7.3.3 Grid Design and System Hardening

7.3.3.1 Capacitor Maintenance and Replacement Program

WSD Initiative Definition: *Remediation, adjustments, or installations of new equipment to improve or replace existing capacitor equipment.*

In addition to providing responses to below five questions for Initiative 7.3.3.1 – Capacitor Maintenance and Replacement Program, Pacific Gas and Electric Company (PG&E) is including our response to Class C Condition PGE-4 at the bottom of this section.

1) ***Risk to be mitigated / problem to be addressed:***

   Low voltage conditions can cause increased current loads on conductors, potentially leading to excessive wire sag, which is a fire ignition risk and also leads to damage to customer and PG&E equipment. Capacitors can improve low voltage conditions. Once deployed, capacitors are maintained to ensure proper operations and mitigation of any risks associated with the failure of the capacitor itself.

2) ***Initiative selection ("why" engage in activity) – include reference to a risk informed analysis on empirical (or projected) impact of initiative in comparison to alternatives:***

   Capacitors are placed on the distribution system based on engineering capacity studies that target low voltage areas where installing capacitors can improve low voltage conditions. Once installed, PG&E's capacitor maintenance, inspections, and replacements are governed by Utility Procedure: TD-2302P-05. This utility procedure classifies maintenance tasks for electric overhead and underground equipment, including capacitor banks, fault indicators, interrupters, reclosers, voltage regulators, Supervisory Control and Data Acquisition (SCADA) and Primary Distribution Alarm and Control controls, sectionalizers, streetlights, and sump pumps. The capacitor inspection and replacement program is intended to reduce the risk of capacitor failure. A failed capacitor can impact wildfires by causing a low voltage condition as described above. This condition can cause wire sag or wire failure which in turn can ignite a fire. In addition, if a capacitor fails during operation it has the potential to spread molten material from the various parts that make up a capacitor on the pole.

   Individually, capacitor banks in the distribution system, both overhead and pad- mounted, are tested and inspected annually. The visual part of the inspection includes verifying conditions on the bushings, switches, capacitor tanks, cut-outs, fuses, control cabinets. Within the control cabinet, PG&E further visually inspects the controller, controller box socket and rack to make sure it is properly grounded, as well as inspecting the potential and current transformers.

Annual testing entails recording a clamp-on ammeter reading on the primary jumper on each phase of the bank while the capacitor bank is energized. These values are compared to standard expected ranges based on the tank size and circuit voltage. If recorded values exceed the normal ranges, further inspection is required to determine the possibility of a failed capacitor unit or a bad connection. This comprehensive annual testing validates the proper operation and wildfire safety of capacitors deployed in PG&E's system.

3) ***Region prioritization ("where" to engage activity) – include reference to a risk informed analysis in allocation of initiative (e.g., veg clearance is done for trees tagged as "high-risk"):***

Annual capacitor maintenance is performed on all distribution capacitors regardless of geography or other factors. As noted above, the actual location of capacitors is determined based on system conditions. Planning engineers perform capacity reviews generally targeting capacitor for areas with known low voltage conditions such as long rural circuits or areas with high inductive loads due to large air conditioning or industrial power usage.

4) ***Progress on initiative (amount spent, regions covered) and plans for next year:***

Work on this initiative is done annually. The testing typically starts in the first quarter and is completed by April 1. PG&E annually tests and inspects approximately 11,400 capacitors, approximately 10 percent of which require corrective action in any given year based on inspection results. All repairs or replacements are required to be completed by June 1 before peak summer conditions increase electric load. PG&E plans to continue this annual inspection and testing approach going forward.

5) ***Future improvements to initiative:***

PG&E is developing a program to remove unneeded capacitors and other voltage regulating equipment. Engineering studies of system capacity needs for this equipment are ongoing. In certain instances where loads have been removed or conductor sizes have been increased, removal of capacitors and voltage support equipment may be feasible. By removing this equipment, the risk of a fire ignition caused by capacitors is reduced. Complicating these analyses, however, are the changing dynamics of the electric distribution system. Photovoltaic (PV) generation (rooftop solar) as well as LED lighting is changing voltage requirements on the distribution system. In some instances, these changes support analyses that some capacitors are no longer needed. However, further industry studies are required to develop overall policies to address long-term PV (rooftop solar) effects on the distribution system as it relates to capacitor needs. We are also investigating approaches to add updated and SCADA-enabled controllers to all capacitors so that they can be operated remotely to address operational needs.

In addition to removing no longer needed capacitors, PG&E is investigating removing or using switches on one type of equipment: fixed bank capacitors. Fixed bank units pose a potential safety risk to utility personnel.

ACTION PGE-25 (Class B)

1) Integrate discussion on long-term planning within the respective section of each individual initiative.

The long-term plan for this initiative is aligned to the future improvements described above. Industry studies, benchmarking and other industry involvement are critical in driving any ensuing possible changes to long-term planning for this class of voltage regulating equipment.

Class C Condition:

PGE-4 is one of the Class C conditions that Wildfire Safety Division (WSD) directed PG&E to address in the 2021 Wildfire Mitigation Plan (WMP). We are including our response below:

DEFICIENCY (PGE-4) (Class C): *PG&E capacitor bank failures on its distribution system cause 500 percent higher rates of ignition compared to other large electrical corporations. Although capacitor bank failures only comprise 2 percent of total PG&E ignitions, the average rate of ignition per incident is high at 15 percent. This means that 15 percent of the time a capacitor bank fails, the failure leads to an ignition.*

CONDITION: *In its 2021 WMP update, PG&E shall list and describe mitigation measures that it is undertaking to reduce the likelihood of a capacitor bank ignition.*

RESPONSE TO CONDITION PGE-4:

The mitigation measures that PG&E is undertaking to reduce capacitor bank failures are described in the response above. PG&E performs annual maintenance on capacitor banks to ensure proper operation and wildfire safety. PG&E is also undertaking the analyses described above in the response to Question 5 to potentially remove capacitors where they are no longer needed, thereby removing the wildfire-related risk posed by that asset.

7.3.3.2 Circuit Breaker Maintenance and Installation to De-Energize Lines Upon Detecting a Fault

WSD Initiative Definition: *Remediation, adjustments, or installations of new equipment to improve or replace existing fast switching circuit breaker equipment to improve the ability to protect electrical circuits from damage caused by overload of electricity or short circuit.*

The below narrative for Section 7.3.3.2 covers the circuit breaker program, including distribution and transmission. In Table 12 (see Attachment 1 – All Data Tables Required by 2021 WMP Guidelines.xlsx), we provide financial and RSE analysis for each initiative. However, Initiative 7.3.3.2 is split into the following 4 categories to accurately reflect the financial spend and RSE information for each of the following circuit breaker programs:

- Baseline – Maintenance Substation Distribution (ongoing base control work that are identified through routine inspection via ground in distribution substations)
- Baseline – Maintenance Substation Transmission (ongoing base control work that are identified through routine inspection via ground in transmission substations)
- Enhanced – Maintenance Substation Distribution (maintenance work that are identified through supplemental inspection via drone in distribution substations)
- Enhanced – Maintenance Substation Transmission (maintenance work that are identified through supplemental inspection via drone in transmission substations)

1) Risk to be mitigated / problem to be addressed:

PG&E's maintenance program ensures that circuit breakers are properly maintained to prevent operational failures. Improper operation of a circuit breaker may result in a variety of problems including increased time to interrupt a line fault and failure to restore power after an outage. Failures may also result in an increased risk of ignition.

2) Initiative selection ("why" engage in activity) – include reference to a risk informed analysis on empirical (or projected) impact of initiative in comparison to alternatives:

Prior to releasing a new circuit breaker for service, it is tested to meet all performance requirements, including opening time. Once a circuit breaker is released for service, the maintenance program oversees its performance to ensure that the circuit breaker operates within its design specification.

When a circuit breaker is identified as no longer being able to reliably operate as designed through the maintenance program, corrective action is initiated to repair or replace. In addition, the proactive replacement program evaluates, prioritizes and replaces circuit breakers based on wildfire risk, equipment condition, age, manufacture, and model.

The maintenance of circuit breakers is governed by PG&E Utility Standard TD-3322S Circuit Breaker Maintenance Template and PG&E Utility Procedure TD-3322M Substation Maintenance and Construction (SM&C) Manual Circuit Breakers Booklet. This standard defines the required maintenance tasks and the frequency in which the tasks are performed. This procedure defines maintenance tasks for circuit breakers from visual inspections to more complex mechanism, compressor, hydraulic system services, and overhauls.

Different maintenance tasks have different time-based frequencies. In addition to the time-based requirements, additional condition-based maintenance may be triggered. An example of a time-based maintenance task is a monthly visual inspection. An example of a condition-based task is a Breaker Oil Analysis performed when an oil circuit breaker reaches 50 percent of the Accumulated Critical Current (ACC) trigger, which is an estimate of the total fault current interrupted by the circuit breaker.

3) ***Region prioritization ("where" to engage activity) – include reference to a risk informed analysis in allocation of initiative (e.g., veg clearance is done for trees tagged as "high-risk")**:*

Substation circuit breaker maintenance is not targeted based on regional location. This maintenance program applies to all substation circuit breakers in the PG&E system, including those installed in substations located in High Fire Threat District (HFTD) areas. Circuit breakers targeted for replacement program are ranked based on wildfire risks, equipment condition, age, manufacture, and model.

4) ***Progress on initiative (amount spent, regions covered) and plans for next year:***

In 2020, the existing maintenance program as defined in PG&E Utility Standard TD-3322S Circuit Breaker Maintenance Template and PG&E Utility Procedure TD-3322M SM&C Manual Circuit Breakers Booklet has been followed. For 2021, we plan to follow our existing maintenance program for all circuit breakers in the PG&E system. This includes both the time-based and condition-based triggers for circuit breaker maintenance.

5) ***Future improvements to initiative:***

The circuit breaker maintenance program is periodically evaluated and adjusted based on equipment performance trends. Currently, there are no planned changes to the maintenance program for 2021. Improvements to the proactive replacement program include factoring in overstress and percent ACC as ranking criteria for replacement. These improvements will be in place for circuit breakers targeted in 2021 and beyond.

ACTION PGE-25 (Class B)

1) Integrate discussion on long-term planning within the respective section of each individual initiative.

Response:

The circuit breaker maintenance program works in conjunction with planned (capital) circuit breaker replacement program to maintain operation and service reliability. Planned replacements are identified through a ranking and prioritization based on circuit breaker condition. Recent efforts include enhancing condition data inputs, which will continue in the short-term, as data gaps are closed. The replacement program shifted priority in recent years to address increases in substation emergency work, effectively reducing the annual planned implementation rates. The 10 year plan is to slowly increase annual replacement rates to reach approximately 50 to 60 distribution and 30 to 45 transmission breakers systemwide.

For the long term, we will continue with periodic evaluations of both the circuit breaker maintenance and replacement programs. These evaluations typically include circuit breaker performance trends, emerging technology and other risk factors. Updates will be made to the programs based on these evaluations

7.3.3.3 Covered Conductor Installation

WSD Initiative Definition*: Installation of covered or insulated conductors to replace standard bare or unprotected conductors (defined in accordance with General Order (GO) 95 as supply conductors, including but not limited to lead wires, not enclosed in a grounded metal pole or not covered by: a "suitable protective covering" (in accordance with Rule 22.8), grounded metal conduit, or grounded metal sheath or shield). In accordance with GO 95, conductor is defined as a material suitable for: (1) carrying electric current, usually in the form of a wire, cable or bus bar, or (2) transmitting light in the case of fiber optics; insulated conductors as those which are surrounded by an insulating material (in accordance with Rule 21.6), the dielectric strength of which is sufficient to withstand the maximum difference of potential at normal operating voltages of the circuit without breakdown or puncture; and suitable protective covering as a covering of wood or other non-conductive material having the electrical insulating efficiency (12 kilovolts per inch (kV/in) dry) and impact strength (20 foot-pound (ft-lb)) of 1.5 inches of redwood or other material meeting the requirements of Rule 22.8-A, 22.8-B, 22.8-C or 22.8-D.*

In this section, PG&E discusses its covered conductor installation initiative and also addresses Action PGE-14 (Class A).

1) ***Risk to be mitigated / problem to be addressed:***

   The installation of covered conductor in both primary and secondary systems can help to reduce the occurrences of phase-to-phase contact (when lines come in contact with each other) either directly or through a medium such as a tree branch, eucalyptus bark, palm fronds, animal/bird, or a foreign object which may result in a wildfire ignition.

2) ***Initiative selection ("why" engage in activity) – include reference to a risk informed analysis on empirical (or projected) impact of initiative in comparison to alternatives:***

   PG&E installs covered conductor and replaces existing poles, cross-arms, and other equipment as part of its System Hardening

Program. Because this installation also includes covered jumpers, animal protection, and eliminates most exposed energized components, it is also effective to mitigate many phase-to-ground type outages. This is an effective mitigation in areas prone to these types of impacts where undergrounding or other mitigations are not as cost-effective. In addition to wildfire related safety benefits, the elimination of these numerous transient type outages also has the potential to improve reliability, the overall health of the power systems, and life expectancy. PG&E's System Hardening Program is described in more detail in Section 7.3.3.17.

3) ***Region prioritization ("where" to engage activity) – include reference to a risk informed analysis in allocation of initiative (e.g., veg clearance is done for trees tagged as "high-risk"):***

   Covered conductor installation is being performed as part of PG&E's System Hardening Program and in reconstruction work performed in the HFTD designated areas to address the risk of wildfire ignition. While system hardening is not currently being performed in non-HFTD areas, it can be an effective mitigation for reliability issues in non-HFTD areas to limit the impacts due to recurring outages.

4) ***Progress on initiative (amount spent, regions covered) and plans for next year:***

   See the discussion of the System Hardening Program in Section 7.3.3.17.1 for program details, future improvements, and financial analysis.

5) ***Future improvements to initiative:***

   See System Hardening Program in Section 7.3.3.17.1 for program details, future improvements (including long-term planning), and financial analysis.

ACTION PGE-25 (Class B)

1) Integrate discussion on long-term planning within the respective section of each individual initiative.

Response:

As stated above, please reference Section 7.3.3.17.1 for more information on future improvements for this initiative.

ACTION PGE-14 (Class A)

In its 2021 WMP update, PG&E shall 1) provide an explanation as to how it is prioritizing replacing aluminum conductors in areas that overlap both corrosion zones and the HFTD, 2) if PG&E is not prioritizing aluminum conductors located in overlapping corrosion zones and HFTDs, explain why, and 3) explain whether any *higher priority is given to aluminum conductor within corrosion zones outside of HFTDs.*

Response:

The prioritization, tracking, and funding of conductor replacement projects in HFTD vs non-HFTD areas is done through two separate Major Work Categories (MWC). Circuit hardening within HFTD areas is completed under MWC 08W while reconductoring of deteriorated conductors within non-HFTD is completed under MWC 08J.

The MWC 08W (HFTD program) is informed by risk modeling that takes many consequence and probability factors into account. Specifically, PG&E's Vegetation Probability of Ignition and Equipment Probability of Ignition Models focus on vegetation and equipment failure modes as they represent a high percentage of the overall ignitions by cause. Combined with the Wildfire Consequence Model, the initiatives are designed to reduce ignitions in the highest wildfire risk areas. These models are described in more detail in Sections 4.3 and 4.5.1.

The focus of MWC 08J (non-HFTD program) is small conductor with high wire down rates and small Aluminum Conductor Steel-Reinforced (ACSR) conductor within severe and moderate corrosion zones because this combination deteriorates the health of the conductor at a higher rate than outside of the corrosion zone. Approximately 70 percent of targeted 4 ACSR conductor within corrosion zones is in the non-HFTD areas.

While aluminum and corrosion are significant indicators of conductor failure, they do not necessarily align with the key factors for wildfire risk. In cases where they do align, they are prioritized by the models described above that used in the prioritization of the MWC 08W program. In general, the criticality of the MWC 08W program is a higher priority than the MWC 08J program given the potential wildfire impact and consequences.

ACTION PGE-27 (Class B)

1) provide the percentage and overhead circuit mileage of small copper conductor replacement projects that fall within HFTD areas

2) explain how PG&E is prioritizing small copper replacement projects

3) explain any parallel upgrades (pole replacements, crossarm repairs, etc.) PG&E is performing that are compatible with small copper conductor replacements, including how such are prioritized.

Response:

1. MWC 08J (non-HFTD) contains essentially 0% of small Cu conductor replacement within HFTD areas. The focus of the System Hardening program is the application of the Fire Rebuild Design Guidance (7.3.3.17.1) across the highest risk miles informed by the 2021 risk model (4.5.1). The quantity of 6CU

removed is not a maintained data point available in a short turn around response. An ad-hoc study would be required to review past projects and compile a new dataset, and if this would be a regular dataset required, would need a process developed to initialize, maintain and report. This datapoint specific to the system hardening program is not operationally relevant to the safe operation of the system nor is it the primary driver for the program. As the intent should be overall small copper conductor reduction over time, it would be more valuable to review overall 6cu removal in the system year to year which would be a more comprehensive report of the company's performance towards that goal.

2. The focus of the MWC 08J (non-HFTD) program is small conductor (6Cu, 4Cu, and 4 ACSR) with elevated wire down rates. The majority of projects are recommended through the Engineer Investigation Wires Down Database and completed following an equipment failure wire down outage. The majority of outages occur on small conductor and if criteria is met (conductor size/type, past wires down, splice count, overstressed conductor relating to available fault current) then a project is created to address the segment(s) of conductor with similar attributes indicating a deteriorated state. Since the failure rates of 6Cu and 4Cu are much higher than the system average as well as 4 ACSR in corrosion zones – these conductors make up the majority of the projects within the 08J program. Where the small copper conductor failure risks align with the risk model, they are used in the prioritization of the MWC 08W program.
3. MWC 08J (non-HFTD) Reconductor projects also include replacing Self Protected (SP) Transformers and deteriorated or open wire secondary within scope boundaries. Since the majority of the reconductor projects involve installing a larger conductor, per PG&E standard, all pole loading needs to be reviewed resulting in approximately 1 in 5 poles being replaced. If any equipment (crossarms, insulators, fuses, etc.) is outdated/non-standard or in a deteriorated state then it too will be replaced. Typically, compliance tag work (E&F tags) have a more rapid due date than an 08J project – so these tags are not bundled. But depending on type of tag (ie. cross arm repair), if the tag is outstanding when a project is being constructed then it may be addressed on the 08J project.

The open E and F EC tags that overlap with the boundary of a system hardening project are re-classified as H status and completed and signed off as part of the system hardening project. Some projects have been created due to a high density of structural impacting tags where system hardening is expected in the near term to gain efficiencies and eliminate re-work. Currently only 17 such jobs are planned in the 2021-2023 timeframe. These tags will continue to be re-assessed to ensure further deterioration of the asset would not require a more immediate response. If a critical risk is found upon re-assessment, that asset would be re-classified as an A or B tag and completed accordingly ahead of the system hardening projects execution schedule.

7.3.3.4 Covered Conductor Maintenance

WSD Initiative Definition: *Remediation and adjustments to installed covered or* *insulated conductors. In accordance with GO 95, conductor is defined as a material suitable for: (1) carrying electric current, usually in the form of a wire, cable or bus bar, or (2) transmitting light in the case of fiber optics; insulated conductors as those which are surrounded by an insulating material (in accordance with Rule 21.6), the dielectric strength of which is sufficient to withstand the maximum difference of potential at normal operating voltages of the circuit without breakdown or puncture; and suitable protective covering as a covering of wood or other non-conductive material having the electrical insulating efficiency (12 kV/in dry) and impact strength (20 ft-lb) of 1.5 inches of redwood or other material meeting the requirements of Rule 22.8-A, 22.8-B, 22.8-C or 22.8-D.*

1) ***Risk to be mitigated / problem to be addressed:***

   Covered conductor maintenance, which occurs as part of routine overhead maintenance conducted through PG&E's GO 165 Program, is focused on the identification, assessment, prioritization, and documentation of the current condition of PG&E's covered conductor facilities. This maintenance would help reduce the risk of water egress into the insulated line and to identify any locations where the jacket could be damaged reducing its insulative properties.

2) ***Initiative selection ("why" engage in activity) – include reference to a risk informed analysis on empirical (or projected) impact of initiative in comparison to alternatives:***

   Covered conductor maintenance occurs as part of PG&E's GO 165 Program and looks to identify potential conditions during patrols and inspections of PG&E's distribution facilities, and any conditions that may occur as a result of operational use, degradation, deterioration, environmental changes, or third-party actions.

3) ***Region prioritization ("where" to engage activity) – include reference to a risk informed analysis in allocation of initiative (e.g., veg clearance is done for trees tagged as "high-risk")**:*

   Covered conductor maintenance will be performed anywhere covered conductor is installed and found to have conditions requiring maintenance. The majority of the covered conductor would be found in the Tier 2 and Tier 3 HFTD areas and Buffer Zones.

4) ***Progress on initiative (amount spent, regions covered) and plans for next year:***

   Maintenance on covered conductors will occur as a part of PG&E's GO 165 program, including maintenance in Buffer Zones. As more covered conductor is installed, this equipment will be inspected as a part of that program.

5) ***Future improvements to initiative:***

PG&E will continue to inspect and monitor covered conductor systems and enhance the requirements in the GO 165 program as needed.

ACTION PGE-25 (Class B)

Response:

1) Integrate discussion on long-term planning within the respective section of each individual initiative.

Since this initiative is closely related to GO 165 requirements, any long-term changes will be guided by changes/ updates to GO 165. PG&E does not currently have any plans to change this initiative in the long-term.

7.3.3.5 Crossarm Maintenance, Repair, and Replacement

WSD Initiative Definition: *Remediation, adjustments, or installations of new equipment to improve or replace existing crossarms, defined as horizontal support attached to poles or structures generally at right angles to the conductor supported in accordance with GO 95.*

1) ***Risk to be mitigated / problem to be addressed:***

   PG&E does not have a formal program to replace cross-arms. PG&E replaces cross-arms as they are deemed necessary for replacement as part of our Electric Corrective (EC) maintenance. Crossarm failure has the potential to drop energized conductors to the ground as well as other falling hazards from the top of utility poles, which can create the potential for an ignition.

2) ***Initiative selection ("why" engage in activity) – include reference to a risk informed analysis on empirical (or projected) impact of initiative in comparison to alternatives:***

   PG&E has an extensive condition monitoring program for overhead assets, including crossarms, in accordance with requirements in GO 165. PG&E conducts annual patrols in urban areas and bi-annual patrols in rural areas, visually looking for damaged equipment and other defects on the distribution overhead system. A detailed inspection is performed every five (5) years in non-HFTD, (every year (1) in Tier 3 and every three (3) years in Tier 2) looking for any damaged or deteriorated equipment.

3) ***Region prioritization ("where" to engage activity) – include reference to a risk informed analysis in allocation of initiative (e.g., veg clearance is done for trees tagged as "high-risk"):***

   GO 165 mandated inspections and patrols, lead to the identification of cross-arms that require replacement. This work has been prioritized because it can prevent fire ignition and hazards to public from falling wire and parts. HFTD areas receive a higher frequency of GO 165 inspections so these regions receive more attention to address failing assets such as cross-arms. In addition, the work being done for this program also includes maintenance in Buffer Zones.

4) ***Progress on initiative (amount spent, regions covered) and plans for next year:***

Progress continues towards completion of identified EC tags including cross-arm EC tags, especially in HFTDs. PG&E prioritizes the completion of EC tags based on risk ranking which includes the evaluation of Facility Damage Action (FDA). The cross-arm facility in FDA typically receives high prioritization for replacement. PG&E inspectors and construction supervisors conduct post-job reviews for crossarm maintenance work performed by contract and internal crews to ensure the work matches the work called for in the job order and is in compliance with GO 95 requirements regarding how overhead facilities should be constructed.

5) ***Future improvements to initiative:***

PG&E identifies failing crossarms primarily through GO 165 inspections and patrols. Through these inspection programs, PG&E identified and completed repairs or replacements of approximately 6,500 crossarms in 2020. Implementation of composite cross-arms is providing an additional level of longevity for cross-arms as the strength and ultimate life span of composite is significantly longer than older standard wood cross-arms.

ACTION PGE-25 (Class B)

1) Integrate discussion on long-term planning within the respective section of each individual initiative.

Response:

PG&E will continue to inspect and monitor crossarms and enhance the requirements in the GO 165 program as needed. PG&E does not currently have any plans to change this initiative in the long-term.

7.3.3.6 Distribution Pole Replacement and Reinforcement, Including with Composite Poles

WSD Initiative Definition: *Remediation, adjustments, or installations of new equipment to improve or replace existing distribution poles (i.e., those supporting lines under 65 kilovolts (kV)), including with equipment such as composite poles manufactured with materials reduce ignition probability by increasing pole lifespan and resilience against failure from object contact and other events.*

1) ***Risk to be mitigated / problem to be addressed:***

Distribution poles need to be inspected and evaluated to determine their condition to support conductors and keep energized conductors in the air, which reduces ignition probability.

2) ***Initiative selection ("why" engage in activity) – include reference to a risk informed analysis on empirical (or projected) impact of initiative in comparison to alternatives:***

The failure of a distribution pole creates the risk of a potential wires down event and ignition risk. To address the risk of a distribution pole failure, PG&E has an extensive condition monitoring program for wood poles in accordance with requirements of GO 165. We conduct annual patrols in urban areas and bi- annual patrols in rural areas, visually looking for damaged poles and other defects on the distribution overhead system. PG&E performs a detailed inspection every 5 years in non-HFTD, (every year (1) in Tier 3 and every three (3) years in Tier 2) to look for external damage or deterioration, as well as an intrusive inspection approximately every 10 years to identify internal or below ground decay that may be present in the pole. PG&E also identifies and repairs pole top damage especially woodpecker damage.

The pole replacement program replaces poles that that PG&E has determined are overloaded or need to be upgraded to support the attachment of telecommunications or cable companies' facilities. PG&E has used both wood and non-wood or composite poles as replacements. Composite poles in conjunction with covered conductor and exempt equipment are less susceptible to cause an ignition, if branches or trees fall onto the conductor, they are less likely to spark and start a fire. Ancillary benefits of composite poles are that they retain their strength if exposed to wildfire temperatures, they are lighter to carry into remote areas, they are less prone to woodpecker, insect, and fungus rot, they do not need intrusive pole testing, and they do not need hazardous disposal when removed.

As a facet of pole replacement, PG&E has been concerned about the lack of current industry standards concerning the performance of distribution poles in wildfire conditions. As referenced in the 2020 WMP, PG&E began exploring new options for pole replacements. Comparative data gathering was performed in 2019 on 11 different sets of poles (33 total) from 7 different manufacturers as a result of a cooperative evaluation between PG&E and various manufacturers. One of the best performing products, per the test report, was the wood pole with an intumescent mesh covering. PG&E has been working with the manufacturer and as a result of the information gained from the comparative data gathered in 2019, additional evaluations concerning the toxicity of the intumescent mesh covering, the ability to determine the pole condition after a fire and the reusability of the pole, PG&E has selected the wood pole with an intumescent mesh covering as its standard pole for use in the Tier 2 and 3 HFTD areas, including new pole installations, routine pole replacements, and the System Hardening Program described in Section 7.3.3.17.1.

3) Region prioritization ("where" to engage activity) – include reference to a risk informed analysis in allocation of initiative (e.g., veg clearance is done for trees tagged as "high-risk"):

Poles identified for remediation each year by the various inspection programs are scheduled for replacement. Replacements are prioritized using a risk-based approach. Specifically, poles replacements are prioritized based on probability of consequence and probability of failure. Probability of consequence takes into account HFTD and circuit density (count of customers). Probability of failure takes into account some pole factors, such as age, class (class 5 poles are smallest) and treatment (cellon).

We use these factors to score each pole and prioritize their replacement accordingly. PG&E scores each of the poles with replacement tags and ranks them based on their scores. The poles that score the highest get worked first. Please note that this is for E/F Tags only. Priority A/B tags are prioritized first, and we try to work them within the time specified by the inspector (*e.g.,* 30 days for A tags and 90 days for B tags). In addition, the work being done for this program also includes maintenance in Buffer Zones.

4) Progress on initiative (amount spent, regions covered) and plans for next year

PG&E works on poles identified for remediation by various inspection programs. Poles that require reinforcement are typically worked the following calendar year. So, poles identified in 2020 will be reinforced in 2021. Through these inspection programs, PG&E identified at least 9,800 poles for replacement and at least 4,100 poles for reinforcement in 2020. Poles identified for reinforcement are in good condition, except for decay around the ground line. By installing a steel truss and banding it to these poles PG&E can restore the strength of the pole to 100 percent.

5) Future improvements to initiative

PG&E continues to review and evaluate improved manufacturing techniques from composite pole manufacturers that participated on the 2019 pole testing with third-party test facilities. However, at this time, we have no plans to expand the application of composite poles except for areas that require them such as environmental or extreme loading conditions.

ACTION PGE-25 (Class B)

1) Integrate discussion on long-term planning within the respective section of each individual initiative.

Response:

At this time, there is no specific long-term plan that is applicable to this initiative other than the pole selection for HFTD Tier 2 and Tier 3 areas described above in the response to Question 2). Programs associated with this initiative are funded by the General Rate Case and discussed in the California Public Utilities Commission (CPUC or Commission) compliance plan quarterly. Industry guidance and availability of alternative pole materials may help guide any future long-term initiatives.

7.3.3.7 Expulsion Fuse Replacement

WSD Initiative Definition: *Installations of new and California Department of Forestry and Fire Protection (CAL FIRE)-approved power fuses to replace existing expulsion fuse equipment.*

In this section, PG&E discusses its covered non-exempt fuse replacement initiative and addresses Actions PGE-46 (Class B) and PGE-48 (Class B).

1) ***Risk to be mitigated / problem to be addressed:***

   To address increasing wildfire risks, PG&E created a program to replace non-exempt fuses and cutouts. Replacing non-exempt fuses with exempt fuses reduces wildfire risk. If a non-exempt fuse fails, it has the potential to spread hot molten metal material which could cause one or more ignitions, while exempt fuses are designed to internalize any molten material which may result from a fuse failure.

2) ***Initiative selection ("why" engage in activity) – include reference to a risk informed analysis on empirical (or projected) impact of initiative in comparison to alternatives:***

   Non-exempt equipment is equipment that may generate electrical arcs, sparks, or hot material during its normal operation. The replacement of non-exempt equipment with exempt equipment will further reduce fire risk since the exempt equipment is considered "non-expulsion" and does not generate arcs/sparks during normal operation. By using exempt fuses, we can reduce the potential for vegetation ignitions due to molten material spread.

3) ***Region prioritization ("where" to engage activity) – include reference to a risk informed analysis in allocation of initiative (e.g., veg clearance is done for trees tagged as "high-risk"):***

   HFTD areas are the focal point for the non-exempt fuse replacement program, specifically Tier 2 and 3 HFTD areas.

4) ***Progress on initiative (amount spent, regions covered) and plans for next year:***

   In 2019 and 2020, PG&E completed 708 and 751 fuse replacements, respectively.

   PG&E forecasts replacing approximately 1,200 fuses/cutouts, and other non-exempt equipment identified on poles in Tier 2 and Tier 3 HFTD areas in 2021.

5) ***Future improvements to initiative:***

The pace of PG&E's fuse replacement program after 2021 will be determined based on available funding and prioritization of other wildfire initiatives.

ACTION PGE-25 (Class B)

1) Integrate discussion on long-term planning within the respective section of each individual initiative.

Response:

PG&E plans to keep replacing fuses with the total target of replacing approximately 10,000 fuses in the next 7-8 years. The pace and scope of replacement will depend on funding and prioritization.

ACTION PGE-46 (Class B)

1) Explain whether it is increasing the scope of fuse replacements and, if so, why,

2) Explain whether the replacement of the originally identified fuses (i.e., 625 per year) are being prioritized before replacement of those in the increased scope (i.e., 1,200 per year), and

3) Describe how prioritization has changed since the initial scope in 2019.

Response:

1) PG&E is increasing the scope of its fuse replacement program in 2021. The target in 2019 and 2020 was 625 fuses per year (which PG&E exceeded in both years). The target in 2021 is replacing 1,200 fuses. The pace of replacement after 2021 will be determined based on available funding and prioritization of other wildfire initiatives. The scope of the program is expanding in order to expedite the replacement of non-exempt fuses (which are all located in HFTD areas) to mitigate ignition risks, as well as mitigate ongoing Vegetation Management (VM) at these non-exempt locations. Fuses will play an important role in hardening our infrastructure against unanticipated surges of energy and the replacement of non-exempt fuses with exempt fuses can mitigate wildfire ignition risks.

2) The increase in the fuse replacement target from 625 in 2020 to 1,200 in 2021 is not the result of replacing different kinds of fuses. Instead, PG&E is replacing non-exempt fuses in HFTD areas in both years. PG&E has increased the pace of the program, but this does not result one group of fuses (i.e., the 625 fuses) being prioritized over other fuses (the additional fuses beyond 625). PG&E is prioritizing non-exempt fuses in HFTD areas for replacement, as explained in more detail in response to subpart (3) below, and sets a program target and funding for each year.

3) As this program evolves and matures, so will the prioritization framework, which is shifting to become more targeted as more data is increasingly integrated into the decision-making process; this means that replacement targets will change and become better-informed from year to year. Prior to 2020, the targeted 625 replacements were based on execution risk and inputs from the engineering department. In 2020, as the program exceeded the original 625 replacement target to hit 751 total units replaced, PG&E placed an increased emphasis on particularly at-risk districts as part of its prioritization framework. As the program expands in 2021 to replace 1,200 units, detailed Geographic Information System (GIS)-based inputs from Technosylva models around the highest fire ignition risks will determine priority replacements going forward.

ACTION PGE-48 (Class B)

1) Provide the cost/benefit analysis performed regarding fuse replacements, including the calculation of reduction of VM costs per fuse replaced.

Response:

Fuse replacements occur periodically as those that are end-of-life need to be substituted for new ones, while VM is an annually recurring cost that includes high outliers in specific instances.

On average, a single fuse installation costs approximately $12,500 per unit, which includes approximately $4,000 in equipment costs and $8,500 in all other costs, such as labor, permitting, and traffic control. Once installed, the fuse-holding device (i.e., cut-out) will not need to be replaced for up to 40 years. On the other hand, the annual base cost for vegetation replacement is approximately $900 per tag, but can range as high as $5,000 per tag, depending on complications that arise from "refusals" from disputing property owners who aim to prevent VM work.

As a result, in the most conservative estimate for a low-cost VM scenario of $900 per tag, the fuse installation would break even in less than 14 years. However, the costs of a fuse replacement can break even as quickly as under three years should there be high-cost refusals, a reasonably likely scenario within PG&E territory. There are ancillary benefits in terms of customer satisfaction when vegetation is not removed and instead a fuse is replaced.

This cost/benefit analysis does not take include the benefits associated with wildfire ignition risk reduction associated with a wildfire that could potentially be ignited by a non-exempt fuse.

7.3.3.8 Grid Topology Improvements to Mitigate or Reduce Public Safety Power Shutoff (PSPS) Events

WSD Initiative Definition: *Plan to support and actions taken to mitigate or reduce PSPS events in terms of geographic scope and number of customers affected, such as installation and operation of electrical equipment to sectionalize or island portions of the grid, microgrids, or local generation.*

For this initiative, PG&E has several sub-initiatives including:

- 7.3.3.8.1: Distribution Line Sectionalizing
- 7.3.3.8.2: Transmission Line Sectionalizing
- 7.3.3.8.3: Distribution Line Motorized Switch Operator (MSO) Pilot

7.3.3.8.1 Distribution Line Sectionalizing

WSD Initiative Definition: *N/A. This is a "PGE-defined sub-initiative" that supports the response for the (parent) WSD-defined Initiative.*

1) ***Risk to be mitigated / problem to be addressed:***

   The installation of remote operated SCADA sectionalizing devices on PG&E's distribution system can support our ability to segment the distribution circuits near the HFTD area boundary to reduce the impact and scope of PSPS events.

2) ***Initiative selection ("why" engage in activity) – include reference to a risk informed analysis on empirical (or projected) impact of initiative in comparison to alternatives:***

   PSPS events can cause significant disruption to communities and customers and therefore we are working to minimize the number of customers impacted. PG&E plans to continue enhancing its distribution segmentation strategy to minimize the number of customers impacted during future PSPS events by being even more precise on what areas of the circuit to shutoff.

3) ***Region prioritization ("where" to engage activity) – include reference to a risk informed analysis in allocation of initiative (e.g., veg clearance is done for trees tagged as "high-risk"):***

   Distribution sectionalizing device installations have been focused on all circuits that traverse into HFTD areas. PG&E plans to incorporate learnings from past events and focus efforts primarily on counties and specific areas that are repeatedly impacted by PSPS. This includes (but is not limited to) Butte, Yuba, Sonoma, Napa, Nevada, and El Dorado counties.

4) ***Progress on initiative (amount spent, regions covered) and plans for next year:***

   a. PG&E installed 603 SCADA commissioned distribution sectionalizing devices by September 1, 2020.
   b. In 2021, PG&E plans to install at least 250 more distribution sectionalizing devices integrating learnings from 2020 PSPS events, 10-year historical look-back of previous severe weather events, and feedback from county leaders and critical customers.

5) ***Future improvements to initiative:***

As each yearly wildfire PSPS season concludes, PG&E will integrate learnings from actual PSPS events and feedback from county leaders and critical customers to become even more precise on what areas of circuits to target for shutoff to minimize customer impact and outage duration. With this data and feedback PG&E can continue to install new SCADA automated sectionalizing devices closer to the refined meteorological shutoff boundaries and learn what areas of the community to analyze for even further granular sectionalizing.

ACTION PGE-25 (Class B)

1) Integrate discussion on long-term planning within the respective section of each individual initiative.

Response:

Since PG&E has already installed over 800 SCADA-enabled distribution sectionalizing devices in years 2019 and 2020 and plans to install at least 250 additional new devices in 2021, it is anticipated that future segmentation needs will be greatly reduced. PG&E plans to install at least 100 new distribution sectionalizing devices annually starting in 2022 and beyond, and within 10 years, it is expected that all HFTD/High Fire Risk Area (HFRA) locations will be fully sectionalized with remote-capability where beneficial.

7.3.3.8.2 Transmission Line Sectionalizing

WSD Initiative Definition: N/A. *This is a "PGE-defined sub-initiative" that supports the response for the (parent) WSD-defined Initiative.*

1) ***Risk to be mitigated / problem to be addressed:***

   PG&E has been installing remote-operated SCADA sectionalizing devices on its transmission system to support the ability to segment the transmission circuits within the HFTD boundary. This will allow operational flexibility to reduce the scope and impact of PSPS events.

2) ***Initiative selection ("why" engage in activity) – include reference to a risk informed analysis on empirical (or projected) impact of initiative in comparison to alternatives:***

   PSPS events can cause significant disruption to communities and customers. PG&E plans to continue implementing its transmission segmentation strategy to minimize the number of customers impacted during future PSPS events by narrowing down the segments of a circuit to de-energize.

3) ***Region prioritization ("where" to engage activity) – include reference to a risk informed analysis in allocation of initiative (e.g., veg clearance is done for trees tagged as "high-risk"):***

   Prioritization of new or upgraded transmission sectionalizing devices is based on HFTD location, likelihood of potential de-energization during future PSPS events (based on a study of ten years of weather data), and potential customer impact. Switch upgrades are typically identified at line junctions and substations, where operational flexibility may be most beneficial.

4) ***Progress on initiative (amount spent, regions covered) and plans for next year:***

In 2020, we installed 54 transmission switches for PSPS mitigation. Some of these switches were redirected from non-HFTD to the HFTD locations. Of these devices, over 23 were installed before the 2020 wildfire season, as committed to in the 2020 WMP.

For 2021, PG&E is planning on installing 29 additional switches impacting HFTD areas. All 29 switches are planned for installation by September 1, 2021.

5) ***Future improvements to initiative:***

Future installation of all identified HFTD transmission sectionalizing devices will be prioritized based on potential PSPS benefit (such as expected frequency of a line being de-energized and impact of de-energization) to provide operational flexibility during future PSPS events. These switches also contribute to overall reliability outside of PSPS events. Approximately 200 additional switches are planned in the next three to five years.

ACTION PGE-25 (Class B)

1) Integrate discussion on long-term planning within the respective section of each individual initiative.

Response:

Within 10 years, it is expected that all HFTD/HFRA locations will be fully sectionalized with remote-capability where beneficial. Switches will continue to be prioritized based on potential operational benefit during PSPS events and funded at engineering and/or constructing approximately 60 switches per year.

7.3.3.8.3 Distribution Line Motorized Switch Operator Pilot (MSO)

WSD Initiative Definition: N/A. *This is a "PGE-defined sub-initiative" that supports the response for the (parent) WSD-defined Initiative.*

1) ***Risk to be mitigated / problem to be addressed:***

Motorized Switch Operators switches were initially installed on PG&E's distribution system as sectionalizing devices with the ability to reduce the scope of PSPS events. Despite these switches being understood to meet CAL FIRE's exempt criteria for not posing an ignition risk during normal operation, PG&E crews identified a risk that some MSO switches were reported to exhibit an arc flash during the opening (de-energizing) operation. Based on this feedback and subsequent testing PG&E is undertaking this sub-initiative to remove or retrofit MSO switches to address this potential risk.

2) ***Initiative selection ("why" engage in activity) – include reference to a risk informed analysis on empirical (or projected) impact of initiative in comparison to alternatives:***

After some concerns regarding MSO switches were identified in the field, PG&E undertook an evaluation of this equipment. During testing of an MSO switch in PG&E's lab environment to replicate the reported field conditions, the MSO switch exhibited an arc flash during its opening operation. PG&E immediately halted further installations of MSO switches. After further testing, PG&E determined that the current version of MSO switches would no longer be installed and is taking the remedial steps described in Question 4 below. This sub-initiative seeks to determine the best alternative for removing this equipment going forward.

3) ***Region prioritization ("where" to engage activity) – include reference to a risk informed analysis in allocation of initiative (e.g., veg clearance is done for trees tagged as "high-risk"):***

PG&E installed over 100 SCADA automated MSO switches during 2019 to be utilized as PSPS sectionalizing devices to deenergize lines traversing into the Tier-2 and Tier-3 HFTD areas. PG&E discovered the problems with these switches in late 2019, as described above. This initiative is focused on just those locations and is not otherwise prioritized or targeted regionally.

4) ***Progress on initiative (amount spent, regions covered) and plans for next year:***

Until all installed MSOs can be replaced or retrofitted, PG&E has issued guidance document TD-076253-B004 "Limited Use of Inertia SCADA MSO" which sets controls in place to mitigate wildfire risk. This control requirement mandates that any MSOs in the field are to be only operated with a Qualified Electrical Worker present during OPEN and CLOSE operations to handle any onsite issues that might arise.

During 2021, PG&E will be assessing various alternatives to address the identified risk with MSOs. PG&E plans to explore several pilot options that will help inform which are the best alternatives and select the appropriate corrective action for MSOs for the next WMP update. Specifically, PG&E will explore corrective actions to prevent any potential arc flash including retrofitting the MSO with new vacuum-break technology or replacement with either new automated Line Reclosers or new automated SCADAMATE-SD switches.

5) Future improvements to initiative:

Based on the results of the pilots in 2021 described above, a strategy to retrofit or replace all MSO switches in HFTD areas and/or intended for use to reduce the scope of PSPS events. This sub-initiative will then be complete once all the MSO switches have either been retrofitted to address the potential arc flash risk or replaced.

ACTION PGE-25 (Class B)

1) Integrate discussion on long-term planning within the respective section of each individual initiative.

Response:

PG&E forecasts that all MSO switches used for PSPS will be either retrofitted or replaced by the end of 2022 and there will not be a long-term need for this sub-initiative.

7.3.3.9 Installation of System Automation Equipment

WSD Initiative Definition: *Installation and replacement of electric equipment with remote capability that provides operations with the ability to control and monitor circuit status. This includes the ability to remotely change device settings like disabling automatic reclose on recloser and FuseSavers (switching devices designed to detect and interrupt faults and can reclose automatically to detect if a fault remains, remaining open if so)*

For this initiative, PG&E has several sub-initiatives including:

- 7.3.3.9.1: Installation of system automation equipment
- 7.3.3.9.2: Installation of single phase reclosers

7.3.3.9.1 Installation of System Automation Equipment

WSD Initiative Definition: N/A. *This is a "PGE-defined sub-initiative" that supports the response for the (parent) WSD-defined Initiative.*

1) Risk to be mitigated / problem to be addressed:

High impedance faults are conditions where line to ground faults do not draw a full fault current that a protective device can reliably sense and trip (function of contact resistance to ground) creating a potential ignition source. The replacement of the legacy SCADA recloser controls protecting fire Tier 2 and 3 HFTD areas with new recloser controllers will enable the use of protective features designed to address high impedance fault conditions as well as integrating with current communication protocols.

2) Initiative selection ("why" engage in activity) – include reference to a risk informed analysis on empirical (or projected) impact of initiative in

comparison to alternatives:

Under this distribution system automation initiative, the existing oil filled reclosers and controllers will be replaced with a solid dielectric recloser and new micro-processor controller with protection elements like Downed Conductor Detection, Sensitive Ground Fault, and platforms that allows for future protection elements that are under development to reliably detect high impedance faults.

3) ***Region prioritization ("where" to engage activity) – include reference to a risk informed analysis in allocation of initiative (e.g., veg clearance is done for trees tagged as "high-risk"):***

There are approximately 80 remaining distribution line legacy 4C controllers and PG&E will replace all those remaining that are located throughout PG&E’s service territory serving Tier 2 and 3 HFTD areas. These 4C distribution line controllers will be replaced prior to the end of 2021.

4) ***Progress on initiative (amount spent, regions covered) and plans for next year:***

PG&E’s 2020 WMP indicated that we would pursue system automation initiatives including the replacement of legacy 4C controllers. In order to meet the 2021 goal of replacing all 84 4C controllers, the design and estimating started in 2020. With the devices’ locations having been identified, work packages were submitted to estimating and locations will be ready for construction in early 2021. Under this initiative, the 84 remaining 4C recloser controls within the Tier 2 and 3 HFTD areas will be replaced.

5) ***Future improvements to initiative:***

This sub-initiative will be completed by the end of 2021 after which time no further improvements are currently planned.

ACTION PGE-25 (Class B)

1) Integrate discussion on long-term planning within the respective section of each individual initiative.

Response:

As stated in the section above, this sub-initiative will be completed by the end of 2021 after which time no further improvements are currently planned.

7.3.3.9.2 Single phase reclosers

WSD Initiative Definition: N/A. *This is a “PGE-defined sub-initiative” that supports the response for the (parent) WSD-defined Initiative.*

1) ***Risk to be mitigated / problem to be addressed:***

   A single phase recloser is a cost-effective intelligent device which can replace fuses and act as a single phase recloser with the capability to trip all phases (*i.e.*, open all phases) eliminating the risk associated with wire down events where a downed wire remains energized by a back-feed condition.

2) ***Initiative selection ("why" engage in activity) – include reference to a risk informed analysis on empirical (or projected) impact of initiative in comparison to alternatives:***

   Distribution laterals are single phase or three phase taps off the mainline distribution circuit that serve single or small groups of customers. The laterals are protected by fuses (one per phase) which isolate faults keeping the mainline energized limiting outages to a smaller number of customers. Fuses are designed to trip open for a fault condition on the phase or phases that experience a fault condition. Fuses are a practical and cost effective way to isolate faults from the mainline, but there is a risk when a fault event like a wire down condition trips the faulted phase but transformers connected to the faulted phase and an un-faulted phase can keep the wire down energized by a "back-feed" condition. The way to mitigate this problem is trip all phases on the faulted lateral. However, fuses do not have the capability to trip all phases.

   This sub-initiative will install single phase reclosers on laterals that have a history of energized wire down conditions. The single phase recloser will open all phases for the initial line to ground fault and eliminate the risk of ignition from a back-feed condition. A single phase recloser can be installed with SCADA allowing for remote operation including non-test and open and close capability.

3) ***Region prioritization ("where" to engage activity) – include reference to a risk informed analysis in allocation of initiative (e.g., veg clearance is done for trees tagged as "high-risk"):***

   PG&E piloted a single phase recloser device in 2019, and it was used in 2020 as an automatic sectionalizing device for potential PSPS areas where field conditions did not require a three phase recloser. In 2020, we identified locations for 2021 single phase recloser device installations based on the following criteria: (1) in Tier 2 or Tier 3 HFTD areas; (2) three or more wire down outages in the last 10 years; (3) fused cutout experienced FIA fire potential days (R4, R5, or R6, which are elevated fire risk classifications); (4) load on all phases greater than 1 ampere (amp); and (5) fault duty below 6,000 amps symmetric.

4) ***Progress on initiative (amount spent, regions covered) and plans for next year:***

   In 2020, locations were selected based on the above criteria and estimating is in progress. By the end of 2021, PG&E plans to install 70 sets of single phase reclosers. PG&E is working with the manufacturer to make design improvements to the existing device that allows more universal application of the device within the fire areas.

5) ***Future improvements:***

The current version of single phase reclosers and similar brands are powered from the energized line and require a minimum of a few amps to function. In many locations, the off-peak load falls below the minimum load requirement and the device stops communicating back to the SCADA system. PG&E will continue to work with manufacturers to develop a cost-effective single phase recloser that are voltage powered and do not have minimum load limitations allowing for more universal application.

ACTION PGE-25 (Class B)

1) Integrate discussion on long-term planning within the respective section of each individual initiative.

Response:

PG&E is in the process of developing a long-term strategy for single phase reclosers. The device limitations described above restrict the wide-spread deployment within Tier 2 and 3 HFTD areas but there are locations where the existing technology can mitigate risk associated with back-feed conditions. In the near-term, PG&E will use historical data and risk model for selection and prioritization of suitable locations to install single phase reclosers. The long-term view envisions larger scale deployment of single phase reclosers to address the risk of back-feed conditions when the technology meets all the needs of the distribution system serving the Tier 2 and 3 HFTD areas.

7.3.3.10 Maintenance, Repair, and Replacement of Connectors, Including Hotline Clamps

WSD Initiative Definition: *Remediation, adjustments, or installations of new equipment to improve or replace existing connector equipment, such as hotline clamps.*

1) ***Risk to be mitigated / problem to be addressed:***

Connector failure can lead to a wires down condition and wires down can lead to a risk of ignition.

2) ***Initiative selection ("why" engage in activity) – include reference to a risk informed analysis on empirical (or projected) impact of initiative in comparison to alternatives:***

With regard to connectors generally, through PG&E's infrared patrols distribution connectors are identified that may be compromised, EC tags are generated based on these infrared findings, and connectors are replaced as needed. For PG&E's transmission lines, maintenance of connectors is generally performed as part of the overhead inspection program with repairs and/or replacement done as determined necessary during these inspections. In addition, as part of other programs such as pole replacement, new business, system hardening, and capacity and reliability, distribution lines must be built to current standards which includes new and improved connectors.

3) ***Region prioritization ("where" to engage activity) – include reference to a risk informed analysis in allocation of initiative (e.g., veg clearance is done for trees tagged as "high-risk"):***

Inspection of connectors through infrared patrols or overhead inspection includes maintenance in Buffer Zones and overall throughout PG&E's system. See Section 7.3.4.4 for more information on PG&E's infrared inspection program.

4) ***Progress on initiative (amount spent, regions covered) and plans for next year:***

PG&E will continue to maintain, repair and/or replace connectors pursuant to its established condition-based maintenance programs. PG&E will also replace existing connectors with new equipment on facilities that are hardened as part of the System Hardening Program.

5) ***Future improvements to initiative:***

There are currently no expected future programmatic improvements. However, PG&E's standards teams meet regularly with industry representatives at trade shows and Institute of Electrical and Electronic Engineers committees to evaluate new technology and products. Fire resilient connectors are one of the items that has received attention recently in industry discussions.

ACTION PGE-25 (Class B)

1) Integrate discussion on long-term planning within the respective section of each individual initiative.

Response:

At this time, there is no long-term plan that is applicable to this initiative since as previously discussed, connectors/claps are identified/replaced through ongoing inspection and infrared testing. Additionally, replacement of these components through significant amount of ongoing replacement work continue to adhere to our current rigorous standards of improved component material. Future industry guidance/studies may possibly have an impact on any new ensuing long-term plans for this asset class of components.

7.3.3.11 Mitigation of Impact on Customers and Other Residents Affected During PSPS Event

WSD Initiative Definition: *Actions taken to improve access to electricity for customers and other residents during PSPS events, such as installation and operation of local generation equipment (at the community, household, or other level).*

For this initiative, PG&E has several sub-initiatives including:

- 7.3.3.11.1: Microgrids and Back-Up Generation:

  This sub-initiative provides an overview of microgrids and back-up generation to mitigate the impact of PSPS events. PG&E then provides more detail concerning five programs as well as responses to certain Action Items:

  A) Generation Enablement and Deployment
  B) Temporary substation microgrids
  C) Temporary distribution microgrids
  D) Back-up power for individual critical customers
  E) Community Resource Centers
  F) Responses to Action Items PGE-49 (Class B) and PGE-50 (Class B)

- 7.3.3.11.2: Substation activities to enable reduction of PSPS impacts
- 7.3.3.11.3: Emergency Back-up Generation – PG&E Service Centers & Materials Distribution Centers

7.3.3.11.1 Generation for PSPS Mitigation

WSD Initiative Definition: *N/A. This is a "PGE-defined sub-initiative" that supports the response for the (parent) WSD-defined Initiative.*

1) ***Risk to be mitigated / problem to be addressed:***

   De-energization due to PSPS can create public safety risks for customers, as well as broader impacts for communities. Keeping communities and "main street corridors" energized helps to mitigate these risks. Temporary microgrids for PSPS mitigation support both the energization of broader communities and specific "main street corridors" with shared services and critical facilities to minimize the impacts of PSPS events.

2) ***Initiative selection ("why" engage in activity) – include reference to a risk informed analysis on empirical (or projected) impact of initiative in comparison to alternatives:***

   PG&E has two microgrid initiatives designed to support customers during PSPS, each of which is configured to address a different type of PSPS impact: (1) temporary Substation Microgrids are focused on keeping safe-to-energize customers online when a substation serving them is impacted by an upstream de-energization; and (2) temporary Distribution Microgrids are focused on energizing "main street corridors" with shared services and critical facilities when the distribution line serving these areas is de-energized. These specific initiatives are described below in subsections B and C. There are two other PSPS mitigation workstreams that leverage temporary generation, these are addressed in subsections D and E.

3) ***Region prioritization ("where" to engage activity) – include reference to a risk informed analysis in allocation of initiative (e.g., veg clearance is done for trees tagged as "high-risk"):***

To determine the appropriate locations for temporary microgrids for PSPS mitigation, PG&E assesses the expected relative frequency of future PSPS impacts through analysis of historical meteorological data, prior PSPS event impacts, and parallel work- in-progress directed at reducing future impacts. The foundational data for selecting temporary microgrid sites for 2021 is an analysis of 10 years of historical weather events and actual 2020 PSPS event data.

Additionally, PG&E seeks to complement its internal location screening process for PSPS microgrids with county and local government collaboration to ensure that local priorities help shape site selection and design where technically feasible.

4) ***Progress on initiative (amount spent, regions covered) and plans for next year:***

Information on the progress of the Temporary Substation Microgrids and Temporary Distribution Microgrids is provided in subsections B and C below.

5) ***Future improvements to initiative:***

In 2021, PG&E intends to expand the pool of contractors and technologies for the development of microgrids, pilot viable non-diesel technologies, and explore opportunities to build a portfolio of non-fossil solutions for the longer term. This improvement is tied to PG&E's desire to meet California's clean energy goals and to increasing the ability of microgrids as one tool to mitigate wildfire risk and increase PSPS resilience.

ACTION PGE-25 (Class B)

1) Integrate discussion on long-term planning within the respective section of each individual initiative.

Response:

PG&E is in the process of shaping long-term plans for its microgrid initiatives, including microgrids for PSPS mitigation, through the Microgrid Order Instituting Rulemaking (OIR) (i.e., Rulemaking 19-09-009). As directed by the Track 2 Decision in that proceeding,[1] PG&E expects to file an application by June 30, 2021 proposing a long-term framework for using generation at substation to mitigate PSPS outages, including consideration of permanent and temporary solutions, the use of diesel alternatives, and the method of considering long-term microgrid solutions against other wires-based solutions. As part of that forthcoming application, PG&E expects to address the continuing evolution of fire risk modeling, which currently creates significant uncertainty regarding the long-term need for PSPS mitigation at specific locations. The framework will therefore need to be flexible, allowing decisions to be based upon the best information available at any given point in time and identifying, based on that information, any long-term microgrid initiatives that are reasonable and prudent across a range of scenarios. The resolution of that Application will determine long-term plan milestones set in future WMPs for this initiative.

A) Generation Enablement and Deployment

1. Risk to be mitigated / problem to be addressed:

The Generation Enablement and Development organization establishes permanent positions comprised of 10 Full-Time Equivalents (FTE) per the following functions: one Senior Manager to oversee the organization; one manager and four supervisors to ensure the safety of internal and contractor crews during deployments, operational readiness and PSPS activations; one Operations Lead to coordinate with the Control Center processes and enhancements; one Substation Strategy manager to study effective and efficient utilization of TG at substations; one Process and Project Management to ensure that processes are developed, financial oversight and any operational readiness activities are appropriately project managed; Testing, Standards and New Technology manager in charge of continually improving and evolving a greener generation program.

Program breakdown of 10 FTE’s per the below:

- 9 FTEs of this Temporary Generation (TG) organization are geared toward PSPS readiness and scalability processes for PSPS.
- 1 FTE of this TG organization will Primarily support the Clean Substation pilot projects contemplated by the Microgrid OIR and more generally the transition to a cleaner fleet of TG as contemplated in that Rulemaking.

The TG Project Management Office (PMO) will reside within the Generation Enablement and Development organization with the purpose to coordinate, organize and establish a single source of reporting to senior leadership the operational readiness of procured TG in relation to the four workstreams incorporated within the TG PMO: Substation; Microgrids & Temporary Microgrids; Back-up Power Support; and Community Resource Centers

1 Decision (D.) 21-01-018, App. A, pp. A-6 to A-8.

(CRC). The TG PMO will also staff, coordinate and train Emergency Operations Center (EOC) TG members for PSPS event response along with other major emergency events.

2. ***Initiative selection ("why" engage in activity) – include reference to a risk informed analysis on empirical (or projected) impact of initiative in comparison to alternatives:***

   Establish a permanent organization structure to ensure uniformity year over year by managing improvement and efficiency gains by capturing, implementing and documenting the actions taken to support reduction of customer impacts during PSPS events. The new organization structure will also be better prepared to develop and execute longer duration New Technology project pilots and implementation.

3. ***Region prioritization ("where" to engage activity) – include reference to a risk informed analysis in allocation of initiative (e.g., veg clearance is done for trees tagged as "high-risk"):***

   The TG PMO will perform an annual analysis of generation uses as it relates to other system hardening, grid improvements, historical data and meteorological study. This analysis will inform the procurement and deployment of generation throughout the PG&E system for the combined four workstreams. The TG PMO will also engage Transmission and Distribution (T&D) planning and other system planning groups and provide suggestions to help improve electrical infrastructure that might reduce the need of TG for PSPS event.

4. ***Progress on initiative (amount spent, regions covered) and plans for next year:***

   In Q1 of 2021, PG&E will establish the new Generation Enablement and Development team, post the above positions and hire successful candidates. The goal of this team will be to procure and deploy TG system wide across the four workstreams as described prior to the start of the 2021 PSPS season. This team will also work closely with stakeholders, vendors and regulators to ensure a transition to a cleaner TG fleet in 2021. The goal for this team is to establish at least one Clean Substation Project candidate site for testing and demonstration in 2021, and work to deploy the project if bids meet CPUC established cost-effectiveness criteria.

5. ***Future improvements to initiative:***

   - Support for the filing of an application to establish a long-term framework for the procurement of local generation and other solutions to mitigate grid outages; once approved, carrying out the solicitations, grid upgrades, and other work described in the approved framework.
   - The TG department will continue to position the organization to fall into line with the PG&E corporation's goal of meeting the new 60 percent by 2030 Renewable Portfolio Standard (RPS) mandate set forth by Senate

Bill 100, as described in our RPS Procurement Plans filed at the CPUC. This will be achieved by continued testing, research, and development by the Generation Enablement and Deployment team to shift current temporary energy solutions to greener solutions that have a significantly lower carbon footprint.

- Support business continuity needs for other TG use cases such as:
  - Winter Storms
  - Capacity Shortfall
  - Planned Outages (T&D)
  - Catastrophic Events (earthquakes, etc.)
- Develop internal represented classification that can perform the TG interconnection process that we are currently contracting.

B) Temporary Substation Microgrids

1. Risk to be mitigated / problem to be addressed:

PG&E transmission lines that run through HFTD areas may be de-energized if weather and operational conditions warrant a PSPS event. It is possible that a distribution substation and its customers could be de-energized even if they physically reside outside of the PSPS event footprint because the transmission line serving the substation is de-energized.

2. Initiative selection ("why" engage in activity) – include reference to a risk informed analysis on empirical (or projected) impact of initiative in comparison to alternatives:

Temporary substation microgrids are focused on keeping customers online when the substation serving them is impacted by an upstream transmission line de-energization and the substation still has safe-to-energize load. During 2020 PSPS events, PG&E was able to energize all substations impacted by a transmission-level outage that still had some safe-to-energize load.

TABLE PG&E-7.3.3-1: 2020 TEMPORARY SUBSTATION MICROGRIDS ENERGIZED

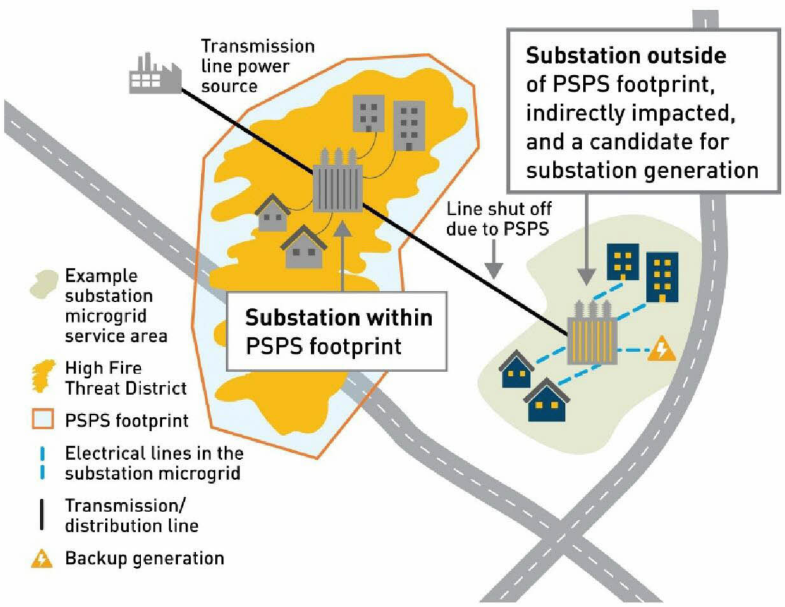
PSPS Event	Substation	Megawatts (MW)	Safe-to-Energize Customer Accounts Served
7-Sep	Brunswick	20	4,191
25-Oct	Hoopa	6	1,791
25-Oct	Willow Creek	12	2,332
25-Oct	Brunswick	20	4,259
25-Oct	Russ Ranch	0.5	2

3. Region prioritization ("where" to engage activity) – include reference to a risk informed analysis in allocation of initiative (e.g., veg clearance is done for trees tagged as "high-risk"):

To determine the appropriate locations for substation temporary microgrids for 2021 PSPS mitigation, PG&E assesses the relative frequency of historical PSPS impacts through analysis of historical meteorological data, actual 2020 PSPS event impacts, and parallel work-in-progress directed at reducing future impacts. The foundational data for selecting temporary substation microgrid sites for 2021 is an analysis of 10 years of historical weather events. This "historical lookback" takes historical weather events and builds the associated PSPS events that would have occurred, including both T&D impacts.

This analysis identifies 28 weather events with 18 potential PSPS events involving transmission-level impacts. Through the historical look-back of these 18 transmission-level events, PG&E identifies substations that are most frequently experience de-energization due to a transmission or distribution PSPS outage. The circuits served by those substations that frequently experience PSPS de-energization in the look-back are screened for the presence of safe-to-energize distribution load. In addition, substations and their circuits are reviewed to determine whether other 2021 PSPS mitigations might remove them from scope (e.g., a switching solution, VM, etc.) or whether an existing solution is already in place (e.g., use of the existing Humboldt Bay Generating Station to create a multi-substation island).

FIGURE PG&E-7.3.3-1: EXAMPLE TEMPORARY SUBSTATION MICROGRID CONFIGURATION



4. ***Progress on initiative (amount spent, regions covered) and plans for next year:***

<u>2020</u>

For 2020, PG&E reserved 350 megawatts (MW) (nameplate capacity) of TG for use across 62 substations in 19 counties. As the 10-year lookback analysis was not yet available, 2020 temp gen substation site selection was based on in-scope substations with safe-to-energize load during 2019 PSPS events.

i. The following substation site selection was used:
   1. During 2019 PSPS events, 124 Substations Were De-energized due to Transmission Impacts But Could Carry Some or All Distribution Load
   2. Less 51 Substations That Had Fewer than 2 PSPS Impacts Caused by Upstream Transmission Outages in 2019
   3. 73 Substations Had 2 or More Transmission Impacts with Safe-To-Energize Distribution Load
   4. Less 16 Substations to be Served by Humboldt Bay Generating Station
   5. 57 candidate substations for temp gen 2020
   6. Additional substations added and removed based on analysis from Subject Matter Experts (SME) in Electric Operations

PG&E prepared substations to receive TG in 3 different ways. This approach ensured PG&E could cover all 62 substations with 350 MW of TG (less than the total peak load of all the substations). The strategy accounted for several substation characteristics including, historical frequency of impact, available land, proximity to other substations, and travel time. Table PG&E-7.3.3-2 below describes these distinct preparation strategies and the number of substations allocated to each strategy.

TABLE PG&E-7.3.3-2: TEMPORARY SUBSTATION DEPLOYMENT STRATEGIES AND NUMBER OF SUBSTATIONS IMPACTED

Deployment Strategy	Description of Strategy	Number of Substations and MWs of Generation Allocated
"Ready-to-Energize"	Substations that have generation interconnected, tested and released in advance of a PSPS event.	18 Substations – 225 MW
"Staged at Substation"	Substations that have generation placed at the substation in advance of a PSPS event.	3 Substations – 50 MW
"Hub-and-Spoke"	Substations that have an engineering guide to interconnect generation during a PSPS event. Generators are staged at yards regionally and dispatched to subs as needed.	39 Substations – 75 MW

<u>2021 Planning</u>

While PG&E has not yet completed the substation selection process described above, PG&E is currently planning to prepare at least eight substations to receive TG for 2021 PSPS mitigation. In addition, PG&E plans to pursue at least one clean substation pilot leveraging diesel-alternative technologies. PG&E issued a solicitation for diesel-alternative front-of-the-meter generation in January 2020 and is also exploring potential behind-the-meter and demand response opportunities at substations identified as needing a 2021 PSPS mitigation.

It is likely that a far higher percentage of substations (but not necessarily MWs) will be supported via a “Ready to Energize” (i.e., interconnected and tested) deployment strategy in 2021 than in 2020. This is due to learnings from 2020 PSPS events which indicated that the time between completion of “Playbook D” (identifies substations that will be de-energized) and de-energization can be constrained to less than 48 hours. PG&E’s process to select locations and procure temporary generation for 2021 PSPS mitigation is still underway. This forecast and the associated language reflects PG&E’s best-available data at the time of this filing. A more complete list of substation candidates for TG in 2021, the total MWs needed to support these substations, and a financial forecast will be submitted in the first quarter of 2021 as part of a Tier 2 Advice Letter required by the CPUC’s Track 2 Decision in the Microgrid OIR.[2]

5. ***Future improvements to initiative:***

As described above, the following improvements are being made to substation site selection and deployment strategy:

- Use of 10-year historical lookback and 2020 PSPS event actuals to inform substation selection
- Transitioning towards greater reliance upon generation that is pre-interconnected at a substation to reduce in-event execution risk
- Development of at least one clean substation pilot

C) Temporary Distribution Microgrids

1. ***Risk to be mitigated / problem to be addressed:***

Temporary distribution microgrids aim to support communities by energizing “main street corridors” with shared services and critical facilities when the distribution line serving these areas are de-energized as a result of a PSPS event.

2. ***Initiative selection ("why" engage in activity) – include reference to a risk informed analysis on empirical (or projected) impact of initiative in comparison to alternatives:***

PG&E’s temporary distribution microgrids are designed to reduce the number of customers impacted by PSPS events and support community resilience by powering a cluster of shared resources (e.g., commercial corridors and critical facilities within the energized zones) so that those resources can continue serving surrounding residents during PSPS events. Though each distribution microgrid varies in scale and scope, the following design features are likely for

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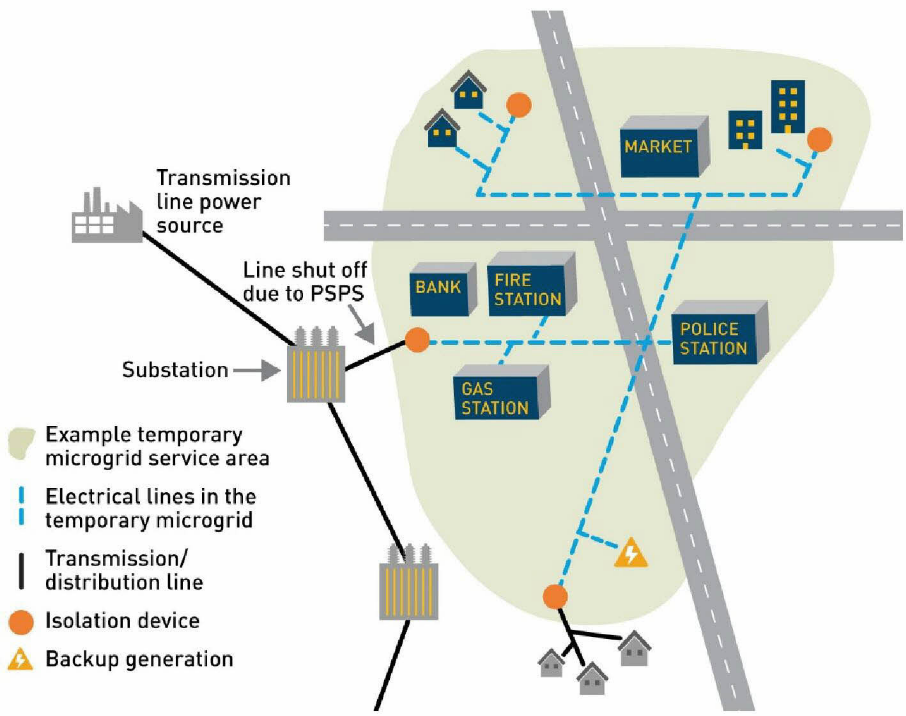
2 D.21-01-018, App. A, pp. A-1 to A-3.

each:

- Devices used to disconnect the distribution microgrid from the larger electrical grid.
- A pre-determined space for backup generation and equipment to allow for rapid connections (e.g., pre-installed interconnection hub (PIH)).
- The use of temporary generators allowing PG&E to shorten the design and construction time typically required to ready a permanent microgrid for operation.

The diagram below represents an approximate layout of a temporary microgrid. With safety being the most critical design factor, each temporary microgrid is unique and is designed based on a number of different variables that dictate the size of the microgrid, what community services are served and what elements are included in the design. The layout and dimensions below are approximate and for illustrative purposes only.

FIGURE PG&E-7.3.3-2: EXAMPLE TEMPORARY DISTRIBUTION MICROGRID



3. ***Region prioritization ("where" to engage activity) – include reference to a risk informed analysis in allocation of initiative (e.g., veg clearance is done for trees tagged as "high-risk"):***

To determine the appropriate locations for distribution microgrids, PG&E identifies distribution circuits most likely to be impacted by PSPS events in the future. PG&E reviews these circuits to identify communities with clusters of shared services (i.e., those involving food, fuel, healthcare and shelter) and critical facilities served by electrical infrastructure that would likely be safe to energize during PSPS events. To determine whether distribution microgrids present viable, effective near-term mitigation measures for a particular location, PG&E also reviews them for implementation feasibility (i.e., land availability and construction complexity) and the potential to be served by alternative grid solutions.

4. ***Progress on initiative (amount spent, regions covered) and plans for next year:***

In 2020, PG&E operated four distribution microgrids with PIHs; thereby, energizing over 2,000 unique service points (customers) for as many as four PSPS events per service point (approximately 5,600 customer-events). PG&E committed 40 MW of TG to temporary distribution microgrids in 2020. The distribution microgrids are identified in Table PG&E-7.3.3-3 below.

TABLE PG&E-7.3.3-3: DISTRIBUTION MICROGRIDS THAT OPERATED IN 2020

Site	County	Year PIH Constructed	Approx. qty service pts	Number of 2020 PSPS Events Supported
Angwin PIH	Napa	2019 Pilot	48	4
Shingletown PIH	Shasta	2020	79	4
Calistoga PIH	Napa	2020	1554	3
Placerville	El Dorado	In progress for 2021	487	1

In addition, in late October 2020, PG&E readied two additional distribution microgrids in Lake County using a temporary configuration without a PIH. These distribution microgrids in North and South Clearlake were on standby to support customers if needed during the October 25, 2020 PSPS event and subsequent PSPS events.

For 2021, PG&E is planning to develop at least five additional distribution microgrid PIHs by the end of the calendar year. PG&E will continue to follow the methodology described in above to locate these sites, which considers likelihood of PSPS impacts, presence of shared services in corridors that can likely be safely energized during PSPS events, and implementation feasibility. As in prior years, PG&E will collaborate with county and local government to ensure local priorities help shape site selection and design where technically feasible.

5. ***Future improvements to initiative:***

In 2021, PG&E intends to expand the pool of contractors and technologies for the development of microgrids, pilot viable non-diesel technologies, and explore opportunities to build a portfolio of non-fossil solutions for the longer term. This improvement is meant to further California's clean energy goals, rather than an activity tied to wildfire risk mitigation or PSPS resilience.

Additionally, the temporary distribution microgrid initiative will benefit from operational and administrative improvements derived from the Generation Enablement and Development organization being stood up in 2021 (see Section 7.3.3.11.1.A for more information).

D) Back-Up Power for Individual Critical Customer Facilities

1. Risk to be mitigated / problem to be addressed:

The loss of power at certain critical customer facilities during a PSPS event could pose significant public health and safety risks, especially for prolonged outages (48+ hour).

2. Initiative selection ("why" engage in activity) – include reference to a risk informed analysis on empirical (or projected) impact of initiative in comparison to alternatives:

As a general policy, PG&E does not offer backup generation to individual facilities. However, PG&E's policy allows for granting exceptions for critical facilities when a prolonged outage could have a significant adverse impact to public health or safety.

3. Region prioritization ("where" to engage activity) – include reference to a risk informed analysis in allocation of initiative (e.g., veg clearance is done for trees tagged as "high-risk"):

PG&E supports individual critical customer facilities through two distinct processes: (1) pre-planned sites; and (2) ad hoc support during an event. For the 2020 wildfire season, PG&E supported intensive care unit hospitals identified in partnership with the California Hospital Association and the Hospital Council of Northern and Central California that were at higher risk of experiencing one or more PSPS-related outages during the 2020 season. PG&E also supported pre-determined vote tabulation centers from October to December for the 2020 national election.

In-event ad-hoc backup power support occurs during a PSPS event. Customers submit a request for mobile backup generation through their PG&E contact or account manager to our EOC. The request is reviewed, and a determination is made as to whether a prolonged outage for the requesting customer would either directly or indirectly affect public health or safety. If the request is approved, mobile TG is deployed to the requesting customer. There is no pre-determined prioritization of these customers, and the location of these customers is dependent on the scope and location of the ongoing weather event. While there is no pre-determined prioritization, there are pre-determined "societal Impact" locations (sites where power loss may impact public health and safety) for which designated customer representatives execute in-event additional outreach to ensure they have a backup power strategy in place. If these locations do not have a backup power strategy in place, a request for backup power deployment is routed to the EOC.

4. ***Progress on initiative (amount spent, regions covered) and plans for next year:***

   In 2021, PG&E plans to continue to support critical customers with backup power support in exceptional circumstances, utilizing our policy to determine eligibility and prioritization. During the first half of 2021, PG&E will continue its direct engagement with critical customers and in coordination with counties to provide consultative support for readiness and resiliency for all hazard, emergencies and the 2021 fire season.

5. ***Future Improvement to Initiative:***

   Improvements to the program will include streamlining the outreach process prior to and during a PSPS event by PG&E customer team, utilizing more hub locations for quicker deployments to the edges of the service territory, and explore clean generation solutions where applicable.

E) Customer Resource Centers

1. ***Risk to be mitigated / problem to be addressed:***

   To minimize public safety impacts during a PSPS event, PG&E opens CRCs focused on providing essential services to customers affected by PSPS events. The risk to be mitigated is ensuring all CRCs in potential PSPS areas are fully equipped with backup power throughout the PSPS season.

2. ***Initiative selection ("why" engage in activity) – include reference to a risk informed analysis on empirical (or projected) impact of initiative in comparison to alternatives:***

   PG&E mobilizes CRCs in counties and tribal communities potentially impacted by PSPS events to provide customers a safe location to meet their basic power needs, such as charging medical equipment and electronic devices.

3. ***Region prioritization ("where" to engage activity) – include reference to a risk informed analysis in allocation of initiative (e.g., veg clearance is done for trees tagged as "high-risk"):***

   PG&E closely coordinates with counties, local governments and tribes to determine appropriate locations for CRCs. Additional details regarding CRC region prioritization can be found in Section 8.2.1.

4. ***Progress on initiative (amount spent, regions covered) and plans for next year:***

   PG&E pre-staged 77 generators to support indoor CRC sites and ultimately activated 62 indoor CRC sites with TG during PSPS events in 2020. More information regarding progress on the CRC program can be found in Section 8.2.1.

5. *Future Improvement to Initiative:*

In 2021, PG&E will continue evaluating additions or changes to our indoor CRC portfolio while taking into consideration factors such as potential PSPS scope, communities impacted by 2020 PSPS events and input from counties and tribes. PG&E will continue to review the program for improvements and efficiencies by reviewing elements such as resources provided, the customer journey and CRC staffing.

F) Responses to Action Items

ACTION PGE-49 (Class B)

Provide additional information about its specific backup generation sites, including

a) the number of times used and
b) challenges faced with the completion of this project and its operation.

Response:

a) The number of times backup generation sites were used during PSPS events:

During 2020 PSPS events, PG&E utilized a total of eight microgrid sites: four temporary substation microgrid locations and four temporary distribution microgrid locations. In addition, PG&E provided backup power support to 31 critical single-customer facilities, including hospitals, water and wastewater plants, and emergency response personnel such as fire and police stations.

Table PG&E-7.3.3-4 below indicates the number of times these sites were energized during the 2020 PSPS events. Some microgrids and single-customer facilities were energized during multiple events, for a total of 53 backup generation site uses across all PSPS events:

TABLE PG&E-7.3.3-4: NUMBER OF TIMES SITES WERE ENERGIZED DURING 2020 PSPS EVENTS

PSPS Event	Temporary Substation MG	Temporary Distribution MG	Individual Critical Customer Backup Power Support	Total
7-Sep	1	2	11	14
26-Sep		1	3	4
14-Oct		4	2	6
25-Oct	4	4	20	28
2-Dec			1	1
Total	5	11	37	53

For additional information regarding microgrids please see

Sections 7.3.3.11.1 B (Temporary Substation Microgrids) and 7.3.3.11.C (Temporary Distribution Microgrids).

For additional information regarding backup power support to single-customer facilities that were supported with backup power per event please see Section 7.3.3.11.1 D (Back-up power for individual critical customers).

b) ***Challenges faced with the completion of this project and its operation:***

Challenges with Project Completion:

As described in PG&E's First Quarterly Report, there are two broad categories of limitations to microgrid deployment for PSPS mitigation:

1. Limitations related to the safety of energizing microgrids with overhead lines in the context of high wind conditions that trigger a PSPS de-energization (i.e. overhead lines that run through the "wind polygon").
2. Limitations related to space constraints for siting generation for microgrids with high peak MW and megawatt-hour requirements over a 24+ hour period.

While the above limitations presented challenges, PG&E largely fulfilled its objective of providing temporary substation microgrids, temporary distribution microgrids, and critical single-facility sites during PSPS events through the use of TG. Energization challenges were managed through the development of site-specific energization playbooks and an in-event scoping process that ensured that only substations with safe-to-energize load outside of the wind polygon were energized. Safe-to-energize limitations for temporary distribution microgrids were managed by limiting energization only to underground lines or short segments of sufficiently hardened overhead lines reviewed by fire safety specialists.

Space constraints were overcome through the utilization of energy-dense, mobile temporary generators and in some instances, collaboration with local governments and landholders to secure temporary easements in advance of 2020 PSPS events which allowed PG&E to place generation outside of its substation fence. In some instances, available land was insufficient, leading to constraints in the number of temporary generators that could be used to serve potential safe-to-energize load from any particular substation. In the case of the Brunswick substation, which was energized during two PSPS events, space constraints meant that only 20 MW of nameplate generating capacity would fit within the substation footprint. The substation has a peak load of 60 MW. Safe-to-energize limitations for temporary substation microgrids led to very few substations being suitable for energization during 2020 PSPS events.

Challenges with Project Operation:

PG&E managed two major challenges in the operation of these sites:

1. PSPS event wind polygons, and thus the PSPS impact scope, can continue to change throughout the event scoping process. Thus, identification of temporary microgrids with safe-to-energize load that will be de-energized can be identified less than 48 hours before de-energization when the final Transmission-level “playbook” is produced, therefore limiting time available to deploy TG to these sites. To manage this operational challenge, PG&E prepared 18 temporary substation microgrids and all temporary distribution microgrids as “ready-to-energize”, with generation interconnected, tested, and released in advance of a PSPS event. In 2021, it is likely that a far higher percentage of substations will be supported via this strategy to further limit in-event operational constraints.
2. Given the dynamics of event scoping, sophisticated and ongoing real-time coordination was required between PG&E’s EOC, Electric Distribution Emergency Center, field engineers overseeing TG deployment, and TG contractors delivering and connecting generators. To manage this operational challenge, PG&E created a specialized EOC “Temporary Generation” Branch within the Operations Section. The TG Branch centralized planning, logistics, and operations functions to ensure as many customers would be supported with TG as safely possible during each event. The TG Branch was staffed with four teams of six individuals each. All individuals who served in the TG Branch underwent significant online training and engaged in at least one of PG&E’s PSPS exercises in advance of wildfire season. In 2021, PG&E is seeking to increase staffing for its TG organization to provide a more permanent solution to this resource issue.

ACTION PGE-50 (Class B)

In its 2021 WMP Update, PG&E shall: (1) provide the cost/benefit analysis completed for microgrids as a mitigation, and (2) define what is meant by a “bridge” solution and “other solutions,” and (3) include a timeline for how long an interim “bridge” solution would be in place.

Response:

This portion of PG&E’s First Quarterly Report was referencing temporary substation and distribution microgrids. In this response, PG&E refers to “temporary microgrids” to include both kinds of microgrids (i.e., substation and distribution).

1) Provide the cost/benefit analysis completed for microgrids as a mitigation:

Decisions regarding the development of temporary microgrids for PSPS mitigation are driven by a location’s expected relative impact frequency and near-term implementation feasibility rather than a cost/benefit analysis. This is in line with a temporary microgrid's intent to be used to serve safe-to-energize areas where no alternate grid solutions can be feasibly implemented in the near-term (i.e. within the next fire season) to mitigate PSPS impacts.

As described in Section 7.3.3.11.1, temporary microgrids are considered as potential PSPS mitigations for locations with a high expected relative frequency of future PSPS impacts. If the analysis of historical meteorological data and prior PSPS events indicates that a location can be expected to experience future PSPS impacts, and no alternate solution can be implemented within the next fire season to mitigate those impacts, that location can be studied for technical feasibility of implementing a temporary microgrid to support customers in the near-term.

For the PSPS mitigation use case, PG&E does not use a quantitative cost/benefit analysis to supplement the methodology described above. Quantifying the exact benefits of a temporary microgrid is difficult because the CPUC has not adopted a standard "value of resilience" or other methodology to quantify the benefit of keeping customers energized when they would otherwise be impacted by PSPS events. To maximize benefits derived from these mitigation measures, in addition to considering expected relative impact frequency, PG&E generally seeks to site temporary substation microgrids in locations that maximize the number of customers that can be safely energized, and temporary distribution microgrids in commercial corridors with critical and shared services that can serve surrounding residents (i.e., to energize "Main Street").

2) ***Define what is meant by a "bridge" solution and "other solutions":***

In the case of temporary microgrids for PSPS mitigation, PG&E used the term "bridge" solution to refer to the near-term implementation feasibility of temporary microgrids at certain locations where other grid solutions might not be viable prior to the next fire season. Temporary microgrids do not present a "bridge" solution for every location—in some locations, they may not be able to be implemented more quickly than an alternate grid solution under consideration.

PG&E used the term "other solutions" to refer to grid solutions that can reduce PSPS scope, and thereby reduce or potentially eliminate the need for a temporary microgrid for PSPS mitigation. "Other solutions" can include undergrounding overhead lines, as well as measures that improve the health score of a transmission line, allow for more granular meteorological event scoping, and enable distribution and transmission sectionalizing.

3) ***Include a timeline for how long an interim "bridge" solution would be in place:***

As PG&E continues to develop and refine its risk modeling (see Section 4.5.1), these developments will drive changes to PSPS scope (see Section 8), and therefore, mitigation solutions designed to address PSPS impacts. Timelines for how long temporary microgrids will be in place as "bridge" solutions will be driven by improvements to PSPS risk modeling and de-scoping criteria, and will vary by location and the demonstrated effectiveness of "other solutions" to mitigate PSPS impacts in those locations.

At certain locations, some of the "other solutions" listed above might be implemented as soon as the year after a temporary microgrid is made operationally ready. At such locations, PG&E would consider adapting site preparation at the start of PSPS season to reflect the availability of an alternate solution. For example, some of the temporary substation microgrids that were made "Ready-to-Energize" in 2020 based on 2019 event actuals might not have generation interconnected and tested on-site in 2021 based on the reduced expected impacts due to improvements to event scoping and transmission health scores. This, however, may not eliminate the potential need for a temporary microgrid solution at these sites altogether. For these sites, PG&E would retain the engineering guide to interconnect generation if needed, even if generators are not staged on-site given the relatively low probability of impacts.

At some locations, "other solutions" may not be available to reduce the need for temporary microgrids for multiple years. This is particularly true for temporary microgrid sites near undergrounding projects. Upon completion, undergrounding projects may reduce the need for nearby temporary microgrids to mitigate PSPS impacts. However, due to the time-consuming nature of undergrounding work (see Section 7.3.3.16), PG&E expects to continue to rely on temporary microgrids for PSPS mitigation in these locations for multiple years.

The recent Track 2 Decision in the Commission's Microgrid OIR provides additional upcoming opportunities to evaluate alternative solutions for mitigating PSPS impacts. First, the decision directs PG&E to submit an Advice Letter describing the substations at which PG&E proposes to use TG microgrids to mitigate PSPS outages in 2021.[3] That Advice Letter, which PG&E expects to file in the first quarter of 2021, will describe the process by which PG&E evaluated candidate substations, including its evaluations of near-term solutions other than temporary substation microgrids (and noting where those alternative solutions obviated the need to pre-stage TG at certain substations). Second, the decision requires PG&E to file an application by June 30, 2021 proposing a long-term framework for evaluating the need for generation at substations to mitigate PSPS outages.[4] In that application, PG&E expects to present an analytical methodology to consider the longer-term alternatives for mitigating PSPS outages, including further consideration of whether it is reasonable to continue using temporary or longer-term microgrids as a bridge until other solutions can be put in place.

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3 D.21-01-018, App. A, pp. A-1 to A-3.

4 *Id.*, App. A, pp. A-6 to A-8.

7.3.3.11.2 Substation activities to enable reduction of PSPS impacts

WSD Initiative Definition: *N/A. This is a "PGE-defined sub-initiative" that supports the response for the (parent) WSD-defined Initiative.*

1) ***Risk to be mitigated / problem to be addressed:***

   The risk to be mitigated are the potential impacts of PSPS events on communities and customers. Risk mitigation efforts include:

   Substations Requiring Protection Upgrades

   Substation activities that enable the reduction of PSPS impacts include the installation or upgrade of protection equipment and automatic sectionalizing devices at various substations to improve operating flexibility thereby minimizing the frequency, scope, and duration of PSPS events.

   Substation Microgrid Locations

   Another activity is substation equipment and protection upgrade to accommodate "Microgrids for PSPS Mitigation" initiative that enables the connection of a generation source or tie line to the substation to serve in an island-configuration during a PSPS event. Additional information about the substation and distribution microgrids initiative can be found in Section 7.3.3.11.1 B and 7.3.3.11.1 C above.

2) ***Initiative selection ("why" engage in activity) – include reference to a risk informed analysis on empirical (or projected) impact of initiative in comparison to alternatives:***

   Both these risk mitigation efforts support PSPS events. PSPS events can potentially impact many customers given the configuration of PG&E's electrical system. As a result, a power shut-off may occur in areas that are not directly in the weather zone, but is served by facilities that are impacted by the extreme wind/weather conditions. The substation activities will allow for minimizing the scope of PSPS events, enable faster restoration for those impacted and, in some cases, an alternative power source (generation) during PSPS events.

3) ***Region prioritization ("where" to engage activity) – include reference to a risk informed analysis in allocation of initiative (e.g., veg clearance is done for trees tagged as "high-risk"):***

   Substations Requiring Protection Upgrades

   Relays for substation equipment operate within overlapping layers of protection zones that are set in such a way that the timing allows the relay to operate in a structured sequence. For example, when a line is taken out of service, PG&E is required to maintain coordination within the remaining energized zone. If the substation equipment (i.e. fuse) within the remaining energized zone does not have the ability to coordinate with the upstream relays, then either the decision is made to de-energize the equipment, remain with the coordinating deficiency, or, if the equipment cannot be adequately protected, then remove it from service.

Substation Microgrid Interconnection

The feedback to determine microgrid locations include but are not limited to transfer capability, infringement to future site plans, adherence to design standards and maintenance considerations. For more details please see Section 7.3.3.11.1 (B).

4) ***Progress on initiative (amount spent, regions covered) and plans for next year:***

Substations Requiring Protection Upgrades

Based on system protection reviews, PG&E has identified one substation for protection or SCADA installation, or upgrade noted within Table PG&E-7.3.3-5 below. The specific dates for this work to be operative are preliminary and may change depending on the availability of resources and other prioritized work.

TABLE PG&E-7.3.3-5: SUBSTATION ELIGIBLE FOR UPGRADE, PROTECTION OR SCADA INSTALLATION

Line No.	Substation Name	Operative Year
1	Rincon	2021

Substation Microgrid Interconnection

Information regarding substation microgrid efforts can be found in Section 7.3.3.11.1.

5) ***Future improvements to initiative:***

Substation activities are driven by the PSPS and microgrid strategy in Section 7.3.3.11.1. This work is necessary to ensure safe and reliable operations and protection of the electric grid.

ACTION PGE-25 (Class B)

1) Integrate discussion on long-term planning within the respective section of each individual initiative.

Response:

As stated above, please reference Section 7.3.3.11.1 for more information on future improvements for this initiative.

7.3.3.11.3 Emergency Back-up Generation – PG&E Service Centers & Materials Distribution Centers

WSD Initiative Definition: *N/A. This is a "PGE-defined sub-initiative" that supports the response for the (parent) WSD-defined Initiative.*

1) ***Risk to be mitigated / problem to be addressed:***

   While several PG&E facilities have an existing emergency backup system onsite, very few are configured to back up the entire campus. In most cases, the emergency system will supply backup power to existing critical communications, emergency lighting and possibly a storm room or EOC. While this level of backup may have been enough for shorter duration emergency response events, such as a mild winter storm, it can be inadequate for the longer duration PSPS events, which can last several days.

2) ***Initiative selection ("why" engage in activity) – include reference to a risk informed analysis on empirical (or projected) impact of initiative in comparison to alternatives:***

   Because the existing emergency generation systems only backup a select number of circuits within the campus, critical systems such as fuel islands, gate operators, exterior lighting, and operations buildings may not be backed up. This can result in operational inefficiencies during PSPS events. Additionally, because some facilities have limited or no existing emergency generation, personnel who would typically work out of these locations have had to work either remotely or at alternate locations in order to support restoration events.

   In order to address this issue, PG&E's Corporate Real Estate Strategy and Services (CRESS) department has initiated a three-year (2020-2022) capital project in order to harden a number of service center locations throughout our service territory against the possibility of extended utility power loss events.

   As part of this project, 52 locations will be equipped with an emergency generation system capable of backing up the campus in its entirety. In order to achieve this, it is expected that existing emergency generators, automatic transfer switches, and in most cases, main switchboards, will need to either be replaced or reconfigured in order to achieve emergency generation back up the for the entire site.

   In addition to the locations mentioned above, another 43 locations will be equipped with generator tap boxes and transfer switches but will not be equipped with permanent generators. This will also allow for the entire campus to be backed up through emergency generation, with the difference being that these locations will be prepared to accept a portable generator instead of being equipped with a permanent generator.

When completed, the electrical reconfiguration and additional equipment installed at these locations will allow these sites to operate with the same amount of functionality as they would if they were being fed from their normal source (utility power). This will ensure that restoration efforts being performed by operational personnel working out of the site can carry on unimpeded.

3) ***Region prioritization ("where" to engage activity) – include reference to a risk informed analysis in allocation of initiative (e.g., veg clearance is done for trees tagged as "high-risk"):***

This three-year project was split into three phases, with one phase being targeted for execution each year (e.g., Phase One (2020), Phase Two (2021), Phase Three (2022)). Each site was evaluated and ranked based on the population of employees working out of the facility and its adjacency to HFTD areas. Sites with higher populations of employees and that are located close to or within an HFTD area were ranked higher and included in Phase One. Sites with lower populations or not adjacent to an HFTD area were ranked lower and included in Phase Three of the project.

Phase One (2020): Phase One of the project will concentrate on the 23 highest priority sites as determined by the facility's location regarding HFTD areas and the workforce population operating out of the facility. As these sites are closest in proximity to the HFTDs they are most likely to be impacted by PSPS event. Prioritizing these sites within the multi-year project thereby presents the greatest benefit to customers since it's most likely that PSPS restoration efforts will be managed out of these locations. By ensuring that these sites are fully operational during an extended power loss events we maximize our operational efficiency during restoration efforts, thereby minimizing outage times for impacted customers.

Phase Two (2021): 2021 will focus on the next highest priorities, again determined by adjacency to HFTD areas and the headcount assigned to the facility. We estimate that approximately 30 sites will be addressed in this phase.

Phase Three (2022): 2022 will focus on the lowest priority sites. These are sites where the likelihood of experiencing a PSPS event is low or the long-term strategy for the facility is currently being evaluated.

4) ***Progress on initiative (amount spent, regions covered) and plans for next year:***

By the end of 2021, at least 23 PG&E Service Centers & Materials Distribution Centers will be equipped to receive permanent or temporary generation. By the end of 2022, the 72 remaining PG&E Service Centers & Materials Distribution Centers will be equipped to receive permanent or temporary generation.

5) Future improvements to initiative:

There are currently no additional plans on this initiative beyond what is described above.

ACTION PGE-25 (Class B)

1) Integrate discussion on long-term planning within the respective section of each individual initiative.

Response:

As stated in the section above, there are no further improvements planned at this time other than the work described above through 2022

7.3.3.12 Other Corrective Action

***WSD Initiative Definition**: Other maintenance, repair, or replacement of utility equipment and structures so that they function properly and safely, including remediation activities (such as insulator washing) of other electric equipment deficiencies that may increase ignition probability due to potential equipment failure or other drivers.*

For this initiative, PG&E has several sub-initiatives including:

- 7.3.3.12.1: Distribution substations
- 7.3.3.12.2: Transmission substations
- 7.3.3.12.3: Maintenance transmission
- 7.3.3.12.4: Maintenance distribution

7.3.3.12.1 Distribution Substation

***WSD Initiative Definition**: N/A. This is a "PGE-defined sub-initiative" that supports the response for the (parent) WSD-defined Initiative.*

1) Risk to be mitigated / problem to be addressed:

The primary wildfire risk with substations is an arc flash event within the substation that propagates into adjacent wildlands. PG&E has taken two specific actions to address this risk. First, we have initiated a defensible space program for substations located in Tier 2 and Tier 3 HFTD areas. Second, we have improved our animal abatement program.

In addition to these specific actions, we also perform corrective repairs and equipment replacements identified through the enhanced inspections of substations. This work is intended to correct deficiencies identified and ensure that substation equipment operates as designed.

2) Initiative selection ("why" engage in activity) – include reference to a risk informed analysis on empirical (or projected) impact of initiative in comparison to alternatives:

Defensible Space: Defensible space for substations is a 100’ perimeter around substation equipment that includes both a 30’ clean zone and a 70’ reduced fuel zone. Defensible space is normally achieved by removing combustible material (primarily vegetation) from these areas. Defensible space is intended to reduce the risk of an event within a substation, igniting a fire, that propagates outside of the facility. By implementing these requirements, the risk of fire spreading is significantly reduced and provides a higher probability that a fire can be extinguished without involving third party property.

Substation Animal Abatement: PG&E has been conducting an animal abatement program for its substations, with reliability (i.e., lower customer outage) as the main driver. The program was expanded to address wildfire risks by reducing the probability of an arc flash within the substation. Animal contacts may result in a catastrophic failure of equipment that can project ignited materials into HFTD areas.

Repairs and Replacements from Enhanced Inspections: PG&E conducts enhanced inspections in substations located in HFTD areas. These inspections identify deficiencies with substation equipment and components. The repair and replacement work are performed to reduce the risk of an equipment failure or miss operation.

3) ***Region prioritization ("where" to engage activity) – include reference to a risk informed analysis in allocation of initiative (e.g., veg clearance is done for trees tagged as "high-risk"):***

Defensible Space: The program requires defensible space to be established and maintained on substations located in Tier 2 and Tier 3 HFTD areas, where possible. At some locations, it is not possible to attain defensible space due to adjacent structures, third-party property owners, or permitting issues.

Substation Animal Abatement: Animal abatement was identified during the 2019 Wildfire Safety Inspection Program (WSIP) as a mitigation to minimize fire ignition, specifically in Tier 2 and Tier 3 HFTD areas. All substations located in these areas that have achieved defensible space will have animal abatement installed. Substations located in these areas that are not able to achieve defensible space will have additional animal abatement installed to further reduce the likelihood of an animal contact

Repairs and Replacements from Enhanced Inspections: Enhanced inspections are performed at substations located in HFTD areas. As a result of these inspections, corrective work is identified at substations located in HFTD areas. The identified repair and replacement work are prioritized based on risk and completed based on the prioritized schedule.

4) Progress on initiative (amount spent, regions covered) and plans for next year:

Defensible Space: As of December 31, 2020, 96 percent of substations (168 of 175) located in Tier 2 and Tier 3 HFTD areas have attained defensible space. At some locations, it is not possible to attain defensible space due to adjacent structures, third party property owners, or permitting issues.

Substation Animal Abatement: 77 locations have been identified as requiring animal abatement. Of these 77 locations, 18 were completed in 2019, 21 were completed in 2020, and the remaining 38 are being prioritized for completion.

Repairs and Replacements from Enhanced Inspections: PG&E has a total of 126 distribution substations located in HFTD areas. Each of these locations is inspected through the enhanced inspection program. All repair and replacement work identified by the inspections is reviewed, prioritized and scheduled for completion. In 2020, 47 of these substations were inspected by the enhanced inspection program and in 2021, 57 of these substations are planned to be inspected. The repair and replacement work generated from these inspections will be reviewed, prioritized and scheduled for completion.

5) Future improvements to initiative:

At this time, no future improvements have been identified; the programs will continue to execute at the substations that have been identified.

ACTION PGE-25 (Class B)

1) Integrate discussion on long-term planning within the respective section of each individual initiative.

Response:

For the long-term, we will continue with periodic evaluations of the defensible space, animal abatement and the repairs and replacement programs. These evaluations typically include performance trends, inspection results, emerging technology and other risk factors. Updates will be made to the programs based on these evaluations.

7.3.3.12.2 Transmission Substation

***WSD Initiative Definition**: N/A. This is a "PGE-defined sub-initiative" that supports the response for the (parent) WSD-defined Initiative.*

1) ***Risk to be mitigated / problem to be addressed:***

   The primary wildfire risk with substations is an arc flash event within the substation that propagates into adjacent wildlands. PG&E has taken two specific actions to address this scenario. First, we have initiated a defensible space program for substations located in Tier 2 and Tier 3 HFTD areas. Second, we have improved our animal abatement program.

   In addition to these specific actions, we also perform corrective repairs and equipment replacements identified through the enhanced inspections of substations. This work is intended to correct deficiencies identified and ensure that substation equipment operates as designed.

2) ***Initiative selection ("why" engage in activity) – include reference to a risk informed analysis on empirical (or projected) impact of initiative in comparison to alternatives:***

   <u>Defensible Space</u>: Defensible space for substations is a 100' perimeter around substation equipment that includes both a 30' clean zone and a 70' reduced fuel zone. Defensible space is normally achieved by removing combustible material (primarily vegetation) from these areas. Defensible space is intended to reduce the risk of an event within a substation, igniting a fire, that propagates outside of the facility. By implementing these requirements, the risk of fire spreading is significantly reduced and provides a higher probability that a fire can be extinguished without involving third party property.

   <u>Substation Animal Abatement</u>: PG&E has been conducting an animal abatement program for its substations, with reliability (i.e., lower customer outage) as the main driver. The program was expanded to address wildfire risks by reducing the probability of an arc flash within the substation. Animal contacts may result in a catastrophic failure of equipment that can project ignited materials into HFTD areas.

   <u>Repairs and Replacements from Enhanced Inspections:</u> PG&E conducts enhanced inspections in substations located in HFTD areas. These inspections identify deficiencies with substation equipment and components. The repair and replacement work are performed to reduce the risk of an equipment failure or miss operation.

3) Region prioritization ("where" to engage activity) – include reference to a risk informed analysis in allocation of initiative (e.g., veg clearance is done for trees tagged as "high-risk"):

Defensible Space: The program requires defensible space to be established and maintained on substations located in Tier 2 and Tier 3 HFTD areas, where possible. At some locations, it is not possible to attain defensible space due to adjacent structures, third-party property owners, or permitting issues.

Substation Animal Abatement: Animal abatement was identified during the 2019 WSIP as a mitigation to minimize fire ignition, specifically in Tier 2 and Tier 3 HFTD areas. All substations located in these areas that have achieved defensible space will have animal abatement installed. Substations located in these areas that are not able to achieve defensible space will have additional animal abatement installed to further reduce the likelihood of an animal contact.

Repairs and Replacements from Enhanced Inspections: Enhanced inspections are performed at substations located in HFTD areas. As a result of these inspections, corrective work is identified at substations located in HFTD areas. The identified repair and replacement work are prioritized based on risk and completed based on the prioritized schedule.

4) Progress on initiative (amount spent, regions covered) and plans for next year:

Defensible Space: As of December 31, 2020, 100 percent of substations (40 of 40) located in these areas have attained defensible space. In 2020, PG&E spent $1.7 million and in 2021, we are planning to spend $2.5 million on defensible space for transmission substations.

Substation Animal Abatement: nine locations were identified as requiring animal abatement, two were completed in 2019, two are were completed in 2020, and the remaining five are being prioritized for completion. In 2020, PG&E spent $1.0 million and in 2021, we are planning to spend $3.1 million on animal abatement in transmission substations.

Repairs and Replacements from Enhanced Inspections: PG&E has a total of 60 transmission substations located in HFTD areas. Each of these locations is inspected through the enhanced inspection program. All repair and replacement work identified by the inspections is reviewed, prioritized and scheduled for completion. In 2020, 29 of these substations were inspected by the enhanced inspection program and in 2021, 22 of these substations are planned to be inspected. The repair and replacement work generated from these inspections will be reviewed, prioritized and scheduled for completion.

5) Future improvements to initiative:

At this time, no future improvements have been identified; the program will continue to execute at the substations that have been identified.

ACTION PGE-25 (Class B)

1) Integrate discussion on long-term planning within the respective section of each individual initiative.

Response:

For the long-term, we will continue with periodic evaluations of both the defensible space and animal abatement programs. These evaluations typically include performance trends, emerging technology and other risk factors. Updates will be made to the programs based on these evaluations.

7.3.3.12.3 Maintenance, Transmission

WSD Initiative Definition: *N/A. This is a "PGE-defined sub-initiative" that supports the response for the (parent) WSD-defined Initiative.*

1) Risk to be mitigated / problem to be addressed:

Since 2019, PG&E has conducted enhanced transmission inspections (performed with enhanced inspection protocols). Detailed inspections are performed with two vantage points (e.g., by ground and by aerial) to fully capture all asset conditions. These inspections have resulted in a significant increase in the volume of corrective action notifications for maintenance. These maintenance notifications are key to trending, prioritizing and reducing asset risk by correcting identified asset hazards, poor conditions, and non-standard concerns.

2) Initiative selection ("why" engage in activity) – include reference to a risk informed analysis on empirical (or projected) impact of initiative in comparison to alternatives:

The maintenance (repair or replacement) work done as a result of enhanced inspections is an important step in mitigating risk. Although there are general priority timelines given to maintenance notifications when identified, prioritization and additional field safety assessments may be done in order to reduce the wildfire risk and manage the work of the maintenance notifications resulting from enhanced inspections. Furthermore, analysis of inspection and maintenance data provides opportunities for trending and refinement of risk prioritization.

3) Region prioritization ("where" to engage activity) – include reference to a risk informed analysis in allocation of initiative (e.g., veg clearance is done for trees tagged as "high-risk"):

PG&E is prioritizing maintenance on the highest risk notifications and using additional Field Safety Reassessments (FSR) to mitigate the risk and manage this large volume of work.

The process for prioritization of these notifications uses the following definitions:

- Ignition-related notification: Notifications related to components included in the 2019 Failure Modes Effects Analysis (FMEA). Ignition risks can be either time-dependent or time-independent, e.g., a bird's nest or steel crossarm that is "no good/out of standard."
- Non-ignition-related notification: Notifications that do not pose an ignition risk and are not considered to be a failure mode for a component in the 2019 FMEA, e.g., a missing "high voltage" sign.

- Time-dependent notifications: Conditions that will worsen with time, e.g., mechanical degradation including fatigue, corrosion, can all worsen with time and are time-dependent.
- Time-independent notifications: Conditions that will not worsen with time, e.g., a missing sign or a missing guy insulator.

Using these definitions, notifications are prioritized as follows:

- Ignition-related notifications on structures in HFTD areas are prioritized over non-ignition-related notifications or notifications in non-HFTD areas.
- Ignition-related notifications are divided into time-dependent and non-time-dependent notifications. Time-dependent notifications are prioritized above non-time-dependent notifications because of the possibility that the condition can degrade further if the repairs are deferred.
- Time-dependent notifications in high fire spread areas are prioritized ahead of notifications in lower spread areas.
- These considerations result in the following prioritization (highest to lowest):
  - Time-dependent ignition-related notifications in highest fire spread areas of HFTDs.
  - Time-dependent ignition-related notifications in lower fire spread areas of HFTDs.
  - Time-independent ignition-related notifications in HFTDs.
  - Non-ignition-related notifications in HFTD areas or notifications outside of HFTDs.

4) Progress on initiative (amount spent, regions covered) and plans for next year:

In 2020, approximately 11,900 notifications within HFTD areas were completed (not including those for steel structures, further discussed in Section 7.3.3.15). In 2021, approximately 8,900 notifications within HFTD areas are expected to be completed, not including any urgent priority notifications that may be identified in 2021.

In 2021, PG&E is expecting to complete all ignition-related notifications in HFTD areas found before 2020 and all time-dependent ignition-related notifications found in 2020 on high fire spread areas, in addition to any new urgent priority notifications identified in 2021.

5) Future improvements to initiative:

As data is collected through enhanced inspections and maintenance, trending analysis will allow for understanding of deterioration rates of specific asset conditions and used to influence future inspection frequency and prioritization. Trending of notification find rates can also influence the maintenance strategy for specific lines or sections. This information will also be utilized in the programmatic approach for repair and replace decisions.

ACTION PGE-25 (Class B)

1) Integrate discussion on long-term planning within the respective section of each individual initiative.

Response:

Long term, it is expected that the volume of maintenance notifications generated through enhanced inspections will be executed in accordance with appropriate timelines associated with the damage found. Where notifications cannot be completed per the timeline, field safety reassessments (FSR) are done, and information will help to refine the understanding of the damage mode decay rates. This information will also be used to improve guidance to maintenance inspectors. Additionally, it is expected that effectiveness of maintenance will be trended and used to inform future maintenance mitigations, processes and procedures.

7.3.3.12.4 Maintenance, Distribution

***WSD Initiative Definition**: N/A. This is a "PGE-defined sub-initiative" that supports the response for the (parent) WSD-defined Initiative.*

1) Risk to be mitigated / problem to be addressed:

The distribution overhead enhanced inspection program is used to identify potential asset failures and gain a better understanding of asset condition for asset maintenance and replacement. EC notifications are a byproduct of the enhanced inspection process. These maintenance notifications are key to reducing asset risk by correcting identified asset hazards, poor conditions, and non-standard concerns.

2) ***Initiative selection ("why" engage in activity) – include reference to a risk informed analysis on empirical (or projected) impact of initiative in comparison to alternatives:***

Detailed inspections are performed with enhanced inspection protocols. Enhanced inspection activities lead to corrective actions taken on the issues identified during the inspection. Since 2019, distribution assets have been inspected more rigorously than in previous years through PG&E's WSIP. These changes have resulted in a significant increase in the volume of EC notifications based on a FMEA approach. The maintenance (or replacement) work done as a result of the inspections is the final step in mitigating risk in the HFTD area.

3) ***Region prioritization ("where" to engage activity) – include reference to a risk informed analysis in allocation of initiative (e.g., veg clearance is done for trees tagged as "high-risk"):***

Since 2019 the distribution enhanced overhead inspection process has been used on all distribution assets located in Tier 2 and Tier 3 HFTD areas. These enhanced inspections exceed GO 165 five-year cycle times as follows:

- Tier 3 – enhanced overhead inspection yearly
- Tier 2 – enhanced overhead inspection every three years

The EC maintenance notifications generated through the enhanced inspection program are assigned a priority based on the potential safety impact. PG&E uses the following priorities:

- A: conditions that require immediate action.
- B: conditions that generally need to be addressed within three (3) months from the date a condition is identified.
- E: conditions that need to be addressed within twelve (12) months from the date the condition is identified or within six (6) months for conditions creating a fire risk located in Tier 3 HFTD areas.
- F: conditions that need to be addressed within five (5) years from the date the condition is identified.

Given the high volume of identified tags since 2019, PG&E utilized a risk-informed prioritization approach to address the highest risk issues on PG&E's facilities. The largest volume of identified corrective actions are the E and F tags, which includes findings such as chipped or broken insulators, pole repairs for woodpecker holes, loose cotter keys (E tags), missing markers, signage, or foundation mastic application (F tags). PG&E has prioritized execution of E and F tags based on ignition risk circuit prioritization and plans to continue to make repairs based on this prioritization.

4) *Progress on initiative (amount spent, regions covered) and plans for next year:*

As of September 30, 2020 (the end of Q3 2020), the following HFTD tag progress has been made since 2019:

- WSIP-Generated Tags: 208,510 tags had been created, 73,359 had been closed (repairs have been completed) and 135,151 remain open.
- Non-WSIP-Generated Tags: 84,949 tags had been created, 21,305 had been closed (repairs have been completed) and 63,644 remain open.

PG&E is continuing to verify the status of tags in Q4 2020, and thus is currently unable to provide the Q4 2020 information. Open tags will continue to be worked in a risk-based priority including new tags generated through the 2021 inspection program. Priority A and B tags are expected to be completed by the required due date. Due to the high volume of priority E and F tags, a risk ranking utilizing the FMEA severity score will be used. Any tag that contains a “time dependent” element and cannot be completed and beyond the due date will receive an FSR.

5) *Future improvements to initiative:*

PG&E is evaluating integrating the 2021 Wildfire Distribution Risk Model results into its maintenance program to allow prioritization of notifications by wildfire risk at the tag location level. This would pinpoint specific locations of ignition concern, allowing both the highest probable ignition potential issues as well as the highest consequence areas to be addressed first.

ACTION PGE-25 (Class B)

1) Integrate discussion on long-term planning within the respective section of each individual initiative.

Response:

At this time, there is no long-term plan beyond 2021. However, we will continue to evaluate the risk based approach for enhanced inspections, including inspection frequency and methods. Additionally, the results of the integration between the Wildfire Distribution Risk Model and the maintenance program will allow for further analysis and planning.

7.3.3.13 Pole Loading Infrastructure Hardening and Replacement Program Based on Pole Loading Assessment Program

WSD Initiative Definition: *Actions taken to remediate, adjust, or install replacement equipment for poles that the utility has identified as failing to meet safety factor requirements in accordance with GO 95 or additional utility standards in the utility's* *pole loading assessment program.*

1) ***Risk to be mitigated / problem to be addressed:***

   PG&E started its pole loading program to reduce the risk of potential fire ignitions resulting from pole failures by evaluating poles so that each pole meets GO 95, Rule 44 strength requirements throughout its service life, both when initially installed and while in-service despite changing conditions, impacts from maintenance activities, attachment additions and potential wood strength degradation. Replacing overloaded poles eliminates the risks associated with pole failure, including potential ignition risk. This program also reduces risk by providing asset intelligence to identify locations that require corrective actions driven by pole safety factors or limitations for wind speeds.

2) ***Initiative selection ("why" engage in activity) – include reference to a risk informed analysis on empirical (or projected) impact of initiative in comparison to alternatives:***

   During a pole's service life, pole loading calculations are performed when load is added to a pole or if a suspected overload condition is observed during inspection. Pole loading calculations are performed in O-Calc software during the design phase to ensure poles are sized correctly to satisfy GO 95 requirements. When poles are analyzed and determined to be overloaded or the pole loading evaluation indicates that the pole does not satisfy GO 95 requirements, a pole replacement tag is initiated to correct the condition.

3) ***Region prioritization ("where" to engage activity) – include reference to a risk informed analysis in allocation of initiative (e.g., veg clearance is done for trees tagged as "high-risk"):***

   PG&E's pole loading program has focused on assessments of poles in the Tier 2 and 3 HFTD areas with the goal to be fully implemented (100 percent poles analyzed) in these areas by 2024. Poles located in non-HFTD areas will follow, with the goal to be fully implemented (100 percent poles analyzed) by 2030.

4) ***Progress on initiative (amount spent, regions covered) and plans for next year:***

   PG&E is strengthening pole loading model parameters and variables considering historical data with various meteorological factors (e.g., wind speed). These enhancements include evaluation of advanced wire strength, clearance, and pole loading using acquired imagery and Light Detection and Ranging (LiDAR) from Inspections, Drones and Helicopters. In addition, the program is using LiDAR to geo-correct pole locations.

   In the 2020 WMP, PG&E forecast assessing approximately

230,000 poles in Tier 2 and Tier 3 HFTD areas. However, PG&E did not anticipate the huge volume of poles that our internal estimating teams would be analyzing every year. In addition, we switched vendors and refined quality standards, which slowed down the evaluation process in 2020. As of December 1, 2020, we have completed pole loading analysis of over 160,000 poles, all of which are considered the highest risk poles, either due to the pole characteristics or location (i.e., located in an HFTD area). In 2021, we will continue to focus on HFTD areas and plan to analyze approximately 160,000 poles. PG&E is on-track to finish poles in Tier 2 and Tier 3 HFTD areas by end of 2024 as originally forecast.

5) Future improvements to initiative:

PG&E is reviewing its pole loading calculation software to see if it can enable analysis of multiple pole models at once, enabling span linking to ensure structural connectivity.

ACTION PGE-25 (Class B)

1) Integrate discussion on long-term planning within the respective section of each individual initiative.

Response:

PG&E does not currently have specific long-term planning beyond 2030, since this effort extends until 2030. When poles are determined to be overloaded, their replacement is incorporated into our overall pole replacement program, which is part of the compliance plan. Please refer to Section 7.3.3.6 for further discussion on pole replacements.

7.3.3.14 Transformers Maintenance and Replacement

***WSD Initiative Definition**: Remediation, adjustments, or installations of new equipment to improve or replace existing transformer equipment.*

1) Risk to be mitigated / problem to be addressed:

PG&E's GO 165 Program, which covers distribution transformer maintenance, is primarily focused on the identification, assessment, prioritization, and documentation of abnormal conditions, regulatory conditions, and third party caused infractions that can negatively impact safety or reliability.

2) Initiative selection ("why" engage in activity) – include reference to a risk informed analysis on empirical (or projected) impact of initiative in comparison to alternatives:

Transformers may by maintained, repaired, or replaced based on their condition as assessed during the GO 165 process. The conditions identified during patrols and inspections of PG&E's distribution facilities may occur as a result of operational use, degradation, deterioration, environmental changes or third-party actions.

Transformers that fail in connection with an outage may be replaced as part of PG&E's Routine Emergency or Major Emergency programs. PG&E is also replacing certain transformers on circuits that are included in the System Hardening Program discussed in Section 7.3.3.17.1

3) ***Region prioritization ("where" to engage activity) – include reference to a risk informed analysis in allocation of initiative (e.g., veg clearance is done for trees tagged as "high-risk"):***

This work is covered under PG&E's GO 165 program covers Buffer Zones and all of our service area. GO 165 inspections for HFTD are the same for non-HFTD. However, while the scope of the inspection is the same, the frequency for HFTD and non-HFTD areas is different. The frequency of GO 165 program inspections is 1-3 three years in HFTD areas as opposed to 5 years in non-HFTD areas.

4) ***Progress on initiative (amount spent, regions covered) and plans for next year:***

PG&E will continue to maintain, repair, or replace transformers as warranted by their condition as part of its ongoing GO 165 maintenance program and Emergency programs. PG&E may also replace certain transformers as part of its System Hardening Program.

5) ***Future improvements to initiative:***

PG&E has two Electric Program Investment Charge (EPIC) projects that are evaluating smart meter technology, data science, and remote monitoring to proactively identify and replace some overloaded transformers before they fail. These projects are covered in depth in Sections 7.1.D.3.12- EPIC 3.20 and 7.1.D.3.11- EPIC 3.13.

ACTION PGE-25 (Class B)

1) Integrate discussion on long-term planning within the respective section of each individual initiative.

Response:

Since this initiative is closely related to GO 165 requirements, the long-term vision will be guided by changes/ updates to the regulation. Please see references in the "Future Improvements" section above for more context.

7.3.3.15 Transmission Tower Maintenance and Replacement

***WSD Initiative Definition**: Remediation, adjustments, or installations of new equipment to improve or replace existing transmission towers (e.g., structures such as lattice steel towers or tubular steel poles that support lines at or above 65 kV).*

1) ***Risk to be mitigated / problem to be addressed:***

   Maintenance, repair and replacement of transmission towers, particularly those located in Buffer Zones and HFTD areas, are integral means of mitigating risk associated wildfire, public and employee safety, and customer reliability.

2) ***Initiative selection ("why" engage in activity) – include reference to a risk informed analysis on empirical (or projected) impact of initiative in comparison to alternatives:***

   PG&E's transmission tower maintenance, repair and replacement program focuses on high-risk steel structures. Many factors feed into determination of high-risk steel structures – including prior inspection conditions, environmental factors (such as location in an HFTD area or corrosion zone), age, structure design, prior outages, prior repairs, etc. Needs associated with Transmission tower maintenance are generally identified through system inspections and patrols.

3) ***Region prioritization ("where" to engage activity) – include reference to a risk informed analysis in allocation of initiative (e.g., veg clearance is done for trees tagged as "high-risk"):***

   Prioritization of maintenance, repair and replacement are based on severity of the issue found, fire ignition risk (i.e., risk associated with HFTD areas and HFRA), and time-dependency of the issue. As conditions are identified, they are given a time-based priority based on guidance in PG&E's Electric Transmission Preventative Maintenance Manual. For certain tags (E and F priority tags), additional prioritization occurs based on the damage found. If the repair needed is time-dependent (meaning that the damage can worsen with time), and in an HFTD area, it may be prioritized before other non-time-dependent, non-ignition potential tags.

4) ***Progress on initiative (amount spent, regions covered) and plans for next year:***

   In 2020, approximately 5,100 tags associated with steel transmission tower repair were completed within HFTD areas. Of these, approximately 50 tags associated with steel structure painting were completed in 2020 in order to extend structure asset life. In 2021, approximately 4,000 tags associated with steel transmission tower repair have been prioritized for completion within HFTD areas, not including any urgent priority tags that may be identified in 2021. Approximately 500 tags associated with steel structure painting are prioritized for completion in 2021 within HFTD areas. Overall, in 2021, it is expected to complete all ignition-related tags in HFTD areas found before 2020 and all time-dependent ignition-related tags found in 2020 on high potential wildfire spread lines, in addition to any new urgent priority tags identified in 2021.

5) Future improvements to initiative:

PG&E is piloting additional inspection and asset-life extension technology for steel structures, which is planned to feed into asset health modeling and repair-replace decision for these assets. For example, below-grade foundation inspections (see Section 7.3.4.10) will inform future repairs and replacements. These inspections aim to assess condition of steel structure foundations below the ground-line. Investigation will include a measure of soil resistivity, pH, Redox & Half Cell Measurement as well as a visual assessment with photographic evidence of each excavated foundation leg. The results will validate data from models, inform (preventive) maintenance and repair decisions, and inform locations most requiring of cathodic protection.

ACTION PGE-25 (Class B)

1) Integrate discussion on long-term planning within the respective section of each individual initiative.

Response:

Long term, PG&E will evaluate potential steel structure failure modes through inspection, maintain structures with life-extension methods such as cathodic protection and tower coating, and replace steel structures at a sustainable rate. There are current pilots underway to expand some of the failure mode identification and life extension methods. Successful completion or additional research will be conducted until proven methods can be integrated into the lifecycle management of the assets, system-wide as needed based on risk priority.

7.3.3.16 Undergrounding of Electric Lines and/or Equipment

WSD Initiative Definition: *Actions taken to convert overhead electric lines and/or equipment to underground electric lines and/or equipment (i.e., located underground and in accordance with GO 128).*

1) Risk to be mitigated / problem to be addressed:

Undergrounding electric lines and facilities can significantly reduce wildfire risk by eliminating overhead lines which may be prone to wires down events or otherwise prone to potential wildfire ignitions. The installation of underground facilities is considered among a suite of alternatives to mitigate wildfire risk in areas prone to tree failures. PG&E also considers secondary risks such as PSPS impacts, egress/ingress routes to support fire department response times and public safety, past fire history and effects on available fuels, current system condition, environmental risks to reconstruction activities, and general accessibility considerations to enhance employee safety when determining whether specific facilities should be undergrounded.

2) Initiative selection ("why" engage in activity) – include reference to a

risk informed analysis on empirical (or projected) impact of initiative in comparison to alternatives:

Undergrounding can be an effective means of addressing wildfire risk, but it is also time-consuming and costly. Thus, each location must be separately evaluated to determine if undergrounding is a prudent approach for mitigating wildfire risk. PG&E does not, for wildfire mitigation purposes, have a stand-alone targeted program to relocate overhead facilities to underground.[5] Instead, PG&E relocates existing high risk overhead medium voltage lines to underground as part of our System Hardening Program. When considering an underground alternative, it is essential to consider risk reduction from undergrounding as well as all execution risks and costs. Execution risks include accessibility, rights-of-way, public utility easements, private property crossings, the number of services, space for necessary subsurface and pad-mounted equipment, environmental restrictions such as naturally occurring asbestos or endangered species, Archeology and Historic Preservation, soil remediation, and soil conditions.

3) ***Region prioritization ("where" to engage activity) – include reference to a risk informed analysis in allocation of initiative (e.g., veg clearance is done for trees tagged as "high-risk"):***

The location and prioritization of undergrounding is addressed in the discussion of PG&E's System Hardening Program in Section 7.3.3.17.1

4) ***Progress on initiative (amount spent, regions covered) and plans for next year:***

The progress on undergrounding and plans for 2021 is addressed in the discussion of PG&E's System Hardening Program in Section 7.3.3.17.1

5) ***Future improvements to initiative:***

Future improvements related to undergrounding are addressed in the discussion of PG&E's System Hardening Program in Section 7.3.3.17.1

ACTION PGE-25 (Class B)

1) Integrate discussion on long-term planning within the respective section of each individual initiative.

Response:

5 PG&E has an undergrounding program under Rule 20A, but that program is not related to wildfire mitigation.

As stated above, please reference Section 7.3.3.17.1 for more information on future improvements for this initiative.

7.3.3.17 Updates to Grid Topology to Minimize Risk of Ignition in HFTDs

WSD Initiative Definition: *Changes in the plan, installation, construction, removal, and/or undergrounding to minimize the risk of ignition due to the design, location, or configuration of utility electric equipment in HFTDs.*

For this initiative, PG&E has several sub-initiatives including:

- 7.3.3.17.1: System Hardening – Distribution
- 7.3.3.17.2: System Hardening – Transmission
- 7.3.3.17.3: Non-Exempt Surge Arrestor Replacement Program
- 7.3.3.17.4: Rapid earth current fault limiter
- 7.3.3.17.5: Remote Grid
- 7.3.3.17.6: Butte County Rebuild

7.3.3.17.1 System Hardening – Distribution

WSD Initiative Definition: *N/A. This is a "PGE-defined sub-initiative" that supports the response for the (parent) WSD-defined Initiative*

In addition to describing PG&E's sub-initiative for our System Hardening Program for electric distribution, this section also provides responses to the following Action Items: Action PGE-3 (Class B), PGE-9 (Class-B), PGE-10 (Class B), PGE-32 (Class B), PGE-33 (Class B), PGE-34 (Class B), PGE-35 (Class B), and PGE-36 (Class B).

1) Risk to be mitigated / problem to be addressed:

PG&E's System Hardening Program focuses on the mitigation of potential catastrophic wildfire risk caused by distribution overhead assets. This program targets the highest wildfire risk miles and applies various mitigations such as line removal, conversion from overhead to underground, application of remote grid alternatives, mitigation of exposure through relocation of overhead facilities, and in-place overhead system hardening. The highest wildfire risk miles are separated into three categories:

1. The top 20 percent of circuit segments as defined by PG&E's 2021 Wildfire Distribution Risk Model for System Hardening
2. Fire rebuild areas
3. PSPS mitigation projects

PG&E also considers secondary risks and benefits as part of the System Hardening Program effort such as PSPS impacts, egress/ingress routes to support fire department response times and public safety, past fire history and effects on available fuels, current system condition, environmental risks to reconstruction activities, and general accessibility considerations to enhance employee safety.

2) ***Initiative selection ("why" engage in activity) – include reference to a risk informed analysis on empirical (or projected) impact of initiative in comparison to alternatives:***

Distribution overhead assets represent high ignition risk due to a combination of a high exposure area (overhead assets traversing HFTD areas) and proximity to risk factors such as vegetation. For utility equipment, estimated distribution-related ignitions per circuit mile are 1.6 times that of transmission-related ignitions. For vegetation drivers, estimated distribution ignitions per mile are up to 6x greater than for transmission circuits. Table PG&E-7.3.3-6 below illustrates the CPUC reportable ignitions from 2015 to September 2020 broken down into major contributing causes in Distribution and Transmission systems.

TABLE PG&E-7.3.3-6: CPUC REPORTABLE IGNITIONS AND ESTIMATED IGNITIONS PER 1,000 CIRCUIT MILES

	2015 - 2020 YTD[1] CPUC Reportable Ignitions in HFTD		Estimated Ignitions per 1,000 Circuit Miles in HFTD[2]	
Initiating Cause	Distribution	Transmission	Distribution	Transmission
Equipment – PG&E	217	30	8.5	5.4
Vegetation	305	11	11.9	2.0
All Other[3]	195	34	7.6	6.1

1. YTD represents data as of the end of September 2020.
2. Circuit mileage in HFTD areas source: 2020 Wildfire Safety Plan – 25,598 of distribution overhead mileage in HFTD areas, 5,542 of transmission overhead mileage.
3. Other includes ignitions primarily driven by 3rd Party and Animal.

PG&E's System Hardening Program is an important initiative that can reduce wildfire ignitions caused by distribution facilities. The System Hardening Program targets the highest wildfire risk miles as identified by PG&E's 2021 Wildfire Distribution Risk Model for system hardening (the 2021 Wildfire Distribution Risk Model is explained in further detail in Section 4.5.1), and also targets overhead structures impacted directly by wildfires, and those areas most impacted by PSPS. There are several ways that locations are identified for system hardening including:

- Identifying circuit segments with the highest wildfire risk using the 2021 Wildfire Distribution Risk Model
- Locations where past events have identified deteriorated overhead conductor
- Electric Corrective Optimization Program (ECOP), where a number of identified corrective repair tags on a single segment of line indicate that hardening the line may be more prudent than repairing each tag individually
- Projects to mitigate the need for PSPS in a certain area
- Fire damaged line sections requiring rebuild
- Idle facilities or other line removal opportunities

3) Region prioritization ("where" to engage activity) – include reference to a risk informed analysis in allocation of initiative (e.g., veg clearance is done for trees tagged as "high-risk"):

As discussed above, the System Hardening Program identifies locations to perform this work based primarily on PG&E's 2021 Wildfire Distribution Risk Model for system hardening. Projects are prioritized at the circuit segments level, as opposed to regional or full-circuit. In addition to the highest priority segments based on the risk model, projects are also included in the system hardening portfolio when needed to address overhead structures damaged directly by wildfires (described in subsection (e) below) and those areas most impacted by PSPS. The following mitigation options (subsections (a)-(c)) are considered for each circuit segment when developing a System Hardening Program project. Those options are evaluated through PG&E's process to consider system hardening alternatives (subsection (d)). Finally, this section also describes PG&E's consideration of Buffer Zones in system hardening (subsection (e)).

(a) Line Removal and Remote Grid

Complete removal of an existing overhead distribution line will also completely eliminate the fire risk associated with that line and is therefore explored for every identified system hardening project. A line removal mitigation can be applied in various ways. The simples application of this mitigation alternative is for known or suspected idle facilities, that are not currently, actively serving customer load. PG&E follows the procedures and requirements in Utility Procedure: TD-2459P-01 "Idle Facility Program" to investigate potential idle facilities and determine if they can been permanently removed. Another line removal alternative is the rearrangement or re-alignment of the existing circuit path. PG&E reviews the targeted circuit segment for redundant distribution ties through high risk areas. It may be possible that removal of certain circuit segments would have little impact on operational flexibility and provide the most cost-effective measure to reduce wildfire risk. Finally, a future removal opportunity lies with the application of the Remote Grid alternative discussed in Section 7.3.3.17.5 below.

(b) Relocation of Overhead to Underground

PG&E will relocate existing high risk overhead distribution lines to underground as part of this mitigation. When considering an underground alternative, it is essential that all execution risks are considered to provide an accurate cost projection for the installation and lifetime of the asset. Among the cost risks to installing underground assets are: accessibility, rights-of-way, public utility easements, private property crossings, the number of services, space for necessary subsurface and pad-mounted equipment, environmental restrictions such as naturally occurring asbestos or endangered species, Archeology and Historic Preservation, soil remediation, and soil conditions to name a few.

PG&E has found that there are many impediments to underground construction that limit its viability to be a cost-effective mitigation alternative when compared directly to overhead system hardening. The teams responsible for scoping this work also take tree density and strike potential trees into consideration as well as ingress/egress risks as some of the primary drivers for choosing an underground alternative.

Another impediment to this alternative is its schedule risks. A typical overhead hardening project can advance from idea to execution, documentation, and close out in 13-16 months. Whereas an underground project can often take 18-45 months depending on the various risks presented. The most impactful driver in many cases is land rights. Most of our systems in the high-risk areas have existing overhead rights only and require the acquisition of new underground easements to complete the relocation. As PG&E is often unable to construct underground in the exact same path as the overhead, these easements are often required with customers and/or agencies without current agreements. This land rights acquisition process alone can take 6-18 months and requires the project to be at a fairly mature design stage prior to contacting property owners about the needed rights.

The final consideration, for PSPS mitigation, is that underground construction presents the most reliable method for mitigating the need for PSPS operations. There will be occasions that undergrounding is chosen even when it does not present the best Risk Spend Efficiency (RSE) of the hardening options because it is the most reasonable alternative to mitigate all risks considered.

(c) Overhead Hardening

The most frequently used method for system hardening is overhead hardening in place. Overhead system hardening can be done more quickly than that of many other alternatives through the use of existing rights and easements. After analyzing projected performance of overhead hardened facilities on more than 4,600 outage types, it is projected that overhead system hardening will reduce 62 percent of the distribution overhead asset ignitions from either equipment failures or due to external contact such as vegetation. This alternative has a higher RSE when compared to the undergrounding alternative in many scenarios. Overhead system hardening achieves risk reduction through these foundational elements:

- **Primary and secondary covered conductor replacement**

  Replacement of bare overhead primary (high voltage) conductor and associated framing with conductor insulated with abrasion-resistant polyethylene coatings (sometimes referred to as covered conductor or tree wire) can be an effective mitigation of wildfire ignitions on distribution lines. Installing covered conductor can help reduce the likelihood of faults due to line to line contacts, tree-branch contacts, and faults caused by animals. Installing covered conductor on secondary lines has similar benefits to installing it on primary lines.

- **Pole Replacements**

  All existing poles are evaluated for the strength requirements to withstand the new heavier covered conductor. Often the majority or all poles on a circuit segment will need to be replaced to support the new, heavier covered conductor and associated equipment. When poles need to be replaced, PG&E has tested and confirmed that composite poles and intumescent wrapped poles have increased fire damage resiliency to reduce the risk of a pole failure during a wildfire.

- **Replacement of Non-Exempt Equipment**

  Replacement of existing primary line equipment such as fuses/cutouts, and switches with equipment that has been certified by CAL FIRE as low fire risk is another component of our System Hardening Program. This replacement work eliminates overhead line equipment and devices that may generate exposed electrical arcs, sparks or hot material during their operation.

- **Replacement of Overhead Distribution Line Transformers**

  Upgrading transformers to those that contain “FR3” dielectric fluid as part of PG&E’s current equipment standards (PG&E implemented the transition from mineral oil to FR3 in 2014) can also be an effective wildfire ignition mitigation. Newer transformers are filled with fire resistant “FR3” insulating fluid, a natural ester derived from renewable vegetable oils—providing improved fire safety, transformer life, increased load capability, and environmental benefits. In addition, new transformers are manufactured to achieve higher Department of Energy electrical efficiency standards.

- **Framing and Animal Protection Upgrades**

  Replacing crossarms with composite arms, wrapping jumpers, and installing animal protection upgrades to reduce contacts and pole related ignition risks.

- **Vegetation Clearing**

  Vegetation is a critical component of the System Hardening Program. In order to access our facilities to execute a project, it often requires significant undergrowth clearing which removes vegetation on the ground directly beneath the lines. In addition, some of the previously mentioned components of a system hardening project require additional clearance space to execute. Regulatory requirements mandate 4 feet of clearance all year long, so that if there is a change to a line's profile, including using taller poles or wider cross-arms, the vegetation must be cleared to be consistent with any changes and provide the required clearing for new overhead lines.

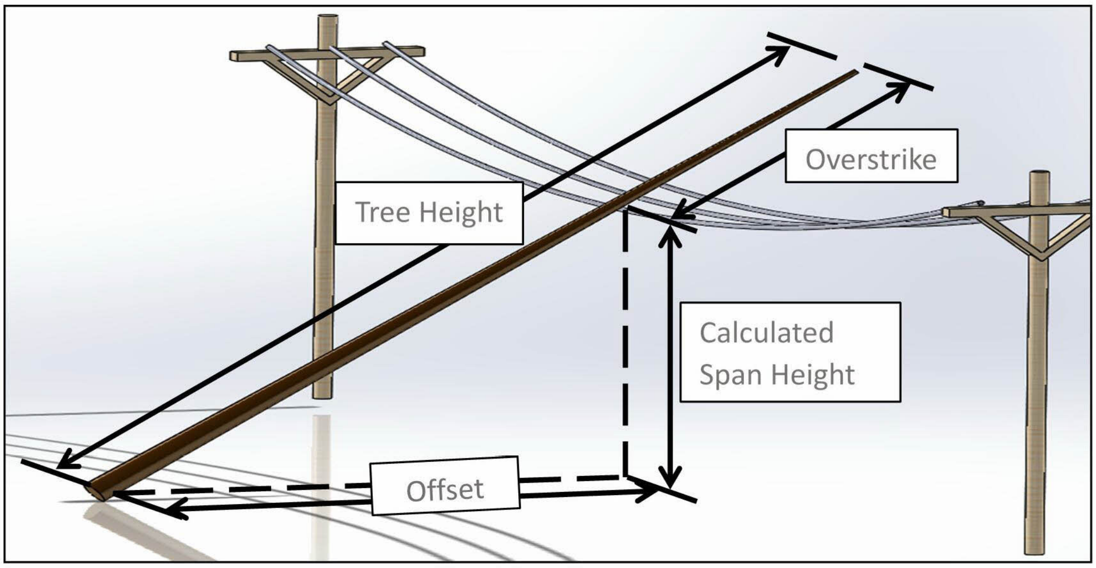
(d) System Hardening Process – Alternatives Consideration and Final Design

Once a circuit segment is targeted for system hardening, a project is launched for a segment that is no larger than 10-miles long. PG&E's Distribution Planning Engineers develop three primary alternatives for construction: (1) all overhead; (2) all underground; and (3) a hybrid alternative utilizing the specific hardening alternative thought to be the best fit for each section in the project. Line removal options are also considered during this scoping phase and, if feasible, thoroughly evaluated as generally the fastest and lowest-cost approach.

The system hardening project design options are brought to a scoping desktop review team made up of various experts to discuss and analyze additional risks such as tree strike potential, ingress and egress, localized fuel types and past fire history, land constraints, environmental risks, PSPS impacts, and general constructability concerns.

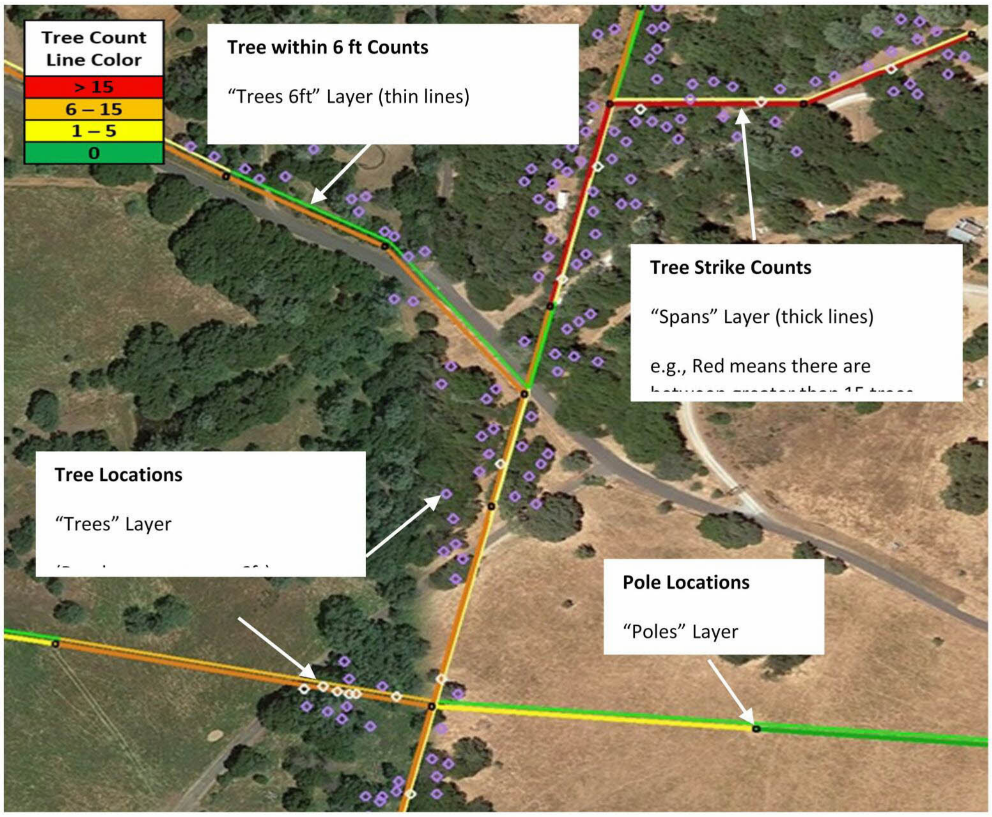
The tree strike potential factor is analyzed by PG&E's Applied Technical Services team. LiDAR data processing extracts pole, span, and fall-in tree geospatial information. This data is processed into an excel spreadsheet to determine Tree-span-pole associations. The tree strike threat is calculated as the number of fall-in trees in each span that can touch the line. A "fall-in tree" is simply a tree that is tall enough to potentially strike the span regardless of wind direction (i.e., when there is a non-zero overstrike, as shown in the figure below). Figure PG&E-7.3.3-3 shows an example of the overstrike assumptions used to calculate this risk.

FIGURE PG&E-7.3.3-3: OVERSTRIKE ASSUMPTIONS USED TO CALCULATE RISK



Spans are then ranked based on the number of fall-in trees in each span. The results are outputted to Google Earth for visualization. The lines are color coded to represent the number of fall-in trees that can touch the line: Red for greater than 15, Orange for 6 to 15, Yellow for 1-5, and green for 0. Figure PG&E-7.3.3-4 below is an example of the tree count and color coding for a potential system hardening project. Cost and constructability are key considerations in which the final mitigation alternative is chosen, but it is important to know and assess this tree fall-in potential risk as it is the largest single remaining risk to an overhead line that has been hardened.

FIGURE PG&E-7.3.3-4: TREE COUNT AND COLOR CODING FOR POTENTIAL SYSTEM HARDENING



Ingress, egress, fuel types and past fire history is also determined and provided by PG&E's Public Safety Specialist (PSS) to the field scoping desktop meeting. The PSS team are PG&E's field fire risk experts, many of them with significant first responder experience (often decades), that help inform PG&E's decision-making process. They analyze the area with a fire fighters' mindset to better understand the fuel types in the area, the historical fires, and the main egress and ingress routes. These experts are invaluable in providing analysis and first-hand experience in these areas, often working with local fire officials to understand the risks and available mitigations. Within the field scoping desktop meeting, it is often recommended to protect main egress routes through undergrounding, relocation or fire resilient poles. Areas where an ignition may be hard to spot are often areas a relocation may be chosen to ensure response times for local first responders are minimized.

The execution of these projects is very challenging with the various environmental and other conditions found in high fire risk areas. Land and environmental specialists analyze the alternatives provided prior to the desktop meeting and Google Earth images are provided to aid in the analysis. Where significant environmental risks, water features, endangered species and habitats, known cultural areas, and local agencies required for the new rights are identified, appropriate scope, schedule, and cost impacts are discussed to aid in the decision making.

Projected PSPS impacts are also analyzed by meteorology team and provided to the project scoping team to aid in the understanding of past potential frequency and customer impact. In areas where greater than an average of one PSPS event per year has been modeled, or greater than 5,000 customer meters are projected to be impacted, the design alternative for undergrounding is strongly recommended due to the potential PSPS mitigation benefits. This benefit can still be difficult to capture in all cases due to the radial (i.e. "one-way") nature of the majority of PG&E's distribution system. If lines that are targeted for hardening are undergrounded, but the source of electricity is still coming from overhead lines that are likely to be de-energized, the PSPS savings may not be realized until significantly more work is done.

Utilizing all of this information, the field scoping team will review the design alternatives provided, make changes as necessary, and provide a final field scope document to the estimating team. An estimator then performs a field check to analyze the assumptions made during the field scoping desktop meeting to confirm viability of the constructability and execution risks associated with the mitigations chosen.

Once the design alternatives have been vetted to this level, a final economic analysis is performed creating net present values for the lifetime costs of each design approach, including long-term maintenance needs and costs including annual vegetation management, inspections, etc. A final recommendation and associated documentation is then submitted to PG&E's Wildfire Risk Governance Steering Committee (WRGSC) to review the project scope, risk spend efficiency and related analysis. The WRGSC provides guidance and approval for the projects that the System Hardening Program should execute upon and the mitigation action to be taken on each project. Once approved, these projects are scheduled for final design, permitting, and execution.

(e) Urgent Fire Rebuild Targeted for System Hardening

During PG&E's emergency response to a wildfire that has damaged its overhead or underground assets, several alternatives may be considered when restoring services to customers. The following guidance has been provided to the Grid Design Engineers, estimators, and assessment leads when choosing the best rebuild alternative tailored to the needs of the area. These alternatives are provided in the order of consideration for each segment and circuit for evaluation:

- **Removal** – Radial tap lines that are identified as Idle Facilities or circuit back-ties that are not required by our design standards for operational flexibility should not be rebuilt or be removed.
- **Remote Grid or Customer Self-Provided Standalone Power System (SPS)** – Isolated customer(s) in Tier 2/3 HFTD areas fed by >0.5 miles of distribution line that, if removed or not rebuilt, could be served remotely through temporary generation solutions until a permanent SPS is installed.
- **Underground** – Distribution primary conductor in an accessible area with adequate space and rights to facilitate underground

infrastructure. Questions to evaluate this option include: Are gas facilities candidates to participate in the trench? Telecoms? Temporary generation may be required to support immediate customer restoration while the underground planning and construction project progresses.

- **Overhead Harden in a Different Location** – Distribution primary conductor through rural, heavily wooded, or inaccessible terrain should be evaluated for relocation to a road or more accessible location. Temporary generation would be required to support immediate customer restoration while the planning and construction project progresses.
- **Overhead Harden in Place** – This solution is appropriate for primary distribution overhead conductor in Tier 2/3 HFTD areas where >4 spans require full reconstruction or large sections of intermittent damage (generally greater than 50 percent of the segment) requires rebuild. These lines often represent mainline or major customer lines that cannot be effectively generated or switched to alternate sources of power and serve large sections of customers/critical facilities.
- **Restore in place** when intermittent damage is found without significant rebuild required.
- **All of the Above** - some combination of all of the above depending on the circumstances for a given circuit.

Once an entire segment has been assessed, the Grid Design Engineer works closely with the Estimating team to document the damage notifications into a Google Earth image to clearly identify the damage found on the distribution assets. Then routes are determined, and initial recommendations are made for protection, switches and wire size. These designs are sent to estimating to discuss with the incident commander at base camp, to distribution planning for fuse sizes and protection settings, and to land and environmental to begin the process of easement acquisitions and dependency clearing. In some cases, more time dependent alternatives must be rejected in favor of quicker mitigations to support customers by quickly restoring service to a community, for example when local, temporary generation until new assets can be constructed is not practical. The incident commander at the assigned base camps has final authority to ensure the customer needs are being met.

(f) Buffer Zones

In addition to work performed in HFTD areas, PG&E may also perform system hardening into “Buffer Zones.” Buffer Zones are areas immediately adjacent to an HFTD area. Because a specific distribution line may continue from an HFTD area into a Buffer Zone, hardening the line may include both hardening the HFTD area portions of the line as well as portions of a line in the Buffer Zone.

4) ***Progress on initiative (amount spent, regions covered) and plans for next year:***

In 2019, based on prioritization derived from the 2019-2029 Wildfire Risk Model, the System Hardening Program began with a target of completing 150 miles of hardened facilities. Much of this targeted work was overhead hardened facilities, though there was also undergrounding, and removal included in this target. In total, 171 miles were hardened by the end of 2019. This included targeted hardening work, idle facility removals, fire rebuild miles and hardened facilities associated with New Business and Capacity projects. As the first year of the program 2019 also featured the development of many key processes such as establishing a clearly defined field scoping document and process, the development of ECOP for evaluating sections with a number of identified corrective tags, the beginning stages of the finite element analysis for tree strikes, and building execution capacity to support annually increasing the target.

In 2020, the System Hardening Program established a 220-mile target to harden overhead facilities within the highest fire risk miles based on 2019-2029 Wildfire Risk Model. PG&E completed approximately 342 total miles, which includes approximately 194 miles hardened in HFTD areas during fire rebuild efforts and another 21 miles undergrounded through the Butte rebuild effort described in Section 7.3.3.17.6. The unprecedent wildfires in 2020 and the damage to PG&E led to the development of a more standardized fire rebuild process, which allowed PG&E to complete nearly 200 miles of hardened fire rebuild in the last four months of 2020.

In addition to the system hardening work completed, in 2020, PG&E further built on its 2019 execution progress by developing a standard tree strike analysis utilizing LiDAR data for facilities and tree locations. PG&E standardized the use of wood poles with an intumescent wrap to increase fire resiliency of hardened lines and supplement the supply limitations and design challenges associated with composite poles. Project strategies were refined to better coordinate permitting, easements, vegetation clearing, and other dependencies in advance of construction.

For 2021, PG&E has switched over from REAX to Technosylva as our Wildfire Consequence Modelling tool. The Wildfire Consequence Model was incorporated into PG&E's 2021 Wildfire Distribution Risk Model. This change and other associated improvements in our modeling, data, and understanding of fire risk, has led to a shift in thinking about where to target system hardening resources. PG&E's 2021 Wildfire Distribution Risk Model resulted in a significant change for PG&E in the targeting of where work would be directed to continue to harden the highest wildfire risk miles.

As mentioned earlier in this section, highest wildfire risk miles are separated into three categories:

1. The top 20 percent of circuit segments as defined by PG&E's 2021 Wildfire Distribution Risk Model for System Hardening
2. Fire rebuild miles
3. PSPS mitigation miles

PG&E is targeting 180 miles in 2021. In particular, PG&E is targeting that 80 percent of these miles be highest risk miles (one of those three categories above) and 10 percent must be performed through undergrounding or asset removal over the 3-year period from 2021-2023.

While this 2021 target of 180 miles does represent a drop from the 2020 mileage target, this is as a result of the previously referenced improvement in modeling and significant pivot in targeting. PG&E needed to change course, stop previously selected projects and start different projects that are in alignment with our updated risk model. More importantly, the 180 miles targeted in 2021 represent a greater risk reduction value than if we had continued on the previously planned work plan and executed approximately 300 miles in 2021. Under the new risk model the 301 miles of potential system hardening work originally planned for 2021 equated to 125 risk units in PG&E's multi-attribute value function (MAVF) calculation. The 180 miles now targeted for completion in 2021 are worth 198 risk units, a 58% increase in quantifiable risk reduction even though the mileage number is reduced. With the significant pivot in the program this target for 2021 is still aggressive because the cycle time for a system hardening project generally exceeds 12 months, as of late January PG&E is moving aggressively to design and execute the 2021 plan as 60 percent of the planned work is still in first project phase (scoping).

5) ***Future improvements to initiative:***

Although we will be hardening fewer miles in 2021 than previously targeted, PG&E will use this year to rebuild our pipeline of projects in alignment with the new risk model that are identified, vetted, designed and permitted for future construction. In doing so, the pace of system hardening will increase substantially in 2022 and going forward to between 400 to 500 miles per year. Even with the shift in the risk model PG&E anticipates generally aligning with previously outlined system hardening goals for the three-year WMP timeframe (2020-2022). In the 2020 General Rate Case (GRC), PG&E targeted 1,021 miles of system hardening for this period and our updated WMP plan forecasts completing 992 miles[6], within 3% of the original, GRC plan.

In addition to increasing the pace of system hardening work in upcoming years, as PG&E continues to develop its risk models (as described in more detail in Section 4.5.1), we will be able to incorporate more data sets, make further programmatic refinements and better scope and target our System Hardening Program. We will be analyzing hardened facilities performance with regard to actual outages, incidents and ignitions so that we can continue to refine our strategy and improve the scope of the System Hardening Program. Performance of hardened facilities that experience a wildfire will also continue to validate assumptions on life expectancy and effectiveness of hardened facilities (like wrapped poles) in various conditions. In addition, improvements in protection schemes—such as Rapid Earth Fault Current Limiters (REFCL)—may allow for a reduced level of work required to make safe a line in a high-risk area. Finally, we will seek closer alignment of our system hardening efforts with PSPS mitigation opportunities.

ACTION PGE-25 (Class B)

1) Integrate discussion on long-term planning within the respective section of each individual initiative.

Response:

As mentioned above, we will focus on enhancing our risk models and hardened facilities performance analysis to ensure that hardening for at-risk infrastructure is consistent with evolving risk prioritization and strategies. Based on current resourcing estimations, for 2024 and beyond, we are targeting to have somewhere between 400 and 500 miles per year in our planned pipeline. These efforts will be aligned to PSPS mitigation strategies to maximize impact for targeted reductions in wildfire risk.

ACTION PGE-3 (Class B)

1) Explain why only hardening efforts are identified within a higher risk tranche as a

[6] 2020 actual: 342 miles, 2021 target: 180 miles, 2022 target:470 miles = 992 from 2020-2022.

solution for the 7,100 miles scoped for system hardening, and no other initiatives are viable as a solution

2) Define what hardening consists of in regard to the 7,100 miles identified to be hardened

3) Provide the supporting materials and calculations showing that assets in the 7,100 is 2.75 more likely to fail, including all conclusions as to the reason why the failure rate is higher

4) The location of the 7,100 miles

5) The explanation of the overlap and increase for these 7,100 and the 5,500 discussed in PGE-5 identified for hardening.

Response:

PG&E is no longer targeting a specific set of miles such as the 7,100 miles or 5,500 miles referenced in the previous WMP. This strategy relies on a stagnant or non-changing risk model and assumes a specific risk reduction from that base value. As PG&E continues to study and enhance the risk model, this value will shift and change. PG&E will continue to harden at-risk infrastructure consistent with the evolving risk prioritization and strategies. For 2021-2023, the target is to harden 1,127 of the highest risk miles as described in Section 7.3.3.17.1. For 2024 and beyond, PG&E is targeting between 400 and 500 miles per year.

1) PG&E is not restricting other mitigation measures from being applied as a short-term wildfire risk mitigation to the highest risk miles. System hardening is a more complete measure as well as a long-term improvement initiative that will take some time to complete. Therefore, it is necessary to consider many other initiatives as part of our risk mitigation efforts both prior to and as part of a system hardening project.

2) A system hardening project can consist of multiple initiatives including but not limited to covered conductor installation, undergrounding, remote grid, PSPS mitigation through undergrounding, non-exempt fuse and surge arrestor replacement and line removal.

3) The calculations that show that the 7,100 miles are approximately 2.75 times more likely to fail are attached. To get to that result, all probabilities of failure were added for the two groups: (1) targeted miles (i.e., 7,100), and (2) the rest of miles (18,300). Subsequently the sum of these probabilities was normalized per mile which resulted in two numbers that represent the expected failure probability per mile of Distribution lines in HFTD for each group. Lastly, to compare these two numbers, they were divided and the result shows that failure rate per mile of Distribution line in HFTD is approximately 2.75 times higher for the system hardening target miles than for those outside the scope of system hardening at the time. See cell U6:W8 for actual calculations in the attached workbook.

Regarding the reasons why, the failure rate was higher for certain portions of the distribution system. As previously described in Condition PGE-7, the sub-model #1 for likelihood of failure processed 20 different input variables using a logistic regression algorithm. The results of this sub-model generate a likelihood of failure for a specific circuit segment. The results were later validated with the proper SMEs to corroborate that the areas showing higher failure rates match their knowledge of the system. While the reasons might vary depending on each individual segment of the distribution system being evaluated, typical conclusions that can be deducted from the model were that sections in certain environments, with higher vegetation density, higher frequency of outages, certain materials of construction, higher number of overhead miles in HFTD areas, or a combination of the aforementioned, were more significant in predicting a higher failure rate.

It is worth noting that the results and calculations were objectively reasonable based on the 2018-19 Wildfire Risk Model results, however, PG&E anticipates a change if a similar calculation was to be conducted today given the improvements reflected in the 2021 Wildfire Distribution Risk Model described in Section 4.5.1.

4) Through the improvement of PG&E's risk model as described in Section 4.5.1, the location of the highest risk miles has shifted and the geographic representation of the 7,100 miles as requested is not representative of the current direction of the System Hardening Program.

5) There is not increase from 5,500 to 7,100 miles. As stated in Condition PGE-5, the 5,500 miles was just an observation from the model. The observation captured the fact that the results showed that 95 percent of the wildfire risk prioritization of system hardening was in 22 percent of the distribution line miles. The 5,500 miles was not meant to represent the scope of the System Hardening Program. It should be noted, however, that the 5,500 miles were part of the 7,100 miles identified for hardening at the time.

ACTION PGE-9 (Class B)

1) Provide details on the System Hardening Hybrid Program, particularly when comparing it to covered conductor and the standard system hardening projects discussed within the WMP

2) When comparing the system hardening hybrid to standard hardening, provide the risk reduction per mile implemented

3) Provide the locations in which the system hardening hybrid has been deployed and piloted, including an explanation of the rationale and any supporting calculations to determine the use of the hybrid over standard hardening approach in those areas

4) Provide the locations in which the system hardening hybrid is planned to be deployed, including an explanation of the rationale and any supporting calculations to determine the use of the hybrid over standard hardening approach in those areas.

Response:

The System Hardening Hybrid Program was being considered as an alternative program in 2020 to help target specific areas of risk for hardening while completing other low impact work to complete in lower risk sections. Specifically, PG&E would target installing covered conductor in areas where tree exposure exists in high risk zones identified by risk modeling and would leave bare conductor in areas with zero tree strike, branch fall, or branch/bark/frond blow in risk. This alternative has not been deployed and we have no plans to implement the System Hardening Hybrid Program at this time. PG&E is focused on reducing risk more fully with an emphasis on alternatives such as undergrounding. It is not believed that the Hybrid alternative addresses enough risk to pursue at this time.

ACTION PGE-10 (Class B)

1) Provide details on the Wildfire Targeted System Upgrades, particularly when comparing it to covered conductor and other system hardening projects discussed within the WMP

2) When comparing the Wildfire Targeted System Upgrades to covered conductor, provide the risk reduction per mile implemented

3) Provide the locations in which Wildfire Targeted System Upgrades have been deployed and piloted, including an explanation as to the reasoning and any supporting calculations to determine the use of upgrades in those areas

4) Provide the locations in which the upgrades are planned to be deployed, including an explanation as to the reasoning and any supporting calculations to determine the use of upgrades in those areas.

Response:

The Wildfire Targeted System Upgrades Program was being considered as an alternative program in 2020 to target low-impact risk reduction alternatives in areas with zero tree strike, branch fall, or branch/bark/frond blow in risk. This would include animal protection, re-framing, pole loading calculations, and potentially spreader brackets to ensure mechanical separation between phase conductors. This would provide potentially a higher RSE mitigation in areas that are potentially high consequence risk yet low probability of failure. This alternative has not been deployed and we currently do not plan to implement the Wildfire Targeted System Upgrades Program. PG&E is focused on reducing risk more fully with an emphasis on alternatives such as undergrounding. It is not believed that the Wildfire Targeted System Upgrades alternative addresses enough risk to pursue at this time.

ACTION PGE-32 (Class B)

1) Explain how the system hardening initiatives provided in this response are prioritized in comparison to one another.

Response:

PG&E's system hardening program as detailed in Section 7.3.3.17.1 is a long term investment into risk reduction that relies on multiple data points to prioritize each stage of the project's development. PG&E targets the highest risk miles as defined in that section for initiation and scoping which will develop the job specific requirements and timelines. Once those details emerge, the workplan will be further prioritized based on work readiness with a bias towards the highest risk miles where the status and timeline of the option is equivalent.

ACTION PGE-33 (Class B)

1) Provide the number of circuit miles and percentage of the 5,500 identified miles each of the targeted approaches consist of

2) Provide the GIS file for the locations of each targeted approach.

Response:

PG&E is no longer targeting a specific set of miles for system hardening, such as the 5,500 miles referenced in the First Quarterly Report. As PG&E continues to study and enhance the risk model, this value will change. PG&E will continue to harden at-risk infrastructure consistent with the evolving risk prioritization and strategies. For 2021-2023, the target is to harden 1,127 of the highest risk miles as defined in Section 7.3.3.17.1. For 2024 and beyond, PG&E is targeting between approximately 400 and 500 miles per year.

ACTION PGE-34 (Class B)

1) Provide the number and percentage of circuit miles out of the 5,500 miles in which EVM work is being completed,

2) Provide the location of such miles via GIS,

3) Provide the number and miles in which the high-risk circuits identified with the Distribution EVM model overlap with the 5,500 miles, and

4) Provide the location of the circuit miles in GIS and in accordance with data attributes and metadata specified in the WSD's GIS data reporting requirements.

Response:

1) PG&E plans to complete EVM work across approximately 5,200 miles of the 5,500 miles or approximately 95%. Approximately 978 miles of EVM work were completed between 2019 & December 31, 2020. Approximately 440 miles of EVM work are in the 2021 plan. See Table PG&E-7.3.3-7 below for further details regarding EVM work. PG&E anticipates scheduling the remaining miles for EVM work beyond 2021.

2) See Attachment with segment data.
   - *2021WMP_ClassB_Action-PGE-34_Atch01.xlsx*
   - *2021WMP_ClassB_Action-PGE-34_Atch02.zip*

3) See attachment:

- *2021WMP_ClassB_Action-PGE-34_Atch03.xlsx*

Table PG&E-7.3.3-7: EVM Program Miles Completed

COMPLETED MILES	MILES COMPLETED NOT IN LIST	MILES COMPLETED IN LIST	TOTAL EVM MILES COMPLETED
1. <= 25%	1,395.2	729.3	2,124.5
2. 25-50%	850.0	128.4	978.5
3. 50-75%	671.4	108.9	780.3
4. >75%	419.3	11.8	431.1
TOTAL EVM MILES COMPLETED	**3,336.0**	**978.4**	**4,314.4**

4) See attachment:
   - 2021WMP_ClassB_Action-PGE-34_Atch04.zip

ACTION PGE-35 (Class B)

1) Describe the reason behind the increase in RSE for system hardening between 2020-2022 and 2023-2026, and

2) Provide the calculations used to determine the RSEs for both date ranges.

Response:

The RSE for System Hardening increases between 2023-2026 versus 2020-2022 for a number of reasons, most significantly:

Climate change increases the frequency of ignition and therefore the overall risk, hence the outer years (2023-2026) have higher risk reduction[7] by the deployment of this mitigation program.

In the 2020 RAMP Report, PG&E adjusted risk reduction and RSEs for a mitigation program considering a portfolio of mitigations.[8]

- Increased miles of investment in system hardening means a larger contribution to the overall portfolio risk reduction benefits, leading to higher allocation of portfolio risk reduction
- Other cross cutting programs have mitigation benefits that expire in the outer years

For the details of the risk reduction contribution and allocation, please see attachment "2021WMP_ClassB_Action-PGE-35_Atch01".

[7] Please refer PG&E's 2020 RAMP Report, Pages 10-17
[8] As discussed in PG&E's post-RAMP filing workshop held on July 14, 2020 [attach the specific presentation slide as an appendix/workpaper].

ACTION PGE-36 (Class B)

1) *Explain how and why the 1,060 miles were prioritized, and*

2) *Provide the location of the 1,060 circuit miles via GIS.*

Response:

PG&E's System Hardening Program's goal is to harden at-risk infrastructure consistent with the evolving risk prioritization and strategies. For 2021-2023, the target is to harden 1,127 of the highest risk miles as defined in section 7.3.3.17.1. For 2024 and beyond, PG&E is targeting somewhere between 400 and 500 miles per year. The specific 1,127 miles planned for the next 3 years have not all been identified at this time. Currently PG&E has approved the initiation of approximately 500 miles of work in the highest risk miles. This subset of the 2021-2023 workplan was prioritized utilizing a risk informed approach. Utilizing the 2021 wildfire distribution risk model as a base reference, PG&E reviewed all previously started work as well as various work types such as Electric Corrective Optimization Program (ECOP) and PSPS mitigation with the Wildfire Governance Committee to gain alignment on those projects deemed to be the highest risk miles.

7.3.3.17.2 System Hardening – Transmission

WSD Initiative Definition: N/A. *This is a "PGE-defined sub-initiative" that supports the response for the (parent) WSD-defined Initiative*

1) ***Risk to be mitigated / problem to be addressed:***

   The failure of overhead transmission assets can cause an ignition and create wildfire risk. To address this risk, PG&E has a number of programs designed to address the safety and health of its transmission system. In addition, aspects of the transmission system are upgraded or improved to reduce the impact of PSPS events from transmission facilities. PG&E's programs related to the hardening of the transmission system are described in more detail below.

2) ***Initiative selection ("why" engage in activity) – include reference to a risk informed analysis on empirical (or projected) impact of initiative in comparison to alternatives:***

   PG&E does not have a single, specific System Hardening Program for its transmission assets. Rather, transmission related programs target the highest wildfire risk areas as identified primarily by PG&E's Operability Assessment (OA) Model, in conjunction with wildfire consequence and/or weather data. These programs have the effect of hardening PG&E's transmission system and mitigating ignition and wildfire risk.

3) ***Region prioritization ("where" to engage activity) – include reference to a risk informed analysis in allocation of initiative (e.g., veg clearance is done for trees tagged as "high-risk"):***

Transmission line related programs are focused in HFTDs but some are also extended into non-HFTD areas. Efforts associated with these programs are prioritized based on review of OA Model results for asset health, historical performance, wildfire consequence, and PSPS likelihood.

PG&E's programs that are related to hardening the transmission system, including impact reduction of PSPS events, are described below.

(a) Line De-energization, Grounding and Removal

The target of this mitigation program is known or suspected idle facilities. PG&E follows the procedures and requirements in Utility Procedure: TD-1003P "Management of Idle Electric Transmission Line Facilities Procedure" to investigate potential idle facilities. When these facilities are identified and confirmed to be within an HFTD area with no operational needs, they are prioritized for de-energization, grounding, and/or removal. Grounding of an already de-energized line addresses residual wildfire risk of induction from nearby energized line(s), until conductor removal or repurposing of the facilities can occur.

(b) Transmission System Islanding and Temporary Substation Microgrid

In some high wildfire risk scenarios, such as PSPS events, transmission islanding schemes and temporary substation microgrid may be the used to mitigate wildfire risk and reduce customer impact. The islanding schemes (such as the Caribou Power House or Humboldt Bay Power Plant Islands) allow a local area of transmission lines and substations to stay energized via local generation, as the system's primary transmission line sources are de-energized for wildfire safety purposes. The temporary substation microgrid focuses on serving substations that have safe-to-energize load. Both of these mitigations allow for those at-risk lines to be de-energized for wildfire risk mitigation, while keeping customers energized.

c) Overhead Hardening, Inspections, and Maintenance

- **Pole Replacements:** PG&E implemented enhanced design criteria for replacing wood pole structures. Most transmission wood poles are replaced with steel (most commonly light duty steel poles (LDSP)) when warranted based on condition or system capacity needs. LDSP have greater phase-to-phase conductor separation and are designed to accommodate peak wind speeds. Steel structures are also less likely to ignite compared to wood poles and crossarms. LDSP also are designed to reduce bird contact incidents by eliminating the exposure between energized conductors and grounded down guys.
- **Animal Protection Upgrades:** Installation of animal protection upgrades such as bird diverters, crossarm shields, and insulated fiberglass link to reduce contacts and pole related ignition risks is another element of transmission line centric system hardening

efforts.

- **Enhanced Inspections and Prioritized Maintenance:** Enhanced inspections are designed to capture condition information aligned with components that can pose an ignition risk. These inspections are performed more frequently in HFTD areas. In addition, inspection methods such as below-grade foundation inspection are being piloted to provide further information on ignition risk failure modes that may not be easily detectable through existing methods. Maintenance work identified through inspections are prioritized (see Section 7.3.3.12.3) based on wildfire risk, wildfire spread consequence and the deterioration mode of the condition found.
- **Sectionalizing Devices:** The addition of transmission line SCADA switches (*see* Section 7.3.3.8.2) provides operating flexibility for lines that traverse HFTD areas. These switches, typically installed at junctions and near substations, can help isolate customers and reduce PSPS impact. During other planned or unplanned line outages, the switches can also be used to reduce outages and shorten restoration time.
- **Asset Replacement:** Though not the sole project driver, asset replacements in HFTD areas help reduce wildfire risk by introducing new assets in place of degraded, out-of-standard, or aged equipment. For major transmission line components – structures, conductor, insulators, and switches, there are corresponding targeted replacement programs to address asset lifecycle and extent of condition concerns. For example, there are several conductor replacement projects for addressing obsolete or failure-prone conductor. In addition, assets may be replaced for compliance or system capacity requirements.
- **Asset Life Extension:** For some assets not in the highest priority for asset replacements, maintenance programs such as tower coating (see Section 7.3.3.15) and cathodic protection are used to extend useful life of the asset. These programs reduce exposure of steel structures to corrosion, thus maintaining its strength and integrity. Another example of life extension pilot program is installation of buddy bushings in hanger plates, to provide additional support to cold-end hardware such as C-hooks. This fail-safe design is being evaluated for more extensive application.

d) Urgent Fire Rebuild Targeted for System Hardening

During PG&E's emergency response to damaged transmission facilities during the 2020 Lightning Complex wildfire, more robust designs were incorporated into the rebuilt efforts. In addition to hardening the lines upon rebuilding (e.g. replacing prior wood poles with steel), conductor was also replaced to ensure future needs of the circuit or assets are met.

4) Progress on initiative (amount spent, regions covered) and plans for next year:

In 2020, approximately 2,700 wood pole structures within HFTD areas were replaced with steel. Avian protection retrofits were installed on 78 structures, mostly on the Drum-Rio Oso 115 kV Lines, which had a high likelihood of bird incidents. Approximately 216 miles of transmission rights-of-way (ROW) were cleared within HFTD areas. Approximately 103 miles of conductor replacement was completed on lines traversing HFTD areas.

In 2021, approximately 1,500 wood pole structures within HFTD areas are expected to be replaced with steel. Avian protection retrofits are identified and addressed through maintenance notifications based on activities. The level of retrofit is expected to decrease as more wood poles are replaced with steel and insulated fiberglass links are installed on poles in HFTD areas. Approximately 200 miles of Transmission ROW expansion are planned within HFTD areas. Replacement of approximately 92 miles of conductor on lines traversing HFTD, including associated asset hardware, is planned to be in-service in 2021.

Other maintenance tags, sectionalizing devices, and tower coating progress is described in their respective sections.

In addition, asset health and risk models informing future planning of system hardening work will be updated. It is anticipated that enhancements such as digitized design data and refinements to the corrosion model will be integrated into the OA Model (see Section 4.5.1(h)) in 2021. The vegetation LiDAR Risk Score Model (see Section 7.3.5.8) will also continue to be validated and improved in 2021. Finally, in 2020, PG&E switched over from REAX to Technosylva, which PG&E has adopted for wildfire spread and consequence information. This data was incorporated with the OA Model in 2021 to provide another layer of risk information to existing workstreams.

5) ***Future improvements to initiative:***

Continued development/maturity of asset risk models will help focus mitigations and key issues, leading to a better understanding of most effective inspection, repair, and replace decision making timelines based on asset design, environment, age, and performance and maintenance history. A new initiative is developing machine learning/artificial intelligence models to predict the presence of various asset threats, such as mechanical wear and corrosion.

The Transmission Overhead Asset Information Collection will search historic asset records, engineering drawings and other information to provide new, quality data fields into the system of record. This will provide better data to the various asset health and risk models, improving granularity and reducing the number of assumptions needed to be made around fields such as asset age.

Continued exploration of new technology for inspections and repair will close the gap on non-visual failure modes, as well as provide additional life extension techniques for medium-risk assets.

ACTION PGE-25 (Class B)

1) Integrate discussion on long-term planning within the respective section of each individual initiative.

Response:

PG&E is working towards a more granular and centrally accessible asset data in better inform various risk models. These predictive, probability and consequence, models will drive more refined risk-informed maintenance plans, repair prioritization and proactive replacements for all transmission line assets to minimize failure and ignition risk.

Based on maintenance condition assessment and wood pole testing, PG&E projects to replace approximately 56 percent (15,000 of the remaining 26,700) wood poles in the HFTD area with steel poles in the next ten years.

Additionally, PG&E is working towards a steady, sustainable level of replacement for key assets such as structures, conductor, insulators and switches.

7.3.3.17.3 Non-Exempt Surge Arrester Replacement Program

WSD Initiative Definition: N/A. *This is a "PGE-defined sub-initiative" that supports the response for the (parent) WSD-defined Initiative*

1) ***Risk to be mitigated / problem to be addressed:***

   The surge arrester sub-initiative is a program that replaces existing non-exempt surge arresters with exempt surge arresters, which have less propensity to cause a fire ignition. In addition, while it is performing replacements, PG&E separates transformer and surge arrester grounds at designated locations.

2) ***Initiative selection ("why" engage in activity) – include reference to a risk informed analysis on empirical (or projected) impact of initiative in comparison to alternatives:***

   The purpose of the non-exempt surge arrester replacement program is to remove ignition risks in HFTD areas and an ancillary benefit of this is to modernize the connections and equipment on the pole at these locations which may improve reliability. The replacement of non-exempt surge arresters with exempt surge arresters will reduce wildfire fire risk since exempt surge arresters are considered "non-expulsion" and do not generate arcs/sparks during normal operation.

3) ***Region prioritization ("where" to engage activity) – include reference to a risk informed analysis in allocation of initiative (e.g., veg clearance is done for trees tagged as "high-risk"):***

The surge arrester program is targeting replacement of non-exempt surge arresters in HFTD areas. PG&E will review lightning strike maps combined with the highest remaining work concentration areas to prioritize completion of surge arresters for 2021. Once HTFD areas are completed this program will be expanded to non-HFTD areas in throughout PG&E's service territory.

4) ***Progress on initiative (amount spent, regions covered) and plans for next year:***

In the 2020 WMP, PG&E forecast replacing 8,850 surge arresters in Tier 2 and Tier 3 HFTD areas. The Surge Arrester Program replaced approximately 10,300 as of December 31, 2020. PG&E anticipates mitigating the remaining Tier 2 and Tier 3 non-exempt surge arresters by the end of 2021. Mitigating non-exempt surge arresters generally involves replacing non-exempt surge arrestors and installing grounds at subject locations. In some instances, surge arrestors have already been replaced under other projects, such as new business or fire resiliency projects. In these instances, the surge arrestor program considers these a "mitigated" location as well.

The surge arrestor program not only replaces non-exempt surge arrestors at each location, but also addresses deficient grounding at each location. The initial reason for the surge arrestor program was to provide separate grounds on poles where surge arrestors and transformers were co-located and shared a single ground. By separating the grounds, lightning strikes and other surges can now safely dissipate to their dedicated surge arrestor ground, while not affecting the separately grounded transformer co-located on the same pole.

The installation of grounds at some locations poses unique challenges, especially in heavily granite and lava cap areas in the Sierra and Cascade foothills. Large HFTD portions of the service territory where these surge arrestor mitigations are needed are located in this rocky soil. Geotechnical studies have been conducted, PG&E grounding Standards have been adjusted, and innovative excavation techniques have been incorporated to safely install these grounds. Unfortunately, multiple attempts and techniques are required to complete some of these ground installations.

Every attempt will be made to complete all of the remaining surge arrestor locations in HFTD in 2021. Even with advance geotechnical surveys, the ability to install grounds at some sites may not be known until crews begin excavating. At these locations rock-drilling or blasting may be required which may extend completion of these sites into 2022. Based on prior years success with these rock locations and the variability of terrain we will likely complete a range of 15,000 to 22,000 locations in 2021.

5) Future improvements to initiative:

Once existing non-exempt surge arrestors in HFTD areas are replaced, PG&E will then shift its focus to the system overall. PG&E is forecasting replacing the remaining non-exempt surge arrestors, located in non-HFTD areas, by the end of 2023.

ACTION PGE-25 (Class B)

1) Integrate discussion on long-term planning within the respective section of each individual initiative.

Response:

This initiative is expected to end by 2023 and thus long-term planning is not applicable.

7.3.3.17.4 Rapid Earth Fault Current Limiter

***WSD Initiative Definition**: N/A. This is a "PGE-defined sub-initiative" that supports the response for the (parent) WSD-defined Initiative.*

1) Risk to be mitigated / problem to be addressed:

A high impedance fault like a wire down or tree contact could remain undetected and become an ignition source. In addition, high impedance line to ground faults on distribution circuits are difficult to detect with traditional overcurrent protection. REFCLs are intended to address these risks.

2) Initiative selection ("why" engage in activity) – include reference to a risk informed analysis on empirical (or projected) impact of initiative in comparison to alternatives:

REFCL technology mitigates ignitions from line to ground faults such as wire down or tree contacts using technology called Ground Fault Neutralizer (GFN) that detects line to ground faults and limits the fault current below ignition thresholds.

3) Region prioritization ("where" to engage activity) – include reference to a risk informed analysis in allocation of initiative (e.g., veg clearance is done for trees tagged as "high-risk"):

PG&E initiated a pilot project for REFCL technology in Calistoga based on wildfire risk in that area and historical line-ground outage events. The Calistoga substation and associated circuits (1101 and 1102) met the design criteria for the REFCL system that include 3-wire 12 kV with transformers connected line to line and charging current less than 100 amps.

4) Progress on initiative (amount spent, regions covered) and plans for next year:

The Calistoga REFCL pilot project finished construction in 2020. The field installation involved replacing 15 line reclosers with advanced controllers, replacing 14 sets of line fuses with Fuse Saver devices that trip all three phases, updating all the distribution line voltage regulating devices, and installing 12 capacitive balancing units to balance the circuit capacitance necessary to tune the REFCL system and maintain sensitivity. The substation work included installing the GFN and Arc Suppression Coil with associated controls (Figure PG&E-7.3.3-5) along with upgrading the feeder relays and voltage regulators.

FIGURE PG&E-7.3.3-5: ARC SUPPRESSION COIL / GFN

PG&E plans to have the final results from this pilot project by September 2021. The system testing will involve stress testing the new and existing distribution equipment by energizing the GFN and adjusting the voltage to simulate a line to ground fault condition. The stress test will be followed by a series of fault test where a specialized test trailer will connect to an energized conductor and create an actual line to ground fault condition. During the live test, the actual line to ground current will be measured to ensure currents are below 0.5 amps (below ignition levels) and the GFN activates within the specified times for the conditions. The result of the pilot project will drive the longer-term REFCL strategy.

5) Future improvements to initiative:

Assuming the result of the pilot supports additional deployment, a long-term strategy will be developed to install REFCL in HFTD areas. The project team will identify improvements to design and materials. Future deployments will utilize PG&E's risk model tools to help drive deployment.

ACTION PGE-25 (Class B)

1) Integrate discussion on long-term planning within the respective section of each individual initiative.

Response:

A long-term plan will be developed after successful completion of the pilot and identifications of lessons learned in 2021.

7.3.3.17.5 Remote Grid

WSD Initiative Definition: N/A. *This is a "PGE-defined sub-initiative" that supports the response for the (parent) WSD-defined Initiative.*

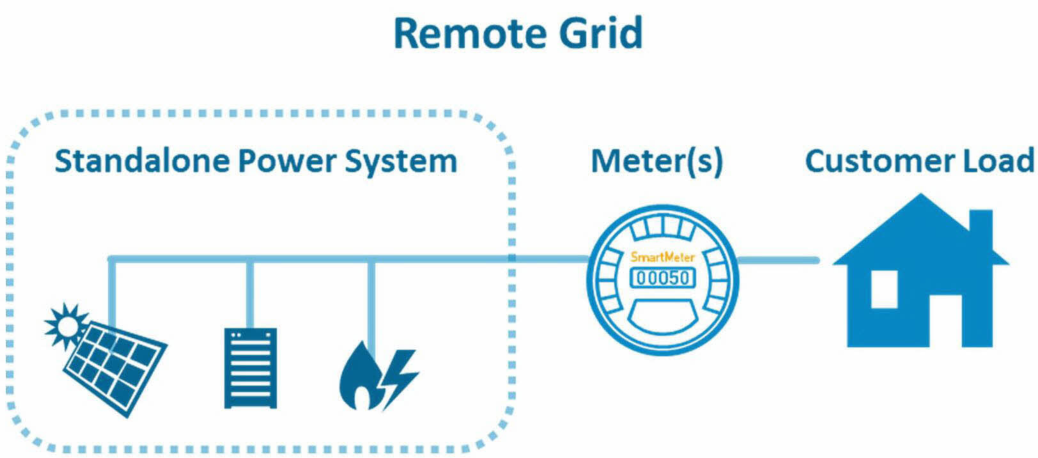
This section describes PG&E's Remote Grid initiative and provides a response to Action PGE-51 (Class B).

1) Risk to be mitigated / problem to be addressed:

Throughout PG&E's service territory, there are pockets of isolated small customer loads that are currently served via long electric distribution feeders. In certain circumstances, these feeders are overhead line construction that traverse HFTD areas and require significant annual maintenance and VM. If these long feeders were removed and the customers served from a local and decentralized energy source (i.e., a "Remote Grid"), the resulting reduction in overhead lines could reduce fire ignition risk as an alternative to or in conjunction with system hardening and other risk mitigations.

"Remote Grid" refers to relatively small, permanently islanded distribution facilities serving customers who are generally located on remote portions of PG&E's distribution system. The Remote Grid facilities include a SPS made up of local sources of electricity supply, such as solar PV generation, battery energy storage, and other distributed generation, as well as distribution and service facilities to connect customers to the SPS. Figure PG&E-7.3.3-6 below provides an example of the components of a Remote Grid.

FIGURE PG&E-7.3.3-6: DIAGRAM OF EXAMPLE COMPONENTS OF A REMOTE GRID



2) ***Initiative selection ("why" engage in activity) – include reference to a risk informed analysis on empirical (or projected) impact of initiative in comparison to alternatives*:**

Remote Grid is a new concept for utility service using decentralized energy sources for permanent energy supply to remote customers as an alternative to energy supply through hardened traditional utility infrastructure. The program leverages clean, emergent technologies such as solar-paired battery storage in a way that is intended to be cost-effective and/or more resilient relative to current distribution service delivery options. The objective of the Remote Grid sub-initiative is to develop and validate the Remote Grid concept as an alternative to other service arrangements and/or wildfire risk mitigation activities such as system hardening. Remote Grids that allow for the removal of lines in high wildfire risk areas could provide benefits to both the customers served by Remote Grids and to all distribution customers who will benefit from the cost-effective elimination of wildfire risks associated with distribution lines that run for significant distances through HFTD areas to serve a small number of remotely located customers. The elimination of these lines will serve two key objectives: (1) reducing the likelihood of fire ignition due to damage or failure of such lines; and (2) elimination or reduction of the cost to harden these lines and to conduct enhanced VM to mitigate the fire-related risks. In addition to acting as an alternative to conventional system hardening approaches for the hardest to reach customers at the end of distribution lines, Remote Grid could help to reduce wildfire risk and be a cost-effective solution for the rebuild of fire-damaged or destroyed infrastructure.

3) ***Region prioritization ("where" to engage activity) – include reference to a risk informed analysis in allocation of initiative (e.g., veg clearance is done for trees tagged as "high-risk"):***

Initial Remote Grid project locations were selected in order to validate a range of Remote Grid configurations while simultaneously providing immediate risk mitigation value at a reduced cost when compared to alternative risk mitigations. In 2019 and 2020, PG&E undertook an extensive review of all distribution feeders in Tier 2 and Tier 3 HFTD areas and developed a preliminary screening protocol, to identify potential Remote Grid projects where this alternative distribution method could deliver superior risk-spend efficiency and overall distribution cost reduction (including reduced capital costs). PG&E prioritized sites for detailed evaluation based on a combination of factors including:

- Located at the end of a radial distribution line
- Consist of a small number and size of customer loads
- Historically served by a long section of line
- Preliminary feasibility assessment based on initial customer outreach and desktop screening for technical viability and constructability of a SPS'
- Potential cost savings: Remote Grid vs preferred alternative risk mitigation strategy (e.g. hardened overhead distribution or underground conversation)
- Risk ranking of line segment(s) to be eliminated or hardened

From this list of preliminary screening results, PG&E has applied criteria including customer response, solar access (shading), civil constructability, and site accessibility to identify initial Remote Grid projects which are likely feasible for this early stage of Remote Grid deployment. PG&E believes initial sites can prove successful, both in terms of operational feasibility and in terms of delivering wildfire ignition risk reduction in a more cost-effective manner. Through initial projects, PG&E aims to develop the actual data needed to validate costs, performance, and customer acceptance of the Supplemental Provisions. Further validation is needed to increase the certainty of this portfolio and to identify the "total addressable market" for Remote Grid.

4) ***Progress on initiative (amount spent, regions covered) and plans for next year:***

PG&E has three (3) Remote Grid projects in the advanced stages of development which when completed will eliminate a total of 25.2 miles of overhead line (1.4 miles in HFTD areas and 23.8 miles in non-HFTD areas) by deploying SPS' at 5 locations to serve 10 customer meters. These initial projects are located in San Luis Obispo and Mariposa Counties. Note that the projects in San Luis Obispo County have been delayed due to unforeseen permitting delays due to presence of threatened species. PG&E plans to begin operations of the first Remote Grid project to serve customer load by the end of 2021.

Key accomplishments in 2020 toward validation and standardization of Remote Grids include:

- A detailed protocol was developed to identify and evaluate potential remote grid projects.
- Technical specifications have been iteratively refined through detailed design of the in-flight projects.
- Commercial availability of specialist vendor equipment and services has been verified at the preliminary level through a successful competitive solicitation for design and construction of a SPS.
- Assumptions about upfront capital costs and ongoing maintenance and operations expenses have found initial validation and refinement through a successful negotiation of a turnkey Purchase and Sale Agreement and a 10-year full-wrap Maintenance Agreement, forming a reusable template for future SPS procurements.
- The majority of customers engaged to date have voiced positive initial interest in pursuit of service conversion from overhead line to a Remote Grid.
- Terms of service have been drafted into a form of Supplemental Provisions to the Electric Rules, as a tariffed form agreement.
- The proposed form of Supplemental Provisions Agreement was filed with the CPUC in Advice 6017-E[9] on December 15, 2020.
- Benchmarking with other utilities shows a point of validation in the advanced program now operational under Horizon Power in Western Australia.[10] In California, Liberty Utilities has procured its first SPS for a similar application.

In addition to the current projects, PG&E has identified and begun development on a portfolio of potential additional Remote Grid deployments designed to validate the viability of this new class of distribution asset. These projects are currently undergoing detailed scoping and feasibility assessment to verify customer interest, environmental requirements, solar access, civil constructability, and site accessibility. After initial assessment of feasibility, projects will move to the design, permitting and build phase which can take 9-12 months or more depending on specific site conditions. A number of site-specific conditions can reduce individual project feasibility or delay implementation. Examples include; customer acceptance, physical space constraints, shading and other constructability related

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9 See AL 6017-E "Remote Grid SPS Supplemental Provisions Agreement": https://www.pge.com/tariffs/assets/pdf/adviceletter/ELEC_6017-E.pdf.

10 https://renewtheregions.com.au/projects/standalone-power-systems/.

considerations such as grading requirements and geological conditions, permitting challenges such as presence of threatened species, cultural heritage, or adjacency to scenic highway among others.

In 2021, PG&E will continue to mature the Remote Grid concept toward an eventual standard distribution grid configuration. Experience gained through the deployment and initial operation of the first Remote Grid projects will contribute to refinements in the deployment processes, design and performance standards, customer agreements and operational protocols for the end-to-end Remote Grid solution. PG&E expects to further validate the availability of viable commercial sourcing agreements via another round of competitive solicitations for SPS' and supporting services. In addition, PG&E is seeking CPUC approval of a Supplemental Provisions Agreement to extend and clarify how the existing rules and tariffs apply to a customer served by Remote Grid, and to make clear the roles, restrictions, and responsibilities of both PG&E and the customer.

5) ***Future improvements to initiative:***

In addition to potential Remote Grid facilities, PG&E is pursuing additional alternative configurations to eliminate the need to harden or rebuild overhead distribution lines in fire-prone areas. The alternative models include the option for PG&E to provide an incentive payment, tied to discontinuance of utility service, that would be sufficient to enable a customer to purchase and maintain its own SPS. If this option for self-provision proves preferable to a PG&E Remote Grid solution for some customers, then it could improve the portfolio reach of the Remote Grid Initiative by enabling broader customer agreement.

ACTION PGE-25 (Class B)

1) Integrate discussion on long-term planning within the respective section of each individual initiative.

Response:

PG&E has not determined a long-term plan yet for this initiative. Pending the success of initial Remote Grid projects, we will be evaluating the reduction in wildfire ignition risk and costs, engineering and execution feasibility, and overall service quality in order to determine the long-term path and program scalability. The long-term goal of the Remote Grid Initiative is to productize Remote Grids as standard offerings such that they can be considered alongside of or in lieu of other conventional service arrangements (including rebuild), and/or wildfire risk mitigation activities such as system hardening, particularly where such alternatives would represent significant costs and/or wildfire risk. Scaling up deployment of Remote Grids will involve creating design standards, developing new planning and decision-making evaluation tools, and establishing operational agreements and commercial arrangements with vendors.

Another long-term goal is to continue to identify other generation and storage technologies that can be effectively utilized in a Remote Grid configuration. Should alternative generation and storage technologies provide similar capabilities while being more favorable to environmental constraints (land availability, solar availability, etc.) and still prove cost-effective, PG&E will continue to incorporate such technologies into the Remote Grid configuration.

ACTION PGE-51 (Class B)

1) Expand on the remote grid initiative in detail and explain the feasibility of it.

Response:

Information requested is incorporated within the narrative provided in Section 7.3.3.17.5 above.

7.3.3.17.6 Butte County Rebuild Program

WSD Initiative Definition: *N/A. This is a "PGE-defined sub-initiative" that supports the response for the (parent) WSD-defined Initiative.*

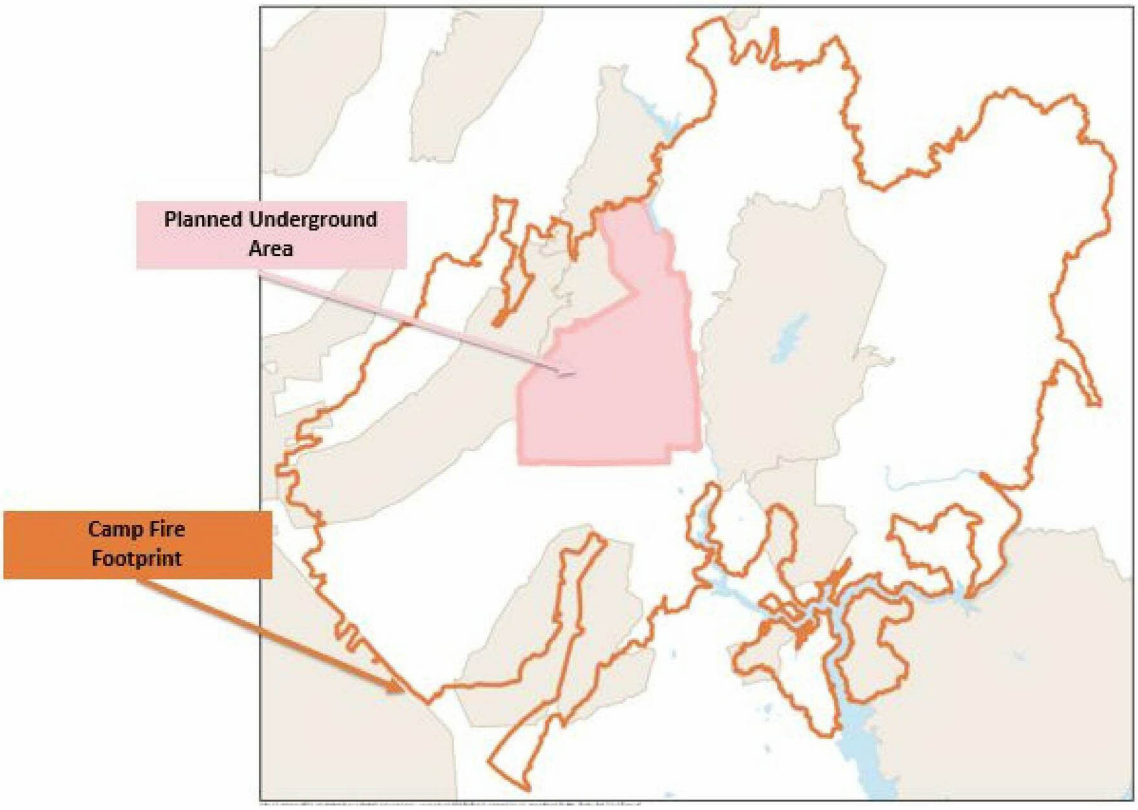
1) ***Risk to be mitigated / problem to be addressed:***

   The 2018 Camp Fire devastated the Town of Paradise (Paradise) and surrounding areas in Butte County. The Butte County Rebuild Program is focused on rebuilding the utility infrastructure to serve Paradise and the surrounding County assets destroyed during the Camp Fire in the safest and most cost-effective manner.

2) ***Initiative selection ("why" engage in activity) – include reference to a risk informed analysis on empirical (or projected) impact of initiative in comparison to alternatives:***

   In the 2018 Camp Fire, over 18,000 structures were destroyed, including 13,400 premises. The impacted area is primarily in Tier 2 and Tier 3 HFTD areas. Approximately 207 miles of electric distribution lines and 34 miles of gas pipeline were destroyed. Some electric distribution lines, such as the Bucks Creek 1101 circuit, have been burned multiple times in the last decade. Paradise and Butte County have expressed a strong desire for underground utilities, which would reduce fire risk and have the added benefit of reducing routine Vegetation Management costs. PG&E plans to underground all 207 miles of the destroyed distribution assets within a 5-10 year period. Figure PG&E-7.3.3-7 below shows the Butte County Rebuild Program area.

FIGURE PG&E-7.3.3-7: BUTTE COUNTY REBUILD PROGRAM AREA

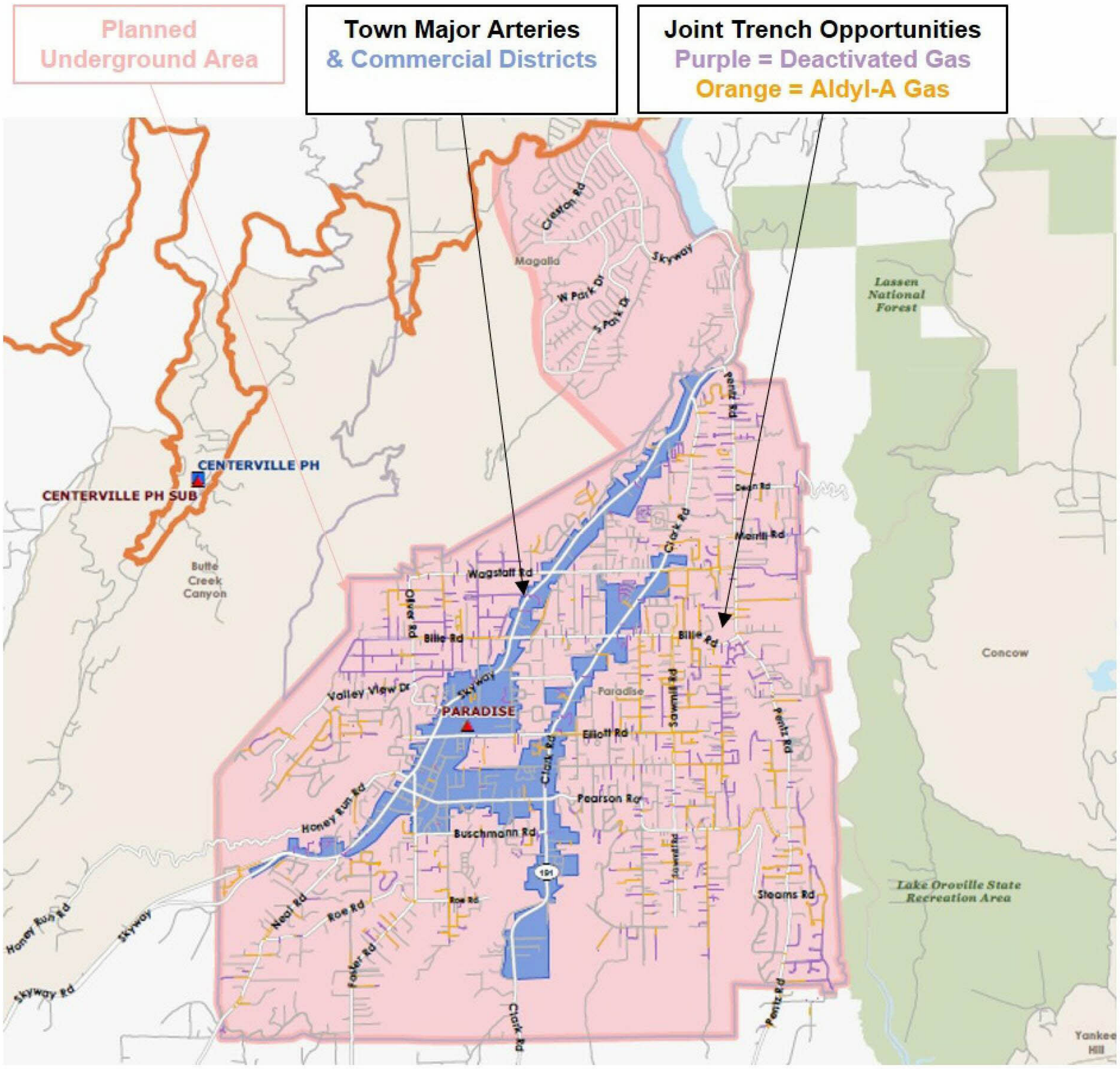


In addition to the electric distribution assets that were destroyed, 34 miles of gas distribution were destroyed by the Camp Fire and must be replaced. PG&E also had plans before the Camp Fire to replace an additional 248 miles of gas distribution pipeline under the Aldyl-A gas pipeline replacement program. For the Butte Rebuild, there is a unique opportunity to cost-effectively underground electric distribution assets by sharing the costs to underground assets in a joint-trench for 58 out of the 207 miles of electric distribution undergrounding.

3) ***Region prioritization ("where" to engage activity) – include reference to a risk informed analysis in allocation of initiative (e.g., veg clearance is done for trees tagged as "high-risk"):***

The Butte County Rebuild Program is coordinating the project plans closely to align with Paradise's and Butte County's re-development plans with the goal of completing construction in specific areas before Paradise repaves the roads of their main arteries and restores the commercial district. In addition, PG&E also prioritizes restoring areas with deactivated gas destroyed by the fire to prevent customers from needing temporary propane if they are ready to rebuild in those areas. Figure PG&E-7.3.3-8 below provides more detail regarding the Butte County Rebuild Program, including commercial areas and joint trenches.

FIGURE PG&E-7.3.3-8: BUTTE COUNTY REBUILD PROGRAM DETAIL



Finally, Paradise has one of the highest rates of PSPS incidents in the PG&E service territory due to the high fire risk. As the Butte County Rebuild Program is executed over the next several years, it will further enable undergrounded areas of Paradise to remain energized during PSPS events. Scoping for the Butte County Rebuild Program is prioritizing PSPS mitigation while working with the community to align with their rebuild plans

4) Progress on initiative (amount spent, regions covered) and plans for next year:

In our 2020 WMP, PG&E articulated a goal of 20 miles for the Butte County Rebuild Program, focusing only on those miles in HFTD areas, and completed just over 21 miles in HFTD areas. For the 2021 WMP, PG&E has identified that all work on this project, including those segments that are in non-HFTD areas (the center of Paradise is non-HFTD on the 2018 CPUC HFTD map) are relevant to track and report on as they are all fire rebuild areas, where a prior fire has indicated an elevated wildfire risk. Therefore, for 2021, the Butte County Rebuild Program target is 23 miles (including both HFTD and non-HFTD areas).

5) Future improvements to initiative:

PG&E is developing the base maps for the future electric distribution system in Paradise before estimating all underground infrastructure. The base maps help speed up the design process, which has been a current bottleneck for initiating project construction. PG&E aims to have all base maps complete for all currently scheduled rebuild areas through 2023 by the end of 2021.

ACTION PGE-25 (Class B)

1) Integrate discussion on long-term planning within the respective section of each individual initiative.

Response:

Once the base maps are done, the goal for PG&E is to bundle the underground projects in multi-year contracts with construction firms. This will help drive down construction costs and provide for stable project schedules. PG&E recognizes that there may be a greater need to underground utilities in the future. In coordination with our construction standards team, PG&E is exploring ways to improve underground construction. Two ideas to bring efficiencies to underground construction include:

- Looking into innovative methods to backfill trenches that will reduce trucking emissions, reduce cost, and reduce schedule time.
- Piloting an underground project in the North Complex Fire rebuild to install a single-phase cable-in-duct to help drive down the cost of underground construction while maintaining quality, improving reliability and reducing system risk.

Finally, PG&E is working with the Edison Electric Institute and recently launched a disaster rebuild benchmarking survey to share best practices with other utilities on how to strategically rebuild after a major disaster. Once PG&E has evaluated the results of the survey, we may incorporate other new items into our long-term planning.