TRANSMITTED VIA ELECTRONIC MAIL

DATA REQUEST

Request Date: October 23, 2026

Response Due: October 28, 2026

To:

Kim Sackett
kim.sackett@pge.com
Electric Program Manager
Pacific Gas and Electric (PG&E)
300 Lakeside Drive, Oakland, CA 94612

Wade Greenacre
wade.greenacre@pge.com
Regulatory Relations Advocacy Director
Pacific Gas and Electric (PG&E)
300 Lakeside Drive, Oakland, CA 94612

Originator:

Adam Berlinerman
Adam.Berlinerman@energysafety.ca.gov
Dmitriy Lysak
Dmitriy.Lysak@energysafety.ca.gov
Richard Cao
Richard.Cao@energysafety.ca.gov

Data Request Number: Energy Safety-DR-EUP-26-09

Subject: CPUC Data Template, Present Value Calculation, Screen 2 BCR Inputs, Risk Modeling

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 Adam Berlinerman (Adam.Berlinerman@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 PG&E EUP Docket #PGE-EUP.

REQUEST

This Data Request pertains to the PG&E EUP.

Q01. EPSS/PSPS Modeling

a. Explain the identical expected outage durations for EPSS-enabled and EPSS-disabled events as outlined in WP016A – EPSS Toy Problem. In this explanation, list all assumptions and assumption justifications, address physical differences between the outage types (e.g., increased circuit segment length impacted by EPSS-enabled outages), and list any expected model updates.
b. What are PG&E's working definitions of failures, events, outages, momentary outages, sustained outages, and Raw WDRM Probability of Failure (PoF)? What are the main differences between them?
c. What if any adjustments to account for EPSS are applied to the Raw WDRM PoF in WP016A – EPSS Toy Problem? List and explain.
d. Does EPSS enablement affect the PoF? Please explain.
e. Why does PG&E use Raw WDRM PoF rather than p(e)Observed[1] as the starting point of EPSS Outage Program Risk calculations?
f. In response to DR No. Energy Safety-DR-EUP-26-04, PG&E stated that "for events where both distribution and transmission facilities are de-energized, the model attributes the associated PSPS outage risk to the distribution system. This treatment is consistent with the modeling assumption that, if the distribution facilities were undergrounded, temporary generation at the substation would be available to serve customers and avoid the outage. Therefore, the modeled risk is evaluated as addressable through the distribution mitigation."
    i. When does PG&E provide temporary generation at the substation to avoid outage?
    ii. Has temporary generation been installed at substations for PSPS that affect only transmission lines or undergrounded distribution lines?

[1] Pacific Gas and Electric Company Electrical Undergrounding Plan Attachment B WP015 Distribution Event Probability Models Version 4 (DEPM V4), at pg. 610.

iii. How long does it take to set up temporary generation at a substation?
iv. Is this applicable to all substations/circuits or limited by generation capacity?

i. WP020 PSPS V1 Risk Model Documentation describes noncore fallback when an upstream ancestor exceeds 11 generations.
   i. What is the average number of circuit segments on a circuit? How often are there more than 11 sequential circuit segments?
   ii. How many events or circuit segments utilize the noncore fallback?
   iii. Why is core spreading limited to 11 upstream generations?
j. Provide separate EPSS and PSPS Table 8 Outage Program Likelihood/Consequence/Risk values for each "circuit segment."
k. WP018 states that "EPSS risk is defined as the incremental risk of outages that exceed the standard outage risk when EPSS is not enabled. This includes outages that were mitigated due to EPSS being active, by considering the likelihood of those outages occurring if EPSS had not been enabled during the same time. In contrast, the EPSS likelihood reported for the EUP reflects the full likelihood of an EPSS outage, encompassing all outages that would have occurred during that time regardless of EPSS activation. This approach ensures a comprehensive representation of outage likelihood, though it introduces a potential mismatch in risk and likelihood reporting."
   i. Is the risk calculated using the incremental likelihood but then reported in Table 8 as the full outage likelihood value?
   ii. Is the consequence reported back calculated using the full outage likelihood value?
   iii. How does the full likelihood of an EPSS outage ensure a comprehensive representation of outage likelihood? In particular, why not report the incremental likelihood of outages to match the EPSS outage risk methodology?

Q02. Project Variable Modifiers (PVMs)

a. Within PG&E's EUP, the trade-off between Ignition Risk and Outage Program Risk in Core Capability 3 is described as "an 80 percent decrease in Ignition Risk and a 46 percent decrease in Ignition Likelihood associated with EPSS and PSPS."[2] However, in response to WMP-Discovery2026-2028_DR_TURN_004-Q002(b), the combined effectiveness of EPSS and PSPS is approximately 95 percent. Please explain this difference in combined effectiveness including any differences in methodologies.
    i. Provide all supporting calculations/assumptions for the combined effectiveness as reported in the EUP in Excel.
b. Explain why there is an 80 percent decrease in Ignition Risk but only a 46 percent decrease in Ignition Likelihood.
    i. Provide all supporting calculations/assumptions for the 80 percent decrease in Ignition Risk and the 46 percent decrease in Ignition Likelihood in Excel.
c. Why are identical percentage reductions (80 percent and 46 percent) applied to circuit segment ignition risk and ignition likelihood regardless of circuit segment-specific risk drivers and circuit segment-specific EPSS and PSPS enablement criteria?
    i. Why not apply identical percentage reductions to risk sub-drivers and/or incorporate circuit segment specific EPSS and PSPS enablement criteria?
    ii. Why not apply identical percentage reductions to any other granularity of risk and/or likelihood?
d. Are PVMs applied at the sub-driver level of granularity for Screen 2 purposes?
e. Fill in the table below with the Blended Average Mitigation Effectiveness Values similar to Table PG&E-8.2.1-3: Ignition Mitigation Effectiveness Representative Blended Average Values within the 2026-2028 PG&E WMP. If PG&E elects to report any portion of the table as "N/A" please justify in a footnote.

[2] Pacific Gas and Electric Company Electrical Undergrounding Plan, at pg. 313

Baseline/Mitigation Scenario	EUP: Ignition Risk	EUP: Outage Program Risk	EUP: Overall Utility Risk	W/o EPSS/PSPS enablement: Ignition Risk	W/o EPSS/PSPS enablement: Outage Program Risk	W/o EPSS/PSPS enablement: Overall Utility Risk
EPSS alone						
PSPS alone						
DCD alone						
EPSS+PSPS						
EPSS+PSPS+DCD						
Covered Conductor alone						
Covered Conductor+EPSS						
Covered Conductor+EPSS+PSPS						
Covered Conductor+EPSS+PSPS+DCD						
UG Primary						
Remote Grid						

Q03. Risk model impact factor justification

a. PG&E's Post-Filing Workshop mentions that WDRM and OPRM refresh will begin in 2028. Please provide estimated model update years starting with the models used for EUP submission and ending at PG&E's proposed EUP end date. These years should reflect when the relevant models will begin impacting the EUP. If all relevant models will not be updated in the same year, please report each model and each associated update year individually.
b. PG&E's EUP cites observed variance in the change to Wildfire Distribution Risk Model (WDRM) v4 from WDRM v3 as well as Interruption Cost Estimate (ICE) 2.0 from ICE 1.0 when determining the Risk Model Impact Factor.
    i. What was the reason for the large changes observed when moving to WDRM v4 and ICE 2.0?
    ii. Does PG&E expect to see similar large shifts in these risk models? Please explain.
c. Does PG&E apply the Risk Model Impact Factor to the stated total risk reduction values of $15.1 billion Overall Utility Risk, $4.5 billion Ignition Risk and $10.6 billion Outage Program Risk?

Q04. High-Risk Threshold

a. PG&E's EUP sets the High-Risk Threshold using an acceptance loss exceedance curve set by "an individual risk acceptance of 0.5 x 10-6 fatalities per year defined as an acceptable risk for an average individual in the vicinity of a nuclear power plant."
    i. Explain why an acceptable risk for an average individual in the vicinity of a nuclear power plant is an appropriate metric to use for determining if a Circuit Segment should be eligible for expedited undergrounding.
    ii. Why does PG&E sort by wildfire risk per mile to set a threshold that uses Overall Utility Risk?

iii. If PG&E sorts Circuit Segments by Overall Utility Risk, how many circuit segments are above the risk acceptance criterion and what is the lowest Overall Utility Risk per mile of these Circuit Segments?
iv. Provide the loss exceedance plot used to determine the High-Risk Threshold
v. Provide the underlying data used to make the plot, including any consequence or other risk values.

b. PG&E's EUP uses HFTD+HFRA primary overhead distribution mileage to calculate overall utility risk density when determining if a Circuit Segment meets the High-Risk Threshold. The EUP then allocates the full Cicuit Segment's risk to the portions of the Circuit Segment in an HFTD or HFRA, citing that "The vast majority of risk on a Circuit Segment that crosses HFTD/HFRA areas and non HFTD/HFRA areas is concentrated in HFRA/HFTD areas."
   i. Please describe why this is an appropriate assumption to make. Has PG&E done any analysis to determine that this assumption can be broadly applied to all Circuit Segments that cross HFTD/HFRA and non-HFTD/HFRA areas?
   ii. The outage program risk values include risk from all customers on the full Circuit Segment as well as downstream Circuit Segments. Does undergrounding portions of a Circuit Segment in an HFTD/HFRA fully mitigate this risk? Would remaining overhead portions of a Circuit Segment outside of HFTD/HFRA still be subject to EPSS settings or PSPS calls if those portions were inside of a PSPS polygon?

Q05. Project Selection

a. explain PG&E's rationale for sorting by WF Risk Rank when creating the Screen 2 Proposed Project List.
b. The Plan Tracking Objectives list 93 projects that have passed Screen 3 and 4 in Year 1. Will all these projects be selected using the criteria described in the Project Prioritization and Decision Tree, or were some projects scoped/selected through a different process?

c. PG&E's Additional Comparison 2 includes areas of impact that include Tree Strike Risk Criteria, Ingress/Egress Risk, and PSPS Risk.
    i. Describe the criteria and method used to determine these areas of impact. Include any SME input.

Q06. Climate Risk

a. PG&E's EUP uses the RCP 8.5 pathway to assess the impact of climate change and calculate climate factors to apply to KDMMs. WP005 describes this as the worst case when compared to RCP 2.6, 4.5 and 6.0. WP005 also states "Marsh did not assess the likelihood of these condition sets occurring." Describe PG&E's rationale for using this pathway.

Q07. PMO basis and explanation

a. PG&E states that the targeted undergrounding of 4,000 miles of the highest-risk Circuit Segments provides the basis for the PMO. What is PG&E's definition of "highest-risk Circuit Segments"[3]?
    i. Does PG&E have a numerical threshold for identifying the "highest-risk Circuit Segments?" If so, list this threshold and explain the basis for the threshold and why PG&E is using a threshold other than the EUP Guidelines specified High-Risk Threshold.
b. PG&E establishes the PMO using approximately 4,000 overhead miles to be removed and deenergized. However, the Project Acceptance Framework results in 20,618.4 Eligible Circuit Segment Miles in HFTD. Explain PG&E's process of reducing 20,618.4 miles to 4,000 miles.
c. What was the basis for choosing to set the PMO based on undergrounding 4,000 overhead miles.
d. Explain why PG&E considers an annual average reduction of $145,000 in Overall Utility Risk per primary overhead mile removed to be substantial risk reduction.

[3] Pacific Gas and Electric Company Electrical Undergrounding Plan, at pg. 52

e. PG&E states that the EUP Portfolio may reduce up to approximately $15.1 billion in present-value OUR over the 55-year life of the underground assets, $4.5 billion in Ignition Risk reduction and $10.6 billion in Outage Program Risk reduction[4]. Does PG&E consider all or some of these values as part of the Public Utilities Code Section 8388.5(d)(2) "substantially increase electrical reliability…" and "substantially reduce the risk of wildfire" requirements?

f. The Plan Tracking Objectives do not align with the Target/Timeline Table when compared at Year 10 instantaneous values.
   i. Can PG&E explain the discrepancy?
   ii. Does the Target/Timeline Table represent the EUP's projected outcome?
   iii. Does PG&E apply a reduction factor other than the Risk Model Impact Factor for the Plan Tracking Objectives and Plan Mitigation Objective from the projected outcome?

g. Table 1-1 states that there are 8,805 Overhead Circuit Miles Eligible for Undergrounding. This is different than the number of eligible miles under the Project-Level Thresholds. Please describe what criteria are used to determine this number of eligible miles.

Q08. Present Value Calculation

a. As stated in WP006, PG&E is using the following formula to derive Present Value of O&M Costs

$$\sum_{t=1}^{Asset\ Lifetime} \frac{Annual\ O\&M\ Costs}{(1 + Real\ Discount\ Rate)^t}$$

Applying the above formula, Energy Safety is able to derive a present value that is close to, but not exactly matching, what is reported in CPUC Table 1. For example, looking at Proj00001-3UG-UGAS, incremental O&M costs are 0.001263181 per year.

$$\sum_{t=1}^{55} \frac{0.001263181}{(1 + 0.0461)^t} \approx 0.025103$$

[4] Pacific Gas and Electric Company Electrical Undergrounding Plan, at pg. 46-47

This is close to the reported incremental_om_cost_pv of 0.026240755. Provide an explanation for the discrepancy.

b. Using the following formula and data fields, Energy Safety is able to derive a Benefit Cost Ratio (BCR) that is close to, but not exactly matching what is reported in CPUC Table 1.

$$\frac{total_mitigation_benefit_scaled}{(total_capex \times PVRR) + incremental_om_cost_pv + incremental_om_savings_pv}$$

Looking at Proj0008-3UG-UGAS as an example:

$$BCR = \frac{95.53408497}{(45.60679451 \times 1.39) + 0.107757102 - 5.644961677} \approx 1.651232$$

This is close to the reported benefit_cost_ratio_scaled of 1.6058. Provide an explanation for the discrepancy.

Q09. Screen 2 BCRs

a. Provide a version of CPUC Table 1 for all BCRs that were submitted in Energy Safety's Screen 2 Table (Table C.1.11). The following conditions must be satisfied.

   i. For purposes of this request, PG&E will need to generate unique rru_ids. PG&E's current rru_ids utilize project_id (e.g. Proj00001-3UG-ALT1). Given that not every Circuit Segment in the Screen 2 Table has a project_id, describe the naming convention for the generated rru_id and how it relates to a row in the Screen 2 Table.

   ii. The cost_benefit_ratio value in Energy Safety Table C.1.11 should exactly match the benefit_cost_ratio_scaled value in CPUC Table 1 for a given Circuit Segment.

   iii. PG&E only provided BCRs for costs and benefits discounted under the WACC discount rate in Table C.1.11 for their EUP submission. In CPUC Table 1, data was provided for all three discount rates. Provide CPUC Table 1 data under the WACC scenario to match the level of detail of Table C.1.11. Data for the Societal and Hybrid scenarios can be provided, if available, but is optional.

b. Provide Screen 2 BCRs calculated using the methodology that would be required if the CPUC Joint Application (A.26-02-005) Proposed Decision is adopted for each circuit segment in the Screen 2 Table.

END OF REQUEST