FILED
02/24/23
12:00 PM
R2001007

**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

Order Instituting Rulemaking to Establish Policies, Processes, and Rules to Ensure Safe and Reliable Gas Systems in California and Perform Long-Term Gas System Planning. U 39 G	R.20-01-007 (Filed January 16, 2020)

PACIFIC GAS AND ELECTRIC COMPANY'S OPENING COMMENTS ON ADMINISTRATIVE LAW JUDGE'S RULING DIRECTING PARTIES TO FILE COMMENTS ON STAFF GAS INFRASTRUCTURE DECOMMISSIONING PROPOSAL

JONATHAN D. PENDLETON
ALEXANDRA J. WARD
NICHOLAS D. KARKAZIS

Pacific Gas and Electric Company
77 Beale Street B30A
San Francisco, CA 94105
Telephone: (415) 973-2916
Facsimile: (415) 973-5520
E-Mail: Jonathan.Pendleton@pge.com

Attorneys for
PACIFIC GAS AND ELECTRIC COMPANY

Dated: February 24, 2023

TABLE OF CONTENTS

Page

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Establish Policies, Processes, and Rules to Ensure Safe and Reliable Gas Systems in California and Perform Long-Term Gas System Planning. U 39 G	R.20-01-007 (Filed January 16, 2020)

PACIFIC GAS AND ELECTRIC COMPANY'S OPENING COMMENTS ON ADMINISTRATIVE LAW JUDGE'S RULING DIRECTING PARTIES TO FILE COMMENTS ON STAFF GAS INFRASTRUCTURE DECOMMISSIONING PROPOSAL

I. INTRODUCTION AND SUMMARY

Pacific Gas and Electric Company (PG&E) provides the following opening comments in response to the Administrative Law Judge's Ruling Directing Parties to File Comments on Staff Gas Infrastructure Decommissioning Proposal (Ruling), issued on December 22, 2022, and in response to the accompanying *Staff Proposal on Gas Distribution Decommission Framework in Support of Climate Goals*[1] (Staff Proposal) prepared by Energy Division Staff.[2]

In these opening comments, PG&E responds to the 42 questions included in the Staff Proposal, as directed in the Ruling, and also (a) provides an overview of its climate commitments and gas infrastructure decommissioning progress to date; (b) outlines its gas strategy roadmap and climate goals; and (c) offers general comments on the Staff Proposal, including an alternative gas distribution decommissioning proposal for Commission and stakeholder consideration and input. Overall, PG&E has serious concerns that the process in the Staff Proposal will not be possible to implement and will result in excessive costs, hamper innovation for meeting GHG goals, and create too much uncertainty for business and financial planning.

[1] California Public Utilities Commission Staff, Staff Proposal on Gas Distribution Infrastructure Decommissioning Frameworks in Support of Climate Goals (Dec. 22, 2022) (Staff Proposal).

[2] Per the Administrative Law Judge's Ruling Granting Extension of Time to File Comments on Staff Proposal, issued on January 17, 2023, opening comments on the Ruling are due February 24, 2023, and reply comments are due March 16, 2023.

In addition to responding to the specific questions in the Staff Proposal, PG&E makes the following primary recommendations in these opening comments:

- <u>PG&E Alternative Proposal</u>: PG&E recommends modifications to Staff's gas distribution system decommissioning proposal that it believes offers enhanced simplicity and flexibility, while providing opportunities for the Commission and stakeholders to monitor and weigh in on gas utilities' progress on reaching California's climate goals. PG&E proposes scheduling a public workshop to examine the details of its alternative decommissioning proposal and gather feedback from stakeholders prior to the issuance of a final Track 2a decision. (See Section IV.A below.) Key components of PG&E's alternative decommissioning proposal are:
    - Working with the Commission to define an emissions-based 2045 goal (or "end state") for gas utilities, in coordination with electric utilities, to work towards.
    - Once the Commission establishes this overall goal, the Commission, gas utilities, and stakeholders can start defining and identifying target areas and costs to investigate for gas infrastructure decommissioning. Rather than the proposed tranche system based on census tracts, PG&E recommends four separate and independent drivers for defining and targeting segments of the gas system for decommissioning: (1) risk, (2) GHG reduction, (3) equity, and (4) cost.
    - Each gas utility will develop an initial decarbonization plan that includes a proposed 2045 gas system design meeting the emissions goal outlined by the Commission, a description of strategies that the gas utility will implement to reach the 2045 system design, milestones that the gas utility will target leading up to the 2045 proposed system design, and a preliminary estimate of the associated costs.

- A gas utility will provide interim updates on its progress in meeting the overall goals established by the Commission as outlined in its gas utility specific plan. Cost recovery review will remain in the General Rate Case (GRC).

- Depreciation/Decommissioning Cost Recovery: In consideration of the Commission's goal to avoid stranded costs and to assist the Commission in determining the cost both to recover the cost of PG&E's gas assets and to retire/decommission those assets, PG&E recommends that cost recovery, including depreciation and decommissioning costs, should be explicitly addressed as one of Commission's cost consideration goals. (See Section IV.C below.) Consistent with this recommendation, PG&E proposes adding a new goal to the "Criteria and Goals" identified in the Staff Proposal: "Providing for depreciation and decommissioning cost recovery consistent with the Commission goal of minimal or no stranded costs."
- Obligation to Serve: Decommissioning efforts will be highly contingent on a gas utility's ability to cease providing service if the Commission determines that adequate substitute service is reasonably available to support the existing end-uses of the affected utility customers. PG&E notes that a clear interpretation of the existing obligation to serve is essential for the ability to maintain affordability and determine appropriate rate design while meeting overall GHG emission reduction targets.
- Funding Sources: Non-pipeline alternative costs should not be borne by utility customers as this is not a sustainable model for gas and electric ratepayers. PG&E recommends that a broad coalition of stakeholders develop and promote alternative funding solutions that will be critical to achieve the Commission's priority of addressing the unique challenges faced by low-income and disadvantaged communities in the context of the transition away from gas.

II. PG&E'S CLIMATE COMMITMENTS AND GAS INFRASTRUCTURE DECOMMISSIONING PROGRESS TO DATE

As the state's largest energy provider, PG&E embraces our foundational role in transitioning California to a decarbonized and more climate resilient economy. In June 2022, PG&E issued its *Climate Strategy Report*,[3] which established our commitment to achieve a net zero energy system in 2040 – five years ahead of the California carbon neutrality goal established in Executive Order B-55-18[4] – and be climate and nature positive by 2050. As a part of this wider commitment, PG&E has developed a gas specific strategy outlined in Section III below. PG&E recognizes the importance that building electrification must play in meeting these carbon goals and the specific leadership role that PG&E and other utilities can serve in gas system decommissioning. As E3 notes in their report, *The Challenge of Retail Gas in California's Low-Carbon Future*, "A managed gas transition would likely require some amount of targeted or zonal electrification, to enable a reduction in the gas distribution infrastructure. Without a managed gas transition and without any effort to target electrification, it would be difficult to reduce the size or scale of gas system investments and costs."[5] In this section, PG&E describes our progress to date with gas system decommissioning activities.

In 2018, PG&E launched its Alternative Energy Program (AEP), which uses electrification to avoid large capital investments or operational costs associated with the gas system. Since its inception, the program has reached agreement with 105 customers to discontinue gas service, avoiding the rebuild of 88 high-pressure regulator stations and 4.4 miles of distribution main and leading to the retirement of 22 miles of transmission pipeline.[6]

---

[3] PG&E, Climate Strategy Report (2022), [PG&E Climate Strategy Report (pge.com)]() (PG&E Climate Strategy Report).

[4] State of California Executive Department, Executive Order B-55-18 to Achieve Carbon Neutrality, issued Sept. 10, 2018.

[5] Energy and Environmental Economics, Inc. (E3), The Challenge of Retail Gas in California's Low-Carbon Future, Apr. 2020.

[6] An additional six conversions to alternative energy sources were funded outside of the AEP program, resulting in the decommissioning of 21 miles of transmission main, 1500 feet of distribution main, and 1 distribution service.

Although the program has been successful at its current small scale, PG&E wishes to note the following lessons that help inform our comments on the Staff Proposal.

First, the number of customers per project in AEP tends to be small (fewer than 5) served from transmission systems. The reason for this is due to a gas utility's obligation to serve leading to the possibility of a single customer to halt an otherwise economically promising electrification project by declining to participate. Even at this small scale and with offering generous customer rebates, AEP has a success rate of approximately 40 percent of customers opting to electrify. As we scale up decommissioning efforts, as contemplated in the Staff Proposal, it will be important to allow utilities flexibility to select projects that are implementable. In these opening comments, PG&E proposes an alternative to the Staff Proposal that, in our experience with implementing zonal electrification efforts, will lead to greater success.

Second, PG&E wishes to note that AEP is a relatively small program funded by less than $2 million dollars annually[7] and is primarily driven by cost-reduction benefits. At larger scale, continuing to fund decommissioning efforts through utility rates, especially if projects are driven by factors other than cost-reduction, will have significant impact on gas rates.

In addition to progress with AEP, PG&E has developed tools like our *Gas Asset Analysis Tool* which helps to prioritize areas that may be good candidates for potential electrification. Similar to the guiding principles outlined in the Staff Proposal, PG&E's tool focuses on four separate utility drivers for zonal electrification: (1) risk, (2) greenhouse gas reduction, (3) equity, and (4) cost. We have used this tool internally to help prioritize communities that may be a good fit for our upcoming Zonal Electrification Equity Program, an effort that will invest $12 million in energy efficiency program funding towards zonal electrification in disadvantaged communities. We also use this tool to collaborate externally with cities and counties within the PG&E service territory on their decarbonization efforts.

---

[7] The AEP was briefly described in Exhibit PG&E-3 at 13-30 of PG&E's 2023 GRC (A.21-06-021).

At PG&E, zonal electrification and gas infrastructure decommissioning are an integral part of our climate goals. PG&E committed in our *Climate Strategy Report* to "evaluate all gas capital projects for electrification as an alternative to the planned gas projects and pursue electrification for the projects evaluated as feasible and cost-effective."[8] It is because of this we are heartened to see the Commission take leadership on this issue through the Staff Proposal. We look forward to working with the Commission and other stakeholders to establish a framework and process that will enable scaling of PG&E's early electrification efforts to reach scale.

III. PG&E'S GAS STRATEGY ROADMAP AND CLIMATE GOALS

As a part of our wider climate commitments, PG&E has developed a comprehensive gas strategy to evolve our natural gas pipeline and storage system to be consistent with state decarbonization goals, while maintaining the safety and reliability of the system. This strategy is built on the four pillars of (1) reducing greenhouse gas (GHG) emissions, (2) decarbonizing hard-to-electrify customers, (3) decreasing future Operations and Maintenance (O&M) costs and investments in the system, and (4) advancing regulatory and policy items to help achieve our overall decarbonization strategy. PG&E highlights this strategy to demonstrate that a holistic systems-level perspective is needed in long-term gas planning, which is why we urge the Commission to set a long-term GHG-based target, as described in Section IV below.

Reducing GHG Emissions

PG&E has identified several pathways to reduce GHG emissions from its gas system. These pathways include proactive methane abatement, methane leak detection and repair, greening the gas supply with renewable natural gas (RNG) and hydrogen, zonal electrification, and research and development into new and innovative ways to reduce emissions.

[8] PG&E Climate Strategy Report at 12.

Decarbonizing Hard-to-electrify Customers

Many industrial and large commercial gas customers will be difficult to electrify. PG&E has been working with several large commercial and industrial customers to convert them from dirty fuels (such as coal, petroleum coke, and even burning tires) to cleaner burning natural gas to achieve immediate environmental gains. In addition, compressed natural gas (CNG) is an area where we can make an immediate and positive impact to the environment by converting fleets that need to make investment decisions now. It is better to convert them from diesel to cleaner burning CNG, especially where electric hydrogen fuel cell technology is not available yet. Marine and rail industries are going to be major areas where PG&E will be viewed as a critical fuel distribution partner to these heavy emitting transportation sectors. Although the majority of these hard-to-electrify customers are on our transmission system, PG&E has identified approximately three hundred or so customers on the distribution system that also may fall into this category.

Decreasing Future O&M Costs and Investments in the System

PG&E reduces costs by identifying and implementing alternatives to status quo maintenance and upgrades to deliver affordable energy to its customers. This is especially critical for hard-to-electrify customers, customers who may not be able to afford to electrify, and customers who are unwilling and not obligated to electrify. Alternatives include gas system modifications, such as selling, retiring, and downrating pipelines, limiting gas system expansion, and supplying energy to customers from non-pipeline sources.

Advancing Regulatory and Policy Objectives

There are many regulatory and policy objectives that will need to be addressed in a comprehensive and collaborative manner to enable the activities above. These include obligation to serve, decommissioning and asset depreciation cost recovery, rate design, and non-traditional funding. PG&E notes that its Opening and Reply Comments on the Amended Scoping Memo, Track 2a, Questions 2.1(B)-2.1(K) contain relevant information on the obligation to serve.[9]

IV. GENERAL COMMENTS ON THE STAFF PROPOSAL

A. PG&E's Proposed Modifications to Process for Gas Distribution System Decommissioning (PG&E Alternative Proposal)

PG&E sees the critical need for clarity around gas decommissioning because of our commitment to zero-carbon electric and gas systems. That said, PG&E has serious concerns that the process in the Staff Proposal will not be possible to implement. Notably, census tracts do not physically align with the gas or electric systems, making it impossible to determine the number of individual decommissioning projects that may be contained within a single census tract. Project-specific data, such as hydraulic feasibility, electric capacity, and cost-effectiveness, cannot be analyzed at a census tract level. PG&E is concerned that the adoption of the Staff Proposal may hamper gas utility action on projects that should be considered regardless of the tranche that the project may be in under the Staff Proposal. As demonstrated in the responses to the questions below, the Staff Proposal will result in excessive costs and create too much uncertainty for business and financial planning.

Below, PG&E lays out recommended modifications to the Staff Proposal for natural gas infrastructure decommissioning that offer greater simplicity and flexibility – a critical need if we are to reach California's ambitious climate goals. This process also maintains important touch points for the Commission and stakeholders to monitor and weigh in on the progress of gas utilities to reach California's climate goals.

To refine the process and framework for decommissioning, PG&E suggests scheduling a public workshop where we can give an overview of the proposed modifications outlined below, along with our experience-based rationale for such modifications. A public workshop would also give PG&E the ability to receive feedback from additional stakeholders and customers that

---

[9] *See* PG&E's Opening Comments to the Administrative Law Judge's Ruling Seeking Comments on Scoping Memo Track 2a Scoping Questions 2.1(b)-2.1(k) at 15; PG&E's Reply Comments to the Administrative Law Judge's Ruling Seeking Comments on Scoping Memo Track 2a Scoping Questions 2.1(b)-2.1(k) at 18.

are not parties to this proceeding. Ideally, such a workshop would be scheduled before the Commission issues a final Track 2a decision.

Step 1 – Define an Emissions-based 2045 Goal

The first step in PG&E's alternative proposal is working with the Commission to define an emissions-based 2045 goal (or "end state") for gas utilities to work towards. Setting such a target aligns with the State's 2045 climate goals and is considered the best practice across industries, sectors, and governments for achieving GHG emissions.[10] For instance, the Commission could consider a percentage reduction in GHG emissions associated with each utility's gas system. This critical step, which has been missing thus far in the proceeding, allows gas utilities to "work backwards" to come up with interim milestones to meet the 2045 goal. Without an emissions-based target, gas utilities risk either under- or over-investing in decommissioning, which would cause negative impacts for the environment and customers.

Step 2 – Simplify Targeting Approach

Once the Commission establishes this emissions goal, the Commission, gas utilities, and stakeholders can start defining and identifying target areas to investigate for gas infrastructure decommissioning. Rather than the proposed tranche system, which rigidly combines all metrics into one shared driver, PG&E recommends four separate and independent drivers for defining and targeting segments of the gas system for decommissioning: (1) risk, (2) GHG reduction, (3) equity, and (4) cost. In this way, each of the four priorities are not ranked against each other but treated as distinct and important drivers.

For example, in PG&E's recently proposed application for approval of a Zonal Electrification Pilot Project at CSU Monterey Bay (A.22-08-003), the project is both cost-effective and has strong customer buy-in. If that project were located in a tranche 3 or 4 census tract (as defined by the Staff Proposal), does that mean that PG&E should instead make capital improvements to the existing gas system (that would be recovered over many years) at a greater

[10] *See* U.S. EPA, EPA Center for Corporate Climate Leadership, https://www.epa.gov/climateleadership/target-setting (last updated Sept. 30, 2022).

cost for our customers? Put simply, any targeting approach needs to allow flexibility at the project level for a gas utility to quickly act on promising electrification opportunities as they arise.

PG&E has piloted the independent driver approach in our *Gas Asset Analysis Tool*, discussed in Section II above. The benefits of the independent driver approach are that we can look at each driver in isolation (for instance, focusing exclusively on cost-driven projects) or in tandem with the other drivers (for instance, choosing areas that have both strong cost and equity drivers). By having four separate drivers available to them, a gas utility would be able to evaluate different projects based on a single factor, or combination of factors, that make most sense for that particular project. Being locked into a tranche approach or being locked into utilizing all factors for all projects will limit the gas utility's ability to execute its their long term decarbonization goals.

By replacing the proposed tranche system with the simplified approach discussed in this section, each gas utility would have the flexibility to focus on areas that have the most benefit for its customer base or specific geographical regions as it works towards its overarching 2045 goal. The top-down approach outlined by staff in the Proposal, focusing first on tranche 1 and working downward to tranche 5, does not take into consideration the realities of a project-based approach to decommissioning – namely that some projects in the higher tranches may not be technically feasible or have customer buy in (obligation to serve notwithstanding). A more fluid approach allowing each gas utility to define its own project parameters, in partnership with their customers and communities, so long as it is on track to meet an overarching emission-based 2045 goal, is more practical and will lead to the ability to take advantage of emerging decommissioning opportunities.

Table 1. Examples of Metrics by Driver

Risk Driver: ➢ CPUC fire threat areas by tier[11] ➢ DIMP risk scores ➢ Asset Management	**GHG Emissions Reduction Driver:** ➢ GHG reduction associated with throughput reduction (e.g., at point of use) ➢ GHG reduction associated with pipeline emissions (e.g., leaks)
Equity Driver: ➢ Disadvantaged communities ➢ % of low income customers on system ➢ % of renters on system ➢ % of multifamily customers on system ➢ Tribal lands	**Cost Driver:** ➢ Gas throughput on system ➢ Number of meters on system ➢ Current O&M Cost on system (including mains, services, valves) ➢ Planned Capital Expenditures on system ➢ Cost to Implement Zonal Electrification Project (electrification and pipeline decommissioning) ➢ Electric Infrastructure Capacity (Distribution Level). Note per Question 12 below, this would likely be an approximate value. ➢ Ratio of # Residential Gas Meters to # of Commercial Gas Meters

Step 3 – Require Gas Utilities to Submit a 2045 Gas System Plan at the Programmatic Level

In this proceeding or a separate proceeding established for this purpose, each gas utility would provide a one-time decarbonization plan showing:

1) A proposed 2045 gas system design meeting the emissions goal outlined by the Commission. The 2045 proposed system design should include a high-level description of

[11] *See* Decision Adopting a Work Plan for the Development of Fire Map 2, D.17-01-009, at 24-25 (issued Jan. 19, 2017). From a safety standpoint, high fire threat areas may benefit from undergrounding and electrification, such that in the case of an emergency utilities are only shutting off one fuel rather than two.

strategies that the gas utility will implement to reach the 2045 system design and a preliminary estimate of the associated costs for review by stakeholders such as Commission Staff. PG&E notes, however, that this system design would require flexibility to change over the coming 20 years to account for new technologies and opportunities. Updates could be contemplated in the GRC, as outlined in Step 4 below.

2) A high-level outlook for milestones that the gas utility will target leading up to the 2045 proposed system. This would include what *types* of projects[12] will be targeted (e.g.: projects that are driven by cost, equity, etc.) and the approximate costs associated meeting the proposed milestones in the 2030, 2035, 2040, 2045 timeframes. PG&E notes that all such planning at this high-level stage would be subject to feasibility (hydraulic and electric capacity analysis) as well as customer acceptance[13].

Step 4 – Project-Level Report Out

Upon completion of the programmatic decarbonization plan, the gas utility would provide an update on its progress in meeting the overall goals established by the Commission (Step 1 above). While we believe the initial high-level decarbonization plan can be provided in a separate proceeding, it is more appropriate for ongoing updates and reporting to be handled through the GRC, due to the need to tie decommissioning to appropriate cost recovery. The update would include progress reports on projects along with an updated decommissioning cost recovery request in each GRC based on the planned decommissioning projects and asset retirement timelines.

PG&E recommends that the report would be approved by the Commission without the need to review specific decommissioning projects, unless those projects meet the requirements of General Order (GO) 177. This programmatic budgeting approach is similar to that of our

[12] "Project" or "projects" for purposes of these Opening Comments refer broadly to individual or particular undertakings, as well as to programs or a set of related measures or activities with a particular aim or focus.

[13] Customer acceptance is a critical factor in initial planning stages. PG&E anticipates that significant portions of the gas system would need to remain in 2045 to serve customers that are unwilling or hard-to-electrify assuming no change to the obligation to serve.

distribution integrity management program and AEP (PG&E's current targeted electrification offering) and would streamline the gas utility's ability to execute on projects once the plan is approved.

Once the plan is approved by the Commission, the forecasted decommissioning and non-pipeline alternatives shall then be integrated into the following GRC application for each gas utility. PG&E notes that, due to the uncertainty inherent in forecast ratemaking, there may be changes between the plan and the forecast in each subsequent GRC.

Beginning in its 2027 GRC, or an earlier proceeding if ordered by the Commission, PG&E plans to propose the development of the annual decommissioning expense needed for the forecast decommissioning of PG&E's gas distribution facilities (and other gas facilities as applicable).

As discussed in the general comments section above, CPUC Standard Practice U-4 (1961) and National Association of Regulatory Utility Commissioners (NARUC) specify that current depreciation rates shall include the future cost of retiring/removing assets currently providing service, net of any proceeds from salvage.[14] Accordingly, in each GRC, PG&E will include cost estimates to decommission its gas facilities and will develop decommissioning expense accrual amounts based on those cost estimates and the expected retirement date of the associated gas facilities. Consistent with the established process in PG&E's GRC,[15] cost

---

[14] CPUC Standard Practice U-4, Determination of Straight-Line Remaining Life Depreciation Accruals, Chapter 1, section 2, states: "In the continuing duties of the California Public Utilities Commission in the fixing of rates and the supervision of accounts of utilities under its jurisdiction, a basic depreciation objective is that of recovering the original cost of fixed capital (less estimated net salvage) over the useful life of the property by means of an equitable plan of Charges to operating expenses or clearing accounts. The straight-line remaining life method presented herein and used as standard procedure by the staff meets this objective." (Net salvage includes cost of removal and gross salvage). NARUC's Public Utility Depreciation Practices, Chapter IV at 43 states, "depreciation accounting is the process of charging the book cost (generally stated as original cost in utility accounting) of depreciable property, adjusted for net salvage value, to operations over its useful life."

[15] The Commission first approved estimating decommissioning costs in D.92-12-057, stating that: "These cost estimates are based on current technology and current local, state, and federal regulations. These estimates will be reviewed and revised in each subsequent GRC filing to account for future increases or decreases resulting from changes in project scope, cost estimating, methodology, technology, and regulations. It may be 20 years or more before some of these plants are actually decommissioned, therefore, a reasonable expectation is that these cost estimates will change. However, the current estimates are the best estimates available at this time. Therefore, absent

estimates and decommissioning expense accrual amounts will be updated in each GRC based on the most recent decommissioning cost and asset retirement date estimates.

B. Utility Cost Per Service Estimates

The Staff Proposal provides cost per service estimates that require additional review and validation by the investor-owned gas utilities (IOUs). Table 1 calculates the annual distribution system cost per service per IOU and provides an average cost for all gas customers in California.[16] However, due to the wide range in the gas distribution system annual cost, it appears that the costs included in the total cost provided by each IOU are not consistent.

For example, PG&E provided its total gas distribution portfolio expense and capital forecast as shown in its 2023 GRC opening testimony, which includes most of the costs associated with operation, maintenance, and capital improvements of PG&E's natural gas distribution system.[17] It is not clear whether the other IOUs' total gas distribution system annual costs are comprised of strictly forecasted or adopted costs for the same programs and other costs (e.g., engineering, support costs, etc.) as PG&E's.

Additionally, while the Table 1 title is "Gas Distribution System Customers," the information provided in row (A) is titled "Services." There is a significant difference, at least for PG&E, in gas services versus gas customers. Gas customers translates to gas bills while gas services does not. PG&E has over 4.5 million gas distribution customers[18] and approximately 3.7 million gas services.

Further, cost models between the IOUs vary based upon how each IOU forecasts its revenue requirements. Unless the total annual gas distribution system costs are comparable, the

---

any future changes, these are the costs that PG&E reasonably can expect to incur for decommissioning. We agree with PG&E that these estimates should be included in rates as reasonable estimates of costs required to provide service in a manner consistent with protection and enhancement of the environment of California. We concur with the recommendations of DRA that such costs should be internalized within rates." (Section 13.1)

[16] Staff Proposal at 6.

[17] The total gas distribution costs provided by PG&E excludes costs associated with Customer Care Meter Services and Engineering and Customer Care Advanced Meter Infrastructure.

[18] A.21-09-018, PG&E Gas Transmission and Storage Cost Allocation and Rate Design (GT&S CARD) forecast of core, industrial distribution, and non-market responsive EG-D customers "aka billings," Chapter 3B.

estimates provided in the Staff Proposal are potentially in need of modification, should not be relied upon to assess affordability, and will require additional discussions with the IOUs.

Similarly, the Staff Proposal states that "PG&E reports a cost of approximately $40,000 per service to install or replace service pipelines and an additional $30,000 per service to replace the average amount of main pipelines associated with that service."[19] The Staff Proposal then reports a lower cost per mile at $15,000 for mains and services combined per affected service for SoCalGas.[20] The Staff Proposal does not provide the basis for the cost per service calculations, and it is not clear whether the basis is comparable between PG&E and SoCalGas. Therefore, PG&E requests that Energy Division staff review and validate its data for consistency across IOUs.

Finally, this data provides a snapshot of costs but does not encapsulate all costs associated with decommissioning as explained further below.

C. Depreciation/Decommissioning Cost Recovery

The Staff Proposal does not recommend direct consideration of depreciation costs when prioritizing among gas pipeline assets for decommissioning. The Staff Proposal states that "it would be unnecessarily complex to determine the embedded depreciation costs of a given pipeline segment."[21] PG&E generally agrees with this statement in the context of prioritizing assets to decommission. However, although specific depreciation cost impacts are not considered when determining prioritization for decommissioning, the overall cost of decommissioning significant portions of PG&E's system cannot be ignored. More precisely, decommissioning of the scale set forth in the Staff Proposal will shorten asset service lives and simultaneously reduce gas demand, raising questions about the method and timing of capital recovery.[22]

---

[19] Staff Proposal at 10.

[20] *Id.*

[21] *Id.*

[22] PG&E has raised these issues in its 2023 GRC (A.21-06-021) and proposed the Units of Production Method to

For these reasons, in consideration of the Commission's goal to avoid stranded costs and to assist the Commission in determining the cost both to recover the cost of PG&E's gas assets and to retire/decommission those assets, PG&E recommends that cost recovery, including depreciation and decommissioning costs, should be explicitly addressed as one of the Commission's cost consideration goals.

Timely cost recovery, including depreciation and decommissioning costs, must be explicitly guaranteed to avoid risk of stranded costs. PG&E stresses the importance of clarity from the Commission on cost recovery to avoid stranded costs. As shown below, investments in PG&E's gas distribution system and estimated costs to retire the assets net of salvage amount to over $23 billion as of December 31, 2020. These investments have been prudently incurred for safety and reliability over the decades, often directed by federal and state legislation and safety regulations. As a regulatory principle consistent with longstanding depreciation practices, both the undepreciated original cost *and* the cost to retire or decommission assets is to be borne by the customers who receive the service from those assets over their expected useful life. If depreciation is too low and these costs are deferred to the future, then customers remaining on the system in the future will pay a disproportionate and inequitable share of these costs.

Estimated Amount to Be Recovered

As presented in PG&E's 2023 GRC depreciation study, and shown below, the unrecovered net book value of PG&E's gas distribution assets and the estimated cost to retire the assets as of 2020 was approximately $17 billion.[23] PG&E is performing a decommissioning study, and future results may increase retirement costs materially from historical amounts.

---

address intergenerational inequities that arise from declining gas throughput.

[23] A.21-06-021, Exhibit (PG&E-10), Ch. 12.

Gas Distribution	Balances 12/31/2020	Percentage Recovered and Remaining to be Recovered 12/31/2020
Costs to Recover (Note 1)	$23.1B	
Recovery in Accumulated Depreciation	$5.9B	25.5%
Remaining Amount to Recover	$17.2B	74.5%
Note 1: Amount includes (1) original cost of the investment plus (2) estimated costs to retire less salvage.		

Additionally, costs to upgrade the electric system to accommodate the increase in load could be significant and would be borne by customers.

V. RESPONSES TO QUESTIONS IN THE STAFF PROPOSAL REGARDING CRITERIA AND GOALS: PIPELINE-RELATED CHARACTERISTICS (SECTION 3.1)

A. Section 3.1.1: Safety and Investment

1. Do you recommend any changes to the five key goals proposed in Section 3?

PG&E generally agrees with the five key goals proposed in Section 3 of the Staff Proposal, with the following recommended edits to Goals 3, 4, and 5. PG&E also recommends the addition of two new goals for a total of 7 goals.

<u>Goal 3</u>

PG&E recommends that the Commission revise Goal 3 as follows:

> Reducing **~~gas demand~~** **<u>greenhouse gas emissions associated with gaseous fuel</u>** and gas distribution infrastructure **~~every year until California's climate goals are achieved~~** **<u>until each gas utility reaches the target reduction in greenhouse gas emissions associated with their respective gas system</u>**.

PG&E offers these recommended revisions to Goal 3 for the following reasons:

1) PG&E proposes a broader definition of Goal 3, clarifying that utilities should focus not only on the emissions associated with end-use demand reduction, but also on

opportunities to reduce GHG emissions by targeting leaking pipeline segments.

2) PG&E recommends striking the clause "every year until California's climate goals are achieved" and replacing this clause with a specific GHG-based metric established by the Commission in this proceeding. As stated in Section II above, an overarching goal for system planning will be critical in informing future gas utility investment into the gas system and/or electrification.

Goal 4 and Goal 5 (Split of Goal 4)

PG&E recommends splitting Goal 4 into two separate goals, Goal 4 and 5, one focused around equity and one focused around cost-savings as follows:

> 4. Maximizing ~~**community**~~ **financial** benefits **for all customers** ~~**ratepayers**~~, ~~**including health benefits and cost savings,**~~ by transitioning ~~**highest-need,**~~ highest-benefit areas first~~**, and prioritizing areas with community champions among those**~~; and
>
> **5. Maximizing community benefits for disadvantaged communities, including health benefits, by transitioning highest-need areas first, prioritizing areas that are traditionally underserved.**

In PG&E's early forays into targeted electrification projects and the mapping of opportunities for decommissioning, PG&E found that these two goals, while equally important, are rarely aligned. By separating the desires for system cost reductions and equity, the Commission reaffirms that costs and equity are separate, distinct goals.

Goal 6 (Formerly Goal 5)

PG&E recommends the following changes to Goal 5:

> Supporting a smooth transition to a lower-**fossil-**gas-use society by saving the most costly or hard-to-decarbonize locations for last **and planning for low-carbon or carbon-free gas delivery systems (such as RNG and Hydrogen) in use cases where the customer cannot feasibly electrify**.

In addition to deprioritizing projects where it is difficult to electrify, PG&E notes that proactive planning for the use of clean fuels to serve hard-to-decarbonize customers will be needed as a part of the overall planning process established in this proceeding.

Goal 7 (New)

PG&E recommends addition of a new goal:

> "**Providing for depreciation and decommissioning cost recovery consistent with the Commission goal of minimal or no stranded costs.**"[24]

This goal is consistent with affordability since timely recovery is more equitable and affordable for customers remaining on the system (who are most likely to be low-income customers and those in disadvantaged communities). This goal is foundational to ensuring the regulatory compact is adhered to so that shareholders recover their past and future investments in the gas system. Additionally, cost recovery will be needed for investments in the necessary capital to fund large scale capacity investments to support zonal electrification.

2. Is *likelihood of failure* (reflecting the probability of failure) or risk score (*likelihood of failure* times *consequence of failure*, thereby reflecting the probability and size of the potential harm) a better way to reflect pipeline risk when prioritizing among communities?

Risk calculated as likelihood of failure times consequence of failure is the common method to assess risk. The Commission and the Pipeline and Hazardous Materials Safety Administration (PHMSA) both recognize this methodology, and it would be appropriate to use this framework in prioritize pipeline decommissioning.

In addition to likelihood of failure and/or risk score, PG&E recommends that prioritization include an evaluation of any pertinent risks such as, but not limited to, fire threat, flood prone areas, sea level rise, and low-pressure systems.

3. Is there a level of risk at which it is not cost-effective or reasonable to replace distribution pipelines? If so, what is that level and by what method should it be assessed?

Risk tolerance for asset replacement or decommissioning is undefined and is generally a function of societal norms. Recency bias related to recent events can lower societal tolerance for

[24] Order Instituting Rulemaking to Establish Policies, Processes, and Rules to Ensure Safe and Reliable Gas Systems in California and Perform Long-Term Gas Planning, R.20-01-007 at 14 (Jan. 27, 2020) ("Track 2 will determine the regulatory solutions and planning strategy that the Commission should implement to ensure that, as the demand for natural gas declines, gas utilities maintain safe and reliable gas systems at just and reasonable rates, and with minimal or no stranded costs".)

risk. Furthermore, other Commission filings, such as the Risk Assessment Mitigation Phase (RAMP), seek to identify risk tolerance levels and cost-benefit ratios. PG&E does not focus replacement on post-1985 gas distribution services or pipelines unless elevated risks such as failures occur or assets need to be repaired to maintain compliance or safety. PG&E annually performs a risk assessment of the gas distribution system and recommends projects to mitigate risk. For main replacement, mitigations are focused on the highest risk segments (not based on census blocks) and are largely limited to pre-1985 for plastic replacement and pre-1941 for steel; however, as assets age these years can change based on asset performance. Newer assets largely are not in need of replacement. However, PHMSA has issued bulletins warning about the risk of certain newer assets, an example being plastic tee cap repairs and replacements.

B. Section 3.1.2: Feasibility

4. Is there a need to conduct hydraulic feasibility analysis in order to inform statewide prioritization or can such modeling be postponed until individual projects are proposed?

Hydraulic modeling cannot be done effectively prior to knowing which customers are electrifying on a project level basis. Since hydraulic feasibility depends on the sequence of projects, system-wide modeling would be premature and likely need to be re-done by local engineers once a project scope is identified. Within one census tract, there could be several hydraulically independent systems, each of which must be separately assessed for retirement feasibility. Hydraulic analysis should instead be conducted on a project-by-project basis by gas utilities once opportunity areas (i.e., drivers or tranches) and individual projects within those opportunity areas are identified.[25]

That said, hydraulic feasibility and electric capacity will be major factors in determining which projects in a given tranche or geographic region may be viable. As described in Section IV.A above, PG&E proposes a modified process that offers a combination of high-level system

[25] PG&E's response to Question 4 is consistent with the Staff Proposal: "Systemwide hydraulic analysis would be time-consuming and is not necessary to prioritize among communities. Rather, when any given decommissioning project is proposed, the gas utility should conduct a hydraulic feasibility check and recommend any lines to be exempted for access or pressure support reasons." Staff Proposal at 9.

planning and project-based output reports in line with each GRC cycle. By using a less rigidly defined ranking system, gas utilities would be able to prioritize projects that are hydraulically feasible without the need to "re-tranche" census tracts should they be deemed unviable or allow minimal asset retirement once hydraulic and/or electric capacity reviews are completed. In this way, the ranking system becomes more akin to guiding principles or priority areas, but projects within each priority area can be assessed independently for feasibility.

5. If or when hydraulic feasibility is assessed, who should conduct that analysis?

It is most appropriate for the gas system planning engineers of each gas utility to perform hydraulic feasibility modeling because they are most familiar with the affected systems.

C. Section 3.1.3: Cost

6. What are the top 10 or fewer key cost input variables necessary to estimate to estimate pipeline repair costs? For example, do they include pipeline mileage, pipeline material, city, county, or region in which the project is located, or number of known leaks?
a) How should pipeline repair costs be estimated using these variables?
b) Will using these variables capture at least 80 percent of the variation in costs?

PG&E proposes that cost variables be driven by the type of repair project. As types of repairs for pipelines vary considerably, these types should be considered illustrative:

- Above ground leak repair to risers or metersets
- Below ground leak repair of mains
- Below ground leak repair of services
- Sections of main replaced under 100 feet
- Service alterations due to customer encroachments
- Valve repairs
- Cathodic protection system repairs
- Tee cap repairs
- Repair location in urban vs non-urban area

The above are not an exhaustive list of repair types; however, they illustrate that an important variable to estimating the cost of pipeline repairs is the type of repair. Geography of the repair is also a key variable along with city permitting costs, restoration costs, and materials being repaired. PG&E classifies repair types into groups called "maintenance activity types" and generates unit costs by region. Using historical unit costs for the repair types, with escalation, has proven to be a reliable method of forecasting annual budget needs and is used in GRC forecasting. While PG&E has not calculated if those factors capture 80 percent of cost variation, these factors have historically proven to be reasonable predictors of cost.

7. What are the top 10 or fewer key cost input variables necessary to estimate to estimate pipeline replacement costs? For example, do they include pipeline mileage, pipeline material, pipeline diameter, city, county, or region in which the project is located?
a) How should pipeline replacement costs be estimated using these variables?
b) Will using these variables capture at least 80 percent of the variation in costs?

Replacement of pipelines can vary considerably. For example, a replacement could be any of the following:

- Replacement of main and services;
- Replacement of mains only;
- Replacement of services only;
- Replacement of capital pipeline appurtenances; or,
- Front-of-the-meter[26] mobile home system replacements.

The above are not an exhaustive list of replacement types; however, they illustrate that an important variable to estimating the cost of pipeline replacements is the type of replacement. Geography of the replacement is also a key variable along with city permitting costs, labor costs, restoration costs, and materials being replaced. PG&E uses maintenance activity types for all replacement types and generates unit costs by region. Although PG&E has not calculated

[26] Front-of-the-meter is used interchangeably with the commonly used term "to-the-meter" or TTM.

whether those factors capture 80 percent of cost variation, the factors have historically proven to be reasonable predictors of cost.

8. Is it most appropriate to estimate pipeline repair costs on a per mile basis, on a per mile basis plus a fixed costs per project, or by some other means?

Repair costs should be estimated as described in Question 6. This is on a per unit repair type, not per linear asset as most repairs are of minimal distance.

9. What are the top 10 or fewer key cost input variables necessary to estimate regulator station repair or replacement costs? For example, do they include number and type of valves, regulators, flow meters and other equipment, and whether they are to be repaired vs. replaced, or city, county, or region where the station is located? If using, "type" of equipment, briefly identify each type and the cost differences among them.

a) How should regulator station repair or replacement costs be estimated using these variables?

b) Will using these variables capture at least 80 percent of the variation in costs?

The following key variables are considered when estimating regulator station repair or replacement costs:

- Relocation feasibility including land acquisition and permitting
- Urban vs. non-urban location
- Number of components requiring replacement (repair)
- Equipment obsolescence and ability to repair
- Proximity to Transmission Tie-in
- Tie-in method/ Clearance Requirements
- Site restoration

Regulator station repair or replacement costs will depend on the scope of mitigations necessary for station reliability. Station rebuilds are designed with a standard design and standard equipment. The cost variances are driven by the location of work performed, restoration costs and construction activities to tie into the transmission and distribution pipelines.

10. Should valve repair or replacement costs also be considered as part of distribution infrastructure repair or replacement costs, for valves not located at regulator stations? If so, how should they be estimated?

Yes, following the process outlined in the responses to Questions 6 and 7.

11. What other costs, such as stub removal, should be considered in decommissioning costs?

Decommissioning costs can be bucketed into separate categories. The first is the cost to decommission the gas assets. The second is the cost of front-of-the-meter electrical upgrades due to the increased load demand associated with electrification. Finally, there are behind-the-meter costs, such as the cost of heat pumps, necessary for the customer to cease gas service.

<u>Decommissioning of gas asset costs</u>:

1. Costs to cut and cap mains, services, and risers, including purging and project management costs, and as needed, excavation of streets and/or sidewalks and use of special equipment.
2. Requirements for permitting, paving, sidewalk repair, noise ordinances, traffic control, and work restrictions. Required installation of equipment such as cameras and handicap ramps.
3. If required to remove gas assets instead of retiring assets in place, the incremental costs associated with removing gas assets.
4. Any environmental remediation costs.

<u>Front-of-the-meter electric costs due to increased load</u>:

1. If required, costs to upgrade front-of-the-meter electric infrastructure. Potential costs could include, but are not limited to, replacement of service transformers, installation of larger secondary services, replacement or installation of new overhead conductor or cable, installation of new substation circuit breakers, replacement or installation of new substation transformers, and replacement or installation of new transmission line conductor.
2. Requirements for permitting, paving, sidewalk repair, noise ordinances,

traffic control, and work restrictions. Required installation of equipment such as cameras and handicap ramps. Various local, state agency, and CPUC permits may be required for new distribution and transmission lines and new substations.

Behind-the meter costs:

1. Cost to install behind-the meter customer electric appliances, as well as any associated "soft" costs such as wiring, demolition, and project management.
2. If required, costs to upgrade electrical panels.
3. If required, costs to mitigate any health and safety issues such as, but not limited to, knob and tube wiring, lead, moisture intrusion, ventilation, or asbestos.

12. How should the incremental electric transmission or distribution infrastructure needs and costs associated with gas infrastructure decommissioning and associated electrification be considered?

Similar to hydraulic modeling, PG&E completes an electric infrastructure evaluation of each potential gas decommissioning/electrification project at the time of project identification and incorporates any anticipated costs into our cost-effectiveness calculations. It is not appropriate for capacity and service transformer needs to be assessed at the state or census tract level, as there may be multiple independent gas and electric systems within a given census tract. A project-based analysis allows utilities to better understand the potential front-of-the-meter impacts and costs associated with zonal electrification, new development, and electric vehicle penetration.

Because the need and costs associated with front-of-the-meter upgrades will vary greatly from project by project, PG&E does not recommend putting any generic estimates of these costs into a framework or tool. These costs will not be accurate unless done on a project-by-project basis, similar to hydraulic modeling. Additionally, putting in a per-building cost would likely deprioritize denser urban sites when, in reality, many of these urban sites could potentially electrify with fewer upgrades to front-of-the-meter infrastructure. Rather, it is more appropriate for utility engineers to evaluate potential front-of-the-meter electrical costs and impacts on a project basis once priority areas are identified. By using a less rigidly defined ranking system, utilities would be able to prioritize projects without the need to "re-tranche" census tracts should they be deemed to be unviable due to capacity constraints, or when census tracts change periodically. In this way, the ranking system becomes more akin to guiding principles or priority areas, but projects within each priority area can be assessed independently for electric feasibility and/or cost impacts.

a) Is there a threshold electric demand increase below which electrification does not impact electric transmission or distribution infrastructure needs enough to merit consideration?

No, from a safety and reliability need, it is critical that transmission and distribution infrastructure be evaluated for each project.

b) What is the average per-home cost to the receiving electric utility to provide the in-front-of-the-meter infrastructure needed to support electrifying a home? What are the cost input variables, and how should they be estimated?

Please see PG&E response to Question 12 above. PG&E strongly recommends against considering these variables in any pre-screening tool or framework. Per-home front-of-the-meter costs are likely to vary greatly from project to project. Adding any estimated per-building estimates to a ranking system would penalize denser urban areas with a higher building to pipeline ratio. It would also needlessly penalize projects where front-of-the-meter upgrades are actually not needed to electrify. Rather, PG&E proposes completing any front-of-the-meter cost estimates on a project-by-project basis.

c) How should the electric infrastructure implications of gas decommissioning be mapped to census tracts?

This is particularly challenging. Currently, PG&E maps feeder capacity associated with each electric meter to the correlating gas meter. Even this approach, however, offers only a first estimate of whether there is adequate capacity for electrification. Our best practice is to always use local engineers to evaluate impact and feasibility once a project has been identified. The issue of mapping this at the census tract level, where you may have multiple gas and/or electric system components, which may or may not be linked to one another (i.e., they could be part of separate circuits or gas systems), becomes increasingly difficult. Because of this, PG&E does not recommend a mapping of this data in any pre-screening or ranking system at the census tract level, but rather a project-based evaluation of electric infrastructure feasibility and cost.

VI. RESPONSES TO QUESTIONS IN THE STAFF PROPOSAL REGARDING CRITERIA AND GOALS: COMMUNITY CHARACTERISTICS (SECTION 3.2)

A. Section 3.2.1: Community Benefits

13. Do the variables discussed appropriately account for the potential community benefits from reduced gas use? Are there other community characteristics that should be considered?

PG&E supports the prioritization of community characteristics such as existing community environmental, economic, and health burdens. These community characteristics fit neatly within PG&E's independent driver proposal discussed in Section IV above. The equity driver includes prioritization of tribal lands. While the CalEnviroScreen (CES) tool is useful, its use does not indicate that census tract is the only method of assessment. PG&E believes the CES tool can be built into the equity driver proposed in PG&E's alternative plan. Furthermore, PG&E supports using the most recently released version of the CES tool (version 4.0) for identifying as that version has the most recently updated data. PG&E also agrees with incorporating a variable that looks beyond individual households located in DACs. In addition to the variables identified, PG&E also recommends considering areas with high populations of renters and multifamily residents to prioritize interventions in traditionally underserved communities. Low-income multifamily renters encounter market barriers that make this group characteristic important to identify and prioritize.

14. Should indoor air quality be a consideration in prioritizing among communities? If so, what data should be used to represent variations in indoor air quality among census tracts?

Compared to the other community characteristics, indoor air quality should not be a consideration for prioritization. Indoor air quality lacks consistency in measurement and historical data. PG&E is unaware of any data on indoor air quality by census tract. In addition, PG&E is not, and should not be, primarily responsible for measuring and tracking indoor air in communities throughout the state. Recent research on potential gas impacts on indoor air has not triggered any action from the Federal Interagency Committee on Indoor Air Quality (CIAQ).[27] At a minimum, greater analysis and study is needed before incorporating this as a metric to prioritize communities. Indoor air quality is not established and readily available as a measurement for prioritization; therefore, it should not be used until it is studied in greater detail as a factor.

B. Section 3.2.2: Gas Demand and Affordability

15. Do the variables discussed above appropriately represent affordability? Are there other affordability metrics that should be considered?

PG&E agrees that affordability is important and informs cost recovery issues. As noted in its response to Question 1, PG&E also proposes that cost recovery, i.e., calculation of the gas revenue requirement, approaches should also be considered in tandem with any decommissioning framework. Customers who remain on the system the longest likely will be customers who may not be able to afford to switch from gas to electric home heating and cooling systems; yet these remaining customers would be required to cover the revenue requirement of the remaining pipeline system costs. Conversely, customers who are able to afford to completely leave the system in the next decade as part of an earlier electrification wave would more than likely be upper income customers.

If affordability metrics are incorporated, then PG&E is generally supportive of using metrics developed in proceedings with robust records such as the Affordability Rulemaking (R.18-07-006); however, PG&E cautions against using variables that were not developed with decarbonization goals in mind. In addition, PG&E cautions against establishing metrics that are duplicative of issues in other proceedings and may lead to conflicting orders from the

[27] CIAQ is comprised of two dozen federal agencies led by the U.S. Environmental Protection Agency (EPA) and routinely addresses indoor air quality issues of public importance.

Commission. Flexibility, especially in the early stages of decarbonization, is needed when accessing variables such as the "Affordability Ratio;" the Socioeconomic Vulnerability Index; and Average Hours Worked at Minimum Wage. Notably, PG&E's proposal helps resolve the issue that the Affordability Ratio does not align with the census tract level proposed in the Staff Proposal.

In addition to the metrics above, the utilities could use metrics that consider utilization rates by location, such as locations with high gas capital and/or operational costs, and locations with unusually high or low utilization rates. High utilization rates indicate the potential for an upcoming gas capacity project that could be avoided with electrification. Low utilization pipelines, conversely, indicate areas with a potentially high operational cost to revenue that may be cost-effective to target for decommissioning.

As discussed in PG&E's 2023 GRC Exhibit 10, Chapters 11 and 12 opening testimony, the Units of Production methodology provides for the recovery of costs in a manner that matches gas throughput and/or customer decline. In this way, customers remaining on the system will not be burdened with paying for gas asset costs that should be shared with existing customers as the assets were installed over the past decades for the benefit for all customers and largely have a high fixed cost of service nature per customer. Although PG&E has presented a proposal for recovering certain costs in its 2023 GRC, a decision is not expected until Q3 2023. As such, it is paramount that the Commission consider appropriate cost recovery in this proceeding.

16. Should distribution pipeline decommissioning efforts focus primarily on residential customers? If so, why? If not, where should they focus?

PG&E does not recommend a particular building type be prioritized for distribution decommissioning efforts. Rather, utilities should evaluate the feasibility, total costs, and benefits associated with each potential project within the defined priority areas. These projects may include a mix of residential and non-residential buildings. In PG&E's experience, residential customer electrification is generally more cost-effective, but non-residential electrification, if technically viable, may offer greater greenhouse gas and financial benefits.

Finally, hydraulic considerations need to be factored in when contemplating decommissioning a particular project. For example, a promising residential project may be upstream of a hard-to-electrify customer; however, the existing pipeline would need to be preserved or rerouted to maintain service to only the hard-to-electrify customer.

17. How should non-residential, non-industrial gas demand be considered when prioritizing among communities?

Please see our response to Question 16 above.

a) Should some sectors, such as restaurants, laundromats, schools, or hospitals, be prioritized for decommissioning, or alternatively, for maintaining gas infrastructure? If so, which ones and why?

As stated in our response to Question 16, PG&E does not recommend that any particular sector be prioritized or de-prioritized at an initial census-tract level screening level. Rather, each project should be evaluated for feasibility, costs, and benefits.

b) What non-pipeline alternatives should be the focus for these sectors?

All viable non-pipeline alternatives should be considered for projects, with the most cost-effective non-pipeline alternative using carbon-neutral technology being selected by the gas utility.

18. How should GHG impacts be considered when comparing among communities?

a) Should GHG emissions from gas combustion, from gas leaks (methane release), and/or from non-gas GHG sources be used as a variable to compare among communities? If so, what data should be used to represent variations in these factors among census tracts?

Yes, the Commission should consider gas combustion and gas leaks in its community prioritization. These two values can be provided by gas utilities. However, the basis for such information would not be aligned with census tracts.

b) If yes to (a), how should this data be used when constructing the tranches discussed below?

As described in Section IV, PG&E recommends that an independent driver be established that assesses potential GHG reduction impact associated with each census tract. The driver should include metrics on both emissions associated with combustion and leaks. An independent driver would allow utilities to prioritize a subset of GHG reduction focused projects without those projects needing to compete with equally important cost or equity drivers.

VII. RESPONSES TO QUESTIONS IN THE STAFF PROPOSAL REGARDING CRITERIA AND GOALS: OTHER CHARACTERISTICS (SECTION 3.3)

A. Section 3.3.1: Community Champions

19. Should the presence of community champions be an important consideration in prioritizing areas for decommissioning? Why or why not?

Consistent with PG&E's proposal for decommissioning in Section IV, we do not think whole areas should be prioritized or deprioritized based on the presence of a community champion even though PG&E believes the presence of community champions is very important and highly correlated to project success. Community champions will be highly specific to individual programs and projects. They may be a Community Based Organization (CBO), a local government, a Community Choice Aggregator, or simply an interested individual located in the affected jurisdiction. For instance, in the case of our application for zonal electrification at CSU Monterey Bay (A.22-08-003), the university is serving in the role of a community champion. We may find, too, that new community champions are identified throughout the lengthy effort to reach California's climate goals. Rather than pre-defining entire areas to prioritize based on the presence of currently known community champions, PG&E suggests that funding be made available to each utility to identify and partner with local community champions on a programmatic or project basis.

20. Please identify the key types (of those listed above, or others) of community champions and attributes for an effective community champion.

As stated above, PG&E recommends an approach where community champions are identified on a programmatic or project basis. What a successful community champion looks like is likely to differ greatly from project to project. As highlighted in the response to Question 19, a community champion could be different entities depending on the needs of the community, and the role could be filled by a CBO, local government, Community Choice Aggregator, or local individual. For example, in the San Joaquin Valley Disadvantaged Community electrification pilots, both a local CBO and a community resident acted as community champions to help advance the proposal. Due to the unique attributes and characteristics of each community and region, allowing for flexibility in identifying community champions is ideal. Further discussion on community champions is recommended in Track 2b to evolve the concept.

21. How should community champions be identified?

a) What process should be used, by whom, and when?

Rather than prioritizing or deprioritizing areas for decommissioning based on the presence of currently known community champions, PG&E suggests that funding be made available to each utility to identify and partner with local community champions on a programmatic or project-by-project basis. PG&E recommends that discussions to identify potential community champions occur early in the process through conversations with local elected officials and CBOs to see which entities may best fit the role for a particular community.

b) If possible, provide a list of any identified potential community champions by name, address and 11-digit census tract.

As set forth in the responses to Questions 19 and 20, PG&E prefers a flexible approach where community champions are identified on a programmatic or project basis.

22. Should the CPUC promote community champions? Why or why not? And, if yes, how?

Yes, the Commission should promote community champions by financially supporting such groups through any programmatic efforts. In the progress report completed by each utility as a part of their GRC, the utility should identify what subset of funds would be allocated to identified community champions. PG&E recommends that financial support for community champions be funded by external sources and not passed onto utility customers.

B. Section 3.3.2: Industrial Facilities and Biomethane

23. Should the presence of hard-to-electrify gas users and sources of biomethane on a pipeline lower its priority for decommissioning? Why or why not?

PG&E agrees with CARB that most hard-to-electrify customers will be served through renewable natural gas and/or hydrogen blended into existing pipeline systems, or potentially through dedicated hydrogen hubs.[28] Therefore, it would not make sense to prioritize decommissioning pipelines that are serving these hard-to-electrify customers. PG&E notes that there may be additional hard-to-electrify users that will want to connect to the gas system (i.e., rail, marine, or industrial facilities using dirtier fuels) in order to reduce GHG emissions from their operations, meaning that additional gas end-users may come online as we head towards our carbon goals.

a) How should this affect decommissioning of transmission vs. distribution pipelines?

PG&E anticipates that significant portions of the gas transmission and select portions of gas distribution systems would need to remain in 2045 to serve customers who are hard-to-electrify or, assuming no change to the obligation to serve, unwilling to electrify. Gas utilities and industrial customer facility engineers would be best positioned to offer specific insight into what this end state of the gas system would look like.

24. How should "hard-to-electrify" customers be defined?

Hard-to-electrify customers typically have high temperature processes that do not allow full electrification from a feasibility and/or cost perspective. For now, PG&E does not propose a specific definition for hard-to-electrify customers as technology and industry needs evolve over time. Rather, our current practice is to determine if we can serve the customer based on the commodity requested, their current and future facility equipment and operations, the location for development, and the current PG&E infrastructure.

---

[28] *See* California Air Resources Board, 2022 Scoping Plan for Achieving Carbon Neutrality, November 2022, https://ww2.arb.ca.gov/resources/documents/2022-scoping-plan-documents, pp. 2, 209.

a) What characteristics should be considered, such as industry classification; boiler temperature; use of gas for chemical reactions; or average or peak, current or forecast gas demand?

Characteristics should not be limited to classification and criteria because customers and their businesses require such diverse considerations for optimal processes and financial viability to ensure sustainability and competitiveness in the marketplace.

b) What future demand forecasts for these industries should be used?

PG&E recommends against using historical demand forecasts because the industries, their utility needs, innovative technology, and advancements are constantly evolving. PG&E should recognize new trends based on interest and project requests from future and existing customers. The ability to track and establish short-term views to develop assumptions to build out long-term forecasts comparing like industries would be prudent.

c) How should those forecasts be allocated among facilities or used to forecast facility-level demand?

Please see the response to Question 24b above.

25. How do the costs per dekatherm of electrifying industrial gas customers compare to the costs per dekatherm of electrifying residential or small commercial gas customers?

Typically, industrial and large commercial customers have processes that require much higher heat content and intense/complicated designs to accommodate operations that result in significantly greater cost than electrifying residential or small commercial customers.

26. How should the presence of industrial gas customers in a census tract affect whether the residential customers in that community have their gas pipelines repaired, replaced, or decommissioned, if at all?

If there is an area that requires gas regardless of customer class, until there is a change in a California gas utility's obligation to serve, a gas utility should continue to provide gas to all customer classifications in that vicinity to avoid a piecemeal approach to decommissioning gas systems. Gas utilities must continue to provide safe and reliable service, which includes repairing and replacing gas pipelines as needed.

27. How should the CPUC identify the set of pipelines and gas customers that should be expected to stay on the gas system using biomethane or other non-fossil fuels?

The CPUC and PG&E should identify pipelines and gas customers based on consumer and community demand to stay on the system. Additionally, to support the demand from the communities, PG&E should ensure that we provide renewable gas supplies (biomethane, hydrogen, or other non-fossil fuels) to reduce GHG emissions in support of carbon neutral service.

28. Is there potential for any industrial gas customers in California to electrify within the next 10 years?
a) If so, how should these facilities be identified?

Yes, there is potential to electrify industrial gas customers in the future, but it is dependent on advancements and innovations in technology to accommodate these customers in their operations. PG&E is not aware of a means to identify those types of industrial facilities at this time.

VIII. RESPONSES TO QUESTIONS IN THE STAFF PROPOSAL REGARDING DEFINING TRANCHES (SECTION 4)

A. Sections 4.1.1-4.1.5 (Tranches 1-5)

29. What adjustments should be made to these tranche definitions?

PG&E refers to its response in Section IV, which sets forth proposed modifications to the Staff Proposal.

30. How often and through what process should tranches be updated using recent data and analysis, given the potential to learn from past experience and new information, vs. the benefit of planning years in advance?

As recommended in Section IV, PG&E recommends that the Commission consider the more flexible approach (instead of using census-based information) to guide decision making, permitting utilities the flexibility to identify their own projects based on the realities of those projects. Under this proposal, the Commission would not need to update tranches given the utilities' ability to identify projects that meet their overall 2045 plan.

Should the Commission decide to keep the proposed tranche system, PG&E recommends any larger tranche update process coincide, as best as possible, with the Integrated Resource Plan, GRC, and any requirements identified in this proceeding. There would also be the need for utilities to dynamically update a subset of tranches between more formal review processes. For example, if a pipeline is originally tagged in a tranche 1 census tract, but is found to be nonviable because of hydraulic or electric system impact, a gas utility should be able to efficiently reallocate that census tract to a lower tranche without waiting for larger, formal tranche-changing milestones to occur. An expedited process may need to be implemented to allow tranches to be quickly updated for minor updates.

IX. RESPONSES TO QUESTIONS IN THE STAFF PROPOSAL REGARDING PROCESS (SECTION 5)

A. Section 5.1, Repair or Replacement

31. Should distribution infrastructure projects that are not covered by the Commission's General Order 177 be considered within or separately from utility rate cases?

As stated in Section IV, PG&E recommends that the utility GRC be the venue for consideration of distribution infrastructure spending not covered by the Commission's General Order 177. PG&E anticipates that this topic will be evaluated further in Track 2c.

a) If not addressed within rate cases, what scale of activity should be considered a single project?

As noted in response 31 above, PG&E recommends that the utility GRC be the venue for consideration of distribution infrastructure spending not covered by the Commission's General Order 177. We believe this approach balances the need for oversight of the decommissioning process with the need for flexibility and timely implementation at the programmatic level.

b) How should the topics covered by future rate cases and separately be defined to avoid duplicative review or expenditures for distribution infrastructure?

See response to Question 31a above. PG&E recommends that the utility GRC be the ongoing venue for the distribution infrastructure spending not covered by the Commission's General Order 177.

c) What ratemaking/ cost structures changes are possible to incentivize gas utilities to decommission distribution pipelines?

Given the many related cost impacts from decommissioning,[29] PG&E is still in the process of evaluating potential ratemaking and cost structure changes to incentivize gas utilities to decommission distribution pipelines. Thus, PG&E cannot provide a fulsome answer at this time and would like a further opportunity to comment in detail at a later date.

Potential Performance Incentives

Currently, PG&E has not considered whether performance-based incentives may be appropriate, including state-funded performance incentives and potential return on equity adders. PG&E would appreciate the opportunity to submit comments on potential performance-based incentives to the Commission at a later date. PG&E anticipates that later tracks of this proceeding may provide such opportunities.

Timely and Equitable Cost Recovery

Aside from potential incentives, PG&E emphasizes that timely and equitable cost recovery (including for depreciation and decommissioning costs) must be expressly guaranteed to avoid stranded costs. As discussed in Section IV.C., PG&E has made significant investments in its distribution assets. Early retirement of those assets may strand PG&E's investment costs. Additionally, early retirement also risks inequitably shifting costs for decommissioning to customers who remain on gas. PG&E is in the process of evaluating potential options and opportunities to ameliorate these issues, including but not limited to, potential cost recovery for decommissioning through both electric and gas customers, potential sources of state and federal funding such as the Inflation Reduction Act, potential exit fees, and potential departing load fees. However, PG&E is still early in the process of evaluating these options and does not yet have a detailed proposal for consideration.

---

[29] For example, we anticipate related cost impacts due to: increased electric load, the necessity for potential electric infrastructure upgrades, impacts to other gas functions (such as gas storage and transmission), and behind-the-meter costs. This is not an exhaustive list.

Initial Regulatory Asset Treatment for Certain Cost-Effective Non-Pipeline Alternatives

As described in our application for the Zonal Electrification Pilot Project at CSU Monterey Bay (A.22-08-003), we believe that zonal electrification can provide safety and customer financial benefits in the near term where pipeline replacements are necessary but avoidable with cost-effective customer electrification. For these benefits to be realized, the Commission must approve appropriate rate recovery for this subset of projects where the cost of non-pipeline alternatives is less than the cost of planned gas replacements. Regulatory asset treatment of the behind-the-meter costs of such cost-effective non-pipeline alternative projects gives the gas utilities the ability to treat these projects in a manner more similar to gas pipeline replacement projects and would unlock the ability for PG&E and other gas utilities to expand the pool of viable decommissioning projects at this early phase (see Staff Proposal, § 3.3.1). This will apply only to a narrow subset of overall projects, and cost recovery for electrification projects will need to be fluid as the landscape is likely to shift as the State moves forward with decarbonization efforts.

As it pertains to the larger subset of non-pipeline alternatives where the costs of electrification outweigh the cost of planned gas pipeline repairs or replacements, PG&E stresses the urgent need for non-ratepayer funds, such as state and federal funding, to fund the projects. To keep rates affordable, gas utilities must seriously evaluate any potential incremental increase in rates that may further burden our customers. We still do not know the full extent of decommissioning costs, electrification costs, and behind-the-meter costs; but those costs could be in the billions in today's dollars. Having a dedicated source of funding that does not increase customer rates will allow gas utilities to pursue environmentally beneficial and non-cost-effective projects without burdening customers with further costs.

32. Are the proposed criteria appropriate for assessing distribution infrastructure projects? Why or why not?

The information requested under section 5.1 is generally consistent with how PG&E already documents its pipeline replacement projects. PG&E notes that cost benefit ratios (item

7) are not currently available for the majority of gas distribution projects. But outside of the pipeline replacement program, much of PG&E's projects are initiated because of compliance requirements or reasonable cost benefit analyses by field employees. For example, a leak repair on a service could result in a full service replacement or a repair, but few, if any, of the criteria proposed would be appropriate or available at the time of decision.

33. How should the CPUC determine thresholds for approval?

For projects to move forward without delay, PG&E recommends that direct CPUC approval be required only for projects meeting the requirements of GO 177. For projects not meeting the GO 177 thresholds, PG&E proposes that such gas distribution spending be approved through the GRC. In conjunction, each gas utility would submit and update their plans for decarbonization consistent with the state's goals in the GRC.

34. What Commission review schedule is necessary so utilities can implement projects in a timely manner?

Consistent with the response to Question 33 above, PG&E recommends that Commission review and approval be limited to projects covered by GO 177. The Commission review process can add up to a year or greater to project timelines. Such delays can impact coordination and scheduling among trades, reduce project interest, and affect pipeline safety and reliability needs. For instance, in our application for approval of a Zonal Electrification Pilot Project at CSU Monterey Bay (A.22-08-003), PG&E decided to omit one portion of the electrification project in our application for pipeline decommissioning and pursue repair and replacement because PG&E knew that safety and reliability work needed to begin before a potential expedited decision.

35. What process (e.g., advice letter; new ongoing proceeding which reviews all such projects; stand-alone application for each project; or other process) should be used to review this information?

PG&E recommends that only projects meeting the requirements of GO 177 be subject to individual Commission project review and approval. PG&E recommends that the utility GRC be the ongoing venue for the distribution infrastructure spending not covered by the Commission's General Order 177. We believe this approach balances the need for oversight of the decommissioning process with the need for flexibility and timely implementation at the programmatic level.

B. Section 5.2, Decommissioning

36. How can electric and gas utilities best perform their respective roles to support cost-effective gas decommissioning?

PG&E believes that electric and gas utilities can best perform their respective roles to support cost-effective gas decommissioning where the utilities can act with synchronization to decommission and electrify assets. As both a gas and an electric utility, PG&E is uniquely positioned to fulfill this role.

In addition, as set forth above in Section IV, PG&E believes that certain modifications must be made to the Staff Proposal in order to support cost-effective gas decommissioning. We believe that the Staff Proposal may result in higher than necessary costs, potentially strand investment costs, and apply costs inequitably among customers. As stated in Section IV, PG&E's proposed modifications to the Staff Proposal for natural gas infrastructure decommissioning would offer greater simplicity and flexibility—which PG&E views as critical if we are to reach California's climate goals and proceed cost-effectively.

Additionally, PG&E generally supports decommissioning gas pipeline equipment where planned repair or replacement costs would exceed the costs of electrification. However, where costs to electrify outweigh the costs for planned gas pipeline repairs or replacements, PG&E emphasizes that external sources of funding should be used so that those costs are not passed onto customers.

PG&E also emphasizes that for cost-effective decommissioning, it will be critical for utilities to gain a better understanding of both the magnitude of electric loads and the hourly load profiles associated with electrification technologies. It may be that certain areas, such as the Central Valley, where both behind-the-meter and front-of-the-meter electric infrastructure are usually sized for heavy summer air conditioning, will be better positioned for widespread conversion to electric heating. What is less understood is the impact of conversion to electric hot water heating, as well as the impact of instantaneous hot water heating, which has high demand and low load factor. Impacts to the grid will depend on load diversity or the extent to which groups of customers use appliances simultaneously. Generally, the more customers served from an asset, the greater the load diversity across those customers. Electrification impacts will most affect customer panels and secondary services, with likely impacts to the service transformer, depending on the number of customers served from it and on existing loading. Fewer impacts to the primary system are expected, but this is highly dependent on the existing system capacity, the characteristics of existing loads, and characteristics of the new loads. Because weather conditions drive peak loading, both utilities and the California Independent System Operator (CAISO) will need to plan the electric system for cold winter peak loads as they do now for hot summer peak loads.

X. RESPONSES TO QUESTIONS IN THE STAFF PROPOSAL REGARDING NON-PIPELINE ALTERNATIVES AND FUNDING (SECTION 6)

37. How should the identification and selection of non-pipeline alternatives be coordinated with other programs or proceedings?

PG&E appreciates Staff's recommendation to consider all viable non-pipeline alternatives and the recognition that funding structures will heavily influence viable options.[30] PG&E's proposed modifications allow for the utility to align requirements such that identification and selection of non-pipeline alternatives do not duplicate or conflict with other programs or proceedings. Regulatory harmonization between proceedings is significant; however, PG&E advocates for flexibility in the early stages and the opportunity to raise requests for deviation or modification of existing requirements that may otherwise be barriers to certain projects. The Commission and parties should support accommodating new projects, especially ones that can provide data and lessons learned to help the success of future requirements. PG&E supports a flexible approach that allows the Commission to grant exceptions provided that a gas utility can demonstrate how certain programs meet emissions goals.

[30] Staff Proposal at 21-22.

The Staff Proposal states that funding and ratemaking options should be explored later in this proceeding (Track 2b).[31] PG&E supports developing a robust record on funding and ratemaking options and reserves the opportunity to comment on these issues in the future. PG&E's cost driver incorporates the cost to implement zonal electrification projects and this component depends on benefits from programs that provide funding. PG&E believes coordination of existing and future federal and state funding is critical to the success of achieving cost-effective decarbonization.

38. What cost "rules-of-thumb" should be used to represent the behind-the-meter costs of implementing various non-pipeline alternatives? Responses should address the residential and small commercial sectors and, if possible, also address large commercial (e.g., refrigeration), industrial (boilers and other energy-using equipment) and electricity generation sectors.

In PG&E's experience with non-pipeline alternatives, behind-the-meter costs for each project can vary dramatically. Until more information can be obtained through various pilots and reporting, costs should be assessed on a project-by-project basis and should not be incorporated into any high-level screening. Some of the notable variables that influence costs include: the number and type of appliances being replaced in the project, the layout of existing HVAC systems, existing electrical panel capacity and access to electrical outlets, local contractor pricing, and local equipment pricing/availability.

PG&E supports data collection and the creation of standard reporting mechanisms included in the GRC for tracking and reporting on behind-the-meter costs for completed projects. As additional non-pipeline alternative projects are completed, utilities and interested stakeholders will have more information and the cost "rules-of-thumb" can be developed based on real-world data and used in future decisions.

a) What are the average cost, cost range, and key cost input variables for each non-pipeline alternative that should be considered?

As stated in the responses to Questions 11 and 12, costs vary considerably that are

[31] Staff Proposal at 22.

specific to the electric infrastructure. Project specific review of current conditions inclusive of items such as costs to upgrade distribution grids, costs for available capacity, and costs to upgrade to serve the new load will need to be studied and reported out on in order to create an average cost or a cost range that will be helpful as a future variable.

39. How should non-pipeline alternatives be paid for, both for customers of dual-fuel and single-fuel gas utilities?

Federal and state funding would be ideal sources of funding for non-pipeline alternatives especially when costs directly benefit the public interest. Given current and projected affordability challenges,[32] the Commission and stakeholders will want to consider carefully whether any such additional non-pipeline alternative costs should be borne by utility customers regardless of whether those customers are gas or electric customers. Maintaining customer affordability and cost treatment between dual-fuel and single-fuel gas utilities while pursuing the State's decarbonization goals is a complex issue that requires additional study and analysis once more robust cost information is available. As stated in response to Question 31.c, initial regulatory asset treatment of the behind-the-meter costs of cost-effective non-pipeline alternative projects gives the gas utility the ability to treat these projects in a manner more similar to gas pipeline replacement projects and would unlock the ability for PG&E and other gas utilities to expand the pool of viable decommissioning projects at this early phase. PG&E reserves the opportunity to refine and expand on funding and ratemaking options in Track 2b where funding and ratemaking options are to be addressed.

40. Should non-pipeline alternatives to be pursued in coordination with decommissioning be identified by the CPUC, by gas utilities, a third party, or a hybrid approach?

Due to the complex analyses required to accurately perform hydraulic and electric capacity assessments, it is the gas utilities' role, in coordination with electric utilities as needed,

[32] Order Instituting Rulemaking to Establish a Framework and Processes for Assessing the Affordability of Utility Service, R.18-07-006 (Jul. 12, 2018).

to identify non-pipeline alternatives. Third parties may potentially trigger a non-pipeline alternative evaluation (such as a city looking to decommission gas assets or a university looking to decarbonize its buildings) and will be important partners in providing "boots on the ground" project support, but also likely would not have the technical skills necessary to evaluate whether a non-pipeline alternative is feasible. As stated in Section IV above, the process for gas decommissioning should begin with defining an emissions-based 2045 goal for gas utilities to work towards. Once this goal is established, gas utilities are best suited to identify and plan for non-pipeline alternatives.

41. How should the current conditions of the electric distribution grid be considered when determining non-pipeline alternatives?

The current conditions of the electric distribution grid are an important component of evaluating non-pipeline alternatives; however, as evidenced by the responses to the questions above, the electric distribution grid is only one piece of the puzzle. The current conditions of the electric distribution grid and the necessary costs to upgrade to accommodate a non-pipeline alternative should be incorporated in the calculation to determine whether a project is cost effective. This should be left to the gas utility's discretion when determining which non-pipeline alternatives to pursue. Since electrification would convert gas demand and shift it onto the electric system, electric capacity and supply would be impacted significantly and need to be adequate to support wide-scale gas decommissioning. Some review of the current conditions related to power generation, transmission infrastructure, and costs to upgrade distribution grids and facilities associated with the distribution and service delivery points will be needed. In instances where information is unavailable to the gas utility, such as where systems of one utility's gas and electric systems do not overlap, coordination and additional information regarding the electric system will be necessary.

42. Should criteria for prioritizing communities for decommissioning (defining tranches) be adjusted in light of the characteristics of non-pipeline alternatives? For example, should areas with colder weather be prioritized or de-prioritized for pipeline decommissioning given the capabilities of heat pumps or geothermal technology?

As outlined in Section IV, PG&E proposes that areas of the gas system be prioritized for decommissioning based on four drivers: risk reduction, GHG reduction, equity, and cost reduction. Thus, weather and non-pipeline alternative technology would not serve as explicit drivers for decommissioning prioritization. In addition, the most cost-effective alternative should be selected for a prioritized pipeline to be decommissioned, which may include heat pump or geothermal technology and may be influenced by viability related to colder weather.

XI. CONCLUSION

PG&E appreciates the opportunity to provide these opening comments on the Staff Proposal.

Respectfully Submitted,

By: *\/s\/ Jonathan D. Pendleton*
JONATHAN D. PENDLETON

Pacific Gas and Electric Company
77 Beale Street B30A
San Francisco, CA 94105
Telephone: (415) 973-2916
Facsimile: (415) 973-5520
E-Mail: Jonathan.Pendleton@pge.com

Attorney for
PACIFIC GAS AND ELECTRIC COMPANY

Dated: February 24, 2023