PACIFIC GAS AND ELECTRIC COMPANY RESPONSE TO ENERGY SAFETY REQUEST FOR COMMENTS AND PROPOSALS REGARDING SB 884 10 YEAR PLAN GUIDELINES

I. INTRODUCTION

Pacific Gas and Electric Company (PG&E) submits these comments in accordance with the Office of Energy Infrastructure Safety's (Energy Safety) October 16, 2023, Request for Comments and Proposals (Request) regarding the Senate Bill (SB) 884 10 Year Electrical Undergrounding Distribution Infrastructure Plan (Plan) guidelines. The Request contains a series of questions and instructs parties to submit response comments via email to ElectricalUndergroundingPlans@energysafety.ca.gov by November 2, 2023.

The Request questions fit under two broad topics – requirements for Energy Safety Approval of a Plan and the required components of a Plan. Below is a summary of PG&E's responses to Energy Safety's questions.

Part 1: Requirements for Energy Safety Approval

- Because different factors affect reliability in each electrical corporation's system and service territory, PG&E proposes that:
    - Question 1(a): Rather than establishing a generic "outage program" definition, Energy Safety direct electrical corporations to define the term as appropriate for their system and territory and demonstrate in their respective plans why that definition is appropriate.
    - Question 1(b): Each electrical corporation submitting a Plan propose a method of determining baseline reliability risk. The baseline should be set as of the year of Plan submission and should be determined using existing data.
    - Question 1(c): Each electrical corporation submitting a Plan propose and justify a definition of a "substantial" increase in reliability.
- With respect to the wildfire risk baseline, PG&E proposes that:
    - Question 1(d): Due to differences in the wildfire risk factors in each electrical corporation's service territory and the specifics of each corporation's wildfire risk model, each electrical corporation submitting a Plan should propose a detailed method of determining baseline wildfire risk.
    - Question 1(e): Each electrical corporation submitting a Plan should propose and justify a definition of a "substantial" reduction in wildfire risk.

Part 2: Required Components of Undergrounding Plan

- Question 2(a): PG&E recommends that an undergrounding "project" be defined as a circuit segment or circuit protection zone. PG&E strongly recommends that no requirements or restrictions be set regarding differentiating features or minimum/maximum mileage for a project.
- Question 2(b): PG&E proposes that projects located in high fire risk areas (HFRAs) are aligned with the scope and intent of SB 884 and should be eligible for inclusion in a 10-year Plan.

- Question 2(c): PG&E interprets Section 8388.5(d) and 8388.5(c)(2) as serving different purposes: 8388.5(d) defines minimum criteria for Energy Safety to approve an undergrounding Plan, and 8388.5(c)(2) defines factors electrical corporations must consider when selecting projects for undergrounding. When approving a plan, it may be appropriate for Energy Safety to evaluate additional requirements in the statute beyond the minimum criteria.
- Question 2(d): PG&E recommends that annual metrics and targets be those identified in SB 884: project completion timelines, annual unit cost targets, and annual mileage completion targets. Energy Safety and stakeholders may consider adopting other indicators of program performance and progress that could be tracked and reported in an electrical corporation's bi-annual Progress Reports.

PG&E appreciates the opportunity to respond to these questions from Energy Safety and looks forward to participating in stakeholder workshops to discuss these topics further.

II. PG&E Responses to Energy Safety's Questions

Part 1: Requirements for Energy Safety Approval

Questions Related to Reliability

Public Utilities Code section 8388.5(d)(2) directs Energy Safety to approve an Undergrounding Plan only if the large electrical corporation "has shown" that the Undergrounding Plan will substantially increase electric reliability by reducing the use of public safety power shutoffs (PSPS), enhanced powerline safety settings (EPSS), deenergization events and any other outage programs, and will substantially reduce the risk of wildfire.

Question (a): Section 8388.5(d)(2) refers to "reducing the use of public safety power shutoffs (PSPS), enhanced powerline safety settings (EPSS), deenergization events and any other outage programs . . ." The term "deenergization event" is defined by 8388.5(a)(3) as "the proactive interruption of electrical service for the purpose of mitigating or avoiding the risk caused by a wildfire." The term "outage program" is not defined. Propose how "outage program" should be defined for purposes of implementation of Section 8388.5(d)(2). Explain why this is an appropriate definition?

PG&E believes that it is appropriate for each electrical corporation to propose and justify a definition for the term "other outage programs" in its Plan. Conditions that affect outages in each electrical corporation's distribution system and territory — including baseline reliability, grid structure, and environmental factors such as climate, tree cover, and topography — can vary, as do individual electrical corporations' outage programs. Rather than trying to develop a single, uniform definition that may not be applicable or relevant to all electrical corporations, Energy Safety should require that an electrical corporation define "other outage programs" in its Plan and demonstrate why that definition is appropriate.

With respect to its territory, PG&E interprets the term "any other outage programs" in Section 8388.5(d)(2) to refer to any interruption to customers' electric service not defined by the three preceding categories (PSPS, EPSS, and deenergization event). This includes, for example, outages due to major events such as storms, fires, or earthquakes; outages requested by emergency responders to safeguard their response to major emergencies; and outages due to car accidents, tree strikes, animals, equipment failures, or other external factors. PG&E interprets the term "programs" in "outage *programs*" to refer to both programs under which it is necessary for an electrical corporation to interrupt electric service (for example, support for emergency responders who have requested an outage) and programs intended to restore electric service when it has been interrupted.

PG&E's interpretation of "any other outage program" is appropriate because a customer's experience of an outage is not primarily influenced by the direct cause of the outage. Instead, outage factors such as duration, frequency, external conditions (for example, weather and air quality), and personal factors (for example, a customer's reliance on medical equipment that requires electric power) more directly impact a customer's outage experience. In other words, an outage of eight hours due to a car accident on a hot, windy day may not differ in its impact on customers from a wildfire-risk-driven outage of eight hours under similar conditions. Therefore, to reflect the full benefits customers will experience from undergrounding, electrical corporations should assess the potential impact of undergrounding on all types of outages.

Question (b): Propose a methodology for determining a level of reliability that should be used as the baseline level of reliability against which any assessment of whether the use of PSPS, EPSS, de-energization and other outage programs is increased or decreased is measured. Should the reliability baseline be set as of the date of plan submission, application approval, or another date? Address whether the proposed baseline can be determined using existing data (and if so, where that data can be accessed), or whether a new data set would be necessary.

In response to Part 1, Question (a) earlier in this Section, PG&E identifies differences in the factors that affect reliability within each electrical corporation's system and territory. Because of these differences, PG&E proposes that each electrical corporation submitting a Plan propose a method of determining baseline reliability risk in its Plan. Energy Safety may determine it is appropriate to provide guiding principles for reliability baselines to ensure consistency across electrical corporations. If Energy Safety makes this determination, PG&E respectfully proposes the following principles:

- Baseline calculations should use existing data to facilitate coherence with other reported reliability metrics and avoid the administrative burden of additional data collection.
- Baseline calculations should be consistent with reliability inputs into a Plan's cost-benefit analysis.
- A reliability baseline should represent a reasonable estimate of what would have happened if undergrounding was not implemented.
- A reliability baseline should be set as of the year of Plan submission so that Energy Safety can assess the Plan with a complete understanding of the baseline conditions that work performed under the Plan seeks to mitigate.

- A Plan's reliability impact should be measured holistically, over the full 10 years. Electrical corporations may report on annual and cumulative-to-date reliability impacts, but the reliability impact achieved in any given year may differ from the total impact expected over 10 years, particularly if sites with greater reliability risk are addressed in earlier years of the Plan.

Question* (c): *What would constitute a "substantial" increase in reliability under the proposed methodology?

For purposes of Energy Safety's approval of a Plan, PG&E recommends that each electrical corporation be required to define and justify in its Plan the "substantial" increase in reliability it will achieve by the end of the 10 years.

Defining "significant" as a specific percentage increase for all electrical corporations – for example, 10% – would be overly prescriptive, as electrical corporations' baseline reliability, the structure of their electric grids, weather trends and topography, and other factors that affect reliability will vary. PG&E recommends that consideration of a minimum threshold for an increase in reliability be informed by reliability data for a corporation's grid in Tier 2 and 3 HFTD and HFRA areas.

PG&E also notes that it would be premature to set a precise threshold for substantial reliability improvement at this time because the amount of reliability benefit a plan could achieve will be affected by the final plan guidelines and requirements set by Energy Safety.

<u>Questions related to reduction of risk of wildfire:</u>
Public Utilities Code section 8388.5(d)(2) directs Energy Safety to approve an Undergrounding Plan only if the large electrical corporation "has shown" that the Undergrounding Plan will substantially increase electric reliability by reducing the use of public safety power shutoffs (PSPS), enhanced powerline safety settings (EPSS), deenergization events and any other outage programs, and will substantially reduce the risk of wildfire.

Question (d): Baseline for Wildfire Risk. Propose a methodology for determining a level of wildfire risk that should be used as the baseline level of wildfire risk against which any assessment of whether wildfire risk was reduced is measured. The baseline and comparisons should isolate wildfire risk reduction from other factors (such as cost, reliability, etc.). Should the wildfire risk baseline be set as of the date of plan submission, application approval, or another date?

As with the reliability baseline discussed in Part 1, Question (b) earlier in this Section, PG&E believes that key details of the appropriate methodology to determine baseline wildfire risk will depend on the risk factors in each electrical corporation's service territory and the specifics of an electrical corporation's wildfire risk model. As a result, PG&E proposes that Energy Safety direct each electrical corporation submitting a 10-Year Plan to propose a detailed method of determining baseline wildfire risk in its Plan.

Energy Safety may determine it is appropriate to provide guiding principles for wildfire risk baselines to ensure consistency across electrical corporations. If Energy Safety makes that determination, PG&E proposes the following principles:

- Baseline calculations should use the wildfire risk model(s) that inform the electrical corporations' undergrounding work plans.
- The method of calculating baseline wildfire risk and total risk reduction that results from the Plan should account for the fact that: (1) risk models may be updated throughout the 10-year course of the Plan; (2) as electrical corporations update their risk models, they may include additional consequence dimensions (for example: egress) which will likely result in changes to risk scores and ranks; and (3) risk model outputs will change as more above-ground assets are placed underground.
- A wildfire risk baseline should be set as of the year of Plan submission so that Energy Safety can assess the Plan with a complete understanding of the baseline conditions that work performed under the Plan seeks to mitigate.
- A Plan's wildfire risk impact should be measured holistically, over the full 10 years. Electrical corporations may report on annual and cumulative-to-date wildfire risk impacts, but the risk impact achieved in any given year may differ from the total impact expected over 10 years, particularly if sites with greater wildfire risk are addressed in earlier years of the Plan.

Question (e): What would constitute a "substantial" reduction in wildfire risk under the proposed methodology?

Consistent with PG&E's response to question Part 1, Question (c) earlier in this Section, PG&E proposes that each electrical corporation be required to define and justify in its Plan the "substantial" decrease in wildfire risk it will achieve by the end of the 10 years. PG&E also cautions against Energy Safety adopting a single fixed percentage threshold for "substantial" reduction for all electrical corporations to achieve in their undergrounding Plans. The ability for a corporation's Plan to reduce wildfire risk will be directly affected by the baseline level of risk in that territory, the scale of the workplan (e.g., 2,000 or 10,000 miles) and the specific locations and miles that will be undergrounded in that corporation's workplan. Defining "significant" as a specific percentage increase for all electrical corporations — for example, 10% — would be overly prescriptive. PG&E recommends that consideration of a minimum threshold for risk reduction be informed by each electrical corporation's risk model, baseline risk, and conditions that affect wildfire risk — such as climate, topography, and vegetation — and the electrical corporation's undergrounding workplan itself.

Part 2: Required Components of Undergrounding Plan

Section 8388.5(c) sets out the required components for the Undergrounding Plan. Subsections 8388.5(c)(2) – 8388.5(c)(4) direct the large electrical corporation to identify, prioritize, and compare undergrounding projects.

Undergrounding Projects

Question (a): Public Utilities Code section 8388.5 refers to "undergrounding projects" that will be constructed as part of the program. The term "undergrounding project" is not defined. How should "undergrounding project" be defined for purposes of section 8388.5? What features or characteristics should be used to differentiate individual undergrounding projects? Should there be minimum or maximum size requirements for individual undergrounding projects?

PG&E proposes that, for the purposes of Section 8388.5, Energy Safety adopt a definition of "undergrounding projects" that is practical, consistent, and informative over the 10 years covered in a Plan. The definition of "project" should not be at such a granular level that a large electrical corporation cannot reasonably forecast projects for the later years of the Plan.

In PG&E's informal comments submitted on September 27, 2023, to the CPUC Staff Proposal on SB 884 guidelines, PG&E defined a "project" at the circuit segment level (also referred to as circuit protection zone (CPZ)) because its current risk model measures risk at the circuit segment level and does not have more granular risk detail. Project reporting is available at the CPZ level. When projects are scoped and planned for near-term completion (e.g., within 3 – 4 years), PG&E creates sub-projects, or jobs, which will reflect portions of a CPZ. PG&E identifies jobs based on mileage, diversity of risk ranking, dependencies (e.g., easements, environmental permitting issues) and constructability. As the risk models are periodically updated and released, projects may be added to the workplan, reprioritized, or removed.

To demonstrate the level of data available for reporting and substantiate the rationale for clarifying the definition of a "project," PG&E illustrates this issue in a sample project and sub-project-level workplan in Table 1 below (noting not all required reporting fields are included).

Table 1 shows that CPZ 1 has three sub-projects that are in various stages of construction (construction, pre-construction, and scoping). Each of the three sub-projects has a unique Project ID (Orders 1234, 1235, and 1236) to track the sub-project's associated costs. The net benefit of each of the three sub-projects is the same as the net benefit of its CPZ because PG&E's risk model measures risk at the CPZ level. While PG&E executes work at the sub-project level, PG&E can only report risk reduction, and therefore net benefits, at the CPZ level. Table 1 shows that circuit segments scheduled for later in the program (2030+ in the example above) have not yet been divided into sub-projects. The number of sub-projects and miles within each sub-project will be determined closer to the planned project start date. For the reasons described above, PG&E recommends that a "project" be defined as a circuit segment or circuit protection zone.

TABLE 1
SAMPLE PROJECT LEVEL 10-YEAR WORK PLAN

Project ID	CPZ	Status	Net Benefit Forecast	Miles Forecasted Based on Latest Risk Model									
				In-flight sub-projects (jobs)				Projects (CPZs) identified by latest Risk Model					
				2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
CPZ 1	**CPZ 1**	**Various**	**67.6**	**1**	**7**	**3**	**5**						
Order 1234	CPZ 1-a	Construction	N/A	1	4								
Order 1235	CPZ 1-b	Pre-construction	N/A		3	3							
Order 1236	CPZ 1-c	Scoping	N/A				5						
CPZ 2	**CPZ 2**	**Various**	**34.7**	**2**	**7**	**3**							
Order 2234	CPZ 2-a	Construction	N/A	2	1								
Order 2235	CPZ 2-b	Permitting	N/A		6								
Order 2236	CPZ 2-c	Scoping	N/A			3							
CPZ 3	**CPZ 3**	**Various**	**20.2**					**35**					

PG&E strongly recommends that no requirements or restrictions be set regarding differentiating features or minimum/maximum mileage for a project. Electrical grids and the undergrounding process are complex, and thus projects vary significantly in their attributes. To arbitrarily establish limitations on what can be considered a "project" could have significant consequences for a workplan and a utility's ability to deliver risk reduction and reliability improvements.

Question (b): Section 8388.5(c)(2) requires the large electrical corporation to identify the undergrounding projects that comprise the plan. Energy Safety intends to require the large electrical corporation to provide the circuit number, mileage, and location (including whether the project is in a tier 2 or tier 3 high fire-threat district or rebuild area) for each undergrounding project. What other information should be provided for this identification? Should the large electrical corporation include projects located in in utility-identified high fire risk areas (HFRA)?

PG&E supports guidelines that require corporations to provide information that supports transparency and accountability for the delivery of an undergrounding program. In addition to the data points noted above by Energy Safety, PG&E would be supportive of providing project information such as:

- Project Status
- Risk Model used for Project Selection
- Risk Rank
- Risk Score
- Feasibility Score

PG&E proposes that undergrounding projects located within the HFRA, like those located within the HFTD, be eligible for inclusion in a corporation's 10-year Plan. Tier 2 and Tier 3 of the HFTDs were developed under supervision by the CPUC to identify areas where stricter fire-safety regulations are to be applied. The maps were created in 2018 by identifying areas with elevated risk and extreme risk, respectively, from wildfires associated with overhead utility power lines and equipment. Similarly, PG&E's HFRA identifies areas in PG&E's service territory where overhead electrical infrastructure could be the source of an ignition that could result in a catastrophic fire during a hazardous offshore wind event. The HFRA is used to inform the geographic scope of PSPS events. The HFRA model is reviewed annually and updated with the most current fuels and weather data. To the extent changes are needed to the HFTD maps, PG&E will continue to engage in the process to incorporate potential updates to the maps.[1]

PG&E believes projects in the HFRA are aligned with the scope and intent of SB 884 and, therefore, should be eligible for inclusion in the Plan based on the logic that eligibility should be extended to projects located in areas where an ignition could lead to a catastrophic fire. Inclusion of projects in HFRA would not dilute the focus from HFTDs – for context, PG&E's 2023-2026 undergrounding workplan as filed in the WMP had approximately 2% of its work planned in an HFRA that did not fall within the boundaries of the Tier 2 or Tier 3 HFTD.

Question (c): Section 8388.5(c)(2) also requires the large electrical corporation to provide a means of prioritizing undergrounding projects based on wildfire risk reduction, public safety, cost efficiency, and reliability benefits. Energy Safety's approval of the plan, however, must be based on wildfire risk reduction and certain reliability improvements. How should the prioritization elements be distinguished from the Undergrounding Plan approval criteria in Section 8388.5(d)?

PG&E interprets the criteria in Section 8388.5(d)—substantial increase in electrical reliability and substantial wildfire risk reduction over the 10-year period—as the minimum criteria needed for Energy Safety to approve an undergrounding Plan.[2] It may also be appropriate for Energy Safety to evaluate additional requirements in the statute when approving a Plan.

The factors described in Section 8388.5(c)(2) serve a different purpose than the minimum approval criteria in Section 8388.5(d). Section 8388.5(c)(2) lays out four factors to be considered by electrical corporations when "prioritizing undergrounding projects," two of which overlap with Section 8388.5(d) (wildfire risk reduction and reliability) and two of which do not (public safety and cost efficiency). Electrical corporations must consider all four factors when

[1] PG&E notes that on April 29, 2023, the Public Advocates Office of the California Public Utilities Commission (Cal Advocates) filed a petition to modify at the CPUC to establish a process and timeline for updating HFTD maps in Rulemaking 15-05-006. Cal Advocates' petition to modify is still pending at the CPUC and it is unclear when the CPUC will act on this request.

[2] PG&E notes that Section 8388.5(d)(2) states that "The office may *only* approve the plan" (emphasis added) if it will substantially increase electrical reliability and reduce wildfire risk. The word "only" communicates that the criteria that follow are required, but the statute does not state that these are the only criteria Energy Safety may consider.

selecting projects for undergrounding, even if public safety and cost-efficiency are not considered by Energy Safety in the process of approving the Plan.

PG&E also notes that the term "prioritization" could be interpreted to mean the order in which projects are sequenced for construction. Because of the myriad factors that impact construction schedules, including permitting timelines, project complexity, and resource requirements, it is not feasible for prioritization based on the four factors identified in Section 8388.5(c)(2) to directly drive construction sequencing. As such, PG&E does not think how projects are sequenced for construction once they have been selected based on an electrical corporation's prioritization methodology should influence Energy Safety's approval of a Plan.

Question (d): Section 8388.5(c)(3) requires the large electrical corporation to provide: (1) timelines for the completion of identified and prioritized undergrounding projects; (2) unit cost targets for each year covered by the plan; and (3) mileage completion targets for each year covered by the plan. Are there other completion metrics or annual targets that should be included in the Undergrounding Plan?

No, there are no other completion metrics or annual targets that should be required in an Undergrounding Plan. However, there are several indicators that could be regularly reported in the bi-annual Progress Reports to provide Energy Safety, the Commission, and stakeholders a fuller picture of the progress, success, and accomplishments of a corporation's undergrounding program. Indicators are distinct from metrics in that targets are not established for indicators. Instead, they convey status and progress and other insights into program performance. PG&E recommends that Energy Safety's guidelines only require the timelines and unit cost and mileage targets as required by Section 8388.5(c)(3) and work with stakeholders to identify various progress and completion indicators that a corporation should provide in its Progress Reports.

III. CONCLUSION

PG&E appreciates the opportunity to provide these comments, and requests that Energy Safety take these recommendations into account in the development of their SB 884 10-Year Plan guidelines.

Respectfully submitted,

/s/ Jamie L. Martin

Vice President, Undergrounding
Pacific Gas and Electric Company