Docket No: A.25-05-009
Exhibit:
Date: April 23, 2026
Witness: Meredith Alexander

ERRATA TO REBUTTAL TESTIMONY OF
MEREDITH ALEXANDER ON BEHALF OF
CALIFORNIA COALITION OF LARGE ENERGY USERS

CALIFORNIA COALITION OF LARGE ENERGY USERS

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I. INTRODUCTION

Q. Please state your name, affiliation and business address.

A. My name is Meredith Alexander, and I am the Principal Consultant for the California Coalition of Large Energy Users (CLEU). CLEU's business address is 901 H St., Suite 120 PMB 176 Sacramento, CA 95814.

Q. Please briefly describe CLEU.

A. CLEU was recently incorporated as a 501(c)(6) non-profit. to represent the interests of large commercial and institutional energy consumers and ratepayers across California– including Genentech, Kaiser Permanente, Microsoft Corporation and the University of California (UC). Together, these organizations represent a significant proportion of the state's non-residential electricity usage, and each of these organizations has its own robust clean energy and distributed resource procurement goals. One of our members, UC, is also an energy service provider (ESP). CLEU was formed to advocate for policies that enhance grid reliability, improve resource planning, support clean on-site generation, streamline utility processes, and promote regional cooperation. Our objective is to ensure that California's large energy users have access to stable, cost-effective electricity, minimizing rate impacts while still achieving ambitious zero-emission goals.

Q. Please identify yourself, your organization, and your role within your organization.

A. Meredith Alexander, Principal, Gridwell Consulting. I am the Principal Consultant to CLEU and serve in the capacity as CLEU's Acting Executive Director.

Q. Please state your relevant educational and professional background.

A. I hold a Juris Doctor and Certificate in Natural Resources Law from the Northwestern School of Law at Lewis & Clark College and graduated Magna Cum Laude with Honors in Environmental Policy and Political Science from Tulane University. My professional experience includes serving as a law clerk on rate cases at the Bonneville Power Administration, three years as a Senior Regulatory Analyst at the California Public Utilities Commission, where I focused on long-term planning, California Independent System Operator (CAISO) issues, and resource adequacy, and participation in rate cases across multiple states as Director for State Policy at

CALSTART. I have been a consultant, advising clients on electricity policy since 2022. I have been the Principal Policy Consultant and Acting Executive Director of CLEU since July, 2025. Since this time I have developed an in depth understanding of the magnitude and type of electricity costs paid by CLEU's members in California, their active energization requests and the confidential details of various projects under development. In my time as a consultant I have focused on grid reliability and done extensive research on the causes of recent grid outages and disturbances. I have also studied the negative effects that both bulk and distribution grid outages have on California's businesses, institutions and all ratepayers. My complete Statement of Qualifications is included at the end of my testimony.

Q. Have you prepared and reviewed this Rebuttal Testimony?

A. Yes I have personally prepared and reviewed this rebuttal testimony.

Q. Please describe the purpose of your rebuttal testimony.

A. The purpose of my rebuttal testimony is to respond to the testimony of other parties through the lens of large commercial customers, and in general to provide meaningful and thoughtful analysis of the recommendations of other parties, as well as the criticisms of Pacific Gas and Electric's (PG&E) proposed revenue requirements made in the testimony of other parties.

II. SUMMARY OF RECOMMENDATIONS

Rate Increases and Scrutiny of the Overall Revenue Requirement

- The Commission should evaluate PG&E's Application overall to determine whether resulting rates would be just and reasonable, as is suggested by the Environmental Defense Fund (EDF). The Commission should aim for meaningful and sustained electricity rate reductions, as recommended by California Large Energy Consumers Association (CLECA).
- The Commission should adopt the California Public Advocates Office (Cal Advocates') CPI-based attrition rate over PG&E's proposed 6% annual attrition.

Base Costs and Base Revenue (Including Diablo Canyon)

- The Commission should immediately remove thirteen non-operational hydropower facilities from the Electric Generation revenue requirement, recover remaining netbook value (~$45.2M) as a regulatory asset with no return, and make ratepayers whole for returns previously collected in error, as recommended by California Community Choice Association (CalCCA).

- As asserted by the Utility Reform Network (TURN), all of the costs that ratepayers will bear during the 2027 General Rate Case (GRC) cycle — including $4.12 billion for Diablo Canyon — must be visible to the Commission and subject to scrutiny in this proceeding.
- The Commission should direct the $712 million Diablo Canyon Variable Performance Fee toward offsetting Resource Adequacy or energy market costs, as recommended by the Energy Producers and Users Coalition (EPUC), consistent with the statutory purpose of the plant's extension.

Depreciation of Existing Assets

- The Commission should require that PG&E correct overcharges for hydropower asset depreciation, as attested by CalCCA, and should reduce hydro depreciation expense by ~$15.7M annually.

Deferred Maintenance and Local Reliability

- The Commission should fund distribution system maintenance at levels sufficient to address PG&E's deferred maintenance backlog, as requested by Coalition of California Utility Employees (CCUE), but should not approve costs PG&E cannot demonstrate it can execute within the GRC period.
- The Commission should not burden ratepayers with higher costs of emergency equipment replacement driven by catastrophic failures attributable to a systemic pattern of failing to conduct routine maintenance. Both Cal Advocates and TURN highlight these patterns and effects on ratepayers in their testimony.
- The Commission should reject TURN's proposed probabilistic "hazard-based framework" and instead should apply the Average Age of Failure as a more appropriate metric for distribution circuit breaker replacement (MAT 48D).
- The Commission should, before approving nearly a four-fold increase in Emergent Reliability Program spending, require PG&E to demonstrate which reliability metrics will improve as a result of this spending, and exactly by how much. This recommendation is distinct from the assertions of TURN and Cal Advocates.
- The Commission should not allow or incentivize PG&E to defer authorized distribution system maintenance work while also inflating the per-unit cost of the work performed during each rate cycle. The Commission should scrutinize all of the per-unit distribution maintenance costs that Cal Advocates asserts are inflated, but it should not reduce service need or replacement volume estimates.
- The Commission should require PG&E to analyze and compare the cost of completing work with contractors vs PG&E employees, for each Major Work Categories (MWC) and Maintenance Activity Type (MAT), as recommended by CCUE.

Cost Escalation for Maintenance, Distribution Grid Resiliency (Grid Hardening), and Asset Depreciation

- The Commission should evaluate applying EPUC's recommended adjustment to the capital escalation factor for overhead maintenance costs. EPUC asserts this will reduce post test year (PTY) authorizations by $170M–$217M annually.
- The Commission should require PG&E to use Commission-adopted cost-per-mile estimates for undergrounding, as asserted by Cal Advocates, rather than PG&E's higher figures.
- The Commission should treat the prior GRC's hybrid portfolio mix (~61% undergrounding, ~39% covered conductor) as a ceiling, not a floor.

Bundled Versus Unbundled Customer Cost Responsibility

- ~~As already required by D.18-10-019 and D.23-11-069, the Commission must conduct the facility-by-facility revintaging analysis of PG&E's eight hydro relicensing facilities that CalCCA asserts is needed. PG&E must prepare for the Commission detailed information so that the Commission can make a vintaging decision that is~~ The Commission has sufficient record in this proceeding to make a facility-by-facility revintaging determination for the eight hydro facilities that PG&E needs to re-license. This determination should be "fact-specific to the plants and spending in question”[1] ~~Revintaging all facilities at once would be inconsistent with D.18-10-019.~~according to D.18-10-019 and the factors identified in D.23-11-069.
- The Commission should ensure that PG&E is not overcharging Community Choice Aggregators (CCAs) and Direct Access (DA) customers for metering and billing services, as CalCCA concludes it has done, and must ensure that if customers overpaid, refunds are returned to ratepayers.

Load Growth and Energization

- The Commission should, as CLECA requests, subject the costs of serving increased load to rigorous scrutiny, to ensure that load growth can bring about expected overall downward pressure on rates. Along these lines, the Commission should require PG&E to sequence and size load growth investments appropriately within rate case cycles by using the most up-to-date demand forecasts.
- The Commission should keep issues regarding how customers pay up front for large scale upgrades to the appropriate interconnection proceedings, such as the Rule 30 proceeding and any future updates to Rule 15. This rate case is not the appropriate place for the issue of costs paid up-front by customers rather than ratepayers.
- The Commission should exclude 2024–2026 Electric Capacity and New Business Interim Memorandum Account (ECNBIMA) capital from plant values pending Track 3 review, but separately and independently ensure (or require PG&E to ensure) that the 2027-2030 forecast is set at a level that reflects the feasible pace of energization activity, based on observations regarding what is achievable, regardless of how the 2024-2026 plant values are ultimately treated. The Commission should ensure that the 2027-2030 forecast reflects the demonstrated, and approved energization need.

[1] D. 18-10-019, "Decision Modifying the Power Charge Indifference Adjustment Methodology," issued October 19, 2018 in R.17-06-026 at 135.

- The Commission should deny PG&E's proposed New Business Balancing Account, as requested by multiple parties. Rather, new business costs should be feasible to forecast and budgeted in the GRC, as observed by CLECA.

III. RATE INCREASES AND SCRUTINY OF THE OVERALL REVENUE REQUIREMENT

Q. Please identify the opening testimonies and list issues raised by each party's Opening Testimony which you will address in this section.

A. This section addresses:

- "Opening Testimony of Sam Harper and John Holler on behalf of California Large Energy Consumers Association" filed February 13, 2026, in A. 25-05-009, discussing (1) the standard for success in this proceeding, framed as meaningful near-term and long-term rate reductions across all customer sectors, and (2) the feedback loop between rate increases and beneficial electrification adoption.
- "Opening Testimony of Michael Colvin on Behalf of Environmental Defense Fund" filed February 13, 2026, in A. 25-05-009, discussing PG&E's failure to establish an overall budget constraint and the risk that item-by-item review of the Application will not produce just and reasonable rates in the aggregate.
- CA-27, "Post-Test Year Ratemaking, Testimony of D. Phan on behalf of Cal Advocates," filed February 13, 2026, in A.25-05-009, discussing PG&E's proposed attrition formula and the appropriate attrition methodology, contrasting PG&E's 6% annual attrition with a Consumer Price Index (CPI)-based approach grounded in Commission precedent.

Q. Do you agree with CLECA's framing of the standard for success in this proceeding?

A. Yes, I agree with CLECA that "[t]he goal post for success must be meaningful electricity rate reductions beginning in the near-term and sustained over the long-term, assuming reasonable load growth forecasts, across all customer sectors."[2] Similarly to CLECA, CLEU's "members have not typically participated in the base revenue requirement setting phase of PG&E's GRC due to the significant time and costs required to do so. Their decision to participate now underscores the magnitude of concern with the revenue requirement request in this proceeding and the potential impact on these customers' operations."[3] CLEU was incorporated very recently, and our members were motivated to form a new ratepayer organization not only because of the impacts of PG&E's rates on their own operations in California, but also based on

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[2] "Opening Testimony of Sam Harper and John Holler on behalf of California Large Energy Consumers Association" filed February 13, 2026, in A. 25-05-009 (CLECA) at 4.
[3] *Id* at 5.

concerns with how general electricity unaffordability is affecting their "customers" who are students, patients, as well as business that provide the technology and innovation that drives California's economy.

CLEU intervenes now because PG&E's revenue requirement is impacting the "end users" of CLEU's members and services, which include over 300,000 University students, as well as patients in the largest integrated healthcare organization in the US. PG&E's increased revenue requirement will affect healthcare costs and education costs. PG&E's rate increases have affected California's economy by reducing the disposable income of California households, and are making people choose between paying their utility bill and buying food, and are affecting the decisions of businesses to operate in California. I agree with CLECA that high rates suppress economic growth by driving large loads out of the state.[4] One of our members chose to locate a new research facility outside of California specifically because of electricity costs.

CLEU's members are fully committed to California's decarbonization goals, which depend on electrifying transportation and other sectors currently run on fossil fuels. Thus, I agree with CLECA that there is a feedback loop created for beneficial electrification,[5] and that could become positive or negative depending on how well the Commission does its job: "If rates rise too quickly or fail to moderate as a result of aggressive anticipatory capital spending, electrification adoption may fall short of PG&E's projections."[6]

Q. Does EDF correctly identify a deficiency in PG&E's overall budget justification?

A. Yes, EDF's testimony identifies an important deficiency in PG&E's overall budget.[7] I agree that the Commission should also evaluate PG&E's application from an overall budget perspective. "EDF's observation is that the Commission could examine the individual parts of each request, modify them in response to intervenor's protests, and the sum of the individual parts may not lead to just and reasonable rates"[8] and CLEU shares this concern regarding the cumulative impact of increased revenue requirements for the hundreds of line items that parties

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[4] CLECA at 28.
[5] CLECA at 28.
[6] CLECA at 28.
[7] "Opening Testimony of Michael Colvin on Behalf of Environmental Defense Fund" filed February 13, 2026, in A. 25-05-009 (EDF) at 4.
[8] EDF at 4.

are being asked to scrutinize in this proceeding. I agree with EDF's assessment that "PG&E has not established an overall budget constraint and explained its reasoning of why the level of investment into each of the programs is sufficient. The magnitude of the rate increase is too high, and while each individual component may be worthy of consideration, in EDF's estimation if the Application were adopted without significant modifications, it would not lead to just and reasonable rates."[9]

Q. Between Cal Advocates' and PG&E's proposed attrition formulae, which do you consider most consistent with Commission precedent?

A. Cal Advocates opposes PG&E's attrition formula and advocates for a CPI-based attrition rate that is consistent with Commission precedent, compared to PG&E's 6% per year attrition.[10] On attrition specifically, the Commission precedent that Cal Advocates cites is compelling, and procedurally and precedentially, I agree with the ratepayer advocate's approach.[11]

IV. BASE COSTS AND BASE REVENUE (INCLUDING DIABLO CANYON)

Q. Please identify the issues regarding Base Cost and Base Revenue that you will address in this section.

A. This section addresses:

- "Prepared Direct Testimony of Ryan Matley on Behalf of the California Community Choice Association," filed February 13, 2026, in A.25-05-009, discussing PG&E's continued collection of returns on thirteen non-operational hydro facilities, four of which PG&E admits remain on its books in error, and the Commission's authority under Public Utilities Code § 455.5(a) to remove such assets from rates.
- TURN-02, "Affordability, Accountability and Deferred Work, Testimony of Jennifer Dowdell on behalf of TURN," filed February 13, 2026, in A.25-05-009, discussing the exclusion of more than $5 billion in costs from PG&E's headline revenue requirement figure, including $4.12 billion allocated to Diablo Canyon over 2027–2030.
- "Direct Testimony and Exhibits of James A. Leyko On behalf of Energy Producers & Users Coalition ("EPUC") and Indicated Shippers ("IS")," filed February 13, 2026, in A.25-05-009, discussing PG&E's proposed use of the $712 million Variable Performance Fee from Diablo Canyon's extended operations and whether that use aligns with the statutory purpose established in Public Utilities Code Section 712.8(q).

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[9] EDF at 5.
[10] "Post-Test Year Ratemaking, Testimony of D. Phan on behalf of Cal Advocates," filed February 13, 2026, in A.25-05-009 (CA-27) at 4.
[11] CA-27 at 4.

Q. Has CalCCA identified material issues with the inclusion of defunct hydropower facilities in PG&E's calculations for the Electric Generation revenue requirement? Has PG&E corrected the errors in their filing?

A. California Public Utilities Code (PU Code) § 455.5(a) gives the Commission explicit authority to remove assets from rates after nine or more consecutive months out of service.[12] CalCCA's testimony identifies that PG&E is continuing to collect a return on thirteen hydro facilities that PG&E has either retired or sold, or which are physically incapable of generating electricity.[13] CalCCA identifies that in some cases these resources have been on the books erroneously for over a decade.[14] PG&E has admitted in discovery that four of the thirteen facilities (Coal Canyon, Lime Saddle, Kern Canyon, Chili Bar) remain on its books in error.[15] The other nine are "mothballed" or physically incapable of generation: Centerville last operated in 2011, Kerckhoff 1 in 2017, Inskip in 2017, and Hamilton Branch in 2018.[16] PG&E's proposal would have ratepayers collecting returns on these assets for up to 19 years of non-operation.[17]

I do not find any legitimate basis for delaying the removal of these facilities from the ratebase**.** CLEU agrees with CalCCA that these assets should be removed from the Electric Generation revenue requirement immediately, with any remaining net book value (~$45.2M) recovered as a regulatory asset with no return.[18] This is a straightforward accounting correction that reduces the 2027 revenue requirement by $10.6M net.[19] Furthermore, I observe that ratepayers should be retroactively "made whole" through compensation for the errors that were known or should have been known, to PG&E in prior rate cases.

Q. Do you agree with TURN's observation that PG&E's headline revenue requirement figure understates the total costs customers will face?

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[12] Cal. Pub. Utls. Code § 455.5(a).
[13] "Prepared Direct Testimony of Ryan Matley on Behalf of the California Community Choice Association," filed February 13, 2026, in A.25-05-009 (CalCCA) at 7-8.
[14] CalCCA at 8-9.
[15] CalCCA at 9-10.
[16] CalCCA at 8-9.
[17] CalCCA at 18.
[18] CalCCA at 20.
[19] CalCCA at 21.

A. TURN identifies that PG&E's headline revenue requirement figure excludes more than $5 billion in costs customers will actually face during the GRC period, including $4.12 billion allocated to Diablo Canyon over 2027 through 2030.[20] CLEU agrees with TURN that the costs included must be complete. If costs will be borne by ratepayers during the 2027 GRC cycle, they must be visible and subject to scrutiny in this proceeding, regardless of how PG&E has chosen to account for them. Excluding Diablo Canyon costs from the headline figure does not make those costs disappear; it simply removes them from the record where intervenors can examine them and where the Commission can evaluate whether the total burden on ratepayers is just and reasonable. The Commission cannot make a reasonableness determination with incomplete information, <u>all</u> costs that will flow through to ratepayers during this GRC period should be in front of the Commission now and not piecemeal in separate proceedings, which would obscure the full picture of the costs' impacts on ratepayers.

The Commission's own 2025 Senate Bill (SB) 695 report, which TURN quotes directly, describes the GRC as the primary mechanism through which the Commission imposes discipline on utility spending: an enterprise-wide review designed to identify the most cost-effective options and determine revenue requirements at the lowest just and reasonable rates.[21] TURN's point, which CLEU agrees with, is that this mechanism only works if all the costs are in front of the Commission at once. Fragmentation of the revenue requirement across separate proceedings, balancing accounts, and legislative arrangements defeats the purpose of the GRC process. The Commission cannot make a holistic affordability determination on an incomplete picture, and it cannot hold PG&E accountable for delivering value for money if the full price tag is never presented in a single place.

Q. Do you agree with EPUC regarding PG&E's proposed use of Variable Performance Fee revenue from Diablo Canyon operations and how it should be used?

A. In his testimony for EPUC, James Leyko raises a concern about PG&E's stated intention to use the $712 million Variable Performance Fee (VPF) revenue from Diablo Canyon's extended

[20] "Affordability, Accountability and Deferred Work, Testimony of Jennifer Dowdell on behalf of TURN," filed February 13, 2026, in A.25-05-009 (TURN-02) at 8-12.
[21] TURN-02 at 5-7.

operations in a manner inconsistent with the stated goal of extending the plant.[22] He argues that the proposed use of VPF revenue in the PTY period undermines the rationale for the fee and should be revisited.[23] I agree that the funds should be used in a manner related to resource adequacy or electric procurement. CLEU recommends that the funds be directly used to offset PG&E ratepayer expenses related to electric procurement: this $712 million could be used to reduce ratepayer costs for Resource Adequacy, or for real time energy market expenses. Both of these would be related to the statutory purpose of extending Diablo Canyon's operations which was supposedly for reliability and to decrease scarcity conditions.[24] It appears that the $712 is currently being treated as a "windfall" for PG&E.[25] Instead, these funds should be returned to the ratepayers in as direct a manner as possible. Thus, in my opinion, offsetting Resource Adequacy (RA) or energy market costs in the 2027 cycle is logical.

V. DEPRECIATION OF EXISTING ASSETS

Q. Please identify the issues regarding Base Cost and Base Revenue that you will address in this section.

A. This section addresses the "Prepared Direct Testimony of Ryan Matley on Behalf of the California Community Choice Association," filed February 13, 2026 in A.25-05-009, discussing (1) a $15.7M annual overcharge in PG&E's hydro depreciation expense resulting from PG&E's omission of $507–$562M of accumulated depreciation from its depreciation study, and (2) the discrepancy between PG&E's GRC filing and its own books and Federal Energy Regulatory Commission (FERC Form 1.

Q. Do you agree with CalCCA's position on PG&E's hydropower depreciation expenses?

A. Yes, I agree with CalCCA that overcharges for hydro-depreciation should be corrected. CalCCA identifies a $15.7M annual overcharge in PG&E's hydro depreciation expense, resulting from PG&E's omission of $507–$562M of accumulated depreciation from its depreciation study.[26] CalCCA observes that there is a direct contradiction between PG&E's

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[22] "Direct Testimony and Exhibits of James A. Leyko On behalf of Energy Producers & Users Coalition ("EPUC") and Indicated Shippers ("IS")," filed February 13, 2026, in A.25-05-009, (EPUC) at 40-41.
[23] EPUC at 41-42.
[24] EPUC at 41-42.
[25] EPUC at 41.
[26] CalCCA at 50-52.

own books and PG&E's "Form 1" filings at FERC.[27] CLEU agrees that this should be corrected. If left uncorrected, CalCCA's analysis shows that customers will pay $507–$562M more than the original cost of the hydro fleet over the life of the assets.[28] CLEU finds this to be unacceptable. I observe that there is no dispute regarding the calculation methods, rather the discrepancy is between what PG&E provides to the Commission in its GRC filing and what it reports on its own books.[29] The Commission should require PG&E to reconcile these figures and reduce the depreciation expense accordingly.

VI. DEFERRED MAINTENANCE AND LOCAL RELIABILITY

Q. Please identify the opening testimonies and list issues raised by each party's Opening Testimony which you will address in this section.

A. This section addresses:

- "Testimony of Robert Earle on Behalf of the Coalition of California Utility Employees," filed February 13, 2026, in A.25-05-009, discussing: (1) the consequences of deferred maintenance on poles, overhead conductors, and underground cable, including outages, public safety hazards, and wildfire ignition, and (2) the need for PG&E to develop and make available cost data comparing contractor versus internally performed work for each MWC and MAT.
- CA-03, "Electric Distribution Capital Expenditures, Part 1 of 6, Testimony of R. Amin on behalf of Cal Advocates," filed February 13, 2026, in A.25-05-009, and CA-28, "Safety, Risk and Integrated Planning, Testimony of M. Gordon, L. Vanderbilt, and M. Hanauer on behalf of Cal Advocates," filed February 13, 2026, in A.25-05-009. These testimonies discuss: (1) chronic underspending on overhead conductor replacement and five consecutive years of deferrals, and (2) the link between deferred proactive maintenance and elevated emergency repair costs.
- CA-04, "Electric Distribution Capital Expenditures, Part 2 of 6," Testimony of G. Wilson on behalf of Cal Advocates, filed February 13, 2026, in A.25-05-009, discussing inflation in PG&E's per-unit cost calculations for distribution maintenance components.
- TURN-02, "Affordability, Accountability and Deferred Work," Testimony of Jennifer Dowdell on behalf of TURN, filed February 13, 2026, in A.25-05-009, discussing worsening reliability metrics despite increased Emergent Reliability Program spending.
- TURN-11, "Addressing Substation Asset Management, Testimony of Jalal Awan, Ph.D. on behalf of TURN," filed February 13, 2026, in A.25-05-009, discussing: 1) PG&E's blended "Average Age of Failure" metric for distribution circuit breaker replacement (MAT 48D) and 2) TURN's proposed reduction to 30 units per year.

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[27] CalCCA at 50-52.
[28] CalCCA at 53.
[29] CalCCA at 52.

- "Opening Testimony of Sam Harper and John Holler on behalf of California Large Energy Consumers Association" filed February 13, 2026, in A. 25-05-009, discussing limiting approved capital work to activities PG&E has demonstrated it can reasonably execute within the GRC period.

Q. Do you agree with CCUE's characterization of the consequences of deferred maintenance?

A. I Agree with CCUE on the dire consequences for reliability that occur when elements of PG&E's distribution system fail, caused by lack of maintenance investment. CLEU's mission is focused on maintaining reliability alongside ensuring affordability, and thus CCUE's assertion that "PG&E's overhead conductor replacement has fallen woefully short for many years and continues to do so under PG&E's forecast"[30] is of grave concern to CLEU, as leading businesses and institutions in the state. Outages caused by distribution system failures have severely impacted Californians in recent months,[31] and these outages have directly impacted CLEU and the customers our members serve. CCUE's Testimony asserts: "[f]ailure of utility poles and non-timely replacement can have dire consequences for the public at large as well as ratepayers. Some examples are... a major blackout event associated with 8 utility poles, the 2011 Windstorm Event resulting in more than 440,000 customers losing power after utility poles and attachments were blown down by a windstorm."[32] Also, "[f]ailure of overhead conduit can cause customer outages, danger to the public when they fall to the ground and remain energized, and ignition of wildfires. Proactive replacement of aging overhead conduits is therefore necessary for safety and reliability."[33] Preventing catastrophic grid events, especially those that pose public health and safety hazards and real economic losses across the state, is a priority for CLEU.

Q. Do you agree that ratepayers shouldn't be stuck with the higher costs of "emergency" maintenance when routine, proactive maintenance was systematically deferred, as asserted by Cal Advocates?

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[30] "Testimony of Robert Earle on Behalf of the Coalition of California Utility Employees," filed February 13, 2026, in A.25-05-009 (CCUE) at 12.

[31] "Fire at PG&E substation in Saratoga causes power outage for over 20,000 customers on Christmas Eve," ABC7 San Francisco (Dec. 25, 2025), *available at* https://abc7news.com/post/fire-pge-substation-saratoga-causes-power-outage-20000-customers-christmas-eve/18312652/; "Tens of thousands across Bay Area lose power on Christmas morning as another storm moves through," CBS San Francisco (Dec. 25, 2025), *available at* https://www.cbsnews.com/sanfrancisco/news/bay-area-christmas-eve-storm-wind-power-outages/.

[32] CCUE at 4-5.

[33] CCUE at 10.

A. Yes, I observe a pattern identified by both Cal Advocates and TURN in their various testimonies that "an ounce of prevention is worth a pound of flesh." Cal Advocates documents that there has been chronic underspending on overhead conductor replacement by 56%–88%[34] and that this has been coupled with five consecutive years of,[35] meaning that the funds authorized in prior GRCs were not spent on the overhead conductor replacements that PG&E previously said were necessary. TURN and Cal Advocates highlight that emergency repairs and replacements that were *more expensive by many orders of magnitude* resulted from PG&E not completing work that was necessary at the time the Commission approved the work.[36] The data presented by PG&E and through discovery shows that 32% of conductor-related emergency repairs were driven by conductor failure[37]—meaning ratepayer funds are now requested for emergency fixes to equipment that PG&E should have proactively replaced. This directly supports my conclusion that emergency (reactive) spending stems from deferred proactive maintenance.

Q. Does TURN's criticism of PG&E's Average Age of Failure metric justify TURN's recommended reduction in authorized replacement units?

A. No. I disagree with TURN's conclusion that its criticism of the metric warrants the reduction TURN proposes. TURN argues that PG&E's blended " Average Age of Failure" metric for distribution circuit breaker replacement (MAT 48D) "does not isolate catastrophic or operational failures and does not establish an increasing hazard rate,"[38] and TURN recommends a probabilistic hazard-based framework (e.g., Weibull analysis), proposing only 30 units per year for 2028-2030 versus PG&E's ramp to 90 units — a 37% cost reduction totaling $71.8M against PG&E's $160M request.[39] While TURN may be correct that the blended metric conflates in-service failures with preventive replacements, the metric need not isolate catastrophic failures to serve its purpose. The relevant question is what

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[34] "Electric Distribution Capital Expenditures, Part 1 of 6, Testimony of R. Amin on behalf of Cal Advocates," filed February 13, 2026, in A.25-05-009 (CA-03) at 44-45.
[35] "Safety, Risk and Integrated Planning, Testimony of M. Gordon, L. Vanderbilt, and M. Hanauer on behalf of Cal Advocates," filed February 13, 2026, in A.25-05-009 (CA-28) at 29.
[36] TURN-02 at 28-30.
[37] CA-28 at 33-35.
[38] "Addressing Substation Asset Management, Testimony of Jalal Awan, Ph.D. on behalf of TURN," filed February 13, 2026, in A.25-05-009 (TURN-11) at 7.
[39] TURN-11 at 7-9.

authorization level is reasonable for this MAT, and the Average Age of Failure metric is adequate for that purpose. Notably, TURN's own recommended alternative, a flat 30 units per year, is itself not derived from the probabilistic framework TURN advocates for, which undermines the force of its methodological critique.

Separately, the Commission should consider whether PG&E is entitled to earn a return on replacements driven by catastrophic failure. Where an asset has failed catastrophically due to inadequate maintenance, that failure represents a performance shortcoming PG&E should not profit from: the Commission should authorize recovery of replacement costs, but deny a return on those investments as an accountability measure reflecting that the failure should not have occurred in the first place.

Q. Do you agree with CLECA's recommendation to prioritize and limit approved capital work to activities PG&E can reasonably execute within the GRC period?

A. I agree with CLECA's recommendation, and their significant caveat. CLECA argues: "[t]he Commission should prioritize and limit approved capital work in this GRC to only those activities that are necessary, urgent, and that PG&E has demonstrated it can reasonably execute within the GRC period."[40] CLECA's last point about feasibility and timing is extremely important. While the record clearly demonstrates an incredible quantity of deferred system maintenance,[41] the record also shows it is unlikely it can all be completed within the pertinent time window for this GRC.[42] Thus, I agree that costs should not be approved in this rate case unless PG&E has clearly demonstrated, based on present and recent experience, that all of the budgeted work can be completed.

Q. How do you respond to assertions in TURN and Cal Advocates testimony that PG&E's increased Emergent Reliability Program spending coincided with worsening reliability metrics?

A. I observe, based on the testimony and my review of PG&E's application, that PG&E is asking for a very large increase for the Emergent Reliability Program in 2027. As noted by

[40] CLECA at 7.
[41] CLECA at 29.
[42] CLECA at 29.

TURN[43] and Cal Advocates,[44] PG&E seeks $28M more than it did in the 2023 GRC: approximately 294% increase. I would recommend that the Commission require the utility to demonstrate how exactly they plan to improve reliability metrics through this increase. TURN's and CalAdvocate's testimonies discuss the various safety metrics employed by PG&E: System Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index (SAIFI) ,Momentary Average Interruption Frequency Index (MAIFI), and Customer Average Interruption Duration Index (CAIDI) and assert that the data on reliability shows reliability metrics have worsened while spending has increased.[45] According to TURN, "reliability metrics exclusive of major events have declined even as revenues have increased." All four metrics (SAIDI, SAIFI, MAIFI, CAIDI) worsened, and "since 2015 all of PG&E's electric reliability metrics have been on a path of decline."[46] Since improving reliability is one of CLEU's goals as an organization, I would also conclude that if reliability metrics and spending on a reliability program have an inverse relationship, the Commission needs to re-evaluate the justification for these programs.

Q. Does Cal Advocates correctly identify inflation in PG&E's per-unit cost calculations for distribution maintenance, and what aspects of its position does CLEU endorse?

A. CLEU does not object to Cal Advocates' position regarding the per-unit cost calculations for distribution maintenance components. Cal Advocates' analysis identifies that PG&E has inflated per-unit costs across multiple Major Work Categories (MWC), including MWC 7 / MAT 07D and MWC 2A / MAT 2AA.[47] The Commission should scrutinize the inflation, and require PG&E to justify it. CLEU would, however, object to any remedy that reduces service need or replacement estimates, because distribution system reliability is critical for all customers, especially CLEU's members. As I discuss above, PG&E has chronically underspent previously authorized maintenance budgets, and that pattern of deferred maintenance has directly contributed to costlier emergency repairs. The per-unit cost inflation Cal Advocates identifies

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[43] TURN-02 at 27-30.
[44] CA-03 at 53-54
[45] CA-03 at 53-54.
[46] TURN-02 at 28.
[47] "Electric Distribution Capital Expenditures, Part 2 of 6," Testimony of G. Wilson on behalf of Cal Advocates, filed February 13, 2026, in A.25-05-009 (CA-04) at, 43-55.

should be evaluated in that context: the Commission should not allow PG&E to defer authorized work while also inflating the per-unit cost of the work it does perform.

Q. Do you support CCUE's recommendation that PG&E develop and make available cost comparisons for work performed by contractors vs. employees?

A. Yes. CCUE recommends that "PG&E should develop and/or make available costs for each MWC and/or MAT for contractor versus internally performed work" and that "this cost data should be used to inform PG&E's workforce planning."[48] I agree. Cal Advocates' own analysis demonstrates precisely why such transparency matters: PG&E's increased reliance on contractor labor has inflated unit costs across multiple MWCs,[49] and PG&E lacks the granular cost data to evaluate whether its contractor spending represents the least-cost approach to performing the work.[50] Without that data, neither the Commission nor intervenors can verify whether PG&E pursues the least-cost labor approach.

CCUE identifies three additional deficiencies in PG&E's workforce planning that reinforce the need for this data. First, PG&E admits that its 60/40 contractor split relies on historical operating ratios rather than any specific analysis of future work composition, and that "PG&E has no defined criteria, thresholds, or quantitative measures" to support this ratio.[51] Second, the limited cost data that does exist (for MWC 16) shows contractors to be substantially more expensive than internally performed work in the short term.[52] Third, PG&E's Section 935 Report fails to account for attrition or retirement considerations in its headcount analysis, meaning PG&E "does not attempt to show how many total hires must occur to reach the total headcount."[53] These gaps confirm that PG&E lacks the analytical foundation to justify its current labor allocation, and that the cost comparison data CCUE recommends is essential for informed workforce planning decisions.

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[48] CCUE at 25.
[49] CA-04 at 41-47, 52-55
[50] *Id.*
[51] CCUE at 24.
[52] CCUE at 25.
[53] CCUE at 27.

VII. COST ESCALATION FOR MAINTENANCE, DISTRIBUTION GRID RESILIENCY (GRID HARDENING), AND ASSET DEPRECIATION

Q. Please identify the opening testimonies and list issues raised by each party's Opening Testimony which you will address in this section.

A. This section addresses:

- "Direct Testimony and Exhibits of James A. Leyko On behalf of Energy Producers & Users Coalition ("EPUC") and Indicated Shippers ("IS")," discussing: 1) the likely cause of PG&E's 33% annual growth rate for electric distribution overhead maintenance and (2) the significant PTY reductions that would result from applying the capital escalation factor instead.
- CA-03, "Electric Distribution Capital Expenditures, Part 1 of 6, Testimony of R. Amin on behalf of Cal Advocates," filed February 13, 2026, in A.25-05-009, discussing: (1) PG&E's divergence from Commission precedent on cost-per-mile estimates for wildfire system hardening and undergrounding, and (2) the appropriate mix of undergrounding versus covered conductor compared with the portfolio approved in the prior GRC.

Q. Does EPUC accurately identify a flaw in PG&E's methodology for 2027 base maintenance costs and justification for escalating those base costs?

A. EPUC's witness, James Leyko, asserts that PG&E's base costs in the 2027 test year are inflated.[54] EPUC asserts that the inflation of base costs is primarily driven by PG&E's bottom-up forecast methodology for electric distribution overhead maintenance, which proposes a 33% annual growth rate from current spending levels.[55] I agree that such a large growth rate is concerning and potentially unjustified. Leyko recommends applying the capital escalation factor to overhead maintenance costs (MWC 2A) rather than the 33% annual growth implied by PG&E's bottom-up forecast.[56] This single adjustment produces the following, significant PTY reductions: 2028: - $170 million, 2029: -$180 million, and 2030: -$217 million.[57] I agree that these are significant potential reductions, and the Commission should carefully analyze the reasonableness of the modified capital escalation factor.

[54] EPUC at 8-9.
[55] EPUC at 26-28.
[56] EPUC at 26-29.
[57] EPUC at 10.

Q. Do you agree with Cal Advocates' position on distribution system hardening costs and the cost per mile for undergrounding?

A. I observe that Cal Advocates points out a material and important divergence from Commission precedent in PG&E's calculation for the cost of wildfire system hardening and undergrounding. Specifically, PG&E estimates the costs of such activities at $3.03–$3.26 million per mile.[58] Cal Advocates testimony reminds us of the Commission's decision, D.23-11-069, approximated that undergrounding costs in 2023 should be *declining to* approximately $2.8 million per mile in 2026, with a four-year average of approximately $2.97 million per mile.[59] CLEU agrees with the ratepayer advocate that PG&E should use the estimates adopted by the Commission and that it has not justified such an extreme divergence from the previously estimated costs.

Q. What is your position on the appropriate mix of undergrounding versus covered conductors?

A. I agree with Cal Advocates' witness who argues that precedent should be followed: in the prior GRC, the Commission approved: the hybrid portfolio (approximately 1,230 miles undergrounding and 778 miles covered conductor out of 2,008 total miles for 2023–2026), corresponding to roughly 61% undergrounding and 39% covered conductor.[60] CLEU agrees with applying the hybrid portfolio for undergrounding, but I recommend that it be viewed as a ceiling and not a floor, as undergrounding is clearly a major driver of the overall revenue requirement, which EDF points out may result in unjust and unreasonable rates.

VIII. BUNDLED VERSUS UNBUNDLED CUSTOMER COST RESPONSIBILITY

Q. Please identify the issues you will address in this section.?

A. This section addresses the "Prepared Direct Testimony of Ryan Matley on Behalf of the California Community Choice Association," filed February 13 2025 in A.25-05-009, discussing: (1) the application of the Commission's D.18-10-019 revintaging framework to PG&E's proposed investments in eight hydropower facilities undergoing FERC relicensing, and whether to revintage those facilities uniformly or on a facility-by-facility basis, and (2) PG&E's

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[58] CA-03 at 26.
[59] CA-03 at 26.
[60] CA-03 at 28.

systematic overcharging of CCA and Direct Access customers for metering and billing services based on a 2015 cost study, as well as (3) the $10.3M surplus collected from 2020–2024 for billing services that PG&E erroneously allocated to bundled customers rather than returning it to unbundled customers.

Q. How does Commission precedent establishing a revintaging framework apply to PG&E's proposed hydro relicensing investments raised in CalCCA's testimony?

A. D.18-10-019 and D.23-11-069 provide the framework for revintaging utility-owned generation assets and deciding which costs are germane to specific "vintages" of the Power Charge Indifference Adjustment (PCIA).[61] The framework identifies four potential revintaging triggers: asset life extension, capacity expansion, changed function, and investment constituting a "significant overhaul."[62] D.18-10-019 lays out that bundled customers should not subsidize unbundled customers, but also that unbundled customers should not subsidize new generation commitments made on behalf of bundled customers.[63] This decision also provides that requires the analysis be "fact-specific to the plants and spending in question."[64] D.23-11-069 then directed PG&E to include in this very filing "(1) the details of any PG&E proposal for new asset life extensions, incremental capacity additions, or changed functions for any of its Utility-Owned Generation (UOG) assets... (2) on whose behalf it is making these new investments, and (3) the appropriate vintaging treatment for each asset."[65]

Q. How does your position compare to CalCCA's recommendation to apply the revintaging framework across eight hydro facilities, which PG&E is in the process of relicensing?

A. ~~CLEU does not agree with CalCCA's recommendation to revintage all eight hydropower facilities based on the FERC relicensing dates without further detailed analysis. Rather, we recommend that each facility be individually reviewed because, for some, relicensing may merely be a paperwork exercise, and for others, relicensing will trigger intensive capital upgrades that will require significant new budget approvals. The testimony demonstrates that the~~

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[61] CalCCA at 21-22.
[62] D.18-10-019 at 135.
[63] D.18-10-019 at 135.
[64] D.18-10-019 at 135.
[65] D. 23-11-069, "Decision on Pacific Gas and Electric Company's 2023 General Rate Case," issued November 17, 2023, in A.21-06-021 at 511.

~~investment magnitude for the facilities is far from equal. In our view, the spending required on Helms ($937M, 34% of original cost), McCloud-Pit ($648.6M, 54% of original cost), and Drum-Spaulding ($463.2M, 38% of original cost) could plausibly constitute a "significant overhaul" on their face. Phoenix at $23.9M (which CalCCA's own witness flags as raising "significant concerns about cost-effectiveness" at nearly $12,000/kW) is a very different case.~~ CLEU agrees with CalCCA that the Commission must make a determination regarding the revintaging of each of these assets. The issue before the Commission in this proceeding is a consequence of the Commission's prior approach to revintaging questions, which left significant issues unresolved. In D.18-10-019 the Commission held that any revintaging analysis must be "fact-specific to the plants and spending in question,"[66] but the Commission did not define what constitutes a "significant overhaul" or "significance" for these purposes. In D.23-11-069, the Commission directed PG&E to include in its future GRC filings "(1) the details of any PG&E proposal for new asset life extensions, incremental capacity additions, or changed functions for any of its UOG assets and why it is undertaking these changes, (2) on whose behalf it is making these new investments, and (3) the appropriate vintaging treatment for each asset in light of this testimony along with any future GRC proposals,"[67] but the Commission stopped short of ordering a case-by-case revintaging assessment by PG&E despite having ample data on which to make its findings. The result is that this GRC now presents the Commission with approximately $1 billion in forecasted hydropower capital expenditures across the eight facilities that must go through FERC relicensing, without this having automatically triggered a revintaging analysis. The Commission must now establish the appropriate process and establish a clear precedent. The Commission now has sufficient information on each of these eight facilities to make a "fact-specific" case by case determination on "the plants and spending in question" as it established in D.18-10-019.[68] There is no logical reason to further delay adopting a binding precedent for how utility-owned generation will be treated prospectively when undergoing relicensing or major capital improvements. Each of the eight carries forecast capital investment of at least $59 million, or at minimum 17% of the original cost of the facility. Both CalCCA and PG&E have provided information regarding the facility-by-facility investment magnitudes, the asset life

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[66] *D.18-10-019 at 134–135.*
[67] *D.23-11-069 at 511.*
[68] *D.18-10-019 at 134–135.*

extension impacts, the changed function of the facilities, and on whose behalf the investments are being made. PG&E cannot credibly contend that a facility requiring either hundreds of millions of dollars in capital investment, or a significant portion of its original cost to build is not a "significant overhaul" sufficient to trigger revintaging review under D.18-10-019, as that decision expressly opened the door to revintaging in cases of a "significant overhaul" or "plant investments[or] upgrades."[69]

To clarify our recommendation: I find that the Commission now has sufficient record in this proceeding to make a determination, based on the "significant overhaul" factor in D.18-10-019 and the factors identified in D.23-11-069, as to whether these hydro resources must be revintaged. CLEU recommends that the Commission finalize a decision on the revintaging of these eight assets in this proceeding.~~[70]~~ ~~CLEU urges the Commission to conduct that facility-by-facility analysis itself using the investment data PG&E has provided in this proceeding.~~

Q. Do you agree with CalCCA that PG&E's metering and billing charges to CCA and Direct Access customers are unjust and require correction?

A. I agree with CalCCA that, based on the data presented in its testimony, PG&E is likely overcharging CCA and Direct Access customers for metering and billing services.[71] PG&E has not contested that its current billing rates are based on a 2015 cost study, or that from 2020-2024 it collected $10.3M more from CCA/DA customers than it spent on those services and then allocated the surplus back to bundled customers.[72] CalCCA argues this is a direct violation of the indifference principle,[73] and if customers were overcharged, I agree that a subsidy from unbundled to bundled customers violates the Commission's indifference principle.

In the beginning, designing a billing system for CCA customers required a lot of administrative time and systems development by PG&E. Now that these systems have been standardized, it would be reasonable to expect costs per capita to decline.[74] Yet the costs per customer do not

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[69] *Id.*
~~[70] CalCCA at 46, fn. 137.~~
[71] CalCCA at 33.
[72] CalCCA at 26.
[73] CalCCA at 78.
[74] CalCCA at 78-79.

seem to have decreased. There seems to be a subsidy flowing from CCA/DA customers to bundled customers. This is precisely the outcome the Commission's framework is designed to prevent. CLEU supports CalCCA's recommendation to cap billing revenues at forecasted cost and refund any excess through Energy Resource Recovery Account (ERRA) pending a Phase 2 cost study update.

IX. LOAD GROWTH & ENERGIZATION

Q. Please identify the opening testimonies and list issues raised by each party's Opening Testimony which you will address in this section.

A. This section addresses:

- "Opening Testimony of Sam Harper and John Holler on behalf of California Large Energy Consumers Association" filed February 13, 2026 in A. 25-05-009 discussing: (1) the potential and conditions under which load growth can suppress rates, (2) the recommendation that PG&E sequence and size investments based on accurate load forecasts, and (3) the Rule 30 tariff proceeding and its role in removing uncertainty around customer cost responsibility for transmission-level upgrades.
- The assertions made in the "Opening Testimony of Michael Colvin on Behalf of Environmental Defense Fund" that ratepayers bear the risk of stranded grid investments to serve large loads, such as data centers. I discuss the role of the present Rule 30 proceeding in dealing with such risks, as well as the existing interconnection Rule 15.
- TURN-16, "Electric, Gas and Common Plant, Testimony of Catherine E. Yap on behalf of TURN," filed February 13, 2026 in A.25-05-009, discussing (1) the exclusion of ECNBIMA costs from 2024–2026 plant values pending reasonableness review, (2) the legal basis for that exclusion under D.24-07-008 and D.23-11-069, and (3) the potential downstream consequences for the 2027–2030 forecast and SB 410 compliance if TURN's recommendations are implemented. I provide an alternative recommendation for dealing with this challenging situation.
- "Opening Testimony of Sam Harper and John Holler on behalf of California Large Energy Consumers Association," filed February 13, 2026, in A. 25-05-009, TURN-02 "Testimony of Jennifer Dowdell on behalf of TURN," filed February 13, 2026, in A.25-05-009," and CA-04 collectively, discussing opposition to PG&E's proposed New Business Balancing Account.

Q. Do you agree with CLECA that load growth can bring about ratepayer savings, and if so, what must the Commission do to realize that potential?

A. I agree on the premise that load growth in PG&E's territory holds the potential to reduce costs for all ratepayers; however, I also agree with CLECA that this benefit is by no means guaranteed.[75] In my professional experience, cost deflation can result from higher rates of utilization of grid assets and by reducing the "peakiness" of California's load.

As CLECA notes, these savings will only materialize if the Commission subjects the costs to serve that load to rigorous scrutiny and pursues least-cost procurement strategies for new generation.[76] I recommend one material modification to CLECA's proposal, that: "the Commission require PG&E to sequence and size load growth and electrification-related investments based on observed load growth and realistic demand forecasts".[77] While I support the intent, I would recommend replacing the word "realistic" with "up to date" so that the proposal would be: "the Commission require PG&E to sequence and size load growth and electrification-related investments based on observed load growth and the most up-to-date demand forecasts." Recently, the California Energy Commission's (CEC) Integrated Energy Policy Report (IEPR) forecast process has highlighted that significant and highly material amounts of new load, based on pending energization work with energization online dates that are verified, has been left out of the forecast used for resource adequacy and reliability planning.[78] Furthermore, I observe that the Commission has issued procurement orders for expensive new generation using outdated (circa 2024) load forecasts, with zero justification as to why the updated numbers were not used.[79] This very likely can and will lead to unnecessary costs from over-procurement, or procurement that is too early for the actual load growth.

Critically, for CLEU's members, it is essential that energization requests for non-speculative, economically vital projects move forward on realistic timelines, which in many cases the utility has already agreed to. Certain parties' testimony lumps all non-transportation load growth together[80] and implies that much of it is speculative. CLEU's members would strongly disagree

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[75] CLECA at 29.
[76] CLECA at 29.
[77] CLECA at 72.
[78] *See* "2025 IEPR Forecast - Updated Results" presented January 5, 2026, in the Demand Analysis Working Group meeting, *available at* https://www.energy.ca.gov/sites/default/files/2026-01/2026-01-05_DAWG_Mtg_Slides-Combined_ada.pdf.
[79] D. 26-02-057, "Decision Requiring 2029-2032 Electric Resource Procurement and Transmitting Portfolios for 2026-2027 Transmission Planning Process," issued March 5, 2026, in R.25-06-019 at 116–117.
[80] *See, e.g.*, EDF at 6-7.

that their projects to build new hospitals, research facilities, laboratories or data centers to support emergency services are “uncertain” or speculative.

Q. Do you agree with CLECA's position on the Rule 30 tariff proceeding?

A. I agree with CLECA that the Rule 30 tariff proceeding, when finalized, will remove uncertainty regarding whether customers will be stuck with transmission or distribution system upgrade costs from new large loads.[81] As PG&E explains in its Rule 30 application, current practice “requir[es] new transmission-level customers to provide advances and pay for actual costs incurred for facilities necessary to interconnect the customer.”[82] The 2025 interim decision partially adopting Rule 30 interconnection processes simply allowed these to be processed in a more efficient and consistent manner, vs the prior practice of each filing being done via an “exceptional case filing.”[83] CLECA correctly observes that the Rule 30 proceeding ‘will likely result in increased customer contributions should sufficiently reduce the uncertainty otherwise entailed in forecasting for such customers.”[84]

Q. How do you view EDF's position on ratepayers bearing the risk of “stranded” grid investments to serve data center loads?

A. The present “Rule 15” interconnection process requires customers to fund the distribution system upgrades needed to serve new large loads on the distribution grid, and both prior utility practice and the interim Rule 30 provisions require customers interconnecting large-loads above 110kv to pre-pay transmission and sub-station costs.[85] Therefore, I note that EDF’s concerns

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[81] CLECA at 72.
[82] “Application Of Pacific Gas And Electric Company (U 39 E) For Approval Of Electric Rule No. 30 For Transmission-Level Retail Electric Service,” filed November 21, 2024, docketed as A. 24-11-007, at 2.
[83] D. 25-07-039 “Decision Partly Granting And Partly Denying Pacific Gas And Electric Company’s Motion For Interim Implementation Of Electric Rule Number 30,” issued July 24, 2025, in A. 24-11-007 at 48-50.
[84] CLECA at 72.
[85] PG&E Electric Rule No. 15, "Distribution Line Extensions," *available at* https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_RULES_15.pdf (governing customer cost responsibility for distribution-level interconnection); PG&E Electric Rule No. 30 (Interim), "Transmission-Level Retail Electric Service," *available at* https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_RULES_30.pdf (adopted on interim basis by D.25-07-039, "Decision Partly Granting and Partly Denying Pacific Gas and Electric Company's Motion for Interim Implementation of Electric Rule Number 30," issued July 24, 2025, in A.24-11-007)..

regarding stranded assets appear to reflect an oversight of the current cost-recovery framework, which already requires significant upfront funding from the customer.

In CLEU's experience, the financial risk of the load not materializing rests with the customer, who would have paid for major upgrades that then don't benefit them if their load doesn't come online, or if they pay for upgrades that are unnecessary based on their "real" vs expected overall load and peak capacity. This upfront funding requirement effectively insulates general ratepayers from the risk of stranded investments.

Q. Do you agree with TURN's identification of the problems with including ECNBIMA costs in Phase One?

A. I agree with TURN's concerns regarding ECNBIMA costs but recommend a modified approach to avoid adverse consequences for new business connections and beneficial electrification. My understanding of the Electric Capacity and New Business Interim Memorandum Account (ECNBIMA) is that it was designed to track incremental capital costs associated with energization and new service requests that exceed what was authorized in the prior GRC.[86] SB 410,[87] passed in 2023, directs the Commission to ensure that electrical corporations have "sufficient and timely recovery of costs" for energization. The bill defines electrification and energization as

> (a) "Electrification" means any new, expanded, or change in use of electricity related to the policies described in Section 933, including, but not limited to, in the industrial, commercial, agricultural, housing, or transportation sectors. (b) "Energization" and "energize" mean connecting customers to the electrical distribution grid and establishing adequate electrical distribution capacity or upgrading electrical distribution or transmission capacity to provide electrical service for a new customer, or to provide upgraded electrical service to an existing customer. The determination of adequate electrical distribution capacity includes consideration of future load. "Energization" and "energize" do not include activities related to connecting electrical supply resources.[88]

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[86] Electric Preliminary Statement Part KH, Electric Capacity and New Business Interim Memorandum Account, *available at* https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_PRELIM_KH.pdf.
[87] Senate Bill (SB) 410, Becker, Chapter 394, Statutes of 2023. Public Utilities Code Sections 930-939.5.
[88] *Id.*

The Commission implemented SB 410 with D. 24-09-020, which established binding average and maximum energization timelines.[89] The ECNBIMA exists because the 2023 GRC authorization was demonstrably insufficient to meet the pace of energization demand necessitated by beneficial electrification and load growth to serve California's economy.[90] The Commission recognized the insufficiency of the 2023 GRC authorization in D.24-07-008 and again in D.25-08-036.[91] As of year-end 2024, PG&E had tracked approximately $582 million in ECNBIMA-eligible incremental capital expenditures above the 2023 GRC baseline.[92] The independent third-party auditor's biannual reports under Public Utilities Code Section 938 provide ongoing evidence of PG&E's energization workload and spending trajectory.[93] These are the inputs that should drive the 2027-2030 forecast, not stale estimates that were developed under a completely different paradigm. The 2023 GRC authorization must not be used as evidence of baseline energization need in this GRC. Three years of recorded and forecast data now demonstrate that energization spending at levels substantially above the old baseline is not an anomaly, but rather is a sustained trend driven by application volumes, statutory mandates, and Commission-ordered timelines.

Because the general rate case cycle operates on a four-year horizon, rates set in this proceeding will govern through 2030. If the 2027-2030 forecast does not reflect the demonstrated pace of energization work, the consequences would include: dramatic growth in the energization backlog, delays in connecting new residential and commercial customers, impediments to electrification and economic development, and a failure to meet the binding timelines the Commission itself adopted in D.24-09-020; the very outcomes SB 410 was enacted to prevent.

Catherine Yap's testimony for TURN argues that PG&E must exclude from its electric distribution plant figures the capital expenditures recorded in, or forecast for, the ECNBIMA for

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[89] *Id.*

[90] D. 24-07-008, "Decision Authorizing a Ratemaking Mechanism for Energization Projects Pursuant to Senate Bill 410," issued July 16, 2024, in A.21-06-021; D. 25-08-036, "Decision Resolving Pacific Gas and Electric Company's Motion to Revise Its 2025 and 2026 Energization Cost Caps," issued September 4, 2025, in R.24-01-018.

[91] *See id. See also* PG&E Electric Preliminary Statement Part KH, Sheet 5 (Revised Cal. P.U.C. Sheet No. 60402-E, filed via Advice 7724-E implementing D.25-08-036), Table 2.

[92] *See id*. *See also* Attachment C to TURN-16 (PG&E Response to TURN-40, Q.2.a).

[93] Pub. Util. Code § 938(a)(3)–(5).

the years 2024 through 2026.[94] Yap's proposed remedy is specific: the adopted 2024-2025 electric distribution plant values should be reduced by the ECNBIMA capital expenditures recorded for those years, and she recommends that the adopted 2026 forecast be reduced by the best estimate of 2026 ECNBIMA capital expenditures.[95]

In PG&E's Results of Operations model, recorded and forecast capital expenditures for 2024-2026 are converted to capital additions and included in electric distribution plant-in-service.[96] These plant values establish the starting rate base from which the test year and post-test-year calculations derive. When ECNBIMA capital (which for 2024 alone amounted to approximately $582 million in tracked eligible expenditures) is removed from the 2024-2026 plant figures, the resulting base-period plant values drop substantially. That lower starting point cascades forward through the model.

Therefore, while TURN's testimony is focused on the correct treatment of 2024-2026 plant values (and does not make an argument about the appropriate level of the 2027-2030 forecast) adopting the proposed adjustment has mechanical implications for the forward-looking authorization that extends beyond the plant question TURN addresses.

Q. What is your assessment of TURN's arguments regarding the inclusion of ECNBIMA figures in the rate base, and do you have an alternative recommendation?

A. I agree with TURN's core premise regarding regulatory practice, and the substance of its proposed adjustment to recorded and forecast plant values for 2024-2026 is valid. TURN cites the Commission's finding in D.23-11-069 that "for amounts recorded in memorandum accounts, the Commission must first review those costs for reasonableness, and to include costs in rate base they must be both <u>used and useful</u> as well as prudently incurred."[97] TURN notes that the Commission made similar findings in D.25-09-030 regarding Southern California Edison's TY 2025 GRC.[98] PG&E has appropriately applied this principle to exclude from its plant figures the amounts

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[94] "Electric, Gas and Common Plant, Testimony of Catherine E. Yap on behalf of TURN," filed February 13, 2026, in A.25-05-009 (TURN-16) at 1-3.
[95] TURN-16 at 4.
[96] PG&E Exhibit (PG&E-10), "Results of Operations," filed May 15, 2025, in A.25-05-009.
[97] TURN-16 at 3.
[98] TURN-16 at 3.

recorded in other memorandum accounts that are pending before the Commission in separate applications.[99] The same principle applies to the ECNBIMA.

I agree generally with TURN's analysis regarding memorandum account costs and rate base. Decision 24-07-008, Ordering Paragraph 1, expressly conditions ECNBIMA cost recovery on reasonableness review in the test year (TY) 2027 GRC.[100] The Assigned Commissioner's Scoping Memo in this proceeding has established Track 3, commencing in 2027, for that purpose.[101] But, until Track 3 concludes, the Commission will not have made a final determination that the recorded ECNBIMA expenditures to satisfy the just and reasonable standard of Public Utilities Code Section 451.

TURN's argument rests on a well-established principle of California utility regulation: that costs recorded in memorandum accounts must undergo reasonableness review before inclusion in rate base. However, adopting TURN's proposed adjustment without addressing its consequences would create a significant new problem not addressed by TURN's testimony, which would have cascading consequences for energization for many years to come.

Q. What are the potential unintended consequences if TURN's recommendation were implemented without modification?

A. If the Commission adjusts the 2024-2026 plant values downward per TURN's recommendation but takes no further action, the practical effect would be a 2027-2030 authorization built on an artificially low foundation. In the "Results of Operations" model plant-in-service values for 2024-2026 serve as the foundation from which the 2027-2030 forecast is built, so the exclusion of ECNBIMA capital from the base period would mechanically depress the forward-looking forecast in a manner that is disconnected from the demonstrated level of energization need.

Therefore, I recommend that the Commission separately and independently ensure (or require PG&E to ensure) that the 2027-2030 forecast is set at a level that reflects the feasible pace of energization activity, based on observations regarding what is achievable, regardless of how the

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[99] TURN-16 at 1-2.
[100] Decision 24-07-008 at 91.
[101] Assigned Commissioner's Scoping Memo and Ruling, issued July 31, 2025, in A.25-05-009 at 17.

2024-2026 plant values are ultimately treated. While TURN does not argue that the 2027-2030 forecast should be set at a level that excludes ECNBIMA-era energization activity, that would be the practical outcome. Therefore, I recommend that the Commission independently ensure that the 2027-2030 forecast reflects the demonstrated, and approved energization need.

The Commission can adopt TURN's plant adjustment and protect the integrity of the forward-looking forecast through a two-part approach: first, accept the substance of TURN's recommendation for 2024-2026 plant-in-service. Recorded ECNBIMA capital additions for 2024-2025, and the best estimate of 2026 ECNBIMA capital expenditures, should be excluded from the electric distribution plant values underlying the TY 2027 rate base. This preserves the Commission's established precedent regarding memorandum account costs and ensures that PG&E does not earn a return on unreviewed assets. Upon completion of Track 3, costs found to be just and reasonable would be incorporated into rate base with appropriate prospective treatment.

Second, set the 2027-2030 electric distribution capital expenditure forecast at levels that reflect demonstrated energization need, independent of the 2024-2026 plant adjustment. The evidentiary record (including three years of ECNBIMA-eligible spending data, current and projected application volumes, the Commission's adopted energization timelines, and the independent auditor's reports) provides a robust basis for establishing the forward-looking authorization. The Commission should evaluate the reasonableness of the 2027-2030 forecast on its own merits in Track 1 of this proceeding, without treating the exclusion of 2024-2026 ECNBIMA costs from rate base as an implicit ceiling on what the forward-looking authorization should be.

My recommended modified approach would still provide full effect to the reasonableness review requirement that TURN asserts is necessary, while ensuring that ratepayers are not paying a return on unvetted assets, and avoiding the unintended consequence of setting a four-year energization authorization at a level that is inconsistent with SB 410, D.24-09-020, and the demonstrated needs of PG&E's service territory.

Q. What is CLEU's position on the New Business Balancing Account vis a vis CLECA, TURN, and Cal Advocates opposition to the NBBA, and how does CLEU propose to account for new business costs in the GRC?

A. CLEU believes that a forecast which includes new business capital expenses is a more appropriate approach to ratemaking as opposed to PG&E's balancing account proposal. We align with CLECA, TURN, and Cal Advocates in opposing the use of a balancing account for new business connections, and agree with CLECA that "New Business costs can and should be reasonably forecasted and budgeted in the GRC" and the Commission should therefore "reject the proposal to create the New Business Balancing Account."[102] As Finklestein's testimony for TURN points out, PG&E's own justification for the New Business Balancing Account (NBBA) undercuts the request.[103] TURN indicates that PG&E says it needs the NBBA because customer energization demand is uncertain and beyond its control.[104] But Finkelstein notes that PG&E already proposed to discontinue two other memorandum accounts (the ECNBIMA and Assembly Bill 841 Memorandum Account (AB841MA)) on the grounds that PG&E "is able to develop a reasonable forecast of program costs" – the exact opposite argument.[105] CLEU's proposal – to exclude ECNBIMA from plant values but forecast future expenditures based on demonstrated energization need – are aligned with the principle that in a forecast-based TY ratemaking model, costs that can be forecast must be included in the GRC revenue requirements for regulatory and intervenor scrutiny. As Dowdell's testimony for TURN argues, "since PG&E operates on forecasted test year with attrition, costs of operations that can be reasonably forecast should be explicitly included in PG&E's GRC request for approval or disallowance by the Commission."[106]

Cal Advocates witnesses Hieta and Myers align with CLECA and TURN, recommending that the Commission should deny PG&E's proposal to create the NBBA.[107] Cal Advocates also recommends the Commission deny PG&E's request to use the alternative forecast for 2027–2030.[108] Cal Advocates points out that PG&E's alternative forecast assumed the Commission had not granted PG&E's SB 410 Motion to increase 2025–2026 capital cost caps — but the Commission actually did grant that motion in D.25-08-036 on August 28, 2025.[109] As Cal Advocates notes in its testimony, PG&E itself conceded that if the SB 410 Motion was granted,

[102] CLECA at 31.
[103] TURN-18 at 56-57.
[104] TURN-18 at 56.
[105] TURN-18, p. 38, fn. 82.
[106] TURN-02, at 11.
[107] *See* CA-04 at 5, 20. *See also* CLECA at 31 and TURN-18 at 56.
[108] CA-04 at 21.
[109] D.25-08-036 at 79.

its alternative (higher) forecast would decrease.[110] These are the cost cap increases that we discussed in the ECNBIMA section above. CLEU's recommendation is not contrary to Cal Advocates' argument: we argue that PG&E's forecast for TY 2027 and the attrition formula applied thereafter should be recalibrated to reflect the Commission's actual authorizations and the demonstrated trajectory of energization demand, rather than relying on either a mechanically suppressed base or an alternative scenario premised on outdated assumptions. Specifically, the forecast should incorporate (1) the Commission-approved ECNBIMA cost cap increases in D.25-08-036, (2) the observed level of recorded and forecast ECNBIMA-eligible spending across 2024–2026, and (3) the workload and timing requirements established pursuant to SB 410 and implemented in D.24-09-020.

Under this approach, CLEU's recommendation is fully consistent with the positions of TURN and Cal Advocates opposing the NBBA. Like those parties, CLEU rejects the use of a balancing account to manage costs that can be reasonably forecast and instead supports incorporation of those costs into the test year revenue requirement, subject to full Commission review. At the same time, CLEU's proposal addresses a gap left by those positions: it ensures that the forecast itself is set at a level that reflects actual, observed energization demand, rather than being inadvertently constrained by the exclusion of ECNBIMA plant from the base years or by reliance on a counterfactual forecast that no longer reflects Commission-approved policy.

X. CONCLUSION

Q. Does this conclude your testimony?

A. Yes, this concludes my testimony. I commend all of the parties who submitted testimony in Phase 1, it was my pleasure to review and comment upon their thoughtful analysis and I hope that CLEU's rebuttal testimony will shed light on areas of shared concern, ways to implement modified party proposals, and overall will strengthen the record in this proceeding.

[110] CA-04 at 20.

STATEMENT OF QUALIFICATIONS OF MEREDITH L. ALEXANDER (Younghein)

Q. I hold a Juris Doctor and a Certificate in Natural Resources Law from the Northwestern School of Law at Lewis & Clark College. I graduated Magna Cum Laude with Honors in Environmental Policy and Political Science from Newcomb College, Tulane University. I am admitted to the Colorado state Bar. While in law school, I clerked for the Bonneville Power Administration, where I was trained in cost-of-service ratemaking, and supported transmission and electric rate cases. During my clerkship, I wrote briefs on transmission system maintenance issues and safety, among other issues. I worked at the California Public Utilities Commission from 2012-2016, and was a Senior Regulatory Analyst on the Long-Term Planning and Resource Adequacy team for two years. During this time I served as the Energy Division's liaison to the CAISO and published reports on reliability and renewables integration. While a Senior Analyst at the CPUC I also attended a week long "rate school" to learn the fundamentals of utility accounting and ratemaking. From 2019-2022 I served as the Director for State Policy at CALSTART, a national 501c3. During this time, I participated in rate cases and rate design proceedings in various states, including New York, Maryland, North Carolina and California on behalf of CALSTART. Since 2022, I have been a consultant on energy policy issues to a wide variety of clients, including Fortune 100 companies, NGOs and technology manufacturers. My work recently has focused on electric grid reliability and procurement. I am currently the Principal Policy Consultant and Acting Executive Director of CLEU. In this capacity, I possess confidential and current information regarding our member companies' and institutions' electricity use and electricity costs, as well as their plans for growth and electrification.