BEFORE THE
PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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

ALLIANCE FOR NUCLEAR RESPONSIBILITY'S OPENING BRIEF

PUBLIC VERSION

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SUMMARY OF RECOMMENDATIONS

For the reasons stated herein, A4NR recommends that the Commission find that:

- PG&E has failed to meet its burden of proving by a preponderance of evidence that extended operation of DCNPP through 2030 would be reasonable, prudent, or cost-effective;
- PG&E should be directed to provide the NRC with the requisite 30-day notice on January 1, 2027 of the company's intent to permanently cease operations at DCNPP;
- PG&E's Record Period revenue requirement should be reduced by $65,227,000 because Pub. Util. Code Section 712.8(c)(1)(C) prohibits payment of the associated O&M Project Expense from rates;
- PG&E's Record Period revenue requirement should be reduced by $31,636,461 because the company had the ability to mitigate the cost impacts of its forecast RA capacity substitution obligations for 2024 – 2025 scheduled outages by this amount;
- PG&E's Record Period revenue requirement should be reduced by $[redacted] because Pub. Util. Code Section 712.8(c)(1)(C) prohibits payment of the associated amortized nuclear fuel procurement costs from rates;
- PG&E should be directed to file a Tier 3 Advice Letter that allocates the costs incurred for DCNPP employee retention prior to commencement of extended operations at Unit 1 and Unit 2 exclusively to customers of LSEs within the PG&E service territory, and thereafter apportioned between customers of all

jurisdictional LSEs on the same basis as other operating costs that are subject to the nonbypassable charge;

- Approval of the nonbypassable charge and rate proposals by PG&E, SCE, and SDG&E should be conditioned upon each of the modifications identified above in order to comply with D.23-12-036 and Pub. Util. Code Section 451;
- PG&E's proposal for allocating the RA attributes and GHG-free energy attributes associated with DCNPP extended operations should be rejected as an impermissible collateral attack on D.23-12-036;
- PG&E's proposed VPFs spending plan should be rejected and all VPFs retained in the Volumetric Performance Fees Subaccount of the DCEOBA pending completion of judicial review of the company's petition for writ of review of D.23-12-036;
- PG&E's proposed modifications to the review process established in D.23-12-036 for VPFs expenditures should be rejected; and
- PG&E has not satisfied the regulatory requirements set forth in D.23-12-036.

I. INTRODUCTION.

Pursuant to Rule 13.12 of the Rules of Practice and Procedure of the California Public Utilities Commission ("Commission" or "CPUC") and the briefing schedule established by the June 18, 2024 Assigned Commissioner's Scoping Memo and Ruling, as amended by the August 27, 2024 email ruling of Administrative Law Judge ("ALJ") Nilgun Atamturk, the Alliance for Nuclear Responsibility ("A4NR") respectfully files its Opening Brief in the Application of Pacific Gas and Electric Company ("PG&E") to Recover in Customer Rates the Costs to Support Extended Operation of the Diablo Canyon Nuclear Power Plant ("DCNPP" or "DCPP") from September 1, 2023 through December 31, 2025 and for Approval of Planned Expenditure of 2025 Volumetric Performance Fees ("VPFs").

A4NR recommends disallowances of $[redacted] from PG&E's cost recovery request for the 2023 – 2025 Recovery Period, and rejection of PG&E's expenditure plan for 2025 VPFs. Because PG&E has failed to meet its burden of proving by a preponderance of evidence that extended operation of DCNPP through 2030 would be reasonable and prudent, A4NR recommends that the Commission order PG&E to provide the U.S. Nuclear Regulatory Commission ("NRC") with the requisite 30-day notice on January 1, 2027 of the company's intent to permanently cease operations at DCNPP. A4NR notes that PG&E has also failed to meet its burden of proving by a preponderance of evidence the cost-effectiveness of DCNPP 2024 – 2030 extended operations.

II. THE 2024 – 2030 RELIABILITY PICTURE HAS CHANGED.

As noted in A4NR-01,[1] the reliability outlook during the DCNPP extended operations period is considerably more robust than it appeared 25 months ago at the enactment of SB 846 – or even 9½ months ago at the adoption of D.23-12-036. The May 2024 Joint Agency Reliability Planning Assessment[2] from the Commission and California Energy Commission ("CEC") indicates that aggressive procurement, and successive rounds of the Commission's Integrated Resource

[1] A4NR-01, p. 4, line 14 – p. 5, line 2.

[2] D.23-12-036, at pp. 14 – 15, identified the most recent reliability assessment in the R.23-01-007 Phase 1 evidentiary record on which it was based as the CEC's and the Commission's May 2023 report, entitled *Joint Agency Reliability Planning Assessment — SB 846 Second Quarterly Report* (May 2023 Joint Planning Assessment)."

Planning process, have greatly mitigated the prospective capacity shortage concerns that motivated SB 846 to focus a spotlight on postponing the retirement of DCNPP's 2,280 MW of Net Qualifying Capacity.[3] The two agencies now estimate 18,800 MW of net qualifying capacity of new resources will have come online between 2020 and 2028 (more than 8,000 MW of that by year-end 2023[4]), and announced,

> The results from the analyses agree that the proposed 2023 Preferred System Plan meets the reliability standard through 2035. The CEC performed additional analysis around potential import and supply shortfalls and concluded the state remains reliable even under extreme scenarios.[5]

Reinforcing the significance of the May 2024 Joint Agency assessment of the 2023 Preferred System Plan is the preclusion in Pub. Util. Code Section 454.52(f)(1) and (2) from including extended operation of DCNPP in adopted integrated resource plan portfolios, resource stacks, or preferred system plans. The Legislature was intent that, after the expiration dates for its current operating licenses, DCNPP be treated as a superfluous resource by energy planners, "thereby forcing LSEs to procure enough resources to treat DCPP as if it did not exist."[6]

PG&E senior management has called attention to the recent surge in capacity. As stated by Chief Executive Officer Patti Poppe in her July 25, 2024 quarterly earnings call with financial analysts:

> On the reliability front, California has added over nine gigawatts of capacity in just the last year, and it did the job. The state now also has ten gigawatts of battery storage that are providing significant benefits in terms of additional

[3] PG&E-01 identifies DCNPP's "Maximum Dependable Capacity" as 2,240 MW at p. 4-2, lines 4 – 5.

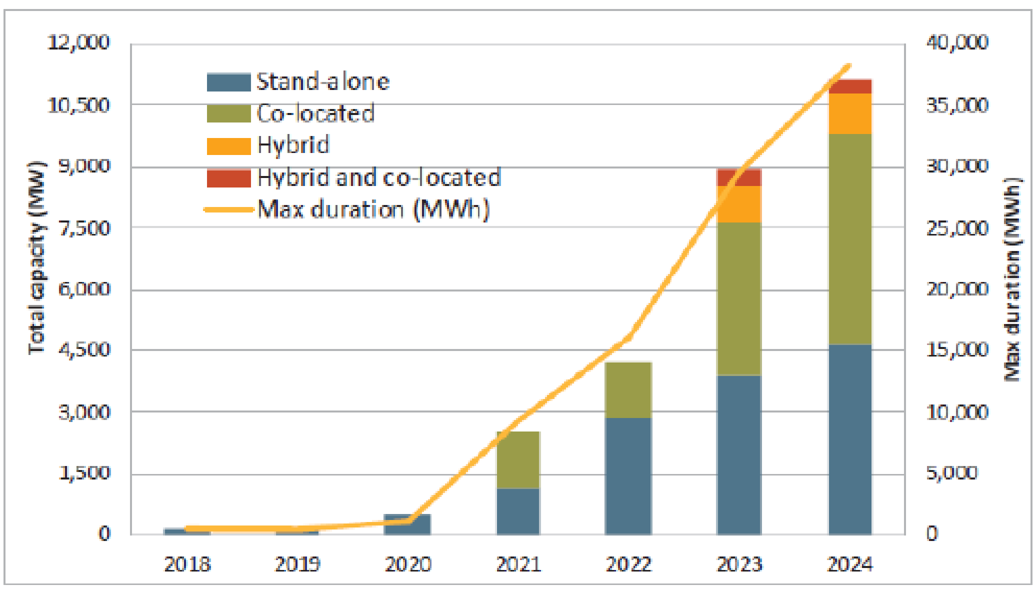
[4] D.23-12-036 at p. 29 had noted: "While it is difficult to parse out the specific procurement orders intended to offset Diablo Canyon, based on the record of this proceeding, as parties have noted D.21-06-035 requires LSEs to bring online at least 2,500 MWs of resources with specified zero-emitting attributes by June 1, 2025, as an explicit showing of replacement capacity for Diablo Canyon."

[5] A4NR-01, Appendix 2, Joint Agency Reliability Planning Assessment, May 2024, pp. 2 – 4. *See* also A4NR-01, pp. 4 – 5, footnote 2, which states: "Governor Newsom's April 25, 2024 announcement that California has increased battery storage capacity to 10,379 MW, up from 770 MW in 2019. https://www.gov.ca.gov/2024/04/25/california-achieves-major-clean-energyvictory-10000-megawatts-of-battery-storage/ Newsom was quoted in the April 25, 2024 edition of *The Hill* as saying, 'This is our biggest power source in California — significantly bigger than the last remaining nuclear plant in the state of California.' "

[6] As stated in the Assembly Floor Analysis SB 846 Senate Third Reading, at p. 12: "This bill also excludes DCPP from any future resource planning, either by state agencies to meet our 100% clean energy goals or by individual LSEs, thereby forcing LSEs to procure enough resources to treat DCPP as if it did not exist."

flexible supply to the grid, and this is more than double the battery capacity from this same time last year.[7]

The July 16, 2024 report on battery storage from the California Independent System Operator ("CAISO") Department of Market Monitoring indicates that battery storage capacity in the CAISO balancing area had grown to 11,200 MW in June 2024, with over half of this capacity physically paired with solar or wind generation.[8] According to the CAISO report, batteries account for a significant portion of energy and capacity during the late afternoon and early evening when net loads are highest: on average during hours 17 to 21, batteries provided about 5.6 percent of the CAISO balancing area's energy in 2023.[9] As of June 1, 2024, batteries made up nearly 12 percent of the CAISO's nameplate capacity,[10] and active battery capacity in the CAISO balancing area (2018–2024) is graphically tracked in the report as follows:[11]



Nothing in PG&E's direct or rebuttal testimony disputes the fundamental change in conditions in California's electricity system since enactment of SB 846. PG&E-02's rejection of the Padilla Report's $58/MWh average cost of new RPS contracts signed in 2023 as an

[7] A4NR-X-05, p. 3 of 3.
[8] A4NR-X-04, p. 2 of 4.
[9] *Id.*
[10] *Id.*
[11] A4NR-X-04, p. 4 of 4.

appropriate greenhouse gas ("GHG") avoidance comparator for DCNPP's exorbitant energy costs – "It should not be considered."[12] – conflicts with the decades-long priority California policy has focused on renewable energy. Ignoring the risk diversification benefits that lie at the heart of portfolio theory, while blurring the distinction between energy and capacity, PG&E-02 instead would limit consideration of emissions-avoiding alternatives to "baseload resources similar to DCPP."[13] It appears lost on PG&E that a specified amount of RA benefit and a specified amount of emissions-reducing benefit need not be supplied by a single plant, and that economic optimization (i.e., least cost/best fit) might instead point to a mix of resources. PG&E-02 climbs into an analytic strait jacket similar to that of the previously discredited cost comparison by the California Energy Commission ("CEC") staff, which PG&E had unsuccessfully argued in R.23-01-007 should be considered the "relevant" cost-effectiveness analysis despite acknowledging the "relevancy" of certain costs omitted by the CEC staff report.[14] As the Commission noted in D.23-12-036: "PG&E's arguments are unpersuasive."[15]

Both the 2024 and 2023 versions of the CEC staff's cost comparison arbitrarily excluded from their analyses any resource types currently being procured by LSEs[16] (i.e., solar, wind, and battery storage). Both versions excused this analytic truncation with the bizarre explanation, "this analysis excludes these conventional clean resources from consideration for further investment from the state, as state investments in conventional solar, wind, and battery storage would only exacerbate the tight market conditions and interconnection bottlenecks in getting these clean resources on-line."[17] Both versions relied upon outdated DCNPP cost forecasts which PG&E subsequently repudiated. Both versions screened out all generating resource types, and restricted their "supply scenario" to currently non-commercial forms of long duration energy storage. Both versions ignored the requirement in Pub. Res. Code Section 25233.2(a) for a comparison with "a portfolio of other feasible resources available for calendar years 2024 to

[12] PG&E-02, p. 1-8, lines 14 – 15.
[13] *Id.*, p. 1-8,
[14] D.23-12-036, p. 58.
[15] *Id.*
[16] LSEs is an acronym for load-serving entities.
[17] PG&E Reply to Protests, Attachment A, p. 10. The CEC staff did not explain the intended meaning of "further investment from the state," or why this was the appropriate framing for its statutorily prescribed cost comparison.

2035, inclusive," and terminated their analyses in 2025. PG&E-02 pronounces the CEC staff's blinkered conclusions "unambiguous, well-considered, and … developed consistent with clear statutory direction,"[18] overlooking undeniable deficiencies to praise the misadventure with *faux* gravitas.

PG&E-02 loses sight of which party has the burden of proving the cost-effectiveness of DCNPP, imbued with the conviction that "it is not clear that it is feasible to bring online incremental resources to obviate the need for Diablo Canyon—at any cost."[19] Discounting the "over nine gigawatts of capacity in just the last year" celebrated by Ms. Poppi, or the paradigm-shifting 11,200 MW of battery capacity – over half physically paired with solar or wind – heralded by the CAISO, PG&E spurns comparison with the $58/MWh average associated with the 2023 portfolio of new RPS contracts (or the $62/MWH average cost of the 2022 portfolio[20]). A4NR-01 makes no estimate of the renewables portfolio's system RA value in a slice-of-day environment or the volume of GHG emissions avoidance it represents – only that PG&E has the burden to prove to the Commission's satisfaction that allocating $8.4 – 9.8 billion of LSE customer payment capacity to DCNPP extended operations is a reasonable and prudent choice. $58/MWh (or $62/MWh, or the $60/MWh average of the two) is an unavoidable benchmark for a reasonable utility manager even if it represents an aggregation of many separate electric generators. The long-awaited ability to store large volumes of use-limited, intermittently-generated electricity over the course of a diurnal cycle is a profound and transformative development. Failure to recognize the face of price competition is how stranded utility assets get made and captive ratepayers get hammered.

III. PG&E IS AN UNRELIABLE NARRATOR ABOUT COSTS.

While increasing its projection of DCNPP's "full cost of extended operations" to $8.4 billion[21] from the $8.3 billion PG&E had indicated to the media just two months previously,

[18] PG&E-02, p. 1-9, lines 26 – 27.
[19] *Id.*, p. 1-8, lines 16 – 17.
[20] A4NR-01, p. 6, line 15.
[21] PG&E-02, p. 1-1, line 28.

PG&E's rebuttal testimony criticizes the $9.8 billion estimate in A4NR-01 for including "$1.4 billion in costs that do not exist."[22] Specifically, PG&E's rebuttal testimony disputes the merit of A4NR's inclusion of the annual 115% cost overrun safe harbor created by Pub. Util. Code Section 712.8(h)(1) and the $300 million of "Performance Based Disbursements" provided by Pub. Res. Code Section 25548.3(c)(16).[23] PG&E-02 does not explain why A4NR-01 is "incorrect" in anticipating that PG&E will make full use of the 115% safe harbor, or in finding a nexus between DCNPP extended operations and the $300 million in General Fund payments made expressly "contingent upon [PG&E's] ongoing pursuit of an extension of the operating period and continued safe and reliable Diablo Canyon powerplant operations."[24] PG&E's rebuttal testimony does not directly address A4NR-01's adjustment for the 5.31% by which the company's generation assumption exceeds average DCNPP annual output over the past five years[25] – a third factor in A4NR's $114.53/MWh (ratepayer/taxpayer) and $96.53/MWh (ratepayer-only) calculations – but does characterize A4NR's cost per MWh estimate as inaccurate.

To be clear, A4NR expects the cost of DCNPP extended operations to considerably exceed $9.8 billion but has limited its A4NR-01 correction of PG&E's evolving forecast to only the most conspicuous examples of omission and distortion. The A4NR-01 estimate does not include recently discovered cost lifters like the $359 million sequestered portion of PG&E's Civil Nuclear Credit award whose receipt (and availability to repay the state General Fund loan) is conditioned upon cost increases,[26] or the more than $295 million in DCNPP 2025 – 2026 Administrative and General ("A&G") costs absorbed by PG&E ratepayers via the 2023 General Rate Case ("2023 GRC").[27] PG&E's refusal to calculate annual revenue requirements past 2025 and the opaqueness of its escalation assumptions[28] likely conceals additional unacknowledged costs. Similarly, PG&E excludes from its costs tally O&M expenditures approved in the 2023 GRC that have been explicitly repurposed by the company's PMO++ review to prepare for extended

[22] *Id.*, p. 1-2, lines 16 – 17.
[23] *Id.*, p. 1-2, lines 17 – 25.
[24] Pub. Res. Code Section 25548.3(c)(16).
[25] A4NR-01, p. 6, lines 1 – 2.
[26] *Id.*, p. 26, lines 5 – 14.
[27] TURN-01, p. 21, line 9 – p. 23, line 4.
[28] A4NR-01, p. 21, line 19 – p. 22, line 5.

operations.[29] Nonetheless, even PG&E's deceptively assembled, understated $86.09/MWh estimate[30] for DCNPP ratepayer/taxpayer costs during 2024 – 2030 extended operations would exceed the company's forecast of CAISO market prices by nearly % during the same period.[31] Juxtaposed against A4NR's more accurate $96.53/MWh ratepayer-only cost, the gap is more than %.[32] When compared to A4NR's more comprehensive $114.53/MWh ratepayer/taxpayer cost, the exceedance is more than %.[33]

PG&E purports to offset these above-market DCNPP generation costs with its appraisal of the value of the DCNPP system RA capacity that D.23-12-036 allocated to jurisdictional LSEs. But the company's appraisal relies on the opportunistic misapplication of the *ex post* RA Market Price Benchmark deployed in a much different setting to calculate the Power Charge Indifference Adjustment ("PCIA"). When groundtruthed to more credible forecasting metrics, like the cost of new entry or the CAISO capacity procurement mechanism's soft offer cap, the amounts available to offset above-market generation costs fall by almost $1.1 billion[34] and the DCNPP extended operations forecast turns unredeemably non-cost-effective. That a harsh critique of the PCIA RA Market Price Benchmark, and the identification of more appropriate forward-looking alternatives, are both found in PG&E's own 2025 ERRA Forecast (A.24-05-009) testimony suggests a wiliness underlying PG&E's cost forecast in this proceeding directly contrary to the expectation for a "more comprehensive and transparent forecast" stated in D.23-12-036.[35]

PG&E's other recent forecasts of what lies in store for electricity ratepayers have had a distinctly Pollyannish quality. Notwithstanding the escalating public debate over affordability, the company has insisted in briefings to investors and financial analysts this past June and July that it plans to hold future bill increases to 2 – 4% per year ("At or Below Assumed Inflation")

[29] A4NR-X-07, p. 2.
[30] PG&E-02, p. 1-3, lines 6 – 7.
[31] **A4NR-01-C, p. 23.** (−) ÷ = %.
[32] ***Id.*, p. 23.** −) ÷ = %.
[33] ***Id.*, p. 23.** −) ÷ = %.
[34] *See* footnote 134 for derivation of this amount.
[35] D.23-12-036, p. 59.

and sees an opportunity to reduce such increases to 1 – 3%.[36] In contrast, the Commission's July 2024 Senate Bill 695 Report estimates PG&E residential and small commercial rates will increase through 2027 at an annual rate of 10.8% and 12.4%, respectively, assuming a general inflation rate of 2.6%.[37] Despite similar assumptions about general inflation, a huge gulf (i.e., a multiple of more than 4X) in the expected impacts on ratepayers separates these two alternate realities. At some point, even the most obtuse observer can start to see a pattern in PG&E cost estimates.

A4NR's long experience with DCNPP issues has been consistent with the insight attributed to Governor Newsom by the *New York Times* in 2019:

> … Gov. Gavin Newsom said the company's record made it hard to take its promises seriously.
>
> 'They have simply been caught red-handed over and over again, lying, manipulating or misleading the public,' Mr. Newsom said in an interview. 'They cannot be trusted.'[38]

In determining whether PG&E has met its burden of proving by a preponderance of evidence that extended operation of DCNPP through 2030 (and the accompanying nonbypassible charges to customers of all Commission-jurisdictional LSEs) will be reasonable and prudent, the Commission cannot sidestep the multiple examples of analytic abuse that undermine the credibility of the company's cost forecasts in this proceeding. The Commission faces a multi-year, multi-billion-dollar allocation decision regarding the finite payment capacity available from LSE customers. Committing $8.4 – 9.8 billion of such payment capacity to DCNPP extended operations unavoidably means that such payment capacity is not available for other clean electricity resources. Determining that "high cost, poor fit" DCNPP extended operations

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[36] A4NR-X-02, pp. 2 of 4 and 4 of 4.

[37] A4NR-X-03, pp. 3 of 5 and 5 of 5.

[38] *New York Times,* "How PG&E Ignored Fire Risks in Favor of Profits," March 18, 2019, accessed September 23, 2024 at https://www.nytimes.com/interactive/2019/03/18/business/PG&E-california-wildfires.html?action=click&module=RelatedLinks&pgtype=Article

would be a reasonable and prudent deployment of such payment capacity would require a significantly different evidentiary record than PG&E's evasions have created.

IV. SCOPING MEMO ISSUES.

1. Whether PG&E's forecast cost of operations and requested revenue requirement of $418 million over the Record Period for DCPP is reasonable, including the following forecasts and their underlying financial assumptions and calculations, subject to PG&E updating these forecasts in the Fall Update:

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

PG&E's Application for recovery of operations and maintenance ("O&M") costs during the 2023 – 2025 Record Period disregards the restrictions established by Pub. Util. Code Section 712.8(c)(1)(C) to protect "ratepayers of any load-serving entities" from costs of PG&E's "preparation for extended operations." The Legislature clearly expected these preparatory costs to be funded either from the $1.4 billion forgivable loan to PG&E from the state General Fund or from "other nonratepayer funds available"[39] to PG&E. Unsurprisingly, in light of the generous subsidies contained in SB 846, this statutory allocation of near-term cost-estimation risks placed the onus for forecast error on PG&E. In the face of its own material underestimates of these preparatory costs, the finite amount of its loan from the General Fund, and its limited ability or willingness to contribute "other nonratepayer funds," PG&E instead seeks to shift these costs to ratepayers.

PG&E's rebuttal testimony attempts to eviscerate these ratepayer protections by arbitrarily confining their application to (1) costs of all projects that are required as a condition of PG&E's NRC License Renewal Application ("LRA");[40] and (2) costs that are forecast to be incurred earlier than November 3, 2024,[41] not funded from the 2023 GRC,[42] and associated with a project "forecast to be complete and in service earlier than December 31, 2026."[43] On the

[39] Pub. Util. Code Section 712.8(c)(1)(C).
[40] PG&E-02, p. 2-11, lines 19 – 21.
[41] *Id.*, p. 2-11, line 16.
[42] *Id.*, p. 2-11, line 17.
[43] *Id.*, p. 2-11, line 18.

other hand, PG&E-02 would exempt entirely from the Pub. Util. Code Section 712.8(c)(1)(C) ratepayer protections any project not required as a condition of the LRA that 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."[44]

None of these dates appears in Pub. Util. Code Section 712.8(c)(1)(C), which instead focuses on the underlying purpose of the expenditure in determining whether it should be paid from government funds or assigned to ratepayers. The Merriam-Webster Dictionary defines "preparation" as "the action or process of making something ready for use or service or of getting ready for some occasion, test, or duty."[45] PG&E's belated substitution of a calendar taxonomy in place of the purpose-driven approach of the statute is a far cry from what D.22-12-005 described:

> PG&E proposes to establish the DCPP Transition and Relicensing Memorandum Account (DCTRMA) to track and record all costs, expenses, and financial commitments in furtherance of the directive in SB 846 to preserve the option for extended operations at Diablo Canyon, including:
>
>> [C]osts for all incremental licensing, permitting, regulatory, legal and litigation, internal and contracted labor, fuel procurement, handling, and management costs, spent fuel-related costs (i.e., incremental dry cask storage costs), fees, and expenditures in connection with transitioning DCPP from existing operations into extended operations (i.e., beyond the current federal license period for Unit 1 and Unit 2), including a monthly performance-based transition fee.
>
> PG&E states that the costs of these transition and relicensing activities will not be recovered from ratepayers. Instead, costs recorded in the DCTRMA are to be funded solely through government funding steams [*sic*], including the amounts allocated by Assembly Bill (AB) 180 and SB 846, as well as any funding made available through DOE's Civil Nuclear Credit program. While PG&E expects most of these costs to be incurred prior to the expiration of the current federal licensing periods, PG&E asserts the costs recorded in the DCTRMA will be defined

[44] *Id.*, p. 2-11, lines 11 – 15.

[45] https://www.merriam-webster.com/dictionary/preparation . Accessed September 23, 2024.

> by the stipulations associated with the relevant loan or funding agreement, and not by the timeframe in which they are incurred.
>
> ***
>
> PG&E proposes to establish the DCPP Extended Operations Balancing Account (DCEOBA) to track and recover extended operation costs that are not eligible for cost recovery under the executed loan agreements with the Department of Water Resources (DWR) pursuant to SB 846 and AB 180.[46]

Neither PG&E's direct testimony nor its rebuttal testimony have made any claim that the $65,227,000 identified in PG&E-1's Table 3-1 as the O&M Project Expense for which PG&E is seeking recovery from ratepayers is ineligible for recovery under PG&E's executed agreements with DWR or the DOE Civil Nuclear Credit program. A4NR's review of these executed agreements has determined that such a claim, if made, would be baseless.

D.22-12-005 provided additional direction to PG&E, which also appears to have been ignored:

> … based upon the broad statutory definition of eligible costs under the SB 846 loan, the need to accurately account for all costs as they relate to the cost cap and cost-effectiveness evaluation in SB 846, as well as the more foundational requirement in Section 451 that "all charges demanded or received by any public utility…shall be just and reasonable," 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 Diablo Canyon (See Section 2); all plant and equipment improvement and investment costs; fuel purchases; spent fuel storage capacity costs; and any related taxes or other revenue requirements. In the event PG&E seeks to transfer any of these costs from the DCTRMA to the DCEOBA, or 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.[47]

Neither PG&E's direct testimony nor its rebuttal testimony contains any explanation for why the company did not seek government funding for these DCEOBA costs, or why it was

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[46] D.22-12-005, pp. 10 – 12. Internal footnotes omitted. DOE is an acronym for the U.S. Department of Energy.
[47] *Id.*, p. 17.

unable to anticipate these needs at the time government funding was being requested. Because the $65,227,000 in forecast O&M Project Expense for the 2023 – 2025 Record Period would pay for the *preparation* of DCNPP for extended operations ("the action or process of making something ready for use or service or of getting ready for some occasion, test, or duty"[48]), the Commission is precluded by Pub. Util. Code Section 712.8(c)(1)(C) from approving its inclusion in PG&E's revenue requirement.

PG&E's rebuttal testimony misconstrues A4NR-01's explanation of the significance of the company's admission about the front-loaded increases in 2023 – 2026 project engineering and capital costs.[49] A4NR-01 does not claim that PG&E "characterized these project expenditures as projects required to prepare for extended operations."[50] Instead, A4NR contends that PG&E's statement, "It is now apparent that these projects are needed earlier in extended operations to ensure plant reliability through 2030,"[51] leaves no room for doubt that they are "preparation for extended operations" subject to Pub. Util. Code Section 712.8(c)(1)(C). PG&E-02's assertion that "these project expenditures are necessary to ensure safe and reliable operation through 2030"[52] in no way alters their status as actions or processes of making something (i.e., DCNPP) ready for use or service or of getting ready for some occasion, test, or duty (i.e., extended operations).

b. Charges for the liquidated damages account pursuant to Pub. Util. Code section 712.8(g);

A4NR does not contest PG&E's calculations of the revenue requirement associated with providing this statutorily specified, but entirely unprecedented, ratepayer indemnification of utility misconduct. This odious transfer of risk should weigh heavily in the Commission's consideration of the reasonableness and prudence of DCNPP extended operations in comparison to alternative uses of $8.4 – 9.8 billion of LSE customer payment capacity. None of the other methods for addressing reliability needs, or reducing GHG emissions, requires

[48] *See* footnote 45.
[49] A4NR-01, p. 10, line 20 – p. 11, line 2.
[50] PG&E-02, p. 2-12, lines 11 – 12.
[51] A4NR-01, p. 10, lines 17 – 19.
[52] PG&E-02, p. 2-12, lines 12 – 13.

advance-funding from customers of a misbehavior fund continuously topped-up to a $300 million level. Under traditional Commission regulation, ratepayers already pay for costs of utility mistakes if such errors can satisfy the reasonable manager standard. On top of that, the Legislature concluded that five more years of DCNPP operation would require customers to automatically cover the first $300 million of replacement power costs where PG&E's conduct has been unreasonable. What does that say about DCNPP? Or PG&E? Or where the Commission should rank DCNPP extended operations among different pathways to achieving electric reliability and GHG emissions avoidance objectives?

A similar argument can be made regarding the 115% cost overrun safe harbor, another SB 846 blandishment that, to A4NR's knowledge, is completely unprecedented in California utility regulation.

Elsewhere in SB 846, the rationale for novel payment streams to PG&E is described as being "in acknowledgment of the greater risk of outages in an older plant that the operator could be held liable for."[53] PG&E's rebuttal testimony disdains A4NR-01's mention of the six separate forced outages suffered by DCNPP Unit 2 between July 17, 2020 and November 3, 2021, a cumulative 149.2 days that PG&E estimated in A.22-02-015 resulted in $178.6 million in replacement power costs. PG&E-02 accurately observes that no determination has been made that any of these outages was the result of a failure by PG&E to meet the reasonable manager standard,[54] but neglects to point out that the Commission has yet to publish even a Proposed Decision in A.22-02-015 where the issue is being litigated. Instead, PG&E recounts its record of unplanned outages since 2010 and reports that only one, on October 11, 2012, resulted in a Commission finding that PG&E had not met the reasonable manager standard, and that "(t)he disallowed cost associated with this unplanned outage was determined by the Commission to be $3,238,185."[55]

[53] Pub. Util. Code Sections 712.8(f)(5) and (6).
[54] PG&E-02, p. 7-8, lines 27 – 28.
[55] *Id.*, p. 7-9, lines 1 – 4.

The Commission should consider the following ramifications of the liquidated damages account in determining whether PG&E has met its burden of proof that DCNPP extended operations will be reasonable and prudent:

- How did a $3.2 million PG&E liability in 2012 metastasize into a compulsory customer indemnification of up to $300 million per annum going forward?
- What role should the determination of financial responsibility for the six A.22-02-015 unplanned outages play in the perception of future outage risk at DCNPP?
- How can the credibility of PG&E's 2024 – 2030 forecast assumption that the liquidated damages account will never be utilized be reconciled with the Legislature's codified apprehensions about the greater risk of outages in an older plant for which the operator could be held liable?
- Will ratepayer absorption of the first $300 million in replacement power costs attributable to unreasonable utility performance create perverse financial incentives for lax operating practices and management oversight?

c. Resource Adequacy (RA) substitution capacity forecast costs;

PG&E's rebuttal testimony attempts to divert attention from the unreasonable padding injected into its RA substitution capacity forecast, documented at $31.6 million by A4NR-01,[56] by shifting discussion to the generic merit of the Commission's RA Adder as a market price benchmark.[57] PG&E-02 never addresses the actionable fact underlying A4NR-01's recommended disallowance: that PG&E's own data responses acknowledge that RA substitution capacity could demonstrably be acquired for the advance-scheduled outages at a cost some 41% lower than the amount of PG&E's request.[58]

PG&E is bound by Standard of Conduct No. 4 to prudently administer all of its contracts and generation resources and dispatch energy in a least-cost manner. In circumstances where it can obtain RA substitution capacity from the bilateral market at a lower cost than from its own

[56] A4NR-01, p. 11, line 19 – p. 13, line 12.
[57] PG&E-02, p. 3-9, lines 7 – 11, 13 – 19.
[58] A4NR-01, p. 13, line 11.

portfolio, it is obligated to do so. Its witness, George Clavier, testified that PG&E's plan for the 2024 – 2025 scheduled outages at DCNPP would not necessarily look to lower-priced RA substitution capacity from the forward market, but would instead utilize the company's PCIA portfolio as it has for past Diablo Canyon outages:

> … the replacement comes from a transfer from the PCIA portfolio. And so … we would not go out into the market to acquire it, because it's already available … there's no reason to think that that capacity wouldn't be available from the PCIA portfolio, and I think it's expected that we would then use it to -- for the replacement of Diablo Canyon when it's on outage.[59]

Mr. Clavier explained the reasoning for why PG&E would forego the cheaper RA substitution capacity available from the bilateral market as follows:

> Well, the situation that we would face is that we have this capacity. So if we don't use it for the -- replacing Diablo Canyon when it's on outage, we would then have to sell that -- we would attempt to sell that capacity in the market. So we'd be in a situation where we're attempting to sell capacity, and at the same time trying to acquire it. So that is problematic. And in -- oftentimes, the -- the available capacity for replacement of -- when Diablo is on outage is largely going to come from our portfolio, because it's just a matter of just there isn't that much supply outside of our portfolio.[60]

But the Commission has made clear that Standard of Conduct No. 4 requires a utility to optimize the value of its overall supply portfolio and, consistent with D.02-10-069 as part of least-cost portfolio management, that utility is prohibited from any action that results in inappropriate preference for its own generation resources or negotiated contracts.[61]

Mr. Clavier further testified that, since D.23-12-036 determined that cost recovery for DCNPP extended operations "should mirror … the CAM process,"[62] then D.24-06-004's adoption

[59] Transcript (PG&E: Clavier), p. 145, line 14 – p. 146, line 3.
[60] *Id.*, p. 146, line 25 – p. 147, line 11. PG&E witness Erica Brown described the company's use of the bilateral market to acquire capacity: "our need is limited to some of the peak summer months. I can't speak to what our procurement teams would bid in. We typically would run a solicitation, and then we would take the lowest price offer. And that's consistent with the rules set out in our bundled procurement plan." Transcript (PG&E: Brown), p. 28, lines 8 – 13.
[61] *See* D.05-01-054, p. 10.
[62] *Id.*, p. CAM is an acronym for Cost Allocation Mechanism.

of a PG&E proposal to use the PCIA market price benchmark in capacity substitutions for CAM resources should be interpreted as the Commission having "ordered"[63] PG&E to do so for substitutions for DCNPP capacity. For the following reasons, A4NR believes Mr. Clavier significantly overstated the extent to which PG&E's approach to forecasting 2024 – 2025 RA capacity substitution costs has been dictated by the Commission:

- D.24-06-004 Ordering Paragraph 15 is permissive, not prescriptive, in allowing utilities who use PCIA-eligible resources to substitute capacity for CAM resources to use the PCIA market price benchmark to determine substitution capacity costs;
- D.24-06-004 finds PG&E's proposal reasonable because it "would minimize cost shifting between bundled customers and departing load,"[64] an issue that does not appear to be present in the DCNPP cost recovery process for capacity substitutions;
- D.24-06-004 makes clear that, in the event that an unplanned DCNPP outage results in PG&E's inability to meet its system RA obligations, obtaining a system waiver will require that PG&E demonstrate "it made every reasonable effort to procure replacement capacity to mitigate the unplanned outage."[65] It would be illogical to hold scheduled outages at DCNPP to a lesser mitigation requirement;
- D.23-12-036 notes PG&E's current practice to schedule outages outside of peak months, "when it is much less expensive to procure substitution capacity, and this practice should continue to be encouraged."[66] The cost reduction benefits of such scheduling would be lost by PG&E's use of the annualized PCIA market price benchmark; and
- PG&E's proposal in A.24-03-018 for revising D.23-12-036's allocation of RA benefits among LSEs would significantly alter the "mirror the CAM" premise of Mr. Clavier's testimony, further distinguishing DCNPP from a bonafide CAM resource. In fact, the Commission's Procurement Policy Manual limits a formal CAM designation to "new or repowered resources selected through a competitive solicitation open to any fuel

[63] *Id.*, p. 148, line 17.
[64] D.24-06-004, p. 67.
[65] *Id.*, p. 65.
[66] D.23-12-036, p. 87.

type or technology."[67] D.23-12-036's use of a CAM "mirror" to allocate DCNPP costs and benefits during extended operations did not transform DCNPP into a CAM resource.

A4NR does not rule out the possibility (or even likelihood) that the best source of RA substitute capacity for the 2024 – 2025 DCNPP scheduled outages may very well be PG&E's PCIA-eligible portfolio. But, as Mr. Clavier explained, "really what we're talking about is what's the appropriate transfer price."[68] A4NR believes that the arm's distance principle, which governs transfer price accounting practices, favors actual prices obtained in contemporaneous market transactions over a weighted average of historic prices obtained retrospectively from past market transactions. Independent parties transacting in comparable circumstances, in order to accurately establish value, would logically prefer to minimize dependence on stale data to price their buy/sell transactions.

PG&E-01 states that the company "has chosen to use the current 2024 Power Charge Indifference Adjustment (PCIA) system RA market price benchmark" of $15.23/kW-Month – a volume-weighted, year-round average of monthly transactions executed between 2022 Q4 and 2023 Q3 for delivery in 2024 -- because "the Commission has not specified a specific market reference price to use."[69] But PG&E's confidential data response to CalCCA,[70] when compared to the 2024 – 2025 scheduled outage months specified in PG&E's confidential workpapers[71] (all non-peak RA months), makes clear that the company actually estimates it could obtain system RA offers for four out of five of those months at prices that are a fraction of the current $15.23/kW-Month PCIA market price benchmark:

COMPARISON OF PG&E FORWARD PRICES WITH PCIA BENCHMARK
(In $/kW-month)

Scheduled Outage	Forward System RA Price	PCIA Price Benchmark
		15.23

[67] Commission Procurement Policy Manual, Section G.3(b) ¶ 4.
[68] Transcript (PG&E: Clavier), p. 147, lines 15 – 16.
[69] PG&E-01, p. 4-4, lines 13 – 17.
[70] PG&E CONFIDENTIAL Data Response CalCCA_001-Q020, attached to A4NR-01 as CONFIDENTIAL Appendix 8.
[71] PG&E-01-WP-C, pp. WP 4-2 – WP 4-4.

		15.23
		15.23
		15.23
		15.23

The significant difference in assumed RA Substitution Capacity Costs for the five months in the Record Period when PG&E had already planned outages – and could lock in substitution costs in the forward market – produce commensurate differences in amounts to be charged to ratepayers:

COMPARISON OF RATEPAYER COSTS BASED ON ASSUMED PRICE

Scheduled Outage	Forward System RA Price	PCIA Price Benchmark
TOTALS	**$44,807,838**	**$76,444,299**

PG&E's choice to use the current $15.23/kW-Month PCIA market price benchmark instead of its own forward price estimates overstates its revenue requirement for system RA replacement capacity by $31,636,461 in 2024 – 2025, more than 41%. A reasonable utility manager has a duty to mitigate the cost impacts of its RA capacity substitution obligations when it has the ability to do so, rather than exploit a questionable benchmark to significantly overstate revenue requirements. Depending upon how the "subsequent true-up to actual costs" is structured, the adverse ratepayer effects of an unreasonably inflated forecast of capacity replacement costs will be increased by the 115%-of-forecast cost overrun safe harbor created by Pub. Util. Code Section 712.8(h)(1). While the specific amounts in PG&E's RA substitution capacity cost forecast may change based upon the forthcoming October update, the associated revenue requirement must be capped at $44.8 million to satisfy the "just and reasonable" requirement of Pub. Util. Code Section 451.

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

As with the $65,227,000 in contested O&M Project Expense discussed in IV.1.a. above, PG&E's rebuttal testimony attempts to exempt its Record Period $[redacted] in amortized nuclear fuel procurement costs from the ratepayer protections of Pub. Util. Code Section 712.8(c)(1)(C).[72] PG&E-02 fails to provide a coherent explanation for such exclusion. The company's assertion that costs for Nuclear Fuel Cycle 27 "are not a condition of PG&E's LRA request with the NRC"[73] is uncontested by A4NR – but irrelevant because it does not address the applicable clause ("including in preparation for extended operations") from the first sentence of Pub. Util. Code Section 712.8(c)(1)(C). PG&E-02's statement that "Nuclear Fuel Cycle 27 costs will be placed in service in the Fall of 2026 for Unit 1 and Spring of 2027 for Unit 2"[74] would seem to indicate that Unit 1's cycle 27 fuel will satisfy the "earlier than December 31, 2026"[75] in-service requirement PG&E-02 describes for government-funded project expenses (unless PG&E's calendar taxonomy inexplicably creates a different in-service requirement for fuel, or Unit 1 and Unit 2 are treated as a single project). PG&E-02 makes no mention of costs associated with cycles 28 and 29, despite the company's prior acknowledgment that those costs are included in the amortization.[76]

As explained in A4NR-01,[77] PG&E has elected to charge fuel expenses for cycles 25 and 26 to its governmental funding and to charge ratepayers for the amortized costs of cycles 27, 28 and 29.[78] Long lead times compelled PG&E to procure in advance all fuel and related services for the entire period of DCNPP's extended operations. PG&E admitted in a data

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[72] PG&E-02, p. 2-12, lines 23 – 28.
[73] *Id.*, p. 2-12, lines 26 – 27.
[74] *Id.*, p. 2-12, lines 25 – 26.
[75] *Id.*, p. 2-11, line 18.
[76] A4NR-X-06, p. 1.
[77] A4NR-01, p. 13, line 13 – p. 15, line 2.
[78] *Id.*, p. 14, line 1.

response that "enforceable commitments to procure each product or service were made on the contracts execution dates as follows:

Line No.	Product/Service	Contract Execution Date
1	Uranium Concentrates	8/17/2023
2	Uranium Concentrates	12/28/2023
3	Uranium Concentrates	12/6/2023
4	Uranium Concentrates	9/18/2023
5	Uranium Concentrates	11/15/2023
6	Conversion Services	11/15/2023
7	Enrichment Services	12/6/2023
8	Fabrication Services	9/18/2023[79]

Notwithstanding PG&E's professed intent to only use DCEOBA for "costs that are not eligible for cost recovery under the executed loan agreements with the Department of Water Resources (DWR) pursuant to SB 846 and AB 180,"[80] neither PG&E-01 nor PG&E-02 offers any basis for why the costs associated with cycles 27, 28, and 29 do not qualify for such funding. Similarly, the Commission's D.22-12-005 direction regarding utilization of government funding (and specifically identifying "fuel purchases"[81]) is left unaddressed by PG&E-01 and PG&E-02. Except for PG&E-02's arbitrary creation of an "earlier than December 31, 2026"[82] in-service requirement, PG&E has yet to explain why each of its financial commitments for fuel needed to operate DCNPP through the 2029 and 2030 retirement dates should not be considered to have been incurred as "preparation for extended operations."[83]

The SB 846 and AB 180 General Fund appropriations were made by the Legislature in 2022 prior to PG&E's fuel-related financial commitments in the second half of 2023, and PG&E's data response A4NR_001-Q013a.v. provides some insight into the company's post-appropriations experience in the nuclear fuel market:

> Fuel procurement costs have experienced market volatility since SB 846 was passed in September 2022. This volatility in the markets was not

[79] *Id.*, p. 14, lines 3 – 6.
[80] D.22-12-005, pp. 11 – 12.
[81] D.22-12-005, p. 17.
[82] PG&E-02, p. 2-11, line 18.
[83] Pub. Util. Code Section 712.8(c)(1)(C).

> anticipated in the forecasts presented in PG&E's May 19 [2023] testimony. Additionally, nuclear fuel costs recovered through the DCTRMA are presented on an as-spent basis. The amortized fuel costs presented for extended operations cycles 27 and on were forecast with awareness of volatility in the markets.[84]

Data response A4NR_001-Q013e. provides additional detail:

> The forecast in PG&E's May 19 [2023] testimony was developed from a trended EUCG reporting submittal of Nuclear Fuel costs that assumed costs would escalate at a constant percentage from a base year of 2021. This was the best information known at the time of preparing the overall forecast through 2030 for DCPP operations. The global price of uranium increased approximately 84.9% between the period of 5/2023 to 1/2024.[85]

This evidence supports a reasonable inference that the financial commitments PG&E entered into in 2023 for fuel procurement exceeded the amounts contemplated for that purpose (and possibly for other actions to be taken "in preparation for extended operations") at the time of the Legislature's 2022 appropriations. SB 846 insulates ratepayers from this risk, however, with the protections provided by Pub. Util. Code Section 712.8(c)(1)(C). PG&E's remedy under that statute for such a funding deficiency is limited to "other nonratepayer funds available." The Commission is precluded by Pub. Util. Code Section 712.8(c)(1)(C) from approving inclusion of the $[redacted] in amortized nuclear fuel procurement costs in PG&E's 2023 – 2025 revenue requirement.

A4NR-01 also challenges PG&E's plan to charge ratepayers in the SCE and SDG&E service territories for amortization of supplemental employee retention costs incurred prior to the commencement of extended operations of Unit 1 in November 2024 and Unit 2 in August 2025. Pub. Util. Code Section 712.8(f)(2) directs the modification of the existing employee retention program "to incorporate 2024, 2025, and additional years of extended operations" with Commission-approved costs "fully recovered in rates." There is no mention in D.23-12-036 that the retention program modifications would commence retroactively beginning on September 1, 2023 and PG&E did not file its proposal to do so (i.e., A.23-10-009) until ten days after reply

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[84] A4NR-01, Appendix 5, p. 2.
[85] *Id.*

briefs were due in the R.23-01-007 Phase 1 proceeding. A table in D.23-12-036 sets out the various costs established by Pub. Util. Code Section 712.8 "and their responsible payers," and for the modified employee retention program D.23-12-036 identifies the "payer" as: "Not specified in subsection (f)(2), so presumed to be ratepayers of all LSEs subject to the Commission's jurisdiction …"[86]

PG&E's DCNPP employees began eligibility for the modified program on September 1, 2023 and PG&E intends to recover a $18,952,960 revenue requirement for 2023 through amortization of recorded costs in the DCEOBA in 2025.[87] Charging LSE customers in the SCE and SDG&E service territories – rather than solely those in the PG&E service territory – for DCNPP employee retention costs before DCNPP electricity becomes available to them from Unit 1 in November 2024 and from Unit 2 in August 2025 is inconsistent with Pub. Util. Code Section 451's requirement for just and reasonable rates.

PG&E-02 offers two misconceived arguments to defend this inappropriate cost shift to the SCE and SDG&E service territories. First, it asserts that the Commission "conclusively determined" that the costs of the Employee Retention Program would be included in the statewide nonbypassable charge.[88] But the allocation of these costs was not before the Commission in R.23-01-007, PG&E's cost shift scheme did not become known to parties until after briefing had been completed, and the mere inclusion of a stated presumption in a table in D.23-12-036 cannot fairly be said to "conclusively" dispose of the matter. Certainly, the snippet of language in the table would not qualify as a "conclusive presumption" under Evid. Code Sections 620 – 624. Treating the D.23-12-036 language as a rebuttable presumption, A4NR-01 clearly constitutes sufficient rebuttal for burden-shifting purposes.

If the Commission had knowingly intended to signal support for imposing costs on the SCE and SDG&E service territories well in advance of their receipt of electricity, it is reasonable

[86] D.23-12-036, p. 67.
[87] PG&E-01, p. 11-3, lines 1 – 2.
[88] PG&E-02, p. 2-13, lines 7 – 10.

to believe that D.23-12-036 would attempt some reconciliation with the "matter of equity" articulated in its Conclusion of Law 34:

> 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 be distributed to each utility and its customers in the same manner of DCPP extended operations costs.

PG&E's cost shift extracts payments from the SCE and SDG&E service territories but provides no benefits in return during the period prior to electricity becoming available from Unit 1 in November 2024 and Unit 2 in August 2025. The absence of any discussion in D.23-12-036 of this unjust and unreasonable cost shift, let alone any attempt to rationalize it, suggests that the Commission was unaware of the potential for such allocative overreach by PG&E.

PG&E-02's second argument in support of the cost shift is even more unsound, stumbling over the distinction between cash and accrual accounting. As PG&E-02 declares:

> Further, A4NR's assertion that employee retention costs will be incurred before DCPP enters the period of extended operations is incorrect as the first employee retention period payment will be made in Spring 2025, well after the commencement of the period of extended operations that begins on November 3, 2024.[89]

PG&E's liability for the costs of the modified employee retention program began to accrue on September 1, 2023 and it is the September 1 – December 31, 2023 period upon which the $18,952,960 revenue requirement for 2023 in A.24-03-018 is based. Indeed, PG&E-01 states that this amount was recorded to the DCEOBA as of December 31, 2023.[90] Additional liability for costs of the retention program has continued to accrue throughout 2024 and will proceed in 2025. The accrual of this cost liability, not the timing of its eventual payment, is the determinant of the inequitable mismatch between costs and benefits that PG&E seeks to impose on the SCE and SDG&E service territories. The SCE and SDG&E service territories will

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[89] *Id.*, p. 2.13, lines 11 – 15.
[90] PG&E-01, p. 1-6, lines 24 – 26.

not receive electricity from DCNPP extended operations until such operations commence at Unit 1 after November 2, 2024 and at Unit 2 after August 26, 2025.

As A4NR has made clear in the A.23-10-009 proceeding, it supports all of PG&E's modifications to the employee retention program except the allocation of costs to the SCE and SDG&E service territories prior to commencement of extended operations at each unit. PG&E should be directed to file a Tier 3 Advice Letter that allocates the costs incurred for DCNPP employee retention prior to commencement of extended operations exclusively to customers of LSEs within the PG&E service territory. Thereafter, DCNPP employee retention costs should be apportioned between customers of all jurisdictional LSEs on the same basis as other operating costs that are subject to the nonbypassable charge established by Pub. Util. Code Section 712.8(l)(1). Record Period extended operations for Unit 1 are limited to 59 days in 2024 and 365 days in 2025, and for Unit 2 are limited to 127 days in 2025. Cost responsibility assigned to customers outside the PG&E service territory must reflect that in order for the nonbypassible charge to be just and reasonable.

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

A4NR takes no position on this issue at this time.

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

A4NR takes no position on this issue at this time.

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

Despite A4NR-01's unrebutted documentation that PG&E's modeling may overstate DCNPP electricity output (and, consequently, CAISO revenues) during the 2024 – 2030 extended operations period, A4NR does not challenge PG&E's granular generation forecast for the near-term period from November 3, 2024, to December 31, 2025. The statistical reversion to mean phenomenon (e.g., to the average electricity output over the past five years) is more likely to be experienced over the longer time horizon of the 2024 – 2030 extended operations period than in the 14-month Record Period for this Application. It must be noted, however, that even the potentially overstated CAISO revenues of $812,991,000[91] will fall considerably short of the $1,241,301,000 Record Period costs forecast by PG&E:[92] a burdensome above-market cost of $428,310,000 to be charged to ratepayers for the electricity generated during the first 14 months of DCNPP extended operations.

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

If modified to reflect the recommendations in this Opening Brief (i.e., reducing the Record Period revenue requirement by $65,227,000 as discussed in IV.1.a. above; reducing the Record Period revenue requirement by $31,636,461 as discussed in IV.1.c. above; reducing the Record Period revenue requirement by $ as discussed in IV.1.d. above; and reallocation to the PG&E service territory exclusively of cost responsibility for employee retention prior to commencement of extended operations as discussed in IV.1.d. above), the nonbypassable charge and rate proposals would comply with D.23-12-036, be consistent with the requirements of Pub. Util. Code Section 451, and could be approved.

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

PG&E-02 makes no attempt to rebut the collateral estoppel argument made in A4NR-01, or explain why the company has not used the appropriate mechanism, a Rule 16.4 Petition for Modification of D.23-12-036, to pursue the changes it seeks in the allocation of RA and GHG attributes. Instead, PG&E-02 deploys its "manner of equity"[93] plea without explaining why the same principle was not applied to the company's allocation of costs for DCNPP employee retention benefits. Selective invocation of moral axioms weakens their persuasiveness. As

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[91] PG&E-01-E, p. 11-5, Table 11-4, line 15.
[92] *Id.*, lines 13 + 17 + 20.
[93] PG&E-02, p. 3-4, line 27.

recounted in A4NR-01,[94] PG&E's advocacy in R.23-01-007 of a more "equitable" allocation of RA and GHG attributes was less than robust, and PG&E chose to exclude the allocation issue from its Application for Rehearing of D.23-12-036. Now PG&E-02 offers to modify the company's RA allocation request by "deferring implementation of PG&E's proposal to the 2026 RA compliance year,"[95] apparent recognition of the difficulties abrupt change would cause.

A4NR has no doubt that the diminished outlook for surplus DCNPP market revenues – which would have been credited to the PG&E service territory under Pub. Util. Code Section 712.8(h)(3) – could prompt second-guessing by PG&E about its acceptance of the D.23-12-036 RA and GHG allocation methodology, especially in light of the $6.50/MWh Volumetric Performance Fee charged exclusively to customers in the PG&E service territory under Pub. Util. Code Section 712.8(f)(5). But Article 16 of the Commission's Rules imposes rigorous requirements on parties seeking second bites at the apple on matters that have previously been litigated. Nothing in PG&E-02 rescues PG&E-01's RA and GHG attributes allocation proposal from its required rejection as an unworthy collateral attack on D.23-12-036.

4. Whether PG&E's proposed volumetric performance fees (VPFs)[96] spending plan for the November 3, 2024 to December 31, 2025 period complies with Pub. Util. Code section 712.8(s)(1) requirements and should be approved.

PG&E-02 fails to address the combined effects of:

- D.23-12-036's express solicitation, "in order to ensure due process,"[97] of party comments in Phase 2 of R.23-01-007 on post-2024 use of VPFs;
- the material change in circumstances between 2024, when no VPFs are expected, and 2025, when PG&E proposes to collect $159,610,000 in VPFs;[98]

[94] A4NR-01, p. 17, line 11 – p. 18, line 10.
[95] PG&E-02, p. 3-6, lines 19 – 20.
[96] Noting that PG&E's receipt of the volumetric fees "is not contingent upon its performance," D.24-05-068 suggested, "(t)hus, the Commission should, going forward, consider referring to the Section 712.8(f)(5) volumetric fees as 'Section 712.8(f)(5) volumetric fees,' or, simply, 'volumetric fees.' D.24-05-068, p. 7, footnote 11. To be consistent with the Assigned Commissioner's Scoping Memo and Ruling in this proceeding, A4NR's Opening Brief uses the term, "VPFs."
[97] D.23-12-036, p. 115.
[98] PG&E-01, p. 11-5, Table 11-4, line 10 + line 11.

- the preemptive effect of PG&E's July 3, 2024 petition for writ of review of D.23-12-036 by the First Appellate District of the Court of Appeal on party comments and Commission authority regarding post-2024 use of VPFs until judicial review has conclusively established

    (1) the meaning of the phrase "to the extent it is not needed for Diablo Canyon" in Pub. Util. Code Section 712.8(s)(1);

    (2) the scope of the Commission's "review" authority under Pub. Util. Code Section 712.8(s)(1); and

    (3) the nature of PG&E's interest in Pub. Util. Code Section 712.8(f)(5) "compensation."

In the interim, the VPFs collected by PG&E should be invested and held in an appropriately segregated account (i.e., the Volumetric Performance Fees Subaccount of the DCEOBA). As indicated in A4NR-01, A4NR believes that application of the entire $159,610,000 in forecast Record Period VPFs to the $65,227,000 O&M Project Expense and $[redacted] amortized nuclear fuel procurement disallowances recommended in this Opening Brief would be consistent with the statutory construction advocated in PG&E's writ petition.[99] The writ petition's analysis of the phrase "to the extent it is not needed for Diablo Canyon" would enable use of VPFs to pay "cost overruns for other categories of expenses, such as transition costs or facility upgrades associated with extended operations that may exceed the funds provided through the General Fund loan or federal funding."[100]

Such a disposition would enable PG&E, as stated in PG&E-02, to "use its discretion to apply the VPF revenues to reduce DCPP operational costs for all customers."[101] It would also be consistent with D.23-12-036's Finding of Fact 60:

> The Senate Rules Committee Senate Floor Analysis, SB 846 Senate Third Reading, states the volumetric payment for energy produced by DCPP 'must be used to first meet needs at [Diablo Canyon] and then to accelerate, or increase spending on, critical priorities.'

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[99] A4NR-01, p. 20, line 12 – p. 21, line

[100] PG&E Petition for Writ of Review, pp. 52 – 53.

[101] PG&E-02, p. 8-14, lines 25 – 26.

A4NR recommends that the Commission seek a stipulation with PG&E in the writ proceeding to enable application of the Record Period VPFs to set off (on a dollar-for-dollar basis) the O&M Project Expense and amortized nuclear fuel procurement disallowed pursuant to Pub. Util. Code Section 712.8(c)(1)(C).

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

A4NR-01 took no position on this issue,[102] but the extraordinary flux in what PG&E is willing to identify as "critical public purpose priorities" under Pub. Util. Code Section 712.8(s)(1) is unsettling. Several months after PG&E-01 unfurled the long-awaited VPF "spending plan," PG&E-02 announces the removal of the $30 – 60 million Comprehensive Pole Inspection Program after "internal due diligence" and "Subject Matter Experts" discovered a way to rate base an undisclosed portion of the spend.[103] In response to intervenor criticism (including from A4NR[104]), PG&E-02 also removes an unquantified amount for "any expenditures that strictly benefit the gas line of business."[105] The new "critical public purpose priorities" are a $30 – 60 million commitment to (1) batteries for resiliency, (2) electric vehicle detection for forecasting and Vehicle-Grid Integration, and (3) electrification customer experience. Despite their newly proclaimed critical priority status, PG&E-02 admits, "None of these have requested funding through another proceeding or mechanism."[106]

PG&E's oscillating process for planning VPF expenditures lacks sufficient maturity to inspire confidence that ratepayer funds (27.5% of which will come from the SCE and SDG&E service territories deemed ineligible for "critical public purpose priorities") will be spent in a reasonable and prudent manner. With pivotal questions of statutory interpretation pending

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[102] A4NR-01, p. 21, line 13.
[103] *Id.*, p. 8-17, line 27 – p. 8-18, line 6.
[104] A4NR Protest, p. 7.
[105] PG&E-02, p. 8-14, line 8.
[106] *Id.*, p. 8-19, lines 2 – 3.

before the First District Court of Appeal, the Commission should not approve PG&E's proposed modifications to the review process established in D.23-12-036.

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

PG&E-02 makes no attempt to address the deficiencies identified by A4NR-01[107] in satisfying the regulatory requirements set forth in D.23-12-036. While the rebuttal testimony does explain why PG&E believes its forecast of nuclear fuel expenses and DCNPP generation in 2024 and 2025 should be confidential[108] – neither are issues raised in A4NR-01 – PG&E-02 leaves unaddressed

- why PG&E has not calculated a DCNPP revenue requirement for years 2026 – 2030;[109]
- why PG&E-01's post-2025 escalation factors for costs other than Statutory Fees are kept opaque;[110]
- why PG&E has not calculated cumulative escalation factors for each annual entry in Table 2-3 of PG&E-01;[111]
- why PG&E-01's cost forecast did not apply escalation factors to Project costs;[112]
- why PG&E has only provided general ranges for its forecast non-labor O&M expense;[113]
- why PG&E's Application limits its request for Commission approval of "forecasts and their underlying financial assumptions and calculations" to the November 3, 2024 thru December 31, 2025 Record Period;[114] and
- why PG&E has not sought Commission approval of its "forecasts and their underlying financial assumptions and calculations" for the 2026 – 2030 remainder of extended operations.[115]

[107] A4NR-01, p. 21, line 16 – p. 22, line 23.
[108] PG&E-02, p. 1-10, line 2 – p. 1-11, line 29.
[109] A4NR-01, p. 21, lines 20 – 21.
[110] *Id.*, p. 21, line 21 – p. 22, line 1.
[111] *Id.*, p. 22, lines 1 – 4.
[112] *Id.*, p. 22, line 4.
[113] *Id.*, p. 22, lines 4 – 5.
[114] *Id.*, p. 22, lines 7 – 9.
[115] *Id.*, p. 22, lines 9 – 10.

Despite the details identified in A4NR-01,[116] PG&E-02 avoids acknowledgment of the impetus for increases in its 2024 – 2026 costs created by the sequestration of $359 million of the $1.1 billion Civil Nuclear Credit. This $359 million in "Incremental Cost Credits" will only become available to repay the loan from the state General Fund if "new, additional, or unexpected costs beyond those currently [as of January 14, 2024] forecast" are incurred. The 115% safe harbor for cost overruns, as documented by A4NR-01,[117] would shelter from reasonableness review slightly over $401 million in the 2024 – 2026 period. In the face of this clear recipe for a state-sanctioned cost overrun, PG&E-02 criticizes A4NR-01's expectation that PG&E will make use of the safe harbor as "unsupported"[118] and emphasizes (accurately) that this expectation "does not exist"[119] in PG&E's forecast. A4NR believes that the Commission's assessment of the cost-effectiveness of DCNPP extended operations should assume that PG&E will make full use of the 115% safe harbor throughout DCNPP extended operations. As measured by the direction in D.23-12-036 "to produce a complete and transparent forecast of DCPP operations through 2030"[120] that encompasses "any and all costs PG&E expects to be recovered from utility ratepayers for DCPP extended operations,"[121] PG&E implausibly and unreasonably omitted any use of the 115% safe harbor from its cost forecast.

PG&E compounds the make-believe quality of its DCNPP 2024 – 2030 extended operations cost forecast by exaggerating the financial value of the RA allocations to LSEs. In addition to its use of the $15.23/kW-Month 2024 PCIA system RA market price benchmark ("PCIA RA MPB") to estimate Record Period RA substitute capacity costs, PG&E mechanically applies this same one-year assumption to the entire period of extended operations to quantify the "value"[122] of the DCNPP system RA to be allocated to LSEs. PG&E-02 acknowledges that use of the 2024 PCIA RA MPB "does not indicate that PG&E expects this price to remain equal

[116] A4NR-01, p. 26, line 3 – p. 27, line 10.
[117] A4NR-01, Appendix 16, p. 1.
[118] PG&E-02, p. 1-2, line 17.
[119] *Id.*, p. 1-2, line 20.
[120] D.23-12-036, p. 58.
[121] *Id.*, Conclusion of Law 18.
[122] PG&E-02, p. 1-4, lines 4 – 14.

during the five years of extended operations."[123] Instead, with unmistakable guile, PG&E-02 explains, "PG&E chose the most recent publicly available and [Commission] developed price and applied it as a proxy in future years."[124]

In fact, PG&E's testimony in its 2025 ERRA Forecast (A.24-05-009) proceeding voices deep apprehension about the appropriateness of basing even 2025 system RA valuation on the PCIA RA MPB, "given known issues with the RA market, imminent regulatory changes, potential issues with the transactions that inform the RA MPB, and whether the RA MPB, as currently calculated, appropriately values RA capacity."[125] PG&E goes on to explain that

> LSEs generally meet their RA requirements through a combination of resources in their portfolio under long-term contracts (which may provide other products such as energy and environmental attributes) and short-term RA-only transactions in the RA bilateral market, which are generally less than 1 year in nature. The RA market is a bilateral market and does not have the price transparency of a centrally-administered market such as the California Independent Service Operator's (CAISO) energy markets. The RA MPBs are estimates of short-term RA market value calculated by the Commission's Energy Division for ratemaking purposes.[126]

Neither PG&E-01 nor PG&E-02 makes any attempt to explain why the PCIA RA MPB – which was created by the Commission to retroactively correct a past year's inequitable cost shift between bundled customers and departed load – is a suitable metric for appraising the future value of DCNPP RA capacity through 2030, which D.23-12-036 allocates to LSEs on the same basis as costs "as a matter of equity."[127] An annual rear-view mirror snapshot focused on "short-term RA-only transactions in the RA bilateral market" may provide a readily calculable measure of the incremental RA cost shift for that year. It is unfit for the purpose, however, of projecting the future value of the RA capacity shared by all LSEs. As PG&E admits, LSEs "meet their RA requirements through a combination of resources in their portfolio under long-term contracts

[123] *Id.*, p. 1-4, lines 8 – 9.
[124] *Id.*, p. 1-4, lines 10 – 12.
[125] A4NR-X-01, p. 4 of 11, lines 12 – 15.
[126] *Id.*, p. 6 of 11, lines 1 – 9.
[127] D.23-12-036, p. 81.

(which may provide other products such as energy and environmental attributes)"[128] in addition to the short-term RA-only transactions found in the RA bilateral market. The RA capacity context for valuation purposes is far broader than the limited number of recorded transactions that retrospectively establish one year's PCIA RA MPB.

PG&E's concerns about using the PCIA RA MPB for 2025 valuation can only intensify when the same flawed, *ex post,* one-year 2024 calculation (based solely on that subset of RA portfolios contracted as RA-only bilateral market transactions) is forcibly applied to the 2026 – 2030 period. PG&E's 2025 ERRA Forecast (A.24-05-009) testimony identifies a potential reasonableness ceiling in the net cost of new entry, which estimates the cost of building a new resource less any forecasted energy market revenues, and cites an $89.48/kW-year calculation from the SCE GRC.[129] A similar benchmark can be found in the CAISO's $7.34/kW-Month (i.e., $88.08/kW-Year) soft offer cap under the capacity procurement mechanism authority, which PG&E says "reflects the going-forward cost of a resource operating a generator including fuel, maintenance, and repair costs plus a 20 percent adder and is a reasonable estimate of operating existing resources."[130] These inherently more reasonable, forward-looking metrics for valuing RA through 2030 would result in a 51.43% reduction from the estimate used in PG&E-01.[131] That shrinks the cumulative system RA value that PG&E claims for DCNPP extended operations from $2,118,188,400[132] to $1,028,804,106[133] – making PG&E-01's forecast an overestimate of nearly $1.1 billion.[134]

Despite the diametrically opposite argument in PG&E's 2025 ERRA Forecast (A.24-05-009) testimony, PG&E-02 asserts that the company's $2.1 billion estimate for system RA value is "reasonable and conservative"[135] because it is below the $2.7 billion estimate produced by PG&E's "confidential internal forecast of monthly RA prices through 2030."[136] But PG&E's 2025

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[128] A4NR-X-01, p. 6 of 11, line 1 – 3.
[129] *Id.,* p. 8 of 11, line 12 – p. 9 of 11, line 2.
[130] *Id.,* p. 8 of 11, lines 1 – 5.
[131] (182.76 – 89.48) ÷ 182.76 = 51.04; (182.76 – 88.08) ÷ 182.76 = 51.81; and (51.04 + 51.81) ÷ 2 = 51.43.
[132] PG&E-01, p. 2-AtchA-2, line 90: 34,724,400 + 277,795,200 + 416,692,800 + 416,692,800 + 416,692,800 + 381,968,400 + 173,622,000 = 2,118,188,400.
[133] 2,118,188,400 X (1 - .5143) = 1,028,804,106.
[134] 2,118,188,400 – 1,028,804,106 = 1,089,384,294.
[135] PG&E-02, p. 1-5, line 6.
[136] *Id.,* p. 1-4, lines 16 – 17.

ERRA Forecast (A.24-05-009) testimony is unsparing in its challenges to the reasonableness of this "more granular forecast:"[137]

> … PG&E's forecast of System RA prices are even *higher* and seem stubbornly resistant to apparent improvements in market conditions. Market fundamentals suggest that RA prices should be decreasing as (1) new supply in response to Commission procurement orders has and will continue to come online and (2) forecasted system peak used to set the 2025 RA requirements is expected to be lower than the forecasted system peak used to set the 2024 RA requirements. The latest adopted CEC energy and demand forecast for CAISO shows a reduction in the system peak load for Commission-jurisdictional LSEs from the prior year's forecast of 1,181 MW for September 2025. For RA purposes, PG&E also expects supply to increase from 2024 to 2025 by at least 3,063 MW due to an allocation of RA capacity from Diablo Canyon's extended operations and in response to procurement ordered by the Commission to support mid-term reliability. Further many parties, including PG&E, proposed changes to the RA program in the Commission's RA proceeding to modify rules in a way that would provide some relief from high RA prices. In total, these market and policy changes could result in up to 7,763 MW of supply being added to the system for 2025 … as indicated in PG&E's forward curves described above, current RA price forecasts do not appear to reflect the decrease in prices that would be expected from lower demand and higher amounts of supply. This potential outcome is consistent with recent experience. Specifically, the RA market saw an increase in supply of approximately 4,885 MW from 2023 to 2024 and yet did not see a decrease in the Forecast or Final RA MPBs.
>
> This seeming misalignment between price trajectory and market fundamentals could indicate a number of things: that PG&E's forward curves are incorrect, that high prices are 'sticky' and not yet reflecting market fundamentals, that potential changes to the RA program are not yet certain so not reflected in market prices, or some combination of those and other factors.[138]

Characterizing one non-credible forecast as "reasonable and conservative" simply because it is $600 million lower than another even less credible forecast is not persuasive. Claiming to use "a constant, publicly-available price calculated by the CPUC"[139] is no virtue when it rests on the fundamental misapplication of that price calculation in light of the purpose

[137] *Id.*, p. 1-4, line 18.
[138] A4NR-X-01, p. 9 of 11, line 11 – p. 11 of 11, line 11. Italics in original, internal footnotes omitted.
[139] PG&E-02, p. 1-4, line 24.

for which it was designed. Stretching a "more granular"[140] 2024 forecast of bilateral market RA prices out to 2030 when transactions in that market "are generally less than 1 year in nature"[141] renders post-2025 results purely speculative. Selecting the lower of the two forecasts as "a conservative, albeit reasonable, underestimation of the potential capacity value that DCPP will provide to California"[142] is an exercise in salesmanship rather than empirical reasoning. The Commission should reject PG&E's assertion of $2.1 billion in DCNPP's system RA value during extended operations as unsupported. More significantly, the Commission should reflect upon what was expected from PG&E by D.23-12-036. As the Commission explained,

> … we find it in ratepayers' best interest to require PG&E to produce a more comprehensive and transparent forecast of the costs associated with DCPP extended operations for Commission and party review, compared to what has been presented to date in this proceeding … An upfront, transparent forecast of all anticipated DCPP costs through 2030 is also expected to provide a more comprehensive framework to aid parties and the Commission in determining whether the costs included in PG&E's annual DCPP Extended Operations Cost Forecast applications are reasonable and prudent.[143]

PG&E has responded with a forecast that is neither comprehensive nor transparent, except for its replay of the same stratagem used to thwart Commission consideration of reasonableness, prudence, or cost-effectiveness in D.23-12-036.[144] The Commission was clear in D.23-12-036 about its desire to avoid a recurrence, and should be forthright in its assessment of how far short of the mark PG&E's testimony has fallen.

V. REASONABLENESS AND PRUDENCE RAMIFICATIONS.

In determining whether PG&E has met its burden of proving by a preponderance of evidence that extended operation of DCNPP through 2030 would be reasonable and prudent, the Commission should evaluate PG&E's response to:

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[140] *Id.*, p. 1-4, line 19.
[141] A4NR-X-01, p. 6 of 11, lines 4 – 5.
[142] PG&E-02, p. 1-4, lines 24 – 26.
[143] D.23-12-036, p. 59.
[144] D.23-12-036, Conclusion of Law 16: "PG&E's cost forecast does not reflect all of the costs associated with DCPP extended operations, and therefore is not an adequate foundation upon which to evaluate the cost-effectiveness, prudence, or reasonableness of DCPP operations."

- whether an evaluation of the cost-effectiveness of extended operations should reasonably assume that PG&E makes full use of the annual 115% cost overrun safe harbor created by Pub. Util. Code Section 712.8(h)(1) – if so, PG&E's forecast costs will increase by $1,219,530,385;[145]
- whether an evaluation of the cost-effectiveness of extended operations should reasonably assume that DCNPP electricity generation during extended operations will not exceed the average annual output of the past five years – if so, PG&E's forecast CAISO market revenues available to offset operating costs will be reduced by 5.31%[146] or $321,419,026;[147]
- whether an evaluation of the cost-effectiveness of extended operations should reasonably assume that the estimated value of system RA capacity from DCNPP should be based on the net cost of new entry and the CAISO soft offer cap under its capacity procurement mechanism authority – if so, PG&E's forecast value of system RA capacity available to offset operating costs will be reduced by $1,089,384,294;[148] and
- whether an evaluation of the cost-effectiveness of extended operations should reasonably include the $295,240,000 interpolated by TURN-01[149] as the amount of 2025 – 2026 DCNPP Administrative and General costs to be recovered from PG&E ratepayers through the company's 2023 GRC – if so, PG&E's forecast costs will increase by $295,240,000.

These four reasonable adjustments would increase the net amounts PG&E forecasts to be paid by ratepayers by a total of $2,925,573,705.[150] This amount assumes that the $359,123,924 sequestered amount in the Civil Nuclear Credit is absorbed within the 115% cost overrun safe harbor created by Pub. Util. Code Section 712.8(h)(1). It may be more likely, however, that the unforeseen incremental costs used to justify the release of the sequestered funds would provide the basis for a Commission reasonableness finding that justified their recovery from ratepayers outside the 115% safe harbor. If so, the total amount of additional

[145] A4NR-01, Appendix 16, p. 1.
[146] *Id.*, Appendix 16, p. 1.
[147] PG&E-01, p. 2-AtchA-2, line 87: (113,090,259 + 699,901,093 + 1,250,820,940 + 1,234,182,191 + 1,139,149,191 + 1,167,917,814 + 448,027,518) X .0531 = 321,419,026.
[148] *See* footnote 133. 2,118,188,400 - 1,028,804,106 = 1,089,384,294.
[149] TURN-01, p. 23, Table 3.
[150] 1,219,530,385 + 321,419,026 +1,089,384,294 + 295,240,000 = 2,925,573,705.

ratepayer burden not identified in PG&E's forecast would be $3,284,697,629.[151] This amount is more than 2.5 times the $1,299,530,095 cumulative total of "Total Extended Operations Net Revenues" PG&E-01-E identifies.[152] DCNPP extended operations will require channeling ratepayer funds to a massively uneconomic plant.

PG&E-02 declines to address A4NR-01's documentation from PG&E's own workpapers of the infrequency of hours when DCNPP can be expected to produce cost-effective energy. Focused only on those 2024 – 2030 extended operations costs which would be absorbed by ratepayers, DCNPP output would cost $96.53/MWh. How will a DCNPP cost of $96.53/MWh stack up against prices in the CAISO energy market? According to PG&E's Workpapers for the forward power price derivation explained in Chapter 8 of the PG&E testimony,[153] the applicable CAISO prices will fall considerably short of $96.53/MWh in each year of the DCNPP extended operations period:

Year	Average of CAISO Monthly Average Price	Adjusted CAISO Price (DCNPP 0.93 weight)
2024		
2025		
2026		
2027		
2028		
2029		
2030		
Grand Total		

While the cost-effectiveness of a baseload plant is probably best evaluated on the basis of these longer-term price averages, it should not go unnoted how seldom (according to PG&E's CAISO price data for the years 2021 – 2023) that a $96.53/MWh plant would have been "in the

[151] 2,925,573,705 + 359,123,924 = 3,284,697,629.
[152] PG&E-01-E, p. 2-AtchA-2, line 92 2024 – 2030 Annual Average of 185,647,156.38 X 7 = 1,299,530,095. 3,284,697,629 ÷ 1,299,530,095 = 2.5276.
[153] PG&E-01-WP-C, p. WP 8-3.

money." DCNPP, of course, is a "must-take" resource under the CAISO tariff and is consequently not subject to economic merit order dispatch. But the data compiled in PG&E's Workpapers[154] indicate that applicable prices in the CAISO market exceeded $96.53/MWh in only 13.24% of the 26,280 hours comprising the three-year period:

Time Period	Total Number of Hours	Number of Hours When Price Exceeded $114.53/MWh (and % of Hours)		Number of Hours When Price Exceeded $96.53/MWh (and % of Hours)	
2021 Q1	2,160	53	(2.45%)	68	(3.15%)
2021 Q2	2,184	24	(1.10%)	40	(1.83%)
2021 Q3	2,208	100	(4.53%)	188	(8.51%)
2021 Q4	2,208	10	(0.45%)	58	(2.63%)
2022 Q1	2,160	1	(0.05%)	15	(0.69%)
2022 Q2	2,184	123	(5.63%)	295	(13.51%)
2022 Q3	2,208	335	(15.17%)	585	(26.49%)
2022 Q4	2,208	831	(37.64%)	1,039	(47.06%)
2023 Q1	2,160	733	(33.94%)	988	(45.74%)
2023 Q2	2,184	23	(1.05%)	78	(3.57%)
2023 Q3	2,208	55	(2.49%)	86	(3.89%)
2023 Q4	2,208	21	(0.95%)	39	(1.77%)
Cumulative Total	26,280	2,309	(8.79%)	3,479	(13.24%)

D.23-12-036 specifies that government-funded transition costs "will not be considered 'costs' as part of any cost-effectiveness evaluation considered by the Commission" because they are "outside the Commission's purview and general mandate to ensure just and reasonable rates."[155] A4NR believes the Commission's evaluation of the reasonableness and prudence of extended operations should nevertheless be cognizant of these taxpayer costs (which boost the DCNPP breakeven threshold to $114.53/MWh) because of the Commission's quasi-fiduciary duty to be a good steward of General Fund resources. As explained in A4NR-01, and ignored by PG&E-02, an interest in maximizing the likelihood of receipt of DOE Civil Nuclear Credit funds to repay a portion of the $1.4 billion state General Fund loan may leave state officials "locked

[154] *Id.*, pp. WP 8-8 – WP 8-605.
[155] D.23-12-036, p. 62.

in" to DCNPP extended operations through 2026 even if cumulative above-market costs to ratepayers exceed the amount expected from DOE.[156]

This surprise entrapment of ratepayers arises because of the "poison pill" inserted by PG&E and DOE into Section 5.2(a) of the Civil Nuclear Credit Award and Payment Agreement executed on January 11, 2024. The provision enables DOE to recapture all Credits awarded in the event that PG&E notifies the NRC prior to January 1, 2027 of its intent to permanently cease operations at DCNPP. The poison pill did not appear in the version of the Credit Award and Payment Agreement attached to the initial DOE grant solicitation, or in PG&E's markup of the draft agreement which it submitted with its grant application. Insertion of the poison pill into the final Credit Award and Payment Agreement apparently came without the participation or approval of DWR.[157] The DOE grant is the primary source of repayment of the General Fund loan to PG&E, and the only source (assuming no other federal funding) unless CAISO market revenues in the final year of extended operations soar above PG&E's current projections.

VI. CONCLUSION.

For the reasons stated herein, A4NR recommends that the Commission find that:

- PG&E has failed to meet its burden of proving by a preponderance of evidence that extended operation of DCNPP through 2030 would be reasonable, prudent, or cost-effective;
- PG&E should be directed to provide the NRC with the requisite 30-day notice on January 1, 2027 of the company's intent to permanently cease operations at DCNPP;
- PG&E's Record Period revenue requirement should be reduced by $65,227,000 because Pub. Util. Code Section 712.8(c)(1)(C) prohibits payment of the associated O&M Project Expense from rates;

[156] A4NR-01, p. 27.

[157] *Id.* p. 26, footnote 44: "A March 13, 2024 letter from the Department of Finance to the Joint Legislative Budget Committee indicated that, because DWR is not a party to the January 14, 2024 Civil Nuclear Credit Award and Payment Agreement between PG&E and U.S. Department of Energy ("DOE"), it was not familiar with specific details. DWR's representative emphasized in testimony that same day to Assembly Budget Subcommittee #4 that it was dependent upon public information about the agreement. https://www.assembly.ca.gov/media/assembly-budget-subcommittee-no-4-climate-crisis-resources-energy-and-transportation-20240313 at 1:55:25."

- PG&E's Record Period revenue requirement should be reduced by $31,636,461 because the company had the ability to mitigate the cost impacts of its forecast RA capacity substitution obligations for 2024 – 2025 scheduled outages by this amount;
- PG&E's Record Period revenue requirement should be reduced by $ because Pub. Util. Code Section 712.8(c)(1)(C) prohibits payment of the associated amortized nuclear fuel procurement costs from rates;
- PG&E should be directed to file a Tier 3 Advice Letter that allocates the costs incurred for DCNPP employee retention prior to commencement of extended operations at Unit 1 and Unit 2 exclusively to customers of LSEs within the PG&E service territory, and thereafter apportioned between customers of all jurisdictional LSEs on the same basis as other operating costs that are subject to the nonbypassable charge;
- Approval of the nonbypassable charge and rate proposals by PG&E, SCE, and SDG&E should be conditioned upon each of the modifications identified above in order to comply with D.23-12-036 and Pub. Util. Code Section 451;
- PG&E's proposal for allocating the RA attributes and GHG-free energy attributes associated with DCNPP extended operations should be rejected as an impermissible collateral attack on D.23-12-036;
- PG&E's proposed VPFs spending plan should be rejected and all VPFs retained in the Volumetric Performance Fees Subaccount of the DCEOBA pending completion of judicial review of the company's petition for writ of review of D.23-12-036;
- PG&E's proposed modifications to the review process established in D.23-12-036 for VPFs expenditures should be rejected; and
- PG&E has not satisfied the regulatory requirements set forth in D.23-12-036.

Respectfully submitted,

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Date: October 1, 2024

Attorney for
ALLIANCE FOR NUCLEAR RESPONSIBILITY