# PACIFIC GAS AND ELECTRIC COMPANY
# PG&E Ref. DRU13828
# Data Request OEIS
# Requester DR No. Energy Safety-DR-EUP-24-02

**Requester: Brant, Simone**
**Request Date: June 17, 2024**
**Response Date: July 01, 2024**

**<u>Question No. 001:</u>**

**Please provide information requested as it pertains to Electrical Undergrounding Plan (EUP) reliability modeling.**

Below are several scenarios for a limited model of Outage Program Risk. For each scenario, please comment on the expected time it would take PG&E to develop the model and any major concerns with using said model for EUP purposes. For each case, if there is a significant difference in the difficulty of performing the separate, collective, and ablation analyses, please specify which analyses are more difficult and why. If there is a difference at the system and portfolio level for any of the listed scenarios, please explain why. If there are any significant differences in the development of the PSPS/EPSS models for any scenario, please indicate which cases and explain why.

a. A model that examines a mitigation on a single isolatable circuit segment at a time and computes likelihoods of PSPS/EPSS and the consequences of PSPS/EPSS to customers on that segment alone based purely on back casting historical data.
b. The same as (a) but using projected weather/climate factors.
c. A model that examines a single mitigated isolatable circuit segment at a time and computes likelihoods of PSPS/EPSS being called on that isolatable circuit segment and the consequences of PSPS/EPSS on that isolatable circuit segment and 'downstream' customers based purely on back casting historical data.
d. The same as (c) but using projected weather/climate factors.
e. Same as (a), but also includes likelihood of the segment being de-energized due to a PSPS/EPSS event on an upstream circuit segment.
f. Same as (e) but using projected weather/climate factors.
g. Same as (c), but also includes likelihood of the segment being de-energized due to an upstream PSPS/EPSS event.
h. Same as (g) but using projected weather/climate factors.
i. Same as (e) but also considering all other proposed EUP Projects.
j. Same as (f) but also considering all other proposed EUP Projects.
k. Same as (g) but also considering all other proposed EUP Projects.
l. Same as (h) but also considering all other proposed EUP Projects.
m. A model with similar levels of granularity, specificity, and accuracy as the WDRM (Wildfire Distribution Risk Model)
n. Is there a modeling gap between scenario (l) and (m)? If so, please explain what factors or features are absent in scenario (l).

**<u>Response to Question No. 001 Response No. 001:</u>**
The information provided by PG&E in these responses is based on our understanding of the Draft Guidelines.

Subparts A and B: PG&E estimates that it will take approximately 9 months to develop a reliability model that can conduct a separate analysis. The model would allow a user to analyze a mitigation on a single isolatable circuit segment at a time and would compute the probability of PSPS/EPSS and the consequences of PSPS/EPSS to customers on that segment alone based on back casting historical data.

Subparts C-H: PG&E estimates that it will take approximately 9 months to develop a reliability model capable of performing collective analyses that will allow a user to analyze a mitigation on a single isolatable circuit segment plus upstream and/or downstream customers. This model would compute the probability of PSPS/EPSS and the consequences of PSPS/EPSS based on back casting historical data.

Subparts I – L: PG&E estimates that it will take approximately 9 months to develop a reliability model capable of performing collective analyses considering all proposed EUP projects. This model would compute the probability of PSPS/EPSS and the consequences of PSPS/EPSS based on back casting historical data.

Our current estimate is that it will take approximately 18-24 months to develop a reliability model capable of performing ablation analysis that we can provide to Energy Safety. We are continuing to explore ways to reduce this estimate.

We can do the work described above in parallel. The maximum time required to build the reliability model would be 18-24 months.

We will develop the reliability model using only back cast data. In our experience, back casting historical data provides a better estimate of potential future events than attempting to estimate weather/climate factors in the future.

Subparts M and N: Our reliability model will have similar levels of granularity, specificity, and accuracy as the WDRM. No, there is no modeling gap between Scenarios L and M.

The reliability modeling requirements presented in the Guidelines do not align with how we currently plan and scope undergrounding work. We would like an opportunity to share with Energy Safety how we consider reliability when developing undergrounding projects to help determine the right parameters for a reliability model.

**<u>Question No. 002:</u>**

**Please provide information requested as it pertains to PG&E-designated 'Hybrid Projects.'**

a. In PG&E's May 29th, 2024 comments on draft guidelines, PG&E described a "hybrid" approach or "hybrid distribution hardening" as "a circuit segment that is hardened using a combination of covered conductor, undergrounding, and/or line removal with remote grid" and "recommends defining hybrid electric distribution hardening as a sub-project that consists of at least 80 percent undergrounding and up to 20 percent overhead covered conductor or line removal."[1] The following questions are intended to clarify, and help Energy Safety better understand, this

[1] 2024 PG&E's Comments on Draft Guidelines page 21

recommendation. Please confirm this is PG&E's recommended definition or provide an updated definition with any changes.

b. Please confirm whether it is PG&E's recommendation to apply the "hybrid" designation at the "project" or "subproject" level. The definition provided states "subproject"; however, further comments discuss the percentages (80% and 20%) of circuit segments, which implies project level. The requested table below assumes the project level. (Note that there are further questions regarding subprojects below)

c. In PG&E's proposed definition of "hybrid distribution hardening," is there a definitive list of alternate mitigations that could potentially be included in the 20% non-undergrounding work?

d. Can PG&E elaborate on how and why a circuit segment would become a hybrid distribution hardening project? Please explain the process of scoping a hybrid project and provide an example that illustrates how and why other mitigations were chosen over undergrounding.

   d1 Is the reason for using an alternate mitigation always due to a better cost/risk performance, a physical limitation (such as a river crossing or granite), a combination of both, or some other factor? Please explain.

   d2 Is there a distinction between how an alternative mitigation will be recorded on the EUP if the alternate mitigation is included because of cost/risk performance versus a physical limitation?

e. Provide an .xlsx document that details the number of planned projects, or isolatable circuit segments, for each expected combination of underground and "hybrid" projects in PG&E's 2023-2026 Workplan. Include all expected mitigations. For each project or isolatable circuit segment, please report:

| Field Name | Description | Unit/ Datatype |
|---|---|---|
| **Total Circuit Segment Miles** | Length of isolatable circuit segment before mitigation | Miles |
| **Total Constructed Miles** | Number of miles of new infrastructure to be energized | Miles |
| **Total Miles Undergrounded** | Number of miles of underground infrastructure to be energized | Miles |
| **Overhead Removed** | Number of miles of overhead line deenergized upon completion | Miles |
| **Covered Conductor Installed** | Number of miles of covered conductor to be installed | Miles |
| **Other Mitigations** | Provide brief description of other mitigation efforts or devices installed that are associated with this project | Text |
| **Justification for Alternate Mitigation** | Provide brief description for each "hybrid" project including the reason undergrounding was not used on the entire circuit segment and why the alternate mitigations were chosen (e.g. better cost/risk performance, physical limitations, or any other reasons) | Text |
| **Other Mitigations Miles** | Add a field for each alternate mitigation to be used and indicate the number of miles of overhead line it will be applied to or replace | Miles |
| **Total Un-Mitigated Circuit-Miles on Circuit Segment** | Number of miles of original, un- mitigated, circuit segment line after completion of project. | Miles |
| **Subprojects** | Number of total subprojects created within this Project. | Integer |
| **Underground** | Number of undergrounding | Integer |

| Field Name | Description | Unit/ Datatype |
|---|---|---|
| **Subprojects** | Subprojects | |
| **Covered Conductor Subprojects** | Number of covered conductor subprojects | Integer |
| **Other Mitigation Subprojects** | Add a field for each alternate mitigation to be used and indicate the number of subprojects associated with it | Integer |
| **Secondary Lines** | Will secondary distribution lines be undergrounded as part of this project? | Boolean |
| **Service Lines** | Will service lines be undergrounded as part of this project? | Boolean |
| **EPSS** | Will EPSS be added to this circuit segment? | Boolean |

f. Provide a general cost comparison, per mile replaced, of each individual mitigation option (e.g. underground, covered conductor, remote grid, other). For remote grids, provide an average cost of the installation and average length of overhead line removed. What is the source for each cost estimate?

g. For the anticipated projects, how many isolatable circuit segments are typical on a given circuit?

h. Are there instances of planned projects in which only a portion of the circuit segment is undergrounded without required overhead hardening work or wildfire mitigation improvements on the remainder of the overhead section(s) of the circuit segment?

i. Provide specific details and examples on how seeking rate recovery through an alternate regulatory process, such as the GRC, for non-undergrounded portions would affect an undergrounding project. Is there a potential for construction delays, and if so, how long would these delays last? Are there scenarios where PG&E would have to return to a circuit segment to construct overhead hardening portions separately?

j. The next PG&E GRC cycle is 2026-2028. The EUP would likely not begin until 2027. Is it possible for PG&E to request covered conductor funding that would otherwise be considered part of a "hybrid project" in the 2026-2028 GRC? If this approach was taken, would this enable EUP undergrounding and GRC-funded covered conductor portions that would otherwise be considered part of a "hybrid project" to be constructed at the same time? Specify any concerns or potential barriers to this approach. If PG&E believes this approach would be inferior to a "hybrid project" approach under the EUP, identify why and provide rationale.

**Response to Question No. 002 Response No. 001:**

a. Yes, the definition provided in our Opening Comments is our recommended definition for a "hybrid" approach or "hybrid distribution hardening."

b. We intend to apply the hybrid designation at the project level; however, we will segment a hybrid project for execution to a sub-project level and therefore a sub-project may also be hybrid.

c. Yes, there is a definitive list of alternate mitigations that could be included in the 20% non-undergrounding work. The list of alternative mitigations that could be included in the 20% non-undergrounding work are: (1) Overhead hardening (covered conductors); (2) Remote Grid (removal); (3) Line Elimination Incentive Plan (LEIP); and (4) removal for redundant ties and potentially idle facilities. If we identify new mitigation technologies or hardening approaches during the 10-year EUP, we may consider adding them to the list of alternative mitigations that make-up the 20% non-undergrounding work.

d. We choose a hybrid approach when the time required and/or cost to deploy undergrounding exceeds the incremental risk reduction benefit for a circuit segment. This is generally due to construction feasibility such as locations where an overhead line crosses a body of water, in very steep terrain, or in areas where we would have to install underground lines in hard rock. Conversely, there are locations where we may have chosen to install overhead covered conductors but, because of tree fall-in risk, ingress/egress concerns, or impacts due to EPSS/PSPS, it is more prudent to locate the line underground.

   We use our system hardening decision tree (see Figures 1-3 below) when we are scoping a hardening project. The engineers scoping the project answer a series of questions on the decision tree to determine if the project is a candidate for a hybrid hardening solution. Using the decision tree, the scoping team evaluates several factors including: if the project is a candidate for a remote grid solution; the PSPS impact on the circuit segment; public safety concerns (e.g. ingress/egress) in the location; the risks from tree fall-in strike on the line; and contracting and/or constructability concerns with undergrounding.[2]

[2] The decision tree includes steps related to internal governance requirements (e.g. route updated scoping documents in EDRS for approval and update schedule) and are not part of the hardening mitigation analysis.

## Figure 1 – PG&E's System Hardening Decision Tree (1 of 3)

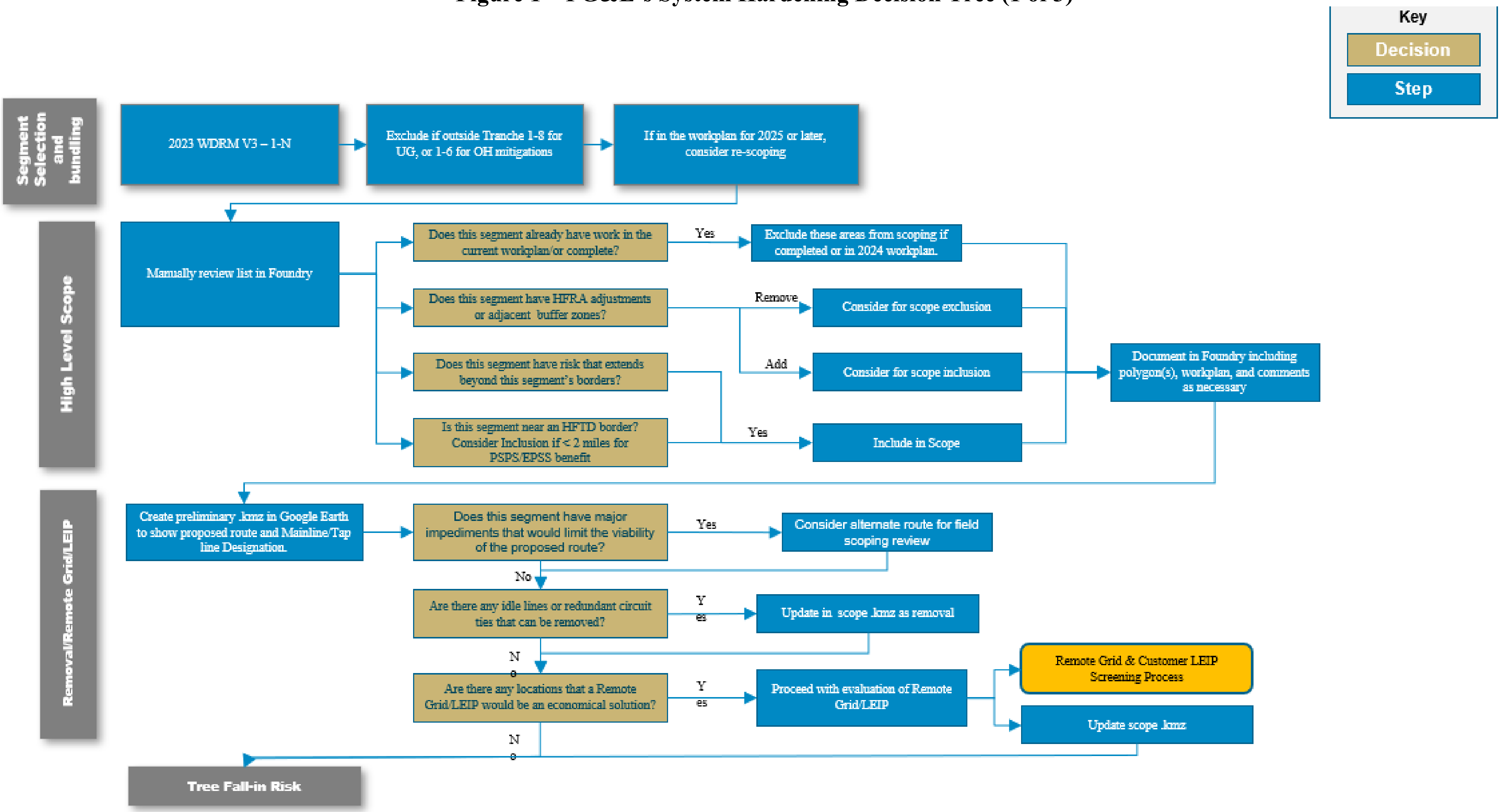


**Figure 2 – PG&E's System Hardening Decision Tree (2 of 3)**

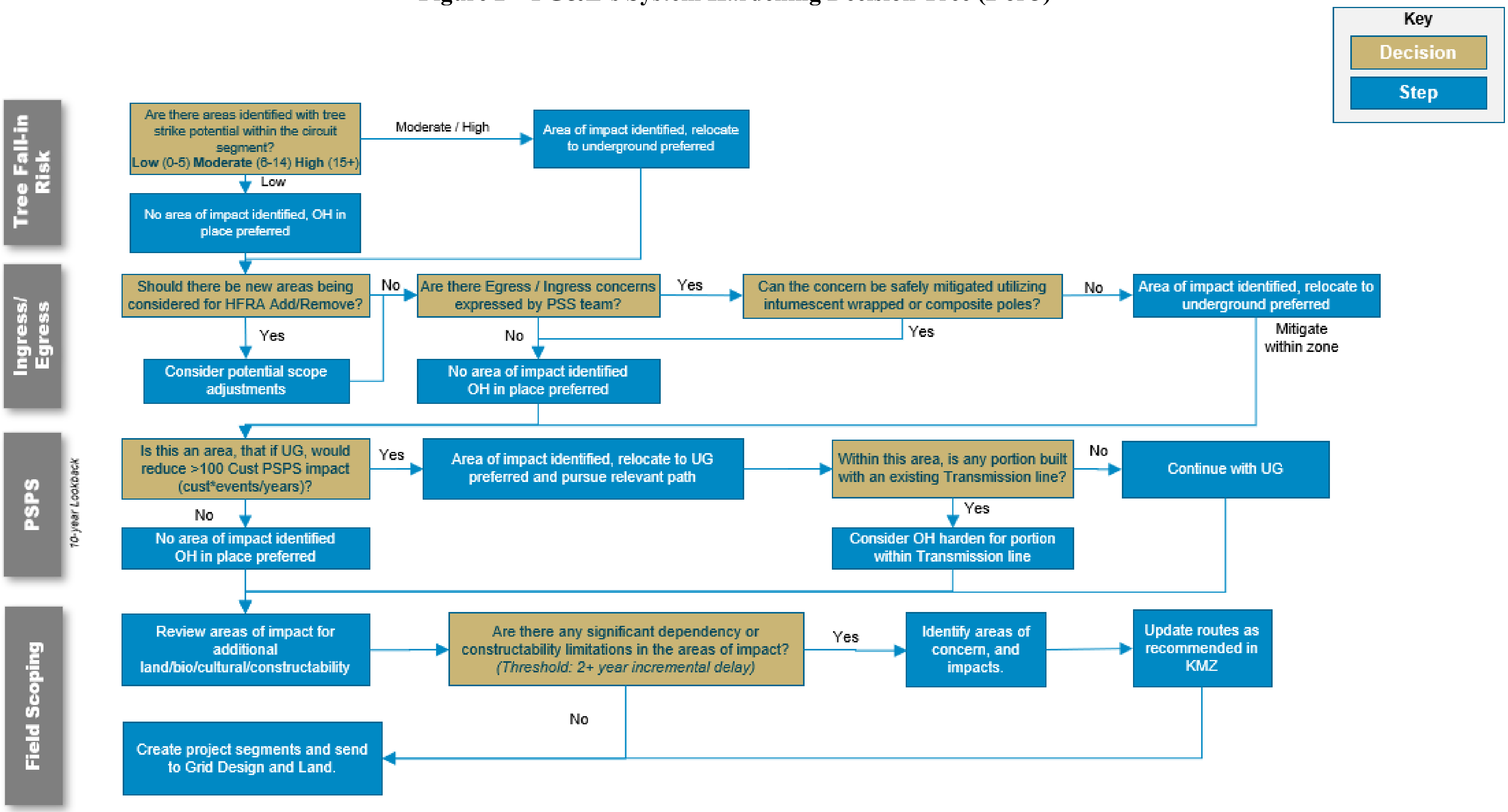
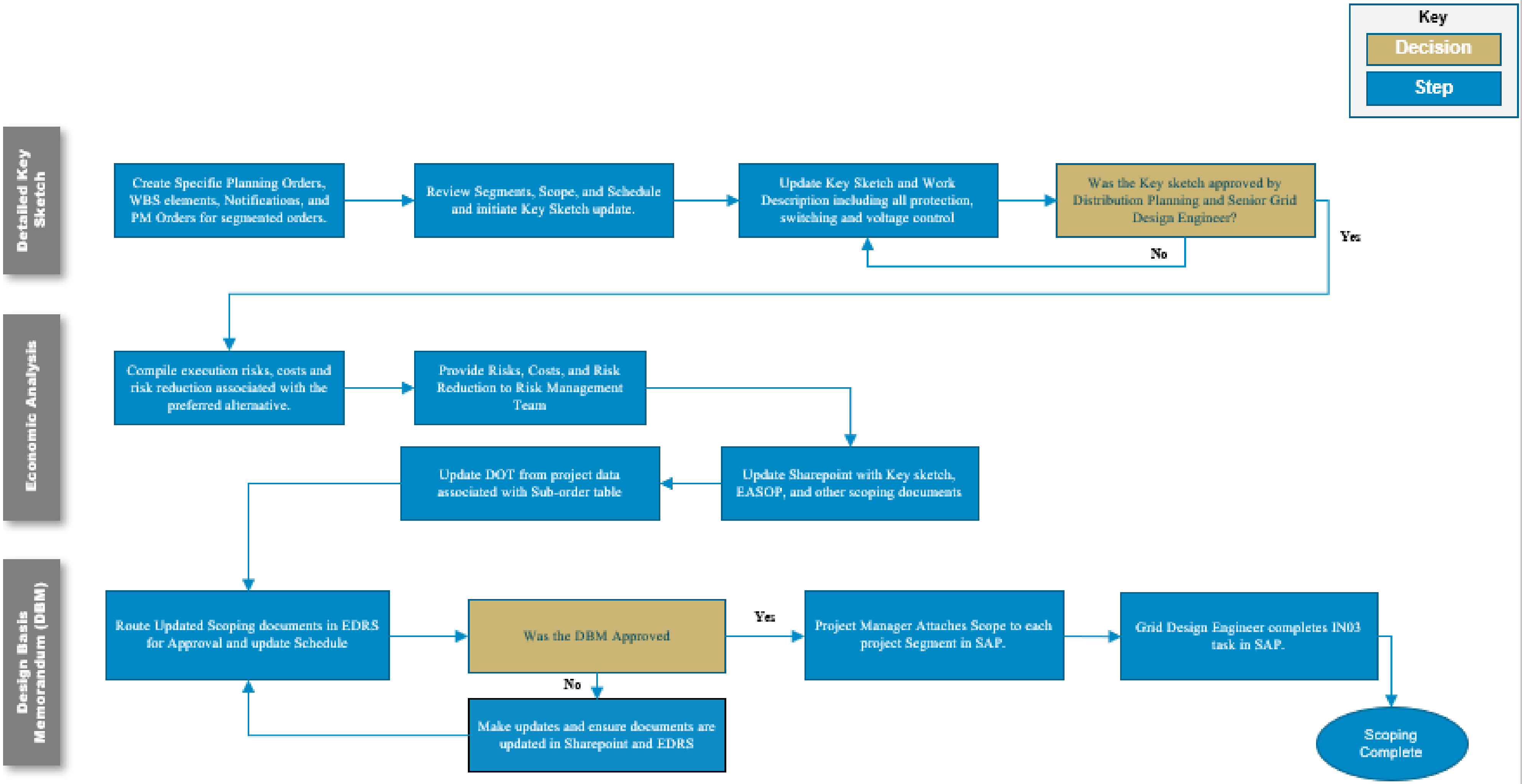


**Figure 3 – PG&E's System Hardening Decision Tree (3 of 3)**



Placerville 210611132 is an example of a project where we are replacing an overhead line with a hybrid solution, using both undergrounding and overhead hardening. This project required relocation of the existing line due to tree fall-in risk and feasibility/constructability challenges. See Figures 4-7 below.

The blue line in Figure 4 below shows the current route of the Placerville 210611132 overhead circuit segment.

**Figure 4 – Placerville 21061132 Current Route**

The purple line in Figure 5 shows the planned hardening route for the Placerville 210611132 overhead circuit segment. The purple line represents the distribution main lines and the dark blue lines are the tap lines.

**Figure 5 – Placerville 21061132 Planned Underground Route**

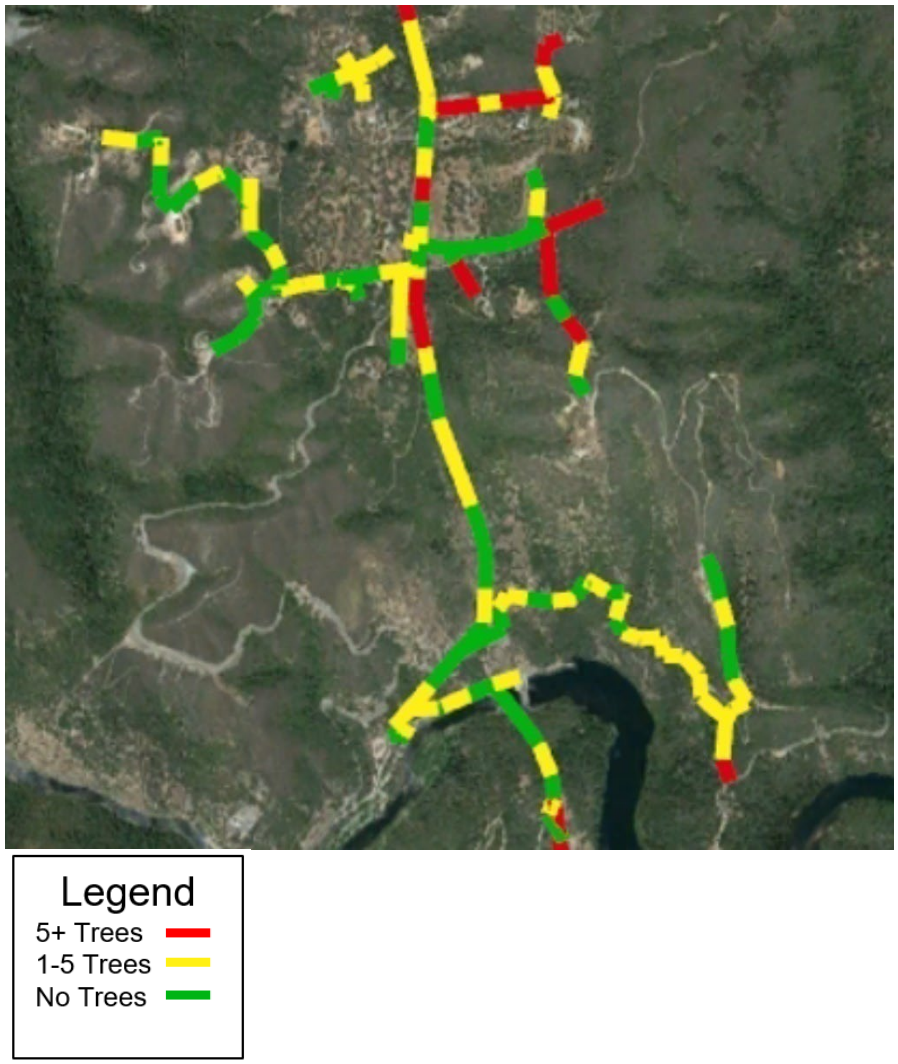
Using our system hardening decision tree, we analyzed the proposed undergrounding route to determine if there are "areas of impact for additional land/bio/cultural/constructability" (Figure 2, Field Scoping).

Figure 6 is a section of the Placerville 210611132 planned hardening route. The figure shows the feasibility challenges (areas of impact due to constructability) along the planned route ― steep terrain, hard rock, and narrow shoulder. Undergrounding costs in this area would be significantly higher than our average costs. Therefore, we currently plan to install covered conductors in the location shown in Figure 6.

**Figure 6 – Section of Placerville 21061132 Showing Steep Terrain and Hard Rock**

Again, using our system hardening decision tree, we analyzed the existing overhead path looking for trees that could fall and break the line if the line was overhead hardened (Figure 2, Tree Fall-In Risk). The decision tree requires that we underground when there are more than five trees in a single span that cannot be mitigated through removal or other means. On this section there was an acceptable level of tree fall-in risk, and we reviewed mitigation strategies for those trees that remained with our vegetation management experts. Figure 7 shows the tree density along the planned system hardening route.

**Figure 7 – Tree Density Along Planned System Hardening Route**




By evaluating the specific circumstances associated with this circuit segment — location, feasibility, and fall-in tree risk — we strategically deployed overhead covered conductors in those locations where the costs to underground would have been significantly higher than average and the tree fall-in risk was managed through other mitigations.

d1. Improved cost/risk performance (like the example above) and physical limitations (water crossing, granite, etc.) are reasons for implementing a hybrid hardening alternative. However, there may be other dependencies such as environmental (protected species habitat, etc.), cultural (tribal lands, protected areas), or agency constraints (open space, or special districts) where we would install covered conductors (or other mitigation) in place of undergrounding.

d2. We have not determined a specific method for "flagging" or providing a "reason code" for adopting a hybrid scope. It would be a reasonable addition to the information required in the project reference sheet (or equivalent document type, such as a spreadsheet workplan). We would identify the reason for a hybrid project as part of the Screen 3 review and incorporate the reason code in either Table E.3 or Table E.4 when a hybrid alternative is identified.

e. *E02725.DRU13828_Energy Safety-DR-EUP-24-02_DR_OEIS_D001_Atch01.xlsx* is a workbook that shows the number of planned projects for each combination of undergrounding and hybrid projects in our 2023-2026 workplan. We can provide most of the information requested with the following exceptions.

- Overhead Miles Removed (Column E) – We began collecting this data in 2023. For work started before 2023 we do not have this data in our system. For work started after 2023 we only have data for projects where the initial construction drawings are complete. Therefore, we are including in the table overhead miles removed on those circuit segments where we have "complete" data. Complete data in this instance means that we have the overhead miles removed for all subprojects on that circuit segment.

- Total Un-Mitigated Circuit-Miles on Circuit Segment (Column J) – We do not track this information in any system. To determine the un-mitigated circuit miles on a circuit segment we would have to individually review more than 700 subprojects and calculate the number of miles of original, un-mitigated, circuit segment line after the hardening subproject was completed.

- Underground Sub-projects, Covered Conductor Sub-projects, and Other Sub-projects (Columns L, M and N) – This is the number of hybrid projects that include undergrounding sub-projects and the number of hybrid projects that include covered conductor sub-projects. The data we used in our response includes pre-2023 data for certain sub-projects so that we could report on completed projects.

  Please note, the sum of undergrounding sub-projects + covered conductor sub-projects + other mitigation sub-projects do not always equal the number sub-projects. This is because certain *hybrid sub-projects* have multiple mitigation types, and the same hybrid subproject can be counted under covered conductor, undergrounding, and/or other mitigation types. This is shown in Table 1 below.

**Table 1 – Example of a Circuit Segment with Hybrid Sub-projects**

| Sub-project | UG Sub-project | OH Sub-project | Other Mitigations |
|---|---|---|---|
| 1 | Yes | Yes | No |
| 2 | No | Yes | No |
| 3 | Yes | No | No |
| 4 | Yes | Yes | Yes |
| 5 | Yes | Yes | No |
| 6 | Yes | Yes | Yes |

In this example circuit segment, the table will show 6 sub-projects consisting of 5 undergrounding sub-projects and 5 overhead sub-projects, and two other mitigations, a total of 12 sub-projects, which is more than the 6 sub-projects on this circuit segment. Certain sub-projects are counted more than once.

- Other Mitigation Sub-projects (Column N) – The only other mitigation sub-projects completed in 2023 are line removal with or without remote grid. Therefore, there is only one column for Other Mitigation Sub-projects in the workbook.

- Secondary Lines and Service Lines (Columns O and P) - We have provided information in these columns where we have data indicating if a secondary and/or service line was undergrounded for one or more of the sub-projects on that circuit segment. Where we have sub-project level data for the entire circuit segment we have indicated "Yes" or "No" to indicate if secondary lines and or services are undergrounded. Where we have partial sub-project data for a circuit segment and at least one sub-project includes secondary lines or services undergrounded, we have indicated "Yes", otherwise it is left blank until all complete sub-project data is available to definitively confirm there is no undergrounding of secondaries or services.

f. Table 2 below shows the approximate cost per mile replaced for four hardening methods. The costs represent sub-projects that were completed in 2023 and therefore include costs that were incurred on these jobs in prior years. The total primary miles removed are not finalized because several projects that were completed in 2023 are still proceeding through the final as-built mapping process, which is where the total primary miles removed will be recorded.

**Table 2 – Cost Comparison of Mile Replaced**

| Hardening Method | Unit Cost/Mile ($M) |
|---|---|
| Overhead Hardening | $1.01 |
| Undergrounding | $2.95 |
| Line Removal | $0.77 |
| Remote Grid | $1.88 |

Please note, Remote Grid costs are dependent on several site-specific factors such as: the number of required sites, the load requirements, the environmental and other constraints associated with site location, accessibility, cost to fuel, and the amount of solar resource available at the proposed site. A remote grid site is only selected where it is more cost effective to install and operate than other alternative hardening methods. If undergrounding is the mitigation initially identified but a portion of the project may be a good location to consider for remote grid, we will further evaluate the location to determine if we can install a remote grid because it is a preferred mitigation. If the remote grid site fails due to customer refusal or cost, then we would revert back to undergrounding. The costs for remote grid vary significantly. For reference, we completed three remote grid sub-projects in 2023.

Additionally, there are only two short line removal projects included in the 2023 data set. The small number of projects influences the cost per mile because the fixed costs associated with each project increase the unit cost on a very small project. If we included costs for multiple years that included larger and a greater volume of sub-projects, the unit cost for line removal would decrease significantly.

g. The isolatable circuit segments on a circuit are typically dependent on the size of the circuit, its design, and its outage history. Many shorter circuits have just one (1) isolatable segment, but longer circuits may have 10-15 segments.

h. Yes, some examples include areas that have already been partially hardened, circuit segments that travel into and out of the HFTD tiered areas, and in response to emergency or fire rebuild work.

i. Seeking funding for the non-underground portions of a hybrid project through the GRC could lead to a mismatch in timing for project approvals between the EUP and the GRC that could result in delays and disruption to our system hardening program. Evaluating the work on an entire circuit segment in one proceeding is more efficient for regulators and stakeholders because it provides a more comprehensive view into our undergrounding program. When we delay hardening work on a portion of a circuit segment because it is being addressed in a separate, delayed regulatory proceeding, we are failing to reduce ignition risk on a high-risk circuit segment, we are less efficient, and it is more disruptive to our customers. In addition, if the EUP funds the non-undergrounding portion of a hybrid project, it will solve the issue of mismatched timing among funding sources.

   If we can complete all the work on a hybrid project at the same time, we can alleviate construction delays, help to reduce costs, and our work will be less disruptive to our customers. For example, it is more efficient for a contractor to complete work on an entire circuit segment at one time whether they are deploying a single or hybrid mitigation solution. When working on an entire circuit segment, the contractor does not have to mobilize and demobilize at the site multiple times. Each time they leave and return to the site means additional time and additional cost to bring in, set up, and remove their materials and equipment.

   Using the EUP Project Acceptance Framework, we will identify specific mitigation solutions for a subproject in Screen 3. If we are unable to include the non-undergrounding sub-projects in the EUP, they would need to be set aside for inclusion in our next GRC. Because we file a GRC every four years (and final GRC decisions are often delayed[3]), the delays between working on the undergrounding and overhead hardening portions of the project could be four years or more. If the GRC did not approve funding for any of the non-underground subprojects, we would need to reconsider the alternative mitigation selection and may need to implement a less efficient solution through the EUP if the subproject met the required thresholds or potentially leaves a section of high-risk line unhardened. Once the decision approving funding for non-underground hardening is received, we could then begin scheduling the work with our contractors. The time needed to schedule and complete the work — and ultimately the lag between completing the undergrounding and overhead hardening portions of the circuit segment — would vary depending on the contractors' availability, permitting, and other dependencies. Most importantly, a system hardening project can be disruptive to our customers and the community. These disruptions can include delays due to streets blocked with construction equipment. When we can complete a system hardening project efficiently with fewer starts and stops, we can limit the disruption the project can cause.

   The Placerville project above (Question 2d) would be an example where it would be detrimental if we could not recover funds for the small sections of overhead hardening in the EUP. It will be much more efficient, less disruptive, and will help us to reduce risk more quickly if we can incorporate all of the hardening work for a predominantly underground project into the EUP.

j. To clarify, our next GRC cycle covers 2027-2030 (not 2026-2028) and will be filed in May 2025.

[3] Both PG&E's 2020 and 2023 GRC decisions were finalized almost a year into the relevant GRC period. PG&E's 2023 GRC decision was received in November 2023 (D. 23-11-069) and our 2020 GRC decision was received in December 2020 (D. 20-12-005).

Although it is possible for us to request funding in our 2027 GRC for the non-undergrounding sub-projects that are identified when we file our GRC, the number of non-undergrounding sub-projects identified by May 2025 will likely be a small sub-set of the non-undergrounding sub-projects we will propose to construct over the life of the EUP. Using this approach, any non-undergrounding sub-project we identify after May 2025[4] would need to be set aside and included in the 2031-2034 GRC.

This approach would be inferior to a hybrid approach in the EUP because, under this approach, our system hardening program and its associated funding would be divided between two different proceedings, making it much more difficult for regulators and stakeholders to evaluate our program in its entirety. Additionally, if the GRC did not fund all the non-undergrounding subprojects forecasted in the rate case, we would be left with unfunded subprojects that we would need to either harden via the EUP using less efficient means if undergrounding the subproject met the EUP thresholds or potentially leave a portion of line in a high-risk area unhardened for a longer period of time.

**<u>Question No. 003:</u>**

**Please provide information requested as it pertains to PG&E-designated 'sub-projects.'**

a. Based on PG&E's definition of "subproject" from their November 3rd, 2023 response to Energy Safety's Request for Comments and Proposals Regarding SB 884, a given project can be broken into various sub-projects, usually "[w]hen projects are scoped and planned for near-term completion (e.g., within 3 – 4 years)" [5]. For the purposes of this program, is there a requirement that every subproject consists of line undergrounding or an alternate mitigation? Is it possible that a subproject would only include line maintenance, equipment replacement, or other line improvements that may not, by themselves, be considered a wildfire mitigation alternative?

b. Would all undergrounding work within a project, one isolatable circuit segment, be consolidated into a single subproject, or could there be multiple undergrounding sub-projects within a single circuit segment?

c. Would a subproject always consist of one contiguous line segment, or could a subproject include multiple, disconnected sections? For example, could one subproject consist of covered conductor installation on miles 2-3, and miles 6-7 of a circuit segment?

d. In a "hybrid project," which has a continuous section to be undergrounded, would it be likely (or even possible) that this continuous undergrounded section would be broken into subproject(s)? If so, is there a minimum or maximum length of the subproject?

e. In a "hybrid project," which has discontinuous sections to be undergrounded, would each of the discontinuous undergrounded portions always be recorded as a separate subproject?

f. Would there be cases where "hybrid sub-projects" would be created? For example, could one subproject have 4 miles of undergrounding and 1 mile of covered conductor on a 10-mile circuit?

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4 Given the time it takes to prepare the GRC, PG&E would need to identify non-undergrounding sub-projects well before May 2025.

5 2023 PG&E's Response to Energy Safety Request for Comment and Proposals Regarding SB 884 10 Year Plan Guidelines page 6.

Alternatively, would this hypothetical project be split into multiple sub-projects based on mitigation type?

g. Provide details on how risk apportioning is handled for a project with multiple mitigation types. Is the apportionment assigned before or after normalization? Does PG&E combine the risk reduction and reliability improvements for each mitigation separately from each other? Can PG&E provide normalized values per mile for each mitigation before blending into overall circuit segment values?

h. Does PG&E anticipate any problems with reporting the sub-projects with respect to the Cost-Benefit Analysis defined through CPUC proceeding R.20-07-013?

i. In PG&E's February 13th, 2024, response to Energy Safety's Data Request, the following clarification was given, "Projects and circuit segments. We define projects at the circuit segment level, while a subproject is a job that breaks out the project into phases. Therefore, based on how they are defined, projects are associated with a single circuit segment. Most jobs (sub-projects) fall within a single circuit segment. However, occasionally, jobs may include assets on multiple circuit segments, due to line relocation. In most cases, a job that includes assets on multiple circuit segments will fall into continuous circuit segments. There may be rare exceptions where circuit segments are not continuous, but are geographically near each other — for example, in the case of a double circuit."[6]
   - i1 Please provide full detail on the circumstances under which "a job [subproject] that includes assets on multiple circuit segments will fall into continuous circuit segments." Provide an example with illustration.
   - i2 How does PG&E propose to account for a subproject that covers multiple circuit segments, and how will it be analyzed and recorded within their EUP?

j. In PG&E's May 29th, 2024, comments on the Energy Safety draft guidelines, PG&E proposes that "[f]or circuit segments where less than 80 percent of the circuit segment has been identified for undergrounding, the sub-projects will be segregated with the undergrounding sub-project presented in the EUP and non-undergrounding portions captured in a different regulatory process (e.g. the utility's GRC)."
   - j1 For circuit segments with 80% or more underground work, how would the underground and non-underground work be divided into sub-projects?
   - j2 For circuit segments with less than 80% underground work, if sub-projects are not identified until screen 3, how would the non-undergrounded portion of the project be presented in the EUP before screen 3?

**<u>Response to Question No. 003 Response No. 001:</u>**

a. Yes, there is a requirement that every subproject consists of a wildfire mitigation. It is not possible for a sub-project to include only maintenance, equipment replacement, or other improvements that are not wildfire mitigations.

b. Typically, there are multiple undergrounding sub-projects within a single circuit segment.

c. A subproject can consist of multiple, disconnected sections on a circuit segment. However, they are geographically close and part of the same project.

[6] 2024 Ref. DRU13015 Data Request OEIS page 3

d. Yes, it is possible that a continuous underground section on a circuit segment could be divided into sub-projects. While there is no minimum length for a subproject, there are maximum lengths. Maximum length is based on the location of the project, our estimating standards, and other dependencies as opposed to line length.

e. No. If a hybrid project has discontinuous sections to be undergrounded, each discontinuous section would not always be recorded as a single subproject. For example, if a single circuit segment has three tap lines (a tap line is typically a protected section connected to the main distribution line) in a Cal Trans right-of-way, we may estimate the three tap line sub-projects at the same time and record them as a single subproject.

f. All circuits are unique, and there are multiple possible hardening scenarios on a circuit segment. While we try to limit the mitigation solution on a subproject to a single solution (underground or overhead), it is not always possible, and at times we must create hybrid sub-projects (e.g. a short water crossing where undergrounding is not prudent).

g. Yes, we apportion ignition risk and reliability benefits separate from each other. Yes, we can provide normalized values per mile for each mitigation before blending into overall circuit segment values. Figure 8 shows an example calculation apportioning risk across a circuit segment with multiple mitigation types on it. The reliability calculation will be done in a similar fashion. Apportionment is applied after normalization.

**Figure 8 – Apportioning Risk Across a Circuit Segment with Multiple Mitigation Types**

| Circuit Segment A | | | | | | |
|---|---|---|---|---|---|---|
| | Circuit Segment Risk Points | Total Length (miles) | Underground Mitigation Effectiveness | Overhead Hardening Mitigation Effectiveness | Line Removal Mitigation Effectiveness | Total Risk Points on System |
| | 10 | 10 | 95% | 66% | 100% | 500 |

| Subproject 123 | | | | |
|---|---|---|---|---|
| | Miles | Circuit Segment A Planned Work | Risk Reduction (raw points) | Risk Reduction (% of entire system) |
| | Underground Miles | 6 | 5.7 | 1.14% |
| | Overhead Hardening Mile | 3 | 2.0 | 0.40% |
| | Line Removal Miles | 1 | 1.0 | 0.20% |
| | **Total** | **10** | **8.7** | **1.74%** |

Note, the values used in the example are to demonstrate how the calculation will work and are not necessarily representative of PG&E's mitigation effectiveness values.

h. PG&E will report projects with respect to the cost benefit analysis defined in CPUC proceeding R. 20-07-013. Starting with the project level information, we will then normalize and apportion risk and reliability among the sub-projects. Because we are apportioning the risk and reliability information among the sub-projects, there may be some loss of accuracy at the subproject level.

i. i1. See *E02725.DRU13828_Energy Safety-DR-EUP-24-02_DR_OEIS_D001_Atch02_CONF.pdf.*

i2. During the project scoping phase (Screen 3) we will determine which CPZs will be part of a subproject that covers multiple circuit segments. Risk reduction will not be assigned until project estimating is complete (post-Screen 4). We will account for a subproject that covers multiple circuit segments in the EUP in the same way we will account for all sub-projects. We will determine the risk and reliability impacts at the circuit segment (project) level for all the circuit segments covered by the subproject. We will then normalize and apportion the risk and reliability data from the circuit segments to the sub-projects based on mitigation type.

j. j1. We divided a circuit segment with more than 80% undergrounding work into sub-projects by considering system design and constructability issues. Dividing a circuit segment into sub-projects will occur during the scoping phase (Screen 3). During project scoping, our engineers identify the route for the hardened line, determine which portions of the line can be underground and which portions, if any, should be hardened overhead or removed, and evaluate any potential feasibility issues (e.g. water crossings, steep slopes, etc.). Based on the information gathered during project scoping, we determine if the project needs to be divided into sub-projects.

   J2. Hybrid projects will not be shown in the EUP until Screen 3. In Screen 2, we will identify projects at the circuit segment-level as either overhead hardening or undergrounding. Once we decide to underground a circuit segment the project moves to the scoping phase (Screen 3) where our engineers evaluate the circuit segment using the decision tree shown in Figures 1-3 above. During scoping, engineers may identify a need for overhead hardening or line removal/remote grid on a portion of the circuit segment.

**<u>Question No. 004:</u>**

**Please provide information requested as it pertains to PG&E-designated 'Remote Grids.**

a. Provide PG&E's definition of remote grid and confirm how this is distinct from "microgrid." What technologies are primarily used?
b. Confirm that remote grids will have no connection, backup or otherwise, to PG&E's distribution system, and that every mile of overhead distribution line "replaced" by the remote grid will be removed.
c. How many remote grids does PG&E intend to deploy over the next 10 years? How many have already been deployed?
d. What has been the source of funding for the remote grids already deployed?
e. What is the average length of distribution line that is expected to be removed for each remote grid?
f. What are the average and median number of customers, and load size, that will be served by each remote grid?

**<u>Response to Question No. 004 Response No. 001:</u>**

a. The term "Remote Grid" as defined in PG&E's Advice 6017-E refers to relatively small, permanently islanded distribution facilities serving customers who are generally located on remote portions of our distribution system. Remote Grids are not connected to the broader electric grid, and are thus distinct from "microgrids," which as defined by the Department of Energy can connect to the grid. The Remote Grid facilities include a Standalone Power System (SPS) made up of local sources of electricity supply, as well as distribution and service facilities to connect one or more customers to the SPS. The primary SPS technologies are solar PV, battery energy storage, and gaseous generators operating on liquefied petroleum gas (LPG) for backup power.

b. Yes, our Remote Grids are permanently islanded and thus are not connected to our distribution system. For System Hardening, every mile of overhead distribution line "replaced" by a Remote Grid will be removed.

c. Starting in 2021, we have deployed nine Remote Grids to date, with three additional Remote Grids currently in construction and commissioning phases prior to operation. By the end of 2024, an additional eight Remote Grids may be under contract for deployment in 2025. Over the next 10 years, similar deployment volumes are possible. Remote Grid deployment forecasts are subject to high uncertainty because the viability of a Remote Grid in a given location cannot be determined from desktop screening alone; preliminary design and feasibility work is required to determine if a Remote Grid can meet the onsite constraints and service needs of a specific project location, and to determine if the Remote Grid is likely to be cost-effective versus alternative mitigations.

d. The Remote Grids already deployed were funded through our GRC or recovered through our Wildfire Mitigation Plan Memorandum Account or Catastrophic Event Memorandum Account in accord with CPUC guidance.

e. The average length of distribution line expected to be removed for the portfolio of Remote Grids described above (nine in operation, three in construction or commissioning, and eight under contract) is nearly 1.1 miles per Remote Grid, excluding the two highest outliers. For reference, the nine Remote Grids already deployed have enabled (or will soon enable, in the case of the more recently operational remote grids) the removal of a total of nearly 8.5 miles of overhead distribution line across the nine Remote Grids. The total miles removed are not finalized because several projects recently completed are still proceeding through the final as-built mapping process, which is where the total miles removed will be recorded.

f. Across the portfolio of Remote Grids described above (nine in operation, three in construction or commissioning, and eight under contract), the average number of meters served per Remote Grid is 1.65, with a median of 1 meter. For reference, the nine Remote Grids already deployed serve a total of 15 customers. The load size across the portfolio of Remote Grids described above ranges from a peak load of a few kVA to approximately 20 kVA, with one remote grid planned to serve a peak load of approximately 175 kVA.

**<u>Question No. 005:</u>**

**Please provide information requested as it pertains to PG&E project and subproject IDs.**

a. In PG&E's May 29th, 2024, comments on draft guidelines, PG&E states that "PG&E's grid is dynamic. Circuit segments and/or circuit protection zones change regularly and therefore there are not static circuit protection zones."[7] Given that these isolatable circuit segments change over time:

   a1 How does PG&E track project and subproject IDs?

   a2 How frequently is this information updated and how is it reported in Wildfire Mitigation Plan data submissions?

b. Suppose a circuit protection zone currently has an undergrounding project planned for development on it. If this circuit protection zone is modified, for example by installation of a new device which splits it into multiple circuit protection zones, how does PG&E track the project which previously was slated for installation?

[7] 2024 PG&E's Comments on Draft Guidelines, page 20.

b1 Does the project become split into multiple new projects?
b2 Do the sub-projects inside that circuit protection zone get renamed, redeveloped, reassigned, or otherwise changed?
b3 How would the above change if a circuit protection zone was modified in some other substantial way, e.g. by new construction, removal of a recloser, or substantial restructuring of the circuit protection zone?

c. Does completing an undergrounding project ever cause a change to the underlying circuit protection zone s, i.e. change the customers and/or general geographic area served by the isolatable circuit segment, either by splitting the circuit protection zone into multiple new circuit protection zone s or by otherwise changing the topology?
c1 If so, how frequently does this cause a change of this type, e.g. every time, most times, rarely, never? What factors affect the likelihood of this type of change?
c2 Do the answers to either of the questions in c1 change when we distinguish between fully undergrounding (100% UG), "hybrid" projects (>80% UG), and other projects (<80% UG)?

**Response to Question No. 005 Response No. 001:**

a. a1. We create an identification number that is used to track sub-projects from the time the sub-project is identified for scoping through subproject completion. Given the unique requirements in the Draft EUP Guidelines to create identification numbers for the portfolio, project, subproject, and circuit segment, the system we use today will need to be modified, and we will need to develop a new EUP-specific project ID structure that will meet Energy Safety's requirements and work with our risk modeling and project scoping tools.

a2. The system we currently use to track sub-projects, generally based on PG&E order numbers, is not regularly updated. We assign an order number to each project (more accurately a subproject per the EUP nomenclature), which remains static from scoping through completion.

The undergrounding workplan we submit in our WMP uses a PG&E order number to identify specific sub-projects. In the 2023 base WMP, we provided the Undergrounding workplan, which includes PG&E order numbers, as well as the Circuit Protection Zone. In the WMP Quarterly Data Report (QDR), we only provide Project_ID (order number), Circuit_ID, Utility_ID and Line_Class.

b. b1. No, the project does not split into multiple new projects.

b2. No, once a project is identified – from original scoping through construction – the name of the project remains the same. The name of the circuit segment will be updated upon release of a new risk model using new GIS vintage.

b3. When an undergrounding project is planned on a circuit segment, we would not change the name of a project even if the segment has been updated from the risk model GIS vintage used to select it.

c. c1. Yes. Every time we complete an undergrounding project, we change the underlying circuit protection zones. A circuit segment is defined by the structure of a circuit, such as the length of the circuit and equipment on the line. When we underground a line, we are rebuilding the circuit (e.g., installing new dynamic protection devices, relocating the line etc.), which means we are changing its structure; therefore, changing the underlying circuit protection zones.

c2. No, the answer to C1 does not change when we distinguish between undergrounding, hybrid, or other hardening projects.