit 2 Fixed Payment forecast for the 2026 extended operations year is the product of: (1) $50 million (2) multiplied by the 2026 cumulative escalation factor of 1.1388.[5]

3. Fixed Payment Cost Recovery Authority

Recovery of the Fixed Payment from PG&E service area customers and by the customers of all Load Serving Entities (LSE) subject to the Commission's jurisdiction is authorized pursuant Pub. Util. Code Section 712.8(f)(6)(A) as follows:

> In lieu of a rate-based return on investment and in acknowledgment of the greater risk of outages in an older plant that the operator could be held liable for, the commission shall authorize the operator to recover in rates a fixed payment of fifty million dollars ($50,000,000), in 2022 dollars, for each unit for each year of extended operations, subject to adjustment in subparagraphs (B) to (D), inclusive. **The amount of the fixed payment shall be adjusted annually by the commission using commission-approved escalation methodologies and adjustment factors.** (Emphasis added.)

Additionally, the Commission found in Decision (D.) 23-12-036 that although Pub. Util. Code Section 712.8(f)(6)(A) did not specify which group of customers would pay for these costs the Commission presumed the costs would be recovered from "ratepayers of all LSEs subject to the Commission's jurisdiction—via an NBC—per subsection (l)(1)."[6]

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5 See Workpapers Supporting Chapter 5.

6 D.23-12-036, p. 68.

D. Volumetric Performance Fees

1. VPF Forecast Request

The total forecast for VPFs collected in 2026 is $263.4 million, which is the sum of the forecast of the VPFs from PG&E's service territory-only and the forecast of the VPFs from all electric LSEs.

a. Forecast of PG&E Service Area VPF

PG&E requests Commission approval to recover a total combined VPF forecast for DCPP Units 1 and 2 in the amount of $131.7 million for the 2026 extended operations record period, to be borne by PG&E' electric distribution customers.

b. Forecast of All Electric LSEs VPF

PG&E requests Commission approval to recover a total combined VPF forecast for DCPP Units 1 and 2 in the amount of $131.7 million for the 2026 extended operations record period, to be borne by the customers of all Electric LSEs.

2. VPF Forecast Request Estimating Methodology

a. Forecast Methodology of PG&E Service Area VPF

The VPF to be borne by the customers in PG&E's service territory for DCPP Units 1 and 2 is the product of: (1) $6.50 multiplied by the 2026 cumulative escalation factor of 1.1130, multiplied by the Unit 1 2026 extended operations recorded period electric generation forecast of 8,621 gigawatt-hours (GWh) plus (2) $6.50 multiplied by the cumulative escalation factor of 1.1130, multiplied by the Unit 2 2026 extended operations electric generation forecast of 9,583 m MWh.[7]

b. Methodology of All Electric LSEs VPF Forecast

The VPF to be borne by all electric LSE's for DCPP Units 1 and 2 is the product of: (1) $6.50 multiplied by the 2026 cumulative escalation factor of 1.1130, multiplied by the Unit 1 2026 extended operations recorded period electric generation forecast of 8,621 GWh plus (2) $6.50 multiplied by the cumulative escalation factor of 1.1130,

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7 See Workpapers Supporting Chapter 5.

multiplied by the Unit 2 2026 extended operations record period electric generation forecast of 9,583 MWh.[8]

3. VPF Forecast Cost Recovery Authority

Recovery of the VPF from PG&E service area customer and statewide LSEs is authorized pursuant Pub. Util. Code Section 712.8(f)(5) as follows:

> In lieu of a rate-based return on investment and in acknowledgment of the greater risk of outages in an older plant that the operator could be held liable for, the commission shall authorize the operator to recover in rates a volumetric payment equal to six dollars and fifty cents ($6.50), in 2022 dollars, for each megawatthour generated by the Diablo Canyon powerplant during the period of extended operations beyond the current expiration dates, to be borne by customers of all load-serving entities, and an additional volumetric payment equal to six dollars and fifty cents ($6.50), in 2022 dollars, to be borne by customers in the service territory of the operator. The amount of the Volumetric Performance Fee shall be adjusted annually by the commission using commission-approved escalation methodologies and adjustment factors.

E. VPF and Fixed Payment Escalation Rates

1. Fixed Payment Escalation Rate

PG&E requests Commission approval of PG&E's proposed 2026 Fixed Payment average cumulative escalation rate of 1.1388. This proposed escalation factor is the 2026 cumulative Consumer Price Index-All Urban (CPI-U) escalation factor. 2022 is the base year for PG&E's cumulative escalation rate calculation.[9] PG&E proposes this methodology given the Fixed Payment is expressly stated in 2022 dollars. The purpose of applying the CPI-U cumulative escalation factor to the Fixed Management Fee is to properly adjust the Fixed Management Fee to account for the loss in the value of the dollar since 2022, the base year for the Fixed Management Fee. Use of CPI-U to escalate the Fixed Management Fee is appropriate because it is a measure of inflation that is widely used across the United States for measuring the change in the value of the dollar.

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8 *Ibid*.

9 See Workpapers Supporting Chapter 5

2. VPF Escalation Rate

PG&E requests Commission approval of PG&E's proposed 2026 VPF cumulative escalation rate of 1.1130.2022 is the base year for PG&E's cumulative escalation rate calculation. PG&E's proposed cumulative escalation rate is a composite escalation rate that is the product of: (1) the weighted average cumulative PG&E labor expense escalation rate and (2) the weighted average cumulative non-labor Operations and Maintenance (O&M) expense escalation rate.[10]

PG&E proposes this methodology given the VPF is expressly stated in 2022 dollars, as excerpted in Section D.3. above. As the funds collected from the VPF are permitted to be spent on public purpose priorities that span CPUC-jurisdictional Functional Areas activities, PG&E proposes this escalation, which is comprised of all CPUC-jurisdictional Functional Areas cumulative annual labor expense and non-labor expense escalation, as an appropriate escalation methodology for the VPF.

a. Weighted Average Cumulative PG&E Labor Expense Escalation Rate

The weighted average cumulative PG&E labor expense escalation rate is the product of PG&E's present companywide labor escalation rate of 3.75 percent cumulative escalation amounts for 2026 with 2022 as the base year for the cumulative escalation factor calculation. The weighted average cumulative labor expense escalation rate weighted average is the 2023 General Rate Case (GRC) imputed adopted test year 2023 total labor expense percentage.[11]

b. Weighted Average Cumulative Non-Labor O&M and A&G Expense Escalation Rate

The weighted average cumulative non-labor O&M expense escalation rate is the sum average of the "S&P Market Intelligence Power Planner Service, Global IHS Markit Power Planner Service Third-Quarter 2024 Forecast" cumulative Gas Distribution, Gas Transmission, Gas Storage, Electric Distribution, Nuclear Generation,

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10 See Workpapers Supporting Chapter 5

11 *Ibid.*

Hydro Generation, and Fossil Generation non-labor O&M escalation forecast values for 2026. The weighted average cumulative non-labor expense escalation rate weighted average is the 2023 GRC imputed adopted test year 2023 total non-labor expense percentage.[12]

F. Liquidated Damages Subaccount

1. Liquidated Damages Subaccount Funding Forecast Request

PG&E requests Commission approval to recover a total combined liquidated damages funding forecast for DCPP Units 1 and 2 in the amount of $75 million for the extended operations period of January 1, 2026, through December 31, 2026. This total request is the sum of: (1) the DCPP Unit 1 liquidated damages funding in the amount of $37.5 million for the DCPP Unit 1 2026 extended operations record period and(2) the DCPP Unit 2 liquidated damages funding in the amount of $37.5 million for the Unit 2 2026 extended operations record period.

2. Liquidated Damages Subaccount Funding Forecast Methodology

The DCPP Unit 1 liquidated damages funding forecast methodology is the product of $12.5 million multiplied by 3, the number of months necessary to collect the Unit 1 share of the remaining $75 million in state authorized liquidated damages subaccount funding. Likewise, the DCPP Unit 2 liquidated damages funding forecast methodology is the product of $12.5 million multiplied by 3, the number of months necessary to collect the Unit 2 share of the remaining $75 million in state authorized liquidated damages subaccount funding[13]

3. Liquidated Damages Funding Recovery Authority

Recovery of the liquidated damages funding from customers of statewide LSEs is authorized pursuant Pub. Util. Code Section 712.8(g) and Section 712.8(i)(1), as follows:

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12 *Ibid.*

13 See Workpapers Supporting Chapter 5

Section 712.8(g):

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).

Section 712.8(i)(1):

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).

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 6

CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION MARKET REVENUES

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CHAPTER 6
CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION MARKET REVENUES

A. Introduction

This chapter presents Pacific Gas and Electric Company's (PG&E) forecast for California Independent System Operator Corporation (CAISO) energy market revenues generated by Diablo Canyon Power Plant (DCPP) during 2026. DCPP receives energy market revenues by generating electricity which is sold into the CAISO's wholesale energy market. Forecasted generation revenues are an important component of the overall revenue requirement forecast for DCPP's extended operations. These revenues represent a significant offset to the plant's operating and fixed costs, reducing the total revenue requirement which must be recovered from statewide customers. This practice is consistent with existing ratemaking procedures in PG&E's Energy Resource Recovery Account (ERRA) forecast proceeding and is consistent with statutory direction contained in Senate Bill 846. Specifically, Public Utilities Code (Pub. Util. Code) Section 712.8(h)(1) directs PG&E "…to recover all reasonable costs and expenses necessary to operate Diablo Canyon… *net of market revenues*…"[1] Additionally, the statute directs this cost recovery to occur in a forecast proceeding structured "similarly to [PG&E's] annual [ERRA] forecast proceeding…"[2] Consistent with this guidance, the methodology below comports with existing practices where possible while accounting for the unique circumstances of DCPP's extended operations. In the following sections, PG&E describes its proposed methodology for forecasting the plant's CAISO energy market revenues and reports out the forecasted results for 2026.

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[1] Pub. Util. Code Section 712.8(h)(1) (emphasis added).

[2] *Ibid*.

B. CAISO Energy Market Revenue Forecast Methodology

The CAISO's energy market revenue forecast starts with the generation forecast described in Chapter 3. The generation volumes are then multiplied by an appropriate market reference price to produce the energy market revenue forecast. Since the California Public Utilities Commission (Commission) does not identify a specific market reference price to be used in this context, PG&E used a market reference price that is analogous to the Power Charge Indifference Adjustment (PCIA) energy index benchmark used in the ERRA forecast proceeding.

The standard PCIA energy index benchmark is constructed using time-weighted Platts on- and off-peak North of Path 15 (NP15) monthly forward prices. The resulting monthly price curve is then averaged across the months to form a single annual price. The single annual price is then further adjusted by a portfolio weighting factor that reflects the average historical variance between generation revenues received by PCIA-eligible resources and actual average NP15 prices calculated over the prior 3-year period.[3]

In this instance, PG&E followed the same approach described above in developing the CAISO market reference price. However, the portfolio weighting factor calculation relied exclusively on actual DCPP CAISO generation and revenue data as opposed to the entire PCIA-eligible portfolio. Separate Platts NP15 on- and off-peak forward price curves generated throughout the month of January 2025 were averaged to form aggregate average on- and off-peak price curves with delivery dates running from January 2026 through December 2026. The two aggregate average price curves were then averaged together using time weights based on the traditional 6x16 on-peak hourly designation with appropriate adjustments for North American Electric Reliability Corporation holidays to form a single forward price curve. The portfolio weighting factor was calculated using historic DCPP CAISO energy market revenues and metered generation spanning the last three calendar years (2022-2024). PG&E will update the market reference price calculation in the Fall using the latest NP15 Platts price curves provided by the Commission as part of its standard PCIA energy index benchmark updating process.

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3 See Decision 23-06-006, Appendix B.

C. Market Revenue Forecast

The resulting generation energy market revenue forecast is summarized in the table below:

TABLE 6-1
FORECAST OF CAISO ENERGY MARKET REVENUES

Line No.	Year	Total Generation (Gigawatt-Hour)	CAISO Market Reference Price ($/Megawatt-Hour)	Generation Revenues (Thousands of Dollars)
1	2026	18,203	51.36	934,925

As described above, the generation energy market revenue forecast will serve to offset the costs of DCPP's extended operations. PG&E's consolidated revenue requirement request, net of the forecasted energy market revenues shown in this chapter, is presented in Chapter 9.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 7

PLANNED USAGE OF FUNDS FROM VOLUMETRIC PERFORMANCE FEES

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CHAPTER 7
PLANNED USAGE OF FUNDS FROM VOLUMETRIC PERFORMANCE FEES

A. Introduction

The purpose of this chapter is to present Pacific Gas and Electric Company's (PG&E) plan for 2026 Volumetric Performance Fees (VPF) expenditures covering the period of January 1, 2026 to December 31, 2026 pursuant to the public purpose priorities identified in Section 712.8(s)(1) of the Public Utilities Code (Pub. Util. Code) and Decision (D.) 23-12-036. The Legislature established the VPFs in lieu of a rate-based return on investment for PG&E to operate DCPP during extended operations. The VPF revenues are a unique opportunity to accelerate work among the enumerated public purpose priorities identified in Senate Bill (SB) 846, as codified in Pub. Util. Code Section 712.8(s)(1). In D.23-12-036, the California Public Utilities Commission (CPUC or Commission) directed PG&E to file an application setting forth planned use of the VPF revenues prior to making any expenditures.[1] PG&E provides its planned uses of the 2026 VPFs to accelerate the critical public purpose priorities to the extent not required to be contributed to offset Diablo Canyon Power Plant (DCPP or Diablo Canyon) operating costs. The forecast for 2026 VPFs is $263.4 million, as shown in Chapter 5.

PG&E's approach for its 2026 VPF expenditures aims to balance multiple needs, including: the need for planning certainty to perform work, the need to fund emergent work related to safety and risk activities, the potential need to use VPFs on Diablo Canyon operations, and the uncertainty of the final amount of VPFs to be earned in 2026. In the event PG&E earns less than the forecasted amount of volumetric fees in 2026, PG&E does not earmark 100 percent of the funds for defined uses (i.e., some amounts are assigned for contingency), so less would be available for use. PG&E's waterfall approach will accelerate realization of benefits for customers while retaining flexibility to address

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[1] D.23-12-036, Ordering Paragraph (OP) 15.

emerging work in 2026 and applying any residual funding to reduce DCPP operating costs.

PG&E's 2026 plan includes programs from its 2025 plan that were approved in D.24-12-033. These programs satisfy and promote Section 712.8(s) by accelerating work on and driving customer benefits from expenditures on the enumerated public purpose priorities, as well as meet all statutory and regulatory requirements. PG&E also presents additional programs that satisfy and promote the critical public purpose priorities and meet all statutory and regulatory requirements. In addition, PG&E's 2026 plan endeavors to accommodate the concerns and interests of a range of stakeholders while advancing priority work.

Finally, PG&E presents the cost tracking, controls, and compliance mechanisms to be used to ensure compliance with SB 846 and D.23-12-036. PG&E takes Section 712.8(s) requirements seriously, including the requirement for no double recovery, shareholder prohibitions, and ensuring that VPF expenditures are spent on programs that accelerate Section 712.8(s)(1) priorities as well as customer benefits. PG&E provided this information to the Commission on February 18, 2025 in Advice 7511-E,[2] which was submitted pursuant to Ordering Paragraph (OP) 5 from D.24-12-033.

B. Legislative and Regulatory Background

1. SB 846

In lieu of a rate base return, Pub. Util. Code Section 712.8(f)(5) authorizes PG&E to recover VPFs, as follows:

> In lieu of a rate-based return on investment and in acknowledgment of the greater risk of outages in an older plant that the operator could be held liable for, the commission shall authorize the operator to recover in rates a volumetric payment equal to six dollars and fifty cents ($6.50), in 2022 dollars, for each megawatt hour generated by the Diablo Canyon powerplant during the period of extended operations beyond the current expiration dates, to be borne by customers of all load-serving entities, and an additional volumetric payment equal to six dollars and fifty cents ($6.50), in 2022 dollars, to be borne by customers in the service territory of the

[2] PG&E Advice 7511-E, Feb. 18, 2025, pp. 17-12, available at hyperlink: https://www.pge.com/tariffs/assets/pdf/adviceletter/ELEC_7511-E.pdf.

operator. The amount of the operating risk payment shall be adjusted annually by the commission using commission-approved escalation methodologies and adjustment factors.[3]

In Section 712.8(s)(1), the Legislature directed that the VPF revenues be used to accelerate or increase spending on critical public purposes priorities as follows:

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; and
f) Increasing resiliency and reducing operational and system risk.[4]

Section 712.8(s)(1) also required that the compensation "shall not be paid out to shareholders."[5] And Section 712.8(s)(2) directs that PG&E "shall not earn a rate of return" on the Volumetric Performance Fees (VPF), that no profit shall be realized by shareholders, that neither PG&E nor any of its affiliates or holding company may increase existing public earning per share (EPS) guidance as a result of the VPFs, and no double recovery in rates.

2. Decision 23-12-036

In D.23-12-036, the Commission directed a formal application process to review and plan for PG&E's use of the compensation.[6] The Commission affirmed that Section 712.8(s)(1) provides PG&E with discretion on the use of the VPFs subject to statutory provisions.[7] However, the Commission directs that in the event that DCPP's actual recorded operating costs are more than fifteen percent above the approved forecast in the annual cost

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[3] Pub. Util. Code § 712.8(f)(5).

[4] Pub. Util. Code § 712.8(s)(1)(A-F).

[5] Section 712.8(s)(1)

[6] D.23-12-036, p. 139, OP 15.

[7] D.23-12-036, p. 110.

forecast Application filings, then PG&E must first use the VPF to offset the costs above 115 percent before they are used for another purpose.[8]

The Commission directed that PG&E's first application focus on the planned usage of the funds.[9] As this is PG&E's second filed Application, this testimony is consistent with the Commission's direction to focus on the planned usage of the VPF funds. The first implementation year of the VPFs is 2025, which is the current calendar year, so a post-spend report is not available until the Diablo Canyon Extended Operations Balancing Account (DCEOBA) has a full 12 months of recorded entries.

For subsequent applications, the Commission instructed that the contents include the following:

- Citation to the DCEOBA and the costs recorded there to demonstrate how the funds were used, and also whether any of the funds were used to offset costs in excess of PG&E's approved DCPP Extended Operations Cost Forecast application.
- [A] declaration, under penalty of perjury, from PG&E's Chief Financial Officer:
  - None of the funds collected pursuant to Section 712.8(f)(5) were paid out to shareholders[;]
  - None of the funds collected pursuant to Section 712.8(f)(5) earned a rate of return for PG&E[;]
  - No profit was realized by PG&E's shareholders through the expenditures of funds collected pursuant to Section 712.8(f)(5)[; and]
  - Neither PG&E nor any of its affiliates or holding company increased public EPS guidance as a result of compensation provided under Section 712.8.
- [A] detailed report on how the fees were used solely for the purpose of covering DCPP extended operations costs or critical public priorities authorized by the previous year's [a]pplication.[10]

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8 D.23-12-036, pp. 110-111.

9 D.23-12-036, p. 112, fn. 294.

10 D.23-12-036, p. 113.

As noted above, PG&E presents its planned usage here for its second year and will include additional required content in subsequent applications.

C. Planned Uses for VPFs Collected in 2026

PG&E presents its 2026 VPF prioritization plan below. For each program, PG&E describes the program, how it complies with the enumerated Section 712.8(s)(1) public purpose priorities, affirms that all program costs are incremental to either the 2023 GRC or other rate cases, and provides a forecast cost summary. As noted above, PG&E's 2026 VPF plan contains some programs approved for implementation in 2025 because extending these programs (especially those that are starting up in 2025) allows them to execute more efficiently by continuing funding through a second year. Doing so also increases customer benefits and overall optimizes program benefits.

Assuming that the recorded actual costs do not exceed fifteen percent above PG&E's approved forecast for DCPP operating costs, PG&E plans to spend the VPFs collected in 2026 on the Section 712.8(s)(1) priorities, described below. While PG&E provides estimated forecast amounts, PG&E may revise the total amounts among the various uses and categories depending on circumstances at the time of their use. Table 7-1 below provides a summary of PG&E's 2026 VPF plan, the estimated range by program, under Section 712.8(s):

TABLE 7-1
SUMMARY OF PLANNED USE OF 2026 VOLUMETRIC PERFORMANCE FEES

Line No.	Proposal	Range	Section 712.8(s)(1) Public Purpose Priority	Description of Program	Incrementality Explanation
1.1	Power Generation (PG) Accelerated/Enhanced Asset Management, Communications, Workforce Safety, and Renewable/Zero Carbon Energy Activities: Asset Management, Inspection, and Maintenance Activities of PG System Infrastructure	$22-40 million	§ 712.8(s)(1)(B), (F)	Address gaps identified during PG&E's ISO 55001 certification process, incorporate corrective actions stemming from asset failures sooner, and implement new, industry-leading practices for proactively managing asset lifecycle and reducing risk.	Acceleration of work that was not forecast in the 2023 GRC.
1.2	PG Accelerated/Enhanced Asset Management, Communications, Workforce Safety, and Renewable/Zero Carbon Energy Activities: PG Communications	$0.2-0.3 million	§ 712.8(s)(1) (E)	Enhances public safety communications	Acceleration of work not forecast in the 2023 GRC.
1.3	PG Accelerated/Enhanced Asset Management, Communications, Workforce Safety, and Renewable/Zero Carbon Energy Activities: PG Workforce Safety Initiatives	$0.5-$1.0 million	§ 712.8(s)(1) (D)	Enables new workforce safety initiatives	Acceleration of work and programs not forecast in the 2023 GRC.
1.4	PG Accelerated/Enhanced Asset Management, Communications, Workforce Safety, and Renewable/Zero Carbon Energy Activities: Zero Carbon Energy Activities	$0.5-$1.2 million	§ 712.8(s)(1) (B)	Advance work on carbon capture technology at PG&E natural gas generation	Acceleration of future work not forecast in the 2023 GRC
1.5	PG Accelerated/ Enhanced Asset Management, Communications, Workforce Safety, and Renewable/Zero Carbon Energy Activities: Renewable Energy Activities	$0.8-$2.5 million	§ 712.8(s)(1) (B)	Advance work on potential Battery Energy Storage Systems sites for renewable energy integration	Acceleration of work not forecast in 2023 GRC.

TABLE 7-1
SUMMARY OF PLANNED USE OF 2026 VOLUMETRIC PERFORMANCE FEES
(CONTINUED)

Line No.	Proposal	Range	Section 712.8(s)(1) Public Purpose Priority	Description of Program	Incrementality Explanation
2.1	Accelerating Interconnections and Actions to Reduce Operational Risk and Modernize the Grid More Efficiently Through Operating System Enhancements: Electric Generation Interconnection	$5-$15 million	§ 712.8(s)(1)(A)	Enable more efficient application processing to support expedited timelines for customer interconnections, as well as work through a backlog of customer interconnection work created by the NEM 2.0 sunset in 2023.	Work that was forecast at $0 in the 2023 GRC. It was historically funded by NEM fees, which experienced a substantial decline for a period following the adoption of the NEM successor tariff (Net Billing Tariff).
2.2	Accelerating Interconnections and Actions to Reduce Operational Risk and Modernize the Grid More Efficiently Through Operating System Enhancements: Propel	$35-$55 million	§ 712.8(s)(A), (B), (D), (F)	SAP system upgrade that aims to simplify processes, resulting in improved customer interconnection timelines, enhanced grid modernization and resiliency, and reduced operational risk.	Work and program that was not forecast in the 2023 GRC
5.2	Customer Electrification Experience: Online Resources for Comprehensive Electrification Support	$1.7-$3.1 million	§ 712.8(s)(1)(A), (E)	Supports development of online resources for comprehensive electrification support	Work that is not forecast in any prior rate case.

TABLE 7-1
SUMMARY OF PLANNED USE OF 2026 VOLUMETRIC PERFORMANCE FEES
(CONTINUED)

Line No.	Proposal	Range	Section 712.8(s)(1) Public Purpose Priority	Description of Program	Incrementality Explanation
5.3	Customer Electrification Experience: Residential BE Support	$1.2-$2.5 million	§ 712.8(s)(1)(C)	Expand and/or supplement existing program offerings to fill gaps in customers served or BE measures offered and thus provide a more holistic solution to customers who are interested in BE.	Three workstreams: 1) Expanding existing program (REEP) to serve customers beyond current eligibility requirements. 2) Expanding the offerings of ESA Pilot Plus/Pilot Deep program to cover project measure costs that are not eligible with existing funding. 3) Work not forecast in any prior rate case. Programmatic support of water heater electrification in emergency replacement scenarios is not a service or measure that PG&E currently offers.
6	Programs to support building decarbonization for small businesses	$1.5-$2.5 million	§ 712.8(s)(1)(C)	Supporting expanded programs to support small business in building decarbonization objectives.	Expansion of existing Simplified Saving Program to now include BE activities where it has not done so before.
7	One VM	$10-$15 million	§ 712.8(s)(1)(D), (F)	Map-based work execution, monitoring, and validation application that supports wildfire mitigation.	Acceleration of work that was not forecast in the 2023 GRC.

TABLE 7-1
SUMMARY OF PLANNED USE OF 2026 VOLUMETRIC PERFORMANCE FEES
(CONTINUED)

Line No.	Proposal	Range	Section 712.8(s)(1) Public Purpose Priority	Description of Program	Incrementality Explanation
8	Pre-staging of Temporary Generation in Support of Winter Storms	$4-$8 million	Section 712.8(s)(1)(D), (F)	Deployment of strategy to pre stage temporary generation in support of winter storms to promote workforce safety, reduce costs of mobilization efforts, and other benefits.	Work not forecast in any prior rate case.
9.1	PG&E Contingency Uses: (1) for Safety and Risk, and (2): DCPP Operational Costs	$40-92 million	Various	Safety and Risk programs: MWCs: BH, BF, GC, GA, and BA DCPP Operational Costs: Permitted by §712.8(s)(1)	Safety and Risk programs: VPFs will be applied in the event of the expansion or acceleration of the program above what was approved in the 2023 GRC. DCPP: Applied if available at PG&E’s discretion.

1. Power Generation Accelerated/Enhanced Asset Management, Communications, Workforce Safety, and Renewable/Zero Carbon Energy Activities ($24-$45 million)

PG&E proposes the following programs in the PG department that accelerate or increase spending on the Section 712.8(s)(1) public purpose priorities, with the cost summary provided below, with detail on each program in the subsequent sections.

TABLE 7-2
COST SUMMARY OF PG ACCELERATED/ENHANCED ASSET MANAGEMENT, COMMUNICATIONS, WORKFORCE SAFETY, AND RENEWABLE/ZERO CARBON ENERGY ACTIVITIES

Line No.	Description	Cost (Millions of Dollars)	Applicable 712.8(s)(1)	Applicable Major Work Categories
1	Asset Management, Inspection and Maintenance	$22-40 million	F, B	AB, AX, IG, KH, KI
2	PG Communications and Education	$0.2-$0.3 million	E	KG
3	Workforce Safety Initiatives	$0.5-$1.0 million	D	AB, KG
4	Zero-Carbon Energy Activities	$0.5-1.2 million	B	AB
5	Renewable Energy Activities	$0.8-2.5 million	B	AB

a. Power Generation Asset Management, Inspection, and Maintenance Activities ($22 million-$40 million)

With large and increasing amounts of intermittent renewables added to the grid and climate change creating extreme periods of heat during the summer months and greater storm severity in winter months, PG&E has experienced new challenges and greater operational demands to support grid reliability and flexible operation on its generation fleet requiring assets to be operated in new ways that are different than originally designed.

Further, the self-evaluation process undertaken by PG to obtain ISO 55001 Certification has illuminated critical system vulnerabilities of the aging infrastructure which must be addressed through a more rigorous understanding of asset condition, operational and system risk, as well as proactive and systematic identification and implementation of mitigations. The external, independent assessment within the ISO

Certification process also attests to the need for enhanced Asset Management Systems (AMS).

Applying VPF funds in 2026 will allow the acceleration of critical risk reduction work at PG&E's reservoirs such as debris removal, dredging, and rodent abatement which can directly impact the effective operation of critical operating equipment and system protections to enable operations. It will also enable the continued enhancements and continued execution of PG's ISO certified AMS to drive continuous improvement throughout the business, incorporating corrective actions stemming from internal and external audits and assessments, cause evaluations for asset failures, and programmatic gaps. In addition, the AMS encourages the implementation of new, industry-leading practices for proactively managing asset lifecycle, including the expansion of an integrated risk management program that better administers risk-informed decision making across the organization. These enhancements enable a holistic asset -risk management approach, focused on bolstering asset knowledge, improving visibility to the threats posed by PG&E's operational context to PG's assets and operations, and better defining consequences of failure in order to improve safety and reliability for PG&E and its customers.

This program accelerates and increases spending on public purpose priority (s) (1) sub-section (F) (increasing resilience and reducing operational and system risk) by proactively addressing growing operational challenges created by extreme periods of heat and more frequent and severe rainfall from atmospheric rivers driven by climate change. This combined with the large amounts of intermittent renewables being added to the grid drives the need for increasing operations and maintenance (O&M) activities to support public safety and operational reliability.

In 2025, PG&E used VPF funds to initiate the AMS enhancements for the hydroelectric generation asset fleet, and in 2026 PG&E intends to continue to implement and mature these enhancements to a "steady-state," as well as expand the same enhancements to its Asset Management programs to its non-hydro generating facilities. An example of a 2025 inspections enhancement is conducting canal inspections on a fully-dewatered basis with third party Subject Matter Expert oversight. Prior practice has been to perform this type of inspection with SME support only on a 5-year basis. Accelerating these inspections, providing greater support to them and developing a more detailed plan of inspection criteria has resulted in re-baselining our understanding of asset condition. PG&E desires to enhance its standard operating practices for canal inspections which would involve more frequent de-watered inspections as well as more in-depth review of canal condition. Further, the enhanced inspections completed in 2024-2025 resulted in newfound asset issues to remediate. In 2026 PG plans to continue the enhanced inspection protocol as well as the conduct additional work for expected new found work.

The learnings from 2025 will continue into 2026. The proposed scope of AMS enhancements includes: (1) critical asset and attribute identification, (2) detailed Failure Modes and Effects Analyses, expansion of risk modeling, and asset failure and health analytics, (3) expanding and optimizing system inspections and maintenance based on risk informed decision making, and (4) advancing inspection methods to include industry -leading technologies enabling early detection of asset failure modes.

To expand, 2026 planned work includes: first, additional critical asset and attribute identification increases resiliency and reduces operational and system risk by enabling a comprehensive and broader view on asset condition than exists in PG&E’s current capabilities. Second, detailed Failure Modes and Effects Analyses and hazard inventory and consequence analyses increases resiliency and reduces operational system risk by enabling PG&E to identify where current controls and mitigations could have failure mode vulnerabilities, PG&E can develop improvements which allow for a robust and holistic asset management process. Third and fourth, expanding and optimizing inspection methods based on risk informed decision making and industry leading technologies increases resiliency and reduces operational system risk by enabling PG&E to identify issues at hard-to-access, higher risk assets and subsequently develop and execute the mitigations to address new as-found conditions.

Additional incremental 2026 O&M activities may be required to resolve known and newly identified gaps during the buildout of the enhanced AMS. This includes, but is not limited to:

- Performance of corrective maintenance, and an increase in routine maintenance including the establishment of additional risk mitigation measures:
  - Hydro Water Storage and Delivery assets and sub-components (including spill channels, gates, valves, alarm testing/calibration);
  - Expedited (or Expanded) Vegetation, Rodent, Dredging and Reservoir Debris Management at Dams;
  - Critical Support Facilities (including roads, bridges, cranes, lodging, trams/cableways, and IT infrastructure);
  - Standardized asset maintenance plans across the PG system, including Instrumentation and Control scope;
- Bolstering public safety programs, enhance asset maintenance plans by improving the coordination and scheduling of enhanced inspections within a standardized program per requirements of the ISO 55001 certification;
- Improving hydro control room operating standard practices to embed critical redundancy in operational decision making and maintenance plan development;
- Developing more comprehensive O&M standards and procedures to reduce operational risk, including training in support of sustaining a skilled and qualified workforce; and
- Enhancing our Hydro Public Safety Program aimed at public safety improvements across our hydro waterways.

The activities described above satisfy Section 712.8(s)(1)(F) (increasing resilience and reducing operational and system risk) by ensuring that the PG assets are being operated, maintained, and inspected as part of a holistic asset-risk management system. By expediting the implementation of such enhancements, PG&E can continue to maintain safe and reliable operation of its fleet, which is critical for enabling intermittent renewable integration, grid reliability, and customer energy needs, and supports California's GHG emissions reduction targets. This program also will indirectly support Section 712.8(s)(1)(B) (accelerating actions needed to bring renewable and zero-carbon energy online and modernize the electrical grid) by promoting flexible operations of PG&E's hydro assets needed to integrate and enable increases to intermittent renewables added to the grid. A large and increasing portion of California's electric generating fleet consists of non-dispatchable energy sources such as wind, solar, nuclear, and regulatory "must take" generation. To successfully integrate these non-flexible resources onto the grid, the CAISO relies on PG&E's resources to satisfy a large portion of its operating reserve requirements. Ensuring safe and reliable operation of PG&E's assets by improving Asset and Risk Management capabilities will enable optimization of new renewable and zero-carbon energy and grid modernization.

The activities enumerated herein were not included in PG&E's 2023 General Rate Case (GRC), and this acceleration is necessary to maintain PG&E's ISO 55001 certification that was originally obtained in March of 2022. The timing of the recommendations resulting from the ISO certification occurred after PG&E concluded its 2023 GRC forecasting activities.

Without the enablement of the 2026 VPF funds, this important critical work would not be performed at this time and leave unidentified and unmitigated the potential for asset risks that could have negative public safety or water delivery outcomes.

These activities will be completed under MWCs AB, AX, IG, KH, and KI. This work in 2026 is a continuation of work identified for the 2025 VPF program.

b. Power Generation Communications ($0.2 million-$0.3 million)

PG&E proposes to expand the scope of the current PG public outreach program beyond its current scope which is limited to the publication of printed brochures which discuss safety around Hydro Assets to K-8 students. The proposed scope expansion is supportive of

Section 712.8(s)(1)(E) (communications and education). Enhancements to the program will introduce new scope that reinforce safety to a broader audience as well as inform the public of the recreation, community and environmental benefits in addition to our commitment to safe operations. To effectively reach our communities PG needs to evolve its public communication to consider:

- Varying preferences and channels beyond printed media, to engage with communities that are in proximity to our assets
- Communications toolsets that can be bettered leveraged by community stakeholders such as emergency response, environmental, water consumers, recreation community, local government and other stakeholders
- Provide more community visibility to where PG intends to drive local infrastructure investments and the purpose of those investments, particularly safety investments such as those at dams, reservoirs and waterways
- Mature PG public safety communications program and offerings consistent with element 2 of PG&E's Safety Excellence Management System (Communication and Stakeholder Awareness)

Scope expansions to be initiated in 2026 include, but are not limited to the following types of activities that create new content, forums, education and engagement:

- Creation of a community tours/events program focused on renewable energy that could include hands-workshops, demonstrations and engagement with local operations teams;
- Creation of interactive models and demonstrations of hydro, solar and battery storage systems for use as education tools at public events;
- Creation of a mobile app that provides interactive learning modules on renewable energy and that includes quizzes, videos and virtual tours of renewable energy facilities and can be tailored across various age ranges; and
- Creation a series of engaging videos on topics like hydro, solar, and battery storage technologies. These can be used for internal coworker awareness and external customer education.

These activities will be completed under MWC KG. The scope of these activities has not been previously contemplated for the 2023 GRC beyond the existing scope of the printed hydro safety materials.

c. Power Generation Workforce Safety Initiatives ($0.5 million-$1.0 million)

PG&E proposes to launch additional scope for its workforce safety initiatives supportive to Section 712.8(s)(1) (D) (workforce and customer safety) that was not previously contemplated, proposed, or approved in the 2023 GRC. These efforts pertain to implementation Incident Management Teams (IMT), responding to employee-led workforce safety improvements and improving support to lone and remote workers.

To improve the safety of lone and remote workers, PG proposes to use VPF funds to implement technology not currently employed within current operations. The enhancement will provide tracking and location services, two-way messaging and integration with Geographic Information System to provide support to those employees in areas with no cell phone reception. This is vital for emergency situations where immediate help could be needed and dispatched.

PG is also planning to improve its response capability to asset emergencies impacting public and workforce safety through implementation of IMTs to support PG assets and areas. Capability will be consistent with Standardized Emergency Management System (SEMS) and incident Command System (ICS), which PG has at a local level and PG&E has at an Enterprise level but did not previously exist at a functional area level, which is why PG plans to fully implement this capability. If required and called upon, PG IMTs will be available to support all PG&E assets and areas in need of support in alignment with the PG&E Company Emergency Response Plan (CERP). The teams may deploy anywhere within the service territory where incident management is needed. The VPF revenues are not planned to be used for labor as these teams will be staffed by current PG personnel. However, the additional coordinated and bolstered support to emergency incidents is expected to create new support expenses which could include, but are not limited to, incremental IMT training, new personnel safety materials, incremental travel and dedicated vehicle expenses. Today, PG has an initial, operating capability formed at the start of 2025, however PG&E plans to use VPF funding to build, test, and validate this operating capability.

Additionally, PG's employee-led Grass Roots Safety Team has identified the need for safety culture training to support the leadership of grass roots safety initiatives. The team identified the important role that front line supervisors play in safety culture and the success of safety initiatives. PG plans to implement recurring safety culture training and training in safety tools at all leader levels, including Supervisors as well with front-line teams, to meet this identified requirement.

This work has not been forecast by the 2023 GRC or any other rate case. To the extent VPF funding is unavailable for this work, PG will need to delay or scale down its pace in implementing these improvements.

The proposed expense across these efforts described in this subsection would be completed in MWCs AB and KG.

d. Zero Carbon Energy Activities ($0.5 million-$1.2 million)

The Utility Owned Generation Carbon Reduction program will allow PG&E to accelerate analyses and/or future development and deployment of carbon capture technology for GHG emission reduction associated with PG&E's natural gas-fired generation facilities (Gateway, Colusa, and Humboldt). This program satisfies Section 712.8(s)(1)(B) (accelerating actions needed to bring renewable and zero-carbon energy online and modernize the electrical grid).

In 2026, PG&E proposes to conduct studies to evaluate existing carbon capture technologies with a view to assess the feasibility of deploying such technologies at PG&E owned gas fired generation sites. The proposed work is an advancement of work PG&E is considering in future years and would be completed in MWC AB. This work was not forecast in the 2023 GRC or any other rate case.

e. Renewable Energy Activities ($0.8 million-$2.5 million)

PG&E proposes to use VPFs to accelerate scope of work that supports California's decarbonization goals and Section 712.8(s)(1)(B) by expanding its Battery Energy Storage System (BESS) program, which enables an increasing amount of renewable energy on the grid through storing surplus renewable hydro, solar, and wind energy generated at non-peak for distribution to customers on-peak. PG BESS referenced herein is large utility-scale storage solar facilities not to be confused with other significantly smaller scale, Behind-the-Meter (BTM) battery programs described elsewhere in this VPF testimony associated with managing local reliability for localized customer needs during wildfire and non-wildfire related outage events. The generation-scale BESS projects that this section of testimony refers to are those used for the purpose of storing solar and wind energy produced at non-peak times of day so that energy can be used during on-peak. Such facilities of approximate sizing of ~25-200MW would be responsive to CPUC procurement orders and specifically proposed projects subject to review and approval by the Commission within separate applications.

A pipeline of potential early-stage development projects is desirable given the growing storage mandates required to address the continued growth of intermittent renewable energy on the grid and the integration needs fulfilled by additional large-scale energy storage.

For BESS pipeline development, PG&E proposes to expedite cross-functional analysis of developing PG&E-owned substation properties that have the potential to house BESS facilities. PG&E plans to more fully evaluate the sites for project physical suitability and energy deliverability, to complete the necessary work to ready the sites for interconnection, and to complete preliminary engineering design, with a goal to establish a pipeline of projects that could be ready to deploy when and where needed, rather than inefficiently reacting and responding to energy procurement solicitations. This would also give us the opportunity to expedite potential BESS projects in support of enhanced operations at the natural gas-fired facilities, in support of bulk electric system reliability, and in support of local behind the meter load management projects. Completion of this work enables the rapid future development of lower cost BESS projects through optimizing use of existing utility property adjacent to points of interconnection. Not only does this work support the integration of renewable energy resources such as wind and solar, the installation of new BESS projects may also enable PG&E to effectively bridge and/or defer the need to construct new electric distribution and/or transmission facilities, and enable improvements in reliable operation of the grid through fast frequency response, peak shaving and load leveling, grid resiliency and restoration, backup power, and reduced grid congestion, all resulting in affordability and reliability benefits for electric customers.

The proposed work is an advancement of work PG&E is considering in future years and would be completed in MWC AB. The proposed work was not forecast in the 2023 GRC.

2. Accelerating Interconnections and Actions to Reduce Operational Risk and Modernize the Grid More Efficiently Through Operating System Enhancements ($40-70 million)

a. Electric Generation Interconnection ($5 million-$15 million)

PG&E proposes to continue the expansion of the Electric Generation Interconnection (EGI) – Work at the Request of Others program in 2026 using VPF funds, which will support the acceleration of customer and generator interconnections and help accelerate the reduction in backlog caused by the Net Energy Metering (NEM) 2.0 sunset. The Expense EGI program manages the electric interconnection process for all generation projects interconnected at PG&E's distribution service but does not include related construction activities. EGI Projects may include retail tariff programs, compliance with Electric Rule 21, and interconnection applications for Federal Energy Regulatory Commission-jurisdictional projects under the Wholesale Distribution Tariff seeking Power Purchase Agreements.

This program supports Section 712.8(s)(1)(A) (accelerating customer and generation interconnections) because by applying VPF funding to these efforts in 2026, PG&E will be able to fund the processing of a greater number of generation interconnection applications than it would have been able to through preexisting filings alone. PG&E is working through a backlog created by the surge of applications caused by the NEM 2 sunset in 2023. Allocating additional funds will allow PG&E to maintain additional temporary resources to accelerate processing customer applications for self generation under Rule 21 Permission to Operate and reduce the backlog in 2026.

The work was forecast at $0 in the 2023 GRC because its EGI application fees were expected to offset expenditures in the program. However, following the NEM successor tariff roll out in 2023, an initial uptick in application volume in 2023 and a reduction in application volume starting in 2024 occurred, resulting in less offsetting customer EGI application revenue. This outcome was not known, included, or assumed in the filing of the 2023 GRC. Without the VPFs, this work would likely not be adequately resourced and the backlog would continue to persist through 2026, increasing interconnection timelines.

TABLE 7-3
COST SUMMARY OF ELECTRIC GENERATION INTERCONNECTIONS PROGRAM
(MILLIONS OF DOLLARS)

Line No.	Description	Cost
1	Electric Generation Interconnections	$5-15 million

b. Propel Program to Upgrade S/4HANA ($35-55 million)

Preparation and planning for PG&E’s SAP system upgrade will likewise accelerate customer benefits across multiple priorities, and especially (s)(1) sub-sections (A), (B), (D) and (F). PG&E’s approach to upgrade SAP — fitting to standard business processes — aims to simplify processes, resulting in improved customer interconnection timelines, enhanced grid modernization and resiliency, and reduced operational risk. By enabling a more efficient work production system, PG&E will increase and expedite its capacity to complete more work for customers within many of the six Section 712.8(s)(1) critical public purpose priorities.

SAP is one of the world's leading producers of software for the management of business processes. PG&E has significant customization in its current SAP system that was implemented in the 1990s, and data spread across 400+ applications. These customizations over time have led to wide variations in business processes that are hindering and slowing PG&E's ability to deliver value for customers. PG&E's current version of the SAP software will be out of support by 2027. As part of the new system implementation, PG&E will adopt industry standard business processes and maximize the use of out-of-the-box technology to keep ongoing O&M costs as low as possible. PG&E will consolidate data into one system to enable timely visibility of costs, assets and work performance so that PG&E can increase efficiencies and deliver more value to customers for the same cost into the future.

Propel is the PG&E program that will lead the migration to S/4HANA that will result in standardizing end -to -end processes, enabling modernization and breakthrough innovation across Engineering, Operations, Finance, Supply Chain, Human Resources and Information Technology. This modernization onto a single SAP platform is expected to enable improvements to communication flow and customer collaboration to meet on time delivery. Data transparency also improves work visualization to improve bundling and coordination of jobs in the same area to avoid multiple customer outages and truck rolls to the same location. This technology implementation will increase PG&E's ability to complete its core work that aligns with the described critical public purpose priorities.

In 2026, using VPF funds will further the implementation of Propel. The Propel program will be realized through a staggered deployment timeline with multiple phases and releases. This approach will enable learnings from each release and balance value delivery and risk mitigation. In 2026, Propel will have recently completed the Enterprise Design phase, focused on developing a solution blueprint that leverages standard business processes and non-customized SAP technology that will be deployed over multiple years. In 2026, Propel will deploy

Release 1, which rolls out the new capabilities to the PG, Human Resources and Enterprise Health & Safety functional areas. In addition, work will begin on Release 2 for Electric Distribution and Vegetation Management.

Propel accelerates and increases spending on public purpose priority (s)(1) sub-section (A) (accelerating customer and generator interconnections) through the overhaul of PG&E's SAP Enterprise Resource Planning (ERP) system. By leveraging the new SAP system to harmonize and optimize core business processes that support interconnections, PG&E will reduce the time required to connect new customers to the grid. Activities performed by Engineering, operations, Supply Chain, Finance and Human Resources are visible on the common SAP platform, allowing departments to work cohesively and minimize delays and errors. Through the integration of SAP with other major technology systems, such as PG&E's customer billing and grid management systems, data on energy consumption, grid conditions and customer requests are available in a visible manner. This enables PG&E to respond promptly to service requests and address any issues that may arise during the interconnection process. SAP's analytical capabilities also enable informed and timely decision-making. By analyzing historical data and current trends, PG&E can forecast demand, plan resource allocation and optimize its operations. These end-to-end planning capabilities ensure that employees are well-prepared to handle new service requests efficiently, reduce wait time and costs for customers and enhance communications and customer satisfaction.

This program also supports sub-section (B) (accelerating actions needed to bring renewable and zero-carbon energy online and modernize the electrical grid) through comprehensive asset and work management features for managing PG&E's hydro generation, nuclear generation and electric transmission and distribution grid, including maintenance scheduling, performance tracking and lifecycle management. Efficient asset and work management ensures these renewable and zero-carbon assets operate at peak efficiency, reducing downtime and increasing reliability. In addition, SAP supply chain capabilities enable end-to-end visibility of materials, equipment and inventory. This ensures that resources are available to support major infrastructure upgrade projects and modernization of the electric grid, operating without supply chain interruptions and minimizing the risk of supply shortages. Lastly, integration of work and asset management in SAP with grid management systems supports the balance of electric supply and demand resources. Real-time data on generation and consumption allows for precise adjustments, maintaining grid stability, preventing outages and coordinated dispatch of field resources for emergency response.

This program also supports sub-section (D) (increasing workforce and customer safety) by adopting standard business processes that include integrated scheduling and deployment of resources such as vehicles and job sites. The environmental, health, and safety module in SAP includes features such as risk assessment, incident management and safety management. The workforce will be equipped with tools to identify potential hazards and implement preventative measures to keep employees, contractors, and customers safe while work is performed on PG&E's assets in the field. SAP also has capabilities to record, track and analyze workplace incidents and accidents. This data is essential for identifying trends, implementing corrective actions and preventing future occurrences. Furthermore, SAP automates compliance processes so that federal and state safety standards are met and documented. This helps ensure that PG&E is always in compliance with relevant safety laws and regulations.

Finally, this program satisfies sub-section (F) (increasing resilience and reducing operational and system risk). SAP provides continuous data collection and monitoring capabilities, which are crucial for the effective management of utility assets. By detecting issues through inspection cycles, PG&E can initiate corrective maintenance repairs to address conditions before they escalate into significant problems. With robust analytics and predictive maintenance tools, PG&E can perform risk-informed analysis of equipment failures and maintenance needs, allowing for timely preventative maintenance, reducing the likelihood of unexpected outages and prolonging the lifespan of critical infrastructure. By maintaining equipment in optimal condition, the risk of operational failures is significantly diminished.

PG&E proposes a portion of VFPs to accelerate the ability to initiate this program and therefore expedite benefits to customers. While funding was requested for a technical ERP upgrade in the 2023 GRC, the scope of the Propel program was not contemplated or included in the forecast. The forecast for Propel is incremental to funding adopted in the 2023 GRC. This work will be completed in MWC JV.

TABLE 7-4
COST SUMMARY OF PROPEL PROGRAM

Line No.	Description	Cost (Millions of Dollars)
1	Propel Implementation Costs	$35-55

3. Reliability Battery Program ($4.6 million-$21.4 million)

The Reliability Battery program (formerly Batteries for Resiliency in A.24-03-018) has been renamed to further differentiate it from existing programs, which only provide resilience to customers impacted by wildfire safety outages, whereas the Reliability Battery program proposed here for VPF funding targets *non*-wildfire reliability issues. This work is an expansion of those existing activities that support permanent BTM battery installations for customers who are heavily impacted by wildfire safety outages (i.e. outages due to Public Safety Power Shutoffs/ PSPS and Enhanced Powerline Safety Settings/EPSS), by now targeting this support to customers outside of High Fire Risk Areas (HFRA) who are served on circuits with non-wildfire-related reliability issues. The existing activities targeting customers frequently impacted by wildfire safety outages range from providing a no-cost permanent battery installation to select customers who are most impacted to offering rebates that offset a portion of the cost of a battery installation for general market customers. By extending this support to customers frequently impacted by non-wildfire-related outages, especially on circuits which are identified as having poor reliability metrics, safe and reliable energy for customers will be improved.

This expansion to customers outside of HFRA is distinct from and incremental to existing activities and budgets, and it will be tracked as a fully separate set of expenditures and activities. The existing activities, by the nature of their funding, are explicitly limited to addressing wildfire safety related outages, and this is enforced through strict eligibility requirements.

This proposed expansion directly supports (s)(1) sub-section (F) (increasing resiliency and reducing operational and system risk) by providing backup batteries that can safely maintain power to customers' critical electrical devices and equipment during outages. Hence, the Reliability Battery Program directly increases resiliency for customers, many of whom may lack the means to adopt a resiliency solution on their own. It also reduces risk as, without this program, many customers may install more affordable but less reliable and safe solutions, such as a gas generator with extension cords, which requires regular maintenance and must be set up during an event.

This proposed expansion program indirectly supports priority (s)(1) sub-section (B) (accelerating actions needed to bring renewable and zero carbon energy online and modernize the electrical grid). The batteries, when not needed for backup power, can be used to respond to Time of Use rates or demand response signals, which provide price signals to increase usage during periods of excess solar generation and decrease usage during the evening hours when solar generation declines.

This Reliability Battery program was approved for 2025 VPF funds in D.24-12-033. PG&E is in the early stages of implementing the 2025 program: PG&E has identified multiple locations outside of HFRAs which are good candidates for this program as they are discrete geographic areas with persistent reliability issues and has finalized a subset of locations to focus on in 2025. PG&E is currently working with multiple battery equipment and installation vendors and is using the 2025 activity as an opportunity to partner with new vendors and use new, locationally-targeted marketing approaches.

The 2026 activities will be a continuation of the 2025 activities: In 2026, PG&E plans to expand this offering to additional customers and possibly additional areas, to refine its approaches to location-based marketing and to enhance its approach to load management requirements. For 2026, PG&E may also consider expanding its Reliability Battery Program offerings to include a rebate option in addition to the direct install approach being implemented in 2025. Learnings over a multi-year period from the Reliability Battery Program can also benefit the existing wildfire-focused programs. A summary cost estimate for this activity in 2026 is provided below.

TABLE 7-5
COST SUMMARY OF RELIABILITY BATTERY PROGRAM

Line No.	Description	2026 Low Range	2026 High Range
1	Variable Battery Costs	$4,200,000	$21,600,000
2	Fixed Program Management Cost	350,000	350,000
3	Total Cost	$4,550,000	$21,350,000

4. Electric Vehicle Detection for Forecasting and Vehicle-Grid Integration ($0.5-$1 million)

The Electric Vehicle (EV) Detection for Forecasting and Vehicle-Grid Integration (VGI) program supports an ongoing need to understand who EV-owning customers are within the PG&E service territory, how much electricity they are using, and when they are charging (EV detection and EV load data). This data needs to be continually refreshed as PG&E customers acquire or sell vehicles, buy or upgrade home chargers, and change their charging schedules. As PG&E anticipates a significant increase in EV ownership in the coming years in PG&E territory, understanding these customers and getting refreshed data on who they are and how they act will only become more critical.[11]

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11 95 percent of light-duty sales forecasted to be EV by 2036; EVs expected to make up 55 percent of medium-/heavy-duty vehicle population in 2045. Medium-/heavy-duty vehicle consumes 17x the energy of a class 1-2a (light-duty) vehicle. Source: IEA Global EV Outlook 2023. Trends in electric light-duty vehicles – Global EV Outlook 2023 – Analysis - IEA

Data on electric vehicle charging and electric vehicle ownership supports key grid needs such as load forecasting and planning transformer upgrades, as well as customer needs like marketing and designing rebates, rates and programs. EV detection and EV load data enables an understanding of where EV loads overlap with current and forecasted constrained transformers, enabling PG&E to bundle work and reduce repetitive truck rolls to replace failed transformers. This data will also enable efficient designing of VGI programs so customers can use their vehicles as backup power and support the grid when it is constrained, allowing EVs to act as a cornerstone of resiliency and reliability.

In 2026, the program's focus will be to expand the work currently ramping up in 2025, including work on internal development of EV detection machine learning models and EV load disaggregation machine learning models. These models will take years to fully develop. PG&E plans to focus initial efforts in 2025 and early 2026 on creating successful base models, which meet the performance expectations and are computationally efficient to run. Once base models are successfully developed, this program's capabilities will be expanded to better detect EV charging at homes with confounding factors, such as solar panels, continually improve base model performance, and ensure the code runs efficiently to save AWS costs. While developing internal capabilities, PG&E plans to retain a contractor for EV detection and EV load disaggregation, to close the gap in EV detection and EV load disaggregation data access. Internal development supports the growth of internal PG&E capabilities, will offer PG&E resilience against changing vendor prices and data availability, and offers the potential to realize efficiencies to further reduce cost over time.

This program accelerates and increases spending on public purpose priority (s)(1) sub-section (B) (accelerating actions needed to bring renewable and zero-carbon energy online and modernize the electrical grid) by promoting vehicle-to-grid integration, a technology that can increase the resilience and clean energy on the grid. EV detection and EV charging load data enables more efficient design of VGI programs so customers can use their vehicles as backup power and support the grid when it's constrained. Charging EVs during times when renewable energy is plentiful on the grid, such as during the day when solar is most abundant, and then discharging them later when electricity is from dirtier sources, has the potential to further increase the clean energy on the grid. By understanding customer habits about when they typically charge their EVs, PG&E program managers better understand the needs of these customers and how to tailor a VGI program into their lifestyle.

In addition, the program accelerates and increases spending on public purpose priority (s)(1) sub-section (F) (increasing resilience and reducing operational and system risk) by helping managers design and market programs to optimize EV charging load time to reduce stress on the grid.

With better data on customers' EV adoption and charging behaviors, PG&E can improve its incentives, marketing, rates and programs to encourage charging when the grid is unconstrained, helping drive grid resiliency. For example, current EV detection results (from a vendor PG&E contracted with for 2024 only) were used in both program design and marketing for EPIC 4.04. This initiative informs efforts to shift EV charging to times when the distribution grid is not constrained, reducing stress on grid assets, extending their useful life, and helping reduce the risk of transformer overloads. EV detection data allowed program managers to select the three counties with the greatest concentration of EVs corresponding with a congested distribution system for this pilot, and to market directly to those EV owners for pilot enrollment.

These costs were not forecast in the 2023 GRC or any rate case.

TABLE 7-6
COST SUMMARY OF EV DETECTION PROGRAM

Line No.	Description	2026 Low Range	2026 High Range
1	2 Full Time Employee (Fully Loaded Labor Rate)	$482,086	$482,086
2	Estimated 3rd Party Contract Cost	N/A	$508,957
3	Grand Total	$482,086	$991,043

5. Customer Electrification Experience ($3.3 - $6.2 million)

To support California in achieving its carbon neutrality goal by 2045, including 100 percent new zero-emissions vehicles sales by 2035 and deployment of 6 million heat pumps by 2030, PG&E proposes to continue using VPF revenues in 2026 to simplify the customer transportation electrification and building electrification (BE) experience and reduce friction as customers consider electric vehicles and appliances. These program costs are not funded through the 2023 GRC or any other revenue request proceeding, and are incremental.

PG&E has identified three areas that could better support customers as they consider and pursue electrification: (1) development of materials and training to provide comprehensive electrification support, (2) development of online resources to provide comprehensive electrification support, and (3) residential BE support (formerly BE weatherization support). The Customer Electrification Experience program intends to provide benefits to all PG&E electric customers, as it is designed to accelerate electrification which should put downward pressure on rates.

In 2026, PG&E intends to use the requested VPF funds to continue and expand on the work initiated in 2025. PG&E is in the early stages of implementing 2025 activities for this program, and certain actions to set up the program (such as issuing RFPs) have lead times that can last multiple months. As PG&E is proposing to extend this program through 2026, a cost summary for these activities for 2026 is presented below:

TABLE 7-7
COST SUMMARY OF CUSTOMER ELECTRIFICATION EXPERIENCE PROGRAM

	Electrification (EV+BE) Customer Experience VPF Forecast		
Line No.	Description	2026 Low Range	2026 High Range
1	Materials and Training for Comprehensive Electrification Support	$400,000	$550,000
2	Online Resources for Comprehensive Electrification Support	1,730,000	3,130,000
3	Residential BE Support	1,231,000	2,510,000
4	Grand Total	$3,361,000	$6,190,000

a. Materials and Training for Comprehensive Electrification Support ($400,000-$550,000)

The goal of developing materials and training to provide comprehensive electrification support is to meet the growing demand from customers looking to understand how to best work with contractors and PG&E to ensure their homes can support increased load from new electrification technologies.

This VPF funding can enable PG&E to accelerate its development of comprehensive materials and deliver training for its CSRs to equip them with the knowledge needed to effectively address electrification-related inquiries. CSRs are often the first point of contact for customers and their ability to provide accurate, helpful, and timely information is critical to a positive customer experience. Currently, limited electrification-specific knowledge can result in missed opportunities if customers come away from these calls so overwhelmed or unclear on the process to electrify that they cease efforts to pursue electrification technologies at that time.

PG&E would also use this funding to conduct outreach to third parties that are part of the customer electrification process; for example, automotive dealerships to whom customers look to answer basic questions about how to charge their new vehicles at home. These third parties can accurately relay information about the PG&E process and/or redirect customers to PG&E is important to ensuring that customers are able to easily and accurately understand how to proceed with safely powering their new electrification technologies.

In 2026, PG&E intends to use the requested VPF funds to continue and expand the work funded by the 2025 VPF funds, including: (a) update its internal database of electrification-related questions and answers for CSRs to refer to during their conversations with customers, as needed; (b) conduct refresher call center trainings; and (c) expand third-party outreach.

This work satisfies Section 712.8(s)(1)(E) (communications and education) as it promotes increased education and communications for electrification technologies, by developing materials and training to support customers as they consider EVs and appliances, including how to work with PG&E and contractors.

b. Online Resources for Comprehensive Electrification Support ($1.7 - $3.1 million)

In addition to contacting the PG&E call center, customers also seek information on the PG&E website throughout the customer electrification journey. Providing comprehensive digital resources supports customers who are at various stages of electrification. Firstly, PG&E plans to build upon existing online resources for customers like the EV Savings Calculator (EVSC) to better support customers. The EVSC was originally funded as a customer education tool about available EV models in support of the EV Charge Network program. Since the sunset of that program in 2020, the EVSC has received only minimal updates and operations and maintenance needs and there has not been a major update to the tool in years. VPF funding would allow PG&E to expand self-service online resources like the EVSC to more comprehensively support customers in their electrification journey: for example, by providing information and tools to support customer decision making about EV charging—including managed charging—at the same time as they are shopping for an EV.

Another online resource to support customers' electrification experience is the Electrification Advisor tool. This tool will provide tailored resources to guide customers to the best approach for electrification such as a cost estimator tool, next steps for energization, recommended programs and incentives, et cetera. The first phase of this tool will incorporate customer-provided information (e.g., EV type, charging needs, interest in other home electrification, panel size, and budget availability) to generate recommendations of how to meet their unique electrification needs in the most cost efficient and streamlined way. The second phase of this tool will improve upon the Phase 1 functionality by allowing customers to upload a picture of their panel, which will be automatically analyzed to estimate available panel capacity and provide a more accurate recommendation of resources and next steps. The tool could eventually be expanded in a Phase 3 to be a comprehensive resource to simplify the process for customers and tie into the PG&E internal load evaluation processes which ensures that the local grid and the wire to the house can support the required load.

This work satisfies Section 712.8(s)(1)(E) (communications and education) as it promotes increased customer knowledge and promotes the adoption of customer electrification through usage of the EVSC and electrification advisor tools. Furthermore, these tools will include resources to help customers better understand PG&E processes, including the service planning customer journey and how to interconnect Distributed Energy Resources (DER) like bi-directional chargers, leading to an improved customer experience.

This program supports (s)(1) sub-section (A) (accelerating customer and generator interconnections) by simplifying the customer experience as customers consider electric vehicles and appliances, and removes cost and timing constraints in accommodating new load onto the grid. Simplifying and streamlining the customer experience of adding new load such as an EV charger or electric appliances makes it easier for customers to adopt these technologies at a greater scale which is essential to reaching the State's ambitious GHG reduction goals.

In 2026, PG&E plans to use the requested VPF funds to: (a) expand the EVSC; (b) build out additional online resources if needed, and (c) complete Phase 1 of the Electrification Advisor tool and begin Phase 2 enhancements to improve functionality. Currently, PG&E is implementing its 2025 activities to: (a) operate and maintain the EVSC and (b) develop technical requirements for the Electrification Advisor tool and determine what is needed for the next phase.

c. Residential BE support ($1.2 - $2.5 million)

The purpose of the residential BE support program is to support BE projects and programs for residential customers by providing BE and other complementary measures that help customers decarbonize and improve both the comfort and safety of program participants. As explained in PG&E's Advice 7511-E,[12] this program was originally titled "BE Weatherization Support" in the A.24-03-018 proceeding and

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[12] PG&E Advice 7511-E, p. 9.

subsequently updated to "Residential BE Support" to better reflect its purpose and use. The residential BE support program is a broad, multi-pronged suite of programs focused primarily on vulnerable and underserved customers in disadvantaged communities that expands the scope of existing BE programs by 1) serving customers that would otherwise be ineligible, or 2) addressing barriers to customer participation not otherwise addressed with existing funding sources, described below.

This suite of programs satisfies sub-section (C) (accelerating building decarbonization) by providing building electrification support and electric appliance support. For example, REEP program offerings include conversion of natural gas appliances to electric appliances, including heat pump water heaters and heat pump space conditioners, which directly contribute to building decarbonization.

1) Single-Family Eligibility Expansion of Residential Equity Electrification Pilot (REEP) Program

PG&E proposes to use VPFs to expand customer eligibility for the REEP program that are currently not served. REEP is an existing PG&E pilot with authorized funding through the Commission's Energy Efficiency (EE) proceeding, R.13-11-005. This pilot has strict eligibility criteria both at a geographic and customer level, with key criteria including customer location with disadvantaged communities and maximum household income levels. This program is strictly focused on single-family homeowners and renters (including 2- to 4-unit properties). REEP program offerings include building electrification equipment (e.g., heat pump water heaters, heat pump space conditioning, electric clothes dryers, and electric cooking appliances), weatherization and other EE measures, and project enabling measures such as remediation, electrical panel replacements and electric service upgrades where necessary for the BE project to proceed. All REEP projects must include at least one BE measure to qualify, but the program offers up to full electrification. Under the approved program design, customers that do not meet the eligibility criteria cannot participate in the program.

In 2026, PG&E plans to continue the work currently being implemented in 2025 to electrify the homes of vulnerable customers. Using 2026 VPF funds would allow PG&E to maintain the 2025 VPF-funded expansion of REEP customer eligibility beyond the current criteria to serve additional customers that would otherwise be ineligible to participate in REEP.

Use of VPF funding would be strictly limited to covering the project costs (installation labor and materials) for those customers that fall outside of REEP's existing eligibility criteria, as well as any incremental administrative and project support costs associated with those projects. This would be accomplished by negotiating separate payments directly tied to the eligibility-expansion projects, and these expenditures would be tracked separately.

2) BE Support for Energy Savings Assistance (ESA) Pilot Plus/Pilot Deep Program

PG&E proposes to use VPFs to on costs not covered by the ESA Pilot Plus/Pilot Deep program. The ESA Pilot Plus/Pilot Deep (PP/PD) program is an existing PG&E pilot funded through the Low Income proceeding in D.21-06-015, and is currently operating through the end of 2026. PP/PD's primary objective is to achieve deep energy savings for participating low--income customers but includes a secondary objective to offer building electrification in conjunction with energy-saving upgrades for select customers. This pilot offers comprehensive EE measures such as weatherization, lighting, and appliance replacements, as well as BE equipment (e.g., heat pump water heaters, heat pump space conditioning, electric clothes dryers, and electric cooking appliances). However, this pilot does not have authorized funding to support electric service upgrades which may be necessary to support the new electric load from the BE measures and enable the BE project to proceed. Such costs include engineering design fees and construction costs typically borne by the project applicant (i.e., the customer).

In addition, the pilot's use of authorized funds is limited by a $2,500 per-project cap on home remediation. In many cases, remediation is necessary to enable the safe installation and operation of BE measures. Such remediation may include things like electrical circuitry repairs, hazard mitigation, replacement of water heater platforms, electrical panel replacements, and/or other work that would be necessary to enable the BE project to safely proceed. In cases where BE-related remediation exceeds the cost cap, the BE measures related to the excess remediation would not be eligible to proceed.

PP/PD building electrification projects that include service upgrades or excess remediation are not authorized to pay for costs above the cap, and the low--income customers selected to participate often lack the ability to cover those costs. These customers are unable receive BE measures and instead are limited to non-BE energy efficiency measures and education. This represents a major barrier to BE within this pilot.

In 2026, PG&E plans to continue the work currently being implemented in 2025 to use VPF funding to fill this gap by funding the cost for electric service upgrades when such upgrades are required for a BE project to proceed, as well as BE-related remediation costs above the cost cap when necessary for the BE project to be installed and operate safely. In this way, the VPF funding helps overcome a critical project barrier to BE and is limited strictly to BE-related project costs that are not covered through existing authorized funding.

3) Emergency Water Heater Replacement Support

An emergency water heater replacement may be necessary when a residential direct install program's home energy assessment determines a water heater to be unsafe. For example, the PG&E ESA Program encountered approximately 1,800 water heater failures in 2024.[13] In a situation where emergency water heaters fail, contractors and residents generally replace the old water heater

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[13] See ESA Table 2 in the PG&E ESA/CARE/FERA Monthly Report for December 2024, available at hyperlink: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M555/K441/555441072.PDF.

with a new water heater of the same type (i.e., old gas water heater replaced with a new gas water heater) in order to minimize the amount of time until hot water is restored to the home. Opting to electrify the gas water heater may result in delays to the restoration of hot water for several reasons such as limited availability of heat pump water heaters in stock, the need for an electrical panel upgrade to support the new heat pump water heater or possibly needing electric utility service upgrades to support the new electric load. Thus, a like-for-like replacement of the gas water heater represents a missed opportunity to electrify this home at the time of equipment failure.

In 2026, VPF funding would be used to explore programmatic opportunities to support the electrification of gas water heaters in an emergency water heater replacement scenario. This may include exploring various options for an immediate but temporary replacement of the gas water heater until a heat pump water heater can be installed safely and permanently, or encouraging contractors to stock more heat pump water heaters. Beyond the direct customer recipients of this solution, using VPF funds in this way could also produce learnings about what option is most effective in an emergency water heater replacement scenario and how to successfully implement it on a broader scale.

Overall, the Residential BE Support program activities described above support California's goals to achieve carbon neutrality by 2045 and its goal to deploy 6 million heat pumps by 2030. Each of these initiatives directly support BE projects, most of which directly support heat pump adoption. Building upon existing programs and pilots allows PG&E to leverage existing program infrastructure while breaking down key barriers and propelling additional BE projects to be completed among PG&E's vulnerable customers and disadvantaged communities. These program channels already exist, include comprehensive BE, and are coupled with EE offerings that can help produce net bill savings while improving comfort and reducing health risks for household members.

6. Programs to support building decarbonization for small businesses ($1.5 million - $2.5 million)

PG&E proposes to use the 2026 VPF funds to continue to expand the Simplified Savings Program (SSP) which is funded through the Energy Efficiency proceeding. SSP is an EE program targeting micro--small businesses that are considered hard-to-reach and/or are located within disadvantaged communities. The primary objective of this program is to produce bill savings for participants. This program offers comprehensive EE measures such as HVAC, lighting, and refrigeration equipment, but does not include building electrification measures. This program accelerates and increases spending on public purpose priority (s)(1) sub-section (C) (Accelerating building decarbonization) by using VPF funds to promote building decarbonization for small businesses.

As described in PG&E's Advice 7511-E,[14] PG&E intends to begin the expansion of SSP to include BE measures in 2025 using VPF funds. Here, PG&E proposes to continue that effort in 2026, including expanding SSP's offerings to include BE equipment to build upon the EE measures already offered. These measures may include heat pump water heaters, heat pump space conditioning, and commercial electric ovens and fryers.

VPF funding would be strictly limited to covering the project costs (installation labor and materials) for the BE-related measures that fall outside of SSP's current offerings, as well as any incremental administrative and project support costs associated with those measures. This would be accomplished by negotiating separate payments directly tied to the expansion measures, enabling new BE conversions among small business customers. These expenditures would be tracked separately.

TABLE 7-8
COST SUMMARY OF SMALL BUSINESS DECARBONIZATION PROGRAM

Line No.	Description	2026 Low Range	2026 High Range
1	Small Business Decarbonization	$1,485,000	$2,475,000
2	Total Cost	$1,485,000	$2,475,000

14 Advice 7511-E, pp. 14-15.

7. One VM ($10 million - $15 million)

One VM is a map-based work execution, monitoring, and validation application enabling PG&E to maintain records and perform work. The application and the Vegetation Management (VM) program reduce wildfire risk and operational outages by cataloging, mapping, and recording veg point risk assessment. VM is planning multiple efforts to improve PG&E's ability to make informed decisions and improve efficiencies based on the information recorded in the One VM application. These efforts include enabling Master Data Management on our underlying Vegetation objects (Poles, Spans, etc.) enabling our VM teams to better operate with records which meet our Traceable, Verifiable, Accountable, and Complete guidelines. Our data strategy/architecture effort will define needed capabilities and implement a data platform better aligned to support both operations and data analytics.

In 2026, VM will expand and improve its capabilities to increase the efficiency and usability of PG&E's technology implementation and functionality in key areas. These improvements directly align with PG&E's goals to improve work performed in wildfire mitigation in a cost-efficient manner, while maintaining our compliance with internal and external policies.

The implementation and expansion of Operational Tree Registry (OTR) is the cornerstone project of Vegetation Management’s technology portfolio in 2026. OTR is designed to reimagine work planning solutions to drive efficiencies in field execution. Development of this work in 2026 will support implementation across the service territory in 2027. Core to this effort, work bundling will allow VM to focus on highest risk areas and provide agility needed to reduce customer costs.

Setting the foundation for the above improvements, VM aims to advance its maturity in application delivery. Focused on business agility and driving business value, this effort will align our organization and processes to more nimbly adapt to current needs, reduce waste, and drive business value within PG&E and for our customers.

This program supports (s)(1) sub-section (D) (workforce and customer safety) by improving field inspections technology and process and while reducing customer touchpoints and (F) (increasing resiliency and reducing operational and system risk) through improved data, ensuring the safety of our workforce, our facilities, and our customers.

This program was not forecast in the 2023 GRC or any other rate case. Without applying the VPFs to this program in 2026, the work would have been delayed or not completed.

TABLE 7-9
COST SUMMARY OF ONE VM PROGRAM

Line No.	Description	2026 Low Range	2026 High Range
1	One VM Application	$3,500,000	$5,500,000
2	Data and Process Improvements	4,000,000	6,000,000
3	OTR	2,500,000	3,500,000
4	Grand Total	$10,000,000	$15,000,000

8. Pre-staging of Temporary Generation in support of Winter Storms (MWC AB6) ($4-$8 million)

In early 2024, the temporary generation program developed a plan to pre-stage temporary generation (Temp Gen) at various substation locations that are typically impacted by winter storms. By utilizing 12 years of historic meteorological data, this valuable analysis identified three divisions that are typically impacted by winter storm events, based on Category (Cat) 2 and greater Operations Emergency Center (OEC) activations within the four-month winter season (December – March) and substations within the divisions that could receive Temp Gen to mitigate customer outages. The three divisions are Humboldt, Sonoma and Central Coast and include a total of eight substations that support approximately 11,000 customers. This proactive preparedness posture allows the program to safely move equipment and resources to these eight locations in a planned efficient manner during “blue-sky” conditions. The equipment is staged, interconnected and tested in this non-emergent environment working closely with our distribution control center. The equipment remains on site in this “pre-stage” posture for the entirety of the winter storm season, typically December through March.

This Pre-Staging Temp Gen strategy was developed outside of the 2023 GRC cycle. In 2026, the focus of the program is to review the updated meteorology data, confirm historical substation deployments for winter storm support, coordinate pre-staging with the vendor, internal crews and control center, and test pre-staged equipment to confirm operational readiness.

Pre-Staging Temp Gen provides many advantages that support Section 712.8(s)(1)(D) (workforce and customer safety) and (F) (increasing resiliency and reducing operational and system risk), as described below:

- Lower potential for safety impacts to our contractors and internal employees during planned "blue-sky" mobilization versus deployments during emergency storm events;
- Pre-staging Temp Gen creates greater operational readiness for storm season and positions us to better serve our customers in these key areas. By utilization of this program during the 2024 winter storm season there were approximately 60 million minutes of avoided customer interruptions;
- By pre-staging Temp Gen the program has reduced the cost of multiple mobilization and demobilization efforts, this has proven to reduce unit cost by greater than 50 percent;
- Realized cost savings when planned mobilizations are completed on straight time pay versus emergency response at premium pay; and
- Upon an OEC activation, the equipment reservation cost, operating cost and a portion of the mobilization/demobilization cost are allocated to the emergency order. The one-time mobilization cost are split equally between all December OEC activations and the one-time demobilization cost are split equally between the January – March OEC activations.

There are two primary cost components to the Winter Storm Pre-stage Program: The first component is the cost allocation to major emergency jobs that include Temp Gen reservation cost, mobilization, labor, fuel, transportation and demobilization; the second cost component is the Temp Gen Stand-by Cost, described as the portion of the reservation cost for the equipment in between OEC activations or blue-sky days. Based on the historical weather modeling, the blue-sky days during this winter storm season average 300 days or equate to approximately $6 million in cost annually. This program was not in any rate case and the work performed and costs proposed here are incremental.

TABLE 7-10
COST SUMMARY OF PRE-STAGING OF TEMPORARY GENERATION PROGRAM

Line No.	Program	Cost Summary in 2026
1	Pre-Staging for Temporary Generation	$4-$8 million

9. PG&E Contingency Uses (40 million-$92 million)

PG&E acknowledges the potential for earning less than the forecasted amount of volumetric performance fees in 2026 depending on DCPP's actual generation. PG&E accounts for this possibility in this application by not earmarking 100 percent of the VPFs for pre-defined uses, but by reserving some as contingency for key safety and risk programs, as well as applying the funds to DCPP operational costs.

a. Usage for Safety and Risk

These or contingency funds, if earned, will be used for any unforeseen key critical risk and safety work that falls within one or multiple of the below MWCs and that exceed imputed GRC authorized amounts for 2026. These categories include areas where emerging needs may occur, such as in response to storm or wind events, landslides, or other unanticipated operational conditions. Each category satisfies at least one if not more of the six public purpose categories in Section 712.8(s)(1).

A table summary of each MWC is provided below, with additional information provided following the table.

TABLE 7-11
CANDIDATE PROGRAMS BY MAJOR WORK CATEGORY
(THOUSANDS OF DOLLARS)

Line No.	MWC	Name	Description	2026 GRC Imputed
1	BH	Electric Distribution Routine Emergency	Corrective Maintenance Expense includes activities related to the repair or replacement expense related to electric distribution infrastructure in response to an outage to customers or an unsafe condition requiring immediate response and standby. This also includes the switching of the system's configuration in response to overhead and underground outages occurring under Level 1 conditions. This switching occurs in order to make the situation safe, restore power to as many customers as possible, and isolate the trouble location so repairs can be made.	$81,910
2	BF	E T&D Patrol/Insp	Patrolling and inspecting overhead facilities, underground facilities; infrared inspecting overhead facilities; inspecting and testing overhead and underground line equipment; inspecting network transformers; performing special patrols; and other work associated with maintenance such as the cost of implementing mobile technology.	$88,705
3	GC	E Dist Subst O&M	Distribution Substation O&M includes operations, preventative maintenance, and corrective maintenance within distribution substations. Specifically, it includes the following: Operations in a substation include – substation facility and equipment inspections; switching; activities associated with providing safe conditions for employees; restoring service to customers; calibrating and adjusting substation equipment; testing; maintaining station logs and prints; janitorial and utility services; landscaping maintenance; purchasing operation supplies; and travel time necessary to perform field work. Preventive maintenance includes – diagnostic testing; overhauls; washing insulators; application of room temperature vulcanized rubber coating to reduce the need to complete periodic insular washing; yard repairs; refurbishing capitalized emergency and surplus equipment; animal abatement; and the associated travel time. Corrective maintenance includes – repairing failed equipment; mobile substation and mobile transformer installation costs; relocating capitalized emergency and surplus equipment; and the associated travel time.	$56,506
4	GA	E T&D Maint OH Poles	Maintain Overhead Electric Poles involves activities to assess the condition of the lower half of poles and to preserve the poles' wood strength. This MWC focuses on inspecting, and as appropriate, testing and treating all 2.3 million distribution poles in PG&E's system in a continuous 10-year cycle in compliance with CPUC regulations. This MWC includes performing a combination of tests on every pole in the system. Where the pole condition warrants reinforcement, the pole is restored to its original strength, extending the pole's serviceable life.	$44,423
5	BA	E Dist Operate System	Electric Distribution Operating Activities include distribution control center and field operations, including work performed by distribution system operators, troublemen, electricians, and electric crews. This work includes operating switches to transfer load between circuits, isolating customers or de-energizing sections of line during construction or maintenance and reconfiguring circuits to mitigate problem situations.	$32,708

Additional spending and acceleration of activities in MWC BH satisfies sub-section (D) (Workforce and customer safety) by addressing safety hazards from damaged distribution assets and keeping customers safe by taking immediate action in response to an outage to customers or an unsafe condition requiring immediate response and standby.

Additional spending and acceleration of activities in MWC BF satisfy (s)(1) sub-section (F) (Increasing resiliency and reducing operational and system risk) by accelerating inspections and patrols of electric distribution facilities to detect conditions that are safety or wildfire risks. BF activities support our overhead ground and aerial inspection programs as well as our underground inspection program. In addition, MWC BF satisfies (s)(1) sub-section D (Workforce and customer safety) because increased activities will not only detect risky conditions that could impact individual customers served by electrical facilities but also lead to investments and pilots in inspections that will ultimately increase workforce safety, for example, leveraging drones for inspections rather than relying on field personnel.

Additional spending and acceleration of activities in MWC GC satisfy (s)(1) sub-section (F) (Increasing resiliency and reducing operational and system risk) by accelerating the corrective repair work on failed equipment, mobile substations and mobile transformers. Accelerating the repair work on mobile transformers will create adequate Capitalized Emergency Materials stock and will reduce the potential risk for power outages that lead to increased system resiliency and reduced system risk. Accelerating corrective work will minimize the number of oil leaks from transformers and circuit breaker failures which is directly connected to reducing operational and system risk. In addition, MWC GC satisfies (s)(1) sub-section D (Workforce and customer safety) because increased corrective repair activities work will reduce the risk for power outages due to not having enough mobile transformer stock needed.

Additional spending and acceleration of activities in MWC GA satisfies (s)(1) sub-sections (D) (Workforce and customer safety) and (F) (Increasing resiliency and reducing operational and system risk) by performing pole intrusive inspections, pole restoration, pole loading analysis, and joint utilities coordination. Pole inspections are designed to determine the condition of poles and, where appropriate, extend their asset life by preserving the pole's wood strength. Based on results of pole intrusive inspection activities, where a pole's condition warrants restoration, PG&E restores the pole to its original strength and extends the pole's serviceable life. Pole loading analysis ensures compliance with regulatory requirements and identifies overloaded poles to be mitigated. PG&E coordinates with joint pole owners to ensure agreements are in place and costs are shared appropriately.

Additional spending and acceleration of activities in MWC BA satisfy (s)(1) sub-section (F) (Increasing resiliency and reducing operational and system risk) by employing and training the distribution system operators and distribution operations engineers who actively monitoring the distribution system, substations and all distribution assets. Their primary activities include:

- Monitoring the distribution system and performing system configuration changes, such as switching and circuit reconfiguration;
- Processing switching applications for work that enables construction to maintain and improve the distribution electric system infrastructure;
- Directing safe responses to outage and 911 emergency calls while minimizing response time and outage duration; and,
- Providing guidance from Engineers to Operators regarding load transfers and circuit reconfigurations.

In addition, BA satisfies (s)(1) sub-section (A) by supporting system hardening and customer interconnections since distribution system operators and engineers perform the primary work to energize and restore customers' electrical service.

Lastly, BA satisfies (s) (1) subsections (D) & (E) by maintaining situational awareness and visibility to the distribution electric grid status within three distribution control centers and communicating with field personnel to safely operate distribution assets during routine and emergency conditions, documenting and directing safe switching operations and reconfiguration of the system to optimize safety and resiliency when conditions warrant.

b. Usage for DCPP Operational Costs

To the extent PG&E determines the expenditures for the above-described categories is not needed, or that the VPFs should otherwise be spent on operational costs of DCPP, PG&E will use its discretion to apply the VPFs to reduce DCPP operational costs for all customers.[15] In the event that DCPP costs exceed 115 percent of approved forecast costs, then D.23-12-036 requires that VPF funds be used to offset costs over 115 percent of the approved forecast.

D. PG&E's Plan for Post-Spend Compliance Review

1. Qualitative Confirmation of Spending Categories

PG&E proposes a process based upon a qualitative and quantitative review of post-spending categories to ensure these expenditures comply with Section 712.8(s)(1).

On a qualitative front, the accounting, finance, and regulatory teams will prepare and document the expenditures and uses, including a demonstration that the actual spend occurred on one of the uses described above and within one of the six categories in Section 712.8(s)(1). A qualitative review both before and after the expenditures will occur to ensure that the VPFs are spent pursuant to Section 712.8(s)(1), D.23-12-036, and any subsequent Commission decisions.

2. Pre- and Post-Spend Accounting Tracking in DCEOBA Sub-Account

PG&E proposes a methodolical approach to track the VPFs in the DCEOBA and ensure compliance with Section 712.8(s)(1) and D.23-12-036 requirements.

First, on the front-end, PG&E proposes a pre-spend tracking process. Specifically, PG&E proposes to allocate the VPF component of the statewide non-bypassable charge (NBC) rate by estimating a percent allocation for storing in a Volumetric Performance Fee Subaccount found within the DCEOBA.[16] This allocation will be the percentage of the total NBC revenue requirement designed to collect VPFs from customers in

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[15] Pub. Util. Code § 712.8(s)(1).

[16] The Volumetric Performance Fee Subaccount is proposed in PG&E's Advice 7204-E, submitted on March 14, 2024 (effective pending disposition).

rates. As part of the collection of the NBC from its own customers, as well as SCE and SDG&E customers, PG&E will use this allocation to estimate the amount of VPFs to be stored in the VPF Subaccount. By storing these revenues as they are collected separately, PG&E ensures that the portion of revenues subject to compliance requirements in Section 712.8(s)(1) and D.23-12-036 is separate and distinct from the remainder of the DCEOBA revenues collected from customers.

Second, PG&E will use these allocated amounts stored/set-aside in the subaccount to spend on Commission-approved categories. PG&E proposes to spend its 2025 revenues on prioritized activities as described in Section C above. Upon approval, PG&E will also record the expenses associated with these prioritized activities to the VPF Subaccount for clear tracking of the approved prioritized costs against collected VPF revenues.

Third, as part of the annual true-up process, PG&E will compare actual recorded costs to true up the amounts in the sub-account. As part of this process, PG&E must determine whether DCPP's actual recorded operating costs recorded to DCEOBA are more than fifteen percent above the approved forecast. This includes comparing the recorded costs in the Extended Operations Subaccount against the approved annual forecast in the prior year's proceeding. If recorded costs in the Extended Operations Subaccount are more than fifteen percent above the forecast, then PG&E will use available VPF funds to offset the costs above 115 percent before they are used for another purpose. In this circumstance, PG&E would transfer these funds back to the Extended Operations Subaccount. If costs are below 115 percent of the approved forecast or there are any remaining VPF funds, PG&E may request for these funds to be used for the other public priorities discussed above. Any remaining over- or under-collected balances in the Extended Operations Subaccount will be presented in the next forecast case to be returned to or collected from customers in the next Annual Electric True-up (AET) AL.

Finally, PG&E is in the process of developing an internal management review process that is consistent with PG&E's Internal Control over Financial Reporting (ICFR) program. This includes applying PG&E's existing controls for order management review, journal entry review, and balance sheet account reconciliations, amongst other management review prior to initiating the annual compliance and fund plan filing. These controls would be subject to PG&E's Sarbanes-Oxley program and ongoing review by External Auditors for testing as selected.

E. How PG&E Will Track VPF Project Expenditures to Ensure They are Incremental to costs Recorded to Existing Accounts Authorized by Commission Decisions

PG&E will demonstrate compliance with the requirement that there be no double recovery in rates,[17] in other words, that they are incremental to costs recorded to existing accounts authorized by the Commission in its annual post-spend report. The first post-spend report will occur in March 2026 for VPF expenditures in 2025. For clarity, this testimony does not constitute PG&E's demonstration of incrementality, which PG&E will provide in March 2026.

In its post-spend report, PG&E will demonstrate that no double recovery occurred in one of three ways: (1) because the program is new and therefore not recovered in rates, (2) costs above what was authorized by the Commission are incurred, or (3) PG&E performed additional work above what was forecast in the GRC or other ratemaking proceeding. PG&E will track the amounts spent on the program to ensure that VPFs are not applied in a way that results in double recovery. For example, any work funded by VPF funds in the Contingency for Safety and Risk program will be incremental to what was authorized in the 2023 GRC.

PG&E will engage in a regular review process by which it ensures that any VPF spend occurs on an incremental basis to any already-approved amounts in a program. PG&E proposes the below table, which is also addressed in Phase 2 of the R.23-01-007.

[17] Pub. Util. Code § 712.8(s)(2).

TABLE 7-12
CATEGORY, FORECAST, AND VARIANCE

Section 712.8(s)(1) Categories	Program	MAT(s)	Forecasted Spend	Actual Spend	Spend Variance	Spend Variance Explanation	Relevant Citation(s)
A Total							
A							
A							
B Total							
B							
B							
C Total							
C							
C							
D Total							
D							
D							
E Total							
E							
E							
F Total							
F							
F							
DCPP Operations Total							
Total							

In addition to this process, PG&E will also engage in accounting practices that are consistent with PG&E's ICFR program. This includes applying PG&E's existing controls for order management review, journal entry review, and balance sheet account reconciliations, amongst other management review prior to initiating the annual compliance and fund plan filing. These controls would be subject to PG&E's Sarbanes-Oxley program and ongoing review by independent third-party auditors for testing as selected.

Specifically, these accounting and control practices include these steps:

- **Separate Order Tracking**: Programs authorized in the VPF Spend Plan will be recorded to orders with unique cost objects to identify the portion related to VPF recovery. Specifically, a program that is authorized in another case (such as GRC) will have an amount tagged to that rate case, and incremental amounts will be recorded to unique orders with an Alternative Funding attribute indicating it is recovered through VPF revenues.
- **Order Management Review**: Systematic comparison of program expense for programs authorized in the VPF Spend Plan. For programs that have authorized recovery in another case, the comparison includes program expense tagged to that other case to authorized amounts and/or work units to ensure that appropriate work authorized under that case is being executed. Separately, program expense tagged to VPF revenues would be incremental should the initial bucket meet or exceed the initial authorized revenues and/or work units.

- **Spend Plan Management**: A quarterly comparison of program spend authorized in the VPF spend plan will be made to ensure that authorized programs in total do not exceed the authorized amounts within the spend plan.
- **Excess Diablo Canyon Spend Monitoring**: A quarterly comparison of DCPP extended operations spend against the 115 percent reasonableness review threshold to determine if extended operations spend may exceed 115 percent of the DCPP extended operations costs adopted by the Commission in the DCPP Extended Operations Forecast Application. In the event that costs do exceed this amount, PG&E will ensure that total VPF spend plan costs plus these excess costs do not exceed the authorized VPF revenues for the period and make an adjusting entry if necessary.
- **VPF Earned Revenue True-ups**: Final authorized DCPP generation is not validated until after the record period is closed. In this case, PG&E will identify any true-up or true-downs for VPF revenues earned in early Q1 and include the true-up or true-down in its annual true-up advice letters. This amount is expected to be included as an adjustment to the next DCPP Extended Operations Forecast Application and associated VPF Spend Plan for the next period.

In addition, D.24-12-033 directed a third-party independent audit for 2025 recorded activity that attests to each of the requirements set forth in Section 712.8(s), including incrementality.[18]

F. Actions PG&E Will Take to Ensure Compliance with the Prohibitions Specified in Sections 712.8(s)(1) and (s)(2)

Section 712.8(s)(1) prohibits compensation being paid out to shareholders. By virtue of PG&E spending the VPF dollars on customer-benefitting programs, with each dollar tracked, no compensation from these funds will be paid by shareholders, as no incremental income (or revenue) will be recognized that would generate additional earnings for dividend distribution.

More specifically, PG&E will not recognize any incremental net revenue on its Generally Accepted Accounting Principles (GAAP) income statement due to executing its approved VPF spend or accounting for VPF funds and spend plan

18 D.24-12-033, OP 6, pp. 85-86.

costs in the VPF Subaccount of the DCEOBA. This is achieved through the nature of the structure of the balancing account mechanism set up to track VPF funds and spending, in conjunction with PG&E's ICFR program and its incrementality showing, both introduced in Section E above. Below elaborates on how the operations of the VPF Subaccount within the DCEOBA prevents shareholder earnings by virtue of its structure.

1. Revenue Recognition Criteria

Under ASC 980, PG&E employs revenue recognition on its SEC financial statements based upon evaluation of Commission directives to record revenue that (1) has a confirmed Commission directive approving recovery of the associated cost or authorized revenue requirements, (2) the recovery is expected to occur within 24 months, and (3) the recovery allows for an automatic rate adjustment mechanism (such as the AET) in future rates for over and undercollections. Importantly, under this criteria PG&E is only able to recognize revenue related to the VPF spend plan on its income statement after there is a Commission directive authorizing the VPF spend plan. Or said another way, PG&E cannot recognize revenue for future spend plans prior to a Commission directive on those plans.

2. Balancing Account Impacts on GAAP Income Statements

The VPF Subaccount in the DCEOBA operates like an expense balancing account. Specifically, in expense based balancing accounts, a set of authorized expenses (in this case the VPF spend plan programs tracked in orders as explained in Section E above) are compared against a revenue stream. In such as account, revenue is only recognized when the authorized expense is incurred as follows:

- **VPF Funds**: Proceeds collected from statewide customers are recorded to the VPF Subaccount. In doing so, revenue recognition is deferred and the proceeds sit in the subaccount waiting to be spent. In this way, there is no revenue recognition until expenses are incurred (see below). Said another way: If funds are collected and no plan is approved, no revenue will be earned on PG&E's income statement.
- **VPF Spend Costs**: Authorized program expenses recorded to the balancing account represent activities that have incurred an expense on

PG&E's income statement when performed. When these costs are recorded to the balancing account, revenue is recorded to offset that spend in an exact offsetting amount. Said another way: Revenues recognized equal expenses incurred, so that no additional income is recognized above and beyond the incremental spend.

3. Incrementality Showing

As discussed in Section E above, PG&E's incrementality review and annual showing ensures that the spend tracked via order management is truly incremental to other authorized expenses. This ensures that there is no double-recovery (or extra income) realized to PG&E's GAAP income statement.

4. ICFR and Controls

Finally, PG&E's operating controls and ICFR Program over accounting processes introduced in Section E ensure that the balancing account is operating as designed. These include a variety of preventative and detective controls including the following:

- Management review and variance analysis on expense, balancing account, and separately funded expenditures;
- Reconciliation of balancing account cost center reports between recorded accounting and management reporting for proper classification; and
- Management quarterly review to ensure that the total VPF spend for a year has not exceeded the total authorized spend plan (as described in Section E above).

Specific to the VPF spend plan, the review of the actual expenses incurred under the spend plan to the overall approved total cap will ensure that no excess incremental expenses beyond that cap is recorded to the balancing account, and thus no incremental revenue is recognized beyond that authorized amount.

The ICFR Program and controls are assessed at least annually through attestation or testing. And annually, PG&E's external auditors, Deloitte & Touche LLP, are required to audit the ICFR based on the criteria established by the Committee of Sponsoring Organizations of the Treadway

Commission framework in accordance with the standards of the Public Company Accounting Oversight Board.

In addition, Section 712.8(s)(1) directs an annual review process and directs the VPF funds to be spent on critical public purpose priorities. As described in testimony, PG&E will ensure compliance with Section 712.8(s)(1) public purpose priority categories through a repeatable, transparent process.

Section 712.8(s)(2) prohibits PG&E from earning a rate of return from the VPFs, prohibits any profit realized by shareholders from the VPFs, that neither PG&E nor its affiliates or holding company may increase earnings per share guidance, and prohibits double recovery in rates.

On the prohibition on earning a rate of return, PG&E will ensure compliance through the same set of controls and the ICFR program described under the prohibition to pay out compensation to shareholders. When the mechanisms for accounting ensure that no increase in income is earned, then there is limited opportunity to earn a rate of return. Similarly, all recovered amounts recorded to the VPF spend account are treated as expense on PG&E's income statement. Accordingly, as there are no revenue requirement models utilized to incorporate a return on equity, no rate of return is earned by shareholders.

On the prohibition on any profit realized by shareholders from the VPFs, PG&E will ensure compliance through the same set of controls and the ICFR program described under the prohibition to pay out compensation to shareholders, as well as the discussion on earning a rate of return above.

On the prohibition on increasing earnings per share guidance, PG&E will ensure compliance through the same set of controls and the ICFR program described under the prohibition to pay out compensation to shareholders, as well as the discussion on earning a rate of return above. By virtue of not recognizing additional income, earnings per share guidance should not be impacted. In addition, PG&E's order management process clearly separates items that are expected to impact earnings versus those that are considered "non-earnings impacting expense". Orders that are expense only and under this category represent passthrough expenses that are recovered dollar for dollar without any rate of return and are excluded from materials providing EPS guidance.

On the prohibition of double recovery in rates, PG&E is engaging in a methodological approach to ensure compliance with its incrementality showing. On the front end, PG&E will use a pre-spend tracking process. Specifically, PG&E will allocate a component of the statewide NBC rate by estimating a percent allocation for storing in the VPF Subaccount within the DCEOBA. By storing these revenues as they are collected separately, PG&E ensures that the portion of revenues subject to compliance requirements in Section 712.8(s)(1) and D.23-12-036 are separated from the remainder of the DCEOBA revenues collected from customers.

Then, PG&E will use these stored/set-aside allocated amounts on the Commission-approved categories. For the 2024 and 2025 VPF funds, PG&E will use these on the programs approved in D.24-12-033, subject to a contingency and the process described above in Section C for if the amounts are needed for DCPP operations above 115 percent threshold.

Next, as part of the annual true-up process, PG&E will compare actual recorded costs to true up the amounts in the sub-account. As part of this process, PG&E must determine whether DCPP's actual recorded operating costs recorded to DCEOBA are more than fifteen percent above the approved forecast. If so, PG&E would transfer these funds back to the Extended Operations Subaccount. However, if not, PG&E will use the funds on the approved programs from D.24-12-033.

G. Conclusion

PG&E requests that the Commission find its plan for 2026 VPFs complies with Pub. Util. Code Section 712.8(s) and D.23-12-036.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 8

DIABLO CANYON EXTENDED OPERATIONS

BALANCING ACCOUNT

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DIABLO CANYON EXTENDED OPERATIONS BALANCING ACCOUNT

A. Introduction

The purpose of this chapter is to provide an overview of the Diablo Canyon Extended Operations Balancing Account (DCEOBA) and amortization of 2025 year-end balances for inclusion in Pacific Gas and Electric Company's (PG&E) 2026 electric rates.[1]

The remaining sections in this testimony are organized as follows:

- Section B – Overview of DCOEBA and Subaccounts;
- Section C – Revision and True-up Process;
- Section D – Extended Operations Subaccount Recorded Activity;
- Section E – Extended Operations Subaccount Forecast Activity; and
- Section F – Conclusion.

B. Overview of DCEOBA and Subaccounts

The purpose of the DCEOBA is to record and recover expenses related to the operation of Diablo Canyon Power Plant (DCPP) Units 1 and 2 beyond the current license expiration dates of November 2, 2024, and August 26, 2025, respectively, that are not eligible for government funding. Costs that are eligible for government funding are tracked and recorded in the Diablo Canyon Transition and Relicensing Memorandum Account. Expenses recorded to the DCEOBA include costs related to the following activities: extended operations, incremental decommissioning planning, liquidated damages, replacement power (if incurred), and performance and management fees. Pursuant to Senate Bill (SB) 846, expenses related to extended operations, incremental decommissioning planning, liquidated damages, replacement power and certain performance and management fees will be funded by customers of all

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[1] To the extent that the overcollection is driven by expenses that do not exceed 115 percent of the forecasted extended operations costs approved by the Commission in PG&E's Application, amounts can be recovered in the next consolidated rate adjustment process via the Annual Electric True-Up (AET).

load-serving entities (LSE) subject to the California Public Utilities Commission's (CPUC or Commission) jurisdiction.

PG&E originally requested establishment of the DCEOBA in Preliminary Statement Part JR as part of PG&E Advice 6870-E, which was supplemented with minor modifications in Advice 6870-E-A.[2] The Commission approved both advice letters in Resolution E-5299 on September 3, 2024 with an effective date of May 9, 2024.

PG&E submitted proposed modifications for the DCEOBA pursuant to Decision (D.) 23-12-036 in PG&E Advice 7204-E, on March 15, 2024, as further amended in Advice 7204-E-A, on February 12, 2025.[3] Subsequently, PG&E submitted further modifications for DCEOBA in Advice 7509-E[4] on February 18, 2025, and in Advice 7531-E[5] on March 10, 2025. Through these advice letters, within Preliminary Statement Part JR, PG&E proposed three types of subaccounts, one of which has multiple subaccounts by investor-owned utility (IOU): Extended Operations, Liquidated Damages, and Volumetric Performance Fees (VPF). Below is a description of the different subaccounts pending Commission approval.

1. Extended Operations Subaccount

The Extended Operations Subaccount (three subaccounts) will be funded by a non-bypassable charge collected from electric retail customers of all LSEs subject to the Commission's jurisdiction. Note that each of the large electric IOUs service territories (i.e., PG&E, Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E)) will have its own subaccount. Revenue requirement expenses to be recovered in the Extended Operations Subaccounts are assigned to the IOU specific subaccount based on allocated 12-month coincident peak load share, or as otherwise authorized by the Commission.

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2 Advice 6870-E was filed on March 1, 2023 in compliance with D.22-12-005, Ordering Paragraph (OP) 4. Advice 6870-E-A was filed on April 12, 2023.

3 PG&E's Advice 7204-E and Advice 7204-E-A are still pending final disposition.

4 Pursuant to D.24-12-033, OP 9. Advice 7509-E has an effective date of February 18, 2025.

5 Pursuant to D.25-01-043, OP 8. Advice 7531-E has an effective date of March 10, 2025.

The PG&E Extended Operations Subaccount will also include an annual entry to reflect the $10,000 in revenues from each of the three small multi-jurisdictional utilities, (i.e., Bear Valley Electric Service, Inc., Liberty Utilities, and PacifiCorp dba Pacific Power) as well as an offsetting subsequent reimbursement for the value of resource adequacy (RA) attributes that remain in PG&E's portfolio.[6,7]

Annual expenses recorded to the Extended Operations Subaccount will include the authorized funding for liquidated damages and actual expenses related to the following: extended operations costs, including fuel costs, any invoiced amounts associated with the Diablo Canyon Independent Safety Committee, replacement power costs for planned and unplanned (if incurred) outages,[8] any incremental decommissioning planning costs, and certain statutory volumetric performance and management fee expenses authorized in SB 846.

Extended operations costs will include operations and maintenance costs, plant equipment and improvement costs, nuclear fuel amortization and associated short-term financing costs, nuclear fuel administrative costs, incremental future spent fuel storage capacity (as offset by any reimbursements received from the U.S. Department of Energy for spent fuel management costs), pension, taxes, benefits and standard PG&E overheads, employee retention costs, and regulatory compliance items.

Performance and management costs will include a VPF charge of $6.50, in 2022 dollars, per megawatt-hour (MWh) generated by the DCPP during the period of extended operations and a fixed fee of $50 million, in 2022 dollars, per unit per year, respectively. These amounts, reflected in 2022 dollars in SB 846, will be adjusted annually by the Commission using Commission-approved escalation methodologies and adjustment factors to reflect the forecast test year's dollar value. The VPF proceeds received

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6 D.23-12-036, OP 8 and OP 11, respectively.

7 Pursuant to D.25-01-043, OPs 3, 6 and 7, PG&E and the Small and Multi-Jurisdictional Utilities are no longer required to collect and distribute the $10,000 of net costs and RA benefits to one another, but instead include a net zero non-bypassable charge in their Public Purpose Program rates.

8 Including capacity costs for replacement RA.

from customers are transferred to the VPF subaccount as described below and are subject to a true-up based upon final MWhs generated.

During the period of extended operations, revenues from the sale of electricity into the California Independent System Operator Corporation (CAISO) market will be used to offset costs recorded in the Extended Operations Subaccount. Any excess revenues remaining after offsetting costs (in the Extended Operations Subaccount), if any, will be credited to PG&E's Extended Operations Subaccount.

Disposition of the balances in the Extended Operations Subaccount will be presented in the AET rate adjustment process, as authorized by the Commission in the new annual DCPP continued operations ratemaking proceeding, or as otherwise determined by the Commission.

2. Liquidated Damages Subaccount

The Liquidated Damages Subaccount (one subaccount) will be funded by a portion of the Diablo Canyon non-bypassable charge (DCNBC) applicable to customers of all LSEs subject to the Commission's jurisdiction. The authorized funding is $12.5 million per month per unit until the Subaccount reaches a balance of $300 million, in total. The balance in the Subaccount will be used to purchase replacement power, if incurred, when a unit is out of service due to an extended and unplanned outage and the reasonable manager standard has not been met as determined by the Commission.[9] If replacement power recovered through this Subaccount, the Liquidated Damages Subaccount will be replenished by authorized funding of $12.5 million per month per until the Subaccount reaches a credit balance of $300 million.[10] Any funds remaining in the Liquidated Damages Subaccount at the conclusion of extended operations will be refunded to customers in PG&E's service territory as determined by the Commission in accordance with the criteria established in SB 846, as codified in the Pub. Util. Code section 712.8.[11]

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9 Public Utilities Code (Pub. Util. Code) §718.8(i)(1).

10 *Ibid.*, §712.8(i)(2).

11 *Ibid.*, §712.8(u).

3. VPF Subaccount

The VPF Subaccount (one subaccount) will be funded by: (1) $6.50 (in 2022 dollars) per MWh generated by DCPP Units 1 and 2 during extended operations from all Commission-jurisdictional electric retail customers within the large IOUs' service territories, and (2) an additional $6.50 (in 2022 dollars) per MWh generated by DCPP Units 1 and 2 during extended operations from PG&E-only electric retail customers.[12] The revenue amounts will be adjusted annually using Commission-approved escalation methodologies and adjustment factors. Monthly, PG&E will debit the extended operations subaccounts for the portion of billed revenues associated with the VPF and credit those billed revenues to the VPF Subaccounts.[13] Expense amounts recorded to the VPF Subaccount upon approval by the Commission will be for critical public purpose priorities identified in Pub. Util. Code section 712.8(t)(1): (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. To the extent that expenses that exceed 115 percent of the forecasted extended operations costs approved by the Commission in PG&E's annual DCPP Extended Operations Cost Forecast Application, a debit will be made in this subaccount (offset by a credit in the Extended Operations Subaccount).

C. Revision and True-up Process

D.23-12-036 also established a new annual forecast application process for Diablo Canyon similar to the annual Energy Resource Recovery Account proceedings to review and authorize DCPP extended operations costs. Specifically, pursuant to OP 4, following the inaugural March 29, 2024

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12 *Ibid.*, §712.8(f)(5).

13 The portion of the non-bypassable charge associated with the VPF revenues is calculated as a percent of the total charge, as presented Chapter 10, Joint IOU Non-Bypassable Charge Proposal. This percentage will used in the IOUs' monthly revenue reports to determine the remitted revenue, by IOU, that will be recorded the VPF Subaccount.

application, PG&E must file DCPP Extended Operations Cost Forecast applications no later than March 31 each year (starting with the next application in 2025). This process should both set the forecast costs to be recovered in the non-bypassable charge in the next year, as well as any over or undercollection to be amortized from the forecasted recorded balance. More specifically, in most years this should focus on costs running through the Extended Operations Subaccount, which includes all initial costs and revenues. Whereas the VPF Subaccount and Liquidated Damages Subaccount set aside funds for prescribed potential future uses, it is the Extended Operations Subaccount balance that shows an under- or overcollection of costs from the non-bypassable rate charged to customers.

Under OP 15, PG&E is directed to file an annual application to report on compensation earned on the VPFs, as well as how any money was spent or is planned to be spent in the future. As described in Chapter 7, PG&E expects this process in future years to consider the amount of compensation earned under Section 712.8(f)(5), how it was spent, and a plan for prioritizing the uses of such compensation the next year, as well as whether its recorded DCEOBA spend for Extended Operations exceeded 115 percent of the forecast for that year. Any approved transfers of costs from the Extended Operations Subaccount to the Liquidated Damages Subaccount, or transfer of VPF revenues back to the Extended Operations Subaccount would flow out of this process.

After both of these processes, the true-ups of the Extended Operations Subaccount and overall cost forecasts are implemented into rates in the AET Process each year.

D. Extended Operations Subaccount Recorded Activity

In December 2024, the Commission issued D.24-12-033, which approved for the first time Extended Operations costs for recovery in rates from statewide customers. Accordingly, PG&E recorded all authorized costs within DCEOBA. As the Extended Operations Subaccount is designed to track amounts collected in rates, this section outlines the recorded amounts within the Extended Operations Subaccount.

The DCEOBA balances recorded through January 2025 include customer revenue, authorized costs, authorized revenue requirements, VPF, CAISO Corporation net revenues, and balancing account interest, in accordance with the Generally Accepted Accounting Principles (GAAP), as well as electric Preliminary Statement Part JR. These transactions will be reviewed by the Commission in PG&E's 2025 annual true-up AL, which is anticipated to be submitted in March 2026, showing the full 12 months of recorded activity.

As of January 31, 2025, the balance of the Extended Operations Subaccount is $75.5 million dollars. This includes following activity has been recorded inception to date.[14] Below are the high-level descriptions of major components.

1. Customer Revenue

PG&E has accrued customer revenue based upon the GAAP standard of accounting. Accordingly, PG&E currently estimates the amounts of revenues earned from customers. Accordingly, the amounts are aligned with expectations from the monthly revenue requirements for each IOU.

2. Authorized Costs

Since September 2023, PG&E has incurred extended operations costs as defined above. This includes: employee retention costs incurred since September 2023, project and operations and maintenance costs incurred during 2024 and 2025, replacement capacity incurred during 2024, and nuclear fuel straight-line amortization recorded in January 2025 to recovery nuclear fuel amortization and associated short-term financing costs.

3. Authorized Revenue Requirements

PG&E has recorded the following authorized revenue requirements through January 2025:

1) $37.5 million for Liquidated Damages. This amount is set aside and made available in the Liquidated Damages Subaccount for future use.
2) $12.0 million in fixed management fees for the period in which Unit 1 has been operating under the extended licensing period.

4. Volumetric Performance Fees

During the recorded period, PG&E recorded VPF as a percentage of accrued customer revenues. These amounts are set aside in the VPF

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[14] Since the 2025 rates for the DCNBC were set to recover costs from 2023 through 2025, PG&E presents the inception to date activity for a comparative basis.

Subaccount subject to use by expenses incurred by PG&E's approved VPF spend plan. Specifically, PG&E set aside 33.55 percent of PG&E customer revenues, as well as 13.53 percent of revenues from SCE and SDG&E customer revenues to the VPF Subaccount.

5. CAISO Net Revenue

Finally, PG&E has recognized net CAISO revenues for Unit 1 related to the period of extended operations, through January 31, 2025.[15]

6. Balancing Account Interest

PG&E has also recognized interest from the period of May 2024[16] through January 2025. Interest is recorded in accordance with electric Preliminary Statement JR, which indicates that the three-month commercial paper rate in Federal Reserve Statistical Release H.15 (or its successor) is used.

E. Extended Operations Subaccount Forecast Activity

At the time of this filing, PG&E's authorized revenue requirements and costs are not deemed to be materially different from the forecast adopted in the D.24-12-033. However, PG&E's recognition of customer revenues and VPF set-asides are highly reliant on rate implementation and remittances from other IOUs.

PG&E will present an updated forecast in the Fall Update of over or undercollection within the DCEOBA Extended Operations Subaccount. Several more variable factors will be available during the Fall Update, including but not limited to: (1) the final RA market price benchmarks used to charge replacement capacity, (2) updated forward CAISO pricing, and (3) more historical information to confirm the expected over or undercollection from other IOUs.

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15 PG&E also records fifty percent of the net common load resource for CAISO to DCEOBA for the same period. As this node is equally shared by Unit 1 and Unit 2, a simplifying fifty percent share is utilized.

16 May 2024 represents the first effective date of Preliminary Statement Part JR. Accordingly, PG&E only recorded balancing account interest income starting at this effective date.

F. Other Balancing Account Matters

In addition to the ongoing operations of DCEOBA described above, PG&E requests authority to modify Preliminary Statement Part DZ, Department of Energy Litigation Balancing Account (DOELBA) to create a subaccount for spent nuclear claims proceeds attributable to the DCEOBA.[17] PG&E proposes to utilize the same approved methodology used today for the existing subaccounts that are transferred to PABA and NDAM, which follow the method initially approved by the CPUC in PG&E's 2014 GRC Decision and reaffirmed in subsequent proceedings. PG&E's explicit percentage allocation including the amounts related to DCEOBA are addressed in Chapter 2.

G. Conclusion

PG&E does not make a specific request about the DCEOBA within its initial testimony but does expect to present an updated forecast of over or undercollection within its Fall Update. In addition, PG&E requests authority to modify Preliminary Statement Part DZ to create a subaccount for spent nuclear claims proceeds attributable to the DCOEBA, consistent with the existing methodology already established.

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17 PG&E has already included an accounting procedure in Preliminary Statement Part JR to record "a credit entry for reimbursements received from the DOE of spent fuel management costs." This tariff line was proposed in PG&E's Advice 7204-E, which is still pending final disposition.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 9

NET REVENUE REQUIREMENT FOR RATESETTING

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NET REVENUE REQUIREMENT FOR RATESETTING

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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 9
NET REVENUE REQUIREMENT FOR RATESETTING

A. Introduction

The purpose of this chapter is to consolidate Pacific Gas and Electric Company's (PG&E) Diablo Canyon Extended Operations Costs, presented in Chapters 2 through 6, with the forecast of market revenues received in the California Independent System Operator Corporation (CAISO) day-ahead energy market presented in Chapter 6, to determine the net Diablo Canyon Power Plant (Diablo Canyon) revenue requirement that will be allocated to the three large investor-owned utilities (IOU) for rate setting. Unit 1 began extended operations on November 3, 2024 and Unit 2 will begin extended operations on August 27, 2025. The costs for extended operations presented in these chapters cover the period January 1, 2026 to December 31, 2026.

PG&E requests that the net revenue requirement be recovered through the statewide Diablo Canyon Extended Operations Non-bypassable Charge (DCNBC). PG&E is requesting that the statewide DCNBC presented in this application be effective January 1, 2026, and be applicable to PG&E, Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E) retail customers. Both the statewide net revenue requirement and PG&E's Volumetric Performance Fee (VPF) revenue requirement will be used to develop the DCNBC rate proposals presented in Chapter 10.

Updates to these revenue requirements and the balance in the Diablo Canyon Extended Operations Balancing Account (DCEOBA) will be presented in the Update to Prepared Testimony, which will be served in October after Energy Division updates the Energy Index benchmark.[1] PG&E will implement the final authorized Diablo Canyon extended operations revenue requirement with other electric revenue requirement and rate changes as part of PG&E's Annual Electric True-up advice letter process.

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[1] PG&E's Application presents a proposed schedule recommending that the Fall Update be submitted in October 2024. The final schedule for the Fall Update will be determined as part of the Scoping Memo that will be issued in this proceeding.

B. Summary of Costs and Revenue Requirements

The consolidated revenue requirement for Diablo Canyon Operations reflects expenses incurred starting in September 1, 2023 to December 31, 2025 as the record period and includes operations and maintenance (O&M) expense and project costs, and fuel expense presented as in Chapter 2, tax expenses presented in Chapter 3, procurement costs associated with capacity and energy substitution for Diablo Canyon's planned and maintenance outages presented in Chapter 4, and costs associated with Statutory Fees authorized in Senate Bill 846, which include the Management Fee, the VPFs, and the Liquidated Damages revenue set-aside presented in Chapter 5.

Employee retention costs incurred starting September 1, 2023, and authorized for recovery through the DCEOBA, will be included in the DCEOBA balance amortized in rates effective January 1, 2025.[2]

In Chapter 6, Table 6-1 presents a summary of the revenue requirement request for 2026 and the values presented are the output of the Results of Operations (RO) model. The RO model computes the annual revenues that are needed (revenue requirement) from customers to recover the cost of service. The model calculates the revenue requirement based on a forecast of O&M expense in Chapter 2 and in Chapter 4. The Chapter 4, Table 4-1 is reproduced as Table 9-1 below:

TABLE 9-1
TOTAL REVENUE REQUIREMENTS
(WHOLE DOLLARS)

Line No.	Description	2026
1	Total Revenue Requirements (excluding revenue fees and uncollectibles (RF&U))	$1,178,507,263

The $1,178,507,263 total is composed of $702,586,664 for O&M expenses and $452,262,070 in Statutory Fees.

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2 See PG&E Advice 7067-E, Diablo Canyon Power Plant Extended Operations Balancing Account Recorded Costs Through October 31, 2023, effective on November 15, 2023; PG&E Advice 7166-E, Diablo Canyon Power Plant Extended Operations Balancing Account Recorded Costs Through December 31, 2023, effective on February 2, 2024.

In addition to the O&M expenses and Statutory Fees expense that are consolidated in the RO Model output presented in Chapter 4, PG&E presents its forecast for expense associated with Resource Adequacy (RA) Substitution costs in Chapter 3. The RA Substitution costs for 2026 were presented in Table 3-1 of Chapter 3 and are reproduced below in Table 9-2.

TABLE 9-2
RA SUBSTITUTION CAPACITY COST FORECAST (2026)

Line No.	Year	Unit 1	Unit 2	Total
1	2026	$114,883,500	$45,953,400	$160,836,900

The last element of the combined revenue requirement is the CAISO market revenues which were presented in Chapter 6, Table 6-1. Those revenues are reproduced in Table 9-3 below and total approximately $935 million dollars for 2026.

TABLE 9-3
CAISO MARKET REVENUES

Line No.		Total Generation Megawatt-Hour (MWh)	CAISO Market Reference Price ($/MWh)	Generation Revenues (Thousands of Dollars)
1	2026	18,203,364	$51.36	$934,925,791

C. Consolidating Costs, Market Revenues, and the DCEOBA Balance to Determine the Net Revenue Requirement Request

Consolidation of Chapter 4’s RO Model output which includes the O&M expense, including fuel costs, and the Statutory Fee expense from Chapter 5, plus the RA Substitution expense presented in Chapter 3 provides a Total Cost Forecast as shown on line 13 in Table 9-4 below.

The Total Cost Forecast amounts on line 13 are then combined with the CAISO Market Revenues (line 15) and the DCEOBA Balance (line 18) to arrive at a Subtotal Net Cost amount (line 19).[3] The last step calculates the RF&U amount for PG&E, the Franchise Fee and Uncollectibles (FF&U) amounts for SCE and SDG&E and presents a total on line 21.[4] Line 24 has the total Revenue Requirement for Ratesetting. Chapter 10, Section C will discuss the allocation of the Revenue Requirement on line 21 to the three large IOUs.

TABLE 9-4
CONSOLIDATED NET REVENUE REQUIREMENT
(THOUSANDS OF DOLLARS)

Line No.		Chapter Cross Reference	Diablo Canyon Extended Operations[a] 2026 Cost ($1000s)		
			Statewide (A)	PG&E Specific (B)	Total (C)
1	Operational Revenue Requirement				
2	Operation and Maintenance Cost Forecast	Chapters 2 & 4	726,245		726,245
3	Resource Adequacy Substitution Capacity	Chapter 3	160,837		160,837
4					
5	**Subtotal Operational Revenue Requirement**		**887,082**		**887,082**
6					
7	Management, Performance Fees, and Liquidated Damages				
8	Management Fee	Chapters 4 & 5	113,884		113,884
9	Liquidated Damages	Chapters 4 & 5	75,000		75,000
10	Volumetric Performance Fee	Chapters 4 & 5	131,689		131,689
11	***PG&E Specific*** Volumetric Performance Fee	Chapters 4 & 5		131,689	131,689
12	**Subtotal Statutory Fees**		**320,573**	**131,689**	**452,262**
13	**Total Cost Forecast (Line 5 + Line 12)**		**1,207,655**	**131,689**	**1,339,344**
14	Offsetting Market Revenues				
15	CAISO Market Revenues	Chapter 6	(934,925)		(934,925)
16	Balancing Account Amortization				
17	DCEOBA	Chapter 8	0		0
18	Subtotal Net Cost (Line 13 + Line 15 + Line 17)		272,730	131,689	404,419
19					
20	RF&U (PG&E) + FF&U (SCE) and FF&U (SDG&E)[b]	Chapter 10	3,924	1649	5,572
21	**DCEO Revenue Requirement for Ratesetting**		**276,654**	**133,338**	**409,992**

Notes:
(a) Amounts in 2026 dollars ($s)
(b) SDG&E FF&U revenue for its DCNBC will be collected in Distribution Charge

[3] The DCEOBA balance in this testimony is set at zero. As discussed in Chapter 8, PG&E will provide a forecast of its expected end-of-year balance for the DCEOBA as part of its Fall Update, which will be filed in October.

[4] Details regarding the RF&U factor and calculated amount applied to PG&E's allocated costs and FF&U factors and calculated amounts applied to SCE and SDG&E's allocated revenue requirements are discussed in more detail in Chapter 10, Section C.

D. Conclusion

PG&E requests that the Commission approve the consolidated net revenue requirement presented in Table 9-4 that will be used to allocate costs to the three large IOUs and will be the basis for setting rates. The cost values presented in this table rely on the costs and revenue requirements presented in Chapter 2 through Chapter 5 netted against the CAISO market revenues presented in Chapter 6.

PACIFIC GAS AND ELECTRIC COMPANY

SOUTHERN CALIFORNIA EDISON COMPANY

SAN DIEGO GAS & ELECTRIC COMPANY

CHAPTER 10

NON-BYPASSABLE CHARGE PROPOSAL

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NON-BYPASSABLE CHARGE PROPOSAL

A. Introduction

The purpose of this testimony is to present the rate proposals for the Diablo Canyon Extended Operations non-bypassable charge (DCNBC), as authorized in Decision (D.) 23-12-036. Pursuant to Senate Bill (SB) 846, the DCNBC will consist of a Statewide charge that will apply to all California Public Utilities Commission (CPUC or Commission) jurisdictional customers of electrical corporations, electric service providers, and Community Choice Aggregators (CCA), which will be billed through the Commission-jurisdictional investor-owned utilities (IOU).[1] There are three Commission-jurisdictional IOUs that are allocated costs for the Statewide charge, which include Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE); San Diego Gas & Electric Company (SDG&E).[2] PG&E retail customers will have an additional volumetric performance fee component required under Public Utilities Code (Pub. Util. Code) Section 712.8(f)(5) included in its non-bypassable charge that will be incremental to the Statewide DCNBC obligation. As noted in D.23-12-036, the non-bypassable charge will vary depending on the Load Serving Entity (LSE),[3] which is discussed in more detail in Section B.

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1 D.23-12-036, pp. 138-139; Ordering Paragraph (OP) 14.

2 Three of the small Commission-jurisdictional utilities (SMJU) were exempted from the Statewide charge pursuant to D.25-02-00x, which modified D.23-12-036 to net the value of Resource Adequacy attributes they would have received payment for against the DCNBC allocation the SMJUs were obligated to pay. The SMJUs are Liberty Utilities/CalPeco Electric (Liberty); Bear Valley Electric Service (BVES) a division of Golden State Water Company (Bear Valley); and Pacific Power, a division of PacifiCorp.

3 *Ibid.*, pp. 92-94.

B. Overview of the Non-bypassable Charges

For the three large IOUs—PG&E, SCE, and SDG&E—D.23-12-036 requires the revenue allocation and the rate design use a 12-month coincident peak (12-CP) allocation for the statewide costs applicable to all load serving entities.[4] The revenue requirement associated with the PG&E specific volumetric performance fee of $6.50 per megawatt-hour (MWh) under Pub. Util. Code Section 712.8(f)(5) is assigned directly to PG&E and the rate design allocation to the rate classes uses PG&E's 12-CP allocation. The three large IOUs are directed to provide joint testimony proposing an allocation among themselves of the applicable statewide costs that are recovered from the load serving entities in each IOUs' service area. The Joint Utility testimony on the revenue allocation of the applicable costs amongst the three IOUs using a 12-month coincident peak demand is discussed in Section C below. The joint utility testimony on the rate design using each IOUs' 12-month coincident peak revenue allocation to the rate classes is discussed in Section D below.

C. Revenue Allocation to the IOUs

Pursuant to directives in D.23-12-036, the large IOUs are to allocate the DCPP extended operations costs amongst themselves using a publicly available 12-month coincident peak load forecast. To narrow down an appropriate peak load forecast to use for the DCPP cost allocation, the IOUs evaluated several forecasts that are utilized in various CPUC proceedings including forecasts used for the Integrated Resource Plan and the Resource Adequacy (RA) Program. A key part of the evaluation was whether the forecast would be appropriate for allocating the DCPP costs given DCPP was designated as a resource needed to support system reliability in both SB 846 and in D.23-12-036.[5] Additionally, the evaluation considered whether the peak load forecast would be consistently available and updated on an ongoing basis over the period of DCPP's extended operations.

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[4] *Ibid.*, p. 129, Conclusion of Law (COL) 30; pp. 136-137, OP 7; pp. 138-139, OP 14.

[5] *Ibid.*, discussion at page 3 and COL 27.

The CPUC's RA policy framework was developed to ensure the reliability of electric service in California.[6] The CPUC's RA Program homepage states that one of the goals of the RA Program is:

> …[t]o ensure the safe and reliable operation of the grid in real-time providing sufficient resources to the California Independent System Operator (CAISO) when and where needed.

The CPUC's RA Program contains three distinct requirements: (1) System RA requirements, (2) Local RA requirements, and (3) Flexible RA requirements. A primary pillar for the RA Program's system requirements relies on of the California Energy Commission's (CEC) development of a peak load forecast.

The IOUs continue to recommend the public 12-month CP load forecast published by the CEC for purpose of allocating the DCPP costs. The CEC's published 2025 12-CP load forecast is developed for use in the Commission's RA Program.[7] The 2025 CEC-adjusted 12-CP RA Forecast plus a 17 percent planning reserve margin is used to set the RA year-ahead resource obligation for all load-serving entities in the three large IOUs' service areas. The CEC's 2024 presentation of the 2025 RA Load Forecast, describes the process used to develop the forecast.[8]

The 2025 CEC-adjusted load forecast for each IOU service territory is shown in Table 10-1 below and extracted from the 2025 RA Forecast:

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6 See Pub. Util. Code §380 and the CPUC's RA Program Homepage at: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/resource-adequacy-homepage.

7 CPUC, RA Compliance Materials, 2025 RA Final Forecast Summary File at hyperlink: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/2025/ra-2025-final-forecast-summary-tables.xlsx.

8 2025 RA Demand Forecasting Update, at hyperlink: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/ra-2025-demand-forecast-update-cec.pdf

TABLE 10-1
2025 CEC RESOURCE ADEQUACY COINCIDENT PEAK LOAD FORECAST
(MW)

Line No.	Month	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept	Oct	Nov	Dec	Total
1	PGE	11,684	11,450	11,365	12,347	14,678	18,354	18,787	18,392	17,595	14,225	11,582	12,029	**172,488**
2	SCE	11,361	11,125	11,792	12,454	13,777	16,248	19,256	18,402	19,784	15,682	12,620	11,415	**173,915**
3	SDGE	2,975	2,870	2,769	2,854	2,523	3,070	3,378	3,383	4,086	3,487	3,223	2,935	**37,552**
4	**Total**	26,020	25,444	25,926	27,655	30,978	37,671	41,421	40,176	41,464	33,394	27,426	26,378	**383,955**

To convert the CEC 2025 RA Forecast into allocation factors, the IOUs summed the monthly values, by IOU, to a total annual MW value. From the annual total MW, by IOU, a percentage that each IOU contributes to the total peak load forecast was calculated. The calculated percentages for each IOU are shown in Table 10-2 below and will be used to allocate the DCPP extended operations costs to the IOUs.

TABLE 10-2
12 MONTH COINCIDENT PEAK LOAD ALLOCATION FACTORS
(MW)

IOU	Source	Duration	Term	MW	Percent
PG&E	2025 CEC 12-CP	1-Year	2025	172,488	44.9%
SCE	2025 CEC 12-CP	1-Year	2025	173,915	45.3%
SDG&E	2025 CEC 12-CP	1-Year	2025	37,552	9.8%
Total				383,955	100.0%

It is expected that the CEC 12-CP load forecast will be updated for 2026 during the Summer of 2025, ahead of the annual System RA filing, filed on October 31 of each year. Thus, the IOUs would update the 12-CP load forecast used in this proceeding as part of its Fall Update once the CEC releases its 2026 12-CP load forecast.

The consolidated DCPP extended operations net revenue requirement to be allocated to the IOUs is presented in Chapter 9. That revenue requirement is replicated in Table 10-3 below and totals $410.0 million. This revenue requirement will be allocated to PG&E, SCE and SDG&E using the allocation 44.9 percent, 45.3 percent, and 9.8 percent, respectively and this allocation is shown in Table 10-4. Table 10-4, line 21 also presents a revenue allocation factor by IOU that will be used to quantify the portion of the DCNBC that is associated with the Volumetric Performance Fee for revenue reporting purposes. This factor is uniquely calculated for each IOU.

TABLE 10-3
2026 DIABLO CANYON EXTENDED OPERATIONS
NET REVENUE REQUIREMENT FORECAST
(THOUSANDS OF DOLLARS)

Line No.		Chapter Cross Reference	Diablo Canyon Extended Operations[a] 2026 Cost ($1000s) Statewide	PG&E Specific	Total
			(A)	(B)	(C)
1	Operational Revenue Requirement				
2	Operation and Maintenance Cost Forecast	Chapters 2 & 4	726,245		726,245
3	Resource Adequacy Substitution Capacity	Chapter 3	160,837		160,837
4	**Subtotal Operational Revenue Requirement**		**887,082**		**887,082**
5	Management, Performance Fees, and Liquidated Damages				
6	Management Fee	Chapters 4 & 5	113,884		113,884
7	Liquidated Damages	Chapters 4 & 5	75,000		75,000
8	Volumetric Performance Fee	Chapters 4 & 5	131,689		131,689
9	***PG&E Specific* Volumetric Performance Fee**	Chapters 4 & 5		131,689	131,689
10	**Subtotal Statutory Fees**		**320,573**	**131,689**	**452,262**
11	**Total Cost Forecast (Line 4 + Line 10)**		**1,207,655**	**131,689**	**1,339,344**
12	Offsetting Market Revenues				
13	CAISO Market Revenues	Chapter 6	(934,925)		(934,925)
14	Balancing Account Amortization				
15	DCEOBA	Chapter 8	0		0
16	Subtotal Net Cost (Line 13 + Line 15 + Line 17)		272,730	131,689	404,419
17	Uncollectibles, Franchise Fees, and SF Revenue Fee Factor[c]	Chapter 10			
18	RF&U (Col. A = Col. D + Col. E + Col. F - Col. B) (Col. B = Col. A, Line 3 x Col. D, Line 23)	Chapter 10	3,924	1,649	5,572
19	**DCEO Revenue Requirement for Ratesetting (Line 16 + Line 18) for PG&E and SCE (Line 16) for SDG&E**		**276,654**	**133,338**	**409,992**

Notes:
(a) Amounts in 2026 dollars ($s)
(b) D.23-12-036, OP8 and OP11

TABLE 10-4
2026 DIABLO CANYON EXTENDED OPERATIONS
NET REVENUE REQUIREMENT FORECAST
ALLOCATION TO THE IOUS
(THOUSANDS OF DOLLARS)

Line No.		Chapter Cross Reference	12-Month Coincident Peak Allocation[a] 2026 Cost Allocation ($1000s) 44.9% Pacific Gas & Electric	45.3% Southern California Edison	9.8% San Diego Gas & Electric	2026 Total
			(D)	(E)	(F)	(G)
1	Operational Revenue Requirement					
2	Operation and Maintenance Cost Forecast	Chapters 2 & 4	326,084	328,989	71,172	726,245
3	Resource Adequacy Substitution Capacity	Chapter 3	72,216	72,859	15,762	160,837
4	**Subtotal Operational Revenue Requirement**		**398,300**	**401,848**	**86,934**	**887,082**
5	Management, Performance Fees, and Liquidated Damages					
6	Management Fee	Chapters 4 & 5	51,134	51,589	11,161	113,884
7	Liquidated Damages	Chapters 4 & 5	33,675	33,975	7,350	75,000
8	Volumetric Performance Fee	Chapters 4 & 5	59,128	59,655	12,906	131,689
9	***PG&E Specific*** **Volumetric Performance Fee**	Chapters 4 & 5	131,689			131,689
10	**Subtotal Statutory Fees**		**275,626**	**145,219**	**31,416**	**452,262**
11	**Total Cost Forecast (Line 4 + Line 10)**		**673,926**	**547,068**	**118,350**	**1,339,344**
12	Offsetting Market Revenues					
13	CAISO Market Revenues	Chapter 6	(419,781)	(423,521)	(91,623)	(934,925)
14	Balancing Account Amortization					
15	DCEOBA	Chapter 8	0	0	0	0
16	Subtotal Net Cost (Line 13 + Line 15 + Line 17)		254,145	123,547	26,728	404,419
17	Uncollectibles, Franchise Fees, and SF Revenue Fee Factor[c]	Chapter 10	1.2520%	1.1061%	3.8314%	
18	RF&U (Col. A = Col. D + Col. E + Col. F - Col. B) (Col. B = Col. A, Line 3 x Col. D, Line 23)	Chapter 10	3,182	1,367	1,024	5,572.486
19	**DCEO Revenue Requirement for Ratesetting (Line 16 + Line 18) for PG&E and SCE (Line 16) for SDG&E**		**257,327**	**124,913**	**26,728**	**408,968**
20	**Distribution Revenue (SDG&E FF&U)**				**1,024**	**1,024**
21	**Volumetric Performance Fee (VPF) as a Percent of Net Costs[d]**		**75.08%**	**48.29%**	**48.29%**	

Notes:
(a) Amounts in 2026 dollars ($s)
(b) D.23-12-036, OP8 and OP11
(c) SDG&E's revenues for its DCNBC will be collected in the Distribution Charge.
(d) VPF Revenue allocation for Revenue Reporting

The allocated net revenue requirement for PG&E is $257.3 million and is higher than the net revenue requirements allocated to SCE and SDG&E due to the additional Volumetric Performance Fee customers in PG&E's service territory are obligated to pay pursuant to SB 846.[9] SCE's allocated net revenue requirement for rate setting is $124.9 million and SDG&E's allocated net revenue requirement for rate setting is $27.8 million.[10] The *DCEO Revenue*

9 Pub. Util. Code § 712.8(f)(5).

10 Consistent with the rest of the components within SDG&E's PPP rate component, the Franchise Fees and Uncollectibles (FF&U) associated with the SDG&E DCNBC rate of $1.0 million will be collected through its Distribution rate component.

Requirement for Rate Setting (line 19) presented in Table 10-4 will be used for rate setting, discussed in Section D.

D. Illustrative Statewide Diablo Canyon Non-Bypassable Charge Rates by IOU

1. PG&E DCPP EO NBC

a. Background

In compliance with OP 14 of D.23-12-036, PG&E proposes to collect the Diablo Canyon non-bypassable charge (DCNBC) revenue requirement for rate setting, including the PG&E's specific volumetric fee, from all customers in PG&E's service territory through Public Purpose Program rates. As directed by OP 7, PG&E utilizes the same 12-CP allocation methodology currently used to allocate the cost allocation mechanism (CAM) revenue requirement to PG&E's customer classes which relies on the most recent year of recorded 12-CP data for PG&E's service territory.[11]

b. PG&E's 2026 DCNBC Rate

To develop illustrative DCNBC rates, PG&E allocates PG&E's share of the revenue requirement to its various customer classes using the 12-CP allocation factors and then divides the allocated revenues by the currently effective sales forecast adopted by D.24-12-038 in PG&E's 2025 Energy Resource Recovery Account (ERRA) Forecast & Sales Application (A.) (A. 24-05-009).[12] Upon implementation, PG&E will calculate DCNBC rates utilizing the sales forecast adopted for rate setting that that time. In Table 10-5, below, PG&E has provided illustrative DCNBC rates applicable to each customer class.[13] The

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[11] At the time of filing this application, recorded 12-CP data is only available for the 2023 calendar year. This data is being used to calculate the PG&E illustrative rates presented in this chapter. PG&E expects recorded data for the 2024 calendar year to be available prior to submitting its update to testimony in October 2025.

[12] D.24-12-038 was implemented in rates effective January 1, 2025.

[13] Rates shown in Table 10-5 are reflective of average rates for each customer class. For Residential customers, however, D.24-05-028, allows for Public Purposes Program charges to be collected through a fixed charge for Residential customers, which may be inclusive of the DCNBC rate revenues resulting from the illustrative Residential DCNBC rate shown in Table 10-5. PG&E expects to implement its Fixed Charge for Residential customers on March 1, 2026

customer revenues associated with these rates will be split between the Volumetric Performance Fees Subaccount and the Extended Operations Subaccount based on the factor presented in line 23 of Table 10-4. For PG&E, the volumetric performance fee, including the PG&E's specific volumetric performance fee, represents 75.08 percent of net costs and thus represents 75.08 percent of the resulting illustrative rates.

TABLE 10-5
PG&E'S 2026 DCNBC RATE CALCULATION

Line No.	Customer Class	12-CP Allocation Factor (a)	Revenue Requirement (RRQ) ($000) (b) = PG&E's RRQ * (a)	Sales Forecast (MWh) (c)	2025 DCNBC Rate ($/kWh) (d) = (b)/(c)
1	Residential	46.5%	$120,059	26,464,950	$0.00452
2	Small Commercial	9.1%	$23,396	7,516,505	$0.00310
3	Medium and Large Commercial	23.6%	$60,916	21,859,171	$0.00278
4	Streetlights	0.3%	$754	242,631	$0.00310
5	Standby	0.7%	$1,803	575,107	$0.00313
6	Agriculture	6.8%	$17,540	5,876,922	$0.00298
7	Industrial	13.0%	$32,859	15,601,775	$0.00215

As a result of the DCEO revenue requirement allocated to PG&E of $257.3 million, the system average bundled rate would decrease by approximately 0.4 percent to 35.4 cents per kWh when compared to the present system average bundled rate of 35.6 cents per kWh, effective March 1, 2025. The system average rate for direct access and CCA customers, whose average rates exclude generation charges that are provided by third-party service providers, would decrease by approximately 0.7 percent to 20.4 cents per kWh, when compared to the present system average rate for DA and CCA customers of 20.6 cents per kWh, which was effective March 1, 2025. Table 10-6 presents illustrative rate impacts by customer class and illustrative bundled residential customer bill impacts.

TABLE 10-6
PG&E ILLUSTRATIVE RATE IMPACTS BY CUSTOMER CLASS

		Bundled				Direct Access and Community Choice Aggregator			
	Customer Class	3/1/2025 Present	1/1/2026 Proposed	Rate Change	% Change	3/1/2025 Present	1/1/2026 Proposed	Rate Change	% Change
1	Residential	36.47	36.30	-0.17	-0.5%	23.99	23.81	-0.18	-0.8%
2	CARE	25.20	25.08	-0.12	-0.5%	9.52	9.40	-0.12	-1.3%
3	Non-CARE	43.16	42.96	-0.19	-0.5%	27.27	27.08	-0.20	-0.7%
4	Small Commercial	44.15	44.02	-0.14	-0.3%	29.77	29.64	-0.14	-0.5%
5	Medium Commercial	39.12	39.00	-0.12	-0.3%	22.83	22.71	-0.12	-0.5%
6	Large Commercial (B-19)	34.34	34.22	-0.12	-0.4%	18.40	18.28	-0.12	-0.7%
7	B-19 T	24.16	24.00	-0.16	-0.6%	8.22	8.09	-0.13	-1.6%
8	B-19 P	28.45	28.33	-0.12	-0.4%	14.85	14.73	-0.12	-0.8%
9	B-19 S	35.31	35.19	-0.12	-0.3%	18.74	18.61	-0.12	-0.7%
10	Streetlight	47.26	47.13	-0.13	-0.3%	29.90	29.77	-0.13	-0.4%
11	Standby	18.67	18.53	-0.14	-0.7%	13.11	12.98	-0.14	-1.1%
12	Agriculture	39.81	39.68	-0.13	-0.3%	24.46	24.33	-0.13	-0.5%
13	Industrial (B-20)	22.71	22.62	-0.10	-0.4%	11.22	11.12	-0.10	-0.9%
14	B-20 T	18.84	18.75	-0.10	-0.5%	6.16	6.06	-0.10	-1.6%
15	B-20 P	27.16	27.06	-0.10	-0.4%	13.68	13.59	-0.10	-0.7%
16	B-20 S	31.63	31.54	-0.10	-0.3%	15.56	15.47	-0.10	-0.6%
17	**Average System Rate**	35.56	35.42	-0.14	-0.4%	20.55	20.41	-0.14	-0.7%

	Illustrative Residential Bundled Customer Bill Impacts	3/1/2025 Present	1/1/2026 Proposed	Bill Change	% Change
18	Non-CARE (500 kWh)	$214.93	$213.95	-0.98	-0.5%
19	CARE (500 kWh)	$128.67	$128.06	-0.62	-0.5%

2. SCE DCPP EO NBC

a. Background

Pursuant to OP 14 of D.23-12-036, SCE will continue to use the DCNBC included in its Public Purpose Programs Charge (PPPC) rates to recover the costs from ratepayers associated with DCPP extended operations for 2026. SCE's portion of the DCNBC will be collected from all customers within SCE's service area and will be remitted to PG&E based on the terms of the executed Servicing Order Agreement between SCE and PG&E.[14]

Pursuant to Rule 3.2 and OP 5 of D.23-12-036, SCE will collaborate with the other IOUs and the Commission's Public Advisor Office to ensure SCE complies with noticing requirements resulting from PG&E's DCPP Extended Operations Cost Forecast application.

Pursuant to OP 7 of D.23-12-036, SCE submits this joint testimony with its proposed allocation of the DCPP extended operations costs.

[14] D.23-12-036, p. 96.

b. SCE's 2026 DCNBC Rate

As discussed in Section C above, SCE's DCNBC revenue allocation is currently set at 45.3 percent, and may be updated as part of the Fall Update. This 45.3 percent equates to $124.913 million in forecasted revenue (including FF&U) for 2026 that is to be recovered in electric rates effective January 1, 2026. Pursuant to D.23-12-036,[15] SCE will allocate its total revenue requirement within its service area based on SCE's then-current 12-CP allocation factors that are used as part of SCE's existing CAM.

To allocate the costs to the various customer classes, SCE will utilize the current approved 12-CP demand that is used for the CAM, which can be found in SCE's latest Transmission Owner (TO) Rate Filing and is shown in Table 10-7 below.[16] Should a new TO filing be approved prior to the Fall Update submittal in this proceeding, SCE will update these allocations to reflect the latest cost allocation factors.

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15 *Ibid.*, p. 74.

16 See SCE Formula Transmission Rate Filings; hyperlink at: https://www.sce.com/regulatory/open-access-information/formula-transmission-rate.

TABLE 10-7
SCE'S 12-CP ALLOCATION FACTORS

Line No.	Customer Class	Factor
1	Domestic	45.04%
2	TOU-GS-1	7.04%
3	TC-1	0.04%
4	TOU-GS-2	15.53%
5	TOU-GS-3	8.36%
6	TOU-8-SEC	7.30%
7	TOU-8-PRI	5.39%
8	TOU-8-SUB	5.10%
9	TOU-8-Standby-SEC	0.14%
10	TOU-8-Standby-PRI	0.47%
11	TOU-8-Standby-SUB	1.99%
12	TOU-PA-2	1.75%
13	TOU-PA-3	1.53%
14	Street Lighting	0.31%

Note: The 12-CP Allocators for the TOU-8-nonStandby and TOU-8-Standby Customer Class have been adjusted from the original allocator values. These adjustments were made to account for the shift of supplemental load from the TOU-8-nonStandby customer Class to the TOU-8-Standby Customer Class. Adjustments were made based on the respective system sales and voltages (SEC, PRI, SUB). No other allocators have been adjusted.

To develop the DCNBC rate, SCE used the current effective sales forecast adopted in SCE's 2025 ERRA Forecast (A.24-05-007), which is shown in Table 10-8 below. If SCE's 2026 ERRA Forecast Application is adopted and effective by January 1, 2026, the same time that the DCNBC becomes effective, SCE will update the DCNBC to reflect the current effective 2026 sales forecast from its 2026 ERRA Forecast Application.

TABLE 10-8
SCE'S 2026 DCNBC RATE CALCULATION

Line No.	Customer Class	12-CP Allocation Factor (a)	Revenue Requirement (RRQ) ($000) (b) = SCE's RRQ * (a)	Sales Forecast (MWh) (c)	2025 DCNBC Rate ($/kWh) (d) = (b)/(c)
1	Domestic	45.04%	56,265	26,720,107	0.00211
2	TOU-GS-1	7.04%	8,798	5,521,411	0.00159
3	TC-1	0.04%	54	52,815	0.00103
4	TOU-GS-2	15.53%	19,400	13,183,085	0.00147
5	TOU-GS-3	8.36%	10,444	7,531,724	0.00139
6	TOU-8-SEC	7.30%	9,120	7,331,304	0.00124
7	TOU-8-PRI	5.39%	6,728	5,737,628	0.00117
8	TOU-8-SUB	5.10%	6,372	6,058,742	0.00105
9	TOU-8-Standby-SEC	0.14%	169	136,088	0.00124
10	TOU-8-Standby-PRI	0.47%	589	502,116	0.00117
11	TOU-8-Standby-SUB	1.99%	2,487	2,364,681	0.00105
12	TOU-PA-2	1.75%	2,182	1,834,363	0.00119
13	TOU-PA-3	1.53%	1,917	1,729,965	0.00111
14	Street Lighting	0.31%	388	430,614	0.00090

The DCNBC rate will continue to be set on a per kWh basis for each customer class and will be added to the components of the PPPC rate for customer billing (i.e., the DCNBC will be embedded as part of the PPPC and will not be a standalone line item). The DCNBC will also continue to be recovered from all customers on a volumetric, per-kWh basis. Any updates to allocation factors or sales forecast will be included in SCE's annual year-end consolidated revenue requirement and rate change advice letter process.

Based on the current rate estimates (i.e., March 1, 2025), the 2026 DCNBC results in the estimated rates shown in Table 10-9, and bill impacts shown below in Table 10-10, both a decrease.

TABLE 10-9
SCE'S ESTIMATED RATES

Line No.	Customer Group	Bundled Average Rates (¢/kWh) Current Rates	Proposed Change	Proposed Rates	% Change
1	Residential	31.4	(0.25)	31.1	-0.8%
2	Lighting – Small and Medium Power	29.1	(0.21)	28.9	-0.7%
3	Large Power	19.2	(0.16)	19.1	-0.9%
4	Agricultural and Pumping	23.0	(0.15)	22.8	-0.7%
5	Street and Area Lighting	34.7	(0.12)	34.5	-0.3%
6	Standby	16.3	(0.16)	16.1	-1.0%
7	Total	27.1	(0.21)	26.9	-0.8%

TABLE 10-10
SCE'S ESTIMATED BILL IMPACTS

Line No.	Description	Residential Bill Impact ($/Month) Current	Proposed Change	Proposed	% Change
1	Non-CARE residential bill	$174.78	($1.38)	$173.40	-0.8%
2	CARE residential bill	$109.92	($0.87)	$109.50	-0.8%

3. SDG&E DCPP EO NBC

a. Background

Pursuant to D.23-12-036, the Commission conditionally approved extended operations at DCPP in response to SB 846 and approved a non-bypassable charge (NBC) to be included in Public Purpose Program (PPP) rates to support the extended operations of DCPP.[17] SDG&E's portion of the DCNBC will be collected from customers within SDG&E's service territory for remittance to PG&E, the operator of DCPP Units 1 and 2, as required by D.23-12-036.[18]

Pursuant to Rule 3.2, SDG&E will collaborate with PG&E, SCE, BVES, Inc., Liberty Utilities, PacifiCorp d/b/a Pacific Power, and the Commission's Public Advisor's Office to ensure all participating utilities comply with requirements that are a result of PG&E's Diablo Canyon Nuclear Power Plant Extended Operations Cost Forecast application.

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17 D.23-12-036, OP 1 and OP 14.

18 *Ibid*., Finding of Fact (FOF) 14 and COL 47.

b. SDG&E's 2025 DCNBC Rate

As discussed in Section C, SDG&E's updated cost allocation is 9.8 percent based on collective 12-CP among PG&E, SCE, and SDG&E (the Joint IOUs). This equates to $26.7 million[19] in 2026 revenue requirement, as shown in Table 10-4, to be recovered in SDG&E's electric rates effective January 1, 2026. This is a decrease of $33.8 million compared to current. As discussed further below, SDG&E allocates its 2026 revenue requirements to its customer classes and then utilizes its most recent sales forecast to develop its 2026 DCNBC rates to be charged by customer class. This calculation and resulting rates can be found in Table 10-11 below.

To allocate costs to its customer classes, SDG&E utilizes the current 12-CP demand that can be found in Statement BL in Docket Number ER25-270-000 of SDG&E's TO 6 Cycle 1 Filing.[20] SDG&E will update these allocations with the Fall Update or upon implementation if a new 12-CP forecast is filed.

To develop the 2026 DCNBC rate, SDG&E utilizes the current effective sales forecast adopted in SDG&E's 2025 ERRA Forecast & Sales (A.24-05-010).[21] Upon implementation, SDG&E will update this forecast to use current adopted sales forecast at that time.[22]

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19 Excludes FF&U.

20 Docket No. ER24-270-000: TO6 Cycle 1 Annual Informational Filing Statement BL, p. BL-2.

21 D.24-12-040 was implemented in rates effective February 1, 2025.

22 For example, SDG&E will put forth its 2026 sales forecast in its 2026 ERRA/Sales Forecast application to be filed in May 2025. If a new sales forecast is adopted and effective January 2026, at the same time this DCPP rate becomes effective, SDG&E will update the DCPP rate to utilize the current effective 2026 sales forecast.

TABLE 10-11
SDG&E'S DCNBC RATE CALCULATION

Line No.	Customer Class	12-CP Allocation Factor (SDG&E's TO6 C1) (a)	Revenue Requirement (RRQ) ($000) (b) = SDG&E's RRQ * (a)	Sales Forecast 2025 ERRA Filing[(a)] (GWh) (c)	2026 DCNBC Rate ($/kWh) (d) = (b)/(c)/1000
1	Residential	45.4%	$12,121.65	7,794	$0.00156
2	Small Commercial	10.9%	$2,916.91	2,465	$0.00118
3	Medium and Large Commercial & Industrial	42.3%	$11,310.27	9,567	$0.00118
4	Agriculture	1.1%	$290.53	367	$0.00079
5	Streetlight	0.3%	$88.63	80	$0.00110
6	System Average	100%	$26,728.00	20,273	$0.00132

(a) SDG&E's sales forecast is utilizing System Delivered sales since PPP is a non-bypassable charge.

The DCNBC rate will be added to components of the PPP rate for customer billing.[23] Any updates to allocation factors or sales forecast will be included in SDG&E's annual electric consolidated advice letter filing process.[24]

The 2026 DCNBC results in a decrease to electric total system average rate of 0.173 cents/kwh,[25] which is a 0.9 percent decrease to delivery rates or 0.5 percent decrease to bundled (delivery plus commodity) rates. Table 10-12 below presents a table summarizing the rate impacts by customer class.

23 D.23-12-036, pp. 138-139, OP 14.

24 The DCNBC is currently fully volumetric ($/kWh) in 2025 rates. However, the residential DCNBC may be eligible to be part of the PPP portion of the Residential Fixed Charge per D.24-05-028.

25 System Average Rate Includes FF&U.

TABLE 10-12
SDG&E'S ILLUSTRATIVE RATE IMPACT BY CUSTOMER CLASS

Rate Impacts (Unbundled)[a]

Line No.	Customer Class	Current Elec. Delivery Class Average Rates Effective 02/01/25 (¢/kWh)	Proposed Elec. Delivery Class Average Rates 1/1/26 DCPP NBC (¢/kWh)	Total Rate Decrease (¢/kWh)	Percentage Average Rate Decrease (%)
1	Residential	20.1	19.9	(0.2)	-1.0%
2	Small Comm.	23.3	23.1	(0.2)	-0.7%
3	Med & Lg C&I	16.4	16.2	(0.2)	-0.9%
4	Agriculture	14.3	14.2	(0.1)	-0.7%
5	Lighting	24.7	24.6	(0.2)	-0.6%
6	System Total	18.5	18.3	(0.2)	-0.9%

(a) "Unbundled" customers receive electric generation from an Energy Service Provider (ESP) that is not SDG&E.

Rate Impacts (Bundled)[a]

Line No.	Customer Class	Current Total Class Average Rates Effective 02/01/25 (¢/kWh)	Proposed Total Class Average Rates 1/1/26 DCPP NBC (¢/kWh)	Total Rate Decrease (¢/kWh)	Percentage Average Rate Decrease (%)
1	Residential	35.9	35.7	(0.2)	-0.6%
2	Small Comm.	36.7	36.6	(0.2)	-0.4%
3	Med & Lg C&I	32.5	32.4	(0.2)	-0.5%
4	Agriculture	25.7	25.6	(0.1)	-0.4%
5	Lighting	35.1	34.9	(0.2)	-0.4%
6	System Total	34.0	33.9	(0.2)	-0.5%

(a) "Bundled" customers receive electric generation from SDG&E.

Table 10-13 below shows illustrative bill impacts for a typical residential customer.

TABLE 10-13
SDG&E'S ILLUSTRATIVE BILL IMPACT FOR A TYPICAL RESIDENTIAL CUSTOMER

		Bill Impacts[a]			
		Current	Proposed		
Line No.	Customer Class	Effective 02/01/25 ($/month)	1/1/26 DCPP NBC ($/month)	Total Rate Decrease ($/month)	Percentage Average Rate Decrease (%)
1	Unbundled, 2021V[a]	$85.75	$84.97	($0.78)	-0.9%
2	Bundled[b]	$152.05	$151.27	($0.78)	-0.5%

(a) "Unbundled" customers receive electric generation from an ESP that is not SDG&E.
(b) "Bundled" customers receive electric generation from SDG&E. May not sum due to rounding.

E. Conclusion

In this chapter, PG&E, SCE, and SDG&E present illustrative DCNBC rates by customer class based on the revenue requirements allocated to each utility using allocation factors developed from the CEC's 2025 12-CP forecast for CPUC jurisdictional utilities. PG&E, SCE, and SDG&E request that the Commission approve the allocation between IOUs presented in this chapter, subject to Fall Update, which would update the CEC's 2025 12-CP forecast to the 2026 12-CP forecast.

In addition, Table 10-4 presents illustrative Volumetric Performance Fee allocation factors that can be applied to the DCNBC revenues to identify the portion of revenues associated with Volumetric Performance Fee, which will be reported separately in the monthly revenue reports for each IOU. PG&E, SCE, and SDG&E request that the Commission approve the Volumetric Performance Fee allocation factor, subject to the Fall Update final revenue requirement allocation.

The Fall Update is expected to be served after CPUC Energy Division staff issues revised Market Price Benchmarks in October 2025, and would include updated illustrative rates for implementation in rates effective January 1, 2026.

PACIFIC GAS AND ELECTRIC COMPANY

APPENDIX A

STATEMENTS OF QUALIFICATIONS

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF THOMAS R. BALDWIN

Q 1 Please state your name and business address.

A 1 My name is Thomas R. Baldwin, and my business address is Pacific Gas and Electric Company (PG&E), Diablo Canyon Power Plant (DCPP), Avila Beach, California.

Q 2 Briefly describe your responsibilities at PG&E.

A 2 I am the Director of Nuclear Generation Business Operations, responsible for the Nuclear Generation functional area strategic and integrated planning, General Rate Case (GRC) activities, and matrixed organizations including business finance and supply chain.

Q 3 Please summarize your educational and professional background.

A 3 I received a Bachelor of Science degree in Mechanical Engineering from University of Colorado, Boulder, in 1984. I joined PG&E in 1985 as a Design Engineer in the Mechanical and Nuclear Engineering Department. I have since held positions as the Supervisor of Systems Engineering, Manager of Regulatory Services, Manager of Procedures Services, Operations Senior Reactor Operator (licensed by the Nuclear Regulatory Commission), Director of Site Services, and the Director of Business Planning for Generation. Additionally, I have presented testimony before the California Public Utilities Commission more recently as PG&E's Exhibit PG&E-5 Chapter 3 witness on "Nuclear Operations Costs" in PG&E's 2023 GRC, A.21-06-021, and in PG&E's 2025 DCPP Extended Operations Forecast Application, A.24-03-018, where I was the Chapter 4, "Generation and Resource Adequacy Substitution Capacity Cost Forecast," witness for sections A, B, and C.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's 2026 Diablo Canyon Power Plant Extended Operations Non-Bypassable Charge Forecast Revenue Requirement proceeding:

- Chapter 3, "Generation Forecast and Resource Adequacy Substitution Capacity Cost Forecast":
  - Sections A, B, and C.

Q 5 Does this conclude your statement of qualifications?
A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF DONNA L. BARRY

Q 1 Please state your name and business address.

A 1 My name is Donna L. Barry, and my business address is Pacific Gas and Electric Company (PG&E), 300 Lakeside Drive, Oakland, California.

Q 2 Briefly describe your responsibilities at PG&E.

A 2 I am a Principal Strategic Analyst in the Energy Policy Analysis and Design Department within the Energy Policy and Procurement organization. I am responsible for developing testimony and analysis to support proceedings filed at the California Public Utilities Commission on matters related to energy procurement and cost recovery.

Q 3 Please summarize your educational and professional background.

A 3 I received my Bachelor of Science degree in Civil Engineering from Washington State University and a Master of Business Administration degree from Santa Clara University.

I began my career with PG&E in 1989 as an Engineer in the Engineering and Construction Business Unit's Gas Construction Department, managing gas distribution and pipeline replacement construction projects. From there, I took an assignment in the Gas Supply Business Unit in the Gas Engineering and Construction (GEC) Department as a Project Manager, managing three gas backbone transmission projects before joining the Gas Planning section in GEC, where I analyzed the reliability of local transmission and distribution systems. I subsequently joined the Cost-of-Service section in the Rates Department, where I performed cost of service studies and marginal cost analyses supporting various gas and electric rate applications.

I joined the Electric Restructuring Cost Recovery section of the Revenue Requirements Department in 2001 and Electric Energy Revenue and Analysis and Ratemaking section in 2002. I was a Case Manager for the Energy Resource Recovery Account (ERRA) Forecast from 2004 through 2006 and sponsored testimony in the case related to PG&E's generation-related non-bypassable charges between 2004-2019 and more recently, I have sponsored testimony supporting updates to PG&E's Green

Tariff Shared Renewables (GTSR) Program rates. I was also the Principal Case Manager for the ERRA Compliance Review proceeding from 2003-2011 and my responsibilities included coordination of the case assessment and strategy development across multiple departments within PG&E, as well as sponsoring testimony related to the review of costs recorded to the ERRA. The department and section were renamed as the Energy Supply Proceedings Department in 2012. I moved to the Revenue Requirements and Analysis Department in 2014.

The Revenue Requirements and Analysis Department was reorganized and renamed several times between 2014 and 2024 and the current department name is Electric Rates. While in Electric Rates, I sponsored written testimony related to cost recovery and rate design and/or submitted cost recovery proposals in advice letters in support of the following applications: GTSR Program, Transportation Electrification Senate Bill 350, Energy Storage System Rulemaking (2014), Energy Storage Plan (2016), Energy Storage Request for Offers (2014 and 2016), Energy Storage Plan and Assembly Bill 2868, among others. I have also contributed to two Applications that involved reform of the Power Charge Indifference Adjustment (PCIA)—the Portfolio Allocation Mechanism Application in 2017 and the PCIA Rulemaking in 2018, both of which were jointly filed with Southern California Edison Company and San Diego Gas & Electric Company. I also sponsored Testimony in the Green Access Program Application advocating for reform of the existing GTSR Program and rate design.

In May of 2024, I moved to my current position in Energy Policy Analysis and Design, and continued to sponsor testimony and analysis in support of PG&E's Energy Policy objectives, including cost recovery proposals.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's PG&E's 2026 Diablo Canyon Power Plant Extended Operations Non-Bypassable Charge Forecast Revenue Requirement proceeding:

- Chapter 9, "Net Revenue Requirement for Ratesetting"; and
- Chapter 10, "Joint Investor Owned Utility Non-Bypassable Charge Proposal":

– Section C.

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF GEORGE P. CLAVIER

Q 1 Please state your name and business address.

A 1 My name is George P. Clavier, and my business address is Pacific Gas and Electric Company (PG&E), 300 Lakeside Drive, Oakland, California.

Q 2 Briefly describe your responsibilities at PG&E.

A 2 I am a Principal Analyst in the Portfolio and Resource Forecasting Department within the Energy Policy and Procurement organization, responsible for preparing, validating, and analyzing energy procurement cost and generation forecasts utilized in regulatory proceedings before the California Public Utilities Commission and the California Energy Commission.

Q 3 Please summarize your educational and professional background.

A 3 I graduated with a Bachelor of Arts in International Economics from the American College in Paris in 1982 and a Master of Science in Agricultural Economics from the University of California, Davis in 1988.

I joined PG&E in 1991 as an Analyst in the Fuels Policy Department. Since then, I have held a number of different positions in the Energy Policy and Procurement organization. In my current position I have worked on various energy procurement forecasts and related analysis to support PG&E in regulatory proceedings and other business processes.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's 2026 Diablo Canyon Power Plant Extended Operations Non-Bypassable Charge Forecast Revenue Requirement proceeding:

- Chapter 3, "Generation Forecast and Resource Adequacy Substitution Capacity Cost Forecast":
  - Section D; and
- Chapter 6, "California Independent System Operator Corporation Market Revenues."

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF MARK COUGHLAN

Q 1 Please state your name and business address.

A 1 My name is Mark Coughlan, and my business address is Pacific Gas and Electric Company (PG&E), 300 Lakeside Drive, Oakland, California.

Q 2 Briefly describe your responsibilities at PG&E.

A 2 My current position at PG&E is Expert Analyst of Electric Rates within the Regulatory Affairs organization. In this capacity, I am responsible for the development of electric rates, including rate design proposals for presentation, review, and approval by the California Public Utilities Commission.

Q 3 Please summarize your educational and professional background.

A 3 I received a Bachelor of Arts degree in History from the University of Notre Dame in May 2005 and a Master of Science degree in Civil & Environmental Engineering from Stanford University in September 2007. From 2008 to 2021 I have worked as a consulting professional engineer and have held various positions in the financial services and technology sectors, where my work focused on operations and regulatory compliance and analytics.

I joined PG&E in March 2021 as an Expert Rate Analyst in the Rates Department within Regulatory Affairs. My work has primarily focused on the design of electric generation rates, and I have assisted with the preparation of PG&E rate design proposals in various proceedings including the Energy Resource Recovery Account Forecast proceeding and PG&E's General Rate Case proceeding.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony and workpapers in PG&E's 2026 Diablo Canyon Power Plant Extended Operations Non-Bypassable Charge Forecast Revenue Requirement proceeding:

- Chapter 10, "Joint Investor Owned Utility Non-bypassable Charge Proposal":
  - Sections A, B, D.1, and E.

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF MARQUES A. CRUZ

Q 1 Please state your name and business address.

A 1 My name is Marques A. Cruz, and my business address is Pacific Gas and Electric Company (PG&E), 300 Lakeside Drive, Oakland, California.

Q 2 Briefly describe your responsibilities at PG&E.

A 2 I am Results of Operations Manager in PG&E's Revenue Requirement and Cost Recovery Department, which is responsible for developing analyses and testimony to support recovery of utility investments.

Q 3 Please summarize your educational and professional background.

A 3 I received a Bachelor of Science degree in Civil and Environmental Engineering from University of Michigan, Ann Arbor and a Master of Business Administration degree in Finance and Corporate Strategy from Ross School of Business at the University of Michigan, Ann Arbor.

In 2013, I joined PG&E as a Project Management Engineer in the Gas Operations Program Management Office, supporting project management and strategic planning for pipeline safety and enhancement projects. In 2015, I accepted a rotational assignment performing financial management and economic analysis of pilot projects for PG&E's Smart Grid Technology Program. In 2016, I joined the Economic Analysis department at PG&E, where I worked for approximately seven years before assuming my current position in 2023.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's 2026 Diablo Canyon Power Plant Extended Operations Non-Bypassable Charge Forecast Revenue Requirement proceeding:

- Chapter 4, "Operational Revenue Requirement":
  - Sections: A, B.1.a through B.1.d, and C.

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF J. CONOR DOYLE

Q 1 Please state your name and business address.

A 1 My name is J. Conor Doyle, and my business address is Pacific Gas and Electric Company (PG&E), Diablo Canyon Power Plant (DCPP), Avila Beach, California.

Q 2 Briefly describe your responsibilities at PG&E.

A 2 I am the Director of Regulatory Proceedings at DCPP. I lead a team that is responsible for supporting DCPP and Humboldt Independent Spent Fuel Storage-related proceedings before the California Public Utilities Commission (CPUC). Additionally, my team and I are responsible for managing compliance activities associated with the Department of Energy Credit Award and Payment Agreement. I presented testimony before the CPUC in PG&E's 2025 DCPP Extended Operations Forecast Application, A.24-03-018, as PG&E's witness for Chapter 1, "Introduction and Policy," and Chapter 7, "Statutory Fees." Prior to my current role, I served as Director General Rate Case (GRC), Risk, and Financial Proceedings leading a team of case managers responsible for various regulatory proceedings before the CPUC including the 2020 and 2023 GRC, Wildfire Mitigation and Catastrophic Events proceeding, the Cost of Capital Proceeding, and various cost recovery proceedings and risk and safety compliance reports. Prior to this role, I served as the regulatory case manager for a number of regulatory proceedings, including: PG&E's Diablo Canyon Retirement Joint Proposal Application; 2015 Nuclear Decommissioning Cost Triennial Proceeding; and 2015 Catastrophic Event Memorandum Account Application, for which I also served as the Policy witness.

Q 3 Please summarize your educational and professional background.

A 3 I received a Bachelor of Arts degree in Political Science from the University of California, Santa Barbara. I have been employed by PG&E for 14 years. Prior to joining PG&E, I worked as an environmental consultant on utility-scale energy projects in California and Nevada.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's 2026 Diablo Canyon Power Plant Extended Operations Non-Bypassable Charge Forecast Revenue Requirement proceeding:

- Chapter 1, "Introduction and Policy"; and
- Chapter 5, "Statutory Fees."

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF AMARA K. HAYASHIDA

Q 1 Please state your name and business address.

A 1 My name is Amara K. Hayashida, and my business address is Pacific Gas and Electric Company (PG&E), 300 Lakeside Drive, Oakland, California.

Q 2 Briefly describe your responsibilities at PG&E.

A 2 I am a Tax Principal in the PG&E Tax Department. I am responsible for developing and supporting income tax estimates in ratemaking and other regulatory filings.

Q 3 Please summarize your educational and professional background.

A 3 In 2003, I earned a Bachelor of Science in Business Administration with a focus on Accountancy from California State University Sacramento. In 2007, I earned a Juris Doctorate degree from Santa Clara University School of Law. I am a member of the California Bar Association (inactive status) and a California Certified Public Accountant (CPA). After law school, I was employed by KPMG, LLP in the firm's tax practice for almost five years. In 2012, I joined PG&E as a Senior Tax Analyst and left the Tax Department in 2017. From 2017 through 2020, I was an Expert Case Manager in PG&E's Regulatory Proceedings and Rates department. In 2020, I rejoined the Tax Department as a Research and Planning Tax Principal. I was the tax witness in the Diablo Canyon Power Plant Extended Operations Forecast 2025 rate case, filed last year. I have worked on various Federal Energy Regulatory Commission (FERC) Transmission Owner (TO) twentieth (TO20) Annual Update filings and was the tax witness for PG&E's FERC twenty-first (TO21) Formula Rate Case. I was the tax witness assistant for PG&E's 2023 General Rate Case and have provided tax regulatory support on other California Public Utilities Commission rate cases with tax issues.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's 2026 Diablo Canyon Power Plant Extended Operations Non-Bypassable Charge Forecast Revenue Requirement proceeding:

- Chapter 4, "Operational Revenue Requirement":
  - Sections B.1.e and Section B.1.f.

Q 5 Does this conclude your statement of qualifications?
A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF BRIAN KETELSEN

Q 1 Please state your name and business address.

A 1 My name is Brian Ketelsen, and my business address is Pacific Gas and Electric Company (PG&E), Diablo Canyon Power Plant (DCPP), Avila Beach, California.

Q 2 Briefly describe your responsibilities at PG&E.

A 2 I am the Director of Business and Technical Services for DCPP where I am responsible for financial management and forecasting at DCPP, including implementation of the financial requirements of Senate Bill (SB) 846 and associated regulatory filings, and DCPP extended operations cost recovery.

Q 3 Please summarize your educational and professional background.

A 3 I earned a Bachelor of Arts in Economics from San Diego University in 2007. I joined PG&E in 2011 after various Financial Analyst roles. Since joining PG&E, I progressed through the Project Finance organization at DCPP where my team facilitated the project approval, controls, governance, and closeout process for all projects at DCPP. I supported testimony and workpaper development for the 2014 and 2017 General Rate Cases. I joined DCPP decommissioning in 2018 and led the development of the 2018 and 2021 Nuclear Decommissioning Cost Triennial Proceeding filings. In 2022, I assumed the role of Director, Business and Technical Services, responsible for DCPP financial management and forecasting including the implementation of the financial requirements of SB 846 and associated regulatory filings, nuclear fuel procurement, and spent fuel management and decommissioning planning. I have presented testimony before the California Public Utilities Commission (CPUC) as PG&E's witness on historical and forecast DCPP costs in the CPUC's DCPP Extended Operations Rulemaking 23-01-007 and in PG&E's 2025 DCPP Extended Operations Forecast Application 24-03-018, sponsoring Chapter 3, "2023-2025 Forecast Operations and Maintenance Costs To Be Recovered in Rates."

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E’s 2026 Diablo Canyon Extended Operations Non-Bypassable Charge Forecast Revenue Requirement proceeding:

- Chapter 2, “2026 Forecast Operations and Maintenance Costs to be Recovered in Rates.”

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

SOUTHERN CALIFORNIA EDISON COMPANY
STATEMENT OF QUALIFICATIONS OF RAY LIANG

Q 1 Please state your name and business address.

A 1 My name is Ray Liang, and my business address is 8631 Rush Street, Rosemead, CA, 91770.

Q 2 Briefly describe your responsibilities at Southern California Edison Company (SCE).

A 2 I am an Advisor for Modeling, Forecasting, and Economical Analysis within the Regulatory Policy & Strategic Analysis organization at SCE. In this role, I conduct analyses that inform the development and implementation of retail electricity rates and customer programs. I also support my colleagues in forecasting electricity demand, evaluate cost of service, and assesses affordability trends for SCE's customers.

Q 3 Please summarize your educational and professional background.

A 3 I received my Master of Business Administration with an emphasis on Data Analytics from San Francisco State University, and a Bachelor of Science degree in Computer Science from San Jose State University. During my career in SCE, I have executed multiple rate implementation and rate design processes in electric, water, and gas proceedings. I am a principal analyst for SCE's Net Energy Metering (NEM) and renewable related topics and proceeding for the past fifteen years. I am involved in the development of many SCE rates related proceedings, including NEM 2.0, Net Billing Tariff, Electric Vehicle rates, standby rates, dynamic rates, change to TOU periods, and the design and implementation of SCE's Income Graduated Fixed Charges.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's 2026 Diablo Canyon Power Plant Extended Operations Non-Bypassable Charge Forecast Revenue Requirement proceeding:

- Chapter 10, "Joint Investor Owned Utility Non-Bypassable Charge Proposal":
  - Section D.2.

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF KEVIN LOUDAT

Q 1 Please state your name and business address.

A 1 My name is Kevin Loudat, and my business address is San Diego Gas and Electric Company (SDG&E), 8330 Century Park Court, San Diego, California.

Q 2 Briefly describe your responsibilities at SDG&E.

A 2 I am a Business and Economics Advisor in the Customer Pricing department of SDG&E. My responsibilities include overseeing Electric Rate implementations and compliance, as well as various aspects of Rate Design for SDG&E.

Q 3 Please summarize your educational and professional background.

A 3 I have worked for SDG&E since December 2015 and have held various positions in the Customer Contact Center, Customer Billing, and Customer Pricing with increasing levels of responsibility. I received a Bachelor of Science degree in Business Administration with a concentration in Marketing Management from California Polytechnic State University San Luis Obispo in 2013. I have previously testified before the California Public Utilities Commission.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's 2026 Diablo Canyon Power Plant Extended Operations Non-Bypassable Charge Forecast Revenue Requirement proceeding:

- Chapter 10, "Joint Investor Owned Utility Non-Bypassable Charge Proposal":
  - Section D-3.

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF KRISTIN MANZ

Q 1 Please state your name and business address.

A 1 My name is Kristin Manz, and my business address is Pacific Gas and Electric Company (PG&E), 300 Lakeside Drive, Oakland, California.

Q 2 Briefly describe your responsibilities at PG&E.

A 2 I am the Vice President of Finance and Planning for PG&E. I am responsible for facilitating our multi-year planning process across the various functional areas of our business, making sure that the plan is assessing and addressing our company's risks, and the plan improves our financial health. I am also responsible for tracking progress against the plan as work progresses from year to year.

Q 3 Please summarize your educational and professional background.

A 3 I have a Master of Business Administration in Finance from DePaul Driehaus College of Business and a Bachelor of Science in Management Information Systems from the University of Florida's Warrington College of Business. I am a 23-year Finance Professional and have previously worked at other utilities; Florida Power and Light Company and NextEra Energy, Inc., as well as in the non-utility sector at Amazon. In April 2023, I joined PG&E. I have presented testimony before the California Public Utilities Commission as PG&E's witness on Volumetric Performance Fee expenditures planned for 2025 in PG&E's DCPP Extended Operations Forecast Application 24-03-018.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's 2026 Diablo Canyon Power Plant Extended Operations Non-Bypassable Charge Forecast Revenue Requirement proceeding:

- Chapter 7, "Planned Usage of Funds from Volumetric Performance Fees."

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF RYAN A. STANLEY

Q 1 Please state your name and business address.

A 1 My name is Ryan A. Stanley, and my business address is Pacific Gas and Electric Company (PG&E), 300 Lakeside Drive, Oakland, California.

Q 2 Briefly describe your responsibilities at PG&E.

A 2 I am a Senior Manager in the Energy Accounting Department within the Corporate and Capital Accounting organization at PG&E. In this position, I am responsible for overseeing and advising on cost recovery, including related to nuclear fuel and operations recovery, in compliance with California Public Utilities Commission directives.

Q 3 Please summarize your educational and professional background.

A 3 I received my Bachelor of Science degree in Business Administration from the Walter A. Haas School of Business, University of California at Berkeley. I received my Master's in Business Administration from the Walter A. Haas School of Business, University of California at Berkeley.

I have over 18 years of regulated utility accounting, financial forecasting, and regulatory experience from having held positions of increasing responsibility at PG&E, in the Controller's and Regulatory Affairs organizations.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's 2026 Diablo Canyon Power Plant Extended Operations Non-Bypassable Charge Forecast Revenue Requirement proceeding:

- Chapter 7, "Planned Usage of Funds From Volumetric Performance Fees":
  - Sections D, E, and F; and
- Chapter 8, "Diablo Canyon Extended Operations Balancing Account."

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.