BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for Authority, Among Other Things, to Increase Rates and Charges for Electric and Gas Service Effective on January 1, 2023. (U39M)	Application 21-06-021 (Filed June 30, 2021)

PHASE II OPENING BRIEF OF THE UTILITY REFORM NETWORK

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1. Affordability concerns should guide the Commission's implementation of SB 410.

2. The Commission should limit the costs eligible for tracking in the new Electric Capacity and New Business Balancing Account (ECNBBA) to those directly related to customer connections, including the following:

   a. MWC 06 – New Business Related Capacity Work and Emergent Work (MAT 06H)

   b. MWC 10 – Energization-related work as defined by PG&E (subject to TURN adjustment for baseline GRC values)

   c. MWC 16 – Residential Connects, Nonresidential connects, PEV, AB 50 direct costs (subject to TURN's alternative connection forecast and assumption that compliance with AB 50 is satisfied through completion of 80% of eligible jobs in 2024)

   d. MWC 46 – NB-Related / Emergent Work (MAT 46H)

3. The Commission should adopt a lower cost cap for the ECNBBA than proposed by PG&E, commensurate with a narrower scope of costs eligible for SB 410 interim cost recovery.

4. The Commission should monitor the impact of D.23-12-037, which modifies the rules regarding line extension subsidies for mixed-fuel new construction, on PG&E's energization costs, and require PG&E to submit the annual reports required by that decision in this proceeding and PG&E's next GRC.

5. The Commission should require PG&E to reduce incremental energization capital expenditures recorded to the ECNBBA by:

   a. Treating Diablo Canyon volumetric payments as Contributions in Aid of Construction.

   b. Using other sources of funding, including Low-Carbon Fuel Standard (LCFS) holdback revenues.

   c. Pursuing alternative ways to interconnect customers in grid capacity constrained areas, including allowing customers to use automated load management systems and dynamic management of consumption based on grid availability.

6. The Commission should require PG&E to comply with the energization targets and reporting required by SB 410 and AB 50 through an annual Advice Letter filing and clarify that failure to comply with the SB 410 energization targets will impact the Commission's reasonableness review of costs recorded to the ECNBBA.

7. The Commission should adopt the following requirements for the SB 410 independent auditor:

    a. The Commission should follow the same process for selecting the SB 410 auditor as the Commission adopted in Resolution M-4855, which addressed the Commission's selection of and PG&E's contracting with the Independent Safety Monitor pursuant to D.20-05-053, including directing PG&E to allow Commission staff to review, revise (as appropriate), and approve PG&E's proposed services contract with the auditor prior to execution, and making the Commission a third-party beneficiary of that contract.

    b. The Commission should require the third-party auditor to confirm costs recorded to the ECNBBA are: 1) incremental to the funding authorized in the GRC, and 2) limited to costs directly necessary to enable pending customer connection requests.

    c. The auditor should review and report on compliance with the energization timeliness targets adopted by the Commission in R.24-01-008, as part of assessing PG&E's energization performance.

    d. The auditor should review the costs recorded to the ECNBBA to verify the number and scope of energization projects completed each year and report on PG&E's achievements relative to the Commission's expectations regarding minimum levels of work.

    e. The auditor should review PG&E's analysis of the fraction of new connections requests (MWC 16 and 10) attributable to new vs. existing customers to determine how changes in the portion of existing vs. new customers submitting applications affects cost forecasting. This review should inform PG&E's customer energization forecasts in the next GRC.

    f. PG&E should submit the auditor's report as part of its reasonableness review showing in the next GRC.

8. The Commission should ensure that PG&E's showing in the next GRC related to costs recorded to the ECNBBA is sufficient to permit a meaningful reasonableness review by requiring PG&E to demonstrate all of the following:

    a. The costs PG&E recorded to ECNBBA are limited to those associated with the activities within MWC 06, 10, 16, and 46 identified by TURN (work directly related to connecting customers / new load).

    b. The costs recorded to the ECNBBA were incremental to the costs authorized in D.23-11-069.

c. PG&E accurately accounted for the fraction of new connections requests (MWC 16 and 10) attributable to new versus existing customers for historic and forecasted work.

d. PG&E prioritized the use of Diablo Canyon volumetric payments to support customer connection expenditures.

e. Before investing in infrastructure upgrades, PG&E determined that alternative approaches to managing load and connecting customers were infeasible (including an explanation of why).

f. Before investing ratepayer funds in infrastructure upgrades, PG&E exhausted all non-ratepayer sources of funding to support new connections, including but not necessarily limited to LCFS holdback revenues.

g. PG&E has complied with the energization timeliness targets adopted in R.24-01-008, or if not, why non-compliance was reasonable.

h. PG&E has met the minimum level of completed projects expected by the Commission in its Phase II decision, or if not, why achieving a lower level of project completion was reasonable.

PHASE II OPENING BRIEF OF THE UTILITY REFORM NETWORK

1. INTRODUCTION

On November 16, 2023, the Commission adopted Decision (D.) 23-11-069, providing Pacific Gas and Electric Company (PG&E) with unprecedented annual revenue requirement increases during the Test Year 2023 General Rate Case (GRC) cycle, 2023-2026, totaling $2.568 billion dollars. These increases include $1.307 billion in 2023, another $716 million in 2024, $359 million in 2025, and $204 million in 2026.[1] In adopting these increases, the Commission recognized the "weighty economic pressures" PG&E's customers face:

> These rate increases for essential energy services come at a time when customers are facing economic pressures that already strain their livelihoods, as well as climate change driven weather events that drive increases in their need for energy. At the same time, California is striving to recover from the impacts of a global pandemic. The Commission reviews PG&E's and other intervenors' proposals with a careful eye toward balancing customer affordability and investments needed to maintain safety and reliability.[2]

The Commission accordingly carefully scrutinized PG&E's GRC request "to balance affordability concerns within PG&E's forecasted financial requirements" and concluded that PG&E could "continue to support and also improve the safety and reliability of PG&E's gas and electric infrastructure and services" with a fraction of the GRC increase PG&E had proposed.[3]

While the Commission was still deliberating over PG&E's TY 2023 GRC request, PG&E returned with its "Phase II" request in this proceeding: to spend an additional $4.076 billion from 2024-2026 on customer energization and collect the associated electric revenue

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[1] D.23-11-069, Appendix A, Table 1.

[2] D.23-11-069, pp. 2, 5.

[3] D.23-11-069, p. 5.

requirements – up to $591 million – on an interim basis, pending a full reasonableness review of incurred costs in the next GRC.[4] PG&E asks the Commission to authorize the creation of a new Electric Capacity and New Business Balancing Account (ECNBBA) in which PG&E would track costs associated with customer energization projects that exceed the costs included in PG&E's authorized Test Year 2023 GRC revenue requirement. PG&E proposes to cap the incremental costs eligible for recovery through the ECNBBA at an amount equal to 2.5 percent of PG&E's 2023 GRC electric distribution revenue requirements, which equates to approximately $1.264 billion in 2024.[5] PG&E ties its new Phase II request to Senate Bill (SB) 410 (Becker, 2023), which seeks to address reported delays in customer energization by directing the Commission to adopt energization time period targets and ensure that each electrical corporation has sufficient and timely recovery of reasonable energization costs, to the extent such costs are not fully covered by the revenue requirements authorized in the GRC.[6]

Pursuant to Rule 13.11 of the Commission's Rules of Practice and Procedure, The Utility Reform Network (TURN) respectfully submits this Opening Brief in Phase II of PG&E's Test Year 2023 GRC. As the Commission considers PG&E's Phase II request, the Commission must exercise the same concern for PG&E's ratepayers as it did in resolving PG&E's Test Year 2023 GRC request. Affordability of PG&E's electric bills has worsened since November 2023, when the Commission issued D.23-11-069.[7] PG&E's electric rates and bills are now so high that they threaten both access to the essential energy services that PG&E provides and the achievement of

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[4] Ex. PGE-PhII-02, page 6, Table 6.

[5] Ex. PGE-PhII-01, p. 33; Ex. PGE-PhII-02, p. 6, Table 6.

[6] SB 410, adding, among others, Sections 932(a)(3)-(4), 934, and 937 to the California Public Utilities Code (P.U. Code).

[7] TURN discusses affordability in Section 3 below.

the state's decarbonization goals, which rely in part on customers choosing to electrify buildings and vehicles. The Commission should protect ratepayers by ensuring that the interim cost recovery mechanism contemplated by SB 410 is limited to the incremental costs of specific work needed to complete pending customer connection requests and by adopting related ratepayer protections.

TURN demonstrates below that PG&E's Phase II request exceeds the limited purpose of SB 410 to facilitate the elimination of PG&E's customer energization backlog. TURN provides recommendations to narrow the scope of costs that should be eligible for tracking in the new ECNBBA. TURN recommends a lower balancing account cost cap, commensurate with TURN's proposed scope of eligible costs and TURN's alternative forecast of customer connections in 2024-2026. The Commission should adopt these proposals to protect ratepayers from excessive rate increases during this GRC cycle.

Further, the Commission should direct PG&E to prioritize the use of up to $446 million in Diablo Canyon volumetric payments to offset incremental capital costs for customer energization projects. Likewise, the Commission should direct PG&E to take advantage of alternative ways to fund and address new service requests and capacity upgrades in the near-term. All of these approaches can relieve rate pressure.

Finally, the Commission should adopt clear requirements for the independent third-party auditor required by SB 410, and for PG&E's showing in the next GRC regarding the reasonableness of all costs tracked in the ECNBBA and recovered through the interim rate relief mechanism, subject to refund.

TURN provides a comprehensive list of its recommendations in the "Summary of Recommendations" included above.

2. STANDARD OF REVIEW

In Phase II of this proceeding, PG&E asks the Commission for authorization to spend and recover, on an interim basis pending a future reasonableness review, up to $4 billion in capital beyond the amounts authorized in D.23-11-069 for the 2023-2026 GRC cycle, which would significantly increase the rates PG&E charges to its customers for electric service. The fact that PG&E would collect revenues subject to potential refund through a future decision does not reduce the significance of its request, nor its burden to demonstrate justness and reasonableness. The rates PG&E charges during the period of interim rate recovery will impact the affordability of PG&E's services. Customers who cannot afford to pay their PG&E bills and are disconnected, and customers who forego other essentials in order to retain PG&E service, will receive no comfort or relief from the possibility of a future refund should the Commission find that PG&E unreasonably incurred the already collected costs. The Commission must take its responsibility as seriously here as in a proceeding for permanent cost recovery.

The Commission is charged with ensuring that "[a]ll charges demanded or received by any public utility, … shall be just and reasonable" and cannot approve a rate change "except upon a showing before the commission and a finding by the commission that the new rate is justified."[8] As the Commission explained in D.01-10-031:

> We have a regulatory responsibility to ensure PG&E provides adequate service at just and reasonable rates, and we must view the facts accordingly. Our legislative mandate encompasses promoting the "safety, health, comfort, and convenience of PG&E's patrons, employees, and the public." *See* Cal. Pub. Util. Code §451.[9]

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[8] Cal. Pub. Util. Code §451 and Cal. Pub. Util. Code §454

[9] D.01-10-031, Order Granting Rehearing of and Modifying Decision 00-02-046, p. 5.

Indeed, the Commission stated in D.19-05-020, "We remain mindful that our fundamental responsibility is to ensure that the utilities under our jurisdiction are equipped to provide safe and reliable service at just and reasonable rates."[10]

In the test year 2009 GRC for Southern California Edison Company (SCE), the Commission succinctly described the utility's burden of proof that follows from these statutory mandates:

> As the applicant, [the utility] must meet the burden of proving that it is entitled to the relief it is seeking in this proceeding. [The utility] has the burden of affirmatively establishing the reasonableness of all aspects of its application. Other parties do not have the burden of proving the unreasonableness of [the utility's] showing. As the applicant in this rate case, [the utility] has the burden of proving that each of its proposals is reasonable.[11]

The Commission must be attentive to important corollaries of the fundamental point that the utility bears the burden of proof. First and foremost, "[t]he presumption is that the existing rates are reasonable and lawful."[12] If the utility does not provide adequate support for its requested increase with regard to any element of its revenue requirement, the current amount should remain in effect. It is not up to intervenors to establish that the utility's forecast is unreasonable unless the Commission first determines that the utility has met its burden of proof with regard to that forecast.

Second, as the Commission has recognized in the past, the practical truth in a proceeding the scale of a GRC is that:

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[10] D.19-05-020, p. 17.

[11] D.09-03-025, p. 8 (citing Cal. Pub. Util. Code §451 and Cal. Pub. Util. Code §454, and D.06-05-016 (SCE Test Year 2006 GRC)), p. 7.

[12] D.00-02-046 (PG&E test year 1999 GRC), 2000 Cal. PUC LEXIS, *57, citing *Southern Counties Gas Company* (1952) 51 CPUC 533; *Citizens Utilities Company* (1953) 52 CPUC 637; *Park Water Company* (1955) 54 CPUC 498.

> [The utility's] burden of proof is not in all areas so burdensome as one might assume. We generally rely on intervening parties to identify proposals or funding requests which should be subject to scrutiny by the Commission. Our reliance on other parties to set a framework for litigation in a general rate case derives from the fact that a single ALJ cannot review an entire rate case showing without an extraordinary expenditure of time and effort. Because intervenor resources are limited and their priorities may differ from ours, the parties may overlook proposals that the Commission might otherwise consider questionable. Nevertheless, where a proposal or funding request has not been challenged by an intervenor, we generally adopt the utility's request as a practical reality of the decision-making process. In those cases, the utility's burden of proof is indeed light.[13]

The other side of this coin is, "Where it faces opposition, [the utility's] reasonableness showing is naturally a more difficult undertaking."[14]

The Commission requires utilities to meet the "preponderance of the evidence" standard of proof in GRC proceedings.[15] Under that standard, the applicant must establish the reasonableness of every aspect of its request with evidence that, "when weighted with that opposed to it, has more convincing force and the greater probability of truth."[16]

In sum, as the applicant, PG&E bears the burden of proving that it is entitled to recover the costs at issue here and must affirmatively establish the reasonableness of its Phase II request. This evidentiary burden is entirely the PG&E's; other parties do not have the burden of proving the unreasonableness of the PG&E's forecasts or requests.[17]

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[13] D.93-12-043 (SoCalGas Test Year 1994 GRC), 1993 Cal. PUC LEXIS 728, *12, 52 CPUC 2d 471.

[14] D.00-02-046 (PG&E test year 1999 GRC), 2000 Cal. PUC LEXIS, *56 - *57, citing D.87-12-067, 27 CPUC 2d 1, 21.

[15] D.14-12-025, p. 21.

[16] D.08-12-058, p. 19 (citing Witkin, Calif. Evidence, 4th, Vol. 1, 187).

[17] *See, e.g.,* D.09-03-025, p. 8; D.06-05-016, p. 7; D.01-10-031, pp. 8-9.

3. AFFORDABILITY CONCERNS MUST GUIDE THE COMMISSION'S IMPLEMENTATION OF SB 410

3.1 Requirements of SB 410

Pursuant to SB 410, an Investor Owned Utility (IOU) may request a ratemaking mechanism that will "track costs for energization projects placed in service after January 1, 2024, that exceed the costs included in the electrical corporation's annual authorized revenue requirement for energization, as established in the … [IOUs GRC] or any other proceeding."[18] The interim rate recovery authorized under SB 410 is limited to "energization projects" that enable customers to connect to the electrical distribution grid.[19] The bill defines energization as

> 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.[20]

As part of authorizing a new ratemaking mechanism to track energization project costs, the Commission is required to "establish an up-front annual cap on the amount that each electrical corporation can recover within the mechanism."[21] In establishing the annual cap, the Commission must first review the information provided by an IOU as part of its request for a ratemaking mechanism.[22] The Commission is <u>not required</u> to set the cap at any specific level or to defer to the amounts requested by the IOU. The statute permits the Commission to determine

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[18] Cal. Pub. Util. Code §937(a)(1).

[19] Cal. Pub. Util. Code §937(b)(1).

[20] Cal. Pub. Util. Code §931(b).

[21] Cal. Pub. Util. Code §937(b)(2).

[22] Cal. Pub. Util. Code §937(b)(2), (c).

the appropriate maximum level of interim rate recovery after evaluating both the IOU showing and any other relevant considerations. As explained in the Senate floor analysis of SB 410, the statutory direction for the CPUC to set an annual cap is intended to "limit impacts on electric ratepayers."[23]

Given the significant new rate impacts that would result from PG&E's proposal, the Commission should avail itself of the flexibility permitted by SB 410 and decline to authorize PG&E's full cap level. The Commission can select a smaller cap by adopting a more limited view of the categories of eligible costs for "energization projects" that can be tracked for special interim rate recovery. Specifically, eligible costs should be those directly related to completing pending customer connection requests.

Linking eligibility for interim rate recovery to customer connection applications is also consistent with the provision of SB 410 that directs the Commission to establish "energization time periods" for "energization projects."[24] The Commission should adopt the view that "energization projects" represent specific work needed to complete an individual customer connection request. Costs to implement general distribution system reliability or capacity upgrade projects, including projects that are intended to address wildfire risk, should not be considered "energization projects" (for which the timing benchmarks in SB 410 would apply) and should not be eligible for the special interim rate recovery permitted under SB 410.

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[23] SB 410 Senate Floor Analysis, September 14, 2023, page 6 ("This bill attempts to limit impacts on electric ratepayers by subject [sic] these costs to CPUC review for just and reasonableness and an annual cap on the amount that may be recovered, as well as, other requirements to mitigate cost impacts.") (https://leginfo.legislature.ca.gov/faces/billAnalysisClient.xhtml?bill_id=202320240SB410#)

[24] Cal. Pub. Util. Code §934 (b).

3.2 Affordability of PG&E's Electric Rates

Affordability should be at the forefront of the Commission's evaluation of PG&E's request as many PG&E's ratepayers are already struggling to afford basic electric service. TURN's testimony detailed the significant increase in PG&E's electric rates over the past five years,[25] including the 33% (non-CARE, $60 monthly bill increase for customers using 500 kWh per month) and 29% (CARE, $35 monthly bill increase for customers using 500 kWh per month) electric rate increase that took effect on January 1, 2024 compared to rates a year earlier on January 1, 2023.[26] TURN also noted there are more rate increases to come later in 2024,[27] in addition to the rate increase resulting from this Application. As addressed in Section 5.2 below, PG&E's total requested capital expenditures cap for 2024-2026 is $4.076 billion dollars with a cumulative revenue requirement increase of $591 million by 2026, resulting in a 7.5% increase in electric distribution rates.[28] The capital expenditures cap proposed by PG&E is unnecessarily high and should be reduced. TURN proposes reasonable reductions to the capital expenditures cap in Sections 4 and 5 below.

TURN's testimony also addressed findings in the most recent Commission Affordability Report regarding the unaffordability of PG&E's electric rates for many of its customers.[29] The Commission cannot ignore the significant affordability challenges facing PG&E's ratepayers

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[25] Ex. TURN-PhII-01-E, pp. 2-4.

[26] Ex. TURN-PhII-01-E, p. 2.

[27] *Id* at p. 4. These requests are pending in A.23-12-001 ($2.18 billion), in A.23-06-008 ($2.5 billion), in A.22-12-009 ($1.4 billion), and in A.21-09-008 ($600 million still in dispute). In D.24-03-006, the Commission granted PG&E interim rate relief of 75% of its total request in A.23-06-008, subject to refund once the Commission's resolves PG&E's request on the merits. D.24-03-006, Ordering Paragraphs 1-2.

[28] Ex. PGE-PhII-02, page 6, Table 6.

[29] Ex. TURN-PhII-01-E, pp. 3-4.

when evaluating the reasonableness of the additional near-term rate increases proposed by PG&E in this Application. TURN does not dispute that energization timeliness is important, but ratepayers simply cannot afford the level of incremental funding PG&E requests, and PG&E's proposal represents the most costly approach to addressing the interconnection backlog. Accordingly, the Commission cannot find that PG&E's proposal complies with P.U. Code §451 and §454. PG&E has not sufficiently justified its request in this Application and its proposed capital expenditures cap is unreasonably high. The Commission should significantly reduce the cap and the scope of work covered by this special interim rate recovery as recommended in Sections 4 and 5 below.

4. THE COMMISSION SHOULD LIMIT THE COSTS ELIGIBLE FOR TRACKING IN THE NEW BALANCING ACCOUNT

4.1 PG&E's customer connection forecast is overly optimistic and should be adjusted to reflect both 2023 recorded data and the AB 50 target

A key driver of PG&E's cost forecast is an assumed increase in new customer applications for service. Approximately $2.3 billion (or 74%) out of the $3.1 billion in capital that PG&E forecasts to be eligible for interim rate recovery involve MWC 16 projects.[30] MWC 16 includes the New Business program which is "responsible for installing electric infrastructure required to connect new customers to PG&E's distribution system and accommodate increased load from existing customers."[31]

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[30] Ex. TURN-PhII-01-E, page 6.

[31] Ex. PGE-PhII-01, page 8.

PG&E's testimony claims that it has "seen an increase in new applications for service" that justify its forecast in this proceeding.[32] But a review of actual data provided to TURN by PG&E shows that, for MWC 16, total applications for new service peaked in 2021 and declined in both 2022 and 2023.[33] This trend is particularly noticeable for residential connects (down 7.3% between 2021 and 2023) and non-residential connects (down 15.7% between 2021 and 2023). This data does not support the claim that customer connection requests are rising.

The MWC 16 cost forecast for 2024, 2025 and 2026 is based on a forecast of applications for service prepared by an outside consultant (Rosen Consulting Group) that was updated in June 2023.[34] Recorded data for 2023 reveals two interesting trends. First, actual customer connections in 2023 were significantly less than forecast. Residential connects were almost 17% below the forecast and non-residential connects were 35% below the forecast.[35] Meanwhile, actual completed jobs were slightly above the 2023 forecast despite the lower number of new applications than forecasted.[36]

TURN's testimony notes that the RCG model has been subject to criticism in Phase 1 of this proceeding by both TURN and Cal Advocates.[37] In evaluating its own model, RCG notes that "actual connects were lower than the vintage model estimated for residential connects as well as the nonresidential electric model during the last two years."[38] Results from 2023 suggest

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[32] Ex. PGE-PhII-01, page 18.

[33] Ex. TURN-PhII-01-E, pages 6-7.

[34] Ex. TURN-PhII-01-E, page 7.

[35] Ex. TURN-PhII-01-E, page 8.

[36] Ex. TURN-PhII-01-E, page 8.

[37] Ex. TURN-PhII-01-E, page 8.

[38] Ex. TURN-PhII-01-E, page 8 (*citing* PG&E response to TURN DR3, Q6, Atch 2, Review and Recalibration of the Utility Connect Forecasting Models, page 1).

that RCG's revised model is similarly overestimating both residential and non-residential connects.

Given these concerns, the Commission should decline to rely upon PG&E's forecast for the determination of anticipated costs eligible for interim rate recovery. TURN's testimony recommended lowering the 2024, 2025 and 2026 residential connects forecast by 17% and the non-residential connect forecast by 35%.[39] As calculated by PG&E, the use of TURN's lower forecast between 2024-2026 would result in a reduction of $264.5 million for residential connects and $324.9 million for non-residential connects. Both of these adjustments are included in TURN's recommendations for MWC 16.[40]

This adjusted forecast does <u>not</u> include incremental work needed to meet the AB 50 target of completing 80% of construction ready work by December 2024 for customers with completed applications submitted prior to January 31, 2023. PG&E's forecast assumes 100% of these customers will be connected in 2024, and PG&E does not appear to have updated its forecast to include all jobs completed in 2023.[41] TURN proposes that the Commission assume that the 80% target is met for purposes of evaluating costs eligible for interim rate recovery.

4.2 PG&E's failure to distinguish between connection requests from new and existing customers should be remedied in its next GRC application

TURN's testimony notes that PG&E fails to distinguish between applications for service from new customers and existing customers.[42] As a result, there is no method of determining what portion of forecasted or recorded costs are due to upgrades by existing customers versus

[39] Ex. TURN-PhII-01-E, pages 8-9.

[40] Ex. TURN-PhII-01-E, page 9 (*see* PG&E response to TURN DR 5, Q1, Atch2).

[41] Ex. TURN-PhII-01-E, page 9 (*see* PG&E response to TURN DR 4, Q2, Supp2).

[42] Ex. TURN-PhII-01-E, pages 9-10.

new customer accounts. Since PG&E is aware as to whether a connection request comes from a new or existing customer, the decision to not track this information is puzzling. TURN's testimony explained that this information would be helpful to understand which connections are driven by new customer growth versus upgrades requested by existing customers that are undertaking electrification projects.[43]

The Commission should require PG&E to provide greater information on the fraction of new connections requests (MWC 16 and 10) attributable to new vs. existing customers in its next GRC application and to incorporate this information into its forecasting efforts. There may be different unit costs for applications submitted by existing vs. new customers that would better inform the forecast. Additionally, the third-party auditor should review this information to determine how changes in the portion of existing vs. new customers submitting applications affects cost forecasting.

4.3 Only costs directly related to pending customer connections should be eligible for interim rate recovery

PG&E proposes to classify a wide range of distribution system costs as falling within the definition of "energization projects". Specifically, PG&E argues that any costs recorded to MWC 06, 16 or 46 that exceed the GRC-approved capital forecasts for all spending within each MWC should be eligible for special interim rate recovery pursuant to the SB 410 framework.[44] PG&E's approach would allow a wide array of distribution-related expenditures to be eligible for interim rate recovery regardless of whether they are directly related to customer energization or enabling

[43] Ex. TURN-PhII-01-E, page 10.

[44] Ex. TURN-PhII-01-E, pages 11-12 (*citing* PG&E response to TURN DR2, Q5).

new customer connections.[45] The cost categories represented by many of the MWCs included in PG&E's testimony are overbroad and include many costs that are not triggered by, or even related to, the need to satisfy individual customer connection requests. TURN is concerned that PG&E is attempting to shoehorn a variety of other distribution-related expenditures into the definition of "energization" for purposes of gaining access to interim rate recovery. The Commission should limit eligibility for the SB 410 ratemaking mechanism to costs directly triggered by actual customer energization requests.

TURN proposes an alternative approach that would limit interim rate relief to cost categories associated with customer applications for service. Under this approach, costs within MWC 06, 10, 16 and 46 should be divided into "non-energization" and "energization" for purposes of determining eligibility for special interim rate recovery. TURN recommends that the following costs be characterized as "energization projects" and eligible for special interim rate recovery:[46]

MWC 06 – New Business Related Capacity Work and Emergent Work (MAT 06H)

MWC 10 – Energization-related work as defined by PG&E (subject to TURN adjustment for baseline GRC values)

MWC 16 – Residential Connects, Nonresidential connects, PEV, AB 50 direct costs

MWC 46 – NB-Related / Emergent Work (MAT 46H)

TURN urges the Commission to limit the scope of SB 410 to interim rate recovery to the cost of completed capital projects in each of the identified line items that exceed amounts authorized in the recently approved General Rate Case decision. If the Commission decides to

[45] Ex. TURN-PhII-01-E, page 12.

[46] Ex. TURN-PhII-01-E, pages 12-13.

expand the scope of costs that may be eligible for interim rate recovery, it should limit such expansion to MWC line item costs that are directly triggered by active customer energization and connection applications.

4.3.1 MWC 06

PG&E proposes to classify all MWC 06 costs as "energization projects" eligible for special interim rate recovery pursuant to SB 410. According to PG&E, MWC 06 costs are related to projects that upgrade distribution line capacity to:[47]

> i) Energize one or more applications for service. PG&E does not differentiate between applications for service involving new customers and applications for service involving existing customers.
>
> ii) Mitigate an overload caused by existing customer increased loads (not associated with applications for service), organic load growth, or inadequate operational capacity for new growth.

PG&E's Phase 1 GRC testimony describes MWC 06 as covering an array of capacity work on distribution lines "to prevent equipment damage or failure due to excessive heating and to prevent outages."[48] Some of this work is designed to replace transformers that "can become potential ignition sources" and "start ignitions with serious consequences especially in High Fire Threat District Areas".[49] In response to a TURN data request, PG&E stated that

> MWC 46 and MWC 06 projects provide substation and distribution line capacity for load growth. Some of these projects are driven by applications for service from new or existing customers. But there is no linkage between applications for service and the capacity projects driven by the applications.[50]

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[47] Ex. TURN-PhII-01-E, page 15 (*citing* PG&E response to TURN DR2, Q3)

[48] Ex. PG&E-4, page 17-30.

[49] Ex. PG&E-4, page 17-31.

[50] Ex. TURN-PhII-01-E, page 15 (*citing* PG&E response to TURN DR2, Q11)

As explained in TURN's testimony, the fact that only <u>some</u> MWC 06 projects are "driven by applications for service from new or existing customers" reinforces TURN's concern that allowing all MWC 06 costs to be eligible for interim rate recovery represents an overly broad implementation of SB 410.[51]

In response to a TURN data request seeking clarification as to which MWC 06 costs are associated with providing service to new customers or providing upgraded service to an existing customer, PG&E stated that "In Table 1-4, Line 6 is associated with applications for service, either new customer applications or existing customer applications. Lines 1-5, and lines 7-10 are not associated with applications for service but are driven by overloads, voltage needs, and inadequate operating capacity."[52]

As shown in TURN's testimony, approximately $288.8 million (48%) of the $604.4 million in 2023-2026 forecasted costs for MWC 06 are "not associated with applications for service" as explained by PG&E.[53] The remaining $315.6. million (52%) are attributable to New Business related capacity work which involve capacity reinforcement projects "to eliminate overloads, due to an individual new development or an existing customer's load increase."[54]

The 48% of MWC 06 costs "not associated with applications for service" should be excluded from SB 410 interim rate recovery because there is no clear linkage to customer energization and no demonstration that these expenditures are necessary to complete work on

[51] Ex. TURN-PhII-01-E, page 15

[52] Ex. TURN-PhII-01-E, page 15; PG&E response to TURN DR 2, Q3.

[53] Ex. TURN-PhII-01-E, page 16 (*citing* PG&E response to TURN DR2, Q3); Ex. PGE-PhII-01, Table 1-4 (lines 1-5 and 7-10 reflect costs "not associated with applications for service"))

[54] Ex. PG&E-4, page 17-34.

pending customer connection projects. Absent a demonstration that these expenditures are caused by customer energization projects, TURN does not believe that general distribution upgrades designed to address "organic load growth" or other system conditions should be eligible for interim rate recovery prior to the next GRC.

TURN's specific recommendations for the costs in MWC 06 that should be eligible for interim rate recovery are included in Section 5 of this brief.

4.3.2 MWC 10

PG&E proposes to classify a portion of MWC 10 costs as "energization projects" eligible for special interim rate recovery pursuant to SB 410. MWC 10 costs relate to "relocating electric distribution and service facilities at the request of a government agency or other third party (e.g. private parties and developers) and for the conversion of overhead electric facilities to underground covered by Electric Rules 20B and 20C."[55] PG&E states that "a portion" of MWC 10 costs "directly support energization projects."[56]

PG&E asserts that 22% of its adopted MWC 10 GRC capital forecast should be characterized as "energization-related" based on a review 2021 and 2022 recorded project costs.[57] PG&E applies this 22% factor to the authorized MWC 10 GRC capital forecasts for 2023-2026 to determine the imputed "energization-related" funding levels already embedded into rates. Actual energization project costs in excess of this baseline would be eligible for SB 410 interim rate recovery.

[55] Ex. PG&E-4, page 18-14.

[56] Ex. PGE-PhII-02, page 2.

[57] Ex. PGE-PhII-02, page 3.

TURN does not oppose allowing SB 410 interim rate recovery for incremental MWC 10 costs that are necessary to allow completion of customer energization projects. However, TURN's testimony disputes PG&E's calculation that only 22% of the MWC 10 GRC forecast should be characterized as "energization-related".[58] TURN explained that PG&E relied on 2021 and 2022 costs to make its determination of the historical baseline and excluded 2020 costs.[59] TURN's alternative approach relies on three years of historical data (2020-2022), rather than the two years (2021-2022) used by PG&E, and yields a calculation that 24% of actual expenditures over these three years were "energization-related".[60] TURN therefore recommends using a three-year historical average and assuming that 24% of the adopted MWC 10 GRC forecast is "energization-related". The use of the 24% value results in an $11.6 million reduction (between 2024-2026) in the amount of energization costs that can be characterized as incremental for purposes of SB 410 interim rate recovery.[61]

PG&E should only be allowed to seek interim rate recovery for MWC 10 "energization-related" costs that exceed the adopted GRC forecast using TURN's alternative approach. The Commission should also require the third-party auditor to review PG&E's methodology for characterizing MWC 10 costs as "energization-related". To the extent that the auditor finds that PG&E has improperly characterized these costs, the Commission should reserve the right to disallow interim rate recovery.

[58] Ex. TURN-PhII-01-E, page 20.

[59] Ex. TURN-PhII-01-E, page 20.

[60] Ex. TURN-PhII-01-E, page 20, *see* footnote 55 for data sources relied upon by TURN.

[61] Ex. TURN-PhII-01-E, page 21.

TURN's testimony calculates a cap for all MWC 10 incremental energization spending based on an updated forecast provided by PG&E.[62] That forecast is incorporated into TURN's specific recommendations for the costs in MWC 10 that should be eligible for interim rate recovery and are included in Section 5 of this brief.

4.3.3 MWC 16

PG&E proposes to classify all MWC 16 costs as "energization projects" eligible for special interim rate recovery pursuant to SB 410. According to PG&E, MWC 16 costs involve projects that "install electric infrastructure required to connect new customers to PG&E's distribution system and accommodate increased load from existing customers."[63] As explained in TURN's testimony, a review of the underlying MWC 16 subcategories does not support PG&E's proposal to treat all MWC 16 costs as energization related.[64]

Two of the line items within MWC 16 forecast costs are for "transformer purchases" and "transformer scrapping".[65] These two line items account for $741.3 million in forecasted expenditures between 2023-2026 and amount to 25% of the total forecast for MWC 16.[66] It is not clear that these costs are directly related to customer energization. As explained in PG&E's direct testimony submitted in Phase 1 of this proceeding, the costs recorded to the "transformer purchases" line item ($720.8 million forecasted between 2023-2026) involve "distribution transformers for all of PG&E's electric distribution programs".[67] In Phase 1 rebuttal testimony,

[62] Ex. TURN-PhII-01-E, page 21 (*see* PG&E response to TURN DR 4, Q4, Atch1).

[63] Ex. PGE-PhII-01, page 8.

[64] Ex. TURN-PhII-01-E, page 22.

[65] Ex. PGE-PhII-01, Table 1-5, lines 5-6.

[66] Ex. PGE-PhII-01, Table 1-5, lines 5-6.

[67] Ex. PG&E-4, page 18-33; Ex. PGE-PhII-01, Table 1-5, line 5.

PG&E explains that it "purchases all the distribution transformers that are part of any PG&E capital project through the Transformer Purchases activity in MWC 16."[68] The main drivers of purchases include "the growth of PG&E's portfolio of electric distribution programs requiring transformer replacements".[69] A review of PG&E's Phase 1 workpapers shows that there are a large number of MWCs that drive transformer purchases.[70]

PG&E has not demonstrated that any particular fraction of these costs is specifically driven by customer connection projects or that these costs are tracked in a manner that allows the Commission to determine the portion of the adopted GRC forecast attributable to customer connection projects.[71] The broad scope of drivers for transformer replacements go far beyond customer energization and connection requests and include a range of distribution programs funded by other portions of the GRC. Allowing all transformer replacement costs to be eligible for interim rate recovery would go beyond the scope of addressing "customer energization" needs as defined in SB 410.

In addition, the costs recorded to the "transformer scrapping" line item ($20.5 million forecasted between 2023-2026) involve "the number of transformers that need to be scrapped each year" and are "a function of total distribution transformer units in service and failure rate."[72] PG&E has not demonstrated that all (or even most) transformer scrapping expenses are directly related to new customer connection projects. Allowing all transformer scrapping costs to be

[68] Ex. PG&E-17 (PG&E rebuttal), page 18-17.

[69] Ex. PG&E-4, page 18-33.

[70] Ex. TURN-PhII-01-E, page 23, footnote 68.

[71] Ex. TURN-PhII-01-E, page 23.

[72] Ex. PG&E-4, page 18-35; Ex. PGE-PhII-01, Table 1-5, line 6.

eligible for interim rate recovery would go well beyond the scope of addressing "customer energization" needs as defined in SB 410.

PG&E's forecast of total incremental costs for MWC 16 relative to the GRC-adopted values also includes a $766.331 million "forecast adjustment" that purports to add costs attributable to the AB 50 goal of completing energization work in 2024 for the population of customers that had completed their applications for new connections by January 31, 2023.[73] While PG&E assumes completion of 100% of applications submitted as of January 31, 2023 by the end of 2024, AB 50 establishes a goal of energizing 80% of these customers by the end of 2024.[74] TURN's testimony adjusts PG&E's forecast downward by $135.3 million to reflect the lower 80% goal.[75] In addition, TURN excludes $89.67 million in transformer costs in PG&E's forecast that may be outside the scope of costs needed to directly connect these specific customers.[76] These adjustments result in an AB 50 "forecast adjustment" of $541.33 million for 2024.

TURN's specific recommendations for the costs in MWC 16 that should be eligible for interim rate recovery are included in Section 5 of this brief. These recommendations include several adjustments to PG&E's forecast. First, TURN incorporates cost reductions to reflect TURN's alternative connection forecast for residential and non-residential customers described in Section 4.1.[77] Second, TURN modifies PG&E's "forecast adjustment" relating to AB 50 costs

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[73] Ex. TURN-PhII-01-E, page 25 (*citing* PG&E response to TURN DR 4, Q2, Supp2).

[74] Cal. Pub. Util. Code §935.5(b).

[75] Ex. TURN-PhII-01-E, page 25.

[76] Ex. TURN-PhII-01-E, page 25.

[77] Ex. TURN-PhII-01-E, page 25 (*citing* PG&E response to TURN DR 5, Q1, Atch2).

by excluding transformer purchases and assuming that 80% (rather than 100%) of the jobs for the eligible customer population are completed in 2024.[78] Finally, TURN excludes transformer purchases and transformer scrapping from the cost categories eligible for interim rate recovery.

4.3.4 MWC 46

PG&E proposes to classify all MWC 46 costs as "energization projects" eligible for special interim rate recovery pursuant to SB 410. According to PG&E, MWC 46 costs are related to projects that upgrade substation capacity to:[79]

> i) Energize one or more applications for service. PG&E does not differentiate between applications for service involving new customers and applications for service involving existing customers.
>
> ii) Mitigate an overload caused by existing customer increased loads (not associated with applications for service), organic load growth, or inadequate operational capacity for new growth.

As noted by PG&E in response to a data request,

> MWC 46 and MWC 06 projects provide substation and distribution line capacity for load growth. Some of these projects are driven by applications for service from new or existing customers. But there is no linkage between applications for service and the capacity projects driven by the applications.[80]

PG&E's admission that only some MWC 46 projects are "driven by applications for service from new or existing customers" highlights TURN's concern that allowing all MWC 46 costs to be eligible for special interim rate recovery represents an overly broad interpretation of SB 410. In response to a TURN data request seeking clarification as to which MWC 46 costs are

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[78] Ex. TURN-PhII-01-E, page 25 (*citing* PG&E response to TURN DR 5, Q1, Atch2).

[79] Ex. TURN-PhII-01-E, pages 25-26 (*citing* PG&E response to TURN DR2, Q2)

[80] Ex. TURN-PhII-01-E, page 26 (*citing* PG&E response to TURN DR2, Q11).

associated with providing service to new customers or providing upgraded service to an existing customer, PG&E stated that "In Table 1-3, Line 3 is associated with applications for service, either new customer applications or existing customer applications. Lines 1 and 2 are not associated with applications for service but are driven by overloads and inadequate operating capacity."[81]

As explained in TURN's testimony, a review of PG&E's descriptions of the scope of projects included in "lines 1 and 2" affirms that these categories should be excluded from eligibility for SB 410 interim rate relief.[82] Line 1 in Table 1-3 (MAT 46A) includes a forecast for "normal capacity deficiencies". As explained in PG&E's Phase 1 testimony, this category includes costs for "projects to support general distribution substation capacity increases".[83] Costs specifically driven by customer applications and New Business projects are not included in this line item. Line 2 in Table 1-3 (MAT 46F) includes a forecast for "emergency and operational capacity". PG&E's Phase 1 testimony explains that the costs of emergency capacity occur "when a transformer is removed from service during an unplanned event, and the remaining capacity is insufficient to serve the load."[84] Projects to address operational capacity are "identified to increase reliability by providing additional capacity in strategic locations to improve system flexibility to switch load between feeders and during planned clearance or

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[81] Ex. TURN-PhII-01-E, page 26 (*citing* PG&E response to TURN DR2, Q2).

[82] Ex. TURN-PhII-01-E, page 26.

[83] Ex. PG&E-4, pages 17-22 and 17-23.

[84] Ex. PG&E-4, pages 17-24.

outage events."[85] The costs tracked in MAT 46A and 46F are not directly related to customer energization projects and should not be eligible for interim rate recovery pursuant to SB 410.

The costs of projects in line 3 (New Business-Related Capacity / MAT 46H) are directly tied to customer energization projects. PG&E's Phase 1 testimony explains that this category "includes projects which address capacity deficiencies for New Business customer demand increases" as well as projects relating to EV charging stations.[86] This category also includes funding for "unidentified emergent work" which "is forecast based on the increasing rate of new applications for service that require capacity work to serve."[87]

TURN's specific recommendation for the costs in MWC 46 that should be eligible for interim rate recovery are included in Section 5 of this brief. The recommendation would limit interim rate recovery MAT 46H costs (NB Related Capacity) that exceed the imputed amounts authorized in the Phase 1 GRC decision.

5. THE COMMISSION SHOULD ADOPT A LOWER COST CAP THAN PROPOSED BY PG&E

5.1 Total cost cap resulting from the adoption of TURN's recommendations

TURN's testimony provided summary recommendations for the cost categories within each MWC that should be eligible for interim rate recovery pursuant to SB 410. For each MWC, TURN provided the total project costs forecasted by PG&E, the imputed capital spending authorized in D.23-11-069 (PG&E GRC Phase 1), and the amounts estimated to be eligible for

[85] Ex. PG&E-4, pages 17-25.

[86] Ex. PG&E-4, pages 17-26.

[87] Ex. PG&E-4, pages 17-27.

tracking and interim rate recovery. As described in the preceding sections, TURN's recommendations include the following modifications to PG&E's request:

> MWC 06 - limit costs to New Business Capacity Work and Emergent Work (MAT 06H)
>
> MWC 10 - assume 24% of the adopted GRC forecast attributable to "energization-related" expenditures (compared to PG&E's 22% assumption)
>
> MWC 16 – rely on TURN's alternative connection forecast for residential and non-residential customers, exclude transformer purchases and transformer scrapping, and assume compliance with AB 50 through completion of 80% of eligible jobs in 2024 (rather than PG&E's 100% completion assumption).
>
> MWC 46 – limit costs to New Business-Related Capacity (MAT 46H).

The following table provides a detailed showing regarding the impact of TURN's recommended approach:[88]

		2024			2025			2026		
MWC	**Description**	**Total Project Costs for Projects Completed in 2024**	**GRC Imputed Amount**	**Balancing Account**	**Total Project Costs for Projects Completed in 2025**	**GRC Imputed Amount**	**Balancing Account**	**Total Project Costs for Projects Completed in 2026**	**GRC Imputed Amount**	**Balancing Account**
6	**NB Related Capacity Work and Emergent Work (MAT 06H)**	151,596	78,294	73,302	210,162	80,521	129,641	243,126	81,803	161,323
10	**Energization work**	112,312	34,711	77,601	40,048	35,699	4,349	42,116	36,267	5,849
16	**Residential Connects**	381,004	284,851	96,153	387,016	292,954	94,062	409,968	297,618	112,350
	Nonresidential Connects	189,182	210,014	(20,832)	203,019	215,988	(12,969)	211,290	219,427	(8,137)
	PEV	61,937		61,937	91,228		91,228	134,779		134,779
	AB50 direct costs	541,330		541,330						
46	**NB-Related / Emergent work (MAT 46H)**	13,673	45,058	(31,385)	81,176	46,340	34,836	271,150	47,077	224,072
	TOTAL	**$ 1,451,034**	**$ 652,928**	**$ 798,106**	**$ 1,012,649**	**$ 671,502**	**$ 341,147**	**$ 1,312,429**	**$ 682,192**	**$ 630,237**
		RRQ for Balancing Account		**$ 115,725**	**RRQ for Balancing Account**		**$ 49,466**	**RRQ for Balancing Account**		**$ 91,384**
		Distribution Rate Increase		1.5%	**Distribution Rate Increase**		0.6%	**Distribution Rate Increase**		1.2%

[88] Ex. TURN-PhII-01-E, page 14. TURN converts project capital costs to revenue requirement using PG&E's "rule of thumb" that "$1 of capital translates to an annual capital revenue requirement of 14.5 cents." Ex. PGE-PhII-03.

The application of TURN's approach across all MWCs would set the balancing account cap at $798.1 million in 2024, $341.1 million in 2025 and $630.2 million in 2026. These levels permit a maximum distribution rate increase of 1.5% in 2024, 0.6% in 2025 and 1.2% in 2026. The maximum cumulative distribution rate increase (through 2026) that would be permitted under this approach is 3.3% (or $256.6 million).

5.2 PG&E's proposed cap is unreasonably high

PG&E proposes to cap incremental capital expenditures at 2.5% of its adopted distribution revenue requirement. <u>The total requested capital expenditures cap for 2024-2026 is $4.076 billion dollars with a cumulative revenue requirement increase of $591 million by 2026 and a 7.5% increase in distribution rates</u>.[89] This level of funding is unreasonable in light of the affordability challenges facing PG&E's customers and unnecessary to achieve the near-term customer energization objectives of AB 50 and SB 410. The broad scope of costs that would be eligible for interim rate recovery under PG&E's proposal is not warranted and would incentivize excessive spending.

The Commission must recognize that the interim rate recovery contemplated in this case would be incremental to the more than $7.3 billion (in $2024) Electric Distribution revenue requirement authorized by the Commission in PG&E's GRC.[90] PG&E's Phase I GRC request included significant funding for the same type of work identified in this Phase II request, and this portion of PG&E's Phase I GRC request was almost completely adopted by the Commission.[91]

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[89] Ex. PGE-PhII-02, page 6, Table 6.

[90] Ex. PGE-PhII-02, page 6, Table 6.

[91] See D.23-11-069, p. 437 "The Commission finds the forecast for work tracked in MWC 10 Electric Distribution Work at the Request of Others General reasonable, as set forth in Section 4.18." RE MWC

The only portion of PG&E's Electric Distribution request related to the costs in this Phase not completely authorized in D.23-11-069 is the $21.691M forecast for MWC 16 PEV forecast for the EV Charge 2 (EVC 2) program, which the Commission deferred until resolution of PG&E's Petition for Modification (PFM) of D.22-12-054. In the PFM, PG&E requests authority to not implement EVC 2,[92] so the Commission's determination in D.23-11-069 to wait to authorize the $21.691M forecast for MWC 16 PEV forecast for the EVC 2 program does not materially impact the level of funding PG&E will receive.[93]

While the proposed annual cap is based on an incremental 2.5% of PG&E's electric distribution revenue requirement adopted in D.23-11-069, all of the incremental costs are capital and involve long lived assets. For long-lived assets such as line transformers (35 year average service life), conductors (44-52 year average service life), and station equipment (50 year

16 Residential Connects see p. 441 "The Commission finds PG&E's Residential Connects MWC 16 forecast aligns with the goal of the state to promote increased growth in residential permits. For these reasons, the Commission finds PG&E's forecast for Residential Connects MWC 16 reasonable." RE MWC 16 Non-Residential connects see p. 443 "For these reasons, the Commission finds reasonable PG&E's forecast for Non-Residential Connects MWC 16." P. 445 "Accordingly, the Commission declines to adopt a 2023 capital expenditure forecast for Plug-In Electric Vehicles MWC 16 and defers to the ongoing proceeding where PG&E filed its Petition for Modification for consideration of EVC 2's scope and budget." RE Distribution Transformer Purchases, see p. 446 "The Commission does not agree with Cal Advocates' analysis because the Commission did not adopt any corresponding reductions to Pole Replacements (MWC 07), New Business (MWC 16) and Major Emergency (MWC 95) to justify the reduction requested by Cal Advocates. The Commission finds PG&E's recommendation for capital expenditures of $141.570 million in 2021, $151.725 million in 2022, and $169.068 million in 2023 reasonable regarding Distribution Transformer Purchases." RE MWC 46 and 06 the Commission adopted PG&E's request shown on p. 430 Table 4-L, "Accordingly, for the reasons stated above, the Commission adopts capital expenditures for Electric Distribution Capacity Program (MWC 46 and MWC 06) of $286.313 million in 2021, $215.512 million in 2022, and $195.7 million in 2023."

[92] D.23-11-069, pp. 444-445.

[93] The Commission granted PG&E's PFM in D.23-09-005, concluding that "a unique set of factors appeared after D.22-12-054 was issued which obviated the need for the EVC 2 program." D.23-09-005, Conclusion of Law 3.

average service life), ratepayer obligations would extend for decades.[94] Over this extended period, ratepayers would pay depreciation costs, taxes, and a rate of return (including the 42.5% tax gross up) every year the assets remain in rate base, making the overall impact of the proposed rate increase more significant in the long term.[95] The true cost to ratepayers of capital spending is illustrated by PG&E's own calculations to drive its proposed 2.5% cost cap discussed in its opening testimony.

> A 2.5 percent increase to that revenue requirement is approximately $213 million. Based on PG&E's electric distribution rule of thumb that $1 of capital translates to an annual capital revenue requirement of 14.5 cents, PG&E's 2024 incremental capital expenditures would be capped at approximately $1.469 billion.[96] (citations omitted)

PG&E's example shows how an annual increase of $213 million in revenue requirement balloons to an annual increase in capital spending of $1.469 billion, the costs of which ratepayers will fund over time. In a 2021 white paper, CPUC staff observed "it will be essential to employ aggressive actions to minimize growth in utility rate base".[97] PG&E's application moves in the opposite direction by proposing potentially large increases to rate base at a time when its electric rates are the least affordable in history.

Finally, the Commission must recognize that the only issue to be considered in this proceeding is what costs are eligible for SB 410 interim rate recovery, a special and temporary ratemaking mechanism specifically for energization costs. As addressed in prior sections, TURN believes that PG&E's proposed scope of costs eligible for SB 410 interim rate recovery is

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[94] Ex. TURN-PhII-01-E, page 33

[95] Ex. TURN-PhII-01-E, page 33 (*citing* PG&E response to TURN Data Request 2, Q18c).

[96] Ex. PGE-PhII-01, page 33.

[97] Ex. TURN-PhII-01-E, page 33, footnote 102 (CPUC, Utility Costs and Affordability of the Grid of the Future, May 2021, page 7)

unreasonably broad. The Commission should adopt TURN's narrower approach to identifying costs eligible for SB 410 interim rate recovery and reduce the cost cap accordingly.

If PG&E overspends in other cost categories not directly necessary to enable pending customer connection requests, TURN notes that PG&E can always request a reasonableness review of these additional costs in the next GRC. The same is true for any costs associated with customer connection requests that PG&E might incur beyond the cap set by the Commission for the ECNBBA. PG&E will have an opportunity to seek recovery of capital-related costs not recovered through the ECNBBA starting in the next GRC.[98] The correct approach to implement SB 410 and protect ratepayers from unreasonably high costs is to use TURN's more limited scope of costs eligible for special SB 410 interim rate recovery and reduce the ECNBBA cap on capital expenditures consistent with this narrower approach.

5.3 The Commission should monitor the impact of D.23-12-037, which modifies the rules regarding line extension subsidies for mixed-fuel new construction, on PG&E's energization costs

In D.23-12-037, issued in Rulemaking (R.) 19-01-011, the Commission eliminated electric line extension subsidies for mixed-fuel new construction effective July 1, 2024.[99] The Commission further required mixed-fuel new construction applicants to pay for the final actual costs of electric line extensions, rather than only the initial estimated costs, effective January 1, 2025.[100] In adopting this change, the Commission noted that "the current process is built around

[98] 17 RT 3126: 12 – 3127: 2 (March 6, 2024, PG&E/Fukui). In that case, PG&E would not recover any capital-related costs incurred during this GRC cycle (2023-2026) for new assets placed into service. PG&E would recover capital-related costs incurred for those assets starting in the next GRC (test year 2027). *Id.*

[99] D.23-12-037, pp. 17-18, 22.

[100] *Id.* at pp. 27-28.

ratepayers paying for any shortfalls between actual and estimated costs for line extensions," and ratepayers should no longer pay any of these costs once electric line extension subsidies for all mixed-fuel new construction are eliminated.[101] Finally, the Commission adopted annual reporting requirements for PG&E, SDG&E, and SCE, starting May 1, 2024, on electric line extension expenditures by customer class for mixed-fuel new construction, all-electric new construction, and retrofits to existing premises.[102] PG&E accordingly modified Electric Rules 15 and 16 to (1) eliminate line extension subsidies for mixed-fuel new construction and (2) change the customer billing process to reflect final actual electric line extension costs for mixed-fuel new construction through Advice Letter 4862-G/7158-E, submitted on January 29, 2024, and approved by Energy Division on February 28, 2024.[103]

PG&E prepared its Phase II forecast in this proceeding prior to the Commission's adoption of D.23-12-037.[104] PG&E later confirmed that its "forecast already assumes the collection of energization costs collectible through various tariffs, through applicable allowances and customer contributions based on a project-specific estimated costs," including Electric Rules 2, 13, 15, 16, 20, and 29.[105] Because PG&E prepared its Phase II forecasts prior to the changes to Rules 15 and 16 required by D.23-12-037, TURN presumes that PG&E's forecast predates those tariff changes, which will impact the extent of electric line and service extension costs

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[101] *Id.* at p. 28.

[102] *Id.* at Ordering Paragraph 8.

[103] https://www.pge.com/tariffs/assets/pdf/adviceletter/ELEC_7158-E.pdf.

[104] Ex. PGE-PhII-01 is dated September 15, 2023. PG&E acknowledged the then-pending staff proposal in R.19-01-011 that would eliminate all line extension subsidies for mixed-fuel new construction. (PGE-PhII-01, p. 18).

[105] Ex. PGE-PhII-04, p. PG&E-PhII-04-26.

collectible from ratepayers after July 1, 2024, among other potential ramifications.[106] Given the uncertain impact of D.23-12-037 on electric customer connection costs, TURN recommends that the Commission direct PG&E to submit its D.23-12-037 annual reports in this docket as well as the next GRC (in addition to R.19-01-011) to promote transparency around line extension energization expenditures.

6. THE COMMISSION SHOULD REQUIRE PG&E TO REDUCE INCREMENTAL ENERGIZATION CAPITAL EXPENDITURES RECORDED TO THE BALANCING ACCOUNT BY APPLYING DIABLO CANYON VOLUMETRIC PAYMENTS

Pursuant to SB 846 (Dodd, Chapter 239, Statutes of 2022), PG&E is authorized to collect $13/MWh for Diablo Canyon production during the period of extended operations. These funds will be collected from ratepayers of the three major Investor Owned Utilities. This mechanism is expected to result in $446 million between 2024 and 2026.[107] Under the relevant statutory language, funding from this source not needed for Diablo Canyon must be spent on critical public purpose priorities that include "accelerating customer and generator interconnections".[108]

SB 410 includes two sections addressing the potential use of "volumetric payments" for the purpose of supporting customer energization costs. Public Utilities Code §932(a)(6) references the availability of these funds to support customer and generation interconnections.[109]

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[106] *See* D.23-12-037, p. 19 (noting the potential impact of eliminating electric line extension subsidies for mixed-fuel new construction on all-electric new construction).

[107] Ex. TURN-PhII-01-E, page 29, footnote 87.

[108] Cal. Pub. Util. Code §712.8(s).

[109] Cal. Pub. Util. Code §932(a)(6)((a) The Legislature finds and declares all of the following…(6) Paragraph (1) of subdivision (s) of Section 712.8 requires the operator of the Diablo Canyon powerplant to submit annually to the commission for its review the amount of compensation earned under paragraph (5) of subdivision (f) of Section 712.8, how it was spent, and a plan for

Public Utilities Code §937(c) requires PG&E to identify, as part of any request for an interim rate recovery mechanism, the amount of Diablo Canyon volumetric payments "that it has forecasted it will spend on energization."[110]

The Assembly Utilities and Energy Committee analysis of SB 410 addresses the opportunity to use these funds, explaining that

> PG&E is poised to soon have access to new funding streams to address this very problem, even beyond what their 2023-2026 GRC requests. For instance, under SB 846 (Dodd, Chapter 239, Statutes of 2022) PG&E is authorized to collect $13 per megawatt-hour for Diablo Canyon extended operations. TURN has estimated these costs could sum to almost $450 million between 2024-2026. According to SB 846, these funds must be dedicated to various "critical public purpose priorities" including "accelerating customer and generator interconnections." It would seem reasonable that PG&E could use these funds to address their energization backlog, without the need for any unique account mechanism as authorized by this bill. However, statute dictates that PG&E cannot receive a profit off any expenditures from these Diablo Canyon funds, likely disincentivizing PG&E from using these funds for energization projects where they would traditionally earn a profit.[111]

On September 11, 2023, SB 410 was amended to incorporate the provisions of Public Utilities Code §932(a)(6) and §937(c) that address the use of Diablo Canyon volumetric

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prioritizing the uses of the compensation the next year. Paragraph (1) of subdivision (s) of Section 712.8 also provides that to the extent that it is not needed for Diablo Canyon, that compensation shall be spent on critical public purpose priorities, one of which is accelerating customer and generator interconnections.)

[110] Cal. Pub. Util. Code §937(c)((c) An electrical corporation, as part of its request for a ratemaking mechanism pursuant to subdivision (b), shall include in its request all of the following…(5) If the electrical corporation is an operator, as defined in Section 25548.1 of the Public Resources Code, the amount of the compensation identified in paragraph (1) of subdivision (s) of Section 712.8 that it has forecasted it will spend on energization.)

[111] Ex. TURN-PhII-01-E, page 30, (*citing* Assembly Utilities and Energy Committee analysis of SB 410, July 12, 2023, page 9)

payments to support customer energization costs. The Senate Floor Analysis of SB 410 noted that "recent amendments attempt to further address these concerns by stating that the costs of these projects is considered eligible use from the compensation afforded to PG&E as part of the extension of Diablo Canyon powerplant."[112]

PG&E's testimony in this proceeding argues that it is "unable to identify how much compensation could be directed" to accelerate customer and generator interconnections because "it does not yet know, nor can it currently forecast, the amounts that would be needed for DCPP."[113] Based on this view, PG&E states that it forecasts spending zero dollars from this source on customer energization.[114]

TURN's testimony strongly disagreed with PG&E's approach and argued that Diablo Canyon volumetric payments should be prioritized to support customer connection expenditures.[115] PG&E's refusal to consider the use of these funds would unreasonably drive up the costs of energization investments charged to ratepayers. The Commission should therefore direct PG&E to maximize the use of these funds prior to seeking interim rate recovery of incremental costs covered by SB 410.

Because the volumetric payments may not be used in a manner that earns a rate of return for PG&E shareholders (pursuant to §712.8(s)), the funds should be used to offset ratebased capital investment.[116] This result could be achieved by treating volumetric payments used for

[112] SB 410 Senate Floor Analysis, September 14, 2023, page 6.

[113] Ex. PGE-PhII-01, page 15.

[114] Ex. PGE-PhII-01, page 15.

[115] Ex. TURN-PhII-01-E, pages 29-31

[116] Ex. TURN-PhII-01-E, page 31

customer energization project as Contributions in Aid of Construction (CIAC) which would preclude shareholders from receiving depreciation, return on, or return of these funds.[117]

In D.23-12-036 (issued in R.23-01-007), the Commission held that PG&E must use these volumetric payments to cover Diablo Canyon operating costs "in the event actual recorded costs are more than fifteen percent above PG&E's approved forecast" for the facility.[118] The Commission also directed PG&E to file an application no later than March 1, 2026 proposing a plan for prioritizing the uses of these funds.[119] PG&E has challenged the Commission's authority to require an application relating to the use of these funds in a pending rehearing request. The Commission did not consider the requirements of SB 410 in reaching its decision in R.23-01-007.

Given the opportunity to use up to $446 million in Diablo Canyon funds to offset incremental capital costs for customer energization projects through 2026, the Commission should direct PG&E to prioritize the use of these funds for this purpose as part of any authorization provided in this proceeding. The Commission can affirm that, to the extent not needed for Diablo Canyon costs, these funds should be allocated to support timely customer interconnections. Further, PG&E should be required to provide an update on the use of these funds in all Advice Letters implementing a decision in this proceeding.

[117] Ex. TURN-PhII-01-E, page 31

[118] D.23-12-036, page 110.

[119] D.23-12-036, Ordering Paragraph 15.

7. THE COMMISSION SHOULD REQUIRE PG&E TO REDUCE INCREMENTAL ENERGIZATION CAPITAL EXPENDITURES RECORDED TO THE BALANCING ACCOUNT BY USING OTHER SOURCES OF FUNDING AND ALTERNATIVE WAYS TO INTERCONNECT CUSTOMERS IN GRID CAPACITY CONSTRAINED AREAS

In testimony, TURN recommended that the Commission "direct PG&E to look for alternative ways to fund and address new service requests and capacity upgrades in the near-term."[120] TURN provided two examples of alternative funding options: 1) PG&E's "Capacity Pilot" to use $20 million in Low-Carbon Fuel Standard (LCFS) holdback revenues for unfunded distribution capacity infrastructure upgrades to enable public EV charging in Priority Communities through 2026;[121] and, 2) SCE's recently approved interconnection rule to allow customers to use automated load management systems to interconnect customers in grid capacity constrained areas during certain times of the day prior to upgrading capacity ("ALMs interconnection rule").[122] Regarding option 1, the Capacity Pilot proposes "to target EV-related new business applications that require capacity upgrades",[123] which are within the scope of costs PG&E proposes to record to the ECNBBA. The Commission should direct PG&E to use this $20 million in LCFS funds first for EV-related new business applications to reduce the incremental energization capital expenditures recorded to the ECNBBA.

[120] Ex. TURN-PhII-01-E, p. 24.

[121] Ex. TURN-PhII-02, pp. 124-132, Advice Letter 7071, Attachment B, 2023 Low Carbon Fuel Standard Implementation Plan.

[122] Ex. TURN-PhII-02, SCE AL 5138-E.

[123] *Id.*

When asked about alternative ways to address new service requests instead of funding through the ECNBBA, PG&E mentioned a flexible service connection pilot.[124] PG&E noted that it is in the planning phases of the pilot, which will use distributed energy resource management systems to manage distribution system constraints dynamically.[125] This pilot should be instituted immediately and should be scaled up quickly to avoid more costly infrastructure capacity investments. Further, the Commission should also instruct PG&E to implement an ALMs interconnection rule similar to SCE's rule, so it is available to PG&E's customers as soon as possible. Under the ALMs interconnection rule, new load can be interconnected more quickly and the use of ALMs may negate, or significantly delay the need for some of the capacity upgrades in the customer energization backlog. The Commission should instruct PG&E to pursue these options not just as interim measures,[126] but potentially also as longer term alternatives to address the customer energization backlog, thus reducing the costs recorded to the ECNBBA.

P.U. Code Section 937(b)(3) requires the Commission to conduct a reasonableness review of all costs tracked in the ECNBBA in PG&E's next GRC. In the next GRC, PG&E

[124] 17 RT 3058: 6-11 (March 6, 2024, PG&E/Nagra). TURN notes that on March 15, 2024, PG&E filed and served its Annual Vehicle-Grid Integration Strategies Report in R.18-12-006 & R.23-12-008, which includes the following statement on page 15: "PG&E is planning a Flexible Service Connection pilot program which is anticipated to launch in 2024 and will enable customers with eligible loads to connect with a new electric service prior to the completion of necessary capacity upgrades by dynamically managing consumption based on near real-time grid availability until infrastructure projects are completed. Ten sites will be initially targeted followed by offering this capability to a broader audience." PG&E submitted this report to the Commission after the 3/6/24 Evidentiary Hearing in this proceeding and the deadline for parties to submit hearing exhibits. PG&E's Annual Vehicle-Grid Integration Strategies Report is not in the record of this proceeding.

[125] 17 RT 3076: 2-17 (March 6, 2024, Nagra).

[126] 17 RT 3056-3057: 17-8 (March 6, 2024, Nagra).

should submit testimony that demonstrates how it took advantage of alternative options, such as LCFS funds and/or ALMs, to energize customers in lieu of, or to reduce, distribution investment costs recorded to the ECNBBA. PG&E's testimony in the next GRC should detail how the two pilots and the ALMs interconnection rule resulted in reduced costs recorded in the ECNBBA. PG&E should demonstrate that all costs recorded to the ECNBBA represent the least cost alternative to address the short term energization backlog. This information should inform the Commission's evaluation of the reasonableness of the costs tracked in the ECNBBA in the next GRC.

8. ENERGIZATION TARGETS AND REPORTING REQUIRED PURSUANT TO AB 50 AND SB 410 SHOULD INFORM THE REASONABLENESS REVIEW OF COSTS RECORDED TO THE ECNBBA IN THE NEXT GRC

As addressed above, P.U. Code Section 937(b)(3) requires the Commission to conduct a reasonableness review of all costs tracked in the ECNBBA in PG&E's next GRC. The Commission should adopt reporting requirements that will inform its consideration of the reasonableness of PG&E's costs recorded to the ECNBBA in the next GRC. Both AB 50 and SB 410 direct the Commission to develop energization timing targets for the Investor-Owned Utilities (IOUs).[127] As addressed in TURN's testimony, these targets should be established in R.24-01-018, which was opened to "(E)stablish reasonable average and maximum target energization time periods" and "criteria for timely service" pursuant to AB 50 and SB 410.[128]

The Commission must make clear in its final Decision on the present Application that the targets adopted in R.24-01-018 will be applied to PG&E, and that the energization targets and

[127] Cal. Pub. Util. Code §934 (a)(1) & Cal. Pub. Util. Code §933.5(a).

[128] Ex. TURN-PhII-01-E, pp. 21, referencing R.24-01-018, p. 2.

the reporting requirements established by the Commission in R.24-01-018 will inform the Commission's consideration of the reasonableness of PG&E's costs recorded to the ECNBBA in the next GRC.

8.1 The commission should require PG&E to comply with cost tracking and reporting requirements of SB 410 and AB 50 through an Annual Advice Letter Filing

P.U Code Section 937(b)(4) "(R)equires only costs associated with energization to be included in the mechanism …." AB 50 also includes reporting requirements that will be addressed in R.24-01-008, including:[129]

- PU Code Sections 933.5(a)(2), 933.5(d), 934 (b), and 934(c) directs the Commission to establish annual energization reporting requirements that reflect the IOUs' average, median, and standard deviation time to complete an energization request, explanation(s) for why select project(s) did not become energized within the required timeline, and barriers that are impacting the IOUs ability to meet established timelines.
- PU Code Section 933.5(b) directs the Commission to establish public reporting requirements for IOUs that fail to demonstrate the ability to energize at least 65% of their projects each year within the adopted energization timing targets.

In order to comply with the statutory directives in P.U. Code 933.5 and 934, the Commission must direct PG&E to satisfy the above reporting requirements and any additional requirements adopted in R.24-01-008. Additionally, in order to comply with P.U Code Section 937(b)(4), the Commission should direct PG&E to report any spending recorded to the ECNBBA in a granular enough manner to allow for the review of specific line items within MWC 06, 10, 16 and 46. As discussed in Section 7 above, PG&E's reporting should also include a discussion of the

[129] Ex. TURN-PhII-01-E, pp. 21, referencing Energy Division Email, Public Notice: Agenda and Further Information for CPUC's AB 50 / SB 410 Energization Timing Workshop on February 2, sent January 26, 2024.

alternatives considered and all of the information necessary to enable the Commission to evaluate if the costs recorded to the ECNBBA represent the least cost alternative to address the short term energization backlog.

As recommended in TURN's testimony, PG&E should be required to report annually in a Tier 3 advice letter on all targets and reporting requirements adopted by the Commission in this proceeding and in R.24-01-008.[130]

8.2 PG&E's failure to comply with the energization targets required in SB 410 and AB 50 should impact the Commission's Reasonableness Review in the next GRC

The special interim cost recovery authorized by SB 410 is intended to address the backlog of energization requests in a timely manner. If PG&E does not achieve the energization targets set by the Commission, then its recovery of these costs should be impacted. The targets set in R.24-01-018 should also be a factor used to evaluate the reasonableness of PG&E's spending recorded to the ECNBBA in the next GRC. The Commission should put PG&E on notice that its performance in regard to these targets could result in a partial or full refund of the interim rate recovery authorized in this application.

9. THE COMMISSION SHOULD ADOPT ADDITIONAL REQUIREMENTS FOR THE SB 410 AUDITOR AND PG&E'S REASONABLENESS REVIEW SHOWING IN THE NEXT GRC

9.1 The third-party auditor should confirm ECNBBA costs are incremental and limited to costs necessary to satisfy pending customer connection requests

P.U Code Section 938(a)(1) requires PG&E to retain an independent third-party auditor (Auditor) to among other things, review:

[130] The Advice Letter should be served on the service list for the PG&E 2023 GRC (A.21-06-021) and R.24-01-008.

> (D) Funding requested by the electrical corporation to support energization requests for the previous three years in the general rate case or any other proceeding, and the efficacy of those previous requests in meeting customer demand.
>
> (E) Commission authorized funding for the electrical corporation to support energization for the previous three years, future authorized funding, and authorized changes to the electrical corporation's business practices or structures to improve its ability to respond to changing customer demand.

P.U. Code Section 938(a)(3)(H) gives the Commission latitude to include "(A)ny other metrics deemed relevant by the commission or third-party auditor to support a thorough evaluation of the electrical corporation's energization performance … ". The Commission must provide clear directions regarding the scope of the Auditor's review and the impact on the reasonableness review in the next GRC.

As an initial matter, the Commission should take steps to promote the independence, and thus the value, of the audit required by SB 410. P.U. Code Section 938(a)(1) requires the Commission to select the independent third-party auditor, based on nonbinding recommendations from the electrical corporation.[131] The Commission should follow the same process for selecting the SB 410 auditor as the Commission adopted in Resolution M-4855, which addressed the Commission's selection of and PG&E's contracting with the Independent Safety Monitor pursuant to D.20-05-053. Consistent with that process, the Commission should direct PG&E to "allow Commission staff to review, revise (as appropriate), and approve PG&E's

[131] Cal. Pub. Util. Code §938(a)(1).

proposed services contract with the [auditor] prior to execution."[132] The Commission should also direct PG&E to make the Commission "a third-party beneficiary of that contract."[133]

The Commission should require the third-party auditor to confirm costs recorded to the ECNBBA are: 1) incremental to the funding authorized in the GRC, and 2) limited to costs directly necessary to enable pending customer connection requests. Regarding the latter, a detailed review is required, including confirmation that PG&E has only recorded costs associated with the specific activities within MWC 06, 10, 16 and 46 that the Commission finds appropriate for the ECNBBA. As explained by TURN in Section 4 above, those activities should be limited to the following:

MWC 06 – New Business Related Capacity Work and Emergent Work (MAT 06H)

MWC 10 – Energization-related work as defined by PG&E (subject to TURN adjustment for baseline GRC values)

MWC 16 – Residential Connects, Nonresidential connects, PEV, AB 50 direct costs

MWC 46 – NB-Related / Emergent Work (MAT 46H)

TURN also recommends that the auditor review and report on compliance with the energization timeliness targets adopted in R.24-01-008, as part of assessing PG&E's energization performance.

The Auditor's Report should be included as an exhibit in PG&E's testimony in the next GRC. Further, as recommended in TURN's testimony the Commission should put PG&E on notice that the auditor's findings will be accounted for in the reasonableness review of the costs recorded to the ECNBBA in next GRC.

[132] Resolution M-4855, Ordering Paragraph 5.

[133] *Id.*

9.2 The Commission should adopt a mechanism to compare ECNBBA costs annually with the number of energization projects supported each year

TURN's testimony proposed the adoption of a mechanism to ensure the costs recorded to the ECNBBA are commensurate with the number of energization projects completed.[134] This proposal is consistent with the spirit of P.U. Code Section 937(c)(4), which requires an IOU requesting the use of the special interim rate recovery mechanism pursuant to SB 410 to include in its request, "(T)he number of anticipated energization projects per year that are expected to be started or completed." The Commission must ensure PG&E's spending is aligned with the number of projects actually completed. As discussed in TURN's testimony, "the problem that typically arises is that if actual unit costs turn out to be higher than forecast, the utility could stay under the annual cap by simply completing fewer energization projects than anticipated."[135] This result is contrary to the intent of the SB 410 to support prompt energization while limiting impacts on electric ratepayers.[136] Accordingly, the Commission should set minimum energization project levels linked to spending levels.

More accountability is needed to ensure the number of energization projects completed per year is commensurate with the spending recorded to the ECNBBA. While TURN acknowledges that each energization project will have different costs, it is possible to develop a mechanism that generally compares the level of work with the level of spending. For example, if PG&E spends 50% of the authorized annual cap in a given year, then it should complete roughly

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[134] Ex. TURN-PhII-01-E, p. 23.

[135] Ex. TURN-PhII-01-E, p. 23.

[136] Cal. Pub. Util. Code §933(c) & (d). See also SB 410 Senate Floor Analysis, September 14, 2023, page 6 ("This bill attempts to limit impacts on electric ratepayers by subject [sic] these costs to CPUC review for just and reasonableness and an annual cap on the amount that may be recovered, as well as, other requirements to mitigate cost impacts.") (https://leginfo.legislature.ca.gov/faces/billAnalysisClient.xhtml?bill_id=202320240SB410#)

50% of the of anticipated energization projects for that year.[137] If a certain level of work minimums are not met in proportion to spending, PG&E should have to specifically address this in its testimony in the next GRC, which should inform the Commission's reasonableness review.

The Commission should also direct the auditor to review the costs recorded to the ECNBBA and verify the number and scope of energization projects completed each year. The auditor should then report on PG&E's achievement of level of work minimums, which would be considered in the Commission's reasonableness review of the costs recorded to the ECNBBA in the next GRC.

9.3 The Commission should ensure that PG&E's showing in the next GRC related to costs recorded to the ECNBBA is sufficient to permit a meaningful reasonableness review

SB 410 requires the Commission to conduct a reasonableness review of costs recovered through the ECNBBA in PG&E's next GRC and order the refund of any costs found to be not just and reasonable.[138] In a reasonableness review of incurred costs, the Commission applies the Prudent Manager Standard as the test to evaluate whether costs are just and reasonable.[139] "Costs are just and reasonable when they 'have been prudently incurred by competent management exercising the best practices of the era, and using well-trained, well-informed and conscientious employees and contractors who are performing their jobs properly."[140] The Prudent Manager Standard requires the utility "to show that its actions, practices, methods, and

[137] See Ex. PGE-PhII-01, pp. 30-31, Table 1-10 and 1-11 & Ex. PGE-PhII-02, p. 5. PG&E provides the anticipated energization projects per year in Tables 1-10 and 1-11 of Ex. PGE-PhII-01 for MWCs 06, 46 and 16, and in Table 5 of Ex. PGE-PhII-02 for MWC 10.

[138] Cal. Pub. Util. Code §937(b)(3).

[139] D.18-07-025, p. 5.

[140] D.21-11-036, Order Modifying Decision 19-09-025 and Denying Rehearing of Decision 19-09-025, as Modified, p. 4 (quoting D.16-06-056, p. 22, and D.14-06-007, p. 31).

decisions show reasonable judgment in light of what it knew or should have known at the time, and in the interest of achieving safety, reliability, and reasonable cost."[141] Prudent acts or decisions are those "expected by the utility to accomplish the desired result at the lowest reasonable cost consistent with good utility practices," where "[g]ood utility practices are based upon cost-effectiveness, reliability, safety, and expedition."[142]

The burden of proof in a prudent manager review "rests heavily on a utility to prove… that it is entitled to the requested rate relief and not upon the Commission, its staff, or any interested party to prove the contrary."[143] The utility "is not entitled to a presumption of prudence regarding its costs."[144] Rather, "[w]hat critically matters is the prudency of the utility's actions, which the utility has the burden of proving, regardless of the testimonies of other parties."[145] As explained by the Commission in D.87-12-067:

> The inescapable fact is that the ultimate burden of proof of reasonableness, whether it be in the context of test-year estimates, prudence reviews outside a particular test year, or the like, never shifts from the utility which is seeking to pass its costs of operations onto ratepayers on the basis of the reasonableness of those costs.[146]

When the Commission does not find that costs forecast or previously incurred by the utility are just and reasonable, "the Commission can and must disallow those costs: that is unjust or unreasonable costs must not be recovered in rates from ratepayers."[147] Disallowances

[141] D.18-07-025, p. 3 (citing to D.87-06-021)

[142] D.18-07-025, p. 5 (quoting D.87-06-021).

[143] D.18-07-025, p. 6 (quoting D.02-08-064), ellipsis in original.

[144] D.21-11-036, p. 15.

[145] D.21-11-036, p. 6.

[146] D.21-11-036, p. 6 (quoting D.87-12-067, p. 24).

[147] D.18-07-025, p. 5 (quoting D.14-06-007).

resulting from the Commission's implementation of Cal. Pub. Util. Code §451 are not penalties to encourage deterrence; they are grounded in the necessity of protecting ratepayers from bearing unjust and unreasonable costs.[148]

Given the purpose and requirements of SB 410, discussed throughout this brief, TURN recommends that the Commission require PG&E to demonstrate all of the following in its reasonableness review showing in the next GRC:

1. The costs PG&E recorded to ECNBBA are limited to those associated with the activities within MWC 06, 10, 16, and 46 identified by TURN (work directly related to connecting customers / new load).

2. The costs recorded to the ECNBBA were incremental to the costs authorized in D.23-11-069.

3. PG&E prioritized the use of Diablo Canyon volumetric payments to support customer connection expenditures.

4. Before investing in infrastructure upgrades, PG&E determined that alternative approaches to managing load and connecting customers were infeasible (including an explanation of why).

5. Before investing ratepayer funds in infrastructure upgrades, PG&E exhausted all non-ratepayer sources of funding to support new connections, including but not necessarily limited to LCFS holdback revenues.

6. PG&E has complied with the energization timeliness targets adopted in R.24-01-008, or if not, why non-compliance was reasonable.

7. PG&E has met the minimum level of completed projects expected by the Commission in its Phase II decision, or if not, why achieving a lower level of project completion was reasonable.

PG&E should also include in its GRC showing the Auditor's Report covering PG&E's energization costs and performance, as discussed above.

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[148] *See,* D.18-07-025, p. 30, fn. 83.

10. CONCLUSION

For the foregoing reasons, the Commission should adopt TURN's recommendations regarding the scope of activities eligible for SB 410 interim rate recovery, the cost cap for the proposed ECNBBA, minimizing costs that PG&E will collect from ratepayers for customer energization, the retention of the SB 410 auditor and the auditor's scope of work, and the showing PG&E should make in the next GRC to support a meaningful reasonableness review of costs recorded to the ECNBBA. TURN's recommendations are reasonable to protect ratepayers in the face of skyrocketing electric rates.

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Respectfully submitted,

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