TRANSMITTED VIA ELECTRONIC MAIL

DATA REQUEST

Request Date: Oct 23, 2026

Response Due: Oct 28, 2026

To:

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Originator: David Rey
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Data Request Number: Energy Safety-DR-EUP-26-08

Subject: Alternative Mitigations and Portfolio Project Selection

INSTRUCTIONS

a. Provide all information in your possession, custody, or control, or the possession, custody, and/or control of your affiliates or agents, that is responsive to these data requests by the due date identified above.

b. Responses and documents may be produced and served electronically, but they shall be fully machine-readable and searchable.

c. If you have any questions about the meaning or scope of the data requests herein, direct such questions to the Energy Safety staff identified as the "Originator" of this request at your earliest opportunity.

    1. Lack of clarity on meaning or scope of requests, without prior request for clarification from the "Originator," will not be a permissible reason for incomplete responses and will be regarded as non-compliance with the request.

d. Identify the personnel (employees, consultants, agents, etc.) who provided information responsive to each of the data requests below. As used in this context herein, "identify" means to provide the full name, business address, and title of each employee, consultant, or agent who provided such information.

e. If you do not know the exact answer to any of the requests below, please so indicate and provide your best estimate.

f. Provide data in its original format (i.e., PDF, Excel, GIS shapefile, etc.), unless otherwise specified in the request.

g. Send your response to David Rey (David.Rey@energysafety.ca.gov), and include a copy to:

    Simone.Brant@energysafety.ca.gov,
    Shaun.Richards@energysafety.ca.gov,
    electricalundergroundingplans@energysafety.ca.gov

h. E-file a copy of the response on the Electrical Undergrounding Docket #EUP-PGE

REQUEST

Q01. Selection of Alternative Mitigation Strategies for Screens 2 and 3

1. Provide the analyses and decision criteria supporting PG&E's selection of the Alternative Mitigation strategies used in Screens 2 and 3:
    a. Identify the mitigation types and combinations of mitigation types PG&E evaluated for inclusion in its Alternative Mitigation framework, including any which were excluded.
    b. Describe the screening criteria applied to each candidate mitigation, including technical feasibility, risk reduction, reliability, costs, scalability, readiness, and applicability to the EUP Circuit Segment population.
    c. Explain why PG&E selected overhead hardening and 100% Remote Grid as the Screen 2 alternatives and how PG&E determines that these alternatives constitute useful comparisons to undergrounding.

Q02. Consideration of Alternative Screen 2 Alt 2 Configurations

1. Identify whether PG&E considered alternative configurations for Screen 2 Alternative Mitigation 2 (Alt 2) other than 100% Remote Grid, including but not limited to combinations of overhead hardening with Rapid Earth Fault Current Limiters (REFCL) or other advanced protection, advanced grid monitoring, line removal, system reconfiguration, or partial Remote Grid:
    a. For each configuration evaluated, identify the components, feasibility and risk-reduction criteria, and the results or basis for eliminating it from further consideration.
    b. For mitigation combinations not evaluated, explain the reasons they were not considered and whether PG&E anticipates assessing their use during EUP implementation.
2. Explain whether PG&E considered using different Screen 2 Alternative Mitigation 2 configurations for Eligible Circuit Segments based on technical applicability, rather than a single 100% Remote Grid design variation, and provide any existing supporting analysis. Include whether PG&E performed any automated circuit segment screening or technical suitability assessments, such as simple checks based on customer count, segment length, and position on the circuit.

Q03. Feasibility and Decision Value of 100% Remote Grid as Screen 2 Alternative Mitigation 2

1. Explain the role of 100% Remote Grid with line removal (100% RG) as Screen 2 Alternative Mitigation 2 (Alt 2):
    a. Identify whether Screen 2 identified any Eligible Circuit Segments for which 100% Remote Grid has a higher modeled benefit-cost ratio (BCR) than both 100% undergrounding and Screen 2 Alternative Mitigation 1, and which appear, based on currently available information, to be reasonable candidates for further Remote Grid scoping.
        i. In making this preliminary assessment, consider factors such as circuit topology and configuration, customer count, circuit segment location, service continuity needs, and other relevant technical or operational constraints.
        ii. For each such segment, provide its Circuit Segment ID, the BCRs for the three Screen 2 design variations, and a brief explanation of the factors supporting its potential suitability for further evaluation, including any significant known constraints.
    b. Describe what segment-level feasibility screening is performed between Screen 2 and Screen 3 for potential 100% Remote Grid projects including customer count, load, system configuration, land constraints, reliability requirements, and any other material limitations.
    c. Explain how results from the 100% Remote Grid comparison inform Screen 2 screening or project progression and later Screen 3 mitigation selection, given that partial Remote Grid opportunities may be identified through separate project-level reviews.

Q04. Remote Grid Screening in Screen 3 and Additional Comparison 3

1. Does the Remote Grid feasibility review used for Screen 3 Alternative Mitigation (S3 AM) follow the same criteria/process as Additional Comparison 3 (AC3)? If not, describe each process and provide the Remote Grid feasibility result for each Portfolio 0 project.
    a. Describe the screening sequence, technical feasibility criteria, and decision points for Remote Grid under each process. State whether the same criteria are used; if not, explain the differences.
    b. Explain how a Remote Grid option could be included in S3 AM rather than being considered only within AC2 or AC3.

c. For all Confirmed Projects for which Remote Grid was considered for S3 AM, please provide the BCR for the model design variation that was compared to the chosen S3 AM.

2. Choose one of the confirmed projects for which OH + Remote Grid was considered for use as S3 AM. Use this project as an example and explain how and where the Remote Grid location was identified, how the total BCR was calculated, and the likely reasons the BCR was less then 100% OH for that project.

Q05. Basis and Application of the 70% BCR Threshold

1. Provide the basis for applying the 70% BCR comparison threshold described in EUP Chapter 3:
   a. Provide the quantitative analysis, empirical evidence, or other documentation supporting the use of a uniform 30% estimate-uncertainty allowance across projects and mitigation types. Distinguish uncertainty in project costs from uncertainty in modeled benefits and BCRs.
   b. Explain how the 30% allowance is translated into the 70% comparative BCR rule, including whether it represents a statistical confidence interval, estimating range, or policy-based screening tolerance.
   c. Identify each Confirmed Project where the BCR of 100% undergrounding or AC2 was between 70% and 100% of the S3 AM BCR. For each, provide the comparison BCRs, mitigation selected, and rationale for selection.
   d. Explain whether PG&E performed sensitivity analyses using different uncertainty thresholds or project-specific uncertainty ranges. Provide any existing results and describe how the project-selection outcome would differ without the 70% rule.

Q06. Project-Level Standards for Confirmed Projects

1. In Table 12, 12 of the 28 Confirmed Projects do not meet the Project-Level Standard for Project as Scoped. For each Confirmed Project that does not meet its applicable Project-Level Standard:
   a. Identify the Project ID, applicable eligibility threshold and Project-Level Standard, the modeled post-mitigation values, and the extent to which the standard is not met.
   b. Provide the specific project-level justification for including the project as a Confirmed Project.

c. Identify the location in the narrative or other submitted material where this justification is provided or indicate that it has not been documented on a project-specific basis.

Q07. Selection of Confirmed Projects and the 28 Portfolio 0 Projects

1. Describe and document how PG&E selected the initial 28 Confirmed Projects from the broader list of Eligible Circuit Segments:
    a. Identify the candidate population at each decision point, including the screening, ranking, feasibility, scheduling, and other criteria used to select the 28 projects.
    b. For each Confirmed Project, identify whether it was in an existing GRC/WMP undergrounding workplan, had completed any scoping, or otherwise entered project development before application of the proposed EUP Project Acceptance Framework. Provide the relevant dates or stage of development.
    c. Identify any higher-ranked eligible Circuit Segments or Undergrounding Projects, under the ranking measures used by PG&E, that were not included in Portfolio 0 and describe the principal reasons for exclusion or deferral.
    d. Explain how Portfolio 0 demonstrates the proposed Project Acceptance Framework, distinguishing the selection of previously scoped projects from projects selected entirely through the proposed EUP process.
2. Describe the process PG&E will use to advance Eligible Circuit Segments through the Project Acceptance Framework to become Confirmed projects during the remainder of the EUP. Include the KDMMs and other criteria that will be used to prioritize which Circuit Segments advance first.

Q08. New Mitigation Technologies

1. In Chapter 3, page 116 of PG&E's EUP, PG&E states that it considers Minimum Cover Distribution Systems (MCDS) and Ground Level Distribution Systems (GLDS) to be improvements to existing undergrounding methods rather than separate mitigation alternatives.
    a. Explain the basis for this classification, particularly given the differences in installation methods and potential differences in risk characteristics and cost compared to conventional undergrounding.
    b. Describe how PG&E envisions incorporating MCDS and GLDS into the EUP if these technologies become suitable for deployment at a greater scale.

i. Would they be used in place of conventional undergrounding on certain projects and evaluated as undergrounding in Screens 2 and 3?
ii. How would PG&E assess and account for any differences in the technologies, including in wildfire risk reduction, reliability, and costs?

c. Provide a brief technical description of MCDS and GLDS, including their intended applications, current testing and pilot status, and what additional testing or validation is needed before deployment at a greater scale.

END OF REQUEST